Estimation of Matrix Flow Contribution in Naturally Fractured Reservoirs

Justin Brand Ferrell
PhD Thesis

Centre for Energy Resources Engineering
Department of Chemical and Biochemical Engineering
Technical University of Denmark
Kongens Lyngby, 2800
Denmark

17th May, 2018
Affidavit

I declare in lieu of oath that I wrote this thesis and performed the associated research myself using only literature cited in this volume.

____________________________________
Justin Brand Ferrell, 06 July 2018
Preface

This thesis has been submitted in support of fulfilling the PhD degree at the Technical University of Denmark (DTU). The work has been carried out within the Department of Chemical and Biochemical Engineering and in collaboration with the Centre for Energy Resources Engineering (CERE) from August 2015 to May 2018 under the supervision of Alexander Shapiro.

I would like to personally thank Alexander Shapiro for his support of this project, as well as, his consistent patience and openness in advising me throughout the programme. It must have been a challenge for him to supervise this project given the unusual working locations and sporadic timing I performed these studies under while working within the industry. However, Alexander was always there to support me regardless the circumstances, and to ensure that I made the necessary progress. Thank you, Professor Shapiro.

I would also like to thank Patricia Wagner for her help with initiating the PhD programme in 2015, and for her support to me in navigating all of the university processes along the way these last three years to ensure I was always in good standing. Thank you, Patricia.

Of course, I must also thank Anne Louise Biede for her consistent positive energy, and in helping me feel part of the wider DTU Kemiteknik and CERE community. Louise was always willing to make the extra effort to get me involved in community activities, and I thank her for it.

I would like to thank Professor Emeritus Zoltan Heinemann for his support and constant inspiration, Professor Heinemann’s research group (PHDG), as well as, Montanuniversität Leoben for allowing me an external research opportunity to further progress this project. None of this would have been possible without Professor Heinemann’s support.

Lastly, and most importantly, I would like to thank my wife, Sara, and my son, Davis, for their personal sacrifices, and never-ending support in allowing me to pursue a life-long goal of completing a doctoral degree. None of this could have been possible without their love, patience, and understanding.

Justin Brand Ferrell

17th May 2018
Kongens Lyngby, Denmark
This dissertation is dedicated to my grandfather, Othal Brand, who taught me the value and importance of a higher education, and motivated me to continuously better myself.
Abstract

Naturally fractured carbonate reservoirs (NFRs) account for a majority of the world’s proven oil reserves (~60%), and a significant portion of proven gas reserves (~40%), as well. However, the petroleum industry as a whole is quite far behind in its understanding of these reservoir systems especially in comparison to single porosity reservoirs with or without induced fracturing/stimulation, i.e. a more recent industry trend with the onset of shale/tight formation development and production.

NFRs are most often modelled as dual porosity systems with a separate matrix and fracture porosity and their each own associated characteristics. NFRs can then be categorized by types (1-4 with 1 being almost entirely fracture storage and 4 being a majority in matrix) in accordance to the Shell 1955 classification system, and this dual porosity definition. This is a static oil/gas storage categorization only, and does not account for dynamic behaviour, i.e. how the field behaves in development/production scenarios.

A majority of the reservoirs currently in development are of type 1 or 2 meaning that their static classification would indicate that a majority of the oil or gas is in the fracture system with low matrix porosity (< 5% avg). Traditional porosity vs permeability plots from core samples would utilize a porosity cut-off based on 10-30 °API oil type that would negate almost the entire matrix system resulting in little to no recoverable volumes from the reservoir matrix. The matrix stock tank oil initially in place (STOIIP) even for low matrix porosities are still significant, and can comprise 50-80% of the overall STOIIP for a type 1 NFR. The current industry approach would then be to model the entire reservoir system as a fracture system only (single porosity), artificially increase fracture porosity to offset this eliminated matrix STOIIP, and ignore the matrix flow contribution. Of course, this often leads to scenarios of overestimated production performance, and underestimated ultimate recovery given this fracture only approach to NFRs. Many attempts have been made throughout the decades with little success to properly model the actual dual continuum behaviour of dual porosity NFR systems including with transmissibility terms, discretized shape factors, etc., however, with little success in industrial application.

The issue remains as to how to estimate the recoverable resources/reserves from the matrix of NFRs, and to also be able to do this for all stages of field life (appraisal to production). This gap is a significant industrial issue in that any improvement or new methodology to help estimate matrix contribution can have significant material impacts on NFR development planning, reserves/asset value, reservoir and production management, etc. The goal of this PhD project is to provide an appropriate method that takes into account the dual continuum behaviour of the matrix and fractures in the application of reserves estimation and development planning.
Dansk Resumé

Naturligt brudte karbonatreservoirer (NFR) indeholder de fleste beviste verdensreserver af olie (~60%), ligesom et betydeligt antal af beviste gasreserver (~40%). Olieindustrien, som helhed, er dog ret langt bagefter vedrørende forståelsen af disse reservoirsystemer, især i sammenligning med enkelt porøsits reservoirer med eller uden induceret frakturering/stimulering, dvs. en nyere tenden indenfor industrien med indvindingen og produktionen af skiffer og tæt reservoirer.

NFR'er er oftest modelleret som dobbelt porøsits reservoirer med en porøsitet for matrix og brud og hver deres tilhørende karakteristika. NFR'er kan derefter kategoriseres efter typer (1-4, hvor 1 er næsten udelukkende akkumulering i sprækker, og 4 er største volumen i matrix) i overensstemmelse med Shell 1955 klassifikationssystemet og deres definition af dobbelt porøsitet. Dette er kun en statisk karakterisering af olie- og gasreserver, og den tager ikke højde for dynamisk adfærd, det vil sige hvordan feltet opfører sig i løbet af indvinding og/eller produktion.

Et flertal af de reservoirer, der i øjeblikket er i indvindingen, er af type 1 eller 2, hvilket betyder, at deres statiske klassificering vil indikere, at størstedelen af olien eller gasen er i brudssystemet med lav matrixporøsitet (<5% avg). Traditionelle plotter af porøsitet vs permeabilitet fra kerneprøver ville udnytte en porøsitsafskæring baseret på en olie af 10-30 ° API, som ville tilsidesætte produktionen fra næsten hele matrixsystemet, hvilket vil resultere i en lille til ingen genskabelig volumen fra reservoirer matrixen. Olien der oprindeligt er på plads i matrix (STOIIP), selv for lave matrixporøsiteter, er stadig signifikant og kan omfatte 50-80% af den samlede STOIIP for en type 1 NFR. Den nuværende industrielle tilgang ville da være modelleringen af hele reservoir som et sprækkesystem (enkelt porøsitet), kunstigt øge sprækkeporøsiteten for at kompensere for denne eliminerede matrix STOIIP og ignorere bidraget af matrixen i strømmen. Selvfølgelig fører dette ofte til scenarier af overvurderet produktion og undervurderet slutningsproduktionen fra en NFR. Mange forsøg er blevet gennemført i løbet af årtierne med ringe succes til korrekt at modellere den faktiske dobbelte kontinuumadfærd af dual-porøsitet-NFR-systemer, herunder med overførselsbetingelser, diskretiserede formfaktorer mv.; dog med ringe succes i industriel anvendelse.

Spørgsmålet er, hvordan man vurderer indvindingsressourcerne/reserverne fra matrixen af NFR'er, samt at kunne gøre dette for alle faser af feltlivet (fra vurderingen til produktionen). Dette er et væsentligt industrielt problem, idet enhver forbedring eller ny metodologi til at skønne matrixbidraget kan have væsentlige konsekvenser for NFRs udviklingsplanlægning, reserver / aktiv evaluering, reservoir og produktionsstyring mv. Formålet med dette ph.d.-projekt er at tilvejebringe en hensigtsmæssig metode, der tager hensyn til matrixens og frakturernes dobbelte kontinuitetsadfærd ved anvendelse af reserver evaluering og indvindingsplanlægning.
## Contents

Chapter 1 Introduction ........................................................................................................ - 13 -

1.1 Motivation of the work .............................................................................................. - 13 -
  1.1.1 Background .......................................................................................................... - 13 -
  1.1.2 The Objectives ..................................................................................................... - 14 -
  1.1.3 Relevance ............................................................................................................. - 14 -

1.2 The Approach ............................................................................................................. - 16 -
  1.2.1 Working Environment ....................................................................................... - 16 -
  1.2.2 Previous Related Works ..................................................................................... - 16 -
  1.2.3 Software Tools ..................................................................................................... - 17 -

1.3 Outline ......................................................................................................................... - 18 -

1.4 Related Publications of the Author ......................................................................... - 19 -

1.5 References ................................................................................................................... - 19 -

Chapter 2 Literature Review ............................................................................................ - 21 -

2.1 Naturally Fractured Reservoirs Recovery Processes ............................................ - 21 -

2.2 The Dual Continuum Concept ................................................................................. - 22 -
  2.2.1 Matrix Blocks and Simulation Cells ................................................................. - 23 -
  2.2.2 Time-Dependent Source/Sink Functions ......................................................... - 23 -
  2.2.3 The Transfer Function and the Shape Factor .................................................. - 24 -

2.3 Discrete Fracture Modelling (DFM) ........................................................................ - 28 -

2.4 Single Matrix Block Simulation ................................................................................ - 29 -

2.5 Theory of Characterization of Naturally Fractured Reservoirs (NFRs) ............. - 31 -
  2.5.1 Naturally Fractured Reservoirs (Definitions) ................................................. - 31 -
  2.5.2 Classification of Naturally Fractured Reservoirs ........................................... - 32 -
  2.5.3 Definition and Classification of Fracture Modes ............................................. - 34 -
  2.5.4 Fracture Orientation ........................................................................................... - 35 -
  2.5.5 Dilating Fractures ............................................................................................... - 36 -
  2.5.6 Shear Fractures .................................................................................................... - 37 -
  2.5.7 Stylolites ............................................................................................................... - 37 -
  2.5.8 Characterization of Naturally Fractured Reservoirs ..................................... - 38 -
  2.5.9 Spatial Organization of Reservoir Fractures ................................................... - 40 -
  2.5.10 Methodologies to Characterize Fractured Reservoirs ................................. - 42 -
    2.5.10.1 Geomechanical Approach ........................................................................ - 42 -
    2.5.10.2 Discrete Fracture Network (DFN) ........................................................... - 43 -
    2.5.10.3 Continuous Fracture Modelling (CFM) .................................................. - 44 -
    2.5.10.4 Seismically Driven Fracture Modelling .................................................. - 45 -
    2.5.10.5 Fracture Indicator Definition ................................................................... - 46 -

2.6 References ................................................................................................................... - 46 -

Chapter 3 Methods ............................................................................................................ - 51 -
3.1 Approach ..................................................................................................................... - 51 -
3.2 Dual Continuum NFR Workflow with Recovery Curve Method ................. - 51 -
  3.2.1 Abstract ................................................................................................................ - 51 -
  3.2.2 Introduction ......................................................................................................... - 52 -
    3.2.2.1 Objective, Content and Scope .................................................................... - 52 -
    3.2.2.2 Modelling Fracture-Matrix Fluid Transfer .............................................. - 53 -
      The Reiss et al. approach .................................................................................... - 53 -
      The Kazemi et al. approach ............................................................................... - 54 -
      The Heinemann and Mittermeir approach ..................................................... - 55 -
    3.2.2.3 Recovery-Curve Workflow for Numerical Simulation ....................... - 56 -
  3.2.3 The Field Case ..................................................................................................... - 57 -
    3.2.3.1 Background .................................................................................................. - 57 -
    3.2.3.2 Field Description ......................................................................................... - 57 -
    3.2.3.3 Application of the Recovery-Curve Workflow for Numerical Simulation - 60 -
      Single Matrix Block Simulation elaboration on initial recovery and resaturation curves ................................................................. - 60 -
      Dual Porosity Material Balance – Tuning of recovery and resaturation curves by phase contact matching ................................................................. - 62 -
      Single Matrix Block Simulation – Determination of apparent matrix properties ............................................................................................................. - 67 -
      Investigation of numerical column model ..................................................... - 69 -
      Full-field simulation using recovery curves ................................................... - 70 -
  3.2.4 Summary and Conclusions ............................................................................... - 72 -
  3.2.5 Acknowledgements ............................................................................................ - 72 -
  3.2.6 Nomenclature ...................................................................................................... - 72 -
    3.2.6.1 Greek symbols ............................................................................................ - 73 -
    3.2.6.2 Subscripts ...................................................................................................... - 73 -
    3.2.6.3 Greek subscripts .......................................................................................... - 73 -
    3.2.6.4 Superscripts .................................................................................................. - 73 -
  3.2.7 Conversion Factors ............................................................................................. - 73 -
  3.2.8 References ............................................................................................................ - 74 -
3.3 Deconvolution ............................................................................................................ - 76 -
  3.3.1 Abstract ................................................................................................................ - 76 -
  3.3.2 Introduction ......................................................................................................... - 76 -
  3.3.3 Deconvolution of transient pressure and rate responses .............................. - 77 -
  3.3.4 Deconvolution experiments (synthetic data).................................................. - 78 -
    3.3.4.1 Case 1 ............................................................................................................ - 78 -
    3.3.4.2 Case 2 ............................................................................................................ - 80 -
    3.3.4.3 Findings on Case1 and Case 2 ................................................................... - 82 -
  3.3.5 Deconvolution with rate fluctuations .............................................................. - 83 -
  3.3.6 Deconvolution with rate measurement errors .............................................. - 84 -
  3.3.7 Deconvolution with sparse data ....................................................................... - 85 -
  3.3.8 Multiple interference response ......................................................................... - 85 -
  3.3.9 Case study ............................................................................................................ - 88 -
  3.3.10 Description of available information ............................................................. - 89 -
List of Figures

Figure 1: Fractured Rock, Matrix cell vs. matrix block, (by Roxar training) ........................................... - 23 -
Figure 2: Idealization of a fractured reservoir (after Warren and Root 1963) ........................................ - 25 -
Figure 3: A geological image depicting an overall view and zoom (with the matrix discretization utilising triangles); after Bourbiaux et al., 1999 ................................................................. - 29 -
Figure 4: Single-porosity model vs. dual-porosity model (form Su et al. 2013) ..................................... - 30 -
Figure 5: Error estimate of the single-porosity model and various cases of dual porosity model (form Su et al. 2013) ................................................................................................................... - 31 -
Figure 6: Classification of naturally fractured reservoirs (Nelson, 1992) ............................................... - 33 -
Figure 7: Fracture Classification of Lawn and Wilshaw (1975) ............................................................. - 35 -
Figure 8: Fracture orientation with respect to the three principal stresses ........................................... - 36 -
Figure 9: Joints in dolomite layers; the mean fracture spacing in the 3.0 m thick bottom layer is approximately 0.15m ................................................................................................................. - 36 -
Figure 10: Shear Fracture ........................................................................................................................ - 37 -
Figure 11: Limestone exhibiting stylolites ............................................................................................. - 38 -
Figure 12: Example of a fracture swarm in the Aalenian Limestone, southern France (from Geosciences Montpellier) .................................................................................................................. - 41 -
Figure 13: Typical vertical pressure profiles obtained from RFT measurements for a layered reservoir showing barriers to vertical flow in several wells (each color denotes an individual well) .............................................................................................................................. - 42 -
Figure 14: Structural reconstruction in geomechanical methods (example image) .............................. - 43 -
Figure 15: A Typical DFN model cube ................................................................................................ - 44 -
Figure 16: General Continuous Fracture Modelling Workflow ............................................................ - 45 -
Figure 17: Schematic representation of recovery curve based workflow for dynamic modelling of NFRs ................................................................................................................................. - 53 -
Figure 18: Estimation of the time and recovery factor on a gas recovery curve at the beginning of the time-step ............................................................................................................................ - 56 -
Figure 19: ABC-Field production and average pressure history ............................................................ - 58 -
Figure 20: Top depth of the ABC-Field with well locations ................................................................. - 59 -
Figure 21: Water-oil capillary pressures and relative permeabilities ................................................... - 59 -
Figure 22: Gas-oil capillary pressures and relative permeabilities ....................................................... - 60 -
Figure 23: The quarter of an SMB model (a) fully surrounded by fractures and (b) bounded by vertical fractures only ................................................................................................................ - 61 -
Figure 24: Shape-factor distribution for lumped single-matrix-block simulation ................................ - 61 -
Figure 25: Recovery curves from single-matrix-block calculations for gas and water drive and associated oil-resaturation curves .................................................................................. - 62 -
Figure 26: Schematic illustration of the dual-porosity MB model creation and model operation .. - 63 -
Figure 27: Comparison of initial and scaled (#15) water drive RC ..................................................... - 64 -
Figure 28: Comparison of initial and scaled (#15) gas drive RC ........................................................ - 65 -
Figure 29: Best fit of the phase-contact history with Setup 15 ............................................................ - 66 -
Figure 30: Production and pressure as calculated with Setup 15 .......................................................... - 66 -
Figure 31: Determination of matrix-block parameters (water drive) ................................................. - 68 -
Figure 32: Determination of matrix-block parameters (gas drive) ....................................................... - 68 -
Figure 33: Comparison between phase-contact movements as calculated by dual-porosity MB and numerical 1D DCM ........................................................................................................... - 70 -
Figure 34: Oil-gas-contact and oil-water-contact history matches with full-field simulation using RC .................................................................................................................................................. - 71 -
Figure 35: WC and GOR match with full-field simulation using RC ................................................... - 71 -
List of Tables

Table 1: Summary of rock properties ........................................................................................... - 57 -
Table 2: Scaling factors and applied aquifer model for the iterative phase-contact match...... - 64 -
Table 3: Parameters used for simulation..................................................................................... - 86 -
Table 4: Production / injection parameters of seven wells ........................................................... - 87 -
Chapter 1 Introduction

1.1 Motivation of the work

1.1.1 Background

Several international oil companies (IOCs) who had previously been restricted country access in the Middle East are now finding themselves with new opportunities to develop world-class oil and gas fields. Both Iran, as well as, the Kurdistan Region of Iraq (KRI) are of particular note, and have become the focus for many IOCs looking to replace diminishing reserves and associated production. These respective oil and gas fields are often extremely material in both size and deliverability, however, they are all naturally fractured reservoirs (NFRs). A vast majority of the world’s conventional reservoirs are naturally fractured, however, none stand out more so as typical reservoir type cases than the multi-billion barrel or trillion-cubic feet (TCF) fields in the Middle East region.

Unfortunately, it is now also become evident that the lack to recent experience (last ~20-30 years) to these sorts of material NFRs that the oil and gas industry has not improved their associated technology and/or approaches to managing these sorts of fields. Clearly, much has improved in regards to fracture characterization of a static nature, however, the industry’s ability to predict the dynamic behaviours of NFRs more accurately capturing the complex interactions of the separate matrix and fracture systems has not improved. Thus, IOCs who have recently entered into Iran, Iraq, KRI, etc. have often found themselves with both reserves and production potential estimates that are often significantly inaccurate, and most frequently overestimated. Several recent industry examples of this include the Taq Taq field (KRI), Shaikan field (KRI), Akri field (KRI), Bakraman field (KRI), etc. all of which were significantly overestimated, and resulted in billions of dollars of lost investment and associated value to governments and shareholders.

Through my experience operating many of these fields, I was involved in multiple development plans, as well as, reserve evaluations on material NFRs. It was clear that all of the current industry approaches to providing these estimates were inadequate, and that the techniques applied within both the IOCs and reserve evaluation firms never resulted in acceptable results. Evaluators most often never attempted to model the matrix-fracture transfer dynamics, and resorted to application of analogue benchmarks provided from decades ago or a simple transmissibility term. When a numerical modelling approach was utilized to properly characterize the matrix and fracture systems separately and then utilize shape factor (matrix-fracture) transfer terms, it was clear that the terms being utilized were also unable to capture a true dual continuum behaviour. The transfer terms that are applied in these software create a discretised matrix at any point the fractures are producing. Thus, the matrix recovery or flow contribution from the matrix in NFRs became the focus of my research project.
1.1.2 The Objectives

The primary objective of this research is to propose an improved method for the reserve estimation and production prediction of naturally fractured reservoirs (NFRs). This was achieved through specifically addressing the material issue of establishing a dual continuum approach to modelling both the fracture and matrix systems so that the matrix recovery and flow contribution is more accurately accounted for.

