



# Analysis of multi-layered commingled and compartmentalized gas reservoirs

Mohamed A. Sallam<sup>1</sup> · Ahmed H. El-Banbi<sup>2</sup>

Received: 21 June 2017 / Accepted: 24 February 2018 / Published online: 13 March 2018  
© The Author(s) 2018

## Abstract

The evaluation and performance prediction of multi-layered compartmentalized gas systems can be difficult. This is mostly due to the uncertainties related to production allocation either within each commingled well or between interrelated reservoir compartments. This paper presents a model that can provide reliable estimates of the total gas in place for multi-layered commingled and compartmentalized reservoirs. The model is also capable of generating prediction profiles for every well in the production system in addition to forecasting individual layers production for each compartment. The proposed model is based on coupling the layered stabilized flow model for material balance calculation in commingled systems with communicating reservoir model that is used as material balance tool for compartmentalized gas reservoirs. The model has the flexibility to be applied for history matching and prediction purposes. In history matching, the model solves the equations simultaneously using optimization routine to find the best parameters of original gas in place (OGIP), deliverability coefficients and compartment transmissibility coefficients. The model requires the knowledge of initial reservoir pressure in every compartment, some rate production history and bottom-hole flowing pressures. The model can also utilize additional information such as shut-in pressures per layer, repeat formation tester and production logging tool measurements (if available) to improve the history match. For prediction, the model uses the estimated parameters (compartment OGIP, transmissibility coefficients between compartments and flow parameters for each layer) to calculate the production rates and reservoir pressures for every well/tank based on a provided bottom-hole flowing pressure. The model was verified against a commercial reservoir simulator for several synthetic cases. The model was also applied on different field cases to estimate OGIP and flow coefficients for every layer as well as compartment transmissibility coefficients. Moreover, calculation of cumulative gas transferred across the communicating reservoirs allows detection of poorly drained compartments, which could be included in future redevelopment plans.

**Keywords** Commingled gas reservoirs · Compartmentalized gas reservoirs · Production allocation · Material balance calculation

## List of symbols

### Terminology

$a$	Stabilized deliverability coefficient, (psia <sup>2</sup> /cp)/(Mscf/D)
$b$	Stabilized deliverability coefficient, (psia <sup>2</sup> /cp)/(Mscf/D) <sup>2</sup>
$C$	Compressibility, psi <sup>-1</sup>
$c_f$	Formation compressibility, psi <sup>-1</sup>
$c_w$	Water compressibility, psi <sup>-1</sup>

$e_1$	Normalized error measure given by Eq. 10
$e_2$	Normalized error measure given by Eq. 11
$\Delta e_{(l,x,y)}$	Indirect gas influx transferred from compartment (x) to compartment (y) in layer (l), MMscf
$G$	Original gas in place, MMscf
$G_{i(l,x)}$	Original gas in place of compartment (x) in layer (l), MMscf
$G_p$	Cumulative gas produced, MMscf
$G_{p(l,x)}$	Cumulative gas produced from compartment (x) in layer (l), MMscf
$\Delta G_{p(l,x,y)}$	Cumulative indirect gas transferred from compartment (x) to compartment (y) in layer (l), MMscf
$m(p)$	Real gas pseudo-pressure, psi <sup>2</sup> /cp

✉ Mohamed A. Sallam  
Msallam\_eng@hotmail.com

<sup>1</sup> Rashid Petroleum Company, Cairo, Egypt

<sup>2</sup> AUC/Cairo University, Cairo, Egypt

$m(p_{wf})$	Pseudo-pressure at bottom-hole flowing pressure, $\text{psi}^2/\text{cp}$
$m(\bar{p})$	Real gas pseudo-pressure at average reservoir pressure, $\text{psi}^2/\text{cp}$
$N$	Number of points used in optimization routine
$p$	Pressure, psia
$p_i$	Initial reservoir pressure, psi
$p_{wf}$	Bottom-hole flowing pressure, psia
$\bar{p}$	Material balance average reservoir pressure, psi
$p_{(l,x)}$	Material balance average reservoir pressure for compartment ( $x$ ) in layer ( $l$ ), psi
$q$	Gas production rate, Mscf/D
$q_t$	Total flow rate in a commingled system, Mscf/D
$q_{(l,x)}$	Gas production rate from compartment ( $x$ ) in layer ( $l$ ), Mscf/D
$S_w$	Water saturation, fraction
$T$	Transmissibility coefficient, $\text{Mscf}\cdot\text{cp}/\text{D}/\text{psi}^2$
$T_{l_{xy}}$	Transmissibility coefficient between compartment ( $x$ ) and compartment ( $y$ ) in layer ( $l$ ), $\text{Mscf}\cdot\text{cp}/\text{D}/\text{psi}^2$
$t_{\text{step}}$	Time step
$z$	Real gas compressibility factor
$\Delta t$	Time step
$\mu$	Gas viscosity, cp

### Abbreviations

BHSIP	Bottom-hole shut-in pressure
CR	Communication reservoir model
CGR	Condensate gas ratio
LSFM	Layer stabilized flow model
MCCR	Multi-layer commingled and compartmentalized reservoirs
OGIP	Original gas in place
PLT	Production logging tool
PVT	Pressure, volume and temperature
RFT	Repeat formation tester
scf	Standard cubic feet
THP	Tubing head pressure
VLP	Vertical lift performance
W.F.	Weighting factor

### Subscripts

$x$	Counter running over the wells located in the main compartment
$y$	Counter running over the wells located in the supporting compartment
$l$	Counter running over layers
$nl$	Total number of layers in the model
$t$	Time
$nt$	Total number of time steps

## Introduction

Material balance analysis is considered a powerful engineering tool when dealing with oil and gas reservoirs. In gas reservoirs which can be represented by simple volumetric tanks, a straight line relationship between  $(P/Z)$  and cumulative gas production exists. However, many gas reservoirs do not follow these simple assumptions. Therefore, several modifications have been presented to handle commingled gas reservoirs (Fetkovich et al. 1990; El-Banbi and Wattenbarger 1996, 1997; Juell and Whitson 2011) and compartmentalized gas reservoirs (Hower and Collins 1989; Lord and Collins 1989, 1992; Payne 1996; Hagoort and Hoogstra 1997; Sallam 2016). Although the complications related to either commingled gas reservoirs or compartmentalized gas reservoirs have been addressed, either model alone cannot be applied when both conditions coexist.

This paper presents a simple model that is capable of overcoming these limitations by coupling the explicit model for compartmentalized gas reservoirs proposed by Payne (1996) with layer stabilized flow model (LSFM) related to commingled gas reservoirs proposed by El-Banbi and Wattenbarger (1996, 1997). The proposed model presents an easy and reliable tool that can detect and assess reservoir compartmentalization in addition to commingled wells using production data and estimates of bottom-hole flowing pressure.

## Background

The proposed model is based on coupling the commingled gas reservoir model with the compartmentalized material balance model. The available models for commingled gas reservoirs and compartmentalized material balance are reviewed in the following sections.

### Commingled gas reservoirs

Commingled reservoirs are defined as reservoirs which are only connected through the wellbore. The main concept is that these reservoirs do not have any communication across reservoir boundaries. Fetkovich et al. (1990) investigated the major factors affecting the performance of multi-layered system with no cross-flow. He demonstrated that a decline exponent of a layered system is always larger than that of a single-layer system. He concluded that decline exponent value between 0.5 and 1 represents an evidence of layered reservoirs.

El-Banbi and Wattenbarger (1996) developed a method for matching production data of commingled gas reservoirs. The concept was that each layer production can be calculated

individually from the knowledge of the layer OGIP and flow coefficients. Assuming that the previous parameters are unique, each layer will exhibit different production performance during production history. The main assumptions required for utilizing this model were constant bottom-hole flowing pressure, pseudo-steady-state production across every layer and negligible non-Darcy flow coefficient.

