Petroleum and Coal

Article **Open Access**

Wettability Effects in Sandstone and Fractured Petroleum Reservoirs

Suresh Kumar Govindarajan

Reservoir Simulation laboratory, Petroleum Engineering Programme, Department of Ocean Engineering, Indian Institute of Technology – Madras, Chennai, India

Received August 17, 2020; Accepted December 21, 2020

Abstract

Wettability remains one of the critical multi-phase fluid flow parameters while characterizing an oil-water petroleum reservoir system. Treating the reservoir to be either completely oil-wet or completely water-wet disguises the actual physics behind reservoir wettability. While the actual wettability is described at the sub-pore-scale, a field-scale oil reservoir requires wettability description at the larger continuum-scale in order to characterize the reservoir using macroscopic Darcy's relation. Given this background, the present work has made an attempt to deduce a list of possible issues that remains unanswered during the up-scaling from sub-pore-scale to a larger field-scale reservoir wettability effects in a conventional sandstone reservoir. Then, the approach was extended to a complex fractured reservoir. In this case, the issues on the wettability effects associated with the low-permeable rock-matrix; and the high-permeable fracture have been discussed in detail, before discussing the consideration of the reservoir wettability for the whole fractured reservoir by coupling the wettability effects from the fracture and the rock-matrix. It is concluded from the present studies that the wettability effects associated with the conventional sandstone reservoir has lot more complexities in the context of up-scaling the wettability physics from sub-pore-scale to a larger field-scale reservoir wettability. It is further concluded that the wettability effects associated with a fractured reservoir may have a completely contrasting wettability effects associated with the high-permeable fracture and low-permeable rock-matrix; and it is relatively difficult to deduce a single reservoir wettability for the entire fractured reservoir at the field-scale.

Keywords: *Wettability; Sandstone reservoir; Fractured reservoir; Up-scaling.*

1. Introduction

The concept of wettability and the its associated forces of wetting critically influence the spatial and temporal distribution of pore-fluid (oil and water) saturations within the three-dimensional volumetric oil reservoir in a very complex way. Since, wettability is all about the preference of the solid grain surfaces that will be in contact with one of the two immiscible pore-fluids in an oil-water petroleum reservoir system, the balance of the forces between the oil-water; solid-water; and solid-oil would lead to the concept of 'contact angle' (θ) between the immiscible fluids on the solid grain surfaces. Thus, in a real field scenario, the concept of wettability is so complex; and for this reason, reservoir wettability is treated simply to be either fully oil-wet or fully water-wet. This extreme simplification disguises the actual reservoir physics associated with the wetting phenomena while characterizing the multi-phase fluid flow through a petroleum reservoir. Thus, it should be clearly understood that in an actual reservoir cannot be characterized either to be completely oil-wet or water-wet; but rather, it is going to be a condition between fully water-wet and fully oil-wet called an intermediate wetting. Now, the problem is that it is still difficult to characterize the so called wetting at the continuum-scale, even if we treat a reservoir to be under intermediate-wet conditions. This is because, at the sub-pore-scale, an oil drop tends to form a bead on a water-wet surface, while the same oil drop tends to spread over the oil-wet surface under the ideal conditions, while for a real field condition with an intermediate-wet surface, a partial bead is formed in accordance to the interfacial tension forces between solid-oil; solid-water; and oil-water – which too complex to be understood at the continuum-scale. In general, a reservoir volume consists of a multiple mineral; and in turn, the wettability characteristics will be varying for every different mineral at the sub-pore-scale. There are plenty of wettability studies both in sandstone as well as in fractured reservoirs [1-15]. However, there is no theoretical basis behind the translation of these 'multiple' (varying) wettability characteristics at sub-pore-scales to the larger continuum-scale 'single' wettability – both in sandstone as well as in fractured reservoirs.

In this context, the objective of the present manuscript is to discuss in detail the real field complexities associated with the translation of sub-pore-scale wettability phenomena into a larger field-scale reservoir wettability that will match with the macroscopic Darcy's law. The present work focuses on two aspects of reservoir wettability: the one on the wettability associated with the conventional sandstone reservoir, while the other on the wettability effects associated with the relatively complex fractured reservoir. It is very critical to have insights on the feasibility of up-scaling the sub-pore-scale wettability effects into a larger field-scale reservoir wettability scenario. Although, there are no earlier works that explicitly provide the theoretical background on its up-scaling, the present work has made an attempt to first bring-in a list of unanswered questions for which further investigations are required. The present work is not only confined for the conventional sandstone reservoirs but also for the complex fractured reservoirs.

2. Discussion on sandstone reservoir wettability

The concept of wettability even in a conventional sandstone reservoir requires a lot more investigation associated with the translation of the wettability effects from the sub-pore-scale to the larger field-scale reservoir wettability. There remains a lot of unanswered questions during this up-scaling of wettability effects. A detailed list of possible questions that remain unanswered in the context of wettability physics has been deduced and listed.

Given the fact that (a) the wettability associated with the small pores do not get altered – irrespective of whether the reservoir is oil-wet or water-wet; and the smaller pores are always filled by water-phase in both water-wet and oil-wet reservoirs (oil has to over-come a huge capillary force exerted by water in smaller pores in order for the oil to enter into the smaller pores; and it is nearly impossible for the oil to over-come such capillary forces exerted by the water-phase associated with the smaller pores) – upon water-flooding;

(1) What exactly we mean by 'larger pores' – where, the water-phase (connate-water) gets wetted with the solid rock surface for a 'water-wet reservoir' (with predominant water in the middle of the pores); and the predominant oil-phase gets wetted with the solid rock surface for an oil-wet reservoir (with relatively smaller water in the middle of the pores)?
(2) How big are these 'larger pores' with reference to those 'smaller pores'?
(3) Is there a 'transition regime' in between these two pores (smaller and larger) – corresponding to the 'fractional wet' (where both oil and water wets the solid rock surface with predominant oil in the middle of the pores)?