1.1.3 Relevance

Naturally fractured reservoirs have always been significant sources of petroleum and hydrocarbon production throughout the world. Examples of large oil-in-place hydrocarbon reservoirs include those of in Saudi Arabia (Ghawar, etc.), West Texas carbonates, North Sea chalk reservoirs, the Asmari Limestone fields in Iran (Agha Jari, Haft Kel, and Gachsaran), numerous fields in Kurdistan, and the Sabah Field in Libya. Many recently discovered oil and gas fields occur in fractured reservoirs and their development constitute a substantial challenge for the oil industry. Naturally fractured reservoirs, often-abbreviated as NFRs, have been the subject of extensive studies during the past several decades. Recent large-scale NFR discoveries, as well as, new country entries for independent oil companies (IOCs) into prolific NFR regions have rekindled interest into improved methods of prediction and recovery for NFRs.

The objectives within reservoir engineering for NFRs is to estimate reserves, predict future production, to understand the matrix and fracture characteristics in order to optimize recovery, as well as, to quantify the uncertainty within all of these aspects. For conventional fields, reservoir engineers can generally provide a reasonable assessment of reservoir performance by combining information about the reservoir’s geologic framework, rock and fluid properties, and results from well logs, rock mechanical tests, formation evaluation tests and most importantly, by matching the production history prior to predicting the respective field’s performance. However, for naturally fractured reservoirs, obtaining the necessary data and forecasting reservoir performance is much more complex than for conventional reservoir characterization given the presence of two separate porosity systems (matrix and fractures). Deriving an appropriate development plan requires a high quality reservoir description that includes detailed fracture characteristics such as sizes, frequency, mineralization ratios, apertures, orientations, etc. This information must be turned into a reliable fracture network characterization. Is this possible? Gilman (2006) hypothesized that it is quite unreasonable to assume an accurate deterministic scenario, and so the focus should be rather on quantifying and accurately capturing the inherent ranges of uncertainty. Significant improvements have been made recently in the industry for fracture detection utilizing seismic attribute analyses and in the static modelling of fracture systems, however, material uncertainty is oftentimes still inherent.

In addition, and more materially to this thesis, there is significant difficulty for reservoir engineers to predict NFR production and/or recovery given there is no approved, generally applicable description of the dynamic processes of dual porosity systems. Doing this for a single porosity (matrix only) case is fairly straightforward given the
displacement efficiency can be estimated by the Buckley-Leverett theory, the reservoir mechanism can be evaluated using the classical material balance approach, and numerical simulation techniques have been deployed and tested in thousands of fields over the last several decades. For dual porosity reservoirs, the methods describing oil recovery and flow contribution from single matrix blocks are still a matter of discussion. No material balance calculation method now exists that considers the fracture-matrix interaction. Very few field studies have been published that demonstrate, even only qualitatively, that the forecasts based on simulation studies of dual porosity reservoirs are of relative quality.

Appropriate modelling of NFRs is much more demanding and complex than modelling conventional reservoirs. History matching is also more difficult in the case of a dual porosity reservoir, primarily because of the difficulty of assessing the fracture-matrix mass transfer behaviour. This transfer function is influenced by several properties which in a real world scenario cannot be measured with high confidence: shape factor, matrix block height, capillary pressure, wettability, relative permeabilities, and heterogeneity. It is often currently accepted practice given these uncertainties that some of these parameters are quite often modified in attempting to calculate an acceptable history match. Even if the reservoir engineer is partially successful, there is no assurance that the actual material factors have been captured given they may simply be artefacts that have been introduced though the modifications. The dynamic model’s resulting predictions, mostly based on false premises, may easily be misleading and materially inaccurate.

It is also noted that the most advanced currently in practice industry approach to NFR numerical simulation utilizes Kazemi’s (1976, 1983) shape factor terms, and that there are significant limitations to this approach. For example, the Kazemi shape factor term discritizes and unitizes an entire single matrix block at any discrete point in time when under dual continuum simulation with fractures. Of course, the reality is that the hydrocarbon in a single matrix block will move at all points and in various ways when under a production scenario, and so simplifying the matrix in this way negates all of these effects.

To create a numerical reservoir model that can more accurately simulate and account for the matrix and fracture porosity systems under production scenarios (a true dual continuum model) would reduce this uncertainty significantly, and lead to much more accurate matrix flow predictions while also removing most of a reservoir engineers needs to modify input parameters resulting in less artefacts introduced into the simulation results. It is therefore necessary to derive a workflow that is capable of true dual continuum modelling accounting for both the matrix and fractures, as well as, the transfer interactions in between these systems.
1.2 The Approach

1.2.1 Working Environment

As the author, it is important for me to state that I would have been unable to conduct and complete this complex research and development work without the helpful and open collaboration with others. Although this dissertation has been written by the author alone, it is the result of a close cooperation within the DTU CERE community, as well as, Professor Heinemann’s research group (PHDG) both of which have accumulated know-how, documentation, case studies and software tools (e.g. PHDG’s H5 reservoir simulator) on reservoir characterization and analysis. Available formulations are not reformulated but used unchanged in subsequent documents and publications, and referenced accordingly. The author of this dissertation makes use of the group’s common knowledge, and all sources are referenced in general, but not attributed in every instance if unpublished or non-matured.

Also, during this research, the author had access to proprietary information. Sources of such information are not referenced to unless written permission, including the right of publication, has been provided by the source. Several real world field and reservoir cases were utilized, however, wherever permissions were not received, synthetic reservoirs where created so as to avoid any violations of confidentiality.

In order to clearly separate collegial contributions from the individual work of the author, the author’s scientific ideas, achievements and additions are noted in the published works, as well as, supported by co-author statements wherever applicable.

1.2.2 Previous Related Works

The following works are listed thematically, instead of chronologically.

Heinemann (2004) suggested that instead of trying to estimate individual rock and fluid properties, the recovery curves should be determined and used directly in a numerical reservoir simulation model. The dimensionless recovery curves display the recovery factor as function of dimensionless time. A recovery curve could be evaluated in three ways:

- Using physical models, a piece of reservoir rock (a proxy for a matrix block) obtained from an outcrop could be saturated with oil and “recovered” under simulated reservoir conditions in an autoclave. This would be an ideal solution but is usually not practical because no reservoir-equivalent rocks are exposed at the surface.

- Calculating the recovery process numerically on a finely gridded single matrix block model surrounded by fractures. The fractures define the boundary conditions for the single porosity matrix. The recovery curves depend on the displacement mechanism and will be different for water imbibition and gravitational gas drive.

- Calculating the recovery of a matrix cell in a dual continuum model by setting the conditions for the matrix-fracture mass transfer.

Pirker (2008) presented more efficient numerical methods for calculating recovery curves for single matrix blocks. She accounted for the fact that matrix blocks are not uniform and therefore recovery curves have to be calculated for classes of blocks. Subsequently, the individual recovery curves had to be consolidated by averaging according to the frequency of each class. The averaged curve was then assigned to a simulation cell.

Amiry (2014) suggested a method based on statistical analysis of matrix blocks in outcrops of fractured formations. He showed that the recovery curve was not influenced by the actual shapes of blocks and could be scalable with respect to the shape factor and apparent permeability. Additionally, he showed that under the same conditions, the results of the recovery curve method and those of the classical conventional method were similar and the two approaches could be combined both in space and time.

Heinemann and Mittermeir (2016) published their approach for a numerical implementation of the recovery curve method (RCM). It is based on the premise that from the recovery curve fracture-to-matrix injection rates will be calculated. Expansion of the fluids in the matrix is then handled with the conventional transfer function.

Ghaedi et al. (2014, 2015) investigated a possible application of the recovery curves by determining the curves directly from historical production data. Based on the findings of the history matching fundamental rock properties such as wettability, capillary pressure and relative permeability functions are determined.

Mittermeir (2015) presented the first dual porosity material balance method that fully accounts for the matrix-fracture interaction by using recovery curves to determine the mass transfer between matrix and fracture. It fully accounts for expansion, capillary and gravitational driving forces, as they are already considered in the numerically derived recovery curves.

Gharsalla (2015) presented the first successful material balance application to a realistic dual porosity two-phase reservoir. The oil-water contact has been matched by adjusting the recovery for oil displacement by water.

Steiner (2017) made the RCM approach generally applicable through required scaling of a recovery curve (RC), which was derived at constant pressure conditions, to the actual state of the matrix block in the numerical model and a correct determination of the mass transfer rates based on the scaled RC.

1.2.3 Software Tools

The simulation software H5 is an alternative to other commercial simulators such as ECLIPSE. It is a proprietary software system developed by Professor Zoltan Heinemann and associates and is the fifth generation of research simulators developed under the supervision of Prof. Heinemann. The first generation was written in FORTRAN-IV in 1968. The development of the fifth generation began in 2006, using FORTRAN-1995 and C++ programming languages. The various "H"-versions served as the foundations for
commercial software packages including SIMULA, SURE, PRS-2012 and PRS-2015. Prior to version H4, the simulators were used as teaching and research tools at the Montanuniversität Leoben. The author has taken instructional courses in the utilization of this software, as well as, application courses at Montanuniversität Leoben for naturally fractured reservoirs as approved components of the author’s DTU study plan.

PHDG members have access to the H5 source code so they can experiment with the existing modules and can design and implement new procedures. Student researchers cannot make unsupervised modifications to the H5 code but can develop standalone modules or simply present detailed descriptions of suggested improvements and extensions to be implemented by professional programmers. Testing and benchmarking is the responsibility of the project author. H5 can operate on ECLIPSE input without any modifications, so identical runs can be made on ECLIPSE and H5 for comparison. These runs can be started in parallel and the results must either be close to each other or the differences must be explainable.

The author has greatly benefited from the H5 software and PHDG technical support which provided the opportunity to develop and test new concepts and procedures for reservoir simulation.

1.3 Outline

Chapter 1 Introduction

This is the current chapter which contains a brief introduction to the objectives and contents of this dissertation.

Chapter 2 Literature Review

This chapter reviews the today common understanding of the dual porosity recovery mechanism and present the relevant methods simulating naturally fractured reservoirs including the dual continuum approach, the discrete fracture methods and also those of the Single Matrix Block (SMB) applications.

Chapter 3 Methods

This chapter presents a paper establishing a new method for performing numerical simulation utilizing a dual continuum approach with the Recovery Curve Method (RCM), as well as, a paper on using deconvolution to characterize a mature oil field with dual porosity systems. The RCM paper provides the primary basis for the methodology utilized for providing the results in this thesis.

Chapter 4 Results

This chapter presents a paper comparing the differences of the RCM approach to dual continuum matrix-fracture reserves and production estimation to the most commonly applied techniques deployed in the industry today. The results are presented, and some conclusions are made.
Chapter 5  Summary & Recommendations

This chapter provides a synthesized executive summary of the thesis, as well as, some further recommendations for progressing this research area.

1.4 Related Publications of the Author


1.5 References


Chapter 2 Literature Review

This Chapter provides further background information about the theory and today’s praxis of modelling naturally fractured reservoirs (NFRs). All industrially-used methods for modelling NFRs are based on the dual continuum modelling (DCM) approach. Recently, discrete fracture models (DFM) have become popular in academic research but no practical application of them is known up to now. The DFM approach attempts to solve the difficulties in and around the NFR by involving more and more details in the investigations. Results from DFM research are of no relevance for this work, therefore they will be mentioned in this Chapter very briefly for information purposes only.

2.1 Naturally Fractured Reservoirs Recovery Processes

There are significant differences between the recovery mechanisms and associated performance between naturally fractured and non-fractured (conventional) reservoirs. For NFRs, the concept of a “matrix block” is introduced, and is reflected as a point at any reservoir location representing a fluid "source" term that contributes flow into the fracture continuum. The mostly low permeable matrix contains predominantly the oil (>95%) and the high permeable fracture provides the flow path for the fluid. A fluid exchange must take place between the matrix and the fractures thus enabling to produce the oil through the wells. The efficiency of the matrix recovery process determines the reserves and the production capacity given a majority of the in-place reserves typically reside in the matrix system of an NFR.

The matrix recovery is induced and assisted by various mechanisms which originate from (1) rock compressibility, (2) single phase fluid expansion, (3) solution gas drive, (4) capillary imbibition, (5) gravity drainage, (6) viscous forces, (7) diffusion and (8) rock compaction. In the following, all of them can be considered but for sake of simplicity emphasis will be put on two categories of driving forces. The first group is built by the mechanisms (1) to (3), governed by the force of compression. Their impact – disregarding only the theoretically-interesting transient effects - depends solely on the change of pressure of the system. The driving force in (4) and (5) originates from the saturation of the displacing phase in the fracture around the matrix block and is purely time-dependent. The viscous (6) forces depend furthermore on the pressure gradient, which naturally changes over time, along the matrix block. The remaining mechanisms (7) and (8) are even more complex but have importance in few cases only. Diffusion acts on light components of the hydrocarbon system and can only be considered in compositional formulation. Compaction depends on both the pressure and saturation and it progresses with time.

The description of the recovery process in NFR faces two serious difficulties. The first is the description of the dual continuum: (1) how to measure the actual size of the single matrix blocks, (2) how to determine their distribution and (3) how to estimate the volume (i.e. porosity) of the fractures. The second difficulty is to capture the driving forces
responsible for the matrix recovery process given the uncertainty if this recovery is a function of the pressure and the production rates or as a function of time.

2.2 The Dual Continuum Concept

Lemonnier and Bourbiaux (2010) published a literature review under the title "Simulation of Naturally Fractured Reservoirs, State of the Art, Part 1, Physical Mechanisms and Simulator Formulation." The author studied all original works which were cited in this survey and realized that they made an excellent assessment. A recapitulation would not have sense, it is suggested to consult this work directly. Only the most relevant facts were extracted, however, the literature survey has been extended to the end of year 2014. The author refers always to the original work instead of the Lemonnier and Bourbiaux (2010) review.

Barenblatt, Zheltov and Kochina (1960), introduced the dual continuum concept and applied it to fractured reservoirs. This concept considers that the fracture continuum on the one hand, the matrix continuum on the other hand, behave like two flow continua interacting with each other. Warren and Root (1963) applied this concept to interpret well tests into a simplified framework that is applicable to a naturally fractured reservoir. A single phase is flowing in fracture continuum which locally interacts with porous parallelepiped matrix blocks, acting as a fluid source only.

Equation (1) gives the black oil balance equations considering three components in three phases (subscripts \( w \), \( o \), and \( g \) for water, oil and gas). Each continuum is a single porosity medium, therefore, the flow equations are identical for both continua. The only difference is that the transfer terms have the opposite sign: \( +/\dot{q}_{wmf} \) for water, \( +/\dot{q}_{omf} \) for oil and \( +/\dot{q}_{gmf} \) for gas. \( k \) is the permeability and \( \mu \) the viscosity, \( B \) is the formation volume factor and \( \Phi \) the phase potential in the fracture (\( f \)) and in the matrix (\( m \)). Equivalent compositional and non-isothermal formulations are also well known. The balance equations have to be written for both continua. The last terms at the left hand side represent the rate of the mass transfer between the fracture and matrix continua.
2.2.1 Matrix Blocks and Simulation Cells

Figure 1: Fractured Rock, Matrix cell vs. matrix block, (by Roxar training)

In order to calculate fluid flow within the dual porosity system numerically, the Equation (1) has to be discretized. To avoid ambiguities one should distinguish between matrix blocks and simulation cells. The red squares in Figure 1 (or cubes in 3D) represent the control volumes, in other words the “simulation cells”. The dual continuum approach considers two simulation cells at each location (i.e. at the place of each red square); one is the “matrix cell” and the other is the “fracture cell”. This divides the space into two identically-shaped domains: the “matrix domain” and the “fracture domain”. The fracture domain, built by the fracture cells, commonly has a much higher permeability and less porosity than the matrix domain. This means that the fracture cells can exchange fluids easily with their neighbouring fracture cells (along the black arrows in Figure 1). Matrix cells, may or may not be able to exchange fluids with their matrix neighbours resulting in dual permeability or dual porosity models, respectively. Figure 1 is the two dimensional outcrop of a naturally fractured formation. This figure explains the fundamental problems that should be overcome while modelling fluid flow in such a discontinuous domain. The fractures surrounding the blue-framed “matrix blocks” determine their boundary conditions, imposing how the hydrocarbon will be recovered from the matrix block. On the other hand, the matrix blocks serve as the internal mass source and sink for the fracture system.

2.2.2 Time-Dependent Source/Sink Functions

Reiss et al. (1973) made the first attempt to apply the dual-porosity approach to calculate three-dimensional multi-phase flows in a fractured reservoir. At the beginning the
fissures are filled with oil and the oil from the matrix is produced into the fissures according the fluid/rock expansion and by solution gas drive. This is a purely pressure dependent process. When the matrix block is reached by the water-oil or gas-oil interface, production is mainly due to capillary and gravity effect. The authors assumed that from this time onwards the phases are completely segregated in the fissures and the matrix block is completely surrounded by water or gas. The matrix-fracture exchange was represented by time-dependent source or sink functions, also named as recovery function or, preferably, a recovery curve. Laboratory experiments were performed and/or numerical simulation of the oil recovery mechanism were derived in a finely-gridded single-block model. Rossen (1977) utilized a similar approach with semi-implicit handling of the associated source terms.

Both Reiss et al. and Rossen had assumed that matrix block oil recovery is only due to capillary and gravity effects and that it is also only a function of the elapsed time. This is all assumed after water (or gas) comes into contact via the surrounding fractures to the matrix block. The effects of viscous fracture flows and compressibilities on matrix-fracture transfer were neglected due to the difficulty in deriving appropriate transfer functions that are time-dependent only and also honour the reservoir properties at each stage of field exploitation and production. Nevertheless, Reiss et al. believed that these simplifications were not very restrictive to normal field conditions.

Nevertheless Reiss et al. (1973) and Rossen (1977) did not significant support for this approach.

2.2.3 The Transfer Function and the Shape Factor

In this section the transfer function with the obligatory shape factor will be discussed followed by the single matrix block calculation.

In black-oil formulation, if the oil component is present in the oil phase only, the transfer function gets the following form:

\[
q_{omf} = \sigma k \frac{k_{ro}}{\mu_o B_o} (\Phi_{om} - \Phi_{of}) \quad \text{[sm}^3/\text{s]}
\]

where \( k_a \) is the apparent matrix permeability and \( \mu_o \) the viscosity, \( B_o \) is the formation volume factor of the oil and \( \Phi \) the phase potential in the fracture (f) and in the matrix (m). \( \sigma \) is called, according to the Warren-Root concept, shape factor and has to be seen as a characteristic value of the fractured dual continuum, proportional to the specific surface of the matrix block and has a dimension \( L^{-2} \). Equation (2) is applicable in pseudo-steady-state conditions only.

Warren and Root (1963) gave the first definition of the shape factor \( \sigma \) when they introduced their idealized sugar cube model (Figure 2) of fractured porous rocks for a cubic matrix block with a side length \( L \), \( \sigma = 12/L^2 \). The goal of later scientists was to extend the Warren-Root transfer function applicable for multi-phase displacement. The matrix-fracture fluid transfer in numerical modelling of dual porosity reservoirs has ever been and is still an area of extensive research and discussion.
Kazemi et al. (1976) introduced a two-dimensional and two-phase water-oil model. In this concept, the matrix-fracture flow rate is driven by the potential differences between the fracture and matrix systems. Kazemi’s two phase model was then extended to three dimensions by Gilman and Kazemi (1983). One of the most accepted and widely implemented (e.g. in ECLIPSE) shape factor definitions utilized in numerical modelling was provided by Kazemi et al. (1976,1983):

$$\sigma = 4\left(\frac{1}{L_x^2} + \frac{1}{L_y^2} + \frac{1}{L_z^2}\right)$$

(3)

The most general definition of the shape factor was given by Heinemann and Mittermeir (2012):

$$\sigma = \frac{1}{V_{mi}} \sum_{j=1}^{N} A_{kj} \left( \frac{\bar{k} \hat{n}_j}{d_{kj}} \right)$$

(4)

$V_{mi}$ is the volume of the $k$-th matrix block, $\bar{k}$ is the normalized permeability tensor, $n=1,N$ is the number of surfaces $A_{kn}$ towards the surrounding fracture network, $\hat{n}_{kn}$ is the unit normal vector, $d_{kn}$ is the distance vector to these surfaces. It is easy to show that this expression contains all other forms of the shape factor introduced earlier.

