Intelligent Well Technology in Underground Gas Storage

Intelligent well technologies are ideal for underground gas-storage facilities. Formation properties have been determined; storage capacity and deliverability can be modeled; and analytical tools can track historical production trends. These technologies provide efficient, cost-effective storage and delivery systems, helping secure the position of natural gas as a dependable energy resource.

When it comes to applying intelligent well technologies to oil and gas production, a prime objective is maximizing the value of a continually diminishing asset. For underground natural gas-storage facilities, the application of these smart technologies can be significantly different, primarily because the gas reservoir can be replenished. Thus, it is the ability to repeatedly inject natural gas into and withdraw it from underground storage at high rates that must be optimized and intelligently managed.

Formation properties define the optimal level at which a well flows at high recovery rates. As the stored natural gas is recovered from the reservoir, the pressure decreases and flow rates fall. Cushion gas, the gas that remains in place between injection and withdrawal cycles, ensures that there is sufficient pressure to maintain the desired minimum flow rates on withdrawal. The pressure and volume provided by the cushion gas also diminish the likelihood of water influx into the gas cap and can prevent gas/water contact movement. Because the most expensive component of an underground gas-storage (UGS) facility can be the cushion gas, minimizing its volume and understanding the reservoir well enough to define the efficient operating range can reduce the overall development cost of a storage project, as well as greatly enhance project profitability.

In hydrocarbon production, intelligent well technologies allow reservoir engineers to use information such as decline curves, material-balance relationships, inflow-performance-relationship (IPR) curves and reservoir simulations and models—all in real time or almost real time. A sophisticated system may automatically take corrective action or alert the operator that intervention is warranted. The ultimate goal of intelligent production wells is to deliver more oil and gas with greater efficiency—at a lower cost.

While UGS facilities also benefit from efficiencies and lower cost provided by intelligent well technologies, they are not operated to maximize the recovery of hydrocarbon. In fact, gas-storage operations in many parts of the world are more analogous to a bank than a producing reservoir. Just as currency flows into and out of a bank, assets in the form of natural gas flow into and out of the storage reservoir. When called upon, sometimes months after injection into a storage reservoir, but increasingly within a few days or even hours, the gas is delivered to a buyer who supplies it to industrial and residential customers. Banks have automated the flow of currency and capital between institutions and users; similarly, storage facilities are automating the flow of natural gas between producers and consumers.
component in the secure delivery of natural gas, these facilities must be managed appropriately.

Maintaining reliable natural gas supplies has recently become a geopolitical priority in many areas of the world. Governmental regulations, such as those in the European Union, have had increased influence on how the UGS industry conducts business. Intelligent well technology is being adopted as a natural by-product of these developments because it helps facilitate automatic storage and delivery of natural gas, improves the operational efficiencies of these facilities, and assists in optimizing the management of assets (gas) in the ground.

The degree of implementation varies between different operations, and not all UGS facilities operate using these relatively new technologies. However, the improved operating performance that has been demonstrated is prompting operators to retrofit and upgrade many older storage operations—sometimes yielding unexpected benefits.

UGS operations also differ from traditional gas production because the wells must be able to withstand high injection pressures, something rarely experienced in producing wells, and the withdrawal rates from UGS can be 5 to 10 times greater. UGS wells have long life expectancy; therefore maintaining well integrity and reservoir integrity are crucial aspects of successful operations. Due to the rapidly changing operational modes— injection to withdrawal—the operator must be reactive and act quickly to avoid well and reservoir mechanical damage. As a vital component in the secure delivery of natural gas, these facilities must be managed appropriately.

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1. Hydrocarbon depletion occurs in a predictable manner based on formation properties and completion hardware. The rate of decline of reserves can be plotted to define a decline curve.

   Material balance is an expression for conservation of mass. The amount of mass leaving a control volume is equal to the amount of mass entering the control volume, minus the amount of mass accumulated in the volume. Through material balance, reservoir pressures measured over time can be used to estimate the volume of hydrocarbons remaining.

   Inflow-performance relationship, IPR, is a tool used in production engineering to assess gas-well performance by plotting the well production rate against the flowing bottomhole pressure (BHP). The data required to create the IPR are obtained by measuring the production rates under various drawdown pressures during a multirate test. The reservoir fluid composition and behavior of the fluid phases under flowing conditions determine the shape of the curve.
After a brief review of gas-storage basics, this article examines the different levels of intelligent well technology being applied to underground gas-storage operations in North America and Europe. We present case studies showing how real-time data are used to identify damage in storage wells and how the implementation of new optimization and surveillance techniques has improved performance. Also included is a description of a cutting-edge, automated operation that integrates three levels of intelligent well technology.

### An Underground Gas-Storage Primer

Traditionally, natural gas has been considered a seasonal fuel because of the higher demand for heating during winter months. Beginning in the 1940s, the US natural gas industry recognized that long-distance pipeline capacity was not sufficient to supply natural gas to large population centers during peak-demand periods. To balance the gas-demand cycle, a gas-storage network was developed to inject gas into underground storage facilities when demand was low and to release gas during periods of high demand. This buffering of demand is referred to as peak-shaving.

