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# Offshore oil production planning optimization: An MINLP model considering well operation and flow assurance

Xiaoyong Gao[a,b], Yi Xie[b], Shuqi Wang[c], Mingyang Wu[d], Yuhong Wang[d,*], Chaodong Tan[e], Xin Zuo[b], Tao Chen[f,*]

[a] College of Safety and Ocean Engineering, China University of Petroleum, Beijing 102249, China
[b] Department of Automation, China University of Petroleum, Beijing 102249, China
[c] Beijing Oil and Gas Pipeline Control Center, PetroChina, Beijing 100007. China
[d] College of Information and Control Engineering, China University of Petroleum, Qingdao 266580, China
[e] College of Petroleum Engineering, China University of Petroleum, Beijing 102249, China
[f] Department of Process and Chemical Engineering, University of Surrey, Guildford GU2 7XH, United Kingdom

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ABSTRACT

With the increasing energy requirement and decreasing onshore reserves, offshore oil production has attracted increasing attention. A major challenge in offshore oil production is to minimize both the operational costs and risks; one of the major risks is anomalies in the flows. However, optimization methods to simultaneously consider well operation and flow assurance in operation planning have not been explored. In this paper, an integrated planning problem both considering well operation and flow assurance is reported. In particular, a multi-period mixed integer nonlinear programming (MINLP) model was proposed to minimize the total operation cost, taking into account of well production state, polymer flooding, energy consumption, platform inventory and flow assurance. By solving this integrated model, each well's working state, flow rates and chemicals injection rates can be optimally determined. The proposed model was applied to a case originated from a real-world offshore oil site and the results illustrate the effectiveness.



## 1. Introduction

Crude oil is the major energy resource in the modern society and continues to be so in the coming years (Kang et al., 2017). It is typically produced by drilling production wells in large oil fields with several reservoirs. Onshore hydrocarbon resources have become increasingly scarce with the continuous exploitation of the past decades. At the same time, the sea contains vast oil and gas resources. The exploitation and usage of offshore oil resources are receiving more and more attention. In general, deep-water oil reserves are difficult to exploit accompanied with large production costs due to the harsh environment and the energy intensity required for the production (Narimanov, 2008; Zhu et al., 2018; Wang et al., 2017). Therefore, there are clear incentives to seek more efficient operations while reducing the risks. To this end, optimization approaches for production planning and scheduling have received increasing attention from both the academic and industrial communities (Hou, 2014; Gao et al., 2018a, 2018b; Wang et al., 2016).

In the literature, significant progress has been reported for the scheduling and planning of oil production processes. Gupta and Grossmann (2012) built an efficient strategic/tactical planning multi-period MINLP model for offshore production optimization with the objective of maximizing the total net present value (NPV), considering three components (oil, gas and water), FPSO (floating production, storage and offloading) topside's inventory level and the well's production rate. Ortíz-Gómez et al., 2002 investigated the oil production planning problem in the wells of an oil reservoir considering nonlinear behavior of the well flowing pressure with respect to time. Heever et al. (2000) considered nonlinear reservoir behavior and its impact on the complex business aspects, and proposed a MINLP model for offshore oil facility design and planning. An integrated MILP model for making a group of strategic decisions about oil and gas development projects simultaneously over a long-term planning horizon was proposed by Shakhsi-Niaei et al. (2014), where production planning, upstream transmission planning and their interactions with projects selection and sequence are addressed. Kosmidis et al., 2005 presented a mixed

*Abbreviations:* ESP, electric submersible pump; FPSO, floating production storage and offloading; MILP, mixed integer linear programming; MINLP, mixed integer nonlinear programming.

* Corresponding authors.
*E-mail addresses:* y.h.wang@upc.edu.cn (Y. Wang), t.chen@surrey.ac.uk (T. Chen).

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**Nomenclature**

| | |
|---|---|
| $i$ | oil production well |
| $k$ | well batch |
| $t$ | time period |

*Sets*

| | |
|---|---|
| $I$ | oil production wells |
| $K$ | well batches |
| $T$ | time period |

*Parameters*

| | |
|---|---|
| $h_{in}$ | convection heat transfer coefficient |
| $r$ | radius of the tubing |
| $\rho_g$ | the density of gas phase |
| $\rho_1$ | the density of liquid phase |
| $H_1$ | the liquid holdup |
| $G$ | the mass flow of the mixture |
| $\lambda$ | the resistance coefficient |
| $\lambda_{ins}$ | thermal conductivity of insulation materials |
| $s$ | thickness of the insulation blanket |
| $s_{tub}$ | thickness of the tubing |
| $\Delta_x$ | valve opening change limit |
| $h^{\max}$ | maximum wax deposit thickness |
| $A_i, B_i$ | coefficients of polymer flooding of well i |
| $F_d$ | distribution density of wax |
| $I^{\max}$ | maximum inventory capacity of oil |
| $I^{\min}$ | minimum inventory capacity of oil |
| $T_{L+\Delta L}$ | temperature of flowing-out |
| $a_{i0}, a_{i1}$ | coefficients of pressure increase of well i |
| $b_{i0}, b_{i1}$ | coefficients of pressure decrease of well i |
| $c_1, c_2$ | coefficients of pressure variation equation which result from combinations |
| $d_{k,\, t}$ | production demand of well batch k in time period t |
| $d_t$ | demand of production in period t |
| $e_k$ | pipe roughness of well batch k |
| $pe_1$ | power generation efficiency of diesel generator set in platform |
| $p_i^{low}$ | up limit pressure of well i |
| $p_i^{up}$ | down limit pressure of well i |
| $pl_0$ | inlet pressure |
| $x_i^{\max}$ | maximum production rate of well i |
| $x_i^{\min}$ | minimum production rate of well i |
| $\alpha_i$ | cost of start-stop operation of unit i |
| $\sigma_i$ | coefficient for electricity consumption of valve in well i |
| $\Delta$L | length of pipeline segment |
| $\theta_1$ | the line angle |
| $A$ | the pipeline cross-sectional area |
| $T_L$ | temperature of flowing-in |
| $Ts$ | temperature of fluid at the fluid entry point |
| $\rho$ | is fluid density |
| $Gl$ | density of wax |
| $Dr$ | length of time period |
| $M$ | suitable upper limit |
| $T$ | length of planning horizons |
| $\gamma$ | coefficient of inventory cost |
| $\delta$ | cost coefficient of polymer flooding |
| $\theta$ | punishment of delivery delay |
| $\tau$ | coefficient of wax removal cost |
| $p_i^{initial}$ | initial bottom pressure for the well i |
| $I_k^{initial}$ | initial inventory level for the oil batch k |
| $D_k$ | half of the radius of the annular region volume by uneven ups and downs |

*Variables*

| | |
|---|---|
| $Te$ | temperature inside the pipe |
| $\Delta E_{i,\, t}$ | recovery ratio differential of oil well i in period t |
| $I_{k,\, 1}$ | initial inventory of well batch k |
| $I_{k,\, t}$ | inventory of well batch k in the time period t |
| $MI_k$ | quality of the precipitated wax in pipeline of well batch k |
| $P_{i,\, t}$ | polymer flooding of well i in time period t |
| $Q_{acc}$ | heat accumulation |
| $Q_{in}$ | heat flow in |
| $Q_{out}$ | heat flow out |
| $Q_r$ | heat transferred |
| $SP_{i,\, t}$ | pressure differential in the well bore when the well i is shut in |
| $TI_k$ | wax removal cycle of well batch k |
| $VI_k$ | volume of the precipitated wax in pipeline of well batch k |
| $XP_{i,\, t}$ | pressure differential in the well bore when the well i is producing |
| $Y_{i,\, t}$ | 0–1variable indicating whether the well bore pressure reaches the maximum allowable value in period t when well i is closed |
| $ele_{cost}$ | consumption of energy |
| $p_{i,1}^{in}$ | initial pressure of well i |
| $p_{i,t}^{end}$ | well bore pressure of well i at the end of period t |
| $p_{i,t}^{in}$ | well bore pressure of well i at the beginning of period t |
| $pr_{k,\, t}$ | production supply of oil well batch k in the time period t |
| $pr_t$ | production supply in period t |
| $v_k$ | wax deposit rate in pipeline of well batch k |
| $wf_{i,\, t}$ | the occurrence of start−stop operation in equipment i during t week and $t + +1$ week. |
| $w_{i,\, t}$ | 0–1 variable denoting whether well i is working in the period t |
| $x_{i,\, t}$ | production rate of oil in well i in the period t |
| $\Delta Te$ | difference in temperature between the pipeline product and the ambient temperature outside |
| $h$ | wax deposit thickness |
| $v$ | fluid velocity in pipeline |
| $ele$ | energy supply |