Heinemann and Mittermeir showed that the expression Equation (4) is exact for the pseudo-steady-state condition, assuming linear potential and homogenous fluid distribution within the matrix block. The rigorous derivation also allows to conclude that no general and constant shape factor can exist if one of these conditions is violated. This is one of the weakness of all methods based on the transfer function.

Gilman (2003) claims that under pseudo-steady-state conditions the shape factor is a function of fracture spacing. The implications for this concept is that the shape factor is
not an inherently time-dependent parameter. Several additional authors have proposed shape factors based on both numerical and/or laboratory experiments. Thomas et al. (1983) studied various fine-grid single-block dual-porosity models. For a three-dimensional oil-water model with near unity mobility ratio they obtain a match with a shape factor of 
\[ \sigma = \frac{12}{L^2}. \]

Coats (1988) derived the shape factor without assuming linearity for the potential gradient. His shape factor is twice the value of Kazemi et al. (1976). Ueda et al. (1989) investigated the shape factor for one and two dimensional flows. They concluded that the shape factor has to be adjusted by factor 2 for a one dimensional flow, a fact that has been verified in this work.

Lim and Aziz (1995) derived a shape factor for linear single phase transient flow. They set a constant pressure \( p < p_i \) at \( x = 0 \). The analytical solution of the boundary condition problem resulted in the shape factor described by the formula \( \sigma = \frac{\pi^2}{L^{-2}} \). The Equation (3) modified accordingly to:

\[ \sigma = \frac{\pi^2}{L_x^{-2}}\left( \frac{1}{L_y^2} + \frac{1}{L_z^2} \right) \]  

Numerous works were published further dealing with the shape factor question, becoming a preferred university research topic. It is easy to discuss shortcomings in previous publications and to suggest alternative possibilities which seems to be applicable under specific conditions. None of those offer a general applicable solution for calculating the transfer term within the dual continuum formulation.

The present author concludes that the shape factor is a mathematical fiction, valid and applicable under the conditions defined in a mathematical model only. Nevertheless, it can be regarded as a useful complex value, which characterizes the matrix blocks based on their size, form and anisotropy.

The second weakness of the transfer function given in the Equation (2) is the driving force, expressed by the potential difference. In single-phase case this is the pressure difference between fracture and matrix. In multi-phase case the effect of capillary pressure and the gravitational forces are vanishing in this formulation.

Gilman and Kazemi (1983) had utilized two different depths for the fracture and matrix nodes for the formulation of gravity forces between both the matrix and fractures. This modelling approach was subsequently improved by Litvak (1985) and Sonier et al. (1986). They had both introduced a transient (time-dependent) gravity term for the matrix-fracture exchange calculated from the from the matrix saturation, height of the matrix blocks, as well as, the surrounding fractures. Matrix and fracture saturations can be converted into fluid contact levels (hypothetical ones) by assuming a gravity-driven vertical equilibrium of fluids in their respective media. This in turn provides an estimate of the gravity head applied on the matrix blocks of the respective grid cell. As a subsequent follow up of these early developments, Balogun et al. (2007) recommended to utilize two
shape factors in the transfer function: $\sigma$ and $\sigma_z$, where the second one is for the gravitational term.

Thomas et al. (1983) utilized pseudo-relative permeability and pseudo-capillary pressure curves to model the gravity effect on matrix-fracture transfers. This was achieved by also utilizing a vertical equilibrium assumption. In order to account for gas diffusion into undersaturated oil within the matrix blocks under non-equilibrium injection of gas and also the pressure gradient across the matrix block, an additional term was also added. Rossen and Shen (1989) utilized pseudo-capillary-pressure curves for the fractures and matrix. The matrix block dimensions and rock properties can be utilized to determine the fracture curve. The results of a single simulation within single matrix block with multiple grid cells is then utilized to provide the matrix curve. According to Bourbiaux (2010), there is no general solution for the determination of pseudo-relative permeability or effective multi-phase permeabilities.

Saidi (1983) proposed that it was necessary to perform detailed simulation of the matrix-fracture transfers utilizing gridded matrix blocks. Saidi also implemented a model where each reservoir zone and its matrix-fracture transfer is characterized by its associated rock properties and through the utilization of a gridded matrix block that also includes gridded fractures.

Pruess et al. (1985), proposed utilizing the Multiple Interacting Continua (MINC) approach to provide a sub-grid two-phase and heat flow model. A three-dimensional compositional thermal simulator was developed by Chen et al. (1987) which allowed the subdivision of a rock matrix block into a two-dimensional grid. This was performed in order to study the effects of capillary pressure, gravity, and energy and mass transfer between fractures and the matrix blocks much more precisely.

The numerical and physical aspects of the dual-porosity/permeability approach was provided by Blaskovich et al. (1983), Hill & Thomas (1985), and Quandalle & Sabathier (1989). This approach has provided useful given it has taken into account “block-to-block” matrix flows, and also accounted for partial matrix continuity in the relevant sections of the reservoir. A dual-permeability approach in the vertical direction alone was derived by Gilman and Kazemi (1988) to more accurately simulate the gravity-driven matrix-fracture transfers for matrix flow contributions. This is in large part due to the utilization of a refined vertical discretization. A dual-porosity/permeability approach was also derived by Por et al. (1989) that utilized additional new connections between a matrix node of any given cell and the fracture nodes of neighbouring/proximate cells. This further facilitated the successful modelling of the block-to-block interactions, as well as, gravity drainage processes and their role on capillary contacts. With this approach, the matrix oil may be drained into the fractures at a given cell location and can then re-imbib the lower located cells of the matrix blocks. A half-block-height shift between the fracture and matrix nodes is obtained once the gravity driving force is applied.

Although dual porosity and dual permeability models have been implemented in many reservoir simulators, fracture uniformity presumed in these models does not conform with outcrop observations, which indicate that height, length, aperture, spacing and directionality of natural fractures vary substantially in the subsurface (Gillespie et al.,
Johns and Jalali-Yazdi (1991) and others extended dual continuum models to include variable matrix block sizes in order to make these models more realistic. Moinfar et al. (2011), however, presented examples where the dual continuum approach fails to provide accurate solutions in the presence of large scale fractures and high localized anisotropy. Thus, dual continuum models are especially appropriate for reservoirs with a large number of highly connected, small scale fractures.

Conclusion: Based on all presented work above - numerous other could be referenced too - it has been concluded that neither the Reiss et al. (1973) recovery curve method nor the Kazemi et al. (1976) concept based on transfer function offer a general applicable solution for calculating the matrix-fracture fluid exchange for simulating multi-phase fluid flow in a dual porosity naturally fractured reservoir.

2.3 Discrete Fracture Modelling (DFM)

More recently, different approaches were implemented to simulate flow directly on the discrete fractured medium without any prior homogenization through the application of fracture characterization software. Discrete element models for the fracture network alone or models of both the matrix blocks and the fracture network are utilized. Discrete Fracture Network modelling as proposed by Bourbiaux et al. (1999) can then be applied to the simulation on a local scale to better depict the water imbibition of a fractured medium. This generally involves two fracture sets to be generated from a stochastic fracture modelling software, as shown in Figure 3. The magnification is 20 m × 16 m (65.6 ft × 52.5 ft), and the fractured medium horizontal dimensions are 200 m (656 ft). This example should demonstrate why the DFM approach is to this project’s objectives of more accurately capturing the matrix flow behaviour. It is stated by Geiger et al. (2009) that the computational cost of DFM techniques has the inherent draw-back that their utility is reduced given is often unrealistic or unpractical to run multiple high resolution field scale and even sector scale realizations for NFRs. Li et al. (2013), presented a multiple-continuum concept that considers globally connected natural fractures, locally connected micro fractures and low-permeability matrix. It is proposed to use this method to model production from shale gas reservoirs. Monifar et al. (2013) presented a hybrid method which includes three domains, matrix, discrete fracture and continuum-fracture domains to model complex networks of natural and hydraulic fractures. They stated that it is neither practical nor advantageous to model a large number of pre-existing natural fractures with discrete fracture model. Such an approach could be a promising solution in future developments.

Conclusion: The Discrete Fracture Modelling approach is neither practical nor advantageous for application in field and sector-scale reservoir simulations.
2.4 Single Matrix Block Simulation

The idea of using Single Matrix Block (SMB) models comes from the ambition to calculate the recovery process for every single matrix block without assuming uniform pressure and saturation in it. Probably the best way to investigate the matrix recovery process is to calculate it numerically on a finely gridded single porosity model. Such a calculation can be done for small scale laboratory measurement on cores, but also for imaginary matrix blocks situated in the reservoir. The comparison with laboratory data is necessary to increase the level of confidence for conclusions. This would be the best approach on the reservoir scale, too, but it is not applicable from many reasons, ie. it is impossible to identify all individual single matrix blocks and also it would not be possible to handle them due of the CPU and memory limits of computers. Nevertheless, SMB calculations are advantageous as reference solutions and as support of conclusions derived from production data.

Different setups of single matrix block (SMB) models and conclusions can be found in the literature: Yamamoto et al. (1971), Kleppe and Morse (1974), Fung and Collins (1991), Kazemi, Gilman and Elsharkawy (1992), Chen et al. (1995), Gurpinar and Kossack (2000), Famy et al. (2005), Abushaikha and Gosselin (2008), Balogun et al. (2009), Ramirez et al. (2009) and Al-Kobaisi et al. (2009), Mora and Wattenbarger (2009), Wuthicharn and Zimmerman (2011), Su et al. (2013). These publications deal with recovery mechanism in fractured reservoirs, primarily with single and two-phase water/oil counter-current imbibition and gas/oil drainage. Without any exception they tried to evaluate a shape factor and using the matrix-fracture transfer function.

It seems that there is no chance to find definitions for shape factors which could make the transfer function Equation (2) applicable at least for some well-defined practical cases. Nevertheless the excellent work of Su (2013) co-authored by Olivier Gosselin (Imperial College) and Hadi Prvizi and Marie Ann Giddins (both with Schlumberger) would be sufficient to put a dot at the end of all this efforts. They made calculation on a
1x1x8 dual continuum column model and created an equivalent single porosity model with 48x48x145 = 334,080 cells (Figure 4). A commercial flow simulator (Eclipse) was used to calculate both models. They compared fine-grid single-porosity model with a coarse dual-porosity equivalent for gas-oil system under gravity drainage without capillary effects and derived a time dependent shape factor matching the matrix oil saturation. They suggested to use dynamic transfer function and to consider block-to-block effects. Figure 5 shows the error estimates for different cases of dual porosity model. How far the today situation from a general and practical solution is can be estimated from the recommendations made by Su et al. (2013):

1. An in-depth study of the block-to-block effect is recommended. A better understanding of the oil re-imbibition and the quantification of this phenomenon would increase the predictive power of the model.
2. The effect of capillary pressure needs to be thoroughly studied.
3. The water-oil gravity drainage study is also recommended to develop a general model for the gravity drainage recovery mechanism.

Su et al. concentrated on transfer function formulation existing in reservoir simulators (i.e. in Eclipse). They last recommendation - the only one with which the author agrees - is:

4. A change of focus to the improvement of the transfer function would be a path to explore.
Su et al. (2013) suggest to make the transfer a time dependent function, which would mean to return to the Reiss et al. (1973)-Rossen (1977) concept. The reason why this approach would not be applied is that they could not merge the solely pressure dependent depletion drive and the capillary/gravitational drive in one recovery curve. Kazemi et al. (1979) integrated all driving forces in one expression of potential gradient (i.e.: in discretized form in an expression of potential difference). All other researcher and developer up to now followed this concept. Heinemann (2004) found the solution to use the recovery functions with contemporarily considering of the depletion drive too.

2.5 Theory of Characterization of Naturally Fractured Reservoirs (NFRs)

2.5.1 Naturally Fractured Reservoirs (Definitions)

Naturally occurring fractures are mechanical interruptions or discontinuities in the rock, usually the result of high pore pressures, lithostatic and thermal stresses or regional tectonic forces. The term “fracture” is often applied to all generic rock failures, covering a broad range of geological discontinuities such as cleats, stylolites, slickensides, joints and faults.

A fractured reservoir, by definition, is a reservoir in which naturally occurring fractures either have, or are predicted to have, a significant effect on reservoir fluid flow either in the form of increased reservoir permeability and/or reserves or increased permeability anisotropy. It is well known that a high percentage of the world’s oil reserves are located in fractured reservoirs, but because of the complex heterogeneous nature of these reservoirs, producing these reserves is a major challenge to the oil and gas industry. The fracture systems usually are very irregular, often disconnected and may occur in swarms. Hydrocarbons accumulate in the pore matrix of the reservoir rock but are
transported to the well by the open fracture network. The fractures themselves play a significant role in the flow of fluid in the reservoir, either as a conduit or a barrier, effectively having a positive or negative effect on fluid flow.

Fracture permeability usually is much greater than the permeability of the rock matrix, which is why flow behaviour in naturally fractured reservoirs is dominated by the fracture network. It is the characteristics of fractures and related networks that govern the transport of fluid in naturally fractured reservoirs and must therefore be understood and well defined as early as possible for optimal reservoir management.

In general, a naturally fractured reservoir has the following characteristics:

- matrix permeability is generally low and heterogeneously distributed,
- drainage of the field is highly dependent on an effective open fracture network,
- naturally occurring open fractures have a significant effect on flow rates and recovery.

### 2.5.2 Classification of Naturally Fractured Reservoirs

Naturally fractured reservoirs can be divided into three main classes:

- **Type 1:** fractures provide porosity and permeability
- **Type 2:** fractures provide most of the permeability
- **Type 3:** fractures only enhance the native permeability of the matrix

This classification system is very useful in distinguishing between the different types of reservoir.

**Type 1:** This type of reservoir is common in many basins. The reservoir volume is very large and it has a very high fracture density. Production is characterized by rapid declines and possibly early water encroachment. It can be treated as a single porosity model and thus is easy to simulate if the fracture density distribution is correctly modelled.

**Type 2:** Permeability is provided by fractures but the porosity comes predominantly from the reservoir matrix. A typical example of a Type 2 fractured reservoir is the vuggy carbonate reservoir common in Mexico. These fractured reservoirs usually must be simulated by a dual porosity model, especially if imbibition between matrix and fracture is the dominant flow mechanism. If not, they can be simulated by a single porosity model. Such reservoirs may show rapid declines and early water encroachment. Enhanced recovery schemes are difficult to implement in such reservoirs because of rapid breakthrough of the injected fluids.

**Type 3:** This type of reservoir is the hardest to detect. Primary production does not usually give any hint that the reservoir is fractured. It is only after fluid injection commences that unusual connectivity patterns may emerge to indicate that the reservoir is actually fractured.
Figure 6 is a graphical illustration of three reservoir types with respect to porosity (matrix or fracture) and permeability (matrix or fracture)

In order to model a fractured reservoir it is very important to understand what types of fractures are present in the reservoir and how they interact with each other and the matrix. Fractures are caused by stresses occurring before and during the formation of the reservoir. The paleostress is the stress state that existed during the time of creation of these fractures. However, it is the current stresses in the reservoir that are most important because they control the opening of fractures and therefore control the permeability.

Fractures can be created under different circumstances, falling into four major categories:

- Tectonic fractures
- Regional fractures
- Stylolites
- Surface–related fractures

Tectonic fractures are caused by folding and faulting. Folds are controlled by compression and extension stresses. Fractures also occur near faults and may overlap with fold-related fractures.

Regional fractures are usually present over very large distances. Such fractures are perpendicular to the bedding surface and align themselves with the paleostress direction. They are extension fractures with the maximum stress in the vertical direction.

Stylolites are solution features that occur in dolomite, limestone and carbonate-cemented sandstone reservoirs. Diagenetic changes resulting from local differential stress lead to the creation of stylolites, which may be indicators of paleostress directions.
Surface–related fractures are visible at the surface and are due mainly to weathering along zones of weakness that may (or may not) result from the relaxation of subsurface stresses. Geologists often base their interpretations of regional stress fields from fracture patterns seen on outcrop: these may be quite different from what is present in the subsurface. Although fractures are ubiquitous at the surface, there are many reasons why these fractures might be non-existent in the subsurface or simply closed by overburden stress.

2.5.3 Definition and Classification of Fracture Modes

Many fracture classification systems have been developed by different authors. Typically, exploration companies use their own in-house nomenclature that may vary from field to field. However, most fractures in the subsurface can be classified into three geologically based groups:

- dilating fractures/joints
- shearing fractures/faults
- closing fractures/pressure solution surfaces

*Figure 7* depicts a sketch of the three fracture modes. Stearns and Friedman (1969) classify natural fractures based on the assumptions that natural fracture patterns are a true representation of the local state of stress during fracturing and that subsurface fracturing occurs in a manner analogous to in-situ laboratory tests. Their classification consists of four groups:

- Tectonic Fractures (due to surface forces)
- Regional Fractures (due to surface or body forces)
- Contractional Fractures (due to body forces)
- Surface-related Fractures (due to body forces)

For reservoir engineering purposes, fractures are classified by their impact on flow and are considered to be large-scale fractures which cross-cut the reservoir or small-scale diffuse fractures which preferentially occur in certain reservoir layers. Large-scale fractures include faults and fracture swarms which act as fluid conduits. Based on geometric properties such as orientation and spacing, the fractures are then grouped into different sets that form the fracture network.

The petrophysical properties of a fracture network should be identified based on the physical morphology, distribution and reservoir properties of the network. These fracture system characteristics affect the performance of the reservoir and are controlled by their mode of origin, mechanical properties of the reservoir rock, and diagenesis.
2.5.4 Fracture Orientation

Stress is a measure of the internal distribution of force per unit area within a body that compensates for the loads applied to it. The three principal compressive stresses of the earth are commonly referred to as $\sigma_1$, $\sigma_2$ and $\sigma_3$, where $\sigma_1 > \sigma_2 > \sigma_3$. The types of fractures that have formed and their corresponding orientations are relative to the surrounding stresses that dominated at the time of fracturing.

Figure 8 illustrates the relationship between the three principal stresses and the formation of different fracture types.

The green line represents a Mode I fracture, commonly referred to as a joint, which has formed perpendicular to the minimum principal stress $\sigma_3$. Variations in $\sigma_3$ can result in formation of a deviated fracture rather than a planar fracture.

Mode II/III fractures are represented by the red lines. This type of fracture, often referred to as a fault, normally occurs at an acute angle (between $25^\circ$ to $40^\circ$) with respect to the maximum principal stress.

A closing fracture, also referred to as a stylolite, is indicated by the blue line and tends to form perpendicular to $\sigma_1$.

Fractures exhibiting a combination of these modes also exist, especially in a region that has been subjected to a complex history of deformation.
2.5.5 Dilating Fractures

A dilating fracture or joint refers to two rough surfaces which have been subjected to normal displacement i.e. the surfaces have moved predominantly normal to each other. They form perpendicular to the minimum compressive stress ($\sigma_3$) direction, i.e., parallel to the maximum compressive principal stress ($\sigma_1$), and therefore show separation or opening of the fracture walls with no appreciable shear displacement parallel to the plane of the fracture.

These types of discontinuities are referred to as Mode I in the rock mechanics classification scheme.

