1.4 Recent Advances in Reservoir Simulation

The recent advances in reservoir simulation may be viewed as:

- Speed and accuracy;
- New fluid flow equations;
- Coupled fluid flow and geo-mechanical stress model; and
- Fluid flow modeling under thermal stress.

1.4.1 Speed and Accuracy

The need for new equations in oil reservoirs arises mainly for fractured reservoirs as they constitute the largest departure from Darcy's flow behavior. Advances have been made in many fronts. As the speed of computers increased following Moore's law (doubling every 12 to 18 months), the memory also increased. For reservoir simulation studies, this translated into the use of higher accuracy through inclusion of higher order terms in Taylor series approximation as well as great number of grid blocks, reaching as many as a billion blocks. The greatest difficulty in this advancement is that the quality of input data did not improve at par with the speed and memory of the computers. As Fig. 1.3 shows, the data gap remains possibly the biggest challenge in describing a reservoir. Note that the inclusion of large number of grid blocks makes the prediction more arbitrary than that predicted by fewer blocks, if the number of input data points is not increased proportionately. The problem is particularly acute when fractured formation is being modeled. The problem of reservoir cores being smaller than the representative elemental volume (REV) is a difficult one, which is more accentuated for fractured formations that have a higher REV. For fractured formations, one is left with a narrow band of grid blocks, beyond which solutions are either meaningless (large grid blocks) or unstable (too small grid blocks). This point is elucidated in Fig. 1.4. Figure 1.4 also shows the difficulty associated with modeling with both too small or too large grid blocks. The problem is particularly acute when fractured formation is being modeled. The problem of reservoir cores being smaller than the representative elemental volume (REV) is a difficult one, which is more accentuated for fractured formations that have a higher REV. For fractured formations, one is left with a narrow band of grid blocks, beyond which

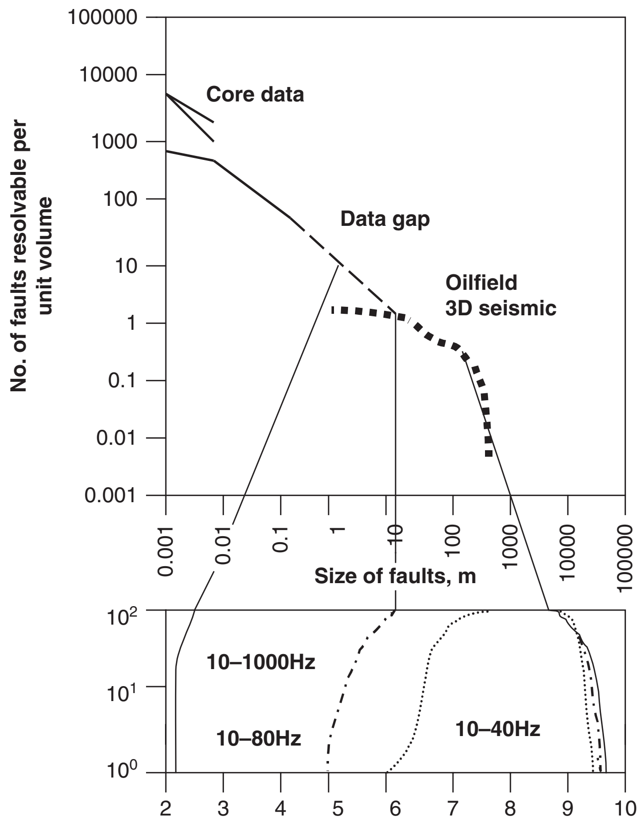

Figure 1.3 Data gap in geophysical modeling (after Islam, 2001).

solutions are either meaningless (large grid blocks) or unstable (too small grid blocks).

1.4.2 New Fluid Flow Equations

A porous medium can be defined as a multiphase material body (solid phase represented by solid grains of rock and void space represented by the pores between solid grains) characterized by two main features: that a Representative Elementary Volume (REV) can be determined for it, such that no matter where it is placed within a domain occupied by the porous medium, it will always contain both a persistent solid phase and a void space. The size of the REV is such that parameters that represent the distributions of the void space and the solid matrix within it are statistically meaningful.

