Brza i pouzdana procjena kvalitete ležišnog modela na temelju dinamičkog ponašanja ležišta

Fast and Reliable Assessment of a Reservoir Model Quality on the Basis of Dynamic Behaviour

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Sažetak

U članku je opisana prva uspješna praktična primjena TPPM metode (*Target Pressure and Phase Method*) na ležištu sa sekundarnom plinskom kapom i komponentnim modelom. Metodom se mogu dobiti točni protoci na granicama ležišta i na lokacijama bušotina u cijelom vremenskom intervalu proračuna ponašanja ležišta, bez modifikacije statičkih parametara, relativnih propusnosti ili graničnih zasićenja. Za 13 od 21 bušotine oglednog polja postignuta je savršena podudarnost protoka triju faza. Primjenom TPPM metode uspjelo se odmah jasno izdvojiti područja statičkog modela koja zahtijevaju modifikacije prije samog početka usuglašavanja historijata proizvodnje.

Abstract

The article presents the first successful industrial application of the Target Pressure and Phase Method (TPPM) on a reservoir with secondary gas cap and a compositional fluid model. The method can provide correct in- and outflow at the boundaries and at the well locations over the entire calculated time interval of reservoir operations, without modification of the static parameters, relative permeabilities or endpoint saturations. For 13 out of 21 wells of the field example a perfect match of three-phase rates was achieved. The TPPM helped to identify immediately and clearly static model-regions, which do not fulfil dynamic requirements and need modifications before a history matching process could start.

1. Introduction

With the aim to assess reserves and to forecast production, the ultimate goal of reservoir simulation would be to create a digital twin of the underground system, describing its state in its entire lifecycle. Hard data about the system's past is available only at the measurement points. Therefore, it is necessary to provide a model, which accurately reproduces these observations. Before starting with the dynamic modelling or history matching, this ability of the static model must be proven, which is one of the main applications of the Target Pressure and Phase Method (TPPM). The underlying theory and applications of the TPPM on test cases and limited field examples have been published by Professor Heinemann's Doctorate Group (PHDG) members since 2010 (Heinemann et al, 2010; Steiner, 2015; Mittermeir et al, 2016). Shortly summarizing, the TPPM utilizes the three-phase rates of all wells, the observed static bottom-hole pressures and the average region pressures as inputs for the simulator, and it searches for conditions under which the observations could be realized. Meanwhile, neither the static parameters nor the relative permeabilities and endpoint saturations are modified.

The boundary conditions for the calculation are given by (1) automatically matched regional pressures by inflow/outflow of water through the boundary and (2) automatically matched well production. Due to this characteristic, it was formerly called an assisted history matching technique. Although it was emphasized, that instead of immediately tuning an upscaled geological model to match the dynamic data, the engineer should first focus on proving the possibility of it. With this method, directly assessing the quality of a static reservoir model becomes possible in one single run (Mittermeir et al, 2016).

This work was carried out by PHDG in cooperation with MOL Hungarian national oil company, using H5, a multipurpose research simulator offering TPPM features. The presented field case is a typical hydrocarbon reservoir in the Pannonian Basin. The geology, the important stages of operation history of the exercised field, and the features of the used static and dynamic models are introduced. Then a detailed model validation workflow, from the preparatory steps to the evaluation of the results, showing technical considerations when using TPPM is presented. The clear benefits for a possible ensuing history matching are explained.

2. Description of the Field

2.1. Geology

The geology of the field is introduced based on the work of MOL experts Molnár (2012), Volford (2017) and Gajda (2017). The field was discovered in 1972 as an undersaturated oil reservoir. Its structural evolution goes back to Prealpian ages and Variscan-orogeny. The reservoir rock is an agglomeration of Palaeozoic, Mesozoic (Lower-and Upper-Triassic) and Miocene features. It is heterogeneous, consists of a Lower-Triassic Quartz-Sandstone with clay-shale beds (serving as a vertical seal) a Middle-and Upper-Triassic Dolomite-breccia, Miocene breccia and conglomerates of Dolomite, Metamorphite, Sandstone and Quartzite. The seal rock of the trap is a Lower-Pannonian Calcite-marl, covered by a thick shale-marl deposit. The major rock type of the Palaeozoic basement is fractured schist.

