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Chapter 3

Optimal Planning for Deepwater Oilfield Development Under Uncertainties of Crude Oil Price and Reservoir

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Abstract

The development planning of deepwater oilfield directly influences production costs and benefits. However, the uncertainties of crude oil price and reservoir and the special production requirements make it difficult to optimize development planning of deepwater oilfield. Although there have been a number of scholars researching on this issue, previous models just focused on several special working conditions and few have considered energy supply of floating production storage and offloading (FPSO). In light of the normal deepwater production development cycles, in this paper, a multiscenario mixed integer linear programming (MS-MILP) method is proposed based on reservoir numerical simulation, considering the uncertainties of reservoir and crude oil price and the constraint of energy consumption of FPSO, to obtain the globally optimal development planning of deepwater oilfield. Finally, a real example is taken as the study objective. Compared with previous researches, the method proposed in this paper is testified to be practical and reliable.

Keywords: uncertainty, deepwater oilfield, development planning, multiscenario mixed integer linear programming, optimization

1. Introduction

The construction of deepwater oilfield development (DWOD) costs much, which is the highest proportion of oilfield development investment [1]. The DWOD facilities and connection modes will be fixed in the working cycles once they are determined and put into use [2]. Hence, it is important to work out totally optimal oilfield development planning, considering the future production during planning stages. Deepwater oilfield exploration and

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development generally consists of four stages: exploration, evaluation, and deliverability construction and production [3], each of which contains a number of uncertain factors [4, 5] that exert influence on the total operation. In the evaluation stage of the early period of oilfield development, there are a great number of uncertain factors and some have strong uncertainties [6, 7]. The essence of optimal planning for DWOD is to calculate the totally optimal oilfield development plan including the type of floating production storage and offloading (FPSO), commissioning plan, drilling plan, connection mode between productive well and FPSO, production plan of each production well, and FPSO energy supply plan. In this way, the optimal planning of DWOD is complex, since it requires various optimization decisions under the premise of strong uncertainty.

Recently, the issue of field development planning has attracted many scholars. Midthun et al. [8] established an optimal model for natural gas field development, which considers the construction rule of processing facilities and pipeline infrastructure. Arredondo-Ramrez et al. [9] focused on the optimal planning for nonconventional shale gas development and proposed a model applicable for multistage development. As for offshore field infrastructure planning, Gupta and Grossmann [10] put forward a multiperiod mixed integer linear programming (MILP) model which involves oil-gas-water, three phases in reservoir. Based on the previous work, Gupta and Grossmann [11] took the production-sharing agreements and the endogenous uncertainties into consideration, making the proposed multistage model more accordant with practical situations. When building up the oilfield development planning model, it is inevitable to consider uncertain factors such as reservoir behavior and crude oil price. Tarhan et al. [12] thought the reservoir uncertainty was related to initial production output of each well, reservoir scale, and water breakthrough time. These variable factors were exhibited as eight scenarios through enumeration. However, it is possible that the reality is too more sophisticated to describe the field's uncertainty based on the eight scenarios. And when it comes to the uncertainty of crude oil price, Jonsbraten [13] build up an MILP model and employed the scenario and policy aggregation technique to solve the construction planning of oilfield development under crude oil price uncertainty. Aseeri et al. [14] addressed the financial risk management of offshore field development planning and scheduling and paid attention to the uncertainties of crude oil price and oil well productivity index. Kang et al. [15] proposed an optimal model of oilfield development programming under stochastic oil price.

As to the model resolution, Dawson and Fuller [16] established a multistage nonconvex MILP model taking the highest net present value (NPV) as the objective function for the offshore oilfield development. During the model resolution, the continuous variables should be discretized, and then, heuristic algorithm was adopted. Heever and Grossmann [17] put forward a multistage MILP model which was solved by an iterative aggregation/disaggregation algorithm. Chen and Feng [18] established a model of oilfield measure program which is predicted by the BP network. Carvalho et al. [19] established an MIP model to work out offshore oilfield infrastructure planning and applied decomposition method to solve the model. Ge et al. [20] investigated the drilling of cluster horizontal wells and set up a platform program ming model. Zhang et al. [21, 22] built an MILP model for optimal offshore oilfield gathering system and a unified MILP model for topological structure of production well gathering pipeline

network, and both were solved by the branch-and-bound method. Li et al. [23] proposed a nonlinear programming model for the integrated development of multiple gas fields, using the improved genetic algorithm (GA) to solve the model.

Although domestic and foreign scholars have researched on the design for offshore field engineering system, reservoir uncertainty, and output fluctuation are considered by simply enumerating several special conditions and few have taken the FPSO energy supply constraint into account. In light of the normal deepwater production development cycles, this paper proposes a multiscenario MILP (MS-MILP) model based on reservoir numerical simulation, considering the uncertainties of reservoir and crude oil price, to obtain the globally optimal planning of DWOD.

