Lecture № 12

Water and gas condensate plugs on the bottom of wells

All oil fields produce water along with oil. If water comes from water layer to the bottom of oil well this causes water plugs which decrease oil production. Such complications as corrosion, scale/salts deposition and gas hydrate formation arise (occur) because of water plugs on the bottom of oil well. Because of these reasons excess water production is not desirable.

Water production

The present worldwide daily water production from oil wells averages roughly 3 BWPD per barrel of oil, although some wells produce significantly higher amounts. It costs money to lift water and then dispose of it. In a well producing oil with 80 % water cut, the cost of handling water can double normal lifting costs. Yet, wells with water cuts in excess of 90 % may still produce sufficient hydrocarbons to be economical (e. g., certain wells in the North Sea Shell Expro Brent fields and in the BP-Amoco Forties fields). Water control technology is intended to reduce the costs of producing water.

It is not necessary, nor desirable, to completely shut off the coproduced water. The logic here is the distinction between “good” (necessary) and “bad” (excess) water. “Good” water is that water produced at a rate below the water/oil economic limit (i. e., the oil produced can pay for the water produced). “Good” water, then, is that water that cannot be shut off without reducing oil production. The fractional water flow is dictated by the natural mixing behavior that gradually increases water/oil ratio (WOR). “Good” water is also caused by converging flowlines from the injector to the producer wellbore. Water breakthrough on injection occurs initially along the shortest (least resistant) flow path between injector and producer, while oil is still being swept along other flow paths.

"Bad" water is water produced into the wellbore that produces no oil or insufficient oil to pay for the cost of handling the water. The remainder of this discussion deals with "bad" water.

Water intrusion

There is no one mechanism for "bad" water intrusion, and there is no one technology that will shut off water intrusion.

There are 10 basic types of water problems.

Problems that are relatively easily controlled:

- Casing, tubing, or packer leaks.
- Channel flow behind the casing from primary cementing that does not isolate water-bearing zones from the pay zone.
- Moving oil/water contact (OWC).
- Watered-out layer without crossflow – this is a common problem with a multilayer production and high-permeability zone isolated with flow barriers (e. g., a shale bed) above and below the zone. It is shown schematically in **fig. 1**.

Problems that are more difficult, but control is still feasible.

- Fractures or faults between injector and producer.
- Fractures or faults from a water layer. Water can be produced from fractures that intersect a deeper water zone.

Problems that do not lend themselves to simple and inexpensive near-wellbore solutions and require completion or production changes as part of the reservoir management strategy (e. g., multilateral wells, sidetracks, coiled tubing isolation, and dual completions).

• Coning or cusping. Coning occurs in a vertical well when there is an OWC near the perforations with a relatively high vertical permeability driving high flow rates.

• Edge water from poor areal sweep. Areal permeability anisotropy causes this problem.

• Gravity-segregated layer. In a thick reservoir layer with high-vertical permeability, water, either from an aquifer or injector, slumps downward in the permeable formation and sweeps only the lower part of the reservoir (**fig. 2**).

• Watered-out layer with crossflow. This is difficult, if not impossible, to treat.

