Storing Natural Gas Underground

Underground storage of natural gas is a growing industry that helps gas suppliers meet fluctuating demand. Techniques for designing, constructing and monitoring gas-storage facilities range from the latest in salt-mining ingenuity to both established and cutting-edge oilfield technologies.

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1. http://www.eia.doe.gov/
Energy demands are increasing as the world’s population of energy users grows. At the same time, many people want to decommission nuclear plants in support of a cleaner environment. Clean-burning natural gas is the fuel most likely to meet society’s complex requirements in the early 21st Century.

Projections for the next 20 years indicate increases in consumption of energy from nearly all sources (right). The estimated demand for nuclear energy shows a decrease, but use of oil, coal, natural gas and renewable sources will likely increase, with natural-gas usage showing the greatest increase.

Current worldwide gas reserves of 5146 trillion cubic feet (Tcf) [146 trillion m³] appear sufficient to meet projected demand for the foreseeable future. These reserves are currently concentrated in the Former Soviet Union and the Middle East, far from areas of demand (right). In about 2020, gas production will outpace oil production in barrels of oil equivalent (BOE) per year. However, by then, some countries that currently have adequate gas reserves, the USA included, probably will become importers.

Natural gas has two main uses—generation of electricity and space heating with gas-burning furnaces. In many parts of the world, demand for natural gas is seasonal. Typically, more gas is used in cold months than in warm months, but in some regions electricity demand rises again in hot weather because of air-conditioning usage.

In addition to seasonal variation in usage, local power demand usually varies over a 24-hour period, with high demand occurring during the workday and lower demand at night. Peak demand periods may last only a half-hour, but utility companies must be prepared to supply additional power whenever peaks occur.

Utility companies that burn gas have to buy supplies for their power plants. Long-term contracts with gas suppliers ensure a base-level delivery for everyday power generation, but seasonal demand may require additional purchases at the instantaneous, or “spot,” price at a given location. When demand is low, utility companies sell excess gas on the spot market or store it, if they can.

Gas suppliers are in a similar situation, and often enter into “take-or-pay” contracts with gas exporters, oil and gas exploration and production (E&P) companies and pipeline owners. These long-term contracts require buyers to pay for an agreed-upon amount of gas, whether there is a demand or not. In times of high demand, gas suppliers also make spot purchases, but as soon as demand falls, they may opt to store gas instead of selling it at a low price.

Underground storage of natural gas is an important way to manage fluctuating prices and demand. Storage is a vital part of the chain that links upstream oil and gas activities, such as exploration and production, with downstream distribution, and ultimately, consumers. Many storage facilities are managed on a merchant basis by independent companies whose business is gas storage. These storage companies provide gas hubs connected to multiple pipelines for several gas suppliers and distributors.

This article reviews the history of underground gas storage and describes types of storage facilities. Several technologies developed for oil and gas formation evaluation, drilling, reservoir characterization, completion and stimulation play important roles in the gas-storage story. Case studies demonstrate how these technologies are used to help in the design, construction and monitoring of underground gas-storage facilities.
Underground Gas-Storage Systems

Underground storage systems can be constructed in salt formations, porous rock and abandoned mines (above). Porous rock systems may be either depleted hydrocarbon reservoirs or aquifers. The first recorded underground gas-storage site opened in 1915, in Welland County, Ontario, Canada. In 1916, the Zoar field, near Buffalo, New York, became the first storage project in the USA, and continues to operate today. These projects injected gas produced elsewhere into depleted hydrocarbon reservoirs in the summer, and produced the gas for use in the winter. Also in 1916, Deutsche Erdöl AG received a German patent on the solution mining of salt cavities for storing crude oil and distillates.

Over the next decades, there were few advances in gas-storage technology, but activity renewed in the USA by 1950. That year, natural-gas liquids were first stored in a solution-mined salt cavity in the Keystone field, Texas, USA. In 1961, a cavern in bedded salt in Marysville, Michigan, USA, was first used for natural-gas storage. These storage projects were initiated to bring gas supply to growing population centers when demand exceeded the capacity of steel pipelines. During 1970, the first leached salt-dome cavern facility opened for gas storage in Eminence, Mississippi, USA. This system was designed to replace Gulf of Mexico production that had to be shut in during hurricanes. Similar structures have been designed to store strategic reserves of oil and gas as national-security measures.

Now there are more than 550 underground gas-storage facilities in operation worldwide. About two-thirds of these are in the USA, and the majority of the rest are in Europe. Most storage is in porous rock systems—either depleted oil and gas reservoirs that have been converted to gas storage, or aquifers—but some cavern-style facilities exist. In Europe, salt-cavern facilities have proliferated thanks to an abundance of naturally occurring salt deposits and a history of salt mining. Salt caverns are also used for storage in the USA, especially near the Gulf of Mexico. Storage facilities in abandoned mines or rock caverns are less common.

