Developing a new technique for the simultaneous optimization of both segmented time and injection rate for water flooding reservoirs: An analysis of Shengli Oilfield XIN-42 reservoir block

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Abstract
The adjustment and control of the water injection rate is a commonly used method for increasing the cumulative oil production of waterflooded reservoirs. This article studies the production optimization problem under the condition of a fixed total water injection rate. The production process is divided into several segments. Considering the correlation between the segment’s time intervals and the well's injection rate distribution, a simultaneous optimization of both segmented time and injection rate is proposed for enhancing net present value. Both empirical simulations and field application demonstrate that the suggested methods produce the highest increase in net present value – of approximately 13% and 10%, respectively – and significantly improve water flooding efficiency compared to other conventional schemes, such as segmented oil production optimization, cumulative oil production optimization and Bang-Bang control. The proposed methods under a 2-segment division increase oil production efficiency and greatly reduce adjustment costs.

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Keywords
Simultaneous optimization, segmented time, injection rate, water flooding, multi-objective

Introduction
With the development of digitized and intelligent oilfields, optimization methods for oil extraction are currently receiving significant attention (Aitokhuehi and Durlofsky, 2005; Brouwer and Jansen, 2002; Brouwer et al., 2004; Hasan et al., 2009; Izadmehr et al., 2018; Jansen et al., 2009; Lin et al., 2019; Oliveira and Reynolds, 2014). The adjustment and control of water injection or fluid production rates is a primary method of increasing oil production. Asheim (1988) studies the optimization problem of the water injection rate without dividing the production process into segments, such that the injection rate of each well remains unchanged across the entire production process. The optimal injection rates for different wells are calculated using the gradient method. Asheim finds that using optimization methods without dividing production processes lowers the efficiency of oil extraction. Van Essen et al. (2010) determine that without segmentation, the water phase will not adequately prime the production wells and, in certain regions, the oil phase will not be fully completed, thereby causing poor sweeping efficiency.

In recent years, research on segmented optimization methods has been extensive. The selection of control variables has mainly focused on two aspects: wells’ injection rate distributions and segmented time (Almeida et al., 2010; Jansen et al., 2009; Sudaryanto and Yortsos, 2000). To analyse the segmented optimization methods of a well’s injection rate, Zakirov et al. (1996) divide the production process equally, select the oil production in each period as the objective function and optimize injection rates in each segment. Their model finds evidence that this method can achieve higher oil recovery rates than methods without segmentation. Durlofsky and Khalid (2002) select cumulative oil production in a complete production process as the objective function. They show that the overall optimization technique also stimulates increased oil production. These reservoir examples suggest that cumulative oil production optimization methods provide economic benefits (Almeida et al., 2010). As a result of the evidence that this method can further increase the efficiency of oil production (Al-Ameri et al., 2019; Fang and Popole, 2020; Madanipour et al., 2016; Montazerigh and Mahmoodik, 2016; Zhou et al., 2019), the methodology of multi-objective optimization is now widely used.

Another common optimization method, mainly represented by Bang-Bang control, includes the operating time of the wells as control variables and is based on the optimal control theory. In this method, the on-off state and operating times of the oil wells are adjusted so that the breakthrough time of the water flooding front can be delayed, thereby improving sweeping efficiency. The numerical simulations of the three-dimensional reservoir examples indicate that Bang-Bang control can significantly increase the level of oil production and enhance the oil recovery factor (Hasan and Foss, 2013, 2015). Sudaryanto and Yortsos (2000) show that the optimal injection policy, which maximizes the displacement efficiency at the time of arrival of the injected fluid, is Bang-Bang control, in which rates take extreme values within the allowed range. However, Zandvliet et al. (2007) find that Bang-Bang control is not always the optimal valve setting for maximizing the net present value (NPV). In certain situations, Bang-Bang solutions are (only slightly) suboptimal.
Within the currently established optimization methods for improving the NPV, the correlation between the time intervals of the segment and the well’s injection rate distribution has not been considered. There is still scope for further optimization of the NPV using technically and economically efficient methods.

To solve the above problems, this article proposes simultaneous optimization methods that consider both segmented time and the injection rate to maximize the NPV. The methodology used and the algorithm for the suggested optimization methods are thoroughly developed. Numerical simulations are based on conceptual models with multiple injection wells and a three-dimensional reservoir with multiple production wells, which show the potential of employing the proposed methods in improving the NPV.

