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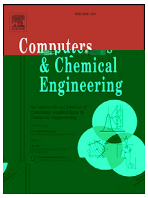

Offshore oil production planning optimization: An MINLP model considering well operation and flow assurance

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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 simul 1 Tf 7.1731 5.1731 5840.000.1731J 0 Tc /F2 1 Tf 6.3761 0 0 6.3747 442.1698 Tm [( )] TJ -0.000299

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
ρ_g	the density of gas phase
ρ_1	the density of liquid phase
H_1	the liquid holdup
G	the mass flow of the mixture
λ	the resistance coefficient
λ_{ins}	thermal conductivity of insulation materials
s	thickness of the insulation blanket
s_{tub}	thickness of the tubing
Δ_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
α_i	cost of start-stop operation of unit i
σ_i	coefficient for electricity consumption of valve in well i
ΔL	length of pipeline segment
θ_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
ρ	is fluid density
Gl	density of wax
Dr	length of time period
M	suitable upper limit
T	length of planning horizons
γ	coefficient of inventory cost
δ	cost coefficient of polymer flooding
θ	punishment of delivery delay
τ	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
Ml_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
Tl_k	wax removal cycle of well batch k
Vl_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
ΔTe	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.

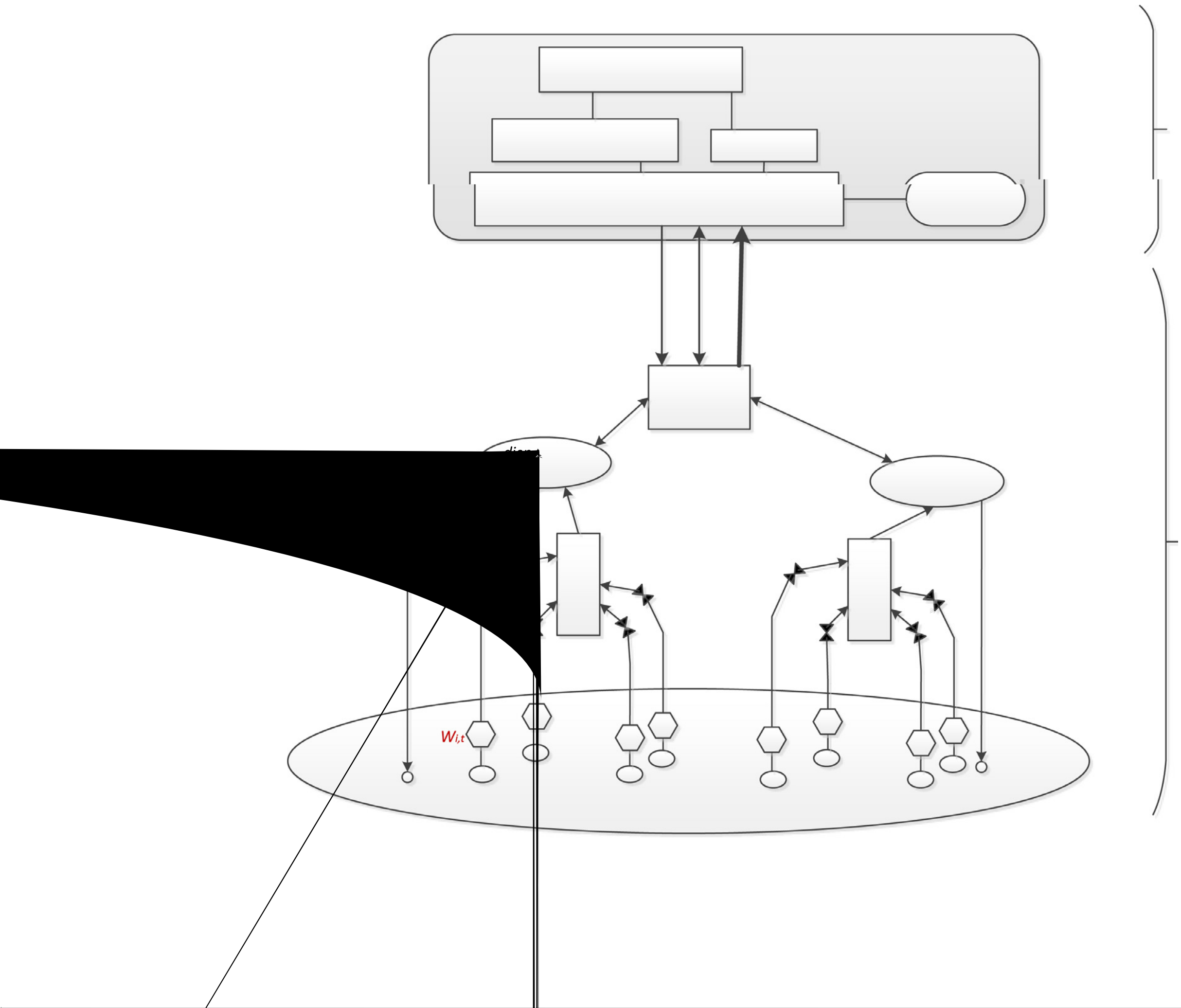
In the field of oil production process optimization, the existing results mainly focused on onshore but very little has been done on the offshore oil production processes, especially for deep water. The above-reviewed studies, whilst often shedding insight into the various aspects of the challenge, are 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.

