Chair of Reservoir Engineering

Doctoral Thesis

Production Forecast based on Reservoir Geological Model Validation

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AFFIDAVIT

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Date 15.10.2021

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Abstract

It is a common petroleum industrial practice to build geo-cellular models of the hydrocarbon storing geological structures, which describe their physical properties in space and characterize their original hydrocarbon content. Based on the generated static models, and the known historical production data from the wells, the numerical model of the phase movements and reservoir pressures over the entire operation history is created. The goal of this is to localize the actual (today's) oil and gas content of the reservoir and to perform production forecasts for planned future operating scenarios. The lack of information about the reservoir in combination with the conventional numerical simulation methods does not make it possible to accurately describe the past behavior of the wells, therefore the characterization of the remaining reserves and forecasts are not reliable either. A reservoir model, which cannot provide this essential information is useless.

As part of the model-building procedure, static properties of the geocellular model are modified and its effect on the modeled dynamic response of the wells is observed. It is often applied to reduce the discrepancy between the measured and modeled well production rates. Operative decisions today are often made based on "history-matched" (HM) models. This dissertation refers to studies proving that the trial-and-error method cannot achieve a perfect three-phase match of all wells, neither can assure the model's resemblance to the real reservoir or increase the reliability of the forecast. With these limitations, the history matching is applicable to perform sensitivity runs, but it cannot be regarded as a solid basis of decision making.

This dissertation presents an alternative, complete reservoir model building approach called the geological "model validation" (MV approach). It states that the real system's dynamic responses must be correctly reproduced over the entire life cycle. To achieve this, the wells must be given access to the nearest reservoir zones with movable phase content: which is the fundamental difference from the classical HM concept. Where the simulation model cannot provide the measured production rates, the model needs re-interpretation. The participation of the perforations, near well area and further accessed zones to the total production indicates the local model quality and can help local refinements. The method is able to overcome geological modeling limitations of mainly large complex heterogeneous structures, which would normally hinder proper conclusions on the remaining hydrocarbon content and evaluation of future development scenarios.

As part of the Ph.D. project, the difference between the history matching attempts and the concept's results introduced here are illustrated on the largest Hungarian hydrocarbon occurrence, the Algyő-2 reservoir. The author analyzes the history matching results of the field operator MOL. The proposed model validation workflow is presented on sectors. Its reservoir-scale implementation is demonstrated over a 20-year long production period. In contrast with the HM approach, it was possible to detect the remaining amount of (inaccessible) movable oil. In this work, the different possibilities of how to get economically viable access to them could not be investigated, because the business strategy of the operator MOL is not known. The Model Validation results already clearly show that the proposed approach is the correct way to go forward with the planned revitalization of the Algyő-2, and probably it will be applicable to the other Upper-Pannonian oil-bearing reservoirs of the Carpathian Basin as well.

Kurzfassung

Es ist gängige Praxis der Erdölindustrie, geozelluläre Modelle von Kohlenwasserstoff enthaltenden geologischen Strukturen zu erstellen, die deren physikalischen Eigenschaften im Raum beschreiben und ihren ursprünglichen Kohlenwasserstoffgehalt charakterisieren. Basierend auf den generierten statischen Modellen und den bekannten historischen Förderdaten der Sonden wird das numerische Modell der Phasenbewegungen und Lagerstättendrücke über die gesamte Betriebsgeschichte erstellt. Ziel ist es, den tatsächlichen (heutigen) Öl- und Gasgehalt der Lagerstätte zu lokalisieren und Produktionsprognosen für geplante zukünftige Betriebsszenarien durchzuführen. Der Mangel an Informationen über die Lagerstätte in Kombination mit den herkömmlichen numerischen Simulationsmethoden ermöglicht es nicht, das vergangene Verhalten der Bohrungen genau zu beschreiben, daher sind auch die Charakterisierung der verbleibenden Reserven und Vorhersagen nicht zuverlässig. Ein Lagerstättenmodell, das diese wesentlichen Informationen nicht bereitstellen kann, ist nutzlos.

Im Rahmen des Modellbildungsverfahrens werden statische Parameter des geozellulären Modells modifiziert und deren Einfluss auf das modellierte dynamische Verhalten der Sonden beobachtet. Es wird häufig angewendet, um die Diskrepanz zwischen den gemessenen und modellierten Sondenproduktionsraten zu verringern. Operative Entscheidungen werden heute oft auf Basis von „History Matched“ (HM)-Modellen getroffen. Diese Dissertation bezieht sich auf Studien, die belegen, dass die Trial-and-Error-Methode keine perfekte Drei-Phasen-Übereinstimmung für alle Sonden erreichen kann, und weder die Ähnlichkeit des Modells mit der realen Lagerstätte sicherstellen noch die Zuverlässigkeit der Vorhersage erhöhen kann. Mit diesen Einschränkungen ist das „History Matching“ zur Durchführung von Sensitivitätsläufen anwendbar, kann jedoch nicht als solide Grundlage für die Entscheidungsfindung angesehen werden.

Diese Dissertation präsentiert einen alternativen, vollständigen Ansatz zur Modellbildung von Lagerstätten, der als geologische „Modellvalidierung“ (MV-Ansatz) bezeichnet wird. Dieser besagt, dass die Dynamik des realen Systems über den gesamten Lebenszyklus korrekt abgebildet werden muss. Um dies zu erreichen, müssen die Sonden Zugang zu den nächstgelegenen Lagerstättenzonen mit beweglichem Phaseninhalt erhalten: Dies ist der grundlegende Unterschied zum klassischen HM-Konzept. Wo das Simulationsmodell die gemessenen Produktionsraten nicht erreichen kann, ist es nötig das Modell neu zu interpretieren. Die Beteiligung der Perforationen, der nahen Sondenregion und weiterer zugänglicher Zonen an der Gesamtproduktion zeigt die lokale Modellqualität an und kann lokale Verfeinerungen unterstützen.

Die Methode ist in der Lage, geologische Modellierungsbeschränkungen von hauptsächlich großen komplexen heterogenen Strukturen zu überwinden, die normalerweise richtige Schlussfolgerungen über den verbleibenden Kohlenwasserstoffgehalt und die Bewertung zukünftiger Entwicklungsszenarien verhindern würden.

Im Rahmen der Doktoratsarbeit wird der Unterschied zwischen den History-Matching-Versuchen und den Ergebnissen des hier vorgestellten Konzepts am größten ungarischen Kohlenwasserstoffvorkommen, der Algyő-2-Lagerstätte, veranschaulicht. Der Autor analysiert die History-Matching-Ergebnisse des Feldoperators MOL. Der vorgeschlagene Arbeitsablauf zur Modellvalidierung wird anhand von Sektoren vorgestellt. Die Umsetzung im Lagerstätten-Maßstab wird über einen 20-jährigen Produktionszeitraum

demonstriert. Im Gegensatz zum HM-Ansatz war es möglich, die verbleibende Menge an (unzugänglichem) beweglichem Öl zu erkennen. In dieser Arbeit konnten die unterschiedlichen Möglichkeiten, wie man wirtschaftlich sinnvoll an sie kommt nicht untersucht werden, da die Geschäftsstrategie des Betreibers MOL nicht bekannt ist. Die Ergebnisse der Modellvalidierung zeigen bereits deutlich, dass der vorgeschlagene Ansatz der richtige Weg für die geplante Revitalisierung von Algyő-2 ist und wahrscheinlich auch auf die anderen ober-pannonischen ölführenden Lagerstätten des Karpatenbeckens anwendbar sein wird.

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Chapter 1

Introduction

1.1 Foreword

It is an inevitable in the context of this dissertation firstly to summarize the reservoir geological model building approaches of history matching (HM) and model validation (MV). The goal of HM is to reproduce measurements (history). HM is classically performed by manipulating the reservoir model or the well-inflow perforation coefficients (e.g. target pressure and phase method TPPM, see later). Only the wells have a history (e.g. production and pressure history), the reservoir does not (there is no available measurement that could continuously indicate a dynamic property in space). Therefore HM means a (Peaceman-) well match. From the well-match it is also expected to describe the reservoir's behavior indirectly, however it was only possible if the match was perfect (normally it is not so), and the static model would not be corrupted (usually it is).

The MV focuses on revealing dynamic information about the reservoir, and not about the wells: e.g. remaining hydrocarbon saturation of the well inflow areas. Since for this no history is available, it cannot be called HM. However MV needs that the material production and injection at the right locations are accurately reproduced already for the initial (not modified) reservoir model, which the MV technique ensures with a proper well model.

The author believes that the HM approach cannot but the MV approach can be applied with confidence to describe the remaining oil saturation of the here presented field case. The author experienced a difference of opinion with the industrial partner. The usual modeling practice of Peaceman-well match is widely followed and promoted by software providers, that is why it might be difficult for many professionals to deviate from it. The MV is often falsely regarded and judged as an alternative form of HM. The lack of understanding of the conceptual difference between HM and MV naturally leads to the lack of recognition of the MV-s main advantages.

1.2 Motivation of Work

1.2.1 Background

The importance of any reservoir model which can not reproduce the actual material (i.e., saturation) distribution and predict the well-performance is limited. To represent the underground fluid contents and movements correctly, the model wells must produce exactly the same amount of oil, gas, and water as the real object did. Because it is impossible to model the reservoir structure and properties accurately -especially for inhomogeneous depositions- the conventionally operated wells cannot do it over the entire production history.

Two main approaches appear in the literature to overcome this: either “manipulating” the property model, or the well model. The classical solution is by means of adjusting reservoir model parameters (history matching), to achieve the closest possible match of certain well-observations. An alternative way is to apply a well model, which always ensures the right phase productions.

Since the sixties thousands of works dealing with different aspects of history matching were published. Manual and automated history matching techniques bring the calculated dynamic features closer to the observed ones and to some extent try to preserve the geological consistency (e.g. Ganzer et al, 2018). Modifying reservoir parameters is also performed during sensitivity runs, in this way it helps to learn about the reservoir. Despite the automatization of the matching procedure a perfect match was never realized in deterministic static models: unlike the classical material balance calculation, the numerical history matching did not manage to assure a correct material balance result. It is proven that there is no significant difference between the reliability of the forecast of the history matched and not matched cases. Today’s common view is that once a reservoir model has been history matched it becomes capable to forecast, which is therefore not true.

An alternative solution, the so-called target Pressure and Phase Method, was presented by Professor Heinemann’s Doctorate Group (PHDG) first in 2010. Instead of adjusting the reservoir parameters the method adjusts and location of the well-connections in a way that the well produces exactly the same amount of all phases as the input measured data. Meanwhile, the realistic run of each identified regions’ average pressure is maintained by automatically adding (or taking out) water through defined aquifer connections. (Abrahema et. al. 2010) The concept distinguishes between the model well and the “pseudo-well” (including a number of connections within the inflow area of the well). The pseudo-well replaces, “masks” the model well to validate the static model. After model validation this solution gives a possibility for a spot-by-spot history matching, by operating a Peaceman-model for the adjusted well location and applying pseudo-wells for all other wells. This approach overcomes two major limitations of history matching: it is able to validate geological realizations without the modification of the static parameters (Mittermeir et. al. 2016), and as long as pseudo-wells are used, the overall material transfer is correct for the entire time period. The limitation of it is that the user has to chose between model validation or capturing the near-well phenomena (history matching).

This dissertation presents a third approach, which offers the possibility of optionally capturing near-well phenomena and ensuring the correct behavior of the well at the same time. It applies Peaceman-models (Peaceman 1978) over the entire production history and at every stage of model refinement, it gives the possibility to compensate for the production surplus or shortage of the trajectory. Ideally, this compensation should take place in the trajectory's immediate environment. This dissertation is strongly based on the above-described TPPM concept, but the here introduced model building approach-and applied well model changed.

1. The concept does not distinguish between the model well and the pseudo-well. A well model is developed, which combines the two features, and which at the same time represents the Peaceman-well and performs model validation.
2. Instead of a well-by-well match objective function (used for history matching) or spot-by-spot match (used for TPPM), the objective is to match the production from the smallest possible volume around the perforations.
3. By pre-defining the perforations and subsequent drainage volumes around the wellbore the convergence to the wellbore has to be automatically established. Unlike earlier, the modeler does not need to manually shift the pseudo well towards the model well.
4. Global match must be always ensured, while history match or alternatively spot-by-spot match can be optionally performed for shorter production periods at the end of the production history.

1.2.2 Objectives

The virtual representation, a “Digital Twin” of the reservoir would be a deterministic (not a probabilistic) numerical model which is able to accurately replicate the object's past- and predict its future behavior. The ultimate goal of the reservoir simulation is to achieve this. The objective of this dissertation is to show that with the utilization of the here presented well model it could be possible to create the Digital Twin of the underground system, and that it is nearly impossible in the conventional way. Based on earlier achievements, this work should contribute to the Target Pressure and Phase Method theoretically and technically.

1.2.3 Relevance

The discovery rate for the giant hydrocarbon fields peaked in the late 60s and early 70s and since then remarkably declined. (Babadagli 2005) Many of the larger reservoirs worldwide categorize as mature fields with still undeniable strategic importance despite the declining production and rising costs. Especially in the low oil price environment, when the economic viability of a project can depend on every percentage of additional recovery, the exact determination of the remaining phase distributions underground and a reliable forecast becomes vital. One of the most important ways for optimizing development strategy and thereby maximizing the expected ultimate recovery is reservoir simulation. (Steiner, 2015) However, it is almost impossible to accurately describe hundreds of wells' behavior with an adequate quality by conventional reservoir simulation (history matching) ways. It also means, that the remaining oil in the underground cannot be accurately characterized, consequently the model is not applicable for forecast either. In lack of a better alternative, forecasts based on unsuccessfully history-matched models are also used today for operational decisions.

The model building usually happens in two separate steps. At first, the static geo-model is established giving - in most of the cases - a good estimate for the original fluids in place but it does not consider their dynamic behaviour. This gains importance in the second phase only, when the prior model's parameter distribution is tuned to approach the measured well phase rates. The usual procedure is to adopt a Bayesian approach with well-matching objective function that is assumed to have a single simple minimum at the "correct" model. (Tavassoli, 2004) Since the realization that the searched closest possible match of the well performance can be far from the best representation of the underground object, it was tried to reform history matching methodology to become "geologically consistent". Some sources falsely claim that they achieved this. In fact, none of the history matching methods can account for the errors of the geological model structure and can give an indication about the correctness of the prior static model.

1.3 The Approach

1.3.1 Working Environment

The author was supported by Professor Heinemann's Doctorate Group (PHDG). In compliance with the rules of the PHDG, members do not claim "property right" for texts displaying the general understanding and knowledge within the group. In this thesis, these texts are inside (and) and are not claimed to be originally drafted by the author. Using these texts without adaptations is allowed and encouraged. Some of the sentences will be identical to ones written before, others will be changed to improve it. The author of this thesis does not claim to be the original creator of the concerned text parts and encourages others to use the written formulations.

1.3.2 Previous Related Works

The following works, which are originating from the PHDG, are listed thematically, instead of chronologically.

Heinemann and Mittermeir (2010) presented a computer-assisted history matching technique and its successful application. Besides the match of reservoir pressures by means of automatic calculation of aquifer inflow, they introduced a three-phase matching technique of the production history of each individual wells. They emphasized, that the underground fluid movements can be described correctly only if the above-mentioned conditions are assured.

They referred to their method as Target Pressure and Phase Method (TPPM).

Steiner (2015) applied numerical methods for assessing the aquifer support in a field with a complex structure located in the Sirte basin in Libya. He subdivided the reservoir into target pressure regions, calculated the corresponding target pressure values of each, assigned boundaries to them and used an automatized match of the region pressures with the calculation best fitting analytical aquifer parameters.

Mittermeir and Steiner (2016) presented the aims of the TPPM, the workflow of its application, and the advantages of the approach above the conventional history matching with a field example.

The author (Schultz, 2017) presented the TPPM's first industry controlled application on a full field example. The terms "dynamic reservoir modelling", "reservoir simulation" and "dynamic validation of geological reservoir models" were differentiated. The TPPM became operational with compositional fluid description and so to oil reservoirs containing mobile gas phase and gas condensate reservoir.)

1.3.3 Utilitarianism

(Utilitarianism is one of the basic principles of the PHDG. The actual research and development was conducted in close connection with real field projects. The new developments are used in parallel with standard methods, whereas new ideas can be discarded if they do not satisfy the expectations of quality and efficiency, within the time constraints of the project. This dualism provides the possibility of close control and will quickly reveal if the standard method is not the best in each step.)

1.4 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 Zoltán 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++ programing 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 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.)

1.5 Outline

Chapter 1 **Introduction**

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

Chapter 2 **Methods and Limitations of the History Matching Approach**

This chapter is a literature review about history matching workflow without details but with particular attention to the reason for it fails in most industrial applications.

Chapter 3 **The Model Validation Concept, and its Comparison to the History Matching Approach**

This chapter introduces the recommended reservoir geological model building workflow, starting with basic definitions, step-by-step procedure, tools and their application, and the concept's comparison to the conventional approaches.

Chapter 4 **Introduction of the Algyő-2 Models Used in this Work**

The demonstrated filed case and its available reservoir models created by the field operator and obtained by the author are introduced. Some modeling and history matching issues are pointed out. The matching results of HM and MV are compared.

Chapter 5 **Demonstration of the Model Validation Workflow on a Sector**

This chapter demonstrates a possible implementation of the concept on a refined small sector containing three oil producers and four water injector wells. The choice and definition of well model, its operation and diagnostics possibilities during validation, refinement stage is discussed.

Chapter 6 **Full Field Model Validation of Algyő-2**

In this chapter, achievements of the proposed method on the full field model are demonstrated for a shorter production period. A more detailed model building workflow was demonstrated for a chosen Algyő-2 sector. The results are compared with the history match provided by the field operator for an identical sector.

Chapter 7 **Production Forecast based on the Validated Reservoir Model**

This section details how the model validation method can be used to identify remaining recoverable oil, the technical possibilities of increasing the wells' drainage area, and calculating the incremental recovery.

Chapter 8 **Conclusions**

1.6 Scientific Achievements and Technical Contributions of the Author

1.6.1 Original Ideas Presented

- The author suggested that the model validation must be ensured even during optional local model refinement.
- The author suggested, that the model building workflow must apply the same well model for validation, refinement and prediction, in this way it simplifies the model building workflow.
- Instead of defining an objective which minimizes the mismatch of the wells, or the mismatch of the inflow area, the author suggested to minimize the extent of the drained units around the well.
- A suggestion is made how to use the presented model validation methodology to identify the remaining oil in a complex reservoir, and to calculate the incremental recovery expected from a potential recompletion.

1.6.2 Scientific Achievements

- The author's investigations on different history matching methods gave clear evidence that the history matching is conceptually wrong if used for other than sensitivity analysis, or to capture a temporary status.
- It is shown, that with the here presented model validation approach it can be possible to match the entire history of a large number of wells sector by sector, and to capture a temporary status (5 years) of the near well region of chosen individual wells.
- The author presented a comprehensive and globally applicable model validation workflow with the integration of the here developed features.

1.6.3 Technical Contributions

- The combination of the Peaceman well model and the "volumetric source" concept was implemented and applied in this work the first time. This means, that the well produces as a Peaceman-well first, afterward compensates from its drainage volume.
- The here implemented well model consists of a Peaceman-well, the near-well region,

the inflow area and supplementary connections. Due to this, it is capable to assure the correct behavior over the entire production history, to describe the communication between the drainage volume, the near well and the perforations, and optionally assisting the modeler in the near-well tuning process.

- The used well model became able to automatically indicate the location of the nearest remaining phase saturations, and its accessibility by the wells.
- The author automatized the distribution of the historical amounts of phases amongst the Peaceman-perforations, the near well and the drainage volume with regards to convergence and numerical stability.

1.7 Publications of the Author

V. Schultz, C. Steiner and T. Báródi, "Fast and Reliable Assessment of a Reservoir Model Quality on the Basis of Dynamic Behaviour", Nafta i Plin, vol.40., no. 165., pp. 53-62, 2020. [Online]. Available: https://hrcak.srce.hr/255921

V. Schultz, Z. Heinemann: "Az Integrált Rezervoár Modellezési Elmélet TPPM, valamint Alkalmazása az Algyő-2 Tároló egy Szekciójára" Accepted to publication at the Hungarian Bányászati és Kohászati Lapok (BKL).

Chapter 2

Methods and Limitations of History Matching Approach

This chapter is a literature review about history matching without details but with particular attention to the reason for it fails in most industrial applications. Since the author expresses her doubts about the applicability of the conventional concept, this position must be deeply explained based on the scientific literature. Some publications see the weaknesses of the applied technique and aim to overcome these. Other authors already concluded that the history matching -as a concept- is unable to give an indication about the correctness of the static model. The author formulates her conclusions about the applicability of the history matching concept, which will be proven in the next chapters.

2.1 Definition of History Matching

2.1.1 Applications of the History Matching

Due to the complex reservoir heterogeneity, the lack of information about the underground, the geophysical measurements' uncertainties, the limitation of the 3D modeling techniques, the upscaling process etc, the initial static model built by the geomodeller is normally not able to reproduce the dynamic behavior of the reservoir. Usually, geostatistical models are used to establish the spatial continuity of the static measurements (well logs, core data, etc). (Wei *et. al.*, 2018) The definition and purpose of classical history matching are fairly similarly formulated by many authors: in its traditional meaning, history matching is the process to condition the static model to production and pressure data, as described by e.g. (Rwechungura *et. al.*, 2011), with other words, to integrate dynamic data in the reservoir model (Sahni *et. al.,* 2010). Looking at the history matching as a data integration process, its main purpose is building a numerical simulation model which is consistent with the entire available reservoir data, i.e. geological, petrophysical, and SCAL data as well as production data including field and well pressure, flow rates, water cuts, and gas oil ratios, (as summarized by e.g. (Ghedan *et. al.,* 2006)). Occasionally

4D seismic measurement results or tracer test results can be integrated too (e.g. the work of (Illyasov *et. al.,* 2002)). The aim of history matching normally is to find a model such that the difference between the performance of the model and the history of a reservoir is minimized (Tavassoli *et. al.,* 2004). It is believed, that based on a history matched model, a more reliable forecast can be made.

During this process, the user manually (trial-and-error) (Zahid *et. al.,* 2016) or automatically (by minimizing one- or multiple objective functions) (Stephen *et. al.,* 2013) modifies either the geostatistical parameters or the flow simulation parameters (Feraille *et. al.,* 2003) of the static model. History matching is in the literature applied to homogeneous, or heterogeneous (including fractured) reservoirs, ranging from reservoir-scale through sector-to sector applications (Lin *et. al.,* 2917) to a near-well scale (Gou *et. al.,* 2018) (Sahni *et. al.,* 2010), normally attempted to the entire production history e.g. (Gervais *et. al.,* 2012) or a shorter period of it (e.g. (Sahni *et. al.* 2010) considered a separate “late-time” matching objective). The first mention of history matching dates back to 1961 (Krueger, 1961), and since then the number of publications about history matching has yearly risen above 100 according to (Rwechungura *et. al.,* 2011). This shows the lack of consistency in the applied methodology and workflow and acceptance criteria are subjective.

2.1.2 Generalized Workflow of History Matching

History matching activity is only a part of a reservoir modeling workflow. Despite the years of effort, there is no unique and globally applicable history matching technique or workflow, which would assuredly lead to the desired result. There are although common elements of the published approaches.

First, at least one reservoir model is constructed, each requiring model parameters. Instead of tuning a single representation of the underground, today’s preference is to obtain many equiprobable realizations, e.g. by combining structural and sedimentological model parameters across their range of uncertainty (Zunde *et. al.,* 2019). By the static modeler, sensitivity runs are created, which help to learn about each parameter’s effect on the dynamic response, or in other words, which geological uncertainty affects the production results, such as oil recovery, plateau strength, produced water, and breakthrough time significantly (Zunde *et. al.,* 2019), (Barbiero *et. al.,* 2019).

Screening is the iterative process of best possible prior model selection, which can take place with or without attention to potential dynamic behavior (e.g. streamline analysis, or already by history matching). This step normally requires resampling the model parameters, so optimizing (upscaling) the simulation grid is necessary, with the objective to capture the critical reservoir features of the fine-grid geological model (Fanjul *et. al.,* 2013). On normally a single, or optionally more chosen models, refinement takes place, e.g. by manual or automatic history matching. During this process is naturally the aim to keep consistency with the geological concept, at the same time, to closely reproduce the well’s measured behavior. A number of recent publications concern geologically consistent history matching. On reservoir modeling software or service provider websites it is also claimed, that there is no single approach, which is appropriate for all circumstances.

2.1.3 Manual and Automated HM Techniques

Manual tuning of the reservoir parameters is traditionally used only on a single geological realization and on examples with limited complexity, such as 2D models (Tavassoli *et. al.,* 2004), sectors (Gruenwalder *et. al.,* 2007), local refinements, concerning only larger volume-average of parameters or considering a limited number of parameters (Krueger 1961). Since no guidelines exist on manual history matching, it is very dependent on the experience and personal judgment of the dynamic modeler (Yang *et. al.,* 1988).

To overcome the time limitations and complexity of the history matching process, different automated history matching methods were developed. The use of computers enables to extend the dimensions, the number of altered parameters. It is also less dependant on the personal judgment of the modeler, but at the same time, it became more difficult to keep the solution under the control of the physical reality. Automated techniques define one or more objective functions, which is in a most general sense depend on the mismatch of a set of simulated and measured dynamic reservoir responses, such as phase production rates of the wells and reservoir pressures (Rwechungura *et. al.,* 2011). In a more complex case it can incorporate many more observation or interpretation results, such as 4D seismic or water breakthrough deviation (La Rosa Almeida *et. al.,* 2018). Functions can be defined and optimized regionally (Ding *et. al.,* 2011)- and time-dependently, for example considering only the transition to the forecasting period (Elahi *et. al.,* 2017). It can be expressed to be minimized by the method of least square roots, but other more complex formulations can be found in the literature (such as weighted least-square methods, etc.).

2.1.4 The Challenges of History Matching

History matching is an inverse problem, one of its main issues is non-uniqueness. The definition of an objective function suggests that it has one single minimum at the correct model (Tavassoli *et. al.,* 2004), although many authors recognized that it is not the case. There can be multiple matching solutions: the best parameter and performance-matched models can be far from each other, and often a good quality history match can lead to false predictions. Since from this work's point of view this is a vital issue, it will be dealt with separately in Section 2.3. The second issue of history matching is to preserve geological consistency. Geologically consistent history matching covers a range of solutions, which all try to realistically represent at least one of the geological features in the model during history matching (e.g. fault seal (Khan *et. al.,* 2020), rock types (Jenei *et. al.,* 2020), streamline trajectories (Anwar *et. al.,* 2017), etc). These techniques are mainly based on the integration of further interpretation results (e.g.matching discrete facies models (Elahi *et. al.,* 2017) instead of continuous reservoir properties), or applying the least possible deviations from the original property models.

Computation time (cost) becomes important when we encounter problems with a large number of unknown parameters, furthermore, some automated history matching methods can increase it (when an estimation of gradients is needed). It is important to consider ways to speeding up the optimization process. One efficient way to accomplish this for some optimization algorithms is to introduce a parallel or distributed computing framework. Another way to considerably reduce computational time is to calculate the gradient of the data mismatch by adjoints. Some examples of today popular ensemble-based techniques are (Chen and Oliver 2010, Gu and Oliver 2004, and Evensen *et al.* 2003). The ensemble Kalman filter (EnKF) method is a Monte Carlo implementation of the Kalman filter in which the mean of an ensemble of realizations provides the best estimate of the population mean and the ensemble itself provides an empirical estimate of the probability density. It is also applicable to correlate between reservoir response (such as water cut and rate) and reservoir variables (such as permeability and porosity), and estimate the uncertainty in future reservoir performance. (Rwechungura *et. al.* 2011). Reducing the number of optimization parameters (reparameterization) is another method for speeding up optimization, which requires the computation of the sensitivity of data to model variables. Gradzone analysis and Principal component analysis are techniques to perform reparameterization.

2.2 Summary of History Matching Errors

Despite the variety of attempts there is no example of a perfect history match in industrial applications. Therefore the question arises, when can one call a history match successful, and what are the quality standards at all. Many papers state that they achieved a successful history match. For example, the work of (Siu *et. al.,* 2000) matches about 500 wells in a giant oil field with a 10% rate accuracy. (Doan *et. al.,* 2011) provided HM scenarios, which achieved also an ~10% oil production rate deviation for two chosen wells with a complex operation history as part of a full field model. Other authors e.g. (Lemouzy *et. al.,* 1995) only claim, that they have achieved a “satisfactory” match, but do not provide any numbers. Improved HM techniques’ results are often shown comparatively to a base case and highlight only the improvement. The author believes, that the above-mentioned HM errors are not satisfactory, and this will be explained in the following chapters.

In his work (Baker *et. al.,* 2006) tries to draw attention to the fact, that despite forty years of simulation the petroleum industry has been reluctant to discuss history match quality standards. This lack of a standard is often justified by statements such as “the reservoir is unique” and the “data type and quality vary from field to field”. While those statements are true to a degree, they leave the non-simulation personnel confused as to whether a model is good or bad. In order to evaluate success and failure, as well as the need for simulation, we must clearly understand why would simulation forecasts succeed or fail.

Also (Baker *et. al.,* 2006) gave a good summary about why HM activities have sometimes been unsuccessful, which is taken over here without major modifications.

Timing

- The simulation study is taking too long relative to the business objective
- Confusing complexity with accuracy. Assuming bigger and more complex simulation,

(considering more variables) is always better or more accurate.

- An assumption that increased computer speed directly translates to simulation time.

Characterization

- Failure to adequately represent reservoir heterogeneity.
- Failure to calibrate the geological model's overall average permeability.
- Improper initial well diagnostic and reservoir diagnostic and failure to recognize reservoir mechanisms.

Modelling

- The lack of understanding of how history match parameters are controlled by physical parameters, such as relative permeability, permeability distribution and porosity and translating those parameters to predict future performance.
- Selecting a small simulation study area, but not correctly considering outer boundary effects, which significantly control the recovery factor within an area
- Poor understanding of how gridding effects affect simulation results.

In his work, (Baker *et. al.,* 2006) rather thinks about the modeling mistakes as possible compilations, but he does not conclude, that a successful history match could not be achieved at all, which is also useful for prediction. Other authors already question even the chance of an applicable history match, and criticize the HM conceptually, which will be shown in the next Section 2.3.

2.3 Papers Criticizing the History Matching Concept

In the light of the HM challenges (Section 2.1.4), it is the question, whether a “perfect” HM workflow could overcome the problems of both geological consistency and HM accuracy at the same time. The here referenced works show, that it so far could not.

Tavassoli et. al. (2004) used a two-dimensional synthetic model (Figure 2.1) to generate numerous realizations and choose one of them as a reference case. The only unknown parameters were the high and low permeability values in the zonation, and the throw of a fault. The applied automatic HM methods to generate the production match, and they compared their best production and parameter matched cases. They concluded that the best production match can be far from the best parameter matched model. This means, that one likely has to compromise between finding a good history match and keeping geological consistency.

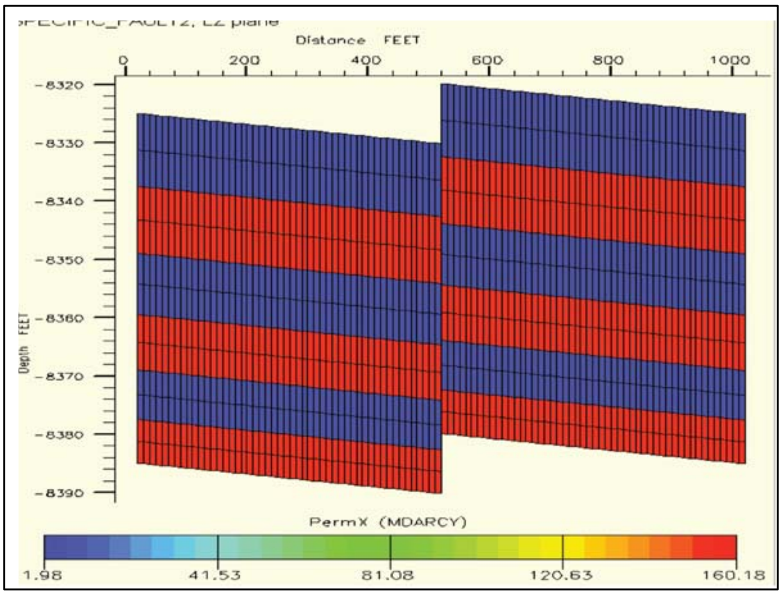

Figure 2.1: The experimental 2D model used by (Tavassoli et. al. 2004)

The PUNQ-2 project (Bos 1999) partly funded by the European Union, examined the reliability of the predictions on the bases of history matched reservoir models. PUNQ is an acronym for Production forecasting with UNcertainty Quantifications. In this project 10 universities, research institutes and oil companies participated. On a synthetic reservoir model, known as PUNQ-S2 (See Figure 2.2), eight years history was elaborated and revealed to the participants with all input data expect the porosity and permeability. The porosity and permeability values at the wells were revealed only. The property fields were created by different geostatistical methods by the participants, and they were asked to predict the cumulative recovery after 16.5 years for a given development schema. Up to 700 realizations were created and calculated, a few of them accepted as matching the history. The predicted recoveries varied in a broad range (Figure 2.3) without significant difference between the matched and not matched cases. Consequently, today's view, that once a model has been history matched, it is applicable to predict future reservoir behaviour is not generally valid.