integer nonlinear (MINLP) model for daily well scheduling in oil fields, where the nonlinear reservoir behavior, the multiphase flow in wells and constraints from the surface facilities are considered to decide the operational status of wells (i.e. open or closed), the allocation of wells to manifolds or separators, the allocation of flow lines to separators, the well oil rates and the allocation of gas-to-gas lift wells. Carvalho and Pinto (2006) proposed an MILP approach, reformulated from an MINLP model, to determine the assignment of platforms to wells and the timing for fixed assignments. In another study, a novel approach to scheduling the startup of oil and gas wells in multiple fields over a decade-plus discrete-time horizon was presented (Kelly et al., 2017). The major innovation was to treat each well or well type as a batch-process with time-varying yields or production rates that follow the declining, decaying or diminishing curve profile. Tavallali and Karimi (2016) developed an MINLP approach for more holistic decisions on the order, placement (Ozdogan and Horne, 2006; Tavallali, 2013), timing, capacities, and allocations of new well drillings and surface facilities such as manifolds, surface centers, and their interconnections, along with well production/injection profiles. Ortıź-Gómez et al., 2002 described three mixed integer multi-period optimization models of varying complexity for the oil production planning in the wells of an oil reservoir in order to determine the oil production profiles and operation/shutdown of the wells in each time period. Moreover, an oil well production scheduling problem for the light load oil well during exploitation was studied, which was to determine the turn on/off status and oil flow rates of the wells in a given oil reservoir, subject to a number of constraints such as minimum up/down time limits and well grouping (Lang and Zhao, 2016). Iyer et al. (1998) presented a MILP model for the planning and scheduling of investment and operation in offshore oil field, in which the net present value is taken as objective function and the choice of reservoirs to develop, the well drilling and platform installation schedule, capacities of each well and production platform, and the fluid production rates from wells are taken as decision variables.

In the field of oil production process optimization, the existing results mainly focused on onshore but very little has been done on the offshore oil production processes, especially for deep water. The above-reviewed studies, whilst often shedding insight into the various aspects of the challenge, are not suitable for direct application in practice. A major limitation is that most of them considered only one or a few sections of the entire production system, such as the well type and location, production rates, status of oil wells, the allocation of flow lines (Yeten et al., 2002; Gunnerud and Foss, 2010; Aseeri et al., 2004; Ulstein et al., 2007), polymer flooding process, artificial lift process (Hallundbæk, 2016) and flow assurance (Luna-Ortiz et al., 2008; Zhou et al., 2014). Flow assurance refers to ensuring successful and economical flow of hydrocarbon stream from reservoir to the point of sale or storage, which is widely viewed as a major challenge for offshore oil and gas production (e.g. due to hydrate formation and wax deposition in the pipe). To the best of our knowledge, integrated planning optimization that consider both facility operation and flow assurance has not been reported in the literature, despite that the topic is of great importance to ensure safety, in particular for offshore oil and gas production.

The particular challenge to be addressed in this work is the flow assurance, in contrast to the existing focus on subsea exploitation equipment operation aiming for maximum yield. It is well known that a change of well operations results in varying flowrate in subsea pipelines, thus has a big impact on the subsequent multiphase flow transportation processes. Therefore, in this work, a multi-period mathematical model involving well operation and flow assurance for the planning optimization of offshore oil production is presented. We propose a discrete time representation based entire process planning model including the subsea production process, polymer flooding process (Wang et al., 2005), flow assurance (Hou and Zhang, 2004), platform storage of oil and delivery process. The rest of this paper is organized as follows. First, the problem statement and process description are given in Section 2. On the basis of process analysis, Section 3 provides the detailed entire process planning model. A case study from a real-world production process is presented to demonstrate the feasibility of the proposed MINLP model in Section 4. Finally, conclusions are drawn in Section 5.

## 2. Process description and problem statement

### 2.1. Process description

From the wells to the platform, the whole production process can generally be divided into three parts: the under-well reservoir process, the under-water production process and the over-water platform section (Fig. 1).