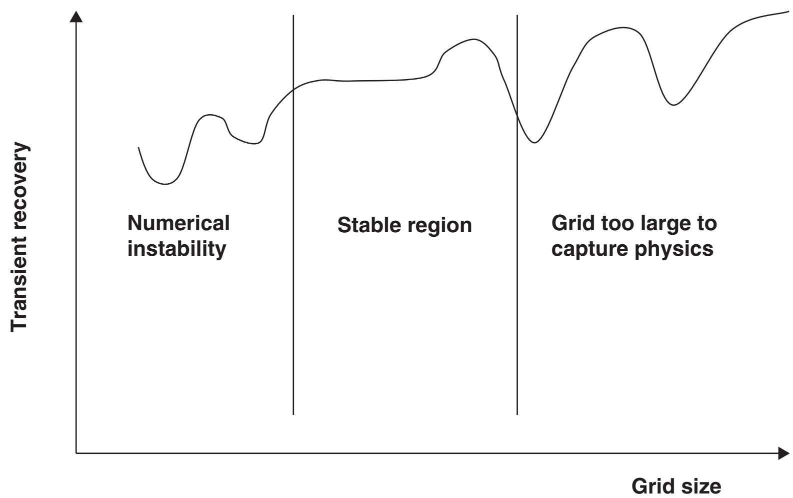

Figure 1.4 The problem with the finite difference approach has been the dependence on grid size and the loss of information due to scaling up (from Islam, 2002).

Theoretically, fluid flow in porous medium is understood as the flow of liquid or gas or both in a medium filled with small solid grains packed in homogeneous manner. The concept of heterogeneous porous medium then introduced to indicate properties change (mainly porosity and permeability) within that same solid grains packed system. An average estimation of properties in that system is an obvious solution, and the case is still simple.

Incorporating fluid flow model with a dynamic rock model during the depletion process with a satisfactory degree of accuracy is still difficult to attain from currently used reservoir simulators. Most conventional reservoir simulators do not couple stress changes and rock deformations with reservoir pressure during the course of production and do not include the effect of change of reservoir temperature during thermal or steam injection recoveries. The physical impact of these geo-mechanical aspects of reservoir behavior is neither trivial nor negligible. Pore reduction and/or pore collapse leads to abrupt compaction of reservoir rock, which in turn cause miscalculations of ultimate recoveries, damage to permeability and reduction to flow rates and subsidence at the ground and well casings damage. In addition, there are many reported environmental impacts due to the withdrawal of fluids from underground reservoirs.

Using only Darcy's law to describe hydrocarbon fluid behavior in petroleum reservoirs when high gas flow rate is expected or when encountered in an highly fractured reservoir is totally misleading. Nguyen (1986) has showed that using standard Darcy flow analysis in some circumstances can over-predict the productivity by as much as 100 percent.

Fracture can be defined as any discontinuity in a solid material. In geological terms, a fracture is any planar or curvy-planar discontinuity that has formed as a result of a process of brittle deformation in the earth's crust. Planes of weakness in rock respond to changing stresses in the earth's crust by fracturing in one or more different ways depending on the direction of the maximum stress and the rock type. A fracture can be said to consist of two rock surfaces, with irregular shapes, which are more or less in contact with each other. The volume between the surfaces is the fracture void. The fracture void geometry is related in various ways to several fracture properties. Fluid movement in a fractured rock depends on discontinuities, at a variety of scales ranging from micro-cracks to faults (in length and width). Fundamentally, describing flow through fractured rock involves describing physical attributes of the fractures: fracture spacing, fracture area, fracture aperture and fracture orientation and whether these parameters allow percolation of fluid through the rock mass. Fracture parameters also influence the anisotropy and heterogeneity of flow through fractured rock. Thus the conductivity of a rock mass depends on the entire network within the particular rock mass and is thus governed by the connectivity of the network and the conductivity of the single fracture. The total conductivity of a rock mass depends also on the contribution of matrix conductivity at the same time.

A fractured porous medium is defined as a portion of space in which the void space is composed of two parts: an interconnected network of fractures and blocks of porous medium, the entire space within the medium is occupied by one or more fluids. Such a domain can be treated as a single continuum, provided an appropriate REV can be found for it.

