Method of Predicting the Location of Water Cresting for Horizontal Wells in a Water-Drive Reservoir for Early Prevention

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1. INTRODUCTION

Despite increasing advances in green energy such as wind, solar, and biomass, fossil fuel is still forecasted to provide up to 78% of the world’s energy needs until 2040. As conventional oil and gas resources dwindle, exploitation of unconventional resources such as tight oil and shale is taking conventional oil and gas resources dwindle, exploitation of unconventional resources such as tight oil and shale is taking place enabled by technologies such as horizontal wells, geosteering, and multistage fracturing. With application of horizontal wells becoming widespread and matured in unconventional reservoirs, its usage is being broadened out to boost productivity in conventional and marginal thin-reservoirs alike. Water-drive reservoirs, as one of the most prolific conventional reservoir types found worldwide, are at the forefront in being increasingly exploited with horizontal wells becoming widespread and matured in geosteering, and multistage fracturing.4 Water-drive reservoirs, as one of the most prolific conventional reservoir types found worldwide, are at the forefront in being increasingly exploited with horizontal wells becoming widespread and matured in unconventional reservoirs, its usage is being broadened out to boost productivity in conventional and marginal thin-reservoirs alike. Water-drive reservoirs, as one of the most prolific conventional reservoir types found worldwide, are at the forefront in being increasingly exploited with horizontal wells becoming widespread and matured in unconventional reservoirs, its usage is being broadened out to boost productivity in conventional and marginal thin-reservoirs alike.5

The first analytical solution describing the movement of the water–oil interface and recovery as a function of well spacing, pay thickness, ratio of horizontal and vertical permeability, and well penetration for a vertical well in a water-drive reservoir while neglecting the effect of density was done in 1946 by Muscat, which laid the groundwork for further modeling of the water cresting phenomenon. With the amount of research has been devoted to this topic. The first analytical solution describing the movement of the water–oil interface and recovery as a function of well spacing, pay thickness, ratio of horizontal and vertical permeability, and well penetration for a vertical well in a water-drive reservoir while neglecting the effect of density was done in 1946 by Muscat, which laid the groundwork for further modeling of the water cresting phenomenon.7 A large portion of subsequent research in the area of water cresting has focused on the numerical determination of breakthrough time and the critical flow rate to delay/mitigate water cresting with a focus on the withdrawal rate, the ratio of water-to-oil mobility, the ratio of vertical-to-horizontal permeability, distance from the wellbore to oil–water contact, productive length of the wellbore, size...
and shape of the drainage area, etc. For ease of field application, Sobocinski and Cornelius reported an empirical correlation for dimensionless height of water cone vs dimensionless time that is hand-calculation for field engineers without access to computing power.\textsuperscript{30} Li et al. performed dimensional analysis and numerical parametric simulations of water breakthrough in horizontal wells in a water-drive reservoir and reported a general correlation model for predicting the breakthrough time.\textsuperscript{29} Aulie et al. developed a steady-state analytical model to predict oil and water production at the supercritical rate and reported a good agreement with experimental recovery results done with visual cells at low pressure.\textsuperscript{30} Yang and Wattenbarger performed extensive sensitivity analysis of water coning using numerical simulation to develop an empirical coning correlation for prediction of the critical rate, breakthrough time, and WOR after breakthrough in both vertical and horizontal wells for cases limited to when the water–oil mobility ratio is smaller than 5 or when viscous forces are not dominating.\textsuperscript{31,32} De Souza et al. reported a numerical correlation of the effect of grid block size, grid patterns, rate, mobility ratio, drainage area, well height, and endpoint and shape of relative permeability on breakthrough time, maximum oil rate, and postbreakthrough behavior for water and gas coning in horizontal and vertical wells.\textsuperscript{33} Bahadoori followed with a simple-to-use correlation for dimensionless breakthrough time of water/gas coning and optimum horizontal well placement for horizontal wells in homogeneous and anisotropic reservoirs as a function of the dimensionless rate and density difference ratio.\textsuperscript{34} Umnuayponwiwat and Ozkan conducted modeling work on the effect of wellbore pressure drop on the breakthrough time of water and gas coning into a horizontal well and reported that wellbore hydraulics have a strong effect on the shape and breakthrough of the coning. They reported that in the case that wellbore pressure drop influences the production significantly, coning and breakthrough take place at the heel and increasing the length of the well does not delay breakthrough.\textsuperscript{35} Papatzacos et al. developed a semianalytical solution for prediction of the breakthrough time as a function of the rate for gas/water coning in a horizontal well and found good agreement with a set of field data.\textsuperscript{36} Sech et al. conducted parametric studies and reported that large diametered horizontal wells produced at a high rate will result in poor recovery due to the dominating water-cresting phenomenon unless the ratio of vertical permeability to horizontal permeability is very low, and that rate sensitivity is exacerbated in low-permeability gas reservoirs.\textsuperscript{37} Mahboob et al. used simulation software to converge on an empirical correlation incorporating reservoir fluid properties, fracture properties, water–oil contact, horizontal and vertical permeabilities, and length of the fracture to compute the critical flow rate to prevent water creasing.\textsuperscript{38,39}

