Reserves/Asset Management

Dean Rietz, *SPE, is Managing Senior Vice President at Ryder Scott Company. He has approximately 24 years of diverse experience in evaluating oil and gas properties, including more than 20 years applying numerical-modeling approaches to these evaluations. Rietz manages the reservoir-simulation group and has built a variety of simulation models, including compositional and thermal. Currently, he is an adjunct professor at the University of Houston and teaches a 2-day simulation course for SPE. Rietz serves on the JPT Editorial Committee. He earned a BS degree in petroleum engineering from the University of Oklahoma and an MS degree in petroleum engineering from the University of Houston. Rietz is a licensed professional engineer in Texas.*

As a consultant who routinely is asked to assist clients on reservoir management (through reservoir studies), it is sometimes surprising when the usefulness of reservoir studies is questioned. First, it should go without saying that a reservoir study should be embarked on only to answer specific questions such as:

- How much oil or gas will be recovered from a particular asset?
- Can the same amount be recovered with less investment?
- Can more be recovered by use of optional operating approaches?

But the real question is, Why conduct a study in the first place? After all, once we find the asset, the reservoir properties (e.g., its size and the rock and fluid characteristics) are "what they are" and we cannot change them. Can we affect recovery by managing the reservoir, or must we simply accept what we get?

This brings us to a simple comparison with hurricanes. Earlier this year, the Houston area was impacted significantly by Hurricane Ike. Hurricanes, like petroleum reservoirs, occur naturally, and the characteristics (the fundamental properties that define them) are unique to that entity and are uncertain. In both cases, however, we can use tools (such as numerical models) to project and forecast their future behavior.

In the case of Ike, the weather models forecasted landfall in the vicinity of Galveston—well in advance, which enabled making decisions and taking action. To save lives, much of the anticipated impact area was evacuated. In addition, relief supplies, equipment, and personnel were prepositioned (out of harm's way) to respond quickly. The result was fewer casualties than experienced with earlier devastating hurricanes and an immediate response to begin the recovery process.

Just like preparing for the inevitable landfall of a hurricane, companies can plan for the inevitable depletion of a reservoir. Reservoir models, for example, can and do help identify more-efficient methods of hydrocarbon recovery. So, why are studies performed and reservoir-management strategies implemented? There are two main reasons: to improve recovery efficiency and/or maximize the return on investment of a particular asset. Our industry has the technology and the know-how. **JPT**

Reserves/Asset Management additional reading available at the SPE eLibrary: www.spe.org

SPE 112932 *• "Simplified Country-Entry Risk-Assessment Model for Global Petroleum Investments" by Surya Rajan, SPE, Marathon Oil Company, et al.*

SPE 113260 *• "Reservoir Management of the Gullfaks Main Field" by Saifullah Talukdar, SPE, StatoilHydro, et al.*

SPE 111717 *• "Real-Time Reservoir Management From Data Acquisition Through Implementation: Closed-Loop Approach" by Saeed M. Mubarak, SPE, Saudi Aramco*

Additional reading available at OnePetro: www.onepetro.org

OTC 19644 *• "International Risk Management" by Daniel V. Murphy, Systech International*

Modeling the Economic Effect of Cognitive Biases on Oil and Gas Decisions

Cognitive biases are known to affect decisions made under conditions of uncertainty. Previous demonstrations of these biases have focused on their effect on a single-parameter, typically technical, judgment rather than examining the potential effect on economics when applied to all of the judgments involved in a complex oil and gas (O&G) decision such as reservoir characterization. Three individual biases—overconfidence, trust heuristic, and availability heuristic—were modeled to measure their effect on economic outcome as represented by net present value (NPV).

Introduction

Cognitive biases are unconscious errors in judgments and decisions (particularly those made under conditions of uncertainty) that arise from the inherent structure and functioning of the brain's cognitive architecture. These errors affect most subjective judgments of probability and value and can be multiplicative—the same biases affecting multiple parameters, thus increasing the effect with the complexity of calculations made with those parameters.

The effects that such biases can have on the complex decisions in the O&G industry, however, have not been assessed. Part of the reason is the perceived difference in scale between simple judgments, on which biases operate, and large exploration and development decisions. This difference is, however, largely illusory because the largest industry decisions, at their base, depend on the judgments of individuals and are, thus, vulnerable to any biases that affect those individuals. Many industry decisions are made by teams, but studies suggest that, in many cases, the "team" decision actually is based largely on the judgment of the most trusted member of that team.

Decisions that seem particularly vulnerable to biases are choices of distributions for input parameters that go into simple volumetrics calculations. Such parameters include average porosity, net-/gross-thickness ratio, and formation volume factor. Given the high degree of subjectivity in assessing these distributions and the difficulty of calibrating the assessments, they are extremely susceptible to cognitive bias. The problem for large O&G decisions is that they rely on many such subjective estimates, all of which are likely to be affected by bias.

This article, written by Technology Editor Dennis Denney, contains highlights of paper SPE 110765, "Modeling the Economic Impact of Cognitive Biases on Oil and Gas Decisions," by ***M.B. Welsh,*** *SPE, and* ***S.H. Begg,*** *SPE, University of Adelaide, and* ***R.B. Bratvold,*** *SPE, University of Stavanger, prepared for the 2007 SPE Annual Technical Conference and Exhibition, Anaheim, California, 11–14 November. The paper has not been peer reviewed.*

Modeling Biases. Three biases were chosen for modeling: overconfidence, trust heuristic, and availability heuristic. The models used for overconfidence and availability heuristic differ slightly but were run using an offshore-development decision regarding a large, but economically marginal, field.

To limit the scope of the problem, bias and uncertainty were restricted to parameters affecting volumetrics. The development characteristics were determined by the interplay of reserves according to realistic rules (including determining the number of wells appropriate to a discovery of a certain size) and by capacity limits, development schedule, and pressure depletion.

Overconfidence

Overconfidence is, perhaps, the best known of the cognitive biases. The nature of this bias is to cause people to overestimate the certainty of their own knowledge with the result that they set too-narrow bounds on the range of possible events. For example, 80%-confidence ranges are used commonly when interpreters are asked to estimate geological parameters such as average porosity and reservoir thickness. Industry data, however, indicate that such ranges, on average, include the actual value less than 50% of the time rather than 80%, as the confidence range should indicate.

Method. To simulate the effect of overconfidence on industry decisions, simultaneous probabilistic reservoir models were used. An offshore development was modeled, using uncertain inputs for determining original oil in place (OOIP), recovery, and a mean-reverting oil-price model. In the base (no-overconfidence) model, the input parameters for the OOIP, recovery, and economic calculations were all determined by Monte Carlo simulation from appropriate, prespecified distributions. The results then were compared with the results of simulations that used the same stochastic process but with transformations of the input parameters that went into the calculation of reserves distributions and which simulated varying degrees of overconfidence.

