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Formulations for automatic optimization of decommissioning timing in offshore oil and gas field development planning☆

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A R T I C L E I N F O

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A B S T R A C T

A mathematical programming formulation has been developed to optimize the drilling program, the production allocation, and the decommissioning time in early-stage field development planning. Various abandonment constraints are considered in the optimization model when searching for the best decommissioning time for the long-term field development strategy. The model is tested on a real field development planning consisting of two reservoirs produced with subsea wells to an offshore facility. The novelty of this work is the utilization of mathematical programming to formulate and solve early-stage field development planning considering the variable decommissioning time. The results show that considering a variable decommissioning time in early-stage field development planning yields improved economic margins. Further, it provides operators a decision-support tool with enhanced capabilities of forecasting the best decommissioning time, improving the forecasts for processing and production planning, expected revenue and lifetime of facilities, and anticipating and preparing for field abandonment in advance. The optimization model is capable of determining the drilling and production schedules, and the optimal decommissioning time that yielded the maximum net present value for the project.

1. Introduction

Most major oil and gas fields produce for 20 to 30 years or more. Decommissioning is the last stage of a field's lifecycle, often treated as an "exit" option when a project's income no longer covers the costs of operation. The decommissioning process is usually long, cost-intensive, and involves a convoluted chain of activities with multiple stakeholders and many considerations: environmental, impact on health and safety, public acceptability, economic, and technical feasibility.

There was not much focus on decommissioning before the 1990s until a significant number of offshore oil and gas installations started to exceed or approach the end of their designed economic life (Athanassopoulos, 1999). Even today, the decommissioning of oil and gas facilities is a relatively new challenge worldwide (Martins et al., 2020). In contrast to the nuclear power industry, which usually performs a detailed decommissioning analysis in their initial technical and economic evaluation, few oil & gas operators create a decommissioning strategy with a long-term perspective during the early stages of offshore field development. Moreover, decommissioning is believed to have an insignificant impact on the project valuation during the planning phase. During the final years of production, however, decommissioning and decommissioning timing are of high importance as the economic cash flow of the project is usually low (i.e., revenues from hydrocarbon sales are similar to production costs). Changes in the oil price or production costs can easily change the cash flow from positive to negative, often triggering a decision to decommission. At this stage, operators usually attempt to delay cost-intensive expenditures for as long as possible, and companies are usually looking to sell their share in the field.

The topic of decommissioning has lately received more attention and is discussed in depth partly due to the following reasons:

- Many offshore oil and gas fields have either exceeded or are approaching the end of their designed economic life span and have to meet the regulatory framework of the country.
- Low oil prices and the market crisis have accelerated some decommissioning decisions due to negative cash flows.

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Nomenclature

$\mathcal{T}$	Set of all time steps
$\mathcal{R}$	Set of reservoirs
$\mathcal{W}^r$	Set of wells in reservoir r
(i)	Well indices $i \in \{1, \ldots, W^r\}$
(j)	Well permutations $j \in \{1, \ldots, 2^{W^r}\}$
q_o^t	Oil production in period t
q_g^t	Gas production in period t
q_w^t	Water production in period t
$N_w^r \in \mathbb{Z}$	Number of wells of reservoir r
$N_w^f \in \mathbb{Z}$	Number of wells of field f
$x_w^r \in [0, 1]$	Status of well i in reservoir r
$S_A^t \in [0, 1]$	Status of abandonment conditions in period t
t_A	Abandoning timing
(f)	Field
(r)	Variables associated with reservoir r $\in \mathcal{R}$
(o)	Oil
(g)	Gas
(w)	Water
(t)	Time periods
D	Discount factor
$q_o^{\max}$	Maximum oil rate in the production platform
q_{Ao}	Abandonment oil rate
$q_g^{\max}$	Maximum gas rate in the production platform
q_{Ag}	Abandonment gas rate
$q_w^{\max}$	Maximum water rate in the production platform
q_{Aw}	Abandonment water rate
$q_l^{\max}$	Maximum liquid rate in the production platform
$q_{o,pot}$	Oil production potential
$N_{w,D}^{\max}$	Maximum drilling capacity per year
P_o	Oil price
P_g	Gas price
G_p^r	Cumulative gas production
N_p^r	Cumulative oil production
W_p^r	Cumulative water production
fn^r	Wells permutation factor
$RF_{\min}$	Minimum required recovery factor
$q_o^{f,min}$	Minimum field production of oil
$t_{\min}$	Minimum licensed production time
$t_{\max}$	Maximum time of facility fatigue
t_{Shadow}	Maximum value of time used for optimization
R^f	Original oil in place of the field f

- Increasing focus on environmental issues in ageing installations with high production costs and production energy per barrel.

Most works in the literature within the decommissioning domain deal with the decommissioning methodology (Fowler et al., 2014; Martins et al., 2020), cost (Abdo et al., 2018; Tan et al., 2021), impact on the environment (Chandler et al., 2017; Sommer et al., 2019), policy (Techera and Chandler, 2015; Torabi and Nejad, 2021), socio-economic issues (Parente et al., 2006; Tan et al., 2021), and the feasibility of using the existing platforms to facilitate and stimulate the well-being of the marine ecosystem (Ekins et al., 2006; Chandler et al., 2017). Only a few papers discuss the abandonment strategy in a long-term perspective during the early stages of field development. Tan et al. (2021) suggested that decommissioning regulations should include strategies and rules for estimation, and it is necessary to formulate a roadmap with a long-term perspective. The work by Borges et al. (2018) used the Center of Gravity Fuzzy Pay-Off Method (CoG-FPOM) as an alternative real options valuation method to calculate the value of the oilfield abandonment option when deciding the abandonment timing. The timing issue is also discussed in the paper by Osmundsen and Tveterås (2003), in which they argue that the abandonment time is as important as the decommissioning method itself. Bakker (2020) addressed the issue of deciding when to cease production using optimization, which focuses on vessel routes and allocation of operation rigs and vessels.

Nowadays, some operators have realized the importance of planning in advance decommissioning strategies. They intend to develop a long-term decommissioning plan after learning from experiences of underestimated, inefficient and poor resource allocation, and opportunities missed. It is recognized that a long-term decommissioning strategy can improve the overall project performance and is also important for regulators who scrutinize offshore exploration and production activities closely as such activities have the potential of environmental impact. The public has generally been against leaving significant portions of oil and gas installations in the oceans (Torabi and Nejad, 2021). Taking Australia as an example, under the OPGGAS[1] and its regulations, decommissioning activities must be conducted under an accepted field development plan, well operations management plan, environmental plan and safety case. Furthermore, variations to the planned decommissioning activities must be approved before they commence (Techera and Chandler, 2015).

Decommissioning also has great financial challenges. Decommissioning costs occur when there is no revenue being generated from the project (Jahn et al., 2008; Abdo et al., 2018). Tax deductions, commonly used in other field development stages, are typically not available for decommissioning activities as they take place when there is no income (Parente et al., 2006). Unlike most other activities in exploration and production (E&P) projects, national governments play an extensive role in assessing and licensing decommissioning options. Most countries that have offshore oil and natural gas installations have laws governing decommissioning. Removal costs are tax-deductible (deducted in advance during the operation phase) in some countries, causing a loss in revenue for the government (Hamzah, 2003). In some cases, the government covers a large share of decommissioning costs (e.g., in Norway). Deferment of decommissioning and continued production to maximize economic hydrocarbon recovery is generally desirable in the North Sea basin. Therefore, a proper decommissioning strategy can be financially beneficial to both oil companies and the host government.

We consider that it is crucial to plan the decommissioning from the early stages of field development for several reasons:

- Avoiding financial troubles and limited maneuverability at the end of the field's life due to low income, high decommissioning costs (on average 10% of the capital expenditure CAPEX), and tax alleviation schemes (that affect the government's capability of intervening).
- To achieve better resource allocation between asset operators and service contractors at an early stage to avoid delays, cost overruns, or stranded decommissions. This is especially important for deepwater and ultra-deep water projects with subsea processing that require long planning and specialized technology for decommissioning. For instance, the presence of subsea facilities increases the complexity of abandonment logistics, and it might be challenging to book vessels for the operation. A hindrance to achieving this is the uncertainty in the abandonment timing, which we will address in this work.
- Minimizing risks and reducing environmental impact. These objectives are better met if a proper planning time is available and the abandonment time is known more accurately.
- To meet regulatory requirements. In many countries, the operator must prepare a decommissioning execution plan and obtain

[1] Offshore Petroleum and Greenhouse Gas Storage Act.

decommissioning approval, which might be a time-consuming and investigation-demanding process. In the UK, for instance, the operator must submit the detailed and revised decommissioning program approximately five years before well production is scheduled to end (Initiative et al., 2010).
- Reduce uncertainty and improve the planning of other development subjects that depend on the abandonment of the asset, for example, impairment tests and determining the depletion rate of tie-backs that will be connected to the field (Borges et al., 2018).

In this work, we focus on methodology development to determine optimal abandonment timing during the early stages of field development. We propose to include the decommissioning timing as an optimization variable along with other typically studied variables, such as production schedule, drilling programs, and structure layout. However, in practice, determining the optimal abandonment time at an early stage might be challenging because of the system uncertainties, for example, the oil price, the size of the reserves, well productivity, and other factors. For instance, any new discoveries nearby the existing field or the implementation of improved oil recovery techniques can create opportunities to extend the field lifetime.

One of the largest uncertainties in the early stage of field development is the initial reserves in place (Goel et al., 2006; Lopes and de Almeida, 2015), which may change the production horizon. Many real-world cases show an optimistic or pessimistic evaluation of the recoverable reserves when operators create the field development plan and leading to an extension or reduction of the field's lifetime. Moreover, there are uncertainties regarding the abandonment cost and because of the immaturity of technology for field decommissioning (Osmundsen and Tveterås, 2003). In 2019, it was reported that, in the year 2016, the Norwegian operator Equinor planned more than 20 field life extensions, but only 8 of them were approved as of 2019 (2019a,b).

The conventional method to plan abandonment of oil and gas fields is to build yearly operational cash flow projections and plan to produce until the year has the last positive estimate (Dias, 2014). We further develop this method into a mathematical optimization model to automatically find the optimum decommissioning timing. Therefore, the mathematical programming method is applied to determine the optimal field development strategy, including the decommissioning timing.