If so, how about the 'wettability' in those 'transition regime'?

(4) Whether the concept of either an 'oil-wet' reservoir or a 'water-wet' reservoir would remain the same at various spatial locations along the flow direction towards the production well (which consists of the vertical cross-sectional area taken along the pay-zone thickness and the width of the reservoir; and that is perpendicular to the principle fluid flow direction)?
(5) Whether, the wetting preference of the solid rock surface of the reservoir would remain the same at various spatial locations (with vertical cross-sectional-area consisting of reservoir thickness and the reservoir width) along the flow direction towards the production well?
(6) Why does the parameter 'wettability' stands distinct with reference to the rest of the reservoir rock/fluid parameters namely 'connate water saturation'; residual oil saturation'; 'oil relative permeability'; ' water relative permeability'; and the 'capillary pressure'?

How exactly the saturation history, i.e., the direction of the saturation change namely the 'imbibition' [measurements taken while increasing the wetting-phase saturation] and 'drainage' [measurements taken while reducing the wetting-phase saturation] influences - the experimentally measured properties – on the resulting 'capillary pressure' and 'relative permeability' curves - while characterizing - the multi-phase fluid flow in a petroleum reservoir?

(7) Wettability being one of the most-sensitive rock-fluid interaction parameters, how exactly the wettability controls (a) spatial locations, i.e., the relative positions of oil, water and gases between injection and production wells within the reservoir volume; and in turn, the relative transmissivity of each fluid phase; (b) the specific tortuous flow paths or direction of these reservoir fluids (individually) towards the production well; and (c) the individual distribution/fraction/saturation of these reservoir fluids within the reservoir volume? Will it be feasible to deduce the threshold value of the wetting fluid saturation below which it cannot be reduced further – upon flooding with an another immiscible fluid?

(8) Whether the concept of 'uniform wettability' (where the reservoir can be explicitly classified either as an oil-wet reservoir or a water-wet reservoir – in the absence of either mixed-wet or fractional-wet) is feasible at all - in any reservoir - having a range of pore-sizes that includes both smaller as well as larger pores?

(9) When and how exactly – the equilibrium nature of the reservoir fluid system (water, oil and gas) gets broken – upon the injection of water during 'pressure-maintenance' or 'water-flooding'? Will the disturbance of the pore-fluid's equilibrium remain uniform throughout the reservoir volume or will it vary as a function of space and time?

(10) Which parameters ensure the continuity on the 'hydraulic connectivity' of the 'non-wetting fluid' that generally accommodate the middle/interior portion of the relatively larger pores; and that form blobs/beads/globules, which extend either over a few pores or sometimes over a larger number of pores; but, not generally, through all the pores of the reservoir volume?

(11) What would be the fundamental difference - resulting from the initial reservoir wettability - while characterizing - the water-flooding of an oil-wet reservoir (associated with the drainage process) from that of a water-wet reservoir (associated with the imbibition process)?

(12) What are the favourable conditions that will accelerate the adsorption of polar-compounds along with the deposition of organic matter (on the mineral surfaces) that were originally present in the crude oil; and subsequently leading to the alteration of a strongly water-wet reservoir towards a more oil-wet reservoir with time?

(13) Isn't true that the mineral surfaces of the concerned reservoir rock with varying surface chemistry and adsorption characteristics would lead to a situation, where the reservoir wettability will neither be purely oil-wet nor a purely water-wet reservoir?

(14) Apart from variations in mineral surfaces, will it be justified to assume a reservoir either to be purely oil-wet or a pure water-wet reservoir – given the non-homogeneous nature of the real field reservoir? In other words, why is it so difficult to characterize a reservoir with a heterogeneous wettability or a fractional wettability or a Dalmation wettability or a spotted wettability?

(15) How exactly a given sandstone reservoir would be identified either to be an intermediate-wet reservoir (that privations a resilient wetting preference of the solid grains by one of the two immiscible fluids) or a mixed-wet reservoir (having a variety of preferences by the solid grain surfaces to both the immiscible fluids) – given the field-scale reservoir heterogeneities?

(16) Is there a strong theory that critically rules out the relation between wettability and pore-fluid saturations in a given sandstone reservoir?

(17) What exactly decides the nature of a reservoir to be either fractional-wet reservoir (a fraction of the rock-surface remains to be strongly oil-wet, while the other fraction of the rock-surface remains to be strongly water-wet); or an intermediate-wet reservoir (nearly

all portions of the reservoir rock surface either have a marginal-preference or an equal-preference to both oil as well as water)?

(18) How exactly the initial-water-saturation and the production behaviour of a sandstone reservoir gets influenced as a function of (a) the original reservoir wettability at the time of formation; and (b) the transformed wettability during, following and after oil migration (from the source rock to the reservoir rock)?

(19) Does the wettability affect the quantum of oil that can be produced both at the pore-scale as well as at the field-scale?

(20) In a water-wet reservoir, will it be feasible to quantify the quantum of oil that becomes trapped – resulting from the presence of oil in relatively larger pores (and its subsequent snap-off of oil)?

(21) Will it be feasible to quantify the 'imbibition force' that dictates the ease with which the external fluid (water) can be injected and the way the injected fluid migrates through the water-wet reservoir?

