# Optimizing Multiphase Flow Characterization via Core-flooding and Automated History Matching Using SENDRA Simulation

Faisal Hussain Memon*, Muhammad Furqan Qureshi†, Tahir Hussain Soomro‡, Ghulam Abbas§, Shoaib Ahmed Memon**

***Abstract***

*Multiphase flow simulation within porous media is essential for predicting the reservoir performance and optimizing the oil recovery strategies. This paper aims to estimate the Relative Permeability ($K_r$) and Capillary Pressure ($P_c$) parameters by performing core flooding experiments using Sendra software. The laboratory experiments were carried out using a sandstone core under controlled conditions. A four-step protocol was developed to obtain the injection rates, production data and pressure responses, which were utilized for simulation and history matching. To analyze the experimental data and obtain $K_r$ and $P_c$ curves, the SENDRA-1D black oil simulator was used. The results were tested using a total of 25 correlation combinations to match the experimental results. The most convincing correlation was derived to be the Sigmund-McCaffery correlation and LET-Primary drainage correlation with least Residual Sum of Square (RSS) for oil production and pressure curves. The analysis identified a Critical Water Saturation ($S_{wc}$) of 40% which indicates the two-phase flow. While, Residual Oil Saturation ($S_{or}$) was obtained at 28%, which signifies oil volume left for post-water flooding. The $P_c$ curve declined quickly with increasing $S_{wc}$ and becomes zero above 45%, indicating a water-wet system. The results demonstrates that this automated simulation workflow using SENDRA software is much more effective and reliable in characterizing multiphase flows in both steady state and unsteady state processes. The proposed methodology saves experimental time and produces reliable data generation over a significant saturation range. Thus, making it a robust tool for reservoir analysis in multiphase flow systems.*

***Keywords:*** Multiphase Flow, Core-Flooding, Relative Permeability ($K_r$), Capillary Pressure ($P_c$), History Matching, SENDRA Simulation.

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## Introduction

Multiphase flow through porous media is a significant phenomenon in reservoir engineering, which directly affects the hydrocarbon recovery via fluid conductivity. Modelling and prediction of multiphase flow processes are critical in the analysis of reservoir performance, optimizing the production, and effective oil recovery techniques (Golparvar et al., 2018; Meakin & Tartakovsky, 2009). Although, the multiphase flow is frequently dominated by viscous, capillary, and gravitational forces of oil, water, and gas fluids, typically contained in reservoir. However, it represents the complexity in terms of fluid movement and distribution, and requires numerical modelling to analyze the fluid flow under various reservoir conditions (Seales, 2020).

Relative Permeability ($K_r$) and Capillary Pressure ($P_c$) are the critical parameters in multiphase flow modelling to control the fluid distribution, phase mobility, displacement efficiency, and recovery (Golparvar et al., 2018; Patel et al., 2019). $K_r$ describes the fluid conductivity of a particular phase in the presence of other immiscible fluids. Whereas, $P_c$ represents the pressure difference between two immiscible fluids across the interface due to interfacial tension (Guo et al., 2022; Patel et al., 2019; Pereira, 2019). These parameters are significant in determining the flow behavior and the possible recovery of hydrocarbons by multiphase systems (Pereira, 2019). Knowledge of these parameters is essential to predict the reservoir behavior in different production scenarios in order to maximize recovery process. Multiphase systems are mainly governed by the capillary forces that control fluid retention and displacement within pore geometry particularly in tight and heterogeneous reservoirs (Liu et al., 2019; Pereira, 2019). $P_c$ effects are more distinguishable in water wet reservoirs at low flow rates where wetting phase occupies smaller pores favorably (Liu et al., 2019). Therefore, precise measurement of $P_c$ curves is significant to model fluid migration, drainage and imbibition in reservoir simulations.