In reservoir rocks older than Miocene age, the storage potential can account for primary porosity or fracture-created voids: in the latter case the original porosity is not considerable. On the contrary, in the Miocene the primary porosity becomes significant, and the fractures have a minor contribution.

According to the newest interpretation, 73% of the STOOIP is stored in the Miocene reservoir rocks, 18% appears in the Triassic Dolomite, and the rest is stored in the Triassic Sandstone.

Table 1: Reservoir fluid properties

Gas		Oil		Water	
Density (kg/m^3)	1.01380	Density (kg/m^3)	810.4	Density (kg/m^3)	999.1
FVF (–)	0.00535	FVF (–)	1.92030	FVF (–)	1.06330
Viscosity (cP)	0.04311	Viscosity (cP)	0.17000	Viscosity (cP)	0.20408
		Bubblepoint pres. (bar)	300.0	Viscosibility (1/bar)	0.00013
		Solution GOR (m^3/m^3)	257.0	Compressibility (1/bar)	0.00005

2.2. Initial state and reservoir fluids

At 2562 m, the initial reservoir conditions were 331 bars and 140°C. Under these circumstances, no gas cap was identified by tests. The bubble point pressure value was concluded to be in the range of 300-314 bars, which is close to the initial reservoir pressure. The initial WOC is at 2630 m depth below sea-level. The reservoir fluid properties are shown in **Table 1.**

2.3. Production and pressure history

The oil production rate, after a sharp increase, reached its peak in 1980. Except for workover periods, the individual producers were in continuous operation. The reservoir is a continuous hydrodynamic unit, which is supported by a weak aquifer. By 1981, the average reservoir pressure dropped to 250 bars, from which point forward the strategy was pressure maintenance. The water injection started with the re-completion of few wells, since then, more water injector wells were drilled. Today, the network consists of 4 peripheral infills and 21 producers. In 1986, a new completion scheme became necessary, as the field development advanced, to avoid excessive water production. Between 1975 and 1990, the average GOR of the reservoir was below 300 sm3/sm3. In the following four year-lasting period, the secondary gas cap was exploited, which appears as a peak on the field GOR curve. Later the GOR stabilized at around the initial value again. The contribution of the wells to the field-totals is imbalanced and show a high range of WC-s and GOR-s.

3. Available Geological and dynamic models

3.1. Geological modelling

The geological model was built based on MOL inhouse interpretations. The used structural realization has a grid size of 50×50 m in horizontal, and 2 m in vertical direction. The grid was adjusted to picks.

Four different facies types/flow units were identified, each containing rock types from more geological ages. Overall, 7 rock types were used to build up the four flow units. Single porosity was used only. Vertical trends were used to create facies volume fraction, 2D krigged maps to constrain facies, variograms to correlate properties in the formation. 3% porosity and 0.1 mD permeability cut-offs were used to define reservoir quality regions (Volford, 2017). Cells with small values were set inactive, resulting in a lack of connectivity as can be seen on **Figure 1.**

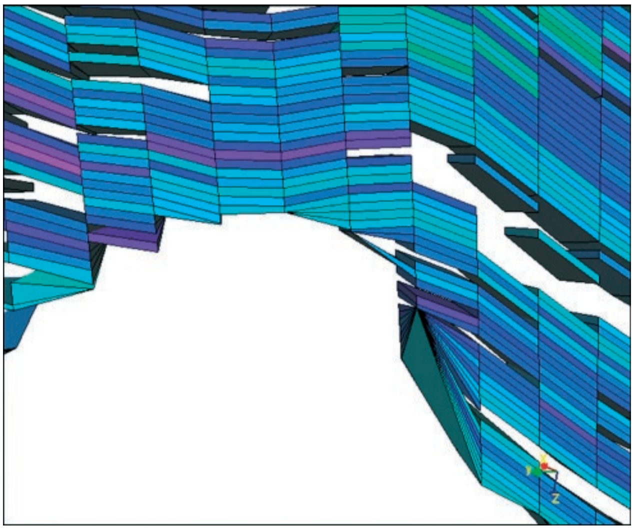

Figure 1:The same distorted grid with low connectivity was used for the volumetric calculation and dynamic modelling.