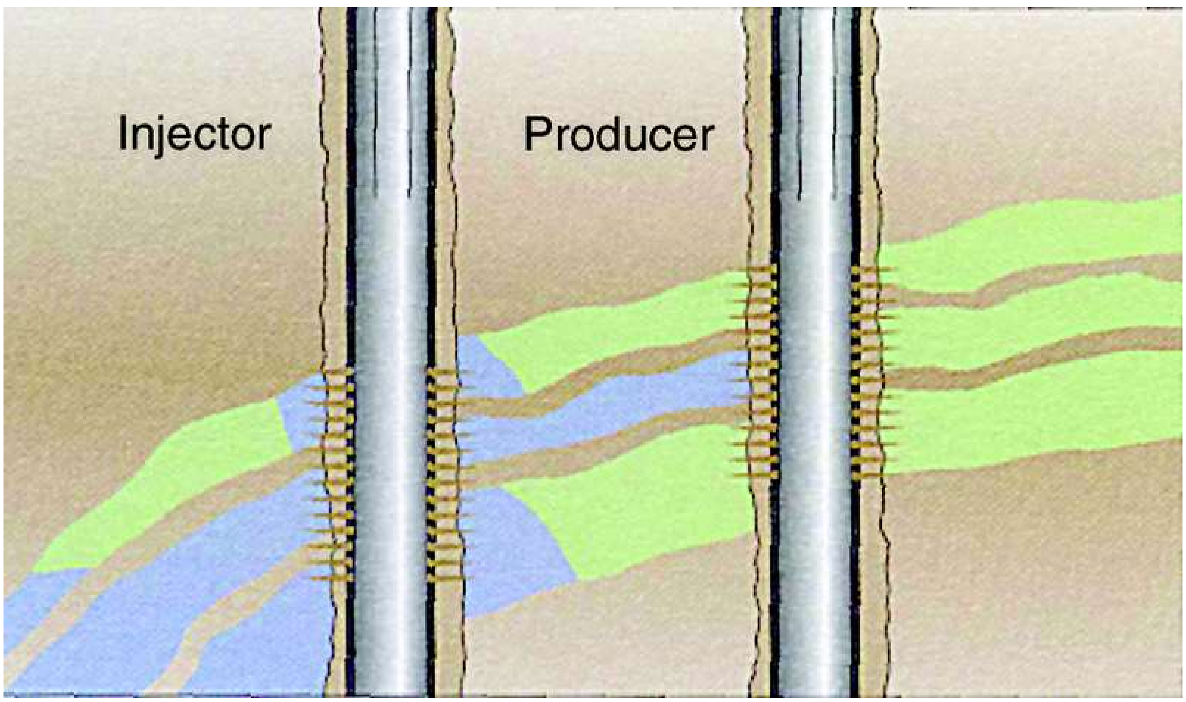

Fig. 1 – Watered-out layer without crossflow

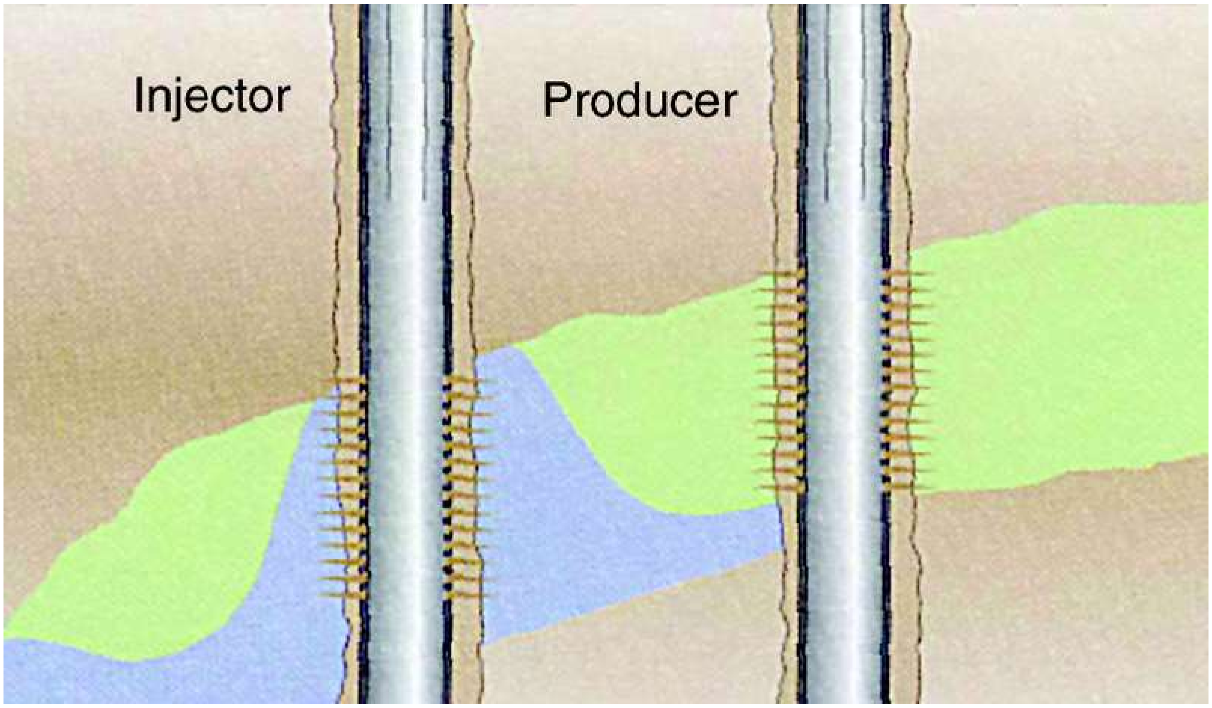

Fig. 2 – Gravity segregated layer

Effective water control is generally predicated on knowing the position and mechanism (source) of the intruding water. These parameters may be established from direct measurement, the well's production logs, and production history.

Shut-in and choke-back analysis of the fluctuating WOR data can provide clues to the problem type. Water-entry problems such as coning or a single fracture intersecting a deeper water layer will lead to a lower WOR during choke-back or shut-in. Fractures or a fault intersecting an overlying water layer have the opposite effect.

Injection problems

There can be additional problems associated with the injector well – primarily because of unplanned and uncontrolled fracturing of the receiving reservoir. One mechanism arises from the buildup of solids because of, for example:

- Filtration
- Bacterial action

- Scale buildup
- Changes in reservoir wettability

Pressure is increased to maintain injectivity and fracturing may occur. Thermal fracturing is often encountered offshore, because of the stress reduction in the injection zone from cool down. The zone with the highest injectivity cools down first and fractures, taking even more injection fluid creating poor sweep efficiency. One strategy to control this problem is to deliberately fracture all receiving zones, increasing sweep efficiency.

Limiting water production (Limiting creation of water plugs)

Mechanical or inflatable plugs are often the solution of choice for the near-wellbore problems:

- Casing leaks
- Flow behind casing
- Rising bottom water
- Watered-out layers without crossflow

