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Geological Factors Affecting CO_2 Plume Distribution

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Abstract

Understanding the lateral extent of a CO_2 plume has important implications with regards to buying/leasing pore volume rights, defining the area of review for an injection permit, determining the extent of an MMV plan, and managing basin-scale sequestration from multiple injection sites. The vertical and lateral distribution of CO_2 has implications with regards to estimating CO_2 storage volume at a specific site and the pore pressure below the caprock.

Geologic and flow characteristics such as effective permeability and porosity, capillary pressure, lateral and vertical permeability anisotropy, geologic structure, and thickness all influence and affect the plume distribution to varying degrees. Depending on the variations in these parameters one may dominate the shape and size of the plume. Additionally, these parameters do not necessarily act independently.

A comparison of viscous and gravity forces will determine the degree of vertical and lateral flow. However, this is dependent on formation thickness. For example in a thick zone with injection near the base, the CO_2 moves radially from the well but will slow at greater radii and vertical movement will dominate. Generally the CO_2 plume will not appreciably move laterally until the caprock or a relatively low permeability interval is contacted by the CO_2. Conversely, in a relatively thin zone with the injection interval over nearly the entire zone, near the wellbore the CO_2 will be distributed over the entire vertical thickness and will move laterally much further with minimal vertical segregation. Assuming no geologic structure, injecting into a thin zone or into a thick zone immediately under a caprock will result in a larger plume size.

With a geologic structure such as an anticline, the CO_2 plume size may be restricted and injection immediately below the caprock may have less lateral plume growth because the structure will induce downward vertical movement of the CO_2 until the outer edge of the plume reaches a spill point within the structure.

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1. Introduction

Displacement processes caused by fluid injection have been studied in the petroleum industry for decades. The earliest reported designed waterflood of an oil reservoir was in 1924 (Craig, 1993). The early literature is dominated by water displacing oil. Other fluids such as CO_2, rich and lean gas, polymer and surfactant injection have been studied in more detail over the last three to four decades. Displacement efficiency is one the most important and heavily researched topics in reservoir engineering because it is directly related to increasing oil recovery. The

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displacement efficiency is the product of microscopic and macroscopic displacement efficiency. For CO_2 sequestration, this product has been called the **storage efficiency** (USDOE, 2006, 2008).

Macroscopic or volumetric displacement efficiency is the fraction of the effective pore volume that the injected fluid contacts. Microscopic displacement efficiency is the fraction of the in situ fluid displaced by the injection fluid from within the **contacted fraction** of the effective pore volume.

Volumetric displacement efficiency (E_v) is predominantly a function of geologic heterogeneity (e.g. vertical and lateral permeability anisotropy) and gravity segregation between the CO_2 and water. An E_V of 100% implies that the entire defined effective pore volume is contacted with CO_2, but does not mean all of the water is displaced from this pore volume. The fraction of the water displaced by CO_2 is the microscopic displacement and is determined by the irreducible water saturation in the presence of CO_2.

In general for a given injection volume, a relatively lower volumetric displacement efficiency reflects a larger areal plume extent, and a relatively higher volumetric displacement efficiency reflects a smaller areal plume extent (Figure 1). The assumption is that a less efficient storage process yields a larger plume size that bypasses effective pore space and creates a larger plume extent.

2. Geologic and Rock Properties

In order to make a comparison between relative plume extent and various geologic features and rock properties, a constant injection volume and injection pressure are necessary. Also common to most all of the descriptions below is that no attempt was made to define “plume” as some maximum saturation of the pore volume or saturated thickness, which for MMV, regulatory and ownership purposes should be done. The relative comparisons made are finite differences without reference to the magnitude of the difference. In all context unless otherwise stated, CO_2 is the displacing fluid and brine is the displaced fluid.