Experimentally, various groups have attempted different experimental investigations on the mechanistic studies on the water-cresting phenomenon in oil and gas reservoirs. Permadi et al. experimented with the Hele-Shaw visual cell with varied oil column thicknesses, horizontal well length, and oil viscosity and reported that a pressure gradient within the wellbore leads to the occurrence of water cresting at the heel and never at the tip of the horizontal well even at 99% water-cuts. They also reported that longer horizontal wells and thicker oil columns both slow down the rate of increase of water-cuts, while shorter wells and higher oil viscosity lead to a faster rise in water-cuts with the corresponding lower recovery.\textsuperscript{14} Jiang and Butler conducted a flow experiment with the Hele-Shaw visual cell varying the flow rate and the viscosity ratio and reported that recovery at breakthrough and stability of the interface usually vary inversely with flow rate and viscosity ratio with the exception of certain cases when a high flow rate concurs with a high viscosity ratio, which results in an apparent higher sweep efficiency due to the formation of multiple finger formations.\textsuperscript{35} Dou et al. used the Hele-Shaw visual cell to investigate the effect of permeability heterogeneity on the rise in water-cuts and recovery and reported that layers of low- or nonpermeable packing between the well and the aquifer element lead to a slower water-cut rise and a higher recovery.\textsuperscript{27} Permadi et al. investigated the effect of impermeable streaks on recovery and the water-cresting phenomenon in another study using the Hele-Shaw visual cell and reported that placement of the heel end of the horizontal well above the impermeable streaks positively affects the recovery. They also reported that the presence of discontinuous impermeable streaks, a less viscous or lighter oil, and longer wells gives higher oil recovery in general.\textsuperscript{31} While water cresting in a gas reservoir is just as important as in an oil reservoir, due to the challenge of higher pressure requirements in physical simulation, there have been very little reports of similar visual cell mechanistic studies of the water-cresting phenomenon in gas reservoirs other than some water invasion studies using reservoir cores. Fang et al. conducted water invasion studies using real cores to examine the effect of aquifer size, gas production rate, and permeability on water invasion in gas reservoirs and reported that aquifer size and production rate positively affect the extent of water invasion.\textsuperscript{42,43} These experimental findings though important are limited by the low-pressure limitation of the Hele-Shaw cell and the qualitative and disassociated nature of observation associated with it. Although these experimental and modeling/simulation research made an important contribution toward a better mechanistic understanding of the water-cresting phenomenon by identifying the relevant parameters, very little work has been done on siting the location of water cresting for early prevention.

Extending from the mechanistic work of previous groups, the authors have devised a mechanistic model from Darcy’s equation incorporating the four main parameters of water crest formation reported as most relevant by the literature: viscosity, distance from the well to the aquifer (i.e., thickness of the oil column), wellbore pressure gradient, and reservoir heterogeneity for computing the breakthrough time at each segment of the horizontal well. From this mechanistic model of water-cresting, a novel characterizing parameter called the breakthrough coefficient was derived that can be used to predict the place of water cresting occurrence, with the model-predicted location of water cresting corresponding to the well segment with the largest breakthrough coefficient. The breakthrough coefficient was used further to quantitate the breakthrough intensity for ranking wells in the same group to predict which well will see breakthrough first. The method detailed in this paper offers potential use in field application as a nonlogging alternative for siting the likely location of water cresting for early prevention.

**1.1. Mechanistic Modeling.** In a real reservoir, due to the complexity of multiple interfering factors, determination of the location of water cresting is very challenging. There are many production-related complexities such as loss of casing, turbulent flow, and presence of fractures that can mask true
underlying forces such as viscous forces, gravity forces, oil—water viscosity ratio, etc. This results in intermingled effects that make it very challenging to determine the location of water-cresting occurrence from well testing data. Realizing this, the authors seek to first construct a workable model that capture the most essential elements in the water-cresting mechanism according to the experimental findings in the literature. In constructing this mechanistic model, the authors first recognized the following.

(1) The driving force in the formation of a water crest is the differential pressure between the pressure gradient along the length of the wellbore to the pressure of the aquifer.

(2) The vertical distance from the top of the aquifer to the wellbore as well as the regional heterogeneity along the length of the wellbore affects the timing of water breakthrough at each section of the wellbore.

(3) For simplicity, complexities due to loss of well integrity (e.g., loss of casing), variation of well perforations, and reservoir complexities such as fractures are not considered in this base model.

(4) Reservoir aquifer pressure is assumed constant.

With these understandings, a simplified diagram of the mechanism of a water crest formation with all of the key essential elements is shown in Figure 1. From the figure, it can be seen that the water-cresting phenomenon can be modeled as a function of pressure along the tubing \((p_i)\), permeability \((k_i)\), porosity \(\phi_i\), height of the water front rising vertically along the pipe \(z_i\), distance from top of the aquifer to the well \(h_i\), and aquifer pressure \(p_a\), i.e.,

water cresting location and intensity

\[
f(x_i, p_i, k_i(x), \phi_i(x), h_i(x))
\]

In a homogeneous reservoir with permeability and porosity invariant along the length of the well (e.g., \(k_i(x) = k_i, \phi_i(x) = \phi_i\)) with the horizontal well level with the aquifer underneath, the resultant water crest is expected to occur at the heel section where the inner pipe pressure is the lowest, creating the biggest pressure drop relative to the reservoir aquifer pressure. However, in a real reservoir, heterogeneity along the well path and deviation from the perfect level are the norm. In this case, the distance from the top of the aquifer to the well \(h_i(x)\), and variation of permeability and porosity along the length of the well at different locations \(x_i\) will end up affecting changes to the breakthrough location of the water crest.

Using the essential parameters for the water-cresting phenomenon summarized above, the authors then seek to build a model for prediction of location and intensity of water cresting in a horizontal well in a water-drive reservoir.

**1.2. Derivation of the Breakthrough Coefficient from Darcy’s Equation: A Characterizing Parameter for Prediction of Location and Strength of Water Cresting in a Horizontal Well.** Recognizing that the velocity of the upward-moving displacement front of the water coming from underneath to displace the oil in the pore space above varies as a function of regional heterogeneity and well trajectory (Figure 1), then for each position \(x_i\), there would be a corresponding different inner well pressure along the horizontal well due to the wellbore pressure gradient \((p_i)\), permeability/porosity variation \((k_i/\phi_i)\), distance between the horizontal well and the top of the aquifer \(h_i\), and water/oil viscosity \((\mu_w/\mu_o)\). Setting the upward displacement front at position \(x_i\) as \(z_i\), then the upward velocity of the displacement front \(v_i\) at location \(x_i\) is

\[
v_i = \frac{-\Delta p}{\mu_w h_i + (\mu_w - \mu_o)z_i}
\]

where \(\Delta p = p_a - p_w\) where \(p_a\) is constant and \(p_w\) varies along the length, and assuming that permeabilities for oil and water are the same.

\[
k_w = k_o = k
\]

Then,

\[
v_i = \frac{-k \Delta p}{\phi_i} \frac{1}{h_i + (\mu_w - \mu_o)z_i}
\]

