Assessment of the Impact of Uncertainties in Relative Permeability Curves on Mature Oil Field Production: A Case Study in UNISIM-I-H

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Abstract. Relative permeability is a crucial parameter in reservoir characterization as it directly influences the behavior of the rock-fluid system and, consequently, oil production. However, estimating this parameter is difficult due to uncertainties originating from various sources, such as geology, measurement errors, parametric modeling, computational, etc. If not properly examined, these uncertainties might undermine prediction accuracy and impair final production. Over time, several correlations were created to estimate relative permeability better. For mature oil fields, a novel kind of industry for Brazil, the research of relative permeability and associated uncertainties is still in its early stages. The main objective of this study is to numerically investigate the effects of uncertainties on relative permeability curves via the software CMG® and the geological model UNISIM-I-H developed by UNICAMP. The LET correlation was used to describe the relative permeability curves. Initially, a base case known as UNISIM-I-H was simulated, upon which the remaining analyses were built. This case consisted of a 15-year production phase followed by a 5-year production pause, a 10-year production restart, the abandonment of the three less productive wells, and the drilling of the three new wells to better represent a mature oil field. Four cases were created with relative permeability parameter uncertainties increased by 5%, 10%, 15%, and 20%. The effects of these uncertainties on the relative permeability curve, production curve, net present value, and recovery factor were then examined. The data analysis revealed that these uncertainties mostly affect the forecasts relating to net present value, reservoir recovery factor, and cumulative production, with the latter being the most impacted. Every uncertainty case increased the maximum and minimum values of the curves. Compared to the base case, an intriguing pattern also showed up, where the maximum increased much more quickly than the minimum, suggesting that the risk of estimating the values for each curve above the actual is significantly higher with increasing uncertainty than the opposite.

Keywords: SCAL; Enhanced Oil Recovery; Black Oil Simulation; Uncertainty.

1 Introduction

Permeability data (k_r) is essential for calculating fluid flow in hydrocarbon reservoirs, serving as a critical property to describe multiphase flow in porous media. These data are used to estimate productivity, injectivity, and ultimate recovery of reservoirs, which is pivotal for the assessment and planning of production operations. Moreover, they can diagnose formation damage under various operational conditions, making them one of the most important datasets for reservoir simulation studies [1].

Accurate understanding and modeling of permeability are therefore vital for predictions and decision-making in exploration and reservoir production projects [2]. However, determining permeability involves inherent uncertainties in the techniques used. Uncertainties are present in all phases of a petroleum field lifetime and are mainly associated with geological characteristics, economics, and technological parameters[3]. According to Berg et al. [4], these uncertainties arise from three main sources: (1) variation among samples from the same formation or rock type and sample heterogeneity, (2) experimental errors in raw data during special core analysis experiments, such as noise in pressure and saturation measurements, and (3) interpretation uncertainties, including errors based on models. Addressing these uncertainties is crucial to ensure the accuracy of k_r data and, consequently, the effectiveness of production operations and reservoir simulation.

Advanced techniques, such as the design of experiments, response surface methodology, and Monte Carlo simulations, stand out for their probabilistic approach to predicting production scenarios. Monte Carlo simulation, also known as the Monte Carlo method or multiple probability simulation, is a mathematical technique used to estimate the possible outcomes of an uncertain event. This statistical technique assumes knowledge of the probability distribution $f_x(x)$. This approach is particularly valuable in situations such as the study of oil reservoirs, where field sampling is unfeasible due to practical constraints or high costs.

The essence of Monte Carlo simulation lies in controlled randomness. To construct a sampling experiment, it is essential to have access to a "random entity," ensuring that the samples are representative and unbiased. Controlled randomness allows the creation of diverse scenarios, reflecting the complexity and uncertainties inherent in an oil reservoir. Uncertainty quantification using Monte Carlo Simulation (MCS) is an increasingly important part of reservoir simulation workflows. MCS uses random sampling as a way to estimate underlying distributions of a physical or mathematical phenomenon, and it is used extensively for uncertainty quantification.[5]

Several studies have investigated relative permeability models, considering the uncertainty in experimental data. Berg et al. [4] provides a framework for a consistent assessment of the uncertainty of relative permeability measurements by extracting relative permeability from experimental core flooding measurements through inverse modeling with the numerical solution of the two-phase Darcy equations. The authors noted that an assisted history fitting strategy, which uses Levenberg-Marquardt optimization and an adequate representation of the relative permeability and pressure-capillary saturation functions, offers a more realistic description of the data and uncertainty, significantly reducing error compared to manual interpretation.

