Semi-analytical model to predict the performance of cyclic steam stimulation oil wells

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Received: 3 November 2020 / Accepted: 3 February 2021 / Published online: 18 March 2021
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Abstract

Prediction of the performance of oil wells under Cyclic Steam Stimulation (CSS) is challenging in complex and heterogeneous reservoirs, especially with limited data. Analytical and numerical simulation models do not usually give accurate predictions in such conditions. In this work, a semi-analytical model was developed to determine consistent mathematical relationships between the injected steam and some of the effective oil production parameters for more accurate prediction of oil production rates. Field investigation indicates that the change of the Cumulative Oil to Steam Ratio (COSR) to production days is related to a group of effective oil production parameters. This group of parameters includes the cumulative injected steam relative to the drainage volume, the oil net pay thickness relative to the gross pay thickness, and the vertical permeability relative to the thermal diffusivity. These parameters were arranged in two dimensionless groups. It was found that plotting these two dimensionless groups on Log–Log scale for any reservoir yields a straight line (correlation). For any reservoir under CSS, measurements of two steam cycles are sufficient to identify the constants of the proposed correlation. This method has been applied and validated on six reservoirs with different reservoir characterizations. Six different wells with a total of 43 steam cycles from these reservoirs were analyzed with the same approach. The mathematical relationships of the dimensionless groups were calculated, and the Log–Log plot was constructed for each well using the data of the first two cycles. Then, the proposed correlation was developed for each well and used to predict the well performance starting from the third steam cycle. At the end, the predicted performance of each well was compared with the corresponding actual measurements. The results showed that the average absolute percentage deviation between the actual and the predicted cumulative oil production through the well lifetime is less than 5% for the six wells. In addition, the absolute instantaneous deviation between the actual and the predicted cumulative oil production for each individual cycle in all cases is (1) less than 15% for about 42% of the tested CSS cycles, (2) between 15 to 25% for about 39% of the tested CSS cycles, and (3) higher than 25% for about 19% of the tested CSS cycles. This work is considered an original contribution to develop dimensionless relationships that can be used to predict the oil production of the CSS operations for reservoirs with limited data. The required data are the historical production rate, steam injection rate, and basic petrophysical parameters.

Keywords Cyclic Steam Stimulation · Performance Prediction of the CSS Wells · Heavy Oil · Thermal EOR · Thermal Enhanced Oil Recovery · CSS Field Applications

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Abbreviations

APD	Absolute Percentage Deviation
COSR	Cumulative Oil to Steam Ratio (STB/STB)
CSS	Cyclic Steam Stimulation
CWE	Cold Water Equivalent
EOS	Equation of State
USA	United States of America

List of symbols

h	Gross pay thickness, ft
R	Drainage radius, ft
V	Drainage volume, bbl
X	$\left(\left(\frac{\text{Injected Steam Volume [bbl]}}{\text{Drainage Volume [bbl]}} \right) * \left(\frac{\text{Net Pay Thickness (ft)}}{\text{Gross Pay Thickness (ft)}} \right) \right)$
Y	$\left(\left(\frac{\text{COSR} \left(\frac{\text{Cum. Oil}}{\text{Cum. Steam}} \right) \left[\frac{\text{STB}}{\text{STB}} \right]}{\text{Production Days [Days]}} \right) * \left(\frac{\text{Vertical Permeability [Darcy]}}{\text{Thermal Diffusivity} \left[\frac{\text{ft}^2}{\text{Days}} \right]} \right) \right)$

Introduction

Conventional oil resources are estimated at only 30% of the total worldwide oil resources, while all other viscous oil including heavy oil, extra heavy oil, bitumen, and oil sand make up the remaining 70% (Finbow and Koop 1978). The CSS has proved its effectiveness as a thermal enhanced oil recovery method in several heavy oil reservoirs with different reservoir characteristics (Basta 2020; Failed 2013). CSS oil production predictive tools are essential requirements to manage reservoirs under CSS (Yang et al. 2014). Generally, there are three categories of methods of CSS oil production prediction: analytical models, numerical simulation, or analogy methods (Abou-Kassem 1996).

The analytical predictive models use different assumptions to simplify the calculations of oil production prediction. The assumptions affect the accuracy of the analytical models (Yang et al. 2014). Several predictive models have been developed for different conditions and assumptions. The first published model assumed that the reservoir is pressurized with a drive mechanism, but generally the CSS is applied in depleted reservoirs with low reservoir pressure (Abu El Ela et al. 2008). Later, several other analytical models were developed to take the effects of the depleted reservoirs and gravity derange into consideration (Ali and Tamin 1998; Alvarez and Sungyun 2013; Boberg and Lantz 1966).

Most analytical models had a limiting assumption which is that steam forms a cylinder in the reservoir at the end of the steam injection period. However, field observation shows that steam goes to the top zone or into highly permeable zones (Jones 1992). Therefore, in 1984, Gontijo and Aziz

developed a model that considered a conical steam shape (Mueller 1967). In 1998, Ali and Tamin developed a model to take into consideration the vertical fractures which were created and surrounded the wellbore after steam injection (Mozaffari et al. 2013).

In 1967, Mueller developed a numerical simulation model for the CSS applications (Rivero and Heintz 1975). This model used the finite element algorithm to predict the CSS oil production. The model assumed that the reservoir under study was homogeneous with radial heat transfer and symmetrical flow around the wellbore. In addition, effects of capillary and gravitational forces were taken into consideration. This initial model could predict the average reservoir performance versus time. Afterward, the model was developed to consider two-dimensional and three-phase flow. Later, it was developed for three-dimensional problems. It should be highlighted that the dissolved gas and steam distillation were taken into consideration for oil production prediction of the CSS by numerical simulation approach (Finbow and Koop 1978).