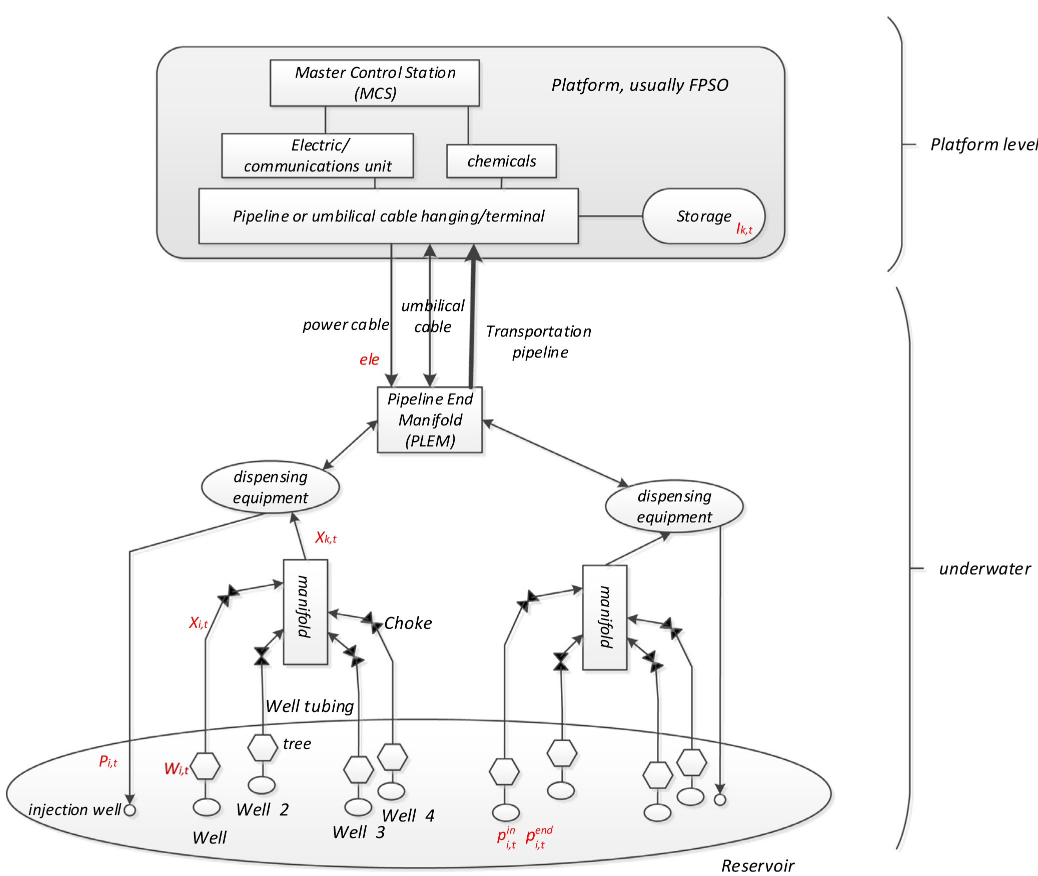



**Fig. 1.** An integrated oil production system.

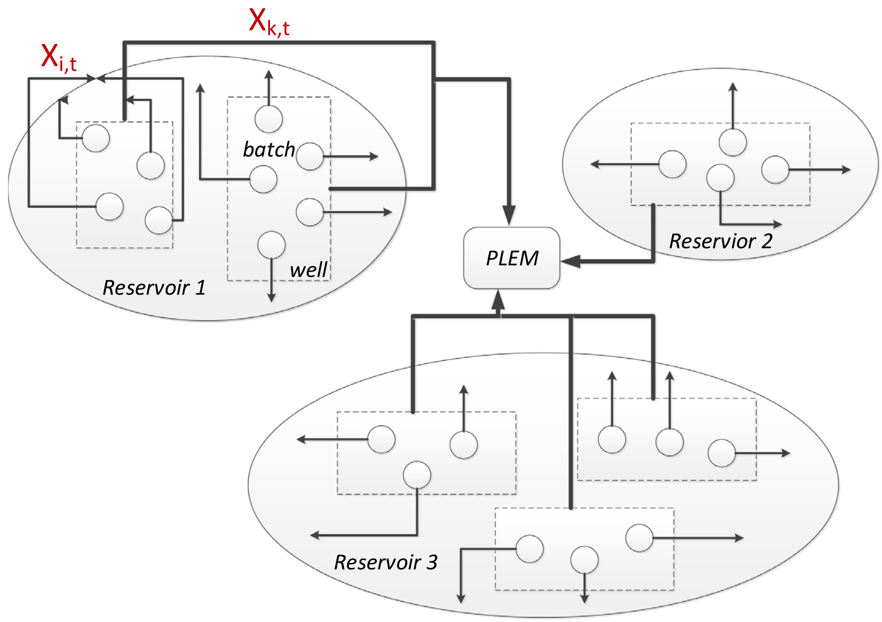



**Fig. 2.** Illustration of pipeline network and well batch in oilfield.

Oil field is composed by a large number of wells which can spread over a wide geographical area. Usually, one oil field contain a lot of reservoirs, each of which contains many wells. The wells can be divided into different batches of oil wells by close geographic location which can determine the well's geological properties and physical characteristics as illustrated in Fig. 2 (Lang and Zhao, 2016). The wells which belong to the same batch interconnect with each other through a complex comprehensive pipeline network to convey liquid to manifold. The wells in one specific reservoir are grouped into one batch. The whole wells normally share a surface equipment, usually named floating production, storage and offloading unit (FPSO).

The typical industrial engineering process flow of the subsea oil production is shown in Fig. 1.

(1) The surface supporting facilities mainly include surface control unit relying on oil treatment facilities, power supply unit and the required chemical injection unit, et al.
(2) Underwater production facilities refer to the well completion equipment, the basic components of subsea production system and equipment on the basis of marine control technology.
(3) Submarine pipelines and risers mainly include production pipeline, umbilical cable, submarine cable et al.

In order to complete the oil production task, decision instructions such as electric and hydraulic signals, chemical injection etc. is transmitted from the surface master control station through umbilical cable to underwater total distribution devices. Electrical signals are distributed by the electric power distribution unit to control Christmas trees and the downhole electric submersible pump. Chemicals are delivered to injection wells close to the production wells to increase production. The opening of the valves are controlled by hydraulic or electric signals. Oil is collected at transmission manifold and then is pumped to offshore platform through output pipeline for further separation and storage.

### 2.2. Problem statement

The main challenges for offshore oil production, largely due to the severe environmental conditions are given below.

(1) For subsea wells, electric submersible pump (ESP) as an artificial lifting method plays an important role due to their minimal space usage, high efficiency and endurance to harsh conditions (Mohammadzaheri et al., 2016) which can replenish energy to the well bottom hole. How to optimize its operating state to save energy is a major challenge.
(2) Due to high pressure and low temperature in the deep-water environment, oil and gas transportation from sea-bed to platform faces great difficulties and risks, such as hydrate formation, wax deposition, severe slug flow and so on (Luna-Ortiz et al., 2008). Moreover, the mechanism of flow assurance problems, such as hydrate formation, wax deposition and so on, is complex and can be described in fluid's temperature, pressure and flowrate. Different sources of oil and gas have different oil-gas-water-sand ratios, different pressures or even temperatures. Individual well operation results in flow changes and thus leads to condition fluctuation, i.e. pressures and temperatures in manifold and risers. Clearly, separate optimization scheme and well operation without considering flow assurance is not suitable. How to utilize the flow assurance mechanism, balance oil wells and optimally determine the operation scheme to guarantee flow assurance is another major challenge.
(3) With the exploitation of offshore oil, bottom-hole pressure tends to decrease. To guarantee the reservoir's safety and production stability, the bottom hole pressure constraint must be satisfied by injecting a particular quantity of polymer flooding. For a well, different injection quantities result in different oil/gas production yield. Moreover, the wells exhibit distinct production yields even under the same injection policy (i.e. injection fluid type and quantity). Hence, how to distribute each well's injection with a given polymer quantity is another challenge.
(4) After the oil/gas has been safely transported to the platform, separation and storage operation is required. However, the separation and storage capacity of offshore platform is limited. Hence, it is necessary to integrate the well and platform operation to avoid mismatch.

In a summary, the whole offshore oil/gas production processes interact with each other, requiring an integrated consideration of the subsea well operation, injection operation, subsea delivery operation and platform operation. In this paper, we propose an integrated planning model to address these problems.

## 3. Mathematical model

The integrated planning model defined as a multi-period MINLP has been developed considering both well operation and flow assurance, taking the minimum value of the total operating costs over the planning horizon as the objective function while satisfying all the constraints.

Several assumptions are made in this study as follows:

(1) The production wells are separated and totally independent of each other. It is natural because each well has its own independent reservoir.
(2) During the middle and later periods of oilfield development, artificial lift technology and polymer flooding is indispensable.
(3) All the electric submersible pumps have the same working characteristic curve.
(4) Geological properties characterizing the well are available.
(5) In the absence of polymerization flooding, oil recovery rate remains the lowest.
(6) The location of easily blocked pipeline section is known.

With the above assumptions, the model relies on the following given information:

(1) A planning horizon and planning period;
(2) Production tasks for each batch of oil wells along the planning horizon;
(3) Working load range of oil production wells;
(4) A set of storage bins, their minimum and maximum stock and initial inventories;
(5) The penalty of switching operations and stock out;
(6) A set of cost coefficient and model parameters.

The decision variables are:

(1) The production rate and operating state of each oil well in each time period.
(2) The detailed delivery quantity in each oil batch in each time period.
(3) The wax removal cycle of each oil well.
(4) The polymer flooding injection policy, i.e. the injection time and quantity.

### 3.1. Objective function

Mathematically, the objective function is given as follows:

$$\min Z = Z_1 + Z_2 + Z_3 + Z_4 + Z_5 + Z_6 \tag{1}$$

The objective described in Eq. (1) aims at minimizing the overall cost ($Z$), which includes the oil well open-close switching penalty ($Z_1$), energy consumption ($Z_2$), oil inventory ($Z_3$), and chemicals cost ($Z_4$), wax removal cost ($Z_5$), and the costs of stock out penalty ($Z_6$).

### 3.2. Open-close operation of oil wells

According to production task and inventory requirements, it is necessary to first determine the working state $w_{i,\,t}$ of the underwater tree in each time period which is related to the production plan task, and is restricted by the downhole pressure. When the well is open, then the well bore pressure decreases, but if the well is closed, then the pressure increases.

Frequent open-close operations should be avoided. The switching cost can be expressed as Eqs. (2)–(4), where $wf_{i,t} = 1$ denotes the occurrence of open-close switches operation. The state switching variable $wf_{i,\,t}$ is penalized in the target function, which can limit $wf_{i,\,t}$ to 0 when there is no state switching operation.

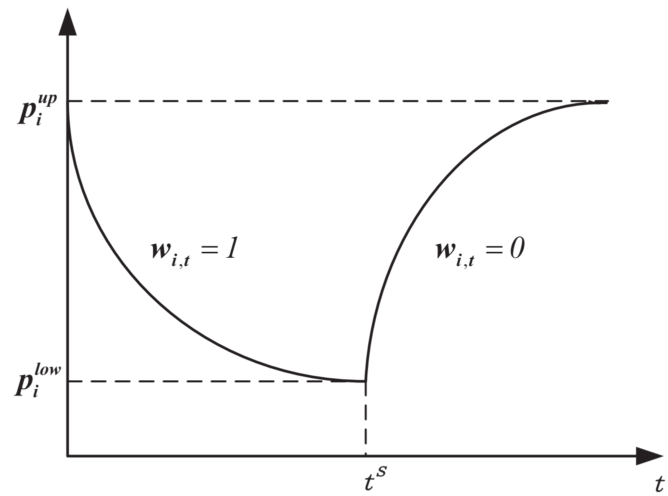



**Fig. 3.** The behavior of the well bore pressure.

$$Z_1 = \sum_i \sum_t \alpha_i \cdot wf_{i,t} \tag{2}$$

$$wf_{i,t} + w_{i,t} \geq w_{i,t+1} \quad \forall i \in I, t \in T \tag{3}$$

$$wf_{i,t} + w_{i,t+1} \geq w_{i,t} \quad \forall i \in I, t \in T \tag{4}$$

Because of the resistance to the oil flow between the reservoir and the well bore, the well bore pressure usually decreases with time. A simple expression has often been used Eq. (5) (Horne, 1998) to describe such behavior:

$$p_{i,t}^{end} = p_{i,t}^{in} - \frac{141.2x_{i,t}B\mu}{kh} \times \left(\frac{1}{2}\left[\ln\frac{0.000246kt}{\Phi\mu c_i r_i^2} + 0.80907\right]\right) \quad \forall i \in I, t \in T \tag{5}$$

where $B$, $\mu$, $k$, $h$, $\Phi$, $c_i$ and $r_i$ are formation volume factor, viscosity, permeability, reservoir thickness, porosity, total system compressibility and wellbore radius respectively, and are experimentally determined geological properties. In this study, it is assumed that the values of the geological properties of the well are known a priori. Therefore Eq. (5) can be reformulated as Eq. (6),

$$p_i^{end} = p_i^{in} - c_1 x_{i,t}(\ln Dr + c_2) \quad \forall i \in I, t \in T \tag{6}$$

where, $c_1$, $c_2$ are the parameters calculated from Eq. (5) and $Dr = t$ is the duration.