**Global Working-Gas Volume Distribution by Storage Types**

Depleted oil and gas fields account for 81.6% of the global supply. The choice of storage type can be driven by availability: aquifers and salt caverns make up 34% of Western Europe’s storage capacity compared with just 14% in the USA where there is greater access to depleted fields. (Adapted from Wallbrecht, reference 6.)

Underground gas storage, however, has been available almost as long as long-distance pipelines. In 1915, natural gas was first successfully stored underground in Welland County, Ontario, Canada. Several wells in a partially depleted gas field were reconditioned, and gas was injected into the reservoir during the summer and withdrawn the following winter.

In 1916, Iroquois Gas Company placed the Zoar field, south of Buffalo, New York, USA, into operation as a storage site, and it is still in operation today. In 1919, the Central Kentucky Natural Gas Company injected gas into the depleted Menifee gas field in Kentucky, USA. By 1930, nine storage sites in six different states were in operation with a total capacity of about 18 Bcf [510 million m³]. Before 1950, essentially all underground gas storage consisted of reused partially or fully depleted gas reservoirs.

Today, the two primary types of underground gas-storage locations are caverns and porous reservoirs. Leached salt caverns and abandoned mines account for a small portion of the total storage capacity, while depleted oil and gas reservoirs and saline aquifers are by far the most common UGS medium (left). Salt-cavern storage, better suited for high-rate delivery and injection, is primarily used for peak-day delivery purposes. Typically, 20 to 30% of the gas must remain in place to maintain the structural stability of the cavern. Saline aquifers can provide high-rate delivery, but cushion-gas requirements are significant, ranging from 50 to 80% of the total storage capacity. By far the most common type of storage, depleted hydrocarbon reservoirs are used for seasonal delivery or buffering high demand. Typically, 30 to 50% of the storage capacity must be maintained as cushion gas.

In recent years, UGS withdrawal practices have changed in the USA because of the increased use of natural gas for electricity generation. Drawdown during summer months is higher than in the past because natural gas is being used to generate electricity for air conditioning and cooling requirements (left). In many ways, this has altered the scope of gas storage in the USA. UGS facilities that are located in proximity to gas-fired power plants are used to moderate the supply for seasonal, as well as hourly, variations. On a daily basis, gas in storage can be tapped during high-demand periods and stored during low-demand periods. Commercial pipelines may be incapable of supplying sufficient quantities of gas during the peak periods—or putting away gas during periods of low demand—but the UGS facility can make up the shortfall in either case.

**^ Underground gas storage by type. UGS facilities can take several forms, but depleted hydrocarbon reservoirs and saline aquifers make up 96% of the global supply. The choice of storage type can be driven by availability: aquifers and salt caverns make up 34% of Western Europe’s storage capacity compared with just 14% in the USA where there is greater access to depleted fields. (Adapted from Wallbrecht, reference 6.)**

**^ The cyclicality of natural gas usage. As a source of residential heating in the USA (blue), natural gas from storage peaks during winter months. When used for generating electricity to provide cooling (red), usage peaks during summer months. Commercial usage, driven by temperature (black), tracks residential demand. Also note the rise in natural gas usage for electricity generation in successive years. [Adapted from http://www.eia.doe.gov/oil_gas/natural_gas/info_glance/natural_gas.html (accessed February 29, 2008).]**
UGS is not just a North American phenomenon—storage facilities are currently operating in 35 countries—although the USA has by far the greatest number. As an energy source, natural gas utilization in residential and commercial sectors of Western Europe has exceeded 44%, highlighting the importance of maintaining a secure, uninterrupted supply. In France, storage facilities have at times supplied more than half the residential gas needed to meet temperature-driven demand.\(^5\)

Western Europe has recently experienced a rise in gas trading between holding companies and market suppliers. The use of gas-storage facilities is often driven by short-term buying and selling, rather than traditional peak-shaving. Profitability for both buyers and suppliers is determined by the ability of the UGS facility to store and deliver gas on demand in a cost-effective manner.

In 1997, there were 580 UGS sites worldwide, of which 448 were in depleted reservoirs. In 2006, of the estimated 606 UGS sites, the number in depleted reservoirs had grown to 495.\(^4\) In 1996, there were 92 UGS operations in Europe, excluding Russia. By 2006, the total number had grown to 127—a 38% increase. The working-gas volume in storage facilities in the same area grew from 60.6 million m\(^3\) [2.14 Bcf] to 110.5 million m\(^3\) [3.9 Bcf], an 82% increase.

Although the USA has had a slight decrease in the number of UGS sites between 1995 and 2004, its total storage capacity has experienced a marginal increase through improved field utilization and retrofitting of existing facilities (top right). Many of these older UGS operations were developed before the introduction of the reservoir modeling tools available today. Advances in sensor technology and surface equipment are being applied to these older facilities, making them “smarter” and more versatile.\(^2\)

How Smart Is an Intelligent Well?
The relative intelligence of gas-storage operations can be grouped into three levels. Level I, automated data flow, is reactive: receive data, analyze data and respond. Level II, surveillance and optimization, is reflective but focuses on action: analyze data, compare and validate models, manage models and determine necessary courses of action. Level III can be described as the digital oil field: integrate processes, optimize, automate and operate remotely, where it is applicable, in a proactive manner (bottom right).