One of the leaders in storage-facility design and construction is Kavernen Bau- und Betriebs-GmbH (KBB), now a Schlumberger company. KBB has been involved in more than 100 such projects worldwide (next page, top). Each project requires petrophysical and mechanical characterization of the proposed subsurface location to ensure that formation properties are suitable for long-term gas storage. Salt formations are evaluated for rock strength and volume. Porous rock formations are assessed for structural closure, seals and adequate porosity and permeability to sustain high deliverability rates.

Two important parameters for all underground storage facilities are the working-gas volume, or gas available for withdrawal, and the maximum withdrawal rate over a defined period of time. Working gas is determined by the storage-facility volume and the difference between maximum and minimum gas pressures. A volume of gas, called cushion gas, always remains in storage. The maximum withdrawal rate from storage can be limited by flow resistance in the production well and in porous rock.

Well-construction techniques for gas-storage wells must ensure that wellbores tolerate high injection pressures, high production rates and frequent cycling—injection followed by production. Gas-storage wells also have long lifetimes, 80 or more years, compared with oil and gas production wells. In the following sections, we first describe technologies used to create salt-cavern facilities, and then highlight case studies in porous rock.

Storage in Salt Caverns

Salt has several properties that make it ideal for gas storage. It has moderately high strength and flows plastically to close fractures that could otherwise become leaks. Its porosity and permeability to liquid and gaseous hydrocarbons are near zero, so stored gas cannot escape. Salt caverns can cycle—switch from injection to production—in a matter of minutes, and contains a large fraction of working gas relative to total gas. Salt caverns are the preferred option for merchant storage, because they allow frequent cycling and high rates of injection and production.
Exploration for salt bodies relies on electromagnetic, seismic and gravimetric surveys, because salt’s conductivity, velocity and density are in high contrast with those of surrounding rocks. Borehole logs and coring help assess salt structure and composition. Salt can occur in layers, but such evaporite accumulations often contain anhydrite, limestone and dolomite, which do not dissolve. Salt domes tend to have more homogeneous composition than mixed evaporite layers, and are preferred for gas storage because they dissolve more uniformly and can accommodate larger caverns.

Rock-mechanical investigations are an essential component of storage design. Theoretical calculations help determine the suitability of a given salt formation to house a cavern. These calculations require knowledge about the salt structure and strength, and help verify the shape and location of the cavern, separation between caverns, and cavern stability at operating pressures (below).


Locations of caverns and salt-production projects constructed by Kavernen Bau- und Betriebs-GmbH (KBB). In addition to hydrocarbon-storage facilities, KBB builds and manages facilities for brine, salt and other mineral production.

Building a salt-cavern rock-mechanical model. Well logs and cores help construct a simplified geological profile (left). This serves as the basis for the theoretical rock-mass model (middle left) for the salt and bounding layers. A two-dimensional finite-element calculation model (middle right), symmetric about the cavern’s vertical axis, divides the theoretical model into elements for stress calculation. The resulting calculations reveal the stress distribution (right) around the proposed cavern.
Salt deforms plastically in relatively short time frames, explaining its superb sealing qualities. While this property helps maintain impermeability and keeps salt caverns from fracturing under large stress changes, it also means that caverns will shrink over time. Experiments on salt cores help determine formation strength and deformation characteristics (above).

Well logs and salt cores are studied to determine the optimal dissolution process for creating salt cavities (above right). The presence of insoluble impurities is an important factor in determining the best leaching tactics, but cannot always be identified on well logs; cores provide samples for laboratory solution testing.

Cavern development involves drilling a well through which fresh water will enter and waste brine will exit (right). This well also is used for gas injection and withdrawal, and will typically have casing cemented to the top of the cavern. When drilling through salt, brine-saturated mud helps avoid excess dissolution of salt while the hole is drilled to the cavern bottom. A typical casing plan includes a 28-in. conductor pipe, intermediate 24-in. or 20-in. casing if required by overburden, 18%-in. or 16-in. surface casing set in caprock, and finally 13%-in. or 11-in. casing cemented below the salt top. Leaching and production strings hang into the cavern from the last cemented casing.

Before leaching operations can begin, a hydraulic well-integrity test (WIT) is performed to confirm that the well system—wellhead, last cemented casing, casing shoe and open section of hole—is sound. During storage and retrieval operations, the highest differential pressures experienced by the cavern are at the last cemented casing shoe, and this is where the maximum pressure is experienced during a WIT.

In one salt-cavern well, the WIT exhibited unacceptable hydraulic losses. Further investigation pointed to a weak zone, probably a microannulus between cement and salt, at the 13%-in. shoe. Traditional repair options were reviewed, but found to be inadequate. Squeezing cement through perforations might damage the integrity
Completion engineers selected the Schlumberger DGS Delayed Gelation System fluid for squeezing into the cemented annulus. The DGS fluid maintains a low viscosity until an internal catalyst causes the gel to form. The gel was squeezed while an inflatable straddle-packers assembly separated the cemented casing around the shoe from the openhole section. The packers also isolated the section for a second WIT run to verify repair-job success (left). Once well integrity was confirmed, leaching could commence.