Valdez et al. [6] investigated the impact of input uncertainty on the performance of petroleum reservoirs through uncertainty quantification and sensitivity analysis of various relative permeability models using polynomial chaos expansion. The authors observed that uncertainties in these models strongly influence performance predictions.

Ranaee et al. [7] studied the effects of parameter uncertainty in three-phase relative permeability models under Water Alternating Gas (WAG) conditions using Monte Carlo simulations. They found that parameter uncertainty significantly impacts reservoir simulation results, including hysteresis, ultimate oil recovery, and gas-to-oil ratio (GOR). Additionally, according to the authors, Stone's formulations, together with the Larsen and Skauge (1998) model, provide oil recovery values within the Monte Carlo (MC) uncertainty limits and GOR values lower than those obtained with the Baker model, both outside the MC-based confidence interval.

Considering these previous studies, this article aims to explore the impacts of uncertainties in relative permeability curves in hydrocarbon reservoir simulation, highlighting the critical role it plays in estimating productivity and the recovery factor. We aim to address the inherent uncertainties associated with permeability measurements and their impact on reservoir simulation accuracy for a mature field scenario.

2 Methodology

A comprehensive preliminary study of the model data is performed in the initial phase. This step involves extracting essential petrophysical and geological information and establishing the entire project's foundational parameters. Moving forward, multiple relative permeability curves are generated randomly using the LET formulation during the computer simulation stage. This process adheres to the proposed uncertainty ranges and employs Monte Carlo sampling techniques. Subsequently, simulations are executed to propagate these uncertainties.

2.1 Model Description

To represent Brazilian mature fields, the selected reservoir model is UNISIM-I-H. The reference model was built in a high-resolution geocelular model, using public data from Namorado Field, Campos Basin, Brazil.[8]. The Namorado Field primarily consists of turbiditic sandstone, making it an excellent representation of most Brazilian mature oil fields, which are predominantly sandstone.

The choice of this model was also due to its being a market benchmark, with a wide variety of previously published articles, which could assist in data studies and indicate confidence in the model's results. In addition, the model is easy to access. The model, created based on the Namorado field, represents a sandstone reservoir with turbidite origin with dimensions of 81 × 58 × 20 cells, where each cell has a size of 100 × 100 × 8 m³. The 3D seismic volume and 2D seismic lines are presented in the ANP public dataset. These data are used to obtain structural (reservoir limits, top, bottom, sequences, and faults) and sedimentology (zones and horizons) information for reservoir characterization.[8]

To accurately represent a mature reservoir, the model is adjusted to encompass a 15-year production period, simulating the initial phase of a greenfield project—developments in previously unexplored locations. Following this, a 5-year interval represents the transition phase, including another company's sale and acquisition of the project. Subsequently, a new 10-year production period is introduced, reflecting the brownfield stage—projects in already explored and mature fields. Other relevant information about the model is presented in Table 1.

Table 1. UNISIM-I-H Model Data

Properties	**Values**
API°	28
Initial Pressure [$\frac{kgf}{cm^2}$]	320
Depth [m]	2860 a 3360
Oil Phase Viscosity [cP]	0.3
Temperature [°C]	80

2.2 LET Correlation

Several predictive models have been proposed, idealizing the porous medium as a bundle of capillaries. The flow through a single capillary is described mathematically, then the total flow through the entire set of capillaries is obtained using the concept of capillary pressure. Some published models based on this strategy include Corey's model for drainage, Naar-Wygal's and Naar-Henderson's models for imbibition, and Land's model for both drainage and imbibition processes.[1]

According to [9], a frequent characteristic of the published correlations seems to be that none of them can describe the relative permeability curves in the entire saturation range, i.e., for low, intermediate, and high water saturations. The Corey model and similar models often show limitations in exhibiting the flexibility necessary to represent relative permeability over the entire saturation range. The choice of this model is since it presents greater degrees of freedom compared to other models, in addition to more accurately representing the relative permeability curve over a wider range of water saturation.