$K_r$ and $P_c$ are usually determined through laboratory tests, such as steady-state and unsteady-state core-flooding approaches (Jahanbakhsh & Sohrabi, 2015; Pereira, 2019). Steady-state experiments require constant rate fluid injections before reaching equilibrium but are lengthy and time consuming. Although, unsteady-state approaches rely on Buckley-Leverett displacement theory, and frequently controls $P_c$ effects at small saturation coverage (Jahanbakhsh, 2016; Jahanbakhsh & Sohrabi, 2015; Nekouie, 2019). To address these limitations, the developed history matching software, such as that of SENDRA, uses numerical optimization tools to determine $K_r$ and $P_c$ simultaneously (Cai et al., 2024; Kumar et al., 2014). This will enable more effective and precise establishment of multiphase flow parameters. SENDRA increases the effectiveness and precision of multiphase flow parameter examination by automatically choosing the most effective functions of numerous correlation models, decreasing the reliance on individual experimental setups (Cai et al., 2024).

The existing literature has reported various studies that have utilized numerical methods to estimate $K_r$. Chardaire-Riviere et al. (1992) introduced a multiscale representation framework to do simultaneous estimation, combining saturation profiles with pressure drop and production profile data. Patrick Egermann et al. (2005) proposed very accurate interval functions to estimate $K_r$ and $P_c$ curve relative to history matching core flood data. Ashrafi et al. (2014) employed genetic algorithms to enhance better precision in estimating $K_r$ using unsteady state displacement experiments through capillary end effects. These techniques have shown better accuracy of history-matching core flood data, enhancing accuracy of $K_r$ estimation in unsteady-state displacement tests. Nevertheless, recent research emphasized the need for appropriate choice of correlation models in multiphase flow in history matching. Safari et al. (2015) concluded that silica nanoparticle flooding improves oil recovery through wettability alteration, which influences the $K_r$ characteristics. Accurate $K_r$ and $P_c$ estimation significantly improve the workflows for reservoir simulation, as highlighted by these studies. Sylte et al. (2002) highlighted the impact of experimental design and adoptive simulation in minimizing mismatch between simulated and observed data in oil wet displacement system. Hustad & Browning (2010) established a three-phase coupled model for implicit compositional reservoir simulation for multiphase flow. Likewise Zhang (2014) and Dang et al. (2017) employed dynamic optimization method to core flooding data analysis framework for demonstrating the flexible correlation selection. Ibiam et al. (2021) and Khosravi et al. (2025) employed automated history matching techniques to determine the flow dynamic in highly heterogenous water flooding reservoirs. These studies emphasized the significance of advanced simulation tools and correlation models for enhancing the reliability of multiphase flow characterization. However, establishing an integrated approach that estimates $K_r$ and $P_c$ using various correlations in a single experimental process is still limited in literature.

This research focuses on developing an integrated methodology to perform simultaneous estimation of $K_r$ and $P_c$ using core flooding experiments through SENDRA simulation. The workflow comprising of experimental design, data collection, numerical models and simulations to carry out the effective estimations in controlled environment. The objective of the study is to classify the optimal correlation model using history matching that enhances the forecasting the multiphase flow characterization. The findings will improve the accuracy in reservoir estimation and providing a solid foundation for enhancing oil recovery procedures in petroleum reservoirs.

## Methodology and Materials

The methodology involves numerical modelling with experimental data for simultaneous determination of $K_r$ and $P_c$. The workflow comprising of multiple procedures including core sampling, core flooding tests, data collection for simulation and history matching using SENDRA to predict multiphase, as depicted in Figure 1. These steps constitute a systematic scheme of obtaining reliable multiphase flow parameters.