2.1. Mobility and viscosity ratio

The mobility ratio (M) is defined as the mobility of the displacing fluid divided by the mobility of the displaced fluid. Mobility (λ) is the ratio of the relative permeability (k_r) of a fluid to its viscosity (μ). For CO_2 and water the mobility formula appears as follows:

$$M = \lambda_{co2}/\ \lambda_w = (k_{rco2}/\mu_{co2})/(k_{rw}/\mu_w)$$

A special case of the mobility ratio is if the displacing and displaced fluids are miscible or soluble (if capillary pressure between phases is zero or near zero). In this case, these relative permeabilities are equal or nearly equal, and the mobility ratio is equal to the ratio of the fluids’ viscosity (viscosity ratio).

$$M = \mu_w\,/\mu_{co2}$$

Mobility ratio is directly related to the relative velocity of each fluid. When the velocity of the displacing fluid is greater than the velocity of the displaced fluid, very small scale flow perturbations start and initiate viscous fingers. This displacement process is less efficient compared to a case where the displaced fluid velocity is greater than the displacing fluid velocity. Consequently, a lower mobility ratio has greater displacement efficiency compared to a higher mobility ratio. For mobility less than one, the displacement fluid’s velocity is less than the displaced fluid’s velocity. For mobility greater than one, the displacement fluid velocity is greater than the displaced fluid’s velocity. A mobility of one represents equal velocity of the displaced and displacing fluids.

For CO_2 and brine, viscosity can only change based on pressure, temperature and water salinity. Water viscosity is much less a function of pressure compared to CO_2 viscosity over the pressure ranges most likely to occur in geologic sequestration. Over a range of temperature and pressure likely in geologic sequestration, CO_2 viscosity may be 0.06 to 0.07 cp, while, depending on salinity, viscosity of brine water may be 0.5 to 1.0. Assuming that these relative permeabilities are similar magnitude, the mobility ratio would be 10 to 15, which represents a relatively inefficient displacement process.

For relatively higher brine salinity and increased viscosity, the plume size would be larger and storage of CO_2 less efficient. With depth and increased temperature and pressure, the viscosity difference mobility ratio may be slightly lower; however, it depends strongly on the temperature and pressure of the injection zone and the salinity of the brine.

To determine the relative permeability used in the calculation of mobility, each fluid's respective saturation is needed. Consequently, there are multiple definitions of mobility ratio in the literature (Green and Willhite, 1998). Relative permeability in this ratio for piston-like displacement or nearly piston-like displacement (when only CO_2 moves behind the CO_2-brine water interface*) can be defined as the end points of the relative permeability curve. For CO_2 this would be the maximum relative permeability at the irreducible water saturation, and for brine water it would be the maximum relative permeability at the irreducible CO_2 saturation. If CO_2 and water are both mobile behind the CO_2-brine water interface, the mobility ratio is defined at a specific brine water or CO_2 saturation and the relative permeability of each fluid is used at that saturation to define the mobility ratio. However, the endpoint ratios are a good means of comparing different sites and a basis for a more generally applicable correlation.

Using Bennion and Bachu's drainage relative permeability end-point data (2006) for CO2-brine systems and the viscosity ratio above, the mobility ratio is between 1 and 5, primarily because the relative permeability to CO2 at irreducible water saturation is relatively low. (Their relative permeability data was normalized to the absolute permeability of water at 100% water saturation where the relative permeability to water is one.) Including the relative permeability in the mobility ratio calculation, reflects a relatively efficient process.

2.2. Effective permeability

In a homogenous, isotropic formation, injection into a wellbore completely penetrating and perforated over the entire vertical height of the formation yields radial flow geometry and an exponential pressure decrease around the well. The lateral extent of a plume is directly related to the horizontal and vertical pressure gradients. The horizontal pressure gradient is due to radial flow, while the vertical pressure gradient is a consequence of the difference in CO_2 and brine density. For this discussion, the permeability is isotropic laterally and vertically, but vertical permeability is much less than lateral permeability.

In general, the horizontal velocity of CO_2 decreases with distance from the injection well as the pressure gradient decreases. The vertical velocity of CO_2 is a constant (assuming constant vertical perm and a specific depth) due to density difference only. At some radius from the well the horizontal and vertical CO_2 velocity will be of similar magnitude and a more noticeable and substantial volume of CO_2 will move upward. At a greater radius the horizontal pressure gradient will decrease below the vertical pressure gradient, and most all of the CO_2 will move vertically. For very thick intervals with lower volumes of CO_2, the plume area will be nearly the distance to this radius of equal velocity. Only when the CO_2 reaches the confining interval will the plume area again grow in size.