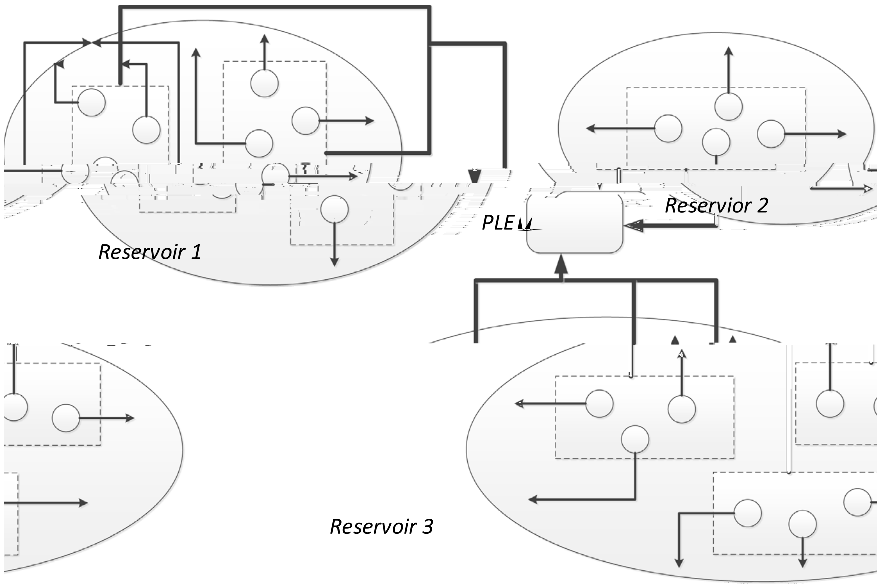
The particular challenge to be addressed in this work is the flow assurance, in contrast to the existing focus on subsea exploitation equipment operation aiming for maximum yield. It is well known that a change of well operations results in varying flowrate in subsea pipelines, thus has a big impact 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).




Reservoir 1
PLEM
Reservior 2
Reservoir 3

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.

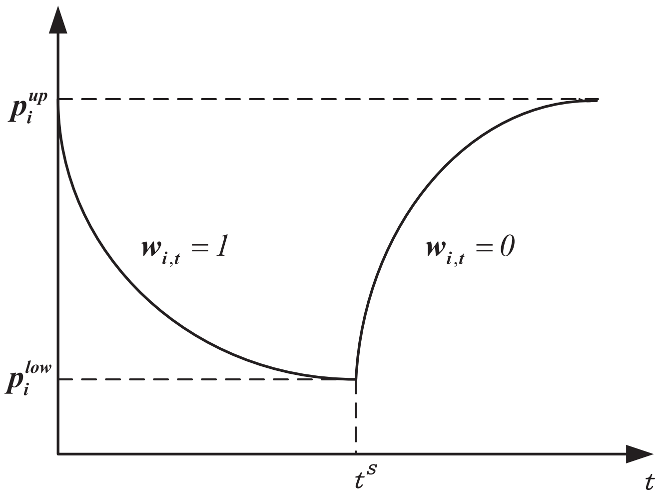


Fig. 3. The behavior of the well bore pressure.

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.

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

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

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

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:

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

where B, μ, k, h, Φ, 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),

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

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).

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

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

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

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.

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

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.

$$\begin{bmatrix} w_{i,t} \\ p_{i,t}^{end} = p_{i,t}^{in} - XP_{i,t} \\ p_{i,t}^{in} - XP_{i,t} \geq p_i^{low} \quad \forall i \in I, t \in T \end{bmatrix} \vee \left[\begin{matrix} \neg w_{i,t} \\ \begin{bmatrix} Y_{i,t} \\ p_{i,t}^{end} = p_{i,t}^{in} + SP_{i,t} \\ p_{i,t}^{in} + SP_{i,t} \leq p_i^{up} \end{bmatrix} \vee \begin{bmatrix} \neg Y_{i,t} \\ p_i^{end} = p_i^{up} \\ p_{i,t}^{in} + SP_{i,t} > p_i^{up} \end{bmatrix} \end{matrix} \right] \tag{11}$$

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

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

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

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

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

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

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

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

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

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

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.