Figure 8: Fracture orientation with respect to the three principal stresses (Lacazette)

Figure 9: Joints in dolomite layers; the mean fracture spacing in the 3.0 m thick bottom layer is approximately 0.15m (Lawn, 1975)
2.5.6 Shear Fractures

A shear displacement discontinuity or fault is the term given to a fracture where the surfaces have moved essentially parallel to each other forming at an acute angle to the maximum compressive principal stress ($\sigma_1$) and an obtuse angle to the minimum compressive stress ($\sigma_3$) direction.

There are two types of shear fractures:

- In-plane shear or Mode II fracture, in which the displacement is within the surface of the fracture and normal to the fracture edge
- Anti-plane shear or Mode III fracture, when the displacement occurs within the surface of the fracture and parallel to its edge.

![Shear Fracture](image)

Figure 10: Shear Fracture (Nelson, “Origin of Fractures” presentation)

2.5.7 Stylolites

Closing fractures are more commonly referred to as stylolites. Stylolites are very distinctive, occurring when movement of the adjacent wallrocks is directly toward each other resulting in a zone of insoluble residue produced by stress-induced dissolution. In general, they are non-planar or wave-like surfaces on which markers (such as bedding planes or fossils) may be truncated or offset. The most common form of stylolite consists of a surface along which columns of rock interpenetrate like meshing teeth. These teeth are typically perpendicular to the overall trend of the stylolitic seam. The surfaces of stylolites commonly are coated by a layer of iron oxides or clay minerals. Some particular stylolites look like small chevron (sharp-hinged) folds, but are differentiated from folds by containing clay minerals. Slickolites are similar to stylolites with the distinguishing characteristic that the teeth are oblique to the enveloping surface of the stylolite. They occur when the convergent movement is oblique. There is generally no deformation of the rock surrounding a stylolite.
Stylolites are sometimes considered as barriers to fluid flow. In fact, they are very weak and are easily reactivated as joints during a later tectonic event. They are often reported to be permeable in hydrocarbon reservoirs.

![Figure 11: Limestone exhibiting stylolites (Lawn, 1975)](image)

### 2.5.8 Characterization of Naturally Fractured Reservoirs

The aims of the fracture characterization process are to:

- Establish an understanding of the fractures, fracture network distribution and its influence on fluid flow behaviour,
- Apply this knowledge to the development of realistic geological models,
- Generate full field dynamic fracture parameters for dynamic simulation.

In order to gain a sound understanding of the reservoir and its rock and fluid flow properties, a fracture modelling study must be performed. The knowledge acquired can then be used to model the fracture network and generate full field dynamic fracture models and parameters for reservoir simulation. This can only be achieved by acquiring a large quantity of high quality data about the fractures and the reservoir, and by utilizing the latest tools to develop the most representative fracture model.

The inherent problems of reservoir characterization are:

- the broad range of scales on which data are measured,
- the different fracture types,
- the complexity of the fracture network.

Reservoir characterization and modelling methodologies for naturally fractured reservoirs (NFR) must be able to integrate data acquired on all scales, from regional seismic data to explicit information acquired from wells. Several models may need to be built if the fracture system is complex, in order to minimize the uncertainty in fracture characterization.
parameters. As with every reservoir, continuous model refinement and development in parallel with history matching is another facet of the NFR modelling process.

Naturally occurring fractures vary greatly; in length, microfractures can be measured in millimeters and at the other extreme, major faults can extend for many kilometers. The propagation of fractures begins when the stresses in the rock reach or exceed the rock strength. With time and varying geological conditions, different fracture patterns form, often resulting in very complicated fracture systems. Orientation, aperture and intensity of the fractures are equally important in the characterizing process.

Fracture data collected in the field are measured on various scales and at different resolutions, depending on the type of measurement performed. Seismic and outcrop analogue data are acquired on a regional scale whereas data measured at the well provide explicit fracture information. Sometimes even dynamic data from well tests are required to constrain the model and assist in producing the most accurate results.

Traditionally, fracture characterization has been done using only data acquired at the well from cores and image logs, or by other approaches that combined the known geological and structural data with geostatistical methods. Recent developments in both seismic acquisition and processing, along with the development of new computer algorithms, has led to powerful analytical procedures for fracture characterization. In the past, mainly paid three approaches have been utilized:

- Geomechanical analysis,
- Discrete Fracture Network (DFN) Modelling,
- Continuous Fracture Modelling (CFM).

Methodologies have been implemented in software platforms that promote the integration of raw fracture data acquired from the field into geological models. These methodologies include:

- identifying the various fracture sets,
- composing the fracture network models and
- determining their respective parameters.

In the DFN workflow, models of the fracture networks are constrained by the fracture information interpolated directly from explicit local measurements performed at the well, and/or from data derived from seismic surveys and occasionally outcrop studies. Hydrodynamic characterization of the fracture network is performed using dynamic flow data. A conceptual fracture model, which represents a general understanding of the distribution and formation of fractures and equivalent fracture parameters, are the desired results from this approach.

Any successful history matched dynamic model, to be used for prediction of future production, must contain a realistic representation of fracture parameters like fracture permeability and matrix block size. It is essential to develop an understanding of the
distribution, formation, geological history and dynamic properties of fractures in the reservoir in order to comprehend the dynamic behaviour of the field.

For the purpose of dynamic modelling a reservoir does not require special consideration if it is considered to have a single porosity. In the simplest case, the reservoir can be regarded as a single continuum for simulation purposes if:

- No fractures exist or fractures are isolated. Then, the fractures merely contribute to the local pore volume and the local conductivity.

- The matrix is tight, the matrix contains no hydrocarbons, or the stored hydrocarbons are not accessible because of a lack of matrix permeability. In this situation, the matrix does not significantly contribute to production.

However, if fractures are numerous enough to create an extended interconnected network influencing the flow of fluid and the associated volume of fractures is significant, then the reservoir may no longer be considered as a single continuum but as dual continua, with one system representing the matrix and another to represent the effect of the fracture system. The major technical issue is modelling the interaction between the two porosity/permeability systems to yield reliable estimates of reserves and recovery factors.

Most reservoirs, however, are fractured only to a certain degree. The degree of fracturing and the spatial distribution of fractures determines whether fractures play a role in reservoir production, and what implications this has for reservoir simulation.

The following parameters are used in the simulation of NFR:

- matrix porosity
- matrix permeability
- fracture porosity
- fracture permeability
- shape factor, σ (used in the calculation of fluid transfer between the matrix and fracture network)

The shape factor is a function of fracture intensity and ideally is calculated from pressure build-up data. However, if dual-porosity behaviour is not apparent in the well test results, the shape factor must be derived from other information such as wellbore image logs.

The permeability of the fracture system depends on the fracture intensity, the connectivity of the fracture network, and the distribution of fracture transmissivities.

2.5.9 Spatial Organization of Reservoir Fractures

To understand the spatial distribution of fractures in a reservoir, it is essential that their occurrence be related to geological controls such as lithology, porosity, and distances to faults. Naturally occurring fractures can be divided into two major groups:
(1) Diffuse fractures and
(2) Fracture swarms.

Diffuse fractures are fractures that are distributed throughout the reservoir in layers that have low ductility. Such layers may contain one or more fracture sets with different spatial characteristics. Diffuse fracturing can be recognized by:

- High fracture intensities confined to distinct reservoir layers and
- Significant dispersion in fracture orientations resulting from the presence of several fracture sets within the same layer.

Fracture swarms are zones characterized by high fracture intensity associated with the presence of faults. Fractures can be identified as fracture swarms if (1) their occurrence is not related to specific geological layers, (2) the dispersion in fracture orientations is small and (3) the dominant fracture orientation follows the direction of strike of nearby faults. An example of a fracture swarm is shown in Figure 12.

Figure 12: Example of a fracture swarm in the Aalenian Limestone, southern France (from Geosciences Montpellier)

Fracture swarms will develop in response to structural deformation by faulting and will occur in the vicinity of major interpreted faults and inferred faults at sub-seismic scales. However, in some instances fracture swarms do not noticeably increase the horizontal or vertical effective permeability. The lack of vertical fracture transmissibility between reservoir zones is best analyzed using RFT measurements, which may reveal major differences in static reservoir pressure, as depicted in an example from an analogous field shown in Figure 13. If hydrocarbons were able to migrate vertically along the fracture planes of fracture swarms, this would lead to a rapid equilibrium of pressure differences and the vertical pressure profiles would be more clearly continuous.
2.5.10 Methodologies to Characterize Fractured Reservoirs

2.5.10.1 Geomechanical Approach

The geomechanical approach (illustrated in Figure 14) requires an attempt to reconstruct the tectonic history of the fractured reservoir. Unfortunately, all the existing tools for this approach employ overly simplistic models in which the complex geology of the reservoir is ignored and homogenous and isotropic rock properties are assumed in the calculations. Furthermore, the end result of this approach is a strain map, which typically is very similar to a simple curvature map that can easily be derived from structural surfaces. Another major deficiency in the geomechanical approach is that it assumes the present open fractures are related only to tectonic events. It ignores the potential for diagenetic changes, including mineralization, to alter fractures after they have formed. Geomechanical models cannot account for the complex and heterogeneous geology of all fractured reservoirs, and there is no way to incorporate 3-D seismic attributes into the geomechanical modelling process.
2.5.10.2 Discrete Fracture Network (DFN)

The second approach most commonly utilized is a Discrete Fracture Network (DFN). The reservoir model utilizing DFN reflects the reservoir volume as filled with fractures represented by disks or planes. This approach relies heavily on image logs (which unfortunately are rare) and wellbore information. It is attractive to modellers because the fractures are treated as individual objects. The fracture statistics obtained from the well information are distributed randomly throughout the reservoir. Unfortunately, the models produced with this approach do not provide any quantitative information about the fluid flow behaviour of the reservoir. Their popularity seems due mainly to the modeller’s misconception that since the models “look” realistic, they must be realistic. A DFN model has never matched field history, let alone the production history of an individual well. Well test data is utilized in this method to calibrate the model, not to confirm it, and this is one reason why this class of models has no predictive power. The resulting geocellular models derived in this approach lack geologic realism because they appear to be, and in fact are, random and very noisy. This approach was developed for modelling of nuclear waste disposal sites, where it was possible to drill and run image logs in boreholes on a regular 50 meter grid. The models are not appropriate in the oil and gas industry where it is very unlikely that image logs will be run on more than a few wells in a reservoir.

DFN models have lacked geologic realism for many years due to the fractures being randomly distributed within the reservoir. Of course, this ignores an important static modelling issue that the fracture density at any point in the system is influenced by the thickness of the reservoir, local lithology, porosity, the proximity to faults due to geomechanical considerations, as well as, by many other geological factors not listed here. It has been recognized since the introduction of DFN models that there was a need to constrain the realizations to some form of geologic input, and attempts have been
made to control the fracture generation by some indicator property. However, these attempts have relied on a single geologic driver, ignoring other factors, and most importantly, not considering the complex interplay of the drivers. Ouenes and Hartley (2000) introduced the concept of a conditioned DFN where a significant effort is spent in integrating all the geologic drivers from within a continuous fracture model is then utilized to constrain the DFN models. An example illustrating this approach is given by Zellou, et al. (2003) on a field in the Middle East.

Figure 15: A Typical DFN model cube (Quenes, 2000)

2.5.10.3 Continuous Fracture Modelling (CFM)

The third and final mentioned approach utilizes a continuous framework that creates an integrated fracture model while successfully incorporating the various and numerous geologic drivers. The method uses various geological drivers (structural setting, proximity to faults, lithology, porosity and thickness) sometimes in association with 3-D seismic data to create a continuous fracture model. A neural network is trained to establish the relationship between various inputs (geological descriptors and seismic attributes) and the known fracture intensity at the well. The result of iterating the neural network is a fracture intensity map.

This methodology was developed to work on various scales ranging from geological to reservoir simulation scale geocellular grids. This method utilizes any type of fracture indicator available at the wells. Any geologic or geomechanical indicator available in the form of a 3-D geocellular grid, or any seismic or field measurement, can be incorporated quantitatively into the modelling process. A set of artificial intelligence tools provide the flexibility needed to deal with complex fractured reservoirs. A typical workflow is shown in Figure 16.
2.5.10.4 Seismically Driven Fracture Modelling

The goal from the early stages of the CFM approach was to utilize seismic data in an application towards fracture modelling. There is clearly some success within this realm, and this early success has now opened up more opportunities to include seismic data as the cornerstone data set in future fracture characterization and modelling. Fracture models can now be seen as much higher quality, however, it must also be noted that they must also include a holistic workflow incorporating multiple data sets in order to fully benefit from this capability. Seismically derived fracture models are often utilized to drill new wells that target fracture swarms and to also more accurately simulate these complex fracture systems which are often described as “plumbing”. In order to capture this “plumbing” the key is to derive relevant seismic attributes that are related to fractures. These seismic attributes are derived from pre-stack or post stack modelling. Examples of these seismic modelling processes are pre-stack elastic inversion, post-stack high resolution inversion and spectral imaging. These processes provide seismic
attributes that are required for any fracture modelling effort. Without such attributes, any fracture modelling effort will lead to very unreliable fracture models.

It is critical to gather seismic and log data to derive key seismic attributes that provide useful information about rock and fluid properties.

2.5.10.5 Fracture Indicator Definition

The fracture indicators in the CFM approach could be anything that provides relative information about fracture density along a wellbore or from one well to another. If image logs are available, they could be easily used as fracture indicators. However, one has to be aware that not all fractures seen in image log are necessarily producing. Hence, it is recommended to use fracture indicators that have some relationship with flow. A good fracture indicator could be core-derived measurements. Since fractures exist at many scales, even small core plugs where it is assumed that no fractures are present (because the eye cannot see the microfractures) may provide valuable fracture indicators.

When no core or image logs are available many other logs could be used to derive a fracture indicator. These include the combined use of sonic and density logs, temperature logs, production logs, etc.

2.6 References


Balogun et al. (2009) Verification and Proper use of Water-Oil Transfer Function for Dual-Porosity and Dual-Permeability Reservoirs, SPE 104580, SPE J. Paper.


Presented at the 8th International Chemical Engineering Congress & Exhibition, Kish, Iran, 24-27 February.


Kazemi et al. (1979) Numerical Simulation of Water Imbibition in Fractured Cores, SPE. J.


Chapter 3 Methods

3.1 Approach
The approach utilized was to develop a methodology or process of applying the Recovery Curve Method (RCM) to full field numerical simulation. Numerous iterations were performed on various combinations and sequences of application, and have resulted in the proposed RCM workflow. The effectiveness of this new workflow has been confirmed through the application of it with real world case studies.

3.2 Dual Continuum NFR Workflow with Recovery Curve Method
The chapter has been prepared for publication SPE-188418-MS and was presented at the Abu Dhabi International Petroleum Exhibition & Conference held in Abu Dhabi, UAE, 13-16 November 2017.

Justin Brand F. and Georg M. Mittermeir,
“A Recovery Curve Method Based Workflow for Reserves Estimation of Naturally Fractured Reservoirs - A Case Study”

3.2.1 Abstract
Naturally fractured carbonate reservoirs (NFRs) account for a majority of the world’s proven oil (~60%) and gas reserves (~40%). Many operators either significantly over-predict production and reserves, or non-optimize NFRs lacking suitable methods for modelling the fracture-matrix fluid interactions. Even complex functional shape factor based formulations fail. Only numerical fine-scale single-matrix-block (SMB) calculations capture the matrix-fracture fluid exchange in its complexity. A workflow and a successful case study (exceeding 80 years history) are presented.

Heinemann (2004) proposed a concept (Recovery Curve Method, RCM) utilizing predefined recovery curves instead of functional descriptions to model the fracture-matrix interaction. Meanwhile, the necessary methods and tools have been researched, developed and proven by field applications.

Our iterative multi-step workflow reduces uncertainty gradually. At first, matrix oil recovery is investigated on SMB models (Steiner and Mittermeir (2017)). The resulting recovery curves are verified and tuned with Mittermeir’s (2015) Dual Porosity Material Balance method. The link to full field simulation is established by a numerical dual porosity column model. Finally, the full field is calculated and matched by the RCM.

Based on a first conceptual reservoir model, burdened with uncertainty, the matrix and fracture rock system is examined gradually. The reservoir volume, time frame and complexity covered is stepwise extended. Using the finely gridded SMB, the physics of matrix-fracture interaction are investigated under different drive mechanisms including
single phase expansion, solution gas drive, capillary imbibition, gravity drainage, viscous and diffusive forces. Effects of these mechanisms can be studied in an isolated or combined way, including its time dependency. The resulting recovery curves give a good estimate of reservoir behaviour under different operating conditions. Dynamic data, such as pressure, production and phase contact history are matched subsequently by dual porosity material balance calculations. Results are water influx requirements (analytical aquifer models) and verified recovery curves. The latter are used to estimate the missing or highly uncertain data used to build the conceptual model by reversing the SMB calculation procedure. Consistency of the obtained improved data set is verified by a numerical dual porosity column model. It resembles the twin-barrels of the material balance model, however accounts for vertical transmissibility distribution. Individual well performance is matched in the full field model, which in addition to the material balance is used for forecasting.

The recovery curve based workflow provides a comprehensive concept and a consistent closed loop modelling of NFR exploitation. The shortcomings of the commonly applied shape factor concept (Kazemi et al. (1976)), which are well documented in the literature, are eliminated by omitting an analytical transfer function. Instead, diligently evaluated recovery curves are used directly to model the complex matrix-fracture interaction under different recovery mechanisms at each stage of the field life.

3.2.2 Introduction

3.2.2.1 Objective, Content and Scope
The objective of this paper is to present a new workflow for the dynamic modelling of naturally fractured reservoirs (NFRs). This workflow is based on the recovery-curve method introduced by Heinemann and Mittermeir (2004, 2015). This paper discusses differences between a classical modelling approach and this new variant, as well as demonstrating the superiority of the latter.

The field model utilized in this paper is derived from a full-field study. The parametrized grid model, created with a geological modelling package, was history matched utilizing the classical Kazemi approach. For want of another option, it is assumed that the matched model represents the true history, since it does not represent a true handicap. Thus, a partial lack of this data set can be successfully circumvented in order to apply the new methodology.

Finally, the dynamic-modelling workflow, using recovery curves, is applied. This consists of the following steps, which are also depicted schematically in Figure 17:

- The recovery curves are calculated utilizing single matrix block (SMB) calculations;
- Dual-porosity material balance (MB) is calculated utilizing the previously calculated recovery curves, before the phase contacts are matched by tuning the curves;
- SMB simulation is utilized to match the final recovery curves from the MB calculation, as well as to acquire information about the true values of the associated matrix block height and the relative permeability curves;
3.2.2.2 Modelling Fracture-Matrix Fluid Transfer

All industrially utilized methods for dynamic modelling of NFRs are based on the dual continuum approach (DCM). At every point in space within a DCM, two values exist for each property: one for the fracture and another for the matrix continuum. Initially, the fissures are filled with oil, and the oil from the matrix is produced in the fissures according to the fluid/rock expansion and solution-gas drive. This is a purely pressure-dependent process. When the water-oil or gas-oil interface reaches the matrix block, production is mainly due to capillary and gravity effects. The difference between the DCM implementations is in their calculation of the fracture-matrix fluid transfer. In current industry practice, the most commonly utilized methods for calculating the matrix-fracture mass transfer are the Kazemi et al. (1969) formulation with either the Gilman and Kazemi (1988) or the Quandalle and Sabathier (1989) gravity-drainage model.

The Reiss et al. approach

In this approach, Reiss et al. (1973) assumed that during NFR production, the phases are completely segregated in the fissures, and the matrix block is entirely surrounded by water or gas. The matrix-fracture exchange was represented by time-dependent source or sink functions, also known as recovery functions or recovery curves. These functions were derived from laboratory experiments and/or from numerical simulations of the oil-recovery mechanism in a finely gridded single-matrix-block model.