Later, El-Banbi and Wattenbarger (1997) modified the layered stabilized flow model to overcome the limitations presented in the preceding model (El-Banbi and Wattenbarger 1996) related to constant bottom-hole flowing pressure and ignoring non-Darcy flow. Good results were achieved for moderate and high permeability reservoirs using the modified model. The model also proved its ability to handle long shut-in periods with considerable variation in the bottom-hole pressure (i.e., cross-flow between layers can be accounted for).

Juell and Whitson (2011) proposed a method which can be used to analyze multi-layered gas reservoirs with or without cross-flow through the formation using a modified backpressure equation. The model is capable of predicting pressure and rate for every layer within the system. Also, using this method can allow detection of productivity impairment within the system through continuous monitoring of well-head backpressure curves. Furthermore, prediction profiles can be created for no cross-flow cases by coupling material balance equation with layered backpressure equation.

### Compartmentalized gas reservoirs

A compartmentalized gas reservoir is defined as a reservoir that consists of two or more partially communicating compartments (e.g., faulted blocks that are partially communicating). The major effects related to the presence of compartmentalization have driven considerable attention toward the subject. Determination of poorly drained compartments will affect future development plans of these fields to increase their recovery and reserves.

Hower and Collins (1989) presented the first building block for an analytical model that detects reservoir compartmentalization using production performance. Their model is comprised of two tanks with a thin permeable barrier which allows gas influx/efflux between the tanks. Major restrictions have been imposed in the models' assumptions such as: The reservoir is under volumetric depletion with no water drive, single well is producing at constant rate, and gas properties are assumed to be constant.

Lord and Collins (1989) overcame some of the limitations of Hower and Collins model (1989) by introducing a model that can be used for multiple tanks. The main assumptions in Lord and Collins work were: conservation of mass, real gas equation of state and Darcy's law apply. Pressure and production history matching of the field performance with

the proposed model allow determination of OGIP in each compartment and transmissibility coefficients. Lord and Collins (1992) compared their model results with simulation of production history for gas wells in extensively compartmentalized fluvial gas system.

Payne (1996) presented an analytical model that permits material balance calculation for multi-compartmentalized gas reservoirs explicitly through calculating OGIP in tanks and communication factor between each pair. The flow calculation between compartments is based on pressure square formulation which may cause serious errors (in high pressure reservoirs), but it is simple and straightforward.

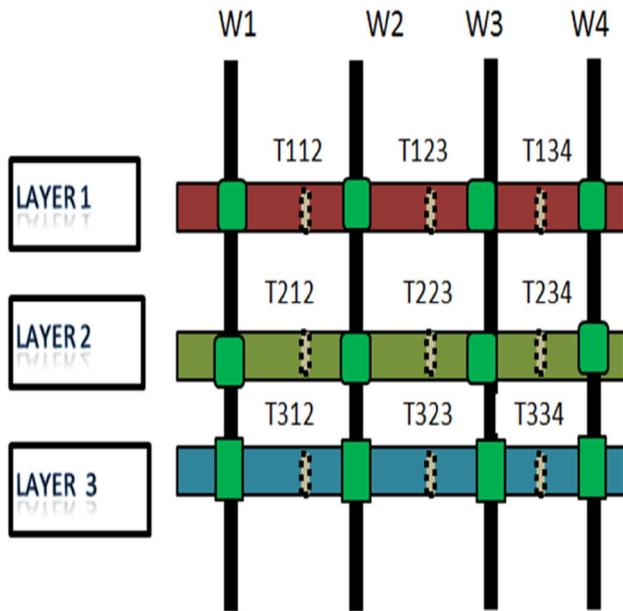
Hagoort and Hoogstra (1997) presented a numerical method for material balance calculation in compartmentalized gas reservoirs. The model is based on the integral form of material balance equation of each compartment rather than the differential form presented by Hower and Collins (1989), Lord and Collins (1989). The model runs an iterative scheme which accounts for pressure dependency of gas properties.

### Proposed model

In the proposed model, the gas reservoir is divided into compartments. The compartments can communicate among themselves across their boundaries based on transmissibility factors between each two compartments. The flow from wells within each compartment is controlled by the gas flow equation. Each compartment can contain an initial volume of gas and can contain up to one well. Material balance for each compartment controls the flow of gas between compartments and from the compartment to the well. The compartments pressure is tracked through time steps. Production from each well is also tracked every time step. The calculations of the proposed model are performed by coupling (1) the explicit model for compartmentalized gas reservoirs proposed by Payne (1996) and (2) layered stabilized flow model (LSFM) (El-Banbi and Wattenbarger 1997) for calculating wells production from commingled gas reservoir systems.

### Model description

Although the model can be used for any number of reservoir layers and any number of wells, a specific model example is described here for simplicity. An example of a compartmentalized gas reservoir model (MCCR) is shown in Fig. 1. This reservoir model example is composed of three separated layers. The layers are penetrated by four wells. Each layer is therefore divided into four compartments (with one well in each compartment). Transmissibility factors are assigned between every two compartments in each layer.



**Fig. 1** Example completion schematic for MCCR model (three separated layers and each layer is divided into four compartments)

### Model assumptions

The proposed model assumptions are:

- Initial reservoir pressure in every compartment is known. Gas can move between compartments based on pressure difference between connected compartments.
- Same gas exists in all compartments.
- Each well flows under boundary-dominated flow conditions.
- No water influx.
- Measured static reservoir pressure represents the average reservoir pressure in the compartment.
- Each compartment can contain maximum of one well or one well completion. Some compartments may not contain any wells.

### Model requirements (input data)

The main requirements for MCCR model are:

- Initial pressure of every compartment in the field.
- Reservoir temperature and either gas composition or gas specific gravity (required for PVT properties calculations).
- For history matching runs, production history of the each well in the field (gas production rate, bottom-hole flowing pressures and some static reservoir pressure points).

- For prediction runs, assumed future rate (or bottom-hole flowing pressure) is needed.

The model uses these input parameters for initialization by assigning initial pressure for every compartment. It also creates a complete PVT data table generated based on gas composition or gas specific gravity covering the expected range of operating pressures during field life. This table will be used as a lookup table which contains compressibility factor, gas viscosity, gas formation volume factor and real gas pseudo-pressure.

### Model parameters

The variables are assigned based on the number of layers, compartments and wells in the field. The declaration of the variables is as follows:

For every well:

Flow coefficients (a, b) describe every well completion and need to be defined as  $a(l, x)$ ,  $b(l, x)$ , where  $l$  and  $x$  represent the layer counter and the well counter, respectively.

Transmissibility coefficients representing the interaction between compartments in a particular layer have to be defined by the expressions shown below:

$$\text{No. of transmissibility factors, } n = \sum_{w=1}^w w - 1 \quad (1)$$

As an example for a single layer containing 4 compartments, the following matrix results.

$$\begin{bmatrix} T_{1-1-1} & T_{1-1-2} & T_{1-1-3} & T_{1-1-4} \\ T_{1-2-1} & T_{1-2-2} & T_{1-2-3} & T_{1-2-4} \\ T_{1-3-1} & T_{1-3-2} & T_{1-3-3} & T_{1-3-4} \\ T_{1-4-1} & T_{1-4-2} & T_{1-4-3} & T_{1-4-4} \end{bmatrix} \quad (2)$$

The compartment transmissibility coefficient is represented by  $T(l, x, y)$  where  $l$  represents the layer counter,  $x$  represents the compartment counter and  $y$  represents the neighbor compartment counter.  $T(l, x, x)$  is zero in all the series and  $T(l, x, y) = T(l, y, x)$ . Therefore, only the parameters above the matrix diagonal will have values, while the matrix diagonal and the lower half will be set to zero. In the above example, the only transmissibility coefficients with values other than zero will be  $T_{1-1-2}$ ,  $T_{1-1-3}$ ,  $T_{1-1-4}$ ,  $T_{1-2-3}$ ,  $T_{1-2-4}$ ,  $T_{1-3-4}$ .