When deciding on abandonment, other issues are typically considered:

- Ageing of the installation and associated infrastructure;
- Guidelines and agreements with regulatory bodies regarding the ultimate recovery factor. Energy or industry departments within governments, in their role as custodians of the national hydrocarbon assets, have a responsibility to ensure that the recovery of oil and gas is maximized and to avoid predatory production;
- Oil and gas market prices, market volatility, inflation, tax regulation, legal regime, and lifting costs.

In this paper, we expand the model presented by Lei et al. (2021) in which a mixed-integer linear programming (MILP) mathematical optimization model was formulated with the objective to maximize the project's net present value (NPV) by optimizing well number, drilling sequence, and production scheduling. The production performance of the field is modeled using production potential curves, a proxy model derived from the output of coupled reservoir-network models covering reservoir, well, pipeline, and processing. We expanded the model by including abandonment timing as an additional decision variable. We then apply the model for the early-stage field planning of a real-world case study. Subsequently, we performed a sensitivity analysis of optimal abandonment timing in terms of the field's reserves. To the best of our knowledge, this is the first work that solves the decision problem of decommissioning timing at the early stage of field development using mathematical programming.

This paper is organized as follows. Section 2 and Section 3 present the problem description and a mathematical model, respectively. Then, in Section 4, abandonment conditions are transferred and included into the model mathematically. In Section 5, we demonstrate the advantages of our approach with a set of illustrative examples and a real-world case study based on realistic data. The conclusions are presented in the last section of the paper.

2. Problem statement

In this paper, we consider the design and planning of an offshore oil infrastructure with a set of $\mathcal{R}$ reservoirs tied-back to the same production facility through subsea wells, as presented schematically in Fig. 1. In each reservoir $r \in \mathcal{R}$, a set of $\mathcal{W}^r$ wells could be potentially explored and drilled as producers. The production from each well flows in and commingles to the same processing facility, e.g., FPSO, jackup, tension leg platform (TLP), or onshore terminal. The wells that belong to the same reservoir are interrelated, and therefore, the production potential from the same reservoir at a given time depends on how much oil remains in the reservoir and how many and which producers are used for production.

The offshore oil & gas field development planning typically consists of at least two parts: the concept screening and the selection of the main development variables. The concept screening usually includes the production facility's type, depletion mechanism, placement of surface and subsea facilities, among others. The development variables involve the selection of the number, capacity, and sequence of facilities/drilling programs and the allocation of the recoverable reserves for each time period (rate allocation).

In this work, we focus on using optimization to determine the drilling and production strategies, and most specifically, the optimal production horizons. We focus on drilling and production schedules because they greatly affect the cash flow and the cost of the installation (and they also define the required processing capacity). Moreover, the drilling sequence and production allocation are interrelated. Generally, the more wells drilled in a given year, the more production can be achieved. Specifically, and due to the fact that wells have distinct production performance, the field's production potential depends on the producing wells' combination. The planned drilling sequence and production allocation are spread to each time period in a specified time horizon, usually on a yearly basis. The reasons for choosing the yearly basis are:

- The focus of our work lies in the "early stage" of oil & gas field development, with the main purpose of selecting the concept and deciding on the main field parameters when information available is uncertain, scarce, or unreliable.
- A time-step of a year is also used typically by the industry when performing discounted cash flow calculations in the early phases of field development, and has been used extensively in recent and established literature (Gupta and Grossmann, 2012; Wang et al., 2019).
- Our problem has some constraints that only make sense in a time frame of a year, for example, the maximum number of wells that can be drilled in a year.
- A yearly time step give a good trade-off between running time and accuracy and it enables performing probabilistic analysis.

The number of active years before stopping production defines the abandonment timing of the field or decommissioning year.

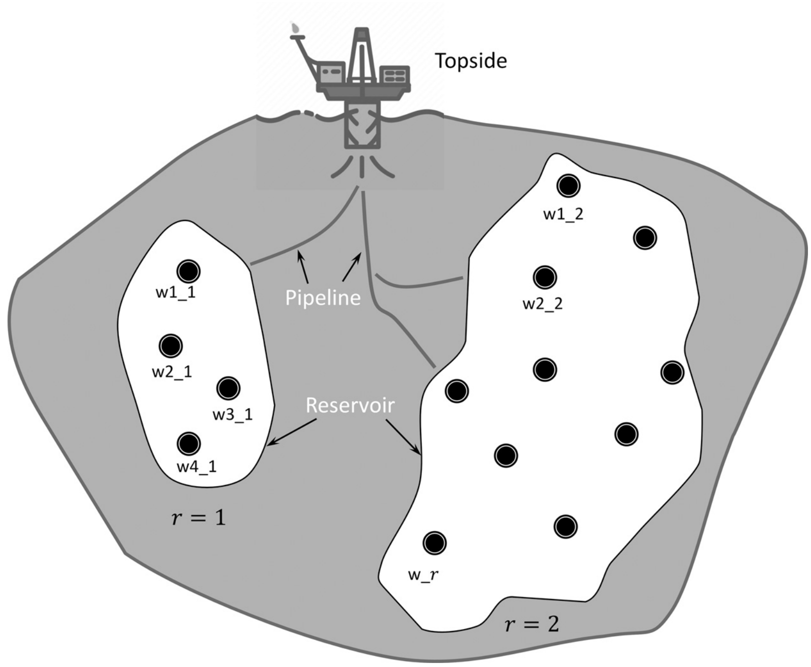

Fig. 1. Configuration of field, reservoir ($r \in \mathcal{R} = \{1, 2\}$) and well.

Usually, it is given as an input by the decision-maker in field development planning (Jørnsten, 1992; Jonsbråten, 1998). For instance, Iyer et al. (1998) illustrated an offshore oil field infrastructure investment and operations scheduling problem under a given production horizon of 6 years. Carvalho and Pinto (2006) studied an offshore oilfields infrastructure planning optimization problem with a fixed time planning horizon of 10 years. Another case is from Goel et al. (2006), which used a 15-year time horizon to optimize a gas field development planning. The disadvantage of optimizing the field development under a fixed production horizon is that it might lead to a sub-optimal solution. However, in our optimization model, the production horizon is a variable.

Therefore, our optimization model considers as decision variables (a) how many total producer wells are needed in each reservoir, (b) what is the drilling sequence in time periods, (c) how much oil production is allocated to each time period, and (d) the field's lifetime.

Several major assumptions are made when constructing the field development problem:

1. The productivity of each well is distinct and changes over time. Therefore, different well combinations will give different production performances.
2. There is no underground communication between reservoirs. Therefore, the production from one reservoir has no impact on the production performance of the rest.
3. The processing capacities of oil, gas, and water are a function of the production profiles and are given as an input into the optimization model.
4. The location of the topside facilities and pipeline, and the assignment of wells to the subsea facilities are fixed and given as input.
5. The production of gas and water is dependent on the production of oil in terms of gas-oil ratio (GOR) and water-cut (WC) rate. The GOR and WC of each reservoir are a function of the recovery factor of each reservoir.
6. The decommissioning costs are fixed and given in future monetary units. Variations in the value due to inflation and actual execution year were not considered. The costs are considered independent upon the number of wells drilled.
7. The produced fluids from different reservoirs are assumed to be compatible at the facilities.

The model and proposed algorithm are flexible enough to incorporate more complex reservoir models.

3. Mathematical formulation

In this section, we formulate the field development optimization problem described in the previous section using mathematical programming. The main decision variables per time are the continuous variables regarding to reservoir and field rates, the integer variables related to the status of the wells and the number of drilled wells, and the field lifetime. Due to the presence of integer variables related to the status of the wells and nonlinearities appearing in the production potential curves, the problem yields a Mixed-Integer Nonlinear Programming (MINLP) formulation. The nonlinearities of the problem are linearized with the use of piecewise linear functions (PWL), which transforms the MINLP problem into a Mixed-Integer Linear Programming (MILP) problem. The notation and key parameters used in the formulation can be found in the Nomenclature table.

The objective function of the formulated optimization model targets the maximization of the NPV over the long-term production horizon $t \in \mathcal{T}$ as follows:

$$\max \ \text{NPV} = \sum_{t}^{T} \frac{P_o^t \cdot q_o^{\text{f},t} + P_g^t \cdot q_g^{\text{f},t} - CAPEX^{\text{f},t} - OPEX^{\text{f},t}}{(1+D)^t} \tag{1}$$

where the sum of revenue from the selling of oil and gas is subtracted by the costs of capital expenditure *CAPEX* and operational costs *OPEX*. This cash flow is then discounted to its present value using the discount factor *D*. The *CAPEX* represents the costs of well drilling, facilities construction, installation, among other planning and investment costs. The *OPEX* costs are associated with production operations, such as power consumption, offshore personnel, logistics, and transportation costs.

Mass balance equations ensure that the total oil, gas and water produced from all reservoirs r in the field f matches the total production commingled to the same processing facilities at the platform as follows:

$$q_o^{f,t} = \sum_{r=1}^{R} q_o^{r,t}, \forall t \in \mathcal{T} \tag{2}$$

$$q_g^{f,t} = \sum_{r=1}^{R} q_g^{r,t}, \forall t \in \mathcal{T} \tag{3}$$

$$q_w^{f,t} = \sum_{r=1}^{R} q_w^{r,t}, \forall t \in \mathcal{T} \tag{4}$$

We assume that no fluids are accumulated in the flowlines and that the reservoirs r are independent. Eqs. (2) - (4) ensure that the cumulative production of field f in each time step is equal to the sum of production from each reservoir r for all time steps $t \in \mathcal{T}$.