These plugs can be deployed on coiled tubing or wireline to ensure shutoff in cased and openhole environments. When the wellbore must be kept open to levels deeper than the water entry, a through-tubing patch may be deployed inside the casing. One technology involves placing a flexible, inflatable composite cylinder made of, for example, carbon fiber, thermosetting plastics, and a rubber skin opposite the area to be treated. A pump then inflates the sleeve and injects well fluid, which heats the resins, turning on the polymerization process. After the resins have set, the sleeve is deflated and extracted.

Rigid gels are highly effective for near-wellbore shutoff of excess water. Unlike cement, gels can be squeezed into the target formation to give complete shutoff of that zone or to reach shale barriers. They have operational advantages over cement treatments because they can be jetted rather than drilled out of the wellbore. Commercial gels can be bullheaded into the formation to treat problems, such as flow behind casing and watered-out layers without crossflow, or they can be selectively placed in the water zones using coiled tubing and a packer.

Certain crosslinked polymers can also have long working times before becoming rigid. They are injected into small faults or fractures but only penetrate formations with permeabilities greater than 2 – 3 darcy. Large volumes (1,000 to 10,000 bbl) of these inexpensive fluids often successfully shut off extensive fracture systems surrounding waterflood injector or producing wells.

Gel treatments are not generally successful for combating coning/cusping problems for prolonged times, because they require very large volumes to be effective. An alternative is to drill one or more lateral drainholes near the top of the formation to take advantage of the greater distance from the OWC and decreased drawdown. Another approach is a dual drain (**fig. 3**).

