Reservoir Performance and Monitoring

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"Reservoir engineering is a complex subject for two reasons. In the first place, we never see enough of the reservoirs we are trying to describe. Therefore, it is difficult to define the physics of the system and, therefore, select the correct mathematics to describe the physics with any degree of certainty. The second problem is that even having selected a sensible mathematical model, there are never enough equations to solve for the number of unknowns involved" (Dake 2001).

Prudent reservoir management requires active reservoir surveillance to optimize reservoir performance. The challenge for reservoir engineers is to justify the additional cost involved in gathering data and also to transform those data into valuable information. The paper describing an integrated reservoir-surveillance process for the greater Burgan field in Kuwait is an excellent example of how to justify implementing a systematic surveillance process.

Lack of data and lack of confidence in data are major challenges in developing brownfields. The paper "Revitalization of Old-Asset Oil Fields Into I-fields" describes how old fields can benefit from the application of modern surveillance technology.

The trend toward intelligent fields has increased the use (and demand) for real-time reservoir management. To take advantage of the continuously and rapidly increasing amount of data, the industry will need a workflow shift from the deterministic approach to one based on statistical approaches. The paper "Where is the Gap? Is It in More Reservoir Engineers or in Leveraging New Skills and Workflows That Enhance Individual Productivity?" examines how reservoir engineers can improve productivity by use of statistical concepts and workflows.

The additional reading addresses some of the challenges the industry is facing in developing unconventional hydrocarbon resources—in this case, shale gas. **JPT**

Reference

Dake, L.P. 2001. *The Practice of Reservoir Engineering,* ix. Amsterdam: Elsevier.

Reservoir Performance and Monitoring additional reading available at OnePetro: www.onepetro.org

SPE 119892 *• "Impact of Shale Properties on Pore Structure and Storage Characteristics" by R.M. Bustin, University of British Columbia, et al.*

SPE 119897 *• "Production Analysis and Forecasting of Shale-Gas Reservoirs: Case-History-Based Approach" by L. Mattar, SPE, Fekete Associates, et al.*

Development of an Integrated Reservoir-Surveillance Process

The Greater Burgan field in Kuwait was discovered in 1938 and contains more than 1,000 wells. It is extremely important to identify and perform focused surveillance work to have a better understanding of the reservoir drainage mechanism, remaining potential, and pressure decline. Considerable data accumulate every year, leading to questions about whether acquiring so much data is justified. This paper describes the approach to develop an integrated reservoir-surveillance plan for monitoring the field.

Introduction

The Greater Burgan sandstone oil field covers a surface area of approximately 320 sq miles. The four main reservoir units are the Wara, Mauddud, Burgan Third sand, and Burgan Fourth sand. Other contributing units are Minagish, Marrat, and Zubair reservoirs. A very dynamic development plan was implemented to sustain production. The strategy involves increased well activity and production-facility and -capacity upgrade. Many new wells are planned, including high-producing-rate horizontal wells in the main Burgan sands.

Reservoir surveillance is key. With new wells being drilled, the need for organized surveillance has increased to monitor this large reservoir, depletion trends, remaining potential, and pressure support. Surveillance planning is critical in ensuring that sufficient data are acquired. Standard processes must be in place to manage and interpret the acquired data. The quality and value of information must be assessed to justify the surveillance plan and the future requirements for continued optimization of current production and reservoir-management strategies.

Current Process

Routine surveillance data are acquired annually to optimize well production and to provide input for reservoir-management studies. Surveillance activities were reviewed over the last 3 years to assess the need for and to highlight the interpretation of the acquired data, and to determine the consequent value-added decisions based on the analysis. Surveillance data add value through incremental benefits in terms of production gain or water curtailment, and by incorporating data into ongoing reservoir-management and -mapping studies.

Focusing on a New Approach

The approach focuses on value generated from the acquired-data interpretation to provide reservoir pressure; reservoir permeability; water saturation; sweep efficiency; well-productivity index; well flow capacity; fluid contacts; and flow rates of oil, gas, and water. The significance of surveillance information through routine and planned diagnostic and monitoring purposes is measured against an ultimate gain in production, water curtailment, production optimization, and overall meeting of best reservoir-management practices. Timely update of information, through surveillance, on the water-encroachment maps and in simulation studies is instrumental for optimizing recovery and formulating a better depletion strategy.

