Real-time reservoir management is an emerging concept in the exploration and production (E&P) industry. However, there are numerous definitions of real-time reservoir management, which reflects the fact that there have been many attempts to implement it. In this article, Fikri Kuchuk, Andrew Carnegie, and Mahmut Sengul define the scope and processes of real-time reservoir management and explore its significance to the various disciplines within E&P.
Imagine an oil field where a few multi-skilled geoscientists and engineers control every aspect of development and production from a control room or iCenter™ immersive visualization systems. When presented with a continuous stream of reservoir, well, facilities, and pipeline information, these geoscientists and engineers have automated systems to analyze the data, helping them to formulate effective responses to changing surface and subsurface conditions, and the means to implement these responses in real-time. The emerging technology allows them to respond quickly to economic factors and increase or reduce production rates from individual wells to reflect changing quotas or market conditions. And they are doing all of this from offices hundreds or thousands of kilometers from the reservoir (Figure 4.1). A few years ago this might have been just a dream, but recent technological advances and closer cooperation between oilfield disciplines are near to making it a reality. Field optimization will drive the future development of oil fields, and this article focuses on a key part of this process—reservoir optimization.

Effective real-time reservoir management will require development in at least five key areas:
- **Surface monitoring**
- **Permanent downhole monitoring**
- **Decision making**
- **Modeling**
- **Reservoir management**

**Figure 4.1:** Asset managers need to respond quickly to changing reservoir or economic conditions so that they can increase or reduce production rates from individual wells to meet their technical and business objectives.

**Figure 4.2:** Technical, logistical, and economic issues all influence the complex decision-making process that is reservoir management.

**Smaller teams—bigger responsibilities**

Reorganization during the 1980s and 1990s reduced employee numbers in many oil and gas companies. However, oil and gas consumption has grown by about 2% per year during the last two decades, but oilfield employment has remained almost constant, or has even decreased slightly during this time. Downsizing, combined with the retirement of those in senior positions, means that today’s upstream industry is lean in terms of an experienced, professional workforce. However, some companies have overcome this challenge by using new technologies that allow them to find and produce hydrocarbons at lower cost and with fewer people. Real-time reservoir management has the potential to take this process a stage further and enable the industry to maximize efficiency and increase revenues.

Any system that delivers true, real-time reservoir management and control must combine all the relevant disciplines, encourage greater cooperation, and increase the efficiency of data utilization and sharing. Continuing improvements in computer processing power and greater connectivity between remote locations are critical to the development of modern reservoir-management processes.

Reservoir management is a complex decision-making process that is influenced by technical, logistical, health, safety, environmental, and economic issues (Figure 4.2). Planning is probably the most important aspect of reservoir management. Successful planning defines the problem and develops possible solutions, but it also involves setting the objectives and limits, such as production targets and budgets, that will influence the project.

The first priority for geoscientists and engineers is to identify and evaluate the factors that control the flow of oil, gas, and water in the reservoir and, sometimes, fractured and faulted rocks that comprise their reservoirs. This involves understanding the physical controls and the combined effects of capillarity, gravity, and rock heterogeneity, as well as the chemical reactions and phase changes associated with multiphase flow conditions. The technical challenges include modeling pore-scale processes, the complex heterogeneities encountered in some reservoirs, and microscopic flow instabilities; and conducting large-scale modeling of enhanced oil recovery.

Once the reservoir has been reasonably characterized and modeled, the asset team can begin to predict how possible modifications to production field development strategies would affect hydrocarbon production rates and recovery. These predictions cannot be made against logistical and economic constraints. The team must also determine the safe design limits for pipelines and other production facilities. This is an important task, particularly when planning how to deal with health and safety hazards, or when designing expensive one-off facilities such as those associated with deepwater developments. The design of production facilities involves being able to confidently predict and then handle events, such as asphaltenes, waxes, and hydrogen sulfide. More importantly, the design process must establish how to handle ever increasing levels of water production. Production scenarios are obtained from the reservoir model, which, in turn, must be based upon a thorough and accurate understanding of the fluid compositions and the rock chemistry.