Sandstones commonly occur as blocky (channels), upward coarsening (barrier bars) and upward fining (point bars) sand bodies. The blocky type sandstone bodies would not have vertical changes in effective permeability; however, the amount of CO_2 that could by injected into an upward fining sandstone body would be greater than upward coarsening. The reason is that the best porosity and permeability in an upward fining would be in the lowermost part of the sandstone body. If the injection well was completed in the lowermost portion of a upward fining sand, the lateral extend of theCO_2 would be greater in the lower portion and, because of buoyancy, move up into the lower quality reservoir rock. Upward coarsening sandstone bodies would have the best quality reservoir (injection zone) in the uppermost part and the lowermost part would not be as effective for sequestration. Examples of fining upward sandstones are the point bar reservoirs of the Frio Formation in the Upper Texas Gulf Coast Basin and fluvial parts of the Middle Pennsylvanian-Lower Mississippian (Pottsville-Weir Sandstones) of the Appalachian Basin.

It is difficult to separate the affects of vertical and lateral permeability on plume size, so the plume size discussion will be developed using the ratio of vertical to horizontal permeability (k_v/k_h). To understand this a few extreme cases can be considered. A lower ratio of k_v/k_h will result in a larger horizontal pressure gradient extending further into the injection interval, and the plume area will be larger. For higher k_v/k_h ratios, a lesser horizontal pressure gradient extends into the formation, and the plume area will be smaller as more CO_2 will move upward. Again, no additional growth in plume area occurs until the confining layer is reached.

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*The interface is also referred to as the CO_2 front.

2.2 Effective porosity

Generally porosity is not considered to have much influence on plume size because it not considered a flow property; however, it is a storage property and plume size (volume) is directly related to porosity. For a given permeability, if porosity increases more pore volume is present within a smaller radius, compared to lower porosity. Plume area is smaller for larger porosity and is larger for lower porosity, for a given permeability and injection volume.

2.3 Net thickness

Net thickness is the portion of the gross thickness that has porosity and permeability adequate for a specific fluid to pass through it. Generally a threshold absolute permeability is used to define net thickness from gross thickness. For example, if a 100 ft gross interval exists and upon injection, CO_2 entered all of the intervals to varying degrees, the net interval would be 100 ft. For a given volume of CO_2 that is distributed evenly over the thickness of the injection zone, a relatively larger thickness will have a smaller plume area. This negates any segregation which is likely to happen in thicker intervals.

If however the net thickness was less than the gross thickness, then the target reservoir is somewhat compartmentalized. This compartmentalization could be caused by changes in depositional facies or diagenetic changes. For example, multiple carbonate cemented intervals in a sandstone could cause the net to gross thickness ratio to change. These types of cementations could have been caused by thin bioclastic layers that were dissolved and subsequently precipitated as cements. Examples of geologic units that have net thickness dramatically less than the gross thickness are the San Andres-Grayburg Formations of the Permian Basin where facies controlled stratification is significant.

2.4 Vertical heterogeneity (layering effect)

Variations in the horizontal permeability and vertical permeability by subintervals within the injection zone can dramatically affect the plume size. Relatively lower vertical permeability zones reduce the vertical velocity of CO_2 through it, and an increase or buildup of CO_2 volume (saturation) occurs below these intervals. The buildup in saturation increases, and the lateral growth of the CO_2 immediately below this interval increases. The k_v/k_h ratio, thickness and areal extent of the relatively lower permeability zone will determine the rate of growth of the CO_2 plume beneath it. In most cases, the permeability difference needs to be nearly two orders of magnitude to have a substantial effect. If the sub-interval is truly impermeable (e.g. a thin shale), CO_2 will build up and move laterally underneath this interval similar to CO_2 moving laterally underneath a confining layer. The plume area will continue to grow until there is a break in the shale. Depending on the distribution of this shale, the CO_2 plume will grow vertically, but will be unsymmetrical with respect to the wellbore and may continue to grow at some distance away from the upper part of the wellbore.