Fig. 3 represents the behavior of the well bore pressure. If the well is open, i.e. $w_{i,t} = 1$, the well bore pressure will then decrease, and flowing pressure is expressed as Eqs. (7)–(8) where $XP_{i,\,t}$ indicates pressure drop. Eq. (9) describes the pressure minimum requirement raised by reservoir engineers. For more information, refer to Horne (1990).

$$XP_{i,t} = \pi_i x_{i,t} a_{i0}(a_{i1} + \ln Dr) \quad \forall i \in I, t \in T \tag{7}$$

$$p_{i,t}^{end} = p_{i,t}^{in} - XP_{i,t} \quad \forall i \in I, t \in T \tag{8}$$

$$p_{i,t}^{in} - XP_{i,t} \geq p_i^{low} \quad \forall i \in I, t \in T \tag{9}$$

When the well is closed, i.e. $w_{i,t} = 0$, two cases should be considered shown in Eq. (10)–(11). $SP_{i,\,t}$ is pressure increase.

$$SP_{i,t} = b_{i0}(b_{i1} + \ln Dr)(1 - w_{i,t}) \quad \forall i \in I, t \in T \tag{10}$$

Define $Y_{i,t}$ representing whether pressure reaches its maximum, the pressure is then calculated separately for different $Y_{i,t}$, shown as Eq. (11) in a generalized disjunctive programming format.

$$\begin{bmatrix} w_{i,t} \\ p_{i,t}^{end} = p_{i,t}^{in} - XP_{i,t} \\ p_{i,t}^{in} - XP_{i,t} \ge p_i^{low} \quad \forall i \in I, t \in T \end{bmatrix} \vee \begin{bmatrix} \neg w_{i,t} \\ \begin{bmatrix} Y_{i,t} \\ p_{i,t}^{end} = p_{i,t}^{in} + SP_{i,t} \\ p_{i,t}^{in} + SP_{i,t} \le p_i^{up} \end{bmatrix} \vee \begin{bmatrix} \neg Y_{i,t} \\ p_i^{end} = p_i^{up} \\ p_{i,t}^{in} + SP_{i,t} > p_i^{up} \end{bmatrix} \end{bmatrix} \tag{11}$$

Eq. (11) can be reformulated by using the big-M formulation Balas, 1985) which is described as following Eqs. (12)–((20).

$$p_{i,t}^{end} - p_{i,t}^{in} + XP_{i,t} \ge -M(1 - w_{i,t}) \quad \forall i \in I, t \in T \tag{12}$$

$$p_{i,t}^{end} - p_{i,t}^{in} + XP_{i,t} \le M(1 - w_{i,t}) \quad \forall i \in I, t \in T \tag{13}$$

$$p_{i,t}^{in} - p_i^{low} - XP_{i,t} \ge -M(1 - w_{i,t}) \quad \forall i \in I, t \in T \tag{14}$$

$$p_{i,t}^{end} - p_{i,t}^{in} - SP_{i,t} \ge -M(1 - Y_{i,t} + w_{i,t}) \quad \forall i \in I, t \in T \tag{15}$$

$$p_{i,t}^{end} - p_{i,t}^{in} - SP_{i,t} \le M(1 - Y_{i,t} + w_{i,t}) \quad \forall i \in I, t \in T \tag{16}$$

$$p_{i,t}^{in} - p_i^{up} + SP_{i,t} \le M(1 - Y_{i,t} + w_{i,t}) \quad \forall i \in I, t \in T \tag{17}$$

$$p_{i,t}^{end} - p_i^{up} \ge -M(Y_{i,t} + w_{i,t}) \quad \forall i \in I, t \in T \tag{18}$$

$$p_{i,t}^{end} - p_i^{up} \le M(Y_{i,t} + w_{i,t}) \quad \forall i \in I, t \in T \tag{19}$$

$$p_{i,t}^{in} - p_i^{up} + SP_{i,t} \ge -M(Y_{i,t} + w_{i,t}) \quad \forall i \in I, t \in T \tag{20}$$

Eq. (21) corresponds to the linking constraints from a time period to the next time period. Eq. (22) provides the initial condition for the well bottom pressure.

$$p_{i,t}^{in} = p_{i,t-1}^{end} \quad \forall i \in I, t \in T \tag{21}$$

$$p_{i,1}^{in} = p_i^{initial} \quad \forall i \in I \tag{22}$$

### 3.3. Energy consumption model

In this section, electric submersible pump (ESP) as artificial lift method and valve opening and closing movement consume a lot of energy. The working characteristic of centrifugal pump usually be presented by discharge curves, power pressure head and efficiency. The characteristic curves were drawn according to the results of laboratory test by the regression, in which the nonlinear curve represents the pump efficiency while the linear one depicts the pump power. For more information about performance characteristics of the centrifugal pump, refer to Muhannad RAM et al. (2018). From Fig. 4, it is clear that there is a nonlinear relationship for the ESP's energy consumption in term of well's production flowrate.

In this study, electricity is the main form of energy consumption. The electricity supply of platform (i.e. FPSO) comes from diesel generating sets.

The total electricity consumption $ele_{cost}$ is calculated in Eq. (23). Meanwhile, the oil well production capacity is restricted by Eq. (24). Eq. (25) represents the whole energy consumption cost.

$$ele_{cost} = \sum_i \sum_t \beta_i(x_{i,t}, w_{i,t}) \quad \forall i \in I, t \in T \tag{23}$$

$$w_{i,t}x_i^{\min} \le x_{i,t} \le w_{i,t}x_i^{\max} \quad \forall i \in I, t \in T \tag{24}$$

$$Z_2 = pe_1 \cdot ele_{cost} \tag{25}$$

where $\beta_i$ is the nonlinear model between production flowrate and energy consumption, shown in Fig. 4; $pe_1$ denotes the power generation efficiency of diesel generator set on platform.

### 3.4. Oil storage model

Since crude oil composition varies from region to region, oil is stored in batches. The inventory balance and inventory capacity

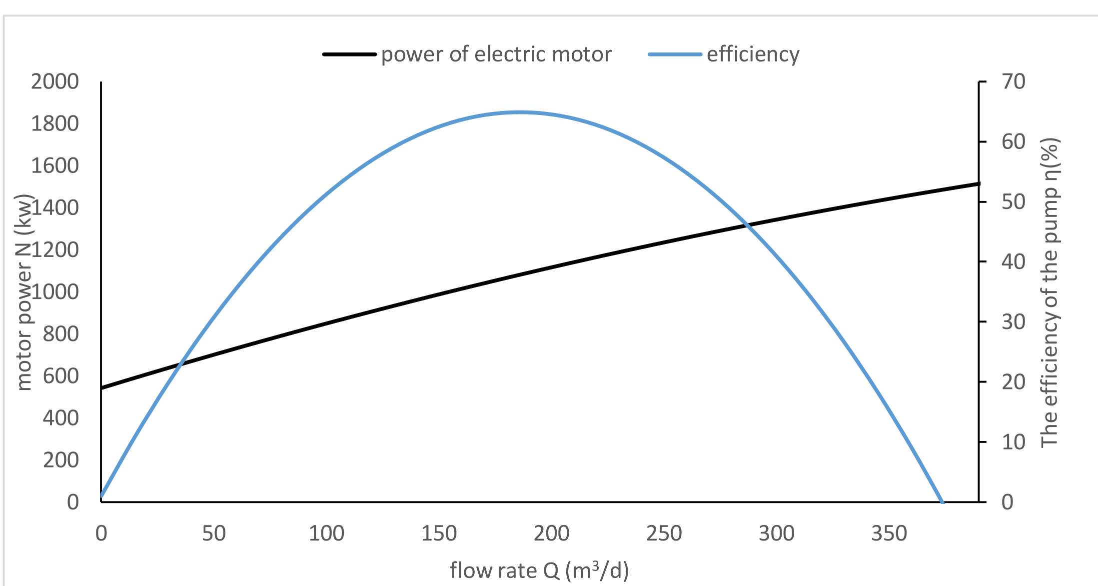



**Fig. 4.** Electric submersible pump performance curve depiction.

constraints for different batches of oil wells are expressed in Eqs. (26)–(29). Eq. (26) shows that final oil inventory $I_{k,\,t}$ is given as the balance on the previous inventory level $I_{k,t-1}$ plus production amount of oil well batch $k$ minus delivery amount $pr_{k,\,t}$. Eq. (27) provides the initial condition for the oil inventory. Storage capacity constraint is described as Eq. (28). Eq. (29) shows the inventory cost where $\gamma$ denotes the cost coefficient of oil inventory.