**Better models—better results**

Modern reservoir models provide the fundamental framework for reservoir management and a flexible logistical tool. But, establishing static (rock-related) and dynamic (flow-related) reservoir properties (Figure 4.3) is only one stage in a process designed to maximize production and recovery rates. Once the team of geoscientists has established the static reservoir description, the discipline of reservoir engineering usually assumes the lead responsibility for the next stage of modeling (but it must be noted that all the geoscience disciplines remain part of the team). The role of the reservoir engineer involves monitoring changes in key physical reservoir parameters, assessing how proposed development and production strategies will affect the field, and implementing...
the necessary changes to optimize field performance. Until recently, these steps were conducted intermittently and the time between the initial data gathering and the implementation of the approved changes was generally measured in months.

The various disciplines involved in reservoir characterization were based in different departments; there was little interaction between them, and they often had slightly different business objectives. For example, geologists created maps of the asset and passed them to the reservoir department. This was effectively a one-way transfer; the geologists were never informed of the drastic changes that reservoir engineers might make to fit the map to the production data. The drilling department was often responsible for the testing of exploration wells, and drilling priorities or production issues determined how well tests were performed and their duration. Thus meant that tests were conducted with little consideration of the wider issues of reservoir characterization such as fault boundaries and aquifers.

The delays and lost production associated with these methods led to the emergence of an asset-team approach, where specialists from different departments work in close association on a particular field asset. Asset teams have investigated new technology and new ways to use existing technology. This has greatly reduced the time between data gathering and intervention (Figure 4.4). The world’s leading oil companies now organize their experts into multidisciplinary teams. Interaction between the various disciplines is well established but, until recently, this was generally achieved without a formal framework for data sharing.

Over the past decade, the industry has focused its research and development efforts on the issues surrounding the static aspects of reservoir characterization. The introduction of 3D seismic surveys has helped companies to make significant progress in 3D reservoir modeling, but merging the static and dynamic features of a reservoir—to provide the vital link between earth science and production engineering—has not yet well established.

**Measuring dynamic properties**

The modern E&P industry combines time-lapse surface and borehole seismic monitoring, directional drilling, permanent downhole monitoring, advanced well completions, fiber-optic sensor technology, data management, Internet technology, and shared earth models to extract and share details about the structure, fluid content, and production capacity of oil and gas fields.

Time-lapse seismic methods can be used to monitor injected fluid fronts, locate bypassed oil, map pressure compartmentalization and pressure changes, and establish the sealing properties of faults. High-resolution, time-lapse seismic monitoring has been conducted in the borehole, in both vertical seismic profile and cross-well geometries. Multicomponent seismic receivers can be installed for little more cost than acoustic sensors. The additional information gained from the shear wave data obtained could help the reservoir engineer to monitor pressure fronts, in-situ stress, and fracturing.

Similarly, newly emerging deep resistivity measurements, acquired using tools available from Schlumberger and run on wireline into a wellbore, can now monitor water fronts several hundreds of meters into the reservoir. Downhole instrumentation and borehole technology have developed rapidly over the past few years. Downhole sensors can now measure key reservoir variables such as pressure, temperature, and oil saturation. When permanently installed, these sensors can deliver continuous data streams to surface control centers using dedicated fiber-optic links. When linked to advanced completion technology, downhole sensors can help to optimize the drainage of multiple reservoir targets by measuring flow rates and pressure during production, and can also help in modifying completion parameters in an effort to maximize recovery, optimize production, and minimize unwanted gas and water production.

**The rise of visualization**

Before the mid-1980s, interest in numerical reservoir modeling was limited. Engineering teams used numerical simulation to create models that estimated and predicted reservoir behavior in a simplistic way. This generally involved setting up a 4D numerical simulation model and adjusting its parameters by history-matching production pressure and water-cut data that are normally 2D (3D spatially and 1D temporally). This incompatibility created a long and arduous history-matching process that was carried out by specialists and often resulted in unrealistic parameter distributions and production predictions. A major problem with this was one of nonuniqueness—the reservoir model created through history-matching could often be one of several plausible models, all of which could satisfy the historical performance of the field in the simulator. This presented a major problem—understanding the uncertainties associated with history-matching models.

