16 Matrix Acidizing

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16.1 Introduction
Matrix acidizing is also called acid matrix treatment. It is a technique to stimulate wells for improving well inflow performance. In the treatment, acid solution is injected into the formation to dissolve some of the minerals to recover permeability of sandstones (removing skin) or increase permeability of carbonates near the wellbore. After a brief introduction to acid–rock interaction, this chapter focuses on important issues on sandstone acidizing design and carbonate acidizing design. More in-depth information can be found from Economides and Nolte (2000).

16.2 Acid–Rock Interaction
Minerals that are present in sandstone pores include montmorillonite (bentonite), kaolinite, calcite, dolomite, siderite, quartz, albite (sodium feldspar), orthoclase, and others. These minerals can be either from invasion of external fluid during drilling, cementing, and well completion or from host materials that exist in the naturally occurring rock formations. The most commonly used acids for dissolving these minerals are hydrochloric acid (HCl) and hydrofluoric acid (HF).

16.2.1 Primary Chemical Reactions
Silicate minerals such as clays and feldspars in sandstone pores are normally removed using mixtures of HF and HCl, whereas carbonate minerals are usually attacked with HCl. The chemical reactions are summarized in Table 16.1. The amount of acid required to dissolve a given amount of mineral is determined by the stoichiometry or from host materials that exist in the naturally occurring rock formations. For example, the simple reaction between HCl and CaCO₃ requires that 2 mol of HCl is needed to dissolve 1 mol of CaCO₃.

16.2.2 Dissolving Power of Acids
A more convenient way to express reaction stoichiometry is the dissolving power. The dissolving power on a mass basis is called gravimetric dissolving power and is defined as

\[ \beta = \frac{C_v \rho_m MW_m}{\rho_a MW_a}, \]  

where

- \( \beta \) = gravimetric dissolving power of acid
- \( C_v \) = weight fraction of acid in the acid solution
- \( \rho_m \) = stoichiometry number of mineral
- \( \rho_a \) = stoichiometry number of acid
- \( MW_m \) = molecular weight of mineral
- \( MW_a \) = molecular weight of acid.

For the reaction between 15 wt% HCl solution and CaCO₃, \( C_v = 0.15 \), \( \rho_m = 2 \), \( MW_m = 100.1 \), and \( MW_a = 36.5 \). Thus,

\[ \beta_{15} = \frac{(0.15)(100.1)}{(2)(36.5)} = 0.21 \text{ lbm CaCO}_3/\text{lbm 15 wt}\% \text{ HCl solution}. \]

The dissolving power on a volume basis is called volumetric dissolving power and is related to the gravimetric dissolving power through material densities:

\[ X = \beta \frac{\rho_m}{\rho_a}, \]  

where

- \( X \) = volumetric dissolving power of acid solution,
- \( \rho_a \) = density of acid, lbm/ft³
- \( \rho_m \) = density of mineral, lbm/ft³

16.2.3 Reaction Kinetics
The acid–mineral reaction takes place slowly in the rock matrix being acidized. The reaction rate can be evaluated experimentally and described by kinetics models. Research work in this area has been presented by many investigators including Fogler et al. (1976), Lund et al. (1973, 1975), Hill et al. (1981), Kline and Fogler (1981), and Schechter (1992). Generally, the reaction rate is affected by the characteristics of mineral, properties of acid, reservoir temperature, and rates of acid transport to the mineral surface and removal of product from the surface. Detailed discussion of reaction kinetics is beyond the scope of this book.

16.3 Sandstone Acidizing Design
The purpose of sandstone acidizing is to remove the damage to the sandstone near the wellbore that occurred during drilling and well completion processes. The acid treatment is only necessary when it is sure that formation damage is significant to affect well productivity. A major formation damage is usually indicated by a large positive skin factor derived from pressure transit test analysis in a flow regime of early time (see Chapter 15).