2. Issue description

In this paper, the study issue is to design and draw up the commissioning plan of infrastructure required for DWOD in the given development cycle. As shown in **Figure 1**, the reservoir includes three parts and there is one FPSO working. On FPSO, oil-gas-water separation, as well as storage and transportation to shuttle tankers, can be carried out for the produced liquid. And there are two types of FPSO: one is the small FPSO of smaller throughput, coming from old oil tanker's conversion, and the other is the large new FPSO of larger throughput. Furthermore, production wells are connected to FPSO by means of drilling vessels or semi-submerged platforms (SSP). One production well can only correspond to one FPSO, while one FPSO can correspond to multiple wells.

The optimization is to draw up the investment and operation decisions during the development cycle. The investment decisions include the type, number, and corresponding processing capacity of development facilities, the manufacture, installation, and service time of these facilities, as well as the wells to be drilled, drilling sequence, and drilling facility. The operation decisions

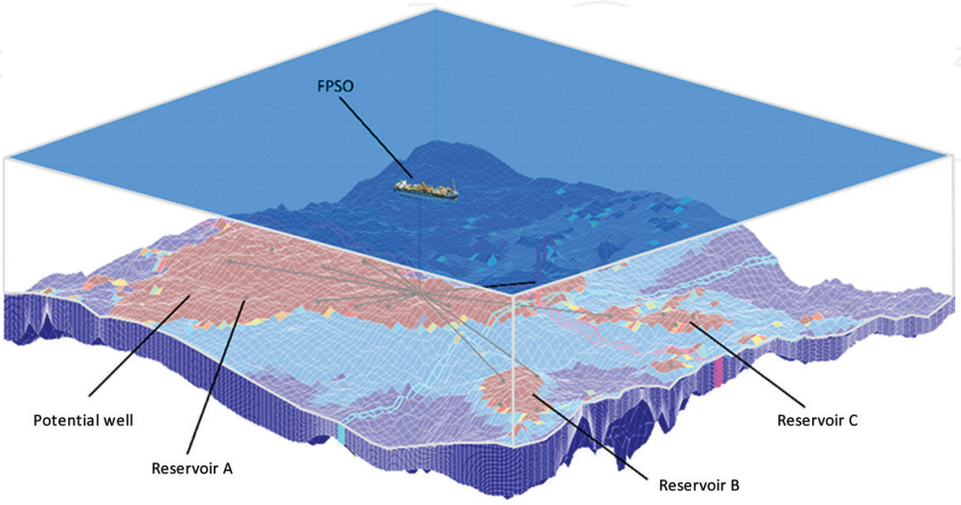

Figure 1. Diagram of DWOD.

need to consider the uncertainties of reservoir and crude oil price and simultaneously provide the recovery rates of reservoirs in each period. The general target is to balance the complex investment and operation decisions, in order to maximize the expected NPV of the project.

The predrilling well number of each reservoir, the construction cycles, and the available FPSO type and corresponding throughput should be known to solve the model. The model decisions include annual drilling site and production output of reservoirs, FPSO commissioning, connection relationship between production well and FPSO, FPSO oil-gas-water throughput, and FPSO energy supply plan.

3. Model establishment

3.1. Objective function

The discrete-time representation is adopted in this model. Suppose $s \in S$ stands for the set that considers uncertainties; $r \in R$ stands for the set of reservoirs; $t \in T$ stands for the set of years; $i \in I_r$ stands for the set of predrilling of reservoir r; $l \in L$ stands for the set of available FPSO; and $a \in A$ stands for the set of accumulated output ranges. Since multiple uncertainties are involved in the model, the maximum mean NPV of various conditions is taken as the objective function. The income is related to the annual crude oil price and output in this year. The expenditure is related to the construction and purchase cost of FPSO, daily maintenance cost, drilling cost, and diesel consumption cost.

$$\max f = \left[\sum_s \sum_t I_t\left(INC_{s,t} - COS_{s,t}\right)\right] \Big/ N_S \quad s \in S \tag{1}$$

$$INC_{s,t} = C_{\mathrm{PER}s,t} \sum_r \sum_i Q_{\mathrm{OP}s,r,t,i} \quad s \in S, r \in R, t \in T, i \in I_r \tag{2}$$

$$\begin{aligned} COS_{s,t} = {} & \sum_l C_{\mathrm{BTLP}\ l} B_{\mathrm{BTLP}t+N_{\mathrm{L}_l},l} + \sum_l C_{\mathrm{FMO}\ l} \sum_{t'=1}^{t} B_{\mathrm{BTLP}t',l} + C_{\mathrm{DIT}} \sum_r \sum_i B_{\mathrm{DIT}r,t+N_{\mathrm{D}},i} \\ & + C_{\mathrm{D}s,t} \sum_l Q_{\mathrm{D}s,t,l} \quad s \in S, r \in R, t \in T, i \in I_r, l \in L \end{aligned} \tag{3}$$