The study of (Barker and Cuypers 2000) also on the PUNQ model highlights, that the static model cannot be uniquely defined, due to the subjective manner of the interpretation, and time relatively small changes in the prior model may have a considerable impact on the difficulty in finding a history match, on the predicted performance and on the uncertainty estimates. This also means, that a close match can might be possibly achieved from static models far from reality, but a reliable forecast can only be made based on good quality prior static models.

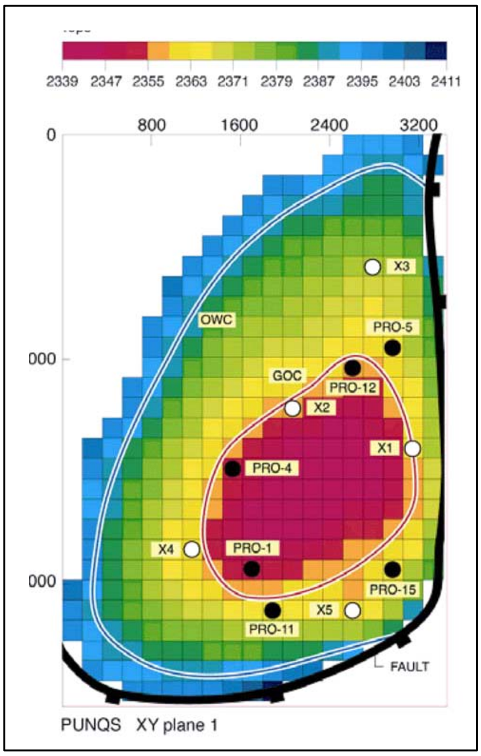

Figure 2.2: The PUNQ-S2 synthetic reservoir model (Barker and Cuypers 2001)

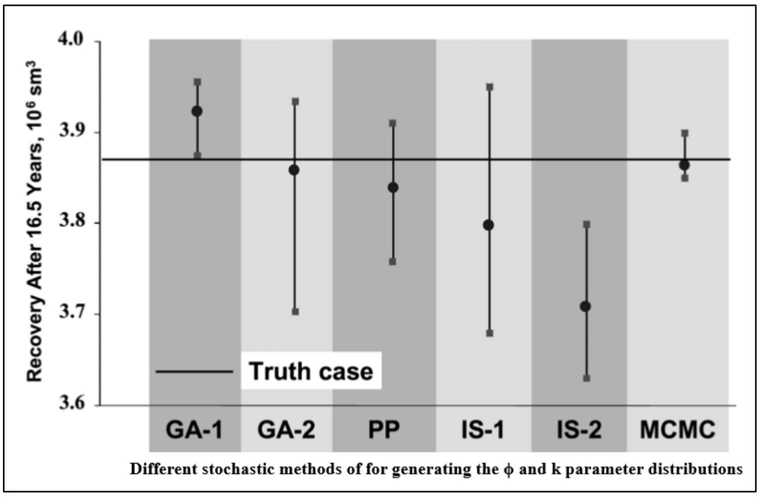

Figure 2.3: Predictions based on history matched PUNQ-S2 model realizations (Barker and Cuypers 2000)

2.4 Summary of Relevant General Statements

- In real field cases, HM is a complicated, and mostly unsuccessful.
- The parameter tuning does not increase resemblance to the real reservoir. The “true” model is not necessarily the most likely to be obtained using conventional history-matching methods. (Bos, 1999)
- The quality of the prior static model has a huge effect on the difficulty of finding a “good” HM. Finding a perfect history match on field scale is impossible. (Barker and Cuypers 2001)
- It is proven, that there is no significant difference between the reliability of the forecast of the matched and not matched cases. (Bos 1999)
- The HM cannot reproduce the reservoir behavior, neither on field scale, nor on well-scale, therefore it cannot be a solid basis of decision making.

Chapter 3

The Model Validation Concept, and its Comparison to the History Matching Approach

This chapter introduces the recommended reservoir geological model building workflow, starting with basic definitions, workflow, tools and their application, and the concept's comparison to the conventional approach.

3.1 Definitions

Building any dynamic reservoir model starts with a *prior static model* displaying the structure of the geological body and its properties on a discrete grid (called s*tructural and property models*). It results from geological interpretation, which is inevitably subjective. On the prior static model, optionally parameter modifications could be performed, also in a subjective manner, which is then called the *refined model status*. Both in prior and in refined model status, the static model must fulfill certain below-defined *dynamic requirements.*

For a prior model realization, the following dynamic requirements hold:

1. Compulsory criteria: With the applied *model validation technique* (explained in Section 3.4), the realization could reproduce the behaviour of all *global units* of the real object, which are the "reservoir", and the "pressure regions" (as represented in Figure 3.1.) This can be achieved if:

a.) The known average pressure development of the regions must be at every time exactly matched.

b.) The measured production and injection are every time exactly matched from every well's inflow areas.

[On Figure 3.1 it is easy to see, that the behavior of the global unit "reservoir" is correctly described, if the overall reservoir material balance (including aquifer influx) is respected, so with the combination of points 1a. and 1b. criteria. The phase contents and communications between the "regions" are correctly described if their average pressure and the intensity of their sources and sinks are realistic, so when points 1a. and 1b. hold.]

If the prior static model conforms with criteria 1a. and 1b, it is considered validated. If the validation fails at prior model status, the static model must be dismissed or re-interpreted. If the realization is validated, optionally local model refinement can be performed. The *model validation concept* implies, that during the model building and refinement, the object must sustain its validated status, meaning that it must fulfill at least the compulsory criterium of a validated model. Therefore model validation first must be carried out directly on its prior status, and afterward in every further refinement stage.

For a refined model realization, the above listed 1a. and 1b. criteria are also compulsory. Optionally additional dynamic requirements can be set:

2. Optional requirement: with the applied model validation method, the model could reproduce the real object's behaviour of local units, which are the "inflow area", "near well regions" and "perforations" (See: Figure 3.1):

a.) Weaker requirement: The measured production and injection are exactly matched from the near well regions at least for desired wells and for a shorter period of time.
b.) Stricter requirement: The measured production and injection are exactly matched from the perforations at least for desired wells and for a period of time.
c.) Stricter requirement: The measured flowing bottom-hole pressures are exactly matched at least for some wells and for a period of time.

[On Figure 3.1 it also can be seen, that the phase contents and communications of a certain "inflow areas" with its surroundings is correctly described already if compulsory points 1a-b. and the weaker requirement 2a. holds for the given well. The communications of a near well area with larger and smaller units are correctly described, if above compulsory criterium 1a-b, also points 2b. holds. If the inflow into the perforations is concerned, the BHP gains importance and if proper data is available, in addition to 1a-b, 2b. and 2c. requirements could be set.]

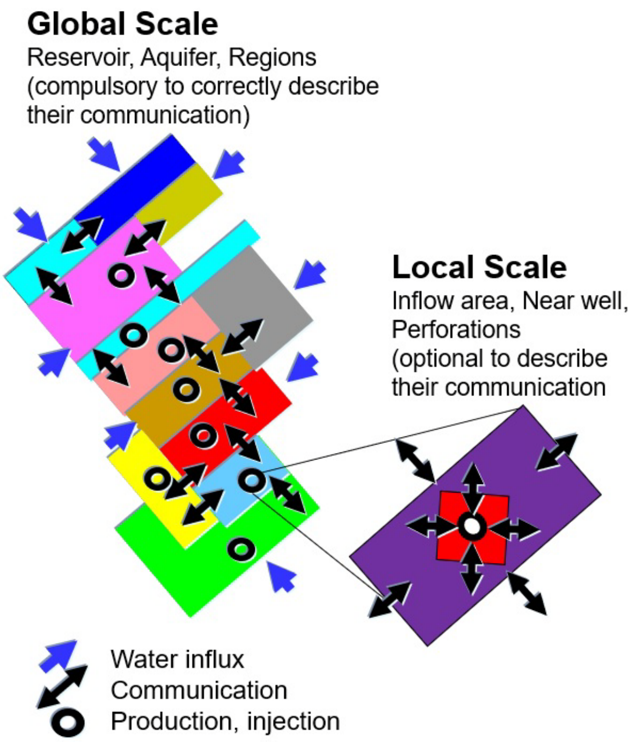

Figure 3.1: Illustration of the identifiable flow units in the reservoir on global scale and local scale, and their communications. (modified after Abrahema et al 2010). For more detailed description of the flow units see Section 3.3)

3.2 The Model Building Workflow with MV Concept

This section describes the theoretically correct way to implement the MV concept to a reservoir model. It is not compulsory to complete the workflow: depending on the engineering task the modeler can decide to stop at the desired level of model refinement. The summary of the working step is shortly summarized in Figure 3.2.

3.2.1 Step 1: Construct an Initial Dynamic Model based on Validated Prior

The prior static model realization(s) must be converted to dynamic one(s) by upscaling geo-grid to a flow-grid. The pressure regions, their boundaries and the drainage volumes of the wells must be identified. The so-constructed model(s) must be validated. The latter step means to prove or disaffirm that the model of the well's drainage volumes always contain the required amount of each phase while the average pressure of the regions equals the measured. This imposes the global applicability of the geological model. If the model cannot operate so, the cause, location and time of the differences must be indicated. If validation was performed on more realizations, the found best valid representation(s) must be selected (screening). If no realizations were validated, the model must be re-interpreted in the suggested locations and the process repeated. It is forbidden to modify the cell parameters, unless those assuredly comply with the geological concept.

The expected result of this step should be an initial dynamic model based on validated prior, which serves a good basis of optional local model refinements. Already after this stage, the following usual modeling tasks can be performed: material balance calculations, remaining reserves characterization, evaluation of past development scenarios, determination of best analytical aquifer parameters, infill well placement, description of the communication between regions, etc.

3.2.2 Step 2: Model Refinement at the Near Well Locations

This step involves local refinement of the parametrization in the near-well areas, after the structural setup is already stabilized (model is validated). It is not always needed to perform refinement near all wells in the model, but for certain modeling tasks this step may be necessary. Model refinement should performed on chosen wells, and for a short (3-5 years) period of the production history (possibly before the intended prediction period, or when the phenomena of interest take place). The inflow area and near well region for the chosen wells must be time-dependently identified. Refinement can be done in a subjective manner (trial-end error), ergo with manual or automatic history matching, but it strictly cannot affect the matching results of other wells or the global applicability of the model.

From the refinement it is expected to describe the communication between smaller flow units within the well drainage areas, converging to a more realistic representation of the well in the reservoir, which can be considered when the goal is to matching BHP, or observing near-well phenomena such as condensate formation etc.

3.2.3 Step 3: Proving the Model's Predictive Power

In this stage the model is operated in prediction mode for the historical last 3-5 years. If the model can reproduce this time interval with the forecasting method in use, it can be applied with confidence for the next 3-5 years. There are several ways to predict, from simple decline-curve calculation to various probabilistic approaches.

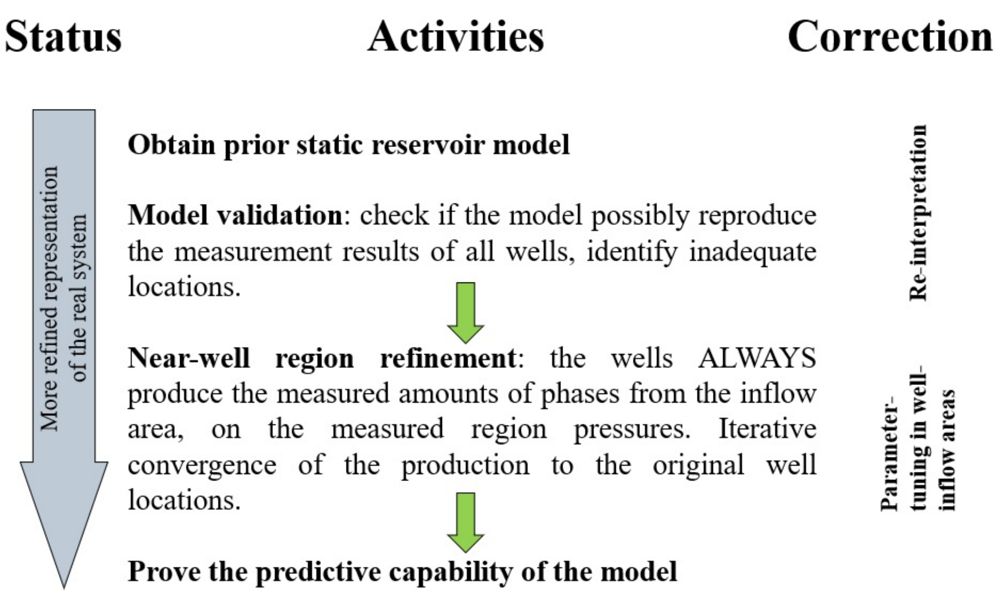

Figure 3.2: The model validation workflow, as recommended in this work.

3.3 Describing Pressure Regions and Drainage Volumes

The 1st Step of the MV workflow (see Section 3.2.1) relies on the identification of regions with uniform pressure development, and the drainage volumes of the wells (which will be explained in the followings). The 2nd Step of MV (Section 3.2.2) can require arbitrarily smaller consistent units to be defined around the wellbore, such as near well region or perforations. In the model, these are assigned as a user-defined heap of cells which mostly represent in the real reservoir physically distinguishable regions. It must be the aim to provide a close representation of the real units, but there are naturally acceptable limitations to that.

It is not the scope of this work to discuss ways to assign pressure regions, although it must be noted, that it is essential to ensure the compulsory criteria of a validated model (Section 3.1). For identifying target pressure regions, their boundaries, their average pressure development, the reader is referred to (Steiner 2010).

In the scope of this dissertation, only identifying well drainage volumes will be discussed in detail. The concept of *Drainage Volume* (DV) is well established in petroleum engineering practice. This is the volume from which the fluids are withdrawn by a well. In reality, the extension of a DV naturally changes due to the well interferences, but for modelling purposes, those can be simplified, regarded as stable (steady-state) units with limited communication between them. In earlier works, only a single consistent drainage volume was used, by its extent not exceeding the real inflow area of the well. In the context of this dissertation, it should not necessarily be so. Besides the real inflow area, other arbitrary groups of cells can be defined, which are all referred hereto as DV-s. These either have a physical meaning or are assigned for a specific modeling purpose. In the latter case, it can be justifiable to use even inconsistent volumes, located outside the actual estimated physical inflow area. The author found, that defining a maximum of 4 independent DV-s for a well could satisfy all modeling tasks during the model validation workflow. For simple reference, in this work, these will be identified by D1-D2-D3-D4, starting from the smallest to the largest.

- D1: "trajectory". It replicates the real well's physical (open or squeezed) perforated sections along its trajectory. It is represented by perforated cells as it is usually done in every simulation models.

- D2: "near well region". Often near well region can be physically distinguished as the regime of increased flow velocities which can bring specific implications. In this work, although, the region is rather assigned to assist certain modeling tasks, and does not necessarily represent any physical unit.

- D3: "inflow area". This volume represents the real inflow area of a well. To fulfill the compulsory criterium of MV, this region must be time-dependently identified for every wells, and must approach the real shape of these volumes.

- D4: "environmental cells". This volume can be formed by independent cells located outside of the D3, having no connections to each other, and are assigned for specific modeling purposes. These indicate the location of the nearest movable oil-gas-water saturated cells outside the inflow area.

The significance of the mentioned DV-s will be discussed in Section 3.4, and their application guidelines in Chapter 5.

3.4 The Model Validation Technique

This dissertation introduces a MV technique implemented in a numerical reservoir simulator. Note that despite this fact, validation must be clearly distinguished from simulation. In an earlier publication on model validation, the author (Schultz 2019) defined how the terms modelling, simulation, and validation, referring exclusively to flow in hydrocarbon reservoirs, should be understood. Since their goals are different, the modelling and validation techniques are different too.

A MV technique incorporates the tools for regional pressure maintenance and a unique well model. As already said, this work does not concentrate on pressure maintenance techniques, but in the author's opinion the so-called Target Pressure Method (TPM) must be applied for aquifer driven reservoirs, as already described by (Abrahema et.a. 2010) and successfully applied to a field case by (Steiner 2015). Shortly summarizing, the TPM assures the correct development of the reservoir pressure by automatically adding or taking out water through the boundary cells.

At the end of every run the optimal parameters of Hurst-van Everdingen, Carter-Tracy, and Fetkovich-aquifer models will be correlated. The latest one can be differentiated in time intervals. The obtained analytical aquifer models can be used in prediction modus. This option is applicable to models performing only history matching too. For this dissertation, one must have a closer look at the applied well models.

3.4.1 Well Models in MV

To complete the MV workflow the modeler must be equipped with a well model which together with the applied target pressure maintenance technique must be:

1. Able to induce the correct phase productions/injections at the right location at the right pressures, therefore the correct communication between the regions, provided that the realization is a close representation of the real reservoir.
2. Able to show the quality of the given geological realization from the dynamic point of view, and able to show which reservoir locations cannot fulfill the compulsory dynamic requirements, therefore must be re-interpreted.
3. Able to show which near-well locations cannot fulfill the optional dynamic requirements, therefore the need of local model refinement.
4. Able to represent the inflow performance relationship and operated in prediction mode.

It is an important scope of this work to conclude in a well model (instead of recommending multiple interchangeably used well models) which is equally applicable to the above-mentioned tasks, therefore simplifies the model validation procedure described by (Abrahema et.al. 2010) and (Mittermeir et.al. 2016). They already established the basic concepts of an MV-well operation. According to them, in conventional simulation the well model's connection to the reservoir has priority. The location and extension of the perforation should be given realistically. The parameters of the inflow equation can be derived from the cell parameters or input directly. On the contrary, for MV well models, their real behaviour has priority and operate with less spatial and physical binding. This means that within its drainage volume the well has access to any cells and these all become well connections. In this way the well and its drainage volumes are operated together forming the MV well model. In MV concept the DV is the primary producing unit assigned to the real well for a given time interval. Even though the mentioned statements are still true, the MV well model's operational principle was modified.

The MV well can drain its connections with a combination of two approaches. (1) The inflow calculation either applies the Peaceman model (applicable to D1 volume), (2) or the production is treated simply as a volumetric source, the injection as volumetric sink, and the well distributes the historical production rates amongst its connections with some reasonably defined weights (applicable to all D1-D2-D3-D4 volumes).

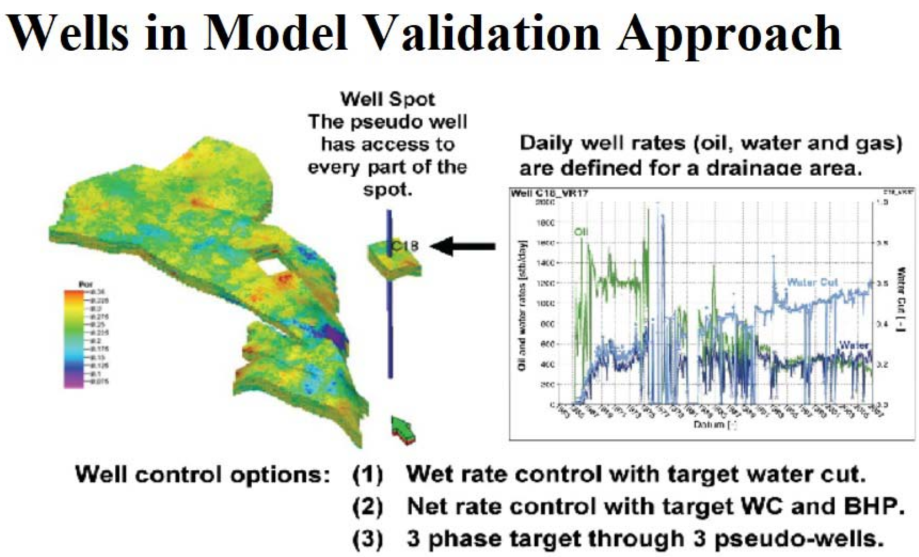

Figure 3.3: In MV concept the DV is the primary producing unit assigned to the real well for a given time interval (Abrahema et al 2010).

3.4.1.1 Production with Peaceman Concept

Numerical well models are usually defined as a "source" (or "sink") located in a grid block with a defined relationship between wellbore pressure, block pressure, and well production rate. This relationship may be called well index or numerical productivity index (PI). Peaceman (1959) introduced the basis for the most common well model. Because of their strict physical dependencies it is not possible to input all flow rates and pressures as input at the same time. It is usual to define a desired target e.g. oil-water-gas production rate, BHP, liquid production rate or reservoir volume production rate, the rest of the parameters become the output of the calculation. Especially at the beginning of the model building process – such a well model rarely can reproduce the real wells' behavior.

(Abrahema et.al. 2010) presented a method to approach the desired WC and GOR: the well can find the temporarily optimal value of the real perforations' productivity indices (PI) while respecting the desired target phase rate. The PI modification is a usual HM step too, but in their work it was carried out automatically. The optimal PI values may vary in each timestep. The PI values are afterward evaluated and the optimal steady values for desired longer time periods are provided. This method has the potential to considerably reduce the discrepancy between the measured and the calculated phase rates, but it still does not resolve their dependency on each other, therefore it cannot guarantee the correct well behavior.

3.4.1.2 Production and Injection with Volumetric Source Concept

The well can directly access cells within its drainage volume using the volumetric source approach. In earlier works it was the only technically feasible way to set up the well model using either only the Peaceman-approach or only the volumetric source approach to all well connections. From the drainage volumes only production took place. In this work it became feasible to operate the well models with the combination of the two approaches. In this case, the DV-s are used only to compensate for any surplus or shortage from the well. This means that as well injection can take place in the drained connections. In the following, for the sake of simplicity might only production is mentioned, but under this always production or injection must be understood when the volumetric source approach is concerned for compensation purposes.

The well distributes the residual or measured production rates amongst some of its connections with a reasonably defined methodology, which can be done even without a relation between the produced rates correlate the cell production rates to a BHP. The latest published industrial application of the drainage volume concept by the author mentioned that multiple acceptable solutions could exist to distribute the compensational rates in the drainage volume. Since this work, it was realized that for complex field applications individual adjustment for each well would be required: the optimal method can vary for each well location and in time. A considerable effort was made to implement generally applicable DV operation and phase distribution principles, which also considered the new injection option. The currently applied methodology takes into account individual static (pore volume, permeability) and actual dynamic cell properties (pressure, movable phase content, etc.).

The most important considerations when implementing the methodology were:

- Convergence
- Numerical stability
- Automated operation

<u>Convergence</u>

In the context of this dissertation *convergence* means the operation of the MV well with the least possible deviation from the Peaceman-model. The aim to do so was already expressed by (Abrahema et. al. 2010), but the well model did not provide a fully automatized possibility to do so. An earlier publication of the author (Schultz 2017) establishes convergence to the wellbore but at that time applying the volumetric source concept only.

The implemented combined well model helps to realize the convergence without any user intervention, but it can be regulated by the number of defined DV-s. Note that defining smaller drainage volumes (D1 and D2) tends to a stronger localization of the production around the wellbore. In case all drainage volumes are defined for a well, the convergence would operate as follows:

1. The trajectory perforations are considered, first from which the inflow is calculated with Peaceman concept.
2. PI multipliers are applied to approach the measured rates and bottom hole pressure, which change in time.
3. If after the second step there it is still a discrepancy from one or another phase than the fluid will be taken from/injected into D2 “near well” volume.
4. The well accesses D3 volume “inflow area”.
5. If the target distribution did not succeed, the well can search for oil-gas-or water saturated cells outside of its D3 drainage volume to indicate the nearest location D4 wherefrom the phases could flow in into the wellbore.

Numerical stability

This work addresses potential numerical stability issues associated with drainage volume operations for the first time. It must be noted that most numerical stability issues are due to modeling errors (including structure, parameters, fluid, boundaries etc) or unfavorable gridding (fail to convert to flow-grid), and are not directly linked to the well operation. It is advised to correct these before model validation (when creating the initial dynamic model). The drainage operation can induce additional numerical stability issues in some heavily drained cells, which commonly take the form of unfounded pressure- or saturation oscillation. It can be partly mitigated by an optimal application of the volumetric source concept. Since it is almost impossible to specify the maximum amounts of phases that can be produced from a cell without causing instability (it depends on the pore volume, saturations and pressure of the cell and its surroundings, number of neighborhood connections, etc), the mitigation reactively takes place, by a constraint system or by the temporary exclusion of cells from the DV operation until its properties stabilize. Constraints to the Peaceman well production and BHP can be applied to, as it is usual practice in the conventional simulation as well.

In an ideal case, constraints applied in favor of numerical stability concern a few cells only and have almost an unnoticeable effect on the MV results. Suffering from severe numerical stability issues, the well will spread out its connections more, opposing the effect of the convergence. It can affect the MV results since the necessary amounts of phases are might there but cannot be produced by the well.

Automation

Especially for a high number of wells in a reservoir model it is advantageous to offer some level of automation on the MV well operation. In the current phase of the technical development automation is offered in many aspects already, and the MV well operation needs a limited user intervention. The automation covers finding the optimal way to drain from the connections: account for the convergence, setting up constraints for the numerical stability, assigning (some of the) drainage volumes to the wells and generating diagnostics such as the volume’s average dynamic properties in time. Especially if the well placement is very dense, it is recommended to set up drainage volumes manually at this point.

3.5 Comparison Between MV and HM

3.5.1 HM-concept

The starting point is a prior reservoir geological model on which wells are operated according to their physical entity. Naturally, these cannot reproduce the measured rates and pressures, so the method is compelled to compromise. Instead of the historical oil, gas and water rates, the model well is produced with liquid rate (oil + water) or reservoir volume rate (oil + water + gas) target. Consequently, not only the performance of the model and real wells differs always, but also the one of the model and real reservoir's. The HM approach attempts to reduce the discrepancy by modifying (and not re-interpreting) the geological model. The identity of the model and real wells is most likely never reached. (Figure 3.4)

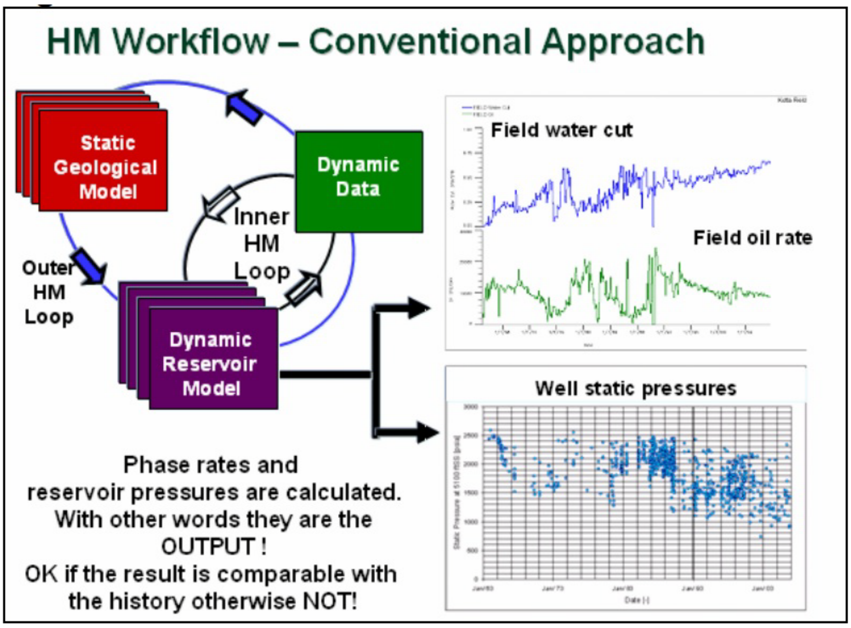

Figure 3.4: The history matching approach (Abrahema et al 2010)

3.5.2 MV concept

The starting step is identical to the one of the HM but the MV searches for compromises in fundamentally different directions. The model wells produce nominally the historical oil, gas and water rates. Because this would be virtually impossible for them, they use their environment - also called drainage volume - to compensate any shortage or surplus of the oil, gas, and water phase. The task of geo-modeling is to time-dependently identify the drainage volumes around the wells, and to find their equivalent parameters. In case of success, the drainage volumes shrink to the location of the real perforations. The major difference between HM and MV is that here every well, naturally together with an integrated reservoir model always produces the target rates. Due to this the model can always be regarded as a step-by step more accurate representation of the real object. Figure 3.5 gives a direct comparison of the fundamentals of the two approaches.

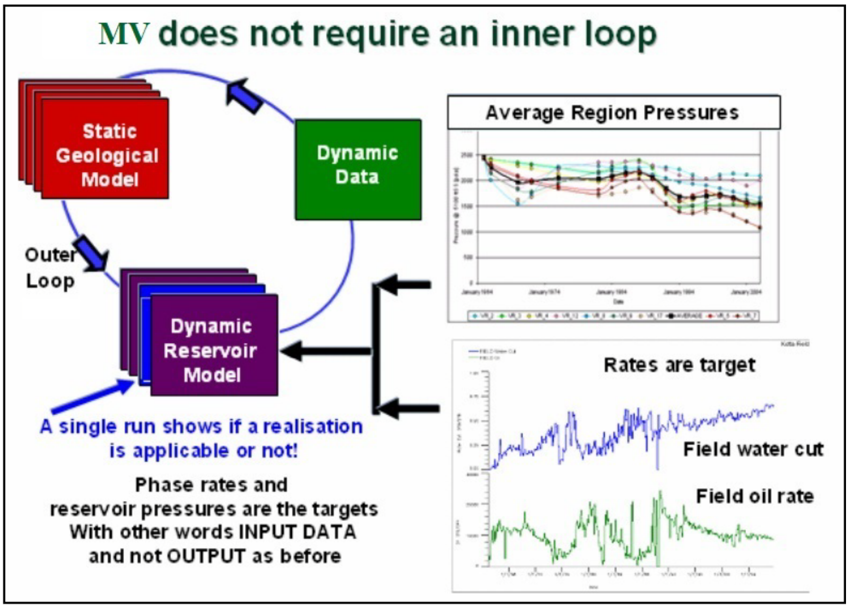

Figure 3.5: The model validation approach (Abrahema et al 2010)

Figure 3.6 compares the workflow of the two approaches. Since the interpretation is never unambiguous, many equiprobable model realizations are possible. When operating a realization the HM can provide only parts of all available dynamic data as an input: the phase ratios become the output of the calculation. In the beginning of the history matching process there is no indication whether is it possible to achieve the equivalency of the calculated and measured values by parameter-tuning. The modeler revises the geological concept usually only after a long matching activity. The MV approach regards all available production data (three phase production-or injection rates) and average reservoir pressures as an input and examines whether the given realization can be operated this way. If the model contradicts the input data, it is not acceptable. The MV prevents the matching of unsuitable realizations. On validated models the success of the history match is guaranteed.

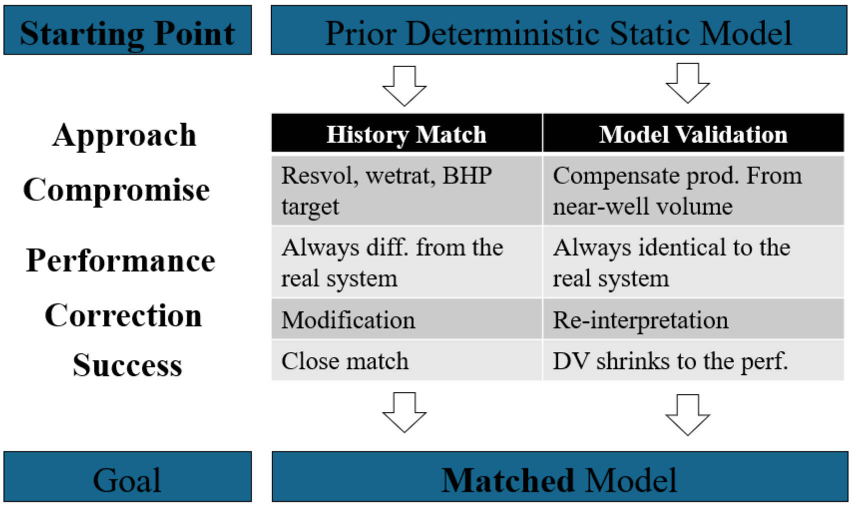

Figure 3.6: Summary and comparison between the two approaches

3.6 Conditions, where the Model Validation Concept is Highly Advantageous

The value of model validation is the most visible when it is applied to:

- Large brown field models with a very long, complex production history, which would be time intensive to try to history match.
- Depleting multi-phase systems with very high WC. History matching normally cannot approach WC-s above 95%
- Complex structure and inhomogeneous parameters, which often makes it impossible to capture the reservoir inhomogeneities on a flow grid (fractures or channel system), therefore between the average saturations and relative permeabilities the usual correlation does not apply.
- When it is desired to concentrate on a pilot sector, while correctly describing its communication with the rest of the reservoir. The model validation concept makes it possible to reduce the dimensions by concentrating on a pilot sector. The modeling task can be distributed the modeling task between a group of engineers. With history matching, the integrity of a pilot sector and the rest of the reservoir is destroyed because it cannot induce the correct boundary conditions.