Thus, the calculation of the time needed for the oil—water interface to move to position \(h_i\) (breakthrough) can be obtained by isolating the time from \(v_i\) and integrating the expression above:

\[
\int_0^t dt = \frac{-\phi_i}{k \Delta p} \int_0^{h_i} [\mu_w h_i + (\mu_w - \mu_o)z_i] dz_i
\]

To get the time of breakthrough at \(x_i\) as

\[
t_i = \frac{-\phi_i h_i^2}{2k \Delta p (\mu_w + \mu_o)}
\]

If the reservoir is homogeneous and the trajectory of the horizontal well is straight and level with the water aquifer underneath, then \(h\) is the same throughout the length of the well. Thus, \(h\) is equal to the average value, \(\bar{h}\), and the time required for the parallel movement of the interface up to height \(h\) is

**Figure 1. Illustration of the water-cresting phenomenon for a horizontal well in a water-drive reservoir (not to scale).**
Thus, it follows that if the average breakthrough time $\bar{t}$ is much bigger than the time $t_i$ for the breakthrough at $x = x_i$, then the likelihood to form water cresting at $x_i$ is much greater. Thus, the relative size of the ratio of the average breakthrough time of the displacement front $\bar{t}$ to the breakthrough time of the displacement front at each point of the horizontal well can be used as a characterizing parameter to determine where the water cresting is going to occur. This ratio is termed the breakthrough coefficient in this paper. The breakthrough coefficient is defined as the ratio of the average breakthrough time of the entire displacement front of the horizontal well to the displacement front of a particular section in the horizontal well.

$$\bar{t} = \frac{2\phi h^2}{\Delta p k} (\mu + \mu_0)$$

Thus, it follows that if the average breakthrough time $\bar{t}$ is much bigger than the time $t_i$ for the breakthrough at $x = x_i$, then the likelihood to form water cresting at $x_i$ is much greater. Thus, the relative size of the ratio of the average breakthrough time of the displacement front $\bar{t}$ to the breakthrough time of the displacement front at each point of the horizontal well can be used as a characterizing parameter to determine where the water cresting is going to occur. This ratio is termed the breakthrough coefficient in this paper. The breakthrough coefficient is thus defined as the ratio of the average breakthrough time of the entire displacement front of the horizontal well to the displacement front of a particular section in the horizontal well.

$$T_w = \frac{\bar{t}}{t_i} = \left(\frac{k_i}{\rho} \frac{\Delta p}{\Delta p/k} \right) \left(\frac{\phi}{h} \frac{\phi}{h} \right) = R_k R_p / R_h$$

with $R_h = h_i / h$ as the wellbore trajectory coefficient; $R_k = k_i / k$ as the permeability distribution coefficient; $R_p = (\Delta p / h_i) / (\Delta p / h)$ as the pressure gradient coefficient; and $R_p = \phi_i / \phi$ as the porosity distribution coefficient.

1.3. Application of Breakthrough Coefficient, $T_w$.

From the derived equation for the breakthrough coefficient in Eq. 7, it can be deduced that closer to unity, the breakthrough coefficients are along the length of the horizontal well, and the more level the displacement front is going to be, the less likely is the formation of a water crest. This in turn results in a higher sweeping efficiency. However, in reality, the breakthrough coefficient is much more likely to be unevenly distributed along the horizontal well.

In this case, the proposed breakthrough coefficient can be used for the functions described next.

1.3.1. Point Out the Location of the Water Breakthrough.

Here, $T_w = T_{w,max}$, i.e., the place with the biggest breakthrough coefficient is the predicted location where the water-cresting formation and water breakthrough are going to occur.

1.3.2. Quantitate the Intensity of the Water Crest.

The intensity of water-cresting occurrence is related to the difference between the maximum and minimum breakthrough coefficients. The bigger the difference between the two, the more uneven the water displacement front, and thus the more intense the water-cresting occurrence. For the purpose of characterizing the water-cresting intensity, the cresting index is defined as
The larger the disparity between the maximum and minimum breakthrough coefficients, the larger the cresting index \(I_C\), signifying that the water-cresting profile is sharper at the place of water breakthrough (where \(T_w = T_{w,max}\)). This signifies faster breakthrough at the location corresponding to the maximum breakthrough coefficient, and thus a faster rise in the water-cut. The cresting index when applied to a group of wells in the same reservoir can be used to judge which well will consequently witness water breakthrough first and can be used to predict the order of water breakthrough among different wells.

2. RESULTS AND DISCUSSION

2.1. Effect of Concavity Location on Water-Cresting Location and Intensity. In Figure 2a–c, comparison for three corefloods in homogeneous cores of permeability of 500 \(\times 10^{-3}\) \(\mu\)m\(^2\) for GT-1, GT-2, and GT-3 is shown; the different experimental conditions are shown in Figure 2a–c-i with the red depression in the illustration representing the place of concavity, the gray area being the reservoir, and the blue area being the aquifer element.

2.1.1. Effect of Concavity Location on Water-Cresting Location. For the coreflood results of GT-1 of a homogeneous sandstone with no concavity shown in Figure 2a–i, the breakthrough coefficient \(T_w\) vs core length calculated using eq 7 is plotted in Figure 2a–ii. The model-predicted breakthrough point corresponding to the maximum breakthrough coefficient \(T_{w,max}\) is shown to be at 70 cm core length. Figure 2a–iii shows the saturation profile at different pore volumes flooded with red for oil and blue for water graded by the water saturation scale at the bottom. The actual breakthrough for the homogeneous sample GT-1 is harder to determine from Figure 2a-iii as there are no obvious blue bands near the top of the model at any pore volume. However, there is a presence of a water crest visible at 0.2 pore volume between 60 and 70 cm core length in Figure 2a-iii. The moderately green to red coloring of the saturation plot at the topside of the model at 0.3–0.4 pore volume suggests that the water breakthrough was a weak one. Still, the model-predicted location of water cresting matched the actual breakthrough from the experiments. This base case result agrees with previous studies by others that the heel region tends to see the water-cresting formation due to the greatest well-reservoir pressure drop.\(^\text{16}\)

For the coreflood results of GT-2 with 3 cm concavity at the heel location shown in Figure 2b-i, the model-predicted breakthrough location corresponding to the maximum breakthrough coefficient is shown at 70 cm core length in Figure 2b-ii. The saturation profile in Figure 2b-iii shows a dark-blue water crest at 60–70 cm core length reaching the topside at 0.1 pore volume. The results for GT-2 show that the location of water cresting predicted by the model falls tightly within the actual breakthrough location from the experiments.