(22) Is there any other critical parameter that will influence the 'wetting preference by the solid surface'; and in turn, the 'wetting forces that are in equilibrium condition' – apart from (a) the solid mineral surface' (b) the chemical composition of water and oil; (c) the reservoir temperature and pressure; and (d) the pore fluid saturation history?

(23) In the context of double layers in the water-phase, what are favourable conditions that will destabilize the water-film in order for the chemical components of the crude-oil that could get attached to the solid grain surfaces; and subsequently be able to alter the wetting tendency towards more oil-wet? How difficult will it be to track the 'water-advancing' and 'water-receding' contact angles – in these double layers?

(24) Will it be feasible to maintain the 'native wettability' by the native-state cores that was taken with the oil-based drilling mud; (and, which is supposed to maintain the original connate water saturation)?

(25) Laboratory core samples being so small with the sensitive end effects on top of having near cent percent sweeping efficiency (which is divergent from the field conditions), whether the laboratory-scale measured wettability at the core-scale could be expected to replicate the real field conditions?

(26) How exactly does the wettability of an oil reservoir get associated with the actual displacement of oil from the sub-pore-scale to the drainage scale of the reservoir?

(27) How exactly wettability scales with the size of the given core sample?

(28) How small can a core-sample be and still yield a wettability measurement that is representative for the entire oil reservoir?

(29) At which spatial scale, are we no longer be able to measure the 'over-all wettability' of the reservoir?

(30) How exactly to ensure the 'representative' wettability conditions during the preparation of reservoir core plugs as the reservoir rock state keeps changing during sampling, mud contamination, storage and cleaning by organic solvent and water?

(31) The 'wettability' characteristics of a reservoir will be varying depending on (a) the other physical properties of the porous media (porosity, permeability, hydraulic connectivity and mineralogy); (b) the chemical properties of the pore fluids; and (c) the thermodynamical properties of reservoir temperature and reservoir pressure. If so, whether the wettability gets reversed systematically as a function of the above three properties?

(32) Whether the strongly water-wet cleaned cores can be used for the measurement of 'liquid permeability' apart from using these cores for porosity and air permeability measurements?

(33) How exactly the concept of dynamic "pore-scale" wettability can be translated into a 'steady-state', "macroscopic Darcy-based continuum-scale" reservoir rock or fluid property?

(34) Is there a way to correlate 'wettability' along with capillary and gravity forces that control the vertical distribution of pore-fluids in an oil reservoir; and subsequently that influences the migration of water-flood front?

(35) How does 'the difference in wettability effects' between 'the laboratory and reservoir fluids' influence 'the difference in interfacial tensions (IFT)' between 'the laboratory and reservoir fluids' – in deducing the magnitude of the 'capillary pressure at actual reservoir conditions' – as a function of 'capillary pressure measured in the laboratory'?
(36) What kind of similarities in wettability characteristics (in two different reservoirs) are expected – when the "J-Function" is to be used?
(37) How does the wettability characteristics respond to the 'hysteresis effect', i.e., the saturation history of a reservoir (the direction in which the fluid saturation of a rock gets varied)?
(38) Apart from pore size heterogeneity, whether the wettability characteristics have any influence in dictating the resulting slope of the capillary pressure curve as a function of wetting-phase saturation?
(39) Whether the magnitude of J-Function for a given wetting-phase saturation would remain the same for various reservoir rocks (having various mean porosity, mean permeability and IFT values) – irrespective of the reservoir's individual 'wetting' characteristics – that decide the magnitude of the contact angle (given the fact that every individual reservoir will have its own pore-size distribution; and dynamically varying in-situ wettability characteristics)?

3. Discussion on fractured reservoir wettability

Most of the naturally fractured reservoirs are associated with carbonate reservoirs. Fractured reservoirs vary significantly from a sandstone reservoir. Unlike a sandstone reservoir, fractured reservoirs have a range of varying pore-size distributions associated with the low-permeable rock-matrix, while a varying high-permeable fracture aperture along the principle fluid flow direction [16-24]. Thus, a fractured reservoir fundamentally differs from that of a sandstone reservoir; and such a complex coupled fracture-matrix system is generally modelled using the well-known dual-porosity approach at the scale of a single-fracture [25-34] in order to characterize the fractured reservoir at the larger field-scale. A fractured reservoir consists of two distinct continuum namely fracture and rock-matrix; and the fluid mass transfer takes place at the interface between these two continua [35-44]. All the oil is stored in the rock-matrix; and the injection of external fluid in the form of water/chemicals/steam/microbes will first get into the high-permeable fracture [45-54]; and then, it will start diffusing into the low-permeable rock-matrix. Once, the external fluid gets into the rock-matrix, here, the concept of wettability will play a crucial role within the rock-matrix; and the resultant mobility of the trapped oil is expected to be increased, which will drain the fluid easily from rock-matrix to fracture [55-61]. Once the residual oil reaches the fracture from the rock-matrix, it will migrate towards the production well. Thus, the major driving force for the displacement of residual oil towards the production well requires significant advective forces [62-64], which is present only in high permeable fractures.

The concept of wettability in a fractured reservoir becomes still more complex and requires a more fundamental understanding associated with the coupling of the wettability effects between the rock-matrix sub-pore-scale wettability effects to a relatively larger fracture-scale wettability. And then, there needs to be a consensus on the overall wettability on the coupled fracture-matrix system that will represent the wettability for the whole fractured reservoir. Thus, there remains a lot of unanswered questions during this coupled wettability as well as during the up-scaling of wettability effects from the scale of a single-fracture to a larger fractured-network reservoir-scale. A detailed list of possible questions that remain unanswered in the context of wettability physics has been deduced and listed.