16.3.1 Selection of Acid
The acid type and acid concentration in acid solution used in acidizing is selected on the basis of minerals in the formation and field experience. For sandstones, the typical treatments usually consist of a mixture of 3 wt% HF and 12 wt% HCl, preceded by a 15 wt% HCl preflush. McLeod (1984) presented a guideline to the selection of acid on the basis of extensive field experience. His recommendations for sandstone treatments are shown in Table 16.2. McLeod’s recommendation should serve only as a starting point. When many wells are treated in a particular formation, it is worthwhile to conduct laboratory tests of the responses of cores to different acid strengths. Figure 16.1 shows typical acid–response curves.

### Table 16.1 Primary Chemical Reactions in Acid Treatments

<table>
<thead>
<tr>
<th>Mineral</th>
<th>Reaction</th>
</tr>
</thead>
<tbody>
<tr>
<td>Montmorillonite (Bentonite)-HF/HCl:</td>
<td>Al₂Si₃O₉(OH)₄ + 4HF → 2AlF₃ + 2H₂O + 4H⁺</td>
</tr>
<tr>
<td>Kaolinite-HF/HCl:</td>
<td>Al₂Si₂O₇(OH)₂ + 4HF → 2AlF₃ + 2H₂O + 4H⁺</td>
</tr>
<tr>
<td>Albite-HF/HCl:</td>
<td>NaAlSi₃O₈ + 14HF → Na⁺ + AlF₄⁻ + 3SiF₄ + 5H₂O</td>
</tr>
<tr>
<td>Orthoclase-HF/HCl:</td>
<td>KAlSi₃O₈ + 14HF → H⁺ + K⁺ + AlF₄⁻ + 6SiF₄ + 6H₂O</td>
</tr>
<tr>
<td>Quartz-HF/HCl:</td>
<td>SiO₂ + 4HF → SiF₄ + 2H₂O</td>
</tr>
<tr>
<td>Calcite-HCl:</td>
<td>CaCO₃ + 2HCl → CaCl₂ + CO₂ + H₂O</td>
</tr>
<tr>
<td>Dolomite-HCl:</td>
<td>CaMg(CO₃)₂ + 4HCl → CaCl₂ + MgCl₂ + 2CO₂ + 2H₂O</td>
</tr>
<tr>
<td>Siderite-HCl:</td>
<td>FeCO₃ + 2HCl → FeCl₂ + CO₂ + H₂O</td>
</tr>
</tbody>
</table>
16.3.2 Acid Volume Requirement

The acid volume should be high enough to remove near-wellbore formation damage and low enough to reduce cost of treatment. Selection of an optimum acid volume is complicated by the competing effects. The volume of acid needed depends strongly on the depth of the damaged zone, which is seldom known. Also, the acid will never be distributed equally to all parts of the damaged formation. The efficiency of acid treatment and, therefore, acid volume also depends on acid injection rate. To ensure that an adequate amount of acid contacts most of the damaged formation, a larger amount of acid is necessary.

The acid preflush volume is usually determined on the basis of void volume calculations. The required minimum acid volume is expressed as

\[
V_a = \frac{V_m}{\chi} + V_p + V_m, \quad (16.3)
\]

where
- \(V_a\) = the required minimum acid volume, ft\(^3\)
- \(V_m\) = volume of minerals to be removed, ft\(^3\)
- \(V_p\) = initial pore volume, ft\(^3\)

and

\[
V_m = \pi (r_a^2 - r_w^2) (1 - \phi) C_m, \quad (16.4)
\]
\[
V_p = \pi (r_w^2 - r_e^2) \phi, \quad (16.5)
\]

where
- \(r_a\) = radius of acid treatment, ft
- \(r_w\) = radius of wellbore, ft
- \(\phi\) = porosity, fraction
- \(C_m\) = mineral content, volume fraction.