The fundamental question to be answered in modeling fracture flow is the validity of the governing equations used. The conventional approach involves the use of dual-porosity, dual permeability models for simulating flow through fractures. Choi et al (1997) demonstrated that the conventional use of Darcy's law in both fracture and matrix of the fractured system is not adequate.

Instead, they proposed the use of the Forchheimer model in the fracture while maintaining Darcy's law in the matrix. Their work, however, was limited to single-phase flow. In future, the present status of this work can be extended to a multiphase system. It is anticipated that gas reservoirs will be suitable candidates for using Forchheimer extension of the momentum balance equation, rather than the conventional Darcy's law. Similar to what was done for the liquid system (Cheema and Islam, 1995); opportunities exist in conducting experiments with gas as well as multiphase fluids in order to validate the numerical models. It may be noted that in recent years several dual-porosity, dual-permeability models have been proposed based on experimental observations (Tidwell and Robert, 1995; Saghir et al, 2001).

1.4.3 Coupled Fluid Flow and Geo-mechanical Stress Model

Coupling different flow equations has always been a challenge in reservoir simulators. In this context, Pedrosa et al (1986) introduced the framework of hybrid grid modeling. Even though this work was related to coupling cylindrical and Cartesian grid blocks, it was used as a basis for coupling various fluid flow models (Islam and Chakma, 1990; Islam, 1990). Coupling flow equations in order to describe fluid flow in a setting, for which both pipe flow and porous media flow prevail continues to be a challenge (Mustafiz et al, 2005).

Geomechanical stresses are very important in production schemes. However, due to strong seepage flow, disintegration of formation occurs and sand is carried towards the well opening. The most common practice to prevent accumulation as followed by the industry is to take filter measures, such as liners and gravel packs. Generally, such measures are very expensive to use and often, due to plugging of the liners, the cost increases to maintain the same level of production. In recent years, there have been studies in various categories of well completion including modeling of coupled fluid flow and mechanical deformation of medium (Vaziri et al, 2002). Vaziri et al (2002) used a finite element analysis developing a modified form of the Mohr–Coulomb failure envelope to simulate both tensile and shear-induced failure around deep wellbores in oil and gas reservoirs. The coupled model was useful in predicting the onset and quantity of sanding. Nouri et al (2006) highlighted the experimental part of it in addition to a numerical analysis and measured the severity of sanding in terms of rate and duration. It should be noted that these studies (Nouri et al, 2002; Vaziri et al, 2002 and Nouri et al, 2006) took into account the elasto-plastic stress-strain relationship with strain softening to capture sand production in a more realistic manner. Although, at present these studies lack validation with field data, they offer significant insight into the mechanism of sanding and have potential in smart-designing of well-completions and operational conditions.

Recently, Settari et al (2006) applied numerical techniques to calculate subsidence induced by gas production in the North Adriatic. Due to the complexity of the reservoir and compaction mechanisms, Settari (2006) took a combined approach of reservoir and geo-mechanical simulators in modeling subsidence. As well, an extensive validation of the modeling techniques was undertaken, including the level of coupling between the fluid flow and geo-mechanical solution. The researchers found that a fully coupled solution had an impact only on the aquifer area, and an explicitly coupled technique was good enough to give accurate results. On grid issues, the preferred approach was to use compatible grids in the reservoir domain and to extend that mesh to geo-mechanical modeling. However, it was also noted that the grids generated for reservoir simulation are often not suitable for coupled models and require modification.

In fields, on several instances, subsidence delay has been noticed and related to over consolidation, which is also termed as the threshold effect (Merle et al, 1976; Hettema et al, 2002). Settari et al (2006) used the numerical modeling techniques to explore the effects of small levels of over-consolidation in one of their studied fields on the onset of subsidence and the areal extent of the resulting subsidence bowl. The same framework that Settari et al (2006) used can be introduced in coupling the multiphase, compositional simulator and the geo-mechanical simulator in future.

1.4.4 Fluid Flow Modeling Under Thermal Stress

The temperature changes in the rock can induce thermo-elastic stresses (Hojka et al, 1993), which can either create new fractures or can alter the shapes of existing fractures, changing the nature of the primary mode of production. It can be noted that the thermal stress occurs as a result of the difference in temperature between injected fluids and reservoir fluids or due to the Joule Thompson effect. However, in the study with unconsolidated sand, the thermal stresses are reported to be negligible in comparison to the mechanical stresses (Chalaturnyk and Scott, 1995). A similar trend is noticeable in the work by Chen et al (1995), which also ignored the effect of thermal stresses, even though a simultaneous modeling of fluid flow and geomechanics is proposed.