Chapter 4

Introduction of the Algyő-2 Models Used in this Work

In this chapter, the basic geological concept and available reservoir model of the presented field case created by the field operator MOL is introduced. The static modeling discrepancies -which would hinder the application of the MV features- are pointed out and corrected. The results of earlier HM attempts of the field operator were analyzed. Additional small-scale models created by the author are presented too.

4.1 Modeling Challenges of Algyő-2

For the development and demonstration of the MV approach the Hungarian national oil company MOL PLC provided field data of their strategically most important reservoir, the Algyő-2. It is situated in South-East Hungary and part of the largest hydrocarbon occurrence in the Carpathian-basin, the Algyő-filed. The field is characterized by more than 70 oil and gas clastic reservoirs in a mature state of exploitation. (Nardiello *et. al.,* 2009) These reservoirs consist of fractured Paleozoic metamorphic rocks, a basal Pannonian conglomerate, and overlying Miocene sandstones. (Dolton 2006). The upper members of these reservoirs (including Algyő-2) have developed in a Pannonian delta system due to complex lateral shifting and prograding phases. These can be subdivided into delta slope (Algyő Formation) and delta plain (Ujfalui Formation) rock bodies. (Szilágyi and Geiger 2012) See Figure 4.1.

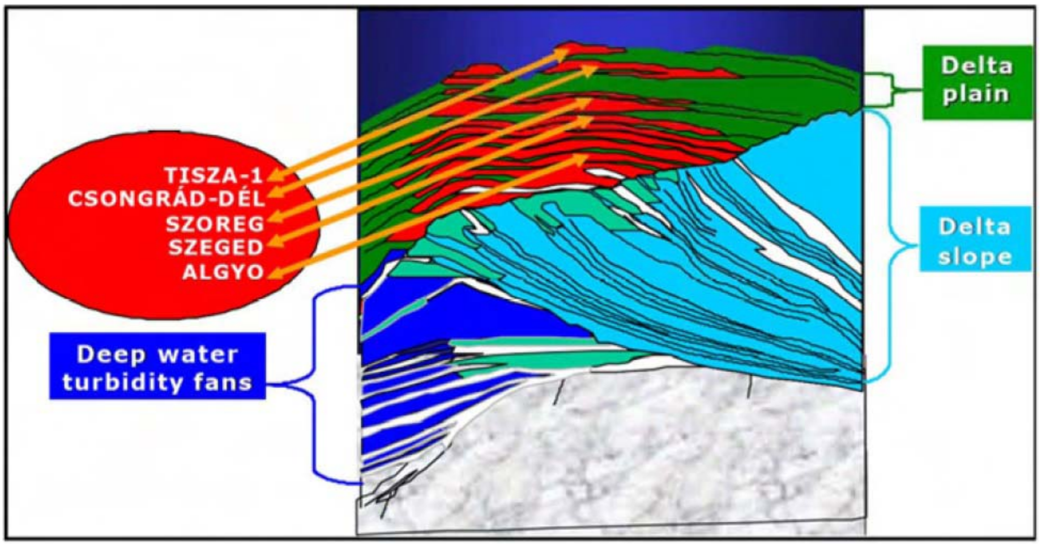

Figure 4.1: Schematic geological structure of the Algyő Field. (Nardiello *et. al.,* 2009)

Most of the deltaic sandstone reservoirs exhibit complex lithofacies as well as petrophysical variations, both laterally and horizontally. (El-Sayed (1986)) created a comprehensive facies analysis and reconstructed facies patterns for the Algyő-2 reservoir rocks using the log curve shapes. According to his work, the sedimentary sequence is characterized by cycles of high and low permeability zones, with various thicknesses and extensions. (Figure 4.2) Sandstone microlenses of 20-30 cm length and 25-50 cm thickness are commonly present. The depositional patterns map (Figure 4.3) of the Algyő-2 reservoir clearly indicates that discontinuities of reservoir properties are very typical in the horizontal directions too.

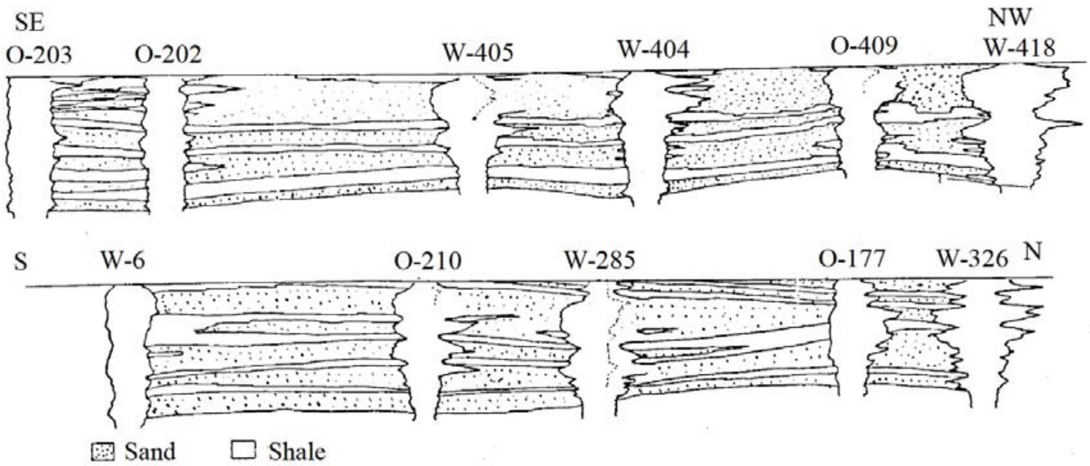

Figure 4.2: Shale and sandstone sequence on two cross sections of Algyő-2. (El-Sayed 1986)

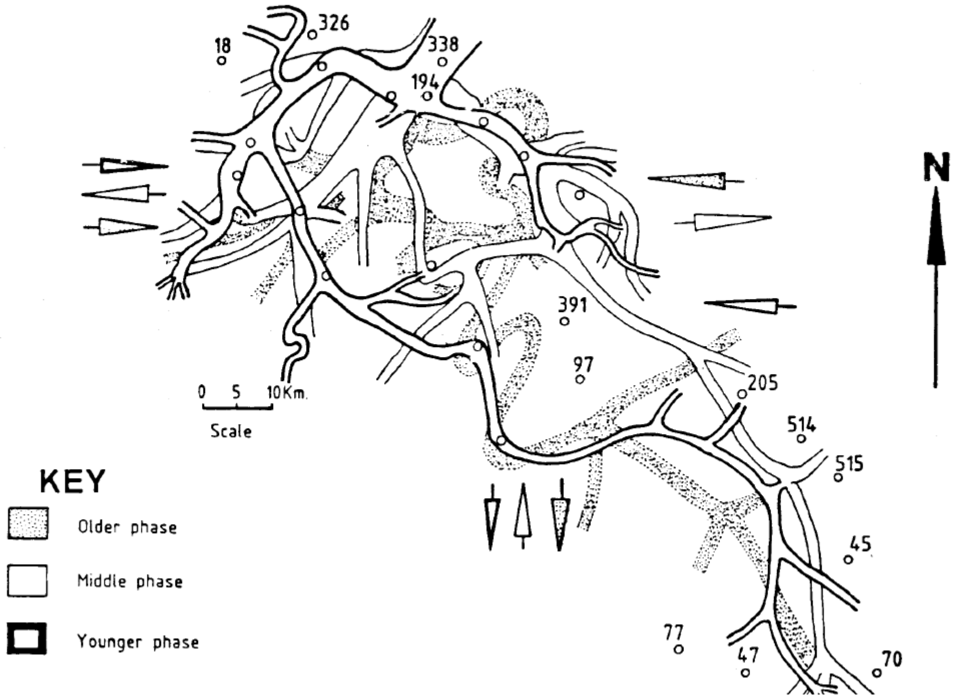

Figure 4.3: Depositional patterns of Algyő-2 reservoir (El-Sayed 1986)

The heterogeneity of the reservoir imposes challenges on both static and dynamic modeling. In order to predict the geometry of individual channels, and to properly characterize the location of permeable and sealing layers, it is important to diagnose the sub-environment, above the overall depositional environment of the associated sediments. It is not adequate to account for the heterogeneity purely stochastically. Especially on a flow grid- it is not possible to distinguish thin sealing layers: only average static and dynamic properties are represented, therefore between the average saturations of the phases in a block, and their relative permeabilities the usual correlations do not apply. In reality, it is very likely, that the imbibing water and gas cannot access all zones, but at greater permeable zones those can break through toward the wells. Modeling such circumstances is impossible by HM means. The MV technique establishes this correlation, although not for each individual block, but inside of the drainage volumes of the wells.

4.2 Operation History of Algyő-2 Reservoir

It is an undersaturated oil reservoir with a large primary gas cap. The depth of the gas-oil contact is 1854 m, the water-oil contact is uneven between 1880 m and 1888 m below sea level. The initial pressure at the gas-oil contact is 190 bar, the reservoir temperature is 95 C. The gas-oil ratio of the saturated oil is 95 sm3/sm3, the bubble point pressure is 191 bar. The density of the oil, gas and water phases are 843.06 kg/sm^3, 1006.1 kg/m^3 and 0.98896 kg/m^3.

The field has 55 years operation history (Figure 4.4): the continuous production commenced in 1965 with wildcat Tape-1. Until 2016, altogether 276 wells of various function were drilled, including many horizontal ones. After a few years of depletion, in 1969 water injection started with the recompletion of oil producers and by new injectors placed in the water, oil and gas body. Between 1973 and 1983 also gas injection took place, from 2004 to 2009 the gas cap was partly exploited. Reservoir sectors are candidates of ongoing EOR projects.

Most of the wells were not in continuous operation, even except the workover periods. As a result of re-completions, those produce with a wide range of WC's and GOR's. Their contribution to the field totals is imbalanced. The field totals in 2016 are 9852319 sm^3 recovered oil, 37350015 sm^3 water and 5178807000 sm^3 gas. The field-WC gradually increases after the water breakthrough in 1968, today approaches 0.96 (Figure 4.5). The GOR linear increases from solution gas ratio to 1500 sm^3/sm^3, but it peaks due to the start of gas injection between 2004 and 2009.

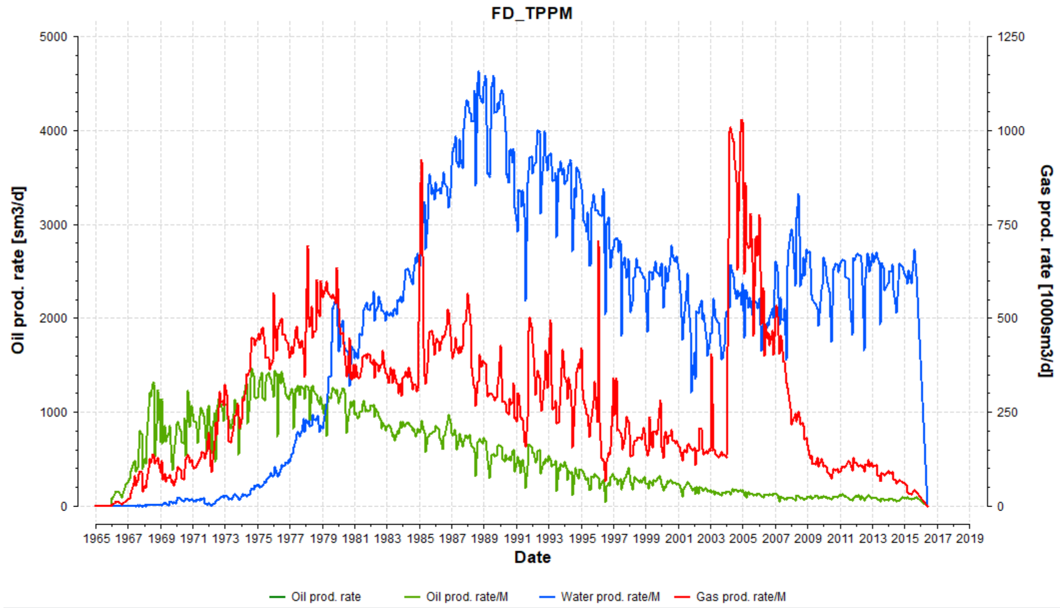

Figure 4.4: Historical production rates of Algyő-2 reservoir

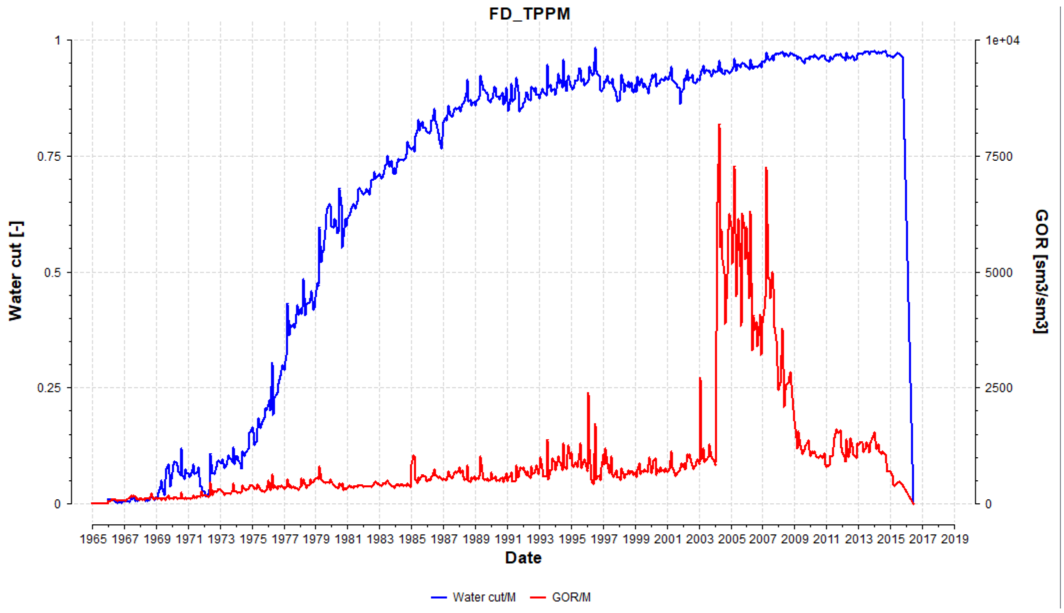

Figure 4.5: Historical water-cut and GOR of Algyő-2 reservoir

The following considerations make the Algyő-2 an ideal candidate for the improvement and the demonstration of the MV approach:

- It is a brown field with a very long production history, makes it possible to validate the model against a large amount of production data. The availability of recent history matching results makes it possible to compare the effectiveness of the conventional and the here proposed methods.
- It is a three phase reservoir, with aquifer and primary gas cap. The methodology's value is the most visible, when it is applied to multi-phase reservoirs.
- Various operation strategies were applied over time, and a large number of wells, including water injectors, gas injectors-and producers, vertical and horizontal wells were drilled. This fact makes it possible to develop and test the validation concept in a most general way.
- Its varying properties in space, heterogeneity is expectably not likely to be captured on a flow grid.

4.3 Static-and Dynamic Modeling of Algyő-2

4.3.1 List of Obtained Data

In the past 50 years, the Algyő-2 geological model was re-investigated multiple times. Unlike earlier attempts, which deterministically correlated the permeable and sealing layers, the latest (2016) revision applied stochastic parameter assignment. Based on this, MOL has also created dynamic models, two of which - the prior and the actual history matched status - were provided for the author in ECLIPSE input data structure. Although the prior static model itself was not available, there was no reason to doubt that the received dynamic model in prior status is a close representation of it.

Obtained data in *ECLIPSE* input data deck:

1. The accepted latest prior (no HM) realization of the full field static model, also used by MOL to perform HM. (Described in Section 4.3.5)
2. Actual history matched status of Point 1. (Described in Section 4.3.5)
3. Black oil fluid description in PVTO, PVDG, PVTW (oil, gas and water) property tables in ***ECLIPSE*** PROPS input format. (Described in Section 4.3.3)
4. Rock SCAL data in SWOF SGOF tables in ***ECLIPSE*** PROPS format. (Described in Section 4.3.4)
5. The local coordinates of the perforations, historical three-phase production rates and well-constraints in a form of an ***ECLIPSE*** Schedule file.

4.3.2 The Grid and Static Properties

The latest static model of Algyő-2 was created with ***PETREL*** 2016.2 (64-bit) from Schlumberger and exported in ***ECLIPSE*** keywords (ASCII) format, in a metric unit system. The grid dimensions are 94x46x84. The horizontal cell sizes are mostly consistent (~150x150 m). The vertical grid layer heights are mostly uniformly 1 m, but where adjusted to horizons and faults, those can be thinner or pinched-out. In the latter case, the cells are sharp and distorted. The pore volumes range from 1 to nearly 4000 m3. Communication was established across pinched-out layers (with PINCH keyword). The 18 faults are zig-zagged and considered impermeable. Stochastic parameter assignment was applied.

The author noted some inadequacies purely from the dynamic modeling point of view. The grid and properties were not upscaled before dynamic modeling was performed. This is normally used for volumetric calculations but is not applicable for flow simulation. The distorted grid cannot describe the flow especially at the fault zones and the near well regions (radial flow) correctly. The horizontal grid size is too coarse for the well spacing (there is no regular block between two perforated ones), while the vertical block size is too small, introducing gridding effects on the dynamic result. In addition, the uneven pore volumes presumably cause numerical instability of the simulation runs.

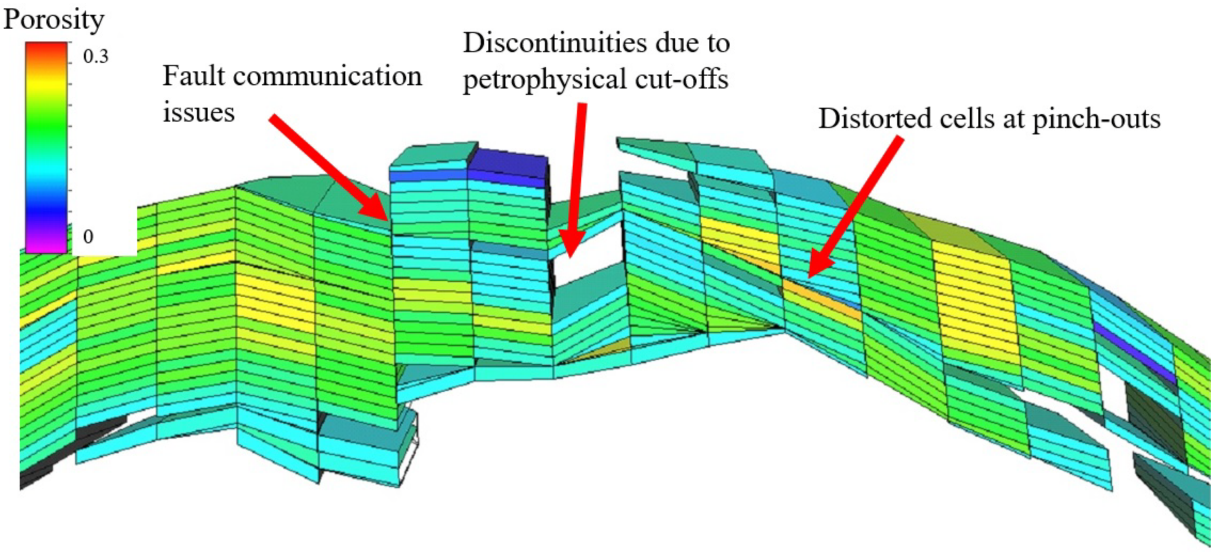

Figure 4.6: A cross section of the prior static realization (M1) created by MOL, showing porosity.

With the used stochastic parameter distribution it was not able to characterize the location and shape of the channels, and the vertically varying permeable and sealing zones, so it is unlikely that it could describe the real flow paths properly. The petrophysical cut-offs introduced discontinuity (partly or completely isolated cell-groups), with this, presumably prohibiting their effective contribution, and causing further numerical stability issues.

4.3.3 Fluid Description

The fluid properties became available for the author only in ECLIPSE input format. At initial conditions of 190 *bar* and 95 *°C,* the reservoir contains three phases: oil, brine, free and dissolved gas (95 *sm3/sm3)*. The bubble-point pressure of the oil is 191 *bar.* Black oil fluid model was defined with PVTW, PVTO and PVDG property tables containing formation volume factor, dissolved gas ratio and viscosity values for oil between 50-200 *bar*, z factor and viscosity values for gas between 50-191 *bar* (bubble point pressure) and compressibility, viscosity and viscosibility values at 190 *bar* reference pressure for water. The used phase densities are 843.06 kg/sm^3 for oil, 1006.1 kg/m^3 for water and 0.98896 kg/m^3 for gas.

The author noticed, that while the PVT property table‘s lowest pressure limit is 50 bar and the highest is 200 bar, pressures out of the range occurred during the simulation runs. Moreover, the water viscosibility value was unrealistically high, and this together with the viscosity approximation function used by ECLIPSE, led to a decreasing water viscosity value at injection pressures, which is a physically unacceptable modeling mistake.

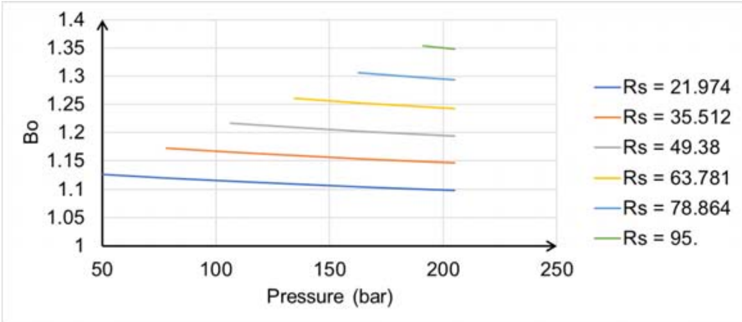

Figure 4.7: Oil FVF on different solution gas ratios, in the function of pressure

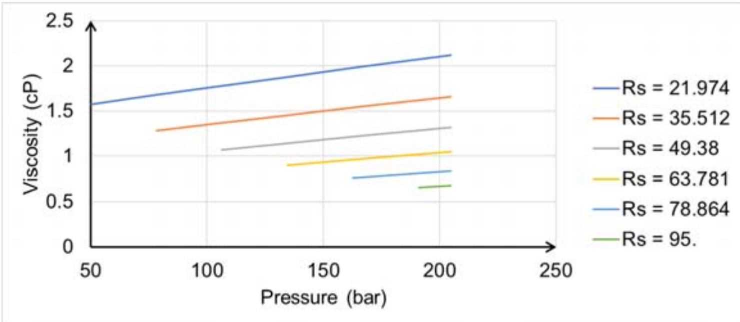

Figure 4.8: Oil viscosity on different solution gas ratio, in the function of pressure

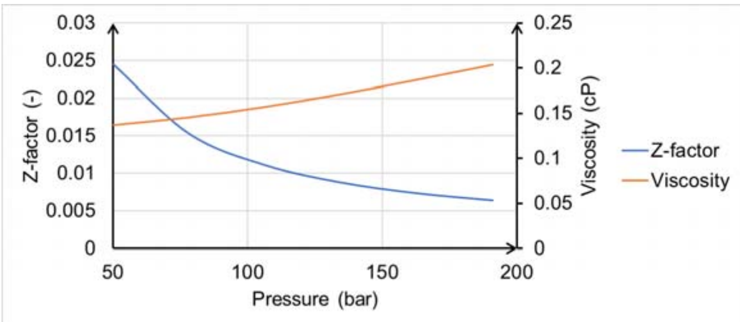

Figure 4.9: Gas Z factor and viscosity in the function of pressure

4.3.4 Rock SCAL Functions

The cells were grouped into 5 rock regions, which 2-phase saturation functions were given in a tabulated form, and STONE 3-phase oil relative permeability model was applied. Figure 4.10 visualizes the SWOF (water-oil saturation function) tables. Multi-phase flow takes place in a very narrow water saturation range only. For regions 1-2-3 the connate water saturation is low

(0.2-0.3-0.4 in this order), but the water relative permeability is flat near the end-point, this makes the water phase immobile below the water saturation of 0.6. For regions 4-5, the connate water saturation is higher (0.55-0.7 in this order), but the water relative permeability curve is steeper. The oil relative permeability end-points vary between 0.7-0.8. During the dynamic modelling carried out by MOL, therefore in this work too, the gas-oil capillary pressure was not considered.

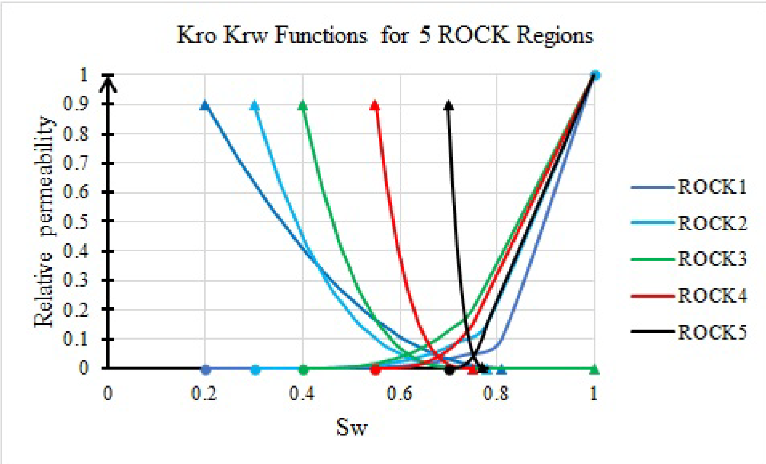

Figure 4.10: Kro and Krw functions for the 5 rock regions.

During the first runs in H5 software, unrealistic high pressures developed around water injector wells, most of those reached their BHP limits. The reason for this was found to be the low water mobility related to the SCAL functions. Especially in cells belonging to rock regions 1-3, (with low initial water saturation but flat water-relative permeability curve), the injected water remained immobile until the water saturation reached approximately 0.6. Besides the failure of the water injection, this caused severe numerical stability issues.(In the MOL's ECLIPSE model, the improper water viscosity estimation hides this effect until the water viscosibility value was corrected.)

4.3.5 The History Matching Setup

For the initialization, the MOL applied three equilibrium regions, with water-oil contacts between 1880 and 1888 m depths. The gas oil contact was consistently 1854 m. No aquifer connections were defined and no analytical aquifer was used in the received dynamic models. Average reservoir pressure and dynamic BHP data were not available. Following the conventional concept, the MOL performed history matching, during which the oil producer wells were operated with reservoir volume target rate, alternatively a BHP target of 10 bars, while the water injectors and gas producers/injectors were operated with a target phase rate. The history matching results for a few wells are illustrated in the figures below.

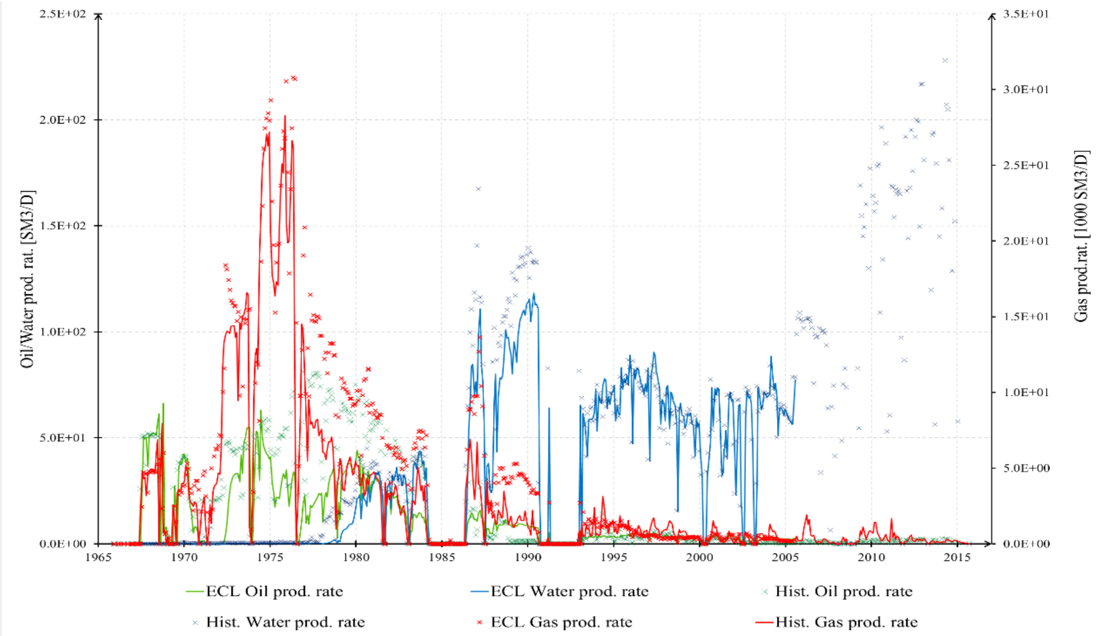

Figure 4.11: History match result of O-156 well as part of the full field model, created by MOL

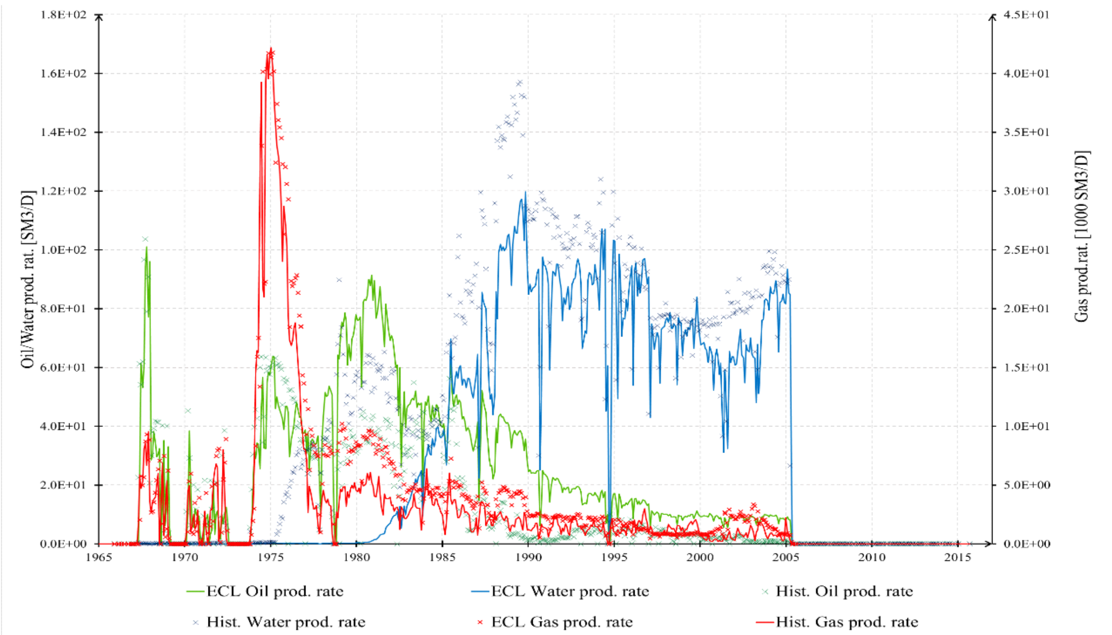

Figure 4.12: History match result of the O-157 well as part of the full field model, created by MOL

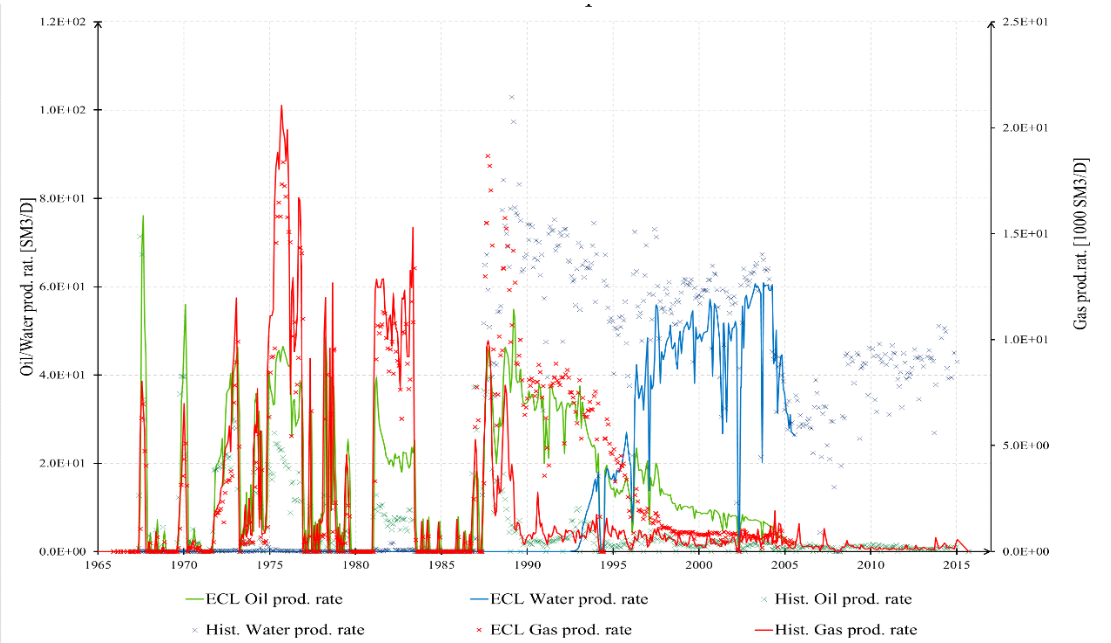

Figure 4.13: History match result of O-152 well as part of the full field model, created by MOL.