**Example Problem 16.1** A sandstone with a porosity of 0.2 containing 10 v% calcite (CaCO\(_3\)) is to be acidized with HF/HCl mixture solution. A preflush of 15 wt% HCl solution is to be injected ahead of the mixture to dissolve the carbonate minerals and establish a low p\\(H\\) environment. If the HCl preflush is to remove all carbonates in a region within 1 ft beyond a 0.328-ft radius wellbore before the HF/HCl stage enters the formation, what minimum preflush volume is required in terms of gallon per foot of pay zone?

**Table 16.2** Recommended Acid Type and Strength for Sandstone Acidizing

<table>
<thead>
<tr>
<th>HCl Solubility &gt; 20%</th>
<th>Use HCl Only</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>High-perm sand (k &gt; 100 md)</strong></td>
<td></td>
</tr>
<tr>
<td>High quartz (80%), low clay (&lt;5%)</td>
<td>10% HCl-3% HF(^a)</td>
</tr>
<tr>
<td>High feldspar (&gt;20%)</td>
<td>13.5% HCl-1.5% HF(^a)</td>
</tr>
<tr>
<td>High clay (&gt;10%)</td>
<td>6.5% HCl-1% HF(^b)</td>
</tr>
<tr>
<td>High iron chloride clay</td>
<td>3% HCl-0.5% HF(^b)</td>
</tr>
</tbody>
</table>

| **Low-perm sand (k < 10 md)** | |
| Low clay (<5%) | 6% HCl-1.5% HF\(^c\) |
| High chlorite | 3% HCl-0.5% HF\(^d\) |

\(^a\) Preflush with 15% HCl.
\(^b\) Preflush with sequestered 5% HCl.
\(^c\) Preflush with 7.5% HCl or 10% acetic acid.
\(^d\) Preflush with 5% acetic acid.

**Figure 16.1** Typical acid response curves (Smith and Hendrickson, 1965).
Solution

Volume of CaCO₃ to be removed:

\[ V_m = \pi \left( r_2^2 - r_1^2 \right) \left( 1 - \phi \right) C_m = \pi \left( 1.328^2 - 0.328^2 \right) / (1 - 0.2)(0.1) \approx 0.42 \text{ft}^3 / \text{CaCO}_3 / \text{ft pay zone} \]

Initial pore volume:

\[ V_p = \pi \left( r_2^2 - r_1^2 \right) \phi = \pi \left( 1.328^2 - 0.328^2 \right) (0.2) = 1.05 \text{ft}^3 / \text{ft pay zone} \]

Gravimetric dissolving power of the 15 wt% HCl solution:

\[ \beta = C_p \frac{v_m MW_m}{v_a MW_a} = (0.15) \left( \frac{100(1.1)}{2(36.5)} \right) = 0.21 \text{lbm} / \text{CaCO}_3 / \text{lbm 15 wt\% HCl solution} \]

Volumetric dissolving power of the 15 wt% HCl solution:

\[ X = \beta \frac{p_w}{p_m} = (0.21) \left( \frac{1.07(62.4)}{169} \right) = 0.082 \text{ft}^3 / \text{CaCO}_3 / \text{ft}^3 15 \text{ wt\% HCl solution} \]

The required minimum HCl volume

\[ V_e = \frac{V_m}{X} + V_p + V_m = 0.42 \left( 0.082 + 1.05 + 0.42 \right) = 6.48 \text{ft}^3 / \text{15 wt\% HCl solution/ft pay zone} = (6.48)(7.48) = 48 \text{ gal 15 wt\% HCl solution/ft pay zone} \]

The acid volume required for the main stage in a mud acid treatment depends on mineralogy and acid type and strength. Economides and Nolte (2000) provide a listing of typical stage sequences and volumes for sandstone acidizing treatments. For HCl acid, the volume requirement increases from 50 to 200 gal/ft pay zone with HCl solubility of HF changing from less than 5% to 20%. For HF acid, the volume requirement is in the range of 75–100 gal/ft pay zone with 3.0–13.5% HCl and 0.5–3.0% HF depending on mineralogy.