To solve the four-well three-layer system described in the example diagram of Fig. 1, twelve compartments are assumed. The model variables are:

- 12 Darcy flow coefficients (12 a).
- 12 non-Darcy flow coefficients (12 b).
- 12 OGIP (for 12 compartments).
- 18 transmissibility coefficients (6 coefficients per layer).

This will result in 54 unknown parameters. Iterating through all these variables to match production rates from the wells and known static compartment pressure can be tedious and may generate inconclusive results. Therefore, simplification should be carried out by fixing some parameters based on geological knowledge of the area and well completion and production performance. Also, neglecting non-Darcy flow coefficient may be warranted in some systems (El-Banbi and Wattenbarger 1996, 1997).

Moreover, good understanding of reservoir behavior will assist in determining a suitable range for every parameter before running the optimization routine.

### Compartments calculations

The sequence of calculations for every compartment follows the logic presented below.

Equation (3) is used to calculate the production rate of every well completion in a compartment. The real gas pseudo-pressure developed by Al-Hussainy et al. (1966) is given by Eq. (4).

$$\left( m(\bar{p}_{(l,x)}) - m(p_{wf(l,x)}) \right) = a_{(l,x)} q_{(l,x)} + b_{(l,x)} q_{(l,x)}^2 \tag{3}$$

$$m(p) = \int_{p_b}^p \frac{2p'}{\mu z} dp' \tag{4}$$

The cumulative gas produced from a specific compartment is calculated from Eq. (5).

$$G_{p(l,x)} = \int_0^t q_{(l,x)}(t) dt = \sum_{i=0}^{NT} \Delta t \times q_{(l,x)}(i) \tag{5}$$

The cumulative gas production from a specific compartment at the end of the time step ( $t_{step}$ ) is used to calculate the compartment pressure at the beginning of the next time step ( $t_{step+1}$ ) by using Eq. (6).

$$\frac{p_{(l,x)}}{z_{(l,x)}} = \left( \frac{p}{z} \right)_{i(l,x)} \left( 1 - \frac{G_{p(l,x)} + \Delta G_{p(l,x,y)}}{G_{i(l,x)}} \right) \left( \frac{1 - \Delta p_{(l,x)} \times (c_w S_w + c_f)}{(1 - S_w)} \right) \tag{6}$$

The calculated reservoir pressure is used to calculate the production rate in the same compartment at the following time step. The model repeats the calculations for all the time steps of the history by solving Eqs. (3, 5 and 6) subsequently.  $\Delta G_{p(l,x,y)}$  represents the gas influx/efflux into or from each compartment, and its calculation is shown in the next section.

The model also calculates the total gas produced from any well with completion in more than one layer at the end of each time step from Eq. (7).

$$q(x)_{x=1 \rightarrow nx} = \sum_{l=1}^{nl} q(x, l) \tag{7}$$

### Integration between communicating compartments

To calculate the impact of communication between compartments, it is important to include the amount of gas influx/efflux between different compartments. The model uses Eq. (8) to calculate the amount of gas influx/efflux between different compartments resulting from different compartment pressures every time step (indirect production).

$$\Delta e_{(l,x,y)} = T_{(l,x,y)} \times (m(p_{(l,x)}) - m(p_{(l,y)})) \tag{8}$$

Cumulative gas influx/efflux between compartments due to difference in compartment pressure every time step is calculated from Eq. (9).

$$\Delta G_{p(l,x,y)} = \int_0^t \Delta e_{(l,x,y)} dt = \sum_{i=0}^{NT} \Delta t \times \Delta e_{(l,x,y)}(i) \tag{9}$$

### Objective function

A comparison takes place between the calculated values of well rates and compartment pressure generated by the model with observed production and available shut-in pressure data. The error between model and observed values is calculated using either objective function given by Eqs. (10) or (11).

$$e_1 = \frac{1}{N_{Rate}} \sum_{i=1}^{N_{Rate}} \left| \frac{Rate\ Data - Model\ Rate}{Rate\ Data} \right| + W.F. \times \frac{1}{N_{Pressure}} \sum_{i=1}^{N_{Pressure}} \left| \frac{Pressure\ Data - Model\ Pressure}{Pressure\ Data} \right| \tag{10}$$

$$e_2 = \frac{1}{N_{Rate}} \sqrt{\sum_{i=0}^{N_{Rate}} \left( \frac{Rate\ Data - Model\ Rate}{Rate\ Data} \right)^2} + W.F. \times \frac{1}{N_{Pressure}} \sqrt{\sum_{i=0}^{N_{Pressure}} \left( \frac{Pressure\ Data - Model\ Pressure}{Pressure\ Data} \right)^2} \tag{11}$$

The optimization routine of MS Excel Solver is used in this work. The solver tries to minimize the objective functions given by either equation by changing the model parameters selected by the user (Darcy and non-Darcy flow coefficients of wells completions in every layer, OGIP of each

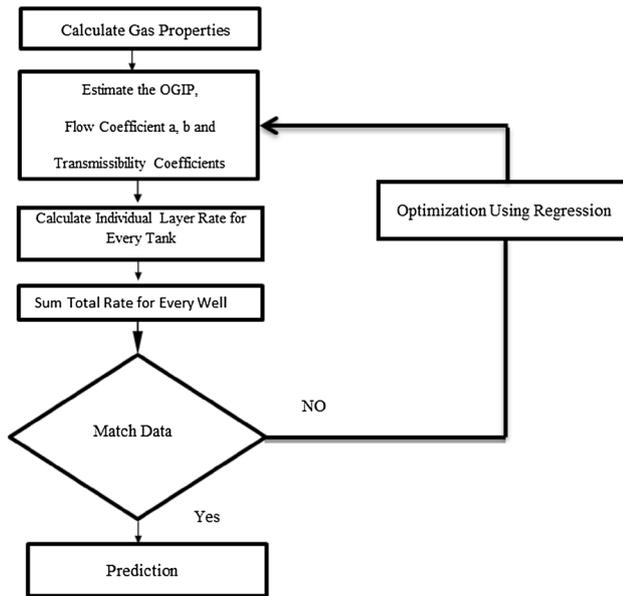


Fig. 2 Flowchart of MCCR model

compartment and transmissibility coefficients between every two compartments). A weight factor can be used for shut-in pressure data for specific to give higher weight for matching compartment pressure if the user desires.

### Model sequence of calculations

The procedure used in model calculations is shown in the flowchart of Fig. 2. The sequence of calculations is as follows: The model calculates the gas flow rate directly from any compartment with a well completion and indirectly due to communication between every two compartments for any time step using Eqs. (3) and (8). Then, the cumulative gas produced directly and indirectly from the start of time and until the end of the time step is determined using Eqs. (5) and (9). Afterward, the direct and indirect cumulative gas produced will be used as inputs to the material balance equation Eq. (6). The average compartment pressure is calculated from Eq. (6) iteratively. The calculated compartment pressure is then used at the starting pressure of the next time step ( $t_{\text{step}+1}$ ) to calculate the gas production rates of the wells completions and the influx/efflux between different compartments for the next time step. At every time step, the model calculates the total production rates of different wells by calculating the sum of the gas produced from different layer completions for every well using Eq. (7).

