Improving Efficiency Through Reservoir Modelling and Production Simulation

In 1997, Mark Smith was exploration manager of Rigel Petroleum UK, and one of the senior executives responsible for overseeing the company’s North Sea exploration program. “Out in the North Sea, a rank wildcat can have a success rate of only one in ten,” he notes. “Even when you make that discovery, there’s still quite a bit of risk with follow-up wells, and if you can manage 50% success, then you’re doing quite well.”

Rigel (which was purchased by Talisman in 1999) and its partners were drilling an offshore license east of Scotland when one of their wildcat wells penetrated a secondary reservoir in a lower Cretaceous sand. “We had limited well control, and it was a tough little sand to follow,” recalls Smith. “No question about it, it was very high risk.”

Wells in the North Sea can cost up to $14 million to drill, so there is very little room for error. “We needed to know as much as possible about the target,” says Smith. “Using IESX (GeoQuest’s seismic interpretation software application), we were able to derive critical data like the gas/oil/water contacts, reservoir thickness and aerial extent, as well as defining porosity and permeability.”

Like thousands of other geoscientists around the world, Smith relies on state-of-the-art technology to do his job. In addition to Schlumberger’s GeoQuest and Merak software divisions, petroleum exploration and production (E&P) software is marketed by a score of international companies, including Landmark, Paradigm, and GMA.

Most of the software is UNIX based, or typically runs on a high-end PC, with 256 Mb of RAM. Depending on the number of users and applications, the software purchase price per license can range from under $50,000 to over $200,000; commonly with a 15 – 18% maintenance fee. Training is generally available, and is conducted in sessions running from one day to one week. Most vendors also maintain help-desk services.

High-end 3D reservoir characterization and geocellular modelling software has proven very valuable in the industry. “There’s been a lot of adoption over the last five years,” reports Anne Siw Uberg, marketing manager for GeoQuest. “The medium-sized companies are really pushing the boundaries. I’d say about two-thirds of all medium-sized and larger companies are quite heavily into this technology, one way or another. These days, every new reservoir discovered has to go through this evaluation process.”

The tremendous growth in third-party E&P software can be traced back to a decision by major oil companies to focus on their core competencies.

Over the last decade, oil companies have re-evaluated their internal business models in order to be more competitive in the capital markets. Where once they looked upon revenues and profits of the company as a whole, they now break down each operating section into discrete units and examine their separate return on investment. Is capital better spent on heavy oil, for instance, as opposed to offshore exploration?

Under this business model, companies compared the value of having proprietary knowledge vs. purchasing state-of-the-art technology from a service provider. Most concluded that, rather than owning the best “black box,” they could derive competitive advantage by taking the best publicly-available technology and exploiting it more intelligently than their rivals.

This outsourcing created a tremendous opportunity for vendors in the service industry, including developers of geological, geophysical, and engineering E&P software. “Schlumberger spent approximately $540 million last year on research and engineering: improving old products and developing new ones,” recalls Tony Lolomari, reservoir engineer for GeoQuest marketing.

E&P software falls into two general categories: geological and geophysical applications, which geoscientists use to create a static model (reservoir modelling), and engineering applications, which are used by the reservoir engineer to create a dynamic model (reservoir simulation). “The static model is the physical approximation of a reservoir—how large it is, the percentage of porosity, the permeability of the rock, the location of the gas/oil/water interface,” says Uberg. “The dynamic model looks at the movement of the phases through the reservoir with time. From these two models, you can determine the optimum well-spacing and configuration, the best production level, how long it will take to drain the reservoir, and how much oil you will recover.”

Geological Software

While some exploration plays occur far from any other hydrocarbon production, most are within a basin that already has some available data. In order to create the static model, the geologist
generally starts with an application like BaseMap that displays wells, tops, seismic lines, geologic cross-sections, and culture data. It allows you to see all the objects and information available relative to the exploration target, according to Sridhar Srinivasan, a senior marketing and support geoscientist with GeoQuest, based in Calgary.

The next step is to accumulate the information. Generally, digitized versions of well logs, tops, seismic lines, etc., can be ordered through third-party vendors and brought together under a common data base. “GeoFrame, which is Oracle-based, is our common project data base,” says Srinivasan. “All geological, geophysical, and engineering applications share the data, so if a geologist changes a formation pick, it instantly appears in real time on the geophysicist’s screen.”

