In mature fields, water is often perceived as a necessary evil. While water often drives primary production and assists in secondary recovery, excess produced water represents a significant liability and cost to the oil and gas producer. Today, improved water-management techniques are minimizing the amount of water brought to surface and transforming excess water from waste into resource.
Most mature oil fields have one thing in common: produced water, and lots of it. Globally, at least three barrels of water are generated with every barrel of oil. Although exact numbers are difficult to obtain, data compiled in 1999 indicate that more than 210 million barrels [33.4 million m³] of water were being produced by the exploration and production (E&P) industry each day. In the USA, produced water comprises 98% of all waste generated by the E&P industry—on average 10 bbl [1.6 m³] of water are produced with every barrel of oil in that country.

Even with the best field-management techniques, water production may eventually increase to the point that it represents more than 90% of liquid volume brought to the surface. Surface-handling systems become overloaded, impacting efficiency and productivity. Eventually, the cost of dealing with produced water precludes field profitability.

Modern field-evaluation techniques combined with management of the water cycle can improve field economics, productivity and hydrocarbon recovery factor (right). A holistic approach to water management in a mature oil field includes reservoir analysis, assessment of production and injection wells, evaluation of flooding or sweeping techniques, surface-systems analysis, and implementation of a plan to best use excess produced water.

Like oil and gas, fresh water is a limited resource. Once referred to as the Great American Desert, today the western USA is becoming even drier, yet it is supporting increased water demands for agriculture, industry and personal consumption (below right). Moreover, the population in the western United States is...
Use of water to promote oil recovery. In management of a mature oil field, the proportion of movable oil produced is often a function of water throughput. Thus, the oil recovery factor depends on the volume of water injected into the system. Injection rates for optimal production efficiency vary and must be adjusted on a case-by-case basis.

Managing the Water System

Virtually every oil reservoir is swept by water from either natural aquifer pressure or waterflooding. Eventually, water production is inevitable. Water movement promotes oil displacement and affects vertical and areal sweep, thereby determining a field's oil recovery factor (above left). Although water is often seen as a problem, good water is critical to the oil-production process. Bad water, on the other hand, is water that brings little value to the production operation, although it may find its way to reuse outside the E&P environment at some future time.

The first step in water management is assessing and diagnosing the water system. Because of the complexity of the system, defining the problem is often the most difficult part of the process (left). Today, engineers and geoscientists apply a multistep process supported by a sophisticated array of techniques and tools to diagnose water-related problems. The process often begins with gathering reservoir, production-history and surface-facility information (next page, top). Using previously acquired data, engineers evaluate the current production system to identify economic bottlenecks and to gain an initial understanding of the water-flow mechanisms in the reservoir, wells and surface system.

Next, engineers and specialists from operator and service companies work together to determine whether any new data are required to properly assess the production system. For example, flow tests of production and injection wells, downhole fluid-flow profiles, wireline and crosswell surveys, and time-lapse seismic acquisition are capable of defining oil and water movements within the reservoir (see “Time Will Tell: New Insights from Time-Lapse
Seismic Data,” page 6). Data from crosswell electromagnetic evaluation are sometimes used to provide reservoir water saturation levels. Flow dynamics in the downhole and surface systems can be evaluated with multiphase flowmeters, helping to fully characterize the water system.

Reservoir compartmentalization, water breakthrough, sweep efficiency and voidage replacement are defined using tools such as OFM well and reservoir analysis software. OFM software displays production history along with other well and reservoir data. Careful data analysis often reveals a wealth of hidden information. Schlumberger uses a set of specifically designed OFM templates for water analysis, allowing rapid reservoir evaluation and diagnosis of flow patterns and well problems. The OFM techniques range from simple breakthrough time maps to production diagnostic plots and heterogeneity plots that display problematic wells at a glance.

Once water problems are identified, tools such as the WaterCASE software for analyzing produced water helps engineers perform further analysis and propose possible solutions (see “Problem Types and Solutions,” page 30). A case-based reasoning engine powers the WaterCASE software, helping engineers solve intricate water problems by linking identified problems with historically successful solutions. The system examines information from all sources including production history, reservoir descriptions and logging results, but makes allowances for missing data. This important aspect allows engineers to perform water-system analysis with only existing and sometimes incomplete datasets. Solutions and methodologies proposed by the WaterCASE software can help optimize all elements of the water cycle.