Mattax and Kyte (1962) performed water imbibition experiments. They demonstrated that in situations in which water imbibition is the dominant force in oil displacement
from the matrix, the cumulative oil recovery by imbibition from a piece of rock surrounded by water can generally be approximated via an exponential function, such as the Aronofsky et al. (1958) equation:

$$E_R(t) = E_{R_{\text{max}}} (1 - e^{-\lambda t})$$ (1)

Rossen (1977) used the same approach during the semi-implicit handling of the source terms. Both Reiss et al. and Rossen assumed that the oil recovery from a matrix block is mainly due to capillary and gravity effects, and that it is only a function of the elapsed time after water (or gas) comes into contact with the matrix block via the surrounding fractures. The effects of compressibility and viscous flow in the fracture on matrix-fracture transfer were neglected by these authors, since they did not manage to derive transfer functions that are only time-dependent and valid at each stage of the field exploitation. The professional community did not acknowledge Reiss et al.’s assertion that this simplification is not overly restrictive to usual field conditions. The Mattax and Kyte (1962) experiments-based, exponential recovery curves were subsequently applied primarily to capillary imbibition. Examples of additional authors who are adopting this approach are de Swaan (1978), Kazemi et al. (1992), Di Donato et al. (2007) and Lu et al. (2008).

The Kazemi et al. approach

Kazemi et al. (1976) extended the Warren-Root (1963) shape-factor approach, which is valid for single-phase flows, to multiphase cases. The resultant transfer equation, in its general form, is valid for oil, water and free gas:

$$q_{pmf} = V_{c\text{ell}} \sigma k_a \frac{k_p}{\mu_p B_p} (\Phi_{pf} - \Phi_{pm}); \quad p = w, o, g;$$ (2)

where $V_{c\text{ell}}$ is the bulk volume of a single simulation cell; $p$ stands for oil, water and free gas; $k_a$ is the apparent matrix permeability; $\mu$ the viscosity; $B$ the formation-volume factor; $k$ the relative permeability and $\Phi$ the phase potential in the fracture ($f$) and in the matrix ($m$). The shape factor, $\sigma$, is a characteristic value of the matrix block, and it will be calculated based on the size and form of the individual matrix blocks. The most complete version is the generalized Kazemi-Gilman-ElSharkawy (1992) shape factor as derived by Heinemann and Mittermeir (2012).

Kazemi presumes that the driving force can be expressed as the difference between two discrete potential values: one is valid at the centre of the matrix block and the second is valid for every point within the surrounding fractures. In this case, Eq. (2) is applicable. However, this is not the case for the gravitational and viscous driving mechanisms. The difference between the average potential values is 0, and Eq. (2) is consequently not directly applicable. To overcome this difficulty, the difference in the potential gradients in the matrix and the fracture must be considered. With this correction in the water-oil two phase flow, the potential differences for the water (index $p = w$) is expressed as:

$$\Phi_{sw} - \Phi_{wf} = p_{sw} - p_{of} - P_{cmw} + P_{cwof} - \kappa P_{Lwo};$$ (3)
where \( \kappa = 1/4 \). The term \( P_{Lwo} \) represents the potential differences originating from differences between the water-pressure gradients in the fracture and those in the oil pressure in the matrix. Multiple authors have made numerous supplementary attempts to make the transfer function more appropriate, without mentionable success.

### The Heinemann and Mittermeir approach

Heinemann and Mittermeir (2004, 2015, 2016) combined the two aforementioned concepts with the underlying aim of separating the matrix-to-fracture and the fracture-to-matrix flow calculations. The Kazemi et al. (1976) approach and one similar to that of Reiss et al. (1973) are used for the first and second of these calculations, respectively. According to Reiss, the rate at which the fracture injects the displacing fluids into the matrix is given by a time-dependent function. However, according to Heinemann and Mittermeir, it should be a function of the matrix-recovery factor that is corrected to the actual pressure. The rate at which the displaced fluid is expelled from the matrix must be calculated by the Kazemi (i.e. Warren-Root) type transfer equation. Therefore, the basic assumption is that the forces of compressions and the capillary and gravitational forces act independently, and their results will be superposed.

The recovery from capillary imbibition and gravitational displacement at constant pressure can be calculated on SMB models (and also measured in laboratories), resulting in recovery curves. One example is shown in Figure 7.15. The additional oil production during time-step \( \Delta t \) is estimated using the increment of the recovery factor during the actual time-step. The following equation is the difference between the recovery factor at time \( t_j + \beta \Delta t \) and the beginning of the time-step \( t_j \) (Figure 7.15), where \( \beta \) is the time-scaling factor:

\[
\Delta E_R^w = E_R^w_{j+1} - E_R^w_j
\]

If the pressure has already dropped but the validity of Darcy’s equation is still assumed, then \( \Delta E \) can be scaled to the actual pressure and saturations:

\[
\Delta E_R^w(p) = \left[ \left( \frac{k_w(S_o)}{\mu_w(p)B_o(p)} \right) \left( \frac{k_w(S_{ob})}{\mu_{ob}B_{ob}} \right) \right] \Delta E_R^w(p_B)
\]

where the index \( b \) relates to the reference pressure of the recovery curve. This type of correction was already used by Gharsalla (2015) and Heinemann and Mittermeir (2016). The same equation is valid for gas displacement by changing the superscript \( w \) to \( g \). The volume of the displacing agent (water or gas) that the fracture injects into the matrix for one standard initial oil volume is then as follows:

\[
\Delta w = \Delta E_R^w(p) \cdot B_o(p) / B_w(p) \quad \text{or} \quad \Delta g = \Delta E_R^g(p) \cdot B_o(p) / B_g(p)
\]
3.2.2.3 Recovery-Curve Workflow for Numerical Simulation

When the Kazemi approach is adopted, the workflow is simply the traditional history-matching workflow, and when the Recovery Curve Method is applied, a more complex workflow can be implemented. An efficient workflow is proposed that consists of SMB simulation, dual-porosity MB and full-field simulation utilizing the recovery-curve method. By using all these methods and tools, it is possible to match an observed phase contact history. At the end of the workflow, there is a history-matched full field and MB model and an improved understanding of the matrix-block properties.

The dynamic modelling workflow, utilizing recovery curves, consists of the following tasks:

- The first step involves the calculation of the recovery curves using SMB simulation. In this step, it is necessary to acquire an understanding of the possible matrix block properties, especially the matrix block height. After the estimation of a geologically reasonable matrix block height, distribution-lumped gas and water recovery curves can be created.

- The next step is a dual-porosity MB calculation using the previously outlined recovery curves. With this MB formulation, it is possible to analyse the matrix-fracture mass transfer. Tuned recovery curves are obtained by matching the observed phase contacts.

- In a next step, SMB simulation is used again to match the scaled recovery curves from the MB calculation. This is done to gain information about the true values of the matrix block height and relative permeability curves, amongst other values.
To ensure the existence of a link between the MB and the full-field model, a dual-porosity column model is created based on the twin-barrel concept of the MB.

Subsequently, those tuned recovery curves can be utilized for a full-field simulation using the recovery curve method. In this process, a further tuning of the recovery curves is performed to match the phase contact, pressure and production history. When acceptable matches are achieved for those quantities, water and gas recovery curves are then derived that correctly describe the matrix-fracture mass transfer.

3.2.3 The Field Case
The aforementioned workflow will now be applied to a real field case.

3.2.3.1 Background

It is difficult to identify a real field case on which the modelling workflow, with all its related concepts, methodologies and tools, could be demonstrated in a generally valid extension. Fractured reservoirs differ markedly in various matrix and associated fracture properties (e.g. Aguilera 1980 and Nelson 1992), whether this be in internal connectivity (dual porosity or dual permeability), in fluid and rock properties (black oil or compositional description, and wettability) or in depletion mechanisms (expansion, water and gas drives, modelled either with or without oil resaturation). In most cases, the observational data related to such reservoirs is incomplete and heavily burdened by uncertainty, with the available history covering only a limited period of the reservoir’s overall field life. Furthermore, field data are generally treated confidentially, which often leads to insufficient access to data to support real-world applications of new approaches. For this reason, we will call our reservoir ABC-Field.

3.2.3.2 Field Description

The ABC-Field is a Type II NFR, and it is assumed to be of dual porosity and dual permeability. Type II NFRs have a low matrix porosity and permeability (Allan and Sun, 2003). The matrix provides some storage capacity, and the fractures provide the fluid pathways. The ABC-Field-model version is derived from a full-field study. The original model was modified to protect the proprietary rights of the field owner. However, the synthetic model still exhibits all of the original’s essential characteristics.

The ABC-Field’s original-oil-in-place (OOIP) is estimated to be 220 million sm³ with 95% stored within the matrix. The current field-recovery factor is approximately 30%. The average reservoir permeability, porosity and net-to-gross ratio are listed in Table 1 (matrix-block heights and shape-factor distributions will be discussed later on).

<table>
<thead>
<tr>
<th>property</th>
<th>mean</th>
<th>min.</th>
<th>max.</th>
<th>unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>permeability</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>X matrix</td>
<td>2.23</td>
<td>1.00</td>
<td>13.94</td>
<td>millidarcy</td>
</tr>
<tr>
<td>fracture</td>
<td>750.00</td>
<td>750.00</td>
<td>750.00</td>
<td>millidarcy</td>
</tr>
<tr>
<td>Y matrix</td>
<td>2.23</td>
<td>1.00</td>
<td>13.94</td>
<td>millidarcy</td>
</tr>
</tbody>
</table>
The case study’s production history recounts nearly all properties and difficulties that could arise when dealing with a typical NFR in the Middle East. The field has been in production operation for more than 80 years (Figure 19), and the reservoir is modelled with a black-oil fluid description. With a standard density of 739 kg/m³ or 46.1 °API, the oil can be classified as light crude oil, and is slightly under-saturated. The standard densities for water and gas are 1094 kg/m³ and 0.788 kg/m³, respectively. The bubble-point pressure is 155 bara, while the initial HC-weighted reservoir pressure is 168.9 bara. The reservoir is a two-phase oil-water system (with dissolved gas) at initial conditions. During the depletion, a secondary gas cap develops, prompting its reclassification as a three-phase gas-oil-water system. The anticlinal structure (Figure 61) is bounded at all sides by an edge aquifer of considerable strengths. Thus, all possible drive mechanisms, such as expansion, water and gas displacement as well as oil resaturation of the matrix, take place in certain parts of the reservoir. Therefore, capturing the matrix-fracture mass transfer in its complexity is crucial.

<table>
<thead>
<tr>
<th></th>
<th>fracture</th>
<th>750.00</th>
<th>750.00</th>
<th>750.00</th>
<th>millidarcy</th>
</tr>
</thead>
<tbody>
<tr>
<td>$Z$ matrix</td>
<td>1.57</td>
<td>0.01</td>
<td>13.70</td>
<td></td>
<td>millidarcy</td>
</tr>
<tr>
<td>fracture</td>
<td>100.00</td>
<td>100.00</td>
<td>100.00</td>
<td></td>
<td>millidarcy</td>
</tr>
</tbody>
</table>

| porosity    | matrix   | 17.79  | 1.00   | 34.63  | %          |
|             | fracture | 0.45   | 0.45   | 0.45   | %          |

| net/gross   | matrix   | 0.96   | 0.05   | 1.00   |            |
|             | fracture | 1.00   | 1.00   | 1.00   |            |

Figure 19: ABC-Field production and average pressure history
The input data for the capillary pressures and the relative permeabilities can be seen in **Figure 21** and **Figure 22**. In initializing the model, which involved calculating the initial pressure and the saturation distributions, the drainage oil-water capillary curve is applied. The imbibition curve is utilized while simulating the oil recovery, and the capillary pressure is set to 0 for the fracture analyses.
3.2.3.3 Application of the Recovery-Curve Workflow for Numerical Simulation

Single Matrix Block Simulation elaboration on initial recovery and resaturation curves

Here, an SMB analysis tool, which was initially developed by Pirker et al. (2007) and integrated into Heinemann’s (2017) research simulator H5, is utilized. The matrix-block model is discretized into grid cells. The matrix block is homogenous; however, it can be anisotropic, having different permeability values in x-, y- and/or z-directions. Figure 23 depicts an SMB model used in this work. It allows for the calculation of the recovery under different boundary conditions, considering capillary, gravitational and viscous forces as well as the oil resaturation after its displacement by water or gas. An in-depth discussion of this model is given by Steiner and Mittermeir (2017).
Methods - Dual Continuum NFR Workflow with Recovery Curve Method

Figure 23: The quarter of an SMB model (a) fully surrounded by fractures and (b) bounded by vertical fractures only

![Figure 23: The quarter of an SMB model](image1)

During the long production history of the ABC-Field, periods with an increasing oil-rim thickness have also been observed. This means that, for some matrix blocks where the oil was already displaced, the saturation boundary condition changes from either water or gas to the oil phase, and a resaturation of the matrix block with oil occurs. This mass transfer is modelled with an oil resaturation curve.

Lumped recovery curves can be calculated to consider different matrix blocks inside a simulation cell. A distribution of shape factors and matrix-block heights must be estimated. The applied shape-factor distributions can be seen in Figure 24. Associated matrix-block heights are in the range of 2.5 to 16 m. It should be noted that applying

Figure 24: Shape-factor distribution for lumped single-matrix-block simulation

![Figure 24: Shape-factor distribution](image2)
average values and conducting a single SMB simulation does not lead to the same results as lumping calculated recovery curves. The resulting initially calculated recovery and resaturation curves are presented in Figure 25.

![Recovery and Resaturation Curves](image)

**Figure 25**: Recovery curves from single-matrix-block calculations for gas and water drive and associated oil-resaturation curves

**Dual Porosity Material Balance – Tuning of recovery and resaturation curves by phase contact matching**

The application of the dual-porosity MB method, as described by Mittermeir (2015), is essential for understanding the matrix oil-recovery mechanisms. The method is based on the recognition that the performance of water and gas displacement from matrix blocks can be depicted by plotting recovery factors against time. These recovery curves determine the matrix-fracture mass transfer. The reservoir’s pressure change depends on the original fluids in place and the strength of the aquifer. Therefore, a close relationship exists between the recovery curves and the aquifer parameters, the matrix-fracture oil transfer and the observed reservoir state (in terms of pressure, position of phase contacts, water cut and GOR).

Within this same publication the approach is further explained as follows. The reservoir model for the dual-porosity MB calculation is built by two columns: one representing the fracture and another, the matrix continuum. The columns are divided into tranches (slices of unit thickness), starting from the initial OWC and progressing upwards. The vertical distributions of the extensive values (for example, OOIP and pore volume) are the sum of the horizontal tranches throughout the reservoir. Summing up the fluid contents of the tranches results in two columns of barrels. One column represents the matrix and the second, the fracture continuum. As a consequence of the vertical
resolution, the distribution of the fluids and the position of both the initial OWC and the oil-gas contact (OGC) are known. Intensive values, such as $S_{wi}$ (initial water saturation), are the averaged sum of them. Figure 26 schematically illustrates the transformation process from a 3D-populated grid model to the twin barrels of the dual-porosity MB. Furthermore, the most important aspects of the latter are also illustrated including behaviours, such as: fluid production and water encroachment through the fracture network only, and, as well as, the different recovery mechanisms.

![Figure 26: Schematic illustration of the dual-porosity MB model creation and model operation](image)

Dual-porosity MB can be run either on its own or embedded in the workflow promoted herein. Within the workflow, the objectives are to verify the previously elaborated SMB-derived recovery and resaturation curves and to subsequently tune them by matching the observed phase-contact movements.

As a starting point for the demonstrated phase-contact matching process, two recovery curves (water and gas drive) and two oil-resaturation curves (resaturation after water flooding and gas flooding) are required. For each recovery and associated resaturation curve, two factors can be used to influence the phase-contact movements:

- Recovery-scaling factors for adjusting the ultimate recovery, and
- Timescale factors for influencing the pace of oil recovery.

The appropriate factors are determined in an iterative process until the observed and calculated phase-contact movements match each other to a reasonable extent. The water influx from the outside aquifer and thus the pressure support were simultaneously regulated using the target pressure method (Mittermeier et al., 2004). This method ensures that the calculated pressure always matches the historical pressure. At the end of such a run, an analytical aquifer model that reproduces this pressure history within close limits will be automatically calculated.

For this case study, an acceptable history match for phase contact movements was achieved after eight calculation runs. At this point, the aquifer model was changed from the target pressure method to the Fetkovich analytical model. Seven additional iteration cycles were performed to fine-tune the phase contact match.
Two sets of scaling factors for the case setups eight and 15 can be seen in Table 2. Recovery scaling factors for water drive and gas drive are abbreviated to SRECw and SRECg, respectively, while TREC and TRES represent the timescale factor for the recovery curve and the resaturation curves, respectively. A visual comparison of the scaled (setup 15) and the original input recovery curve can be seen in Figure 27 and Figure 28.

Table 2: Scaling factors and applied aquifer model for the iterative phase-contact match

<table>
<thead>
<tr>
<th></th>
<th>SRECw</th>
<th>SRECg</th>
<th>SRESw</th>
<th>SRESg</th>
<th>TRECw</th>
<th>TRECg</th>
<th>TRESw</th>
<th>TRESg</th>
<th>AquiModel</th>
</tr>
</thead>
<tbody>
<tr>
<td>8</td>
<td>1.75</td>
<td>1.00</td>
<td>1.75</td>
<td>1.00</td>
<td>1.00</td>
<td>0.10</td>
<td>1.00</td>
<td>0.10</td>
<td>PTARGET</td>
</tr>
<tr>
<td>15</td>
<td>1.65</td>
<td>1.15</td>
<td>1.65</td>
<td>1.15</td>
<td>0.75</td>
<td>0.10</td>
<td>0.75</td>
<td>0.10</td>
<td>FETKOV</td>
</tr>
</tbody>
</table>

Figure 27: Comparison of initial and scaled (#15) water drive RC
Methods - Dual Continuum NFR Workflow with Recovery Curve Method

Figure 28: Comparison of initial and scaled (#15) gas drive RC

**Figure 29** depicts the calculated phase contacts as solid lines and the phase-contact history as circles. The displayed heights are those above the initial oil-water contact. The initial oil-water contact depth is at 945 m subsea. **Figure 30** illustrates the belonging pressure, oil rate, water cut and gas-oil ratio. Each quantity is valid at the field level. The scattered data is the historical data, and the solid lines are the calculated results. The deviations in GOR are a direct consequence of the PVT data. As long as no secondary gas cap is formed, the production GOR must be equal to the solution GOR. To paraphrase more generally, when considering the production GOR, two cases must be examined: first, the production GOR cannot be less than the solution GOR; second, it cannot be greater than the solution GOR in the absence of free gas in the fracture.
The objective of these iterative steps was to successfully match the oil-rim thickness at the end of the production history. Naturally, deviations from the measured values are possible. The phase contacts, especially the oil-water contact, do not form a perfect horizontal plane in the reservoir.
Single Matrix Block Simulation – Determination of apparent matrix properties

The single matrix block analysis described above were performed to obtain a first educated guess of the matrix oil recovery based primarily on data distributions derived from the geological model and PVT and SCAL data. No dynamic, measured data, such as observed rates, pressures and phase contacts, have been considered. In the subsequent dual porosity MB, those data were accounted for and thus the previous “static” recovery curves became “dynamic” ones. The next step in the workflow will now be to improve the quality of the geological model.

Based on the results of the previous phase contact matching procedure, recovery curves can be calculated, using H5’s SMB tool, that match the scaled recovery curves of the dual porosity MB. Multiple combinations of parameters can be manipulated to achieve a desired match of the recovery curves. Therefore, the determination of the matrix properties requires an understanding of the reservoir and knowledge of which parameters are relatively certain or uncertain. This section on the determination of SMB parameters is not intended to provide a single correct solution. Instead, its purpose is to demonstrate that it is possible to derive multiple sets of parameters by matching the recovery curves. Therefore, this part of the workflow is suitable for conducting a sensitivity analysis and an uncertainty estimation.