In the leaching process, fresh water is pumped down one tubing string of the well, and brine is returned through another. Roughly eight volumes of water are required to dissolve one volume of salt. The cavern roof is protected from uncontrolled dissolution by pumping in a protective fluid, usually liquefied gas—typically nitrogen—that floats on the surface of the brine. Below this protective blanket, the cavern can be solution-mined in approximately cylindrical form in accordance with the rock-mechanical and solution-mining calculations and targets. The relative depths of the leaching strings can be modified to control the shape of the cavern. The shape and size of the resulting cavern can be confirmed with sonar caliper tools (left).

The produced brine can be used by the chemicals industry for salt and other mineral extraction, released into nearby seas if allowed, or disposed of by injection into other rock layers with sufficient injectivity. In some cases, waste brine is disposed of in abandoned salt mines.

Undissolved impurities in the salt form a water-saturated residue, or sump, in the bottom of a cavern. After the cavern is filled with dry gas, water from the sump will evaporate into the gas as the gas is produced. The depressurization of this wet gas may cause the formation of hydrates that can block downhole pipes and surface facilities. Cavern pressure, temperature, humidity and dewpoint should be monitored to determine conditions for hydrate-free gas withdrawal. Injection of inhibitors to prevent hydrate formation is a common practice before gas withdrawal.

The time required to create a cavern depends on solubility of the salt and the desired size of the cavern. One recently constructed cavern facility consists of five separate salt caverns about 250 m [820 ft] high and 40 m [131 ft] across. Construction costs, including drilling wells, leaching salt, installing surface facilities and injecting cushion gas totaled US $150 million.
Total project duration from feasibility to hookup and commissioning was more than five years. KBB is constructing a cavern that, when finished in 2003, will be the largest in the world (above).

Another example of a cavern gas-storage facility is in Nuettermoor, Germany. The Nuettermoor location provided operator EWE Aktiengesellschaft, Oldenburg, with ideal conditions: salt of high quality, a favorable location within the transport network, problem-free extraction of fresh water and disposal of brine into the Ems estuary. The caverns in Nuettermoor are up to 400 m [1312 ft] high and 75 m [246 ft] wide. The Nuettermoor facility has 18 caverns of which two are still under construction. The total geometrical cavern volume is about 8.5 million m³ [300 MMcf] and can accommodate about 1.3 billion m³ [46 Bcf] of natural gas, of which 80% is working gas and 20% is cushion. The volume of working gas is 68 million m³ [2.53 Bcf], and the remainder is cushion gas. Adjacent to the Huntorf facility is a compressed-air energy storage facility (see “Storing Compressed-Air Energy,” page 10).

Drilling Porous-Rock Gas-Storage Wells

Most gas-storage facilities are in the porous rock of depleted gas reservoirs that have been in operation for decades. Depleted fields are less expensive to develop than other types of installations, because existing production wells and gathering lines can be converted for storage use. In many cases, depleted fields contain the base gas needed to operate a storage facility. In general, porous-rock facilities are appropriate for seasonal and strategic-reserve storage. Limited production capacities and deliverability constrain their use for supplying energy during peak-load electricity generation. Operators of these fields contend with many of the same problems that oil and gas E&P operators experience, and often apply proven oilfield technology to increase field capacity and improve rates of gas deliverability.

Another example of cavern gas-storage is the facility in Huntorf, Germany, operated by E.ON Kraftwerke GmbH. Four gas-storage caverns were created by dissolution of a Permian salt dome in 1975 for a total volume of 1.1 million m³ [39 MMcf]. Each cavern is 220 to 275 m [720 to 900 ft] high and about 60 m [200 ft] across at maximum width. With a maximum storage pressure of 100 bars [1450 psi], the total storage capacity is 137 million m³ [5.10 Bcf]. Of this, the volume of working gas is 68 million m³ [2.53 Bcf], and the remainder is cushion gas. Adjacent to the Huntorf facility is a compressed-air energy storage facility (see “Storing Compressed-Air Energy,” page 10).

In 1998, CNG Transmission, now part of Dominion Transmission, made plans to create a high-deliverability horizontal well by reentering an existing well in the South Bend gas-storage reservoir, Armstrong County, Pennsylvania, USA. If a short-radius sidetrack could be drilled with coiled tubing and could follow the sands in the fluvially deposited 100-Foot Sand of Mississippian age, CNG Transmission would have a cost-effective way to improve field performance. The resulting well would tie into the existing pipeline infrastructure and surface facilities, and underbalanced coiled tubing drilling would cause minimal environmental impact with reduced formation damage.