Often, information states that a field is "large" and is, therefore, more likely to come from the upper end of the distribution that describes the sizes of all fields. This knowledge comes from all prior knowledge and from all information about this field in particular. More generally, uncertainty results from lack of knowledge. Therefore, uncertainty is in our heads, and uncertainty assess-

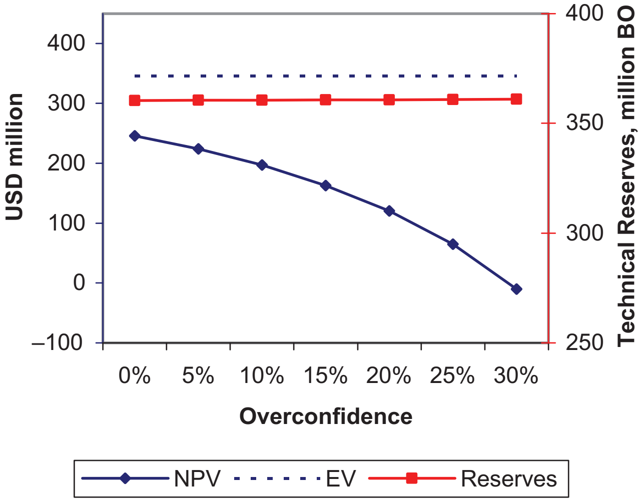


Fig. 1—Effect of overconfidence on NPV.

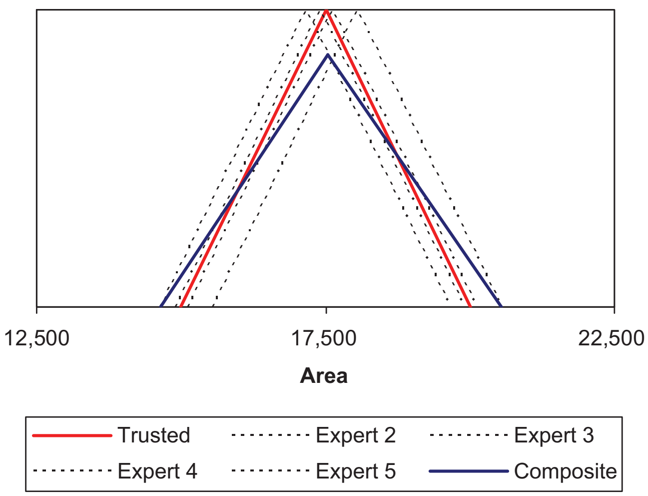


Fig. 2—Single vs. multiple expert opinions.

ments are personal because knowledge is personal. Hence it is not only possible, but valid, for two people to have different probability estimates for the same event, on the basis of their differing knowledge, differing ways of processing it, and of incorporating different past experience. Further, an individual's estimate of a probability might change over time as their knowledge changes. Thus, there is no single "correct" probability distribution, unless all people have identical experience and information, and process these in the same way.

Results. Fig. 1 shows the effect that the varying degrees of overconfidence had on the NPV of the modeled project. The mean NPV from the 10,000-iteration simulation for each level of overconfidence is shown. The deterministic expected value (EV) of the project remained at USD 346 million because the EVs of the input distributions did not change between conditions. The same is true of the volumetric reserves, approximately 360 million bbl. (The actual reserves, being a function of economics, changed).

The simulation results did not reach the EV. Even in the 0%-overconfidence case, the project NPV is only USD 246 million because of nonlinearity arising from model complexity. This result shows the need to use probabilistic rather than deterministic calculations when calculating the EV of complex systems. Fig. 1 shows an accelerating decline in the true expected NPV as overconfidence increases.

Trust Heuristic

Heuristic methods are exploratory problem-solving techniques that use self-educating techniques (i.e., evaluation of feedback) to improve performance. Trust heuristic refers to an observation that managers have a tendency to rely on the judgments of individuals whom they have learned to trust rather than incorporating opinions of everyone working on an interpretation task. The trust underpinning this reliance should have been earned through superior performance and, thus, be justifiable. Even so, an argument can be made for incorporating multiple sources of information rather than relying on a single source.

Fig. 2 shows the beliefs of five experts in the form of triangular probability-distribution functions (PDFs) of the value that an uncertain input parameter, such as area, might take. For simplicity, all the PDFs have the same shape, differing only in their mode to reflect differences in accuracy between the individuals. The assumption is that the most central of the five individuals is the most accurate and, thus, is the one that a manager has learned to trust. Contrasting this "trusted" distribution

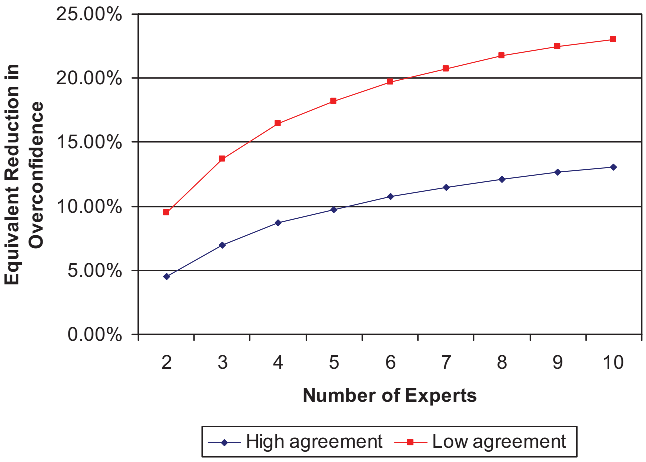


Fig. 3—Reduction in overconfidence by number of experts and degree of agreement.

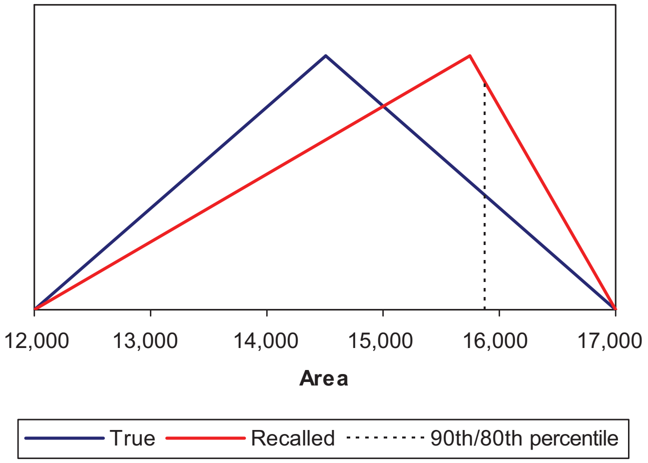


Fig. 4—Bias resulting from availability.

with the composite distribution of all five individual distributions, the single, trusted distribution is noticeably narrower than the composite distribution but the mode has changed very little. Given the observation that individuals are almost universally overconfident when estimating the range of possible values that a parameter might have, the wider, composite distribution is likely to represent reality better.

Results. Fig. 3 shows that including even a single additional expert is the equivalent of reducing overconfidence by an average of 5% when agreement between experts is high and by an average of 10% when agreement is low. With information from five experts, this process would reduce any overconfidence in the trusted expert's distributions by approximately 10%, even if high agreement existed, and by approximately 18% if agreement between experts was low.

Availability Heuristic

Availability heuristic describes the method used commonly by people asked to estimate the frequency of events—simply to use the number of events of a particular type that can be recalled. This method leads to biases resulting from human memory processes that cause us to more easily recall recent events, salient events, and unusual events. While availability could apply equally to both unusually good and bad results, the nature of the exploration side of the O&G industry (which has a need for optimism) is such that extremely good results are more likely to stand out in memory and, therefore, be overestimated in terms of their frequency, particularly in the minds of successful personnel. The most likely result is to skew subjective distributions, as shown in **Fig. 4.**

Results. As in the overconfidence model, the mean NPV calculated by simulation fails to reach the deterministically calculated EV. In this case, however, the EV itself changes from one condition to the next because the availability bias results in changes to the EV of each input parameter. Thus, as the degree of bias increases, the predicted value of the reserves, and the EV, increases. In the unbiased case, the EV is USD 27 million, but the simulated NPV is USD –60 million, again indicating the nonlinearity of the calculation. Therefore, a probabilistic assessment based on unbiased data would show the most likely outcome of the field as a loss, and development would not proceed.