Integrated Reservoir Surveillance

A fieldwide integrated surveillance plan was developed with benchmarks and guidelines streamlining the needs and processes for data procurement for best reservoir-management practices. Recommendations for each selected category of surveillance are made to ensure that the approach is consistent with the needs for obtaining required information.

Stage 1—Historical Surveillance Data Compilation. The vast amount of data are stored primarily in corporate databases. The first step was to amass all data acquired from more than 6,500 surveillance jobs conducted over the 3-year period. Then, data were filtered and cleaned to remove unnecessary records. Incomplete jobs and some that were cancelled for various operational concerns were removed.

The third step in Stage 1 was to segregate the core category of jobs relevant to reservoir and well surveillance, which are performed specifically for the purpose of reservoir monitoring and production optimization. The following core surveillance activities formed the basis of this study.

- Portable well tests
- Static bottomhole pressure (SBHP)
- Flowing bottomhole pressure (FBHP)
- Pressure buildup
- Pulsed-neutron capture (PNC)
- Production logging test (PLT)

Stage 2—Data Interpretation and Identifying Value Addition. The second stage required multidisciplinary teams to perform quality control on the filtered data and to report the results from analysis and interpretation, preferably as tangible benefits in terms of barrels of oil gained or reduction in water/gas production. Historical data were grouped by surveillance type, performed in given

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This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper SPE 120229, "Development of an Integrated Reservoir-Surveillance Process for World's Second-Largest Field in Kuwait," by ***Sameer F. Desai,*** *SPE,* ***Hussain Z. Al-Ajmi,*** *SPE, and* ***Jamal H. Al-Humoud,*** *Kuwait Oil Company, and* ***Naz H. Gazi,*** *SPE, Halliburton, prepared for the 2009 SPE Middle East Oil & Gas Show and Conference, Kingdom of Bahrain, 15–18 March. 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.

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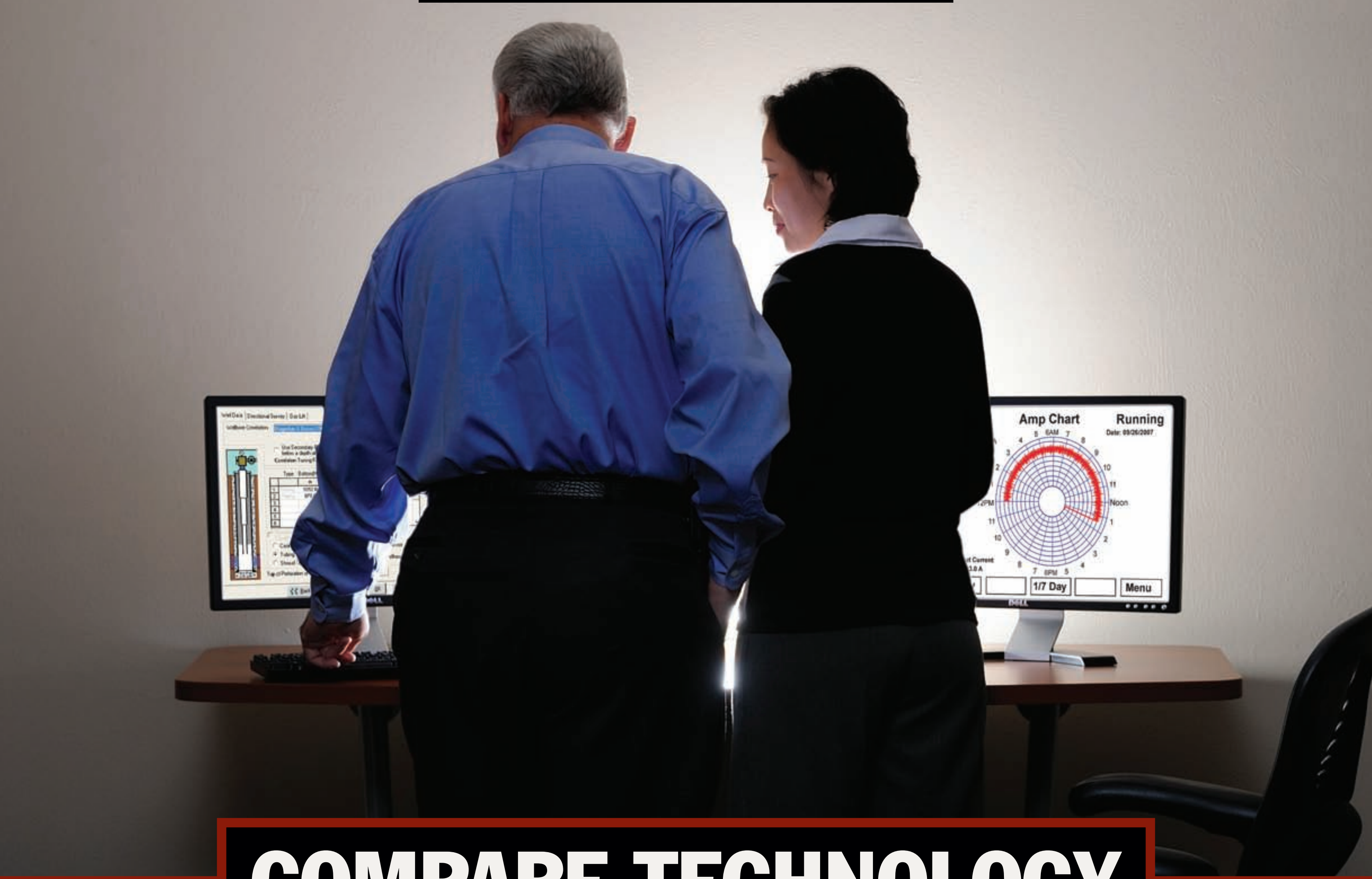