3.2. The initial dynamic model

This dynamic model used a black oil type fluid description, with black oil and wet gas property tables. The initial gradient for both dissolved gas and vaporized oil versus depth was assumed to be constant. The equilibrium initialization was referenced to the grid points (block centres). The HC weighted reservoir pressure was in agreement with the reported values. Tabulated relative permeability curves and Stone-2 three-phase model were used. Oil-water capillary pressure was considered, gas-fluid capillary pressure data was not available.

To save time, the dynamic modelling was carried out in the same distorted grid as the volumetric calculation as can be seen on **Figure 1**. Due to the characteristics of the grid, cells with an increased number of neighbours, and several sharp-end cells occurred along pinch-outs. The uneven cell-volumes are not ideal for flow simulation, due to the potential error, excessive run-times and instabilities. The run was carried out between 1974/05/01 and 2013/01/01.

Following the usual reservoir engineering approach, history matching was performed (utilizing E100/E300 software packages) based on one of the possible static model realizations, and then this model was used for investigating future development scenarios. During history matching, the wells were operated with a reservoir volume target rate and the aquifer as with Fetkovich-model. The match of the field totals

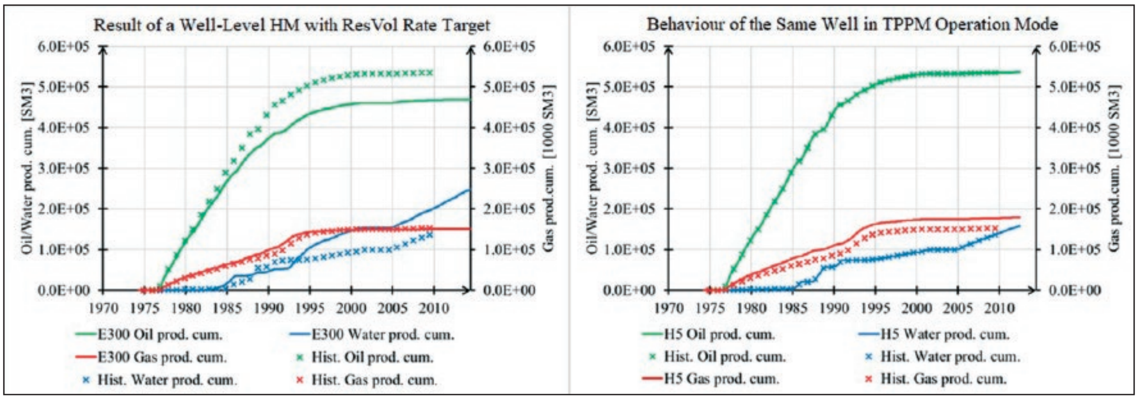

Figure 2: Result of a well level history match with reservoir volume rate target, and the behaviour of the same well in TPPM operation mode

and the reservoir pressures are satisfactory, but the well-by-well three-phase match is poor as can be seen on **Figure 2.**

3.3. Conversion of the model

1st step: E100–E300

The model validation feature was originally developed for models with a compositional fluid description; therefore, the PVT was converted to compositional format with 7 pseudo-components and Peng-Robinson EOS. Criteria towards this compositional model were to be consistent with the black oil type: this was tested by switching to E-300 software. Besides this, other inputs and settings were identical to the E-100 model. The equivalency of the fluid models was proved by checking the consistency of calculated initialization, production and pressure results between the black oil and the compositional case.

2nd step: E300–H5

The similar input data structure, the support of E300 keywords enable a swift conversion to H5 with small effort. The H5 input, as far as it was feasible, was kept identical to ECLIPSE. To achieve consistency of the two models, the viscosity correlations and the volume shifts were calculated according to E300 calculation procedures. Besides, the H5 internal transmissibility calculation was disabled, and E300 non-neighbourhood connections and transmissibility were read in.

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. To ensure that both the H5 and the E300 model lead to the same conclusions, it was necessary to make sure that the H5 dynamic model is similar – to the E-300 model. Therefore, during the conversion process, the H5 runs were permanently cross-checked against the E300 dynamic model with identical setup. The consistency of the results indicates that the conversion was successful.