> A growing supply. The working-gas volume has grown steadily in the past 35 years with most of the increase occurring outside North and South America (blue), especially in Eastern Europe and the Middle East (black), which includes Russia. Current projections indicate that capacity is insufficient to meet the long-term demand and increased growth is required. (Adapted from Wallbrecht, reference 6.)

> Levels of intelligence. Three levels can be identified in the implementation of intelligent well technology. Each level brings added complexity and builds upon the others. The most comprehensive is the digital oil field with optimization and opportunities for automation.

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Level-I intelligence begins by developing confidence in the data. Supervisory control and data acquisition (SCADA) systems can be found in most UGS operations. These computerized networks remotely acquire well data such as flow rate, pressure and flowing volume, and control transmission of gas throughout a pipeline system. With millions of data points thus acquired, it is impossible to manually validate all the information. Automating quality control of the data flow is a necessity.

Software for traditional oil and gas production is often used for UGS applications to identify performance problems as well as monitor individual wells, evaluate completions and characterize the reservoir. Trend analysis and type-curve matching are frequently used in these programs. However, most petrophysical programs are poorly equipped to handle the huge volume of SCADA data coming from UGS operations. Also, they cannot effectively deal with noisy data resulting from sensor errors and spurious responses (above). Since proper use of these applications often depends on the ability to identify the onset of linear trends over time or clearly identify subtle features in various type-curve plots, the data must be cleansed and reduced so that proper identification of such features can be accomplished (next page). Therefore, intelligent data reduction is applied before importing the data into these programs.

The data provide insight for evaluating the relative health of individual wells, as well as that of the producing field. The repeated cycling ability of gas-storage wells—periods of injection followed by periods of production—is a fundamental difference between producing reservoirs and storage reservoirs. Occasionally, the storage wells remain static for varying lengths of time and the collected data can be treated as a conventional short-time buildup test. Changes that occur from cycle to cycle can be indicative of problems developing in individual wells, in the reservoir or in the surface equipment. By analyzing these data, the presence of damage can be recognized, and remediation plans implemented.

Early uses of electronic flow measurement (EFM) data in UGS fields clearly demonstrated their value in monitoring well performance, conducting routine surveillance and identifying operational problems. In 2002, as part of a Gas Technology Institute (GTI) sponsored study, Schlumberger engineers used EFM data to develop a reasonably accurate, cost-effective means of detecting wellbore damage in gas-storage wells. The impetus for this work was the fairly common practice of performing surface backpressure tests in UGS wells to evaluate damage on a very infrequent basis—testing every 1 to 3 years was typical. The infrequent nature of such testing made it impossible to determine incremental damage or sudden changes over reasonable time frames, such as during an injection or withdrawal cycle. Determining changes in damage in near real time is important, since damage might be occurring during injection or withdrawal, or during the changeover from one to the other. This work made it possible to estimate damage levels.


12. The pseudocritical temperature and the pseudocritical pressure are the pressure and temperature conditions of a multicomponent mixture at which liquid and vapor cannot be distinguished (because the properties are identical at this combination of pressure and temperature).

The z-factor, or ideal-gas deviation factor, is the departure of a gas behavior from that of the ideal gas law. The gas formation volume factor represents the fractional change of volume per unit change in pressure. The coefficient of isothermal compressibility is a measure of the relative volume change of a fluid or solid in response to a pressure (or mean stress) change. The gas formation volume factor is used to convert a volume of gas at reservoir conditions to a volume of gas at standard (surface) conditions, since the volume of any gas depends on its pressure and temperature.
in UGS wells on a more frequent basis than was previously possible.

In a more recent GTI study, Schlumberger engineers developed a method to utilize EFM data to continuously track and identify wellbore damage over time. Developments in intelligent well technology, including sensor improvements and real-time streaming data, have been combined with the experience gained from earlier EFM studies to develop damage-identification techniques for use in UGS facilities, such as one operated by Columbia Gas Transmission Corporation in the northeast region of the USA. The reservoir consisted of a consolidated sandstone, which formed a stratigraphic trap with an average thickness of 10 ft [3 m], average porosity of 10% and average permeability of 150 mD. Of the 20 wells in the field, five were identified as key wells for the purpose of the study.

A SCADA system collected high-frequency pressure and flow-rate EFM data from the wellheads at 15-second intervals. The operator collected monthly records, with as many as 115,000 data points per well per day, and supplied them to Schlumberger engineers. A software routine parsed the field-wide data into individual files for each well, reduced the datasets to a more manageable volume and automated the process of making the information useful.

