In many of the Middle East’s major oil fields, water production is rising. This, coupled with stringent new environmental regulations being introduced across the region, has encouraged operating companies and their service partners to find imaginative solutions to the problems of waste water handling.

The industry has responsibilities for water management in all phases of its operations. From extraction for an injection program to filtration and safe disposal of waste water, the oilfield manager must protect fresh water resources and safeguard the environment.

In this article Fikri Kuchuk and Mahmut Sengul discuss the environmental aspects of water management.
In many countries around half of all drinking water is groundwater. Three-quarters of the world’s cities derive part of their water supplies from underground sources. Given these figures it is obvious that no oilfield water disposal system can be allowed to threaten the purity of groundwater supplies.

The oil industry’s water disposal wells must be designed to ensure that water is contained below the depths where it might enter drinking supply aquifers. Typical disposal wells (Figure 4.1) inject waste water into a deep aquifer, with shallow formations being protected by a combination of mechanical (surface casing) and geological (sealing layer) barriers.

Waste water from oil and gas operations is usually a fairly complex mixture of solids, liquids and emulsions (Figure 4.2). Modern filtration processes (Figure 4.3) can deal with this complex mixture, settling out solids and separating liquid phases to high levels of purity. Commercial filter systems can be very large and in recent years, efforts have been made to reduce their size (e.g., for use offshore) without affecting their performance.

Produced water may contain trace residues of production treatment chemicals such as demulsifiers, defoamers, wax inhibitors, corrosion or scale inhibitors and hydrate-control additives. When this produced water is to be reinjected the operator must ensure that the chemicals used are compatible with those already in the system. If the produced water is to be disposed of outside the production-injection loop then its environmental impact must be considered very carefully.

Figure 4.1: A typical waste water disposal well, injecting unwanted fluids to a deep horizon

Figure 4.2: Waste water from the oilfield contains a range of solid and liquid components
Egyptian experience

In 1988 a major onshore production facility in Egypt's Western Desert was producing oil from eight formations in six fields. Two of these formations contained active aquifer water, and there was a water-injection scheme to enhance recovery. Khalda Petroleum Company (KPC) started production from these fields in 1986. At that time the produced fluids were processed to extract oil from the produced water. The oil was reprocessed and the water was transferred to a disposal pond in the desert.

A water-injection plant set up in 1988 caused a major increase in produced water (Figure 4.4). The water produced from the KPC fields contained a number of pollutants (including heavy metals, hydrocarbons, formation solids and hydrogen sulfide) that posed environmental concerns. Changes in Egyptian legislation and a growing awareness of environmental issues led KPC to commission an extensive study of water disposal options.

Three options were discussed: disposal wells, surface ponds and reinjection.

Disposal wells

Injection into disposal wells involves pumping the produced water to a formation for permanent disposal. This is a safe environmental option, but requires careful design and monitoring of the injection system and must be operated under pressure restrictions.

Surface ponds

The study showed that the surface formations in the area around the fields were too hard for cost-effective excavation of evaporation ponds. More importantly, dumping the produced water in this way would result in the concentration of salts and residual hydrocarbons post-evaporation. This could lead to contamination of the ground water and soil; special liners and precautions would therefore be required.

Figure 4.3: This spectrum indicates the range of industrial filtration processes currently available and their uses.

Figure 4.4: In this Egyptian example a water-injection plant set up in 1988 led to a major increase in produced water. The water contained a number of pollutants, including heavy metals, hydrocarbons, formation solids and hydrogen sulfide.
Reinjection

The study indicated that reinjection was the most appropriate option. A leading-edge reinjection process has been developed for the field, combining chemical treatment, gas liberation, settling, filtration and injection. This process reduces the overall volumes of produced water for disposal, helps to increase total reserves, reservoir pressure and oil production while conserving underground water resources. Chemical treatment and careful monitoring are key elements in the success of this environmentally responsible scheme. The injected water must:

• be compatible with the formation water under reservoir conditions (i.e., it should not be susceptible to scale formation)
• not affect the pore or fracture systems in the reservoir rock (i.e., it should not cause plugging).