For the coreflood results of GT-3 with 3 cm concavity in the middle shown in Figure 2c-i, the model-predicted breakthrough location corresponding to the maximum breakthrough coefficient is shown at 50 cm core length in Figure 2c-ii. The saturation profile in Figure 2c-iii shows that a dual crest formed at 0.01 pore volume with one at 31–44 cm and the other at the heel 55–70 cm core length. From the saturation plots, the water crest at the heel appears to break through prior to the water crest in the middle and is shown in a darker blue color as seen in Figure 2c-iii as early as 0.1 pore volume injected.

For the case of homogeneous cores of GT-1 and GT-2, the experimentally determined location of water-cresting occur-
rence by resistivity plots matched well with the model-predicted location. For the sample GT-3, the model-predicted location falls in between the two locations of water crest formed during the experiments.

2.1.2. Effect of Concavity Location on Water-Cresting Intensity. The cresting index (ratio of the maximum breakthrough coefficient to the minimum breakthrough coefficient) calculated by eq 8 characterizes the intensity of the water-cresting phenomenon. Theoretically, the lower the cresting index, the smaller the difference between the maximum and minimum breakthrough coefficients, the more even the displacement, the slower the breakthrough, and the higher the recovery. For comparison among similar wells or corefloods, the one with the highest cresting index should see the breakthrough first. To illustrate this point, the recoveries and water-cuts for samples GT-1, GT-2, and GT-3 are plotted together in Figure 3. 

The cresting index \( I_{WCl} \) of the base case GT-1 is 2.65, calculated by taking the maximum value of the breakthrough coefficient and dividing it by the minimum value from Figure 2a-ii. Experimentally for GT-1, the blue dashed curve in Figure 3 shows that 0.02 and 0.10 pore volumes of water were injected before breakthrough and 80% water-cut was reached, respectively, resulting in a recovery efficiency of 29.16% (blue curve in Figure 3).

The cresting index \( I_{WCl} \) of GT-2 with the concavity at the heel is higher than that of GT-1 at 5.57. The higher cresting index suggests a more uneven water displacement front, indicating that its water breakthrough should come earlier with a lower recovery than GT-1. Experimentally, this was validated by the coreflood results of GT-2. The green dashed curve in Figure 3 shows that the water breakthrough came at 0.01 pore volume and immediately after the water-cut reached 80% at 0.1 pore volume, resulting in a lower recovery of only 13.69% for GT-2 (green curve in Figure 3).

The cresting index \( I_{WCl} \) of GT-3 with the concavity at the middle is slightly smaller than that of GT-1 at 2.61. The small cresting index suggests that GT-3 probably had a more even water displacement front with a delayed breakthrough and a higher recovery more similar to the base case GT-1. This interpretation is supported experimentally. The red dashed curve in Figure 3 shows that 0.08 and 0.35 pore volumes of water were injected before breakthrough and 80% water-cut was reached, respectively, resulting in a recovery efficiency of
29.75% (red curve in Figure 3). In summary, corelood results of GT-2 with the highest cresting index value corresponded to the fastest breakthrough and the lowest pore volume injected before 80% water-cut was reached among these three homogeneous synthetic sandstones. Corelood results of GT-1 and GT-3 with similar values of the cresting index of 2.65 and 2.61, respectively, had slower breakthroughs and higher pore volumes of water injected prior to seeing an 80% water-cut and a similar recovery. By ranking the cresting index of the three corelood results, the order of which corelood would first see breakthrough emerged naturally. This demonstrates that the cresting index is a useful tool for prediction of order of water breakthrough among a group of similar wells.

2.2. Effect of Concavity Depth on Water-Cresting Location and Intensity. In Figure 4, comparison for two coreloods in homogeneous cores of permeability of 500 × 10⁻³ μm² for GT-4 and GT-5 is shown, and the different experimental conditions are shown in Figure 2a,b-i with the red depression in the illustration representing the place of concavity, the gray area being the reservoir, and the blue area being the aquifer element.

2.2.1. Effect of Concavity Depth on Water-Cresting Location. For the corelood results of the homogeneous sample GT-4 with 5 cm concavity depth at the heel location shown in Figure 4a-i, the model-predicted breakthrough location corresponding to the maximum breakthrough coefficient is shown at 70 cm core length in Figure 4a-ii. The saturation profile in Figure 4a-iii shows an expensive water crest at the range of 33–70 cm core length reaching the topside at 0.1 pore volume. The results for GT-4 show that the location of water cresting predicted by the model falls well within the wide breakthrough range from the experiments.

Comparison of the location of breakthrough between GT-4 with 5 cm concavity depth at the heel in Figure 4a-iii and GT-2 with 3 cm concavity depth at the heel in Figure 2b-iii made it immediately apparent that having a deeper concavity depth drastically alters the corelood by increasing the breakthrough speed and the swept volume (i.e., the range of the blue zone changed from 60–70 cm core length to that of 33–70 cm core length). For GT-4, once the breakthrough occurred at 0.01 pore volume, there was very little change after that. The swept volume and its saturation as indicated by the color distribution remained little changed.

For the corelood results of the homogeneous sample GT-5 with 5 cm concavity at the middle location shown in Figure 4b-i, the model-predicted breakthrough location corresponding to the maximum breakthrough coefficient is shown at 50 cm core length in Figure 4b-ii. The saturation profile in Figure 4b-iii shows a wide water crest at the range of 37–63 cm core length reaching the topside very early at 0.01 pore volume. The results for GT-5 show that the location of water cresting predicted by the model falls tightly within the wide breakthrough range from the experiments.

