WEEK OF MAY 31, 1999
US$5.00
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OIL&GAS JOURNAL

INTERNATIONAL PETROLEUM NEWS AND TECHNOLOGY
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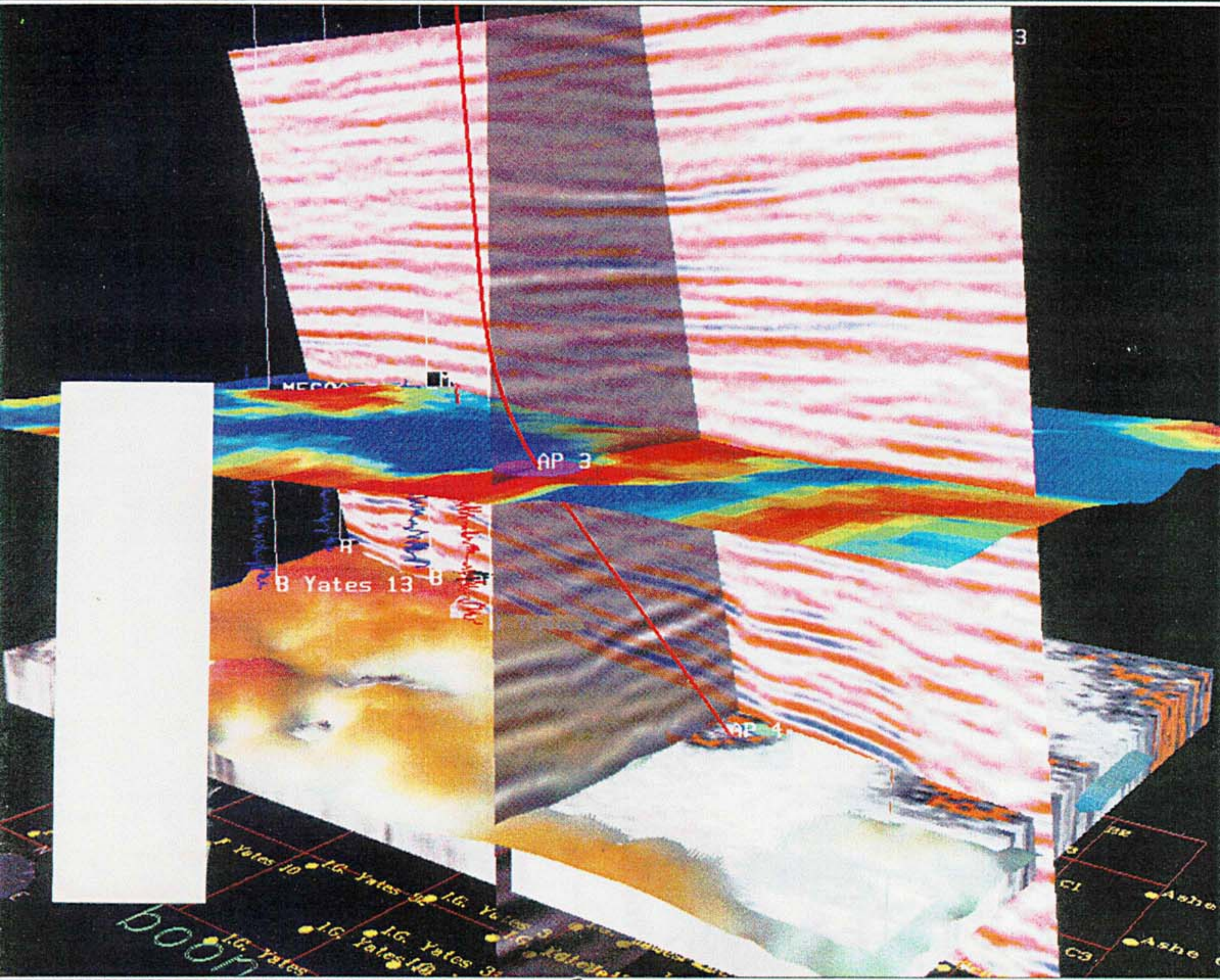


GEOPHYSICS IN PETROLEUM DEVELOPMENT PAGE 38

WHOLE-OF-LIFE APPROACH TO OIL-FIELD ECONOMICS HELPS TECHNOLOGY DECISIONS

Richard Uden *Continuum Resources International Houston*
Roger Anderson *Columbia University New York*

Operating an oil field at low oil prices usually means that budgets are reduced and costs are further scrutinized. However, unless the operator is careful, production can be damaged.

A period of low oil prices, such as the one from which the oil and gas industry seems to be emerging, is a good time to reexamine the technical premises that the field has been built upon. The individual economic benefits of many technologies previously taken for granted must now be reexamined and tested for their service to the profitability of the field. This implies looking at the field over its entire planned (and, nowadays, often unplanned) life.