Subsequently, another numerical simulation model was developed to predict the CSS oil production from fractured carbonate reservoir by Biggs in 1989 (Sun and Ertekin (2016)). In this study, three-phase, three-dimensional, fully implicit, compositional simulator was built. This simulator was developed to use different correlations to predict the change in the relative permeability curves with the application of the CSS. In 2013, Mozaffari et al. developed a numerical simulation model to solve the mass and energy balance for the steam injection in heavy oil reservoirs (Towson and Boberg 1967). Generally, difficulties exist in using the numerical simulation models in cyclic steam injection applications at the primary stage of production. These difficulties are related to the sensitivity of the thermal simulation models to the rock and fluid properties and the geological characterization. Usually, this information has high degree of uncertainty in the heterogeneous reservoirs (Yoelin 1971). As highlighted by Abou-Kassem (1996) and Tamim et al. (2000), the numerical simulation is sensitive to the accuracy of the representing Equation of State (EOS) of the crude oil. They clarified that the accuracy of the thermal numerical simulation is affected by the grid refinement and the grid orientation which directly affect the steam movement (Esmaeili et al. 2019; Faergestad 2016). In an attempt to improve numerical simulation predictions, in 2019, Esmaeili et al. developed a data-driven model to predict the effect of temperature on water–oil relative permeability (Failed 1983). Also, in 2019, Marquez et al. studied the effect of the temperature-dependent relative permeabilities on simulation results using data of a heavy oil reservoir in the Middle East (Failed 1984). In 2016, Sun and Turgay developed an artificial intelligence model to predict the oil production in

the CSS processes (Jones 1977). The model was verified and tested using data of a homogenous sandstone reservoir.

On the other hand, the analogy relationships in the CSS applications for specific reservoirs are built using historical data for the parameters which have impact on the oil production rates or the cumulative oil production. The established relationships in the analogy approach can be used to predict the oil wells performance in the same reservoir. Several different approaches were published to develop effective prediction relationships (Yang et al. 2014; Popa and Patel 2012; Uribe et al. 2010; Failed 1995). These methods aimed to find direct relationships between one of the effective parameters and oil production rate. However, till now, there is no effective approach in the previous trials because the developed methods failed to define a general formula or correlation suitable for all reservoirs. The previous methods also ignored the deterioration of the level of interaction between steam injection and oil production from one steam cycle to another. This interaction changes due to the hysteresis effect from injection and production phases in addition to the changes of the reservoir temperature from one steam cycle to another. This paper presents a semi-analytical model to predict the oil wells performance under the CSS applications using limited input data.

Features of the developed model

Main concepts of the model

The main idea of the developed model is to define which parameters are important in predicting oil production in different CSS cycles, and to identify mathematical relationships between those effective parameters and the CSS oil production. A large database of wells undergoing CSS was used empirically to identify which parameters are the most important in predicting oil production rates. The oil production by CSS depends on the interaction between steam, oil, and rock. The heat efficiency-related parameters as well as the net pay thickness relative to the reservoir gross pay thickness along with the steam injection rates were considered in the mathematical relationships. These parameters are different from well to well and have impact on the oil production rates of the wells.

Actual CSS well data were used to identify the general forms of the expected mathematical relationships. The data were collected from an oil well (Well 1–1) from Upper Dolomite reservoir—Issaran field (Egypt). Upper Dolomite reservoir is characterized by heterogenous reservoir properties. Several different mathematical relationships were tried and tested with the available data in different forms. The best mathematical relationship that relates oil production with simple reservoir and operations parameters was

obtained, when (1) the effective parameters were arranged into two dimensionless terms as shown in Eqs. (1) and (2), and (2) the two terms in Eqs. (1) and (2) were plotted in Log–Log plot.

$$X = \left(\left(\frac{\text{Injected Steam Volume [bbl]}}{\text{Drainage Volume [bbl]}} \right) * \left(\frac{\text{Net Pay Thickness (ft)}}{\text{Gross Pay Thickness (ft)}} \right) \right) \quad (1)$$

$$Y = \left(\left(\frac{\text{COSR (Cum. Oil/Cum. Steam)} \left[\frac{\text{STB}}{\text{STB}} \right]}{\text{Production Days [Days]}} \right) * \left(\frac{\text{Vertical Permeability [Darcy]}}{\text{Thermal Diffusivity} \left[\frac{\text{ft}^2}{\text{Days}} \right]} \right) \right) \quad (2)$$

The drainage volume can be calculated per each well according to Eq. (3).

$$V = \left(\frac{1}{5.615} * \pi R^2 * [h] \right) \text{ bbl} \quad (3)$$

where R drainage radius of the well (ft), h gross pay thickness (ft), COSR Cumulative Oil Production to Cumulative Steam Injection Ratio (STB/ STB).

The Log–Log plot between X and Y Functions provided a straight line with a general mathematical form as shown in Eq. (4).

$$Y = aX^{-b} \quad (4)$$

where a and b are constants in the general mathematical form (correlation). They can be obtained from the Log–Log plot. These constants are changed from well to well. They might account the effects of the other parameters which are not mentioned in X and Y functions such as lateral permeability, relative permeability, oil viscosity, and wettability.