Once the geological information is accumulated, it can be massaged through an interpretation package like StratLog, which allows the user to create cross-sections for picking formations and prospective zones. Once a potential reservoir has been identified, a rock property application can be used to highlight rock type, porosity, and permeability.

**Geophysical Software**

As the geological portion of the static model is being prepared, the geophysicist simultaneously downloads available 2D and 3D seismic data in order to check quality and, using interpretation suites such as IESX, begin a wide range of analysis. “You can generate a synthetic, edit it, display it on the seismic section and move it about,” notes Tom Cox, a senior marketing geoscientist with GeoQuest. “It has advanced wavelet extraction tools that allow you to model anomalies and identify stratigraphic changes.” The system also allows the user to convert seismic from time-to-depth and integrate it with the geology.

Tom Borthwick, a geophysicist at Talisman, works in the Foothills exploration basin, which contains a complicated assortment of structures, including overthrusts, steeply-dipping beds and faulting. “There’s a lot of out-of-plane energy, so I need to play with different velocities to get an image that makes the most sense,” he notes. “Using interpretation applications, I can get a quick overall view in one day, where it might take me two weeks to go through the paper version.”

Often, exploration plays can occur in structurally complex regions, and many programs come equipped with fault modeling capabilities. “They allow you to add faults, then slide one side of a fault up and down to correlate,” says Cox. “This is great for the East Coast of Canada, the Foothills, and international projects. A lot of Canadian companies are looking offshore, and need a robust tool.”

When a geophysicist is working with 2D/3D seismic and well data in complex structural areas, inconsistencies in the interpretation can creep in. Fortunately, three-dimensional visualization tools, designed to allow the geophysicist to rotate an interpretation on three axes are available to quickly identify and correct these interpretation “busts.”

The introduction of 3D voxel technology over the last decade has allowed for sophisticated attribute analysis. “Amplitude anomalies that may be associated with gas can be highlighted and mapped in 3D,” says Cox. “For instance, geoscientists at one of my client companies were able to identify where the steam front was in a heavy oil field by voxel picking a particular velocity range of a seismic velocity volume.”

“The static model has been vastly improved by the move from 2D seismic to 3D,” agrees Uberg. “The 3D/4C seismic gives you much more refined information regarding lithology, porosity and permeability, and you have much finer control points of information.”

When the geologist and geophysicist are satisfied with their interpretations, information can then be coalesced into a geocellular model. “This allows the interpreter to first quality check all data, then to identify relationships between seismic information and geological well information,” notes Srinivasan. “Once the correlations are made, the interpreter can then use geostatistical and stochastic methods to populate the 3D geocellular model away from the well with relative confidence.”

**Engineering Software**

Once the quality and detail of the static model has been confirmed, it can be handed off to the reservoir engineer for simulation. “At this point, the model can consist of many millions of cells and this is usually way too much for a dynamic simulator.
to handle,” says Srinivasan. “You therefore commonly have to scale it back or upscale it in order for the simulator to handle it in a reasonable amount of time and computing power.”

Streamlines simulation is another technique available to reduce the amount of upscaling to be performed. For example, the FrontSim simulator from GeoQuest enables engineers to simulate large geological models comprised of millions of cells in a practical length of time. Although streamline methods cannot incorporate complex physical processes, they have other unique advantages besides faster computation including quantitative flow visualization, improved accuracy (reduced numerical dispersion and grid orientation effects) and rapid history matching.

All available production data for the prospective reservoir is incorporated into the model. “Even a small piece of data can be leveraged to create huge knowledge value,” says Uberg. “Take a DST—it is highly accurate near the well-bore, but less so the farther away you get. We have statistical tools that let you take the little amount of information you have and add your knowledge regarding the type of reservoir—it makes the simulation results more accurate.”

Depending on the needs of the engineer, applications with various levels of sophistication are available.

Most reservoirs can be simulated using a “black oil” model. ECLIPSE Blackoil (GeoQuest’s base-level reservoir simulation suite application), can simulate oil, water, and gas flow in the reservoir. The “black oil” model assumes oil and gas to be the only two hydrocarbon components in the model, allowing for some pressure-dependent mixing of gas in oil. “This is an excellent practical approximation for most reservoirs,” Srinivasan says.