4. TPPM Modelling Workflow

4.1. Model validation theory and methodology

Instead of a detailed technical description, this paper refers to former related works of PHDG. According to the principles of model validation as underlying the TPPM, an integrated static-dynamic model must be elaborated in one simulation run, without modification of the static parameters, relative permeabilities or endpoint saturations. The results of measurements (usually the production rates of the wells, well flowing or static pressures and RFT data) must be recognized as the only reliable source of information. During the simulation run, these should be used as an input for the model/simulator. The model is validated if the given realization has the ability to reproduce the measured results. It is emphasized, that the underground fluid movements can be described correctly only if the above-mentioned conditions are assured. If it is possible, then the static model is a good basis for further improvements e. g. by history matching means.

For a long time, no such tool existed, which would be applicable for model validation. First in 2010, Heinemann and Mittermeir prognosed a method and a technical solution. Their method is based on two pillars, each responsible for fulfilling the pressure and the 3-phase production targets,

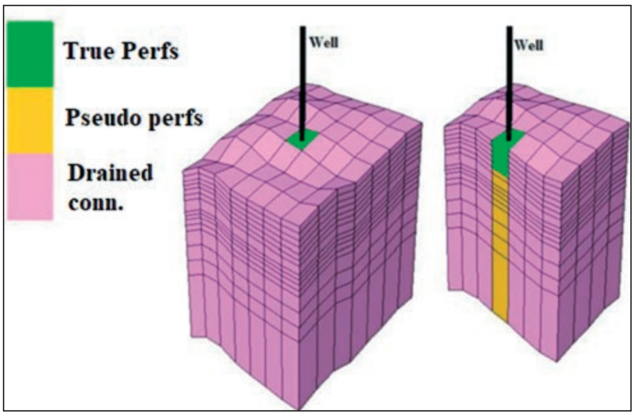

Figure 3: Elements of the drainage volume (Mittermeir et al, 2016)

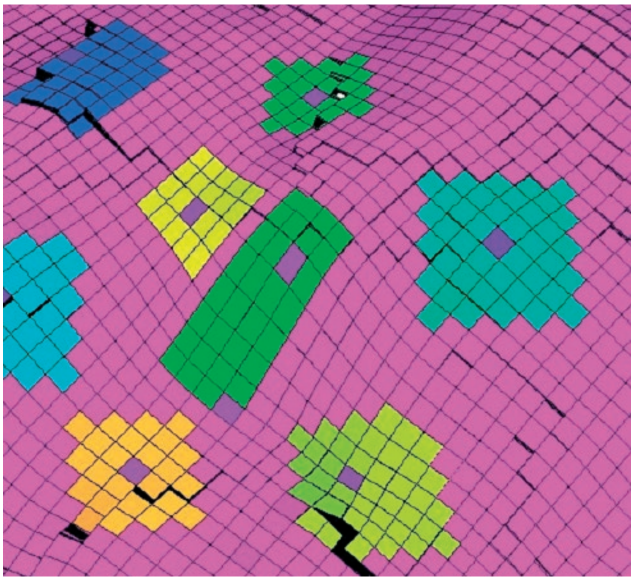

Figure 4: The assignment of the steady, ring–and cuboid–shaped drainage volumes around the wells avoids overlapping

and those can be used independently. With Target Pressure Method, the reservoir pressure is maintained on the required level by the automatic operation of the aquifer through the original aquifer connections. For this, the modeler must identify regions, determine their average pressure development and assign boundary segments to them. At the end of every run, the optimal parameters of Hurst-van Everdingen, Carter-Tracy, and Fetkovich aquifer models will be correlated. (Steiner, 2015) The Target Phase Method assures the correct three-phase production of all the wells by enabling them to automatically search for the required amounts of phases in their entire inflow area. To keep the relation with the reality, Mittermeir et al (2016), constructed the numerical representation of a well of three elements: 1. the real perforations along the trajectory, 2. the pseudo perforations placed on the trajectory and 3. supplementary chosen cells forming the drainage volume, as seen in **Figure 3**. At every non-linear iteration step, the actual target molar rates of oil and gas must be distributed among the perforations. Since 2010, both pillars of the method are implemented and operational, improved regarding general applicability and numerical stability. Since 2019 it is applicable for BO and compositional fluid description and it offers an automatic convergence to the model well.