The mathematical relationships of Eqs. (1) and (2) depend on the rate of change of the COSR (Cumulative Oil Production to Cumulative Steam Injection Ratio) per day of production from cycle to cycle. The term of COSR per days of production is related to four effective parameters. It is directly proportional to three parameters: (1) the ratio of the heated zone volume relative to the drainage volume; (2) the ratio of the net pay thickness relative to the gross pay thickness; and (3) the thermal diffusivity. In addition, it is inversely proportional to the heat losses, which are directly proportional to the vertical permeability to overburden and underburned rocks.

It should be highlighted that the terms of Eqs. (1) and (2) can be identified with minimum available data. The

oil production and steam injection data are usually readily available. The oil production data include oil production rates and days on production which can be extracted from the daily production reports. The steam injection data include the cumulative injected steam per each steam cycle which can be extracted from the daily injection reports. The reservoir net pay thickness and gross pay thickness can be extracted from the petrophysical log interpretation of the well under study. The vertical permeability can be usually extracted from core analysis reports. Thermal diffusivity can be obtained from published values depending on lithology. For sandstone and carbonate reservoirs, thermal diffusivity is equal to $2.15 \times 10^{-6} \text{ m}^2/\text{s}$ ($1.99 \text{ ft}^2/\text{Day}$) and $1.96 \times 10^{-6} \text{ m}^2/\text{s}$ ($1.82 \text{ ft}^2/\text{Day}$), respectively (Basta 2020).

It should be highlighted that the two dimensionless terms X and Y were obtained after several different mathematical forms were tried and tested with the available data (trial and error process) to get the best mathematical relationship that relates oil production with the reservoir and operations parameters. Although the developed relationship is

presented in a simple form, it includes mass and heat balance parameters. The mass balance parameters can be considered in the volume of the cumulative steam injected, the volume of the cumulative oil production, and the estimated drainage volume. However, the heat balance parameters can be counted in the thermal diffusivity rate and two heat losses factors. The thermal diffusivity rate is defined as the thermal conductivity divided by the density and the specific volumetric heat capacity. However, the first heat losses factor is the heat losses inside the reservoir due to the existence of non-productive layers such as shale or anhydrite. This factor is a function of the ratio of the net pay thickness relative to the gross pay thickness. While the second heat losses factor is the heat losses due to the heat flow from the producing layers into the overburden and the underburned rocks. This factor is a function of the vertical permeability.

Testing of the approach

The developed relationships of Eqs. (1) and (2) were tested using the CSS data of Well 1–1 (Upper Dolomite

Table 1 Main properties and conditions of the field applications

	Unit	Upper Dolomite reservoir-Issaran field	Buffalo Creek reservoir-Gros-mont formation	Diatomite reservoir-Orcutt oil field	Tar Sand reservoir-Huntington Beach field	Well 8 Section 25 formation-Kern River field	Buena Fe Fee lease - Midway Sunset field
Estimated original oil in place	STB	1.1×10^9	145×10^6	2×10^9	338×10^6	3.1×10^9	34.1×10^6
Reservoir average depth	ft	850–1000	400–600	1700–2000	1500–2000	750–1300	600–1500
Average initial water saturation	%	30	15	35	21	20	25
Average porosity	%	35	25	24	35	35	34
Average reservoir permeability	mD	10–35	10–200	< 10	400–800	3000–4000	2000
Oil net pay thickness	ft	150	50–80	125	40–58	190	205
Gross reservoir thickness	ft	400	100–200	500	115	210	300–500
Reservoir dip angle	degrees	5	4	5	< 3	4	up to 70°
Initial reservoir pressure	psi	500	150	350	935	225	< 500
Initial reservoir temperature	°F	100	70	100	127	80	90
Oil viscosity at standard conditions	cP	4000	> 100,000	1000	11,000	4000	1500
Oil formation volume factor	rbbl/ STB	1.05	1.03	1.04	1.033	1.05	1.06
Oil gravity	°API	10–12	7	12	12–15	14	12

Table 2 Oil production and steam injection data of Well 1–1 (Upper Dolomite reservoir-Issaran field)

Cycle no	Cumulative steam injection per cycle (bbl/Cycle)	Actual cumulative oil production per cycle (bbl/cycle)	Actual cumulative steam injection (bbl)	Actual cumulative oil production (bbl)	COSR (STB/STB) ^a	Days on production cycle	Total days on production	Net pay thickness (ft)/gross pay thickness (ft)	Drainage volume ^b (bbl)	Permeability/thermal diffusivity (Day/ft) ^c	X ^d	Y ^d
1	8137	14,016	8137	14,016	1.7	349	349	0.525	4,338,701	0.01003	9.9E-04	4.95E-05
2	8011	5,099	16,148	19,115	1.2	124	473	0.525	4,338,701	0.01003	1.95E-03	2.51E-05
3	5731	13,869	21,879	32,984	1.5	439	912	0.525	4,338,701	0.01003	2.65E-03	1.66E-05
4	10,006	12,377	31,885	45,361	1.4	274	1186	0.525	4,338,701	0.01003	3.86E-03	1.20E-05
5	15,423	6,649	47,308	52,010	1.1	178	1364	0.525	4,338,701	0.01003	5.73E-03	8.09E-06
6	14,263	3,406	61,571	55,416	0.90	71	1435	0.525	4,338,701	0.01003	7.45E-03	6.29E-06