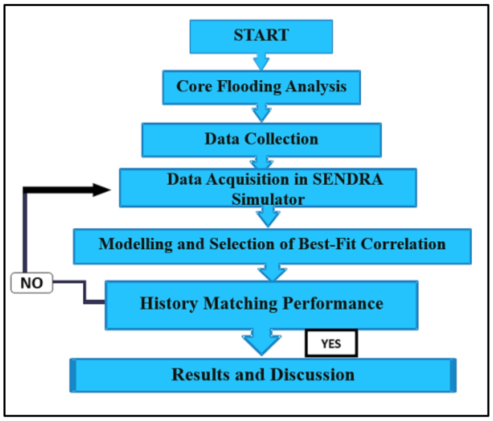
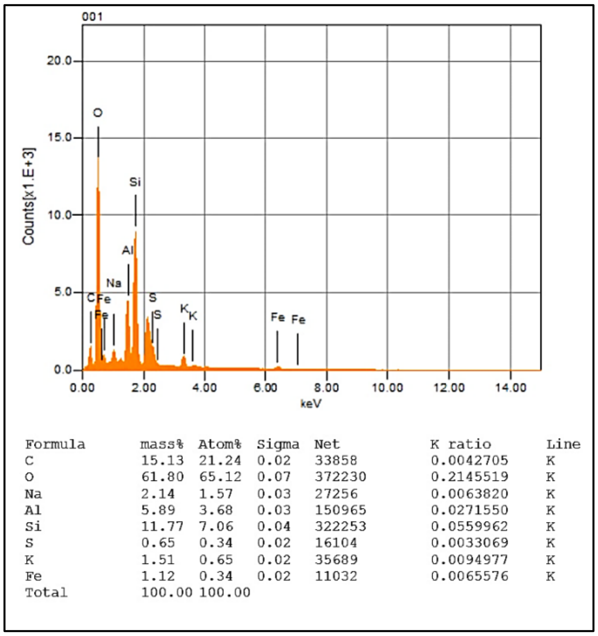


*Figure 1: Schematic workflow of the simulation study.*

### *Core Sample and Experimental Setup*

The selected sandstone sample was utilized for this study. Figure 2 illustrated the signified mineralogy of the sandstone core sample obtained through EDS analysis. The core sample exclusively underwent sample preparation procedures including core plugging, trimming, cleaning, and drying prior to core flooding experiment. Subsequently, oil wet core sample was saturated with formation brine to achieve the Irreducible Water Saturation ($S_{wi}$). The description of the core sample and the fluid data utilized for core flooding is well presented in Table 1. The core was placed in a Hessler type core holder containing a differential pressure transducer for monitoring pressure drop during fluid injection under ambient conditions, as shown in Figure 3. Similarly, flooding setup consist of a fluid accumulator, constant rate injection pump, effluent collection and an overburden pressure system. Brine and crude oil were employed as wetting and non-wetting phases respectively. A four-step imbibition displacement experiment was planned, initially with oil injection, followed by brine flooding for secondary water recovery, under controlled flow rate conditions depicted in Table 2.



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Formula     mass%  Atom%  Sigma  Net        K ratio    Line
C           15.13  21.24  0.02   33858      0.0042705  K
O           61.80  65.12  0.07   372230     0.2145519  K
Na          2.14   1.57   0.03   27256      0.0063820  K
Al          5.89   3.68   0.03   150965     0.0271550  K
Si          11.77  7.06   0.04   322253     0.0559962  K
S           0.65   0.34   0.02   16104      0.0033069  K
K           1.51   0.65   0.02   35689      0.0094977  K
Fe          1.12   0.34   0.02   11032      0.0065576  K
Total       100.00 100.00
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*Figure 2: Mineralogy of the examined sandstone core sample for the study.*

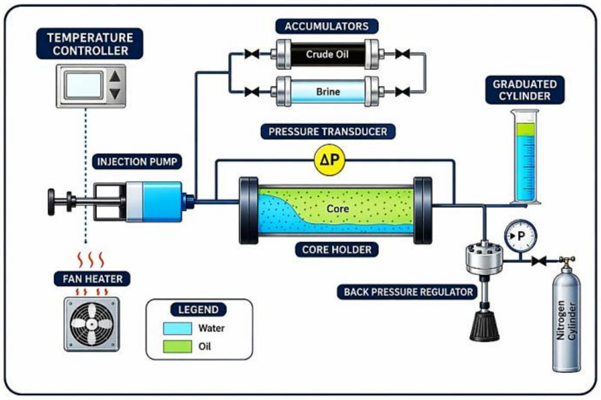


*Figure 3: Schematic diagram of Hessler core flooding experiment.*

*Table 1: Core sample and fluid description for core flooding experiment*

| Parameter | Values | Unit |
|---|---|---|
| Core Length | 24.7 | cm |
| Core Diameter | 3.74 | cm |
| Porosity | 20 | % |
| Pore Volume | 54.14 | $Cm^3$ |
| Permeability | 244.5 | md |
| Water Viscosity 70°C | 0.71 | cp |
| Oil Viscosity 70°C | 2.17 | cp |