Unfortunately, this meant that predictions about reservoir behavior could be extremely inaccurate. This approach also encouraged those responsible for assets to downgrade the value of the measurements made at the reservoir. For example, some operators would question the value of acquiring core permeabilities because these would be changed drastically during the history-matching process. During the mid-1980s, the concept of reservoir description was introduced to provide a realistic framework for history-matching. Although field measurements were used to constrain the simulations, and to reduce the problems associated with nonuniqueness, they did not provide a consistent methodology or any of the benefits of modern techniques such as 3D reservoir modeling.

**A better view**

The introduction of large collaborative and immersive visualization systems has had a major impact on the upstream industry. Visualization was a vital part of E&P activities long before computers became commonplace, but then it was carried out on paper, with visualization being achieved using bar charts, graphs, well logs, and seismic sections. Once computer technology had been introduced, there was a rapid increase in the use and value of visualization. However, it took time to develop visualization tools (charts, graphs, etc.) for computer applications. At first, everything remained on paper or was presented in a paper-like format on small computer screens. Over the past three to five years, computer-generated displays have undergone dramatic improvements in resolution, physical size, and interactivity, particularly since the introduction of 3D seismic data. And the upstream sector is benefiting as a result.

The emergence of virtual-reality systems has taken the trend even further. Being able to interpret huge volumes of seismic, drilling, and reservoir data, and then project the resulting 3D images of geological structures onto an immersive,
A 4D seismic monitoring project involves repeating 3D seismic surveys for a field, or its subsection, after a given period. The results from these surveys help the asset team to monitor fluid movement over time. The images produced by 4D seismic monitoring help to identify fluid flow and reveal spatial and temporal variations in fluid saturation and possible pressure and temperature changes. The most important applications include mapping bypassed oil; monitoring injected reservoir fluids such as water, steam, gas, and carbon dioxide; studying the effect that production and/or injection has upon pressure throughout the field; estimating the fluid-flow variations related to pressure compartmentalization; and assessing the hydraulic properties of faults and fractures (Figure 4.6).

Monitoring fluid flow with 4D seismic techniques requires close collaboration between the disciplines of structural and stratigraphic geology, fluid-flow simulation, rock physics, and seismology. Seismic reservoir monitoring can significantly help to understand recovery in new and existing fields by helping the asset team to monitor and predict the interwell positions and the movement of reservoir fluids. Fluid monitoring helps the team to locate bypassed oil, avoid premature water breakthrough, optimize infill well locations, and evaluate enhanced-oil-recovery pilots before full-field implementation.

**Modeling for management**

Reservoir management is based on a series of decisions that enables oil and gas companies to meet their technical and business objectives (Figure 4.7). The process requires an accurate model of the reservoir system and the ability to predict the consequences of implementing possible, alternative strategies.

Reservoir characterization, a vital part of the model creation process, involves generating an editable, mathematical subsurface model. The model is calibrated to reproduce the past, observed dynamic performance of the reservoir, and is expected to be able to predict future performance. Since the objective in making predictions is to optimize production, it may be necessary to take surface processing facilities into account. The calibration process does not necessarily provide a unique solution, but the level of uncertainty can be reduced by increasing the amount and range of information incorporated into the model and by verifying that the selected model is consistent with all the available data.

Reservoir characterization is a continuous process that must be updated as new information is gathered from the asset. For simplicity, it may be considered to be divided into three major consecutive steps:

1. Generate data interpretations for each technical discipline.
2. Integrate these interpretations into a model of the reservoir.
3. History-match this model. Generally, the models in steps 2 and 3 are grid based, i.e., the reservoir (structure, rock fabric, and fluids) is represented by a set of cells. The models created as part of step 2 are called geocellular models and do not generally have the capability to simulate fluid flow. Thus, takes place as part of step 3—the geocellular models of step 2 are transformed into the flow simulation models in step 3. The cells in geocellular models are generally at a finer scale (i.e., smaller) than those in the equivalent flow simulation model. Hence, a process known as upscaling is required to convert the properties from geocellular models into those in simulation models. The process involves two consecutive steps: generating data interpretations for each technical discipline and integrating these interpretations into the reservoir model.