^aCOSR cumulative oil to cumulative steam ratio (STB/STB)^bDrainage Volume was calculated using Eq. 3^cThe thermal diffusivity for carbonate reservoirs is equal to 1.82 ft²/Day (Yang et al. 2014)^dEquations (1) and (2) were used to calculate X and Y, respectively **Fig. 1** The mathematical relationship on Cartesian scale for Well 1–1 **Fig. 2** The mathematical relationship on Semi-Log scale for Well 1–1 **Fig. 3** The mathematical relationship on Log-Log scale for Well 1–1

reservoir—Issaran field—Egypt). Table 1 summarizes the main parameters and properties of the Upper Dolomite reservoir. Table 2 presents the oil production and steam injection data of Well 1–1. Table 2 presents the data which

were used to build the mathematical relationships of X and Y functions (Failed 2013). Figures 1, 2 and 3 present the relationship between X and Y functions on Cartesian, Semi-Log, and Log–Log scale; respectively. Plotting the two terms on Log–Log scale shows a linear relation between X and Y functions. The approach of plotting Y versus X functions was tested using actual data of several wells. In all cases, a straight line was formed on the Log–Log scale.

The approach indicates that the Log–Log relationship can be developed for each well using data of only two steam cycles. Then, this linear relationship (on Log–Log scale) can be used to predict the oil production of the CSS for future cycles. For a new CSS oil production prediction, the X function can be estimated by Eq. (1) and using the proposed cumulative steam injection. Then, the corresponding point in Y axis can be identified and used to predict the oil production by defining the total days on production at the end of each steam cycle.

Steps of the approach

The methodology which can be used to develop the mathematical relationship for any CSS well includes the following steps:

1. Identify the petrophysical parameters: net pay thickness, gross pay thicknesses, and vertical permeability.
2. Estimate the drainage volume of the well from Eq. (3).
3. Estimate the thermal diffusivity according to the type of the reservoir rock.
4. Collect data of two steam cycles: the production and injection data are collected at (1) the end of the first steam cycle, and (2) any time at the second steam cycle. The main parameters at each point are the cumulative oil production, total days on production, and cumulative injected steam.
5. Calculate the main terms of the mathematical relationship (X and Y functions) using Eqs. (1) and (2) for the selected two cycles.
6. Develop the Log–Log plot and identify the straight line on the plot.
7. Extrapolate the Log–Log relationship for the CSS oil production prediction.
8. Identify the form and the constants of the mathematical relationship between X and Y functions using the Log–Log plot (Eq. 4)
9. For prediction of oil production in a new cycle, X function is estimated using Eq. (1) and considering the cumulative steam injection. Then, the corresponding point in Y axis is determined using Eq. (4) or the developed Log–Log plot. Then, the value of Y term can be identified and used to back-calculate the oil production

by defining the total days on production at the end of each steam cycle.

Validation of the model using field applications

Data of six more CSS wells were collected from six CSS reservoirs of different conditions. The collected data include data of another well (Well 1–2) from the CSS project at the Upper Dolomite reservoir of Issaran field (Egypt). The other five wells (Well 2, Well 3, Well 4, Well 5, and Well 6) belong to different reservoirs: Buffalo Creek reservoir of Grossmont formation (Canada), Diatomite reservoir of Orcutt Oil field (USA), Tar Sand reservoir of Huntington Beach field (USA), Section 25 of Kern River field (UAS), and Buena Fe Fee Lease of Midway Sunset field (USA); respectively. They represent variation of reservoir properties, rock types, and operations conditions.

The Upper Dolomite reservoir of Issaran field and Buffalo Creek reservoir of Grossmont formation are fractured carbonate reservoirs (Basta 2020; Failed 2013). However, Diatomite reservoir of Orcutt oil field includes tight matrix (Abou-Kassem 1996). On the other hand, the Tar Sand reservoir of Huntington Beach field is unconsolidated sandstone with thin interbedded shale (Abu El Ela et al. 2008). Section 25 of Kern River field is a layered sandstone reservoir (Ali and Tamin 1998). Finally, the CSS data of Buena Fe Fee Lease of Midway Sunset field represent sandstone reservoir with high dip angle reaching up to 70° (Alvarez and Sungyun (2013)).

Table 1 presents the main properties and conditions of the six fields. Table 1 indicates that the studied reservoirs have different reservoir depths. Buffalo Creek reservoir depth is 400 ft, while Diatomite and Tar sand reservoirs reach 2000 ft. Also, the initial water saturation varies from 24 to 35%. Table 1 also shows a wide variation in the reservoir permeability for the six reservoirs. The Diatomite reservoir is very tight matrix with a permeability less than 10 mD, while Section 25-Kern River field is unconsolidated reservoir with a permeability greater than 3,000 mD. In addition, the average reservoir net pay thickness ranges from 40 to 205 ft. Also, the reservoir dip angle varies for the selected reservoirs. Tar Sand reservoir has dip angle less than 3°, while Buena Fe Fee Lease has dip angle up to 70°. Table 1 indicates variation in oil viscosity. The viscosity ranges between 1000 cP to greater than 100,000 cP. This variety in reservoir properties supports the applicability of the developed model to wide range of reservoirs under CSS.