Certain reservoirs, however, need a more detailed characterization of their fluids. ECLIPSE Compositional enables the engineer to model oil and gas in terms of hydrocarbon components (such as CH₄, C₂H₆, etc.) thus allowing modeling of more complex problems such as condensate reservoirs and CO₂ injection.

Special projects, such as steam injection programs, require further refinement, and applications such as the thermal option in ECLIPSE Compositional are designed to handle temperature variations within reservoir phases.

Once the reservoir simulation results have been obtained, they can be displayed in a number of ways, from graphs to 3D. FloViz is an interactive fluid-flow visualization package that displays results in a 3D canvas. “You can create a time-animation of oil saturation, for instance,” says Srinivasan.

Regardless of sophistication level, all reservoir simulation packages deliver the same essential results: the volumes, rates, percentage of oil/water/gas, coning and other conditions. “This allows you to make optimal decisions about your reservoir to maximize its value,” he says.

Leveraging Value

Historically, geoscientists and engineers have operated in relative isolation when creating their respective static and dynamic models. “We’re trying to break down the barriers that exist between the various disciplines of geology, geophysics, and engineering,” reports GeoQuest’s Tony Lolomari. “Traditionally, software has been purpose-built to each profession. But geologists, geophysicists, and engineers don’t work in isolation. Now, we are embracing the “office” concept (as in Geology Office, Modelling Office) where interdisciplinary communication is promoted.”

“Integration is the key to all this,” Uberg continues. “The link to the core data base is very comprehensive. You only enter data once, and all data is instantly updated. All team members can have access to changes and interpretations made to the data. Simulation engineers can gain insight into how geological applications work, and the same with geologists.”

By integrating all the software and databases, the groundwork is laid to allow the static and dynamic models to exist together in a continuum. “That’s where the true value lies—how quickly can you move from one to the other,” says Uberg. “There has been an evolution over the last five years, and it is happening as we speak. By closing the gap between static and dynamic modelling, we are really shortening the discover-to-production cycle.”
For John Gerlach, former senior development engineer with Rigel, having a solid foundation of geological and geophysical information was key to simulating the potential field. “In the North Sea, you don’t get well production data until you’ve committed hundreds of millions in investment in wells and a floating production vessel,” he notes.

Before they committed to a major program, Rigel and its partners examined the available data closely. “The geologic and geophysical modelling indicated that the unconsolidated sand was clean, with low laminations, and very high vertical permeability,” says Gerlach. “Coning (watering or gassing out) was a key concern.”

A pattern of horizontal wells appeared to be the solution, and the engineers ran extensive simulations in order to optimize the stand-off between gas/oil/water contacts. “You have to be careful—if you go too high, you gas out, and if you go too low, you create an oil attic and leave a lot behind,” says Gerlach.

**Economic Considerations**

For oil companies, the value of reservoir modelling and production simulation software can be measured in time, efficiency, and reduction of risk.

“The time cycle between discovery and production has been compressed,” Uberg says. “You can’t sit around waiting for an asset to be worked up. In the past, it was months-to-years between discovery and exploitation. Now, it is weeks-to-months. There has been an order-of-magnitude decrease.”

E&P software also allows geologists, engineers, and geophysicists to use their time more efficiently. A common database reduces the amount of time spent hunting for well logs, seismic lines, and DSTs. The software also automates many tasks that formerly had to be done by hand. “There are certain tasks that the reservoir engineer performs, like in-fill well-placement and history matching, that tend to be monotonous,” says Lolomari. “Software optimization tools (like PlanOpt and SimOpt) can eliminate a lot of that. These tools don’t take away the need for good engineering judgement and experience, but significantly reduce the time spent with the more mundane tasks.”

E&P software also lowers the risk inherent in exploration. “It would be an interesting study to see how much risk has been removed,” states Uberg. “Nobody doubts that there has been a significant overall reduction due to the increased resolution and model size. New technologies also embolden its users, however. Exploration companies are searching farther and farther out into the depths, and they are examining more complicated structural areas.”

All of these factors—time, efficiency and risk—came together in the North Sea. “A rig in the North Sea costs around US$100,000...
per day to operate, and there is a limited window—nobody likes to be drilling between November and February,” says Smith. “We were really pushed because they wanted to keep the rig busy. There was no way we could have kept up to that schedule without the software to do analysis.”