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areas such that the respective team could review and provide feedback for each survey performed during the given period of time. The primary objective was to establish a relationship between the well performance before and after a surveillance activity and to identify measures taken. Noticeable changes in fluid-production rates, water/oil ratio, gas/oil ratio (GOR), changes in choke sizes, and others were used as leading indicators. The information then was used to determine incremental benefits obtained in terms of production and/or additional reserves. Correspondingly, a value addition from the job was highlighted.

Stage 3—Quantify Value To Justify the Need for the Acquired Data. Data acquisition is expensive, and it can be a challenge to obtain permission to acquire the desired information. However, the reservoir characteristics are required for a thorough understanding of the reservoirs being produced. Likewise, every well's performance needs to be monitored routinely for decline analysis and production optimization.

To justify the importance of data acquisition, a dual approach was implemented:

- Establish the need for continuous generation of reservoir and well data.
- Quantify the information showing value addition.

This was achieved by performing quantitative analysis followed by qualitative analysis on the historical data.

Quantitative Analysis. A comparative analysis was performed to determine the overall demand for information and for each class of surveillance activity. Through the filtration process of identifying only those surveys relevant to reservoir management, well-performance optimization, and associated requirements, the number of surveys used in the study was reduced from 6,500 to 3,810. These surveys accounted for more than 70% of the annual surveillance-target work identified each year. The analysis further revealed that these targets increased each year. The demand for information increases with time as more wells are drilled and the reservoir is depleted. The increased activity in well work for meeting strategic planning and long-term goals is a major contributor toward the increasing demand for more surveillance jobs.

Optimum production management is achieved through knowing, with confidence, how the wells perform. Therefore, production tests must be performed on a routine basis. The operator has established a target of testing every open completion at least three times per year. Often, the wells can be tested at the gathering center (GC). When the system is not functional or is incapable of testing wells at high rates or with high GOR, portable test measurement is needed. Each well must be tested at least once with a portable test unit during the year to ensure consistency in data measurement. Hence, the portable test figures are highest in the surveillance review for each year.

Qualitative Analysis. In this process, a measure was required for each survey that was analyzed and interpreted by the multidisciplinary team. The selected measure was a "direct gain" or an "indirect gain."