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

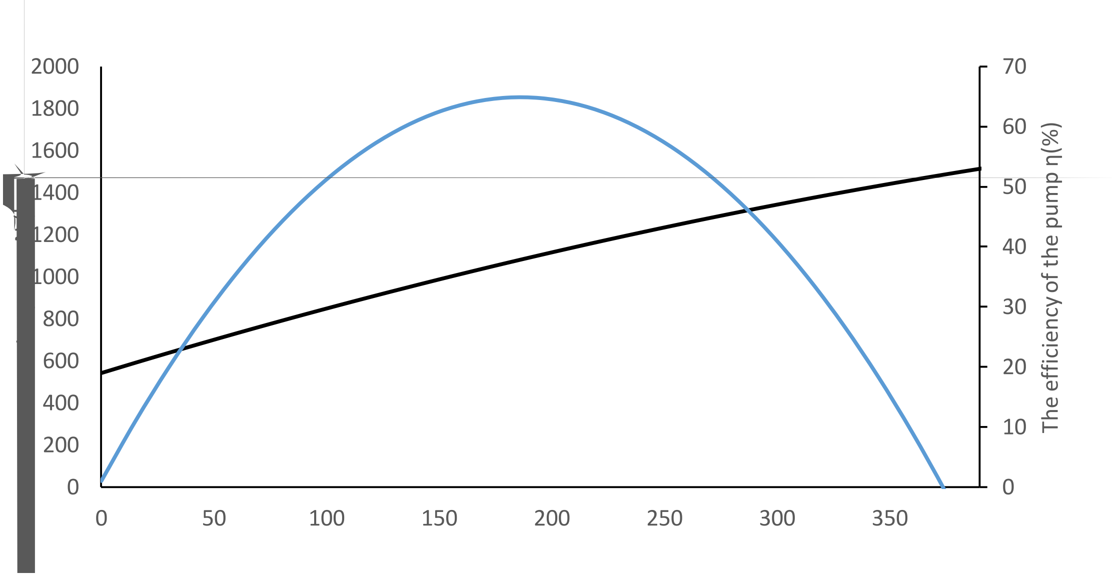
$$w_{i,t}x_i^{\min} \leq x_{i,t} \leq w_{i,t}x_i^{\max} \quad \forall i \in I, t \in T \tag{24}$$

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

where β_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



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 γ denotes the cost coefficient of oil inventory.

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

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

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

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

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 δ denotes the cost coefficient.

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

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

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

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).

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

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

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

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

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

where r denotes the radius of the pipeline, λ_{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, ρ 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.

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

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 τ 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.

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

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

$$Vl_k = {}^{Ml_k}\!/_{Gl} \qquad \forall k \in K \tag{42}$$

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

$$\mathrm{T}l_k = {}^{h}\!/_{2v_k} \qquad \forall k \in K \tag{44}$$

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

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 θ is introduced. Production planning is formulated in accordance with the well batch production which can be described in Eqs. (47)–(48).

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

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

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

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

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.

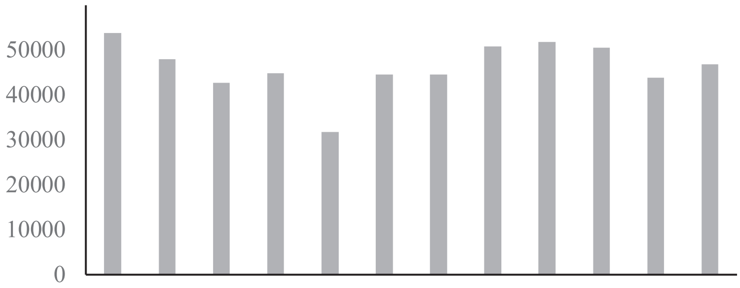
The detailed delivery of each well batch is shown in Fig. 7. The working state of each oil well during the planning time horizon is shown in Table 3 (a working state of a well is represented as shaded, while the idle state as white). From observation of Table 3, wells 4#, 5#, 8# and 11# are working during 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