Once each element of the downhole and surface system has been thoroughly analyzed, key performance indicators (KPI), help identify bottlenecks and rank potential opportunities by financial impact (right).

Water-management solutions ultimately focus on the economics and direct cost of managing water. Costs related to surface handling and disposal vary greatly, but estimates ranging from US$ 0.10 to US$ 2.00 per barrel are not uncommon. Taking a nominal water-disposal cost of US$ 0.50/bbl, the E&P industry expenditure to manage 210 million barrels of water daily would be on the order of $38.3 billion per year.

A systematic process for water management. Production-system assessment considers the entire water and production cycle to identify economic bottlenecks. Subsequent analysis focuses on the most critical problems. Only after completing the reservoir and facilities analysis can engineers diagnose wells to determine specific problem types. Then, all feasible solutions are identified. Expected results are determined using NODAL production system analysis or simulation. Risk and economics are evaluated to arrive at an optimal solution. The last step is critical: proper design must be followed by proper execution and evaluation to validate the applied solution.

Key Performance Indicators
- Reduce water-handling cost
- Reduce environmental impact
- Increase oil productivity
- Increase reserves

Bottlenecks
- Water-handling cost per bbl
- Water-production rate
- Oil-production rate
- Sweep efficiency

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(continued on page 32)

4. Good water is defined as that produced below the economic limit of the water/oil ratio (WOR). Conversely, bad water is water produced above the economic limit of WOR.
6. Voidage occurs as the result of production of oil from the reservoir. As oil is removed, it is often replaced by water. Voidage-replacement calculations are used to ensure that sufficient water is injected to maintain reservoir pressure.
7. OFM templates contain predefined calculations, maps, crossplots and trend plots designed specifically to assist in water analysis at the reservoir and well level.
Ten specific types of water problems are shown by degree of complexity. Elevated water cut may result from one or more problem type. Already available information should first be used to diagnose excess produced-water problems. Solving less complex problems first can reduce risk and decrease the time required for payout.

1. **Tubing, casing or packer leak.** Production logs such as temperature and spinner may be sufficient to diagnose these problems. Solutions typically include squeezing shutoff fluids and mechanical shutoff.

2. **Flow behind casing.** Failed primary cementing or creation of a void space due to sand production may allow water to flow behind casing in the annulus. Temperature or oxygen-activation logs can detect water flow behind casing. Shutoff fluids may provide a solution.

3. **Oil/water contact (OWC) moving up.** Typically, this is associated with limited vertical permeability, usually less than 1 mD. With higher vertical permeabilities, coning (7) is more likely. In vertical wells, the problem may be solved by mechanically isolating the lower part of the wellbore. In horizontal wells, there is no near-wellbore solution, and sidetracking the well may be required.

4. **High-permeability layer without crossflow.** A shale barrier above and below the layer is usually the cause of this condition. The absence of crossflow makes this problem easy to solve by applying rigid shutoff fluids or mechanical shutoff either in the injector or in the producer.

5. **Fissures between injector and producer.** Water can rapidly break through to production wells in naturally fissured formations. Pressure-transient testing and interwell tracers can confirm the problem. Applying a shutoff fluid at the water injector may be effective without adversely affecting the fissures that contribute to oil production.

6. **Fissures or fractures from a water layer (2D coning).** Water is produced from an underlying water zone through natural fissures. A similar problem results when hydraulic fractures penetrate vertically into a water layer. The application of shutoff fluids may be effective for this problem.
1. **A dual drain involves perforating above and below the oil/water contact.** Then, both oil and water zones are produced through separate completions at the same flowing pressure. High volumes of water are produced, although the produced oil often contains very little water.

(7) **Coning or cusping.** Production draws water upward toward the wellbore. A layer of gel placed above the cone may be effective in slowing the coning process. However, to be effective, a gel-placement radius of at least 50 feet [15 m] is typically required, often limiting the economic viability of the treatment. As an alternative to gel placement, a new lateral borehole may be located near the top of the formation, increasing the distance from the OWC and decreasing the drawdown, both of which reduce the coning effect. A dual-drain production technique may also be an effective treatment.

(8) **Poor areal sweep.** This problem is often associated with poor areal permeability heterogeneity or anisotropy; it is particularly severe in depositions with sand channels. One solution is to divert injected water away from the already swept pore space. Another way to access unswept oil is by adding lateral boreholes to existing wells, or by infill drilling.