Table 3 presents the oil production and steam injection data at the end of the first and second cycles for the six wells (Well 1–2, Well 2, Well 3, Well 4, Well 5 and Well 6). The developed model was applied on the available data of the

Table 3 Oil production and steam injection data of the first and second cycles of the field applications

Case name	Cycle no	cumulative steam injection per cycle (bbl/Cycle)	Actual cumulative oil production per cycle (bbl/Cycle)	Actual Cumulative Steam Injection (bbl)	Actual Cumulative Oil Production (bbl)	COSR (bbl/bbl) ^a	Days on production/cycle	Total days on production starting from the 1st cycle	Net pay thickness (ft)/Gross Pay thickness (ft)	Drainage volume ^b (bbl)	Permeability (Darcy)	Thermal diffusivity (Day/ft ²) ^c	X ^d	Y ^d
Upper Dolomite Reservoir-Issaran Field (Well 1–2)	1	10,034	7714	10,034	7714	0.77	240	240	0.50	8,589,752	0.03895	1.8228	5.84E–04	6.71E–05
	2	10,278	5889	20,312	13,603	0.67	177	422	0.50	8,589,752	0.03895	1.8228	1.18E–03	3.24E–05
Buffalo Creek Reservoir-Grosmont Formation (Well 2)	1	43,967	3076	43,967	3,076	0.07	104	104	0.50	9,290,956	0.0213	1.8228	2.37E–03	7.88E–06
	2	44,332	8372	88,299	11,448	0.13	221	324	0.50	9,290,956	0.0213	1.8228	4.75E–03	4.66E–06
Diatomite Reservoir-Orcutt Oil Field (Wells 3)	1	8080	420	8,080	420	0.05	177	177	0.80	13,269,316	0.0305	1.8228	4.87E–04	4.91E–06
	2	8010	580	16,090	1000	0.06	100	277	0.80	13,269,316	0.0305	1.8228	9.70E–04	3.75E–06
Tar Sand Reservoir-Huntington Beach Field (Well 4)	1	5884	28,900	5884	28,900	4.91	480	480	0.43	4,508,460	0.040	1.9995	5.56E–04	2.05E–04
	2	4320	30,700	10,204	59,600	5.84	420	900	0.43	4,508,460	0.040	1.9995	9.64E–04	1.30E–04
Well 8 Section 25 Formation-River Field (Well 5)	1	8278	143	8278	143	0.017	16	16	0.44	4,601,653	2300	1.9995	7.80E–04	1.25E+00
	2	12,451	294	20,729	437	0.021	42	58	0.44	4,601,653	2300	1.9995	1.95E–03	4.19E–01
Buena Fe Fee Lease - Midway Sunset Field (Well 6)	1	6332	5,585	6,332	5,585	0.88	120	120	0.89	33,039,379	1000	1.9995	1.71E–04	3.68E+00
	2	6179	8,784	12,511	14,369	1.15	216	336	0.89	33,039,379	1000	1.9995	3.38E–04	1.71E+00

^aCOSR cumulative oil to cumulative steam ratio (STB/STB)^bDrainage Volume was calculated using Eq. 3^cThe thermal diffusivity for sandstone and carbonate reservoirs is considered 1.99 ft²/Day and 1.82 ft²/Day, respectively (Yang et al. 2014)^dEquations (1) and (2) were used to Calculate X and Y, respectively

Fig. 4 Log–Log plots of the six wells

six wells. Table 3 also presents the calculations of the X and Y functions according to (1) Eqs. (1) and (2) and (2) the reservoirs data which is presented in Table 1. The data of the first two cycles in each well enabled us to obtain the change in the COSR (Cumulative Oil to Cumulative Steam Ratio) per production days. The different reservoirs show different values of the change of the COSR (Cumulative Oil Steam Ratio) with days on production.

The calculated X and Y functions of the first two cycles of each of the six wells (Table 3) were used to develop the corresponding Log–Log plots. Figure 4 shows the developed correlation of the established mathematical relationship on the Log–Log plots of each well in the six reservoirs, and its extrapolation. In addition, Table 4 summarizes the calculations of the oil production prediction starting from the 3rd cycle for each well. Table 4 presents the actual cumulative steam injection of each cycle of the six wells. The actual cumulative steam injection values at each cycle in each well was used to calculate the X function at the end of each cycle using Eq. (1). Then, the corresponding value of the Y function was extracted at each cycle using the extrapolated Log–Log relationship for each well (Fig. 4). After that, the oil production was calculated using Eq. (2) and the corresponding Y function at each cycle for each well. As shown in Fig. 4, there is a unique slope for the line in each case due to the change in the COSR per production days for each case. This change is achieved according to the variation in

the petrophysical parameters, type of the rock, and the heat efficiency (e.g., the parameters of Eqs. (1) and (2)).

Results of the validation

Table 5, Fig. 5 and Fig. 6 present comparisons between the predicted and actual cumulative oil production performance at each cycle for each well. These comparisons were performed through the well lifetime per each steam cycle. There is a good match between the calculated and the actual oil production in all cases even in the well that has 13 steam cycles. Table 5 presents also the average absolute percentage deviation between the actual and predicted CSS oil production to quantify the validity of the developed model. The deviation percentage was calculated using Eq. (5).