**Combining data**

Asset team members may generate their own data interpretations, but they usually use in-house experts, consultants, and/or service companies. The interpretation process may differ drastically from one company to another and may depend on the importance of the field. In any case, these data will typically include static data (geology, geophysics, geochemistry, and petrophysics) that correspond to a description of the reservoir's shape and structure, and dynamic data (fluids, geomechanics, tracers, production logs, well tests, and production) that relate to reservoir behavior.

Data interpretations use widely varying scales and resolutions (surface seismic interpretations are measured in meters, while core samples are measured in millimeters) and reveal different aspects of the formation and the reservoir and its behavior. Geophysical data modeling, for example, reveals acoustic impedance contrasts, whereas pressure transient data at different scales (from wireline formation testing to conventional buildup testing) primarily identify mobility and storativity contrasts. Understanding the significance of such diverse information and measurements requires cooperation across the asset team as well as the involvement of many other professionals.

**Transferring data into the**
cellular reservoir model

The asset team can incorporate direct and interpreted data into the reservoir model using deterministic or stochastic methods. A stochastic approach allows the team to integrate knowledge from different data interpretations (a process known as conditioning) while taking into account the different levels of reliability (uncertainty) associated with each interpretation. Stochastic modeling provides multiple, equiprobable 3D realizations of the reservoir model that can then be used to explore, and perhaps even quantify, the effects of the uncertainty about various aspects of the reservoir characterization on the predicted performance of the field (Figure 4.8).

Stochastic techniques are most useful where data are sparse, typically during the early stages of field development, and/or when significant heterogeneities such as thin, high-permeability streaks are at a smaller scale than those of the available measurements. Deterministic techniques are more appropriate for fields with high data density—those with lots of wells and years of production information (though stochastic modeling is still useful for evaluating the level of uncertainty in an established reservoir model).

Validation, history-matching, flow simulation

Once the team has completed its reservoir description, it must ensure consistency with all the available information and data interpretations. This process is known as validation. The model must honor all of the data that were used in the characterization process—seismic, log, well, and production-test data if available. If the reservoir model is consistent with the available information and the data interpretations, the correlation between the field data and the model responses is normally good and, therefore, relatively simple to improve by adjusting the reservoir model parameters within the limits imposed by available knowledge. This is history-matching.

The numerical simulations used to evaluate production behavior add a further complication to reservoir management. The grids applied in numerical simulators are coarser than those in the reservoir model. Consequently, the asset team must upscale the model data before it can examine model behavior (Figure 4.9). Though essential, the upscaling process introduces errors that affect model verification.

Figure 4.9: Model data must be upcaled before an asset team can examine model behavior, as the grids applied in numerical simulators are coarser than those used in the reservoir model.

Measure to manage

Surface monitoring of wells has been routine since the oil and gas industries were in their infancy. For commercial and material balance reasons, oil companies have always needed to know the volumes of produced fluids. Through the early decades of the twentieth century, engineers and geoscientists came to realize how complex the subsurface environment could be and began to extract information about reservoir rocks and fluids in situ. Downhole data gathering started with electrical coring to characterize producing formations (Figure 4.10). Service companies emerged to conduct these specialized tasks and, over the years, have improved and extended their technology, thus providing the operating companies with better information about their vital hydrocarbon assets (Figure 4.11).

For example, the CHDT™ Cased Hole Dynamics Tester drills through casing with electrical coring to characterize producing formations was the start of downhole operations.

Modern logging can deliver precise information on fluid content and movement, and the latest sampling methods can retrieve formation fluid samples from behind casing.

Figure 4.10: Electrical coring to characterize producing formations was the start of downhole operations.
A permanent solution

The first permanent downhole gauges were installed during the 1970s (Figure 4.12). These early systems were often hindered by poor reliability, but the benefits of continuous monitoring encouraged the pioneers to overcome these problems. Since the early 1980s, permanent reservoir-monitoring systems (mainly pressure gauges) have been installed in a number of reservoirs around the world. The principal aims of successful downhole monitoring are to improve asset management and optimize production through the acquisition, management, and interpretation of a continuous stream of real-time data. The key requirements for a successful downhole monitoring system are good reliability and durability, and the design flexibility to meet the operator’s requirements.