(9) **Gravity-segregated layer.** In thick reservoir layers with good vertical permeability, water, either from an aquifer or a waterflood, is segregated by gravity and sweeps only the lower part of the formation. Shutting off lower perforations in injection or production wells often has only marginal effect; ultimately, gravity segregation dominates. If this occurs, production wells will experience coning. Gel treatments are unlikely to provide lasting results. Additional lateral drainholes may be effective in accessing the unswept oil. Foamed viscous-flood fluids, gas injection or alternating between the two may also improve vertical sweep efficiency.

(10) **High-permeability layer with crossflow.** In contrast to the case without crossflow (4), the presence of crossflow precludes solutions that modify production or injection profiles only near a wellbore. Deep-penetrating gel may provide a partial solution.

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1. A dual drain involves perforating above and below the oil/water contact. Then, both oil and water zones are produced through separate completions at the same flowing pressure. High volumes of water are produced, although the produced oil often contains very little water.
In mature fields, profitability is based on the economic limit of the water/oil ratio (bottom left). Producing a well with a water cut above the economic limit generates negative cash flow. If water-treatment costs increase, then the economic water-cut limit decreases. To maintain profitability, a well may have to be abandoned and reserves lost.

Reducing water-management cost and improving production in mature fields are not always straightforward. Balancing the complete production system—injector wells, production wells and the water-management system—is essential to maximizing field performance.

**Water at the Surface**

Surface-system assessment is a critical step in the water-management process. Assets must be viewed as a complete system; identifying reservoir-related opportunities without simultaneously determining potential bottlenecks in surface-handling capacity could be fruitless.

The efficiency of a mature-field system is often related to its capacity to deal with produced water. The initial surface design often fails to account for escalating water cut with time. As a field matures, water cut increases and its surface-handling system becomes overloaded. Whether in separation, transmission or disposal, a high water rate reduces oil-handling capacity and threatens the economic viability of the field.

Restrictions, or bottlenecks, in the surface systems are often complex and expensive to rectify. In the late 1990s, Petrobras engineers predicted that oil production from the southern area of the Campos basin, offshore Brazil, would exhibit a significant increase in water cut during the next decade. Solving the looming water-handling problem presented significant technical challenges, but the economics of the Campos basin demanded an early solution to the problem.

The 90-km [56-mile], 24-in. export pipeline had been designed to flow 180,000 bbl [28,600 m³] of crude oil daily from the central production platform to a shore-based refinery. Offshore water-management facilities at the central and satellite production platforms were limited. As water cut approached 45%, oil-production targets and quality through the pipeline could not be sustained. As an interim measure, Petrobras began supplementing the export pipeline with shuttle tankers, transporting the water-laden oil to shore.

Petrobras and Schlumberger engineers evaluated options for reducing water production, the choices being downhole intervention, improving surface-management systems, or both. Ultimately the decision was made to increase the capacity of surface-handling facilities. This avoided the pipeline bottleneck by separating water from oil offshore.

Working in conjunction with Schlumberger, the Sedco 135D semisubmersible drilling rig was converted to a floating dewatering facility (below). Connected to the central production platform, the facility can process 169,000 B/D [27,000 m³/d] of high-water-cut crude.

Water-laden crude is processed to remove water from oil and to reduce the oil concentration in the produced water below 20 parts per million (ppm). First, a degasser removes dissolved gases and stabilizes the crude oil. Then, an electrostatic coalescer reduces the basic sediment and water (BS&W) content of the oil phase to less than 1%, and it reduces the oil content of the water phase to less than 1,000 ppm. This produced water enters a water surge drum and then a hydrocyclone, further reducing oil content to less than 40 ppm. Lastly, a sparger, which is an induced-gas flotation device, reduces oil content to less than 20 ppm.

Dewatering efforts in the Campos basin resulted in an immediate 60,000-B/D [9,530-m³/d] increase in capacity of oil transported to shore through the export pipeline. As engineers and operators optimized the water-removal system on the 135D, oil production increased by 20,000 B/D [3,180 m³/d].

Optimizing oil removal from produced water has two primary effects: more oil is recovered, and a cleaner produced water is delivered for disposal or reuse.

**Improvements in Water-Treatment Technology**

A new process for produced water cleanup is now being field-tested with promising results. The light water treatment unit (LWTU) uses coalescing and separation techniques to reduce the amount of oil-in-water to levels below 20 ppm at flow rates up to 3,000 B/D [477 m³/d].