With even the lowest level of availability bias, however, the deterministic estimate of EV rises to USD 210 million while the probabilistic NPV calculation indicates an expected result of USD 118 million. As the strength of the availability bias increases, estimates of NPV continue to rise until (at the highest level of availability) the project's estimated NPV is USD 326 million—USD 386 million more than the value estimated with unbiased inputs.

Summary

All three examined biases resulted in changes to estimates of the value of a project, with errors of up to USD 386 million recorded. Although this result is striking, it should be of greater concern that these results assume the effect of only a single bias on any particular decision and have covered only a fraction of known biases. Further research is recommended into the ways in which biases can affect economic outcomes in the O&G industry and into how the effect can be mitigated.

Therefore, knowledge of decision making under uncertainty can no longer be regarded as simply a benefit but must be regarded as necessary for all industry personnel. It is recommended that the industry ensure that its personnel are aware of the nature and effects of biases, and that they be prepared to avoid or reduce those effects where possible because previous work has shown that awareness of at least some biases can reduce their effect and active training in debiasing can have additional benefit.

While recognizing that current industry personnel can and do receive such training, the dictates of work schedules have tended to result in piecemeal coverage across the industry. Therefore, the authors recommend that cognitive biases, their effect, and methods for avoidance be introduced to petroleum engineering and geoscience students as part of their program curricula. In this way, the industry can be certain that new staff will be equipped with the knowledge and tools for dealing with uncertainty and the biases that can result from it. **JPT**

Kuwait Case Study: Integrated-Reservoir-Management Approach Offsets Effects of Reservoir Heterogeneity, Injectivity Challenges, and Delayed Waterflood

The Upper Burgan is a multilayered reservoir in the Sabiriyah field of northern Kuwait, currently undergoing the initial phase of waterflood development. The reservoir is highly complex with respect to reservoir heterogeneity, connectivity, and structural compartmentalization. Early waterflood performance was too poor to achieve the targeted injection rates. Detailed channel mapping enhanced the subsurface understanding to add value to the ongoing drilling, production, and injection plans. The integrated-reservoir-management (IRM) approach, with a strategy for depletion and pressure support for each segment, increased short-term production and is sustaining the rates. The current and short-term drilling plans target reservoir segments with higher pressures for well placement.

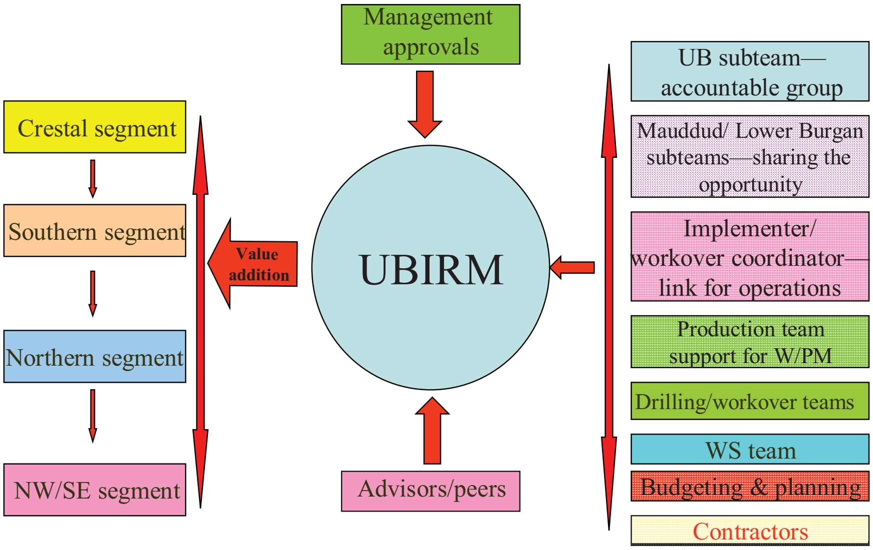


Fig. 1—IRM approach. W/PM=well/production management, WS=well surveillance.

Introduction

The Upper Burgan reservoir in the Sabiriyah field was discovered in the 1950s. The reservoir comprises a complex series of tidal, estuary, deltaic, valley-fill, and shoreface sands interbedded with semicontinuous shales. The first facies is carbonaceous sand, fine- to medium-grained sand with porosity of 22 to 25% and permeability greater than 400 md. The thickness can reach 40 ft, with 10 to 20 ft being typical.

This article, written by Technology Editor Dennis Denney, contains highlights of paper SPE 111472, "Integrated-Reservoir-Management Approach Beats the Impact of Reservoir Heterogeneity, Injectivity Challenges, and Delayed Waterflood in Upper Burgan Reservoir in North Kuwait—A Case History," by ***H.B. Chetri,*** *SPE,* ***Abd Aziz El-Sabry, Mishal Al-Mufarej,*** *and* ***Ealian Al-Anzi,*** *SPE, Kuwait Oil Company, prepared for the 2008 SPE North Africa Technical Conference and Exhibition, Marrakech, Morocco, 12–14 March. The paper has not been peer reviewed.*

The second sand-prone facies is bioturbated sand, a very-fine- to fine-grained facies with variable reservoir quality. The thickness averages 20 ft.

The third facies is heterolithic sand and typically is very-fine- to fine-grained. This facies type is abundant in the Upper Burgan. Reservoir quality is erratic because of its laminated nature, and vertical permeability is low.

The reservoir was subdivided into five mappable layers (UB1 through UB5) in 1992. This zonation scheme was reviewed and modified where appropriate by the Upper Burgan Team in 1997. Average net-pay thickness is 60 to 100 ft. The initial reservoir pressure was 3,800 psia, with a bubblepoint pressure of 1,500 to 2,450 psia. The current reservoir pressure ranges from 2,600 to 3,500 psia.

Reservoir Heterogeneity

Key lessons from analog reservoirs suggest the necessity of flexible development planning. Connectivity was reviewed in terms of stratigraphy, structure, and pressure, with the following general conclusions.

- In many analogous reservoirs, the paralic depositional environment proved more complex than originally thought. Closely spaced wells can exhibit drastic changes in sand character—continued infill drilling most likely will be necessary in some parts of the field in the future.
- Most peripheral floods in paralic environments are converted to pattern floods.
- Small faults in the Upper Burgan can cause nonjuxtaposition of productive layers.
- Structure, channel architecture, and stratigraphy likely will play a significant role in the waterflood performance of the reservoir.