$$I_{k,t} = I_{k,t-1} + \sum_{i\in K} x_{i,t} - pr_{k,t} \quad \forall k \in K, t \in T \tag{26}$$

$$I_{k,1} = I_k^{initial} \quad \forall k \in K \tag{27}$$

$$I^{\min} \le I_{k,t} \le I^{\max} \quad \forall k \in K, t \in T \tag{28}$$

$$Z_3 = \sum_k \sum_t \gamma \cdot I_{k,t} \tag{29}$$

### 3.5. Cost of polymer flooding

During the middle and later periods of oilfield development, injection of oil displacement agent is significant to increase the oil recovery. It can be described as Eqs. (30)–(32). Based on the assumptions that were made at the beginning, the improvement of oil recovery ratio can be expressed as Eq. (30). The formula of polymer flooding $P_{i,\,t}$ and recovery ratio $\Delta E_{i,\,t}$ is represented as Eq. (31) where $A_i$ and $B_i$ are the specific relationship coefficient which can show that $P_{i,\,t}$ is linear with $\Delta E_{i,\,t}$ on semi-log coordinate. There is a hypothesis that if polymer flooding is not injected then the oil recovery rate has been at the lowest production speed. Eq. (32) shows the cost of polymer flooding in which $\delta$ denotes the cost coefficient.

$$\Delta E_{i,t} = {w_{i,t}\left(x_{i,t} - x_i^{\min}\right)}/{x_i^{\min}} \quad \forall i \in I, t \in T \tag{30}$$

$$\log P_{i,t} = A_i + B_i \Delta E_{i,t} \quad \forall i \in I, t \in T \tag{31}$$

$$Z_4 = \sum_i \sum_t \delta \cdot P_{i,t} \tag{32}$$

### 3.6. Flow assurance

In deep water, extreme conditions such as low temperatures and high pressures promote the formation of solid in pipeline that can potentially reduce or completely block the flowline. In this work, flow assurance is considered as constraints.

#### 3.6.1. Hydrate formation prevention

Pipeline temperature is of importance for hydrate formation prevention, so it is necessary to model it. For a specific point in the pipeline, heat balance[28] is satisfied, shown as Eq. (33),

$$Q_{in} - Q_{out} - Q_r = Q_{acc} \tag{33}$$

where $Q_{in}$ represents the incoming heat by convection in pipeline, calculated as Eq. (34); $Q_{out}$ represents the heat taken away by convection, calculated as Eq. (35); $Q_r$ is the radial heat transfer, as Eq. (37). The heat stored in fluid is $Q_{acc}$, as Eq. (36).

$$Q_{in} = \rho C_p v A T_L \Delta t \tag{34}$$

$$Q_{out} = \rho C_p v A T_{L+\Delta L} \Delta t \tag{35}$$

$$Q_{acc} = \rho C_P A \Delta L \Delta Te \tag{36}$$

$$Q_r = \frac{2\pi r k_1 \Delta L \Delta t \left(Te_{k,t} - T_{out}\right)}{R_t} \quad \forall k \in K,\ t \in T \tag{37}$$

$$R_t = \frac{1}{h_{in} r} + \frac{1}{\lambda_{ins}} \ln \frac{r + s + s_{tub}}{r + s_{tub}} \tag{38}$$

where $r$ denotes the radius of the pipeline, $\lambda_{ins}$ is the thermal conductivity of insulation materials, $h_{in}$ is convection heat transfer coefficient, $s$ is the thickness of the insulation blanket, $s_{tub}$ is the thickness of the tubing, $v$ is the fluid velocity in pipeline, $\rho$ is fluid density, $A$ is the pipeline cross-sectional area, $C_p$ is the fluid heat capacity. $R_t$ represents the thermal conductivity of the unit pipe length, which is a conductivity characteristics and determined by the pipe material and structure.

From Eqs. (34) to (38), to obtain the fluid temperature $T_e$ in pipeline, the outside water temperature $T_{out}$ is needed. The most common T–type distribution structure for vertical temperature is adopted (Romero et al., 1998).

Once the inside fluid temperature $Te_{k,\,t}$ for the batch $k$ is obtained, the Eq. (39) is listed to prevent hydrate formation. What should be highlighted is that $Te_{\mathrm{k}}^{\min}$ and $Te_{\mathrm{k}}^{\max}$ are given based on complex hydrate mechanism analysis, which is out of scope of this paper. Clearly, $Te_{\mathrm{k}}^{\min}$ and $Te_{\mathrm{k}}^{\max}$ need update when fluid composition varies. According to field experience, there is no need to change in the planning horizon.

$$w_{i,t} Te_k^{\min} \le Te_{k,t} \le w_{i,t} Te_k^{\max} \quad \forall k \in K,\ t \in T, i \in I \tag{39}$$

#### 3.6.2. Wax removal model

At a given pressure, as the temperature drops, the wax will first precipitate out. So the wax should be cleaned at the same time with the prevention and treatment of hydrate. Eq. (40) describes the wax removing cost related with the wax removal cycle $Tl_k$, where $\tau$ denotes the cost coefficient. Assume that pipe roughness is $e_k$, and $D_k$ is half of the radius of the annular region volume accounted for by uneven ups and downs, so the side of well pipe capturing the quality of wax in unit time can be represented as following Eq. (41). Then the volume is represented as Eq. (42) where $Gl$ denotes the density of wax. Wax deposit rate is described in Eq. (43) that is used to calculate the wax removal cycle as Eq. (44). Eq. (45) signifies the constraint of wax deposit thickness which should not interfere the production.

$$Z_5 = floor\left(\frac{TT}{Tl_k}\right) \cdot \tau \tag{40}$$

$$Ml_i = 2F_d \sum_{k\in K} x_i \frac{e_k^2 + D_k e_k^2}{D_k^2 + 2e_k^2 + 2D_k e_k} \quad \forall i \in I \tag{41}$$

$$Vl_k = {Ml_k}/{Gl} \quad \forall k \in K \tag{42}$$

$$v_k = \frac{D_k - \sqrt{D_k^2 - \frac{4Vl_k}{\pi L_k}}}{2} \quad \forall k \in K \tag{43}$$

$$\mathrm{Tl}_k = {h}/{2v_k} \quad \forall k \in K \tag{44}$$

$$0 < h \le h^{\max} \tag{45}$$

### 3.7. Model of delivery

Oil delivery should be no more than the demand as shown in Eq. (49). Therefore stock out state of oil is considered as Eq. (46), in which the penalty factor $\theta$ is introduced. Production planning is formulated in accordance with the well batch production which can be described in Eqs. (47)–(48).

$$Z_6 = \sum_{\mathrm{t}} \theta \cdot (d_t - pr_t) \tag{46}$$

$$d_t = \sum_k d_{k,t} \quad \forall t \in T \tag{47}$$

$$pr_t = \sum_k pr_{k,t} \qquad \forall t \in T \tag{48}$$

$$pr_{k,t} \le d_{k,t} \qquad \forall t \in T, k \in K \tag{49}$$

## 4. Case study

### 4.1. Description of the case

The model is tested on a case originated from a real-world subsea oil site in China to verify the effectiveness of proposed model. The site has 12 oil wells split into 3 well batches depending on their geographic location, where the wells 1#~4#, 5#~8# and 9#~12# are grouped into three different batches respectively. Table 1 shows the monthly demands of 3 oil well batches. The planning horizons are 12 months. The parameters used in the case, such as production rate limits of each oil well, max and min limitation of downhole pressure and inventory, which are originated from the actual production, are shown in S1 in the Supporting Information.