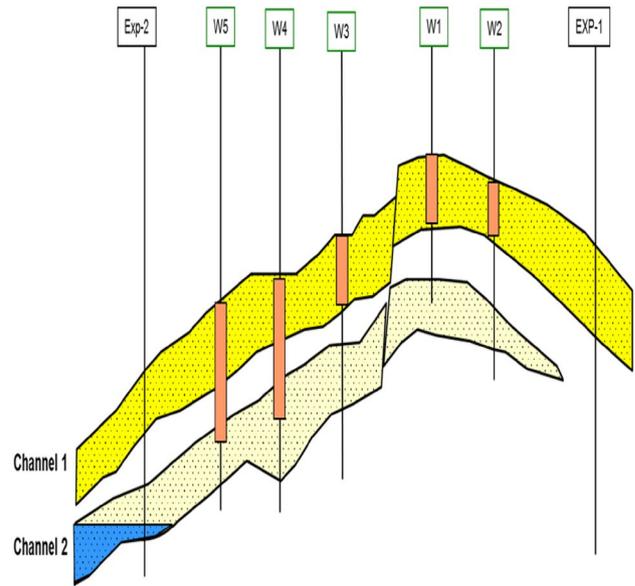


Fig. 3 Schematic of field case 1 wells completion

### Model validation

Before using the proposed model for field cases, the model was verified against a commercial finite difference black oil reservoir simulator. Several cases representing variable conditions of commingling and compartmentalization were used to generate pressure and production data from the reservoir simulator. The pressure and production history for the different cases were used as input for the MCCR model for different synthetic cases. The estimated parameters (compartment OGIP, completion flow coefficients (a and b) and compartments transmissibility coefficients) were compared with the known parameters from the reservoir simulator. The MCCR model was verified with good results (Sallam 2016). The interested reader can consult Sallam (2016) for the details of verification cases. For the sake of space, we only present applications of the model to actual field cases in this paper.

### Field applications

In this section, we present two applications of MCCR model for analyzing and forecasting actual field data for two gas reservoirs producing from layered and compartmentalized reservoirs. The compartments exist due to inter-field faults. Several wells in these field cases are completed as commingled wells producing from more than one layer.

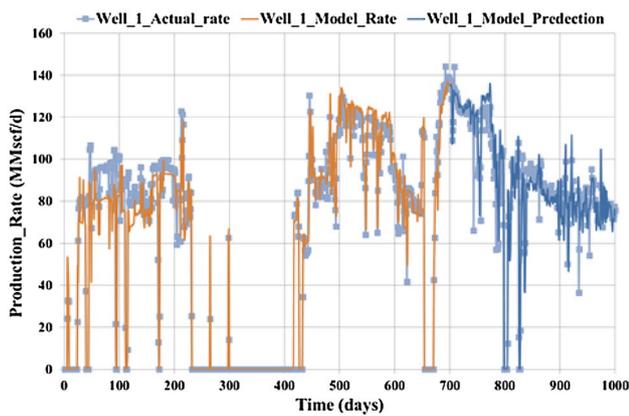


Fig. 4 Well 1 rate history match and prediction (case 1)

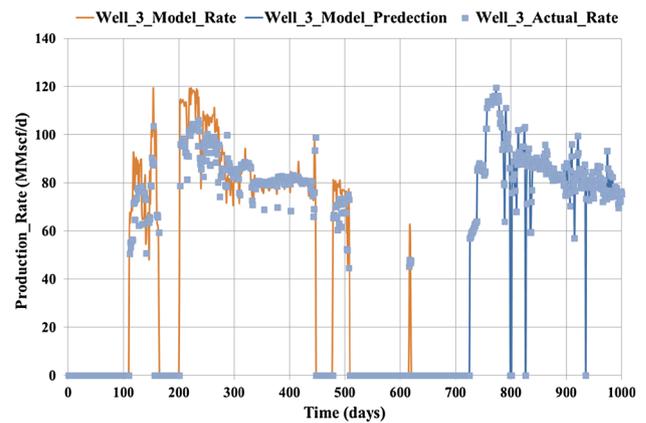


Fig. 6 Well 3 rate history match and prediction (case 1)

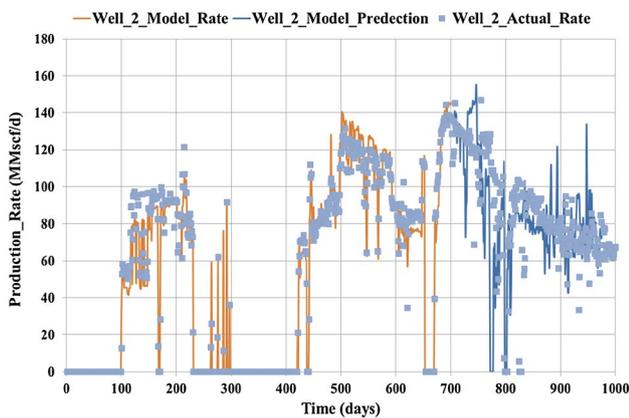


Fig. 5 Well 2 rate history match and prediction (case 1)

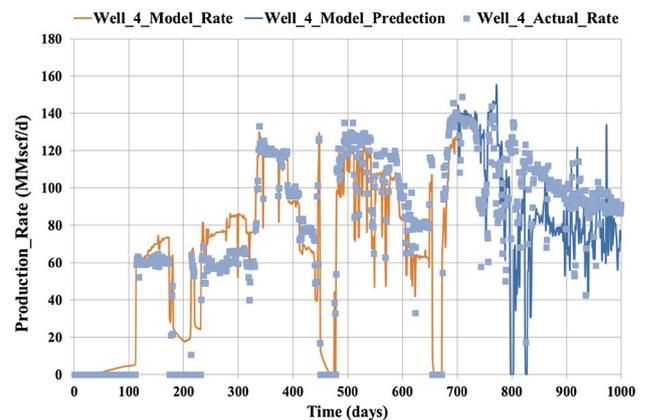


Fig. 7 Well 4 rate history match and prediction (case 1)

## Field case 1

The first case is for a dry gas reservoir. This reservoir is developed in a channel system that extends for several kilometers. There are two main channels (Channel 1 and Channel 2) that are separated by vertical barrier. The reservoir also contains few faults. The largest of these faults splits the structure into the northern and southern parts. Other smaller faults exist within the reservoir, separating it into partially communicating compartments. Five development wells produce from both channels as illustrated in Fig. 3. Three wells were completed only in channel 1, and the other two wells were commingled in both channels.

Down-hole pressure measurements and production rates were available on daily basis. The available data extend to cover nearly 1000 days of production history. In this case the first 700 production days were used for history matching to obtain model parameters. Then, the model parameters were used to predict the rest of the 300 days. For prediction, the measured bottom-hole pressures for all five wells were used as input data, and the

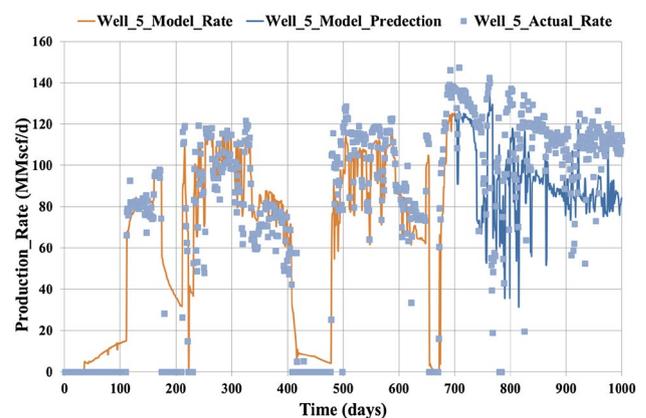


Fig. 8 Well 5 rate history match and prediction (case 1)

model calculated production rates (from every completion) and average compartment pressure. The calculated production rates and static pressures were compared with actual measurements. Figures 4, 5, 6, 7, 8, 9, 10, 11, 12 and 13 presents comparison between the model forecast