Most of the past research has been focused only on thermal recovery of heavy oil. Modeling subsidence under thermal recovery technique (Tortike and Farouq Ali, 1987) was one of the early attempts that considered both thermal and mechanical stresses in their formulation. There are only few investigations that attempted to capture the onset and propagation of fractures under thermal stress. Recently, Zekri et al (2006) investigated the effects of thermal shock on fractured core permeability of carbonate formations of UAE reservoirs by conducting a series of experiments. Also, the stress-strain relationship due to thermal shocks was noted. Apart from experimental observations, there is also the scope to perform numerical simulations to determine the impact of thermal stress in various categories, such as water injection, gas injection/production etc. More recently, Hossain et al (2009) showed that new mathematical models must be introduced in order to include thermal effects combined with fluid memory.

1.5 Future Challenges in Reservoir Simulation

The future development in reservoir modeling may be looked at different aspects. These are may be classified as:

- Experimental challenges;
- Numerical Challenges; and
- Remote sensing and real-time monitoring.

1.5.1 Experimental Challenges

The need of well designed experimental work in order to improve the quality of reservoir simulators cannot be over-emphasized. Most significant challenges in experimental design arise from determining rock and fluid properties. Eventhough progress has been made in terms of specialized core analysis and PVT measurements, numerous problems persist due to difficulties associated with sampling techniques and core integrity. Recently, Belhaj et al (2006) used a 3-D spot gas pearmeameter to measure permeability at any spot on the surface of the sample, regardless of the shape and size. Moreover, a mathematical model was derived to describe the flow pattern associated with measuring permeability using the novel device.

In a reservoir simulation study, all relevant thermal properties including coefficient of thermal expansion, porosity variation with temperature, and thermal conductivity need to be measured in case such information are not available. Experimental facilities e.g., double diffusive measurements, transient rock properties; point permeability measurements can be very important in fulfilling the task. In this regard, the work of Belhaj et al (2006) is noteworthy.

In order to measure the extent of 3-D thermal stress, a model experiment is useful to obtain temperature distribution in carbonate rock formation in the presence of a heat source. Examples include microwave heating water-saturated carbonate slabs in order to model only conduction and radiation. An extension to the tests can be carried out to model thermal stress induced by cold fluid injection for which convection is activated. The extent of fracture initiation and propagation can be measured in terms of so-called damage parameter. Time-dependent crack growth still is an elusive topic in petroleum applications (Kim and van Stone, 1995). The methodology outlined by Yin and Liu (1994) can be considered to measure fracture growth. The mathematical model can be developed following the numerical method developed by Wang and Maguid (1995). Young's modulus, compressive strength, and fracture toughness are important for modeling the onset and propagation of induced fracture for the selected reservoir. Incidentally, the same set of data is also useful for designing hydraulic fracturing jobs (Rahim and Holditch, 1995).

The most relevant application of double diffusive phenomena, involving thermal and solutal transfer is in the area of vapor-extraction (VAPEX) of heavy oil and tar sands. From the early work of Roger Butler, numerous experimental studies have been reported. Some of the latest ones are reported by the research group of Gu at Petroleum Technology Research Centre (PTRC) in Canada. Despite making great advances (e.g. Yang and Gu, 2005; Tharanivasan et al, 2004), proper characterization of such complex phenomena continues to be a formidable challenge.

1.5.2 Numerical Challenges

1.5.2.1 Theory of Onset and Propagation of Fractures Due to Thermal Stress

Fundamental work needs to be performed in order to develop relevant equations for thermal stresses. Similar work has been initiated by Wilkinson et al (1997), who used finite element modeling to solve the problem. There has been some progress in the design of material manufacturing for which in situ fractures and cracks are considered to be fatal flaws. Therefore, formulation of complete equations is required in order to model thermal stress and its effect in petroleum reservoirs. It is to be noted that this theory deals with only the transient state of the reservoir rock.