The case is computed by GAMS win32 24.0.2, and solved by the solver of ALPHAECP in an Intel core i5-7500 CPU, 3.41 GHz machine with 8 GB of RAM. The model statistics and solution times of the case are shown in Table 2. The optimality tolerance is set to 1% and the computational time limit is set to 7200 s. Clearly, the optimality gap does not reach the set value; we also observed that it is difficult to improve the performance by simply increasing the computational time limit. It is clear to know that the large-scale properties of the MINLP model is the critical factor result in difficulty in finding its solution. Consequently, how to reduce the optimality gap and improve the solution quality of the proposed integrated model is under our further research.

### 4.2. Results and discussions

The solution shows that the total cost is 515,030,600 CNY. The amount of monthly oil production of wells is shown in Fig. 5. The inventory of oil in each well batch is shown in Fig. 6. According to the Figs. 5 and 6, the monthly amount of oil production minus the monthly inventory of oil well batch can satisfy the given monthly demand. That is to say, there is no shortage. From Fig. 5, the largest oil production is 53,700 ton per month. The total demands in the sixth and seventh months exceed the maximum production capacity of the well. The inventory of each oil well batch in fourth and fifth months as shown in Fig. 6 is large in order to satisfy the demands.

The detailed delivery of each well batch is shown in Fig. 7. The working state of each oil well during the planning time horizon is shown in Table 3 (a working state of a well is represented as shaded, while the idle state as white). From observation of Table 3, wells 4#, 5#, 8# and 11# are working during the whole planning horizon. There are start-stop operations for the rest of oil production wells. The trade-off among the constraint of bottom hole pressure, the demand of oil production and switching operation cost need the frequent start-stop switching operations of oil production wells. The production plan arrangement of each well is shown in Fig. 8, where although the oil production wells 4#, 5#, 8# and 11# are working through the whole planning horizon, but do not reach their capacity. The surplus production capacity is chosen by given task and limited by downhole pressure.

**Table 1**
Monthly demands of well batches.

| Well batch | Monthly demand | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| 1 | 12,600 | 15,000 | 15,000 | 16,200 | 9000 | 27,000 | 15,000 | 15,000 | 22,000 | 18,000 | 16,200 | 9000 |
| 2 | 21,000 | 16,800 | 18,000 | 9000 | 11,400 | 15,000 | 9000 | 18,800 | 15,000 | 14,400 | 15,000 | 19,800 |
| 3 | 19,200 | 16,200 | 9000 | 9000 | 10,200 | 9000 | 23,400 | 16,200 | 9000 | 24,000 | 13,200 | 21,000 |

**Table 2**
Model statistics.

| Equations # | Binary variables # | Continuous variables # | CPU time (s) | GAP (%) |
|---|---|---|---|---|
| 6656 | 2304 | 4760 | 7200 | 6.4 |

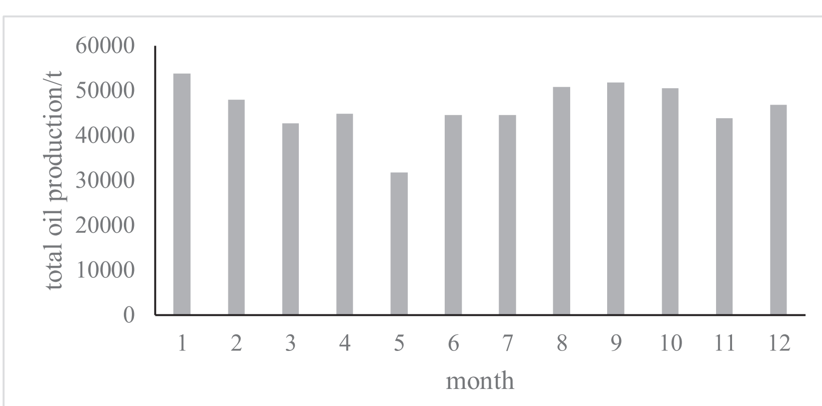



**Fig. 5.** The monthly total oil production.

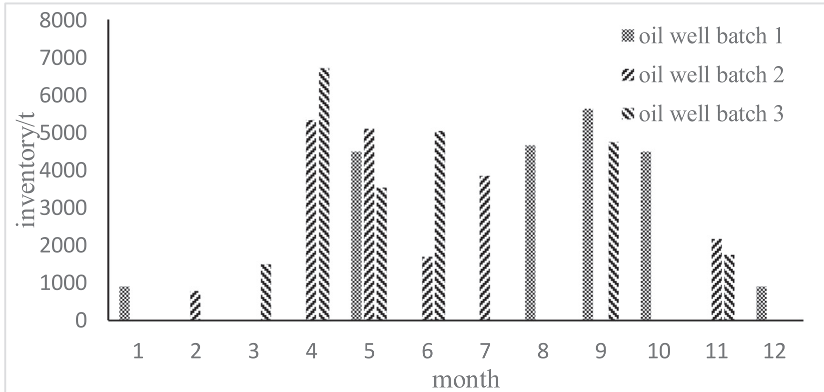



**Fig. 6.** The inventory of each well batch.

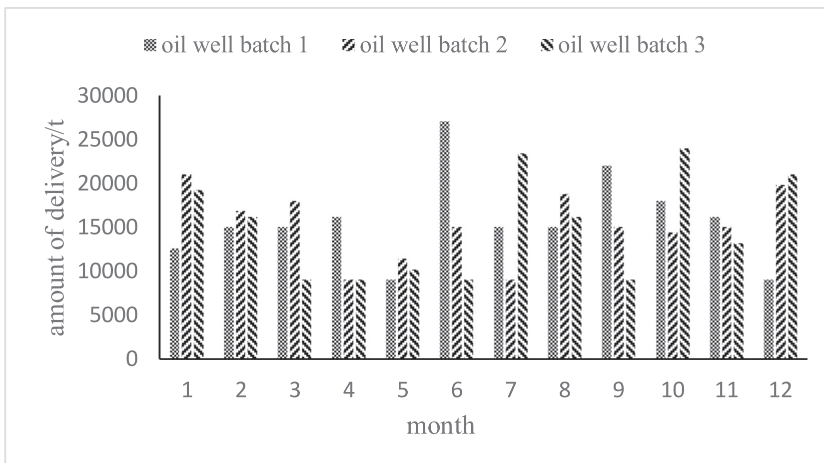
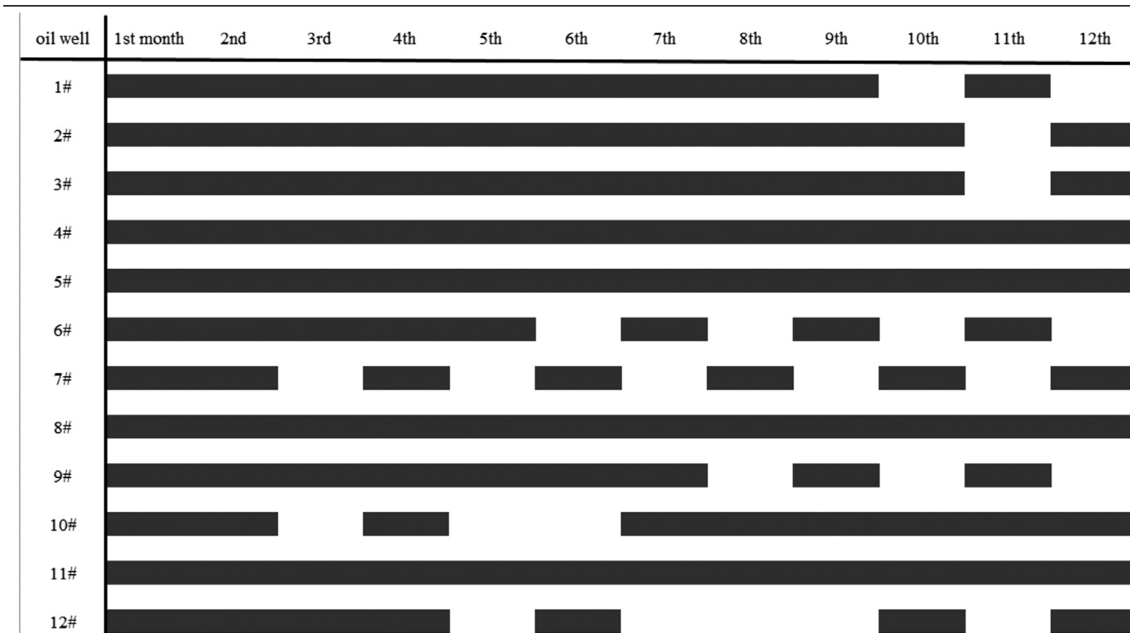