A statistical representation of vertical layers assuming negligible vertical flow is the permeability variance. The Lorenz and Dykstra-Parsons coefficients are examples of the permeability variance. These methods were developed in the oil industry to use in estimating waterflood performance in layered reservoirs. A similar development can be made for sequestration to estimate storage efficiency and plume size (figure 2).

The lateral extent of these shale layers can be estimated if the depositional environment is identified. Shale layers deposited in a marine system will have a lateral extent significantly greater than 610 meters (2000 feet) (Zeito 1965). In fact some thin shale bodies deposited in a transgressive maximum flooding surface can extend across most of a sedimentary basin. In contrast, the lateral extent of shales in a floodplain is less than 305 meters (1000 feet) long (Weber 1982; Zeito 1965). In marine systems it is possible to have multiple seals with their own sequestration system. Depending on how transmissive the shale is to CO_2, it is possible to have numerous seals for inhibiting the vertical movement of CO_2 and developing multiple sequestration systems. This could significantly increase the amount of CO_2 that could be sequestered in reservoirs deposited in marine deposition environments. Whereas, in fluvial systems, the reservoirs would be all interconnected and the CO_2 would continue to migrate vertically until it encountered a continuous seal such as a maximum flooding surface.

Examples of marine shale systems are the Anahuac Shale of the Texas Gulf Coast, the New Alban Shale of the Illinois Basin and Marcos Shale of the Piceance Basin (Colorado).

If the perforated interval is low in the injection zone, the layering effect can increase storage efficiency substantially, but may increase the area/extent of some portion of the plume much more than if the layering effect was negligible.

2.5 Lateral heterogeneity

Anisotropic horizontal permeability leads to an irregular CO_2 front as CO_2 grows in the relatively higher permeability portions of the formation. These types of anisotropic permeability variations are completely due to the depositional environment. Permeability anisotropy will cause the plume area to be much larger in one direction compared to an isotropic horizontal permeability, and will lead to an asymmetrical plume shape.

The lateral plume migration is controlled not only by the lateral extent of the shales, but also by the anisotropy of the permeability and porosity. For example, in many siliciclastic systems the reservoir facies has a depositional strike that is significantly greater in one direction versus the other direction. Such systems could include barrier islands and various channel deposits. Injecting CO_2 into a barrier island sandstone could result in the CO_2 migrating along the strike of the channel that could cause the CO_2 plume to migrate multiple kilometers in an updip direction and be less than a kilometer in width.

Weber and van Geuns's 1990 classification system on reservoir heterogeneity can be used to understand the potential for lateral and vertical migration of the CO_2 plume. Those depositional systems with poor reservoir continuity, such as individual sandstone bodies in braided river deposits would not be laterally extensive. In a cross section, reservoir sandstones may appear to be isolated but there probably are some interconnections from the erosion of one sandstone channel (channel) into another channel.

Examples of barrier island systems are the Frio Formation of the Central Texas Gulf Coast Basin and the Almond Formation of the Greater Green River Basin (Wyoming); examples of braided river deposits include much of the Ivishak sandstone of Prudhoe Bay Field (Alaska) and the Lower Manville Group in the Alberta Basin.

2.6 Geologic structure

Injection under a geologic structure such as an anticline or dome may reduce the lateral movement of CO_2 regardless of other features discussed. CO_2 injection immediately below a confining interval (assuming adequate vertical permeability) will tend to fill the area under the structure with CO_2 and move the plume downward while it grows horizontally. This lateral growth will continue to be limited and storage efficiency maximized until the CO_2 reaches the spill point of the geologic structure and moves beyond the limits of the structure. Depending on the geologic feature outside of the structure, the plume area is likely to grow dramatically as CO_2 moves beyond and outside of the structure.

An ideal combination of layering effects deep in a thick formation underneath a geologic structure will lead to a small plume size and high storage efficiency.

3. Grouping Properties

Because of the relative effects of changing rock and fluid properties, grouping similar properties into families of terms reduces the number of variations or combinations of rock and fluid properties necessary to understand displacement processes (Green and Willhite, 1998). As an example, viscous and capillary terms can be grouped to improve understanding of microscopic displacement. Additionally, viscous and gravity terms can be combined to understand gravitational component to macroscopic storage efficiency. Different combinations of properties into different groups of terms are possible and should be tested for CO_2 and brine in the laboratory and through modeling. The following is not intended to be the only combination of terms that could best represent CO_2-brine displacement but is intended to show how useful these relationships can be in designing sites with regards to plume size and storage efficiency.