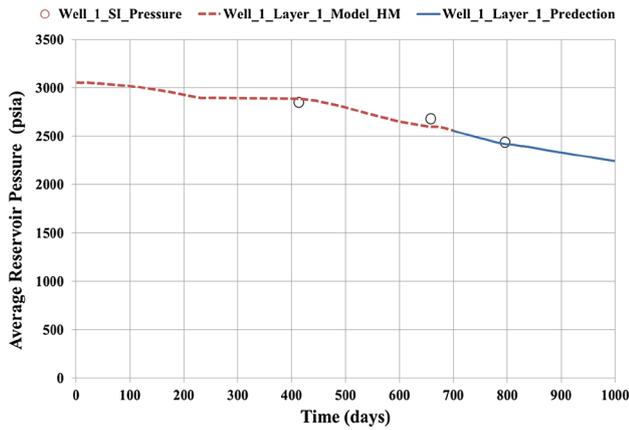


Fig. 9 Well 1 Pressure History Match and Prediction (Case 1)

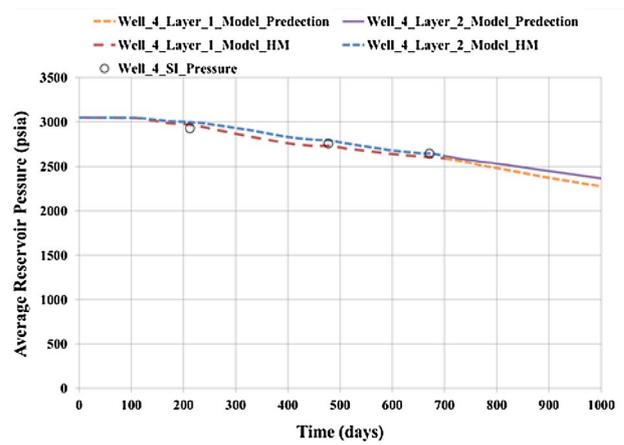


Fig. 12 Well 4 pressure history match and prediction (case 1)

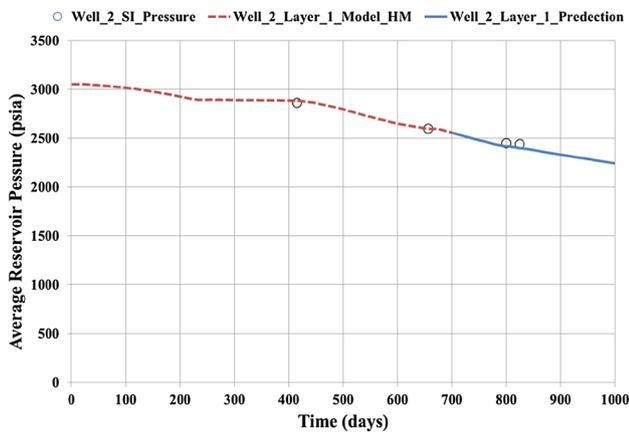


Fig. 10 Well 2 pressure history match and prediction (case 1)

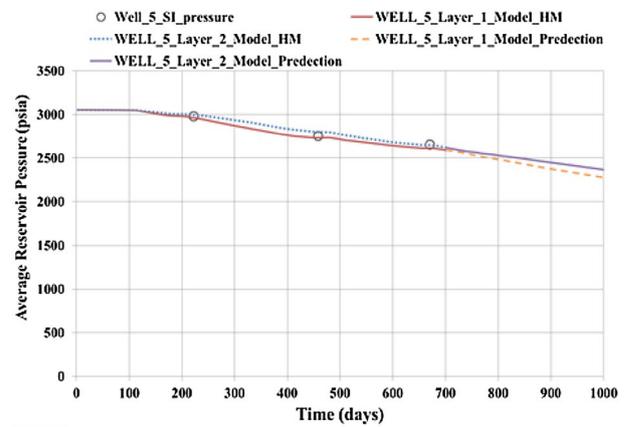


Fig. 13 Well 5 pressure history match and prediction (case 1)

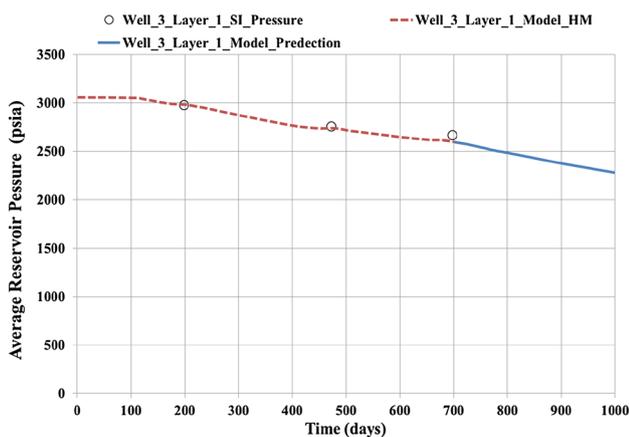


Fig. 11 Well 3 pressure history match and prediction (case 1)

Table 1 Gas composition for field different cases

Case	Case 1	Case 2
Component	Mol%	Mol%
N <sub>2</sub>	0.1	0.07
CO <sub>2</sub>	0.308	0.194
C <sub>1</sub>	98.447	90.423
C <sub>2</sub>	1.094	4.797
C <sub>3</sub>	0.03	1.256
I-C <sub>4</sub>	0.009	0.494
N-C <sub>4</sub>	0.004	0.513
I-C <sub>5</sub>	0.003	0.243
N-C <sub>5</sub>	0.004	0.157
C <sub>6</sub>	0.0001	0.325
C <sub>7+</sub>	0.0009	1.53

**Table 2** Matching parameters for field case 1

Parameter	Well	Layer	Value	Unit	
Compartment OGIP	1	1	209,736	MMscf	
		2	77,257	MMscf	
	2	1	299,900	MMscf	
		3	200,629	MMscf	
	4	1	207,093	MMscf	
		2	93,479	MMscf	
	5	1	169,262	MMscf	
		2	63,356	MMscf	
	A	1	1	484	(psia <sup>2</sup> /cp)/(Mscf/D)
			2	716	(psia <sup>2</sup> /cp)/(Mscf/D)
3		1	161	(psia <sup>2</sup> /cp)/(Mscf/D)	
		4	844	(psia <sup>2</sup> /cp)/(Mscf/D)	
5		2	1350	(psia <sup>2</sup> /cp)/(Mscf/D)	
		2	2556	(psia <sup>2</sup> /cp)/(Mscf/D)	
B	1	1	0.0027	(psia <sup>2</sup> /cp)/(Mscf/D) <sup>2</sup>	
		2	0.0001	(psia <sup>2</sup> /cp)/(Mscf/D) <sup>2</sup>	
	3	1	0.0099	(psia <sup>2</sup> /cp)/(Mscf/D) <sup>2</sup>	
		4	0.0082	(psia <sup>2</sup> /cp)/(Mscf/D) <sup>2</sup>	
	5	2	0.0049	(psia <sup>2</sup> /cp)/(Mscf/D) <sup>2</sup>	
		2	0.0008	(psia <sup>2</sup> /cp)/(Mscf/D) <sup>2</sup>	

and the actual performance of the wells. The fluid composition is presented in Table 1, and the final matching parameters are given in Tables 2, 3 and 4.

Further analysis was performed to investigate the robustness of the proposed model in predicting the total OGIP. A sensitivity analysis was performed by changing the number of days used in history matching and checking the effect of the duration used on the calculated OGIP. The results are presented in Table 5. Other parameters that affect the optimization problem were investigated. The weight factor placed on matching the static reservoir pressure was also varied in these sensitivity analyses. In every sensitivity run, the objective function error was calculated and is reported in the table. Although the different sensitivity runs showed slightly different predictions, the results demonstrated that the variations of total gas in place were within an acceptable ± 10% (reported in the table). This means that once there are enough points in the history and the model can match these points, the calculated value of the total OGIP will be reasonably accurate.

**Field case 2**

The second field case is a gas reservoir consisting of three main sand intervals separated by flow barriers. The field is defined by a combination dip, stratigraphic and fault closure. The exploration wells indicated the presence of wet gas in the trap (with initial condensate gas ratio, CGR = 18 STB/MMscf). The gas composition is presented in Table 1). The lower sand layers (layer 2, layer 3) are laterally extended over most of the field, but the shallower sand (layer 1) is only present in one well.