4.2. Preparation for the runs

With the conversion, the H5 model is obtained, which serves as the basis for the model validation run. For TPPM, additional settings/input are needed, such as pressure regions, target pressure boundaries, and well-drainage volumes. Since MOL has carried out material balance calculations already, the same reservoir pressure data was used as a target, and the original aquifer connections have been chosen as a target pressure boundary. The pressure measurements indicate good communication across the entire reservoir; therefore, one target pressure region was enough to assign to the entire volume.

For the definition of the well drainage volumes, the following was considered:

1. It is advisable to keep the relation with the real inflow area of the well. The volume should approximate the true drainage volume. Smaller volumes can be applied, which still fulfil the production requirements.
2. A volume is time dependant, due to well interferences. The H5 offers the possibility of altering the settings in time, but for modelling purposes, those were regarded as steady. Overlapping of two drainage volumes was always avoided, as shown on **Figure 4**.
3. It is possible but not advised to temporary discard a well from the drainage volume operation during the model validation. Although, this option can be useful in history-matching/tuning a near-well region.
4. The volume should not cross a target pressure region boundary.

Technically, the drainage volume can be an arbitrary heap of cells around the well, which approximates the real drainage volume the best, but in this example, the user had to asses to the following possible options offered currently for manual assignment:

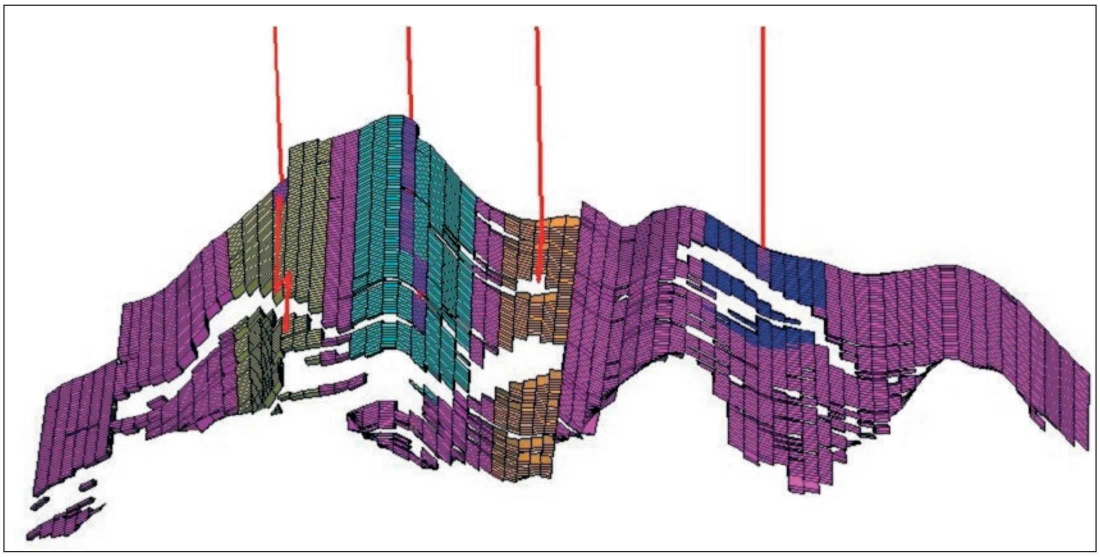

Figure 5: Cross section, showing normal–and vertically extended drainage volumes

1. The drainage volume is concentric and symmetric cylinder around the trajectory (also called RING), formed by the 1st,2nd etc neighbours of the open perforations or all defined perforations.
2. The cuboid shape (called CUBOID or CUBE) is defined by the maximum deviation from the real perforations in 6 directions along I J K axes. It allows asymmetry in the horizontal extensions, mainly used to avoid overlapping of neighbouring drainage volumes.
3. Both types can be extended below the lowermost perforation, or above the uppermost one, as can be seen on **Figure 5.**
4. The RING-shaped volume can be restricted to the (spherical) vicinity of the open perforations. The cuboid-shaped volume is available along the entire trajectory (considering all defined perforations) only.