where N_S represents the number of the considered uncertainties; N_{Ll} represents the construc tion time for FPSO$_l$; N_D represents the drilling time; I_t represents the discount rate in the year t; $INC_{s,t}$ represents the total income in the year t under the specified scenario s, \$/y; $COS_{s,t}$ represents the total expenditure in the year t under the specified scenario s, \$/y; $C_{\mathrm{PER}s,t}$ represents the crude oil price per unit volume in the year t under the specified scenario s, \$/m^3; $C_{\mathrm{BTLP}l}$ represents the construction cost for FPSO$_l$, \$; $C_{\mathrm{FMO}l}$ represents the daily maintenance cost for FPSO$_l$, \$/y; C_{DIT} represents the unit price of drilling cost, \$; $C_{\mathrm{D}s,t}$ represents the diesel price unit under the scenario s, \$/m^3; $Q_{\mathrm{OP}s,r,t,i}$ represents the crude oil output from the predrilling well i of the reservoir r in the year t under the specified scenario s, m^3/y; $Q_{\mathrm{D}s,t,l}$ represents the con sumption diesel for FPSO$_l$ electricity generation in the year t under the specified scenario s, m^3/y; $B_{\mathrm{BTLP}t,l}$ represents a binary variable, if FPSO$_l$ needs to be put into production in the year t, $B_{\mathrm{BTLP}t,l} = 1$, otherwise $B_{\mathrm{BTLP}t,l} = 0$; $B_{\mathrm{DIT}r,t,i}$ represents a binary variable, if the predrilling well i of the reservoir r is drilled in the year t, $B_{\mathrm{DIT}r,t,i} = 1$, otherwise $B_{\mathrm{DIT}r,t,i} = 0$.

3.2. Drilling constraint

There are two states for all the predrilling wells: development or not.

$$H_{\mathrm{DIT}r,\,i} + \sum_{t} B_{\mathrm{DIT}r,\,t,\,i} \le 1 \quad r \in R, t \in T, i \in I_r \tag{4}$$

where $H_{\mathrm{DIT}r,\,i}$ represents a binary variable, if the drilling operation for the predrilling well of the reservoir r has been finished before the start time of the study, $H_{\mathrm{DIT}r,\,i} = 1$, otherwise $H_{\mathrm{DIT}r,\,i} = 0$; other variables are defined the same as before.

The drilling number of drilling vessels should be less than the maximum drilling capacity per year.

$$\sum_{r} \sum_{i} B_{\mathrm{DIT}r,\,t,\,i} \le N_{\mathrm{CFmax}t} \quad r \in R, t \in T, i \in I_r \tag{5}$$

where $N_{\mathrm{CF\,max}\,t}$ represents the maximum drilling number of the year t; other variables are defined the same as before.

3.3. Output constraint

The accumulated output of each reservoir equals to that of the last year plus all the output of this reservoir in this year.

$$V_{\mathrm{APs},\,r,\,t} = V_{\mathrm{APs},\,r,\,t-1} + \sum_{i} Q_{\mathrm{OPs},\,r,\,t,\,i} \quad s \in S, r \in R, t \in T \tag{6}$$

where $V_{\mathrm{APs},\,r,\,t}$ represents the accumulated crude output of the reservoir r in the year t under the specified scenario s, m^3; other variables are defined the same as before.

Binary variables can be divided by ranges to determine the range that accumulated output belongs to. When $B_{\mathrm{APs},\,r,\,t,\,a} = 1$, $V_{\mathrm{AP\,min}\,a} < V_{\mathrm{APs},\,r,\,t} \le V_{\mathrm{AP\,max}\,a}$ should be met.

$$V_{\mathrm{APmin}a} + \left(B_{\mathrm{APs},\,r,\,t,\,a} - 1\right)M < V_{\mathrm{APs},\,r,\,t} \le V_{\mathrm{APmax}a} + \left(1 - B_{\mathrm{APs},\,r,\,t,\,a}\right)M \quad s \in S, r \in R, t \in T, a \in A \tag{7}$$

where $V_{\mathrm{APmins},\,r,a}$ represents the minimum value of the accumulated crude output range a in the reservoir r under the specified scenario s, m^3; $V_{\mathrm{APmaxs},\,r,a}$ represents the maximum value of the accumulated crude output range a in reservoir r under the specified scenario s, m^3; M represents a positive maxima; $B_{\mathrm{APs},\,r,\,t,\,a}$ represents a binary variable, if the accumulated crude output of the reservoir r in the year t belongs to the range a under the specified scenario s, $B_{\mathrm{APs},\,r,\,t,\,a} = 1$, otherwise $B_{\mathrm{APs},\,r,\,t,\,a} = 0$; other variables are defined the same as before.