**Fig. 7.** The amount of delivery of each well batch.

**Table 3**
Working states of oil wells.



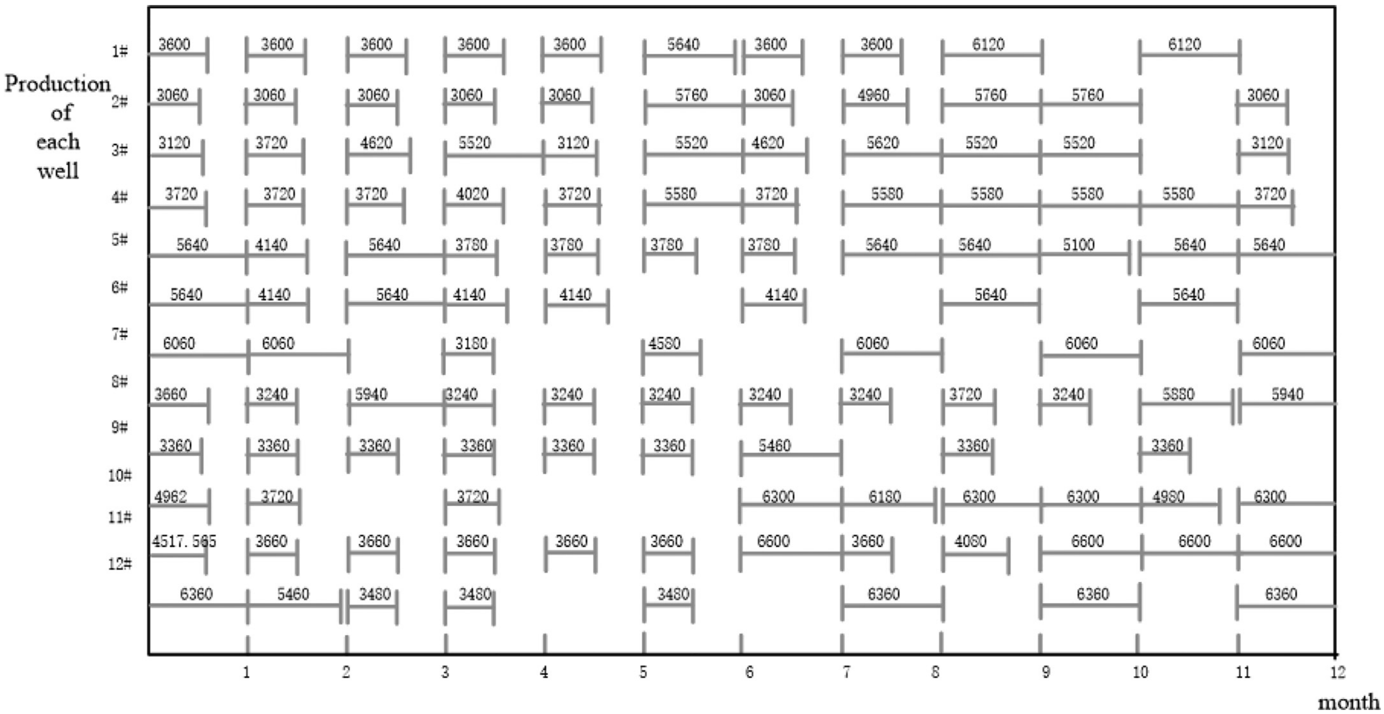



**Fig. 8.** Gantt chart of detailed production.

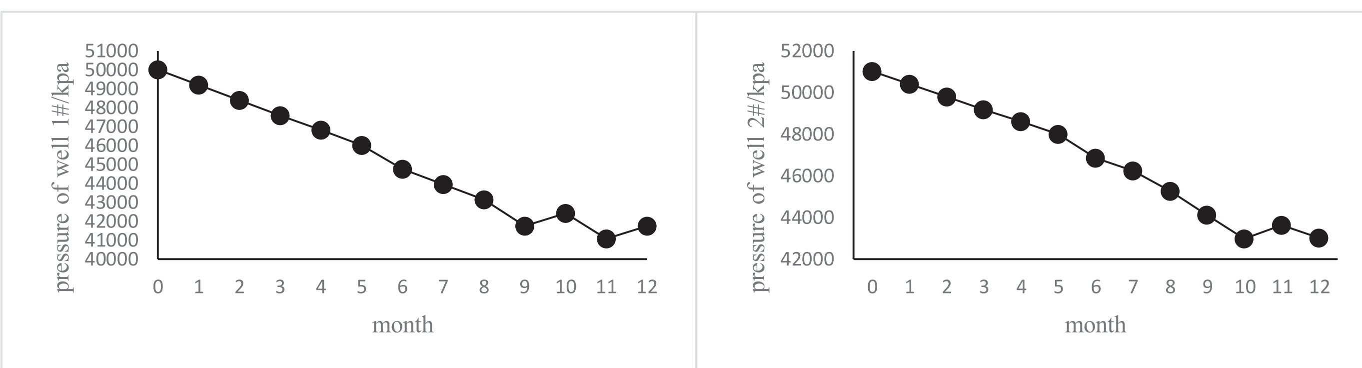



**Fig. 9.** The well downhole pressure changes with time.

The well downhole pressure (i.e. wells 1# and 2#) variation curves are shown in Fig. 9. When the well is open, the downhole pressure decreases along with time. In contrast, when oil wells are closed, the downhole pressure increases. The more oil is exploited, the more pressure drop is resulted.

The diesel consumption of the platform (FPSO) diesel generator sets is shown in Fig. 10. As we can see, the power consumption of diesel is largest in ninth month. The larger demands in ninth and tenth months lead to the full load condition of oil wells 2#, 3#, 4#, 7#, 10#, 11# and 12# in ninth month. However, the diesel consumptions in fourth and fifth months are less. The cause of this situation is the demands of fourth and fifth months are few and there are a lot of wells closed.

The monthly polymer flooding injection quantity is shown in Fig. 11. Due oil well 1# is shut during 10th and 12th month, the quantity of polymer flooding is zero for the well 1# in 10th and 12th month. On the contrary, the ninth and eleventh month have the maximum oil production, so the quantity of polymer flooding in these two months is maximum.

For each batch, there is a dedicated transportation pipeline after manifold. The temperatures of well batch 1, 2, and 3 are shown in Fig. 12. When the oil well is open, the temperature satisfies the temperature constraint. Moreover, the faster the flowrate, the higher the temperature. That is because the heat transfer time between the fluid and the environment decreases as the flow velocity increases. Both well 10# and 12# are closed in the fifth month, which is also reflected in the temperature change. It is clear that the pipeline cools down to the ambient temperature. The flow rate in the fifth month was minimal, so the lowest temperature came in the fifth month. About the change in pipeline pressure, the change of pressure is too small, not an order of magnitude with external pressure, which has little effect on solid formation, so it need not be discussed here.