*Table 2: Injection pattern of core flooding Experiment.*

| Flooding pattern | Flow rate (cm3/min) | Volume Injected (PV) |
|---|---|---|
| Brine | 0.5 | 3.5 |
| Oil | 0.5 | 4.5 |
| Water | 0.2 | 2.0 |

### Data Acquisition and SENDRA Simulation

The data set generated from core flooding test, required for simulating the two-phase flow through the sandstone core sample. During the experiment, real time critical parameters such as injection rates, differential pressures, cumulative oil and water production were recorded, and subsequently utilized as input data for numerical simulation. A one-dimensional black oil simulator, SENDRA by Core Laboratories was employed to evaluate the $K_r$ and $P_c$ functions through automated history matching. The simulation was initiated using experimental input of core properties, fluid properties, injection rates, oil production, and differential pressure data were considered as fixed inputs in SENDRA software. Further the constant flow-rate inlet, constant pressure outlet and measured initial saturations provided as boundary and initial conditions. Subsequently, a primary simulation was performed using default correlation models with iterative history matching to minimize the deviation between simulated and observed outputs. The SENDRA engine provided testing of 25 pairs of correlations with the industry standard models including Sigmund-McCaferry, LET, and Corey correlation models. The history matching application dynamically utilized the nonlinear regression and least-squares minimization to fit the experiment data with adjusted correlation parameters. This data acquisition process makes SENDRA an interpretation tool based on experimental control. This workflow for simulation ensures the correct laboratory results and develop the smooth $P_c$ and $K_r$ curves of the given saturation ranges. This combined approach did not require $P_c$ measurement separately, saving the time and provided precise pathway to the two parameter estimations based on single core flooding test.

### *Selection of Best-Fit Correlation and Data Integration*

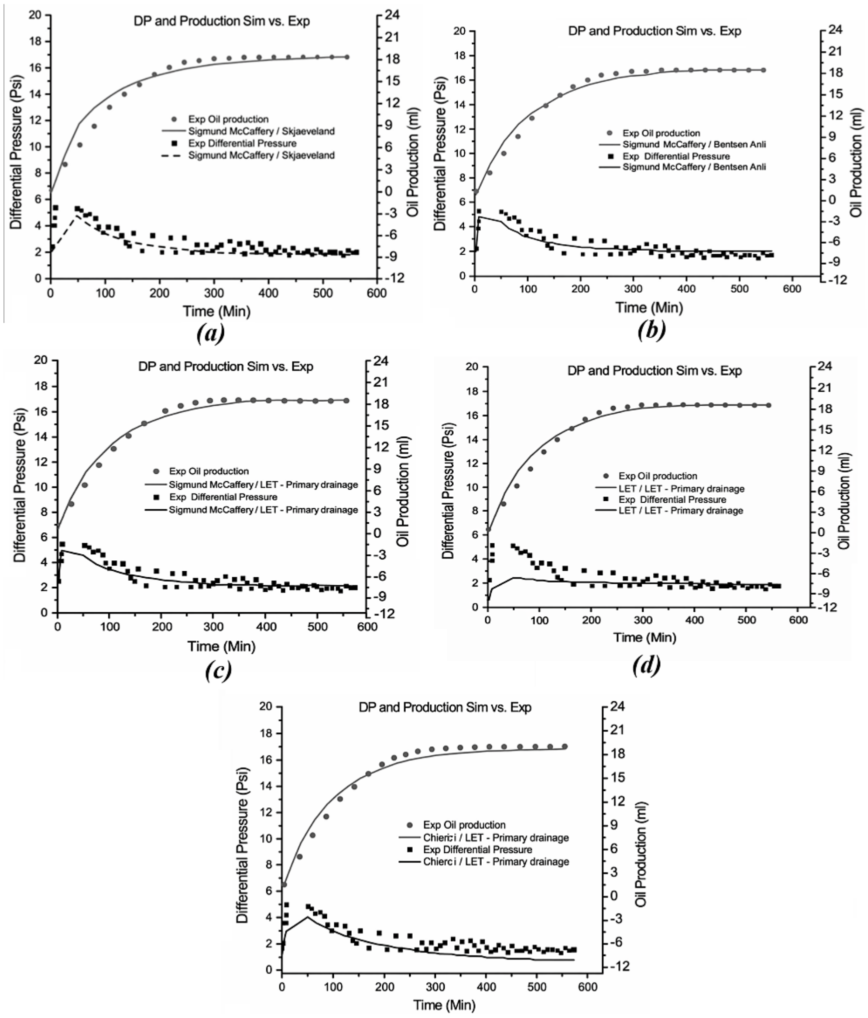
To evaluate the correlation, every simulated accuracy was evaluated on the basis of Residual Sums of Squares (RSS) between the simulated and observed oil production and the pressure decline data. The least mismatched correlation pair was chosen to define the best fit model, which revealed the higher consistency with the experimental data within the saturation range. Final step is to combine experimental and numerical data to produce $K_r$ and $P_c$ curves. The curves are interpreted to identify the multiphase flow properties, including $S_{wi}$, Residual Oil Saturation ($S_{or}$), two-phase fractional flow, and $P_c$ response. This unified and multidimensional method enhances confidence in reservoir simulation by eliminating single experimental procedures to determine $K_r$ and $P_c$.