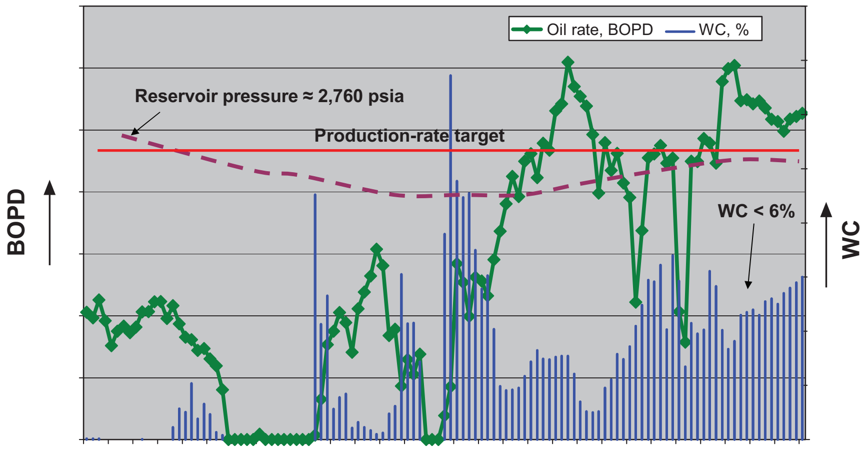


Fig. 2—Southern segment Upper Burgan production trend.

From existing data, the Sabiriyah Upper Burgan reservoir has sufficient connectivity for a waterflood, provided the injector and associated producers are in the same major fault block and channel. Thin sands exist, with numerous faults. Available production and pressure data indicate significant reservoir heterogeneity, with some areas that are effectively pressure-isolated.

IRM

The Upper Burgan IRM (UBIRM) is a multidisciplinary-team approach in which the reservoir is treated as different segments according to actual dynamic performance. A depletion plan was defined and implemented for each segment. The primary objective was to sustain or improve the production, keeping the reservoir pressure above the bubblepoint pressure, thereby nullifying negative effects of the delay of several years in full-scale water injection.

Heterogeneity Effects

The IRM approach was adopted to overcome the effects of reservoir heterogeneity on short- and long-term production and on reserves delivery. A matrix of components leading to uncertainties and their associated effects was created on the basis of feedback from key geologists, geophysicists, and engineers. The following key actions were identified.

- Reinterpret seismic data and the reservoir structure.
- Review the existing petrophysical model covering all key wells of the reservoir, and update the model, if deemed necessary.
- Build a new static model with an updated reservoir description.
- Proceed slowly in drilling new wells in the crestal part of the reservoir where offtake is constrained by a formation-pressure sink.
- Focus on short-term development, drilling in segments having high reservoir pressures.
- Conduct high-level reservoir surveillance, particularly pressure-buildup tests and specially designed interference tests, to further enhance the understanding of reservoir connectivity.

Reservoir Segments

To implement the recommendation, a team approach was adopted in which groups associated with studies and reservoir monitoring and analysis, along with operational groups, were made fully aware of the effects of the approach through regular meetings, discussion sessions, and presentations. **Fig. 1** shows the UBIRM organization.

Implementation of the new approach achieved production redistribution, meeting objectives and targets of keeping the pressure above the bubblepoint, despite delays with the water-injection facilities. Water cut (WC) has been kept to a low level. Waterflood response has affected well rates in the crestal part by use of limited water injection. The target for the reservoir is 15,000 to 20,000 BOPD through 2012, but IRM helped the team to produce the field at a rate as high as double the target rate, as shown in **Fig. 2.**

Steps leading to enhanced production with low WC were as follows.

- Studied the injectors and diagnosed reasons for poor injectivity.
- Injectors selected to be put on line.
- Monitored reservoir pressure and injection-well performance continuously.
- Increased crestal reservoir pressure by 200 to 400 psia, which enabled withdrawing the earlier decision of cutting crestal production.
- Reviewing and revising the injection allowables on the basis of pressure/production-performance data every month delayed water breakthrough.
- Identified segments receiving aquifer support.
- Optimized well use in the southern segment (with no historical off-take and remaining high pressure).
- Enhanced surveillance to monitor reservoir pressure.
- Identified wells having potential as intermittent producers, opening these wells periodically for bonus production (especially wells having mild aquifer support).
- Prioritized the flowline connection for new wells on the basis of reservoir pressure and well productivity.
- Conducted well reviews with an integrated-team approach for planning and prioritizing rigless operations and rig-workover jobs.
- Prioritized gas lift candidates on the basis of reservoir pressure.
- Improved communication with the operational teams and contractors.

IRM Effect on Overall Development Strategy

The IRM approach led to the recommendation that the development plan include the following strategies.

Short-Term Strategies (2007 to 2010). The crestal area of the Sabiriyah Upper Burgan has been drained. As a result, the reservoir pressure has declined to 2,600 psi (close to the bubblepoint). Ideally, this will be repressurized to the pressure of the flank areas (i.e., 3,200 psi), if this can be achieved without compromising production targets. Unfortunately, additional water injection will not be available until 2010, which means that the off-take from this portion must be restricted. The plan during this period is as follows.

- Restrict off-take from the low-pressure area, aligned with the limited water-injection options available, to prevent development of a secondary gas cap in these layers.
- Target low-water oil-segment production, keeping the pressure above the bubblepoint by 200 to 700 psi. Increase production from layers having additional well and reservoir poten-

tial and having a saturation pressure significantly higher than the reservoir pressure.

- Continue to evaluate waterflood performance of segments in the crestal area and integrate with the overall-development activities.
- Place new development wells in areas with high reservoir pressures.
- Take advantage of aquifer support in the western flank and increase off-take with pumps and gas lift.
- Map the channels, reduce subsurface uncertainty, and rebuild the static and dynamic models.
- Continue efforts to evaluate the injectivity performance, and identify methods to improve it.
- Implement the highest degree of reservoir surveillance and management to reduce reservoir uncertainties.

Medium-Term Strategies (2010 to 2012). The plan for this period is as follows.

- Confirm details on the basis of early results of the short-term plan and reservoir-performance results.
- Develop an upside contingency plan (if the reservoir performs better than expected), drill additional producers, and use the enhanced surface facilities such as the new gathering center and water-injection plant.
- Implement a downside contingency plan (if the reservoir performs poorer than expected), diagnose the problems, and investigate the feasibility of aggressive efforts for electrical-submersible pumping and gas lift, including stimulation techniques to sustain target rates.
- Continue the highest degree of reservoir surveillance and management.

Long-Term Strategies (After 2012). It is anticipated that the development plan will continue to be depletion with waterflooding with a combination of pattern, peripheral, or irregular patterns, as suited to the channel distribution. However, experience from the short and medium terms will indicate the need for any change in strategy. Surveillance and new well data obtained during the early development phases will provide data needed for review. Implementation for achieving the highest degree of reservoir surveillance and management to reduce reservoir uncertainties must continue to be the focal point. JPT

Moving From Vision to Reality—Optimal-Value Testing

Optimal-value testing (OVT) could replace conventional drillstem tests (DSTs) for in-situ measurement of dynamic reservoir properties such as permeability and drainage volume. OVT is any pressure-transient test in which live hydrocarbons are not produced directly to surface. Although OVT is safer, less costly, and environmentally friendly, the OVT-results quality might be inadequate for some development decisions. The technology is immature, and there are issues to resolve. However, with increasing experience, future value-of-information (VOI) decisions about performing in-situ dynamic measurements will, more often, include OVT.