**Table 3** Transmissibility parameters for layer 1 in field case 1

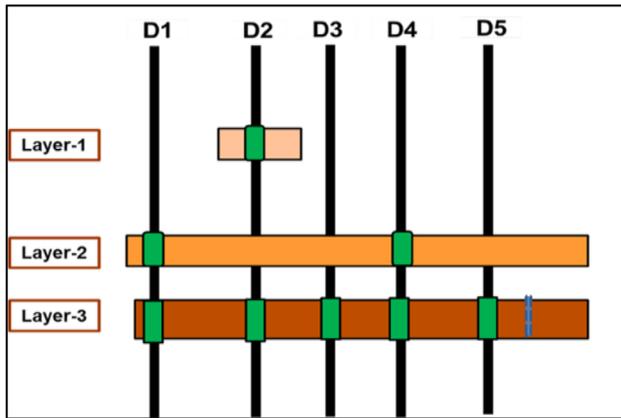
Compartment Number	1	2	3	4	5	Unit
1	0	0.0941	0.00031	0	0	(Mscf.cp/D/psi <sup>2</sup> )
2	0	0	0	0	0	
3	0	0	0	0.0731	0.0628	
4	0	0	0	0	0.0963	
5	0	0	0	0	0	

**Table 4** Transmissibility parameters for layer 2 in field case 1

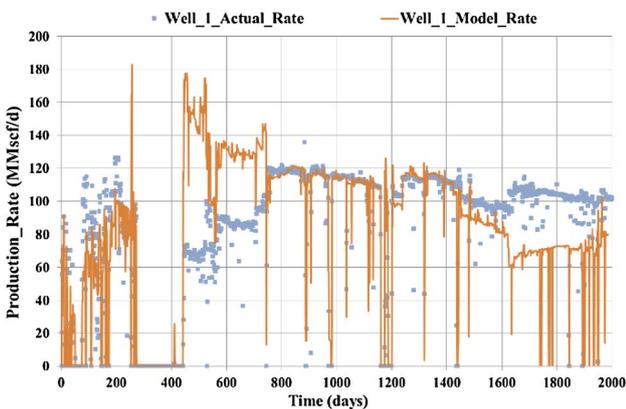
Compartment Number	1	2	3	4	5	Unit
1	0	0	0	0.00611	0	(Mscf.cp/D/psi <sup>2</sup> )
2	0	0	0	0	0	
3	0	0	0	0	0	
4	0	0	0	0	0.0662	
5	0	0	0	0	0	

**Table 5** Sensitivity analysis for field case 1

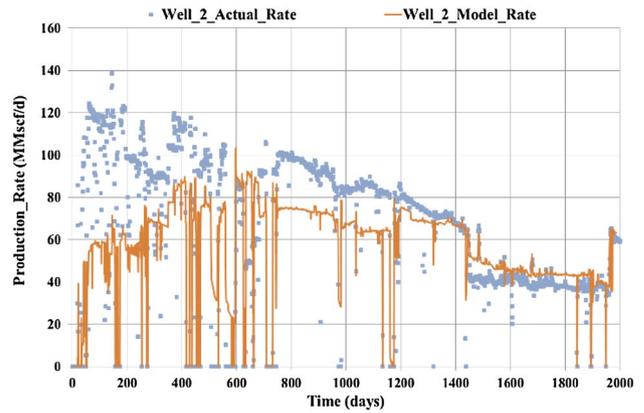
Case no.	Calculated OGIP TCF	Assumed duration of history	Weight factor for static pressure	Total error
1	1.365	1000	Low	0.16
2	1.49	1000	No W.F.	0.19
3	1.423	565	Low	0.17
4	1.375	1000	High	0.15
5	1.369	1000	High	0.15
6	1.406	300	No W.F.	0.2
7	1.353	800	High	0.16
8	1.258	400	No W.F.	0.2
9	1.406	300	No W.F.	0.2
10	1.228	500	No W.F.	0.18
11	1.321	700	Mid	0.16
12	1.261	700	Low	0.17
13	1.237	600	Low	0.17



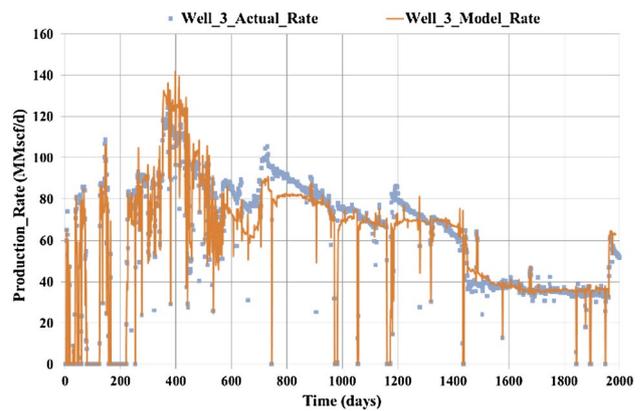
**Fig. 14** Schematic of field case 2 wells completion in relation to sand layers



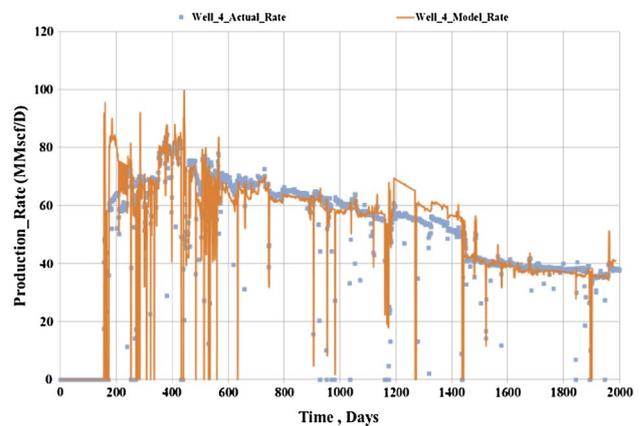
**Fig. 15** Well 1 production history match (case 2)



**Fig. 16** Well 2 production history match (case 2)



**Fig. 17** Well 3 production history match (case 2)



**Fig. 18** Well 4 production history match (case 2)

The field was developed by drilling 5 wells. Three wells were completed as dual completion by using flow control valves which facilitate selective production from each zone as well as zonal pressure testing. Figure 14 shows the

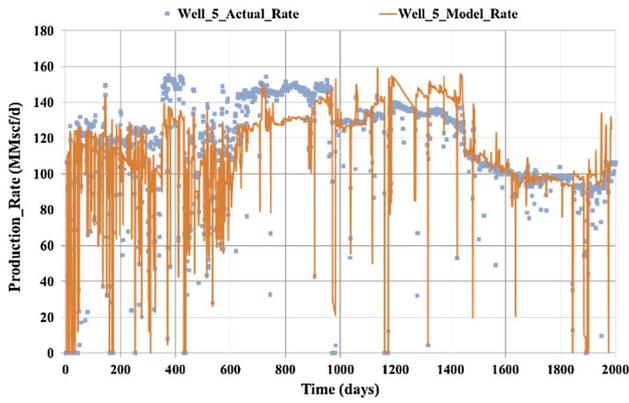


Fig. 19 Well 5 production history match (case 2)

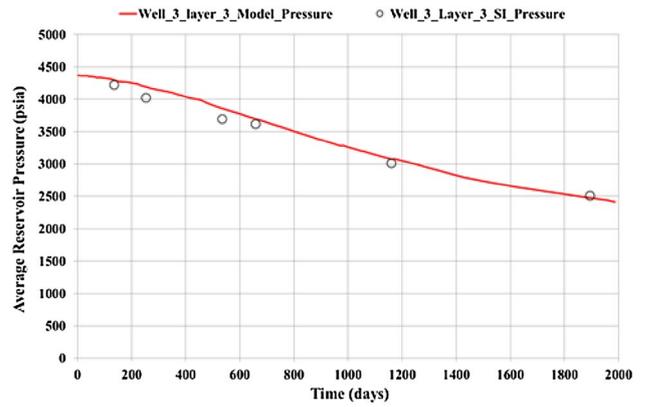


Fig. 22 Well 3 pressure history match (case 2)