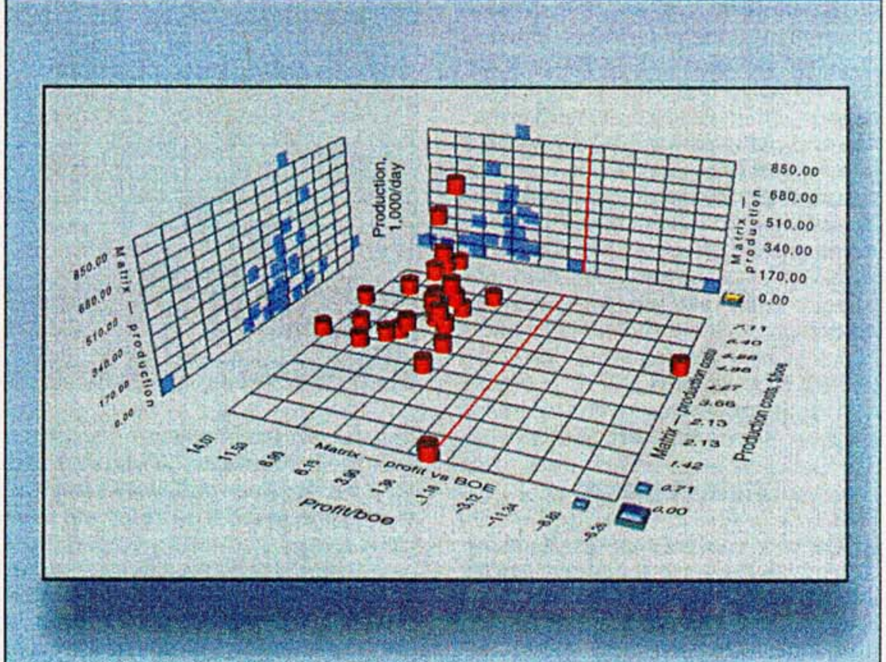
The goal of economic analysis must be to assess each technology that is applied and applicable to the field by rating and ranking it according to its likely impact on the return-on-capital employed (ROCE) profit stream. Should a technology already be in use, then the analysis is confined to the learning that can benefit future use of the technology. Obviously, we are looking for positive economic improvement; otherwise, why use that particular technology in the first place?

The economic analysis can use constant oil price, predictions on future prices, upper and lower bounds, or both. We are interested in the time value of money as the results of the technology unfold during the economic stages of the field, so the price premise need only be kept constant for analyses among different technologies. For each specific technology, we can predict what increase in production is needed to pay for the technology, or how the technology changes the indices used to monitor oil field production. Think of it as ROCE for each technology.

Economic indices such as net cash flow, return on investment, profit, and cost per barrel of oil equivalent (boe) are used to determine conclusions from the analysis. The particular geological conditions of that field make results field-specific, and although general trends emerge basin to basin, the analysis should be done for each field in your portfolio that has substantial remaining value. The operator knows the general economic performance metrics of his field, but attributes specific to each technology require considerable effort to extract.

Fig. 1

PRODUCTION VOLUME VS. PROFIT, COST*



*In barrels of oil equivalent (boe) and dollars per boe for 27 companies.

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Economic impact of EOR processes

As oil prices fluctuate, companies are increasingly concerned with how to survive, let alone prosper. Given that the price is largely out of their control, cost reduction is often seen as the only viable solution to maintain ROCE. This is necessarily done in the short term by reducing exploration and production budgets and by further reducing staffing levels.

Rather than stabilizing the "floor" or foundation of the company, financial strength often further drops. What often happens is that not only does discovery and infield growth of new reserves fall as expected, but existing production levels drop as well.

One reason for this unwanted feedback loop is that understanding of the cause and effect between technologies being applied during enhanced oil recovery (EOR) becomes disconnected from ROCE of the specific technologies. Reductions in cost and personnel can often erode the fundamental ROCE of the field itself.

This article discusses the analysis methodology for associating ROCE to specific EOR technologies and offers al-