Plant process

Produced water is treated to achieve injected water quality. Any entrained gas is liberated before the water is sent to a skim tank. Here, internal distributors produce a uniform flow pattern that allows most of the dispersed oil to separate under gravity. The oil/water level within the tank is set by an adjustable siphon leg that discharges the treated water into the surge tank. The next step is to pump the water through the upflow media filters and into the injection tank. Centrifugal pumps draw water from this tank and boost the pressure to match injection pump requirements. The filtered produced water is then pumped at high pressure to the injection manifold.

Chemical treatment

The performance of produced water as an injection medium depends on a number of chemicals. For example, treatments may be required to control bacteria, scaling and corrosion within the system. To achieve acceptable water quality for waterflooding, the plant was provided with the following chemical injection facilities:

• reverse emulsion breaker
• scale inhibitor
• oxygen scavenger
• iron chelating agent
• biocide
• polyelectrolyte
• surfactant
• corrosion inhibitor.

Since the production facilities and the produced waterflood plant facilities represent a closed system, free of oxygen, field applications indicated that there was no need for either an oxygen scavenger or the iron chelating agent.

Reading the signs

A systematic monitoring program was established to control water quality. This tracked concentrations of iron, suspended solids, hydrogen sulfide and oil. The program also monitored physical properties such as turbidity and particle-size distribution.

An increase in iron content monitoring changes within the system would indicate corrosion while a decrease might suggest that iron compounds were being deposited.

Rising values for suspended solids could indicate corrosion, scale formation or bacterial activity. The solids should be analyzed to determine the exact nature of the problem.

• An increase in the concentration of hydrogen sulfide could indicate the presence of sulfate-reducing bacteria which would require chlorination or treatment with another biocide.
• The oil content for the system is assessed from samples upstream and downstream of the skim tank and filters to check their efficiency.
• Increasing turbidity in the water would indicate the presence of plugging solids.
• Particle size distribution is probably the most important parameter for injection water quality. Samples taken upstream and downstream of the filters are used to evaluate filter efficiency.

Figure 4.5: Water reinjection at the Salam Alam El-Buib 3D reservoir began in 1989. The initial rate of 3200 BWPD was increased to 9500 BWPD in 1994 when a second reservoir (Salam Lower Bahariya) was introduced. The program has dramatically increased recoverable reserves.

(1996) EE Farid and MH Nour, Subsurface brine injection: Proactive approach to close the produced water loop in the Western Desert of Egypt, SPE 35875
Performance

Injection of treated produced water was started in 1989 at the Salam Alam El-Buib 3D reservoir. The initial rate of 3200 BWPD was maintained until 1994 when it was increased to 9500 BWPD with the introduction of a second reservoir; Salam Lower Bahariya. The water reinjection program has brought about significant improvements in both reservoirs (Figure 4.5).

Downhole flow in the Gulf of Suez

Conventional production logs (spinner, density, capacitance, temperature and pressure) are routinely used in Egypt’s Gulf of Suez for reservoir monitoring and for the diagnosis of production problems. Unfortunately, these methods are unsuitable for some of the more complex problems facing production engineers. For example, they cannot identify water entries or exits in horizontal wells or assess water flow behind casing in cement channels or behind tubing in dual completion systems.

The WFL* Water Flow Log tool’s oxygen activation technique can be used to diagnose these problems and guide workover activities. The WFL system, unlike some tools, is unaffected by hole orientation and only reacts to flowing water. Consequently, stationary water and any of the other fluids that might be present in a borehole will be ignored. Using a nuclear technique the WFL can investigate water movements beyond the wellbore.

In one central Gulf of Suez field (Figure 4.6) water is injected into the upper Kareem zone through the annulus and into the lower Kareem through the tubing (Figure 4.7). This technique is particularly useful for diagnosing and addressing water-related issues in production wells.