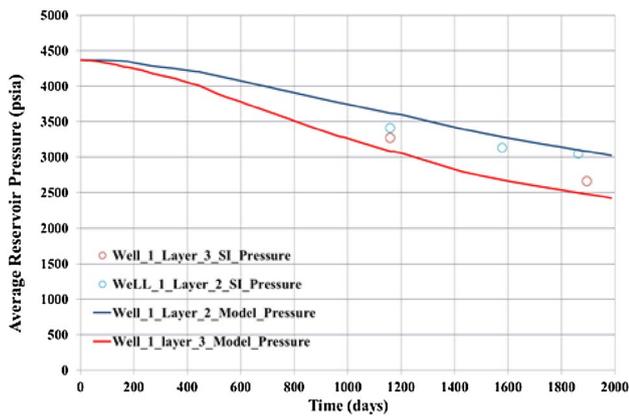


Fig. 20 Well 1 pressure history match (case 2)

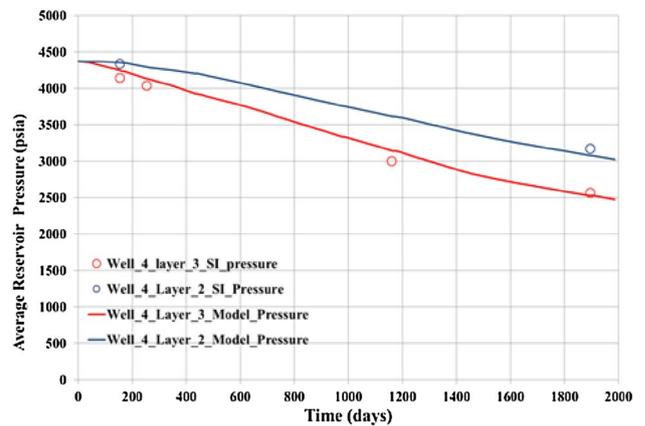


Fig. 23 Well 4 pressure history match (case 2)

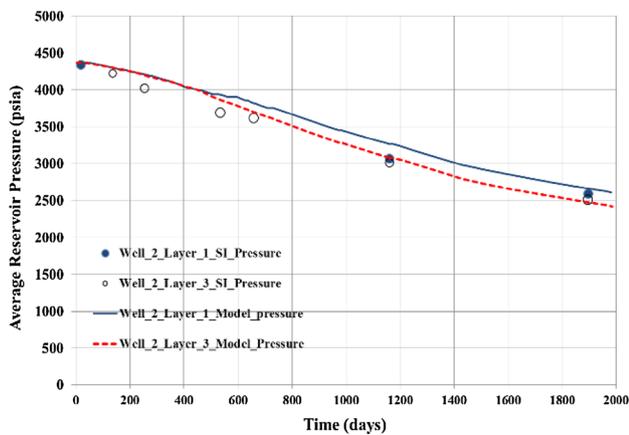


Fig. 21 Well 2 pressure history match (case 2)

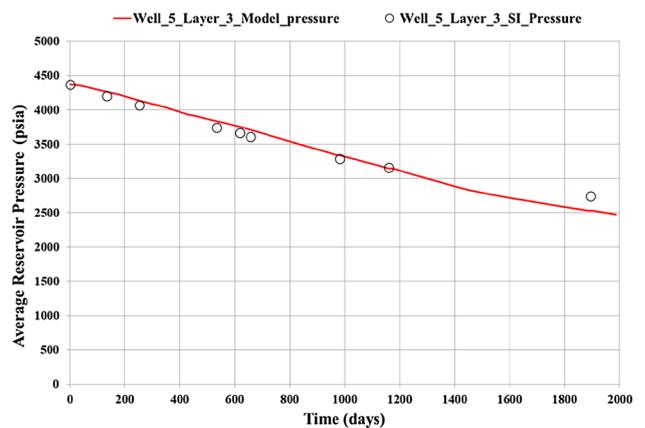


Fig. 24 Well 5 pressure history match (case 2)

schematic diagram that explains the wells completions in different sands. Based on geological information, an additional compartment was created in layer 3 to mimic the

presence of a permeability barrier in the eastern area of the fifth well as shown in Fig. 14. Therefore, layer 3 is divided into six compartments.

**Table 6** Matching parameters for field case 2

Parameter	Well	Layer	Value	Unit	
Compartment OGIP	1	2	126,472	MMscf	
		3	372,936	MMscf	
	2	1	72,232	MMscf	
		3	192,648	MMscf	
	3	3	134,213	MMscf	
		4	168,894	MMscf	
	4	2	131,148	MMscf	
		3	401,936	MMscf	
	5	3	211,136	MMscf	
		6	3	211,136	MMscf
	A	1	2	8000	(psia <sup>2</sup> /cp)/(Mscf/D)
			3	100	(psia <sup>2</sup> /cp)/(Mscf/D)
2		1	15,000	(psia <sup>2</sup> /cp)/(Mscf/D)	
		3	1385	(psia <sup>2</sup> /cp)/(Mscf/D)	
3		3	3783	(psia <sup>2</sup> /cp)/(Mscf/D)	
		4	2	15,479	(psia <sup>2</sup> /cp)/(Mscf/D)
4		3	10,376	(psia <sup>2</sup> /cp)/(Mscf/D)	
		5	3	764.548	(psia <sup>2</sup> /cp)/(Mscf/D)
b		1	2	0.0579	(psia <sup>2</sup> /cp)/(Mscf/D) <sup>2</sup>
			3	0.02,529	(psia <sup>2</sup> /cp)/(Mscf/D) <sup>2</sup>
		2	1	0.07821	(psia <sup>2</sup> /cp)/(Mscf/D) <sup>2</sup>
			3	0.0828	(psia <sup>2</sup> /cp)/(Mscf/D) <sup>2</sup>
	3	3	0	(psia <sup>2</sup> /cp)/(Mscf/D) <sup>2</sup>	
		4	2	0.0122	(psia <sup>2</sup> /cp)/(Mscf/D) <sup>2</sup>
	4	3	0.00789	(psia <sup>2</sup> /cp)/(Mscf/D) <sup>2</sup>	
		5	3	0.00369	(psia <sup>2</sup> /cp)/(Mscf/D) <sup>2</sup>

Although down-hole pressure measurement and production rates were assumed to be available on daily basis, they suffered from erroneous readings as well as the presence of some gaps in recorded pressure present due to down-hole pressure gauge malfunction. Corrections were applied to generate bottom-hole flowing pressure estimates (when not available) from tubing head pressure (THP) using vertical lift performance (VLP) relationships. The available production history data were used for history matching. Because of the previously mentioned challenges, the match quality of the first two wells was less than the results obtained for other wells. The pressure match was also affected for Well 1. The rest of the wells show good agreement between the calculated and historical production and shut-in (SI) pressure data through the whole history. Figures 15, 16, 17, 18, 19, 20, 21, 22, 23 and 24 presents comparison between the calculated model results after history match and the actual performance of the wells. The final matching parameters used for the model are presented in Tables 6, 7 and 8. Notice that Well 2 compartment in layer 1 is not connected to any other compartment and therefore does not have transmissibility coefficients.