The proposed correlation is described by 3 parameters: L, E, and T. For a water-oil flow, the parameters for oil relative permeability are written as L_o^w, E_o^w, T_o^w To where the subscript denotes the oil phase and the superscript denotes the water phase. [9]

$$k_{row} = k_{ro}^x \frac{(1 - S_{wn})^{L_o^w}}{(1 - S_{wn})^{L_o^w} + E_o^w S_{wn}^{T_o^w}} \tag{1}$$

$$k_{rw} = k_{rw}^x \frac{S_{wn}^{L_w^o}}{S_{wn}^{L_w^o} + E_w^o S_{wn}^{T_w^o}} \tag{2}$$

Where the equation for the normalized water saturation is:

$$S_{wn} = \frac{S_w - S_{wi}}{1 - S_{wi} - S_{orw}} \tag{3}$$

The LET correlation is developed for use in special core analysis and reservoir simulation in general. [9].

2.3 Uncertainty Analysis

The *CMG* software, alongside a *JavaScript* code developed by a researcher from the Advanced Petroleum Recovery Laboratory (LRAP) cited at UFRJ, is utilized to create relative permeability curves for the model using the LET correlation. This code was specifically designed to generate a distribution of points for the relative permeability curve (K_r) in relation to water saturation (S_w), using the permeability curve data from the UNISIM-I-H model as a reference. Table 2 shows the parameters for the base case, upon which the uncertainties were applied, where $K_{ro}@S_{wi}$ is the relative oil permeability at initial water saturation; $K_{rw}@S_{or}$ is the relative water permeability at residual oil saturation; L_{wo}, E_{wo} and T_{wo} LET parameters for the water relative permeability curve; L_{wo}, E_{wo} and T_{wo} LET parameters for the oil permeability curve.

Table 2. Relative permeability curve data and LET parameters.

Parameter	Value
S_{wi}	0.17
S_{or}	0.18
$K_{ro}@S_{wi}$	0.58
$K_{rw}@S_{or}$	0.42
L_{ow}	3
E_{ow}	2
T_{ow}	1
L_{wo}	3
E_{wo}	2
T_{wo}	1

For this study, five distinct cases are presented. The first case, referred to as the base case, represents the actual production of the oil field with no uncertainty in the parameters of the relative permeability curve. This base case serves as a reference for the subsequent analysis of the other cases. The other cases, labeled A through D, represent variations of the base case with increasing uncertainty increments of 5% in the parameters of the relative permeability curve, starting with 5% for case A and reaching up to 20% for case D. Each case undergoes approximately 500 simulations using the Monte Carlo sampling technique, assuming a uniform distribution of uncertainty, facilitated by the *CMG* software. Table 3 shows the parameters for the base case, upon which the uncertainties were applied.

Table 3. Base Case Parameters

Base Case Parameters	
Total Production Time (years)	30
Accumulated Production of the Whole Productive Life of the Field [MMm³]	15,5
Accumulated Production of the Whole Productive Life of the Field [MMbbl]	97,4
Accumulated Production of the Productive Life of the mature field [MMm³]	2,9
Accumulated Production of the Productive Life of the mature field [MMbbl]	18,2
Recovery Factor - RF [%]	49,1

3 Results and Discussions

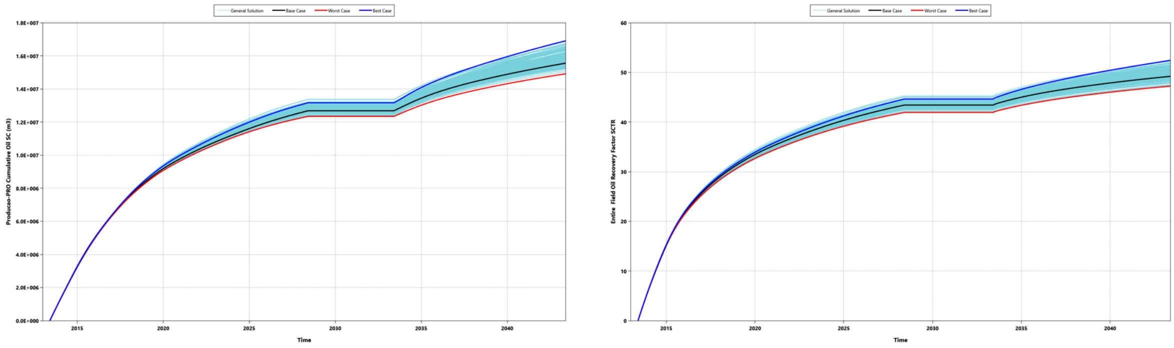
The curves presented below were generated from variations in the parameters listed in Table 2, providing a detailed understanding of the nuances of reservoir behavior. Additionally, the production curves of the reservoirs, which result from these variations in the permeability curves, are presented.