Direct gain is the subsequent increase in production, or curtailment in water, obtained through corrective or remedial actions taken after diagnosing a well problem through a surveillance activity. The remedial action could be a rig or rigless workover, choke change, stimulation work, or other action.

Indirect gain is an enhancement in production or reservoir management that would not have come as a direct result of a surveillance activity but rather from optimizing the reservoir-simulation model for increased recovery and sweep efficiency, well-production optimization through nodal analysis, or updating of the water-encroachment maps to formulate a better depletion strategy. The full-length paper details several reviews and justifications.

Stage 4—Benchmarks and Guidelines. On the basis of the in-depth review and analysis of historical surveillance activities, justifications for data acquisition, and quantifying the value of information, standard benchmarks and guidelines were recommended for future surveillance needs for the Greater Burgan field to establish an integrated reservoir-surveillance plan. Each core surveillance category has a strategy.

Production Well Tests at the Wellhead With a Portable Test Separator.

- Plan multirate tests rather than a single rate.
- Perform tests after every choke change when the GC test facility is not operational.
- Test all new wells and recently-worked-over wells to determine maximum potential.
- Ensure that target/well/year is met for every flowing completion.

PLT.

- Interpret survey and recommend an action plan.
- Capture interpretation and recommendations in a corporate database.
- These data will guide identifying candidates for well-intervention work according to defined priorities.

FBHP/SBHP.

- Update productivity index (PI) and determine inflow-performance-relationship (IPR) for the well.
- Recommend a production strategy for the well.
- Maintain PI/IPR data in a corporate database for future comparative studies.
- Update data in the reservoir model, determine anomalies, and recommend a modified production strategy if necessary.

PNC.

- Link changes in oil/water contact and highest known water (HKW) to history, to surrounding well data, and to other recent surveillance data.
- Develop an action plan on the basis of an increase in HKW and cross-section maps for optimizing well performance.
- Update mapping database and water-encroachment maps.
- Recommend guidelines to obtain maximum sweep from all areas.

The value in maintaining a corporate database is very high. Information from such data warehouses can be used in collaboration with contemporary analytical software that is available for tracking, monitoring, evaluating, and assessing this information precisely. Subsequent value is generated through varied applications and incorporation of data into various tools and models.

Future Plan

The integrated reservoir-surveillance plan for the Greater Burgan field was developed on the basis of results from the study of the historical surveillance data, interpretation, follow-up actions, value generated, and feedback. Through this process, benchmarks and guidelines for future surveillance needs are recommended for the core categories that cover the major portion of the annual Greater Burgan field surveillance plan. **JPT**

Where Is the Gap? Is It in More Reservoir Engineers or in Leveraging New Skills and Workflows That Enhance Individual Productivity?

Primary functions of reservoir engineers include estimating hydrocarbons in place, evaluating the recovery factor, and scheduling of the recovery. These roles are central in meeting the complex challenges of the development life cycle of hydrocarbon resources. These challenges have increased because mature assets require more attention to maximize recovery. The traditional deterministic approach of working is people-intensive and is no longer adequate. Statistical techniques can help in many core reservoir-engineering roles such as surveillance, history matching, and reservoir management.

Introduction

Our industry needs more people to meet the growing energy demands. The skills gap appears more pronounced in reservoir engineering because the complex issues may not migrate to automation with current traditional workflows. Reservoir-engineering practice relies, in large part, on limited, unstructured, and, often, uncertain data. With these limitations, statistical methods could be a vital part of a reservoir engineer's toolkit. Unfortunately, this has not been the case, and statistics has failed to make its way into mainstream reservoir-engineering practice. Statistics offers a disciplined approach to collecting, organizing, analyzing, and interpreting data. Statistics also facilitates the making of inferences, predictions, and decisions about the characteristics of a data population on the basis of information obtained from a subset of the population. Reservoir engineers can improve productivity and bridge the skills gap in the industry by harnessing statistical concepts and stochastic workflows that depend on these concepts.