The total flows of oil, gas, and water are constrained by the maximum processing capacities at the topside processing facilities. Additionally, the sum of oil and water production is also constrained by a maximum liquid processing capacity $q_l^{\max}$. Eqs. (5) - (8) ensure that the field production is bounded by the processing capacities for the entire producing horizon:

$$q_o^{f,t} \le q_o^{max}, \forall t \in \mathcal{T} \tag{5}$$

$$q_g^{f,t} \le q_g^{max}, \forall t \in \mathcal{T} \tag{6}$$

$$q_w^{f,t} \le q_w^{max}, \forall t \in \mathcal{T} \tag{7}$$

$$q_o^{f,t} + q_w^{f,t} \le q_l^{max}, \forall t \in \mathcal{T} \tag{8}$$

The oil production potential curves are obtained from the output of an integrated model encompassing a coupled reservoir, a set of wells, pipelines, and processing facilities. These proxy models for the integrated models are referred to as production potential curves, and these are used to bound the oil production from the reservoir such that it does not exceed its maximum feasible production rate at a given time, see Eq. (9). Notably, the oil production rate $q_o^{r,t}$ is one of the decision variables in the optimization model. The production potential $q_{o,pot}^{r,t}$, the maximum field oil rate at a given time step t, depends on the selection of wells producing from the reservoir at that time, namely the wells permutation factor $fn^{r,t}$, and the cumulative amount of oil that has been produced until that time $N_p^{r,t}$. The production potential curves are nonlinear curves which are approximated with piecewise-linear functions. Compact formulations for piecewise-linear approximations of production potentials were presented in a previous work by Lei et al. (2021).

$$q_o^{r,t} \le q_{o,pot}^{r,t}, \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \tag{9}$$

$$q_{o,pot}^{r,t} = fn^{r,t} \cdot f_q^r(N_p^{r,t}), \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \tag{10}$$

The well status $x_{\mathbf{w}}^{r,t} \in \{0,1\}$ is a binary variable that takes on the value 0 when the well is shut-in and 1 when it is producing. The production potential of the reservoir is adjusted depending on the selection of wells permutation to produce from the reservoir. In Eq. (10), the wells permutation factor $fn^{r,t}$ is a factor that indicates the actual production potential of the reservoir r for a selected subset of active wells $\mathbf{w}_{act} \in W^r$ among all the possible well permutations W^r, as formulated in Eq. (11), where the function $\mathbf{F}^r(\cdot)$ is the wells permutation factor based on the subset of active wells $\mathbf{w}_{act}$. For more details, please refer to the complete well selection formulation for different well combinations provided in Appendix A.

$$fn^{r,t} = \mathbf{F}^r(\mathbf{w}_{act}), \ \forall \mathbf{w}_{act} \in W^r, \ \forall r \in \mathcal{R}, \ \forall t \in \mathcal{T} \tag{11}$$

The total number of active wells $N_w^{r,t}$ in reservoir r at the time t is a summation of the binary variables representing the status of the wells $x_{\mathbf{w}}^{r,t}$. The total number of active wells in the field $N_w^{f,t}$ is given by the summation of the variables corresponding to the active wells in all reservoirs. These relations are formulated in Eq. (12).

$$N_w^{f,t} = \sum_{r\in\mathcal{R}} N_w^{r,t} = \sum_{r\in\mathcal{R}} \sum_{\mathbf{w}\in W^r} x_{\mathbf{w}}^{r,t}, \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \tag{12}$$

Additionally, the total number of new wells drilled each year is constrained by the drilling capacity $N_{w,D}^{\max}$, as shown in Eq. (13). Subsequently, we defined that the well is not shut-in once it has been drilled using Eq. (14), in order to ensure a smooth flow profile.

$$0 \le N_w^{f,t} - N_w^{f,t-1} \le N_{w,D}^{\max}, \forall t \in \mathcal{T} \text{and } t \ge 1 \tag{13}$$

$$x_{\mathbf{w}}^{r,t+1} \ge x_{\mathbf{w}}^{r,t}, \forall r \in \mathcal{R}, \forall \mathbf{w} \in W^r, \forall t \in \mathcal{T} \text{and } t \le |T| - 1 \tag{14}$$

When accounting for the total gas and water production in the field, the cumulative gas G_p^r and water W_p^r production in reservoir $r \in \mathcal{R}$ are defined as functions ($\mathbf{F}^{G,r}(\cdot)$, $\mathbf{F}^{W,r}(\cdot)$) of the cumulative oil production N_p^r in the reservoir, as formulated in Eqs. (15) and (16). These functions G_p^r, W_p^r and N_p^r are built from output data sampled with the integrated reservoir-network model. Later on, these relations are approximated using PWL functions, which are described in Appendix B. Both the yearly gas q_g^r and water rates q_w^r are back-calculated from the cumulative produced gas G_p^r and water W_p^r, as formulated in Eqs. (17) and (18).

$$G_p^{r,t} = \mathbf{F}^{G,r}(N_p^{r,t}), \ \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \tag{15}$$

$$W_p^{r,t} = \mathbf{F}^{W,r}(N_p^{r,t}), \ \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \tag{16}$$

$$G_p^{r,t} = G_p^{r,t-1} + q_g^{r,t-1}, \ \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \text{and } t \ge 1, G_p^{r,0} = 0 \tag{17}$$

$$W_p^{r,t} = W_p^{r,t-1} + q_w^{r,t-1}, \ \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \text{and } t \ge 1, W_p^{r,0} = 0 \tag{18}$$

$$N_p^{r,t} = N_p^{r,t-1} + q_o^{r,t-1}, \ \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \text{and } t \ge 1, N_p^{r,0} = 0 \tag{19}$$

Eqs. (20) and (21) denote the field costs, namely the capital expenditures *CAPEX* and operational expenditures *OPEX*. The *CAPEX* is further divided into costs related to drilling $CAPEX_{\text{Drilling}}$, subsea facilities $CAPEX_{\text{Subsea}}$ and topside $CAPEX_{\text{Topside}}$. The *OPEX* is split into rate-dependent $OPEX_{\text{rate}}$ and rate-independent $OPEX_{\text{Nonrate}}$. All cost functions are created through cost proxy models based on regional history data and cost estimates, which are described in Appendix C in details. A similar expression of costs estimation using proxy models can be found in previous papers (Fedorov et al., 2021; Gonzalez, 2020).

$$CAPEX^{f,t} = CAPEX_{\text{Drilling}}^{f,t} + CAPEX_{\text{Subsea}}^{f,t} + CAPEX_{\text{Topside}}^{f,t} \tag{20}$$

$$OPEX^{f,t} = OPEX_{\text{rate}}^{f,t} + OPEX_{\text{Nonrate}}^{f,t} \tag{21}$$

The conceptual formulation presented in this section formulates an optimization problem that is capable of determining the optimal drilling sequence and production allocation such that the field's NPV is maximized for the given production, drilling, and processing constraints. More details about the piecewise-linear models and the actual formulation of the selection of the wells permutation factor can be found in Lei et al. (2021).

4. Field abandonment formulation

In this section, we have extended the presented optimization model in Section 3 with a new set of constraints to model the impact of field abandonment in field development planning. Essentially, in typical field development planning methodologies, the field lifetime or production horizon T is regarded as fixed and as an input to the optimization model. However, the abandonment time can also be considered a crucial decision in field planning, which should be made by stakeholders and is subject to the remaining profitability and other technical-economic criteria of the field. Herein, we propose an extension to the traditional field planning methodologies that consider the field lifetime T as a decision variable in the optimization model in addition to the production rates q_o, the number of wells N_w, and the drilling schedule fn^r.

The conditions that trigger the abandonment of a field are mainly economic and technical, but could also be governed by governmental and local authority issues. Operating companies have a responsibility to their shareholders to yield a competitive return on investment. On the other hand, government plays an extensive role in assessing and licensing decommissioning options since they are responsible for ensuring that oil and gas recovery is maximized in a sustainable manner. Meanwhile, the government is responsible for minimizing potential impacts on the environment, ensuring human health and safety, and gaining public acceptability. Therefore, the oil companies and host government's preferred time for decommissioning will diverge and possibly conflict with each other. Our model takes into account both the government's and oil companies' perspectives as a set of conditions modeled as constraints in the optimization model.

The conditions for field abandonment that are considered in the proposed optimization model are the following:

1. **Economic lifetime**: the cash flow permanently turns negative.[2] When the cash flow turns permanently negative due to a decreasing revenue, the field operation is halted, and the production rate becomes zero. In the model, this condition reflects on the production rates of the field, oil rate in this case.
2. **Technical lifetime**: the field's life can not be longer than the facility's design lifetime. However, it could happen that the field is abandoned earlier, e.g., due to low rates of oil and gas, which give low revenue, or high rates of water, liquid, or gas, which bottleneck the processing facilities, which prompt a reduction in rates of oil and give low revenue.
3. **Governmental policy**: the recovery factor has reached a minimum value, within the license period, and a minimum field lifetime has been reached. This is usually dependent on previously agreed goals between the operator and government for sustainable social development.

More details about the practical implementation of these conditions will be provided later.

4.1. Abandonment conditions

The main principle to devise long-term processing and decommissioning plans of offshore oil and gas fields is that all financially

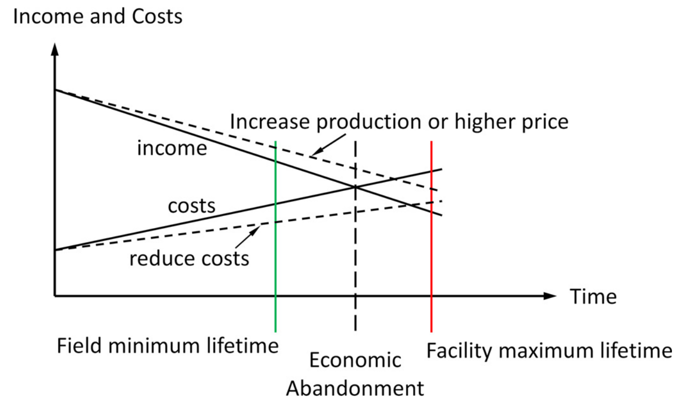

Fig. 2. Decommissioning conditions.

profitable and recoverable oil and gas resources should be produced. Fig. 2 illustrates the conditions discussed earlier that should be met to decommission a field. To keep the explanation simple, in this figure, we assume the income declines with time as oil and gas production from fields typically also declines in time. Costs are assumed to increase with time due to increased maintenance costs with time and processing and disposal of undesired by-products. The economic abandonment condition occurs when the project's income crosses the costs for operating the field.

Besides this, the abandonment should also lie between the field minimum lifetime required by the local authorities and the design life of the facilities. Notice that, although calculating the economic abandonment time looks straightforward in this figure, the curves for income and cost are highly uncertain in reality. For instance, the income will vary depending on the production scheduling, the sales price, or due to a change of the size of the reserve and well delivery capacity.