After completing the simulation, the Cumulative Oil Production and Recovery Factor curves were generated, covering the entire production period of the field. The analysis includes four cases where the properties of the LET correlation relative permeability curves were modified by 5%, 10%, 15%, and 20% relative to the base case. These variations enhance the understanding of the impact of uncertainties on the results. Each case was evaluated individually, observing the accumulated production parameters and the recovery factor, allowing for a detailed assessment of the effects of these uncertainties.

3.1 Case A - 5% Uncertainty

In Case A, the parameters of the relative permeability curves exhibit an uncertainty of 5%. This uncertainty significantly impacts the projected production outcomes. The results indicate that the maximum accumulated production could reach 16.9 Mm³, while the minimum could drop to 14.9 Mm³. These figures represent a production variation of roughly 10% higher and 4% lower compared to the base case, respectively.

For the recovery factor, the observed extremes were 52.4% at the maximum and 47.2% at the minimum, compared to the base case value of 49.2%. This variation suggests a slight tendency for estimates to exceed the base case, indicating that the parameters' uncertainties may positively influence the projected outcomes.



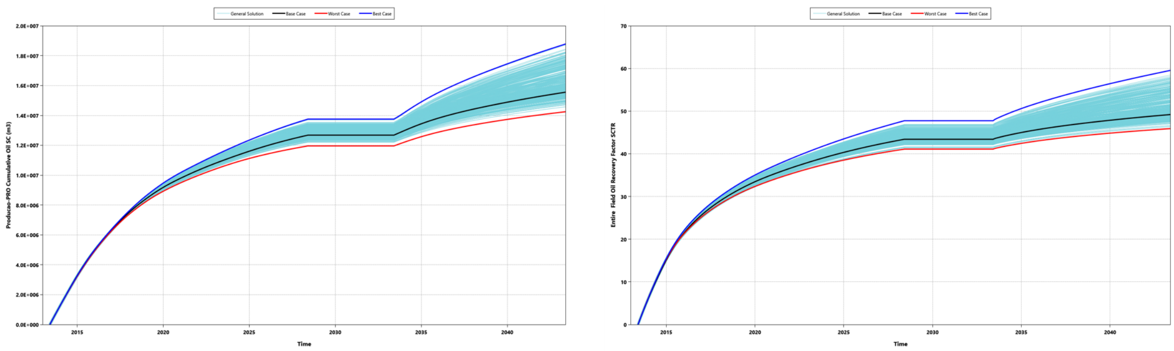
(a) Cummulative Oil Production for Case A.

(b) Recovery Factor for Case A.

Figure 1. Uncertainty curves associated with accumulated oil production and recovery factor for case A.

3.2 Case B - 10% Uncertainty

In Case B, where a 10% uncertainty was introduced to the parameters of the relative permeability curves, the accumulated oil production curves exhibited a maximum value of 18.79 Mm³ and a minimum of 14.2 Mm³. These values represent a production variation of approximately 21% higher and 8.4% lower than the base case. Additionally, the recovery factor ranged from 45.9% to 59.5%. These results indicate a substantial increase in the amplitude of the production curves, underscoring that as uncertainties rise, making reliable production forecasts becomes increasingly challenging.



(a) Cummulative Oil Production for Case B.