Comparison of the location of breakthrough between GT-5 with 5 cm concavity depth at the heel in Figure 4b-iii and GT-3 with 3 cm concavity depth at the heel in Figure 2c-iii shows that increasing the concavity depth from 3 to 5 cm changed the breakthrough from that of dual breakthrough fronts (one at the heel and one in the middle) to just one breakthrough front. For GT-5, similar to that of GT-4, once the breakthrough occurred at 0.01 pore volume, there was very little change after. The swept volume and its saturation as indicated by the color distribution remain little changed.
2.2.2. Effect of Concavity Depth on Water-Cresting Intensity. To examine the effect of concavity depth on water-cresting intensity, the recoveries and water-cuts for samples GT-1, GT-2, GT-3, GT-4, GT-5 are plotted together in Figure 5 for comparison.

The cresting index \( I_{WCI} \) calculated for GT-4 with 5 cm concavity and the higher pressure drawdown effect concurrently at the heel is 16.61, which is \( \sim 3 \) times that of GT-2 \( (I_{WCI} = 5.57) \) with 3 cm concavity at the heel and \( \sim 6 \) times that of GT-1 \( (I_{WCI} = 2.65) \). Comparison of the water-cut production in Figure 5 shows that GT-2 saw a slightly faster breakthrough and water-cut rise to reach 80% water-cut at 0.01 and 0.1 pore volume, respectively, compared to GT-4 at 0.02 and 0.12, respectively (two green dashed curves), resulting in a lower recovery for GT-2 vs GT-4 (two solid green curves). Comparison of the water-cut results for GT-2 and GT-4 going from 3 to 5 cm concavity at the heel shows that though the cresting intensity increased with increased concavity depth, the water breakthrough was still faster at 3 vs 5 cm concavity depth. Additionally, the pore volume to reach breakthrough and reach 80% water-cuts did not vary significantly.

The cresting index \( I_{WCI} \) calculated for GT-5 with a 5 cm concavity in the middle is 4.60, which is a medium–low value slightly higher than that of GT-1 with \( I_{WCI} \) of 2.61. Comparison of the water-cut production in Figure 5 shows that GT-3 saw a similarly slightly faster breakthrough and water-cut rise to reach 80% water-cut at 0.08 and 0.35 pore volume, respectively, compared to GT-5 at 0.11 and 0.36, respectively (red and pink dashed curves), with slightly higher recovery of 29.75 vs 27.32% for GT-3 and GT-5, respectively (red and pink solid curves). Comparison of the water-cut results for GT-3 and GT-5 going from 3 to 5 cm concavity at the heel shows that though the cresting intensity increased with increased concavity depth, the water breakthrough was still faster at 3 vs 5 cm concavity depth. Additionally, the pore volume to reach breakthrough and reach 80% water-cuts did not vary significantly.

The cresting index \( I_{WCI} \) calculated for GT-7 with a 5 cm concavity in the middle is 4.60, which is a medium–low value slightly higher than that of GT-1 with \( I_{WCI} \) of 2.61. Comparison of the water-cut production in Figure 5 shows that GT-3 saw a similarly slightly faster breakthrough and water-cut rise to reach 80% water-cut at 0.08 and 0.35 pore volume, respectively, compared to GT-5 at 0.11 and 0.36, respectively (red and pink dashed curves), with slightly higher recovery of 29.75 vs 27.32% for GT-3 and GT-5, respectively (red and pink solid curves). Comparison of the water-cut results for GT-3 and GT-5 going from 3 to 5 cm concavity at the heel shows that though the cresting intensity increased with increased concavity depth, the water breakthrough was still faster at 3 vs 5 cm concavity depth. Additionally, the pore volume to reach breakthrough and reach 80% water-cuts did not vary significantly.

Figure 6. (a) Sample GT-6 is the heterogeneous base case (permeability: 2500, 1000, 800, 300 \( \times 10^{-3} \) μm\(^2\)) with no concavity. (b) Sample GT-7 is the case of the heterogeneous model with 3 cm concavity at the high-permeability region at the toe.
the middle shows that though the cresting intensity increased with increased concavity depth, water breakthrough is still faster at 3 vs 5 cm concavity depth. Additionally, the pore volume to reach breakthrough and reach 80% water-cuts did not vary significantly.

In summary, increasing the concavity depth from 3 to 5 cm at the same location did not change the breakthrough time or recovery significantly. Additionally, the cresting index did not predict the order of breakthrough correctly going from 3 to 5 cm concavity depth from GT-2, GT-3 to GT-4 and GT-5. However, the cresting index did predict the order of breakthrough between GT-4 and GT-5 with both samples with concavity depth at 5 cm.

2.3. Effect of Heterogeneity on Water-Cresting Location and Intensity. 2.3.1. Case of Heterogeneous Cores Varying from High to Low Permeability (2500, 1000, 800, 300 × 10⁻³ μm²) from Toe to Heel. 2.3.1.1. Effect of Heterogeneity on Water-Cresting Location. In Figure 6, corefloods in heterogeneous cores varying from high permeability (2500 × 10⁻³ μm²) to low permeability (300 × 10⁻³ μm²) in equal sections from toe to heel are shown for GT-6 and GT-7, with the red depression in the illustration representing the place of concavity, the gray area the reservoir, and the blue area the aquifer element.

For the coreflood of the heterogeneous base case sample GT-6 with no concavity shown in Figure 6a-i, the breakthrough coefficient (T_w) vs core length calculated using eq 7 is plotted in Figure 6a-ii. The model-predicted breakthrough point corresponding to the maximum breakthrough coefficient (T_w,max) is shown to be at 10 cm core length. Figure 6a-iii shows the saturation profile at different pore volumes flooded with red for oil and blue for water graded by the water saturation scale at the bottom. The actual place of breakthrough according to the saturation plots in Figure 6a-iii at different pore volumes of the coreflood is at 35–55 cm region at 0.01 pore volume.