1. How about the concept of reservoir-wettability at the larger field-scale for a fractured reservoir, when the injected fluid flows only through the connected network of high-permeable fractures – in the absence of the injected fluid getting diffused into the low-permeable rock-matrix?

2. Whether the wettability of the low-permeable rock-matrix will be sensitive enough to attract the injected fluids from the fractures, if the mean fracture aperture sizes fall below 1 micron; and if the mean fracture aperture sizes are above 1000 microns?
3. Whether the concept of Spontaneous Imbibition (SI) will be favourable at all, if the rock-matrix is more towards oil-wet or mixed-wet; or if the permeability of the rock-matrix is very low; or the thickness of mean fracture aperture remains very small?
4. Assuming that the low-permeable rock-matrix is initially more oil-wet, whether the wettability alteration alone within the rock-matrix (towards more water-wet) will yield an enhanced oil recovery – if the mean fracture aperture thickness remains small?
5. To what extent, the wetting characteristics on the fracture surfaces (walls) will influence the resulting oil mobility – before and after the fluid mass exchange between fracture and rock-matrix?
6. When the external fluid is injected into the fracture, it slowly gets diffused into the rock-matrix. Thus, the rate at which the fluid that gets diffused into the rock-matrix may be varying from one matrix block to another (depending on the fluid velocity within the fracture, the thickness of the mean fracture aperture, the rock-matrix porosity, the rock-matrix diffusion coefficient and the rock-matrix tortuosity) – within the same fractured reservoir. If so, how to treat such a physical system, where the depth of the diffused fluid front keeps varying from one matrix block to another – within the same fractured reservoir?
7. How exactly to deduce the relative importance of gravitational to capillary forces within the fracture when (a) the mean fracture aperture falls below 1 micron; and (b) the mean fracture aperture varies between 1 and 10 microns – that will eventually dictate the fate of the fluid mobility to be either co-current or counter co-current Spontaneous Imbibition (or a combination of both) within the low-permeable rock-matrix?
8. What are the favourable conditions that will enhance the oil recovery by Spontaneous Imbibition (SI) – upon the wettability reversal of the rock-matrix from more oil-wet or more mixed-wet to more water-wet?
9. Having known the fact that the imbibition of water into water-wet rock-matrix blocks will be significant; and that the imbibition of water into oil-wet rock-matrix blocks will be insignificant, how exactly to delineate the various rock-matrix blocks of a given fractured reservoir to be either more oil-wet or water-wet rock-matrix blocks?
10. What are the favourable conditions under which the coupled effect of 'wettability alteration' along with the 'buoyant force' will play a crucial role in releasing the trapped residual oil – from the rock-matrix into the fracture?
11. Will the concept of adsorption of ions on the mineral surfaces of the rock-matrix and on the fracture walls; and its associated translation of surfaces into more water-wet – be a strong function of fracture and matrix parameters – apart from the consideration of chemical reactions alone?
12. Will it be feasible to deduce the properties of viscosities, relative permeabilities and capillary pressures as a function of both space and time – within the high-permeable fracture; and within the low-permeable rock-matrix separately and simultaneously – in order to characterize the wettability effects at the reservoir-scale?
13. When exactly the concept of 'gravity drainage' would really favour the release of trapped residual oil from a fractured reservoir? (a) when the fractures are predominantly in horizontal direction in such a way that both fracture and rock-matrix are arranged side by side on the same horizontal plane?; (b) when the fractures are predominantly in horizontal direction in such a way that fracture and rock-matrix are arranged one above the other in the vertical direction?; (c) when the fractures are predominantly in vertical direction?
14. Will it be feasible to delineate the concept of co-current and counter-current production of flow associated with the low-permeable rock-matrix, when the mean fracture aperture sizes remain less than 1 – 10 microns? How difficult is it to capture the transitional fluid flow from co-current to counter-current fluid flow – where the quantum of the released oil is expected to be less?

15. Whether the concept of wettability has any direct relevance with the residence time of the injected fluid between the fracture inlet and fracture outlet?
16. As the coupled effect of fluid flow rate, mean fracture aperture size and the mean fluid velocity within the fracture is going to decide the residence time of the injected fluid within the high-permeable fracture, will it be feasible to have a control over the wettability effects by controlling the fluid flow rate at the injection well – from the surface level?
17. If the fracture spacing remains small (the distance between the centres of nearly parallel adjacent fractures) in a fractured network reservoir, how does the boundary of the rock-matrix will influence the wettability attributes of the low-permeable rock-matrix; and high-permeable fracture? Mathematically, how exactly the wettability attributes of low-permeable rock-matrix will get influenced if the event of experiencing 'back-diffusion' within the rock-matrix – which happens when (half) matrix length or (half) fracture spacing remains too small so that the diffused fluid from a fracture reaches quickly the other face of the fracture?
18. Given the fact that the 'fracture density' is a function of exposure of the concerned fractured rock mass to the physical and/or chemical weathering, how exactly the concept of 'fracture density' will influence the wettability characteristics of low-permeable rock-matrix; and high-permeable fractures?
19. How exactly the coupled effect of 'capillary imbibition' and 'free molecular diffusion' within the rock-matrix would influence the wetting characteristics of a low-permeable rock-matrix?
20. How does the 'pressure gradient' of the injected fluid within a given fracture length would influence the wettability attributes of the high-permeable fracture?
21. Whether the concept of 'fluid mixing' at the fracture intersection or a fracture junction – in a connected network of a fractured reservoir – will anyway influence the wettability characteristics of either fractures or rock-matrix?
22. How does the wettability attribute of a high-permeable fracture with spatially varying fracture aperture sizes would influence the wettability attributes of a low-permeable rock-matrix?
23. Is there a way to figure out how sensitive the wettability attributes are (a) when the fractured reservoir is characterized by only a discrete network of high-permeable fractures in the absence of fluid mass exchange between fracture and rock-matrix (DFN Model); (b) when the fractured reservoir is characterized by fluid flow in both fracture and rock-matrix of constant block sizes [Rate-Limited dual-permeability model]; (c) when the fractured reservoir is characterized by fluid flow in fracture (fluid mobility by advective and dispersive forces) and fluid storage within the rock-matrix of constant block sizes (fluid spread by diffusive concentration gradient) [Rate-Limited dual-porosity model]; (d) when the fractured reservoir is characterized by fluid flow in fracture and fluid storage within the rock-matrix of variable block sizes (with varying time-scales for Spontaneous Imbibition) [Multi-Rate Dual-Porosity Model]?
24. If the porosity and permeability values of fracture and rock-matrix keep varying as a function of space and time, whether the wettability characteristics will also be varying accordingly or the wettability attributes of the fractured reservoir will remain more or less the same irrespective of the time period?
25. Whether the IFT of the released oil will get influenced significantly during its mobility through the fracture-matrix interface? If so, will it be favourable or unfavourable, once the fluid reaches the high-permeable fracture, after crossing through the fracture-matrix interface?
26. Once the released oil enters the high-permeable fracture, to what extent the dispersive nature of the fluid will influence the wettability attributes of the fracture – during its transportation towards production well?
27. Will it be feasible to deduce the values of (a) oil saturation in fracture; (b) oil saturation in rock-matrix; (c) water saturation in fracture; and (d) water saturation in rock-matrix