The author noted, that at the time of this work, the HM has not achieved an adequate well-by well three-phase match. Many oil producers, (e.g. O-156 between 1975 and 1985, see Figure 4.11) failed to achieve their reservoir volume rate targets due to low permeabilities or phase mobilities around the perforations, and these were switched to BHP targets of 10 bars instead. For many wells the history matching method could not reproduce the time of the water breakthrough, and the high WC values towards the end of the production history (e.g. O-157 and O-152, see Figure 4.12 and Figure 4.13). The oil production rates could not be reproduced either and were mostly overestimated towards the end of the run. Due to the improperly applied water viscosity function, the modeled water injection rates and BHP-s are not acceptable either. Since the average reservoir pressure data was not provided by the field operator, the quality of the pressure-match could not be evaluated.

4.3.6 Quality of the Obtained Data

In summary, in the obtained full field Algyő-2 model, more static and dynamic modeling mistakes were found, which would hinder the MV method's application, therefore needed correction.

- The grid is not upscaled to flow grid. The fault-communications and flow in near-well zones are not represented adequately on the distorted grid.
- Petrophysical cut-offs result in many inactive cells, due to which the model lost continuity.

- The low water mobility in the model, due to which especially water injectors cannot operate.
- The fluid properties are tabulated in a narrow pressure range (50-290 bar) and during the simulation run, the near-well pressures fall outside of this.
- The water viscosibility value is higher than the realistic by a magnitude, for which the ECLIPSE viscosity approximation function does not hold, and the water viscosity decreases with high pressure.
- No average reservoir pressure data was considered to confirm the correctness of the modelled pressure development, or to establish the need of an analytical aquifer.

The author did not get assistance from the field operator in improving the model and had to consider corrections on her own. The author had access to tools for converting the distorted grid into flow grid. Since this would be a huge amount of work, it could not be possibly performed for the full field by the author alone, only in reduced dimensions. The continuous property fields were not available, therefore only the discreet properties could be used for upscaling or refinement. It was possible and considered to modify the SCAL data at least locally, around the water injectors to promote water flow. In the lack of available data, the fluid property table could not be extended, instead stricter BHP limits (50-250 bar) were set, but the water viscosibility was corrected to a realistic value.

4.4 Upscaled and Refined Models Created by the Author

In the context of this dissertation, the author obtained additional vertically upscaled and horizontally refined sector models. All used the prior full-field model structure, the received rock data and fluid description. The averaged cell properties of the sector models created by the author are comparable with the same sector of the original full field prior static model. (See: Figure 4.14). The purpose of these models was:

- Applying corrections to the grid-related modeling issues (mentioned in Section 4.3.6), which would hinder the progress of the features' development.
- During the implementation of new features in the H5 software, performing feasibility studies on simplified models with reduced spatial dimensions or time, to account for specific cases.
- Demonstrating, that the model of Algyő-2 can be divided into sub-problems, which can be calculated one-by-one or can be released to a group of engineers as an individual task.

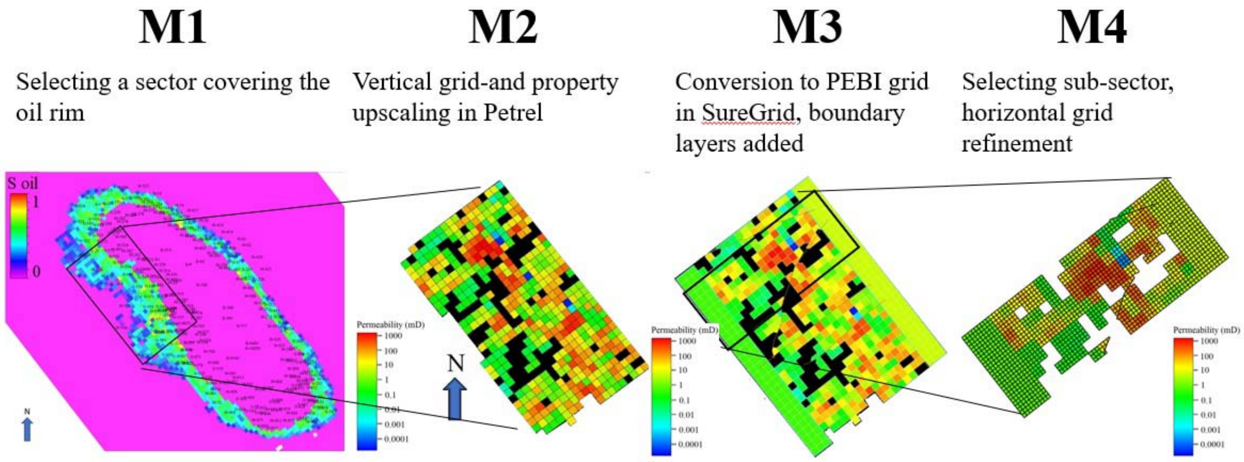

Figure 4.14: Obtaining sector models used by the author. M1: received prior static model, M2: vertically upscaled sector, M3: sector converted to flow grid, M4: horizontally refined sector with flow grid.

4.4.1 The Obtained Vertically Upscaled Sector Model

As a target area to correct for the grid-related modeling mistakes, a sector was cut out from the full field model with the following horizontal index-filters: 35-50, 25-44, (it covers the full vertical extent). It contains 30 oil producers and 12 water injectors, amongst them vertical, slanted, and horizontal. The expectation from the corrections was to improve the flow-modeling quality (the grid orientation and shape can have a considerable effect on the dynamic modeling, zig-zagging is not optimal to represent the fault communication, etc.) and to avoid numerical stability issues (caused by very low pore volume cells and blocks with multiple neighbors). Upscaling the grid from a distorted to a perpendicular-bisection (Pe-Bi) system was performed to the chosen sector. The upscaling happened in two main steps: 1st: grid-and property upscaling in ***PETREL*** and 2nd: grid conversion and property population in ***SUREGrid*** software based on the upscaled ***PETREL*** property values.

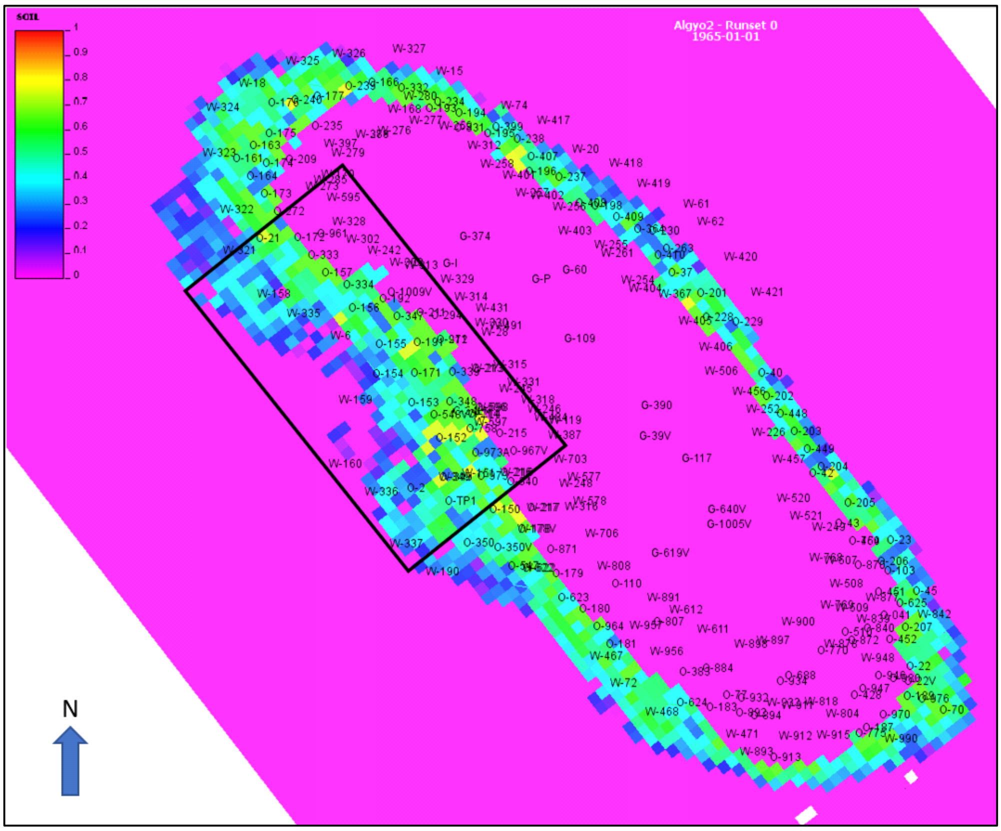

Figure 4.15: Initial oil rim of the full field model, and the location of the chosen sector.

As the first step, structural upscaling was performed in ***PETREL*** after checking the possibility of vertical integration of the horizons for the sake of continuous and evenly thick layering. Many layers pinched out, but non-neighborhood connections were allowed in ***PETREL***, so a vertical integration had no impermeable constraint. It was tried to recognize patterns in the property distribution, and performing the upscaling with regards to trends, but no trends were significant in the stochastic distribution. Figure 4.16 shows the upscaled properties, and the method of upscaling:

Inputs	Method	Outputs	Calc...
ALGYO_noUPSC.EGR...	Sample source cell centers		
NTG	Arithmetic averaging, volume weighted	NTG	Yes
PERMY	Harmonic averaging, volume weighted	PERMY	Yes
PERMX	Harmonic averaging, volume weighted	PERMY	Yes
PERMZ	Harmonic averaging, volume weighted	PERMZ	Yes
PORO	Arithmetic averaging, volume weighted	PORO	Yes
FIPNUM	Most of averaging, volume weighted	FIPNUM	Yes
PVTNUM	Most of averaging, volume weighted	PVTNUM	Yes
SATNUM	Most of averaging, volume weighted	SATNUM	Yes

Figure 4.16: Parameter upscaling method used in Petrel

Since the ***PETREL***-input is not compatible with the ***SUREGrid*** software, the author had to re-build the same model in ***SUREGrid***. The main features, such as modeled horizons, faults, property maps and well trajectories of the sector model had to be exported and converted into an applicable format. Ideally, spatially continuous features should be exported, but since the interpretation results were not available, only discreet horizon depths and cell property models could be obtained. To avoid the zig-zagging of the faults, these were manually detected. Since the direct conversion of the well trajectories was also not possible due to technical problems, the perforations' local and global coordinates were obtained. The structure of the original model was re-built in ***SUREGrid***, which was followed by the basic grid construction. The Pe-Bi grid construction automatically adjusts to the fault lines and other structural features, and usually requires only limited manual corrections. The result is a ***SUREGrid*** model of 18 continuous layers (no pinch-out), with the same horizontal grid size (150 x 150 *m*), the same tilt-angle as in the upscaled ***PETREL*** model. Afterward, the property fields are automatically distributed on the existing grid structure, using the proper averaging method. The final step is reading the well trajectories-in, considering that the upscaling merged some originally separate perforated sections. Naturally, it cannot be expected, that the upscaled model has exactly the same initialized properties as the original model, but a considerable effort was made to reduce the difference.

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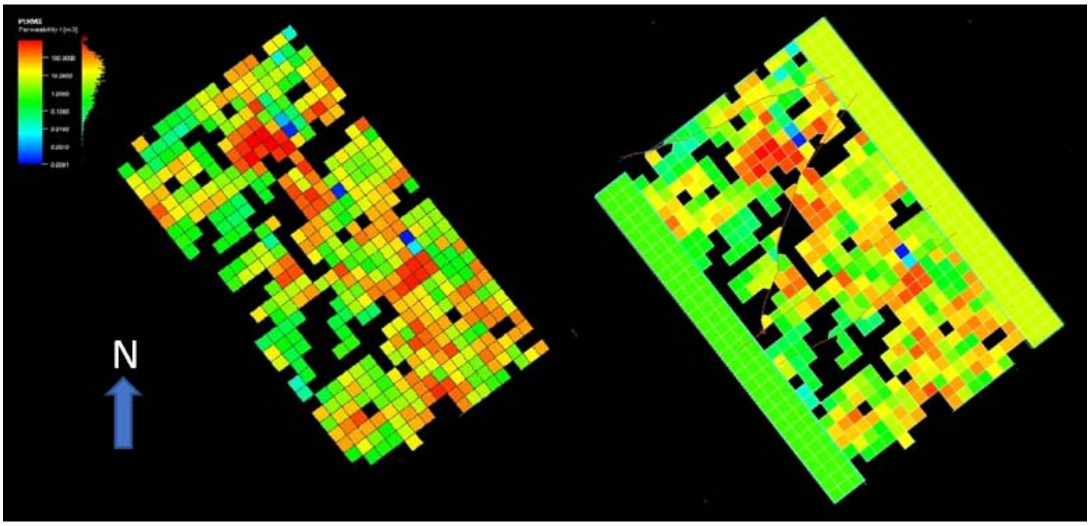

Figure 4.17: The original Petrel grid (left) and the upscaled Pe-Bi grid (right), with similar property-distributions.

4.4.2 The Obtained Vertically Upscaled and Horizontally Refined Sub-Sector

For feature-development and demonstrational purposes, it was necessary to obtain a simplified, horizontally refined sub-sector from the upscaled model, containing three oil producers (O-156, O-157, and O-334 with dense well spacing) and four water injectors (amongst which three are located in the gas cap and one in the water body. The goal of the refinement was to obtain more regular cells between perforated ones, so as to achieve a refined representation of the drainage volumes. The sector covers the entire vertical extent, stretches above the gas-oil contact and below water-oil contact. During grid refinement, the original grid cells with 150x150m horizontal grid size were divided into 3x3 grid cells with 50x50m grid size. Each cell received the same properties and region numbers as the coarse grid cell (see Figure 4.18). Since the aim was to reform the model as a realistic but simple demonstration example, the following simplifications/modifications were applied:

- The sector was considered isolated, and artificially boundary conditions were assigned on the gas-cap side to imitate its expansion. The model does not consider the flux along the longer horizontal boundaries. This is because the main flow direction can be expectably perpendicular to the phase contacts.

- SCAL data with segregated flow input was used. The oil-water relative permeability and capillary properties were considered to be uniform for all 6 rock regions, but the gas-oil relative permeability remained different. The gas oil capillary pressure was neglected.

- The production history of the producer wells was unaltered, but to avoid increasing the isolated sector's pressure, it became clear, that the injector rates had to be limited. The highest injection rate was set to 100 m3/d, as seen in Figure 4.19.

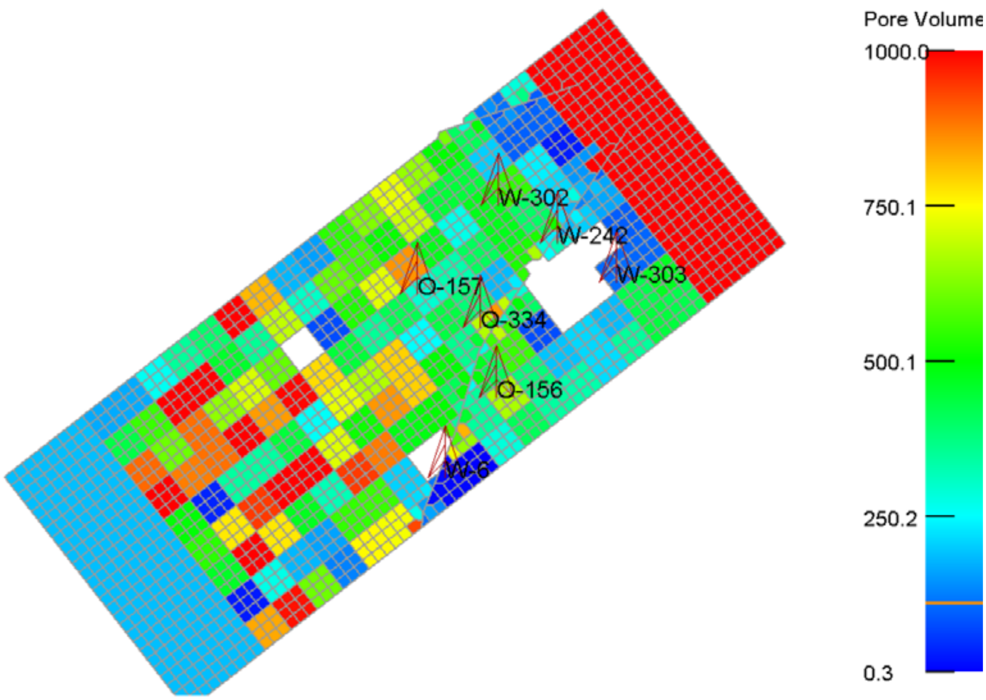

Figure 4.18: 2D illustration of the refined sector, showing cell pore volume. The pore volume of 9 rows of initially gas-containing and water containing cells was increased to maintain pressure.

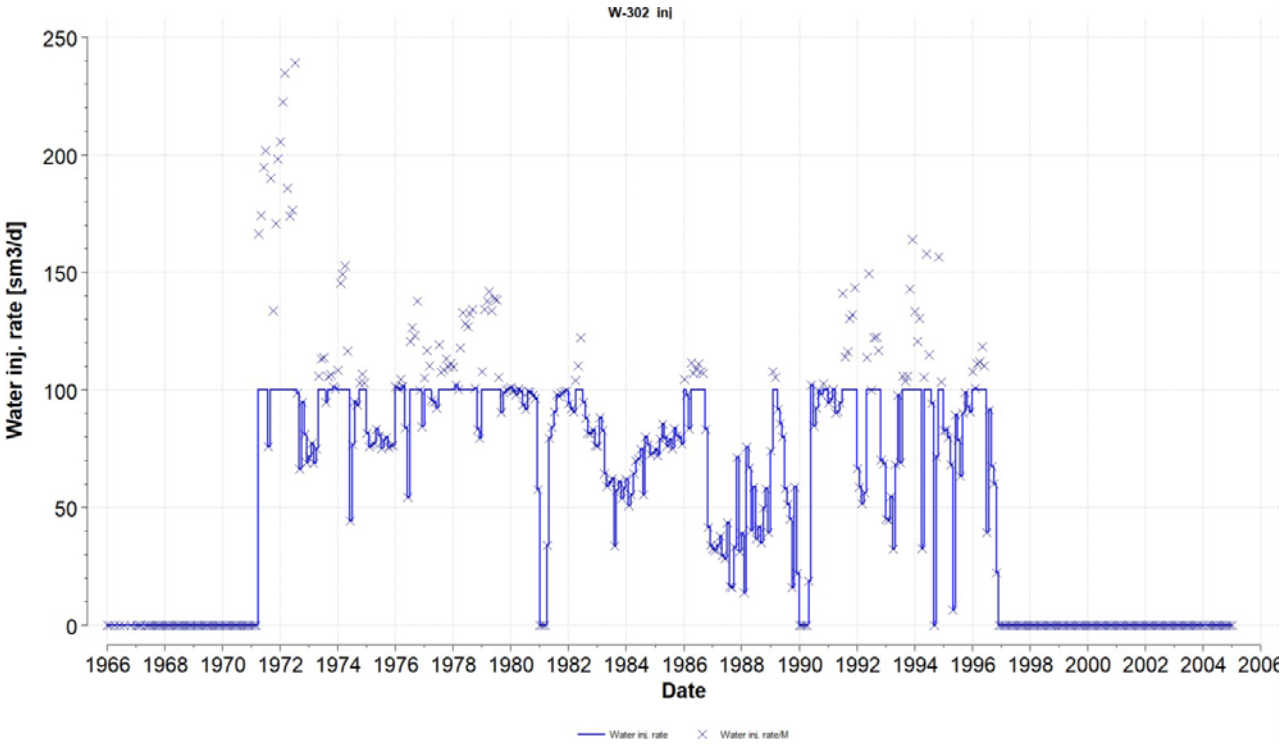

Figure 4.19: Water injection rates limited to 100 m3/d to the extent of this example.

Chapter 5

Demonstration of the Model Building Workflow on a Sector

The recommended model-building workflow based on model validation has been discussed in Chapter 3. It was emphasized, that only the 1st step: constructing a dynamic model based on validated prior is compulsory, using the Peaceman model, and one single drainage volume for compensation.

Although this is fundamentally enough, it can might be beneficial to find the smallest drainage volume, which can already provide the proper compensation. In this work, some effort was made to find a favorable distribution of the compensational phases inside the drainage volume, which provides maximum convergence to the Peaceman model, which the actual reservoir model allows. For this, defining smaller DV-s and observing their contribution to the total production rate is recommended, as will be described in this Chapter.

The author expressed in Chapter 2, that history matching is not the right way of dynamic modeling, but it can still be an acceptable aim to further increase the convergence to the wellbore by local parameter modifications, with this, to capture a temporary status. It has no benefit to doing that for a large number of wells, but for chosen ones and a limited section of the production history, it can be tried to do so. If all phase rates can be provided from the Peaceman-well only, it gives the Digital Twin of the real well. In case this is the aim, this chapter also shows a possible way to progress.

5.1 Technical Summary

On a refined small sector (introduced in Section 4.4.2) containing three oil producers and four water injector wells, the model building workflow was completed as model validation and many refinement stages. At the beginning of each run, the author assigned both the shape of the time-dependent drainage volumes and their operation methodology. Usually, it is a trial and error process to find the most suitable combination of the features. Lots of effort was made to give a general guideline, how all these could be carried out. This is not the aim to give a user manual here, but interesting technical details, as to the definition of well model, or its operation and diagnostics possibilities are discussed in Appendix A.

5.2 A Possible Application of the Drainage Volume Concept during Model Validation

The only compulsory step of the model validation concept is to ensure the integrity of the constructed model. Only the extension of the outermost (D3) drainage volumes plays an important role. Thus, the contribution of smaller drainage volumes, or the methodology to distribute the phases inside the drainage volume is not necessarily analyzed.

On the demonstration example, validation was performed between 1966/01/01 and 2005/01/01, with all wells operated in drained mode, without the Peaceman concept. With the dense well spacing, overlapping of the drainage volumes had to be avoided, and it was done as described in Appendix A/1. The so constructed shapes behaved as one single drainage volume, D3. (See Figure 5.2) Environmental connections (D4) were allowed to compensate for the gas phase, which were missing from the drainage volumes, and to indicate their nearest location to the well.

The distribution of the phases in the drainage volume was not localized around the wellbore. This is to promote numerical stability instead of convergence, (see Appendix A/2), but for a short period with higher GOR, convergence was necessary to induce a stronger gas inflow. Since it was possible to find a suitable operation methodology to achieve a 100% match of the cumulative production rates, the model can be considered validated.

The following diagnostics data were gathered: The field cumulative productions, and the inflow area's production rates were plotted with the historical data during the entire operation. The movable oil content of the D3 was obtained (see Appendix B) The 3 dimensional representation of the remaining oil in place at the end of the run was observed. Based on the diagnostics data, the model's performance was evaluated.

Date	Name	Active	Type	Peaceman well	DV Phase Distribution	RING Extension	CUBE Extension	Environmental Cells
01/01/1966	O-156	no	oil prod	not defined	numerically stab	4	-	no
01/07/1967		no	oil prod	not defined	numerically stab	-	1-18-5-5-5-5	no
01/08/1967		yes	oil prod	not defined	converging to well	-	1-18-5-5-5-5	yes
01/01/1975		yes	oil prod	not defined	numerically stab	-	1-18-5-5-5-5	yes
01/01/1966	O-157	no	oil prod	not defined	numerically stab	3	-	no
01/05/1967		no	oil prod	not defined	numerically stab	-	1-18-9-3-6-3	no
01/06/1967		yes	oil prod	not defined	converging to well	-	1-18-9-3-6-3	yes
01/01/1966	O-334	no	oil prod	not defined	numerically stab	4	-	no
01/05/1970		no	oil prod	not defined	numerically stab	-	1-18-4-4-4-4	no
01/06/1970		yes	oil prod	not defined	converging to well	-	1-18-4-4-4-4	yes
01/01/1975		yes	oil prod	not defined	numerically stab	-	1-18-4-4-4-4	yes

Figure 5.1: Time-dependent drainage volume assignment and operation methodology of the producing wells, applied for model validation. For detailed explanation, see Appendix A.

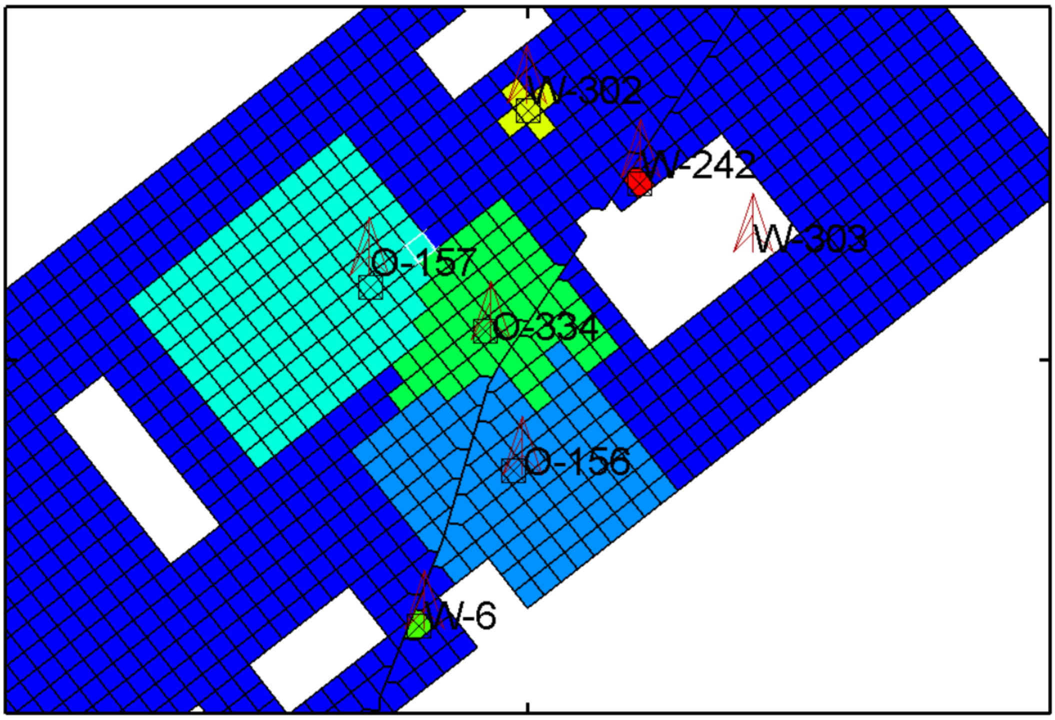

Figure 5.2: Shape of the assigned D3 drainage volumes belonging to each well during model validation.

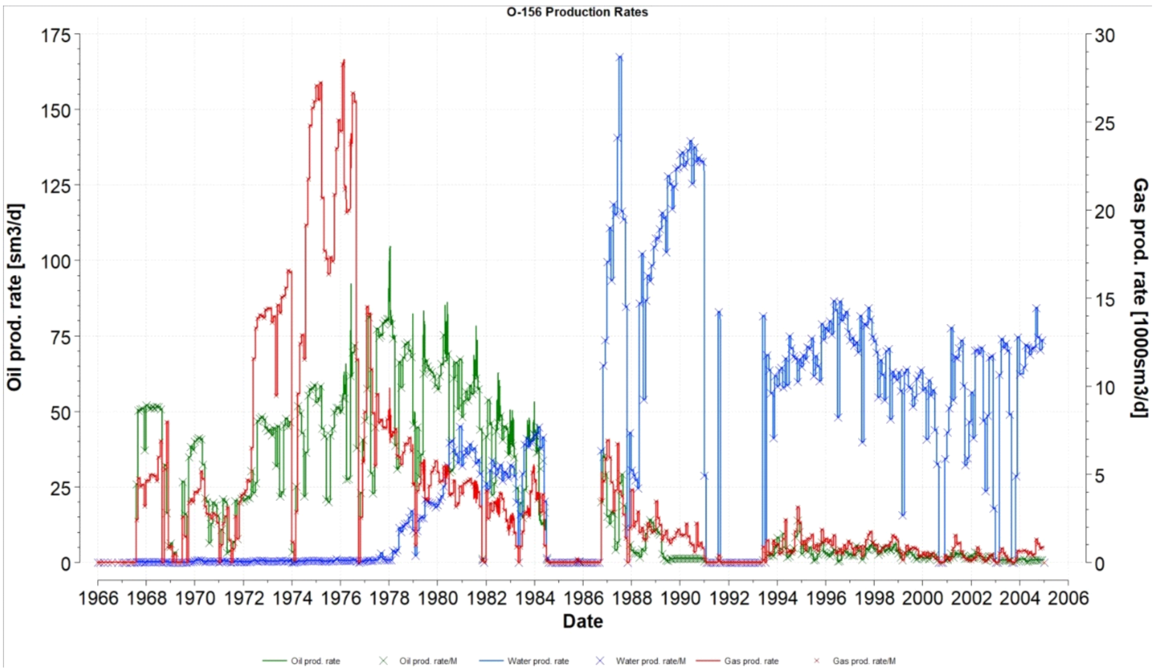

Figure 5.3: Achieved production match from the well O-156 from its D3 drainage volume during model validation.

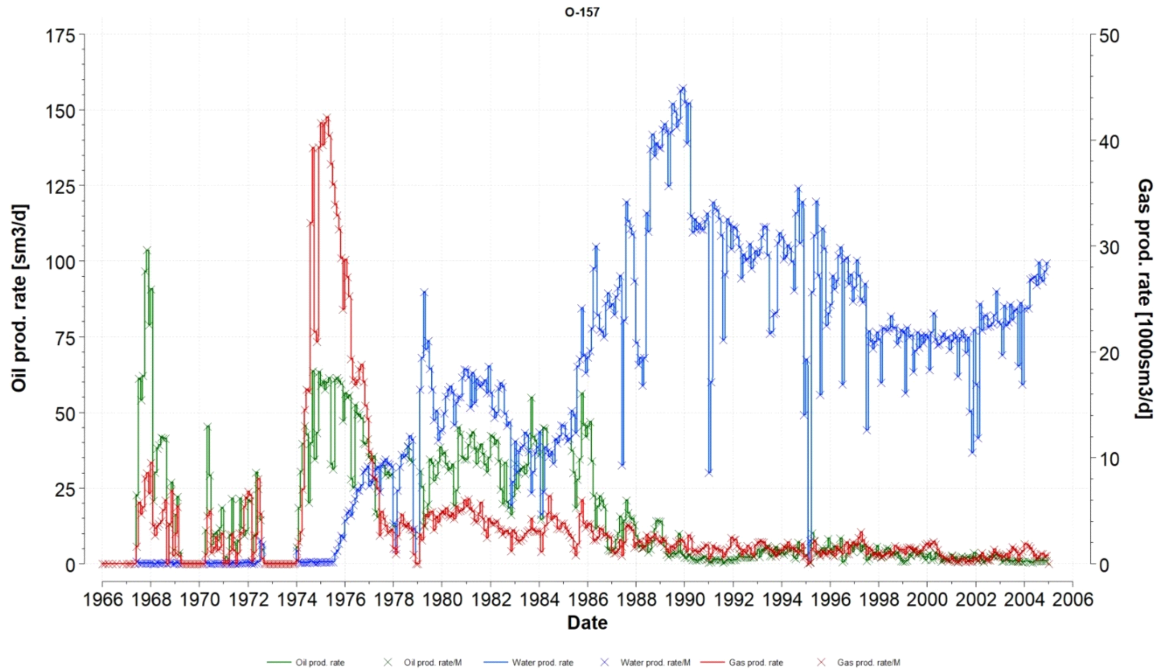

Figure 5.4: Achieved production match from the well O-157 from its D3 shaped drainage volume during model validation.