The accumulated output must only exist in one set of range.

$$\sum_{a} B_{\mathrm{APs},\,r,\,t,\,a} = 1 \quad s \in S, r \in R, t \in T, a \in A \tag{8}$$

After the accumulated output range is determined, the maximum output of single well can be obtained by the linear fitting formula between the maximum output of single well and the

accumulated output in the range. If the accumulated output locates in range a, $B_{\mathrm{APs},r,t,a} = 1$, and then, $Q_{\mathrm{UWPMs},r,t} = \omega_{s,r,a} V_{\mathrm{APs},r,t} + \mu_{s,r,a}$.

$$Q_{\mathrm{UWPMs},r,t,i} \le \omega_{s,r,a,i} V_{\mathrm{APs},r,t} + \mu_{s,r,a,i} + \left(1 - B_{\mathrm{APs},r,t,a}\right)M \quad s \in S, r \in R, t \in T, i \in I_r, a \in A \tag{9a}$$

$$Q_{\mathrm{UWPMs},r,t,i} \ge \omega_{s,r,a,i} V_{\mathrm{APs},r,t} + \mu_{s,r,a,i} + \left(B_{\mathrm{APs},r,t,a} - 1\right)M \quad s \in S, r \in R, t \in T, i \in I_r, a \in A \tag{9b}$$

where $\omega_{s,r,a,i}$ and $\mu_{s,r,a,i}$ represent the coefficients of the linear fitting formula for the maximum output of single well and the accumulated crude output; $Q_{\mathrm{UWPMs},r,t,i}$ represents the maximum output of the predrilling i of the reservoir r in the year t under the scenario s, m^3/y; other variables are defined the same as before.

The single well output needs to be less than the maximum output of the single well.

$$Q_{\mathrm{OPs},r,t,i} \le Q_{\mathrm{UWPMs},r,t,i} \quad s \in S, r \in R, t \in T, i \in I_r \tag{10}$$

If drilling operation does not begin, the well output should be zero.

$$Q_{\mathrm{OPs},r,t,i} \le \left(H_{\mathrm{DIT}r,i} + \sum_{t=1}^{t} B_{\mathrm{DIT}r,t,i}\right)M \quad s \in S, r \in R, t \in T, i \in I_r \tag{11}$$

3.4. Production facility constraint

If one predrilling well is to be developed, one FPSO should be determined to be connected.

$$\sum_{t} B_{\mathrm{DIT}r,t,i} = \sum_{l} B_{\mathrm{OIT}r,i,l} \quad r \in R, t \in T, i \in I_r, l \in L \tag{12}$$

where $B_{\mathrm{OIT}r,i,l}$ is a binary variable, if the predrilling well i of the reservoir r is connected to FPSO_l, $B_{\mathrm{OIT}r,i,l} = 1$, otherwise $B_{\mathrm{OIT}r,i,l} = 0$; other variables are defined the same as before.

If predrilling wells need to be connected to one FPSO, the FPSO should be put into production before being connected.

$$\frac{B_{\mathrm{DIT}r,t,i} + B_{\mathrm{OIT}r,i,l} - 1}{2} \le H_{\mathrm{HTLP}l} + \sum_{t=1}^{t} B_{\mathrm{BTLP}t,l} \quad r \in R, t \in T, i \in I_r, l \in L \tag{13}$$

where $H_{\mathrm{HTLP}l}$ is a binary variable, if the FPSO_l has been put into production before the start time of the study, $H_{\mathrm{HTLP}l} = 1$, otherwise $H_{\mathrm{HTLP}l} = 0$; other variables are defined the same as before.

All the available FPSO can be put into production or not.

$$H_{\mathrm{HTLP}l} + \sum_{t} B_{\mathrm{BTLP}r,t,l} \le 1 \quad r \in R, t \in T, l \in L \tag{14}$$

The predrilling wells to be developed can only be connected to one FPSO, and the transportation flow to the FPSO should be equal to the well output. If the predrilling wells to be developed do not connect to an FPSO, the transportation flow must be zero.

$$Q_{\mathrm{OPs},\,r,\,t,\,i} = \sum_{l} Q_{\mathrm{OPLs},\,r,\,t,\,i,\,l} \quad s \in S, r \in R, t \in T, i \in I_r, l \in L \tag{15}$$

$$Q_{\mathrm{OPLs},\,r,\,t,\,i,\,l} \le B_{\mathrm{OIT}r,\,i,\,l} M \quad s \in S, r \in R, t \in T, i \in I_r, l \in L \tag{16}$$

where $Q_{\mathrm{OPLs},\,r,\,t,\,i,\,l}$ is the transportation flow from the predrilling well i of the reservoir r to the in FPSO_l the year t under the specified scenario s, m^3/y; other variables are defined the same as before.

The total oil flow of one reservoir received by an FPSO should equal to the total output of all the predrilling wells in the reservoir that are connected to the FPSO.

$$Q_{\mathrm{LPRs},\,r,\,t,\,l} = \sum_{i} Q_{\mathrm{OPLs},\,r,\,t,\,i,\,l} \quad s \in S, r \in R, t \in T, i \in I_r, l \in L \tag{17}$$

where $Q_{\mathrm{LPRs},\,r,\,t,\,l}$ is the total flow of the reservoir r received by FPSO_l in the year t under the specified scenario s, m^3/y; other variables are defined the same as before.