Numerous efforts have been made to develop a rigorous method for calculating the minimum required acid volume in the past 2 decades. The most commonly used method is the two-mineral model (Hekim et al., 1982; Hill et al., 1981; Taha et al., 1989). This model requires a numerical technique to obtain a general solution. Schecter (1992) presented an approximate solution that is valid for Damköhler number being greater than 10. This solution approximates the HF fast-reacting mineral front as a sharp front. Readers are referred to Schecter (1992) for more information.

Because mud acid treatments do not dissolve much of the formation minerals but dissolve the materials clogging the pore throats, Economides and Nolte (2000) suggest taking the initial pour volume (Eq. [16.5]) within the radius of treatment as the minimum required acid volume for the main stage of acidizing treatment. Additional acid volume should be considered for the losses in the injection tubing string.

16.3.3 Acid Injection Rate

Acid injection rate should be selected on the basis of mineral dissolution and removal and depth of damaged zone. Selecting an optimum injection rate is a difficult process because the damaged zone is seldom known with any accuracy and the competing effects of mineral dissolution and reaction product precipitation. Fortunately, research results have shown that acidizing efficiency is relatively insensitive to acid injection rate and that the highest rate possible yields the best results. McLeod (1984) recommends relatively low injection rates based on the observation that acid contact time with the formation of 2–4 hours appears to give good results. da Motta (1993) shows that with shallow damage, acid injection rate has little effect on the residual skin after 100 gal/ft of injection rate; and with deeper damage, the higher the injection rate, the lower the residual skin. Paccaloni et al. (1988) and Paccaloni and Tambini (1990) also report high success rates in numerous field treatments using the highest injection rates possible.

There is always an upper limit on the acid injection rate that is imposed by formation breakdown (fracture) pressure \( p_{bd} \). Assuming pseudo-steady-state flow, the maximum injection rate limited by the breakdown pressure is expressed as

\[ q_{i,\text{max}} = 4.917 \times 10^{-6} \left( \frac{kh}{\mu_\text{s}} \right) \left( \frac{p_{bd} - p - \Delta p_f}{\mu_\text{s}} \right) \ln \left( \frac{2r_w}{r_e} + S \right). \]

where

- \( q_i \) = maximum injection rate, bbl/min
- \( k \) = permeability of undamaged formation, md
- \( h \) = thickness of pay zone to be treated, ft
- \( p_{bd} \) = formation breakdown pressure, psia
- \( p \) = reservoir pressure, psia
- \( \Delta p_f \) = safety margin, 200 to 500 psi
- \( \mu_s \) = viscosity of acid solution, cp
- \( r_w \) = wellbore radius, ft
- \( r_e \) = drainage radius, ft
- \( S \) = skin factor, ft

The acid injection rate can also be limited by surface injection pressure at the pump available to the treatment. This effect is described in the next section.

16.3.4 Acid Injection Pressure

In most acid treatment operations, only the surface tubing pressure is monitored. It is necessary to predict the surface injection pressure at the design stage for pump selection. The surface tubing pressure is related to the bottom-hole flowing pressure by

\[ p_u = p_{bf} - \Delta p_b + \Delta p_f, \]

where

- \( p_u \) = surface injection pressure, psia
- \( p_{bf} \) = flowing bottom-hole pressure, psia
- \( \Delta p_b \) = hydrostatic pressure drop, psia
- \( \Delta p_f \) = frictional pressure drop, psia.

The second and the third term in the right-hand side of Eq. (16.7) can be calculated using Eq. (11.93). However, to avert the procedure of friction factor determination, the following approximation may be used for the frictional pressure drop calculation (Economides and Nolte, 2000):

\[ \Delta p_f = \frac{51.8 \rho^{0.79} q^{0.79} \mu^{0.207}}{1000 D^{1.97}} L, \]

where

- \( \rho \) = density of fluid, g/cm³
- \( q \) = injection rate, bbl/min
- \( \mu \) = fluid viscosity, cp
- \( D \) = tubing diameter, in.
- \( L \) = tubing length, ft.