In order to include the time of abandonment in the model, we add a new decision variable t_A that indicates when one of the conditions for abandoning the field is met. Among the conditions are zero-field production rate and when the revenue is surpassed by the project costs. Moreover, since the capital expenditures and asset depreciation are generally negligible towards the end of the field lifetime, the timing of abandonment or decommission can be defined as a point at which the gross income no longer covers the operational costs ($OPEX$).

As there is currently no general internationally accepted guidelines on whether and when decommissioning would be accepted and in what circumstances, we use generic statements and explanations with specific model details to describe the variable abandonment time in the optimization model in terms of the following conditions:

Condition 1 (economic abandonment): project's income must be higher than costs before abandonment. Once the revenue income becomes less than or equal to the operational costs, the field meets the economic abandonment criteria, which implies closing the field and setting the production rates to zero from that time on:

$$q_o^{\mathrm{f},t_A} = 0, \ \forall t_A : t \in \mathcal{T} \text{ such that } Revenue^{\mathrm{f},t} \ \leq \ Cost^{\mathrm{f},t} \tag{22}$$

Condition 2 (technical abandonment): when the oil production rate is less than the minimum processing rate:

$$q_o^{\mathrm{f},t_A} = 0, \ \forall t_A : t \in \mathcal{T} \text{ such that } q_o^{\mathrm{f},t} < q_{Ao}^{\mathrm{f}} \tag{23}$$

where q_{Ao}^{f} is termed abandonment oil rate, and it represents the minimum processing rate at the facilities, being either a fixed technical minimum rate or a varying flow rate related to the cost and product prices. For instance, a lower rate can be compensated by a higher oil price. The minimum required rate can also change with

[2] This condition is widely used in early-phase field planning in current industrial practices.

upgrades in processing equipment as such expansions typically require extra investments.

Condition 3 (technical abandonment): when produced water and gas rates reach the corresponding upper limits in the processing facilities:

$$q_o^{f,t_A} = 0,\ \forall t_A : t \in \mathcal{T} \text{ such that } q_w^{f,t} > q_{Aw}^f \quad (24)$$

$$q_o^{f,t_A} = 0,\ \forall t_A : t \in \mathcal{T} \text{ such that } q_g^{f,t} > q_{Ag}^f \quad (25)$$

where q_{Aw}^f and q_{Ag}^f are the maximum water and gas processing rates. In some scenarios, the field must stop production ($q_o^{f,t} = 0,\ \forall t \geq t_A$) when water and gas rates approach the maximum allowed processing capacity of the facilities (Eq. (6) and (7)). These conditions will vary depending on the study case. For example, excessive amounts of produced water may not affect the production from an onshore field because it is possible to cost-effectively expand and upgrade the facilities, but it may cause a production shutdown in an offshore field. Water and gas production rates are computed by the model using the water cut, the gas-oil ratio, and the oil rate.

Condition 4 (governmental requirements to avoid predatory production): the ultimate recovery factor (*RF* at abandonment) needs to be above a certain threshold:

$$\frac{N_p^{f,t_A}}{R^f} \geq RF_{min}^f \quad (26)$$

$$q_o^{f,t} \geq q_o^{f,\min}, \text{ if } \frac{N_p^{f,t}}{R^f} < RF_{\min}^f \quad (27)$$

here, $RF_{\min}^f$ is the minimum required recovery factor. This value is often defined in an agreement between the government and the operator. Before reaching the minimum recovery factor, the field normally produces above a certain minimum field production ($q_o^{f,t} \geq q_o^{f,\min}$). In the optimization model, the ultimate recovery factor is calculated based on the ultimate oil cumulative production.

Condition 5 (governmental policy): often, the field production lifetime must last more than the minimum licensed production period $t_{\min}$ for ensuring a socio-economic sustainable development:

$$t_A \geq t_{min},\ \forall \{t_A\} \in \mathcal{T} \quad (28)$$

$$q_o^{f,t} \geq q_o^{f,\min}, \text{ if } t \leq t_{\min} \quad (29)$$

A similar approach can be used to model the case where there is a maximum licensed production period, if applicable.

4.2. Mathematical modeling of abandonment conditions

In our work, we formulate the field abandonment by constraining the production rate when abandonment conditions are met, instead of considering economic issues in the definition of the field lifetime only. Fig. 3 presents a schematic of how the constraints in the oil rate are used to represent the field abandonment. A binary variable $S_A^t \in \{0, 1\}$ is introduced to indicate when at least one of the abandonment conditions is met. The corresponding time of abandonment is the abandonment time t_A, and it occurs when the field oil rate is less than the abandonment oil rate, then $S_A = 1$. It also requires the production rate to be equal to or higher than a minimum oil rate when triggering technical abandonment conditions, as illustrated in Fig. 3.

$$S_A^t = \begin{cases} S_A^t = 1, & \text{if } q_o^{f,t} < q_{Ao}^f \text{(abandonment active)} \\ S_A^t = 0, & \text{otherwise} \end{cases}$$

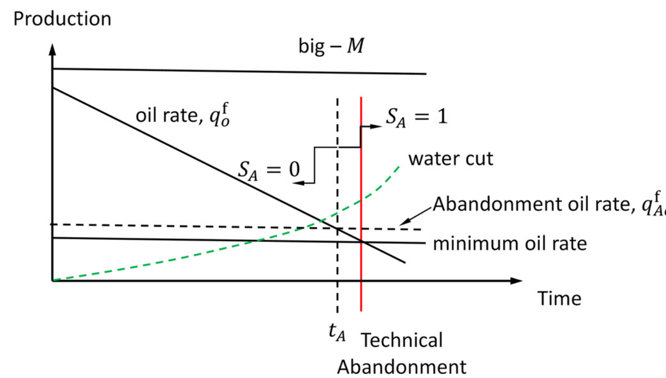

Fig. 3. Algorithm formulation illustration.

Formulation of constraint 1 (economic abandonment): the economic abandonment condition is triggered when the costs become higher than the revenue obtained with the selling of the hydrocarbons.

$$0 \leq Cost^{f,t} \leq Revenue^{f,t} \cdot (1 - S_A^t),\ \forall t \in \mathcal{T} \quad (30)$$

notice that if $S_A^t = 1$, the condition is met, and the above constraint is activated. When the field is producing, $S_A^t = 0$ and this constraint will ensure that the costs remain below the revenue.

Formulation of constraint 2 (minimum production rate): the minimum production rate condition is met when the field production becomes lower than a minimum threshold.

$$q_o^{f,t} \geq q_{Ao}^f \cdot (1 - S_A^t),\ \forall t \in \mathcal{T} \quad (31)$$

$$q_o^{f,t} \leq M \cdot (1 - S_A^t),\ \forall t \in \mathcal{T} \quad (32)$$

where M is a big-M, as illustrated in Fig. 3. When the field is producing, $S_A^t = 0$ and these constraints ensure that the field production is above a certain minimum rate. The big-M condition is relaxed. Otherwise, when $S_A^t = 1$, the field abandonment condition is met and the field rate $q_o^{f,t}$ is set to zero.

Formulation of constraint 3 (maximum processing capacity): the maximum processing capacity abandonment condition is met when the gas or water production of the field surpasses the maximum processing capacity.

$$0 \leq q_w^{f,t} \leq q_{Aw}^f \cdot (1 - S_A^t),\ \forall t \in \mathcal{T} \quad (33)$$

$$0 \leq q_g^{f,t} \leq q_{Ag}^f \cdot (1 - S_A^t),\ \forall t \in \mathcal{T} \quad (34)$$

in which, q_{Aw}^f and q_{Ag}^f are the maximum water and gas processing rates, respectively. The maximum liquid handling capacity of a platform $q_l^{\max}$ can be included as an abandonment condition when suitable.

Formulation of constraint 4 (minimum recovery factor): this abandonment condition is met when the recovery factor of the field becomes lower than a certain lower bound.

$$\frac{N_p^{f,t}}{R^f} \geq RF_{min}^f \cdot S_A^t,\ \forall t \in \mathcal{T} \quad (35)$$

in which, $N_p^{f,t}$ is the cumulative oil production at time t, R^f is the original oil in place of the field, and $RF_{\min}^f$ is the minimum requirement for the field recovery factor.

Formulation of constraint 5 (feasible window for field production): this abandonment time requires the field to operate within a feasible time window ($t_{\min},\ t_{\max}$).

$$t_{Shadow} - \sum S_A^t \geq t_{min},\ \forall t \in \mathcal{T} \quad (36)$$

Table 1
Parameters of the reservoir and network model.

Reservoir & Well		
Parameter	Reservoir-1	Reservoir-2
Reservoir Pressure (bara)	195	243
Reservoir Temperature (°C)	70	90
Oil in place (MSm^3)	56.25	39.25
Solution gas-oil ratio (Sm^3/Sm^3)	115	150
Initial water saturation (fraction)	0.05	0.05
Number of wells	6	3
Productivity index ($Sm^3/d/bar$)	1500	500
Tubing size (inch)	5.5	5.5
Surface Network		
System type	Production	
Seabed Temperature (°C)	4	
Pipeline diameter (inch)	6 - 10	
Pipeline Length (km)	17.5	
Separator Pressure (bara)	20	

Table 2
Abandonment constraints variation.

Constraints	Base case	Case-A	Case-B
Minimum field lifetime, $t_{\min}$ (year)	15	15	15
Facility Design lifetime, $t_{\max}$ (year)	25	25	25
Minimum recovery factor, $RF^{f}_{\min}$ (%)	20	20	20
Abandonment oil rate, q^{f}_{Ao} (Sm^3/day)	900	1500	500
Ceiling gas rate, q^{f}_{Ag} (MSm^3/day)	6	6	6
Ceiling water rate, q^{f}_{Aw} (Sm^3/day)	11000	11000	11000
Optimization Results			
Optimal abandonment timing, t_A (year)	20	18	20
Net present value, NPV (MUSD)	4,749.98	4,690.87	4,753.00
Recovery factor, RF (%)	22.00	21.83	22.00
Computational time (second)	1621	3843	755

Table 3
Computational performance and optimization details of the **Base Case**.