In order to prove up the field, Rigel and their partners drilled a total of five wells, four of which were on target, for a success rate of 80%. “We proved up a 130 million barrel reservoir with a 50% recovery rate between the initial discovery in 1997 and the summer of 1999,” he says. “That’s a good cycle time for the North Sea.”

Financial Market Considerations

In order to be successful, petroleum companies must focus not only on their core E&P business, but also on the global equity markets.

Early E&P software suites included internal economic models that would calculate the value of the commodities being exploited over time, but that is no longer sufficient for today’s financial markets. “Oil companies are now competing with other sectors of the economy for working capital and intellectual capital,” says Lolomari. “They have to show value to stockholders, or they will lose their investment somewhere else. They have to do a lot more portfolio optimizations and understand how market forces impact their work.”

The economics of the reservoir are now linked back very early in the discovery process, and the impact is extrapolated over a wide range of internal and external facets by economic modelling programs. Merak Projects Ltd., a Schlumberger GeoQuest software firm that specializes in petroleum economic analysis, offers Peep, the Petroleum Economics Evaluation Program, which allows engineers to do economic and decline analyses. “You can take information from reservoir modelling and go on to a possible production scenario,” says Mike McGovern, Merak’s product marketing manager. “Peep is designed to allow the forecaster to customize price, production and operating costs.” It will also take into account important external market considerations, such as taxation, regulation, borrowing rates, restriction of supply due to political factors, and other tangibles. With the link between Eclipse, OFM (Oil Field Manager, a reservoir surveillance tool) and Peep, the interaction between applications enables the asset teams to work together much more closely than ever before.

The Future

Most industry observers agree that E&P software will increase in sophistication over the next few years. “In the early days, a lot of assumptions and simplifications were made in the software because the computing power wasn’t there,” Lolomari says. “There’s no such thing as a homogenous or black oil reservoir: all reservoirs are heterogeneous and reservoir fluids are naturally compositional to some degree. These assumptions were made to make the computations faster. However, they led to inaccuracies and consequently to poor decisions.”

Today, however, a laptop can have more processing power than a mainframe of a decade ago. “We can routinely account for more heterogeneities like faults and fractures, and include more physics like phase behaviour and EOR processes. We can look at geomechanical effects, like rock compaction due to production which can lead to changes in the reservoir pore volume, permeability, and wellbore stability. Complex fault and horizontal well configurations used to be impossible to model accurately. Today, with unstructured gridding techniques like in PetraGrid, there are no limits to the complexity you can add to your model. In the end, you get more accurate models which lead to better forecasting.”

New features will also be added as warranted. “The recent step from 3D to 4D (adding time), has been huge,” comments Uberg. “Now you can look at phase movements—you can see the advance of a waterflood front.”

More platforms will also be made available. “There’s been increased interest in the Linux operating system in the E&P industry,” says Lolomari. “We’ve made ECLIPSE available on the Linux platform this year. IT departments can therefore make the best decision regarding what will work best on their own systems.”

Customization of needs will also become more common. “Formerly, service companies tended to create a huge suite and marketed it on an all-or-nothing approach,” notes Uberg. “We know that nobody uses everything, and the new trend is to a smaller, more focused number of applications that precisely fits the user.”

Clientele will also be able to access the software remotely over the internet. Application Service Provider (ASP) services such as LiveQuest, which was launched in late 2000, take away the need to install, maintain, and upgrade software. All of the applications are housed in a central location on super-computers. The user signs into the central location over the Internet using a security pass-code. Once there, the user downloads all information to a central database and interprets the data. The ASP saves clientele from having to invest in expensive hardware or train and maintain a dedicated IT staff. “It allows smaller shops access to sophisticated suites of software,” says Lolomari. “They don’t have any upfront costs—they can pay-as-they-go.”

“We are redesigning our software to be more amenable to our customers’ workflow,” he reports. “They always need to get results faster, especially in the reservoir simulation domain. Software will have to get faster, cheaper and easier to use. It is very important that we enable the user to get up to speed as quickly as possible.”

For a seasoned veteran like John Gerlach, the future of E&P software bodes well. “I’m a big proponent of reservoir simulation,” he says. “People should use it a lot more. It can give you some pretty valuable information.”

Gordon Cope has been involved in the petroleum sector for over 20 years as a professional geologist, business reporter, and industry consultant.