Downhole monitoring sensors are deployed in extremely hostile and demanding environments. The challenges include high temperature and pressure, and harsh chemical and physical conditions (Figure 4.13). Consequently, reliable transducer technology is essential. Conventional electronic gauge technology has been deployed successfully in a range of downhole monitoring applications, predominantly in wireline-retrievable systems, but also, more recently, for permanent reservoir monitoring. Unfortunately, electronic systems have inherent limitations that render downhole applications particularly challenging, for example, electronic systems are less reliable at high temperatures. Today, fiber-optic technology is becoming an important part of the reservoir-monitoring toolbox. The advanced sensor systems developed by companies such as Sensa have applications across the oil and gas industries where, through downhole monitoring, they are helping to change the way reservoirs are developed and managed.

Downhole fluid measurements

Flow-rate and multiphase meters for downhole use will be vital elements of the real-time reservoir-management strategy, but are still in the early stages of development. Useful information on downhole flow rates and fluid compositions can be inferred from downhole temperature and pressure measurements in combination with surface measurements. For example, downhole production logging using the PS Platform™ new-generation production services platform in combination with PhaseTester™ multiphase well testing equipment at the surface has proved effective for multiphase flow characterization and production rates (Figure 4.14). Downhole electrically or hydraulically actuated control valves allow engineers to determine flow rates from individual well intervals by closing all other intervals and measuring flow at the surface (Figure 4.15).

Reliable? You can depend on it

When a permanently installed downhole gauge stops working, reservoir engineers lose their window on the reservoir. It is vital, therefore, that gauges remain operational throughout their planned working life. Over the past decade, Schlumberger has focused on improvements in engineering and testing processes, system design, risk analysis, training, and installation procedures to enhance the reliability of its permanent monitoring systems.

The development of a permanent gauge system follows a sequence of engineering operations, with dependability being paramount during each stage. The engineering sequence begins with a careful description of the technical concept that sets out possible applications for the gauge. This serves as a framework and defines the role of each component and the environmental conditions that it will encounter during its expected lifetime. System components are generally tested and qualified to withstand the expected conditions. Accelerated destructive tests subject the components to conditions that are more extreme than those expected in service, such as greater mechanical shocks and vibrations, and higher-than-downhole temperatures and pressures. This type of testing helps to determine the causes and modes of failure. Long-term testing of the system enables engineers to validate reliability models and quantify measurement stability. Feedback from field engineers is a vital input to all laboratory-testing methods.

Innovation in action

Technical innovation has been the key to recent improvements in reservoir management. The Schlumberger portfolio of products geared to achieving optimum reservoir life and reservoir production has expanded dramatically in recent years; for example, WellWatcher®, FloWatcher, and PumpWatcher™ monitoring systems are operating successfully in some of the world’s most demanding reservoirs (Figure 4.16). Saturation monitoring is a crucial part of reservoir management. In
the past, engineers relied on pulsed neutron methods—such as that implemented with the RST* Reservoir Saturation Tool—to assess fluid type (oil, water, or gas) and its associated saturation through casing. The relatively shallow readings achieved with the RST tool mean that near-wellbores effects such as poor cement and residual acid from stimulation jobs may severely affect the reading. However, the CHFR* Cased Hole Formation Resistivity tool reads deeper into the formation and is little affected by the near-wellbore environment. Its measurements are often much closer to those obtained from openhole logging (Figure 4.17).

Despite increasing interest in the new gauges, very few of the world’s oil and gas wells have continuous downhole monitoring. Many wells have been allowed to produce for years without checking how production has modified the reservoir around the well—this is all right while the well is producing at a reasonable rate with a low water cut. But it can be very difficult to establish the cause and even harder to select the most appropriate remedial action when a problem occurs.

The few wells that do have monitoring systems generate a wealth of data. Changing pressure–volume–temperature conditions and flow rates can be measured every few hours, minutes, or seconds, depending on the needs of the reservoir management. Special software packages have been developed to manage the flow of data from downhole gauges and to pass these data around the world using secure Internet and intranet connections. Once the data have been distributed, the asset team can get to work on the needs of the reservoir.