Item	Value
Variables:	13,214
Binary variables:	1150
Integer variables:	90
Constraints:	8041
Nonlinear constraints:	24
Linear constraints:	8017
Equality constraints:	1162
Inequality constraints:	6850
Computational time:	1621 seconds

$$t_{Shadow} - \sum S_A^t \le t_{max}, \forall t \in \mathcal{T} \quad (37)$$

where t_{Shadow} is the maximum number of time in the dataset $\mathcal{T}$ that can be used in the optimization. It has to be large enough to cover the optimized abandonment time t_A. The parameter $t_{\min}$ is the minimum time that the field must operate according to the authorities, see Eq. (28), and $t_{\max}$ is the maximum lifetime of facilities due to design lifetime. Notice that the maximum viable producing time $t_{\max}$ can be used as the optimization feasible time window, t_{Shadow}, directly.

5. Case studies and simulation results

In this section, we describe a case study involving a real-world field to demonstrate the benefits of the proposed formulation, in which the field abandonment timing is optimized together with the decisions regarding the drilling program and the production scheduling. In field development activities, it is often the case that the operations are extended when new discoveries are made. To assess the impact of field operation extensions, an uncertainty analysis considering the field lifetime is performed using a sampling method that generates a discrete set of cases over the field lifetime uncertainty envelope.

The case study involves the field development planning for the exploration of two oil discoveries located in the Barents Sea. These discoveries are considering for a joint development. The main product is oil, and the produced water and gas will be re-injected into the reservoir for pressure maintenance. In total, there are 9 candidate wells (6 from Reservoir-1, and 3 from Reservoir-2) which were proposed after a detailed geological and reservoir engineering study. The field production potential is a function of the produced oil and the selected subset of producing wells from the field. The key reservoir parameters are listed in Table 1.

Two case studies are investigated for the optimization of field development planning for the reserves described previously.

- **Study-1**: The first case study involves a field development planning with the main decision variables being the production allocation, the selection of a subset of wells to produce with its corresponding drilling schedule, and the field abandonment timing. The purpose of **Study-1** is to assess the results obtained with the mathematical model with a large focus on the automatic and proper calculation of the more profitable abandonment timing for the field.
- **Study-2**: The second case study is a field development planning with the same variables of the **Base case** in **Study-1** but considering uncertainty on the total recoverable reserves. In practice, there is high uncertainty regarding the recoverable reserves at an early stage of the field development activities, thus the inclusion of uncertainty associated with the total recoverable reserves in the model is particularly relevant for its great impact on the field's lifetime.

5.1. Case study 1

In **Study-1**, we set t_{Shadow} to 30 years, assuming that the abandonment timing will not be longer than 30 years. The base case is built using the parameters listed in Table 2 for the abandonment constraints, and some other optimization results are also shown in the table. The problem is formulated using AMPL (Fourer et al., 2003), solved with Gurobi (Gurobi Optimization, 2020), and computed using ThinkPad of Intel(R) Core(TM) i7-8565U CPU 1.80 Hz 1.99 GHz 64 bytes. The computational performance and more information about the formulation size for the **Base case** are shown in Table 3.

Fig. 4 presents the optimal results obtained for the base case, including the optimal production schedule, drilling program (both subset of active wells and drilling schedule), and abandonment timing. From Fig. 4, we can see that the optimized subset of active wells contains 8 out of the 9 candidate wells, with $w1$ being left out of the drilling program. The elimination of $w1$ is an optimization result respecting the distinguishment of different wells combinations and the resulting balance of costs and the NPV value. Wells of $w2$, $w4$ and $w5$ are selected to be pre-drilled before production, and the optimized sequence of drilling is to drill wells $w6$ and $w9$ in the first year, then drill wells $w7$ and $w8$ in the second year, and finally, well $w3$ is drilled in year 3. The optimal timing of abandonment is in the year 20, meaning that the optimum production lifetime is 20 years for the considered parameters and constraints. The optimized abandonment timing is identical to the operator's plan of a 20 years production horizon, which is based on a cross domain study conducted in decision gates. This serves as a soft validation of the model as an actual validation in the real field

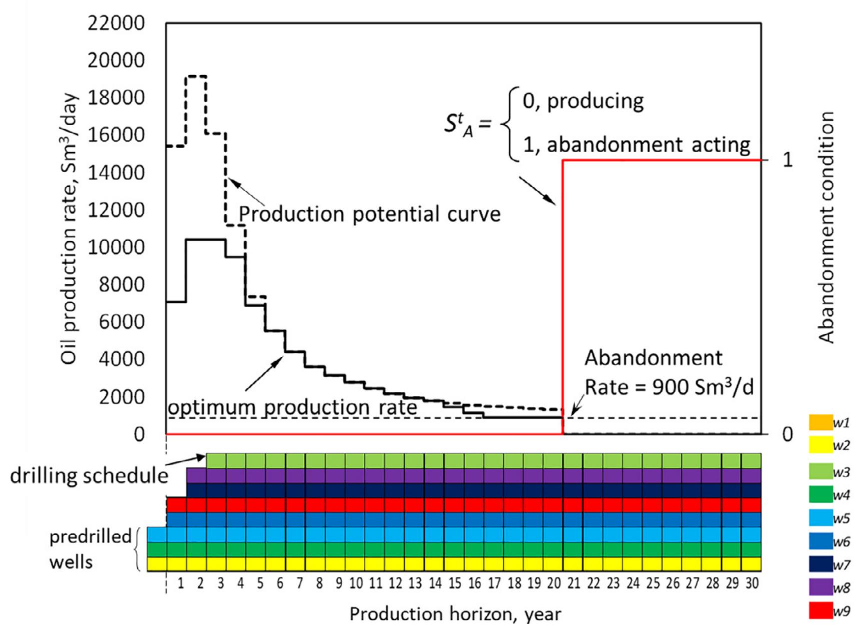

Fig. 4. Optimal results for the Base case.

Table 4
Fractional factors of different well combinations.

Well combinations	f_n^1	Well combinations	f_n^1
Reservoir-1			
w1	0.166	w2	0.249
w3	0.195	w4	0.293
w5	0.198	w6	0.113
w1,w2	0.332	w1,w3	0.357
w1,w4	0.413	w1,w5	0.365
w1,w6	0.279	w2,w3	0.436
w2,w4	0.467	w2,w5	0.448
w2,w6	0.362	w3,w4	0.477
w3,w5	0.393	w3,w6	0.308
w4,w5	0.492	w4,w6	0.406
w5,w6	0.304	w1,w2,w3	0.516
w1,w2,w4	0.524	w1,w2,w5	0.530
w1,w2,w6	0.445	w1,w3,w4	0.591
w1,w3,w5	0.556	w1,w3,w6	0.470
w1,w4,w5	0.611	w1,w4,w6	0.526
w1,w5,w6	0.470	w2,w3,w4	0.642
w2,w3,w5	0.635	w2,w3,w6	0.549
w2,w4,w5	0.665	w2,w4,w6	0.580
w2,w5,w6	0.553	w3,w4,w5	0.676
w3,w4,w6	0.590	w3,w5,w6	0.499
w4,w5,w6	0.597	w3,w4,w5,w6	0.781
w2,w4,w5,w6	0.771	w2,w3,w5,w6	0.740
w2,w3,w4,w6	0.755	w2,w3,w4,w5	0.841
w1,w4,w5,w6	0.717	w1,w3,w5,w6	0.661
w1,w3,w4,w6	0.704	w1,w3,w4,w5	0.790
w1,w2,w5,w6	0.636	w1,w2,w4,w6	0.637
w1,w2,w4,w5	0.722	w1,w2,w3,w6	0.629
w1,w2,w3,w5	0.714	w1,w2,w3,w4	0.696
w1,w2,w3,w4,w5	0.895	w1,w2,w3,w4,w6	0.809
w1,w2,w3,w5,w6	0.820	w1,w2,w4,w5,w6	0.828
w1,w3,w4,w5,w6	0.895	w2,w3,w4,w5,w6	0.946
w1,w2,w3,w4,w5,w6	1.000		
Reservoir-2			
Well combinations	f_n^2	Well combinations	f_n^2
w7	0.527	w8	0.606
w9	0.644	w7,w8	0.807
w7,w9	0.878	w8,w9	0.907
w7,w8,w9	1.000		

is not feasible as the asset is still not approved for development. Moreover, in the obtained results, the abandonment rate was the trigger for the field abandonment. Before the abandonment of the field, the production rate is maintained at a level slightly higher or equal to the abandonment rate of 900 Sm^3/day in the last 4 years.

Two additional cases, i.e., Case-A and Case-B, are created, as shown in Table 2, with the goal of assessing the impact of different abandonment oil rates on the field production performance. All optimizations achieved a dual gap of 0% but used different computational budgets of time. Fig. 5 shows a comparison of the optimal results for all three case studies, Case-A, Case-B and the Base case, as described in Table 2. The dashed lines in the plots show the optimized production rate and abandonment time for cases A and B.

In all the cases studies, the constraints regarding the ceiling gas and water rate, minimum recovery factor, and the facility design lifetime are not active at the time of abandonment.

Fig. 5 (a) presents a comparison of the results obtained with Case-A and the base case. In Case-A, the abandonment oil rate q_{Ao} is increased from 900 Sm^3/day to 1500 Sm^3/day in comparison with the base case, whereas the other constraints are the same as the base case. The optimal results show the following: (1) the abandonment time t'_A is reduced from 20 to 18 years in Case-A, (2) the production profile is different from the base case from year 4, and (3) the NPV and recovery factor are slightly reduced when the abandonment rate is increased, see Table 2.

Fig. 5 (b) shows a comparison of the results obtained with Case-B and the base case. In Case-B, the abandonment oil rate q_{Ao} is reduced from 900 Sm^3/day to 500 Sm^3/day compared to the base case, whereas the other constraints remain the same. The conclusions based on the results obtained are the following: (1) the optimal abandonment time t''_A obtained is 20 years in both cases, (2) the production profiles are the same up to year 15, (3) the recovery factor obtained with the strategies is the same, being 22.00% as all recoverable reserves are produced, and (4) the NPV is slightly increased in Case-B compared to the base case, see Table 2.