## Results and Discussion

### *History Matching Performance and Simulation Accuracy*

The history matching is the most crucial step in simulation setup, validating the data through SENDRA software. Five various correlation combinations of $K_r$ and $P_c$ were statistically tested using the oil production and differential pressure data from core flooding experiment as illustrated in Figure 4. The best correlation between the simulated and measured values was found to be the Sigmund-McCaffery $K_r$ and LET-Primary drainage $P_c$ combination correlations. This optimal combination reflects the least possible RSS value, which is a significant parameter in model performance assessment. The above correlation pairing established the best relation in oil recovery profiles and differential pressure response, as depicted in Figure 4(a-e). The curves resulting from this combination accurately represented the physical behavior of the system than other compared models, avoiding overprediction of pressure buildup or underprediction of oil recovery during early injection stages (Alakbari et al., 2025). These identified correlations assess the impact of $K_r$ and $P_c$ on displacement efficiency during secondary water flooding conditions. The capability of SENDRA software to adjust multiple flow properties based on history matching significantly improves its reliability compared to manual tuning methods. The results are aligned with previous studies and supported by (Jahanbakhsh, 2016; Li et al., 2003; Yousefzadeh et al., 2023).

The study confirms the reliability of multiphase flow simulation in porous media by selecting suitable flow function correlations, as described by (Cai et al., 2024). It also advocates for adaptive correlation modeling for estimation of $K_r$ and $P_c$ sensitive to saturation changes, especially under unsteady-state conditions (Yaralidarani et al., 2016; Yaralidarani et al., 2018).



(a) (b) (c) (d) (e)

*Figure 4: Estimation of differential pressure and oil production with different combination correlations: (a) Sigmund-McCaffery/ Skjaeveland; (b) Sigmund-McCaffery/ Bentsen Anli correlation; (c) Sigmund-McCaffery/ LET-Primary Drainage correlation; (d) LET/ LET-Primary Drainage correlation; (e) Chierci/ LET-Primary Drainage correlation.*

The consistency between simulation and laboratory data confirms the model robustness and validates the ability of SENDRA simulation to perform automated history matching with high accuracy (Shams et al., 2019). The study focused on the importance of integrating core-flooding data into simulation processes, keeping the flow parameters based on experimental behavior. The Sigmund-LET combination improves the confidence in reservoir development and oil recovery planning through the strong simulation accuracy, particularly in water-wet sandstone systems under secondary recovery conditions.