3.1. Viscous and capillary forces

As an example, viscous forces (F_v) can be represented by the interstitial velocity (v) and viscosity of CO_2, and the capillary forces (F_c) represented by the surface tension between CO_2 and brine (σ_{co2-w}). The ratio of these two is called the capillary number (N_{ca}):

$$N_{ca} = (v\ \mu_{co2}) / \sigma_{co2-w}$$

For water-displacing-oil processes, water is assumed to be the wetting phase, and the capillary number correlates with the microscopic displacement of oil, which basically predicts the residual oil saturation. Oil-water correlations show that dramatic reduction in residual oil saturation (non-wetting fluid) occurs as the capillary number increases. This can be used to approximate the microscopic displacement efficiency and with assumptions on the flow geometry, the plume size can be inferred.

For water displacing oil, the displaced fluid (oil) is the non-wetting fluid. For CO_2 displacing brine, the displaced phase is the wetting phase. So a direct correlation of the capillary number to the irreducible water saturation may not be as strong because it is the wetting phase. However, as a design tool to estimate the microscopic storage efficiency, a similar trend is likely. Laboratory experiments designed to collect this type of information would be worthwhile to have a correlation that would predict the irreducible water saturation (microscopic displacement efficiency, E_d), which would lead to conclusions regarding the plume area and storage resource (figure 3).

3.2. Viscous and gravity forces

A comparison of viscous and gravity forces can be useful to understand a component of vertical storage efficiency due to gravity (not layering). Viscous forces are represented by the interstitial velocity, horizontal permeability and viscosity of the displaced phase. Gravity forces are represented by the difference in density between the two fluids ($\Delta\rho$). Because the thickness (h) is relevant to the gravity term, a length (L) component is also used in the viscous term. The ratio of viscous to gravity forces ($R_{v/g}$) is below:

$$R_{v/g} = ((v\ \mu_{co2}) / (k\ \Delta\rho))\ (L/h)$$

The viscous/gravity forces ratio correlates with the gravity vertical storage efficiency, E_g. As the ratio increases, the vertical storage efficiency increases. As the vertical storage efficiency increases, the plume size decreases (figure 4) because CO_2 moves more uniformly and contacts more of the formation without CO_2 growing vertically and laterally under the caprock (gravity override). These parameters can be studied individually to understand relative effects of each. For example, a larger difference in density lowers the storage efficiency and reduces the plume size.

4. Conclusions

Generalizations can be made on plume area based on geologic depositional environment and rock properties using correlations in the oil industry. CO_2 and brine water specific correlations can be built using laboratory data, field data and modeling. Tools like these should be used during the site screening process and to verify numerical simulation model results. In general less efficient storage processes have larger plume areas.

5. References

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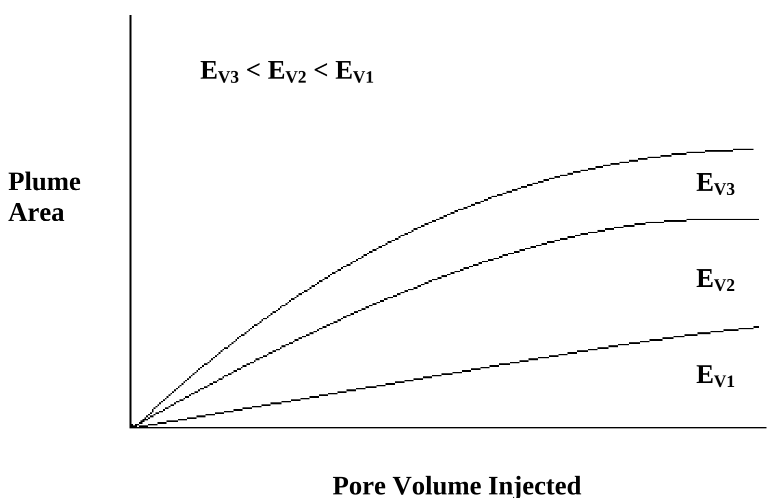

Figure 1: Relationship between volumetric storage efficiency (E_V) and plume area. For a given pore volume of injected volume of CO2, the greater fraction of the pore volume filled with CO2 the lesser the area of the plume. Higher storage efficiency provides a reduced plume area.