Fig. 2

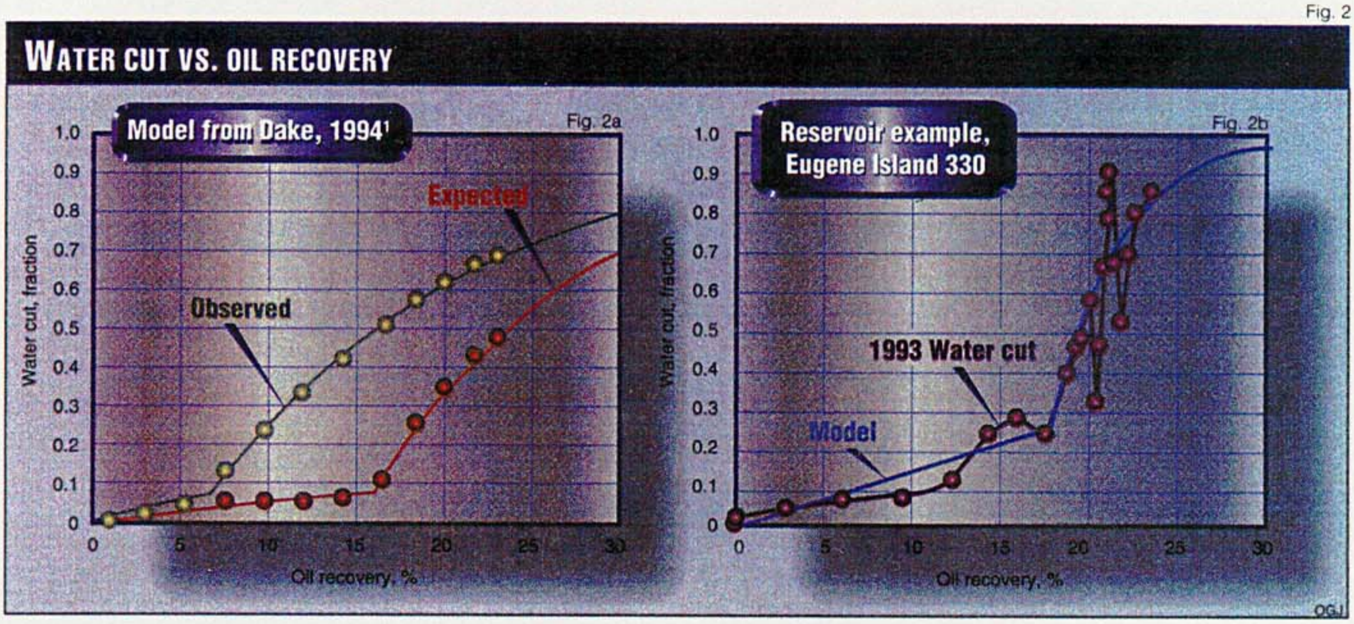
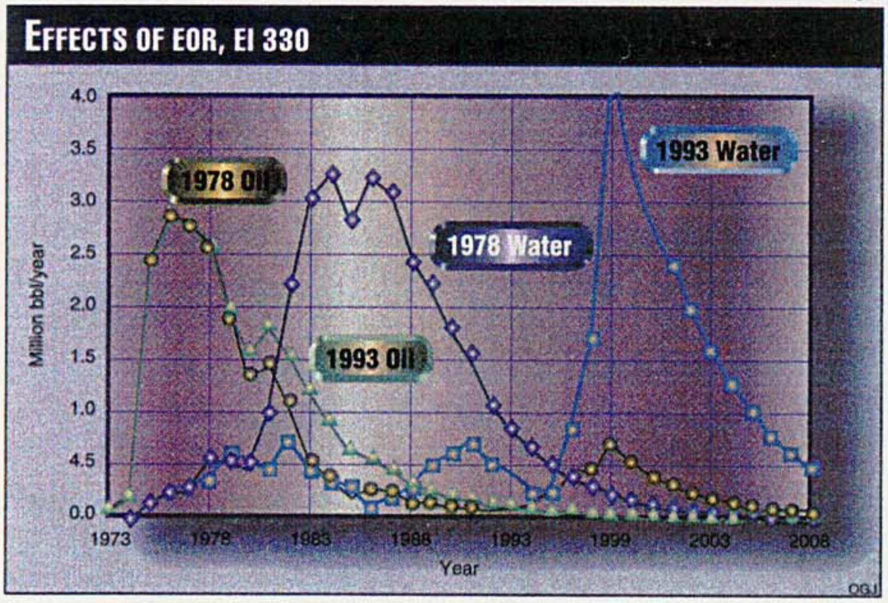


Fig. 3



ternative ways to simultaneously satisfy shareholder ROCE requirements while continuing to grow infield reserves and raise the floor for your company.

The target is cheaper oil produced from existing fields, or higher profit per boe produced. However, it does not come free since you have to spend money to make money through increased reserves. That often sets off alarms with management because cost per boe must be cut in tough times.

The distinction between competing production metrics is important. Consider the performance of 27 publicly owned companies that span the size spectrum from the supermajor to the smallest of international independent.

Fig. 1 shows the red data points in 3D and their 2D projections in blue on the walls. Some producers are very good at keeping production costs down, while others are very good at profit per barrel. But only 6 of the 27 companies have mastered the linkage between high profit, low cost, and high production volumes. Only the latter produces cash flow directly.

The danger in cutting costs or concentrating on profit per boe without understanding their linkage to production volumes is that in tough economic times a company may sever the linkage. We believe that in order to understand the linkage, a company must first determine the specific benefits, or ROCE, of each important technology being used or considered for use in each important field of its portfolio.

This problem will not go away if just the price increases. As producers move into ever deeper water searching for the remaining elephants, the wellhead cost per barrel is currently constraining field development to only the largest fields. As we further understand the linkage among cost and profit per boe and production volumes, smaller fields will become economic.