Because each well generated 3 million data points over the course of the study, a routine was developed just to handle the raw data. It performed three primary functions: a gas-properties correlation, a bottomhole-pressure calculation and data processing. The gas-properties correlation module calculates pseudocritical temperature and pressure, z-factor, coefficient of isothermal compressibility, gas formation volume factor and gas density, viscosity and pseudopressure. It also formats the data for export to Excel workbooks.

The high-frequency EFM data are aggregated over 10-minute intervals during flow. The software routine computes average flow rate and average pressure, along with the standard deviation of these quantities. It flags outlying data points as invalid if there is a flow reversal or if there is a mix of zero and nonzero EFM-rate measurements.

During shut-in periods, a variable-width window is applied to the data to give approximately the same number of points for each cycle. The software routine fits the data to establish weight factors. To qualify the data as a valid shut-in period for buildup or falloff analysis, a series of filters is applied based on the length of the prior injection or production period, the length of the shut-in period and the length of time necessary.
for sufficient data to be acquired for the analysis to be valid. Additional controls were implemented to avoid limitations when exporting data to an Excel worksheet.

At this point in the data-handling process, a user must intervene to select the plots and adjust the scales as applicable. Apparent mechanical skin damage factor, $S$, can be plotted as a function of time or rate. If the mechanical skin damage factor, $s$, and non-Darcy flow coefficient, $D$, are constant with time, then the apparent mechanical skin damage factor, $S$, will be a linear function of rate and can be used to estimate $s$ and $D$. If $s$ or $D$ changes with time, the data will not be a linear function of rate. Abrupt changes will cause clusters of data points, and gradual changes will result in the data drifting away from the baseline model (above).

One study found that 60% of the reservoirs evaluated had wells in which non-Darcy flow was identified as a damage mechanism. If the damage is assumed to be related to mechanical skin damage factor alone, erroneous conclusions might lead to inappropriate or ineffective intervention. Mechanical skin damage is often improved by pumping acid into the perforations or by hydraulically fracturing the formation. These types of remediation would not effectively treat non-Darcy flow effects, and performing them could be a waste of time and money.

A change in non-Darcy flow effects during injection was observed during the Columbia Gas Transmission study period. The onset of damage was isolated to a particular week in 2004. Several wells in the field exhibited this increased non-Darcy flow effect, which was identified by an abrupt change of the slope on the apparent skin damage versus rate plot, while other wells in the field did not experience this change. The analysis suggests that the cause of this perceived damage is related to an increase in turbulent flow during injection, rather than mechanical damage to individual wells. Thus, no remediation was warranted. Had the problem been detected during an annual test conducted on an individual well, rather than by continuous monitoring of all the wells in the field, it is possible that the results could have led the operator to the wrong conclusion and needless expenditures.

Existing data sources and new data mining techniques were used to perform the analyses, allowing the operator to determine the source of perceived damage and make the proper decision for dealing with it. In this case study, the wells in question were able to remain in operation and no remediation was necessary.

Practical Improvement Leads to Level II

A systemic approach to the processes of injection, storage and delivery for UGS facilities is likely to provide the greatest benefit to operators. Individual-well analysis, reservoir modeling, surface hardware and system inefficiencies need to be fully evaluated, but it is not enough to focus on one or two aspects of.
the operation, such as EFM data, reservoir characterization or surface hardware. The optimization process requires that all the components be considered together to develop a model that represents the total system. Optimization, modeling and surveillance are key components in developing a Level-II intelligent UGS facility.

Most testing experts would agree that the first step in optimization is to characterize individual wells or completions. The condition and quality of the reservoir in the vicinity of the wellbore and the level of damage affect the flow efficiency of the completion. Once these are determined, a predictive model can be developed to provide the expected performance under various operating conditions. Multirate well testing is the standard method for full characterization of well damage and flow performance, and, with regard to developing a realistic model, it is indispensable.

Multirate pressure-transient testing quantifies mechanical skin damage factor, \( s \), and non-Darcy flow effects, \( D \), and establishes a baseline for future comparison. Once the individual wells have been tested, the next step is to characterize the production properties of the system with a multirate test across the entire field. Using operational data, such as flow rates, temperatures and pressures from wellheads, treatment facilities and metering stations, an operator can design an effective field-wide multirate test. If all the wells in the field can flow simultaneously, this type of test provides a field-wide deliverability curve. The field-wide flow rate should be high enough to identify the first bottleneck in the system.

Bottlenecks can be characterized as system inefficiencies that affect overall performance at some specific operating condition. Wellbore size, tubulars, wellhead equipment, gathering lines and treatment facilities impact the system and may act as bottlenecks (right). Once these bottlenecks are identified, economics determine whether it is worthwhile to remove the cause of the bottleneck. For example, if a multirate test indicates that larger tubing will eliminate a bottleneck but the wellbore size limits the tubulars that can be installed, there is little that can be done to fix the problem. Adding wells or replacing existing wells might be the only solution, albeit an expensive one.

If a total-field flow test cannot be conducted, a deliverability curve can be constructed from tests performed on individual wells. However, surface-facility effects must then be measured and included. Nonetheless, the total-field method will yield the most accurate results.