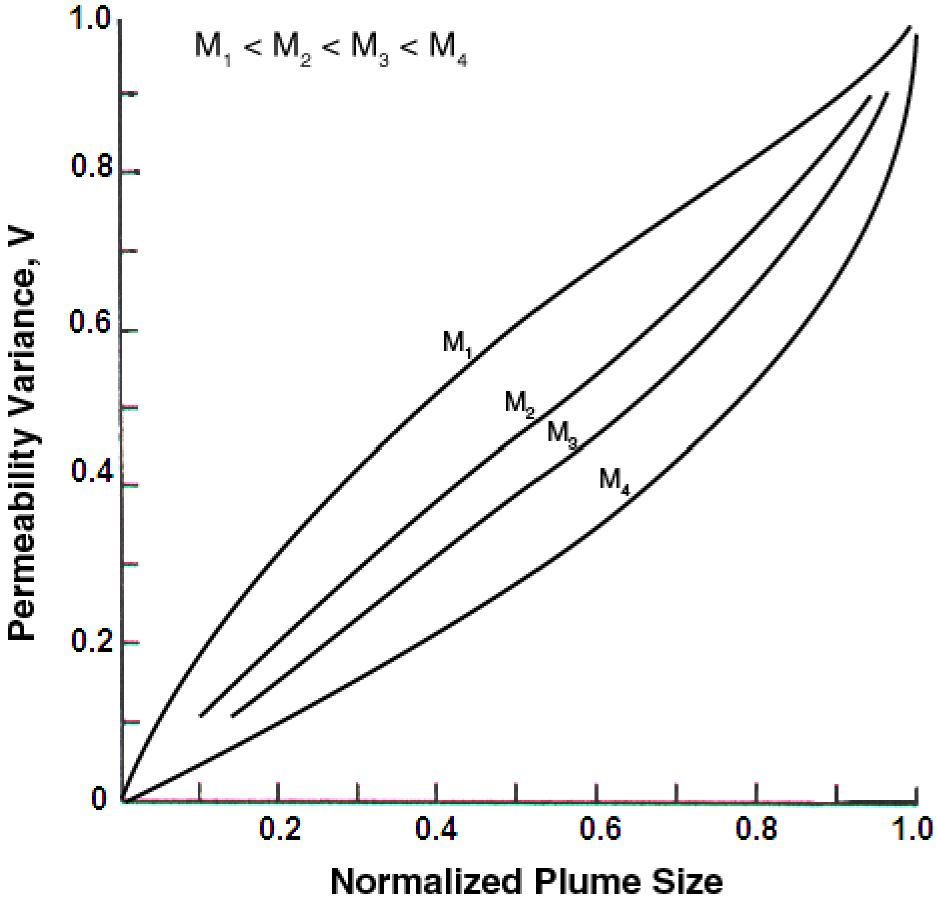

Figure 2: Permeability variance is a statistical means of representing permeability variations in layers within a geologic unit. A variance of 1.0 is extremely heterogeneous, while a value of zero is homogeneous. For a given variance, an increase in mobility ratio increase the plume size.