### *Relative Permeability ($K_r$) Curves Estimation*

$K_r$ curves are the key component of the multiphase flow behavior in porous media and are significantly affected by the hysteresis process. These curves are typically classified as the drainage (wetting phase displacement by non-wetting phase) or imbibition (non-wetting phase displacement by wetting phase) curves (Rostami et al., 2019; Suekane et al., 2015). In this study, the imbibition curves were generated, where the wetting phase (water) injected to displace the non-wetting phase (oil) under secondary conditions. Figure 5(a-d) illustrated the derived $K_r$ curves for oil and water versus Water Saturation ($S_w$) function, providing insights into displacement and wettability characteristic of the rock. The Sigmund-McCaffery Bentsen Anli and Sigmund-McCaffery Skjaeveland models both indicated a sharp change in Oil $K_r$ ($K_{ro}$) near Critical Water Saturation ($S_{wc}$), which causes less accurate history matching at intermediate saturations. In contrast, the Sigmund-McCaffery-LET Drainage and LET-LET Primary Drainage models generated smoother, more realistic curves in the two-phase flow regime between 40 and 72 percent $S_w$. This encourages a uniform decrease in oil mobility with a rise in water mobility, which is consistent with Corey-type behavior in Special Core Analysis (SCAL) experiments.

Further, it was observed from the $K_r$ curves that when $S_{wi}$ reached around 40%, indicating 60% oil saturation and water becomes immobile. At this stage single-phase oil flow controls the porous media. When water injection begins, $K_{ro}$ decreasing from its initial maximum value, indicating reduction in oil mobility as $S_w$ increases. Simultaneously, Water $K_r$ ($K_{rw}$) increasing, indicating enhanced wetting phase conductivity as water started moving through porous media. Between 40% and 72% $S_w$, both oil and water were mobile, establishing the two-phase flow regime. Above 72%, the system approaches to $S_{or}$, indicating 28% of oil flow essentially stopped.

These results are consistent with predicted action which reflects the strong water-wet reservoirs, where water saturates within smaller pore throats leading to an early water breakthrough and higher $S_{wc}$. The results are in consistent with conventional observations reported by Brooks et al. (1966), Gong et al. (2021) and Rostami et al. (2019), signifying definite

$S_{or}$ thresholds with sharp $K_{rw}$ rises after imbibition in two-phase behavior water-wet sandstones. Safari et al. (2015) reported that the two-phase system specifies a wide range of saturation in water-wet sandstones to characterize the flow transitions, as observed in the study. In addition, the intersection points of $K_{ro}$ and $K_{rw}$ curves in the saturation range, confirms the validity of the multiphase flow modeling, particularly in reservoir scale models (Cai et al., 2024). Validity of these curves reflects the effectiveness of the simulation methodology that involves the laboratory data in SENDRA history matching workflow to generate realistic functions. The study offers valuable information on the fluid flow behavior for secondary water flooding, describing reservoir wettability and flow regimes. The results are essential in designing water injection techniques, improving displacement rates, and hydrocarbon recovery in such reservoir conditions.

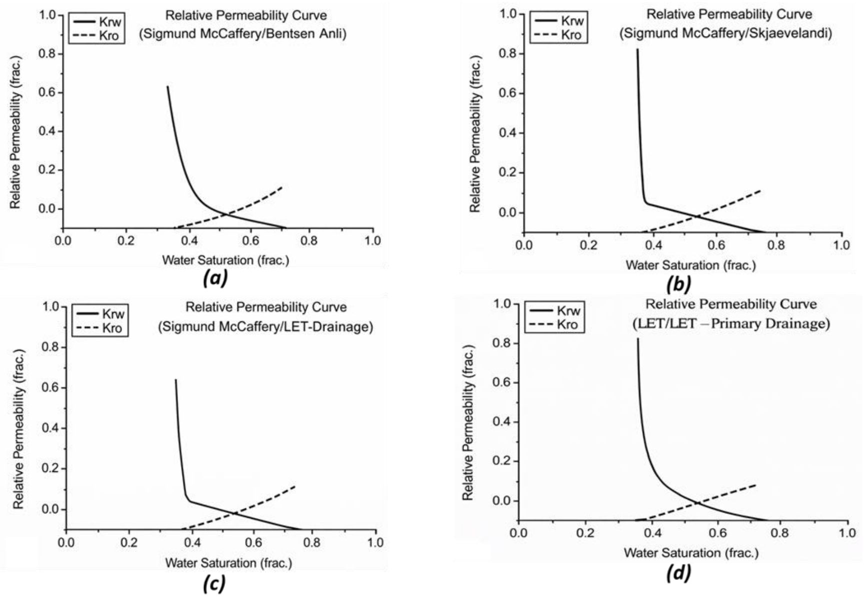


*Figure 5: $K_r$ curves for the examined combinations: (a) Sigmund McCaffery/Bentsen Anli correlation; (b) Sigmund McCaffery/Skjaeveland correlation; (c) Sigmund McCaffery/LET-Drainage correlation; (d) LET/LET-Primary Drainage correlation.*