at any given time explicitly? Whether the sum of all these saturations will become equal to unity as observed in a sandstone reservoir?

28. Whether the phase-pressures (a) pressure of oil in fracture; (b) pressure of oil in rock-matrix; (c) pressure of water in fracture; and (d) pressure water in rock-matrix; - would satisfy the local equilibrium conditions, i.e., the difference between wetting and non-wetting phase pressures in fractures and in rock-matrix will exactly yield the respective capillary pressures?
29. Upon significant dispersion of the injected fluid concentration within the high-permeable fractures, will the magnitude of relative permeabilities to oil and water depend on the concentration of the injected fluid as well in addition to the local water-saturation – in deducing the oil- and water-phase mobilities within the fracture and rock-matrix (assuming a constant viscosity)?
30. Which mode of fluid transfer from fracture into the rock-matrix would favour the rock-matrix to become more water-wet; and in turn, it would result in an enhanced release of trapped oil: (a) pressure-gradient between fracture and rock-matrix driving the injected fluid from fracture into rock-matrix; or (b) concentration-gradient between fracture and rock-matrix driving the injected fluid from fracture into rock-matrix?
31. How to deduce the normalized water saturation in a coupled fracture-matrix system as a function of connate-water-saturation and residual-oil-saturation in order to estimate the phase relative permeabilities?
32. How does wettability influence the relative permeability of the high-permeable fracture as a function of (a) mean fracture aperture thickness; (b) gravity; (c) capillarity and (d) fracture wall roughness?
33. Advective and dispersive forces being dominant within the high-permeable fracture; and diffusive forces being dominant within the low-permeable rock-matrix, how exactly adsorption of the injected fluid materials influence the wettability attributes in fracture and rock-matrix?
34. Whether the reversal of wettability within the low-permeable rock-matrix can be expected to be instantaneous or will it be rate-limited?
35. Whether the way, the thermodynamic state of the in-situ fluid gets disturbed from its equilibrium state – upon the entry of the injected fluid into a fractured reservoir – will remain the same for both fracture and rock-matrix?
36. Will it be feasible to differentiate the reversal of wettability resulting from (a) the changes in the initial fluid saturation; and (b) the changes initiated from the imposed chemical reactions upon the entry of the externally injected fluid – in fracture and rock-matrix?
37. Will it be feasible to assume the continuity of the fluid mass fluxes in terms of ‘capillary pressure’ as well in addition to the ‘concentration’ at the fracture-matrix interface?
38. How does wettability influence the resulting recovery profiles for the cases: (a) when the rock-matrix is more oil-wet or mixed-wet; and (b) when the rock-matrix is more water-wet? How different the water breakthrough will be in the above two cases?
39. How does wettability of the rock-matrix will get influenced, if the capillary pressure within the fracture remains zero – resulting from the fact that the fracture is completely saturated with water?
40. How sensitive the details of fracture dips (inclination/angle) associated with a network of fractures – in deciding the fluid flow from the low-permeable rock-matrix towards the high-permeable fracture - to be either counter-current Spontaneous Imbibition or the counter-current gravity drainage?
41. Upon the entry of the injected fluid from fracture into rock-matrix, how to have control over the variation of capillary pressure resulting from (a) the increased water saturation; and (b) the increased adsorption of particles from the injected fluid – within the rock-matrix? How does it influence in the successful reversal of wettability within the rock-matrix?
42. Which wettability attributes of low-permeable rock-matrix favours the temporal variation of fractional flow and total oil recovery?

4. Conclusions

This work has made an attempt to project the actual complexities associated with the characterization of wettability physics in describing the multi-phase fluid flow through a petroleum reservoir. It is clearly observed that the kind of complexities associated with a fractured reservoir remains completely different from that associated with the conventional sandstone reservoir.

The following conclusions have been drawn from the present study.