The LWTU is based on the TORR Total Oil Recovery and Remediation technology developed by EARTH (Canada), a process in which oil-laden water flows through a succession of coalescing beds loaded with RPA (reusable petroleum absorbent) material (next page, top right). The dispersed oil droplets, varying in

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### Water at the Surface Equation

\[ WOR_{e} = \frac{Vo}{Cw} \]

- US$ 20/bbl oil/US$ 0.7/bbl water
- 28.6 bbl water/bbl oil

\[ \text{Water cut} = \frac{WOR}{1+WOR} \]

- 28.6/(1+28.6) = 96.6% at economic limit.

---

\[ \text{Economic limit} \]

The water cut at the economic limit can be determined from \( Vo \), the value of a barrel of oil after tax and lifting cost, excluding water handling, and \( Cw \), the cost to manage the produced water. In this case, the values are assumed to be US$ 20/bbl of oil for \( Vo \) and US$ 0.7/bbl of water for \( Cw \). Using these values, the economic limit of the water/oil ratio, \( WOR_{e} \), is 28.6, and for water cut it is 96.6%.

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\[ \text{Dewatering offshore. The Sedco 135D semisubmersible dewatering facility can process up to 169,000 B/D [27,000 m³/d] of produced liquids. Oil volumes of up to 107,000 B/D [17,000 m³/d] are processed, reducing the basic sediment and water (BS&W) concentration below 0.6%. Associated produced-water volumes of up to 63,000 B/D [10,000 m³/d] are treated, reducing total oil and grease (TOG) content of discharged water below 20 ppm.} \]
size down to 2 microns, adhere to the surface of the oleophilic RPA material where the droplets coalesce and fill void areas.

As flow continues, the RPA beds become sequentially saturated with oil. The continuing flow of fluid through the beds begins to strip the coalesced oil from the saturated RPA surfaces in large droplets, several millimeters in diameter. The system forms a steady-state equilibrium in each bed between the emulsion coalescing on the saturated RPA surface and the flow stripping large oil droplets into the next tank section.

The behavior of the larger oil droplets is governed by Stokes law: the larger the oil-droplet diameter, the greater the tendency for the oil to separate and float. The larger oil droplets aggregate at the upper interbed space, where they form a free-oil layer that is bled from the LWTU vessel (above left). Several RPA beds are spaced along the length of the unit; each successive bed intercepts increasingly smaller oil droplets not removed in earlier stages of the process.

In August 2002, engineers field-tested a 750-B/D [120-m³/d] pilot unit on a production lease in West Texas, USA. Production water fed from a field oil and gas separator delivered 33,500 bbl [5,320 m³] of water to the LWTU. At an average flow rate of 670 B/D [107 m³/d], oil concentration was reduced from 300 to 10 ppm.

More recently, a test conducted in the North Sea with a larger prototype unit reduced oil from 200 to 300 ppm at the inlet to an average of 19 ppm at the discharge (right). Technicians processed a total of 600 bbl [95 m³] out of 20 ppm oil.

A much clearer picture. Tiny dispersed oil droplets cause the inlet water turbidity, or cloudiness, seen in the bottle labeled INLET. After passing through only one coalescing bed, a significant portion of the oil is removed, as indicated by the clarity of the fluid in the bottle labeled BED 1.

Deoiling through a coalescing process. Mixtures of up to 3% oil in water enter the light water treatment unit (LWTU). The solution passes through RPA Bed 1, where tiny droplets of oil are stripped from the flow by the RPA (reusable petroleum absorbent). Once the RPA bed is loaded with oil, continuing fluid flow through the bed forces oil droplets out of the bed and into Tank 2. The coalesced oil droplets are large and float to the surface, where oil collects and is removed. Successive sets of beds continue the process, ultimately reducing oil content to less than 20 ppm.

of oil-water mixture at a rate of 3,000 B/D. In July of 2004, a 25,000-B/D [3,970-m 3/d] unit is scheduled for installation on the Sedco 135D crude-dewatering installation.

**Water at the Wellbore**

While new water-treatment technologies, such as the LWTU, help operators deal with water at the surface, engineers are using novel logging techniques to look behind casing, identifying sources of water and bypassed reserves.8

In mature oil fields located offshore in the South China Sea about 130 km [78 miles] southeast of Hong Kong, the China National Offshore Oil Corporation and its partners are using logging behind casing technology to minimize produced water and improve oil recovery.