The results of **Study-1** clearly show that the optimum field lifetime depends on the criteria of abandonment; changes to the abandonment rate impacted the optimum abandonment timing. Consequently, the solutions yield different economic performance,

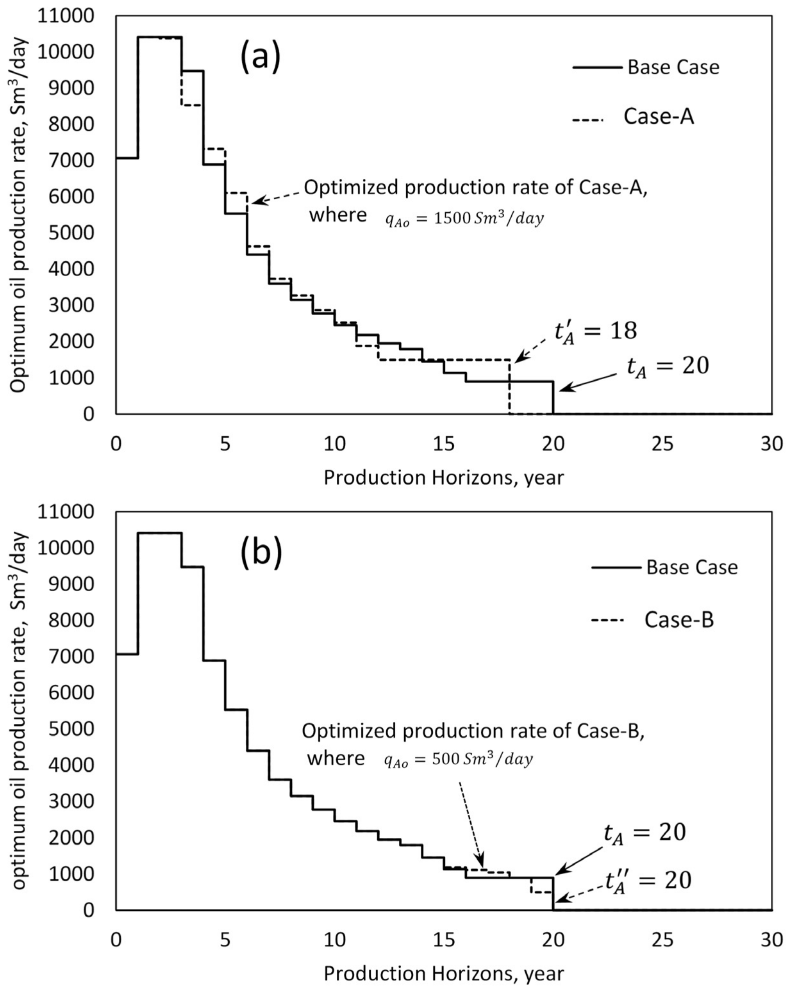

Fig. 5. Optimal results for Case-A, Case-B and the Base case.

recovery factors (although very similar in this case), production strategy, and drilling sequence[3]. In other words, if we set a fixed production horizon of a given value (e.g., 20 years for Case-A), the project's performance and economic margins might be sub-optimal solutions even the optimization is used to search for an optimum drilling and production schedule.

5.2. Case study 2

In the second case study, referred to as **Study-2**, we designed a set of scenarios considering uncertainty in the recoverable reserves to assess its impact on the abandonment timing and the effect of the field design lifetime. This is usually a case of practical interest for oil and gas companies.

The analysis is performed using simulation-based optimization, in which a set of optimization runs are performed for different recoverable reserves within a certain uncertainty envelope. The samples of the uncertain variables are obtained using Latin Hypercube Sampling (LHS), which has an advantage of achieving convergence with fewer samples than other methods (for example, Monte Carlo Sampling). A total of 100 samples of the recoverable reserve were generated using LHS. The distributions of the recoverable reserves for each discovery are synthetic, but the distribution parameters are based on real spreads reported in plans for development and operations.

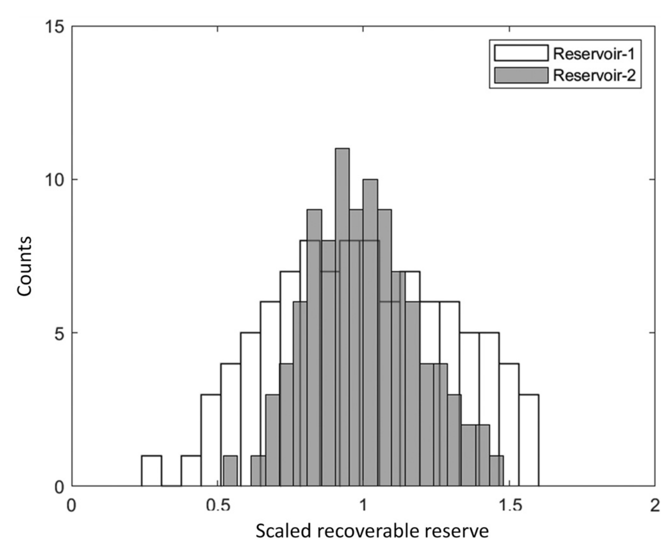

Fig. 6. Distribution of normalized recoverable reserves. (the original recoverable reserve of each reservoir refer to 1.00).

[3] The drilling sequence is not displayed in plots, but it is interrelated with the production rate.

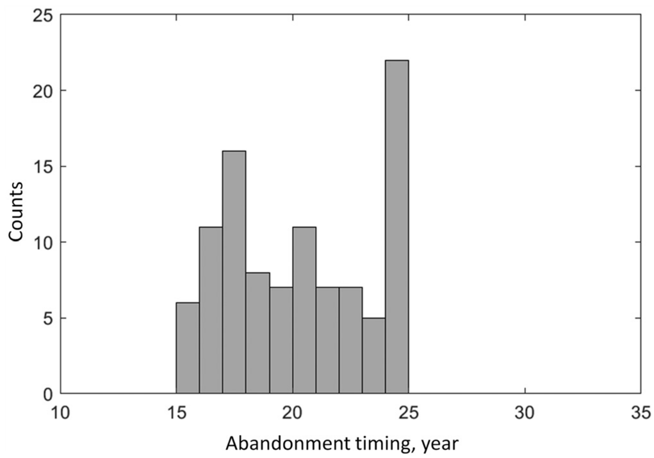

Fig. 7. Sensitivity analysis: Distribution of abandonment timing with constraints both on minimum license lifetime of 15 years and facility design life of 25 years.

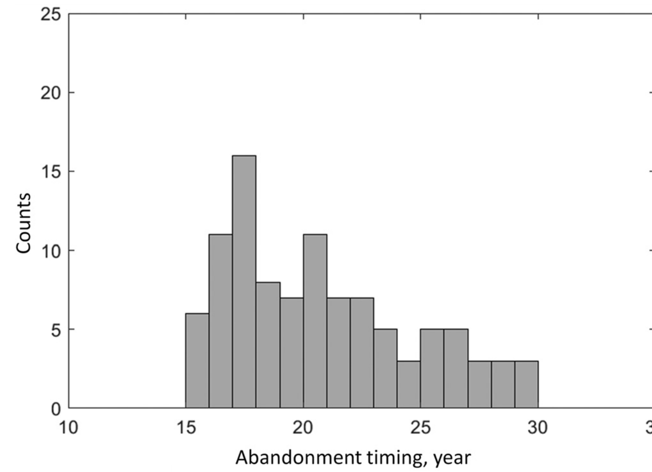

Fig. 8. Sensitivity analysis: Distribution of abandonment timing with constraints of minimum license lifetime of 15 years only.

When generating samples, the reserve distributions of these two reservoirs are considered to be independent, considering a long distance in location and the separate setting of the actual production potential of the selected subset of producers within each reservoir (see Table 4). These sampled recoverable reserves were then used as input data for the optimization problem, resulting in 100 optimal solutions.

The distributions of the normalized recoverable reserves for each reservoir are shown in Fig. 6. In the diagram, each LHS-generated recoverable reserve is normalized by dividing the recoverable reserve value of the base case. Then, a total of 100 optimizations were run to find the corresponding optimal drilling schedule, production allocation, NPV, and abandonment timing.

Fig. 7 shows the optimized abandonment timing for different recoverable reserves but the same abandonment constraints of the base case. The results show that both abandonment constraints of minimum 15 years field lifetime and the maximum facility design lifetime of 25 years are met for several samples. The upper bound in optimal abandonment timing of 25 years is met in 22 samples out of the 100 scenarios. Suppose the constraint on the facility design lifetime is increased to 30 years and the optimizations for these 22 samples are re-run, the resulting distribution has a log-normal shape, exhibiting a peak at 17 years, as shown in Fig. 8.

We further studied the relation between the abandonment timing and the values of recoverable reserves of Reservoir-1 and Reservoir-2. A bubble chart is presented to display the relation between abandonment timing and reservoir size in Fig. 9. The optimization results show that the abandonment timing is more sensitive to the size of Reservoir-1 compared to the size of Reservoir-2. An explanation for this is that the reserves in Reservoir-1 are larger and there are also more producers available in this reservoir. When the reservoir size is reduced, it is likely that the field production

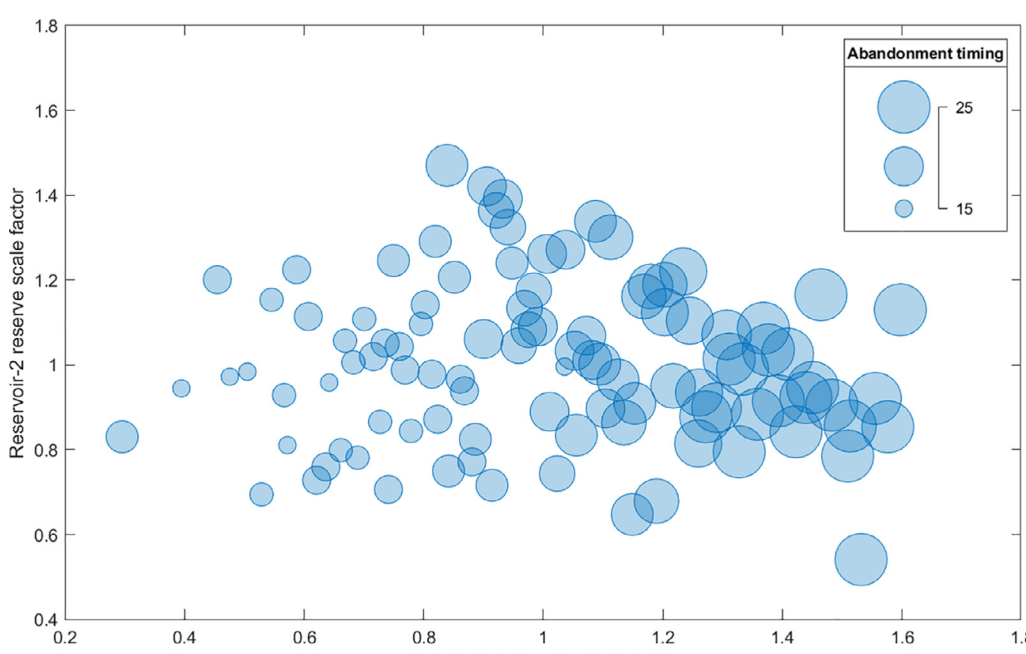

Fig. 9. Bubble chart of abandonment timing in terms of reserve scale factors both of Reservoir-1 and Reservoir-2.

time is shortened. Similarly, when the reservoir size is larger, the abandonment timing is likely to be postponed.