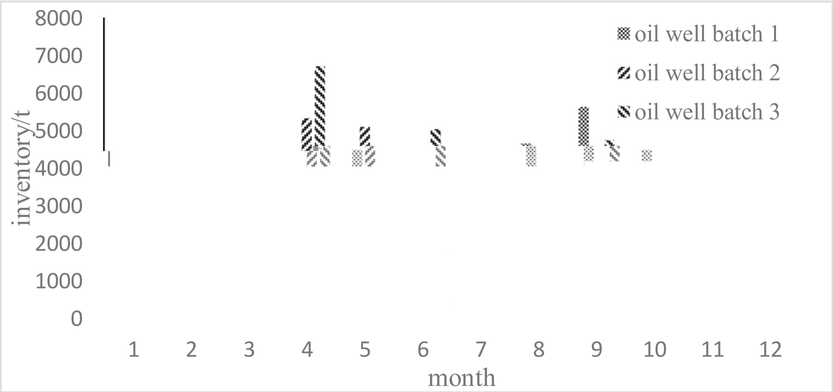
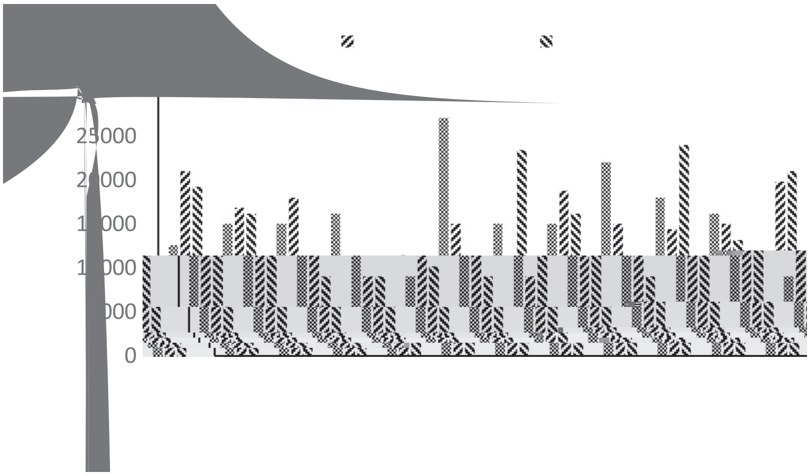


Fig. 6. The inventory of each well batch.