The South Bend gas field was discovered in 1922, and was converted to gas storage in 1951. Reservoir capacity is 17.34 Bcf [491 million m³] of which 5.81 Bcf [164 million m³], or 33.5%, are available for withdrawal. The field contains 61 injection-withdrawal wells and 4 observation wells. Seventy-five percent of the gas deliverability comes from only 12 wells, evidence that reservoir heterogeneity has made for challenging well placement.

To enhance the chances for a successful horizontal sidetrack, the company needed to understand the petrophysical characteristics and stratigraphic nature of the high-quality sands within the 100-Foot Sand formation. The existing openhole well was cleaned, and slimhole wireline logs and images were acquired. Image logs from neighboring wells were also examined (above). Interpretation of the complete dataset
indicated a 14-ft [4-m] zone of high porosity dipping 3 to 4° SSW. The new well was planned to enter this zone and continue for a 500-ft [152-m] horizontal section.

The original wellbore casing dated back to the 1920s, and was deemed too fragile for conventional rotary drilling. The sidetracking plan was further complicated by the presence of a depleted “thief zone” behind the casing string set immediately above the reservoir section. To avoid entering the thief zone, the sidetrack would have to kick off in openhole using a cement plug instead of a more accepted mechanical whipstock.

The sidetrack kicked off 5 ft [1.5 m] below the 5½-in. casing shoe with a Schlumberger VIPER coiled tubing drilling steerable bottomhole assembly (BHA). A steerable BHA and motor were deployed on 2½-in. coiled tubing with a wireline installed to drill the 4½-in. horizontal well. Because reservoir pressure had declined, the well ended up being drilled with a 200-psi [13.6-atm] overbalance pressure. The performance of this system surpassed expectations and achieved build rates of up to 100° per 100 ft [30 m], which exceeded the planned 65° per 100 ft. However, unexpectedly hard rock required several bit changes and slowed the rate of penetration, so the well plan was revised to stop drilling 290 ft [88 m] after kickoff.

Two months after cleanup, well performance had increased from 0.337 MMscf/D to 2.83 MMscf/D [9650 m³/d to 81,050 m³/d], a deliverability increase of 840%.

After the successful results of this first sidetrack, CNG Transmission used coiled tubing to drill short-radius sidetracks in two other wells. The second well exhibited a 320% increase in deliverability, and deliverability of the third well increased by 2400%.

Drilling Under Pressure
While gas-storage reservoirs in the northeastern USA tend to be in relatively shallow formations of competent porous rock, facilities elsewhere in the world experience drilling conditions and wellbore-stability problems that require different solutions.

In one example, Wintershall AG planned to drill a series of additional horizontal wells in their underground gas-storage reservoir in Rheden, Germany. To avoid mud losses in the reservoir section, wells had to be drilled while storage pressure was at its highest. To ensure adequate well control, Schlumberger, Wintershall and the drilling contractor jointly developed a set of strict operational procedures. These included preventive measures and emergency-response procedures to ensure the correct sequence of actions to avoid critical situations.

Reservoir pressures were so high that in the early stages of well construction, the drillstring was not heavy enough to run in without being pushed. Tripping pipe out for a BHA or bit change and pushing the BHA back into the hole under high pressure required a snubbing unit to push the BHA downhole. The Sedco SN24 snubbing unit selected for the job had to undergo structural modifications approved by the responsible mining authorities to fit into the derrick of the drilling rig. Once the drillstring weight was high enough to overcome the gas pressure in the wellbore, the string could be run without snubbing-unit assistance. At that point, the snubbing unit could be rigged down and removed from inside the rig mast, and the drilling crew could continue with normal drilling operations.

The snubbing unit was required whenever tripping out of the hole until reaching total depth (TD) and completing the well at TD. The last operation with the Sedco SN24 unit was the running of a 7-in. liner. This procedure is now certified and available for future underground gas-storage drilling applications.

**Imaging While Drilling**

The Breitbrunn/Eggstatt gas field in Bavaria, Germany, was discovered in 1975. The field produced from vertical wells in four sands until 1993, when the uppermost layer, Layer A, was converted into a gas-storage reservoir. In 1996, demand for natural gas during winter months led to a campaign to double the storage capacity of this anticlinal reservoir by additional drilling into Layers C and D, two deeper, less homogeneous sands. The deeper layers consist of isolated sand lenses that could suffer sanding problems during production cycles. Intersecting as many sand lenses as possible required snubbing horizontal wells with real-time logging-while-drilling (LWD) data for geosteering. LWD data would also help optimize trajectory orientation to avoid azimuths prone to sanding.

Geological, petrophysical and geomechanical studies conducted before drilling improved the accuracy of the reservoir structural model, helped assess sand distribution and wellbore stability, and aided in the selection of drilling mud and LWD tools that would allow successful well steering within the thin—5- to 15-m (16- to 49-ft)—reservoir layers. The structural model achieved 99.9% depth accuracy, or maximum inaccuracy of 1.5 m, by including resurveyed well locations, directional surveys and log-derived markers from existing wells.