When the accumulated output range is determined, the total flow of water and gas of one reservoir received by an FPSO can be obtained from the range.

$$Q_{\mathrm{LGRs},\,r,\,t,\,l} \le Q_{\mathrm{LPRs},\,r,\,t,\,l} R_{\mathrm{PGs},\,r,\,a} + \left(1 - B_{\mathrm{APs},\,r,\,t,\,a}\right) M \quad s \in S, r \in R, t \in T, a \in A \tag{18a}$$

$$Q_{\mathrm{LGRs},\,r,\,t,\,l} \ge Q_{\mathrm{LPRs},\,r,\,t,\,l} R_{\mathrm{PGs},\,r,\,a} + \left(B_{\mathrm{APs},\,r,\,t,\,a} - 1\right) M \quad s \in S, r \in R, t \in T, a \in A \tag{18b}$$

$$Q_{\mathrm{LWRs},\,r,\,t,\,l} \le Q_{\mathrm{LPRs},\,r,\,t,\,l} R_{\mathrm{PWs},\,r,\,a} + \left(1 - B_{\mathrm{APs},\,r,\,t,\,a}\right) M \quad s \in S, r \in R, t \in T, a \in A \tag{19a}$$

$$Q_{\mathrm{LWRs},\,r,\,t,\,l} \ge Q_{\mathrm{LPRs},\,r,\,t,\,l} R_{\mathrm{PWs},\,r,\,a} + \left(B_{\mathrm{APs},\,r,\,t,\,a} - 1\right) M \quad s \in S, r \in R, t \in T, a \in A \tag{19b}$$

where $R_{\mathrm{PGs},\,r,\,a}$ is the gas/oil ratio of the accumulated output range a in the reservoir r under the specified scenario s; $R_{\mathrm{PWs},\,r,\,a}$ is the water/oil ratio of the accumulated output range a in the reservoir r under the specified scenario s; $Q_{\mathrm{LWRs},\,r,\,t,\,l}$ is the transportation water flow from the predrilling well i of the reservoir r to the FPSO_l in the year t under the specified scenario s, m^3/y; $Q_{\mathrm{LGRs},\,r,\,t,\,l}$ is the transportation gas flow from the predrilling well i of the reservoir r to the FPSO_l in the year t under the specified scenario s, m^3/y; other variables are defined the same as before.

The water and gas flow received by each FPSO should be less than the throughput.

$$\sum_{r} Q_{\mathrm{LPRs},\,r,\,t,\,l} \le Q_{\mathrm{LPmax}l} \quad s \in S, r \in R, t \in T, l \in L \tag{20}$$

$$\sum_{r} Q_{\mathrm{LWRs},\,r,\,t,\,l} \le Q_{\mathrm{LWmax}l} \quad s \in S, r \in R, t \in T, l \in L \tag{21}$$

where $Q_{\mathrm{LPmax}l}$ is the maximum oil throughput of the FPSO_l, m^3; $Q_{\mathrm{LWmax}l}$ is the maximum water throughput of the FPSO_l, m^3; other variables are defined the same as before.

The FPSO energy consumption in production is related to the received oil and water flow, which can be supplied by natural gas or diesel.

$$\alpha_{\mathrm{PE}} \sum_r Q_{\mathrm{LP}\ s,r,t,l} + \alpha_{\mathrm{WE}} \sum_r Q_{\mathrm{LWR}\ s,r,t,l} = \beta_{\mathrm{GE}} \left[\sum_r \left(Q_{\mathrm{LGR}\ s,r,t,l} \right) - Q_{\mathrm{LGP}\ s,t,l} \right] + \beta_{\mathrm{DE}} Q_{\mathrm{D}\ s,t,l}, \quad s \in S,\ r \in R,\ t \in T,\ l \in L \tag{22}$$

where α_{PE} is the energy consumption required for processing the oil of a unit volume, MJ/m^3; α_{WE} is the energy consumption when the water of a unit volume is processed, MJ/m^3; β_{GE} is the available energy produced by the gas of a unit volume, MJ/m^3; β_{DE} is the available energy produced by the diesel of a unit volume, MJ/m^3; $Q_{\mathrm{LGP}s,t,l}$ is the gas emitted from the FPSO$_l$ in the year t under the specified scenario s, m^3; other variables are defined the same as before.

If production wells are connected to FPSO before the start time of the study, it will be unnecessary to identify the connection relationship. In other words, when $H_{\mathrm{OIT}r,i,l} = 1$, $B_{\mathrm{OIT}r,i,l} = 1$.

$$B_{\mathrm{OIT}r,i,l} \geq H_{\mathrm{OIT}r,i,l} \quad r \in R, i \in I_r, l \in L \tag{23}$$

where $H_{\mathrm{OIT}r,i,l}$ is a binary variable, if the predrilling well i of the reservoir r has been connected to the FPSO$_l$ before the start time of the study, $H_{\mathrm{OIT}r,i,l} = 1$, otherwise $H_{\mathrm{OIT}r,i,l} = 0$; other variables are defined the same as before.

4. Model solution

The crude oil price and the reservoir parameters (i.e., porosity, permeability, and thickness of reservoir structure) play an important role in the construction planning of deepwater oilfield infrastructure. The crude oil price volatility is full of randomness and thereby hard to be characterized by statistical probability functions [6]; thus, its uncertainty is defined as the range uncertainty. The reservoir parameters can be measured according to the data from exploration or production wells, and the measurement accuracy will be further improved along with oilfield developing and historical data increasing. Therefore, the reservoir parameters can be roughly characterized by statistical probability functions and their uncertainty is defined as stochastic uncertainty whose variance will decrease accordingly with oilfield developing [24].