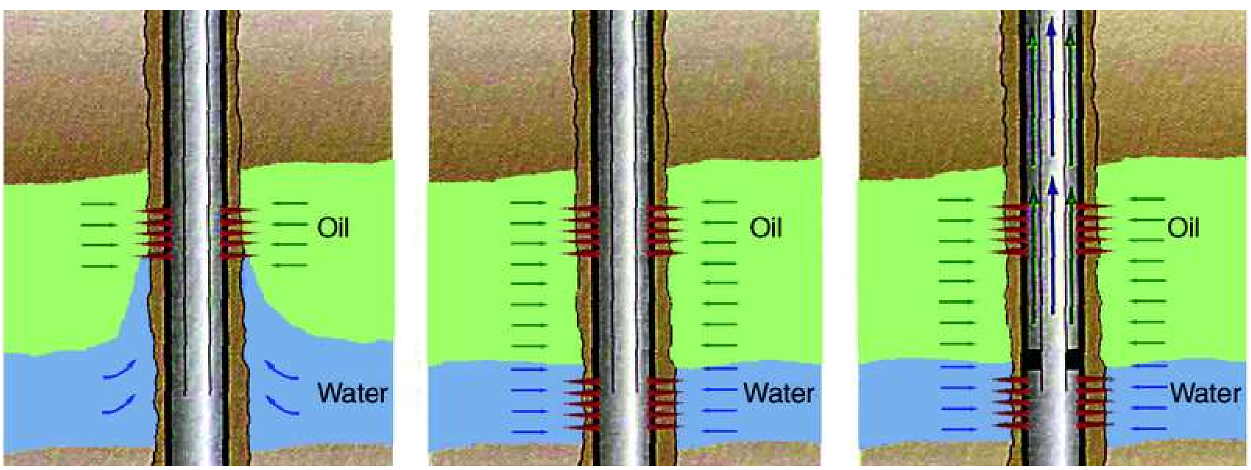

Fig. 3 – The coning problem is on the left; perforating the water leg eliminates the coning (middle). Alternatively, the water can be coproduced separately through tubing and annulus

Gel treatments are also not likely to work on the "gravity-segregated-layer" problem. Lateral drainholes may be effective in accessing the unswept oil. Infill drilling is often the best approach to improving the areal sweep efficiency edgewater problem. A large, likely uneconomic treatment of gel would be required to divert the injected water away from the pore space that has already been swept by water.

Treatments for water problems in horizontal wells are most effective when the treatment zone is isolated from the remainder of the wellbore. In cased holes, this is achieved mechanically with packers. However, when a screen or liner has been run but left uncemented, such mechanical devices are not effective in isolating the open annular space behind the pipe. One product developed for such situations is the annular chemical packer (**fig. 4**).

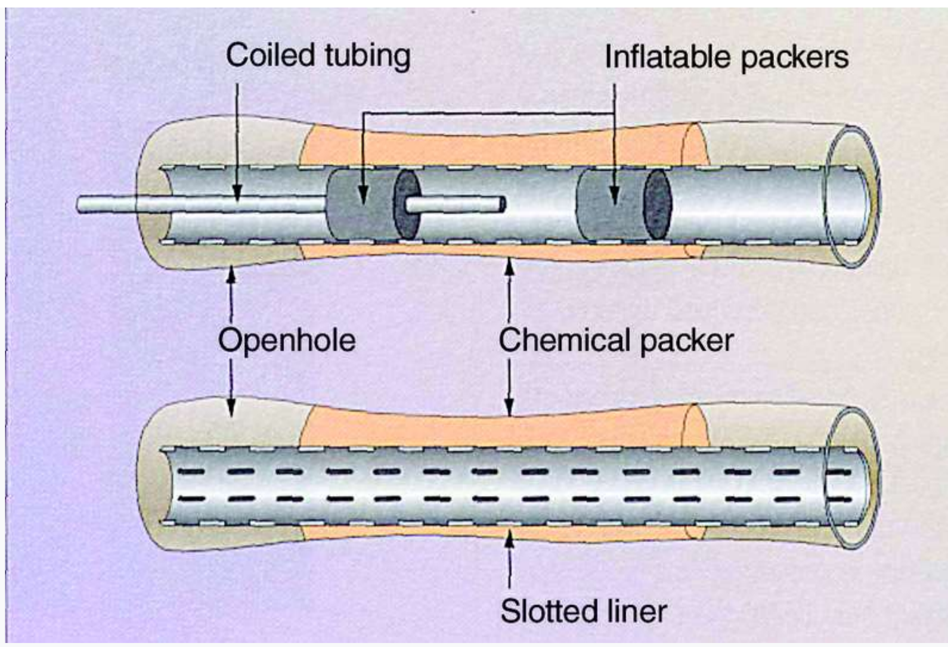

Fig. 4 – This technology involves placement of a cement-based fluid into the annular space between an uncemented liner and the formation. The fluid is conveyed into the treatment zone using coiled tubing and injected between and inflatable packer assembly to fill the annulus over a selected interval. It is designed to sit in this position forming a permanent, impermeable, high-strength plug, fully isolating the volume of the annulus (after Schlumberger *Oilfield Review*).