Petrophysical and stratigraphic evaluation predicted that reservoir sands would be present as isolated lenses. To penetrate as many lenses as possible, well trajectories were designed in gentle U-shaped profiles to traverse Layers C and D from top to bottom and back to the top within each horizontal section (above).
Natural gas is not the only type of gas that is economically worthwhile to store in caverns. Compressed air, which is also needed by power-generating plants, can also be stored in compressed-air energy storage (CAES) facilities.

The basic idea of CAES is to store off-peak energy produced by nuclear or coal-fired units as compressed air to be used in high-demand periods. During low-cost, off-peak load periods, a motor consumes power to compress and store air in underground salt caverns. During peak load periods, the compressed air is withdrawn to burn natural gas in surface combustion chambers.

In pure gas-turbine power stations, about two-thirds of the output is used to compress the combustion air. In a CAES power station, no additional compression is necessary, because the air is already compressed. A CAES facility can use all output for power generation.

To date, two CAES plants have been built, one at Huntorf in 1978, and the second at McIntosh, Alabama, USA, in 1991. A third is being planned for a 10 million m³ [353 MMcf] limestone mine in Norton, Ohio, USA. The two compressed-air storage caverns at Huntorf are about 250 m tall and 60 m across, for a total volume of 310,000 m³ [11 MMcf].

To monitor gas-storage cavern stability, a sonar tool performs regular surveys of the cavern shape to assure storage-facility longevity. Frequent pressure and temperature changes associated with air injection and withdrawal can affect salt stability. To conduct work on the wellheads or production strings, it is sometimes necessary to reduce cavern air pressure at the Huntorf facility to atmospheric pressure. This pressure reduction could allow the salt to flow plastically, a phenomenon known as salt creep. Also, stresses in the outlying salt volume can cause large amounts of deformation. One cavern in Mississippi is reported to have suffered a 50% loss in volume due to salt convergence.

Surveying cavern contours of the Huntorf CAES facility has been difficult because the ultrasonic tools used in natural-gas caverns have...
inadequate range in humid CAES caverns. Instead, surveying with a heated laser tool shows how little the contours of the cavern wall have changed during the 20 years of operation (below right).

A critical aspect when designing the compressed-air wells was the specification for extremely high withdrawal rates with low pressure losses. This required a 24½-in. last cemented casing size and a 21-in. production tubing string. Because there is no packer sealing the tubing-casing annulus, the last cemented casing string is open to corrosion. Water in the sump of undissolved components on the cavern floor saturates the compressed air, making it highly corrosive. At Huntorf, attempts to counteract corrosion of the final casing are made by injecting dry air into the annulus.

To further reduce the impact of corrosion, the production string inside the last cemented casing was made of extra-thick steel. However, after only a few months of operation, serious corrosion problems became apparent with the appearance of rust in filters upstream of the gas turbine. Fiberglass-reinforced plastic (FRP) replaced the 13½-in. steel production casing in the 1980s. Now, however, even the FRP strings are experiencing partial destruction (previous page, bottom).

To replace the FRP in one well, the damaged section was removed, and the 24½-in. last cemented steel casing was cleaned and then inspected using METT Multifrequency Electromagnetic Thickness Tool logs to assess wall thickness. Because of the large casing diameter, the tool was used outside its usual measurement range of up to 13½ in. Evaluation of the logs indicated that the corrosion-protection measures of injecting dry air between the steel and FRP casings had successfully inhibited corrosion of the steel casing. No pitting or corrosion was seen on the steel surface.


Monitoring salt-cavern shape and size. The similarity between the contours detected with a sonar tool in 1984 and those seen by laser measurements in 2001 show how little the two caverns have changed shape in nearly 20 years of operation.
Well trajectories were also designed to minimize wellbore instability and sanding. A geomechanical study indicated the maximum horizontal stress is oriented N-S, minimum horizontal stress is oriented E-W, and the intermediate stress is vertical. Based on this information, and assuming isotropic rock strength, wells would be designed to trend N-S. However, rock-strength tests showed distinct strength anisotropy, with maximum strength in the N-S direction and reaching three times the minimum-strength value. In addition, stress was considered likely to increase on the flanks of the anticline. Wells placed closer to the anticlinal axis, away from the flanks, would be more stable. This led to a final selection of NE-SW, along the anticlinal axis, as the optimal well azimuth.

Geomechanical analysis also influenced the choice of drilling mud. Sometimes, foamed muds are selected for underbalanced drilling to prevent invasion in depleted reservoirs destined to become gas-storage fields. In this case, a water-base mud would provide better borehole stability and produce a thin mudcake on the borehole wall to reduce invasion.

