Abstract
In the past, high-volume water shutoff treatments have not been applied because of the economic burdens they incur. Today, many operators have reconsidered high-volume water shutoff treatments because these treatments make oil production from mature reservoirs more economically feasible. Many wells in mature North Sea reservoirs produce a large amount of water. Consequently, these wells often produce less oil than they potentially could.

The evolution of diagnostic and interpretation techniques has significantly enhanced the degree of accuracy and completeness of production problem diagnoses. Reservoir models can be used to identify and design effective water shutoff treatments.

This paper describes how a production operation simulator is used with an advanced-processes reservoir simulator to design water shutoff treatments. The following reservoir simulator options were necessary to design the treatments properly.

- thermal options
- chemical-injection options
- chemical-reaction options
- flexible-gridding options

The technique was recently used to design water shutoff treatments and their placement for jobs in the North Sea area. The results of the simulations were used to predict the effects of the following factors.

- interval permeability distribution
- treatment rate
- reaction rates of treatment fluids
- resulting gel strength

The technique also allows treatments to be designed on the basis of realistic treatment temperatures rather than bottomhole static temperatures. The results of the simulations were used to help optimize treatment placement rates, fluid composition, and shut-in times of jobs pumped in the Norwegian sector of the North Sea.

One case shows how cooldown inside the reservoir can be used to place a treatment that would have otherwise spontaneously gelled at reservoir temperature. In another case, temperature histories for different stages of the treatments were constructed from the simulation results. These temperature histories showed that different activator compositions and/or concentrations were required for early, intermediate and final treatment stages.

Introduction
Water production can seriously compromise the profitability of oil- or gas-producing wells. Although prevention is usually more effective than treatment, excessive water production is most often treated rather than prevented. The process of designing a typical water shutoff (or conformance) treatment is as follows:
1. selecting the candidate well
2. identifying the water-production mechanism
3. identifying candidate treatments
4. designing placement
5. designing final treatment formulation

Generally, after engineers have designed the placement, they will determine the details of the treatment formulation based on bottomhole temperature (BHT), permeabilities, final strength requirements, and placement time. When treatment systems that gel in the rock matrix are used, wells are shut in after placement until the treatment thickens (or gels).

Historically, treatment gel times were chosen only on the basis of the placement time that was required (pump-rate dependent) and the bottomhole static temperature (BHST). This approach assumes that the treatment will be at BHST while it is setting. However, when treatment fluids are injected into a hot zone, the temperature of the zone reduces significantly. Temperature reductions are more dramatic at higher injection rates and volumes.

Surprisingly, temperature simulations indicate that when wells are shut in after treatment, the time required for a zone to reheat to reservoir temperature can be days or even weeks. This relatively slow temperature recovery while the well is shut in after treatment is because heat is being transferred only by conduction. To accurately predict the downhole temperatures during the placement and gelation of a water shutoff treatment, cooldown and temperature recovery calculations should be performed. These temperature predictions allow treatments to be fine-tuned.

Temperature Predictions
The effects of temperature variations while the water shutoff treatments are injected can significantly influence treatment gelation times. The success rates of water shutoff treatments increase when temperature predictions are used. The temperature simulations presented in this paper were conducted by the following method that is applicable to all water shutoff treatments. This method requires two steps: calculating temperatures and using tracers. Descriptions of these steps follow.

Calculating Temperatures
The bottomhole treating temperatures were calculated as a function of time with a commercially available software package for wellbore temperature simulations. These temperatures were then used as input for the downhole injection temperatures in a commercially available, advanced-processes reservoir simulator. The reservoir simulator was chosen because it could apply the following:

- thermal effects
- multiple phases in the reservoir
- multiple components in injected fluids
- reactions between components
- viscosity variations
- different grid geometries

The results of the simulations were plotted as temperature and/or distribution of gelant concentrations in vertical cross sections of the near-wellbore area. A typical example of simulator output for a dual-injection treatment is shown in Figs. 1 and 2.