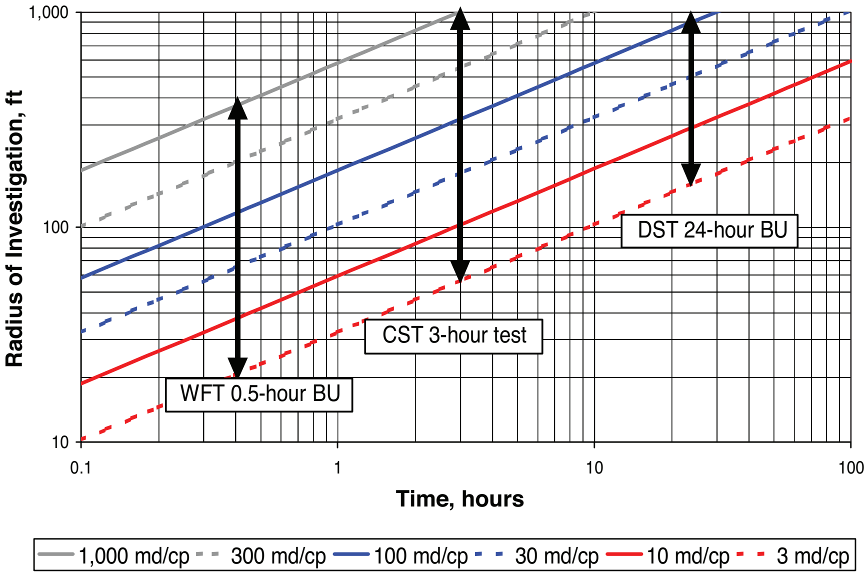


Fig. 1—Radius of investigation for OVT types. CST=closed-system test, BU=buildup.

Introduction

The focus of this paper is the use of dynamic well testing in exploratory and appraisal wells. Historically, the industry called this testing a DST. This type of test, in which hydrocarbons flow directly to surface while measuring rate and pressure, is a major tool in deciding how to develop a hydrocarbon resource. Cost along with health, safety, and environmental (HSE) concerns encourages seeking better ways of obtaining similar reservoir and fluid data. OVT is any fit-for-purpose well testing with minimal cost and HSE effect in which no significant volume of live hydrocarbons is produced to the surface. Three types of tests are wireline formation tests (WFTs), closed-system tests, and injection tests.

Background

Any assessment of OVT must include an understanding of resource-development uncertainties and the reliability of the technology. The types of technologies considered for OVT are not new, but certainly are not as mature as conventional DSTs.

WFT. These tests are performed by use of an electrically controlled formation-testing and -sampling tool anchored at depth (usually on wireline and in open hole) while reservoir communication is established through one or more probes or packers. Modern WFTs can collect a massive amount of data at multiple depths, helping to quantify changes in rock and fluid properties along the wellbore, to define hydraulic flow units, and to understand reservoir architecture. These tests are used routinely in many applications including pressure and mobility profiling vs. depth, fluid sampling, downhole-fluid analysis, pressure-transient testing, and microfracturing. Wireline testers have reached a maturity level at which their performance often can match that of production tests such as those carried out with a DST.

The modular and configurable nature of these tools enables scanning fluid properties as well as collecting samples from multiple depths across a reservoir to delineate complex gradations in the fluid column. WFTs provide information on rock/fluid mobilities at different scales, from core-like pretest scale to tens of feet with mini-DSTs and vertical-interference testing. The applications of modern WFTs can be

This article, written by Technology Editor Dennis Denney, contains highlights of paper SPE 114870, "Moving From Vision to Reality—The State of Optimal-Value Testing," by ***Hani Elshahawi,*** *SPE,* ***Robert H. Hite,*** *SPE, and* ***Melton P. Hows,*** *SPE, Shell, prepared for the 2008 Asia Pacific Oil and Gas Conference and Exhibition, Perth, Australia, 20–22 October. The paper has not been peer reviewed.*

For a limited time, the full-length paper is available free to SPE members at www.spe.org/jpt.

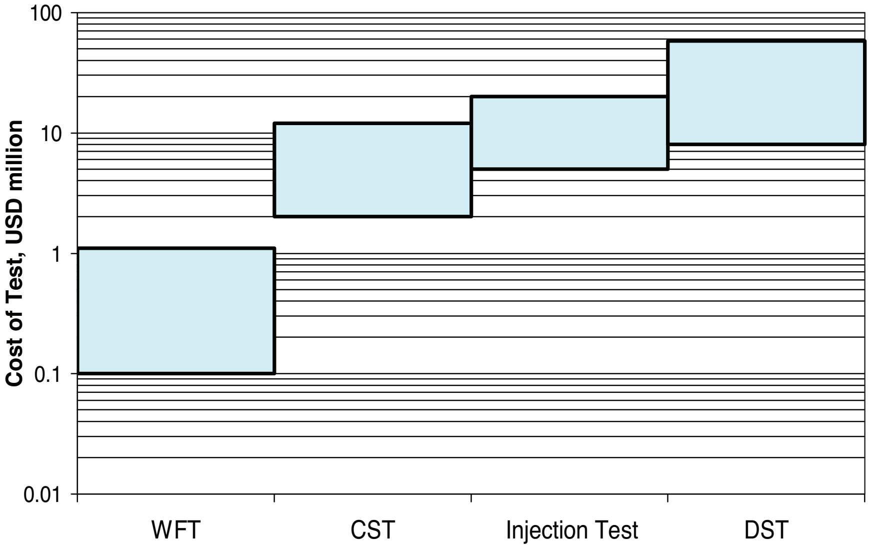


Fig. 2—Approximate costs for various types of well tests.

grouped as pressure profiling, fluid sampling, downhole-fluid analysis, and permeability profiling.

Closed-System Test. Closed-system tests establish a pressure differential between the reservoir and a chamber. Reservoir fluids flow quickly into the lower-pressure chamber either by perforation or by opening a valve. These tests are called surge tests or closed-chamber tests, but the phrase "closed-system test" indicates a modified design. The high-pressure side, below the valve, initially is close to the pressure in the reservoir. The test begins by opening the valve and allowing reservoir fluids to enter the tubing chamber above the valve rapidly. The fluids, chamber size, and initial pressure in the inflow chamber vary, depending on the test design. This type of test can occur immediately after underbalanced perforating. Because these tests occur during the initial flows from the well, a common drawback is the lack of cleanup. Because well properties often change during the first few days of flow in conventional tests, a closed-system test with a much shorter duration of flow will be more prone to this problem. Although skin is the well-test parameter most associated with cleanup, increasing permeability-thickness value has been observed as a well cleans up. Theoretically, this change cannot happen in a homogeneous system, but real systems with different skins on different layers can exhibit this behavior.

A sequence of operations to remedy the cleanup problem was devised and is detailed in the full-length paper. An advantage of a closed-system test over a WFT is the larger volume of fluid samples collected, but typically the quality and representativeness of the samples are not as good as those in samples typically acquired with WFT tools.

Injection Test. Injection testing is a simpler concept than either wireline formation testing or closed-system testing. Fluid is injected into the formation at a measured rate, and then the well is shut in, leading to a pressure falloff. In this sense, an injection test is the mirror image of a conventional DST. However, the analysis of injection data is more complex, primarily because of multiphase-flow effects. Fracturing, stemming from cold water and/or high pressure, and gravity segregation are other possible complications. Although most injection tests use water, a gas injectant might be useful in tight gas reservoirs. For a test in which water is injected into a hydrocarbon zone, the sequence is counterintuitive in that the outer oil bank shows up on the derivative before the inner water bank does. However, the falloff sees farther from the well, as would be expected from similar later-time responses. Because of the complex near-well flow, using an injection test to determine skin or completion quality is not recommended.