This type of mud system would allow all conventional LWD logging and imaging techniques to be performed with real-time data transmission. The GVR GeoVision Resistivity tool, which is a recent version of the RAB Resistivity-at-the-Bit tool, was selected because of its ability to differentiate sand lenses from bounding shales. The ADN Azimuthal Density Neutron tool was chosen to assist in identification of clay features and carbonate concretions. Together, these tools made it possible to assess porosity and sand content while drilling the 8½-in. horizontal sections down and up within the C and D layers.

Computed dips from GVR real-time images defined the relative position of the borehole within the reservoir. Drilling up- or down-section is easily recognizable on these images. The sinusoidal bed boundaries point uphole when drilling down-section, and downhole when drilling up-section.5

After drilling, all LWD, wireline and core data were analyzed for the final petrophysical evaluation. Zones of highest permeability were selected for perforation, as long as the geomechanical data indicated that sand-free production would be possible. Oriented perforating guns were deployed to place perforations in sand and not, for example, in an underlying shale lens or a carbonate concretion.6

With these techniques, three horizontal wells were drilled and completed in each of the two inhomogeneous sands. Each well exceeded 1000 m (3280 ft) in length, and together, the six wells doubled Breitbrunn storage capacity to 1.085 billion m³ (38.3 Bcf).

**Sand Control for Gas-Storage Wells**

Sand control can be a major concern in some gas-storage wells, especially since they experience repeated cycles of high-rate injection and production. Controlling sand production was a primary objective for Taiwan Petroleum and Exploration, a division of the Chinese Petroleum Corporation, when they initiated a project in 1997 to deepen six wells in the Tiehchenshan reservoir and establish a gas-storage facility.

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^ A typical gravel-pack completion (not to scale) in the six-well Tiehchenshan gas-storage project, Taiwan. The storage formation was a poorly consolidated sandstone, and each well required sand-control treatment to sustain high gas-injection and withdrawal rates.
The storage formation at 2800-m (9184-ft) depth is a poorly consolidated sandstone with negligible shale content. Average porosity is 20% and permeability is 250 mD. To sustain the specified maximum injection and withdrawal rate of 28.2 Mscf/D (808,000 m³/d) per well, all six wells would be completed with openhole gravel packs. Each well had already been predrilled with 9%‐in. production casing cemented just above the reservoir.

The Tiechenshan project allotted 12 days per well for a total of 72 days to deepen the six wells. The work scope included cleaning the 9%-in. casing, drilling an 8½-in. openhole section for about 30 to 40 m (100 to 130 ft), coring five of the six wells, placing gravel pack, running a final completion string and cleaning up the wells (previous page, left).

The project was completed in 60 days with two rigs and no lost-time incidents. Completion specifications included a picklee treatment of 10 bbl [1.6 m³] of 15% HCl, corrosion inhibitor and iron-chelating agent. Then followed a 20-bbl [3.1-m³] scrubber treatment of 40 pounds per thousand gallons (ppt) hydroxyethyl cellulose (HEC) gel containing 400 lbm [181 kg] of 20/40 sand.

The gravel pack consisted of 10 bbl of 40-ppt HEC gel pad, followed by circulating 40-ppt HEC gel and gravel concentration of 1 pound proppant added (ppa) per gallon of slurry. Some wells had slurry packs of 80-ppt HEC gel and 4 ppa per gallon of slurry. Post-pad treatment was 5 bbl [0.8 m³] of 40-ppt HEC gel. The completion fluid left in the casing annulus for each well was a mixture of 8.47-ppg 3% potassium chloride [KCl] with IDFILM 820X corrosion inhibitor to minimize bacteria and corrosion buildup throughout the life of the wells. Each well was cleaned up and flow-tested with positive results.

The gravel packs have successfully prevented sand production during the three years of gas production since these wells were constructed. The wells have not yet been used for gas injection, but throughout this time, well deliverability has remained at the high levels initially achieved because of the successful gravel packs.

Monitoring Gas-Storage Wells

All gas-storage facilities require some type of monitoring to make sure wells can deliver or accept gas at required flow rates. High flow rates experienced during gas withdrawal can cause formation damage in the near-wellbore region. Similarly, well damage may occur during high-rate injection. Damage may also result from switching frequently from withdrawal to injection.

Well monitoring in porous rock systems traditionally consists of performing surface tests of backpressure every 1 to 2 years. A surface back-pressure test consists of shutting the well in for a few hours for stabilization and then alternately flowing and shutting in the well over a 4- to 8-hour period. Flow rate is controlled and surface pressures are recorded, typically every 5 to 10 minutes, during flow and shut-in periods.

Data from a conventional backpressure test can be used to predict flow rate, or deliverability, for any reservoir pressure and wellhead pressure. Thus, any damage that has occurred since the last test will be evident. However, infrequent testing may fail to identify wellbore damage in time to avoid lost deliverability and also can make it difficult to determine the cause of damage. More frequent testing using downhole pressure gauges is usually considered too expensive. In the surface tests, individual wells are flowed at a variety of rates to determine well deliverability and to detect any damage incurred since the last test.