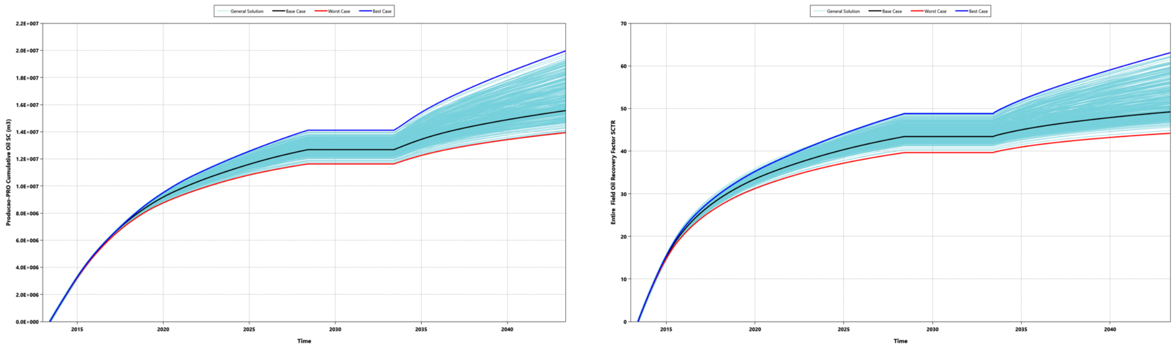
(b) Recovery Factor for Case B.

Figure 2. Uncertainty curves associated with accumulated oil production and recovery factor for case B.

3.3 Case C - 15% Uncertainty

In Case C, where a 15% uncertainty was introduced into the parameters of the relative permeability curves, the analysis of the accumulated oil production curves reveals significant extremes. The maximum value reaches 19.9 Mm³, while the minimum is 13.9 Mm³. This variation represents approximately 28% more and 10.32% less production compared to the base case. These results underscore the system's sensitivity to variations in the parameters outlined in Table 3, highlighting the wide range of possible estimates and the substantial influence of uncertainty on reservoir production projections.

The recovery factor in Case C also exhibits a wide range, from 44.2% to 63.1%. This indicates a higher probability of overestimating the data if the base case, which recorded a recovery factor of 49.22%, is considered the actual production. The likelihood of estimating a value above the real production is relatively greater than underestimating it. This observation further reinforces the significant influence of uncertainty in estimating the recovery factor.



(a) Cummulative Oil Production for Case C.

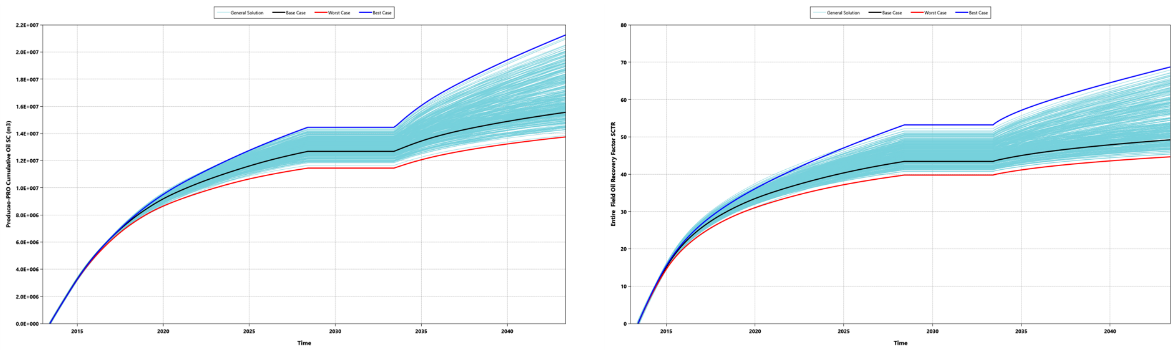
(b) Recovery Factor for Case C.

Figure 3. Uncertainty curves associated with accumulated oil production and recovery factor for case C.

3.4 Case D - 20% Uncertainty

In Case D, where a 20% uncertainty was incorporated into the parameters of the relative permeability curves, the accumulated oil production curves displayed notable extremes. The maximum value reached 21.2 Mm³, while the minimum value was 13.7 Mm³. This variation represents a significant difference of approximately 36.8% higher and 11.6% lower compared to the base case output.

Regarding the recovery factor in Case D, it varies widely from 43% to 68.7%. Similar to the accumulated production scenario, this analysis indicates a higher risk of overestimating the real value compared to underestimating it. This further emphasizes the impact of uncertainty on production forecasts.