**Discussion**

Although the model can identify the presence of poorly drained compartments, precise estimation of reservoir pressure in poorly drained compartments requires geological data, production data and estimates of bottom-hole flowing pressure. The presence of few static pressure measurements controls the volumes predicted by the compartmentalized

**Table 7** Transmissibility parameters for layer 2 in field case 2

Compartment Number	1	2	3	4	5	Unit
1	0	0	0	0.07958	0	(Mscf.cp/D/psi <sup>2</sup> )
2	0	0	0	0	0	(Mscf.cp/D/psi <sup>2</sup> )
3	0	0	0	0	0	(Mscf.cp/D/psi <sup>2</sup> )
4	0	0	0	0	0	(Mscf.cp/D/psi <sup>2</sup> )
5	0	0	0	0	0	(Mscf.cp/D/psi <sup>2</sup> )

**Table 8** Transmissibility parameters for layer 3 in field case 2

Compartment Number	1	2	3	4	5	6	Unit
1	0	0.049	0.00822	0	0	0	(Mscf.cp/D/psi <sup>2</sup> )
2	0	0	0.008505	0	0	0	(Mscf.cp/D/psi <sup>2</sup> )
3	0	0	0	49E-03	0	0	(Mscf.cp/D/psi <sup>2</sup> )
4	0	0	0	0	0.01809	0	(Mscf.cp/D/psi <sup>2</sup> )
5	0	0	0	0	0	5.95E-05	(Mscf.cp/D/psi <sup>2</sup> )

model. Comparison between OGIP calculated by the model with volumetric calculations can help in detecting isolated or un-drained compartments which can be targeted for further field development.

Working with field data revealed that estimates of bottom-hole pressure from tubing head pressure data to fill the missing bottom-hole pressure points have assisted in reducing the uncertainty in the match. It is important to start modeling any field case with the minimum number of compartments (as suggested by geological information) and increasing the number of compartments as needed. This approach will be useful in reducing the number of parameters for the history matching problem and will decrease the uncertainty.

Throughout the matching of the simulated cases, it was clear that a good match was achieved for production rates and static reservoir pressures. However, the optimization routine can yield different results for the unknown parameters that can replicate the match. This is an outcome of increasing degrees of freedom as the number of unknown variables may be too many in a case with several layers and compartments. The best practice to determine the parameters of the well is to utilize all the available data to provide an upper and lower range for each parameter, for instance, by using well test data for determination of the well deliverability coefficient of the layers if available. Then, the estimated upper and lower values for each history matching parameter will be respected by the optimization routine. Furthermore, utilization of geological data and wells' completion diagram are important to both give reasonable initial guesses for compartments OGIP and to reduce the number of unknown transmissibility coefficients (transmissibility coefficients for compartments that cannot exchange fluids are set to zero). The measured static pressures for the compartments are found to play a significant role in decreasing the uncertainty of OGIP values. As there are usually more production history points than static reservoir pressure points, applying high weight factor for the reliable static pressure points in the objective function reduces the uncertainty.

When the proposed model is run in forecast mode, production can be predicted with different bottom-hole flowing pressures resulting from changing the choke size of one or more wells. Like in the layered reservoir model (El-Banbi and Wattenbarger 1997), the proposed model can predict any wellbore backflow.

## Conclusions

In this paper, a model based on coupling multi-layered commingled well/reservoir model with compartmentalized gas reservoir model was developed and used to history match and forecast several field cases. Based on the work done here, the following conclusions can be made:

- (1) The proposed model can provide a reliable estimate of total gas in place in the field. The breakdown of the OGIP per compartment, flow coefficients for wells and transmissibility coefficients between reservoir compartments can be also determined.
- (2) The proposed model uses minimum data to forecast the production and pressure behavior of multi-wells in layered and compartmentalized reservoirs, under variety of production conditions. The input data needed are initial pressure, few static pressure measurements and some production and bottom-hole flowing pressure history.
- (3) When the model parameters are estimated (i.e., from history match), the model can be used to forecast the reservoir behavior. The proposed model calculates the production rate from every well completion, static pressure of every compartment, cumulative gas production from every layer and compartment and amount of gas influx/efflux between communicating compartments.
- (4) Using the proposed model can assist in providing development opportunities that cannot be identified from traditional material balance methods. This is due to the model's ability to identify the compartments that still have high pressure and contain large amounts of gas after a period of depletion.
- (5) Although the number of matching parameters in a typical field case could be significant, the estimated total gas in place is usually within a reasonable range if the static pressure points are matched. Presence of more points of both static and flowing pressure data provides better control on the match and reduces the non-uniqueness of the model.
- (6) Utilization of geological data is particularly important in decreasing the uncertainty in the model parameters and reducing the non-uniqueness problem. In a typical model, many compartment transmissibility coefficients can be set to zero based on understanding of geology.

**Open Access** This article is distributed under the terms of the Creative Commons Attribution 4.0 International License (<http://creativecommons.org/licenses/by/4.0/>), which permits unrestricted use, distribution, and reproduction in any medium, provided you give appropriate credit to the original author(s) and the source, provide a link to the Creative Commons license, and indicate if changes were made.

## References

- Al-Hussainy R, Ramey HJ, Crawford PB (1966) The flow of real gas through porous media. *JPT* (May) 18:624–636
- El-Banbi AH, Wattenbarger RA (1996) Analysis of commingled tight gas reservoirs. In: Paper presented at the SPE annual technical

- conference and exhibition, Denver, Colorado, 6–9 October. SPE-36736-MS. <http://dx.doi.org/10.2118/36736-MS>
- El-Banbi AH, Wattenbarger RA (1997) Analysis of commingled gas reservoirs with variable bottom-hole flowing pressure and non-darcy flow. In: Presented at SPE annual technical conference and exhibition, 5–8 October, San Antonio, Texas. SPE-38866-MS. <http://dx.doi.org/10.2118/38866-MS>
- Fetkovich MJ, Bradley MD, Works AM, Thasher TS (1990) Depletion performance of layered reservoirs without crossflow. SPE Form Eval 2(04):310–318. <https://doi.org/10.2118/18266-PA> (SPE-18266-PA)
- Hagoort J, Hoogstra R (1997) Numerical solution of material balance equations of compartmented gas reservoirs. In: Presented at SPE Asia Pacific oil and gas conference and exhibition, 14–16 April, Kuala Lumpur, Malaysia. SPE-38082-MS. <http://dx.doi.org/10.2118/38082-MS>
- Hower TL, Collins RE (1989) Detecting compartmentalization in gas reservoirs through production performance. In: Presented at SPE annual technical conference and exhibition, 8–11 October, San Antonio, Texas. SPE-19790-MS. <http://dx.doi.org/10.2118/19790-MS>
- Juell A, Whitson CH (2011) Backpressure equation for layered gas reservoirs. In: Presented at SPE annual technical conference and exhibition, 30 October–2 November, Denver, Colorado, USA. SPE-146066-MS. <http://dx.doi.org/10.2118/146066-MS>
- Lord ME, Collins RE (1989) Detecting compartmented gas reservoirs through production performance. In: Presented at SPE annual technical conference and exhibition, 6–9 October, Dallas, Texas. SPE-22941-MS. <http://dx.doi.org/10.2118/22941-MS>
- Lord ME, Collins RE (1992) A compartmented simulation system for gas reservoir evaluation with application to fluvial deposits in the frio formation, South Texas. In: Presented at SPE mid-continent gas symposium, 13–14 April, Amarillo, Texas. SPE-24308-MS. <http://dx.doi.org/10.2118/24308-MS>
- Payne DA (1996) Material balance calculation in tight-gas reservoirs: the pitfalls of P/Z plots and a more accurate technique. SPE Res Eng 11(04):260–267. <https://doi.org/10.2118/36702-PA> (SPE-36702-PA)
- Sallam M (2016) Analysis of multi-Layered commingled and compartmentalized gas reservoirs. M.S. thesis, Petroleum Engineering Department, Cairo University, Egypt

**Publisher's Note** Springer Nature remains neutral with regard to jurisdictional claims in published maps and institutional affiliations.