1.5.2.2 2-D and 3-D Solutions of the Governing Equations

In order to determine fracture width, orientation, and length under thermal stresses as a function of time, it is imperative to solve the governing equations first in 2-D. The finite difference is the most accepted technique to develop the simulator. An extension of the developed simulator to the cylindrical system is useful in designing hydraulic fractures in thermally active reservoirs. The 3-D solutions are required to determine 3-D stresses and the effects of permeability tensor. Such simulation will provide one with the flexibility of determining fracture orientation in the 3-D model and guide as a design tool for hydraulic fracturing. Although the 3-D version of the hydraulic fracturing model can be in the framework put forward earlier (Wilkinson et al, 1997), differences of opinion exist as to how thermal stress can be added to the in situ stress equations.

1.5.2.3 Viscous Fingering During Miscible Displacement

Viscous fingering is believed to be dominant in both miscible and immiscible flooding and of much importance in a number of practical areas including secondary and tertiary oil recovery. However, modeling viscous fingering remains a formidable task. Only recently, researchers from Shell have attempted to model viscous fingering with the chaos theory. Islam (1993) has reported in a series of publications that periodic and even chaotic flow can be captured properly by solving the governing partial differential equations with improved accuracy (Δx^4, Δt^2). This needs to be demonstrated for viscous fingering. The tracking of chaos (and hence viscous fingering) in a miscible displacement system can be further enhanced by studying phenomena that onset fingering in a reservoir. It eventually will lead to developing operating conditions that would avoid or minimize viscous fingering. Naami et al (1999) conducted both experimental and numerical modeling of viscous fingering in a 2-D system. They modeled both the onset and propagation of fingers by solving governing partial differential equations. Recent advances in numerical schemes (Aboudheir et al, 1999; Bokhari and Islam, 2005) can be suitably applied in modeling of viscous fingering. The scheme proposed by Bokhari and Islam (2005) is accurate in the order of Δx^4 in space and Δt^2 in time. Similar approaches can be extended for tests in a 3-D system in future. Modeling viscous fingering using finite element approach has been attempted as well (Saghir et al, 2000).

1.5.2.4 Improvement in Remote Sensing and Monitoring Ability

It is true that there is skepticism about the growing pace of applying 4-D seismic for enhanced monitoring (Feature-*First break*, 1997), yet the advancement in the last decade assures that the on-line monitoring of reservoirs is not an unrealistic dream (Islam, 2001). Strenedes (1995) reported that the average recovery factor from all the fields in the Norwegian sector increased from 34–39% over 2–3 years, due to enhanced monitoring. The needs for an improved technique was also emphasized to face the challenges of declining production in North Sea.

One of the most coveted features in present reservoir studies is to develop advanced technologies for real-time data transmission for both down-hole and wellhead purposes (chemical analysis of oil, gas, water, and solid) from any desired location. This research can lead to conducting real-time control of various operations in all locations, such as in the wellbore, production string and pipelines remotely. However, a number of problems need to be addressed to make advances in remote sensing and monitoring.

1.5.2.5 Improvement in Data Processing Techniques

The first stage of data collection follows immediate processing. Even though great deal of care is taken for collection of rock and fluid samples, the importance of improving data processing technique is seldom felt. Of course, errors in core data may enter due to measurement errors in the laboratory and/or during sample collection, but the most important source of error lies within processing the data.

Data can be from fluid analysis (e.g. PVT), core analysis, geophone data, real-time monitoring data, wellhead data, or others. Great difficulties arise immediately, as practically all processors are linear. Recently, Panawalage et al (2004a, 2004b) showed how non-linear modeling can be used to reverse absolute permeability information from raw data. This work has been advanced further to permeability tensor by Mousavizadegan et al (2006a, 2006b). Even though great advances have been made in laboratory measurements of permeability data and the possibility of in situ permeability measurement is not considered to be unrealistic (Khan and Islam, 2007), processing of such data with a non-linear solver is at its infancy.

In processing sonic data, the wave equations are solved in order to reverse calculate reservoir properties. Most commonly used wave equation is Maxwell's equation. While the original form of this equation is non-linear, due to the lack of a truly non-linear solver, this equation is linearized, leading to the determination of coefficients that have limited application to say the least.