Equation (16.8) is relatively accurate for estimating frictional pressures for newtonian fluids at flow rates less than 9 bbl/min.
Example Problem 16.2 A 60-ft thick, 50-md sandstone pay zone at a depth of 9,500 ft is to be acidized with an acid solution having a specified gravity of 1.07 and a viscosity of 1.5 cp down a 2-in. inside diameter (ID) coil tubing. The formation fracture gradient is 0.7 psi/ft. The wellbore radius is 0.328 ft. Assuming a reservoir pressure of 4,000 psia, drainage area radius of 1,000 ft, and a skin factor of 15, calculate
(a) the maximum acid injection rate using safety margin 300 psi.
(b) the maximum expected surface injection pressure at the maximum injection rate.

Solution
(a) The maximum acid injection rate:

\[
q_{h, \text{max}} = \frac{4.917 \times 10^{-6} k h (p_{\text{inj}} \cdot f - \Delta p_f)}{\mu_s \left[ \ln \left( \frac{0.472 p_{\text{inj}} + S}{p_w} \right) \right]} = \frac{4.917 \times 10^{-6} (50)(9,500) \cdot (0.7)(9,500) - 4,000 - 300}{(1.5)(10,000)(0.328) + 15} = 1.04 \text{ bbl/min}
\]

(b) The maximum expected surface injection pressure:

\[
p_w = p_{\text{inj}} - \Delta p_f = (0.7)(9,500) - 300 = 6,350 \text{ psia} \]

\[
\Delta p_f = 518(0.7)^{0.79} (1.04)^{1.79(1.5)^{0.207}} = \frac{518}{1.04(2)^{1.79}}(9,500) = 218 \text{ psi} 
\]

\[
p_{\text{inj}} = p_w + \Delta p_f = 6,350 - 4,401 + 218 = 2,167 \text{ psia}
\]

16.4 Carbonate Acidizing Design

The purpose of carbonate acidizing is not to remove the damage to the formation near the wellbore, but to create wormholes through which oil or gas will flow after stimulation. Figure 16.2 shows wormholes created by acid dissolution of limestone in a laboratory (Hoefner and Fogler, 1988). Carbonate acidizing is a more difficult process to predict than sandstone acidizing because the physics is much more complex. Because the surface reaction rates are very high and mass transfer often plays the role of limiting step locally, highly nonuniform dissolution patterns are usually created. The structure of the wormholes depends on many factors including flow geometry, injection rate, reaction kinetics, and mass transfer rates. Acidizing design relies on mathematical models calibrated by laboratory data.

16.4.1 Selection of Acid

HCl is the most widely used acid for carbonate matrix acidizing. Weak acids are suggested for perforating fluid and perforation cleanup, and strong acids are recommended for other treatments. Table 16.3 lists recommended acid type and strength for carbonate acidizing (McLeod, 1984). All theoretical models of wormhole propagation predict deeper penetration for higher acid strengths, so a high concentration of acid is always preferable.

16.4.2 Acidizing Parameters

Acidizing parameters include acid volume, injection rate, and injection pressure. The acid volume can be calculated with two methods: (1) Daccord’s wormhole propagation model and (2) the volumetric model, on the basis of desired penetration of wormholes. The former is optimistic, whereas the latter is more realistic (Economides et al., 1994).