6. Conclusions

We proposed a formulation based on mathematical programming for early-phase field development optimization of offshore hydrocarbon fields. The optimization consists of determining the abandonment timing and the drilling and production schedule that maximizes the project value for a multi-reservoir field.

The main contribution of this work is that we proposed a novel way to automatically search for optimal abandonment timing, in addition to determining optimal drilling and production scheduling for field development problems.

The proposed methodology was applied and tested on a real-world case in order to assess the benefits of including a variable abandonment timing in the optimization. The results of this work indicate that the abandonment timing can significantly impact a project's economic and performance evaluation; the decommissioning timing has to be optimized, similar to the searching of optimum drilling and production scheduling in the early stage of field development. The commonly used method of running optimization with a fixed production horizon might lead to sub-optimal solutions, which will yield lower net present value, lower recovery factor, and unfavorable production strategy.

Through an uncertainty analysis on the recoverable reserves, we conclude that the field's production horizon is highly sensitive to the size of the reservoir reserve, which is very uncertain at an early stage of field development. Performing an uncertainly analysis allows to map the limiting constraints and it allows to obtain lower bounds and upper bounds of the abandonment timing of the project, which is often of practical interest for oil and gas companies.

Future work includes the expansion of the proposed methodology. For instance, decommissioning timing is more than a technical or economic issue but also involves concerns regarding environmental impacts, which have a critical role in the management of decommissioning timing. It may be interesting to expand the model to a multiobjective optimization model including other decommissioning elements, such as policy, environmental impacts, and taxation. There is currently no general internationally accepted guidelines on whether and when decommissioning would be accepted and in what circumstances. Therefore, an interesting direction for research involves extensions to the proposed formulation to consider environmental constraints and policies in the decision-making.

As the abandonment cost varies in terms of decommissioning methods, risks, and financial rewards, an open question is how to include these parameters into the mathematical programming, particularly when the industry experience and historical data are scarce. For instance, as operators are often looking for the cheapest way to abandon a field, an interesting application of the formulation would be to optimize the abandonment timing for fields in operation when accounting for decommissioning costs.

Some other possible directions for future work could be: considering blending and compatibility complexities when mixing fluids from different reservoirs, performing stochastic optimization to evaluate rigorously the effect of uncertainty in, for example, the initial oil and gas in place, abandonment cost, or well production performance.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

CRediT authorship contribution statement

Guowen Lei: Conceptualization, Data curation, Formal analysis, Investigation, Methodology, Software, Validation, Visualization, Writing – original draft. **Milan Stanko:** Conceptualization, Funding acquisition, Methodology, Project administration, Resources, Supervision, Validation, Writing – review & editing. **Thiago Lima Silva:** Conceptualization, Investigation, Methodology, Software, Validation, Writing – review & editing.

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Appendix A. Formulation of wells permutation selection

Let $g^r : \{1, \ldots, 2^{|\mathcal{W}^r|}\} \to \mathcal{W}^r$ be a function that maps an index j from all permutations of well combinations w^r_j to the set of wells $\mathcal{W}^r$ such that:

$$g^r(j) = \{i \in \mathcal{W}^r : w^r_j(i) = 1\}, \ \forall j \in \{1, \ldots, 2^{|\mathcal{W}^r|}\} \tag{38}$$

where $w^r_j(i)$ denotes the i-th element of the tuple w^r_j. This function indicates which wells $\mathbf{w} \in \mathcal{W}^r$ are active in reservoir r for the j-th well combination. A table with a map generated by function $g^r(\cdot)$ is calculated off-line and used in the constraints regarding the well permutation selection as follows:

For all $r \in \mathcal{R}, j \in \{1, \ldots, 2^{|\mathcal{W}^r|}\}$:

$$fn^{r,t} \leq fn^r_j + \sum_{i \in g^r(j)} (1 - x^{r,t}_{\mathbf{w}}) + \sum_{\in \mathcal{W}^r \setminus g^r(j)} x^{r,t}_{\mathbf{w}}, \ \forall \mathbf{w} \in \{1, \ldots, |\mathcal{W}^r|\} \tag{39}$$

$$fn^{r,t} \geq fn^r_j - \sum_{i \in g^r(j)} (1 - x^{r,t}_{\mathbf{w}}) - \sum_{i \in \mathcal{W}^r \setminus g^r(j)} x^{r,t}_{\mathbf{w}}, \ \forall \mathbf{w} \in \{1, \ldots, |\mathcal{W}^r|\} \tag{40}$$

Eqs. (39) and (40) create a set of disjunctions such that, depending on the active wells denoted by the binary variables x^r_i, the potential factor of the reservoir $fn^{r,t}$ will be set to the potential factor fn^r_j corresponding to the correct well combination w^r_j from all permutations.

Appendix B. Piecewise linear equations

The non-linearities of the problem appear in the production potential curves, including the actual potential based on the wells permutation in Eq. (10), but also in the cumulative production rates for gas phase in Eq. (15) and water phase in Eq. (16). In this work, we propose PWL approximations using Log model for the non-linear functions Eqs. (10), (15) and (16).

The Log model implementation of the branching scheme proposed by Vielma and Nemhauser (2011) requires new concepts and definitions. Let $\mathcal{S}_e = \{s_0, \ldots, s_n\}$ be the set of ordered breakpoints on the coordinate e, and $\mathcal{I}_e := \{[s_0, s_1], \ldots, [s_{n-1}, s_n]\}$ be the intervals containing pairs of consecutive breakpoints. Let $\mathcal{I}_e(s) := \{\mathcal{I} \in \mathcal{I}_e : s \in \mathcal{I}\}$ be a set of the intervals containing the breakpoint s, and $\Phi_e([s_i, s_{i+1}]) = i + 1$ be the index of an interval $[s_i, s_{i+1}] \in \mathcal{I}_e$. We define the function $B : \{1, \ldots, |\mathcal{I}_e|\} \to \{0, 1\}^{\lceil \log_2(|\mathcal{I}_e|) \rceil}$ to be a mapping between the interval indices and a binary code according to the Gray code property, meaning that $B(i)$ and $B(i+1)$ must differ by only one bit. The vertices of the domain is $\mathcal{V}(\mathcal{P}) = S_1 \times \cdots \times S_d$ and d is the dimension.

The first phase of the branching scheme uses the sets $J^{+}_{e,B,l} := \{s \in \mathcal{S}_e : B(\Phi_e(\mathcal{I}))_l = 1, \forall \mathcal{I} \in \mathcal{I}_e(s)\}$ and $J^{0}_{e,B,l} := \{s \in \mathcal{S}_e : B(\Phi_e(\mathcal{I}))_l = 0, \forall \mathcal{I} \in \mathcal{I}_e(s)\}$. The constraints which implement the first phase of the Log branching scheme are defined as follows:

$$\sum_{\mathbf{v} \in \mathcal{V}^{+}_{e,B,l}} \lambda_{\mathbf{v}} \le x_{e,l},\ \forall e \in \{1,\dots,n\},\ l \in \{1,\dots,\lceil \log_2(|\mathcal{I}_e|) \rceil\} \tag{42a}$$

$$\sum_{\mathbf{v} \in \mathcal{V}^{0}_{e,B,l}} \lambda_{\mathbf{v}} \le x_{e,l},\ \forall e \in \{1,\dots,n\},\ l \in \{1,\dots,\lceil \log_2(|\mathcal{I}_e|) \rceil\} \tag{42b}$$

$$x_{e,l} \in \{0,1\},\ \forall e \in \{1,\dots,n\},\ l \in \{1,\dots,\lceil \log_2(|\mathcal{I}_e|) \rceil\} \tag{42c}$$

where $\mathcal{V}^{+}_{e,B,l} := \{\mathbf{v} \in \mathcal{V}(\mathcal{P}) : \mathbf{v}_e \in J^{+}_{e,B,l}\}$ and $\mathcal{V}^{0}_{e,B,l} := \{\mathbf{v} \in \mathcal{V}(\mathcal{P}) : \mathbf{v}_e \in J^{0}_{e,B,l}\}$. The sets $\mathcal{V}^{+}_{e,B,l}$ and $\mathcal{V}^{0}_{e,B,l}$ create the partitioning $\mathcal{P}$ in each coordinate e of the domain, and the intersection of the partitioning in all coordinates will constrain the domain to a single active hypercube.