### *Capillary Pressure ($P_c$) Curves Estimation*

$P_c$ is a key parameter in modelling multiphase flow in porous media for water-wet systems particularly, where wetting and non-wetting phase distribution in pore spaces strongly influences fluid displacement. This study represents the $P_c$ curve as a function of $S_w$ obtained from the simulated results based on various correlation combinations, as shown in Figure 6. It was observed that the most physically realistic and typical behavior existed with the LET–Primary Drainage relationship for $P_c$ coupled with Sigmund McCaffery for $K_r$. This relation collectively simulated the laboratory imbibition process more precisely and better than other combinations. The $P_c$ declined continuously with increased $S_w$, and reaches to zero above 45% approximately, as illustrated in Figure 6. This is due to the spontaneous imbibition process in water wet system, where water encroaches smaller pores, and moving oil and lowering interface curvature (Jamaloei et al., 2010). The decrease in interfacial curvature is directly equivalent to decreasing $P_c$, according to the Young–Laplace equation (Young, 1832). Similarly, water remains at its $S_{wi}$ below 40%, with maximum $P_c$ due to predominance of oil in the larger pores and water flow restriction (Shanley et al., 2004).

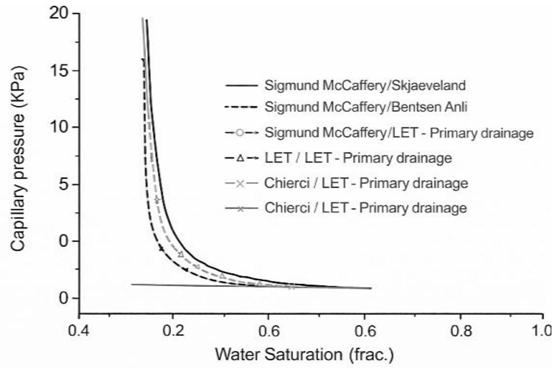


***Figure 6: $P_c$ curves for the examined correlation combinations.***

Further, all $P_c$ curves indicated a sharp decrease with increasing $S_w$ above 40% of $S_{wr}$, signifying the gradual intrusion of the wetting phase into smaller pore throats. The Sigmund-McCaffery-LET Primary Drainage and LET-LET Primary Drainage models represent a continuous decrease in $P_c$ to near negligible values, resembling with measured $P_c$ trends of water-wet sandstones. The combination of McCaffery and Bentsen-Anli correlations produced an unrealistic $P_c$ curve, where $P_c$ was still zero above only 38% $S_w$. This flow behavior simplifying the phase transition and overlooking the pore geometry effects. Such combination model is less suitable for quantitative displacement simulations, particularly under imbibition conditions. as highlighted by Chardaire-Riviere et al. (1990), representing the need for dynamic capillary forces in reservoir simulation. The decreasing $P_c$ curve by LET-Primary Drainage model is aligned with earlier studies by Brooks et al. (1966) and Yaralidarani et al. (2016). These studies demonstrated capillary effects to become insignificant at increased saturations (>45-50%), as proven through findings of this study. LET-Primary Drainage correlation model successfully simulates imbibition conditions to ensure smooth and continuous drop in $P_c$ over the appropriate saturation range. It supports the interface curvature and pore geometry limitations, which are usually oversimplified in conventional Corey-type models. Cai et al. (2024) and Jahanbakhsh & Sohrabi (2015) suggest such adaptive correlations in modeling capillary-sensitive flow processes, particularly when incorporating saturation profile information for history matching.

This analysis confirms the efficiency of the LET-Primary Drainage model in describing water-wet systems under imbibition conditions. The steep reduction of $P_c$ with increasing saturation beyond $S_{wc}$ is consistent with theory and increases the reliability of the combined experimental and numerical approach. Correct modeling of $P_c$ is important for the interpretation of displacement mechanisms and predictive simulation optimization in oil recovery processes.