Engineers at Schlumberger Data and Consulting Services have developed a new way to use results from surface measurements to quantify wellbore damage over time. Only one initial pressure-transient test analysis (PTTA) using data from a downhole gauge is required. The new method has been tested using data from a gas-storage well in a sandstone reservoir in the eastern USA.

The well selected for validation of the new method was initially tested in June 1996. A deliverability test was conducted with a bottomhole pressure gauge installed. Pressure-transient test analysis of the bottomhole gauge data helped to determine the well’s mechanical skin, s_{Dq}, and non-Darcy factor, D, as of June 1996. The total skin, s_T, is given by s_T = s_{Dq} + Dq, where q is the flow rate. The product Dq is called the non-Darcy skin and is caused by high flow velocities near the wellbore.

The well was subsequently tested in June 1997, and two days later it was hydraulically stimulated. Two additional tests were conducted in September 1997 and May 1998. In each of these three tests, a deliverability test was conducted and surface pressures were recorded. To validate the new method, a bottomhole pressure gauge simultaneously provided downhole data for determination of mechanical skin and non-Darcy factor. These values were then calculated from the surface data alone and compared with measured PTTA values (above left).

The new method makes it reasonable for operators to monitor wells more frequently at minimal cost. Implementation of this technique may provide insight into the source of damage in gas-storage wells, allowing repairs or mitigation before deliverability declines to uneconomic levels.

In another study, Schlumberger consultants have shown how multirate flow tests can help determine reservoir quality, quantify inventory volume, construct a total system model, catalog downhole and surface-facility bottlenecks, and even determine the horsepower required to cycle the working gas multiple times per year.

Another source of valuable monitoring information comes from wellhead electronic flow...
measurements (EFM). EFM equipment measures, stores and transmits gas rate and pressure data from the wellhead to an office computer. These systems are not yet commonly installed in gas-storage wells, but are becoming more popular.

An EFM system installed in the Belle River Mills gas-storage field in Michigan in the mid-90s helped engineers detect operational problems that rendered several wells inoperable.10 The measurements also helped assess the impact of subsurface safety valves on well deliverability and formed part of an automated system designed to alert field operators to deteriorating well performance.

Michigan Consolidated Gas Company operates the Belle River Mills field, a Niagaran-age reef structure that was discovered in 1961 and converted to gas storage in 1965. The field has 23 active injection-withdrawal wells capable of producing in excess of 1.2 Bscf/D [34 million m³/d] during peak flow periods. Wide variations in flow rate are common within a single day.

Early reservoir-surveillance methods consisted of backpressure tests every three to five years to assess well deliverability, and differential pressure tests two to four times per year to determine the contribution of each well to total field flow.

Installation of wellhead EFM devices now allows operators to continuously monitor well deliverability and all flow parameters. A computer network links the wells and polls them once per hour. The hourly readings are compressed and transferred to the corporate office once a day. These frequent updates help identify operational problems, such as valve malfunction, in addition to chronic problems, such as wellbore damage.

One way to identify anomalous well performance is through bubble plots of relative production rates from EFM data. The OFM production management software system can be used to monitor well performance. A bubble plot for a typical day at the Belle River Mills field shows lower withdrawal rates from wells on the flanks, or edges, of the structure where reservoir quality is low. The center of the field shows higher production (larger bubbles). An open circle indicates a well with no production.
France, where the Institut Français du Pétrole and Gaz de France have monitored acoustic emissions in underground gas-storage facilities. Newer experiments have monitored gas-column height and saturation using time-lapse surface seismic and borehole seismic imaging.

Rehabilitating Damaged Gas-Storage Wells

The American Gas Association estimates a deliverability loss of about 3 Bscf/D [85.9 million m³/d] in the more than 15,000 gas-storage wells operating in the USA. Gas-storage operators spend more than $100 million annually to restore lost deliverability either by remediation or drilling new wells.

Some of the damage mechanisms, such as invasion and sanding, are familiar to E&P operators, while other mechanisms, such as bacterial growth or compressor oil plugging pores, are more specific to gas injection and storage. The Gas Technology Institute (GTI) recently conducted a research project to investigate damage mechanisms in gas-storage wells. To supply data for this investigation, gas-storage operators evaluated cores, fluids and tests from wells in more than 10 storage fields. Four main types of damage were identified:

- bacteria
- inorganic precipitates, such as iron compounds, salts, calcium carbonate and barium sulfate
- hydrocarbons, organic residue and production chemicals
- particulates.

In the study wells, sand production, mechanical obstruction, completion- and stimulation-fluid problems, and relative-permeability effects were less frequent problems.

All these damage mechanisms require different stimulation methods to restore injectivity and deliverability, and over the years, a great deal of experience has been accumulated on the diagnosis of damage mechanisms and design of stimulation techniques.