This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper SPE 118727, "Where Is the Gap? Is It in More Reservoir Engineers or in Leveraging New Skills and Workflows That Enhance Individual Productivity?" by ***C. Amudo,*** *SPE, Chevron Australia, and* ***T. Graf,*** *SPE, Schlumberger, prepared for the 2009 SPE Middle East Oil & Gas Show and Conference, Kingdom of Bahrain, 15–18 March. The paper has not been peer reviewed.*

Data Handling

Reservoir engineering centers on pattern recognition. Pattern recognition underpins well-test analysis, estimates of ultimate recovery for different development decisions, and diagnosis of reservoir and drainage-point performance. It also forms the basis for seeking analogs to verify or corroborate technical evaluations independently. To identify a pattern, one must overcome many data-related problems. These problems vary from scarcity of data in many exploration assignments to data overload in intelligent fields. This also includes how the adopted workflow handles uncertainties associated with the data.

Data Accuracy, Error Propagation, and Influential Parameters. Traditionally, engineers spend considerable time validating data accuracy before proceeding with an analysis. Because it is not known which parameters will have the greatest effect on the study's objectives, the engineer may spend a disproportionate amount of time reviewing a nonvalue-adding parameter. Stochastic workflows overcome this problem by assigning an error margin to data and propagating the error through the workflow with the objective of minimizing the error range. With the aid of experimental design, response-surface models, and diagnostic tools such as Pareto charts, it is possible to assess the effect of uncertainties on business decisions and identify the most-influential parameters. This approach simplifies the workflow design by arranging tasks in parallel, regardless of the preceding tasks, on the condition that the data or interpretation on which the task is based has boundaries (i.e., errors and uncertainties) associated with it. The approach enables simultaneous handling of the uncertainty-reduction process in a so-called top-down approach.

Data Gaps and Stochastic Database. A big challenge in reservoir studies is the availability and completeness of data. Reasons can range from low frequencies of measurement, unknown losses in the system, or inaccurate or incorrect measurements from subjective valuation (i.e., human error). Intelligent fields have minimized these problems, but older and more-matured fields are still vulnerable.

Although the initial reservoir pressure is the most commonly known reservoir parameter, for more than 15% of the reservoirs, the initial pressure is unknown. In 95% of the reservoirs, factors such as average permeability and dewpoint pressure are unknown. Incomplete and inconsistent databases are detrimental to portfolio or asset management. This problem is more accute when in-place volumes show inconsistency to the measured-pressure behavior.

It is normal to calculate missing parameters by a process known as back population before proceeding with the analysis. In many cases, back population might be straightforward because many data in the reservoir databases are directly related. For example, reservoir depth and temperature usually have a linear relationship across the reservoir section.

In the traditional workflow, engineers also spend much time estimating the missing parameters before proceeding with the analysis. This method is fraught with individual biases, and usually it is difficult to verify the accuracy of the calculated parameters. However, several established techniques derived from statistical principles overcome these shortcomings by use of nonlinear, multilayered, and parallel regressions to establish the high-order, multidimensional connections between the various data in the data sets. Self-organizing maps are examples of artificial neural networks that can reconstruct missing parameter areas of the data sets efficiently with multidimensional interpolation, clustered and grouped. It also is possible to extract a measure of the confidence level (i.e., standard deviation) for each of the data points in the clusters. Thus, in a stochastic workflow, it becomes possible to represent each parameter by use of the statistical concepts of mean and standard deviation. The former represents the most likely value for each parameter, and the latter quantifies the confidence level for each of the data.

Data Mining and Reservoir Surveillance. As the number of intelligent-field developments increases, the amount of data from production facilities has increased exponentially. This volume of data has overwhelmed the traditional workflow that relies on spreadsheets for reservoir surveillance. Mature fields now have a significant amount of historical production data. Even with the use of sophisticated spreadsheets, it is difficult to identify production patterns that can improve reservoir performance.

Data mining uses pattern-recognition technologies in addition to statistical and mathematical techniques to process vast amounts of data and reveal relationships between data in a data set. The area with limited application is mature fields that still rely on spreadsheets to manipulate vast amounts of data for reservoir surveillance and drainage-point optimization. By applying data-mining concepts, it is possible to complement the traditional workflow by screening these data rapidly and identifying new correlations that may explain reservoir and drainage performance better.