1. Focusing exclusively on the chemical nature of the injected fluid and its potential ability to alter the reservoir wettability characteristics will remain successful only when the reservoir is relatively homogeneous and isotropic, while the up-scaling of observed wettability characteristics from the sub-pore-scale to a larger field-scale remains imprecise for a heterogeneous and anisotropic sandstone reservoir.
2. It remains unclear whether the wettability gets reversed systematically in a sandstone reservoir as a function of physical properties of porous media, chemical properties of pore fluids and the thermo-dynamical properties of reservoir temperature and pressure as the wettability characteristics observed at the sub-pore-scale cannot be up-scaled convincingly to a macroscopic Darcy's-scale; and hence, application of wettability attributes from the laboratory core-scale studies to a larger field-scale application deserves special attention and requires further investigation.
3. The wettability characteristics become too complex, when the average thickness of fracture aperture size falls below 1 micron, where gravity and buoyancy becomes insignificant with reference to capillarity, while the interplay between all these three forces becomes too complex for the mean fracture aperture thickness varying between 1 micron and 10 microns while characterize the wettability physics.
4. Wettability physics for a fractured reservoir at the scale of a single fracture can be relatively well observed, when the mean fracture aperture sizes vary between 50 microns and 500 microns, while the coupling between fracture and rock-matrix will get detached for an aperture size that exceeds 500 microns; and in turn, the required wettability reversal associated with a more oil-wet rock-matrix to more water-wet rock-matrix will remain difficult.
5. The wettability characteristics of a fractured reservoir not only depends on the wettability attributes of the low-permeable rock-matrix but also depends on the wettability attributes of the high-permeable fracture, particularly, before and after the fluid mass exchange between fracture and rock-matrix.
6. The wettability of a fractured reservoir will strongly depend on fracture and rock-matrix parameters also in addition to the complex ion-exchange, adsorption and aqueous complexation processes that generally alter a reservoir from more oil-wet or mixed-wet to more water-wet.
7. Since the depth of diffusion of fluid front keeps varying from one matrix block to another within the same reservoir, the wettability of a fractured reservoir at the field scale becomes very dynamic in nature.

References

[1] Al-Hadhrami HS, and Blunt MJ. Thermally induced Wettability Alteration to Improve Oil Recovery in Fractured Reservoirs. SPE Reservoir Evaluation & Engineering, 2001; 4:179-186.
[2] Behbahani H, and Blunt MJ. Analysis of Imbibition in Mixed-Wet Rocks Using Pore-Scale Modeling. SPE Journal, 2004; 10:466-474.
[3] Chilingar GV, and Yen TF. Some Notes on Wettability and Relative Permeabilities of Carbonate Reservoir Rocks, II. Energy Sources, 1983; 7:67-75.
[4] Delshad M, Najafabadi NF, and Anderson GA. Modeling Wettability Alteration by Surfactants in Naturally Fractured Reservoirs. SPE Reservoir Evaluation & Engineering, 2009; 12:361-370.
[5] Gupta R, and Mohanty KK. Wettability Alteration Mechanism for Oil Recovery from Fractured Carbonate Rocks. Transport in Porous Media, 2011; 87:635-652.

[6] Haugen A, Ferno MA, and Bull O. Wettability Impacts on Oil Displacement in Large Fractured Carbonate Blocks. Energy & Fuels, 2010; 24:3020-3027.
[7] Hirasaki G, and Zhang DL. Surface Chemistry of Oil Recovery from Fractured, Oil-Wet, Carbonate Formations. SPE Journal, 2004; 9:151-162.
[8] Ma S, Morrow NR, and Zhang X. Generalized Scaling of Spontaneous Imbibition Data for Strongly Water-Wet Systems. Journal of Petroleum Science and Engineering, 1997; 18(3-4):165-178.
[9] Pooladi-Darvish M, and Firoozabadi A. Cocurrent and Counter Current Imbibition in a Water-Wet Matrix Block. SPE Journal, 2000; 5:3-11.
[10] Andersen P, Steinar E, Kleppe H, and Skjaeveland SM. A Model for Wettability Alteration in Fractured Reservoirs. SPE Journal, 2015; 20:1261-1275.
[11] Rao DN. Wettability Effects in Thermal Recovery Operations. SPE Reservoir Evaluation & Engineering, 1999; 2:420-430.
[12] Schmid KS, and Geiger S. Universal Scaling of Spontaneous Imbibition for Water-Wet Systems. Water Resources Research, 2012; 48:W03507.
[13] Schmid KS, and Geiger S. Universal Scaling of Spontaneous Imbibition for Arbitrary Petrophysical Properties: Water-Wet and Mixed-Wet States and Handy's Conjecture. Journal of Petroleum Science and Engineering, 2013; 101:44-61.
[14] Sedaghat MH, and Azizmohammadi S. Dynamic Wettability Alteration in Naturally Fractured Rocks. Computational Geosciences, 2019; 24:581-591.
[15] Treiber LE, and Owens WW. A Laboratory Evaluation of the Wettability of Fifty Oil-Producing Reservoirs. SPE Journal, 1972; 12:531-540.
[16] Abhishek K, and Kumar GS. Numerical Investigations on Compressible Non-linear Fluid Flow associated with a Stress-Sensitive Fractured Reservoir. Energy Sources, Part A: Recovery, Utilization, and Environmental Effects, 2020; https://doi.org/10.1080/15567036.2020.1777224.
[17] Ghassemi A, and Kumar GS. Changes in fracture aperture and fluid pressure due to thermal stress and silica dissolution/precipitation induced by heat extraction from subsurface rocks. Geothermics, 2007; 36(2):115-140.
[18] Kumar GS, and Ghassemi A. Numerical Modeling of Non-Isothermal Quartz Dissolution/Precipitation in a Coupled Fracture-Matrix System. Geothermics, 2005; 34(4):411-439.
[19] Kumar GS, and Ghassemi A. Spatial Moment Analysis for One-Dimensional Nonisothermal Quartz Transport and Dissolution/Precipitation in a Fracture-Matrix System. Journal of Hydrologic Engineering, 2006; 11(4):338-346.
[20] Kumar GS, and Sekhar M. Spatial Moment Analysis for Transport of Nonreactive Solutes in a Fracture-Matrix System. Journal of Hydrologic Engineering, 2005; 10(3):192-199.
[21] Kumar GS, and Sekhar M. and Misra D. Time Dependent Dispersivity Behavior of Non-Reactive Solutes in a System of Parallel Fractures. Hydrology and Earth System Sciences Discussions, 2006; 3(3):895-923.
[22] Kumar GS. Mathematical Modeling on Transport of Petroleum Hydrocarbons in Saturated Fractured Rocks. Sadhana-Academy proceedings in Engineering Sciences, 2014; 39(5):1119-1139.
[23] Kumar GS. Mathematical Modeling of Groundwater Flow and Solute Transport in a Saturated Fractured Rock using Dual-Porosity Approach. Journal of Hydrologic Engineering. 2014; 19(12): 04014033-1 –04014033-8.
[24] Kumar GS. Effect of Sorption Intensities on Dispersivity and Macro-dispersion Coefficient in a Single Fracture with Matrix Diffusion. Hydrogeology Journal, 2008; 16(2):235-249.
[25] Kumar GS, Sekhar M, and Mishra D. Time dependent dispersivity of linearly sorbing solutes in a single fracture with matrix diffusion. Journal of Hydrologic Engineering, 2008; 13(4):250-257.
[26] Kumar GS. Influence of Sorption Intensity on Solute Mobility in a Fractured Formation. Journal of Environmental Engineering, 2009; 135(1): 1-7.
[27] Kumar GS, and Rakesh TV. Numerical Modeling of Reactive Solute Transport in a Single Fracture with Matrix Diffusion under Complex Boundary Condition. ISH Journal of Hydraulic Engineering, 2015; 21(2):125-141.
[28] Kumar GS. Modeling Fluid Flow through Fractured Reservoirs: Is it different from Conventional Classical Porous Medium? Current Science, 2016; 110(4):695-701.
[29] Kumar GS, and Rakesh TV. Numerical Modeling of Hyperbolic Dominant Transient Fluid Flow in Saturated Fractured Rocks using Darcian Approach. Groundwater for Sustainable Development, 2018; 7:56-72.