The final extent of the drainage volumes was formed after a few control-runs, see **Table 4.** The table shows each well's type (oil producer or water injector), the applied control modes (drained with three-phase target, net rate or liquid volume rate), the drainage volume's vertical extent (open perforations or trajectory) the shape of the assigned drainage volume (RING or CUBE) and its extensions. E. g. „trajectory RING 2" means a cylinder, centred around all defined perforations and formed by the 1st and 2nd neighbours of those. In the case of cuboid, the extensions in 6 directions are shown. The drainage volumes were regarded mostly steady, but for stability reasons, some of the wells were reset to net (oil) rate or wet (oil+water) rate target.

4.3. The model validation run

The target pressure region and its boundary cells were assigned. The original Fetkovich aquifer was deactivated, instead, target pressure data file and TPM aquifer were defined. The original well definitions were modified to the desired format: instead of reservoir volume rate, a three-phase rate target was used. The well definition activates TPPM features in a time-dependent format. These features offer different levels of convergence to the model well. Namely: the multipliers for the perforation inflow coefficients, opening new perforations on the trajectory and opening drained perforations inside the drainage volume. For the test case, the third level was applied only, as this is sufficient

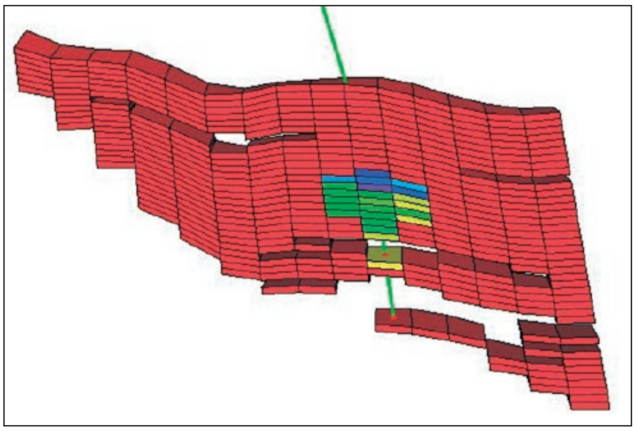

Figure 6: Self–shrinking characteristics of the drainage volume

to validate the static model. Characteristically, the well shrinks the production from the drained volume to the smallest possible heap of cells around the trajectory, as can be seen on **Figure 6.**

The time-step regulation was optimized to similarly favourable CPU times as the Eclipse run, as can be seen in **Table 2** and **Table 3.**

Table 2: Well operation modes and drainage volume assignments.

Well	Date	Type	Control	Extent	Shape	Z –	Z +	Y –	Y +	X –	X +
Prod-1	01/06/1974	oilprd	drained	trajectory	ring 2	1	100				
Prod-2	01/06/1974	oilprd	drained	trajectory	ring 2	1	100				
Prod/Inj-3	01/06/1974	oilprd	drained	trajectory	ring 2						
	01/09/1981	watinj	net rate								
Prod-4	01/08/1975	oilprd	drained	trajectory	cube	1	500	4	4	4	0
Prod-5	01/06/1974	oilprd	drained	trajectory	cube	1	10	3	0	3	3
Prod/Inj-6	01/06/1974	oilprd	drained	trajectory	cube	1	10	2	2	1	3
	01/09/1981	watinj	net rate								
Inj-7	01/09/1980	watinj	net rate								
Prod-8	01/06/1974	oilprd	drained	trajectory	ring 2	1	200				
Prod-13	01/03/1975	oilprd	drained	trajectory	ring 3	1	200				
Prod-14	01/02/1977	oilprd	drained	trajectory	ring 2	1	200				
Prod-15	01/04/1976	oilprd	drained	trajectory	ring 4						
Prod-20	01/01/1980	oilprd	drained	trajectory	ring 3	1	500				
Prod-21	01/09/1979	oilprd	drained	trajectory	ring 3						
Prod-22	01/07/1979	oilprd	drained	trajectory	cube	1	10	1	1	5	1
Prod-23	01/02/1978	oilprd	drained	trajectory	ring 3	1	50				
Prod-24	01/12/1978	oilprd	drained	trajectory	ring 3	1	300				
Prod-25	01/06/1979	oilprd	drained	trajectory	ring 4	1	550				
	01/01/1985	oilprd	liquid rate								
Prod-26	01/07/1979	oilprd	drained	trajectory	cube	1	500	2	2	1	2
Prod-27	01/04/1978	oilprd	drained	trajectory	ring 3	1	300				
Prod-28	01/05/1984	oilprd	liquid rate								
	01/01/1978	oilprd	drained	trajectory	ring 3	1	460				
Prod-29	01/01/1984	oilprd	liquid rate								
	01/03/1978	oilprd	drained	trajectory	ring 3	1	400				
Inj-30	01/06/1984	watinj	net rate								
Prod-31	01/12/1988	oilprd	drained	trajectory	cube	1	500	2	2	2	0
Prod-32	01/11/1978	oilprd	drained	trajectory	ring 3	1	350				