The wax removal cycle of each oil production well batch is shown in Fig. 13. The wax removal cycle of batch 1 is the shortest, only 43 days. And the longest cycle of wax removal belongs to batch 3. The cause of this situation is as follows. Firstly, well 4# has always been in working state and working at full capacity in the whole planning time cycle and most of the time well 1#, 2# and 3# are working, which results in a lot wax precipitation content. Furthermore, well 9#, 10# and 12# are idle for at least three months and not working at full capacity,

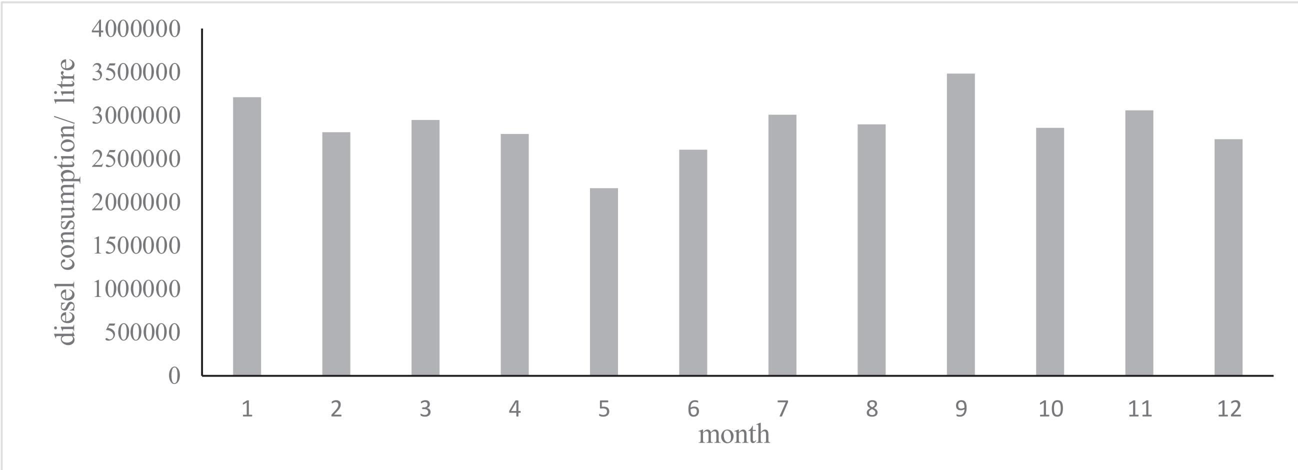



**Fig. 10.** The diesel consumption of each month.

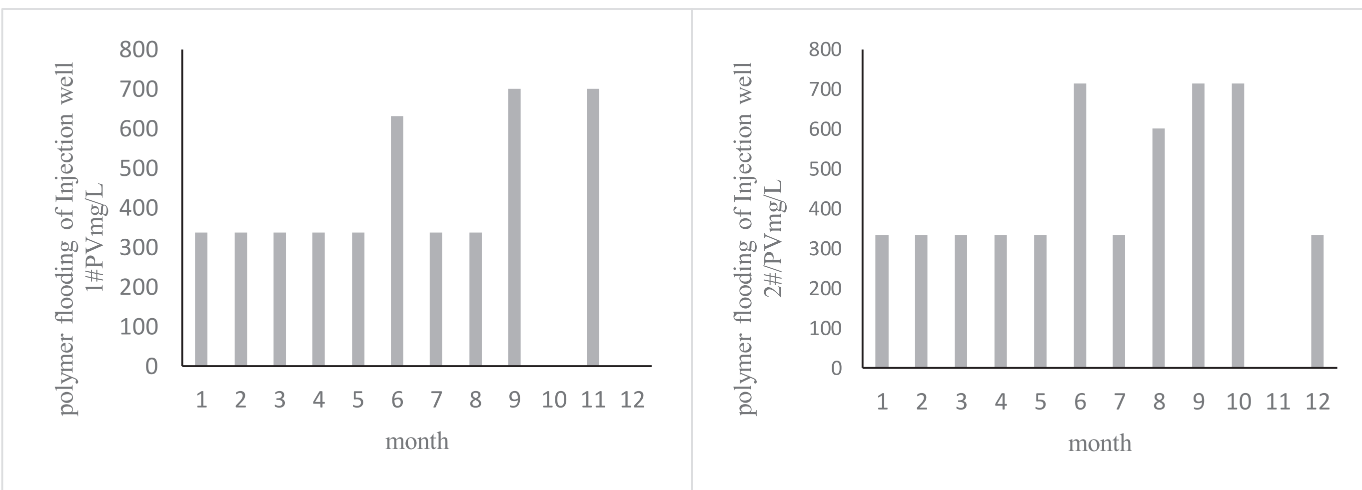



**Fig. 11.** The monthly polymer flooding injection.

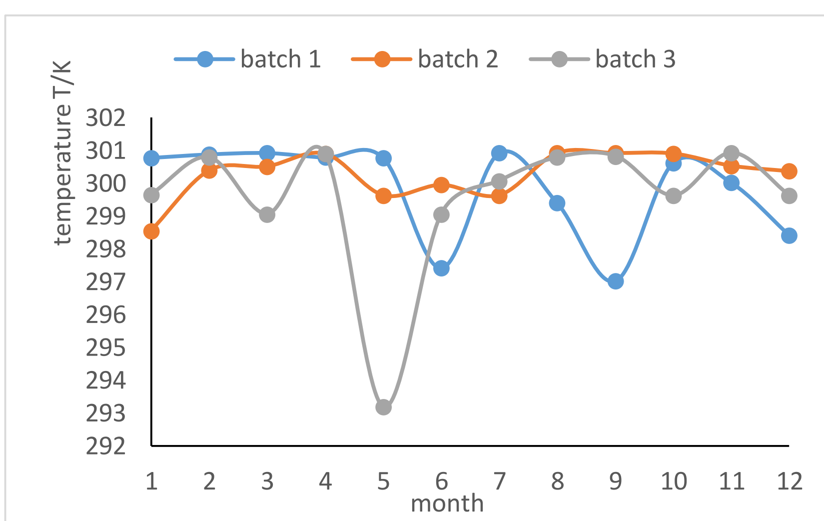



**Fig. 12.** The pipeline temperature.

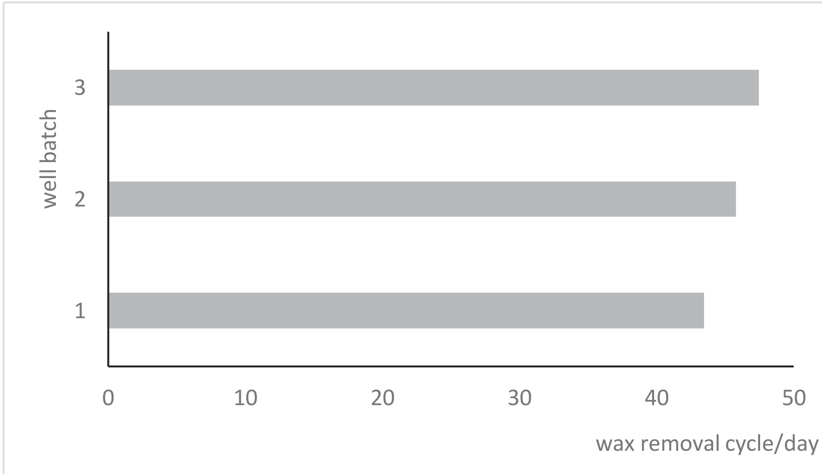



**Fig. 13.** The wax removal cycle of each well batch.

so the wax precipitation content is little without frequent wax removing.

## 5. Conclusion

In this paper, the study has addressed the integrated optimization of both plant-wide production process. An MINLP planning optimization model is proposed for a real-world practical deep sea oil production in a discrete time period which is aimed to minimize the cost of whole oil production process. The proposed model can reflect start-stop operation of oil wells to reduce unnecessary costs. Energy consumption has been taken into consideration by modeling the diesel consumption of diesel generator set. Also the polymer flooding injection and flow assurance is taken into account in order to assure that the simulated results are well in agreement with that of the practical production. The practical production constraints, such as the well batches demand for oil production, the limit of bottom holes pressure, the pipeline temperature and pressure constrains, and the minimum and maximum of oil inventory are taken into consider. Then one case originated from a real production process have been provided to verify the applicability and superiority of the proposed model. Compared with the previous research results, this study considers various aspects of oil production such as oil well production state, polymer flooding process, energy consumption, platform storage and flow assurance which can possess more significant effects on practical production. The productivity and reliability of deep-water developments will be enhanced as a result of this work.

## Declaration of Competing Interest

The authors declare no competing financial interest.

## CRediT authorship contribution statement

**Xiaoyong Gao:** Conceptualization, Methodology, Writing - original draft. **Yi Xie:** Data curation, Formal analysis, Software, Writing - original draft. **Shuqi Wang:** Data curation, Methodology, Formal analysis. **Mingyang Wu:** Formal analysis. **Yuhong Wang:** Conceptualization. **Chaodong Tan:** Methodology, Formal analysis. **Xin Zuo:** Investigation, Visualization. **Tao Chen:** Conceptualization, Supervision, Writing - review & editing.

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## Supplementary materials

Supplementary material associated with this article can be found, in the online version, at doi:10.1016/j.compchemeng.2019.106674.

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