1.5.3 Remote Sensing and Real-time Monitoring

The conventional seismic technology has a resolution of 20 m for the reservoir region. While this resolution is sufficient for exploration purposes, it falls short of providing meaningful results for petroleum field development, for which 1 m resolution is necessary to monitor changes (with 4-D seismic) in a reservoir. For the wellbore, a resolution of 1 mm is necessary. This can also help detect fractures near the wellbore. The current technology does not allow one to depict the reservoir, the wellbore, or the tubular with acceptable resolution (Islam, 2001). In order to improve resolution within a wellbore, acoustic response need to be analyzed. In addition, fiber-optic detection of multiphase flow can be investigated. Finally, it will be possible to develop a data acquisition system that can be used as a real-time monitoring tool, once coupled with a signal processor. Recently, Zaman et al (2006) used a laser spectroscope to detect paraffin in paraffin-contaminated oil samples. After passing through the oil sample, the laser light was detected by a semi-conductor photodiode, which, in turn, converted the light signal into electric voltage. In their study, the paraffin concentrations ranged between 20% and 60% wt and a thickness of 1 and 10 mm. They developed a 1-D mathematical model to describe the process of laser radiation attenuation within the oil sample based on energy balance. Furthermore, the problem was numerically solved with reasonable agreement with experimental results. Their model can be used to predict the net laser light and the amount of light absorbed per unit volume at any point within the oil sample. The mathematical model was extended to different oil production schemes to determine the local rate of absorption in an oil layer under different working environments.

1.5.3.1 Monitoring Offshore Structures

In order to remain competitive in today's global economic environment, owners of civil structures need to minimize the number of days their facilities are out of service due to maintenance, rehabilitation or replacement. Indicators of structural system performance are needed for the owner to allocate resources toward repair, replacement or rehabilitation of their structures. To quantify these system performance measures requires structural monitoring of large civil structures while in service (Mufti et al, 1997). It is, therefore, important to develop a structural monitoring system that will integrate:

a. Fiber optic sensor systems;
b. Remote monitoring communication systems;
c. Intelligent data processing system;
d. Damage detection and modal analysis system; and
e. Non-destructive evaluation system.

It will be more useful if the monitoring device is capable of detecting signs of stress corrosion cracking. A system of fiber optic-based sensor and remote monitoring communication will allow not only monitoring of the internal operating pressures but also the residual stress levels, which are suspected for the initiation and growth of near-neutral pH stress corrosion cracking. Finally, the technology can be applied in real-time in monitoring offshore structures. Along this line of research, the early detection of precipitation of heavy organics such as paraffin, wax, resin, asphaltene, diamondoid, mercaptdans, and organometallic compounds, which can precipitate out of the crude oil solution due to various forces causing blockage in the oil reservoir, well, pipeline and in the oil production and processing facilities is worth mentioning (Zaman et al, 2004). Zaman et al (2004) utilized a solid detection system by light transmittance measurement for asphaltene detection, photodiode for light transmittance measurement for liquid wax, detection, and ultrasound and strain gauge solid wax detection. Such an attempt, if effectively used, has the potential to reduce pigging (the common commercial term for cleaning the pipeline) and in turn, the maintenance cost considerably.

1.5.3.2 Development of a Dynamic Characterization Tool (Based on Seismic-while-drilling Data)

A dynamic reservoir characterization tool is needed in order to introduce real-time monitoring. This tool can use the inversion technique to determine permeability data. At present, cuttings need to be collected before preparing petrophysical logs. The numerical inversion requires the solution of a set of non-linear partial differential equations. Conventional numerical methods require these equations to be linearized prior to solution (discussed early in this chapter). In this process, many of the routes to final solutions may be suppressed (Mustafiz et al, 2008a) while it is to be noted that a set of non-linear equations should lead to the emergence of multiple solutions. Therefore, it is important that a nonlinear problem is investigated for multiple-value solutions of physical significance.

1.5.3.3 Use of 3-D Sonogram

This feature illustrates the possibility of using 3-D sonogram for volume visualization of the rock ahead of the drill bit. In order to improve resolution and accuracy of prediction ahead of the drill bit, the 3-D sonogram technique will be extremely beneficial. The latest in ultrasound technology offers the ability to generate images in 4-D (time being the 4th dimension). In preparation to this task, a 3-D sonogram can be adopted to detect composition of fluid through non-invasive methods. Note that such a method is not yet in place in the market. Also, there is the potential of coupling 3-D sonogram with sonic while drilling in near future.