Eugene Island example

We illustrate the methodology for a single reservoir in Eugene Island in the Gulf of Mexico. This 100-ft thick Pleistocene sand reservoir has experienced several EOR events over its 25-year production history. One of the key EOR events was the early use of 4D seismic analysis using three generations of 3D seismic surveys. New drainage targets resulted in a very successful field rejuvenation project conducted from 1992 to 1996. In particular, we analyzed the timing of the EOR events for their impact on the ROCE of the reservoir.

The intuitive concept is that the sooner the ROCE of each EOR process is understood by the reservoir management, the higher and quicker the impact on the cash flow and ROCE. We built models to quantitatively visualize this intuitive concept and estimate financial impact.

Fluid-production modeling

We began with fluid-production models, which were built from a combination of empirical and measured data. The fluid-production rates from 1998 into the future were predicted through use of reserves-decline curves. The oil rate was predicted with a standard, exponential decline of 23.6%/year, derived from the production data between 1978 and 1998. The gas rate was predicted by using a linear relationship with the oil rate. The water rate was based on a model derived from analyzing both

Fig 4

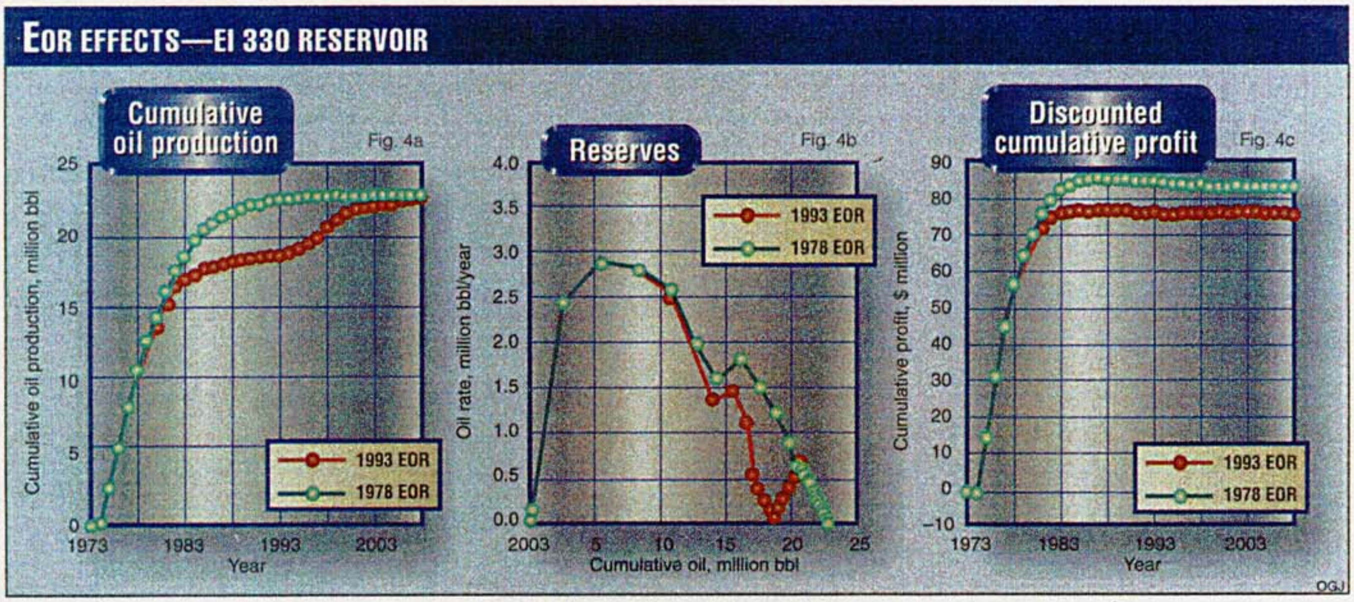
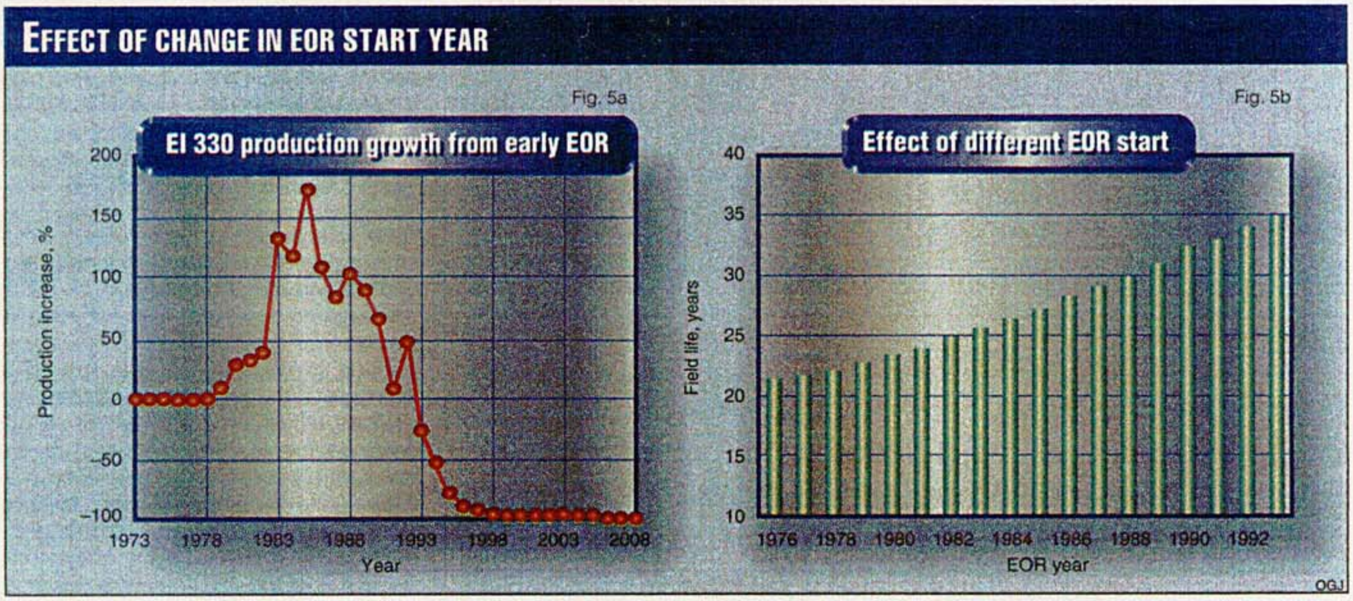