Discovered in 1984 and commercial since 1994, wells in the area produce from 44 stacked reservoir sands in the middle Miocene XH formation.9 The permeability in the sandstones typically exceeds 1 darcy, and the reservoir has a strong aquifer waterdrive. Despite 10 years of production, aquifer pressure has dropped by only a few psi. This has provided excellent production pressure support, but permeability heterogeneity has led to early water breakthrough in many of the wells.

The average water cut in the field has risen to 84%. Total liquid-production volume is 550,000 B/D [87,400 m 3/d], close to the maximum surface-handling capacity. Electrical submersible pumps (ESPs) assist in production lifting operations, but the high water cut makes this more difficult. Most of the available platform well slots have been used, so infill drilling cannot be used to improve oil recovery. Lower than expected oil-production rates have led engineers to focus on a water-management solution.

Reservoir, drilling and service-company engineers began the process of field and systems evaluation to formulate a water-management plan. Weighing the economics of several approaches, engineers chose downhole intervention to improve hydrocarbon recovery.

Reservoir evaluation and modeling studies based on seismic data, log evaluation and production history helped identify remaining reserves in the field. Engineers established the repeatability of the CHFR Cased Hole Formation Resistivity tool and correlated it to the original openhole resistivity logs (above right).

Resistivity data from behind the casing, processed with ELANPlus advanced multimineral log analysis software, established promising oil-bearing zones. By comparing original log data with new data from the CHFR logs, engineers observed little resistivity change since production began and determined that the XH1 sand still contained recoverable oil.

Well X13, a wellbore penetrating the XH1 sand, was chosen for intervention. Using a combination of real-time directional drilling tools, drillers sidetracked the well, traversing the XH1 sand along a 300-m [984-ft] borehole at about a 90-degree deviation, 3 m [10 ft] from the top of the sand. The combination of INFORM Integrated Forward Modeling software, arcVISION Array Resistivity Compensated tool, adnVISION Aximuthal Density Neutron tool, PowerDrive rotary steerable system and PowerPulse MWD telemetry system helped drillers place the borehole within a 1-m [3-ft] window across 98% of the borehole path (next page).

The X13 sidetrack was completed using 6 1/2-in. expandable screens. An ESP was placed at the bottom of the 3/8-in. upper completion to assist with lift. Prior to intervention, the X13 well was producing more than 90% water. Initial production after sidetracking was 3,500 B/D [556 m 3/d] with only 2% water cut. Once stabilized, production doubled to 7,000 B/D [1,112 m 3/d] while maintaining low water cut.

Following the successful X13 water-management intervention, several other wells were sidetracked with similar success. Overall, the sidetracked wells have helped achieve a 28% increase in field oil output while reducing water production by more than 17,000 B/D [2,700 m 3/d]. The operator avoided major expenditures for a facilities upgrade, and continues to enjoy reduced costs associated with produced water handling.

**From Waste to Resource**

Despite advances made by operators and service companies in surface and downhole water management, produced water remains a necessary, if burdensome, by-product of oil and gas production.10 In mature fields around the world, operators dispose of 30% to 40% of produced...
water. As demand for usable water increases in some areas, engineers and scientists look for ways to convert this economic liability into a viable resource.

The path from waste to resource often depends on water chemistry and contaminant level. Produced-water quality varies with geology, geography, production techniques and the type of hydrocarbons being produced. The water may contain dispersed oil, light hydrocarbons, metals, salts and a wide variety of other organic and inorganic materials.

As with produced water, about 97% of Earth's water is salty. Only 3% of available water is fresh—2% is locked in Earth's polar ice caps, leaving only 1% for consumption by plant and animal life. Although water is a renewable resource, in some areas, agricultural demand, population growth and climate changes have resulted in fresh water being consumed faster than the resource can recover.

The World Health Organization and other agencies suggest that severe regional water shortages affect over 400 million people today and may affect 4 billion by 2050. In 1995, the United States Geological Survey reported that 17 western states support 10 times more people than they did 100 years ago. Over the next 50 years, demand for fresh water in the USA is expected to increase 100%, potentially outstripping groundwater supply in some areas.

Agricultural usage accounts for at least two-thirds of global water consumption. Shortages of water for irrigation are either already occurring or projected to occur in major grain-growing regions of the world.

Of the more than 210 million bbl of water produced daily from oil and gas operations, 30% to 40% is considered waste and disposed of. With treatment, these 73.5 million barrels (11.7 million m³) of water have the potential to play a key role in relieving demand on natural freshwater systems.