The Absolute Percentage Deviation (APD)

$$= \left[\frac{(\text{Actual Cum. Oil} - \text{Calculated Cum. Oil})}{\text{Actual Cum. Oil}} \right] \% \quad (5)$$

Table 5 presents the absolute percentage deviation between the actual and predicted cumulative CSS oil production for each well at different conditions: (1) at each specific steam cycle and (2) through the well lifetime. It should be highlighted that the first two cycles of each well were excluded from the validation as the data of the first

Table 4 Prediction of the oil production from the wells of the field applications

Case name	Cycle no	Cumulative injection per cycle (bbl/Cycle)	Cumulative steam injection (bbl)	Drainage volume ^a (bbl)	Net pay thickness (ft)/gross pay thickness (ft)	X ^b	a ^c	b ^c	Y ^b	Permeability (Darcy)	Thermal diffusivity (Day/ ft ²) ^d	Total days on production	COSR (STB/STB) ^e	Predicted cumulative oil production per cycle (bbl/Cycle)	Predicted cumulative oil production (bbl)
A															
Upper Dolomite reservoir-Issaran field (Well 1–2)	3	4302	24,614	8,589,752	0.50	1.43E–03	3E–08	1.044	2.72E–05	0.03895	1.8228	547	0.70	3,654	17,257
	4	10,788	35,402	8,589,752	0.50	2.06E–03	3E–08	1.044	1.82E–05	0.03895	1.8228	752	0.64	5,595	22,852
	5	10,003	45,405	8,589,752	0.50	2.64E–03	3E–08	1.044	1.39E–05	0.03895	1.8228	850	0.55	2,168	25,020
Buffalo Creek reservoir-Gros-mont formation (Well 2)	3	44,489	132,788	9,290,956	0.50	7.15E–03	8E–08	0.749	3.36E–06	0.0213	1.8228	533	0.153	8,883	20,331
	4	44,653	177,441	9,290,956	0.50	9.55E–03	8E–08	0.749	2.71E–06	0.0213	1.8228	720	0.167	9376	29,707
	5	44,684	222,125	9,290,956	0.50	1.20E–02	8E–08	0.749	2.30E–06	0.0213	1.8228	887	0.175	9178	38,885
	6	59,629	281,754	9,290,956	0.50	1.52E–02	8E–08	0.749	1.93E–06	0.0213	1.8228	1057	0.175	10,481	49,366
	7	45,093	326,847	9,290,956	0.50	1.76E–02	8E–08	0.749	1.74E–06	0.0213	1.8228	1212	0.180	9528	58,894
	8	46,005	372,852	9,290,956	0.50	2.01E–02	8E–08	0.749	1.58E–06	0.0213	1.8228	1381	0.186	10,604	69,498
	9	87,701	460,554	9,290,956	0.50	2.48E–02	8E–08	0.749	1.35E–06	0.0213	1.8228	1553	0.180	13,211	82,709
	10	88,060	548,614	9,290,956	0.50	2.95E–02	8E–08	0.749	1.19E–06	0.0213	1.8228	1697	0.173	11,978	94,686
Diatomite reservoir-Orcutt oil field (Well 3)	3	15,140	31,230	13,269,316	0.80	1.88E–03	3E–07	0.368	2.98E–06	0.0305	1.8228	427	0.076	1,374	2374
	4	4390	35,620	13,269,316	0.80	2.15E–03	3E–07	0.368	2.84E–06	0.0305	1.8228	501	0.085	654	3028
B															
Tar Sand reservoir-Huntington Beach field (Well 4)	3	11,650	21,854	4,508,460	0.43	2.07E–03	9E–08	1.032	5.43E–05	0.040	1.9995	1410	3.830	24,104	83,704
	4	15,362	37,216	4,508,460	0.43	3.52E–03	9E–08	1.032	3.16E–05	0.040	1.9995	1920	3.032	29,149	112,852

Table 4 (continued)

Case name	Cycle no	Cumulative steam injection per cycle (bbl/Cycle)	Cumulative steam injection (bbl)	Drainage volume ^a (bbl)	Net pay thickness (ft)/gross pay thickness (ft)	X ^b	a ^c	b ^c	Y ^b	Permeability (Darcy)	Thermal diffusivity (Day/ ft ²) ^d	Total days on production	COSR (STB/STB) ^e	Predicted cumulative oil production per cycle (bbl/Cycle)	Predicted cumulative oil production (bbl)
Well 8	3	9265	29,994	4,601,653	0.44	2.82E-03	0.0004	1.112	2.97E-01	2300	1.9995	93	0.024	285	722
Section 25	4	7181	37,175	4,601,653	0.44	3.50E-03	0.0004	1.112	2.34E-01	2300	1.9995	128	0.026	242	964
formation-Kern River	5	7251	44,426	4,601,653	0.44	4.18E-03	0.0004	1.112	1.91E-01	2300	1.9995	176	0.029	337	1301
field (Well 5)	6	12,338	56,764	4,601,653	0.44	5.35E-03	0.0004	1.112	1.45E-01	2300	1.9995	235	0.030	381	1682
	7	11,984	68,748	4,601,653	0.44	6.47E-03	0.0004	1.112	1.17E-01	2300	1.9995	300	0.031	415	2,097
	8	6753	75,501	4,601,653	0.44	7.11E-03	0.0004	1.112	1.05E-01	2300	1.9995	343	0.031	272	2369
	9	12,961	88,462	4,601,653	0.44	8.33E-03	0.0004	1.112	8.79E-02	2300	1.9995	412	0.032	420	2,789
	10	12,298	100,760	4,601,653	0.44	9.49E-03	0.0004	1.112	7.60E-02	2300	1.9995	472	0.031	350	3139
	11	13,225	113,985	4,601,653	0.44	1.07E-02	0.0004	1.112	6.61E-02	2300	1.9995	515	0.030	234	3372
	12	18,032	132,017	4,601,653	0.44	1.24E-02	0.0004	1.112	5.60E-02	2300	1.9995	586	0.029	397	3769
	13	9792	141,809	4,601,653	0.44	1.34E-02	0.0004	1.112	5.17E-02	2300	1.9995	689	0.031	622	4391
Buena Fe	3	5170	17,681	33,039,379	0.89	4.77E-04	7E-05	1.256	1.05E+00	1000	1.9995	498	1.049	4,179	18,548
Fee lease	4	4592	22,273	33,039,379	0.89	6.01E-04	7E-05	1.256	7.84E-01	1000	1.9995	694	1.088	5,694	24,241
- Midway	5	5618	27,891	33,039,379	0.89	7.52E-04	7E-05	1.256	5.88E-01	1000	1.9995	992	1.167	8,310	32,551
Sunset	6	4520	32,411	33,039,379	0.89	8.74E-04	7E-05	1.256	4.86E-01	1000	1.9995	1254	1.218	6,915	39,466
field (Well 6)	7	5664	38,075	33,039,379	0.89	1.03E-03	7E-05	1.256	3.95E-01	1000	1.9995	1594	1.260	8,505	47,971