Finally, an inventory model for the storage field can be developed that describes the total gas inventory as a function of reservoir pressure. This is accomplished by maintaining a constant flow rate from the storage field for a period of time sufficient to reach pseudosteady state, and using the pressure-decline rate observed during pseudosteady-state flow to calculate the reservoir pore volume. In other words, this technique can determine the size of the underground storage “tank” available for storage and delivery. Once this reservoir pore volume is quantified, the operator can estimate the total gas contained in the reservoir for a given average reservoir pressure.

With existing technology, the average reservoir pressure can be estimated from a buildup test any time there is a sufficiently long shut-in period during normal operations. Since the field-inventory model quantifies the relationship between average reservoir pressure and total inventory, the operator can perform more frequent inventory audits than were possible using data acquired only during routine spring and fall shut-in periods. Calculation of average reservoir pressure from flowing data, perhaps available with currently developing technology, may allow real-time inventory auditing in UGS fields rather than waiting for long- or short-term buildup data. This is especially important in cases where frequent cycling of gas is occurring and there is no routine shut-in.

Once the pore volume has been established by collecting both individual well and field-wide data from extended tests, two independent estimates of pore volume can be derived and compared. This information is integrated with the deliverability-testing data to create the total system model.

Identifying bottlenecks with multirate flow testing. NODAL production system analysis indicates that the tubing size is a bottleneck in this test. Tubing inside diameter (ID) is varied from the existing size of 3.092 in. (green) to 8.0 in. (blue). The analysis confirms that increasing the tubing ID from 3.092 in. to 5 in. (red) would provide a 54% increase in flow capacity, from 11 MMcf/d [311,000 m3/d] to 17 MMcf/d [481,000 m3/d]. Above 5-in. ID, only a nominal flow increase would be added. (Adapted from Brown and Sawyer, reference 14.)

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13. Mechanical skin damage factor, \( s \), is a dimensionless number calculated to determine the production efficiency of a well by comparing actual conditions with theoretical or ideal conditions. A positive skin value indicates that some damage or influences are impairing well productivity. A negative skin value indicates enhanced productivity, typically resulting from stimulation.

The non-Darcy flow coefficient, \( D \), is calculated from fluid flow that deviates from Darcy’s law. Darcy’s law assumes laminar flow in the formation, and if the flow is turbulent rather than laminar, it is referred to as non-Darcy flow. Typically observed near high-rate gas wells, turbulent flow occurs when the flow converging to the wellbore reaches velocities exceeding the Reynolds number for laminar or Darcy flow. Since most of the turbulent flow in producing formations occurs near the wellbore, the effect of non-Darcy flow can be represented as a rate-dependent skin effect, \( D \).

Apparent mechanical skin damage factor, \( s \), is similar to \( s \) but may be a result of mechanical damage or non-Darcy flow effects such as a rate-dependent restriction.


15. For more on recent sensor and data-handling developments: Bouleau et al, reference 7.
Various programs, such as the PIPESIM and NODAL production system analysis software, can be used to construct a nodal analysis model (below). Model creation begins with identifying the physical components of the system and integrating the reservoir properties obtained from well logs and well tests. Characteristics of the gathering systems, processing equipment and surface equipment are added to the model, which is then calibrated for system variables such as pipe roughness and gathering-line lengths. The model is adjusted to match the pressure data obtained during the well testing, focusing on bottlenecks.

Trend analysis compares actual results from ongoing, routine operations with the model-based results established during the characterization phase. More advanced predictive tools, such as the DECIDE! data mining based production optimization software, have been utilized to automate the process of comparing model-derived data with operational data.

Starting from Scratch—or Not

The potentially long lifetime of a UGS facility—the Zoar field, for example, has been in operation for more than 90 years—may demand well construction practices that differ from nonstorage wells. Storage wells must be able to tolerate high injection rates, high production pressures and frequent cycling. Reuse of existing downhole and surface equipment may be possible, but more common is a mixture of existing wellbores and newly drilled wells. The original producing operation may, however, dictate well placement and facility location. The transition from production to storage should focus on optimization and thorough understanding of the reservoir.

Ideally, optimization begins during the identification of prospective fields to be used for gas storage. The first step in choosing a candidate is to understand the reservoir. Characteristics for UGS prospects are good porosity and permeability and an effective trapping mechanism. If the choice of reservoir is not an option, such as an existing gas-storage facility in need of upgrading or improving, new technologies can still be employed to enhance the value of an UGS operation.

An example of optimizing an existing gas-storage field with intelligent well technologies is the Falcon Gas Storage Company, Hill-Lake field operation in Texas (left). Formerly an oil producer, this field was discovered in the 1920s and by the 1950s had reached the end of its productive life. It was converted to a gas-storage facility in the 1960s. When Falcon took over the operations in 2001, there were 21 wells in the field, 10 of which were active in the gas-storage operation. No development had taken place since the 1950s, and 2.5 Bcf [71 million m³] of gas could not be accounted for by previous operators, attributed to “meter error.”