History Match

Reservoir simulation is the preferred tool to explain past performance and to predict the performance of a reservoir under different development scenarios. The mode complexity varies depending on the study's objectives, available data, computing power, and personal preferences. Construction of reservoir-simulation models usually involves significant human as well as computational efforts. Automated history matching can aid the effort. Construction of a reliable history-matched model remains a time-consuming and challenging exercise. Because of the nonuniqueness of a history-matched model, the quality often deteriorates with time, and there is a constant need to evaluate its continued representativeness and to establish an appropriate time to update the model. In a traditional workflow, this judgment often is subjective and the model update may require construction of an entirely new model. There is evidence to suggest that applying statistical methods can ease this problem.

Update and Proxy Models. The traditional approach of assessing the quality of a history-matched model involves visual inspection of the observed data vs. corresponding simulated-data values over the history-match period. Besides the lack of consistency in this approach, the method becomes increasingly difficult as the number of data points increases. The use of a match factor derived from the deviations enables a statistical measure between the observed and corresponding simulated-data values to quantify the representativeness of the model. Use of weighted-average match factors can reveal the quality of the match at both the well and area levels and for different data types. This quantitative approach helps eliminate personal biases in discriminating between competing and equally probable models.

With statistical concepts, such as a response-surface model (or proxy model), a set of polynomials replaces the flow simulators. These polynomials are functions of the most-influential parameters. Being polynomials, the models are easy and quick to update compared to numerical simulators.

Ensemble Kalman Filtering and Predictive Capability. The nonuniqueness of the inverse problem posed the same problem for methods based on deterministic concepts. Thus, a statement on the validity of the predictive capability of a model remains difficult, despite a good history match. This problem can be overcome with stochastic methods that consider a range for the uncertainty parameters for history matching. Ensemble Kalman filtering is a group of realizations that contains the information regarding uncertainty in the estimates and that is processed sequentially and updated with production data. The continuous update or assimilation of the data leads to a history-matched entity of realizations that defines the uncertainty estimates of all parameters.

Proxy-Based History Match. Although proxy models contain inherent inaccuracies, advantages of speed and applications in processes requiring rapid intervention make proxy models attractive and worthy of further investigation. For example, it is possible to use the Bayesian framework to condition geological information to the production history and generate a posterior probability-density function. Proxy functions replace the output of the flow simulator for all measurements defined in the global objective function. These proxy functions are constructed with polynomials and multidimensional kriging. It is possible to improve the quality and representativeness of the proxy functions by interrogating the probability-density function to assess the uncertainty through ensembles of reservoir models sampled by a Markov-chain Monte Carlo algorithm.

Standardization, Automation, and Uncertainty Handling

For automation to succeed, especially in reservoir engineering, standardization of processes and data is required along with effective handling of uncertainties. Unfortunately, standardization remains an intractable problem in reservoir engineering because of the uncertainties associated with both the data and the subsurface understanding of the reservoir itself. The advent of stochastic workflows has eased the way for automating many reservoir-engineering practices, including integrated reservoir studies.

Recommendations

While recognizing the need to address the skills gap in the industry, a shift from the more traditional deterministic approach to workflows derived from statistical principles offers huge advantages in productivity and potential to bridge the skills gap in reservoir-engineering practice. The large increase in computing power available is enabling this shift to the more computationally intensive statistically derived workflows. Such a shift in workflow can have profound implications on core reservoir-engineering roles such as reservoir surveillance, history matching, forecasting, reserves estimates, and risk quantification. **JPT**

Revitalizing Old-Asset Oil Fields Into Intelligent Fields

Recent advances in oilfield technologies have led to the emerging development of intelligent fields. Integrating these technologies whether downhole or at the surface, coupled with communication networks and sophisticated simulation and monitoring applications, provided significant advancements in monitoring and control capabilities and in decision-making processes. An overall system upgrade in Saudi Arabia resulted in enhanced field surveillance, which led to higher levels of oil production.