[30] Kumar GS, Mishra A, and Kumar A. Fluid Flow through Shale Gas Reservoirs: Simplified Conceptual and Mathematical Models. Petroleum & Coal, 2020; 62(3):776-791.

[31] Manojkumar G, and Kumar GS. Numerical Modelling of Coupled Single-phase fluid flow and geomechanics in a fractured porous media. Journal of Petroleum Science and Engineering, 2020; 191:107215.

[32] Natarajan N, and Kumar GS. Radionuclide and Colloid Co Transport in a Coupled Fracture-Skin-Matrix System. Colloids and Surfaces A: Physicochemical and Engineering Aspects, 2010; 370(1-3):49-57.

[33] Natarajan N, and Kumar GS. Numerical Modeling and Spatial Moment Analysis of Thermal Fronts in a Coupled Fracture-Skin-Matrix System. Geotechnical and Geological Engineering. 2011; 29(4):477-491.

[34] Natarajan N, and Kumar GS. Numerical Modeling of Bacteria Facilitated Contaminant Transport in Fractured Porous Media. Colloids and Surfaces A: Physicochemical and Engineering Aspects, 2011; 387(1-3):104-112.

[35] Natarajan N, and Kumar GS. Evolution of Fracture Permeability due to Co-colloidal Bacterial Transport in a Coupled Fracture-Skin-Matrix System. Geoscience Frontiers, 2012; 3(4):503-514.

[36] Natarajan N, and Kumar GS. Lower order spatial moments for colloidal transport in a fracture-matrix coupled system. ISH Journal of Hydraulic Engineering, 2014; 20(2):200-211.

[37] Natarajan N, and Kumar GS. Numerical Modeling and Spatial Moment Analysis of Solute Transport with Langmuir Sorption in a Fracture Matrix Coupled System. ISH Journal of Hydraulic Engineering, 2015; 21(1):28-41.

[38] Natarajan N, and Kumar GS. Spatial Moment Analysis of Solute Transport with Langmuir Sorption in a Fracture-Skin-Matrix Coupled System. Journal of King Saud University – Engineering Sciences, 2016; 28(2):157-164.

[39] Natarajan N, and Kumar GS. Effect of Sips Adsorption Isotherm on Contaminant Transport Mechanism in Fractured Porous Media. KSCE Journal of Civil Engineering, 2016; 20(5):1714-1720.

[40] Natarajan N, Kumar GS, and Vasudevan M. Impact of Coupling terms on the Thermal Transport Mechanism in a Fracture Matrix Coupled System. Modeling Earth Systems and Environment, 2020; https://doi.org/10.1007/s40808-020-00863-1.

[41] Nikhil BL, and Kumar GS. Effect of Non-Linear Sorption on Multispecies Radionuclide Transport in Fracture-Matrix System with Variable Fracture Aperture: A Numerical Study. ISH Journal of Hydraulic Engineering, 2015; 21(3):242-254.

[42] Nikhil BL, and Kumar GS. Thermal Front Propagation in Variable Aperture Fracture-Matrix System: A Numerical Study. Sadhana-Academy proceedings in Engineering Sciences, 2015; 40(2):605-622.