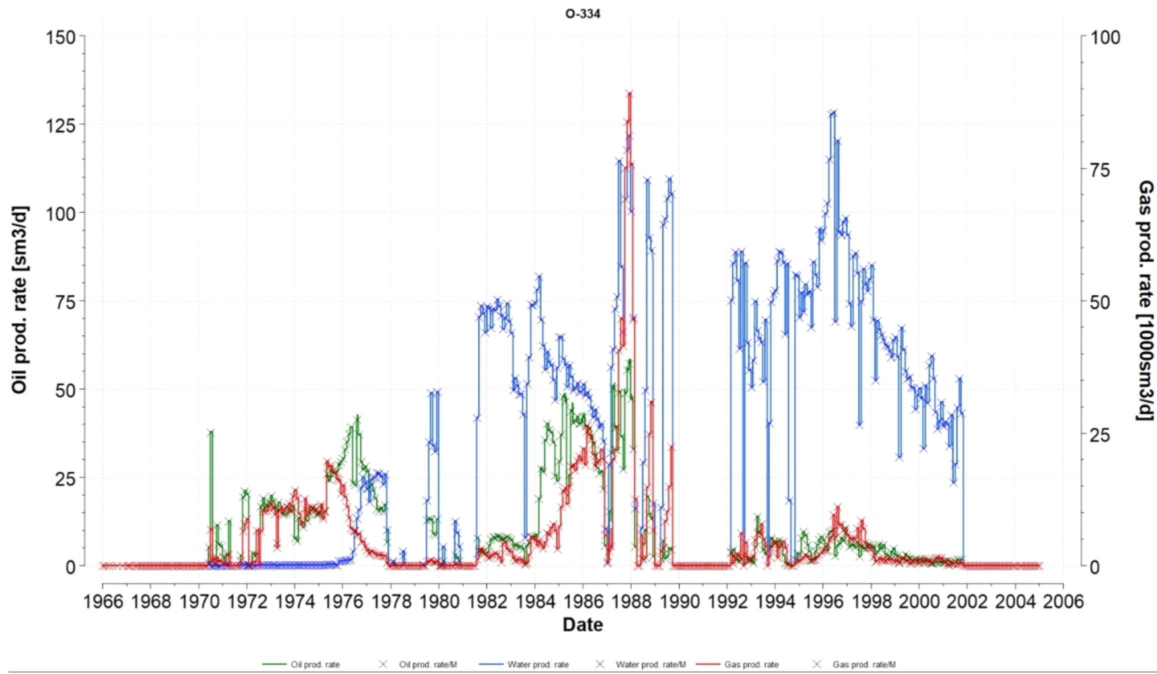

Figure 5.5: Achieved production match from the well O-334 from its D3 shaped drainage volume during model validation.

5.3 A Possible Application of the Drainage Volume Concept to Promote Convergence

After the structural setup's integrity is already stabilized. optionally the description of the communication of the near well and between the real perforations can be targeted. Therefore, in addition to the earlier assigned D3 volume, the user must define at least D2. Above this, possibly further convergence-promoting features can be applied.

It was tried to achieve the maximum possible convergence to the wellbore which the model allows without modification. As required, during limited time intervals, the previously assigned inflow areas were subdivided into smaller drainage volumes (now D2 and D3 were both present). No environmental connections (D4) were allowed this time. The well attempted to achieve its targets from the smaller drainage volumes first. The distribution of the phases within the drainage volume was more localized around the wellbore, to promote convergence.

The following diagnostics data were gathered: The D3 volumes' production rates were plotted with the historical data during the entire operation. The movable oil content of the individual drainage volumes (D2 and D3) were obtained and compared with the 1st Run, to ensure that the distribution of the phases within the drainage volume does not significantly influence the well model's communication with its surrounding. (Figure 5.6). The three-dimensional representation of the remaining oil in place at the end of the run was also obtained. Based on the diagnostics data, the model's performance was evaluated.

Date	Name	Active	Type	Peaceman well	DV Phase Distribution	RING Extension	CUBE Extension	Environmental Cells
01/01/1966	O-156	no	oil prod	not defined	numerically stab	4	-	no
01/07/1967		no	oil prod	not defined	numerically stab	4	1-18-5-5-5-5	no
01/08/1967		yes	oil prod	not defined	converging to well	4	1-18-5-5-5-5	yes
01/01/1975		yes	oil prod	not defined	numerically stab	4	1-18-5-5-5-5	yes
01/01/1966	O-157	no	oil prod	not defined	numerically stab	3	-	no
01/05/1967		no	oil prod	not defined	numerically stab	3	1-18-9-3-6-3	no
01/06/1967		yes	oil prod	not defined	converging to well	3	1-18-9-3-6-3	yes
01/01/1966	O-334	no	oil prod	not defined	numerically stab	4	-	no
01/05/1970		no	oil prod	not defined	numerically stab	4	1-18-4-4-4-4	no
01/06/1970		yes	oil prod	not defined	converging to well	4	1-18-4-4-4-4	yes
01/01/1975		yes	oil prod	not defined	numerically stab	4	1-18-4-4-4-4	yes

Figure 5.6: Time-dependent drainage volume assignment and operation methodology of the producing wells, applied for convergence and near well tuning.

Based on the cumulative plots of the individual wells it was confirmed that the matching from them remained 100% successful. It was observed, that for wells O-157 and O-334, the assigned D2 contained the necessary amount of phases. This means, that on a near-well scale, the model was also able to describe the communication between the D3 and D2 volumes, reflecting a good local model quality. Although, for the well O-156, the oil phase was missing from the D2 volume between 1980 and 1984 (See: Figure 5.7). Here therefore the original model could not describe the communication between the D3 and D2 volumes.

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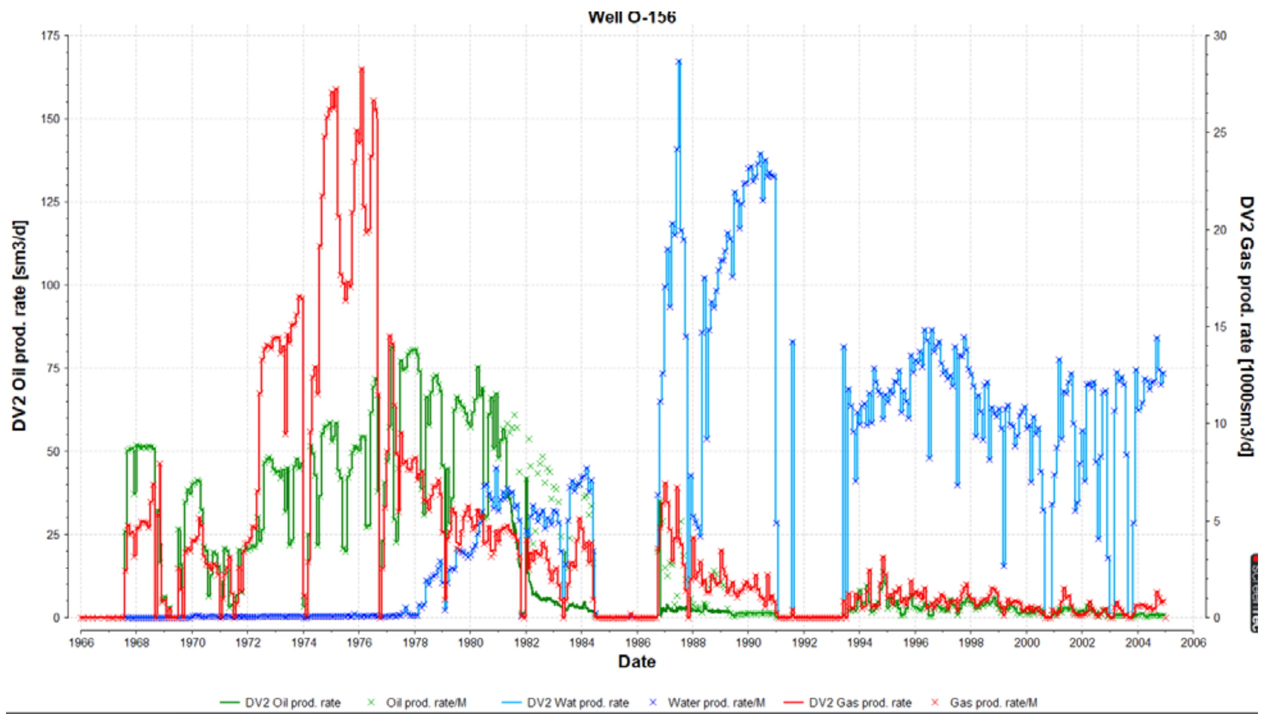

Figure 5.7: Oil Production mismatch of the well O-156 from its D2 volume between 1980 and 1984.

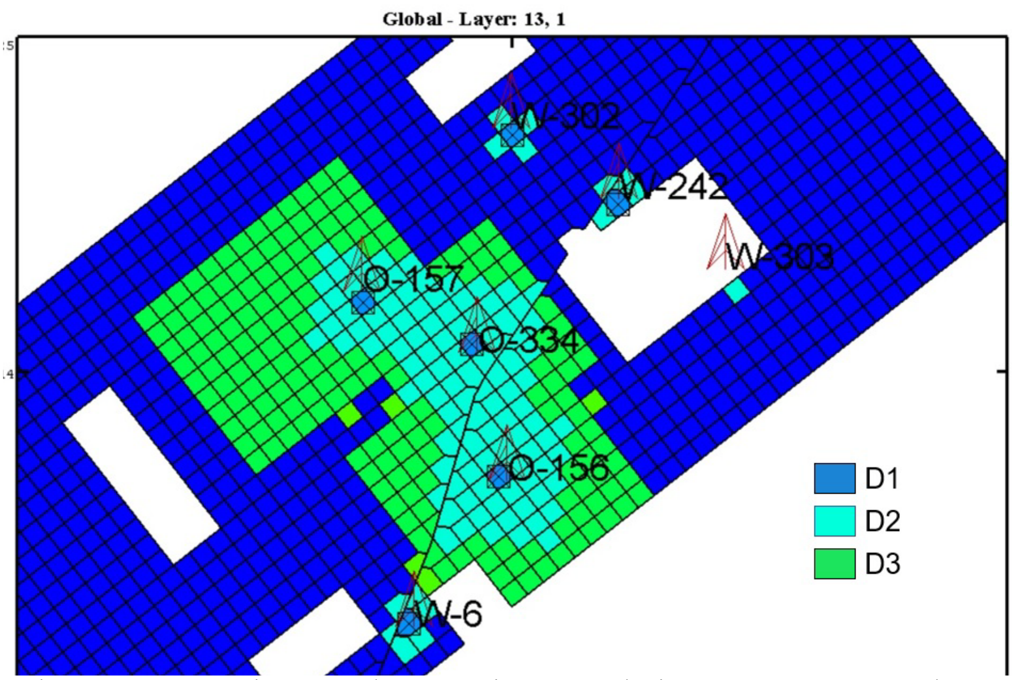

Figure 5.8: Drainage volume assignment during convergence and near-well tuning.

5.4 A Possible Application of the Drainage Volume Concept with Near Well Tuning

Near well tuning is an optional step in case the aim is to increase the convergence to the wellbore beyond the level, which the actual reservoir model can provide. During near well tuning, the user is allowed to modify cell parameters. Modifications of this kind must focus on the convergence of the production to the real perforations (D1), resulting in a well model, which represents the real well's behavior correctly. It must be every time checked, that it assuredly does not affect other wells' and the field's global performance: which means that the well totals must always be correct. To perform near-well tuning has no benefit for all wells. (That when it can be considered, is described in Section 3.2.2)

The author applied manual localized property modification inside of the drainage volume of O-156 to achieve, that it matches from its D2. To perform this, the 3D plots of the movable oil content near the well were observed between 1980 and 1984. Mainly in layer no.10, the D3 volume of the well contained a significant of movable oil in this period, which could not flow into D2. (Figure 5.9) The author increased the oil phase mobility of individual cells of the D2 volume (indicated in Figure 5.9) in the direction of the higher oil saturation, to induce stronger oil flux in this area, and repeated the run with the same setup.

During this run too, the global cumulative productions of all wells were matching the measured values from their D3, which means, that the parameter modification did not destroy the global integrity of the model. The parameter modification improved the match from the D2 of O-156, but had a negative effect on the D2 water production rate of O-157 (Figure 5.11). Following a similar approach, manipulation took place in layer no 12 and 13 in the D2 of the O-157 too, to correct for the water phase, and this time achieved the desired result.

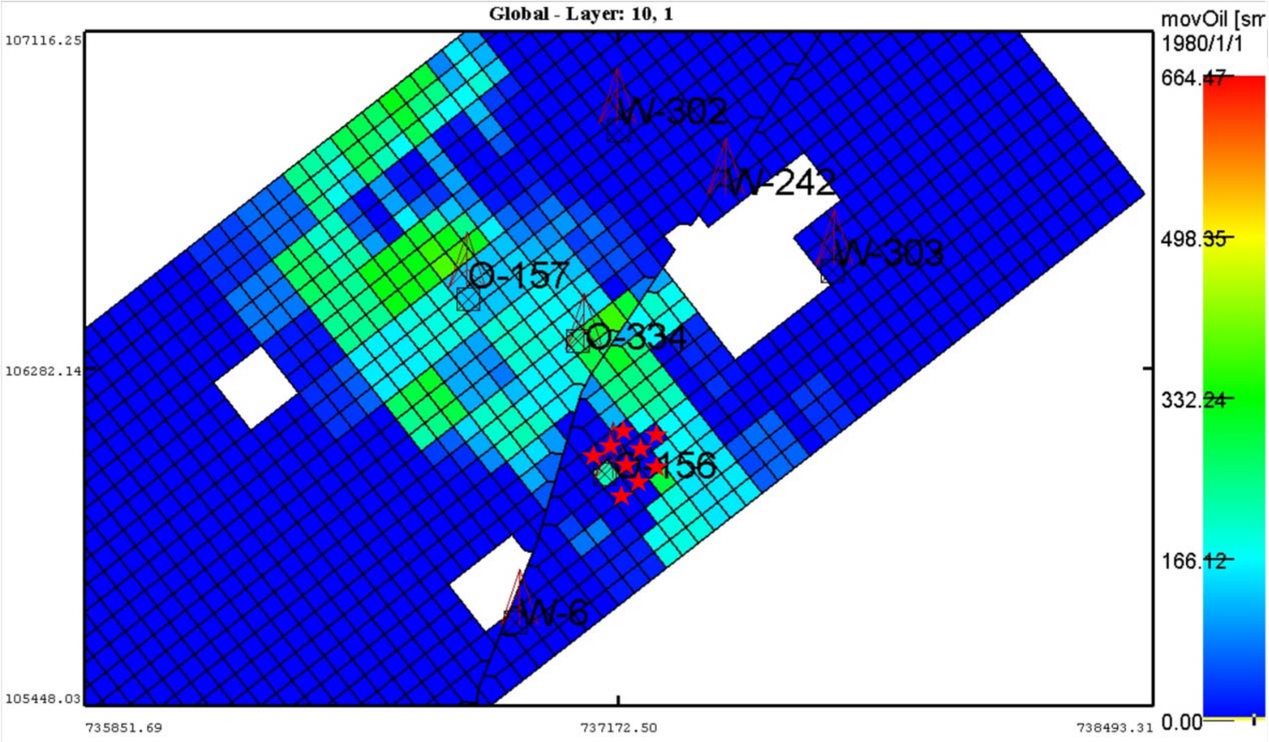

Figure 5.9: Movable oil content of the model at 1980/01/01, when the well O-156 fails to match oil phase from its D2.

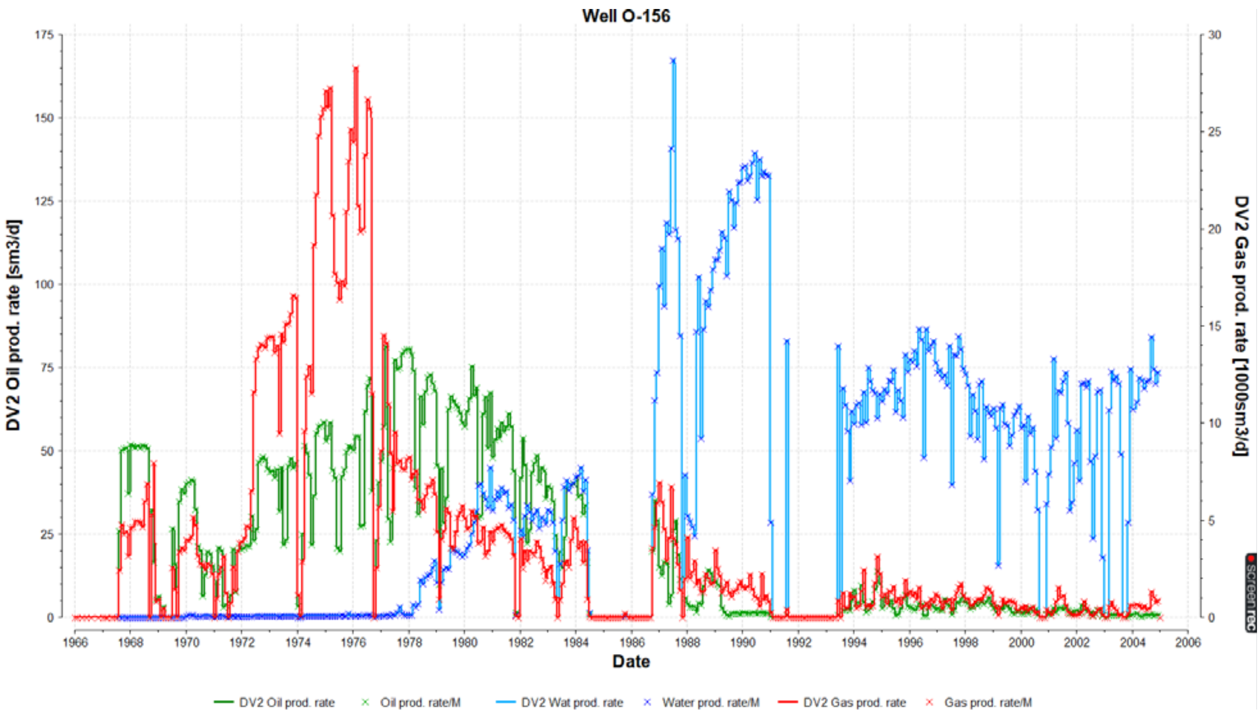

Figure 5.10: Improved oil production of the well O-156 from its D2 RING after parameter modification in the D2 of O-156.

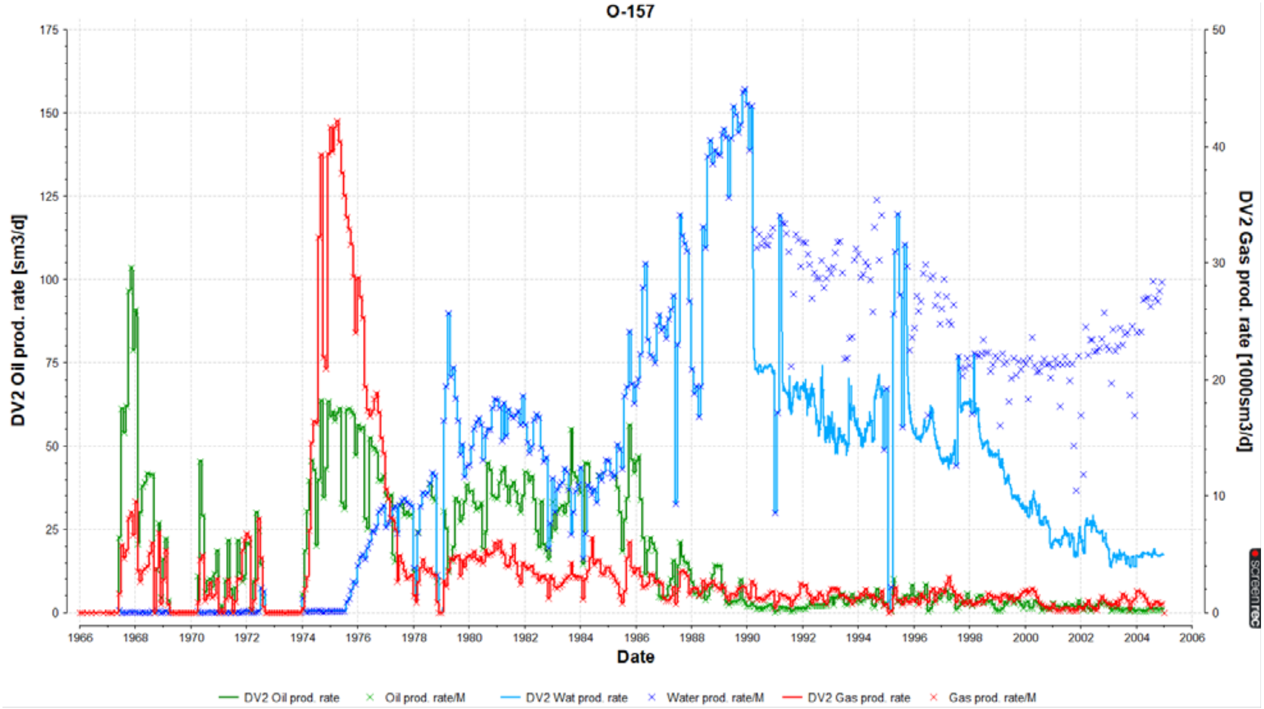

Figure 5.11: Water production mismatch of the well O-157 from its D2 after parameter modification in the D2 of O-156.

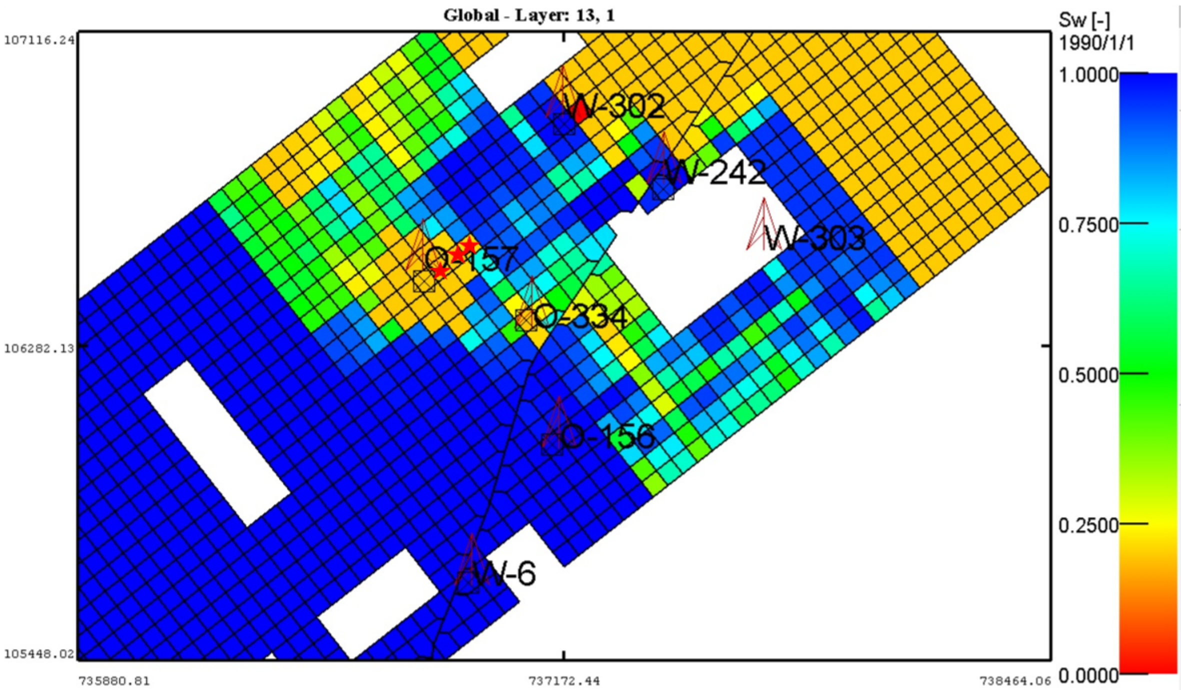

Figure 5.12: Water saturation of the model at 1990/01/01, when the well O-157 fails to match water phase from its D2.

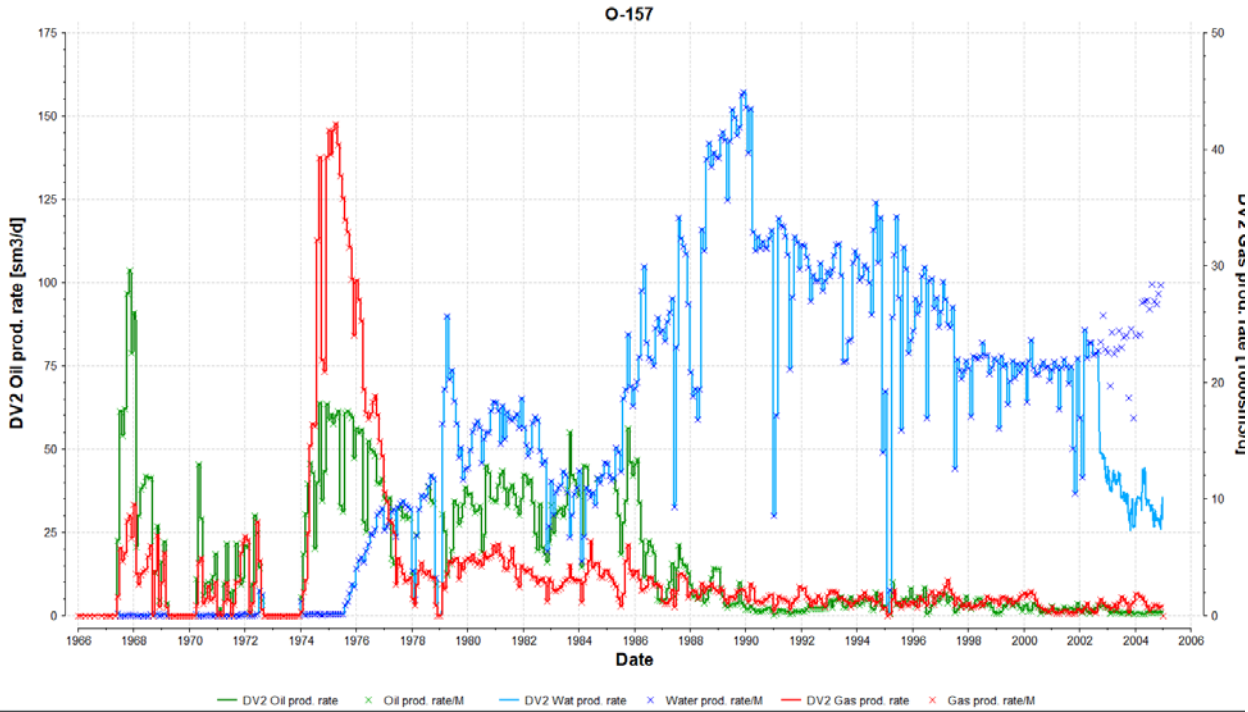

Figure 5.13: Production match of the well O-157 from its D2 after parameter modification in the D2 of O-157.

After the size of the producing near well volumes adequately shrank, the modeler can optionally describe the real dynamic conditions in the perforations too. In this phase, it is naturally necessary to operate the wells in a combination of the Peaceman model and the drainage volumes. In all cases, the possibility of compensation from the near well must be maintained. (In this refinement stage too, the D3 volume should be defined, even if it is might not necessary to access.) If the reservoir model is a very improved one, it can be possible to achieve the target rates from the D1 by only modifications of the perforation productivity indices (See Section 3.4.1.1). It is then called the Digital Twin of the well.

In the demonstration example, for further model refinement, the O-157 was chosen. The O-157's Peaceman well was operated with a liquid rate target and with 60 bar lower BHP constraint, with keeping the original D2 and D3 assignments for compensation purposes. The other wells were operated as in the previous step. The O-157 could achieve an accurate match of the WC for a 5-year long production period of the demonstration example, as illustrated in Figure 17. It cannot be normally expected, that a well fulfills both its WC and GOR targets over a longer period.

As was described above, the author applied manual parameter modifications in a subjective manner and automatized parameter modifications of the perforation properties. Naturally, other automatized matching techniques are encouraged too, although this dissertation does not deal with this.

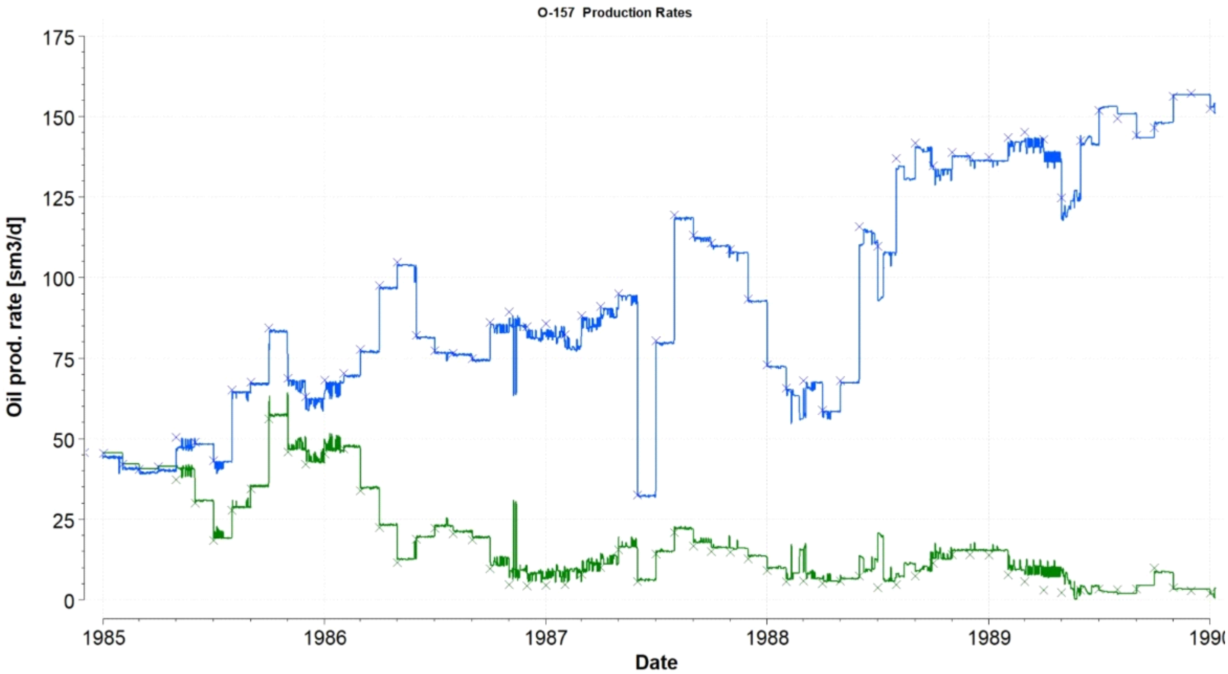

Figure 5.14: As a result of HM in the near well region, oil and water production rates are successfully matched from the wellbore of O-157 for a short production period.

Chapter 6

Model Validation Applied to Algyő-2

In this chapter, achievements of the proposed method on the full field model are demonstrated for a 20 year long production period. Model validation for the entire production history is presented on a sector. The results are compared with the history match provided by the field operator. The aim of this chapter is to demonstrate, that the proposed method can be applied with confidence to full field models, or that it can be sub-divided into sectors that are individually validated and refined.

6.1 Model Conversion to H5 Format

The ***ECLIPSE*** data deck had to be converted to ***H5*** format, as far as feasible, keeping those identical. The similar input data structure, the mostly uniform keywords enable a swift conversion between ***ECLIPSE*** and ***H5*** with small effort. Since the implementation and numerical handling of the underlying mathematical descriptions can be different in two software products, the created dynamic models of the same input can be different. It was necessary to make sure that the ***H5*** dynamic model is similar- leads to the same conclusion as -to the ***ECLIPSE*** model, therefore, during the conversion process, the ***H5*** runs were permanently cross-checked against the ***ECLIPSE*** dynamic model with an identical setup.