This coupling will allow one to use drilling data to develop input data for the simulator with high resolution. Availability and use of a sophisticated compositional 3-D reservoir simulator will pave the way to developing real-time reservoir modeling – a sought after goal in the petroleum industry for some time.

1.5.3.4 Virtual Reality (VR) Applications

In the first phase, the coupling of an existing compositional, geomechanical simulator with the VR machine is required. Time travel can be limited to selected processes with limited number of wells primarily. Later time travel can expand as the state-of-the-art in simulation becomes more sophisticated.

Describing petroleum reservoirs is considered to be more difficult than landing man on the moon. Indeed, reservoir engineers have the difficult task of conducting reservoir design without ever going for a site inspection. This application is aimed at creating a virtual reservoir that can undergo various modes of petroleum production schemes (including thermal, chemical, and microbial enhanced oil recovery or "EOR"). The authors comprehend that in future the virtual reservoir, in its finished form, will be coupled with virtual production and separation systems. A virtual reservoir will enable one to travel through pore spaces at the speed of light while controlling production/injection schemes at the push of a button. Because time travel is possible in a virtual system, one does not have to wait to see the impact of a reservoir decision (e.g. gas injection, steam huff-and-puff) or production problems (e.g. wellbore plugging due to asphaltene precipitation).

The use of virtual reality in petroleum reservoir is currently being discussed only in the context of 3-D visualization (Editorial, 1996). A more useful utilization of the technique, of course, will be in reservoir management, offshore monitoring, and production control. While a full-fledged virtual reservoir is still considered to be a tool for the future, one must concentrate on physics and mathematics of the development in order to ensure that a virtual reservoir does not become a video game. Recently, several reports have appeared on the use of virtual reality in platform systems, and even production networking (Editorial, 1996). An appealing application of virtual reality lies in the areas of replacing expensive laboratory experiments with computational fluid dynamics models. However, petroleum-engineering phenomena are still so poorly described (mathematically) that replacing laboratory experiments will lead to gross misunderstanding of dominant phenomena. Recently, Statoil has developed a virtual reality machine that would simulate selected phenomena in the oilfield. Similarly, Norsk Hydro has reported the virtual modeling of a cave. The reservoir simulator behind the machine, however, is only packed with rudimentary calculations. More advanced models have been used in drilling and pipelines.

Even though the concept is novel, the execution of the described plan can be realistic in near future. The reservoir data (results as well as the reservoir description) will be fed into an ultra-fast data acquisition system. The key here is to solve the reservoir equations so fast that the delay between data generation and the data storage/distribution unit is not "felt" by a human. The data acquisition system could be coupled with digital/analog converters that will transform signals into tangible sensations. These output signals should be transferred to create visual, thermal, acoustic, and piezometric effects. Therefore, this task should lead to coupling the virtual reality capability with a state-of-the-art reservoir model. When it becomes successful, it will not be a mere dream to extend the model to a vertical section of the well, as well as surface facilities.

1.5.3.5 Intelligent Reservoir Management

Intelligent systems can be utilized effectively to help both operators and design engineers to make decisions. The major goal of this management program is to develop a novel Knowledge Based Expert System that helps design engineers to choose a suitable EOR method for an oil reservoir. It should be a comprehensive expert system ES that integrates the environmental impacts of each EOR process into the technical and economical feasibility of different EORs.

Past intelligent reservoir management referred to computer or artificial intelligence. Recently, Islam (2006) demonstrated that computer operates quite differently from how humans think. He outlined the need for new line of expert systems that are based on human intelligence, rather than artificial intelligence. Novel expert systems embodying pro-nature features are proposed based on natural human intelligences (Ketata et al, 2005a, 2005b). These expert systems use human intelligence which is opposite to artificial intelligence. In these publications, authors attempted to include the knowledge of non-European races who had a very different approach to modeling. Also, based on Chinese abacus and quipu (Latin American ancient tribe), Ketata et al (2006a; 2006b) developed an expert system that can be characterized as the first expert system without using the conventional computer counting system. These expert systems provide the basis of an intelligent, robust, and efficient computing tool.