Fig 5



these data and data from Dake.[1] Dake discusses several fields in the North Sea, which show the relationship between water cut and cumulative oil recovery and the expected and observed water cut curves. These curves, Fig. 2a, and those seen in the Eugene Island data example in Fig. 2b, show a form approximated by an initial linear rise, followed by a curved rise, which asymptotes to unity with maximum oil recovery. A generic form of the model used to describe these curves is shown in Equation 1:

$$WC = A + (1 - A)(1 - e^{-AX})$$

where A = constant, X = oil recovery, and WC = water cut.

The models fit the data points for all three examples very well over the entire data range, even allowing for fluctuations seen in the Eugene Island water-cut data that relate to workover events. The Gulf of Mexico curves maintained a low water cut for a longer oil recovery percentage than that observed in the North Sea examples. It is not clear whether this indicates a difference in the rocks themselves or a difference in the production mechanisms (all were from water drive reservoirs).

Impact of EOR on reservoir performance

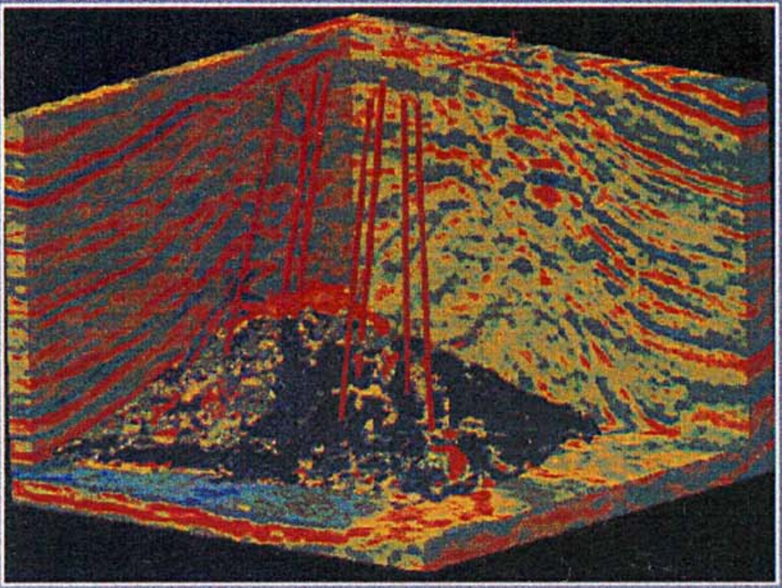
The EOR events that we analyze in the Eugene Island reservoir were applied beginning in 1992. Second and then third 3D seismic surveys were obtained and a 4D seismic analysis applied.

Bypassed pay compartments and unswept oil pockets were identified, and horizontal and deviated holes drilled. Production, which had peaked at 3 million bbl/year in 1975, had dropped to 53,300 bbl/year by 1992. In 1993, oil production began increasing and peaked in 1998 at 700,000 bbl/year. We used the fluid-decline model discussed above to predict the production beyond 1998 assuming decline from 1999 (Fig. 3).