^aDrainage Volume was calculated using Eq. 3^bEquations (1) and (2) were used to calculate X and Y, respectively^cEquation 4 and the Log-Log chart were used to calculate a and b, respectively^dThe thermal diffusivity for the carbonate reservoirs is 1.82 ft²/Day (Yang et al. 2014)^eCOSR: Cumulative Oil to Cumulative Steam Ratio (STB/STB)

Table 5 Absolute percentage deviation between the actual and predicted oil production

Case name	Cycle number	Cumulative oil production prediction per each steam cycle			Cumulative oil production prediction through the well lifetime		
		Actual cumulative oil production/cycle (bbl/cycle)	Predicted cumulative oil production/cycle (bbl/cycle)	The absolute percentage deviation between actual and predicted cumulative oil production per each steam cycle %	Actual cumulative oil production (bbl)	Predicted cumulative oil production (bbl)	The absolute percentage deviation between actual and predicted cumulative oil production (%)
A							
Upper Dolomite reservoir-Issaran field (Well 1–2)	1	7714	7714	0%	7714	7714	0
	2	5889	5889	0%	13,603	13,603	0
	3	3160	3654	16%	16,763	17,257	3
	4	4736	5595	18%	21,499	22,852	6
	5	2915	2168	26%	24,414	25,020	3
Absolute percentage deviation through the well lifetime%						3	
Buffalo Creek reservoir-Grosmont formation (Well 2)	1	3076	3076	0%	3076	3076	0
	2	8372	8372	0%	11,448	11,448	0
	3	7699	8883	15%	19,147	20,331	6
	4	12,234	9376	23%	31,381	29,707	5
	5	10,127	9178	9%	41,508	38,885	6
	6	4900	10,481	114%	46,408	49,366	6
	7	12,674	9,528	25%	59,082	58,894	0
	8	9,429	10,604	12%	68,511	69,498	1
	9	16,184	13,211	18%	84,695	82,709	2
	10	12,913	11,978	7%	97,608	94,686	3
Absolute percentage deviation through the well lifetime %						3	
Diatomite reservoir-Orcutt oil field (Well 3)	1	420	420	0%	420	420	0
	2	580	580	0%	1000	1000	0
	3	1,350	1374	2%	2350	2374	1
	4	590	654	11%	2940	3028	3
Absolute percentage deviation through the well lifetime%						3	
B							
Tar Sand reservoir-Huntington Beach field (Well 4)	1	28,900	28,900	0%	28,900	28,900	0
	2	30,700	30,700	0%	59,600	59,600	0
	3	21,700	24,104	11%	81,300	83,704	3
	4	37,800	29,149	23%	119,100	112,853	5
Absolute percentage deviation through the well lifetime %						5	

Table 5 (continued)

Case name	Cycle number	Cumulative oil production prediction per each steam cycle			Cumulative oil production prediction through the well lifetime		
		Actual cumulative oil production/cycle (bbl/cycle)	Predicted cumulative oil production/cycle (bbl/cycle)	The absolute percentage deviation between actual and predicted cumulative oil production per each steam cycle %	Actual cumulative oil production (bbl)	Predicted cumulative oil production (bbl)	The absolute percentage deviation between actual and predicted cumulative oil production (%)
Well 8 Section 25 formation-Kern River field (Well 5)	1	143	143	0%	143	143	0
	2	294	294	0%	437	437	0
	3	317	285	10%	754	722	4
	4	208	242	16%	962	964	0
	5	261	337	29%	1223	1301	6
	6	466	381	18%	1689	1682	0
	7	351	415	18%	2040	2097	3
	8	304	272	11%	2344	2369	1
	9	414	420	1%	2758	2789	1
	10	448	350	22%	3206	3139	2
	11	195	234	20%	3401	3372	1
	12	589	397	33%	3990	3769	6
	13	538	622	16%	4528	4391	3
Absolute percentage deviation through the well lifetime %							3
Buena Fe Fee lease - Midway Sunset field (Well 6)	1	5585	5585	0%	5585	5585	0
	2	8784	8784	0%	14,369	14,369	0
	3	5702	4179	27%	20,071	18,548	8
	4	5898	5694	4%	25,969	24,241	7
	5	7218	8310	15%	33,187	32,551	2
	6	5137	6915	35%	38,324	39,466	3
	7	7393	8505	15%	45,717	47,971	5
Absolute percentage deviation through the well lifetime %							5

Fig. 5 Comparisons between the actual and predicted cumulative oil production through well lifetime

Fig. 6 Deviation percentage between the actual and predicted cumulative oil production per each steam cycle

two steam cycles were used to develop the corresponding relationship of each well as presented in Table 3 and Fig. 4. As presented in Tables 4 and 5, the prediction was carried out starting from the third cycle of each well. Accordingly, the developed mathematical relationships predicted 31 steam cycles out of the 43 steam cycles related to the six wells.