## Discussion

The research involves the numerical modeling based on the core-flooding experiment results to determine the $K_r$ and $P_c$ in controlled conditions. The model was developed with the well-structured data set according to experimental constraints, providing opportunity to history match with several correlation combinations. SENDRA engine uses non-linear regression to estimate the best-fit parameters of the flow functions by minimizing interpretation time and errors. The methodology aims to establishing the $K_r$ versus $P_c$ curves, which the flow behavior within reservoir conditions. The SENDRA simulation provides the wide variety of various correlation combinations in order to enhance the interpretation level. The $K_r$-$P_c$ models were simulated with several pairs of correlations including Sigmund-McCaffery, Corey, LET and Bentsen-Anli combinations for comparison. This provides an extensive and efficient workflow for SCAL assessment, as presented by Egermann et al. (2005) and Zhao et al. (2020). They described that this combined experimental-numerical models improve the prediction of petrophysical characteristics in multiphase flow system. This workflow system utilizes iterative cycles for simulation and experiment that refines and cross-checks the each other step to get the final product. The usefulness of this approach is to history matching the saturation-profile data, which improving its reliability and predictability in intricate flow conditions, as demonstrated by Hussain (2024) and Hussain et al. (2021). Such numerical interpretation has shown the higher consistency between the lab and simulation outcomes. The best fit correlations like Sigmund-McCaffery and LET Primary Drainage correlations observed the minimal RSS values, which indicated that both flow functions mathematically and physically represent the imbibition process. The findings like onset of two-phase flow at 40% $S_w$ and oil stability near 28% $S_{or}$ significantly demonstrated the oil trapping models. The obtained $K_r$ curves resemble to Corey-type and published SCAL databases of similar sandstone systems. The water-phase $K_r$ signified with concave upward slope at the moderate saturation levels, while, the oil-phase curve exhibits a gradual fall. These characteristics are attributed to water-wetness behavior, which reflect the artificial numerical limitation and consistency of obtained correlations (Cai et al., 2024; Gong et al., 2021). The $P_c$ curve increases at low $S_w$ and decreases at low $S_{or}$ levels. Thes findings supports the model appropriateness as capillary-dominated, aligns with reported imbibition $P_c$ profiles (Alaamri et al., 2023). The RSS analysis showed the model sensitivity and specified that traditional Corey models may be inadequate to more accurately model nonlinear imbibition processes in certain sandstone reservoirs. This supports the necessity of wider correlation testing in SCAL integrated workflow simulation.

These results represent the essential need of laboratory data integration into the SCAL modelling simulation. This combined system allows testing of multiple correlation models at once without the use of extraneous experiments, signifying a foundation for the model choice. Eventually, this workflow enables the accurate reservoir modeling with increasing the confidence of resulting parameters and making SENDRA, a best tool for describing multiphase flows. Therefore, mitigating recovery prediction uncertainties and minimizing risks in reservoir management decisions.

## Conclusion

This study combines SENDRA modelling with core-flooding experiments to determine $K_r$ and $P_c$ cures simultaneously in multiphase flow system. Advanced correlation combinations were precisely simulated with laboratory measurements to characterize the multiphase flow during secondary water injection using SENDRA history matching. The Sigmund McCaffery and LET-Primary Drainage correlation was found to be the most accurate combination, provided the specific results with minimized residual errors between oil production and pressure differentials. The resulting flow curves reflected the behavior of water-wet sandstone reservoirs, where $S_{wi}$ was indicated at 40 percent with oil saturation remained at 28 percent. Two phase behavior was evident between 40 and 72 percent of $S_w$ in $K_r$ curves, displacing the trapped oil during secondary waterflooding. Whereas, the $P_c$ declined with increasing $S_w$, and reduced to zero at 45 percent of $S_w$ and above, signifying the water-wet system. In addition, the automated optimization of SENDRA has precisely evaluate the multiphase flow parameters, making estimation easier by decreasing interpretation time. This approach significantly provides an effective workflow for multiphase flow modeling during secondary recovery in sandstone reservoirs. Further, it is recommended to characterize three phase system in heterogeneous lithologies for both research and applied reservoir engineering.

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