Relative Comparisons. Generally, highly reliable results can be extracted from WFTs with mobilities ranging between 5 and 500 md/cp, the range that is most interesting from an economic perspective. Reservoirs with much lower permeability normally require stimulation, while reservoirs with much higher permeability normally are constrained mechanically rather than by reservoir deliverability.

A typical duration for the main buildup is 30 minutes for a WFT, 3 hours for a closed-system test, and 24 hours for a conventional test. Taking these durations and considering a range of fluid mobilities, one can understand the types of information obtained from each type of test. **Fig. 1** assumed a porosity of 25% and a total compressibility of 1 E–05 psi^{-1} for all the mobility cases. Even in the lowest-mobility case, a WFT can sense more than 25 ft away from the well, and up to 400 ft in the highest-mobility case. Therefore, a WFT in even the lowest-mobility case will obtain average properties significantly beyond any drilling-induced damage, which almost never exceeds 10 ft. However, the relatively small radius of investigation limits the wider use of this type of test for learning about boundaries. For closed-system tests, the radii of investigation are between a WFT and a conventional test.

Another important aspect is cost. When VOI is used to determine whether to perform OVT, the initial focus is on the comparative benefits of OVT, but much of the relative value comes from lower costs. **Fig. 2** compares cost ranges for the different types of tests. This graph was prepared in 2003 but is still valuable in estimating relative costs. It should be noted that these costs assume offshore operations in which a rig would be required throughout the test. Onshore operations for which it might be possible to release expensive equipment during portions of the test will have a different cost structure. Still, the important observation is that WFTs are less expensive than other types of testing.

Reliability of OVT

Although OVT often costs less and has less HSE risk than conventional tests, reliability must be addressed before they are more widely accepted as full

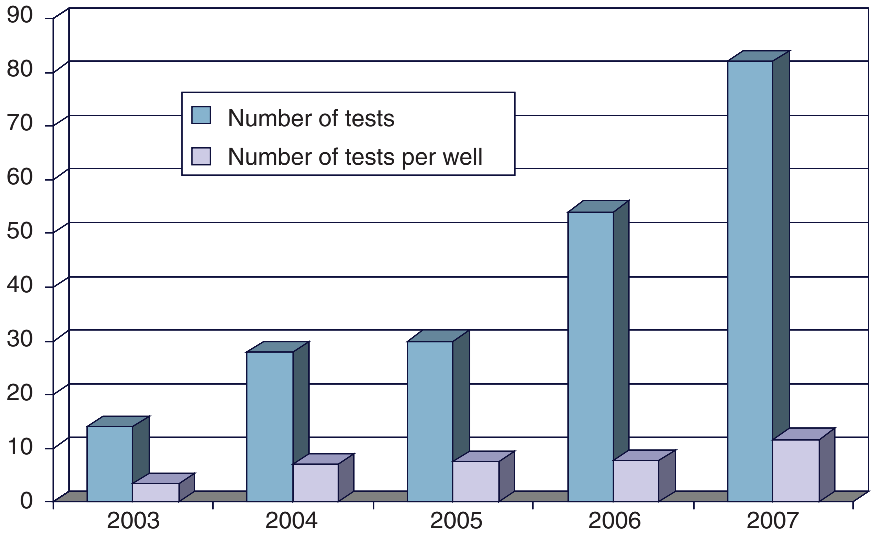


Fig. 3—Increase in the use of WFT-type OVT in Shell.

alternatives. A series of optimal-value tests was performed, and the results were examined in the context of well-established well-testing principles. Analytical reliability was assessed by comparing results from OVT techniques with results from the conventional techniques. Operational reliability is related mostly to the mechanical complexity of the operations required to gather the pressure/volume data.

WFTs. Fig. 3 shows the increase in the number of tests in general and the number of tests per well. Confidence in the ability of WFTs to replace conventional DSTs for determining permeability and acquiring fluid samples requires that many real-data cases behave as theory would predict and a massive body of operational experience.

Although it is possible to include the flowing and buildup periods, a log-log diagnostic graph of each buildup was made first. The primary flow patterns expected in a WFT are spherical followed by radial. The radial-flow pattern is, by definition, always transient and is most useful for determining horizontal permeability. It is important to emphasize that observing radial flow is not mandatory in all cases. Even when radial flow does not appear, unique horizontal-permeability results can be obtained through analysis of offset (observation) probe data. Therefore, the analytical reliability of WFTs has been demonstrated to observe radial flow in nearly three-fourths of the tests performed.

Closed-System Test. Similar to WFTs, there have been limited opportunities to compare closed-system tests directly to conventional DSTs. Reliability issues for closed-system tests are operational. Many of the analytical issues result from the operational complexity. Similar to WFTs, a closed-system test is inherently more complex than a conventional DST—there are many more steps of moving fluids between the annulus and the tubing. The use of as many as 24 gauges is required to estimate the locations of fluid in the well at any time.

Closed-system tests cost more than WFTs and generally provide less information about the reservoir. Therefore, their use has been limited. The permeability from such a test would be averaged over a slightly larger radius than that of the WFT, but most importantly, the closed-system test does not lend itself to permeability profiling. The small pressure-signal size and intermediate durations mean that closed-system tests are also not reliable for boundary or connected-volume testing.

Injection Test. Testing for skin in an exploratory or appraisal setting is rare, primarily because the well usually is not completed in the same manner as in the final production phase. For horizontal or hydraulically fractured wells in which testing the completion is required before deciding the field-development plan, none of the OVT options will work well, thus requiring a conventional DST.

Testing for boundaries is the main purpose for injection testing. Because the radius of investigation is linked directly to the duration of the test, proving large drainage volumes generally requires test durations longer than those experienced with WFTs or closed-system tests. Investigating a large radius by injecting rather than producing fluids reduces emissions, a primary driver for OVT. Although injection-test data are less reliable than production data, because of multiphase flow and possible fracturing effects, injection testing might be preferred for an oil reservoir having a pressure close to the bubblepoint, thus avoiding release of solution gas that would obscure material-balance volumetrics.

Falloff analysis of the late-time data is the same as late-time buildups. Therefore, long-term injection testing will have reliability similar to that of extended DSTs.

Conclusions

- OVT is becoming accepted. Many conventional DSTs are being replaced with WFTs, closed-system tests, or injection tests.
- Confidence in the reliability of OVT is improving. Confidence increases as well-test patterns from OVT are observed to fit the theory and exhibit the same radial-flow stabilizations found in conventional tests.
- The WFT is accepted for gathering fluid samples. WFTs can replace DSTs when the main purpose is to determine permeability. The WFT provides more details about the permeability than does a DST.
- Because of the limited flow rates and small pressure changes during a WFT, there is an upper limit of reservoir quality, above which a WFT will not produce accurate results. However, in most cases this limit is high enough to allow use of WFTs.
- Closed-system tests are capable of measuring permeability and a cleaned-up skin, but they are not widely used because WFTs deliver more-detailed results at lower costs with less operational complexity.
- Injection tests are the only type of OVT with the potential to measure boundaries and reservoir compartments consistently.
- None of the OVT types address completion properties for horizontal or hydraulically fractured wells. **JPT**

Decision Environments: Lessons Learned From Implementation and Future Direction

Chevron and Science Applications International Corporation (SAIC) are implementing asset-decision environments (ADEs) across business units as part of Chevron's *i-field* initiative. Decision and collaboration environments address challenges associated with response to real-time data, scarcity of experienced resources, and integration of and collaboration between disciplines and locations. Practical lessons learned on how to design an ADE are presented to address problems and deliver value, and still remain flexible to developments in the future.