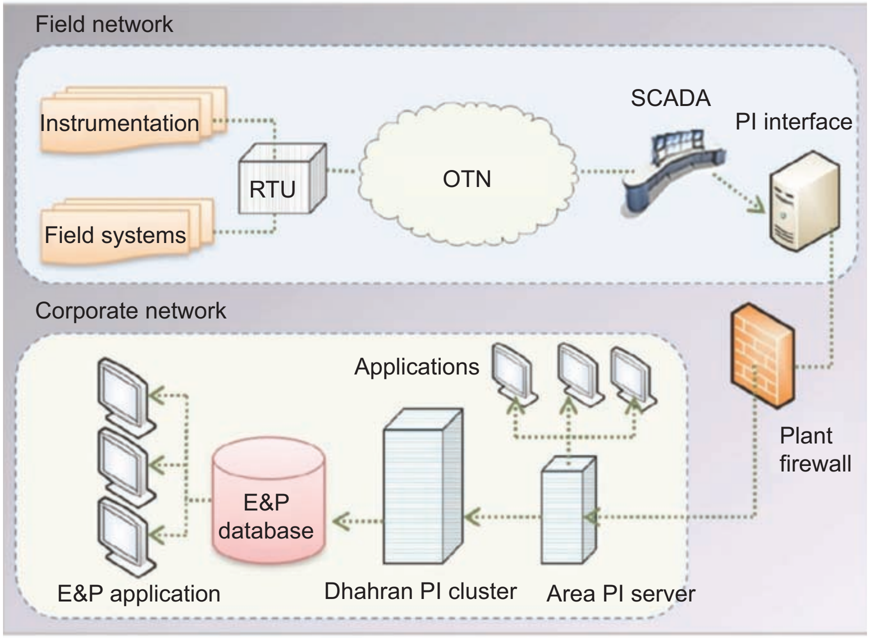

Fig. 1—Data-management infrastructure.

Introduction

The Abu Hadriya, Fadhili, and Khursaniyah (AFK) complex consists of three fields that share a common surface infrastructure for fluid-processing facilities and pipelines. Production from the AFK fields started in the early 1960s, but the fields were shut-in from 1983 to 1990 because of the low demand for oil in the international markets. The early production from all of the producing reservoirs was supported by gravity injection because the facilities did not have power water-injection capability and all produced associated gas was flared because there was no gas-handling facility.

Saudi Aramco has embarked on the development of several fields, including the AFK fields, with an aim to transform the mature and remote fields into state-of-the-art intelligent fields equipped with proper handling facilities for oil, water, and gas. The new AFK project is a two-fold plan. The first part called for drilling new wells, both oil producers and water injectors. The newly drilled water-injection wells are part of a planned peripheral water-injection program for pressure maintenance. The second part implements intelligent-field components that will enhance automation as well as the communication network between downhole equipment and surface facilities. Construction included a new processing facility to handle 500,000 BOPD of Arabian Light crude blend, a new gas plant to process 1 Bcf/D of sour gas from this and other nearby fields, a water-injection plant with a capacity of 1.1 million BWPD to support reservoir pressure, and a complete infrastructure of flowline networks to interconnect the three fields with the centralized processing facility.

The newly drilled wells of the redevelopment project were completed with up-to-date downhole and surface production technologies to monitor and optimize production performance. These technologies include remotely operated chokes and diversion valves, emergency shutdown systems, permanent downhole monitoring systems (PDMSs), compact multiphase flowmeters (MPFMs), electrical submersible pumps, and smart-well completions (SWCs). All these technologies are connected at the surface with a fiber-optic-based data-communication network called an open-transport

This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper SPE 126067, "Revitalization of Old Asset Oil Fields into I-Fields," by ***Mohammed N. Al-Khamis,*** *SPE,* ***Konstantin I. Zorbalas,*** *SPE,* ***Hassan M. Al-Matouq,*** *and* ***Saleh M. Almahamed,*** *Saudi Aramco, prepared for the 2009 SPE Saudi Arabia Section Technical Symposium and Exhibition, Al-Khobar, Saudi Arabia, 9–11 May. The paper has not been peer reviewed.*

network (OTN) and a state-of-the-art supervisory control and data-acquisition (SCADA) system to provide real-time data acquisition and monitoring of these technologies for fast decision making. The challenge of the AFK fields, and therefore the decision to implement the intelligent-field concept, was the remoteness of these fields from existing infrastructure.