Possible paths for matching the water drive recovery curve include adjusting the matrix permeability, the matrix-block height and the oil-water capillary pressure curve. Manipulating the matrix permeability by multipliers produces the expected linear relationship between permeability value and time to achieve a certain recovery value. However, this does not influence the potential difference between the matrix and fractures in the individual phases. Therefore, as long as permeability is greater than 0, this factor does not influence the ultimate theoretical recovery. It must be noted that very low permeability values limit the practical application of this methodology, and do not provide reasonable ultimate recovery estimates.

Both the matrix-block height and the oil-water capillary pressure curve have a more complex impact on the recovery curve by influencing both the nature and the speed of the ultimate recovery. In this case, the phase-potential difference is not only scaled by a constant factor, but the fundamental driving forces are also manipulated (in this context, gravitational and capillary forces).

For water drive, the scaled recovery curves can be reproduced twofold with SMB calculations—either by setting the permeability to 4 md and the matrix-block height to 14 m or by only adjusting the oil-water imbibition capillary pressure. A graphical comparison of both these two possibilities and the un-scaled and scaled water recovery curves is presented in Figure 31.

While matching the gas-drive recovery curve, only the period that was also used in the MB calculation was considered (approximately 30,000 days). The results of the matching process can be seen in Figure 32. The match has been achieved by adjusting the permeability to 0.35 md and the matrix-block height to 18 m.
Figure 31: Determination of matrix-block parameters (water drive)

Figure 32: Determination of matrix-block parameters (gas drive)
**Investigation of numerical column model**

The twin-barrel model, which is illustrated in Figure 26 and which was created for the dual-porosity MB calculation, can also be utilized as a dual-continuum grid model (1D column). In this case, the block transmissibilities must also be determined based on the parametrized (geo-cellular) model. The sum of all vertical transmissibilities—now being connected in parallel in the column model—must be summed up. The fracture-matrix transmissibilities must be built as an oil-in-place weighted average, and the column model can be initialized in either equilibrium or in non-equilibrium states. In the second case, the OOIP will be equal to that of the geocellular and MB models, although some initial instabilities will have to be endured.

In the actual field project, the column is built from 2x454 cells of a uniform thickness of 1 m. The equilibrium initialization was used, and a single well was introduced, representing the entire field’s production. This single well is placed within the column model’s middle 20 cells, and then opened. Furthermore, the recovery curve scaling factors evaluated at the MB calculation were used. The target pressure and phase method (TPPM), which was introduced by Abrahem et al. (2010), was used with the possibility of opening pseudo-perforations at the top and the bottom of the fracture column. This ensures an exact pressure and that the WC and GOR match.

As illustrated in **Figure 33**, the OWC movement is exactly the same as in the MB calculations; however, the OGC calculated with the column model is generally in a deeper position. The main difference between the MB and column models is the pressure utilized in each approach. The MB operates with the average pressure, which is equal for the fracture and all matrix tranches. However, in the column model, there is a pressure gradient in both the matrix and the fracture columns. The pressure difference between the top and the bottom is 38 bara in the column. This results from the associated hydrostatic pressure gradient on a large reservoir thickness.
Methods - Dual Continuum NFR Workflow with Recovery Curve Method

The full-field example was also calculated using the recovery-curve method. Calculating an entire field history in a full-field simulation is much more time-consuming than the previous steps of the workflow. Therefore, the generation of recovery curves using SMB and the scaling of these curves using MB and column models is a necessary prerequisite to starting this simulation.

In this setup, the wells are only controlled by their net oil-production rates. In contrast to the MB or the column model, the full-field model is not only a dual-porosity model but also one of dual permeability. This means that matrix cells are communicating, and a possible water or gas displacement of the oil can occur.

The same recovery curves as those for the dual-porosity MB calculation are used. The RC and timescale factors have also been taken from the MB analysis. If necessary, the position of the phase contacts of the full-field model could be influenced by adjusting the values of the recovery and timescale factors. When the same factors as those in the MB calculation are used, the resulting calculated phase contacts can be seen in Figure 34.

Again, as for the column model, TPPM was applied to achieve a satisfactory history match for pressure and produced phases. Water cut and gas/oil ratio matches are shown in Figure 35.
Methods - Dual Continuum NFR Workflow with Recovery Curve Method

Figure 34: Oil-gas-contact and oil-water-contact history matches with full-field simulation using RC

Figure 35: WC and GOR match with full-field simulation using RC
3.2.4 Summary and Conclusions

For the first time, the recovery-curve-based workflow provides a closed-loop numerical modelling approach for the development planning and associated recovery factor estimation of NFRs. This numerical modelling approach can be carried out at any time of the field’s life to perform the associated investigations of the reservoir’s dual porosity behaviour.

At any point in the field’s life, the analyses will always begin with the first workflow step of analysing the SMBs’ behaviours under possible recovery mechanisms, which can be performed in any number of combinations. On the basis of a conceptual reservoir configuration, the concurrence of the fracture and matrix block system in space and time can be examined at any level of complexity. Material balance, column or cross-section model calculations and single well modelling make it possible to adjust the initial starting point of a field’s analyses. Moreover, together with practical observations, they make it possible to improve the reservoir’s associated development concept. At this point, it is possible to return to the SMB investigation, matching fundamental properties, such as matrix block height, rock wettability and capillary functions, before starting the loop again. All investigations can now be undertaken utilizing the same tool and based on a common data repository. None of these features had been previously possible utilizing any classical modelling approach.

Until now, this workflow was only exercised on a few field cases (three real-world applications and associated data sets). For future research initiatives, supplementary efforts will be necessary to test and generalize the recovery curve method.

3.2.5 Acknowledgements

The authors thank Zoltán E. Heinemann, emeritus professor at the Mining University of Leoben, for his encouragement and suggestions, and the PHDG association for supporting this work.

3.2.6 Nomenclature

\[ B \quad \text{formation volume factor, } L^3/L^3, \text{ STB/res bbl} \]
\[ E \quad \text{efficiency/recovery factor} \]
\[ g \quad \text{specific gas amount, scaled to unit oil in place} \]
\[ k_a \quad \text{apparent matrix permeability, } L^2, \text{ md} \]
\[ k_r \quad \text{relative permeability} \]
\[ p \quad \text{pressure, m/L}^3, \text{ psia} \]
\[ P_c \quad \text{capillary pressure, m/L}^3, \text{ psia} \]
\[ P_t \quad \text{potential difference due to different pressure gradients in matrix and fracture, m/L}^3, \text{ psia} \]
\[ q \quad \text{production rate or flow rate, } L^3/t, \text{ STB/day} \]
\[ t \quad \text{time, t, day} \]
\[ S \quad \text{saturation} \]
\[ V \quad \text{volume, L}^3, \text{ res bbl} \]
\[ w \quad \text{specific water amount, scaled to unit oil in place} \]
3.2.6.1 Greek symbols

\( \beta \) \quad \text{time scaling factor}
\( \Delta \) \quad \text{difference operator}
\( \kappa \) \quad \text{multiplier}
\( \lambda \) \quad \text{exponential recovery constant, } 1/t, \text{ 1/day}
\( \mu \) \quad \text{viscosity, } m/Lt, \text{ cp}
\( \Phi_p \) \quad \text{phase potential, } m/L^3, \text{ psia}
\( \sigma \) \quad \text{shape factor, } 1/L^2, \text{ 1/ft}^2

3.2.6.2 Subscripts

\( a \) \quad \text{apparent}
\( b \) \quad \text{bubblepoint}
\( f \) \quad \text{fracture}
\( g \) \quad \text{gas phase}
\( j \) \quad \text{time point index}
\( m \) \quad \text{matrix}
\( o \) \quad \text{oil phase}
\( p \) \quad \text{phase}
\( R \) \quad \text{recovery}
\( w \) \quad \text{water phase}

3.2.6.3 Greek subscripts

\( \nu \) \quad \text{apparent}

3.2.6.4 Superscripts

\( g \) \quad \text{gas}
\( r \) \quad \text{reference}
\( w \) \quad \text{water}

3.2.7 Conversion Factors

\[ \frac{141.5}{(131.5^{15} \text{API})} = \text{kg/m}^3 \]

<table>
<thead>
<tr>
<th>Unit</th>
<th>Conversion Factor</th>
<th>Equivalent</th>
</tr>
</thead>
<tbody>
<tr>
<td>bar</td>
<td>x 1.0' E+05</td>
<td>= Pa</td>
</tr>
<tr>
<td>bbl</td>
<td>x 1.589873 E-01</td>
<td>= m(^3)</td>
</tr>
<tr>
<td>cp</td>
<td>x 1.0' E-03</td>
<td>= Pa.s</td>
</tr>
<tr>
<td>day</td>
<td>x 8.64' E+04</td>
<td>= s</td>
</tr>
<tr>
<td>ft</td>
<td>x 3.048' E-01</td>
<td>= m</td>
</tr>
<tr>
<td>ft(^3)</td>
<td>x 2.831685 E-02</td>
<td>= m(^3)</td>
</tr>
<tr>
<td>lbm</td>
<td>x 4.535924 E-01</td>
<td>= kg</td>
</tr>
<tr>
<td>lbm/ft(^3)</td>
<td>x 1.601846 E+01</td>
<td>= kg/m(^3)</td>
</tr>
<tr>
<td>md</td>
<td>x 9.869233 E-04</td>
<td>= m(^2)</td>
</tr>
<tr>
<td>psi</td>
<td>x 6.894757 E+00</td>
<td>= kPa</td>
</tr>
</tbody>
</table>

*Conversion factor is exact.*
3.2.8 References


3.3 Deconvolution

The chapter has been prepared for the Journal of Petroleum Science & Engineering in February 2018, and is still currently under further peer review for article publication.

Justin Brand F., Cristian Enachescu, Viktor Acs,

“Using deconvolution to characterize heterogeneity in a mature oil field”

3.3.1 Abstract

The paper presents a case study where a large amount of available dynamic information was used to characterize the heterogeneity of a mature oil field composed of four reservoirs; three carbonate formations and one clastic formation.

The elements of heterogeneity identified a priori include fractures, faults and karstic features in the carbonate formations as well as sand bodies and channels in the clastic reservoir. The oil field described is a mature field, which was discovered in 1936 and started production in 1947. Over the past 8 decades a large number of producers were drilled. In addition, pressure maintenance through water injection started in 1974.

The distribution of formation permeability was calculated at approx. 100 m scale by using a large number of tests. In addition, large scale permeability and interference behaviour between producers and/or injectors was characterized by using historical production data, which was deconvolved to equivalent constant rate responses. This approach, combined with detailed modelling of interference responses under complex conditions helped to understand well behaviour and provided direct input both to an upgraded model of the field and helped improve the current infill drilling decisions.

The paper presents the available information, describes the analysis methods used and summarizes the results.

3.3.2 Introduction

The motivation of this work was to devise a method to derive understanding of the hydraulic behaviour of a mature oil field by using the available rate decline information. Different from the traditional RTA the method presented here uses pressure-rate deconvolution and evaluates the results (i.e. the unit rate pressure derivative) in the presence of multiple interferences from neighbouring producers and injectors. Since the deconvolution method has been shown to be very sensitive to rate measurement errors and gaps in the data, additional work presented here researches the robustness of the method when applied to a rate decline data set subject to noise in the rate measurement and sparse data.

The method used is described in the first part of the paper. Since deconvolution has received a lot of attention in the testing literature of the past two decades and a wealth of seminal papers describe the mathematical and algorithmic background in great detail, this paper limits itself to referencing to the relevant papers and reporting the methodology used and the results.
The second part of the paper presents a case study where a large amount of available dynamic information was used to characterize the heterogeneity of an oil field composed of four reservoirs; three carbonate formations and one clastic formation. The elements of heterogeneity identified a priori include fractures, faults and karstic features in the carbonate formations as well as sand bodies and channels in the clastic reservoir.

The oil field described is a mature field, which was discovered in 1936 (?) and started production in 1947. Over the past 8 decades a large number of producers were drilled. In addition, pressure maintenance through water injection started in 1974.

3.3.3 Deconvolution of transient pressure and rate responses

Traditionally deconvolution has been applied until now to pressure transient responses (mainly well tests) with the aim of extending the analysable duration of the test sequence beyond the duration (and radius of investigation) of the pressure build-up phase and calculating an equivalent unit flow rate response for the entire duration of the test.

The primary quantity of interest in well test analysis is the well bore pressure drawdown as function of time for production at constant rate. If the flow is governed by a set of equations linear in pressure and rate, the pressure drawdown $\Delta P(t)$ measured in a well with time varying production rate $Q(t)$ is given by the convolution integral:

$$\Delta P(t) = \{Q \ast g\}(t) = \int_0^t Q(t')g(t-t') dt' \quad (1)$$

with $g(t)$ being the time derivative of the rate normalized wellbore pressure drop.

In well-testing $g(t)$ is the function of interest and solving equation (1) for it is a process named deconvolution. While equation (1) is written in time domain, it can be re-written in frequency domain by using a spectral transformation (Laplace, Fourier) in the form:

$$\Delta \bar{P} = \bar{Q} \times \bar{g} \quad (2)$$

with the bars denoting the quantities transformed into frequency domain. Methods solving equation (2) for $\bar{g}$ are frequency domain deconvolution methods, while solving equation (1) for $g$ are time domain deconvolution.

Assuming we use the Laplace transformation, the typical workflow of frequency domain deconvolution is to calculate the Laplace transforms of $P(t)$ and $Q(t)$, solve equation (2) for $\bar{g}$ and invert $\bar{g}$ back into time domain (to $g$) by using a Laplace inversion algorithm. The well-testing community has historically been using the Stehfest inversion algorithm. Recent work has shown that the Stehfest algorithm has strong smoothing behaviour and does not handle well functions with discontinuities and singularities, as usually seen when the flow rate of a test changes stepwise. Because of this reason, it has been suggested (Al-Ajmi et al., 2008) that the recently developed den Iseger (2006) algorithm will provide superior results.

Methods for solving the deconvolution problem in time domain by using inverse convolution (i.e. using an optimization method) were described by von Schroeter, Hollaender and Gringarten (2002) and by Levitan et al. (2003 and 2004). A frequency domain method using FFT was presented by Cheng et al. (2003). Several authors (Ilk et
al., 2005) presented different spline interpolation methods used in the transformation in frequency domain.

This algorithm used in this paper is described in great detail in Onur and Reynolds (1996). We used trapezoidal integration for the Laplace transformation of the rate and pressure data and the Stehfest inverter. In the specific case presented in this paper, since we focus on a gradual rate decline data situation (as typically used in RTA) the Stehfest inverter was deemed to be appropriate.

3.3.4 Deconvolution experiments (synthetic data)

In a first step of our work we wanted to establish whether the frequency domain algorithm presented by Onur and Reynolds (1996) works well in recovering the unit rate pressure derivative used in synthetically simulating a declining rate production. The simulations were calculated in single phase and using a numerical wellbore simulator.

The workflow used was to first establish a declining rate curve, which, together with different unit rate derivative shapes would be used as input to simulate the corresponding pressure response by using a finite differences approach. The pressure and rate responses would be subsequently deconvolved to retrieve the unit rate pressure derivative, which was compared with the initial derivative input.

3.3.4.1 Case 1

Case 1 used an arbitrary rate decline curve and a derivative generated using a radial composite flow model with decreasing mobility thickness product away from the well. The simulation inputs (rate and derivative are shown in Figure 36 and Figure 37, the resulting pressure response is presented in Figure 38.

The frequency domain deconvolution used the declining rate schedule presented in Figure 1a and the simulated pressure response presented in Figure 1c to retrieve the unit rate derivative used in the simulation. The deconvolution result compared with the input derivative is shown in Figure 39.
Methods - Deconvolution

Figure 36: Case 1 simulation input - rate

Figure 37: Case 1 simulation inputs – pressure and derivative
Methods - Deconvolution

3.3.4.2 Case 2

The workflow of Case 2 was identical to Case 1. The same declining rate schedule was used, however in this case a different (more complex) derivative shape was used. The derivative was generated by adding a third composite shell of higher mobility thickness product to the initial model used in Case 1. The inputs and simulation results are presented in Figures Figure 40, Figure 41 and Figure 42, respectively.

Figure 38: Case 1 resulting pressure response

Figure 39: Case 1, comparison of input and deconvolution unit rate derivative
The deconvolution result compared with the input derivative is shown in Figure 43.

![Graph 1](Image 1)

**Figure 40**: Case 2 simulation input - rate

![Graph 2](Image 2)

**Figure 41**: Case 2 simulation inputs – pressure and derivative
3.3.4.3 Findings on Case 1 and Case 2

Both cases show that, provided perfect information regarding the pressure and rate sequence and provided both data sets are smooth (without discontinuities and singularities), the deconvolution algorithm used here manages to retrieve the unit rate derivative reasonably well.
3.3.5 Deconvolution with rate fluctuations

In this section we address the question whether the unit rate derivative can be accurately calculated in case the flow rate was noisy (i.e. fluctuating). Here we assume that the rate measurement was accurate, thus the fluctuating rate was used together with the derivative of Case 1 as input for the simulator and the corresponding pressure was calculated. The rate fluctuations were generated as uniformly distributed noise of a magnitude of 5%, 10%, 20% and 30% of the maximum rate. The simulation and deconvolution results are presented in Figure 44. We can see that in the here presented case the deconvolution derivative resembles the input derivative reasonably well up to a fluctuation magnitude of approx. 1 m³/d. For larger fluctuations the smoothing effect of the Stehfest inversion algorithm creates erroneous derivative responses, which can easily be misinterpreted for formation behaviour.

![Graphs showing deconvolution results for different rate fluctuations.](image)

- 5% ≈ 0.4 m³/d
- 10% ≈ 0.8 m³/d
- 20% ≈ 1.5 m³/d
3.3.6 Deconvolution with rate measurement errors

In this section we address the question whether the unit rate derivative can be accurately calculated in case the flow rate measurement was erroneous. The correct and smooth declining rate sequence was used together with the derivative of Case 1 as input for the simulator and the corresponding pressure was calculated. Subsequently the erroneous rate was used to calculate the deconvolved derivative. The rate errors were generated as uniformly distributed noise of a magnitude of 5\%, 10\%, 20\% and 30\% of the maximum rate. The deconvolution results are presented in Figure 45. We can see that in the here presented case the deconvolution derivative resembles the input derivative reasonably well up to a measurement error magnitude of approx. 0.5 m$^3$/d. For larger errors the deconvolved derivative shows erroneous features, which mask the formation behaviour.
3.3.7 Deconvolution with sparse data

Up to this point we used in our calculations rate and pressure data distributed evenly in log time between 1E-4 h (0.4 s) and 1000 h (41 d). Historically, production rates are typically reported as daily or monthly average rates (actually the total production of a day or month) and pressures are recorded only daily or monthly as well. Recent new developments in permanent gauge installation and production monitoring provide denser and more accurate data. However, in the case study presented here we are concerned with historical production data where rates and pressures are reported on a monthly basis.

In order to understand how data density and flow rate averaging influences the deconvolution results, we re-sampled the initial data sets for values of pressure and average rate on a daily basis. For Case 1 presented in this paper the result of re-sampling and of the deconvolution are shown in Figure 7.

![Figure 46: Deconvolution with sparse data (daily measurements)](image)

Analysing the results in Figure 46 we observe that at first visual inspection the daily average flowrates (Figure 46a) resemble reasonably well the true rate sequence, with exception of the first day where, because of the fast rate change during the first 24 hours, the average rate does not reflect the general shape of the rate decline curve. This inaccuracy influences the early time shape of the deconvolution derivative (Figure 46b). We also observe that, because we do not have information for times less than 24 hours, the deconvolution derivative misses the early time formation behaviour. In our case the derivative was generated using a radial composite flow model with a discontinuity radius of 100 m. This means that, in the case presented here, because we use pressure and rate data starting at 24 hours, we cannot characterize the first 100 m of formation in the vicinity of the well.

Cases with sparse data sets and rate fluctuations as well as errors in rate measurement were calculated as well, but they do not add to the general understanding and are not shown here in the interest of brevity.