Figure 4.6: Many of Egypt’s major oil fields are located in the Gulf of Suez

Figure 4.7: In the central Gulf of Suez water is injected into the upper Kareem zone through the annulus and into the lower Kareem through the tubing.

*WFL: Water Flow Log

(1997) HN Minhas and MA Elsa, Selective downhole flow measurement of water phase using oxygen activation logs in Gulf of Suez wells, SPE 37737
injection scheme was employed because differences in the productivity indices and pressures in these zones precluded a commingled injection. A conventional spinner flowmeter could determine flow in the lower Kareem, but injection to the more important upper zone, with 300 ft of perforations, could not be monitored this way.

Oxygen activation log measurements were taken inside the tubing, at a depth corresponding to the upper Kareem zone to determine the injection profile through the annulus. During this survey flow through the tubing was stopped. Measurements were subsequently taken from depths corresponding to the lower Kareem zone, below the tubing. The injection rate through the tubing was 8000 B/D and through the annulus the figure was 10,000 B/D. The injection profile in the lower Kareem zone (Figure 4.8) shows that about 30% of injected water goes to the perforation around 7435 ft, while the bottom section takes no water. The injection profile in the upper Kareem zone (gas cap) through the annulus is shown in Figure 4.9. This indicates that most of the water goes to the lower section, with 60% going to the perforations at 7160 ft.

Riding the wave of water management

Petroleum Development Oman (PDO) currently produces around 330,000 m³ of water every day. The volume of this produced water has risen steadily over time and is predicted to rise to about 650,000 m³ per day by 2005 (Figure 4.10).

The disposal of large volumes of produced water presents PDO with serious environmental and economic challenges. To meet these challenges, the company developed a detailed water management plan. This ensures that the quest for optimum disposal methods at each PDO production site involves full evaluation and testing to determine the best technical solution. Over half of PDO’s reserves are in reservoirs with conditions which result in high water production. Around 37% of the water currently produced by PDO operations is reinjected for reservoir pressure maintenance (mainly into the Yibal, Lekhwair and Saih Rawl fields in northern Oman). About 42% is disposed of in shallow (150-400 m) formations at oilfield sites. The remaining 21% is placed in deep formations at field sites in southern Oman.

While the subsurface disposal of production water is an accepted practice within the oil industry, it is essential that the disposed water is contained within the formations. It must be adequately sealed from other aquifer layers and prevented from breaking through to the surface.

Deoiling trials

From 1990 to 1994, PDO conducted a number of trials to evaluate various technologies for the removal of oil from produced water. The projects were motivated by three basic considerations:
• good environmental practice
• clean water supply for injection
• economic oil recovery.

Unfortunately, none of the available technologies could provide water that met the legal requirements for alternative uses. The small oil droplet sizes typically encountered in PDO’s produced water (for
Nimr and Marmul production centers all droplets are less than 50 µ and half are smaller than 10 µ) meant that the unit cost for oil recovery using centrifuges, membranes, hydrocyclones or a flotation/filtration method would exceed $15/bbl.

**Agricultural trials**

In March 1991 field trials were carried out at the desert agricultural project near Marmul, using untreated Nimr production water for irrigation and for the germination of indigenous tree species (Figure 4.11). The Nimr production water contained a number of contaminants (oil at 50 mg/l, selenium 0.2 mg/l and total dissolved solids of 7100 mg/l); the results of this trial were not encouraging. Nimr water was much less beneficial to plants and seeds than the potable water from the Umm er Radhuma aquifer, which was used as a control.

From 1994 to 1995 consultants were asked to investigate possible alternatives to subsurface use or disposal of produced water. The list of possibilities was a long one, but several were quickly rejected.

Evaporation was rejected as it would require ponds with an excessively large surface area and residual salts would incur additional disposal costs.

Infiltration was rejected because it had the same problems as evaporation with the added problem of uncontrolled transfer of pollutants to the soil.

Energy production through methane generated by algal growth was rejected because it involved evaporation, and the value of any gas produced would be low.