Materials and methods

Conceptual model

In order to verify the effectiveness of the proposed methods in improving the NPV, a conceptual model with multiple injection wells is constructed. The simulation area is a two-dimensional reservoir with a size range of $337.5 \times 225$ m (as shown in Figure 1). The outer boundary is imposed with impermeable boundary conditions. The total production time is 30 days. Both the total water injection rate and the total fluid production rate are $486 \text{ m}^3/\text{d}$. The oil revenue, water production costs and production costs are $370$, $37$ and $37 \text{ $/m}^3$, respectively. The discount factor is 10%. The parameters of the reservoir and fluids are presented in Table 1.

Shengli Oilfield XIN-42 reservoir block

A three-dimensional reservoir construction is studied to test the optimization efficiency of the proposed methods for practical engineering. The study area is taken from the Shengli Oilfield XIN-42 reservoir block in China, which consists of two injection wells and five production wells. The wells’ location, initial oil saturation distribution, average absolute permeability distribution, average porosity distribution and relative permeability curves are shown in Figure 2. The total production time is 300 days. Both the total fluid production rate and the total water injection rate are fixed at $500 \text{ m}^3/\text{d}$. Two injection wells’ water injection rates are fixed at $250 \text{ m}^3/\text{day}$, respectively. The parameters, including the pressure–volume–temperature properties of dead oil, are presented in Table 2. The commercial software ECLIPSE 2013 (version 13.01.13165) is used for the calculation. Lin and Lin (2018) and Li and Hu (2012) show that the ECLIPSE software is both highly efficient and precise.

Simultaneous optimization methods

The NPV, which is defined as the total oil revenue minus the total injection and production costs over a time interval of $[0, T]$, is selected as the objective function for simultaneous optimization methods. The multi-objective function $J_{\text{npv}}$ can be written as (Zandvliet et al., 2007)

$$ J_{\text{npv}}(u) = \sum_{i=1}^{M} \left[ \sum_{j \in N_{\text{prod}}} r_{\text{oil}} q_{j,0,\text{prod}} - \sum_{j \in N_{\text{prod}}} r_{\text{prod}} q_{j,\text{w,prod}} - \sum_{j \in N_{\text{inj}}} r_{\text{inj}} q_{j,\text{w,inj}} \right] \times \frac{1}{(1 + \frac{100}{T})^{1/4}} \Delta t_{i} \quad (1) $$
The production process is divided into $M$ segments of time $D_t_i$ $(1 \leq i \leq M)$ (d). $r_{oil}$, $r_{inj}$ and $r_{prod}$ are oil revenue per unit volume, water injection cost per unit volume and production cost per unit volume ($$/m^3$), respectively. $I$ is the discount factor. $q_i^j; o; prod$ and $q_i^j; w; prod$ $(m^3/d)$ denote the oil and water production rate of well $j$ $(1 \leq j \leq N_{prod})$ in segment $i$, respectively, while $q_i^j; w; inj$ $(m^3/d)$ is the water injection rate of the well $j$ $(1 \leq j \leq N_{inj})$ in segment $i$. $N_{inj}$ and $N_{prod}$ are the number of injection and production wells, respectively.

The control variable $u$ consists of segmented time $D_t_i$ and the water injection rate $q_i^j; w; inj$, and can be written as

$$
u = [\Delta t_1, \ldots, \Delta t_M, q_{1,w,inj}^1, \ldots, q_{N_{inj},w,inj}^M]^T$$ (2)

The simultaneous optimization methods for the water flooding problem can be expressed by

$$\text{maximize}_{u \in \mathbb{R}^{Nw}} \ J_{npv}(u)$$ (3a)

subject to $0 \leq q_i^j; w; inj \leq Q_{inj}$ $(i = 1, \ldots, M; j = 1, \ldots, N_{inj})$ (3b)

$0 \leq \Delta t_i \leq T$ $(i = 1, \ldots, M)$ (3c)

Figure 1. Location of wells in the conceptual model. Note: The numbers of injection wells and the production well are presented in the dialog box.