As illustrated in Table 5 and Fig. 5, it is clear that the maximum absolute percentage deviation between the actual

and predicted cumulative CSS oil production for each well through its lifetime is less than 5% for any of the six wells. However, Table 5 and Fig. 6 show that the absolute percentage deviation between the actual and predicted cumulative CSS oil production per cycle for 42% of the tested steam cycles (13 out of the 31 steam cycles) is less than or equal 15%. In addition, the absolute percentage deviation between the actual and predicted cumulative CSS oil production per

cycle for 39% of tested steam cycles (12 out of the 31 steam cycles) ranges between 15 and 25%. Only 19% of tested steam cycles (6 out of the 31 steam cycles) achieve absolute percentage deviation between the actual and predicted cumulative CSS oil production above 25%.

The prediction results were analyzed to determine the reasons of increasing the percentage deviation for some cycles such as the 6th steam cycle in Well 2 of Buffalo Creek reservoir as shown in Fig. 6b and Table 5A. The actual field conditions were reviewed. It was recognized that steam injection was replaced by hot water injection which led to decrease in the actual oil production in the 6th steam cycle in Well 2 of Buffalo Creek reservoir. The other reasons of the higher deviation might be related to lower pump efficiency, steam production or interference between wells.

Discussion

The results confirm the validity of the general form of the mathematical relationship to predict the oil production of the CSS wells. Actual CSS field data were compared with the results obtained by the developed mathematical relationship. The developed mathematical relationship predicted 31 steam cycles related to six wells. These wells belong to six reservoirs of different reservoir characteristics. The absolute percentage deviation between the calculated and actual cumulative oil production through the well lifetime ranges between 0 and 5%. This low error verifies the capability and the strength of the developed mathematical relationship to predict CSS oil production for any case.

The selected cases take into considerations the effects of reservoir characteristics, reservoir dip, cumulative injected steam, total days on production, and number of steam cycles. The reservoir types include fractured carbonate, tight matrix, unconsolidated sandstone, and layered with shale. The field applications include cases of different numbers of CSS cycles (between 4 and 13 cycles). In addition, the total days on production are different from case to case: it reaches up to 1920 days in one of the cases. Also, the field applications include cases with a wide range of the injected steam volume per cycle. The injected steam volume per cycle ranges between 4302 and 88,806 bbl Cold Water Equivalent (CWE).

90% of the tested steam cycles (28 out of the 31 steam cycles) recorded less than 30% of the absolute percentage deviation between the actual and predicted cumulative oil production per cycle. The remaining three steam cycles of the tested CSS recorded higher than 30% of the absolute percentage deviation between the actual and predicted cumulative oil production per cycle. The reason behind that might be related to the following reasons: (1) bad performance of the well pump, (2) inaccurate steam production records or

(3) interference from the surrounding wells. Although the absolute percentage deviation between the actual and calculated oil production per cycle is high in some cases, the predicted cumulative oil production through the well lifetime matches the actual oil production very well (deviation ranges between 0 and 5%).

Compared to the other predictive methods, the developed mathematical relationship can deal with different reservoir conditions. The other analytical methods have significant limitations and assumptions. In addition, data unavailability and time limitations along with the uncertainties of the available data in many cases may not support using numerical simulation in prediction. Moreover, the high degree of heterogeneity within the same reservoir does not favor other analogy methods. As shown in the field applications, the developed mathematical relationship was able to deal with different reservoir conditions. Furthermore, the developed mathematical relationship was able to deal with limited available data and limited assumptions. The required data are mainly the petrophysical data and the oil production and steam injection quantities at the end of two previous steam cycles (historical data). The assumptions are mainly the drainage volume and the thermal diffusivity. Therefore, the change in the COSR (Cumulative Oil to Steam Ratio) per day divided by production days has a direct relationship with the effective heating parameters. These parameters are related to the heat injection efficiency. This efficiency is affected by the ratio between the oil net pay thickness to the gross pay thickness, the thermal diffusivity, and the heat losses to the surrounding rocks. Also, the developed mathematical relationship can be presented simply in Log–Log form using dimensionless quantities. This effective and simple mathematical relationship facilitates the method application for any case.

Conclusion

1. Semi-analytical model was developed to predict the CSS oil production. The model can be applied using injection and production data of two steam cycles in addition to basic petrophysical data.
2. Semi-analytical model was validated using data of six wells from six different reservoirs of varying characteristics and operating conditions. The reservoir data included cases from heterogeneous fractured carbonate reservoirs, low matrix permeability reservoirs, layered unconsolidated sandstone reservoir, and a reservoir with a steep dip.
3. The results showed good match between the predicted and actual cumulative oil production through the well lifetime with average absolute percentage deviation less than 5% for the six wells.

4. The absolute instantaneous deviation between the actual and the predicted cumulative oil production for each individual cycle in all cases is (1) less than 15% for about 42% of the tested CSS cycles, (2) between 15 to 25% for about 39% of the tested CSS cycles, and (3) higher than 25% for only about 19% of the tested CSS cycles.

Acknowledgements The authors would like to thank Dr. Mohamed Samir for the valuable discussions with him on the topic.

Funding This work was executed through unfunded research project at Cairo University (Egypt).

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