The substantial availability of produced water, along with a need for less costly alternatives to disposal, leads researchers to study the reuse of produced water for irrigation, industrial use and other applications. With proper treatment, produced water may find many uses while relieving pressure on the Earth's freshwater supply.

### From Well to Rangeland

Approximately 47% of the Earth's terrestrial surface comprises rangelands. Left in its natural state, indigenous rangeland vegetation, primarily grasses, manages itself through natural processes. Human movement into these delicately balanced ecosystems has left its mark. Among other things, overgrazing, recreation and mechanical manipulation of marginal soils have led to desertification, a process whereby biosystems decline in the absence of significant climatic changes.

Although considerable time may be required, desertification often naturally reverses in the absence of commercial livestock operations. With much of the world's rangelands in decline, scientists are exploring methods to assist the natural revitalization process.

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**Graph:**

- Directional drilling along the reservoir cap. Measurements-while-drilling (MWD) and logging-while-drilling (LWD) tools enabled engineers to place the borehole within meters of the reservoir cap, maximizing oil contact and minimizing water production. Drillers encountered a fault at around 360-meters (1,180-ft) horizontal displacement causing the borehole to briefly intersect the shale section above (dark brown). The LWD response to the shale is clearly seen in the gamma ray, resistivity and density data (top three tracks).

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11. Many of the basics of water treatment were discussed in Bailey et al, reference 5.
Climate research studies conducted by the University of Arizona, Tucson, USA, indicate that the state of New Mexico, located in the south-western USA, will continue to be drier over the next 30 to 40 years. Today, researchers, oil and gas operators and government officials are taking steps to prepare for the drier times ahead.

At New Mexico State University (NMSU), scientists are exploring revegetation of pipeline right-of-ways and wellsites using selected grasses irrigated by water produced from local coalbed methane (CBM) wells.

Working in conjunction with several E&P companies and the US Bureau of Land Management, researchers at NMSU selected six sites for experiments to identify varieties of grass capable of sustained growth in the arid New Mexico climate. These grasses would be supported only by limited natural rainfall and irrigation with CBM-produced water.
Control plots of rangeland grass were established during April and October 2002 using 16 varieties of native and nonnative grasses with only natural rainfall. After 12 to 15 months of growth, grass stands were evaluated for establishment, or survival. Several varieties showed promise (previous page, top).

In late summer of 2003, Phase 2 of the project began with an identical set of grasses planted at each site. During a 4- to 6-week period after planting, two of the new test sites were irrigated with CBM-produced water (bottom left). Quantities varied from 26,880 gal [102 m³] to 50,000 gal [189 m³] in three or four applications (left). Although final reports will not be prepared by NMSU until later in the year, several species of rangeland grass showed adaptation to CBM-produced-water irrigation.19

At Texas A&M University, College Station, Texas, USA, a team of engineers and rangeland, soils, wildlife and irrigation specialists is taking the produced-water rangeland irrigation process one step further. Working with the Texas Water Research Institute (TWRI), engineers have built a prototype mobile produced-water treatment unit. Water can be treated on site to remove contaminants and dissolved salts prior to rangeland irrigation (previous page, bottom).20

The process of converting produced water to irrigation quality may require several steps. First, the produced-water feed stream is subjected to pretreatment filtration to remove sand and larger particulates. Hydrocyclones and microfiltration units separate the majority of the dispersed oil from the produced water. Then, organoclay adsorbents remove the remaining oil.21 The essentially oil-free produced water is

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then passed through a reverse osmosis (RO) filtration unit, reducing total dissolved solids (TDS) below 500 ppm (left). The rejected brine stream from the RO process is disposed of by conventional methods such as injection into waste-disposal wells.

The water-treatment technology being developed by Texas A&M may provide operators with a cost-effective alternative to disposing of produced water. Researchers estimate that more than one-third of the produced water in Texas has TDS less than 20,000 ppm, a level suitable for RO desalination and freshwater recovery. Field tests indicate that mobile unit water-processing cost is approximately US$ 0.80 per barrel of produced water, a rate often half that of conventional regional-disposal practices. Scientists are investigating alternative techniques for effluent disposal that might further reduce desalination cost.