Based on the wormhole propagation model presented by Daccord et al. (1989), the required acid volume per unit thickness of formation can be estimated using the following equation:

\[
Y_h = \frac{\pi \phi D^{2/3} h}{b N_{ac}}
\]

where

\[
V_h = \text{required acid volume per unit thickness of formation, m}^3/m \\
\phi = \text{porosity, fraction} \\
D = \text{molecular diffusion coefficient, m}^2/s \\
q_h = \text{injection rate per unit thickness of formation, m}^3/sec-m \\
r_{wh} = \text{desired radius of wormhole penetration, m} \\
d_f = \text{1.6, fractal dimension} \\
b = 105 \times 10^{-3} \text{ in SI units} \\
N_{ac} = \text{acid capillary number, dimensionless,}
\]

where the acid capillary number is defined as

\[
N_{ac} = \frac{\phi \beta r_{wh}}{(1 - \phi) s_{wh} (b N_{ac})}.
\]

Table 16.3 Recommended Acid Type and Strength for Carbonate Acidizing

<table>
<thead>
<tr>
<th>Perforating fluid:</th>
<th>5% acetic acid</th>
</tr>
</thead>
<tbody>
<tr>
<td>Damaged perforations:</td>
<td>9% formic acid</td>
</tr>
<tr>
<td>10% acetic acid</td>
<td>15% HCl</td>
</tr>
<tr>
<td>Deep wellbore damage:</td>
<td>15% HCl</td>
</tr>
<tr>
<td>28% HCl</td>
<td>Emulsified HCl</td>
</tr>
</tbody>
</table>
where

\[ y_m = \text{acid specific gravity, water} = 1.0 \]
\[ y_m = \text{mineral specific gravity, water} = 1.0. \]

Based on the volumetric model, the required acid volume per unit thickness of formation can be estimated using the following equation:

\[ V_s = \pi\phi\left(r_0^2 - r_f^2\right)(PV)_{th}, \quad (16.11) \]

where \((PV)_{th}\) is the number of pore volumes of acid injected at the time of wormhole breakthrough at the end of the core. Apparently, the volumetric model requires data from laboratory tests.

**Example Problem 16.3** A 28 wt% HCl is needed to propagate wormholes 3 ft from a 0.328-ft radius wellbore in a limestone formation (specific gravity 2.71) with a porosity of 0.15. The designed injection rate is 0.1 bbl/min-ft, the diffusion coefficient is \(10^{-9}\) m²/sec, and the density of the 28% HCl is 1.14 g/cm³. In linear core floods, 1.5 pore volume is needed for wormhole breakthrough at the end of the core. Calculate the acid volume requirement using (a) Daccord’s model and (b) the volumetric model.

**Solution**

(a) Daccord’s model:

\[ \beta = C_0 \frac{v_m MH}{v_w MH} = (0.28)\frac{1}{(100.1)} \frac{(14)}{(36.5)} \]
\[ = 0.3836lbm CaCO_3/lbm 28 wt% HCl solution. \]
\[ N_{ac} = \frac{\phi\gamma_m}{(1 - \phi)\gamma_w} = \frac{0.15}{0.3836}(1.14) \]
\[ = 0.0285 \]
\[ q_s = 0.1 \text{ bbl/min-ft} = 8.69 \times 10^{-4} \text{ m}^3/\text{sec-m} \]
\[ r_{th} = 0.328 + 3 = 3.328 \text{ ft} = 1.01 \text{ m} \]
\[ V_s = \frac{\pi\phi D_{2D} q_s^2}{b} \]
\[ = \frac{\pi(0.15)(10^{-9})^{1/2}(8.69 \times 10^{-4})^{1/2}(1.01)^{1/2}}{(1.5 \times 10^{-9})(0.0285)} \]
\[ = 0.107 \text{ m}^3/\text{m} = 8.6 \text{ gal/ft}. \]

(b) Volumetric model:

\[ V_s = \pi\phi\left(r_0^2 - r_f^2\right)(PV)_{th}, \]
\[ = \pi(0.15)(3.328^2 - 0.328^2)(1.5) \]
\[ = 7.75 \text{ ft}^3/\text{ft} = 58 \text{ gal/ft}. \]

This example shows that the Daccord model gives optimistic results and the volumetric model gives more realistic results.

The designed acid volume and injection rate should be adjusted based on the real-time monitoring of pressure during the treatment.