Table 1. Parameters of the reservoir and fluids in the conceptual model.

| Parameter                        | Value          |
|----------------------------------|----------------|
| Mesh size                        | $\Delta x = \Delta y = 7.5\text{ m}$ |
| Porosity                         | $\phi = 24\%$ |
| Absolute permeability            | $K = 500\text{ mD}$ |
| Initial water saturation         | $s_w^0 = 0.301$ |
| Irreducible water saturation     | $s_{wc} = 0.3$ |
| Residual oil saturation          | $s_{or} = 0.2$ |
| Formation pressure               | $P = 22\text{ MPa}$ |
| Viscosity                        | $\mu_w = 1\text{ mPa} \cdot \text{s}$ |
| Viscosity                        | $\mu_o = 4\text{ mPa} \cdot \text{s}$ |
| Relative permeability            | $K_{ro} = (\frac{s_o - s_{wc}}{1 - s_{wc}})^2$ |
| Relative permeability            | $K_{rw} = (\frac{s_w - s_{wc}}{1 - s_{wc}})^2$ |

The production process is divided into $M$ segments of time $\Delta t_i$ $(1 \leq i \leq M)$ (d). $r_{oil}$, $r_{inj}$ and $r_{prod}$ are oil revenue per unit volume, water injection cost per unit volume and production cost per unit volume ($$/m^3$), respectively. $I$ is the discount factor. $q_i^j; o; prod$ and $q_i^j; w; prod$ $(m^3/d)$ denote the oil and water production rate of well $j$ $(1 \leq j \leq N_{prod})$ in segment $i$, respectively, while $q_i^j; w; inj$ $(m^3/d)$ is the water injection rate of the well $j$ $(1 \leq j \leq N_{inj})$ in segment $i$. $N_{inj}$ and $N_{prod}$ are the number of injection and production wells, respectively.

The control variable $u$ consists of segmented time $\Delta t_i$ and the water injection rate $q_i^j; w; inj$, and can be written as

$$u = [\Delta t_1, \ldots, \Delta t_M, q_{1,w,inj}^1, \ldots, q_{N_{inj},w,inj}^M]^T$$ (2)

The simultaneous optimization methods for the water flooding problem can be expressed by

$$\text{maximize}_{u \in \mathbb{R}^{Nw}} \ J_{npv}(u)$$ (3a)

subject to $0 \leq q_i^j; w; inj \leq Q_{inj}$ $(i = 1, \ldots, M; j = 1, \ldots, N_{inj})$ (3b)

$0 \leq \Delta t_i \leq T$ $(i = 1, \ldots, M)$ (3c)
\[
q_{j,w,\text{inj}}^{\text{f}} = Q_{\text{inj}} \quad (i = 1, \ldots, M)
\]  

Equations (3b) and (3c) give the inequality constraints with upper and lower bounds on control variables. Equations (3d) and (3e) give the equality constraints with a fixed total
water injection rate $Q_{\text{inj}}$ and fixed total production time $T$. In the solution of the above constrained optimization problems, as produced by the elimination method, the control variables include $M/C_2(N_{\text{inj}}/C_0)^1$ injection rates and $M/C_0^1$ segmented time intervals. Therefore, the total number of control variables is $N_u = M/C_2(N_{\text{inj}}/C_0)^1$. The steepest descent method is employed to solve the optimization problem, which is described by

$$u^{(k+1)} = u^{(k)} - \alpha^{(k)} \nabla J_{\text{npv}}|_{u^{(k)}}$$

The optimal step factor $\alpha^{(k)}$ can be determined by the one-dimensional search technique (Yuan, 2006)

$$J_{\text{npv}}[u^{(k)} - \alpha^{(k)} \nabla J_{\text{npv}}|_{u^{(k)}}] = \max_{\alpha \geq 0} J_{\text{npv}}[u^{(k)} - \alpha \nabla J_{\text{npv}}|_{u^{(k)}}]$$

The algorithm steps are presented below:

1. Let $k = 0$; set the initial value of $u^{(0)}$ and the stopping criterion as $\varepsilon > 0$;

### Table 3. Optimization results for time, the water injection rate and the NPV, including simultaneous optimization methods and comparison schemes in the conceptual model.