The original interpretation provided to Falcon was fairly simplistic. From limited well control and old electric logs obtained in the vicinity of the injection site, the structure was
mapped as a fluvial delta (right). Between 2003 and 2006, Falcon added 16 wells to the field, with well placement aided by FMI Fullbore Formation MicroImager analysis. The images from the FMI data suggested a new interpretation, that the reservoir was a braided channel sand, not a delta.

In 2006, Schlumberger geologists used Petrel seismic-to-simulation software to develop a basic geological model (bottom right). The existing wells were incorporated into the model, and an additional 17 wells, drilled by Falcon in 2006 and 2007, were included in the analysis.

These new wells, drilled as step-outs from the original injection site, followed trends indicated by the interpretation of the FMI images. The additional wells led to some interesting discoveries, such as a previously unknown sand lobe to the southwest of the main injection wells. As an isolated sand, it should have been depleted by earlier production but, unexpectedly, the pressure was similar to that in the rest of the Hill-Lake reservoir, proving that they were in communication. Based on information derived from the Petrel geological model, this structure is believed to have contained the 2.5 Bcf of missing gas.

Not only was unaccounted gas discovered, but as gas was injected into the field, the originally depleted reservoir was recharged. New wells penetrating down-dip sand sections encountered oil left behind during the initial production phase that could now be recovered because of the increased reservoir pressure.

A by-product of the recovery of stored gas is additional oil production in the form of natural gas liquids (NGLs). When gas is injected and recovered, it is enriched by hydrocarbon liquids that were left behind after the original oil production ceased. These liquids are stripped out of the recycled gas using a cryogenic gas processing plant, and then recovered and sold, adding to the profitability of the UGS operation. The Petrel reservoir model identifies candidate locations for future field development where the sand properties are most conducive to the production of liquids during gas withdrawal.

In 2007, because of the insight provided by the preliminary model, Falcon initiated a detailed Petrel geological and reservoir model, incorporating a total of 72 wells. The ELANPlus advanced multimineral log analysis program and FMI analysis were used to interpret 29 of the wells. Core data from five wells provided calibration for the model. With advanced petrophysical analysis, the initial simplistic interpretation of a deltaic deposition evolved into a more realistic model of the reservoir.

Changing interpretations. The Hill-Lake field was originally mapped as a fluvial delta (left). Two structural highs were identified on the isopach map (top left). New well locations were drilled according to the original structural map, which was based on wells drilled before 1960. An updated interpretation, using Petrel seismic-to-simulation software (right), included 17 new wells and identified a previously unknown southern lobe (top right). The original sand body’s geometry could be more accurately visualized, and the structure was characterized as a braided channel sand (bottom right). Because the FMI interpretation provided flow direction, well placement was improved. The southern lobe contained 2.5 Bcf of stored natural gas that the original operators assumed had been lost because of metering errors.

Petrel Model Construction Workflow

Petrel Geological Modeling

Rock type identification (facies properties)

Interwell correlation

Framework modeling (facies, net to gross, porosity, permeability, saturation)

Property modeling

Fluid PVT

ECLIPSE software

Reservoir simulation model (history and forecasting)

Volumetrics

Petrel Reservoir Modeling

Data inventory and loading (logs, markers, surfaces)

Petrophysics and borehole geology (ELANPlus, BorView software)

Property modeling

Reservoir simulation model (history and forecasting)

Volumetrics

Volumetrics

Modeling a reservoir. Geologists used Petrel software to model the Hill-Lake reservoir. Once the geological model is fully developed, the reservoir properties can be used to develop simulations for volumetrics and field performance.
As additional wells were drilled, greater insight into the reservoir geometry was gained, and the depositional environment was recharacterized as an ancient riverbed with anastomosed channel sands. Optimal well placement depends on understanding the reservoir structure. Visualization of the subsurface topography provided by the Petrel model was crucial in identifying the correct depositional environment and ruling out the two previous interpretations (below). Thorough understanding of the reservoir has added new storage capacity to the field, defined new exploration areas to recover oil left behind after the initial production ceased, and helped optimize future field development. Production and capacity improvements in the USA, such as those found with the Hill-Lake operation, help explain the UGS capacity increase, despite a decrease in the number of sites.

Falcon’s use of new applications and technology is not limited to subsurface modeling and optimization. Because this facility had been in operation since the 1960s, production facilities needed an upgrade. A SCADA system was installed, providing instantaneous information about temperature, pressure and flow rates. The flow of gas can be managed from the wellhead, at individual compressor sites or at the central field control room. Although the SCADA system is not used to remotely control the facility at present, it has the capability to do so.

Falcon’s Hill-Lake facility is now a state-of-the-art, multicycle UGS operation with the capability of being used in a variety of ways, including storage, high-rate delivery, peak-shaving, “park and loan” and market trading. The maximum capacity is now 15 Bcf [425 million m³], representing 11 Bcf [311 million m³] of working gas and 4 Bcf [113 million m³] of cushion gas. The field can deliver 515 MMcf/d [15 million m³/d] and inject 300 MMcf/d [8.5 million m³/d]. Injecting in summer and supplying in winter have been replaced by a flexible operation capable of on-demand delivery and storage as required by customers, while recovering oil and NGLs that were left behind during initial production.