Proactive water control includes choking back zones with high permeability to create a more uniform sweep. This means sacrificing early cash flow for an uncertain return because of incomplete knowledge of heterogeneity. The production (and injection) profile can be improved through selective stimulation of zones with lower permeability. Coiled tubing is used to precisely place these small hydraulic fractures.

Water disposal

Whether water production is minimized or not, some water (e. g., "good" water) will be produced and must be disposed. To minimize costs, the water should be removed as early as possible (e.g., with a downhole separator if possible); see **fig. 5**.

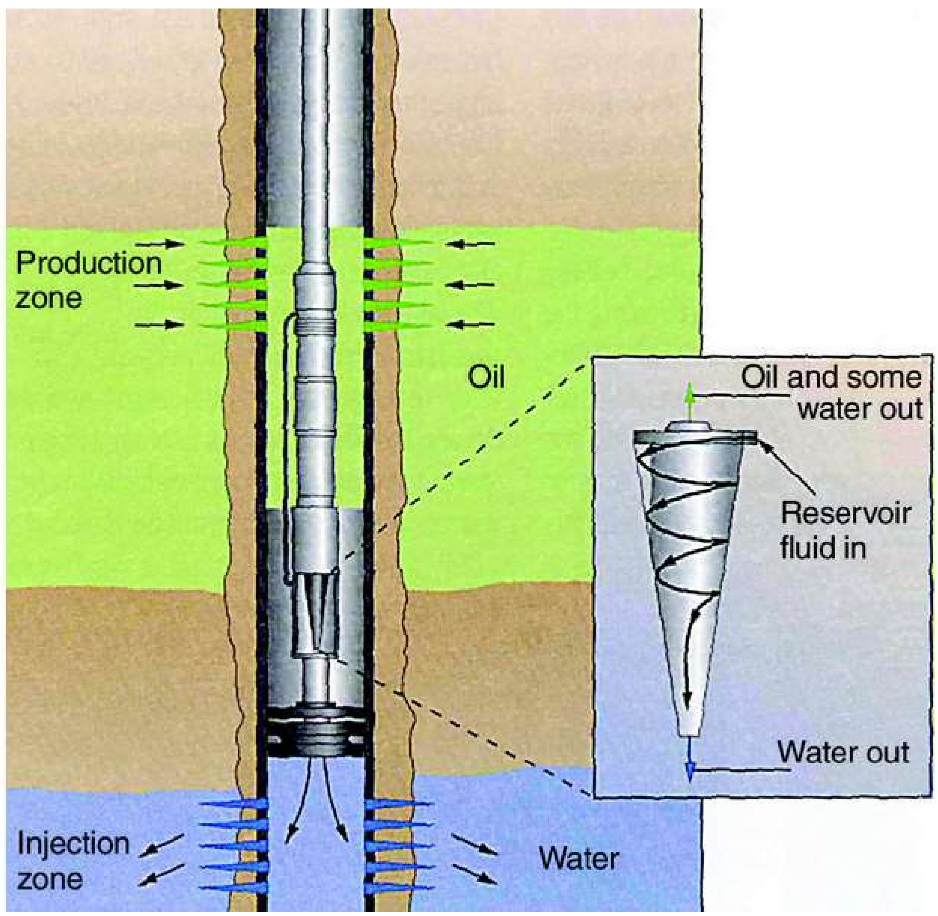

Fig. 5 – Such downhole separators, coupled with electrical submersible pumps, allow up to 50 % of the water to be separated and injected into another formation