**Summary**

This chapter briefly presents chemistry of matrix acidizing and a guideline to acidizing design for both sandstone and carbonate formations. More in-depth materials can be found in McLeod (1984), Economides et al. (1994), and Economides and Nolte (2000).

**References**


PACCALONI, G., TAMBINI, M., and GALOPPINI, M. Key factors for enhanced results of matrix stimulation treatment. Presented at the SPE Formation Damage Control Symposium held in Bakersfield, California on February 8–9, 1988, SPE Paper 17154.


Problems

16.1 For the reaction between 20 wt% HCl solution and calcite, calculate the gravimetric and volumetric dissolving power of the acid solution.

16.2 For the reaction between 20 wt% HCl solution and dolomite, calculate the gravimetric and volumetric dissolving power of the acid solution.

16.3 A sandstone with a porosity of 0.18 containing 8 v% calcite is to be acidized with HF/HCl mixture solution. A preflush of 15 wt% HCl solution is to be injected ahead of the mixture to dissolve the carbonate minerals and establish a low-pH environment. If the HCl preflush is to remove all carbonates in a region within 1.5 ft beyond a 0.328-ft-radius wellbore before the HF/HCl stage enters the formation, what minimum preflush volume is required in terms of gallon per foot of pay zone?

16.4 A sandstone with a porosity of 0.15 containing 12 v% dolomite is to be acidized with HF/HCl mixture solution. A preflush of 15 wt% HCl solution is to be injected ahead of the mixture to dissolve the carbonate minerals and establish a low-pH environment. If the HCl preflush is to remove all carbonates in a region within 1.2 feet beyond a 0.328-ft-radius wellbore before the HF/HCl stage enters the formation, what minimum preflush volume is required in terms of gallon per foot of pay zone?

16.5 A 30-ft thick, 40-md sandstone pay zone at a depth of 9,000 ft is to be acidized with an acid solution having a specific gravity of 1.07 and a viscosity of 1.2 cp down a 2-in. ID coil tubing. The formation fracture gradient is 0.7 psi/ft. The wellbore radius is 0.328 ft. Assuming a reservoir pressure of 3,500 psia, drainage area radius of 1,200 ft, and skin factor of 15, calculate

(a) the maximum acid injection rate using safety margin 200 psi.
(b) the maximum expected surface injection pressure at the maximum injection rate.

16.6 A 40-ft thick, 20-md sandstone pay zone at a depth of 8,000 ft is to be acidized with an acid solution having a specific gravity of 1.07 and a viscosity of 1.5 cp down a 2-in. ID coil tubing. The formation fracture gradient is 0.65 psi/ft. The wellbore radius is 0.328 ft. Assuming a reservoir pressure of 3,500 psia, drainage area radius of 1,200 ft, and skin factor of 15, calculate

(a) the maximum acid injection rate using a safety margin of 400 psi.
(b) the maximum expected surface injection pressure at the maximum injection rate.

16.7 A 20 wt% HCl is needed to propagate wormholes 2 ft from a 0.328-ft radius wellbore in a limestone formation (specific gravity 2.71) with a porosity of 0.12. The designed injection rate is 0.12 bbl/min-ft, the diffusion coefficient is $10^{-9}$ m$^2$/sec, and the density of the 20% HCl is 1.11 g/cm$^3$. In linear core floods, 1.2 pore volume is needed for wormhole breakthrough at the end of the core. Calculate the acid volume requirement using (a) Daccord’s model and (b) the volumetric model.

16.8 A 25 wt% HCl is needed to propagate wormholes 3 ft from a 0.328-ft radius wellbore in a dolomite formation (specific gravity 2.87) with a porosity of 0.16. The designed injection rate is 0.15 bbl/min-ft, the diffusion coefficient is $10^{-9}$ m$^2$/sec, and the density of the 25% HCl is 1.15 g/cm$^3$. In linear core floods, 4 pore volumes is needed for wormhole breakthrough at the end of the core. Calculate the acid volume requirement using (a) Daccord’s model and (b) the volumetric model.