Introduction

This digital-oilfield initiative was launched in late 2002 with a vision of transforming the way assets are managed and operated by integrating new technologies, new work processes, and new ways of working. The integrated field is an operational transformation philosophy that drives enhanced and optimized operating processes with these common attributes.

- Manage by exception (focus on highest value)
- Improve collaboration across distance and function
- Remove people from harm's way
- Standardize and centralize analysis and decision making
- Use real- or right-time data in decision making

An assessment process to engage assets and business units was developed that identifies an asset's key issues and makes recommendations on how to resolve those issues and add value. Early assessments, carried out in 2003 and 2004, recognized some common issues associated with different groups not able to access the same data at the same time, the need to collaborate across disciplines and locations, and how to make best use of scarce expert resources. The concept of the ADE was developed in 2004 in response to these needs.

ADEs at Chevron. The definition of an ADE is intentionally general, allowing several types of decision environments to be included. An ADE is a real-time operating environment in which people can manage and execute business processes by use of collaborative decision making across part or all of an asset or business unit. **Fig. 1** shows how an ADE, or collaborative environment, spans the office and field, and may include experts from other locations or other organizations. It may be a physical operation room, a virtual environment, or a hybrid of both. An ADE is not defined by its physical properties; rather, it is thought of in terms of the activities and processes that it enables and facilitates.

There are two main ADE types at Chevron:

- Continuously staffed—one or more individuals work in the ADE full time. This ADE may be staffed during the working day, 7 days/week, or even "24/7".
- Event-driven—not staffed continuously, it is used for scheduled or opportunistic events. These events can include regularly scheduled activities such as a daily morning meeting or a well-pattern review, ad hoc events, or meetings held in response to a particular problem or issue.

Approach Overview

To assess suitability, the team looked at examples and lessons learned from other industries and investigated several approaches. Two types were identified; one focused on the physical design of the environments, and the other focused on process design for use in the environments.

- Physical design—this approach focuses on building the physical environments, with the assumption that once they are up and running, people will use them. Without the correct level of attention to process redesign and user training, there is a high level of risk that the rooms will not get used or will be used as standard meeting rooms, without users taking advantage of the advanced collaboration facilities.
- Focus on process design—this approach involves a high level of upfront user involvement. A detailed process-design and re-engineering exercise is carried out that designs new processes to run in the collaboration environment and is used to drive physical and technical requirements for the new environment. Users are heavily involved throughout the process and are provided intensive training on the new processes and use of the technology. This approach could be successful in an environment having a high level of management support, but it can be a lengthy process. There is a risk that user enthusiasm and management support will diminish during the months required for process design and implementation.

This article, written by Technology Editor Dennis Denney, contains highlights of paper SPE 112215, "Evolution of Decision Environments: Lessons Learned From Global Implementations and Future Direction of Decision Environments," by ***Michael Hauser,*** *SPE, Chevron, and* ***Helen Gilman,*** *SAIC, prepared for the 2008 SPE Intelligent Energy Conference and Exhibition, Amsterdam, 25–27 February. The paper has not been peer reviewed.*

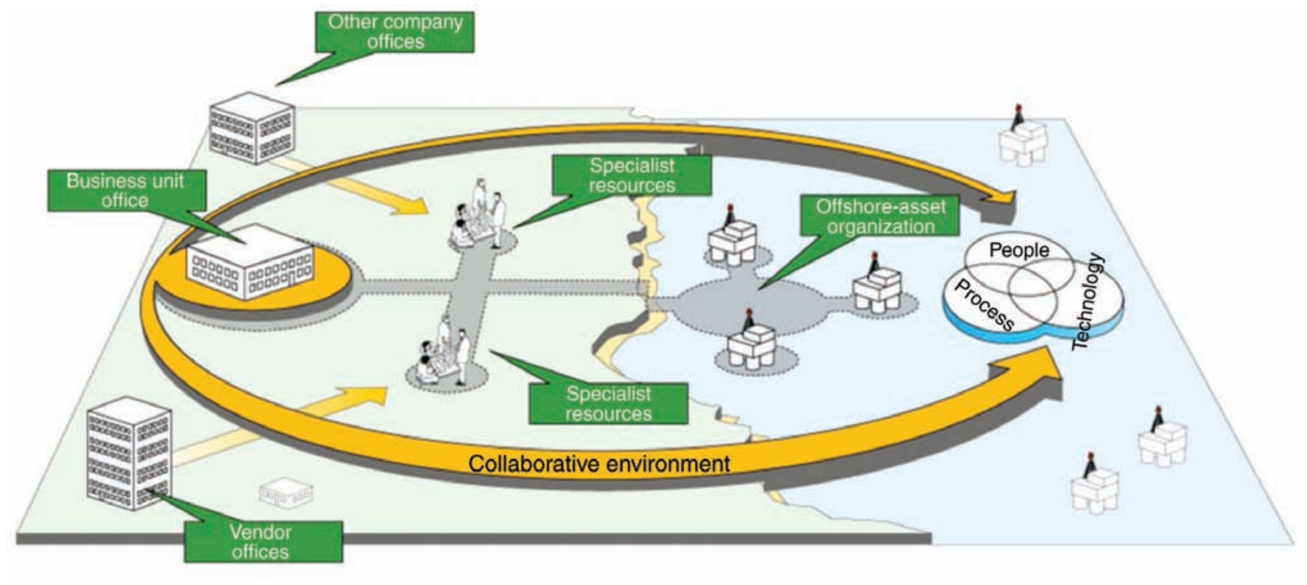


Fig. 1—Illustration of the collaboration environment, or ADE, at Chevron.

The ADE concept was new, and taking an extended process-based approach would not help to deliver value quickly, or get people (and management teams) to support the concept. Conversely, building rooms and expecting people to use them was risky, one that delivered mixed success elsewhere in the industry.

A compromise approach combined advantages of the two approaches. The aim was to build the rooms quickly to provide facilities that could be used to deliver value, but at the same time, carry out focused process and training work to ensure that the user communities were comfortable using the ADE. Lessons from other industries and other oil companies showed that when people started using ADEs, possible solutions were studied that were not obvious before working in an ADE. Focus was placed on getting a few processes operational in the ADE while putting the right levels of support in place to enable users to develop and expand the use of ADEs after becoming familiar with the operation. The basics of the approach are as follows.

- Identify and understand key areas of business-driven opportunities.
- Identify a few key processes to be implemented in the ADE.
- Start with processes having initial leadership support.
- Allow flexibility.
- Focus on starting quickly and cheaply, identifying the initial learnings and then building on them.
- Provide the right level of support mechanisms for the user community after implementation.

The process-design work takes place in parallel with physical design and build out, and users are trained in the new processes and use of the collaboration technology. This approach provided the right combination of process, technology, and people activities, and it delivered results quickly. Once users start working in an ADE, a "pull" is created to implement further processes and uses of the ADE.

This approach delivered success in that many early implementations are demonstrating benefits that were not envisioned in the original design. These benefits become apparent as users become familiar with ADE operations and identify new ways of working. The user communities are responding with increased collaboration and suggestions of new processes.

Key Challenges

The challenges were not unique. To a large extent, all oil companies (and perhaps other industries) need to address similar challenges.

People. Actions taken by Chevron to address people issues include the following.