Cross-well electromagnetic technology

Cross-well electromagnetic technology is an emerging method that promises to revolutionize the industry’s understanding of what goes on between wells (Figure 4.18). Scientists and engineers at Electromagnetic Instruments Inc., a Schlumberger company based in California, USA, have been working on the technique for more than a decade to develop deep-reaching, electromagnetic borehole sensors that can produce 3D resistivity images on a reservoir scale. At present, there are two options; both are conveyed using conventional electric wireline and can be customized to suit specific requirements. The first system investigates large rock volumes around a single wellbore. This single-well logging tool can investigate rock for tens of meters around the borehole.

The second system images formation between adjacent wells. The vertical resolution of this cross-well system is approximately 5% of the well spacing. The volume of rock measured is much greater than can be achieved with conventional wireline technology. Cross-well electromagnetic technology can provide an interwell resistivity distribution and so map water saturation and reservoir structure between wells. By mapping resistivity, engineers can identify faults and fractures; locate bypassed hydrocarbon zones, and monitor water, steam, and polymer flooding operations. This wealth of subsurface information allows asset teams to make better decisions about their reservoirs.

The cross-well technique has been used for more than five years to image thermal oil-recovery operations (steamfloods) and, more recently, for reservoir waterflood monitoring. The resistivity contrast between the zone flooded with saline water and the hydrocarbon-filled pay zones usually provides an excellent electromagnetic signal.

Cross-well electromagnetic technology promises to revolutionize the industry’s understanding of what goes on between wells.
Waterflood monitoring in Oman

In 1998, Shell and Schlumberger launched a joint project to prove the feasibility and value of dynamic reservoir-drainage imaging (DRDI). The aim was to develop time-lapse monitoring of water saturation that would allow engineers to evaluate drainage efficiency in reservoirs. The method selected was resistivity monitoring. The development team applied this technique by cementing in an array of electrodes at reservoir level to provide continuous measurement of formation resistivity. In 1999, a field test was set up with Petroleum Development Oman to demonstrate the technology and to evaluate the value of data gathered at Fahud field, Oman.

The DRDI installation for the test program was located at the center of a waterflooding cell between dual horizontal injectors and producers (Figure 4.19). Two resistivity arrays were deployed behind casing and across the reservoir zone. The monitoring period was estimated at around 18 months. Readings were taken at regular intervals from late 1999 until early 2000 to indicate the water-saturation variations at several depths (Figure 4.20). These data showed that the reservoir was being unevenly swept and that water breakthrough times were reduced. The findings were confirmed by production data, which indicated a rising water cut, and by a logging campaign, which indicated localized saturation increases.

Turning data into decisions

The production process involves a series of decisions on how to drain the reservoir efficiently. Efforts are usually focused on cash flow and maximizing revenues. Eventually, as the asset matures, production priorities change and, in the latter stages of field life, the team aims to maximize ultimate recovery and minimize operating expenditure.

Many oil companies are changing the way they develop and manage reservoirs. Identifying and implementing best practice helps a company to optimize initial field development so that revenues can be maximized and, in the latter stages of field life, the emphasis in oil and gas production is on maintaining low water cuts. The drive toward real-time reservoir management is a major opportunity for asset teams and reservoir engineers. New data sets such as well logs are not easily incorporated into reservoir models because of their expense and technical difficulty. New data sets such as well logs are not easily incorporated into reservoir models because of its expense and technical difficulty. New data sets such as well logs are not easily incorporated into reservoir models because of its expense and technical difficulty. New data sets such as well logs are not easily incorporated into reservoir models.

The value of real-time data provided by sensors installed within the well is becoming widely recognized. Downhole pressure, temperature, and flowmeters can be distributed within the well to provide the required resolution. These distributed measurements enable, for example, location of specific regions of high water production in a horizontal well. This ability to determine when and where intervention is needed is of critical importance. In addition to direct production monitoring, the tracking of distributed pressure, temperature, and multiphase flow measurements within a reservoir over time provides valuable input to the reservoir model. By increasing the fidelity of reservoir characterization, modern systems enable more effective management of the hydrocarbon reservoir.

Observation, evaluation, and planning are vital steps, but once the asset team has selected the best strategy it must be implemented across the field because of its expense and technical difficulty. New data sets such as well logs are not easily incorporated into reservoir models.