Data Management

Real-time data captured from the AFK fields are delivered to desktop applications by a series of components that make up the infrastructure of data management, as shown in **Fig. 1.** Data transmitted by instrumentation systems in any wellsite start at the remote terminal unit (RTU). The RTU communicates data collected from site systems to SCADA servers that represent the central processing and control system in the field. Plant-information (PI) servers then handle the archiving of data and form the data source for the enterprise database and applications.

Field Management

The general scope of the AFK fields project was to upgrade these three assets, which were shut in, to a modern facility that will enhance and optimize the overall operation of these fields.

Control Capabilities. Proper integration of intelligent-field components, such as MPFMs, enabled accurate measurement of well-production rates from the 11 developed reservoirs of the three AFK fields, which in turn ensured correct blending of the various crude grades. At the same time, this integration enabled proper production allocation for every well, which is crucial for reservoir simulation. Furthermore, the use of remotely operated chokes and SWCs to adjust well rates and to divert wells to test headers facilitated prompt control of individual wells without the need of field support. Because wells are spread over a geographical distance of more than 50×30 km, it would be extremely difficult to adjust the crude blend and implement optimized production and injection strategies without these systems.

Real-Time Reservoir Surveillance. Real-time reservoir-pressure management also was an important consideration during the planning and implementation phases of AFK development. With all three fields under pressure maintenance by use of peripheral water-injection patterns, close monitoring of reservoir pressure is crucial to ensure that the implemented production and injection strategies are updated appropriately and to make timely adjustments in these strategies as necessary.

In general, there are two sources for reservoir pressures: real-time data from the installed 31 PDMSs and 17 electrical-submersible-pump systems and estimated reservoir-pressure data from flow simulations. Integration of these two reservoir-data sources with the field-management data-mapping package enabled generating real-time reservoir-pressure maps. This approach improved reservoir surveillance significantly. The decision-making process advanced from the normal 6-month period, to real time, and, at the same time, tangible cost savings were realized from the use of information from intelligent-field components and methods.

Optimizing Well Performance. Incorporating intelligent-field technologies in the AFK fields facilitated optimization of the performance of oil-production and water-injection wells. The system can display live statistics of the total number of active wells, shut-in wells, overproducing or -injecting wells, and underproducing or -injecting wells.

Also, the performance of wells is optimized further by an automated multirate-test-validation technique by use of commercial flow-simulation software. This procedure involves modeling results of performed rate tests in the field to track changes in reservoir pressure and well productivity or injectivity with time, without the need for conducting costly pressure-transient tests.

Operation Enhancement. A challenge in this project is the complexity of the crude blend in which 11 reservoirs with different crude grades, ranging from 24.1 to 38.6°API, will be produced, and a meticulous blending process must take place to yield a distinctive crude grade of Arabian Light crude. Therefore, it is imperative to establish a mechanism that will ensure that the crude properties from the AFK fields meet the required specifications at all times. Consequently, real-time monitoring and control are essential elements of production allocation and, in turn, appropriate crude blending. For this objective, the monitoring/surveillance systems are used to ensure the crude-grade quality continuously.

Conclusions

The project to revitalize the AFK complex of fields by use of intelligent-field technologies was sanctioned because of the need to modernize and optimize a facility that was below its potential. Saudi Aramco management realized the opportunity to enable previously identified reserves to come on stream quickly and under an operation that allowed remote control and surveillance to conduct fast decision making toward optimizing the entire process from the wellhead to the pipeline-transportation system.

The factors that mandated the revitalization of the AFK assets into intelligent fields can be summarized as follows.

- Construct a central and modern facility, designed to handle the produced fluids from all three fields and replace the old individual facilities in each field.
- Improve water-injection capability in all three fields to support reservoir pressure.
- Increase the capacity to process produced sour gas and avoid flaring.
- Enable producing a certain crude blend from a mixture of 11 crude grades from different reservoirs among the three fields, and implement intelligent-field methods to ensure crude-quality compliance.
- Provide the ability to control key parameters remotely and monitor vital equipment in real-time to optimize hydrocarbon flow from the fields to the processing facility.
- Minimize human interaction associated with field operations in source-crude producing environment. JPT