(a) Cummulative Oil Production for Case D.

(b) Recovery Factor for Case D.

Figure 4. Uncertainty curves associated with accumulated oil production and recovery factor for case D.

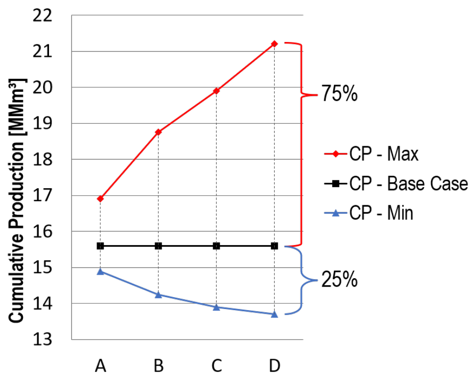
3.5 Results Analysis

Table 4 presents the data for each case from A to D, as well as the base case, detailing the Accumulated Production and the Recovery Factor (RF). By examining this table, it becomes evident that as the uncertainty increases, there is a higher probability of overestimating both the Accumulated Production and the Recovery Factor relative to the base case values. This trend underscores the substantial impact of uncertainty on the accuracy of reservoir production projections.

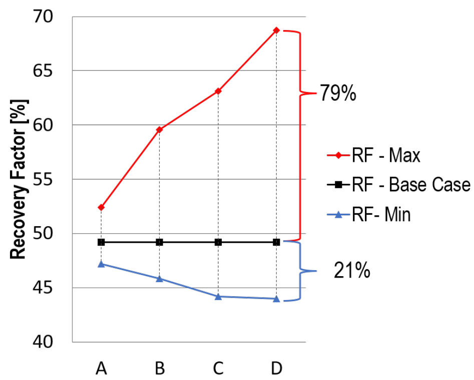
Table 4. Uncertanties Cases

	Accum. Prod. Max	Accum. Prod. Min	RF Max	RF Min	Uncertainty
Base Case	97,4	97,4	49,1	49,1	0%
Case A	106,3	93,7	52,4	47,2	5%
Case B	117,9	89,6	59,6	45,8	10%
Case C	125,1	87,4	63,1	44,2	15%
Case D	133,3	86,2	68,7	44,0	20%

By observing the table, it is clear that both the Accumulated Production and the Recovery Factor show a trend of higher estimates as the level of uncertainty increases, indicating a greater likelihood of overestimating compared to the base case.



(a) Cummulative Production Relative to the Base Case.



(b) Recovery Factor Relative to the Base Case.

Figure 5. Uncertainty Growth Relative to the Base Case.

The Graph 5a illustrates the increasing distance from the base case as uncertainty grows, depicted in blue for the maximum values and in red for the minimum values. For a 20% uncertainty in the the relative permeability curve parameters, the maximum accumulated production is nearly 75% higher than the base case, while the minimum accumulated production is about 25% lower. A similar pattern is observed for Graph 5b, where the maximum value achieved is 79% higher, and the minimum value is 21% lower than the base case.

By examining both the table and the graphs, it is evident that both the Accumulated Production and the Recovery Factor exhibit a trend of higher estimates as the level of uncertainty increases. This trend indicates a greater likelihood of overestimating these values compared to the base case, highlighting the significant impact of uncertainty in the relative permeability on production forecasts.

4 Conclusions

The study on the impact of uncertainties in relative permeability curves on mature oilfield production using the UNISIM-I-H model provided valuable insights. The simulations revealed significant variations in cumulative oil production and recovery factors by varying the LET correlation parameters. As uncertainty levels increased from 5% to 20%, the range of production estimates widened, highlighting the need for accurate permeability data to ensure reliable predictions. The high sensitivity of the reservoir model to these parameter changes highlights the importance of accurate estimates in reservoir simulations.

Furthermore, the analysis showed that increased uncertainty led to higher maximum recovery factors, suggesting a tendency to overestimate potential recovery, as the degree of uncertainty increases, the chance of estimating a final production result above the expected real value, can approach 75%. This consistent pattern of overestimation poses risks to production planning and decision-making. The study highlights the critical need for careful consideration of uncertainties in reservoir simulations and the importance of advanced characterization techniques and robust uncertainty quantification methods to improve the accuracy and reliability of production forecasts.

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