To capture this knowledge and make it available to engineers in the gas-storage industry, Schlumberger and the GTI developed the DamageExpert computer model for diagnosing formation damage. The model, designed for gas-storage wells, combines gas-storage-domain knowledge bases, fuzzy logic and expert-system technologies. Based on user input, the program helps diagnose the most likely type of formation damage and then helps select the best stimulation and fluid treatment.

The first step in the system development consisted of building a knowledge base. This in turn consists of two parts: knowledge acquisition and knowledge representation. Knowledge acquisition is the process of extracting and organizing knowledge from experts in the domain and from technical literature. For this system, the knowledge comprised information and experience from operators, service companies and other experts on formation-damage mechanisms in gas-storage wells as well as the corresponding treatment methods.

Next, the acquired knowledge is represented, or structured, in a way that makes the problem easier to solve. In this case, knowledge bases were built for four steps of the problem-solving sequence: candidate selection, damage-mechanism diagnosis, treatment recommendation and treatment evaluation.

The domain knowledge was represented using fuzzy logic combined with production rules, neural networks and genetic algorithms. Fuzzy logic is a way of representing knowledge that is difficult to capture in a strict rules-based system. Classical binary rules-based logic solves problems by filling in statements such as, “If condition A is true, then situation B exists.” The

Main types of damage in gas-storage wells. Operators identified four main mechanisms that plug pores and impair deliverability: bacteria, inorganic precipitates, hydrocarbon residue and particulates.

statement can be only true or false. The mathematical values for the truth can be only one for true or zero for false. Under fuzzy logic, truth values can range between zero and one, and can take on linguistic variables, such as highly, large, somewhat and rarely. Fuzzy logic provides a way to help emulate the thought process of an engineer who is diagnosing formation damage and designing a removal treatment.

Information flows through seven modules during the diagnosis and treatment-design process (left). The data-input module receives information such as well identification, dimensions, completions and history, along with reservoir rock and fluid-property data. All subsequent modules use this input information.

Next, the damage-mechanism diagnosis module analyzes the input information to identify possible types of wellbore and formation damage. Mechanisms are ranked from most likely to least likely. This module can be bypassed if the user is confident that the damage mechanism is known.

The treatment-feasibility module determines whether the well is a good candidate for damage remediation. This is followed by the treatment-selection module, which recommends the best available treatment for removing the identified damage.

The treatment-fluid module helps select the best fluid to use for a matrix treatment or wellbore wash. The module checks on formation and fluid compatibility, and specifies the necessary fluid additives to avoid undesirable chemical reactions. The pumping-schedule module recommends a combination of injection rate and fluid volume for each zone to be treated. And, finally, the reporting module issues reports from any of the other modules.

The expert system was tested on several gas-storage wells, and information was fed back to improve the system. One example well was completed openhole with cemented casing above the gas-storage sandstone reservoir. The well had moderate deliverability at 2500 Mscf/D [71,600 m³/d], and its withdrawal capacity had declined by 53%.

The damage-mechanism module indicated that plugging of pores and relative-permeability effects were the dominant causes of damage to the wellbore, along with iron oxide [Fe₂O₃], calcium carbonate [CaCO₃], iron sulfide [FeS₂] and chloride scales.
The expert system suggested stimulation fluids and a pumping schedule (bottom right).

The well was stimulated with the recommended treatment, which included surfactant, iron inhibitor, corrosion inhibitor and diverting agent. After the treatment, gas deliverability was five times greater than before.

**Beyond Storage**

Underground gas storage is just one of the industries that is developing to meet the world’s growing and rapidly changing energy needs. In Europe, for example, the European Union (EU) Parliament Gas Act of 1998 requires all countries to liberalize their gas and electricity sectors over the next decade. Success of this type of deregulation—designed to increase competition and decrease total cost—will demand new efficiencies in the gas-supply chain.

Full gas supply-chain management means real-time monitoring and control of the transport of gas from the wellhead, via the pipeline and liquified natural gas (LNG) grid, through storage facilities to the burner tip of the end consumer. It will also include information technology services to facilitate asset management, third-party access, customer care, billing and trading. SchlumbergerSema Energy & Utilities is designing and implementing this type of systems solution for customers in many projects worldwide.

Such large-scale integration projects could initially entail developing a satellite-network solution to connect producing gas fields, gathering and pipeline stations, underground gas-storage sites and gas-export terminals to a central database. The ultimate project goal would be to install Internet-accessible gas-trading and exchange hubs in the major consumer areas and at export border check-points, similar to the SchlumbergerSema-designed and operated electricity trading hub that is currently in place for APX in Amsterdam, The Netherlands.

The anticipated rise in gas consumption and continued deregulation will create opportunities and bring changes in business practices for oil and gas E&P companies, gas-transport and storage companies, gas-trading companies, utilities and service companies. Making the most of these opportunities will require vigilant technology development and application of tools and services that increase efficiency and value. —LS