Increasing numbers of operators are expected to apply water-reuse technology in the coming years. TWRI estimates that by the year 2020, more than 10% of the water used in Texas will come from recycled sources, representing a savings of as much as 40 million gallons per day [151,000 m3/d] in fresh water.

Oil and gas operators, local communities and the environment benefit from the conversion of an oilfield waste to a rangeland resource. Significant quantities of agricultural-quality water can be generated, helping to reclaim rangelands, supporting environmental initiatives and conserving freshwater resources while simultaneously helping operators manage production and disposal costs more effectively.

**Sustaining Agriculture**

As some parts of the world experience drier conditions, farmers must work harder to produce ample food to support growing populations. Today, modern land-management techniques coupled with irrigation produce ample food supplies. However, one cost of food production is consumption of vast amounts of fresh water. Alternative sources of water are needed both to conserve potable water and to supply the growing demands of agricultural irrigation.

The San Joaquin Valley in California, USA, home to the giant Kern River oil field, has one of the largest produced-water reuse projects. Each day, ChevronTexaco produces 100,000 bbl [15,900 m3] of oil along with 860,000 bbl [136,700 m3] of water from this mature field—a 90% water cut. Of this water, 79,000 bbl [12,600 m3] are reused for waterflooding and

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23. Cogeneration is the simultaneous production of electricity and heat using a single fuel such as natural gas. The heat produced from the electricity generating process is captured and utilized to produce steam. In the Kern River field, injecting steam into oil-bearing reservoir rock enhances oil production.


other in-field operations; 345,000 bbl [54,800 m³] are treated and supplied to several electric power cogeneration facilities; and 436,000 bbl [69,300 m³] are sent to the Cawelo Water District.23

Treatment of produced water is often required prior to agricultural use. However, water from the Kern River field is of high quality and contains minimal dissolved solids and metals. The very low amounts of hydrocarbon present are removed prior to use. ChevronTexaco maintains an intensive water-monitoring program to assure the quality of its produced water.24

In the absence of irrigation, the San Joaquin Valley might be a desolate, barren environment. Today, the Valley produces a variety of crops including grapes, citrus fruits, almonds and pistachios. To supplement freshwater supplies and maintain 46,000 acres [18,600 hectares] of fertile, irrigated farmland, the Cawelo Water District manages produced-water storage and transmission facilities, distributing more than 400,000 bbl [63,600 m³] of irrigation-quality produced water daily (left).

Watering the Desert
In the deserts of Oman, fresh water is a rare commodity. Efforts by Petroleum Development Oman (PDO) focus on converting produced water into a usable resource through a combination of biotreatment and biosaline agriculture.

Mature oil fields produce large volumes of water. For example, PDO produces more than 200,000 m³ [53 million US gal] of water daily from the Nimr oil field in southern Oman. At costs as high as US$ 15.00/m³ [US$ 2.40/bbl], the produced water is reinjected as waste into a deep aquifer.25

PDO’s Greening the Desert project began in the late 1990s. Experiments in south Oman tested converting produced water into a usable resource in a desert environment at a cost lower than that of disposal. Ideally, access to this fresh water could convert a dry, inhospitable environment into one of economic prosperity through agriculture and other associated benefits. By selecting special salt-tolerant crops and trees for produced-water irrigation, growth can be sustained even in desert environments.

Typical separation techniques remove oil dispersed in water to a concentration below 200 ppm. After primary oil-water separation, the effluent has salinity that is only 25% that of seawater. This water irrigates a lined-bed planted with halophytes, reed-type plants that grow well in saline environments (previous page, bottom).

Farming operations have demonstrated that natural processes in the reed beds degrade residual oil, while the halophytes cleanse the water of heavy metals. With most of the contaminants removed, only dissolved salts preclude the water’s use for conventional agriculture and other applications.
Removing dissolved salts by common techniques, such as RO, is not always cost-efficient. A novel polymer engineered by Akzo Nobel allowed Solar Dew B.V., working with Shell and PDO, to develop an alternative membrane-based water-purification concept. By taking advantage of the arid climate and abundant sunlight, the mostly oil-free produced water is passed through special polymer tubes made by Solar Dew. Energy from the sun heats the water inside the tubes. Water molecules migrate to the outside of the semipermeable polymer tube, leaving salts and impurities concentrated within.

The purified water evaporates, then condenses, on the underside of a rigid plate covering the apparatus and is channeled to and captured in holding tanks. Unlike more conventional techniques, the process requires no pressure or external energy other than that supplied by the sun (above left).