5. Case study

5.1. Initial data

In this paper, an oilfield is presented as a case study. The water depth in the field comes up to 1350–1525 m, and the area is 10.5 km^2 or so. There are no other neighboring oilfields, and the field consists of A and B reservoir. It is evaluated that the geologic reserve of reservoirs A and B is about 1.9 × 107 m^3 and 3.7 × 107 m^3, respectively, and rich in the natural water. The mean

and standard deviation of reservoir parameters are shown in **Table 1**. Considering the top-priority economic benefit and quick cost recovery, the oilfield is to be developed depending on natural energy. The recovery cycle is 10 year. The predrilling wells of each reservoir are 15, and the drilling cycle is 1 year. At the beginning of development, there are 5 kinds of FPSO optional, as shown in **Table 2**. FPSO lease preparation and construction cycle both are one year. The crude oil price forecast over the next decade is shown in **Figure 2**, and the uncertain fluctuation range of the oil price is given as 2%. Several series of reservoir parameters that are selected stochastically are incorporated into the reservoir numerical model, to carry out the relationship between the recovery degree of each reserve and the maximum output of single well, as shown in **Figure 3**.

5.2. Calculation result

The scenario number exerts great influence on the model solution since the smaller scenario number leads to poor convergence, while the bigger leads to low calculation speed. To explore the influence of scenario number on the model solution, the uncertain scenario number is increased successively and the MILP solver, GUROBI, is applied in MATLAB R2014a to solve the model. The implementation result is shown in **Figure 4**. It can be seen that the model tends to be convergent when the number comes up to 40 and finally the net profit is 1.551 billion dollars for 10-year development of the oilfield. The NPV variation with years is shown in **Figure 5**.

The final result shows 18 drilling wells and 1 FPSO converted from old oil tanks are required, and all the drilling and construction can be finished in the first three years. The detailed construction and drilling plans are shown in **Table 3**. The annual oil, gas, and water production outputs of the oilfield are shown in **Figure 6**. The annual diesel consumption of FPSO is shown in **Figure 7**. In the first year, 10 wells are to be developed and one oil tank should be turned into the FPSO. In the next two years, six wells and two wells are required to be developed, respectively, in order to stabilize the production. Since there is higher crude output in the third and fourth years, resulting in the produced natural gas insufficient for FPSO energy supply, addictive diesel is necessary for FPSO.

To verify the solving effect of the proposed MS-MILP method, three different methods, namely the MILP method that does not involve uncertainty, the improved GA [21], and the multistage goal programming (MGP) method in literature, are determined to solve this case. In this paper, 45 groups of reservoir parameters and crude oil price are generated

Reservoir	Permeability (mD)		Porosity (%)		Thickness of reservoir structure (m)	
	Mean	Standard deviation	Mean	Standard deviation	Mean	Standard deviation
A	180	10	15.9	1	38	1
B	180	10	14.0	1	38	1

Table 1. Uncertainty parameters of reservoir.

FPSO type	Conversion of old oil tank	Lease	New construction of small size	New construction of medium size	New construction of large size
Construction cost (10^8\$)	0.5	0	1	1.6	2.4
Assistant production cost (10^4\$/y)	200	1200	200	250	300
Oil throughput ($10^4 m^3$/y)	140	200	210	280	330
Water throughput ($10^4 m^3$/y)	240	265	273	420	570

Table 2. Optional FPSO cost and throughput.

stochastically as the test group. Based on the field planning by each method, the field NPV of 45 groups is calculated and the result is shown in **Figure 8** [25].

As seen from the **Figure 8**, the improved GA has the lowest mean NPV because its self-limitation causes converging to locally optimal solution. Compare with the MILP method, the MGP method is better because it considers the situation changing with the field development and models are established corresponding to different periods. However, the involved factors of MGP are less than MS-MILP; thus, the mean NPV of the former is lower than the latter. Particularly, when the oil price is lower than the expected and the reservoir scale is smaller than the expected, the NPV by MS-MILP is far higher than the other. In this way, considering