Table 3: Timestep regulation

Timestep regulation in days	
1974.05.01.	0.1 – 10
1982.01.01.	0.1 – 4
1984.01.01.	0.1 – 5
1988.01.01.	0.1 – 10

Table 4: Run performance statistics

Run performance statistics	
Number of Timesteps	1777
Number of Timestep Repetitions	8
Average timestep length (day)	7.9
CPU time (sec)	51016.3
Solutions/Timestep	2.4
Equations/Block (Degree of Impl.)	1.8

4.4. Evaluation of the results

The evaluation of the results is done by the comparison of the target-and calculated cumulative well-productions and reservoir pressure curves. The reservoir model is validated, if:

a) The calculated average pressure development for all identified volume units nearly follows the observed trends.

b) All TPPM operated wells (drained control) can provide the historical oil, gas and water rates over the entire production time.

After the successful assurance of the pressure-criteria, as can be seen on **Figure 7**, the optimal aquifer productivity index values were determined up to four equal time-intervals.

It can be seen, that in the case of a few evaluated wells, the necessary amounts of phases were not present in the drainage volume. One can conclude that the geological model has an overall good quality, with some local discrepancies, which needs revision. **Table 5** contains the statistics on the evaluated wells only (excluding injectors and those with a short production history). If the drained (3-phase) control mode is applied, only an excellent three-phase match can be accepted as successful. E. G. Prod-2 fails to match the water phase from the real perforations. This indicates that at the well location, the geological model is not ideal, because it contains insufficient amount of water-not enough water can flow in. Although Prod-13 shows a perfect match of the oil and water phases, the gas is slightly mismatched. The well is supposed to produce with solution gas only, the oil phase in undersaturated. That the calculated curve runs slightly below the target (similarly to **Figure 2**) indicates the lack of solution gas in the oil. The match is accepted, but this fact must be considered when revising the drainage volume.

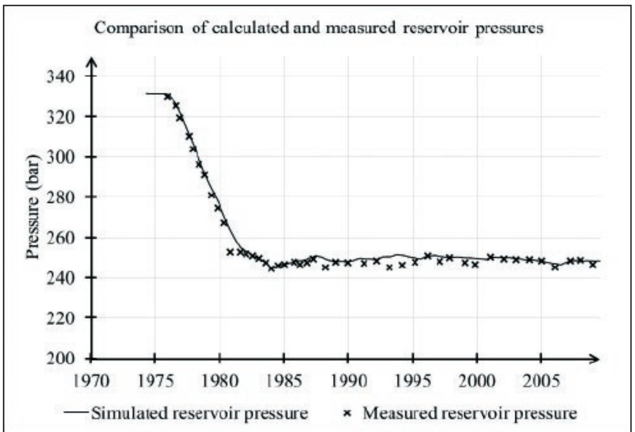

Figure 7: Result of the automatic aquifer operation

Table 5: Analysis of the matching success

Well	Control	Oil Match	Water Match	Gas Match
Prod-1	drained	ok	ok	ok
Prod-2	drained	ok	failed	ok
Prod/Inj-3	drained	ok	ok	ok
Prod-4	drained	ok	ok	ok
Prod-5	drained	ok	ok	ok
Prod/Inj-6	drained	ok	ok	ok
Prod-8	drained	failed	ok	ok
Prod-13	drained	ok	ok	ok (undersat)
Prod-14	drained	ok	ok	ok (undersat)
Prod-15	drained	ok	failed	ok
Prod-20	drained	ok	failed	ok
Prod-22	drained	ok	ok	ok
Prod-23	drained	ok	ok	ok (undersat)
Prod-24	drained	ok	ok	ok (undersat)
Prod-25	drained	ok	ok	ok
	liquid rate	failed	failed	failed
Prod-26	drained	ok	failed	ok (undersat)
Prod-27	drained	ok	ok	ok (undersat)
Prod-28	liquid rate	failed	failed	failed
Prod-29	liquid rate	ok	ok	ok
	drained	ok	ok	ok
SZE-31	drained	ok	failed	ok
SZE-32	drained	ok	ok	ok

The pattern of a non-matching wells, as can be seen on **Figure 8**, fences off a relatively consistent area, where the static model is not ideal. It is clearly shown, that for these wells a conventional history matching approach could not be successful and a revision of the static model in these areas is necessary.