The novel produced-water treatment processes being developed by PDO exploit available and renewable resources to produce usable water from waste, potentially leading the way to greener environments, habitability and improved economic sustainability for many arid oil-producing regions of the world.

Sandia National Laboratories in the USA is one group working on the next generation of desalination technology. The laboratory serves as an engineering and research center for the US Department of Energy (DOE). Over 8,000 scientists and support personnel staff Sandia Laboratories, headquartered in Albuquerque, New Mexico.

In the past several years, Sandia has used its expertise to support federal produced-water reuse initiatives. In 2002, Sandia, working with various federal agencies, developing a National Desalination and Water Purification Technology Roadmap. The roadmap outlines the water supply challenges facing the USA and suggests areas of research and development that may lead to technological solutions. The roadmap defines critical objectives and metrics for technological changes required before desalination and water-reuse technologies can become affordable and widely used. The treatment and utilization of both traditional and CBM-produced waters are specifically identified and addressed in the roadmap because they have the potential to at least partially address water-supply challenges in many areas of the United States.

Key to this research is an ion-sequestration process. Natural zeolite materials are modified to create a matrix capable of capturing specific cations and anions (above right). In initial testing with brackish produced water containing 10,000 ppm TDS, surface-modified zeolite materials sequestered a wide range of cations and anions including sodium, calcium, chlorine, carbonate and sulfate, reducing the TDS to 2,000 ppm.

In most desalination processes, salts and other contaminants are removed and become concentrated in a waste material. Because of its unique structure, spent zeolite material may be usable as construction material or in roadbeds, thus turning another waste product into a resource. Sandia is currently conducting scale-up engineering and materials processing cost studies to further evaluate the potential of this promising material.

Researchers at Sandia continue to study other types of desalination processes, including direct-contact distillation, forward osmosis and hydrate desalination techniques.

Coal and Water

The global community is highly reliant on electrical energy. Power plants that provide this electricity rely on transmission lines, a fuel such as natural gas or coal, and water for cooling. Ranked in 2000 just behind agriculture in water use, thermoelectric energy generation in the USA withdraws 195 billion gallons [738 million m³] of water daily from the ecosystem, most of which is fresh water (below).27

Located in northwestern New Mexico, the coal-fired Public Service Company of New Mexico (PNM) San Juan Generating Station (SJGS) is one of the state’s largest power generating facilities, producing the majority of PNM’s electricity and withdrawing a significant amount of fresh water from the San Juan basin (bottom). While generating as much as 1,800 megawatts of power, the facility withdraws 400,000 to 500,000 bbl [63,560 to 79,450 m³] of cooling water daily. All but 6% of this water evaporates to the environment.

Engineers concluded that the natural gas transmission infrastructure in the form of abandoned, or limited-use, pipelines is capable of delivering as much as 43,000 B/D [6,800 m³/d] of produced water to the power plant—8 to 11% of the daily cooling intake at SJGS and representing a 10- to 20-year supplemental cooling-water supply. Although some adaptation of power plant cooling systems may be required to use untreated conventional and CBM-produced water, the benefits outweigh modification costs.

The SJGS represents only one case in which governmental agencies and power generators are working together to conserve a vital resource by converting waste into a resource.

Managing Future Resources

Advances in water-management technologies are allowing engineers to better analyze, optimize and manage water in the reservoir and at the surface. At the same time, researchers around the world are working to find alternative uses for excess produced water.

Today, operators and services companies are making great efforts to minimize the amount of water produced to the surface. As regional climatic paradigms shift, supply and demand may increase the value of water produced by the E&P industry. What was once a waste and liability may tomorrow be a valuable resource in agriculture, industrial applications and beyond. Even though oil and water are said not to mix, the future of each resource is becoming more entwined. Managing our liquid resources, oil and water alike, will play a crucial role in developing the future.

—DW

^ Daily water withdrawals in the USA. From 1950 to 1995, the US population nearly doubled. During the same time period, freshwater withdrawals from the ecosystem grew at a faster rate, with withdrawals for thermoelectric power increasing by almost fivefold. (Adapted from Hutson et al, reference 27.)

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* Last complete data set

^ Coal-fired power in New Mexico, USA. The San Juan Generating Station near Farmington is capable of producing 1,800 megawatts of electrical power. Significant amounts of water are required to cool and condense water used in the thermoelectric generating process. In the future, produced water may supplement the daily cooling-water demand.

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