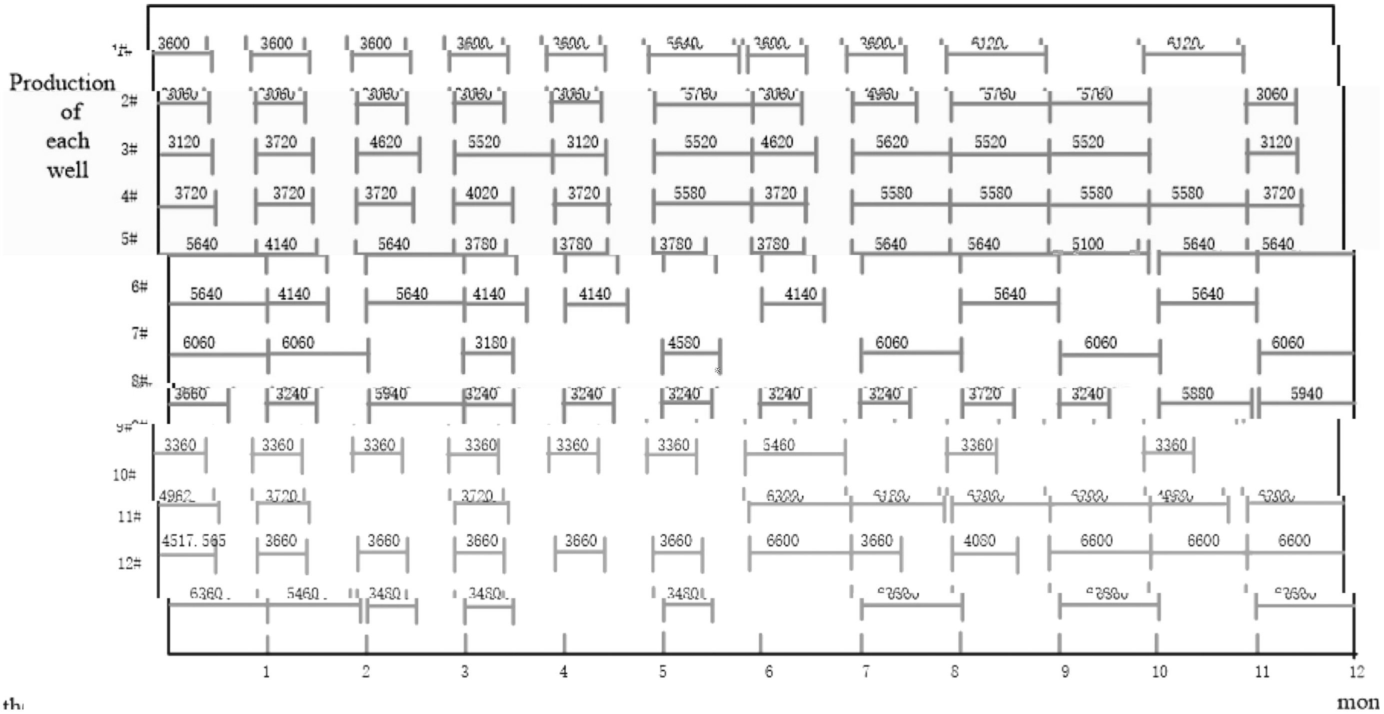
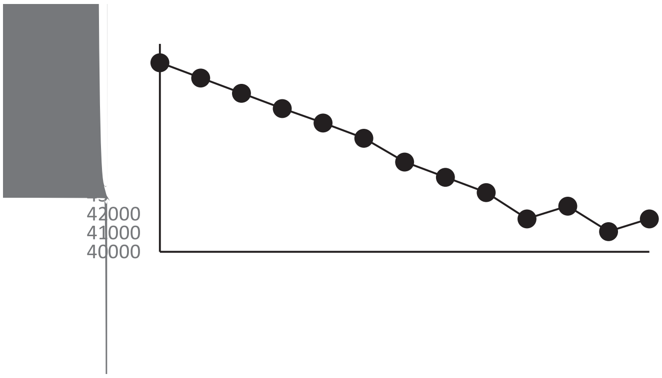
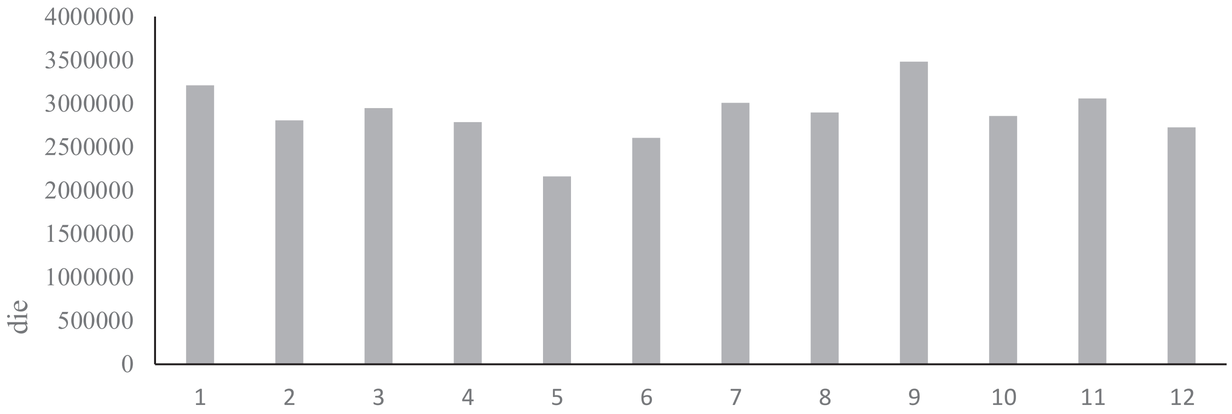


Fig. 8. Gantt chart of detailed production.

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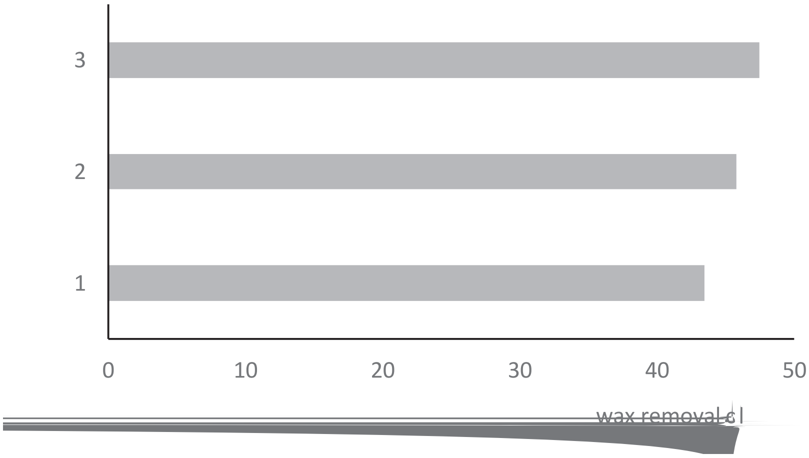
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