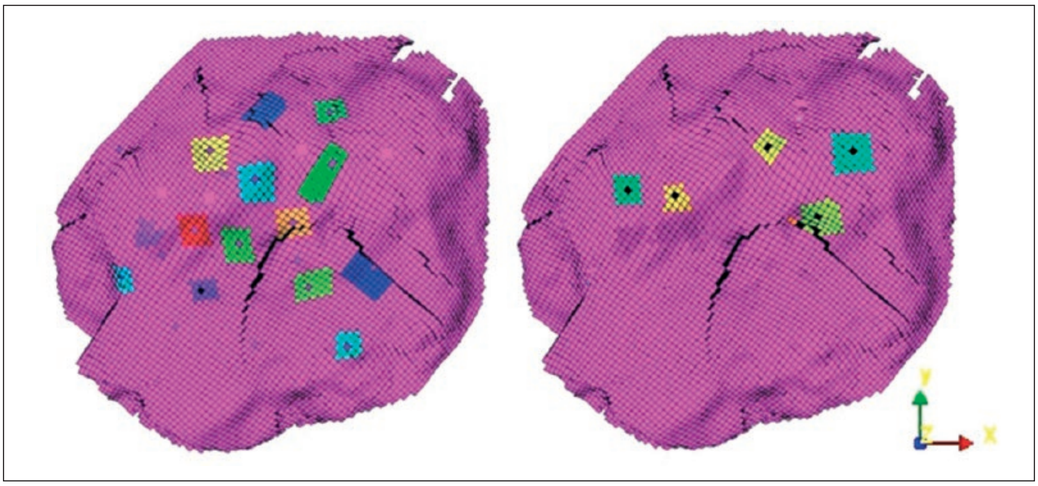

Figure 8: Pattern of matching wells (left) and non–matching wells (right)

5. Summary

The idea of dynamic validation of static reservoir models, instead of history matching, is new. Until now, it was consciously applied in some cases only, usually under the restriction of publication. For this reason, it is too early to present a generally applicable methodology. It should be admitted that a better procedure than applied in the test example could exist too. Nevertheless, here a successful application of the method is shown on a brown field, history matched model with compositional fluid description.

The setup of the model validation run did not require any data other than an adequately long production and pressure history. One single validation run was performed, after conversion to H5 format. During this run, the model was operated by TPPM, assuring that all the wells productions and the reservoir pressures were in an agreement with the measured data at any point in time during the entire history. In the case of a few wells it was impossible to do so, indicating that improvement at certain locations of the static model is necessary.

6. Conclusions

- The value of the method is best shown when it is used for multi-phase flow, for a wide range of phase ratios, and wells with a long observation period. This includes oil producers where water cut and/or GOR is measured, gas producers with considerable liquid loading.
- The validation run can be performed at any time during the field development (and model building) process, before and during history-matching.
- The TPPM setup is easily achieved by only a few additional settings, which do not require special skills from the modeller.
- It is applicable for all well-types and a wide range of phase-ratios.
- The complexity of the demonstration example (secondary gas-cap, increasing water cut) was adequate to examine the applicability for various cases.
- The static model is of good quality, with local inadequacies only.
- It is desired to increase the level of connectivity in the model either by different property-cuts or by excluding the separated volumes. Cells with no or few neighbours impaired stability, and parts appeared hydrodynamically separated from the rest of the reservoir. Moreover, it unfavourably reshaped flow paths of water and gas, hindering their approach to the wellbore.
- Major stability issues can be mitigated by upscaling the grid into a coarser and more uniform structure with cells of appropriate shape and direction. The application of a flow-grid would also favourably reduce CPU times.

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