The ROCE impact of the EOR events on the reservoir performance was estimated by extracting the effect of the EOR events and continuing the decline curve from 1993 instead of increasing the oil production rate. The recovery factor to 2008 without the EOR events in place was estimated as 21.3%, which increased to 25.9% when EOR was included. The EOR events provided an increase of 4.6

Fig. 6

WATER FINGERING—EI 330*



*Imaged with 4D seismic differences. Blue is water, green is remaining oil, and red is gas.

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percentage points in recovery factor.

The cumulative oil production in Fig. 4a clearly shows the increase due to the EOR events from 1993. We estimate that an additional 4 million bbl will be delivered at an estimated cost of $10 million for the EOR program, which factors into a cost of $5/bbl and a profit of $7/bbl, resulting in an ROCE of 2.8:1 for the EOR program. This ROCE must be fed into the overall facility and operating costs of the field, which includes other producing reservoirs. However, the EOR program has clearly raised the ROCE for the whole field.

Additional models were used to examine the effect on the reservoir performance had the EOR events been applied earlier than 1993. The EOR oil component was estimated from the actual production data and was temporally moved forward in time in relation to the production estimated with no EOR taking place. It is likely that 1978 was the earliest time for the EOR events to take place since that is just after peak production.

Fig. 3 shows both the 1993 EOR and 1978 EOR oil production rates whereby the 1993 EOR bump has been moved earlier in time, giving a production rate increase from 1978 onwards. The 1978 EOR effect in Fig. 4a is to push the recoverable reserves limit forward in time.

Moving the EOR effect earlier in time does not add reserves but adds financial value. The recoverable reserves from both 1993 EOR and 1978 EOR models are shown in Fig. 4b. The exponential decline in this figure indicates nearly 23 million bbl of recoverable reserves.

The discounted cumulative profit comparison between 1993 EOR and the 1978 EOR model in Fig. 4c largely reflects the cumulative oil production profiles. Approximately $9 million extra profit is available from the 1978 EOR events and at an earlier time than the 1993 EOR events. The 1978 EOR model produces more revenue sooner, which increases the time value of money. The oil and gas prices were held constant at $10/bbl and $1.80/Mcf during this analysis, and the discount rate used was 10%.

The production growth realized by the early EOR is seen in Fig. 5a. The growth between 1993 EOR and 1978 EOR averages about 100% between 1980 and 1990, again reflecting the time value of money. The impact of choosing a different year than 1978 as the EOR event year is shown in Fig. 5b. Here the EOR year has been started between 1976 and 1993, and the field life computed based on an economic limit of 50,000 bbl/year (the production rate in 1992). Now we see that applying EOR in 1993 implies a field life of 35 years, but applying EOR in 1978 implies a field life of 22 years, which represents a tangible saving of 13 years in operating costs for the same oil volume. This cost saving is not usually reflected in cost-per-barrel calculations. Of course this modeling has been done for only one of the reservoirs being produced, but the conclusion reached thus far is that EOR can be evaluated as an ROCE proposition.

The time value of money must be included to truly reflect the balance between profit, profit per barrel, and cost per barrel. In addition, early EOR adoption realizes significant additional cost savings. Hence applying an EOR technology such as 4D seismic with a second or subsequent survey scheduled for acquisition as soon as the production plateau is reached potentially maximizes the profit even if it results in no additional reserves being discovered (an unlikely scenario in our experience). It even results in cost savings because the oil is delivered to market early.

Overall economic effects

Other produced fluids are important to the economic analysis as well since they affect both revenue and cost.

Using the fluid-model descriptions discussed above, we modeled the 1978

THE AUTHORS

Uden

Anderson

Richard Uden is a senior staff explorationist with Continuum Resources International Corp. Prior to joining Continuum he worked as an independent consultant in the U.K. for oil and gas companies, consulting firms, and geophysical contractors.

During the past 10 years, Uden has focused on reservoir geophysics, especially time-lapse seismic studies and amplitude variation with offset (AVO) projects. He holds a BSc degree in mathematics from Southampton University, U.K.

Roger N. Anderson is director of the Energy Research Center at Columbia University and president of Columbia Enterprise Systems. He received a PhD from the Scripps Institution of Oceanography, University of California, San Diego, and has worked for Columbia for 25 years.

Anderson manages a 10 person software-development team at the Lamont-Doherty Earth Observatory that has created more than 12 million lines of code relating to new methods for processing and interpreting 4D seismic monitoring data in oil fields. The group holds seven patents for this and associated geopressure-detection, downhole monitoring, and thermal detection of hydrocarbons.

Anderson is also codirector of the Lamont Portfolio Management Consortium, which develops new management approaches and decision tools to aid exploration and production planning for a group of major oil companies. He is a founder and member of of the board of directors of Bell Geospace Inc., a geophysical survey company.

EOR total fluid productions as shown in Fig. 3. The water production now shows a large bump between 1982 and 1989, which is the result of the oil-driven water cut and increased oil production in those years.