The reason for the difference between the model-predicted and actual location of breakthrough could be due to the pull of the two forces at two opposite ends. The higher drawdown at the heel and the higher permeability at the toe could be pulling the water crest to rise in their middle where these two forces reached equilibrium. Additionally, as the breakthrough coefficients for most of the core length are lower than 1, this suggests that the water front was relatively uniform; thus, the place of water breakthrough had a higher probability of randomness.

For the coreflood of the heterogeneous sample GT-7 with 3 cm concavity at the toe location shown in Figure 6b-i, the model-predicted breakthrough location corresponding to the maximum breakthrough coefficient is shown at 10 cm core length in Figure 6b-ii. The saturation profile in Figure 6b-iii shows a dark-blue water crest at 0–20 cm core length reaching the topside at 0.01 pore volume. The result for GT-7 shows that the location of water cresting predicted by the model falls tightly within the actual breakthrough location from the experiments.

2.3.1.2. Effect of Heterogeneity on Water-Cresting Intensity. To examine the effect of heterogeneity on water-cresting intensity, the recoveries and water-cuts for samples GT-6 and GT-7 are shown in Figure 7.

The cresting index calculated for the heterogeneous sample GT-6 with the effect of higher permeability at the toe and higher drawdown at the heel set in opposition is 2.84. This relatively low value suggests that the water front was rising more uniformly. The yellow dashed curve in Figure 7 corresponding to GT-6 shows that 0.02 and 0.19 pore volumes of water were injected before breakthrough and 80% water-cut was reached, respectively, resulting in a recovery efficiency of 22.76% (yellow curve in Figure 7).
The cresting index calculated for the heterogeneous sample GT-7 with a compounding effect of 3 cm concavity and higher permeability effect at the toe is 7.33, which is 2.58 times that of GT-6. This suggests that the water front was more unstable compared to GT-6 with a lower recovery. The experimental data supporting this interpretation was more mixed. The blue dashed curve in Figure 7 corresponding to GT-7 shows that 0.034 and 0.23 pore volumes of water were injected before breakthrough and 80% water-cut was reached, respectively, which is a little slower than GT-6. However, the recovery efficiency of GT-7 is slightly lesser than GT-6 at 19.3% (blue curve in Figure 7).

Comparison of the water-cut data for GT-6 and GT-7 with cresting intensities of 2.84 and 7.33, respectively, shows that the breakthrough time for GT-6 was faster at 0.02 pore volume compared to 0.034 pore volume for GT-7. Looking at the recovery data, GT-6 also has a slightly higher recovery than GT-7 up to 0.34 pore volume. Despite the difference in the cresting index, overall, comparison of the recovery and water-cut results of GT-6 and GT-7 shows that they actually look very similar. This suggests the effect of the ordering of the permeability and the magnitude of the permeability in these two samples may outweigh the importance of the presence of concavity.

2.3.2. Case of Heterogeneous Cores Varying from Low to High Permeability (300, 800, 1000, 2500 × 10⁻³ μm²) from the Toe to the Heel.

In Figure 8, corefloods in heterogeneous cores varying from low permeability (300 × 10⁻³ μm²) to high permeability (2500 × 10⁻³ μm²) in equal sections from the toe to the heel are shown for GT-8 and GT-9, with the red
depression in the illustration representing the place of concavity, the gray area the reservoir, and the blue area the aquifer element.

2.3.2.1. Effect of Heterogeneity on Water-Cresting Location. For the coreflood of the heterogeneous sample GT-8 with 3 cm concavity at the heel shown in Figure 8a-i, the breakthrough coefficient \( (T_w) \) vs core length calculated using eq 7 is plotted in Figure 8a-ii. The model-predicted breakthrough point corresponding to the maximum breakthrough coefficient \( (T_{w,\text{max}}) \) is shown to be at 70 cm core length. Figure 8a-iii shows the saturation profile at different pore volumes flooded with red for oil and blue for water graded by the water saturation scale at the bottom. The presence of a dual cresting front is visible as early as 0.01 pore volume injected, with one at 17−35 cm core length and the other at 50−70 cm core length. However, as can be seen from the greenish bands at the top of the cresting front at 17−35 cm core length, this one did not break through to the top plane of the core until after 0.1 pore volume was injected. The actual place of breakthrough happens mostly at the heel according to the saturation plots in Figure 8a-iii at the 50−70 cm region at 0.01 pore volume. The results for GT-8 show that the location of water cresting predicted by the model falls well within the wide breakthrough range from the experiments.

For the coreflood of the heterogeneous sample GT-9 with 3 cm concavity at the toe shown in Figure 8b-i, the breakthrough coefficient \( (T_w) \) vs core length calculated using eq 7 is plotted in Figure 8b-ii. The model-predicted breakthrough point corresponding to the maximum breakthrough coefficient \( (T_{w,\text{max}}) \) is shown to be at 70 cm core length. Figure 8b-iii shows the saturation profile at different pore volumes flooded with red for oil and blue for water graded by the water saturation scale at the bottom. Due to the loss of resistivity monitoring at the top node of the heel region, the top right-hand corner of the saturation profile for GT-9 is missing in Figure 8b-iii shown in white. Despite this, the presence of the dark-blue region in the remaining heel saturation plots indicates that breakthrough has happened here along with a very narrow section in the toe region. The dual cresting front as shown by the saturation profiles in Figure 8b-iii suggests that reduction in the well to water-source distance may be just as important as the presence of higher permeability zones in affecting water cresting occurrence.

2.3.2.2. Effect of Heterogeneity on Water-Cresting Intensity. To examine the effect of changing the order of heterogeneity on water-cresting intensity, the recoveries and water-cuts for samples GT-8 and GT-9 are shown in Figure 9. The cresting index calculated for the heterogeneous sample GT-8 with the compounded effect of an overlaying higher permeability effect, higher drawdown at the heel, and thinner well−aquifer distance of having a 3 cm concavity together at the heel is 16.81. This very high cresting index value suggests that the water front was rising very unevenly, resulting in fast breakthrough and low recovery. The gray dashed curve in Figure 9 corresponding to GT-8 shows that 0.015 and 0.2 pore volumes of water were injected before breakthrough and 80% water-cut was reached, respectively, resulting in a recovery efficiency of 24.22% (gray curve in Figure 9). Though the data shows that the breakthrough happened very fast, the pore volume to reach 80% water-cut took longer than expected, resulting in a recovery higher than expected.