- User involvement—getting users involved in the early stages helped build user buy-in and ensured credible process design and subsequent implementation success.
- Identify champions—part of the change-management activity in which local champions are more persuasive and have a higher degree of credibility than those from outside.
- Secure management support—active communication with the management team ensured backing of the ADE project and positive communication to their teams.
- Emphasize "the positive"—ADEs do not watch or monitor individual performance, and this message had to be reinforced.
- Use other successes—attitudes changed after individuals visited an ADE; members of other asset teams were encouraged to visit and talk to people working there.
- Train—some of the technology was new, and if it was not easy to use, people would not use it. An effective training program was critical. Scenario-based training was more effective than function-based training.
- Coach—an ADE coach helped when implementing a large number of ADEs.

Fig. 2—Chevron's vision for the **i-field.**

Process. Actions taken to address these issues include the following.

- Process design—identified a few key processes that could add value, developed detailed use cases for them, and then implemented them to deliver early results.
- Load—carefully regulated the amount of process mapping undertaken.
- Initiative—allowed users to generate their own ideas.

Technology. Actions taken to address these issues include the following.

- Usability—attention was given to the people issue associated with "the technology is too difficult to use."
- Early version—carefully evaluated anything that was "release 1" or still in development.
- Bandwidth limitations—ensured that bandwidth limitations were understood. Some collaboration solutions (e.g., video conferencing) offer very limited advantage in low-bandwidth environments.
- Central team—even a few part-time people responsible for collecting the knowledge gained in implementing business units could transfer this information to other areas.
- Software—the central team tested new software, moving the risk and effort from the business unit to a central team.
- Facilities—leveraged new-office builds or office moves.

Lessons Learned

The first Chevron ADE was delivered at the end of 2005. By mid-2008, there were more than 50 ADEs implemented in Bakersfield, California; Houston; New Orleans; Aberdeen; and in Nigeria.

The challenge is measurement of results. At Chevron, the approach is to not build a business case for the ADE alone. Usually, ADEs are implemented as part of an integrated project that includes other elements, such as new hardware and instrumentation, software tools, analysis and visualization tools, or improved processes. Metrics can be put in place to capture "soft" benefits.

- Availability: Is the ADE available? Does everything in it work?
- Use: How often is the ADE in use vs. expected usage from the design phase? How at ease are the users working in an ADE? Is it easy to operate?
- Effect: What difference is the ADE making?

Typical results from ADE implementations include the following:

- Work faster
- Faster decision making
- Improved collaboration
- Improved visualization leading to greater understanding
- Making better use of experts
- Reduced misinformation
- Helping to embed digital-oilfield-initiative changes

Key lessons learned include the following.

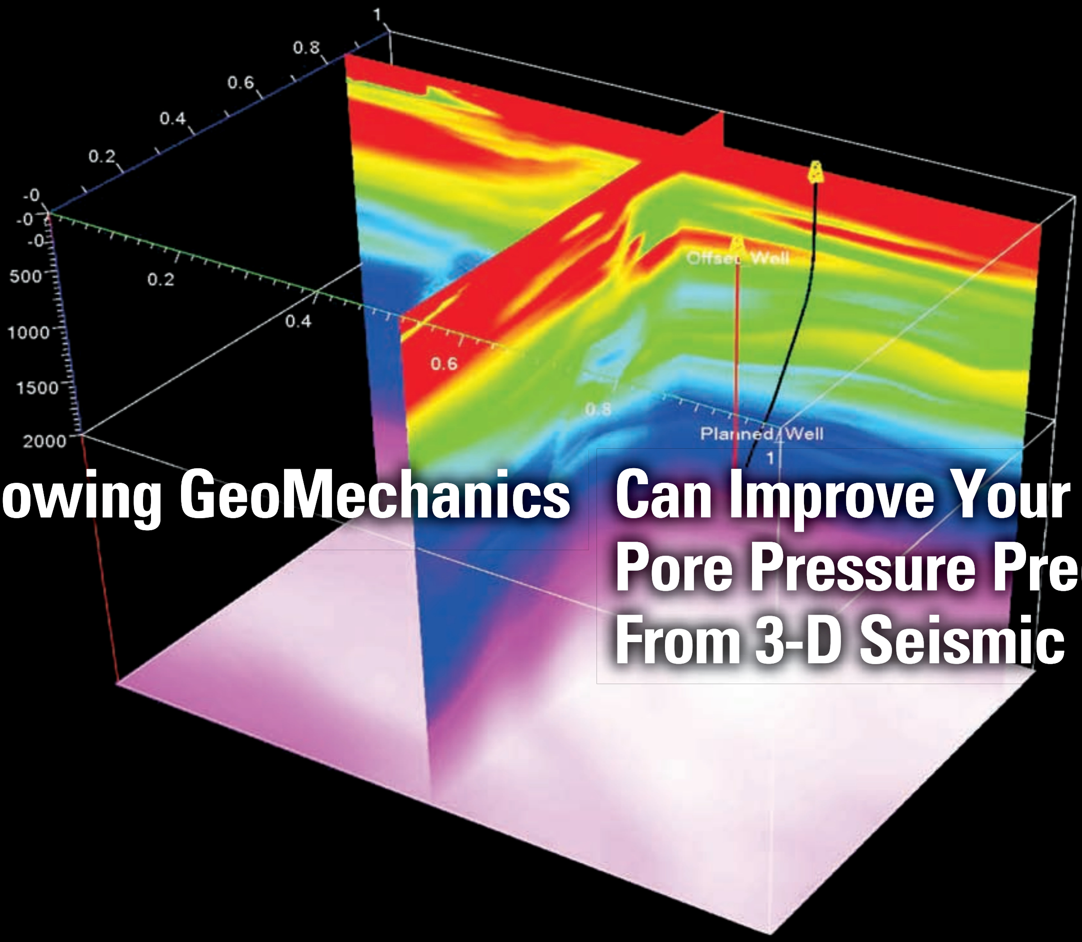
- Strike the proper balance between early delivery and process design.
- Pay attention to technical and usability issues. If it is too difficult to use, the users will not engage.
- Involve the user community from the beginning, but be sensitive to time commitments required for the project.
- Remember that the opportunities are significant.
- As ADEs are implemented, users will generate new ideas to transform how they work.
- Management of change (not just training) is very important.
- Post-implementation support is important to maintain changes. For suites of ADEs implemented simultaneously, consider a full-time ADE coach.
- Leverage success. Once an ADE has been implemented successfully, use it to demonstrate its value.
- Develop and capture success metrics for the ADE (e.g., a mixture of availability and usability statistics, user surveys, and anecdotal evidence). Do not develop a business case for an ADE in isolation.

This is just the beginning. Chevron believes that ADE implementations to date are a small step in collaboration and transformation. The approach is to manage the scope of an implementation to deliver benefit early, but at the same time, remain flexible as to how the work could change in the long term.

Future Direction of ADEs

The potential of ADEs in production operations has been transformed. As we continue to progress toward more-advanced digital oil fields, there will be opportunities to increase expectations in defining the transformed state of operating assets. **Fig. 2** shows Chevron's vision of the advanced *i-field*. Our limitation will most likely be how comfortable we will feel changing work processes and how much behavioral change we will be willing to absorb. **JPT**

GEOMECHANICS FOR DRILLING



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Knowing GMI will complete your pore pressure prediction picture. Predicting pore pressure is critical for any well plan.

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