The total fluid peak occurs in 1983 and is higher than the oil production peak by more than 50%. This illustrates that the facilities design for a field must include enough capacity to handle these fluid volumes cheaply, hence the need for an acceptable water-cut model to make future predictions so that costs can be properly contained in the ROCE model. In addition, account must be made for the added fluid volumes from late EOR. The total fluid production from the 1993 EOR management has peaked higher than the 1978 EOR model, but this is a characteristic of all-out fluid production near the end of a reservoir's life.

Additional water volumes from one reservoir may be offset by lower volumes from the other reservoirs in the field, precluding the addition of extra processing facilities. Whole-of-life field economics means all the reservoirs in a field over the field lifetime and may even include neighboring fields that exploit hubbing as a way of maximizing fluid handling across the group of fields.

EOR practices such as 4D seismic that indicate preferential fluid-flow pathways and water-fingering, as shown in Fig. 6, assist in controlling the increasing water production through optimized infill drilling programs. Water production plays a significant role in determining field abandonment time, and operators may resort to using EOR to partly offset these increasing costs through increasing oil production. This philosophy hides the real economics of the advantages of performing early EOR backed by an economic analysis of whole of field life.

The economics of oil field production must consider not only cost reduction but also profit per barrel and volume of barrels predicted over the whole of life for the field.

Acknowledgment

Acknowledgments are made to PennzEnergy for permission to use the data from the Eugene Island field. Continuum Resources supported the project.

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COMMENT: CHANGE COMING FOR THE 'UPSTREAM EXPLOITATION MACHINE'

Roger Anderson *Columbia University New York*
Dave Ridyard *Continuum Resources Houston*

The production, refining, and distribution of oil and gas are not ordinarily thought of as a manufacturing processes. However, recent years have produced a wonderful explosion of technological improvements that make the oil and gas "factory" run more efficiently. Individual exploitation improvements such as 3D and 4D seismic, full tensor gradiometry, and multilateral completions, to name a few, have driven growth in production that, until the recent price collapse, accounted for impressive earnings-growth improvements for the whole industry in the 1990s.

Though ultimately charged with making most of the profit for energy companies, this upstream exploitation machine still does not perform optimally in very low price environments. One reason is that it costs money to make more money using advanced technologies, and companies simply may not have the profit margins to make this investment until the price rebounds and stays reasonable for many, many months. It is, however, possible to apply several of the new exploitation technologies in sound financial ways that make sense even in today's recovering oil patch.

In the manufacturing world outside of oil and gas, price pressures have resulted in just such smart applications of new technologies, sometimes with company-saving results. Reengineering and continuous-improvement revolutions were introduced precisely at times of low margin and profit crises in industries as diverse as autos (led famously by Toyota), computers (from Intel to IBM), the military, and aerospace contractors. However, it is easier to manufacture cars under factory roofs, or chips in sterile cleanrooms, or gasoline in refineries, for that matter, than it is to manufacture oil and gas in the sprawling underground outdoors of the entire globe.

Why must this transition to more efficient manufacturing propagate to the oil and gas business? Because there still is room for a company to differentiate its business performance relative to its peers because operational costs are still too high. The world energy business is a mature industry that has more than $10 trillion of net present value, yet performance from company to company, by any measure of Wall Street business metrics, is all over the map.

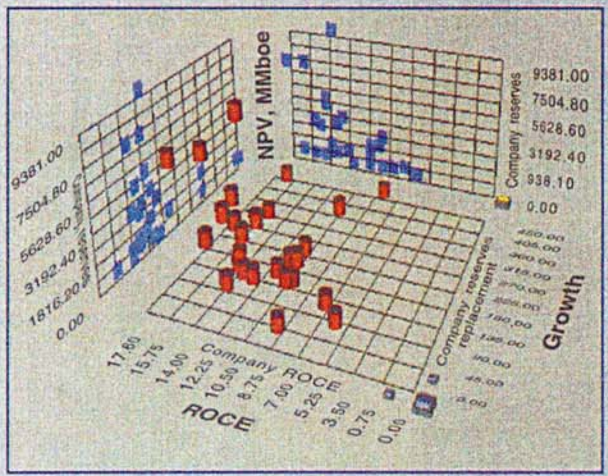
For example, the three-way consideration of net present value of reserves (NPV), return on capital employed (ROCE), and reserves replacement (growth) shows no clear trends (Fig 1). The industry performs inconsistently when measured by these metrics. How can this be when the oil service companies provide a worldwide datum of quality technologies that are available to all in the business, for hire? These technologies are of both high technical quality and utility. Good technologies are available to all, yet performances are scattered. Why?

We believe this to be a strong indicator that the problem lies in the successful execution of new technologies in ordered, planned, monitored, cost-effective ways that constantly improve the manufacturing process. The likely reason that new technologies available industry-wide do not level the upstream performance field is perhaps that there are significant communications and logistics gaps within companies that hinder their manufacturing efficiency in ways unique to each company.