| Scheme number | Time (d) | $q_{1,\text{w.inj}}$ (m$^3$/d) | $q_{2,\text{w.inj}}$ (m$^3$/d) | NPV (million $) | Increase (%) |
|---------------|----------|---------------------------------|---------------------------------|-----------------|--------------|
| 1             | $\Delta t_1=30$ | 243.0                           | 243.0                           | 1.7409          | –            |
| 2             | $\Delta t_1=30$ | 432.5                           | 53.5                            | 1.901        | 9.22         |
| 3             | $\Delta t_1=15$ | 437.6                           | 48.4                            | 1.9117         | 9.81         |
|               | $\Delta t_2=15$ | 358.4                           | 127.6                           |                |              |
| 4             | 2-segment       | $\Delta t_1=15$ | 486.0                           | 0               | 1.9299       | 10.86        |
|               | $\Delta t_2=15$ | 351.9                           | 134.1                           |                |              |
|               | 4-segment       | $\Delta t_1=7$                | 486.0                           | 0               | 1.9323       | 10.99        |
|               | $\Delta t_2=8$  | 486.0                           | 0                               |                |              |
|               | $\Delta t_3=7$  | 486.0                           | 0                               |                |              |
|               | $\Delta t_4=8$  | 154.6                           | 331.4                           |                |              |
| 5             | 2-segment       | $\Delta t_1=19$               | 486.0                           | 0               | 1.9410       | 11.49        |
|               | $\Delta t_2=11$ | 0                               | 486.0                           |                |              |
|               | 4-segment       | $\Delta t_1=12$               | 486.0                           | 0               | 1.9410       | 11.49        |
|               | $\Delta t_2=0$  | 0                               | 486.0                           |                |              |
|               | $\Delta t_3=7$  | 486.0                           | 0                               |                |              |
|               | $\Delta t_4=11$ | 0                               | 486.0                           |                |              |
| 6             | 2-segment       | $\Delta t_1=21$               | 486.0                           | 0               | 1.9655       | 12.90        |
|               | $\Delta t_2=9$  | 196.9                           | 289.1                           |                |              |
|               | 4-segment       | $\Delta t_1=11$               | 486.0                           | 0               | 1.9721       | 13.28        |
|               | $\Delta t_2=10$ | 486.0                           | 0                               |                |              |
|               | $\Delta t_3=5$  | 196.4                           | 289.6                           |                |              |
|               | $\Delta t_4=4$  | 193.3                           | 292.7                           |                |              |

NPV: net present value.
2. Calculate the gradient values $\nabla J_{\text{npv}|u^{(k)}}$. If $\|\nabla J_{\text{npv}|u^{(k)}}\| \leq \epsilon$, then stop the iteration and output $u^{(k)}$. Otherwise go to the next step;

3. Calculate the step factor $\gamma^{(k)}$ using Equation 5. Update $u^{(k)}$ by $u^{(k+1)}$ using Equation 4. Then return to Step 2.

Comparison schemes

For comparison purposes, several conventional adjustment and optimization schemes are selected. The comparison schemes are numbered from 1 to 5 and the scheme using the proposed methods is labelled as Scheme 6. Each scheme is accompanied by a brief introduction to the optimization methods.

1. Scheme 1: Average water injection – the total injection rate is assigned to each well equally.
2. Scheme 2: Water injection rate optimization – the production process is not divided and the injection rate of each well is fixed with the optimized value during the complete production process.
3. Scheme 3: Segmented oil production optimization – divides the production process into several time-averaged segments and optimizes water injection rates in each segment independently.
4. Scheme 4: Cumulative oil production optimization – divides the production process into several time-averaged segments and optimizes the water injection rates at each segment simultaneously.
5. Scheme 5: Bang-Bang control optimization – divides the production process into several segments and optimizes the segmented time with Bang-Bang control.
Results and discussion

Optimization results for the conceptual model

The conceptual model is calculated firstly to verify the effectiveness of the proposed methods. The optimization results of the NPV analysis in the conceptual model with

Table 4. NPV results in Shenli Oilfield XIN-42 reservoir block with simultaneous optimization methods and comparison schemes.

| Scheme number | Time (d) | $q_1_{prod}$ | $q_2_{prod}$ | $q_3_{prod}$ | $q_4_{prod}$ | $q_5_{prod}$ | NPV (million $) | Increase (%) |
|---------------|----------|--------------|--------------|--------------|--------------|--------------|----------------|--------------|
| 1             | $\Delta t = 300$ | 100 | 100 | 100 | 100 | 100 | 32.0912 | – |
| 2             | $\Delta t = 300$ | 192 | 0 | 70 | 0 | 238 | 34.8943 | 8.73 |
| 3             | $\Delta t = 150$ | 80 | 0 | 102 | 100 | 218 | 34.5243 | 7.58 |
|               | $\Delta t = 150$ | 213 | 0 | 32 | 0 | 255 | – | – |
| 4             | $\Delta t = 150$ | 177 | 31 | 69 | 0 | 223 | 34.9757 | 8.99 |
|               | $\Delta t = 150$ | 192 | 0 | 67 | 0 | 241 | – | – |
| 6             | $\Delta t = 213$ | 185 | 39 | 70 | 0 | 206 | 35.3868 | 10.27 |
|               | $\Delta t = 87$  | 192 | 0 | 49 | 0 | 259 | – | – |