[43] Nikhil BL, and Kumar GS. Numerical Modeling of Two Species Radionuclide Transport in a Single Fracture-Matrix System with Variable Fracture Aperture. Geosciences Journal, 2016; 20(5):627-638.

[44] Nikhil BL, and Kumar GS. Effect of Random Fracture Aperture on the Transport of Colloids in a Coupled Fracture-Matrix System. Geosciences Journal, 2017; 21(1):55-69.

[45] Nikhil BL, and Kumar GS. Colloid Transport in a Single Fracture–Matrix System: Gravity Effects, Influence of Colloid Size and Density. Water, 2018; 10(11):1531.

[46] Nikhil BL, and Kumar GS. Influence of Fracture Heterogeneity Using Linear Congruential Generator (LCG) on the Thermal Front Propagation in a Single Geothermal Fracture-Rock Matrix System. Energies, 2018; 11(4):916:1-13.

[47] Rakesh TV, and Kumar GS. Numerical Modeling on the Sensitivity of Directional Dependent Interface Heat Transfer on Thermal Transport in a Coupled Fracture-Matrix System. Geosciences Journal, 2016; 20(5):639-647.

[48] Renu V, and Kumar GS. Numerical Modeling and Spatial Moment Analysis of Solute Mobility and Spreading in a Coupled Fracture-Skin-Matrix System. Geotechnical and Geological Engineering, 2012; 30(6):1289-1302.

[49] Renu V, and Kumar GS. Temporal Moment Analysis of Solute Transport in a Coupled Fracture-Skin-Matrix System. Sadhana-Academy proceedings in Engineering Sciences, 2014; 39(2):487-509.

[50] Renu V, and Kumar GS. Numerical Modeling on Benzene Dissolution into Groundwater and Transport of Dissolved Benzene in a Saturated Fracture-Matrix System. Environmental Processes, 2016; 3:781-802.

[51] Renu V, and Kumar GS. Temporal Moment Analysis of Multispecies Radionuclide Transport in a Coupled Fracture-Skin-Matrix System with a Variable Fracture Aperture. Environmental Modeling and Assessment, 2016; 21(4):547-562.
[52] Renu V, and Kumar GS. Multicomponent Transport of BTX in a Discretely Fractured Aquifer with Fracture-Skin: Numerical Investigation and Sensitivity Analysis. Environmental Earth Sciences, 2017; 76(17):1-15.
[53] Renu V, and Kumar GS. Benzene Dissolution and Transport in a Saturated Sinusoidal Fracture with Non-uniform Flow: Numerical Investigation and Sensitivity Analysis. Environmental Processes, 2017; 4(3):587-601.
[54] Renu V, and Kumar GS. Interaction of Dissolution, Sorption and Biodegradation on Transport of BTEX in a Saturated Groundwater System: Numerical Modeling and Spatial Moment Analysis. Journal of Earth System Science, 2018; 127(4):1-21.
[55] Renu V, and Kumar GS. Mathematical Modeling on Mobility and Spreading of BTEX in a Discretely Fractured Aquifer System under the Coupled Effect of Dissolution, Sorption, and Biodegradation. Transport in Porous Media, 2018; 123(2):421-452.
[56] Renu V, and Kumar GS. Multispecies Transport Modeling on Biodegradation of BTX in a Saturated Fracture-Matrix System with Multiple Electron Acceptors. Environmental Engineering Science, 2018; 35(10):1096-1108.
[57] Renu V, and Kumar GS. Co-colloidal BTEX and Microbial transport in a Saturated Porous System: Numerical Modeling and Sensitivity Analysis. Transport in Porous Media, 2019; 127(2):269-294.
[58] Rockey A, Kumar GS, and Sapru RK. Wettability Alteration in Carbonate Reservoirs using Nano-Fluids. Petroleum Science and Technology, 2015; 33(7):794-801.
[59] Rockey A, Nikhil BL, and Kumar GS. Effect of Transverse Forces on Velocity of Nano-particles through a Single Fracture in a Fractured Petroleum Reservoir. International Journal of Oil, Gas and Coal Technology, 2016; 12(4):359-378.
[60] Sekhar M, and Kumar GS. Modeling Transport of Linearly Sorbing Solutes in a Single Fracture: Asymptotic Behavior of Solute Velocity and Dispersivity. Geotechnical and Geological Engineering, 2006; 24(1):183-201.
[61] Sekhar M, Kumar GS, and Mishra D. Numerical Modeling and Analysis of Solute Velocity and Macrodispersion for Linearly and Nonlinearly Sorbing Solutes in a Single Fracture with Matrix Diffusion. Journal of Hydrologic Engineering, 2006; 11(4): 319-328.
[62] Sivasankar P, and Kumar GS. Numerical Modeling of Enhanced Oil Recovery by Microbial Flooding under Non-isothermal Conditions. Journal of Petroleum Science and Engineering, 2014; 124:161-172.
[63] Sivasankar P, and Kumar GS. Influence of pH on dynamics of Microbial Enhanced Oil Recovery Processes using Biosurfactant Produced Pseudomonas Putida: Mathematical Modeling and Numerical Simulation. Bioresource Technology, 2017; 224:498-508.
[64] Sivasankar P, and Kumar GS. Modelling the influence of interaction between injection and formation brine salinities on in-situ microbial enhanced oil recovery processes by coupling of multiple-ion exchange transport model with multiphase fluid flow and multi-species reactive transport models. Journal of Petroleum Science and Engineering, 2018; 163:435-452.

To whom correspondence should be addressed: professor Suresh Kumar Govindarajan, Reservoir Simulation laboratory, Petroleum Engineering Programme, Department of Ocean Engineering, Indian Institute of Technology – Madras, Chennai, India; E-mail: gskumar@iitm.ac.in