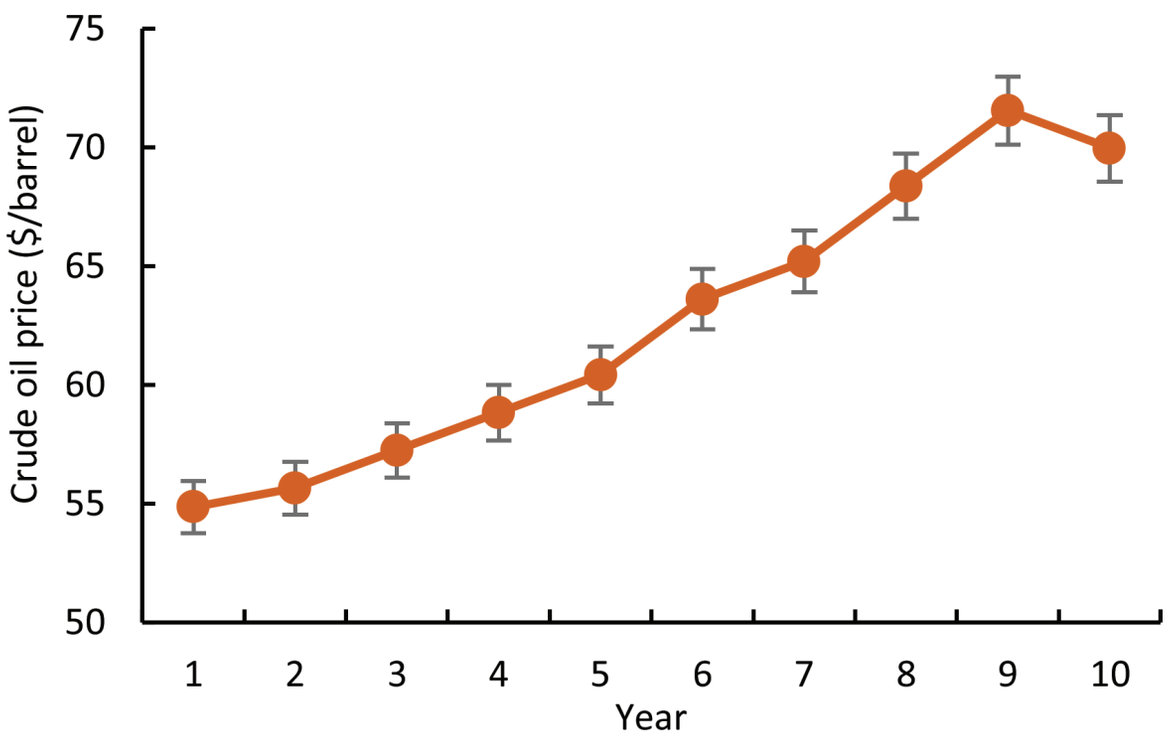

Figure 2. Crude oil price forecast.

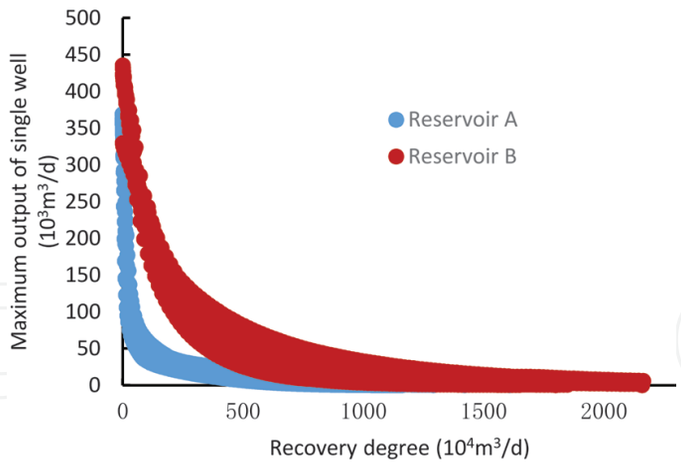

Figure 3. Result of reservoir numerical simulation.

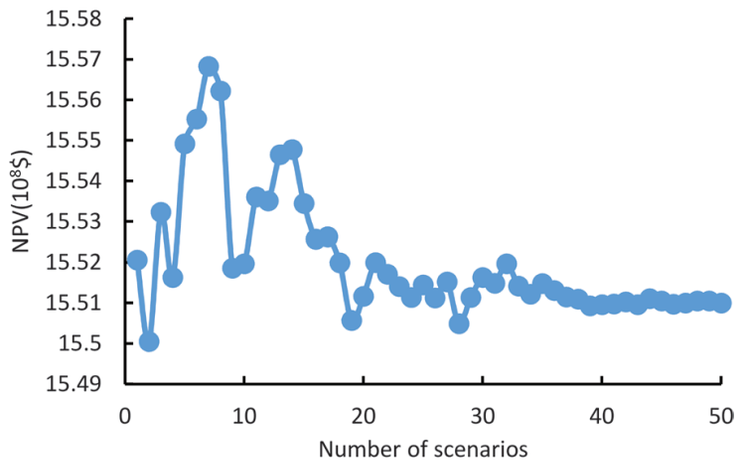

Figure 4. NPV for different numbers of scenarios.

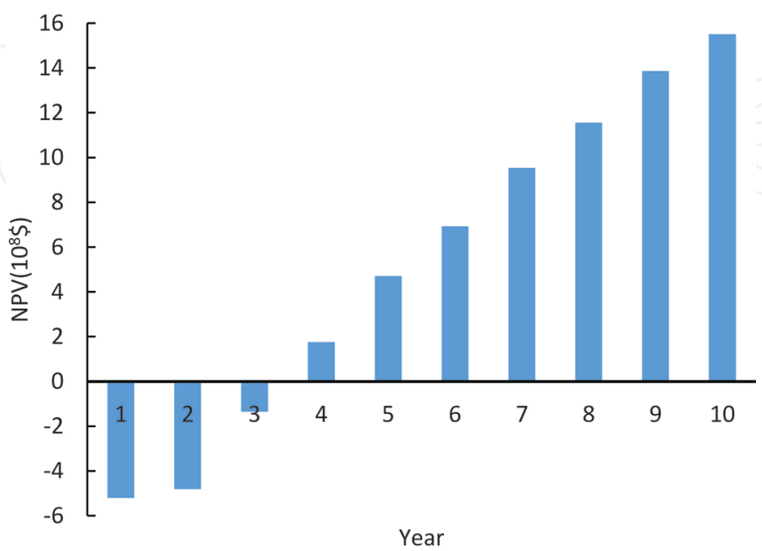

Figure 5. Variation of NPV.