The second phase selects a simplex of the hypercube obtained in phase one using the sets $\mathcal{L}_{r,s} = \{\mathbf{v} \in \mathcal{V}(\mathcal{P}) : \mathbf{v}_r \text{ is even and} \mathbf{v}_s \text{ is odd}\}$ and $\mathcal{R}_{r,s} = \{\mathbf{v} \in \mathcal{V}(\mathcal{P}) : \mathbf{v}_r \text{ is odd and} \mathbf{v}_s \text{ is even}\}, \forall r,s \in D = \{1,\dots,d\}$, such that $r < s$. The second branching phase can be implemented in Log with the following constraints:

$$\sum_{\mathbf{v} \in \mathcal{L}_{r,s}} \lambda_{\mathbf{v}} \le y_{r,s},\ \forall (r,s) \in \Gamma \tag{43a}$$

$$\sum_{\mathbf{v} \in \mathcal{R}_{r,s}} \lambda_{\mathbf{v}} \le 1 - y_{r,s},\ \forall (r,s) \in \Gamma \tag{43b}$$

$$y_{r,s} \in \{0,1\},\ \forall (r,s) \in \Gamma \tag{43c}$$

where $\Gamma := \{(r,s) \in \{1,\dots,d\} \times \{1,\dots,d\} : r < s\}$ is the set of index pairs indicating which weighting variables are to be disabled in the convex combination. The sets $\mathcal{L}_{r,s} := \{\mathbf{v} \in \mathcal{V} : \mathbf{v}_r \text{ is even and} \mathbf{v}_s \text{ is odd}\}$ and $\mathcal{R}_{r,s} := \{\mathbf{v} \in \mathcal{V} : \mathbf{v}_r \text{ is odd and} \mathbf{v}_s \text{ is even}\}$ create the partitioning responsible for scoping the active polytope to a simplex within the selected hypercube in phase 1.

The Log PWL approximation of $G^{r,t}_p$ defined in Eq. (15) is formulated as follows:

$$\widetilde{G_p}^{r,t} = \sum_{k \in \mathcal{K}_G} \eta^{r,t}_k \cdot f^{r,k}_{G} \tag{44a}$$

$$N^{r,t}_p = \sum_{k \in \mathcal{K}_G} \eta^{r,t}_k \cdot N^{r,k}_p \tag{44b}$$

$$\sum_{k \in \mathcal{K}_G} \eta^{r,t}_k = 1,\ \eta^{r,t}_k \ge 0 \tag{44c}$$

$$\sum_{k \in \mathcal{K}^{+}_{G,l}} \eta^{r,t}_k \le x^{Gp}_l,\ l \in \{1,\dots,\lceil \log_2(|\mathcal{I}_{Gp}|) \rceil\} \tag{44d}$$

$$\sum_{k \in \mathcal{K}^{0}_{G,l}} \eta^{r,t}_k \le 1 - x^{Gp}_l,\ l \in \{1,\dots,\lceil \log_2(|\mathcal{I}_{Gp}|) \rceil\} \tag{44e}$$

$$x^{Gp}_l \in \{0,1\},\ l \in \{1,\dots,\lceil \log_2(|\mathcal{I}_{Gp}|) \rceil\} \tag{44f}$$

where $\mathcal{K}^{+}_{G,l}$ and $\mathcal{K}^{0}_{G,l}$ are the first-phase branching sets for the set of ordered breakpoints $\mathcal{K}_G$, and $\mathcal{I}_{Gp}$ is the set of intervals containing the ordered pair of breakpoints in $\mathcal{K}^{0}_{G,l}$. These sets are defined analogously to the sets used in the first branching phase formulated with Eqs. (42a), (42b), and (44f).

Next, we formulate an approximation using Log for the function $f_W(N^r_p(t))$ defined in Eq. (16) with the following set of equations:

$$\widetilde{W_p}^{r,t} = \sum_{k \in \mathcal{K}_W} \sigma^{r,t}_k \cdot f^{r,k}_{W} \tag{45}$$

$$N^{r,t}_p = \sum_{k \in \mathcal{K}_W} \sigma^{r,t}_k \cdot N^{r,k}_p \tag{46}$$

$$\sum_{k \in \mathcal{K}_W} \sigma^{r,t}_k = 1,\ \sigma^{r,t}_k \ge 0 \tag{47}$$

$$\sum_{k \in \mathcal{K}^{+}_{W,l}} \sigma^{r,t}_k \le x^{Wp}_l,\ l \in \{1,\dots,\lceil \log_2(|\mathcal{I}_{Wp}|) \rceil\} \tag{48}$$

$$\sum_{k \in \mathcal{K}^{0}_{W,l}} \sigma^{r,t}_k \le 1 - x^{Wp}_l,\ l \in \{1,\dots,\lceil \log_2(|\mathcal{I}_{Wp}|) \rceil\} \tag{49}$$

$$x^{Wp}_l \in \{0,1\},\ l \in \{1,\dots,\lceil \log_2(|\mathcal{I}_{Wp}|) \rceil\} \tag{50}$$

with $\mathcal{K}^{+}_{W,l}$ and $\mathcal{K}^{0}_{W,l}$ being the first-phase branching sets, and $\mathcal{I}_{Wp}$ the set of intervals containing the ordered pair of breakpoints of $\mathcal{K}_W$. Notice that the Log approximations of both (15) and (16) use only the first branching phase. This is because the function domains are unidimensional, thus the active polytopes will be an interval belonging to $\mathcal{I}_{Gp}$ and $\mathcal{I}_{Wp}$.

The last function to be approximated with Log is the production potential f_q. As this function is present in a nonlinear multiplication of variables in Eq. (10), we approximate these relations with a two-dimensional PWL approximation using Log as follows:

$$q^{r,t}_{o,pot} = \sum_{j \in \mathcal{K}_F} \sum_{k \in \mathcal{K}_Q} \Omega^{r}_{j,k,t} \cdot f^{r}_{q,k} \tag{51}$$

$$fn^{r,t} = \sum_{j \in \mathcal{K}_F} \sum_{k \in \mathcal{K}_Q} \Omega^{r}_{j,k,t} \cdot fn^{r}_{j} \tag{52}$$

$$\sum_{j \in \mathcal{K}^{+}_{F,l}} \sum_{k \in \mathcal{K}_Q} \Omega^{r}_{j,k,t} \le x^{F,r}_{t,l},\ l \in \{1,\dots,\lceil \log_2(|\mathcal{I}_F|) \rceil\} \tag{53}$$

$$\sum_{j \in \mathcal{K}^{0}_{F,l}} \sum_{k \in \mathcal{K}_Q} \Omega^{r}_{j,k,t} \le 1 - x^{F,r}_{t,l},\ l \in \{1,\dots,\lceil \log_2(|\mathcal{I}_F|) \rceil\} \tag{54}$$

$$x^{F,r}_{t,l} \in \{0,1\},\ l \in \{1,\dots,\lceil \log_2(|\mathcal{I}_F|) \rceil\} \tag{55}$$

$$\sum_{j \in \mathcal{K}_F} \sum_{k \in \mathcal{K}^{+}_{Q,l}} \Omega^{r}_{j,k,t} \le x^{Q,r}_{t,l},\ l \in \{1,\dots,\lceil \log_2(|\mathcal{I}_Q|) \rceil\} \tag{56}$$

$$\sum_{j \in \mathcal{K}_F} \sum_{k \in \mathcal{K}^{0}_{F,l}} \Omega^{r}_{j,k,t} \le 1 - x^{Q,r}_{t,l},\ l \in \{1,\dots,\lceil \log_2(|\mathcal{I}_Q|) \rceil\} \tag{57}$$

$$x^{Q,r}_{t,l} \in \{0,1\},\ l \in \{1,\dots,\lceil \log_2(|\mathcal{I}_Q|) \rceil\} \tag{58}$$

$$\sum_{(j,k) \in \mathcal{L}_{j,k}} \Omega^{r}_{j,k,t} \le y^{r}_{j,k,t},\ \forall (j,k) \in \Gamma^{r}_{t} \tag{59}$$

$$\sum_{(j,k) \in \mathcal{R}_{j,k}} \Omega^{r}_{j,k,t} \le 1 - y^{r}_{j,k,t},\ \forall (j,k) \in \Gamma^{r}_{t} \tag{60}$$

$$y^r_{j,k,t} \in \{0,1\}, \forall (j,k) \in \Gamma^r_t \quad (61)$$

where Eqs. (53)–(55) implement the first branching phase of the Log for the set $\mathcal{K}_F$, whereas Eqs. (56)–(58) are responsible for the first phase branching for set $\mathcal{K}_Q$. The second phase branching scheme is implemented by Eqs. (59)–(61). Notice that the sets $\mathcal{K}^+_{F,l}$, $\mathcal{K}^0_{F,l}$, $\mathcal{K}^+_{Q,l}$, $\mathcal{K}^0_{F,l}$, $\mathcal{I}_F$, and $\mathcal{I}_Q$ are defined analogously to the definitions of the first phase branching in Eqs. (42a)–(42c). The sets $\mathcal{L}_{j,k}$, $\mathcal{R}_{j,k}$, and Γ^r_t on its turn are defined analogously to the definitions used in the second phase branching scheme denoted by Eqs. (43a)–(43c).

Appendix C. Cost model

The cost model in Eq. (20) and Eq. (21) might further be expressed as:

$$CAPEX^{f,t}_{Drilling} = \alpha_1 \times (N^{f,t}_w - N^{f,t-1}_w) + \beta_1, \forall t \in \mathcal{T} \quad (62)$$

$$CAPEX^{f,t}_{Subsea} = \frac{\alpha_2 \times L^f_{pipe} + \alpha_3 \times N^f_{joint} + \beta_2}{N_D}, \forall t \in \{1, \cdots, N_D\} \quad (63)$$

$$CAPEX^{f,t}_{Topside} = \frac{\alpha_4 \times q^{max}_o + \alpha_5 \times q^{max}_g + \alpha_6 \times q^{max}_w + \beta_3}{N_D}, \forall t \in \{1, \cdots, N_D\} \quad (64)$$

$$OPEX^{f,t}_{rate} = \alpha_7 \times q^{f,t}_o + \alpha_8 \times q^{f,t}_g + \alpha_9 \times q^{f,t}_w + \beta_4, \forall t \in \mathcal{T} \quad (65)$$

$$OPEX^{f,t}_{Nonrate} = \alpha_{10} \times N^{f,t}_w + \alpha_{11} \times L^f_{pipe} + \alpha_{12} \times N^f_{joint} + \beta_5, \forall t \in \mathcal{T} \quad (66)$$

which L^f_{pipe} and N^f_{joint} represent the length of pipeline and the number of subsea joint units (manifold, flowline joints, or subsea pumps). The N_D is the total number of years in which the initial CAPEX is distributed. The coefficients of $\alpha_1 - \alpha_{12}$ and $\beta_1 - \beta_5$ are the value used in the cost proxy model.

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