To achieve consistency of the two models includes:

- Obtaining input data files by converting/restructuring existing files: routine procedure, guided by a conversion manual, automatized by coded converters (e. g. SCHEDULE converter).
- Searching for not supported keywords: during the initialization, a list of not-supported keyword is written out. Implementations are rarely needed.
- Checking the consistency of defaults.
- Analyzing the success of the conversion: comparison of initialization-and dynamic results with an identical setup. The two results must be comparable.

During the conversion, the original ***ECLIPSE*** case is allowed to vary slightly. Note, that the aim is to achieving equivalence of the input data, not to operate the model identically. The comparison usually happens with a variant of the original case.

6.2 Correction of the Input Data

With the aim to correct for some of the geological modeling-and input issues (see Section 4.3) the full field model validation input was slightly altered compared to the original ECLIPSE case.

- The improper grid selection caused some concerns from dynamic modeling aspect, considering numerical stability and true representation of the underground fluid movements. To correct for this on a field scale was naturally beyond the scope of the dissertation.

- The pressure ranges of the PVT tables (50 and 290 *bar*) were narrow compared to the allowed well BHP lower limit of (10 *bar*), the calculated fluid propertied were therefore occasionally invalid, the H5 run crashed. To avoid this, the BHP limits were corrected to 60 and 250 *bars*.

- Water viscosibility value was a magnitude larger than usual, for which the ECLIPSE viscosity approximation function does not hold. Water viscosibility was corrected to a realistic value.

- Due to the very narrow water mobility range, the water injectors were unable to inject at reasonable BHP-s. To overcome this, the SCAL input data was modified and the mobility of the water around the water injectors was further increased.

- For certain oil producers and for shorter time periods, unrealistic GOR-s or WC-s were detected, but not corrected in this work.

6.3 Full Field Model Validation

The first attempt to apply the model validation features on a full field model of Algyő-2 took place without converting the structure to flow-grid or correcting for the mentioned modeling issues. It was promising to try, what the model validation can achieve on the actual model status, with this to establish a global understanding of the model quality, to help to find a suitable sector for model refinement, etc., and naturally without the expectation to achieve a 100% match of all phase productions over the entire production history.

To apply individually the most suitable time-dependent drainage volumes to all wells is beyond the scope for a large-scale model. Due to the dense well placement and the complex structure, it would have been nearly impossible to define, which well should drain from which oil-bearing zones. The initial setup globally applied a Peaceman-well model in combination with consistent drainage volumes of small extent and arbitrary shape. (Figure 6.1) Since these could not provide the necessary amounts of phases (mostly the gas phase was found missing from the drainage volumes), D4 environmental cells were searched for chosen wells. The scanning for oil-water and gas-containing cells took place at the beginning of the run, in every direction from their perforations. The nearest cells with adequate movable phases were assigned to the wells. Oil and water-containing cells could be easily found in the vicinity of the wells, but for the gas phase, it was necessary to reach farther. No additional convergence promoting features were applied at this stage because it imposed the risk of numerical stability issues. The environmental connections made it possible to operate the full field model for a 20 years long observed period with a perfect cumulative production match on field level for the oil and water phase. (See Figure 6.3) Examples of production rate match of a few wells are illustrated in Figure 6.4 and Figure 6.5.

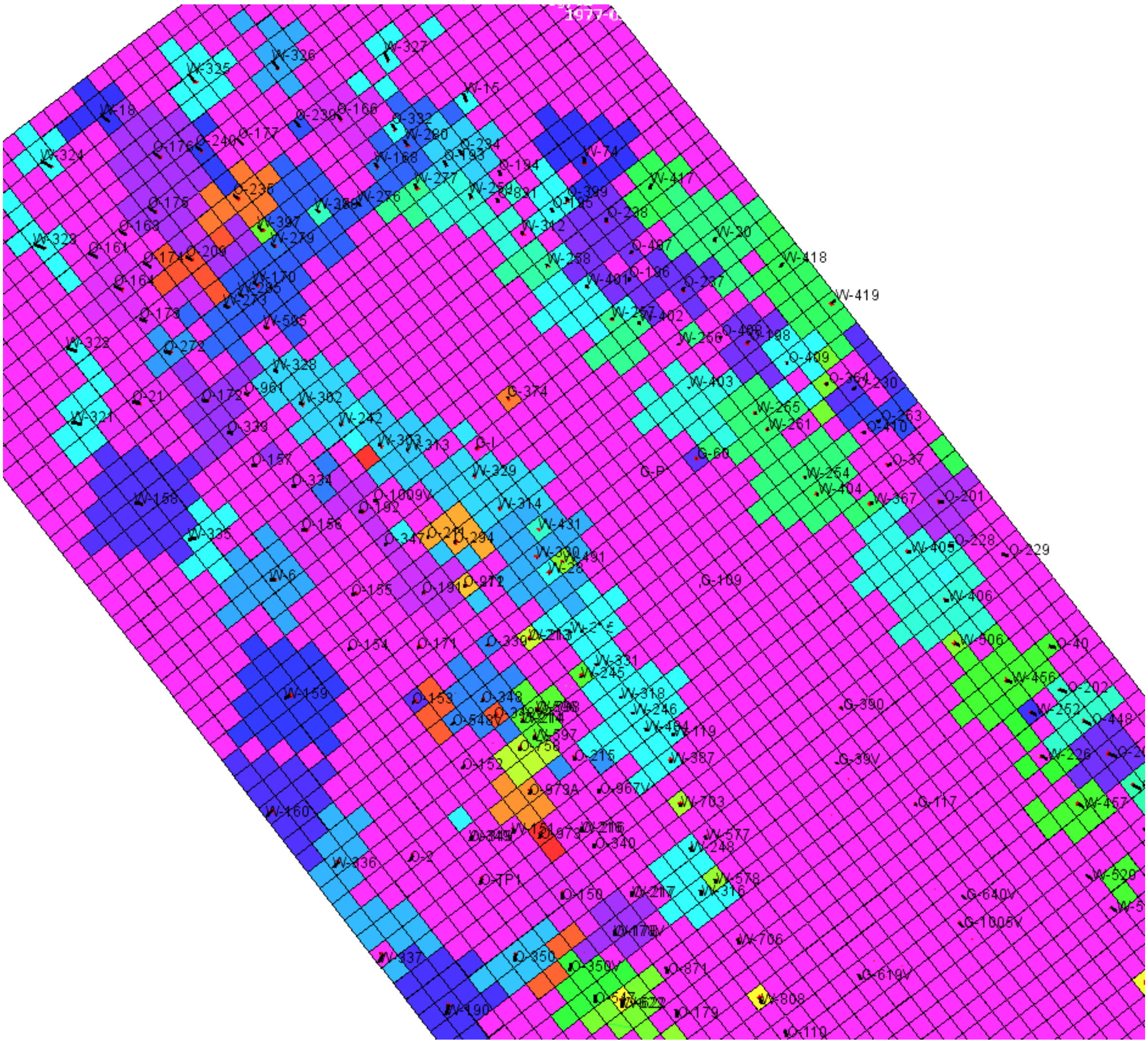

Figure 6.1: DV assignment on the full field model of Algyő-2.

During the test runs, it became obvious, that for the progress of this work, conversion to flow-grid, vertical model upscaling and horizontal model refinement would be needed. Since this could not be performed by the author alone on a field scale, an applicable sector was chosen.

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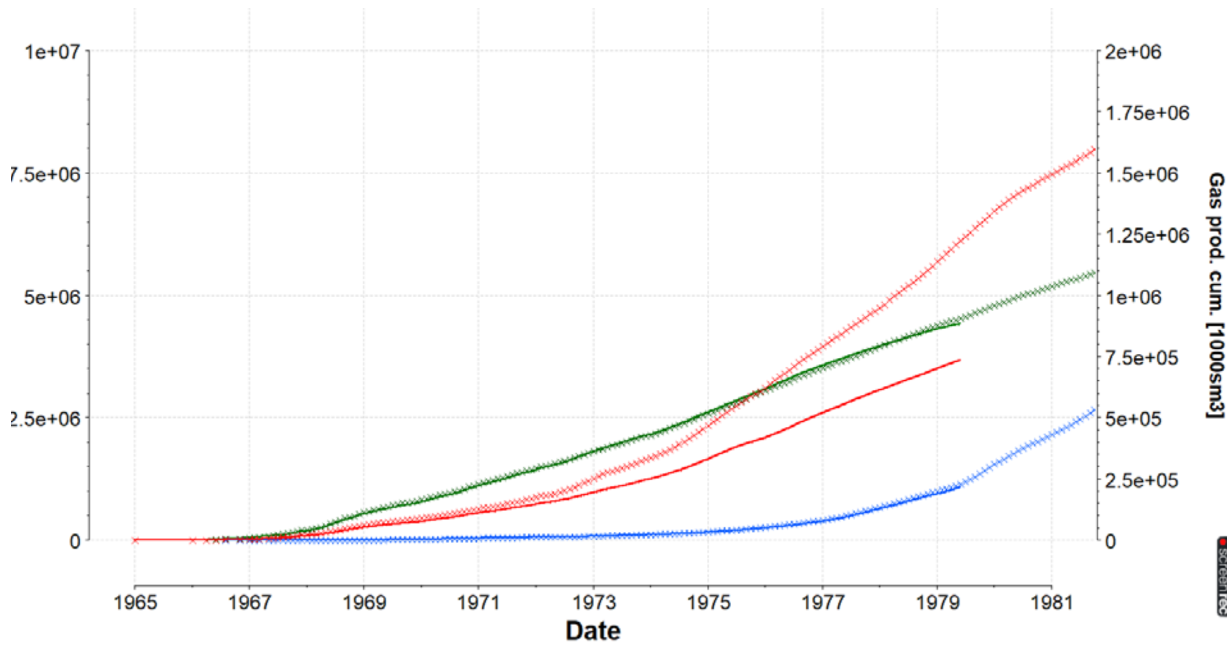

Figure 6.2: Cumulative production match for 20 years on the full field model of Algyő-2.

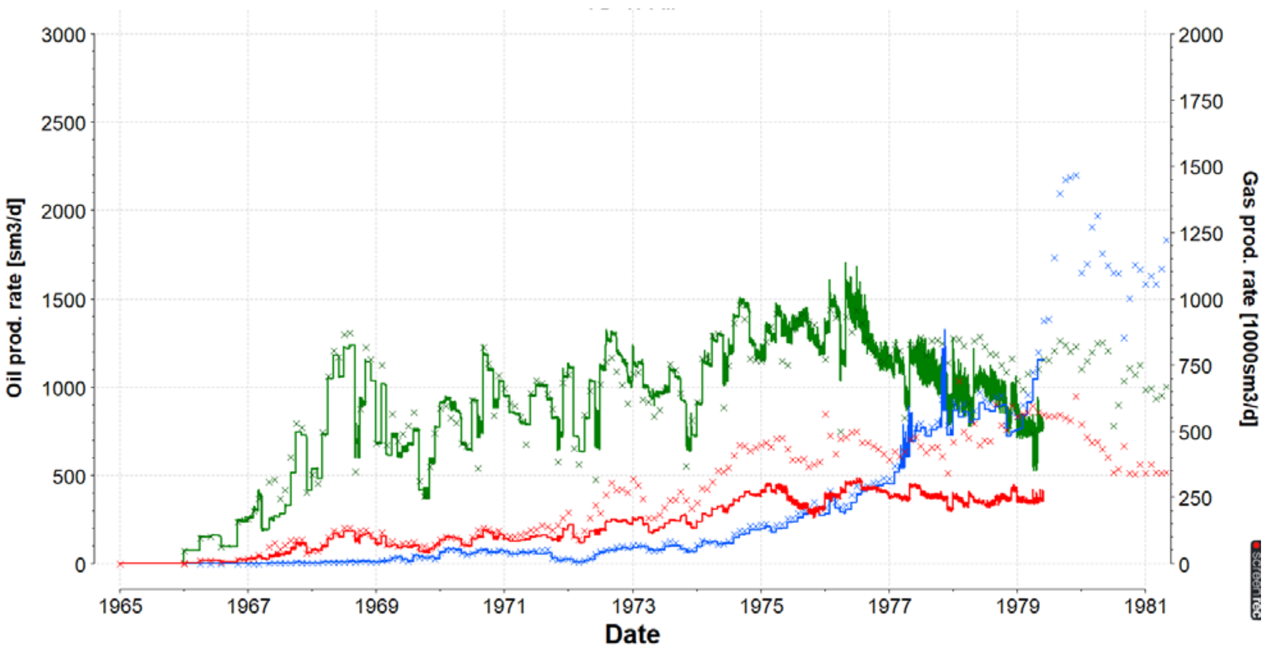

Figure 6.3: Production rate match for 20 years on the full field model of Algyő-2.

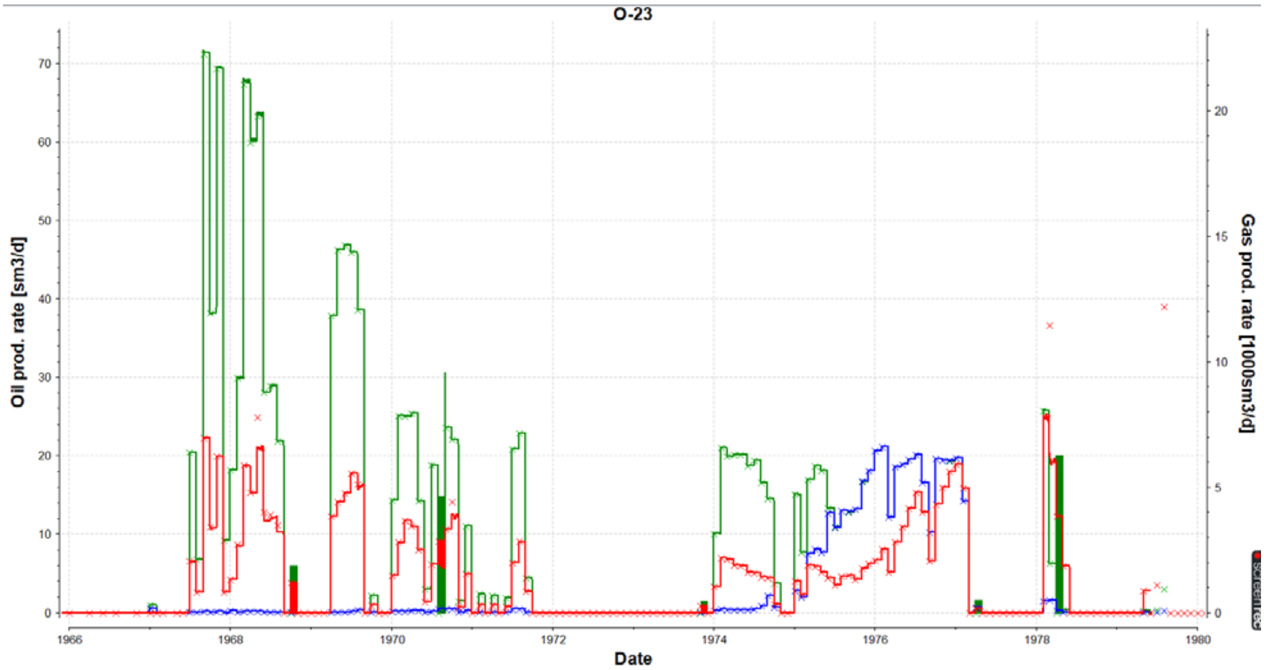

Figure 6.4: Early validation results of the well O-23 in the full field model.

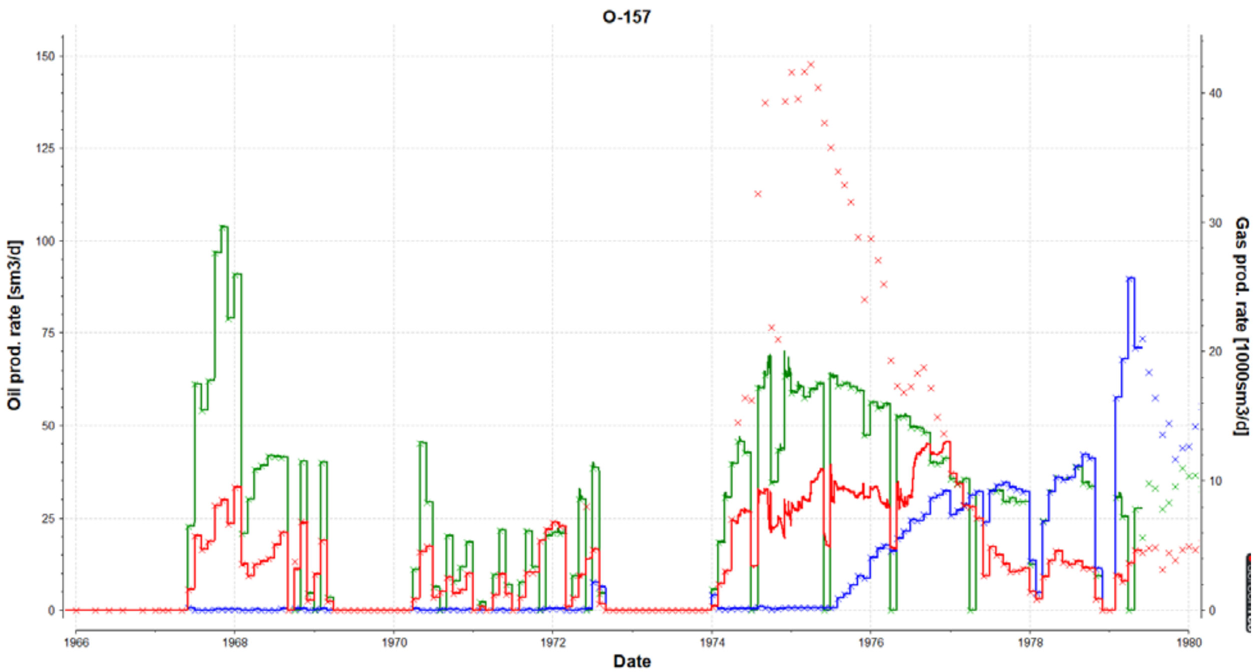

Figure 6.5: Early validation results of the well O-157 in the full field model.

6.4 Sector Model Validation

6.4.1 Establishing boundary conditions

To reduce the dimensions of the full field model, a sector was cut (as described in Section 4.4.1.) and converted to flow-grid. A sector can only be simulated concerning its integrity with the surrounding reservoir regions. For this, it is essential to give a good estimate of the phase fluxes along the sector boundaries and average region pressures over time. The author did not receive average reservoir pressure data from the field operator, only recent static bottom-hole pressure measurement from a limited number of wells in the region. Based on this data the author could only assume, that the sector can be considered as a single pressure region. By analyzing the short-term full-field model validation result, it became obvious, that its communication with the gas-cap and the aquifer side (long-sides of the rectangle, see Figure 6.6) cannot be neglected. On the contrary, no significant water or gas influx was observed across the short sector sides, except the effect of some water injector wells, which are located mostly far enough from all other considered wells in the sector.

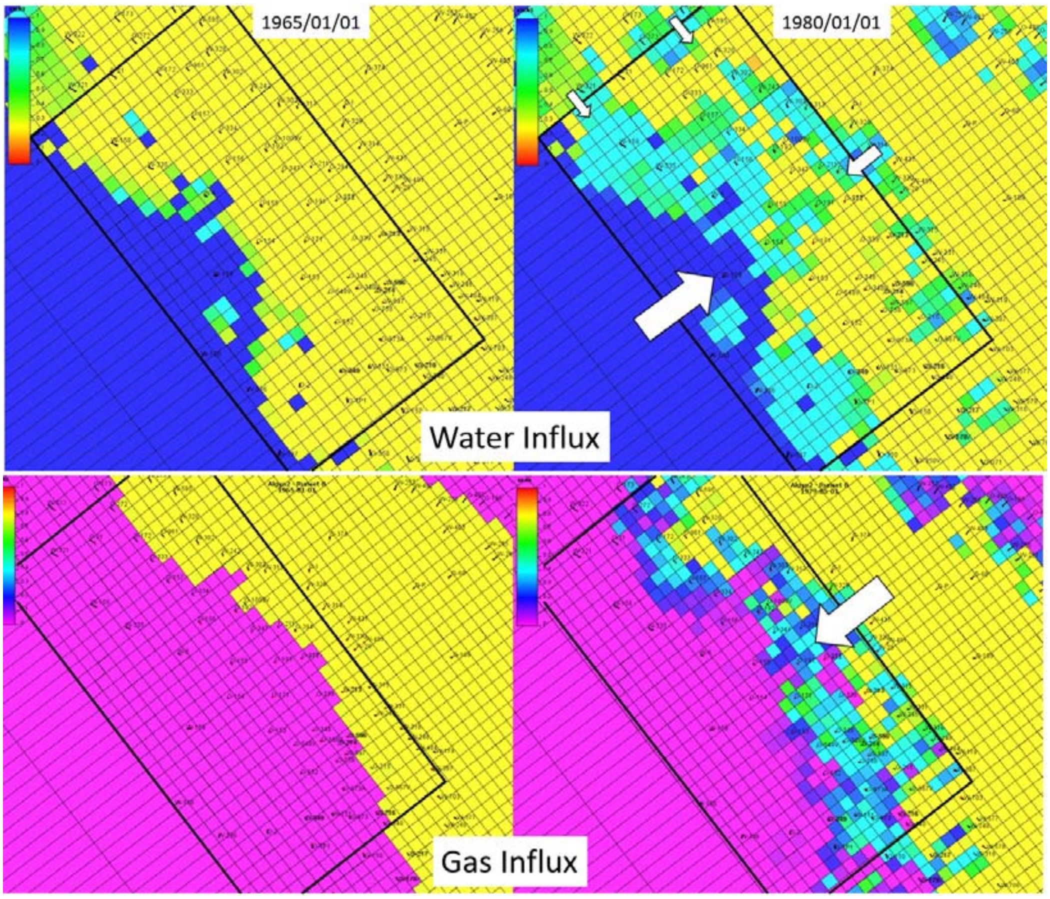

Figure 6.6: Main directions of water and gas influx through the boundaries of the chosen sector, as part of the full-field model.

To account for the sector's communication with the surroundings, the following way was considered justifiable:

- Complete isolation of the sector along its short sides, but choosing its extent appropriately, in a way that its communication with the surroundings can be neglected. For the same reason, wells located very near to the sector boundaries were also neglected.

- No analytical aquifer boundary was applied on the aquifer side. The reason for this is that the pressure maintenance is apparently achieved by the water injectors. In the lack of exact average reservoir pressure data, no automatically operated aquifer could be applied, although it must be noted, that the Target Phase Method would be the recommended way to maintain the real region pressures.

- Despite the fact that the sector covers the entire oil rim, (stretches over WOC and GOC), it became obvious that a stronger gas expansion-related pressure maintenance and gas influx through the GOC was necessary. For this reason, a large pore-volume gas body was attached to the model, which at the same time acted as a pressure-buffer.

6.4.2 Defining well operation

The author aimed to give a better approximation of the drainage volumes for the limited number of wells in the area of interest, considering, that due to the potential overlapping, manual assignment was necessary. The model validation features were globally in use for all except the horizontal wells for the first time. The drainage volumes were considered steady. Due to the coarse grid relative to the well placement, it was impossible to define both D2 and D3 volumes, therefore only one DV was considered, which was mostly extended over the entire trajectory. Figure 6.7 illustrates that to avoid overlapping, the consistent drainage volumes were often asymmetrical and small in size.

It is important to mention, that D4 environmental cells were also automatically assigned to some wells to ensure their correct operation. It is normally not possible or beneficial to describe the static properties to the level of detail, to represent all existing connections between pore volumes and the perforations. However, by the use of environmental cells, it is possible to discover and represent these. In the introduced model, during the 1st validation run, D4 cells were necessary for mostly the oil and gas phases. This is because the original model did not contain adequate initial movable oil, moreover the expanding gas cap could not reach most wells at the desired times in the lack of a possible thin permeable layer.

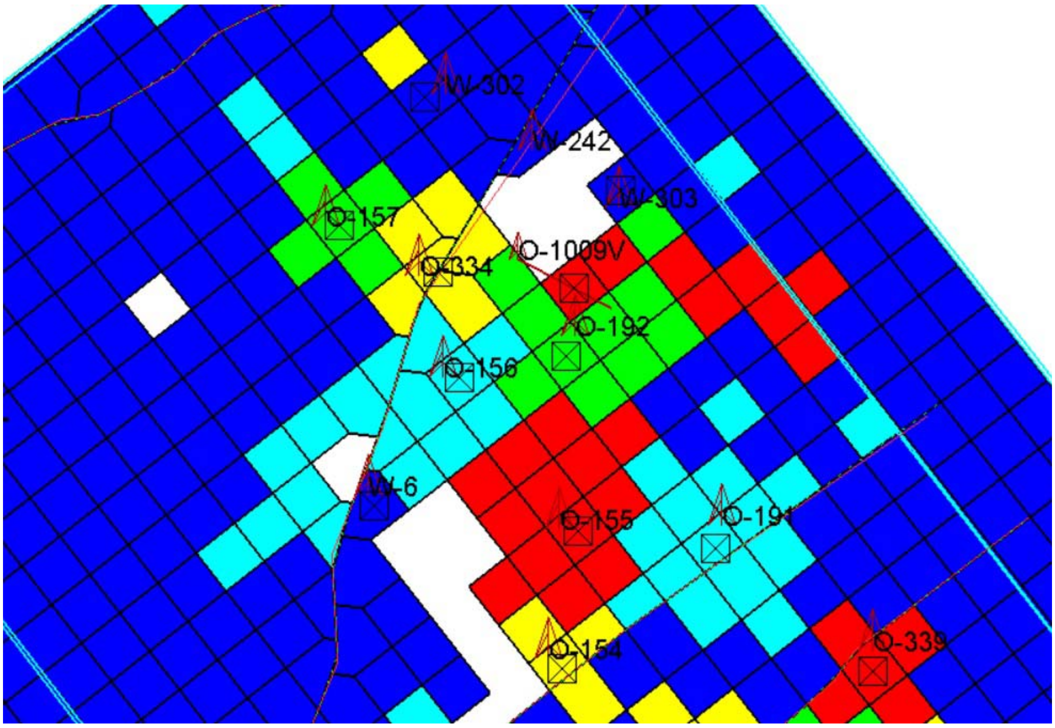

Figure 6.7: Outermost consistent drainage volumes assigned by the author avoiding overlapping, and automatically set environmental connections (D4). The cells belonging to the same well are indicated with the same color.

By the choice of the operation mode, both numerical stability and convergence to the real perforations played a role. Converting to flow-grid with upscaled properties eliminated most grid-related numerical stability issues that occurred in the full-field model, which as expected, led to better convergence. As opposed to the full field application, the model validation run could be performed to the entire production history this time. Due to the dense well placement, it was found especially advantageous to operate the wells in combination with the Peaceman-well, because it reduced the contribution and size of the drainage volumes. Most wells could be operated so, without any numerical stability problems.

6.4.3 Results and corrections after the 1st model validation run

The 1st model validation run's results are summarized in Figure 6.8. During the evaluation, the cumulative well production rate plots, and for combined wells, the bottom-hole pressure plots were observed, and the location/pattern of the non-matching wells was indicated. Since the authors had no access to BHP measurements, the calculated values exclusively served a control function. The indicated "successful" wells produced a 100% accurate match of the historical rates, for all phases during the whole history, regardless of their BHP result. Otherwise, the table shows the deviation of the cumulative production curves from the historical values at the end of the run. For many wells, the BHP curves run on its specified minimum or maximum limits for a considerable period. The lack of the movable oil phase was globally experienced: the producers' drilled before 1968 run out of oil already between 1974 and 1982. This can account for either the inadequate initial quantities in the well's drainage volumes, or their weak communication with the environment. The pattern of non-matching wells indicated a consistent model area lacking oil. Based on the initial MV results, the re-interpretation of the model would be recommended.

	Operation mode	Missing	BHP	1st divergence
O-152	Peaceman+DV+Environ's	perfect	ok	
O-153	Peaceman+DV+Environ's	70% oil shortage	ok	1981
O-154	Peaceman+DV+Environ's	oil missing	ok	1979
O-155	Peaceman+DV+Environ's	70% oil + sol.gas shortage	min	1968
O-156	DV+Environ's	50% oil shortage	not evaluated	1976
O-157	Peaceman+DV+Environ's	30% oil shortage	ok	1978
O-191	Peaceman+DV+Environ's	oil missing	min	1982
O-192	Peaceman+DV+Environ's	10% oil shortage	min	1974
O-2	DV+Environ's	failed	not evaluated	
O-214	Peaceman+DV+Environ's	perfect	ok	
O-215	Peaceman+DV+Environ's	40% oil shortage	min	1982
O-216	Peaceman+DV+Environ's	10% oil shortage	ok	1981
O-334	Peaceman+DV+Environ's	60% oil + sol.gas shortage	min	1976
O-339	Peaceman+DV+Environ's	perfect	ok	
O-340	not evaluated			
O-348	Peaceman+DV+Environ's	30% oil shortage	min	1978
O-348V	not evaluated			
O-349	Peaceman+DV+Environ's	20% oil shortage, wat missing	min	1976
O-548	not evaluated			
O-548V	not evaluated			
O-596	Peaceman+DV+Environ's	10% oil shortage	min	1978
O-758	Peaceman+DV+Environ's	90% oil shortage	ok	1984
O-967V	not evaluated			
O-973A	not evaluated			
O-TP1	DV+Environ's	failed		
W-151	Peaceman+DV+Environ's	perfect	ok	
W-159	DV	perfect	not evaluated	
W-160	DV	failed at peak inj rate	not evaluated	
W-214	DV	perfect	not evaluated	
W-216	DV	perfect	not evaluated	
W-242	DV	perfect	not evaluated	
W-302	DV	perfect	not evaluated	
W-303	DV	perfect	not evaluated	
W-336	DV	perfect	not evaluated	
W-337	DV	perfect	not evaluated	
W-349	DV	perfect	not evaluated	
W-597	DV	perfect	not evaluated	
W-598	DV	perfect	not evaluated	
W-6	DV	perfect	not evaluated	

Figure 6.8: The applied drainage volume assignments during the 1st model validation run, and its matching results.

To demonstrate the effect of a potential re-interpretation, global model corrections were applied based on the 1st MV run's conclusions. The following modifications were introduced: (a) increasing the initially oil saturated pore volume in a rectangular region containing the failed wells, (b) multiplying the lateral permeability with 30 globally, (c) mobilizing oil content in chosen areas of not preferred rock properties

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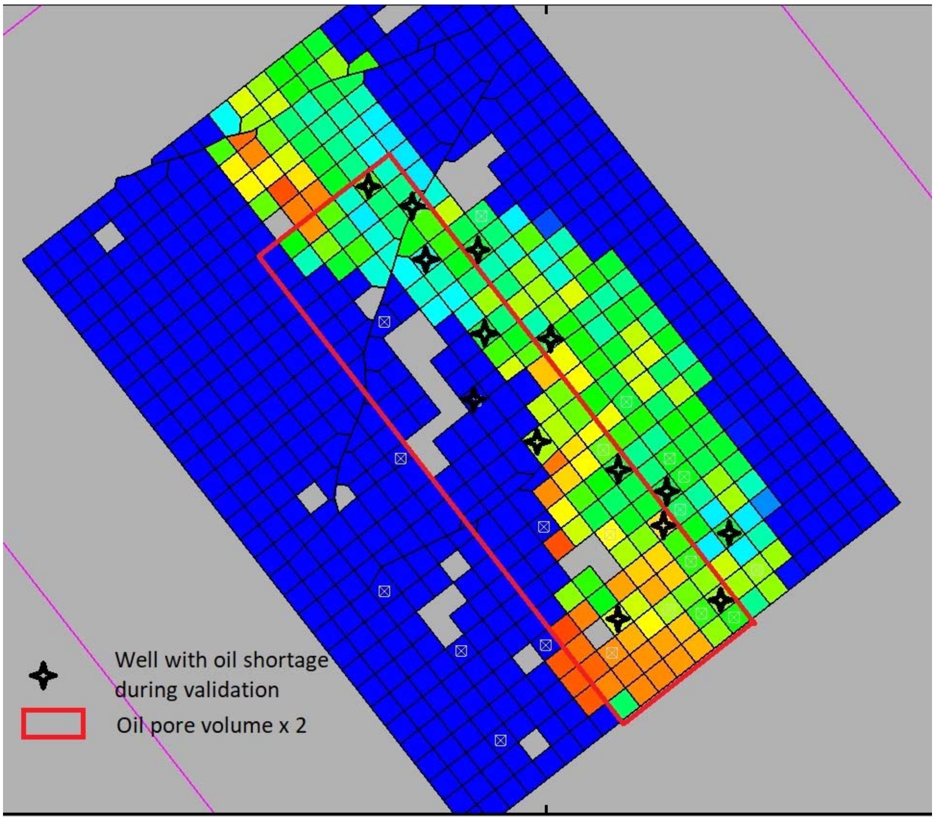

Figure 6.9: Location of the wells with oil shortage and applied global corrections: Increasing the oil-containing pore volume with a multiplier of 2 in the indicated area.