6. Scheme 6: Simultaneous optimization of both segmented time and injection rate, described by equations (3a) to (3e).

Figure 4. Reservoir pressure of the proposed methods and comparison schemes at day 30 in the conceptual model: (a) Scheme 1; (b) Scheme 2; (c) Scheme 3; (d) Scheme 4 (4-segment); (e) Scheme 5 (4-segment); (f) proposed scheme (4-segment).
Simultaneous optimization methods and other comparison schemes are shown in Table 3. It is indicated that the simultaneous optimization of both segmented time and injection rate provides the highest NPV among the six adjustment schemes. Compared with the average water injection scheme, the proposed methods with 2-segment and 4-segment divisions achieve a 12.90% and 13.28% improvement in NPV, respectively. The cumulative oil production optimizations with 2-segment and 4-segment divisions produce a 10.86% and

**Figure 5.** Residual oil abundance maps for the proposed methods and comparison schemes at day 300 in Shengli Oilfield XIN-42 reservoir block: (a) Scheme 1; (b) Scheme 2; (c) Scheme 3 (2-segment); (d) Scheme 4 (2-segment); (e) proposed Scheme 6 (2-segment).
10.99% improvement in NPV, respectively. For Bang-Bang control optimization, both the 2-segment scheme and the 4-segment scheme produce an 11.49% increase in NPV. This demonstrates that simultaneous optimization methods can be sufficient to stimulate the NPV in the conceptual model.

Since the simultaneous optimization methods with 2-segment and 4-segment divisions produce similar increases in NPV, and the 2-segment scheme has a greater computational efficiency with fewer control variables, this indicates that the proposed methods can achieve a substantial increase in the NPV under the circumstance of fewer divisions within production processes. For engineering practices, the proposed methods can increase oil production efficiency as well as reduce the computation time and regulation costs.

The contour maps for water-phase saturation of each scheme at day 30 are shown in Figure 3. Map F shows that simultaneous optimization methods produce the largest water sweeping areas, demonstrating that this method has a better displacement efficiency compared with other conventional optimization schemes. The distributions of reservoir pressure in each scheme at day 30 are provided in Figure 4.

**Optimization efficiency in Shengli Oilfield XIN-42 reservoir block**

Shengli Oilfield XIN-42 reservoir block is studied subsequently to test the proposed methods' optimization efficiency in practical engineering. Different to the empirical simulations,
the oilfield case has more than two production wells; however, the control variables of segmented time and fluid production rate remain and are optimized simultaneously. Besides, Scheme 5 will not be discussed in Shengli Oilfield case (multiple production wells) for the reason that Bang-Bang control only supplies to the oilfield with two injection or production wells. Table 4 shows that simultaneous optimization methods produce the highest NPV for the reservoir with multiple production wells. Compared with the average water injection scheme, the proposed methods with 2-segment divisions raise the NPV by 10.27%. By contrast, the production rate optimization scheme, the segmented oil production optimization scheme and the cumulative oil production optimization scheme produce

![Figure 6. Reservoir pressure of the proposed methods and comparison schemes at day 300 in Shengli Oilfield XIN-42 reservoir block: (a) Scheme 1; (b) Scheme 2; (c) Scheme 3 (2-segment); (d) Scheme 4 (2-segment); (e) proposed Scheme 6 (2-segment).](image-url)
increases of 8.73%, 7.58% and 8.99%, respectively. In addition, compared with the optimization results in empirical simulations, the simultaneous optimization methods still achieve considerable improvement rates in NPV when used in field applications.

The residual oil abundance map (Figure 5(e)) shows that the simultaneous optimization methods have the minimum residual oil abundance in the west and east region of the XIN-42 block, which can be concluded that maximum amount of the crude oil is driven from centres to the boundary area by simultaneous optimization methods. It demonstrates that the proposed methods have better water flooding efficiency for practical engineering compared with other conventional optimization schemes. The residual oil abundance maps are drawn with the commercial software PETREL (version 2015.5). The distributions of reservoir pressure in each scheme at day 300 are provided in Figure 6.

Conclusions

This article proposes a simultaneous optimization of both segmented time and injection rate to increase oil production efficiency for waterflooded reservoirs. The proposed methods optimize the time intervals of the segment and the well’s injection rate simultaneously. Both empirical simulations and field application show that simultaneous optimization methods produce the highest improvement rates in NPV – of approximately 13% and 10%, respectively – and induce better water sweeping efficiency compared with other conventional schemes. Additionally, the proposed methods with 2-segment division and 4-segment division produce similar increases in the NPV. For practical engineering, the proposed methods with 2-segment division increase oil production efficiency and greatly reduce the adjustment cost.

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