The cresting index calculated for the heterogeneous sample GT-9 with the compounded effect of overlaying higher permeability, higher drawdown effect together at the heel countered by the effect of having a 3 cm concavity at the toe is 3.39. This relatively low value suggests that the water front was rising more evenly, resulting in a slower breakthrough and higher recovery. The black dashed curve in Figure 9

Figure 9. Recoveries and water-cuts vs pore volume injected for samples GT-8 and GT-9.
corresponding to GT-9 shows that 0.018 and 0.23 pore volumes of water were injected before breakthrough and 80% water-cut was reached, respectively, resulting in a recovery efficiency of 24.23% (black curve in Figure 9).

Comparison of the water-cut data for GT-8 and GT-9 with cresting intensities of 16.81 and 3.39, respectively, suggests that GT-8 with a bigger cresting intensity value should have a faster breakthrough. Experimentally, this was proven to be true with the breakthrough time for GT-8 being slightly faster at 0.015 pore volume compared to 0.018 pore volume for GT-9. Looking at the recovery data, GT-8 had a slightly better recovery up to 0.3 pore volume, but overall the recovery data for both look very similar. In summary, the use of the cresting index to characterize the effect of heterogeneity on the water-cresting intensity for determination of the order of breakthrough and recovery for GT-8 and GT-9 is shown to be justified.

3. SUMMARY AND DISCUSSION

As a summary of the experiments, a total of nine corefloods were done using synthetic cores to experimentally validate the prediction of the location of the water-cresting occurrence corresponding to the region with the highest breakthrough coefficient ($T_w$) introduced in this paper.

Table 1 shows a summary of the results.

As the summary of experiments in Table 1 shows, the breakthrough coefficient incorporating the parameters found to be key parameters affecting water cresting (namely, pressure gradient within the wellbore, viscosity, permeability heterogeneity, and thickness of oil columns) is proven useful in predicting seven out of nine experimental occurrences (accuracy of 78%) of water cresting in corefloods with variation of heterogeneity, heterogeneity orientation, and aquifer-to-well distance. This result gives support for the use of the breakthrough coefficient for prediction of location of water cresting in horizontal wells in a water-drive reservoir.

Figure 10 shows the plot of pore volume at breakthrough vs the cresting index. In the discussion above, the data suggest that the cresting index proved useful in predicting which sample will see the breakthrough first in similar floods. Figure 10 shows a general inverse relationship between pore volumes at breakthrough vs the cresting index ($I_{WCI}$) with a weak correlation constant of −0.30.

As usage of horizontal wells becomes evermore common in conventional and unconventional petroleum exploitation alike, the problems of overcoming/preventing water cresting in horizontal wells in water-drive reservoirs remains a significant challenge for operators to consider. The finding in this paper gives an experimentally validated method of prediction of water-cresting location for early prevention.

4. CONCLUSIONS

(1) In this paper, a method of prediction of location of water cresting and characterizing/ranking its intensity among a group of similar wells for early prevention is introduced for the first time. A mechanistic model for water cresting in a horizontal well in a water-drive reservoir is derived from Darcy’s equation incorporating viscosity, aquifer—well distance, wellbore pressure gradient, and heterogeneity as the primary variables. Based upon this model, a novel characterizing parameter called the breakthrough coefficient as a ratio of the average breakthrough time to time of breakthrough at each well segment is derived with the model-predicted location of water cresting corresponding to GT-9 shows that 0.018 and 0.23 pore volumes of water were injected before breakthrough and 80% water-cut was reached, respectively, resulting in a recovery efficiency of 24.23% (black curve in Figure 9).
Figure 11. Synthetic sandstone model for simulating water-cresting occurrence in a horizontal well: (a) horizontal well feature; (b) stainless steel pan with recess holding water maintained at pressure to simulate the bottom aquifer-drive; (c) pressure taps; (d) saturation taps.

Table 2. Experimental Overview

| model | dimension (cm) | concavity position and depth | synthetic core type | permeability (10^{-3} μm²) |
|-------|----------------|-------------------------------|---------------------|---------------------------|
| GT-1  | 5 × 10 × 80    | none                          | homogeneous         | 500                       |
| GT-2  | 5 × 10 × 80    | heel, 3 cm                    | homogeneous         | 500                       |
| GT-3  | 5 × 10 × 80    | middle, 3 cm                  | homogeneous         | 500                       |
| GT-4  | 5 × 10 × 80    | heel, 5 cm                    | homogeneous         | 500                       |
| GT-5  | 5 × 10 × 80    | middle, 5 cm                  | homogeneous         | 500                       |
| GT-6  | 5 × 10 × 80    | none                          | heterogeneous       | 2500; 1000; 800; 300      |
| GT-7  | 5 × 10 × 80    | toe, 3 cm                     | heterogeneous       | 2500; 1000; 800; 300      |
| GT-8  | 5 × 10 × 80    | heel, 3 cm                    | heterogeneous       | 300; 800; 1000; 2500      |
| GT-9  | 5 × 10 × 80    | toe, 3 cm                     | heterogeneous       | 300; 800; 1000; 2500      |

corresponding to the place of the maximum breakthrough coefficient. The cresting index, which is a ratio of the maximum to minimum breakthrough coefficient, is derived further as a characterizing parameter for the relative intensity of water cresting within a group of similar wells, with the sample with a higher cresting index theoretically having a faster breakthrough.

(2) Experimental validation of this methodology for prediction of the location of water cresting and characterization of its intensity was done through a series of nine sophisticated corefloods using synthetic sandstone modeled with horizontal well and aquifer element with saturation and pressure monitoring in real time. The results of the corefloods found the breakthrough coefficient with a prediction accuracy of 78%. However, the cresting intensity was found to be only weakly correlated to the order of breakthrough with a correlation of ~0.30.

(3) This work provides an experimentally validated theoretical model that could be used as a base case model for siting the likely location of water cresting in a horizontal well in a water-drive reservoir. This method can potentially be extended in field application for early prevention of water cresting.