Thus, there is a wonderful opportunity for market differentiation if one company can master what other companies are having trouble with. In fact, we can see the change coming. The oil industry is just now emerging from common practices that required the keeping of paper records of all of the business, disseminated largely by

Fig. 1

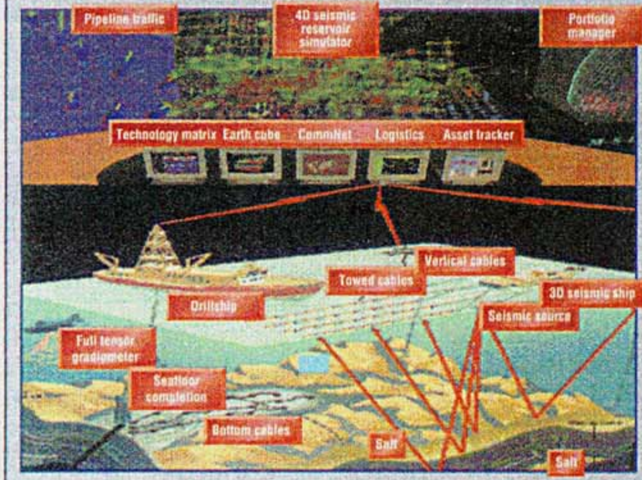
A THREE-WAY LOOK AT INDUSTRY PERFORMANCE*



*Net present value (NPV) of reserves, return on capital employed (ROCE), and reserves replacement (growth).

Fig. 2

DATA NETWORK FOR FUTURE DEEPWATER PROJECT



telephony (albeit by faxes and cell phones). Computers and accounting systems such as SAP AG have recently replaced the record-keeping, accounting, and payroll maintenance with an electronic enterprise system.

While a few scattered attempts have been made to make overall efficiency improvements in the E&P manufacturing business, no enterprise-wide redesign or reengineering of the structure of the exploitation business has occurred since the computer revolution that we are aware of. One of the primary reasons is likely that the industry lacks the systematic understanding of what tasks are really creating bottlenecks and choke points over time.

Many E&P activities are done simply because that's the way they have always been done. The information supply, asset tracking, computer-aided manufacturing, portfolio management, business simulation, and optimization loops necessary for continuous improvement do not yet exist in the manufacture if oil and gas.

There are abundant examples today of locations around the globe where the oil industry does not get giant and super-giant projects executed correctly from the beginning. Consequently, we spend enormous resources fixing the plant, or the drilling platform, or the pipeline, or the oil well on the fly and after breakdown has happened. The modern oil field is just too complicated a place to continue to manage in such an *ad hoc* way.

But change is coming, and a new paradigm it will be! It is, in fact, in times of economic crisis that such paradigm changes occur in most industries. In hard times, improvement in the manufacturing process is a requirement in order for any company to survive, whether you produce oil, steel, or hamburgers.

So what will be required in order to address bottlenecks in the manufacture of oil and gas? Massive amounts of data must be continuously collected, transmitted, and used effectively in near real-time over remote communication links. Data must be gathered from sensor networks that are making the relevant measurements of appropriate physical attributes that must be controlled in ALL assets critical to the successful execution of the company's business plan, whatever and wherever that may be.

Computation, simulation, and visualization will be similarly distributed across the emerging global, high-bandwidth, information infrastructure. We believe that operations will be steered at distributed control centers by remote personnel who are comparing simulations (model predictions) of what is expected to be occurring, with observations coming in live from the field of what is really happening in the E&P manufacturing business. And the monitoring tasks will be passed around the globe among virtual team members who work with the sun (Fig. 2).

The upstream oil and gas business requires more than just communications improvement. At the often low commodity prices of today, the modern energy company has significantly different infrastructure needs to those that served adequately in the high-priced days of old. And change must begin with the questioning of the underlying assumptions of the E&P manufacturing process itself. The industrial change that this challenge sets off will be every bit as all-encompassing and difficult as that experienced by auto workers more than 20 years ago, but oh the results will be wondrous. ■

THE AUTHORS

Roger N. Anderson is director of the Energy Research Center at Columbia University and president of Columbia Enterprise Systems. He received a PhD from the Scripps Institution of Oceanography, University of California, San Diego, and has worked for Columbia for 25 years.

Anderson manages a 10 person software-development team at the Lamont-Doherty Earth Observatory that has created more than 12 million lines of code relating to new methods for processing and interpreting 4D seismic monitoring data in oil fields. The group holds seven patents for this and associated geopressure-detection, downhole monitoring, and thermal detection of hydrocarbons.

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Dave Ridyard became chief operating officer of Continuum Resources in September 1998. He earlier worked for Input/Output, which in 1994 acquired a company he had founded in 1989 called QC Tools, a producer of data quality control software for the seismic industry. He earlier worked in marine 3D seismic data acquisition and engineering for GSI.

Ridyard has a degree in applied physics from University of Durham.