Falcon’s success with Hill-Lake resulted in the recent retrofitting of another gas-storage field in north Texas, its Worsham-Steed facility. Utilizing an abandoned oil and gas field originally converted to gas storage by another operator, this retrofit is a multicycle UGS operation employing similar intelligent well technologies. This field produces oil and NGLs along with providing 24 Bcf [680 million m³] of working-gas capacity.

Level III—Automated Reservoir Surveillance

Whether UGS facilities are buffering demand cycles or acting as gas repositories, the ability to automate the process is an attractive reason for implementing intelligent well technologies. An operator in Europe, working with Schlumberger reservoir geologists and engineers, designed and implemented an automated reservoir surveillance operation using an integrated platform built around DECIDE! software. An operator can optimize and perform predictive modeling for highly complex systems using the artificial intelligence and software simulation of the PC-based DECIDE! software (next page, top).

This software provides a way to bring together people, technology, processes and information in a secure, global system—reducing cost, lowering risk and enhancing operations. The DECIDE! program has two major components—a data hub and an engineer’s desktop. Responsibility for retrieving, storing and distributing data, as well as automation of tasks, lies primarily with the data hub. The engineer’s desktop uses state-of-the-art data mining techniques to perform analytical petroleum-engineering calculations, giving the operator a powerful tool for managing the asset.

RWE Transgas Net, an independent natural gas operator in the Czech Republic, has installed DECIDE! software to manage and optimize all of its depleted reservoir and aquifer gas-storage facilities. Implementation began in 2004, and was completed in 2007 (next page, bottom).
RWE Transgas Net, working with Schlumberger engineers, began the process of implementing the DECIDE! program by first developing an integration platform. A SCADA system was installed to provide continuous high-frequency measurements (on the order of seconds), which are grouped into 15-minute increments and streamed in real time from individual wells, gathering systems and facilities. At this Level-I step in the process, the software system checks that a connection to a datastream has been established and generates a notification if there is a failure. When a valid connection is confirmed, the high-frequency data are imported, filtered, quality checked and aggregated over longer time intervals to reduce the size of the dataset. The software filters sensor errors and transmission errors prior to data aggregation and generates statistical reports to allow the engineer to evaluate the reliability of the information. Artificial intelli-

^ Level-III intelligence. Level III combines all the components of intelligent well operations together. By integrating processes such as trend analysis, modeling and simulations, the UGS facility can be optimally managed with high levels of automation.

^ DECIDE! program workflow. SCADA data are streamed into the data buffer where they are quality checked, cleansed and reduced using a neural network (NN) proxy model. Data are fed to various software modules for automated surveillance, report generation and preparation. Proxy models process the information and use trend analysis and simulation-matching to look for optimization opportunities and to detect developing system problems. Reports are available in almost real time. History-matching is available to determine the ongoing health of the operation. The majority of these processes are carried on in the background with little operator intervention required.
ence has been developed to automate these routine tasks as well as increase the speed of delivery. With the newly acquired data, key performance indicators are available to evaluate the ongoing operation.

At Level II, the cleansed data are fed to software modules to validate proper system performance. The DECIDE! program can integrate external applications that allow data exchange, including ECLIPSE reservoir simulation software, PIPESIM production system analysis software and various modules available in the DECIDE! software. The process automatically conducts history-matching for trend analysis, provides individual well status and determines production and capacity constraints. Current and future delivery requests for injection and withdrawal—inputs into a dispatcher’s module—are passed to a DECIDE! software module. This module then provides all the necessary calculations and predictions to ensure that the reservoir has sufficient capacity to meet the dispatcher’s requests.9

The advanced programs used for the reservoir-surveillance models require computer-intensive calculations. Running optimization iterations cannot provide satisfactory results in the required time frame using the large volume of data, even after the data have been aggregated and cleansed. Proxy models, although not as accurate, are substituted for full-scale simulations and can provide results in seconds or minutes.20

Proxy models, in the form of trained neural networks (NNs) optimized to require a reduced number of input parameters, use artificial intelligence to mimic large-scale simulators. The NN learns to behave like the simulator and, once trained, it can perform a set of calculations in a fraction of a second for a given set of input parameters. The NN drastically reduces the computation time necessary, allowing real-time history-matching with the optimized original outputs of full-scale numerical models.

An example of the use of a NN is a production forecast and optimization simulation. If small changes of the input parameters are involved, such as tubing-head pressure, a forecast can be calculated immediately, rather than waiting for a time-intensive full simulation to be performed. Multiple iterations can also be run quickly to determine the best course of action. Additionally, NNs are used to evaluate uncertainties in the input data provided in the Level-I data-acquisition phase. This speeds up the quality-control and data-cleansing functions prior to inputting data into the proxy models.

An automated surveillance system compares calculated results with measured results. If information from proxy models indicates that a well or surface component has failed to perform as expected, an event alarm is triggered and reported to the operator by way of the engineer’s desktop. For the parameters that are set to trigger alarms, a deviation range can be established and adjusted as required. Once an alarm has been triggered, the reservoir engineer can react in a timely manner to investigate the source of the problem (above).