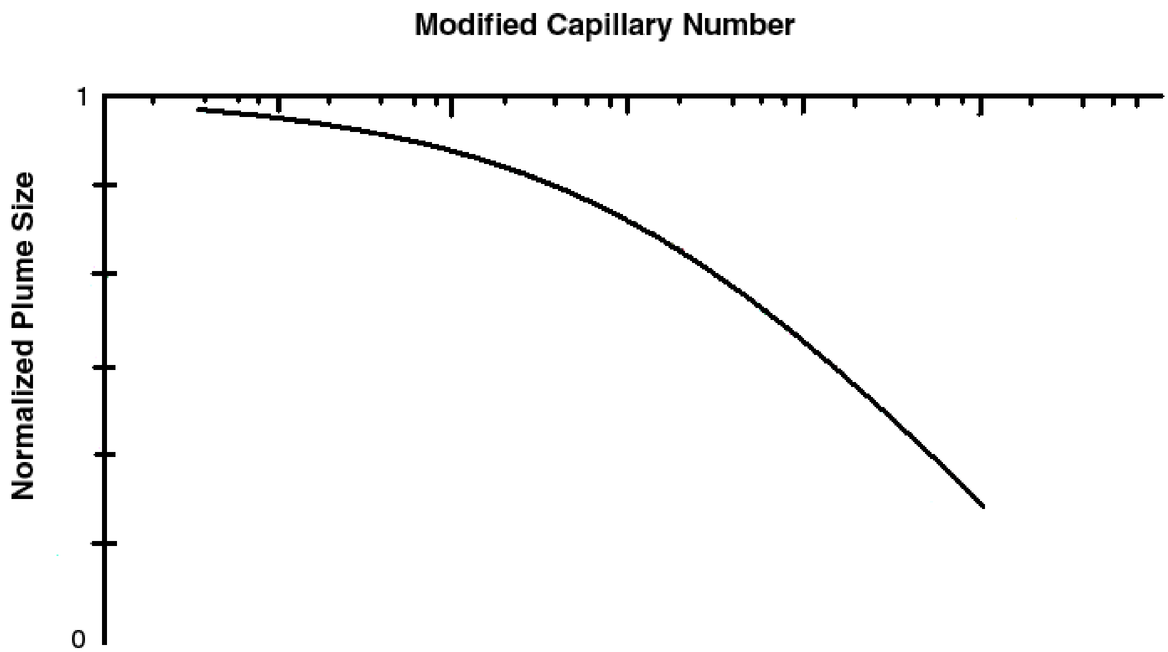

Figure 3: General trend of decreasing residual saturation (y-axis) with increasing capillary number. Generally accepted that flow rate or velocity maximum is limited such that very little can be done operationally to reduce residual saturations, which reduces the plume size. In CO2 sequestration, residual water saturation may be reduced through vaporization of water due to contact with dry CO2. The capillary number does not include this phenomenon.

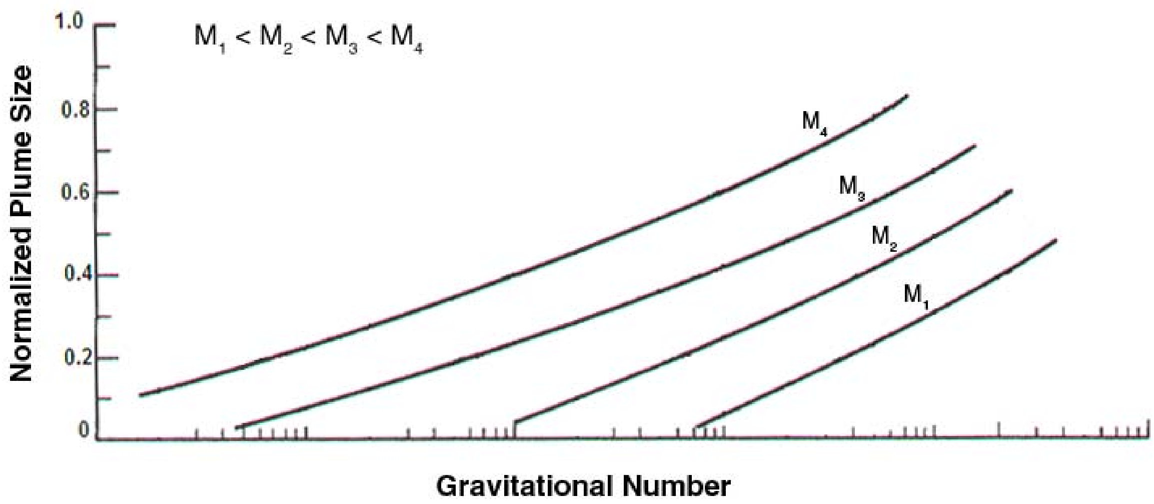

Figure 4: For a given mobility ratio, the plume size increases as the gravity number or more substantial gravity segregation occurs.