5. MATERIALS AND METHODS

To test the validity of the proposed mechanistic model for prediction of water-cresting occurrence in a horizontal well, a series of nine corefloods for validation of the model proposed above were performed using a setup incorporating the use of synthetic sandstone at targeted permeability and porosity coupled to real-time pressure and saturation monitoring. The theoretical position of water-cresting locations corresponding to the largest breakthrough coefficient as calculated with eq 7 is compared against experimental saturation results in the Results and Discussion section.

5.1. Experimental Setup. 5.1.1. Physical Model. To investigate the phenomenon of water cresting in horizontal wells, a synthetic sandstone model representing the reservoir as shown in Figure 11 was devised. A ditch was dug into the top plane to simulate the horizontal well as shown in Figure 11a, and a stainless steel plate with a machined recess pocket holding the water at the bottom was used to simulate the aquifer-drive as shown in Figure 11b. The whole system was sealed in epoxy with an inlet, an outlet, a system of five pressure taps, and 21 saturation electrical resistivity taps positioned along the length of the synthetic sandstone model for real-time pressure and saturation monitoring.

Synthetic sandstone in Figure 11 was modeled after the permeability and porosity range of the Jidong oilfield in China. The synthetic sandstones were made of quartz sands bound together with inorganic minerals, pressurized at high pressure and cured at moderately high temperature. By control of particle size distribution, cementation, compression pressure, the basic porosity, and permeability characteristics of the target reservoir can be replicated in this physical model. The dimension of the synthetic sandstone models was 5 cm in width, 10 cm in height, and 80 cm in length. Synthetic sandstones used for this work were made either homogeneous or heterogeneous. Homogeneous synthetic sandstone models were made to have the same permeability and porosity. However, heterogeneous sandstones were composed of equal sections of homogeneous sandstone at different permeability and porosity cemented together in a different order. Homogeneous synthetic sandstones were made with a permeability of 500 × 10^{-3} μm² and a porosity of ~27%. Heterogeneous models were made with a permeability distribution of 2500:1000:800:300 × 10^{-3} μm² as outlined in Table 2. In this study, for simplicity, the horizontal well element shown as Figure 11a was modeled by a 70 × 0.3 cm² wide ditch carved into the center of the top plane of the synthetic sandstones. To model the effect of trajectory deviation in a horizontal well, a concavity of additional 3–5 cm depth in the horizontal well element was scored. Placements of concavities were either at the heel, the middle, or the toes of the horizontal well element to model wellbore trajectory deviation. The aquifer-drive element shown in Figure 11b was modeled by ~700 cc brine stored in the pocket machined into the stainless steel pan placed underneath the synthetic sandstone with a pump maintaining a set pressure.
The experimental setup is shown in Figure 12. For each test, the synthetic sandstone (Figure 12f) was put inside an oven (Figure 12e) set to the test temperature. The overburden pressure on the synthetic sandstone was maintained by a pump (Figure 12g). Pumps were also used for maintaining pressure of the aquifer element underneath the synthetic sandstone (Figure 12a) and for coreflooding with oil (Figure 12c)/water (Figure 12d). Effluents from the experiments were collected by the fraction collector (Figure 12h). Pressure data in real time gathered at the pressure inlet, outlet, and the five pressure taps along the synthetic sandstone were logged by a data acquisition device (Figure 12i) and sent to the computer (Figure 12j) for storage. In the figure, the symbol \( \text{\&} \) represents valves, and the lines represent stainless steel high-pressure tubing.

5.2. Experimental Overview. Different synthetic sandstones were used for different investigation targets. For the purpose of this study, the effect of concavity, placement of concavity, heterogeneity, degree of heterogeneity, and heterogeneity relative to positioning were all topics of investigation. The parameters of each tests are summarized in Table 2. The effect of concavity was investigated with variation of depth and placement of concavity from three different positionings of heel, middle, and toe of the horizontal well. The effect of heterogeneity was investigated using heterogeneous synthetic sandstone blocks of 5 \( \times \) 10 \( \times \) 80 cm\(^3\) with equal sections at different permeabilities with either higher permeability ends positioned at the heel or toe end. The effect of placement of concavity in high- vs low-permeability zones was investigated using synthetic sandstone with variation of the permeability range of 2500:1000:800:300 \( \times \) \( 10^{-3} \) \( \mu \text{m}^2\). Heterogeneous sections were cut to equal lengths and cemented together with inorganic mineral.

5.3. Experimental Procedure. The brine used in this work has salinity 1600 mg/L, with viscosity 0.9 mPa s. The oil used in this work has density 0.91 g/mL, with viscosity 90.34 mPa s. The test temperature for coreflooding was set at 75 °C. Using model GT-1 as an example, the procedure for each coreflood test consisted of the following: (1) the vacuum was pulled on the synthetic sandstone for 24 h; (2) the sample was saturated with brine from all inlets of the model at the same time, and then its porosity was determined gravimetrically and volumetrically; (3) using oil injection at 2 mL/min, the water saturation was reduced to irreducible saturation with the oil saturation determined volumetrically; (4) brine displacement of oil was done at 4 mL/min for 0.8 PV, and then the water saturation amount was determined.

For the purpose of this work, real-time pressure and fluid saturation distribution monitoring was set up. The outputs of the experiments included brine and oil production, pressure distribution data, and saturation distribution data. Five pressure taps were placed along the length of the model as shown in Figure 11. The pressure sensors were linked via a data acquisition system to a computer where the pressure data was logged in real time (Figure 12). Twenty-one electrodes with spacing distribution as shown in Figure 11 were placed along the side of the core model to collect resistivity change as a way to monitor change in fluid saturation. During displacement, saturation data in the form of measurements of raw resistivity changes was obtained and converted with the use of interpolation through a standard curve to obtain a two-dimensional (2D) saturation plot. The resultant plot shows a 2D map of the 21 saturation distribution points on the side of the core as a function of the pore volume injected. Interpolation was done to generate a continuous distribution of 2D saturation profile that is shown in the Results and Discussion section of this paper.

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Notes

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