6.4.4 Results after the 2nd model validation run

The 2nd MV run already activated the so far not evaluated horizontal wells in the sector and implied more convergence promoting functions (e.g. PI multipliers, described in Section 3.4.1.1). The modified model clearly outperformed the earlier version in terms of matching quality. Due to well PI multipliers, the real perforations' participation of the total production significantly increased, parallel to which the drainage volumes' exploitation dropped, their extension shrank. For many wells maximum D2 volume including only the real perforations nearest neighbors was found adequate. For all wells, no D4 connections were necessary for oil and water phases, only matching the gas phase required environmental cells. The validated realization could be regarded applicable if a static modeler approves its consistency with the geological concept. This proof is always inevitable before progressing with the model refinement.

	Operation mode	Missing/Surpluss	BHP	1st divergence
O-152	Peaceman PI tune+DV+Environ's	perfect	ok	
O-153	Peaceman PI tune+DV+Environ's	perfect	ok	
O-154	Peaceman PI tune+DV+Environ's	perfect	ok	
O-155	Peaceman PI tune+DV+Environ's	perfect	ok	
O-156	Peaceman PI tune+DV+Environ's	perfect	ok	
O-157	Peaceman PI tune+DV+Environ's	perfect	ok	1974
O-191	Peaceman PI tune+DV+Environ's	perfect	ok	1976
O-192	Peaceman PI tune+DV+Environ's	perfect	ok	1966
O-2	Peaceman PI tune+DV+Environ's	failed	ok	1966
O-214	Peaceman PI tune+DV+Environ's	perfect	ok	
O-215	Peaceman PI tune+DV+Environ's	perfect	min	
O-216	Peaceman PI tune+DV+Environ's	perfect	ok	
O-334	Peaceman PI tune+DV+Environ's	perfect	ok	
O-339	Peaceman PI tune+DV+Environ's	perfect	ok	
O-340	Peaceman PI tune+DV+Environ's	perfect	ok	2001
O-348	Peaceman PI tune+DV+Environ's	perfect	ok	
O-348V	Peaceman PI tune+DV+Environ's	perfect	ok	
O-349	Peaceman PI tune+DV+Environ's	perfect	ok	
O-548	Peaceman PI tune+DV+Environ's	perfect	ok	
O-548V	Peaceman PI tune+DV+Environ's	perfect	ok	
O-596	Peaceman PI tune+DV+Environ's	perfect	ok	
O-758	Peaceman PI tune+DV+Environ's	perfect	ok	1992
O-967V	Peaceman PI tune+DV+Environ's	perfect	ok	1998
O-973A	Peaceman PI tune+DV+Environ's	perfect	ok	
O-TP1	Peaceman PI tune+DV+Environ's	15% gas shortage	ok	1979
W-151	DV	perfect	ok	
W-159	DV	perfect	not evaluated	
W-160	DV	perfect	not evaluated	
W-214	DV	failed	not evaluated	
W-216	DV	perfect	not evaluated	
W-242	DV	perfect	not evaluated	
W-302	DV	perfect	not evaluated	
W-303	DV	perfect	not evaluated	
W-336	DV	perfect	not evaluated	
W-337	DV	perfect	not evaluated	
W-349	DV	failed	not evaluated	
W-597	DV	perfect	not evaluated	
W-598	DV	perfect	not evaluated	
W-6	DV	perfect	not evaluated	

Figure 6.10: The applied drainage volume assignments during the 2nd model validation run

6.5 Comparison of the HM and MV Achievements

The author reproduced the dynamic results of a nearly identical sector model received from the field operator. (The HM status was unknown to the author.) The following figures show the sector's production rate match achieved with HM (Figure 6.11) and with the MV technique. (Figure 6.12) While the MV method generally managed to describe the wells' and the entire sector's behavior, the HM method was not able to do so.

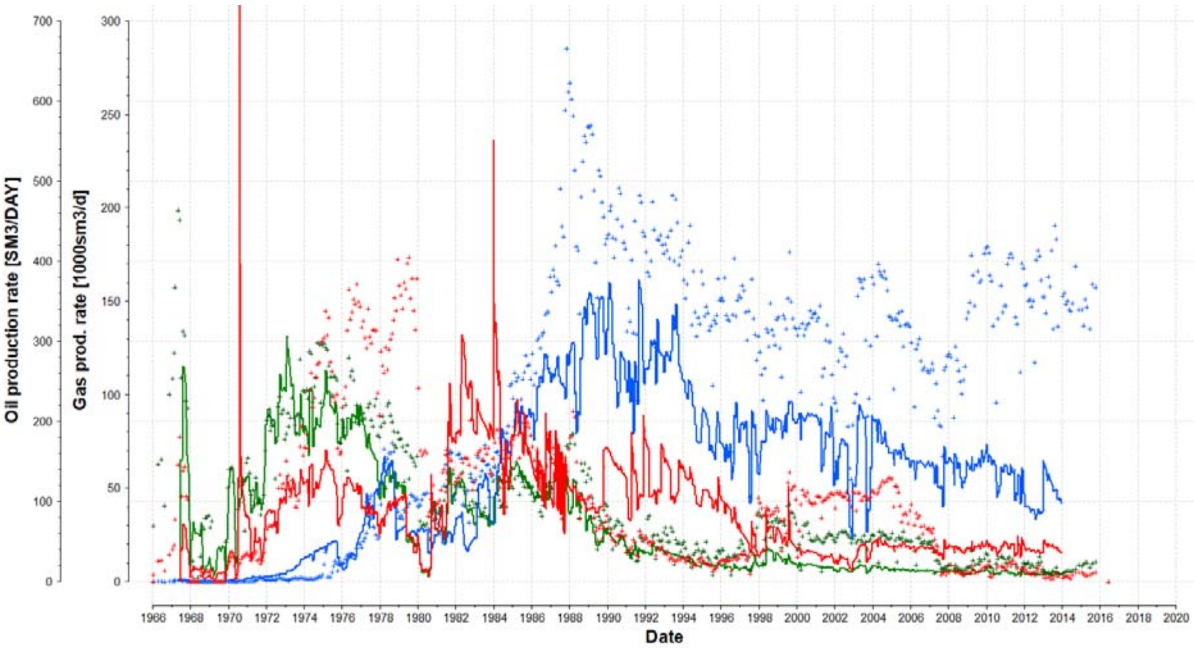

Figure 6.11: Total production rates of the sector created by MOL, with HM.

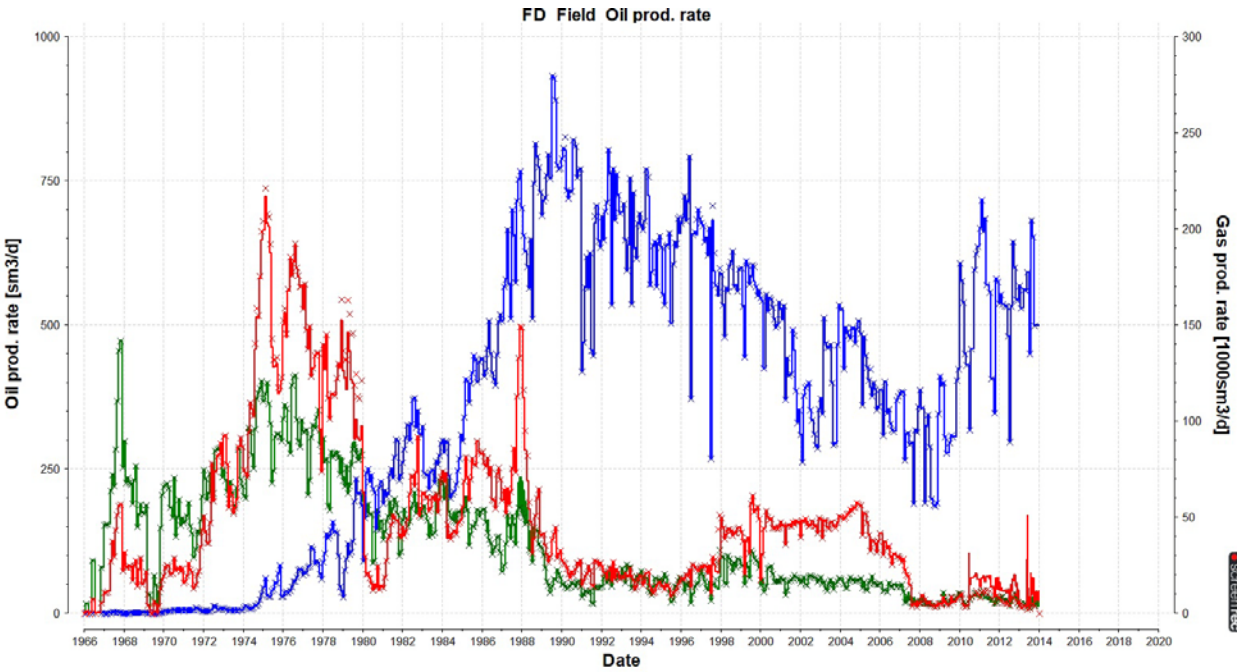

Figure 6.12: Total production rates of sector model created by the author with MV.

Looking at the individual wells' matching results, in the case of the MOL's HM dynamic model, both WC and GOR matching imperfections are notable. For example, the well O-157 when operated with reservoir volume rate, produced an average water-cut of 0.88 between 1995 and 2005, while for the same period the average measured value was 0.97. (Figure 6.13) Since any parameter change in favor of this well would influence other well's performance, to globally improve the match by HM means can be considerably time-intensive to nearly impossible. Since the HM model in its current status cannot reproduce the declining oil production rates, it hardly could specify today's downhole phase distributions, moreover, it is hardly imaginable, that after an almost 10% mismatch of the oil phase towards the end of the production history a reliable forecast can be conceivably made.

Also, the MV model's O-157 well could not provide the historical rates purely from its real perforations, but by proper compensation from their narrow environment, it could achieve a 100% accurate match. By minor parameter adjustments in the well's close environment, it could be achieved with a reasonable workload, that the phase extraction narrows down to the real perforations. The similar success of most wells in the model proves, that the so constructed integrated reservoir model provided a possible residual hydrocarbon distribution.

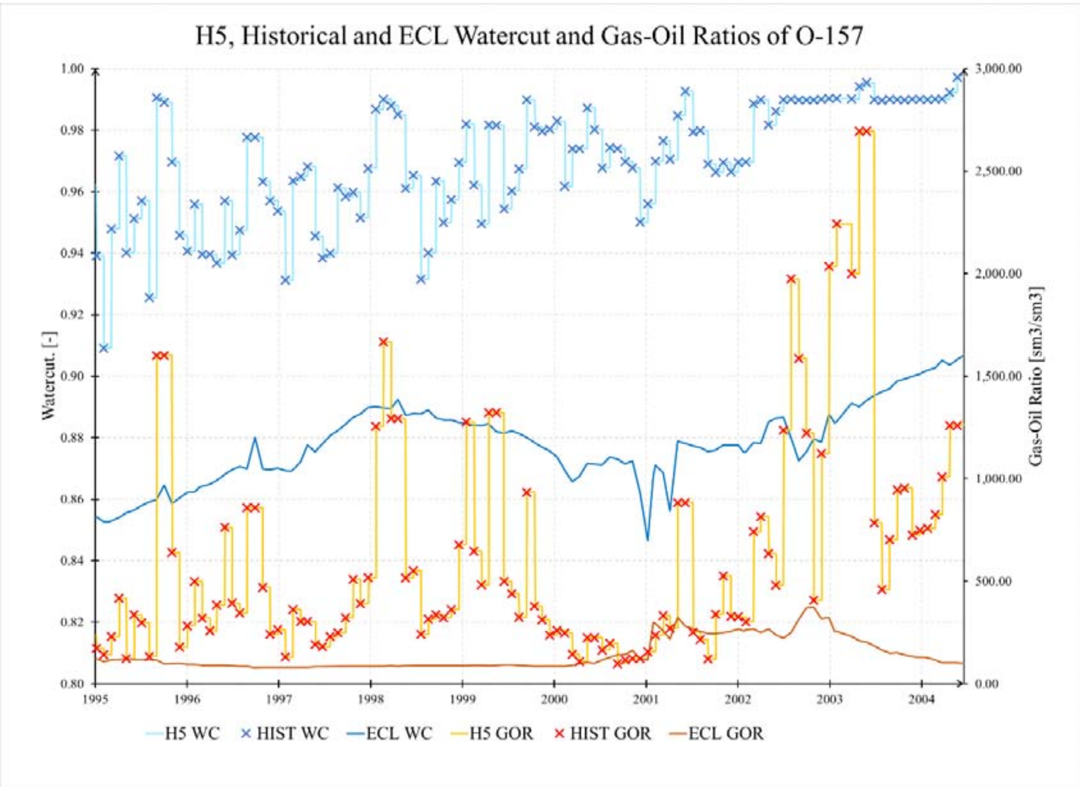

Figure 6.13: Comparison of the WC and GOR match achieved with HM and MV dynamic models for a 10 years production period of O-157

Chapter 7

Production Forecast Based on the Validated Reservoir Model

Most oil producers of the full-field model of Algyő-2 have been shut in till today or approaching their economical limit, not being able to mobilize more oil in the surroundings of the wells with the used production technology. The target of the reservoir management could be to maximize the long-term profit by the acceleration of the reserves, reaching so far inaccessible hydrocarbon accumulations, either by re-entering existing wells or identifying new drilling locations. This section details how the MV method can be used to identify the location of the remaining recoverable oil, and to calculate the possible incremental recovery by physically increasing the wells' drainage area with the considered production technologies.

7.1 Detection of Supplementary Recoverable Oil Volumes

Figure 7.1 displays the typical sedimentary sequence in a vertical section of the Algyő-2 reservoir, based on the work of (El-Sayed (1986)). It clearly indicates that discontinuities of the reservoir properties are typical in both vertical and lateral directions. The sedimentary sequence is characterized by cycles of high and low permeability zones with various thickness and extension. Sandstone microlenses of 20-30 cm length and 25-50 cm thickness are commonly present. Either due to a very tight reservoir rock, interbeddings or faults, parts of the total reservoir volume are not in communication with any perforations. Consequently, these parts did not contribute to the wells' historical production rate. Theoretically, it would be possible to represent all these discontinuities (e.g. on a very refined grid), but this would not be practical for flow simulation. Most of such discontinuities are not detectable by geophysical measurements, only by hydrodynamics- and production observation; and so, this information can be recovered by a successful model validation. The method of MV presented in this work is ideal for this purpose. This advantage of MV will be demonstrated on the well O-217.

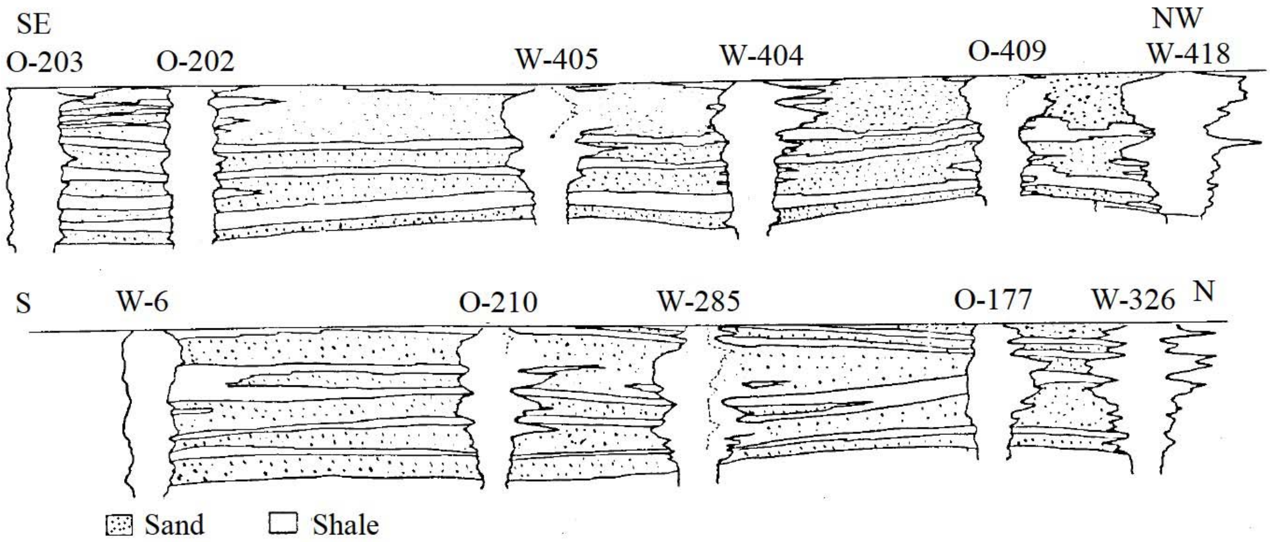

Figure 7.1: Shale and sandstone sequence on two cross sections of Algyő-2. (El-Sayed 1986)

After 10 years of production, the oil production rate of the well O-217 declined, and a few years later the well was shut-in. At this time it was already recompleted in the high permeability top trenches. The Figure 7.2 shows the excellent 3-phase match during MV from its estimated drainage volume until 1977/01/01. This ensures, that the movable oil content and its distribution within and around the O-217's DV was correctly described at the final MV date. Visual observation on 3D distribution plots (See: Figure 7.3) shows that the original drainage volume's oil content at the end of its production history was low, however in the close-vicinity in the low permeable bottom formation a considerable amount of movable oil remained (indicated by red color in the cross-section of Figure 7.3).

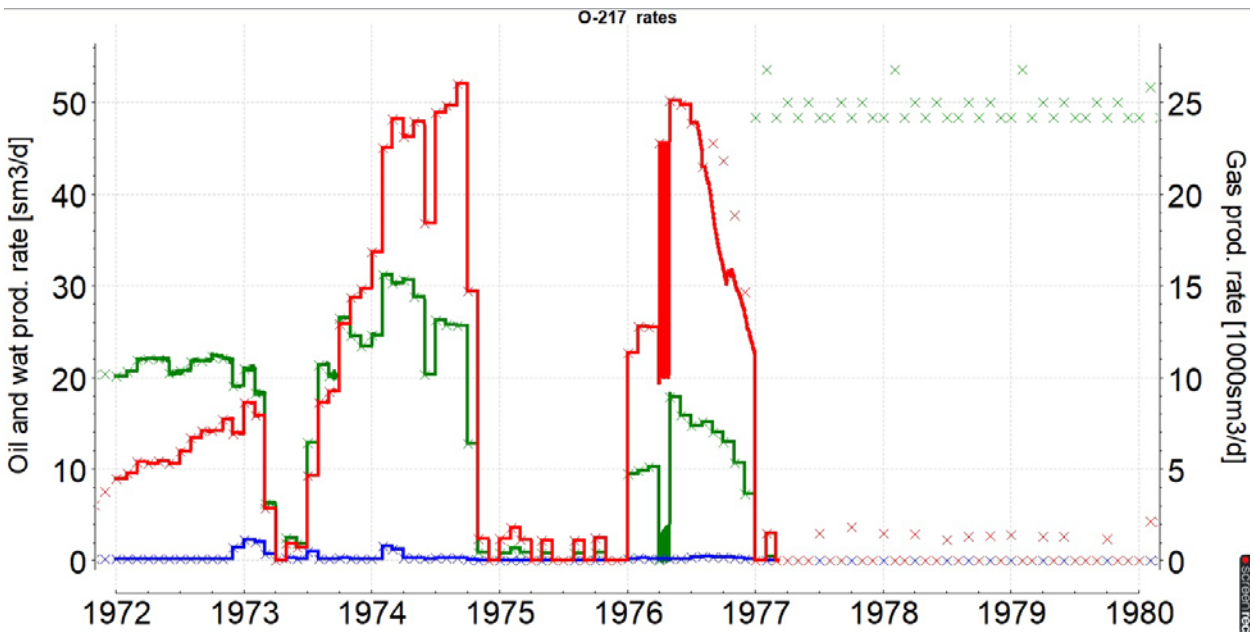

Figure 7.2: Match of the declining oil production from the DV of O-217 well at the end of the production history.

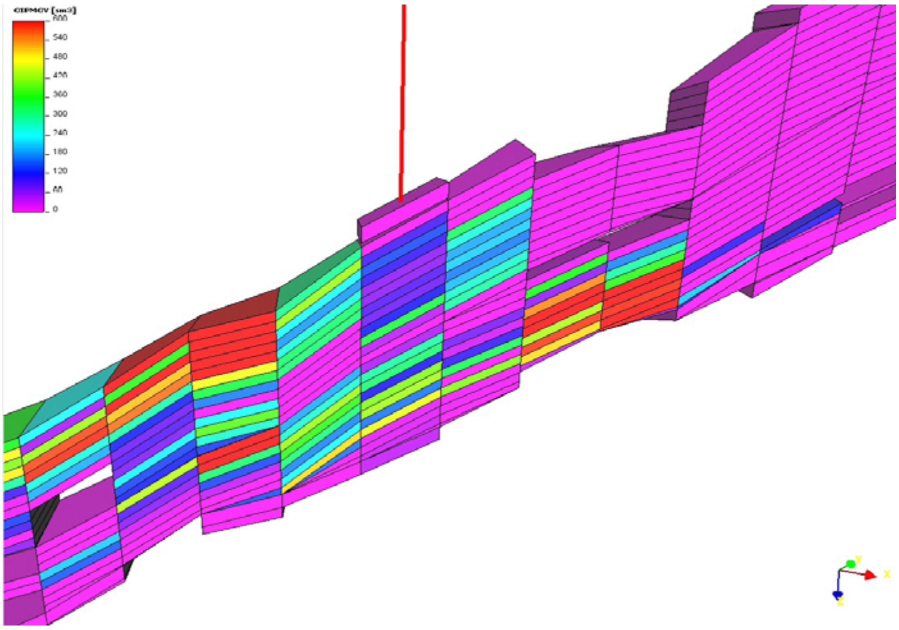

Figure 7.3: Movable oil content near O-217 at 1977/02/01, at the beginning of the forecast period.

The zone with high oil content is located at approximately 100-200 m distance from the trajectory, and is not in connection with the wellbore because of its very low permeability (according to the assigned cell-properties). Recompletion techniques could easily reach and give access to volumes of similar distances. Assuming that recompletion will take place (e.g. a potential sidetrack will be opened), the new shape of the increased DV can be reestimated, and drained connections can be established in the identified zone at the beginning of the forecast period (now 1977/01/01). The increment in total oil production and the accelerated recovery can be illustrated by producing the well with an increased oil rate until depletion. (See Figure 7.4) While producing from a tight zone, with the declining formation pressure the development's effect would rapidly deteriorate. Therefore it is likely required to apply techniques to maintain pressure in real applications, and to account for that in the simulation model as well. As an example, the effect of the pressure maintenance technique could be illustrated in the model by reinjecting the dissolved gas-content of the produced oil into the blocks.

The above-mentioned method was implemented on O-217. At the beginning of the forecast period the original movable oil content of the DV was 16414 sm3. After the shape of the drainage volume was reestimated to imitate a potential recompletion (See Figure 7.4), its movable oil content was increased to 21409 sm3. The well's desired oil production rate in the model was increased to approximately 50 m3/day and it was attempted to recover as much oil from the new drainage volume as feasible, assisted by gas-reinjection. Between 1977/01/01 and 1979/01/01 approximately 40000 sm3 incremental oil was recovered: partly because of the increased drainage volume, and partly due to the inflow into the DV through the permeable zones. In theory, this would roughly double the total recovered and recoverable amount of oil by the well O-217.

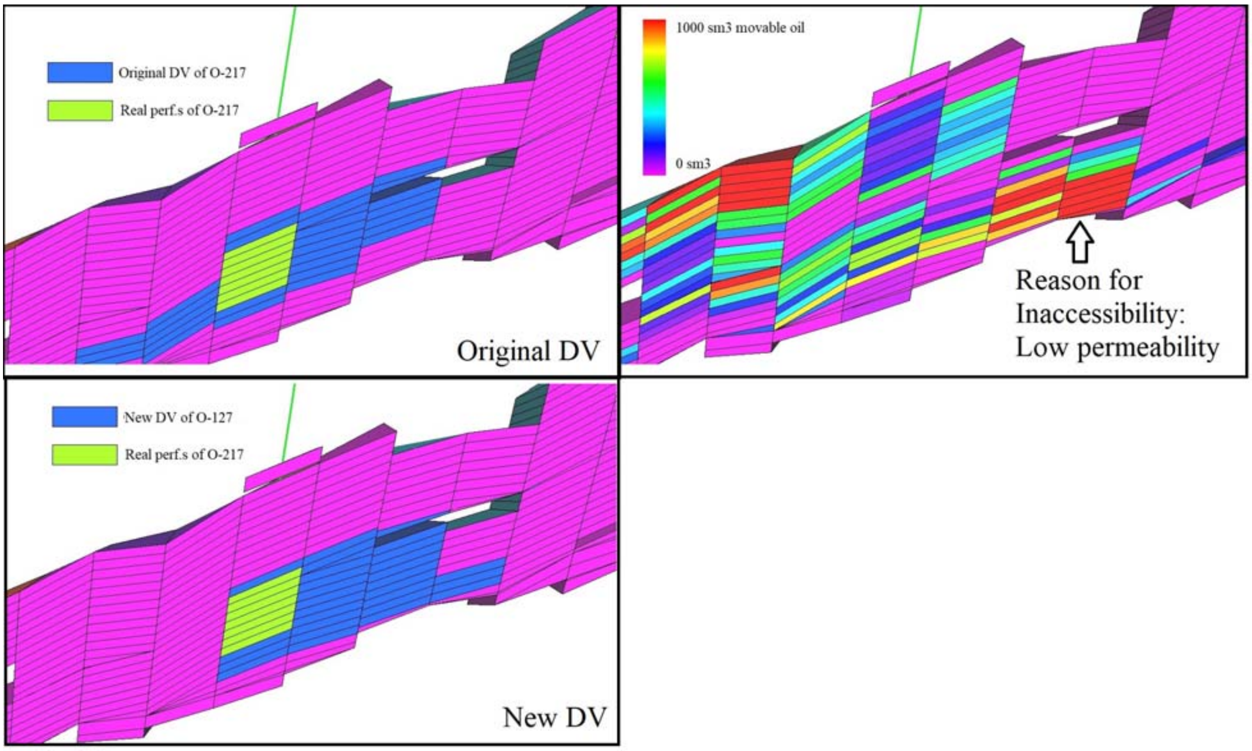

Figure 7.4: Reassignment of drainage volume for well O-217 to access remaining oil content.

Instead of purely visual investigation, the identification of the remaining oil zones before the forecast period could be automatized for considered wells by enabling D4 environmental connections to detect the zones around the DV with the highest remaining oil content. With their assignment, those could be automatically connected to and accessible by the well. The total oil content of the original and increased drainage volume is automatically calculated. That how much of the accessible hydrocarbons is recoverable it must be modeled for economical feasibility. This should be done by running the model for the next 3-5 years with an increased oil production rate and monitor the incremental oil recovery.

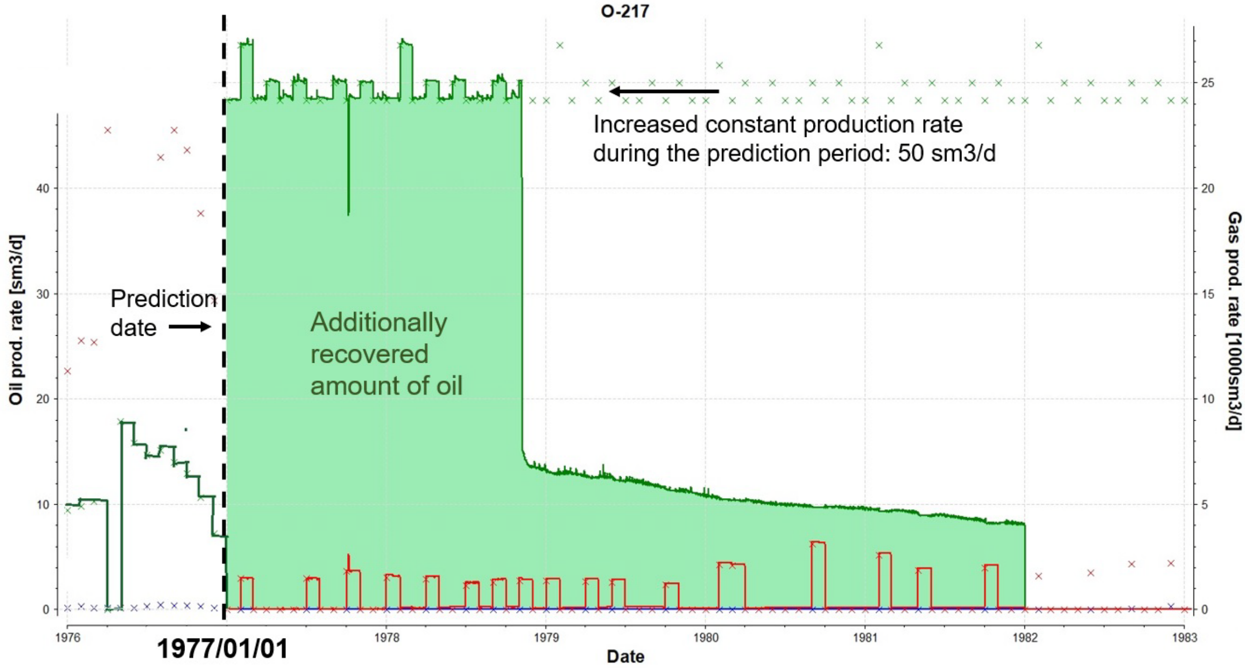

Figure 7.5: Increased constant oil production rate during the forecast period of O-217.

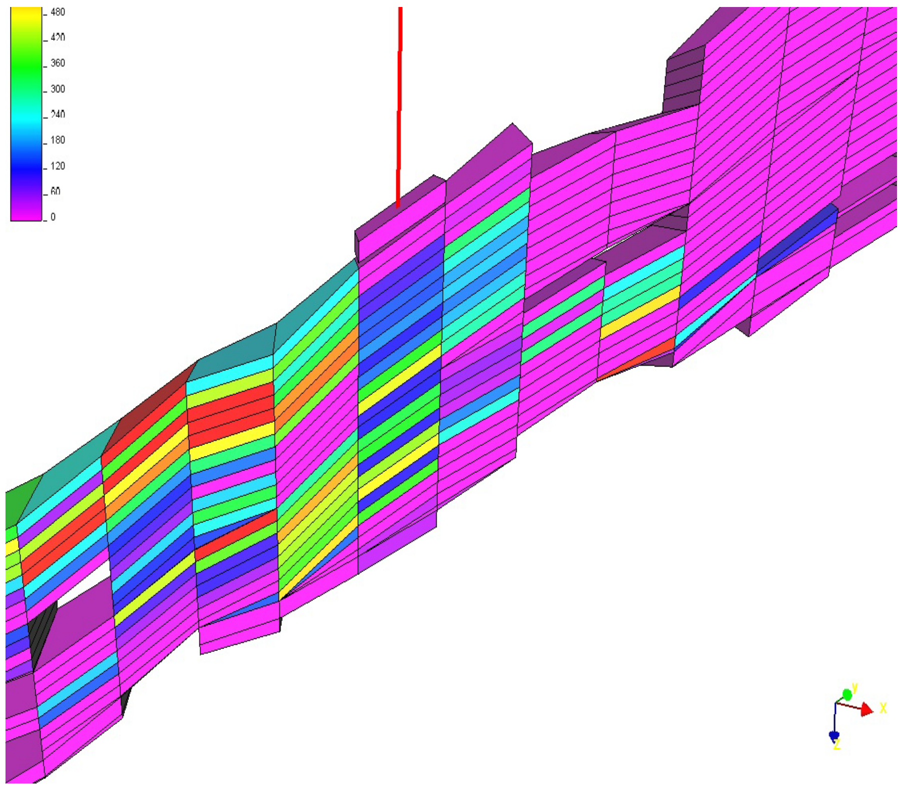

Figure 7.6: Movable oil content at 1978/03/01 remained after the forecast period.

7.2 Technical Possibilities to Increase the Recovery

In this work, the different technological possibilities for how to get economically viable access to the oil-containing zones could not be modeled because the business strategy of MOL was not known. For this reason, the proposed forecasting method cannot consider a time-scale, only the possible incremental oil recovery assisted by pressure maintenance. Although, it is important to list economical and technically feasible methods, which have been applied in the past, or could still be considered to the Algyő-2 wells.