Intervention—making the changes

Today, production and reservoir engineers have an extensive range of production and drilling technologies, all designed to maximize production rates and boost recovery. These include gas-lift methods, electrical submersible pumps, horizontal drilling, and multilateral and intelligent completions. These solutions often create a complicated network of vertical, deviated, and horizontal wells that produce varying proportions of oil, water, and gas from multiple reservoir zones (Figure 4.21).

Modern technology allows asset teams to control fluid flow in the borehole, for example, by shutting off sections of a well when a particular zone is watered out, and increasing or reducing production on demand. In fields where this technology is applied in several wells, asset teams can set production rates and squeeze more oil and gas from the reservoir while maintaining low water cuts.

At present, monitoring of reservoir conditions is extremely sparse. Because of its expense and technical difficulty, new data sets such as well logs are not easily incorporated into reservoir models.

Performance with simulated behavior

They do this by generating cross-sectional and areal views of the reservoir. This approach is highly interpretative because information is only obtained at the wells and its reliability is reduced by the heterogeneous and anisotropic nature of most formations. The ability to visualize fluids between wells would clearly make it easier to locate bypassed hydrocarbon areas within the reservoir and reduce the risks in drilling and completing the wells designed to drain them.

Bringing it all together

The drive toward real-time reservoir management is a major opportunity for the industry—a chance to change the emphasis in oil and gas from a race to extract natural resources to a controlled process industry where production can be monitored and optimized. Oil companies that seize this opportunity will be transforming one of their core competencies—asset management. This, in turn, will help them generate additional growth.
establish important business advantages, and position themselves as technological leaders within the oil and gas sectors.

In establishing systems that will deliver real-time management, operating companies will have to rely on tested technology to create new asset-management team structures. These new asset teams will help companies reduce development capital needs, generate operating cost advantages, and improve recovery rates and yield.

Speed is of the essence

Real-time reservoir management will allow asset teams to identify quickly, and then capitalize on, opportunities to improve field productivity and efficiency. The new approach reduces cycle time, which allows the asset team to identify and rectify problems rapidly with less disruption to production. This approach also promotes rapid assessment of data that will modify the reservoir model, thus enabling the earth scientists to reach a better understanding of asset structure and reservoir engineers to make better-informed development decisions.

Achieving this will require the integration and modification of diverse technologies that give the asset team improved understanding of the day-by-day performance of the field and the means to assimilate this information and transform it into good business decisions. A cooperative approach, where operators work with key research and development companies, vendors and, even, other oil companies, will help to ensure that the technology is developed quickly and efficiently, and at a reasonable cost.

The result could be asset-management systems that link data from the reservoir, well, and facilities monitoring and sensing devices directly to the subsurface model (Figure 4.22). This approach would support asset team decisions and help to capture and retain each individual’s knowledge of the asset more effectively. The challenge is to integrate existing and emerging technologies and to modify work processes to take full advantage of these opportunities. In some parts of the industry, these changes are already taking place.

Better performance through the life of the field

There are generally four key stages in the development of an oil field:

1. exploration—reservoir structure and contents are being investigated, but are not well defined
2. delineation—the size and extent of the reservoir is being assessed
3. development—the reservoir is fairly well understood and production is rising toward peak level
4. maturity—the reservoir is well understood and its contents are changing as it is depleted

Every asset team faces several fundamental challenges at each stage of field development: accelerating production flow, achieving a greater return on investment, and extending the useful life of the reservoir (Figure 4.23).

These objectives are the main reasons for real-time reservoir management. Real-time technologies can be applied when the first well is drilled in a field. High-resolution 3D seismic surveys help to delineate the detailed structure of the field and provide the baseline for future monitoring of fluid movement.

Once the field has started to produce oil and gas, real-time reservoir management helps to maximize production, minimize operating expenditure, maximize recovery, and extend the productive life of the reservoir. These benefits rely, to a large extent, on the asset team’s ability to collect, process, and analyze large volumes of data and, crucially, to translate these analyses into corrective actions.

A major consequence of these trends will be that, in the future, a small team could handle the entire reservoir-management process. The team will use advanced software systems to integrate all the tasks of reservoir management in a transparent manner. This system will handle a continuous feed of automatically acquired data. The reservoir team will then be able to analyze these data, update the reservoir model, make predictions and recommendations, and implement the recommendations, subject to management approval.