Salt production (collection and processing of post-evaporation residues) was rejected because it involved evaporation, and the value of any salt produced would be low.

Using produced water as an industrial utility was rejected due to the remoteness of production locations.

Four other options on the original list were considered possibilities and examined in greater detail. These were:

- fresh water production: this was deemed uneconomic with disposal costs of $0.9/m³
- aquaculture, harvesting fish in the evaporation ponds to provide a relatively high-value fish crop, was the most attractive of the evaporation pond options with disposal costs of $0.35/m³

Figure 4.11: In some cases produced water can be a valuable resource for farmers. Unfortunately, water from the Nimr Field contained too many contaminants for use in agricultural projects

(1997) A Al-Muscati, J Huijskes and DH Parker, Production water management in Oman, SPE 37786
at the desert agricultural project near Marmul, using untreated Nimr production water for irrigation and for the germination of indigenous tree species (Figure 4.11). The Nimr production water contained a number of contaminants (oil at 50 mg/l, selenium 0.2 mg/l and total dissolved solids of 7100 mg/l); the results of this trial were not encouraging. Nimr water was much less beneficial to plants and seeds than the potable water from the Umm er Radhuma aquifer, which was used as a control.

From 1994 to 1995 consultants were asked to investigate possible alternatives to subsurface use or disposal of produced water. The list of possibilities was a long one, but several were quickly rejected.

Evaporation was rejected as it would require ponds with an excessively large surface area and residual salts would incur additional disposal costs.

Infiltration was rejected because it had the same problems as evaporation with the added problem of uncontrolled transfer of pollutants to the soil.

Energy production through methane generated by algal growth was rejected because it involved evaporation, and the value of any gas produced would be low.

Salt production (collection and processing of post-evaporation residues) was rejected because it involved evaporation, and the value of any salt produced would be low.

Using produced water as an industrial utility was rejected due to the remoteness of production locations.

Four other options on the original list were considered possibilities and examined in greater detail. These were:

- fresh water production: this was deemed uneconomic with disposal costs of $0.9/m³
- aquaculture, harvesting fish in the evaporation ponds to provide a relatively high-value fish crop, was the most attractive of the evaporation pond options with disposal costs of $0.35/m³
- ocean discharge is practiced internationally and involves pretreatment to achieve an oil-in-water level of 5 ppm with disposal costs of $0.22/m³.

Unfortunately, there could be no guarantee that excess oil discharge could be avoided in the event of processing problems and the ecological fragility of Omani coastal waters made this option less attractive

- irrigation of salt-tolerant crops avoids the worst of the environmental risks associated with ocean discharge and has disposal costs of $0.23/m³.

After all of these studies had been completed it became apparent that the most cost-effective ($0.17/m³) and environmentally sound option for disposal of produced water was in deep disposal wells. PDO’s deep water disposal plans were confirmed in 1994 and nearly all of the produced water in southern Oman is disposed of in this way, with the remainder being used for pressure support in reservoirs.
Good design calls for water productivity slightly below well limits. Oil can be produced initially to monitor reductions in the water–oil ratio in response to a rapid shift in fracture fluid saturation. Water productivity above the well limits will produce a long period of constant water-rate water production and, in the past, many of these production periods have been abandoned as failures before oil entry could be achieved.

A summary of 16 completion deepening operations demonstrates the potential of the technique. The completions were deepened by an average of 42 ft by adding perforations, drilling out casing shoes or extending open holes (none of the existing intervals was plugged off). Within three weeks of deepening the average oil rate had increased by 100 BOPD for each well. Over the same period total producing GOR fell from 4800 scf/BO to 2300 scf/BO and the WOR dropped from 3.8 BW/BO to 2.5 BW/BO. Figure 4.12 provides a comparison of performance that plots all of the wells from their workover date.

Conclusions

Water production is an unavoidable problem, but can be minimized by practicing sound reservoir management. As the oil and gas industry faces tighter environmental regulations there will be a greater emphasis on minimizing water cut and the good completion and management practices which will make this possible.