Using the Tracer Technique
Tracers were used in the simulations to label different stages of the treatment. These labels allowed the construction of temperature histories for the different stages of the treatment. Fig. 3 demonstrates how the temperature history curves were constructed from the reservoir simulator output. The construction is shown for three different times: 3.5 hours, 7 hours, and 9 hours. The top graphs show the concentration of the tracer as a function of distance away from the well. The positions of the peaks in the top graphs allow users to find the corresponding temperatures in the middle graphs. The resulting temperatures were then used as data points in the final temperature history graph (bottom graph in Fig. 3). The procedure was repeated for different
times and their corresponding peaks to construct the complete temperature history for each stage of the treatment. The temperature histories provided a realistic picture of the actual conditions that the fluids in each stage were exposed to. This information was used to select appropriate activator types and/or activator concentrations for each stage.

Field Application
Design modifications as a result of cooldown and temperature recovery calculations could include changing the pumping rate to obtain an optimum cooldown, changing the treatment formulation to fit the predicted temperatures, or both. High-injection rates may be selected to achieve a dramatic cooldown and prevent premature gelation of the treatment. For example, a gelant may be selected because of its thermal stability after gelation; however, that gelant might gel too quickly at the well’s BHST. Fast injection rates of both a preflush and the gelant itself could be an effective way to get the gelant in place. Case history I is an example of this technique.

In contrast, low-injection rates can minimize cooldown. A minimized cooldown would be useful when the selected gelant reacts very slowly at temperatures cooler than the initial BHST. Cooldown and temperature recovery calculations were used for treatment formulation designs. It is often useful to calculate the cooldown and temperature recovery for several injection rates. Then treatments should be formulated that will react slowly enough to allow placement and quickly enough to avoid long shut-in times. When sealant formulations for sequential treatment stages are designed based on temperature profiles predicted by near-wellbore temperature simulations, shut-in times can be reduced by several days or even weeks, as illustrated in case history II.

Case History I
An operator in the Norwegian sector of the North Sea identified a candidate well that was producing around 90% water: 795 m³ of oil per day and 6360 m³ of water per day. After reservoir, completion, and well production data was reviewed, a recommendation was made to shut off the lowest set of perforations since the perforated interval produced virtually no oil. Earlier failures in shutoff attempts with through-tubing inflatable packers were attributed to the relatively high BHST of 147°C. In addition, there were doubts about the quality of the cement integrity. A decision was made to try a matrix water shutoff system although the BHST in this well is above the gel set temperature of most shutoff systems in existence. Laboratory data showed that a monomer/polymer (MP) gel system would hold up under these extreme temperatures. The only problem remaining was to place the gel. Temperature simulations were used to tackle this problem.

MP Gel Systems
The MP gel system is placed as a monomer solution that contains an internal initiator. The initiator is thermally degraded to form free-radicals. These free radicals initiate polymerization of the monomer in solution. Initiators for this system are chosen based on the treatment temperature history (the temperature the solution will be exposed to both during placement and shut in). Reaction rates are dependent on gel temperature history, initiator choice, and initiator concentration. The resulting material is a rigid, ringing gel.

The treatment was to be pumped through coiled tubing with a dual injection technique similar to what is depicted in Fig. 4. However, maximum possible pumping rates through the 1.75-in. coiled tubing were not sufficient to obtain the required cooldown. An injection sequence was designed consisting of two high-rate cooldown stages before setting the packer on coiled tubing. The pumping schedule and the resulting BHTs as calculated with the wellbore simulator are shown in Fig. 5. Five hours of high rate pumping was required to obtain a BHT of approximately 68°C. The resulting temperature distribution inside the reservoir and the temperature profiles during the placement of 32 m³ of sealant solution that was required are shown in Fig. 6. The temperature inside the reservoir changed slightly during these low-rate placement stages. Fig. 7 shows the temperature recovery after the treatment. Based on the simulations five different gel compositions were prepared for different stages of the treatment. The treatment was pumped with small changes in pump rates and a temperature gauge with surface read-out in August 1996. The treatment successfully reduced the inflow from lower set of perforations though a complete shutoff was not obtained.5
Case History II
An operator in the Norwegian Sector of the North Sea identified a candidate well that was producing 70% water. A production log showed that the lower perforated interval only produced water, and the upper intervals produced both water and oil. The separation between the two perforated intervals in this deviated well was only 5 m of measured depth. Separation between the two intervals in the reservoir was provided by a shale barrier of 1.3 m of true vertical depth. After reviewing the reservoir and well data, a team of operators and engineers recommended that the well be treated with 250 m³ of an IAS system. The treatment was to be placed with a dual-injection technique. The gelant chosen for use in this application was an internally activated silicate (IAS) system.