The level beyond monitoring and surveillance is Level-III intelligence—an example of the digital oil field. Although oil companies and service providers have found it difficult to provide a single definition for this term, the digital oil field essentially provides a high level of automation, simulation modeling, decision-making tools (the faster, the better) and an integrated approach that does not lose sight of the small details (or at least has a system to monitor them). Schlumberger refers to this level of field operation as the BlueField intelligent asset integration service.21

At the BlueField level, data are acquired and prepared for processing, and integrated-simulation models are run from various performance modules. System checks are carried out at the highest level, and reports concerning the health of the complete operation, using deterministic models, are generated and delivered to the DECIDE! engineer’s desktop (next page). The service provides the ability to oversee scheduled automated tasks or those triggered by event alarms.


In the system implemented by RWE Transgas Net, automated tasks have the following structure: first run scheduled tasks or trigger automation tasks, then run predictive data-mining proxy models and apply rules. Triggering events are either discrepancies from expected trends or violations of predefined constraints. The actions triggered by the alarm include system notification, retrieval and execution of surveillance software, exchange of data with third-party software, initiation of subordinate tasks and generation of e-mail or text messages to alert the operator of an error condition.

Along with the alarms, the software automatically provides key performance indicators to the operator at the engineer's desktop. It formats the data for visualization and provides forecasts based on current performance of the field. Reservoir performance modules identify bottlenecks, like facility constraints, and report on optimization opportunities along with recommended courses of action. With dramatically reduced analysis cycle time, the engineer can react almost instantaneously. Automated data flow and transparently updated models allow the engineer to focus on system optimization and problem elimination. Proactive, intelligent reservoir management—a BlueField application—becomes a reality.

**Into the Future**

Underground gas storage in depleted reservoirs has proved to be well-suited for many of the intelligent well and intelligent field technologies that are being developed for traditional oil and gas production. The UGS industry has achieved great success in the adoption of these techniques. The lessons learned by UGS operators are being applied with greater confidence by the oil and gas production side of the business because these new technologies have demonstrated their ability to provide reduced costs and increased efficiencies.

Because UGS fields have long life expectancies, they afford a long-term outlook for payback. Compared with conventional hydrocarbon fields, gas-storage fields do not experience the same decline in their asset's value as the reservoir depletes because gas-storage fields can be repeatedly recharged. Retrofitting older facilities with modern intelligent-field equipment makes financial sense, increasing the value of the existing asset.

Maximizing the asset, above and below the ground, leads to innovative approaches like those discussed in this article, but there are still more technologies and techniques to apply. For instance, cushion gas can be the most expensive component in a UGS facility and realistically will be returned to the operator only when the field is decommissioned. As an example, UGS in a depleted field with 20 Bcf [566 million m³] of total capacity would require 30 to 50% of the gas to remain in place as cushion gas. Borrowing from the bank analogy, that equates, at the high end, to 10 Bcf [283 million m³] left in an interest-free checking account. At 2008 price levels, that comes to more than US $80,000,000.

Even if the reservoir is operated in the most efficient pressure and flow range, some cushion gas must be left in the ground to enable high-rate delivery. Reservoir engineers have tested the feasibility of injecting inert gas into the reservoir to function as cushion gas. This approach is especially practical considering current natural gas prices. The technique does, however, require detailed understanding of the reservoir storage properties and flow characteristics, the consequences of mixing different gases and the long-term effects of the inert gas on the reservoir. This is yet another example of UGS operators applying novel reservoir management techniques.

As operators develop UGS fields and attempt innovative approaches, the emphasis on reservoir characterization, process optimization and automated operation bring greater flexibility and opportunities to UGS projects. As an example, Falcon Gas Storage Company is applying much of its experience with intelligent field technology in UGS to the first offshore UGS facility in North America. The reservoir has been characterized and modeled using Petrel software. The surface equipment has been designed, and operations are expected to commence during 2009. This high-deliverability, multicycle facility is designed to have a working volume of 50 Bcf [1.4 billion m³], with injection and withdrawal capabilities of 1 Bcf [28 million m³] per day.

By 2030, global demand for natural gas is projected to range from 556 to 581 Bcf [10 billion to 16.4 billion m³] per day, up from 243 Bcf/d [6.9 billion m³/d] in 2000. The Middle East has by far the largest natural gas reserves with an estimated 2,566 Tcf [72.7 trillion m³]—or 41% of the world’s total. Russia, second in proven reserves, has extensive pipelines into Europe and has proposed pipeline construction to China and other countries. As demand for natural gas grows, new methods will be developed to transport, store and deliver it. Because the supply is generally far removed from most users, UGS facilities are a major component in providing a stable, secure source of natural gas for industrial and residential consumption.

As the character of UGS evolves from peak-shaving to flexible applications, intelligent field technologies are assisting operators in the quest for greater efficiency, lower costs and innovative methods of doing business. As a result, the digital oil field has become a reality in the underground gas-storage industry. —TS