Year	Well number		Construction
	Reservoir A	Reservoir B	
1	4	6	One FPSO converted from old oil tank
2	4	2	-
3	-	2	-

Table 3. Construction and drilling plans.

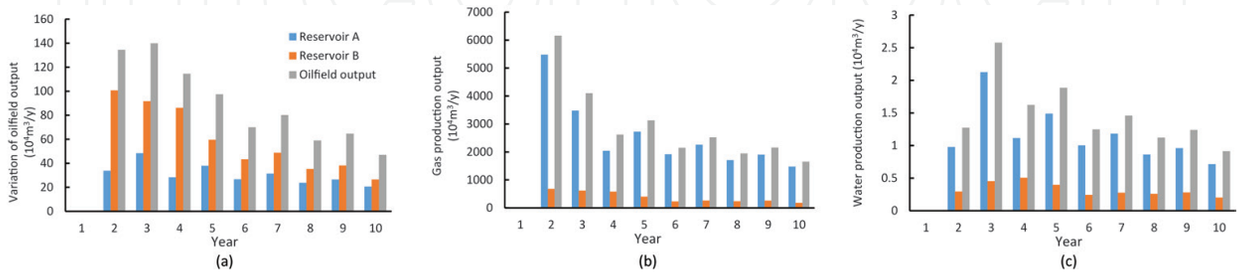

Figure 6. Variation of oilfield output. (a) Crude oil production output. (b) Gas production output. (c) Water production output.

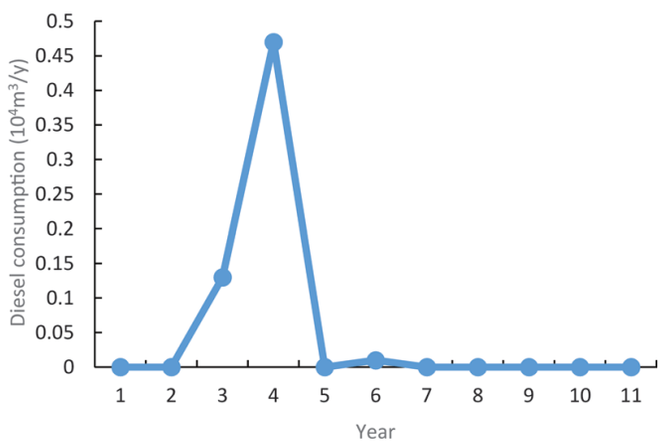

Figure 7. Variation of diesel consumption.

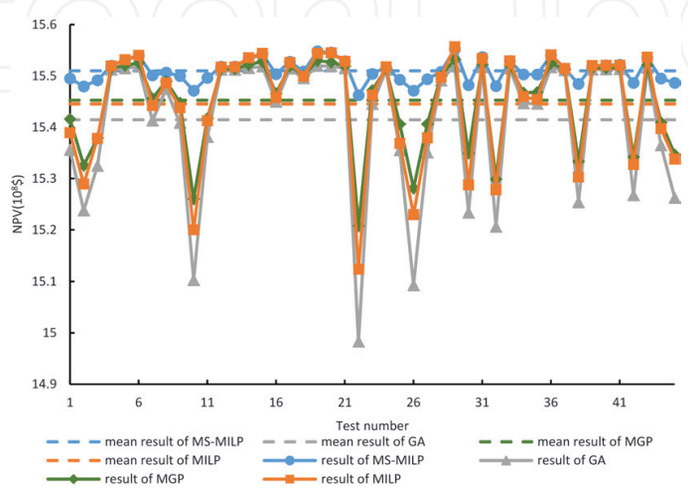

Figure 8. Comparison of different methods.

the complex uncertainties of reservoir and oil price, the oilfield planning by MS-MILP has higher rate of return and its anti-risk ability is superior to the other.

6. Conclusion

This paper put forward an optimal planning method for DWOD under the uncertainties of reservoir and crude oil price. The method takes the maximum total NPV as the objective function. The MS-MILP model is established, coupling with reservoir numerical simulation model and taking the constraints including drilling, output, production facilities, and energy consumption into account. The GUROBI solver is used to solve out the globally optimal planning of DWOD.

Finally, a study case based on a deepwater oilfield is given to work out an optimal development planning and evaluate the model's practicality. The proposed method is compared with the previous, illustrating that the oilfield development planning calculated by this paper's takes the advantage of high rate of return and strong anti-risk ability.

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