7.2.1 Producing from Inaccessible Reservoir Zones

Sidetracking and fracturing and the combination of these are techniques to increase the recovery by reaching by-passed hydrocarbons and reduce exploitation time with the increased production rate/productivity index. (Palásthy 2000) Both methods can bring existing shut-in wells into production again. The methods are mostly applied, where vertical wells would not be economical (anymore) due to very thin or very heterogeneous reservoir layers, very low permeability or even unconventional rocks. Horizontal wells are widely applied in the Algyő-2 reservoir for both producers and water injectors already (See: Figure 7.7).

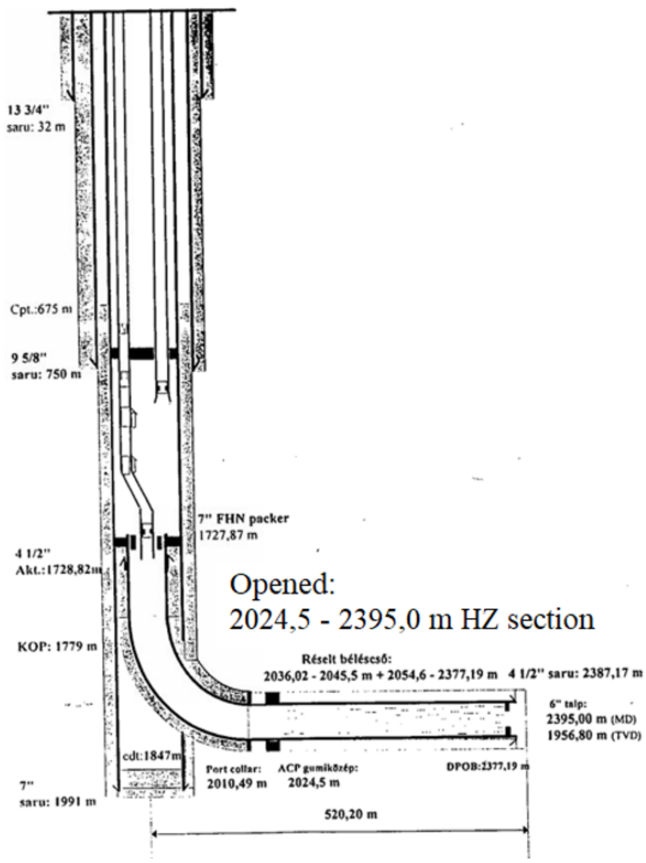

Figure 7.7: Completion of the oil producer O-348 with an 520 m horizontal section, and opened in a 70 m long section.

7.2.2 Cost Effective Recompletion Techniques

Since the remaining oil-bearing zones, and the forecasted potential incremental recovery by recompletion is most likely limited, the economical viability of the proposed techniques can be vital. Applying a light rig-infrastructure, or tools performing multiple tasks with one-trip are ways of reducing the cost of the re-intervention.

PDC Mill Technology

Polycrystalline diamond compact cutting elements offer a cost-effective approach to creating multiple wellbores from the same mother bore. PDC cutters, which are commonly used in drilling bits, now can be applied to casing sidetrack mills, which mill trough the casing and ahead into the formation as part of a one-trip sidetracking system. (Nye et al 2001.) Accessing multiple horizontal high-permeability sections, which are not inc communication through the same well can increase the productivity, therefore it can be highly advantageous for heterogeneous reservoirs with multiple permeable and sealing layers.

Rigless Cement Packer Recompletion

This includes techniques to access uphole reserves above the existing production packer without the rig infrastructure, applying coiled tubing. This includes punching the tubing to establish circulation, setting a cement plug and bullhead the existing formation, identifying the target interval of recompletion by logs, after setting cement retainer, pumping cement through coiled tubing in the annulus above the retainer. (Friedly et al. 2016)

Wireline Recompletion Techniques

It is an unconventional way of uphole recompletion of existing wells, which is cost-effective and limited rig space compared to the coiled tubing operations. It utilizes a wireline tractor to perform the entire well recompletion on a standalone light-weight electric wireline unit. The wireline tractor's communication and internal power source are electric, the remaining parts are hydraulic. The tool is able to automatically deploy wheels, rotate them and to centralize itself. It is able to pull a wireline in the wellbore to large depths. The downhole tools such as bridge plugs can be run with the wireline tractor, which can be utilized to isolate unwanted zones, perforate, etc. (Kueh et. al. 2021)

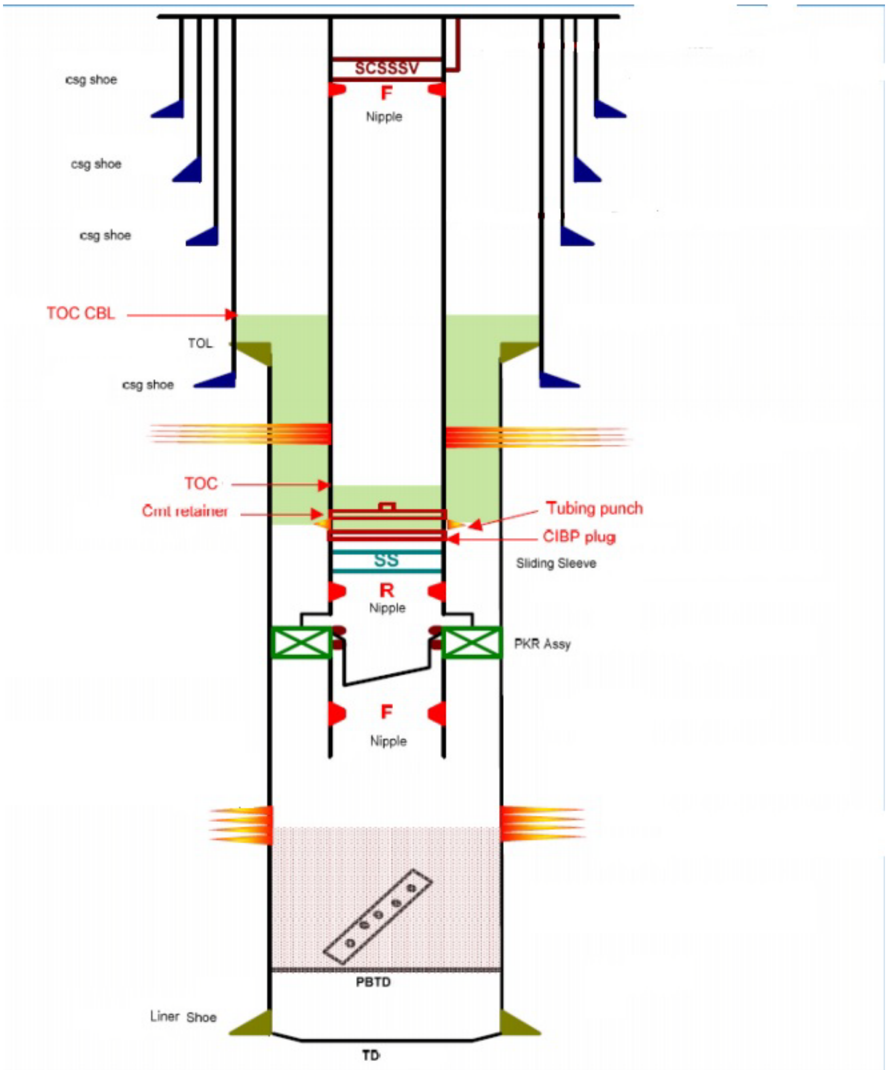

Figure 7.8: Example of a well after cement packer recompletion (Friedly et al. 2016)

Chapter 8

Conclusion

8.1 Applicability of History Matching Approach

- All the results seem to suggest that in using the conventional history-matching methods, one cannot practically guarantee to recover model which represents the real geological structure of the reservoir.
- A good history-matched model might have geological properties quite far from those of the "truth" and therefore could lead to a bad forecast.
- Relatively small changes in the prior model may have a considerable impact on the difficulty in finding a history match, on the predicted performance and on the uncertainty estimates.

8.2 Application of Model Validation Approach

- The Model Validation approach potentially can operate - on a global scale acceptable - reservoir models' wells with the measured three-phase rates and pressures. If it is not possible, the geology must be re-interpreted. In case of its success the MV is also applicable to describe the field's dynamics in a physical sense, and for this only local parameter corrections are needed. The greatest difference compared to the HM approach is that with MV all wells, and naturally the entire field, always produce the target rates. Due to this fact the model can always be regarded as a step-by-step more accurate representation of the real object.
- When the MV is able to incorporate a reservoir unit's (e.g. field, section, formation) initial movable phase contents and its wells' cumulative production-time functions in the same model, then it also provides a possible residual distribution of the movable hydrocarbons and their accessibility through the wells. The MV method can provide more model realizations which as prior satisfy the dynamic requirements. The task

and only responsibility of the geo-modeler is to examine which ones among these harmonize with the geological concept. It is important to mention that all MV wells operate in their own regime. MV modeling excludes the chance that a model correction introduced for a specific well has an influence on other wells.

8.3 Applicability to Full-Field Models

- The HM cannot be used to Algyő-2 field because it is not able to calculate, not even to approach the correct oil rates for the current 98% water cuts. It is therefore not applicable for forecast either.
- If the original movable OOIP of the DV is N and the well produced Np standard oil volume then the drainage volume still should own N - (minus) Np recoverable oil, plus the influx. The HM approach could not correctly describe the movable oil content of the wells' drainage volumes, since the MH wells did not produce the correct Np amount. Therefore is not possible to estimate the actual and future recovery. The MV procedure does not suffer from this weakness, therefore it can always localize the amount of the actual reserves. An illustration of this can be found in Appendix C.
- It is unlikely that the model based on HM could reliably describe the transport of injected additives such as tracer, polymer, surfactants, etc.
- The Algyő-2 is a heterogeneous reservoir with thin variably permeable and sealing zones. The separation of the phases – if it plays a role at all - does not take place for the entire reservoir thickness. It is very likely, that the imbibing water and gas cannot access all zones, but at greater permeable zones those can break through toward the wells. To model such circumstances is almost impossible by conventional means. Between the average saturations of the phases and their relative permeabilities the usual correlations do not apply. The MV establishes this correlation, although not locally, but inside of the drainage volumes of the wells.

Appendix A
Technical Considerations when Defining DV-s

A/1 Implemented Method to Define Drainage Volumes

It is technically possible to define drainage volumes to active-or shut-in wells, to any well types (producer or injector), and to any trajectory types (vertical, slanted or horizontal). The MV offers the possibility to define 4 independent DV-s for a well: for simple reference, identified by D1-D2-D3-D4, starting from the smallest to the largest. The significance of the drainage volumes D1 D2 D3 D4 has been detailed in Section 3.3. The modeler must identify at least those DV-s, which represent physical flow units in the reservoir: these are D1 "trajectory" and D3 "inflow area". Optionally, additional hypothetical DV-s can be assigned too, such as the D2 "near well" or the D4 "environmental cells".

The Figure A.1 illustrates arbitrary combinations of D1, D2, D3 and D4 units.

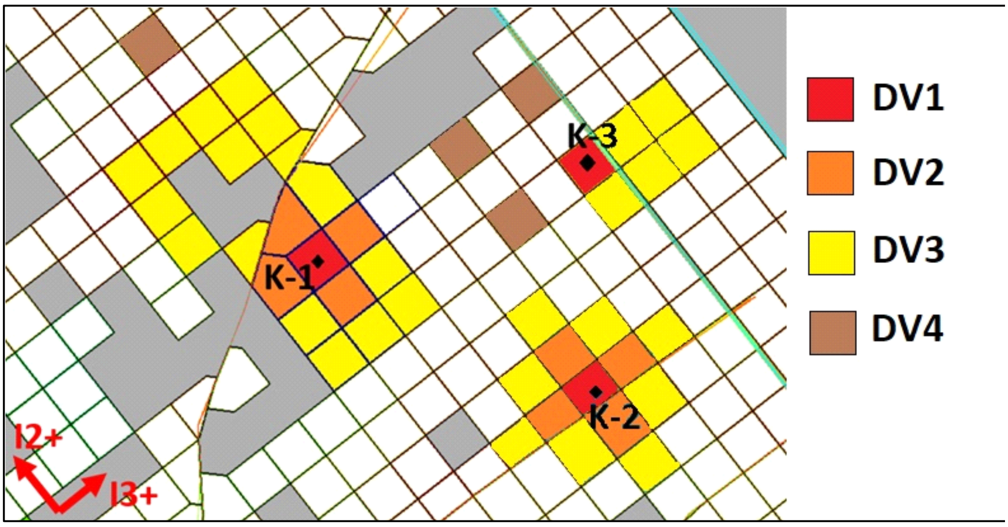

Figure A.1: Representation of the drainage volumes.

Defining the trajectory (D1) of the well is identical to the conventional approach. The trajectories can be defined with their connections to the grid, with other word, perforations. In model validation runs, only those cells are considered a trajectory cell, for which either an "OPEN" or "SHUT" perforation is defined (e.g. in SCH file).

The drainage volumes D2 and D3 can be approached with simple geometrical shapes. Usually the D2 volume is a symmetrical cylinder around the trajectory. It is called RING and defined with a single integer, the desired the number of rings around the OPEN perforations. The first ring is formed by the lateral neighbors of the perforated cell i.e. the OPEN perforations. The further rings are set around the previous ones.

The drainage volume can take the shape of a cuboid, called CUBE. The CUBE is specified by six integer numbers with which the cuboid is extended in negative and positive coordinate directions from the OPEN perforations, as follows: Z-, Z+, X-, X+, Y-, X+. Both the RING and the CUBE can be extended around the entire trajectory, or even above or below the trajectory cells. In the latter case the user must also define these extensions.

The user can assign in each input instruction line only one RING and one CUBE shaped drainage volume. Always the RING shape volume is assumed to represent the near well region, which is to be smaller than the CUBE shaped volume. Since the RING volume is rather a tool the extension of the RING can be set according to the desired convergence level to the well. Technically it is not a requirement, for the CUBE to entirely cover the RING. The CUBE is usually the largest consistent volume (D3), and must fall within the physical inflow area of the well. In an ideal well placement, the size and shape of the CUBE is not restricted by other wells.

Upon user instruction, at the defined date, D4 environmental cells for oil, water ad gas can be automatically searched for and assigned. The screening of the applicable cells takes place with increasing radius from the trajectory. This method ensures, that the nearest possible cells would be found considering all directions. There is a possibility to identify and assign 15 cells for each phase with adequate volume, which phase saturation is high enough at the time of the search.

With dense well placement an overlapping of the drainage volumes could naturally occur. With manual drainage volume assignment, the overlapping of the drainage volumes of separate wells at the same time must be avoided where possible, otherwise specially handled. In the current technical solution, a cell can only belong to one well at a time, and in case of overlapping, the earlier established assignment is kept: not overwritten by newer drainage volume definitions. The construction of the defined drainage volumes takes place in a following order: (1) based on the date of the input instruction (earlier defined volumes will be constructed first). (2) for the same date based on the serial numbers of the well, (3) for the same date and same well firstly RING, secondly CUBE, thirdly environmental cells are defined. It is possible to reset a drainage volume for a certain well to free volume for another well. (E.g. when a well is shut in, its connections can be restored.) If overlapping is expected, a possible way is to define a RING shaped near well volume at the initial date for all wells, and to assign the CUBE shaped volumes only when each well starts producing.

A/2 Defining DV-s Operation Methodology

This section explains the user's possibilities to time-dependently regulate the drainage volume operation by input instructions. The best operation methodology can vary for each reservoir model, even for each wells in the model, for different operation periods for the same well, and it can be (should be) different in each stage of the model building. The most important considerations of choosing the methodology are convergence to the real perforations, numerical stability and automated operation. For a more detailed explanation of the aspects refer to Section 3.4.1.2.

Some convergence and numerical stability promoting features are automatized, and will not be discussed here. The user can also activate additional convergence and numerical stability promoting features. Features, that can be utilized by the user to increase the convergence are: (1) applying the Peaceman concept to the D1 cells, (2) applying productivity index multipliers to the D1 cells, (3) decreasing the size of D2 while not altering the D3, (4) applying a production distribution methodology based on the cell's distance from the trajectory. Features that increase the numerical stability are: (1) temporarily excluding those perforations of the Pieceman well with extreme phase ratios, (2) deactivating the Peaceman concept to the D1 volume, (3) decreasing the production rates from the individual drained cells, and distributing the compensation rate evenly, (4) increasing the size of the D2.

It must be noted that increasing numerical stability by controlling the individual cell's productions could limit the rates that can be possibly produced from the volumes, and the dispersed production distribution would cause a more even pressure distribution inside the volume, which could induce different phase fluxes into and between the drainage volumes. Despite the effort to automatize the drainage volume operation, it is not yet applicable without user intervention.

Appendix B
Diagnostic Tools and their Application during the Model Validation Workflow

Cumulative production of the wells: It represents the cumulative productions of a well versus time, from all its drainage volumes. It is used in every phase of the model building. During validation, the user should try to establish cumulative production match. This takes place by trial-and-error establishing the necessary size/rough estimation of the shape of inflow areas. If it was not possible to assign drainage volumes, which provide the historical production rates, the model must be re-interpreted. In later model building steps, the cumulative production match ensures that the global integrity of the model is maintained.

Phase production rate of the individual DV-s: It represent the sum of production rates from the cells belonging to one certain DV. This diagnostics is used when more than one DV is defined, ideally during near-well refinement. Analyzing the contribution of a DV to the total well production is used to diagnose the local static model quality. Hence according to the model validation concept, the well always has to produce its targets, the question is, what is the actually the smallest volume which can provide this. During local model refinement it can be targeted to achieve match from the D1 volume only, which means, that the model is both globally and locally a close representation of the reality.

Dynamic properties of the individual drainage volumes: It represents the total movable phase contents in standard volumes and the average pressures of all cells belonging to an individual DV and all smaller DV-s of the same well. In combination with production rate plots, it can diagnose the drainage volume operation. Comparing the dynamic parameters of two subsequent runs can show the effect of e.g. a different distribution of the phases within the drainage volume on the local pressures and phase contents. The phase contents of the outermost DV shows the remaining movable oil which is still recoverable by the well.

3D visualization of the actual movable phase contents: It indicates the location of oil, which can be accessed by the well during the run and at present time. It indicates the direction of water-gas inflow in the DV-s, with this, it assists the local parameter tuning.

Location of possible new well connections: When so-called environmental connections are enabled, the well can access and produce from the nearest cell containing the missing phase from the drainage volume at any point of time. It indicates that between two points of the static model an unforeseen hydrodynamic connection can exist. It assists production technology related decisions as how to access movable oil containing zones.

Appendix C
Material Balance and Remaining Oil Characterization with Conventional and Drained Wells

The refined-grid sector model (introduced in Section 4.4.2) has been run both with the conventional well operation (1st Run) and with different drainage volume definitions (2nd and 3rd Run), and their difference regarding the field totals, the remaining oil content of the individual inflow areas, and the residual movable oil saturation was compared on reservoir-and regional scale.

The demonstration example was operated first with conventional well models with reservoir volume targets, afterward with different drained operation setups. For all runs, field cumulative productions, recovery factor and the well production rates were plotted against the historical data. D3 drainage volumes were assigned to the wells (but in RESVOL operation only for diagnostic purposes and no compensation took place.) The movable oil content of the well inflow area N was obtained.

When analyzing the global performance of the model, the followings were noted: The conventional well model was not able to reproduce the correct field totals, with this, the correct material balance and the actual recovery factor, whereas the model operated with drained modes did. With this, the above-mentioned actual reservoir parameters could be correctly determined. When analyzing the model performance on a local scale, the followings can be noted: The conventional well operation mode was not able to provide the correct cumulative phase productions (Np) on well-level, while the drained operation modes did. The difference in movable oil content of the well-inflow areas is significant both during and at the end of the run (see Figure C.1). It means, that the conventional well operation was not able to describe the amount of oil accessible by the wells today. Since the average phase saturations within the inflow area are incorrect, it cannot be expected that it reliably forecasts future production rates. The run of the curves are very close for the two different drainage volume operations. The real behavior of the wells were correctly described, therefore the variation of the movable oil content of the inflow areas with time are always true representations of the real near-well conditions.

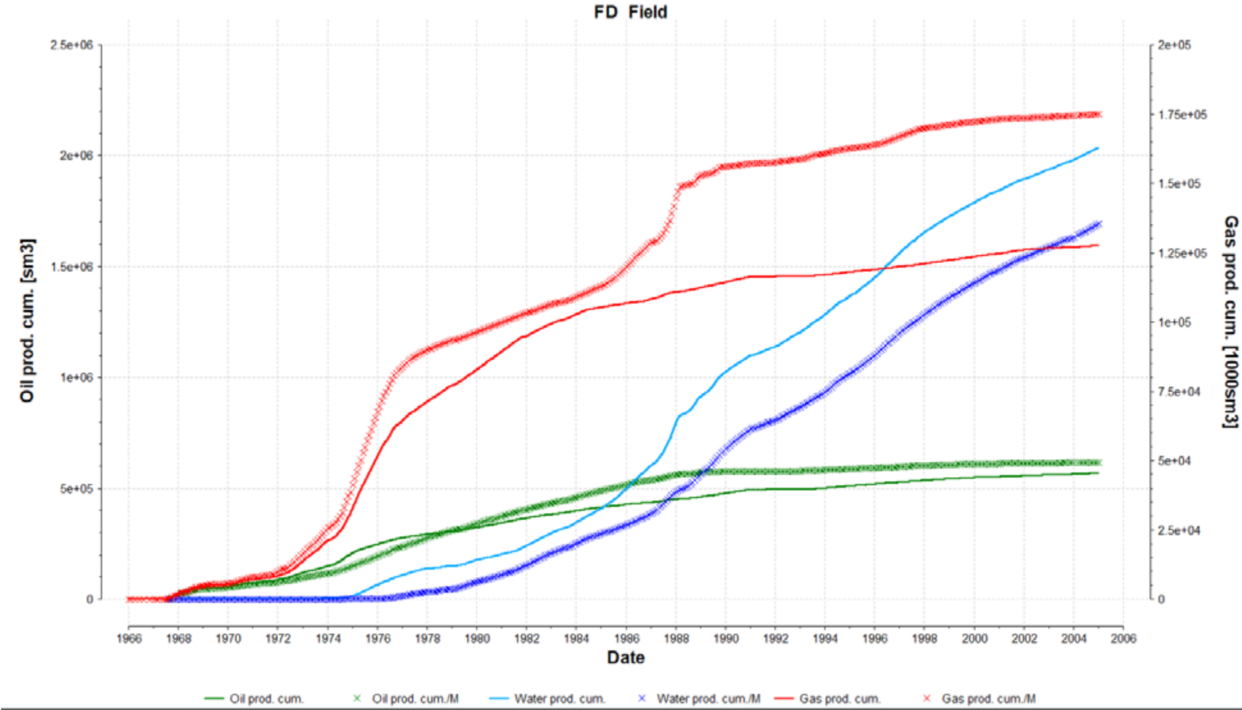

Figure C.1: Field totals when all wells operated with RESVOL target.

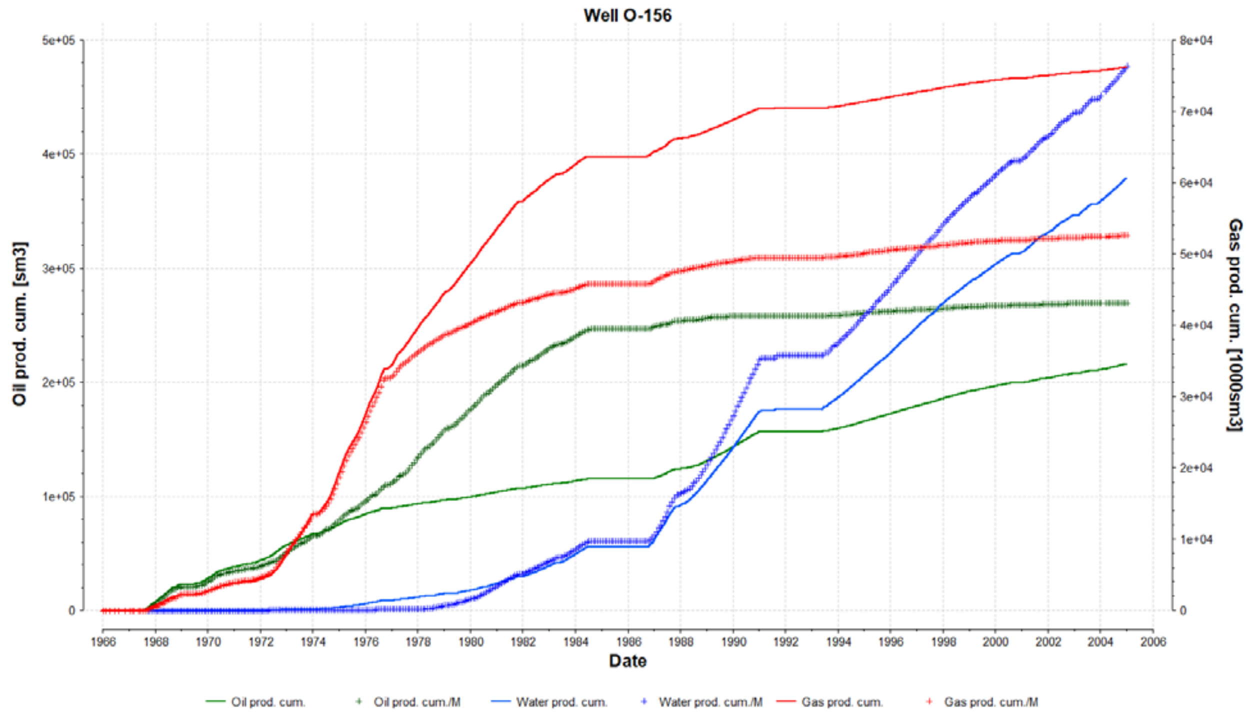

Figure C.2: Cumulative phase productions of the well O-156 when operated with a conventional well model and RESVOL target.

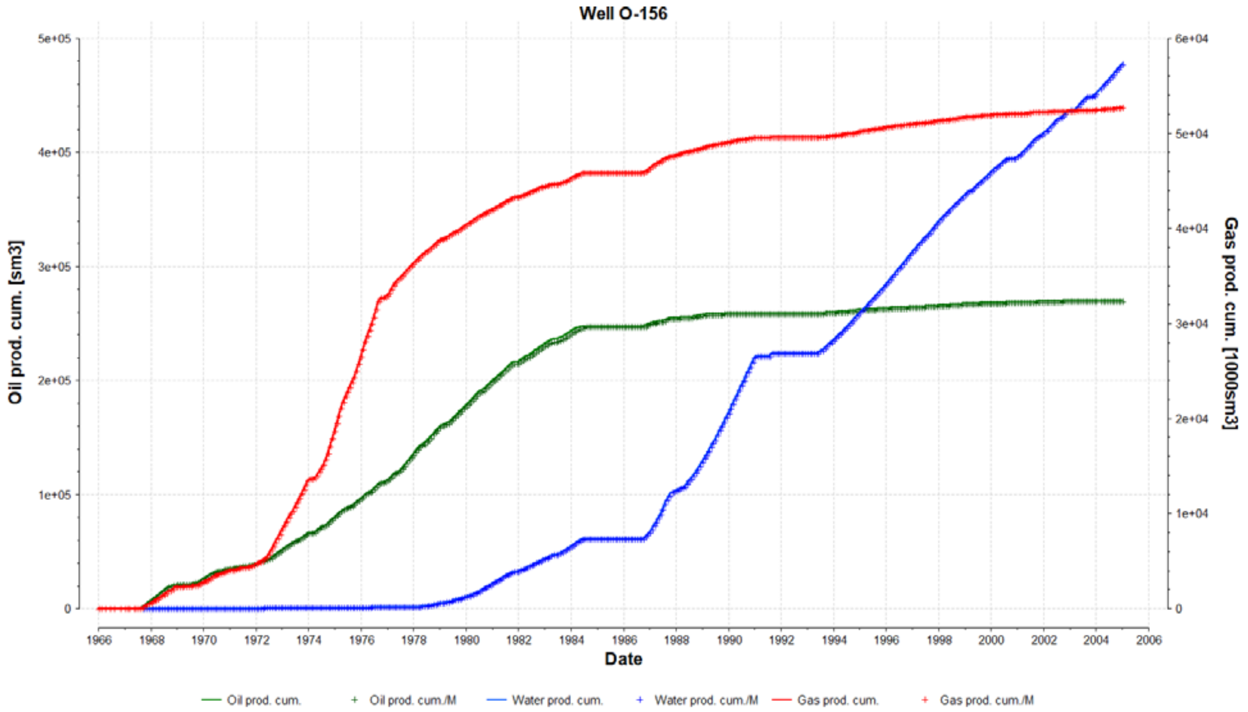

Figure C.3: Cumulative phase productions of the well O-156 when operated in drained mode.

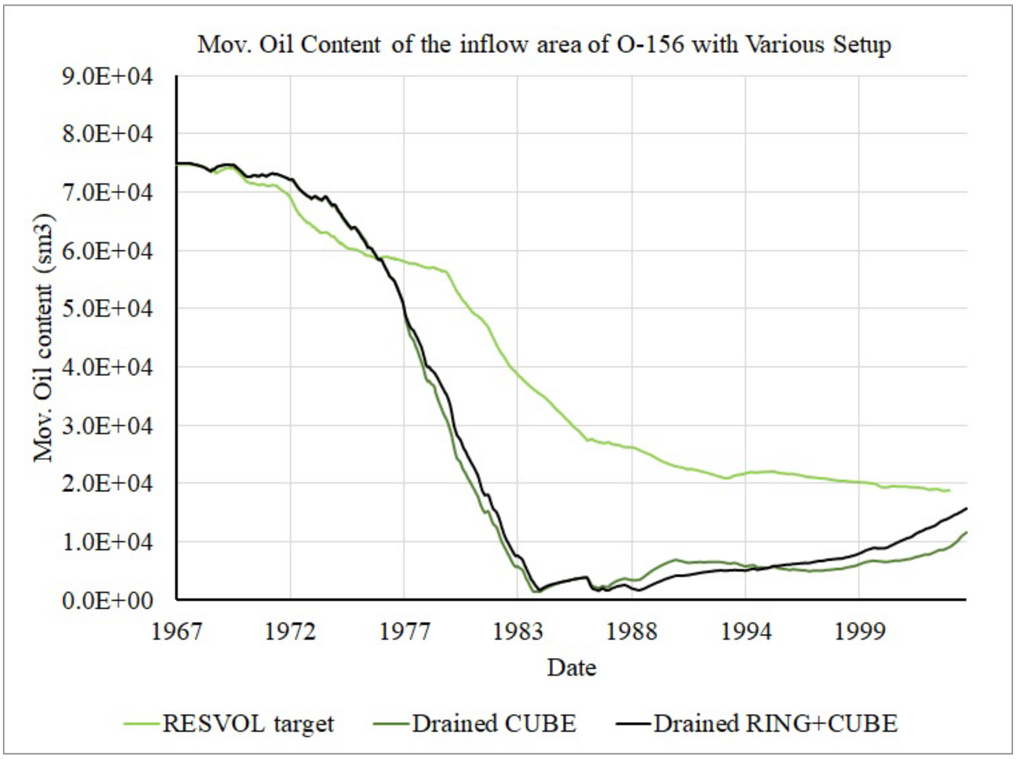

Figure C.4: Comparison of the movable oil content N of the estimated inflow area (D3) of the well, producing with RESVOL target vs two different drained operation modes.

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Nomenclature and Abbreviations

Symbols

A	-	area, [m²]
B	-	formation volume factor, [-]
d	-	distance, [m]
k	-	permeability, [mD]
L	-	length, [m]
m	-	gas cap factor, [-]
N	-	original oil in place, [sm³]
N_P	-	cumulative oil production, [sm³]
OOIP	-	Original Oil In Place, [kmol]]
P_c	-	capillary pressure, [bar]
p	-	pressure, [bar]
q	-	flow rate, [m³/s]
R_s	-	solution gas-oil ratio, [sm³/sm³]
S	-	phase saturation, [-]
t	-	time [days]
V	-	volume, [m³]

Greek Symbols

ϕ	–	porosity, [-]
µ	-	viscosity, [cp]
ρ	-	density, [kg/m³]

Abbreviations

BHP	-	Bottom-Hole Pressure
DV	-	Drainage Volume
GOR	-	Gas Oil Ratio
HM	-	History Matching
MV	-	Model Validation
MB	-	Material Balance
OOIP	-	Original Oil In Place
OWC	-	Oil Water Contact
PHDG	-	Professor Heinemann's Doctorate Group
PI	-	Productivity Index
PUNQ	-	Production Forecast with Uncertainty Quantification
PVT	-	Pressure-Volume-Temperature

SCAL - Special Core Analysis
TPPM - Target Pressure and Phase Method
WC - Water Cut