IAS Systems
An IAS system is generally placed as a water-thin, freshwater-based solution that consists of a silicate source and an activator designed to trigger gelation of the silicate at a designated time. The gel times of IAS systems are controlled by pH and temperature. The target pH either is reached on the surface with strong or weak acids, or in situ when materials that slowly release acids are added. The gelants result in stiff, brittle solids. The exposure temperature during gelation dictates the gelation time of the treatment. However, it should not be assumed that the reservoir temperature will necessarily be the curing temperature.

The IAS solution was to be pumped through coiled tubing into the lower set of perforations, while 2% KCl-brine would be simultaneously pumped down the production tubing into the upper set of perforations. This technique minimized the pressure differential across the mechanical packer and also minimized the risk of the IAS treatment being injected outside the target zone if the hydraulic barrier provided by the shale was insufficient. Fig. 4 depicts the well’s layout during placement.

The reservoir temperature was 92°C. The high-temperature activator (HTA) initially considered for this treatment could react only above 80°C to avoid premature gelation. Because the HTA would become active only above 80°C, the team decided to run near-wellbore temperature simulations. These simulations allowed engineers to determine the time required to heat the reservoir back up to 80°C.

Fig. 8 shows the bottomhole injection temperature during the treatment as predicted by the wellbore simulations. As one might expect, the bottomhole region cools rapidly at first, and then the cooldown rate slows as the temperature difference between the injection water and the bottomhole region decreases. Temperature recovery profiles as a function of the distance from the well are presented in Fig. 9. According to the profiles, at least 1 month would be required for the near-wellbore area to warm up to 80°C. This information indicated that the shut-in time would have been at least 1 month if all the treatment was activated with the HTA and would not be economically feasible.

Additional simulations were conducted with the tracer technique. These simulations were used to determine the temperature-time histories for different parts of the job. The results are presented in Fig. 3. The figure shows significant differences between the early and later stages of the treatment. The temperature of the later stages of the job does not exceed 80°C while the treatment is pumped. Based on these temperature-time histories, the design team decided to use the IAS system with a low-temperature activator (LTA) that is effective at ambient temperatures for the later stages of the job. Activating the silicate with the LTA would allow the shut-in time to be as short as 6 hours after treatment. The treatment was placed successfully as designed and had a payback time of 50 days. The well produced 116,000 m³ of oil during the first 6 months after the treatment.

Conclusions
- Temperature calculations can effectively predict formation temperature cooldowns during treatments and post-treatment temperature recoveries.
- The tracer technique introduced in this paper can help construct temperature-time histories of different treatment stages.
- These temperature-time histories can help tailor treatment formulations that minimize post-treatment shut-in times.
References
Fig. 1 - The reservoir simulator output shows temperature (left) and gelant distribution (right) during a typical dual-injection treatment. The figure represents a 10-m long, 30-m high vertical cross section.

Fig. 2 - The reservoir simulator output shows temperature (left) and gelant distribution (right) at the end of a typical dual-injection treatment. The figure represents a 10-m long, 30-m high vertical cross section.

Fig. 3 - Construction of temperature history curves from reservoir simulator output.
Fig. 4 - Layout of well during placement of water shutoff treatment.

Fig. 5 - The pumping schedule and resulting BHT as calculated with the wellbore simulator, case history I.
Fig. 6 - Temperature distribution inside reservoir and temperature profiles during placement of 32 m³ of sealant solution, case history I.

Fig. 7 - Temperature recovery after treatment, case history I.
Fig. 8 - Bottomhole injection temperature during treatment of the well in Norwegian Sector of the North Sea as predicted by wellbore simulations, case history II.

Fig. 9 - Temperature recovery profile as a function of distance from the well in the Norwegian Sector of the North Sea, case history II.