3.3.8 Multiple interference response

When analysing long running rate decline curves spanning periods of several decades and measured in mature oil fields with many producers and injectors we must expect
interference between neighbouring wells to influence the data. In order to understand how relevant interferences are and how producers and injectors located at different distances from the source well and starting activity at different points in time and at different rates would influence the shape of the derivative at the source well, we implemented a simple multiple interference analytical model, which would allow us to explore the problem.

The following example (having the parameters presented in Table 3) shows the case of one source well and six neighbouring production and injection wells situated at distances of between 300 and 700 m away from the source. The production / injection parameters of the 7 wells are presented in Table 4 and Figure 47. The resulting drawdown response at the source and the derivative are shown in Figure 9. In experimenting with the model we could derive following simple observations:

- Interference wells starting production (injection) before the source well start of production will influence the drawdown at the source in a way that could be interpreted as a positive (negative) skin factor.

- Interference wells starting production (injection) after the source well start of production will cause an upward (downward) trending derivative at the source, which could be interpreted as a decrease (increase) of mobility thickness product or no-flow (constant pressure) boundary. The time when the derivative distortion occurs depends on the time delay and distance between the source and interference wells. The magnitude of the derivative distortion depends on the ratio of flow rates between the source and interference wells. The slope of the derivative however, can be outside of the -1 to +1 window expected from a normal formation response (i.e. the derivative can be steeper).

These observations are consistent with what we would intuitively expect, so we assume that they can be regarded as generally valid.

Table 3: Parameters used for simulation

<table>
<thead>
<tr>
<th>Formation &amp; Fluid Parameters</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>k</td>
<td>10 mD</td>
</tr>
<tr>
<td>porosity</td>
<td>10%</td>
</tr>
<tr>
<td>h</td>
<td>10 m</td>
</tr>
<tr>
<td>rw</td>
<td>0.057 m</td>
</tr>
<tr>
<td>s</td>
<td>0</td>
</tr>
<tr>
<td>C</td>
<td>5E-07 m3/Pa</td>
</tr>
<tr>
<td>density</td>
<td>950 kg/m3</td>
</tr>
<tr>
<td>viscosity</td>
<td>20 cP</td>
</tr>
<tr>
<td>ct</td>
<td>1E-08 1/Pa</td>
</tr>
</tbody>
</table>
Table 4: Production / injection parameters of seven wells

<table>
<thead>
<tr>
<th>#</th>
<th>Start time [a] source starts at t=0</th>
<th>q [m3/d]</th>
<th>Distance to source [m]</th>
</tr>
</thead>
<tbody>
<tr>
<td>W1 (src.)</td>
<td>0</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>W2 (int.)</td>
<td>-30</td>
<td>-1</td>
<td>400</td>
</tr>
<tr>
<td>W3 (int.)</td>
<td>-10</td>
<td>-0.3</td>
<td>300</td>
</tr>
<tr>
<td>W4 (int.)</td>
<td>-5</td>
<td>-0.7</td>
<td>500</td>
</tr>
<tr>
<td>W5 (int.)</td>
<td>1</td>
<td>-0.4</td>
<td>400</td>
</tr>
<tr>
<td>W6 (int.)</td>
<td>2</td>
<td>0.4</td>
<td>500</td>
</tr>
<tr>
<td>W7 (int.)</td>
<td>4</td>
<td>3</td>
<td>700</td>
</tr>
</tbody>
</table>

Figure 47: Example of a multiple interference production/injection schedule (source shown as solid line)
3.3.9 Case study

The motivation for the research presented above was to understand the hydraulic heterogeneity of a mature oil field by using a large amount dynamic information (well tests and production data). The field is composed of four reservoirs; three carbonate formations and one clastic formation. All four reservoirs are of Carboniferous age and from bottom to top we will call them Reservoir A (carbonates), Reservoir B (clastic), Reservoir C (carbonates) and Reservoir D (carbonates). The elements of heterogeneity identified a priori include fractures (A, C and D), faults (A, B, C and D), karstic features (C and D) as well as sand bodies and channels (B). The oil field was discovered in 1936 (?) and started production in 1947. Over the past 8 decades more than 500 producers were drilled. In addition, pressure maintenance through water injection started in 1974. In 2015 there were approx. 350 active wells, of which approx. 60 were water injection wells, with the rest producing oil. A map of the well distribution is presented in Figure 49.

In the interest of conciseness, the present study is limited to the findings related to Reservoir A.
3.3.10 Description of available information

The study used the responses of well tests conducted in 70 wells and production data from 36 wells completed in Reservoir A.

The well tests comprised of approx. 72 hours pressure recoveries conducted after well clean-up prior to production. The limited data quality did not allow for detailed test analysis, which was limited to estimating the permeability and the skin by means of semilog straight line analysis and calculating the superposition derivative. The typical conceptualization of the test responses was used: wellbore storage and skin at early times, infinite acting radial flow at middle times and in some cases, heterogeneous formation response and/or flow boundaries at late times. The radius of investigation of the tests was calculated to values typically smaller than 100 m.

The production data was available in the form of monthly average rates of oil, water and gas. The production data set was screened for production sequences showing the typical rate decline response, which was deemed amenable for deconvolution with the method described above. As mentioned, production data from 36 wells was selected. The production data was deconvolved to equivalent unit liquid downhole rate drawdown and the unit rate derivative was calculated. The radius of investigation of the deconvolved production was calculated to values between 400 and 700 m; because the data was only available as monthly values, the nearest 200 m to 300 m around the well
could not be characterized due to lack of early time production data. The conceptual model used for the deconvolved production data was undisturbed formation response during the approx. initial 6 months of production and subsequent multiple interferences with neighbouring producers and/or injectors.

In keeping with this model conceptualization we expect that the rate normalized late time derivative response of a test would be similar with the early time deconvolved derivative production response in the same well. The normalization of both tests and production derivatives was calculated using the following equation:

\[
k h = \frac{qB_u}{4 \pi p'} \quad \text{with} \quad p' = \frac{dp}{d \log(t)}
\]

(3)

(in case of the deconvolved production derivative the rate used for normalization was 1)

**Figure 50** shows the normalized test derivatives side by side with the derivatives of the deconvolved production.

The derivative were color coded according to three ranges of permeability thickness product (kh): less than 80 mDm (blue), 80 mDm to 300 mDm (green) and larger than 300 mDm (red). The distribution of wells belonging to the respective kh group is shown in **Figure 51** for the tests (a) and for the production data (b).
Figure 51: kh distribution as derived from tests (a) and from production (b)

From analysing Figure 50 and Figure 51 we can see that the kh distribution at a scale of 100 m or less is similar to the kh distribution at a scale of approx. 400 m. From the fact that the late time test derivatives show good consistency with the early time production responses we can conclude that the model conceptualization described above is reasonably accurate.

In addition to the analysis presented above, the deconvolved production was analysed using a model accounting for the interference effects of producers and injectors within a radius of 1000 m around the source well. A simple radial homogeneous infinite acting flow model was used. The production rate of the neighbouring wells was simplified by calculating average liquid rates for the individual phases of well operation. A typical operation sequence was: (a) continuous production (with possible longer interruptions) or (b) production, stop production, water injection and possibly abandonment. Figure 52 shows a typical example of a well with 11 neighbouring producing wells, starting production at different times and operating at different rates. In addition to the production rate simplification described, the average rates were normalized to the production rate of the central well. This was necessary because the flow model was calculated for a unit rate at the central well (due to the deconvolution).
The results of model matching for the example well presented here are shown below. As presented in Figure 53, an acceptable model match could be achieved with a $k_h$ of 470 mDm, a porosity of 17% (the total compressibility used was 5.2E-9 1/Pa) and a skin factor of 0. It should be noted that in such an interference case both skin and storage can be resolved individually.

Apart from rate history simplifications (described above), the most important assumption of this analysis approach is that the flux resulting from production from a
well is homogeneously distributed 360° around the well. While this assumption is correct in case of a homogeneous formation, large deviations may occur in cases when the flow is fracture dominated. In several cases it was not possible to match the deconvolved production by using the interference model described. The probable explanation is that in these cases the flow had an important directional component controlled by the local formation heterogeneity (possibly fractures). Particularly analysing interferences from neighbouring injectors was unsuccessful. A sensitivity analysis of the injection rate showed that reasonable matches could be achieved if assuming that only approx. 10% of the injected water was contributing to the interference response, the rest flowing into regions not captured by the model.

3.3.11 Conclusions

The study shows that deconvolution can be used successfully for the analysis of rate decline curves. Experiments with synthetic data showed that the flow model and formation parameters can be extracted with reasonable accuracy. In a case study the results were shown to be consistent with the results of well tests.

Accounting for interference with neighbouring producers and injectors is important. In the presence of multiple interferences, the model diagnosis capacity decreases to the extent that only simple flow models should be used.

3.3.12 Acknowledgements

We would like to provide our sincere appreciation to Pierre-David Maizeret (Schlumberger), as well as, Professor Alexander Shapiro (Technical University of Denmark) for their technical review of this article.

3.3.13 References


3.4 Next Steps and Research Design

Highlights of this deconvolution approach are as follows:

- Paper addresses one of the most common industrial problems of addressing heterogeneity in mature oil fields that lack high quality pressure and geologic data; this is most often encountered in Soviet era legacy developed fields in CIS and CEE regions
- Paper utilizes real world reservoir and well data from hundreds of wells in a mature Russian oil field
- Approach was utilized and tested in a real-world application to identifying new infill drill targets in a mature Russian oil field; led to identification of over 100 new infill wells that overall exceeded legacy initial well production rates by over 70%, i.e. very promising results.
- Can be applied to fields with secondary permeability features including fractures and karsts, and is a pragmatic approach to simplifying this complex issue in fields where insufficient geologic and testing data exists to fully model these features
- Provides an additional Subsurface tool for cross-referencing permeability models, etc. in a common static model building workflow

Recommended next steps would include the following:

- Application of this approach to a field with good quality data including sufficient secondary permeability characterization to depict the averaging
impact of deconvolution on both the matrix and secondary permeability systems

- Perform a comparative analyses of this deconvolution approach to the same Russian fields to evaluate any significant improvements or deficits in the results. For example, it would be useful to understand what infill wells, etc. may have been done differently utilizing an alternative or more conventional approach.
- To compare an averaged, single porosity permeability model for the field utilized in this case study versus this deconvolution approach in order to better understand the differences in approaches to static and dynamic characterization versus differences simply due to lack of adequate field data (inherent uncertainty).
Chapter 4 Results

The chapter has been prepared for publication for the Croatian Oil & Gas Journal (HUNIG), and will be formally published in the June 2018 quarterly edition.

Justin Brand F. and Christoph Steiner

“Estimation of Reserves and Production Potential of Newly Discovered Naturally Fractured Reservoirs”

Abstract

Estimating the URFs of NFRs at the green field stage is based on either by tabulated values for different reservoir types and drive mechanisms or by numerical simulation on a dual continuum model. For numerical models, calculation of the matrix-fracture mass transfer is critical and is typically performed with transfer functions. In this work it will be shown that more accurate results can be gained by utilizing the Recovery Curve Method, which combines numerical SMB modelling with full field dynamic modelling. The method is applied to case study, demonstrating that the other approaches lead to an overestimation of the URF and a non-optimized development scenario.

Keywords

Matrix-fracture Fluid Transfer, Naturally Fractured Reservoirs; Dual Continua Formulation; Ultimate Recovery Factor

4.1 Introduction

The basis of all technical and financial (economic) decisions regarding the strategy of field development and operation is based on the reserves and estimated production potential. The most important questions arise already in the beginning of an operation as the fewest data are available and also that with the highest and most material uncertainty. The industry learned to live with this situation making benefit from its worldwide experiences at least concerning the classical cases being able to regard them as a single porosity and permeability continuum. The appraisal practice for these single porosity reservoirs is well established and already successfully applied under variable conditions. (e.g. Meziani et al. 2012, Sunhaji et al. 2013)

However, this is not the case when dealing with fractured dual porosity reservoirs. In these cases, it is necessary to not only model each porosity system (fractures and matrix) separately, but to also correctly model their associated dynamic interactions together under production scenarios. Many efforts have been published to work out a generally applicable characterization procedure to model this dynamic behaviour, however, due to the extreme diversity of NFRs, all these efforts were only partially successful (Gauthier, Garcia and Daniel 2002).
Figure 54 shows Nelson’s (1992) classification of NFRs based on the contribution to the storage and conductivity of matrix and fracture. The class II and III are the typical dual porous reservoirs, which will be considered in this work. To design an appropriate development plan (dynamic reservoir model), one needs a credible reservoir description that includes all fracture and matrix related properties.

For the fracture system:

- Fracture lengths,
- Number of fractures per unit height (fracture density),
- Fracture net to gross ratio,
- Fracture orientation,
- Fracture aperture,
- Fracture porosity,
- Fracture mineralization ratio,
- Conductivity,
- Fracture connectivity,
- Fracture saturations,
- Fracture relative permeabilities.
Regarding the matrix, all properties usually requested in single porosity cases are of importance. Supplementary for calculating the matrix-fracture mass exchange terms it is necessary to define

- the typical shapes and
- the size of the matrix blocks.

The measures of these two matrix properties are the height of the matrix blocks and the shape factor.

Recent efforts were to discretely model the fractures, and to discretize and homogenize the matrix so that its production contribution to the main fracture conduits were captured by a single transfer term. However, this approach neglects the dynamic behaviour of the hydrocarbon within the matrix under various production scenarios. Especially critical is the impact of capillary forces and gravity drainage on the ultimate recovery factor.

4.2 Current Industry Approaches

There are several approaches and industry-accepted practices to estimating ultimate recovery factors in early development NFRs, including stochastic volumetrics with a fixed recovery factor distribution, material balance with a single fixed transmissibility term, and numerical simulation.

In all cases, it is common practice to consider ultimate recovery factor analogues (e.g. Aguilera 1999, Allan and Sun 2003) to cross-correlate the results from each of these methods before those assessments are completed. The issue with this approach is apparent. If the analogue providing the URF benchmarking assurance to the NFR study is insufficient, then the URF estimation for the NFR in question will be materially off acceptable tolerances.

The complication arises from the industry utilization of these URF analogues to support their NFR modelling efforts. It is quite often the practice to perform several iterations of matrix and fracture reservoir characteristics, and to manipulate this input data in contrast to the measured data to find agreement of the URF calculations with these benchmarks. Thus, it is not uncommon to find a final early development NFR reserve estimate that has utilized reservoir input data that runs contrary to normally accepted value ranges for fracture porosity, fracture compressibility, and matrix URF to name a few of the material inputs. The practice of benchmarking NFR URFS when making these reserve estimates will likely continue, therefore, it is necessary to first confirm whether the methodologies to estimate these benchmarks are appropriate. The critical question is how the matrix fracture mass transfer should be calculated by considering all possible driving forces under various realistic conditions. In the past, two concepts were proposed. The Reiss (1973) type solutions use time depending functions while the Kazemi at al. (1976) type approaches utilize discrete algebraic equations. For both types, different realizations (e.g. Di Donato et al. 2007, Lu et al. 2008) were suggested from which the Gilman and Kazemi (1988) version and the Heinemann-Mittermeir recovery curve method will be considered.
It should be emphasized that the only difference between the two simulation approaches lies within the calculation of the matrix-fracture transfer term, which describes the interaction between the two continua.

### 4.2.1 The Kazemi Type Approach

The transfer term according to Kazemi et al. (1976) utilizing a gravity drainage model by Gilman and Kazemi (1988) provides a functional approach for determining the transfer rate:

\[ q_{pmf} = V_{bulk} \sigma k_a \frac{k_{rf}}{B_p} (\Phi_{pf} - \Phi_{pm}) \]

where \( V_{bulk} \) is the bulk volume, \( p \) stands for oil, water and free gas, \( k_a \) is the apparent matrix permeability, \( \mu \) the viscosity, \( B \) the formation volume factor, \( k_r \) the relative permeability and \( \Phi \) the phase potential in the fracture (f) and in the matrix (m). The shape factor, \( \sigma \), is a characteristic value of the matrix block. It will be calculated based on the size and form of the individual matrix blocks. The most complete version is the generalized Kazemi-Gilman-ElSharkawy (1992) shape factor as derived by Heinemann and Mittermeir (2012). As demonstrated by Steiner and Mittermeir (2017), the shape factor is not a constant during the depletion of single matrix blocks (SMBs) for all driving mechanisms except for single phase expansion and solution-gas drive. This can lead to an over- or underestimation of the speed of oil recovery from the matrix. Steiner (2017) also showed that both the development of the oil recovery factor over time and also the URF of SMBs are overestimated when this transfer function is applied. This is especially the case for an oil-wet matrix with gravity drainage as the dominant driving mechanism.

### 4.2.2 The Recovery Curve Approach

Heinemann and Mittermeir (2004, 2015, 2016) combined the two aforementioned concepts, with the underlying aim of separating the matrix-to-fracture and the fracture-to-matrix flow calculations. The Kazemi et al. (1976) approach and one similar to that of Reiss et al. (1973) are used for the first and second of these, respectively. According to Reiss, the rate of the displacing fluids injected by the fracture into the matrix is given by a time-dependent function. However, according to Heinemann and Mittermeir, it should be a function of the matrix recovery factor corrected to the actual pressure. The rate of the displaced fluid expelled from the matrix must be calculated by the Kazemi (i.e. Warren-Root 1963) type transfer equation. The basic assumption is therefore that the forces of compressions and the capillary and gravitational forces act independently and their results will be superposed.

The recovery from capillary imbibition and gravitational displacement at constant pressure can be calculated on SMB models (and also measured in laboratories), resulting in recovery curves. The additional oil production during timestep \( \Delta t \) is estimated using the increment of the recovery factor during the actual timestep. This is the difference between the recovery factor at time \( t_{j+\beta \Delta t} \) and the beginning of the timestep \( t_j \) (Figure 55), where \( \beta \) is the time scaling factor:

\[ \Delta E_R = E_{R_{j+\beta \Delta t}} - E_{R_j} \]
For scaling the speed of the oil recovery to the actual conditions at the certain grid cell two corrections of the increment have to be considered. Firstly, if the pressure has already dropped but the validity of Darcy’s equation is still assumed, then $\Delta E$ can be scaled to the actual pressure and saturations (Heinemann and Mittermeir 2016, Gharsalla 2015):

$$
\Delta E_R^w(p) = \left( \frac{k_{ro}(S_o)}{\mu_o(p)B_o(p)} / \frac{k_{ro}(S_{ab})}{\mu_{ab}B_{ab}} \right) \Delta E_R^w(p_b)
$$

where the index $b$ relates to the reference pressure of the recovery curve. The same equation is valid for gas displacement by revising the superscript $w$ to $g$. Secondly, the input recovery curve is calculated at a certain matrix permeability, and therefore the $\Delta E$ must be increased/decreased according to the actual value of the matrix cell for which the increment is calculated.

Scaling of the URF of the input recovery curve is also done, considering the changes in the oil formation volume factor and the change in the gravitational driving force with pressure (Steiner 2017).

The volume of the displacing agent (water or gas) injected by the fracture into the matrix for one standard initial oil volume is then:

$$
\Delta w = \Delta E_R^w(p) B_o(p)/B_w(p) \text{ or }
$$

$$
\Delta g = \Delta E_R^g(p) B_o(p)/B_g(p) \text{ or }
$$

Figure 55: Estimation of the time and recovery factor on a gas recovery curve at the beginning of the timestep (Brand, Mittermeir and Heinemann 2017)
4.3 The Field Case

4.3.1 Field Description

The case field’s reservoir is a Type III NFR according to the classification by Nelson (1992), and has an associated high matrix porosity and low matrix permeability (Allan and Sun, 2003). The matrix provides storage capacity and fractures provide the fluid pathways. The reservoir model utilized in this paper is derived from a real case full field reservoir model. This original model has been modified to protect the proprietary rights of the field owner. However, the synthetic model still exhibits all of the original’s essential characteristics.

The reservoir is at the greenfield stage of development meaning no production history exists. Fluid samples, as well as, relative permeability curves from core measurements are available. It is modelled with a black-oil fluid description. With a standard density of 739 kg/m³ or 46.1 °API, the oil can be classified as light crude oil. The standard densities for water and gas are 1094 kg/m³ and 0.788 kg/m³, respectively. The oil is slightly undersaturated. The bubble point pressure is 155 bara, while the initial HC-weighted reservoir pressure is 168.9 bara. The reservoir is a two-phase oil-water system, but during the depletion the development of a secondary gas cap is expected. Based on experience in the basin where this reservoir is situated, it is expected that the anticlinal structure is bounded at all sides by an edge aquifer of considerable strength. Thus, all possible drive mechanisms, such as expansion, water and gas displacement take place in certain parts of the reservoir. Consequently, capturing the matrix-fracture mass transfer in its complexity is crucial, and will make the differences in the results between the Kazemi and RCM approaches more pronounced.

4.3.2 Matrix and Fracture Characterization

Based on FMI logs, the matrix blocks are estimated to have a height of 10 m and a lateral dimension of 2.5 x 2.5 m. It is assumed that this is uniform throughout the reservoir. On core samples, matrix porosity and permeability are estimated to be in the range of 1 % to 34.63 % and 0.01 to 13.94 mD, respectively. The matrix properties are distributed by geostatistical methods. The average values for the characteristic parameters are:

- $\Phi = 0.18$ [-]  
- $S_{oi} = 0.82$ [-]  
- $k_h = 2.2$ [mD]  
- $k_v = 1.6$ [mD]

Fracture permeability is estimated based on transient well testing to be 750 mD in lateral direction and 100 mD in vertical direction. From these tests also the porosity is estimated to be 0.45 %. Both porosity and permeability of the fracture system are uniformly distributed to all grid cells.

The input data for the capillary pressures and the relative permeabilities can be seen in Figure 56 and Figure 57. In initializing the model, which involved calculating the initial pressure and the saturation distributions, the drainage oil-water capillary curve is applied. The imbibition curve is utilized while simulating the oil recovery. For
the fracture continuum, straight line relative permeability curves are utilized and the capillary pressure is zero.

Figure 56: Water-oil capillary pressures and relative permeabilities
4.3.3 Evaluation of oil recovery from single matrix blocks

Based on this data recovery curves are calculated with a numerical SMB model, which has been utilized previously by Pirker, Mittermeir and Heinemann (2007) and Heinemann and Mittermeir (2016), where also a detailed description of this model can also be found.

The matrix-block model is discretized into grid cells. The matrix block is homogenous; however, it can be anisotropic, having different permeability values in x-, y- and/or z-directions. Figure 58 depicts one of the various SMB models utilized in this assessment. It allows for the calculation of the recovery under different boundary conditions, considering capillary, gravitational and viscous forces, as well as, the oil resaturation after its displacement by water or gas. The model also offers the option of calculating a lumped recovery curve to consider different matrix blocks inside a single simulation cell. However, for this NFR study, this option was not utilized. The resulting recovery curves for all drive mechanisms and the oil resaturation curves are depicted in Figure 59.
Figure 58: Quarter SMB model bounded by fracture planes on all sides (left) and with vertical fractures only (right).

Figure 59: Recovery and oil resaturation curves.

4.3.4 Depletion Process
For this NFR, oil recovery from the matrix is expected to follow a process, as described by Heinemann and Mittermeir (2014) and illustrated in Figure 60. Initially, both the matrix and fracture are oil filled between the initial oil-water contact (OWC) and the initial oil-gas contact (OGC). When production starts, oil is removed from the fracture network and the equilibrium between matrix and fracture is disturbed. As pressure in the system drops, solution gas is liberated and the OGC moves downward. Water influx from the aquifer causes an upward movement of the OWC. As saturation and pressure in the fracture change, the resulting driving forces (expansion, capillary and gravitational forces) cause the displacing phase, gas or water, to enter the matrix as oil is expelled from it. The expelled oil forms an oil rim in the fracture domain, resulting in a possible oil resaturation of matrix regions that have previously been swept by water or gas.

4.3.5 Full Field Modelling

For estimating the reserves, two distinct dynamic models have been created. They differ in the applied method for determining the matrix-fracture mass transfer. One utilizes the RCM, the other the Kazemi et al. (1976) transfer equation with the Gilman and Kazemi (1988) gravity drainage model. Note that both are based on the same petrophysical and reservoir fluid properties. The only difference is in the calculation of single matrix recovery processes.
Both models are operated such that a target production on field level is given, which is then distributed to the wells by internal procedures of the numerical simulator. The ramp-up phase of the production is given as an input, since this depends on the rig availability, drilling time, etc. However, the plateau phase as an input is kept until the end of the calculation. Perforations being squeezed off or wells shutting-in are also taken into consideration as a result of the calculation. When the well shut-ins occur is governed by well constraints, which ensure a realistic production plan.

4.3.5.1 Wells
A total of 34 wells are planned and their location can be observed in Figure 61. All production wells are vertical in orientation and their associated placement is a compromise between delaying water breakthrough from the bottom and gas breakthrough from the top. This is due to the expected secondary gas cap formation due to the pressure of the reservoir being initially only slightly above bubble point pressure. For this scenario, neither gas nor are water injection wells planned.

4.3.5.2 Well Constraints
Because of technical and economic limitations, a GOR constraint of 200 sm3/sm3 and maximum water-cut constraint of 0.4 were set for all wells. This means that after this constraint is reached, gas or water breakthrough occurred at this well and the perforation having the breakthrough will be squeezed. If all perforations of the well suffered from gas or water breakthrough, the well is shut-in indefinitely.

4.3.5.3 Production Target Input
The development plan schedules 10 production wells to be completed at the initial stage of field development, with two additional wells coming on stream every 5 months afterwards. The 10 initial production wells together are estimated to produce 1760 sm3/day oil with every following additional well providing an increment of about 180 sm3/day to the total field oil production rate. This results in a production profile on field level as depicted in Figure 62. At this stage, the tail production is not yet estimated,
therefore, the plateau rate of 6000 sm3/d remains constant for 35 years. During the calculation, it is expected that this rate cannot be produced continuously and that wells will be shut-in because of early gas or water break through. The calculated oil production rate of both numerical models then provide two estimates for the production potential. After a 40 year production period, the calculation is stopped as further incremental oil recovery is expected to be inconsequential for the assessment of the production potential and URF of this NFR.

![Field level production target as input for the simulation](image)

**Figure 62:** Field level production target as input for the simulation

### 4.4 Results

The calculated field oil production rate can be seen in Figure 63. Both models achieve the desired plateau oil rate, but the RCM predicts that decline in production starts earlier. As a result, after 12500 days or approximately 35 years of prediction, both models again calculate the same oil production rate.
Figure 63: Oil prod. rate when using the Kazemi (1976) eq. (dark green) and the RCM (bright green)

**Figure 64** depicts the water-cut development over time. The RCM predicts a faster advancing water-oil contact than the other approach, which leads to the evident earlier water break through at the wells.

Figure 64: Water cut when using the Kazemi (1976) eq. (dark blue) and the RCM (bright blue)

The expected average reservoir pressure is also influence by the transfer model, as depicted in **Figure 65**. This influence is indirect, and stems from the fact that the oil
production and associated reserves when utilizing the RCM will be lower. As a consequence of material balance, the average pressure is, therefore, higher.

Figure 65: HC-weighted average reservoir pressure when using the Kazemi (1976) eq. (black) and the RCM (gold)

The recovery factors after 40 years of predicted production demonstrate that the Kazemi approach for calculation of the matrix-fracture mass transfer yields a recovery factor of 0.22. In contrast, when the RCM is utilized, ultimate oil recovery factor after 40 years is 0.19.

Compared to the results of either approach with the numerical model, the Aguilera (1999) recovery factor analogue table would predict an URF of 0.35-0.45, which is the highest estimation of the three approaches.

4.5 Discussion

The underlying assumptions and simplifications for both transfer models have to be considered in order to explain the differences in the URF estimates emanating from the different matrix-fracture mass transfer models from these numerical simulations.

When the Kazemi transfer equation is applied, all properties inside a SMB are considered by an average value. This means that possible inhomogeneities in the saturation or pressure distribution cannot be considered explicitly. For calculation of the gravitational driving force a mathematical model is applied, where the gravitational potential difference is a function of the average water, oil, and/or gas saturation of the SMB. The capillary forces are also a function of this average saturation, which makes it possible to determine the net value of the capillary and gravitational forces as a function of an average saturation. This is demonstrated in Figure 66 for the case of water drive.
4.5.1 Waterdrive

In this field case, the equilibrium of forces (the saturation at which the gravitational and capillary forces are balanced), is similar in both the Kazemi and RCM approaches yielding a water saturation value of 0.34 and oil saturation of 0.66. During the calculation of the full field model, the average pressure depleted from 170 to 120 bara, which resulted in a change in the oil formation volume factor from $B_{oi} = 1.24$ to $B_{o} = 1.18$. With this data, a URF for one matrix block after waterdrive and decreased pressure can be calculated with:

$$URF = 1 - \frac{S_o B_{oi}}{B_{o} S_{oi}} \approx 1 - \frac{0.66 \times 1.24}{1.18 \times 0.82} = 0.141$$

(10)

When the RCM is utilized, the input recovery curve, calculated at bubble point pressure, predicts an ultimate recovery value of 0.149 and a residual oil saturation of 0.69. Scaling this value according to the change in the oil formation volume factor from $B_{oi} = 1.26$ at bubble point pressure to 1.18 at 120 bara:

$$URF = 1 - \frac{S_o B_{oi}}{B_{o} S_{oi}} = 1 - \frac{0.69 \times 1.259}{1.18 \times 0.82} = 0.09$$

(11)

This would indicate that the expected ultimate oil recovery value of a SMB is over-predicted by the Kazemi type transfer equation by roughly 5% due to water drive effects.
4.5.2 Gasdrive

For gas drive, the equilibrium of forces occurs at a gas saturation of 0.52 when utilizing the Kazemi et al. (1976) equation. Considering the same pressure changes as for the water drive case, this results in:

\[
URF = 1 - \frac{S_g B_{ai}}{B_o S_{ai}} = 1 - \frac{0.30 \times 1.24}{1.18 \times 0.82} = 0.61
\]  

When the RCM approach is utilized and the associated scaling is performed in the same manner as for water drive, the URF for one SMB is:

\[
URF = 1 - \frac{S_g B_{ai}}{B_o S_{ai}} = 1 - \frac{0.40 \times 1.259}{1.18 \times 0.82} = 0.48
\]  

For both, gas and water drive, it is clearly demonstrated that benchmarks for cases like the one presented here, originating from calculations utilizing Kazemi’s (1976) equation, provide overly optimistic estimations for the URF. Such deficient predictions can only be avoided by implementing a process for the assessment of NFRs which incorporates numerical SMB analysis and the RCM approach.

4.6 Summary and Conclusions

- URF benchmarks originating from numerical simulation utilizing Kazemi et al (1976) type transfer equations can lead to overly optimistic URF expectations.
- Numerical SMB modelling and an application of the results from it in numerical simulation with the RCM approach is recommended for avoiding errors form matrix-fracture mass transfer model.
- Commonly utilized analogue URF benchmarks (e.g. Aguilera 1999, Allan and Sun 2003) are significantly overly optimistic as compared to both the Kazemi and RCM numerical modelling approaches
- The development of an integrated workflow utilizing the various tools of the Recovery Curve Method concept is suggested.

4.7 Acknowledgements

The authors thank Zoltán E. Heinemann, professor emeritus at the Mining University of Leoben, for his encouragement and suggestions and the PHDG association for supporting this work.

4.8 Nomenclature

- \(B\) formation volume factor, \(L^3/L^3\), sm3/res m3
- \(E\) efficiency/recovery factor
- \(g\) specific gas amount, scaled to unit oil in place
- \(k\) permeability, \(L^2\), md
- \(p\) pressure, \(m/L^3\), psia
\( P_c \) \hspace{1em} \text{capillary pressure, m/L}^3, \text{psia} \\
\( P_L \) \hspace{1em} \text{potential difference due to different pressure gradients in matrix and fracture, m/L}^3, \text{psia} \\
\( q \) \hspace{1em} \text{production rate or flow rate, L}^3/t, \text{STB/day} \\
\( t \) \hspace{1em} \text{time, t, day} \\
\( S \) \hspace{1em} \text{saturation} \\
\( V \) \hspace{1em} \text{volume, L}^3, \text{res bbl} \\
\( w \) \hspace{1em} \text{specific water amount, scaled to unit oil in place} 

### 4.8.1 Greek symbols

\( \Delta \) \hspace{1em} \text{difference operator} \\
\( \kappa \) \hspace{1em} \text{multiplier} \\
\( \mu \) \hspace{1em} \text{viscosity, m/Lt, cp} \\
\( \Phi_p \) \hspace{1em} \text{phase potential, m/L}^3, \text{psia} \\
\( \sigma \) \hspace{1em} \text{shape factor, 1/L}^2, 1/ft^2 

### 4.8.2 Subscripts

\( a \) \hspace{1em} \text{apparent} \\
\( b \) \hspace{1em} \text{bubblepoint} \\
\( f \) \hspace{1em} \text{fracture} \\
\( g \) \hspace{1em} \text{gas phase} \\
\( j \) \hspace{1em} \text{time point index} \\
\( m \) \hspace{1em} \text{matrix} \\
\( o \) \hspace{1em} \text{oil phase} \\
\( p \) \hspace{1em} \text{phase} \\
\( r \) \hspace{1em} \text{relative} \\
\( R \) \hspace{1em} \text{recovery} \\
\( w \) \hspace{1em} \text{water phase} 

### 4.8.3 Greek Subscripts

\( v \) \hspace{1em} \text{apparent} 

### 4.8.4 Superscripts

\( g \) \hspace{1em} \text{gas} \\
\( r \) \hspace{1em} \text{reference} \\
\( w \) \hspace{1em} \text{water} 

### 4.9 References


Results - References

Petroleum Conference and Exhibition, Abu Dhabi, UAE, 11-14 November 2012. SPE-161507-MS. https://doi.org/10.2118/161507-MS


Chapter 5 Summary and Recommendations

The project to establish an improved methodology for dual continuum modelling of naturally fractured reservoirs (NFRs) has been carried out. The main issue in the investigation of developing a “true” dual continuum approach at any point for modelling both the matrix and fractures of an NFR has been addressed. This has been accomplished through the establishment of the Recovery Curve Method (RCM) workflow for numerical modelling of NFRs, and has successfully addressed the current industry problem of more accurately accounting for the matrix flow contribution in these dual-porosity systems. The confirmation of this approach was performed utilizing several real-world case studies with extensive data sets, and also through an approach of utilizing new-build synthetic reservoir models with this data to honour confidentiality. A comparison of the new RCM numerical workflow was then performed against the current industry approach for numerical simulation of NFRs, as well as, the most widely utilized NFR recovery factor analogues. These differences in the results between the various methodologies were then highlighted, and some conclusions were derived as presented in the earlier thesis chapters.

Recommendations for further research and next steps include the following:

• It is quite important to not only know the overall NFR recovery factors, as well as, production potential, but to also have the capability to predict these figures with accounting split between the matrix and fracture systems separately. The current software limitation of the H5 simulator could be removed to provide this view. Several of the current industry approaches utilize separate analogue recovery factor tables for both matrix (treated as conventional single-porosity reservoirs) and fractures (also treated as single porosity systems). In addition, under production scenarios, it is quite important to have an improved understanding of these separate figures to better predict the timing of significant water cut increases. This is often the behaviour observed with NFRs as the fractures are depleted, and the matrix becomes the dominate system contributing to production. Lastly, this capability would provide further insights that may support further optimized development planning approaches. For example, an operator may only choose to target the high confidence static fracture zones of an NFR field, and would, therefore, need an improved estimation of fracture only production and recovery scenarios.

• The project provides the view that the utilization of analogue recovery factor tables and numerical simulation with Kazemi shape factors are overestimated, however, further case studies should be performed to prove this trend conclusively.

• It is also recommended to eventually replace the industry’s most-widely utilized NFR recovery factor references (e.g. Aguilera, etc.) with a similar table derived from the application of the new RCM workflow for NFRs. Several synthetic NFR cases should be established, and the cases run with varying sensitivities to the normal
material uncertainty factors such as the degree of aquifer energy support, NFR type (1-4), and initial NFR conditions including the presence of a primary gas gap, saturated reservoir with no gas cap, etc. Overall NFR recovery factors for each case could then be provided, as well as, separate ranges of recovery factors for the matrix and fracture systems. Sufficient numbers of cases would need to be set up and run utilizing realistic uncertainty ranges, and then the new NFR recovery factor tables populated with the figures. It is envisioned that over time this tool could be adopted for industry application with reserve evaluation firms, as well as, operators as an improvement and eventual replacement of the currently in use analogue tables.
Appendix A  Joint Author Statements

A.1 A Recovery Curve Method Based Workflow for Reserves Estimation of Naturally Fractured Reservoirs - A Case Study

14th September, 2017

Re: Paper Authorship & PhD Thesis Permission (Technical University of Denmark)

To whom it may concern:

We (the undersigned) acknowledge the following regarding the paper, "A Recovery Curve Method Based Workflow for Reserves Estimation of Naturally Fractured Reservoirs - A Case Study":

- Justin Brand is the primary author
- Justin Brand has our permission to utilize this paper as chapter for his PhD thesis

Please accept this as our joint author statement. Thank you.

Sincerely,

Georg M. Mitterneit
Gábor F. Heinemann

26. Sept. 2017
A.2 Using deconvolution to characterize heterogeneity in a mature oil field

17th January, 2017

Re: Paper Authorship & PhD Thesis Permission

To whom it may concern:

We (the undersigned) acknowledge the following regarding the paper, "Using deconvolution to characterize heterogeneity in a mature oil field":

- Justin Brand is the primary author
- Justin Brand has our permission to utilize this paper as chapter for his PhD thesis

Please accept this as our joint author statement. Thank you.

Sincerely,

Cristian Enachescu

Viktor Acs
### Estimation of Reserves and Production Potential of Newly Discovered Naturally Fractured Reservoirs

**MURIG (Croatia Oil & Gas Journal), June 2018**

**Justen Brand F., Christoph Steiner**  
*Names capitalised*  

**PhD student details of Justen Brand F.**  

25/01/1978

**Declaration of the PhD student’s contribution**  
For each type of work, please specify below the contribution as appropriate:

<table>
<thead>
<tr>
<th>Minor contribution to the work (please specify)</th>
<th>Substantial contribution to the work (please specify)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formulation of the conceptual framework and/or planning of the design of the study including scientific questions</td>
<td>Justen Brand carried out the conceptual framing of the thesis and approach to addressing the scientific questions.</td>
</tr>
<tr>
<td>Carrying out of experiments/data collection and analysis/interpretation of results</td>
<td>Christoph Steiner provided quality assurance on the experiments.</td>
</tr>
<tr>
<td>Writing of the article/revising the manuscript for intellectual content</td>
<td>Christoph Steiner assisted w/ technical editing and formatting</td>
</tr>
</tbody>
</table>
## Title of article

*Estimation of Reserves and Production Potential of Newly Discovered Naturally Fractured Reservoirs*

### Journal/Conference

*HUNIG (Croatia Oil & Gas Journal), June 2018*

### Author(s)

Justin Brand F., Christoph Steiner

### Name (capital letters) and signature of PhD student

Justin Brand F. Ferrell

### PhD student’s date of birth

25/01/1978

<table>
<thead>
<tr>
<th>Date</th>
<th>Name</th>
<th>Title</th>
<th>Signature</th>
</tr>
</thead>
<tbody>
<tr>
<td>30/04/2018</td>
<td>Justin Brand F.</td>
<td>Mr.</td>
<td>Signature</td>
</tr>
<tr>
<td>30/04/2018</td>
<td>Christoph Steiner</td>
<td>Dr.</td>
<td>Signature</td>
</tr>
</tbody>
</table>