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A mixed-integer non-linear problem formulation for miscible WAG injection

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ABSTRACT

The paper presents a formulation to evaluate optimal injection scenarios or production strategies in an oil reservoir. The decisions variables involved in such strategy formulations are a mix of both continuous and integer nature variables. The time-line of the operation or the recovery strategy addressed in this paper is divided into three action periods: cyclic injection (a single or multiple/alternating cycles), continuous injection, and depletion.

Two reservoir models description used in this study: a pattern sector model with a single producer and single injectors based on the SPE 5th comparative project miscible WAG (Killough and Kossack, 1987), and a multi-well case with 5 producers and 8 injectors with a more complex reservoir geology that is an extension of the SPE 5th comparative project. The study addresses two independent production modes, each with a different set of production constraints, artificial-lift from the start to the end of the timeline and natural-flow from the start to the end of the study period.

For the two simplest injection strategies: continuous gas or continuous water injection, the only control variable is tubing-head pressure in the injection wells. For more complex injection strategies more decision variables are required including tubing-head pressures, injection volume, and time to change the injection strategy. The 8 studied strategies with their relevant decision variables are stated in a case matrix table in the paper. Each of the 8 strategies is studies with either natural flow mode or artificial lift mode.

The objective function is the maximum of a Net Present Value (NPV) formula using revenue with a time escalation sales price, and a simple Operating Expenditures (OPEX) and Capital Expenditure (CAPEX). The optimization function is simple but captures the important trends in comparing oil recovery strategies. The optimization program is run for each strategy stated in the case matrix table, searching for the optimum by varying the continuous decision variables of that particular strategy. To ensure a proper location of the global optimum of each strategy, the optimization search employs several starting values of the continuous variables, with the number of starting values increasing with increased strategy complexity. The starting values are randomly generated. The overall optimum operation strategy is the one with the highest calculated NPV.

The entire optimization study is conducted in a semi-automated manner. A proprietary program runs and manages the integration of the reservoir simulator, the NPV model and the optimizer. This is done automatically for each investigated strategy. The proposed methodology is applicable to any oil reservoir where both surface water and gas injection is available. This work contributes to the literature by establishing a general mixed-integer problem formulation for water and gas injection and providing an efficient heuristic method for solving the problem.

1. Introduction

During the production lifetime of an oil field, reservoir production can potentially be divided into three distinct stages – (1) low cost depletion, (2) higher-cost enhanced oil recovery (EOR) with gas and/or water injection, and (3) a reduced-cost, end-life “tail”-production period. Two well control methods are used in oil production: natural flow and artificial lift. Natural flow is the simplest, least-expensive approach using individual-well choke control. Artificial lift consists of installing additional technology such as gas lift or pumps in a production well to enhance the rate of oil production by lowering the constraining bottom-hole pressure (BHP).

After several years of production, an oil reservoir may not be able to maintain a sufficiently high economic production of oil due

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Nomenclature

d discount factor
D well tubing diameter, m
N total project time step
N_i number of injection wells
N_p number of production wells
r_g gas price, USD/m^3
r_o oil price, USD/S m^3
r_{gi} gas injection cost, USD/m^3
r_w water injection and production cost, USD/S m^3

Abbreviations

CM case matrix
GI gas injection
GAW gas alternating water (multi-cycle injection)
GIV gas injection volume
GOR gas–oil ratio
GW gas–water injection (single-cycle injection)
GWR gas–water ratio
THP-GI tubing-head pressure for gas injection
THP-WI tubing-head pressure for water injection
WG water–gas injection (single-cycle injection)
WI water injection
WAG water alternating gas (multi-cycle injection)
WLR water liquid ratio
WIV water injection volume

to a decrease in reservoir pressure, despite the fact that significant oil reserves remain in the reservoir. When this condition occurs, the reservoir typically enters the secondary recovery stage. Production may be improved by injecting gas and/or water to extract the remaining oil. At the end of secondary recovery, the oil production rate declines again, and a new production strategy may be introduced to increase recovery further.

The water alternating gas (WAG) injection technology was introduced by Caudle and Dyes (1958) in an effort to improve the macroscopic (areal and vertical) sweep efficiency by injecting water and microscopic pore-level sweep efficiency by injecting gas. WAG scenarios have been studied extensively; Daoyong et al. (2000) applied optimization using Genetic Algorithms (GA) in China's Pubei oil field. Kulkarni and Rao (2004) compared the WAG process to the gas injection (GI) process by conducting tertiary mode miscible and immiscible core-floods. The WAG mode of injection proved better than GI when “overall performance” was considered.

Gharbi (2004) tested WAG injection, simultaneous water alternating gas (SWAG) injection, and gas injection at the bottom of the reservoir with water injection at the top of the reservoir. The injectors use horizontal wells and the producers are vertical wells. The simulation results show that to simultaneously inject water at the reservoir top and gas at the reservoir bottom produced a better sweep efficiency and, therefore, the oil recovery was improved. Panda et al. (2009) optimized the Eileen West End Area in Greater Prudhoe Bay, operated by BP, using WAG. The key parameters evaluated were injection volume, injection rate, WAG ratios and WAG sequencing or WAG cycle number.

However, there are still significant areas in WAG optimization to be explored, such as the optimization of WAG by combining WAG with other scenarios. Thus far, WAG has been implemented in several fields on the Norwegian Continental Shelf such as Snorre, Brae South, Statfjord, Brage, Gullfaks and Ekofisk; see also Lien et al. (1998), Jensen et al. (2000), Christensen et al. (2001), Crogh et al. (2002), Awan et al. (2008), and Talukdar and Instefjord (2008).

Mathematical optimization has some merit in long term production optimization. In secondary recovery using water flooding injection, Nævdal et al. (2006), Van Essen et al. (2006), and Saputelli et al. (2009) have applied various optimization methods to improve oil recovery. A comprehensive overview is given in Jansen et al. (2008).

This paper introduces a general formulation for different injection scenarios assuming that surface water and injection gas are available. The mixed-integer problem formulation provides a framework for analyzing alternative production strategies. A solution method for solving this problem is discussed and a heuristic procedure is proposed. Subsequently case example are introduced and used as a means to study the proposed method's capabilities.

2. Problem formulation

The problem formulation includes four steps. First, alternative injection scenarios are discussed before an economic model is introduced based on a relatively general Net Present Value (NPV) calculation. Subsequently, the optimization problem formulation is presented prior to the solution approach.

2.1. Injection scenarios

Knowledge of the heterogeneities of the reservoir itself, including the rock and fluid characteristics, provides a basis for deciding an appropriate injection scenario. The injection scenarios could be parameterized according to the timeline in Fig. 1. Phase 1 may include a single cycle water injection followed by gas injection (WG) or vice versa (GW), or multiple injection cycles termed water alternating gas (WAG) or gas alternating water (GAW). The only difference between the latter two is whether water or gas that starts the first cycle, which for longer cycles may have measurably different performance.

Phase 2 includes either water injection (WI) or gas injection (GI) while the last phase assumes no injection of any fluid. The choice of injection scenario obviously includes many decisions. They include which scenario to choose, the length of Phases 1, 2 and 3, and specific parameters for a given phase such as well pressures, rates and injection volumes. One may therefore observe that several different combinations are possible and each of them include a number of decision variables since a typical case will include several injection wells.

2.2. Economic model

An economic model will be presented next by the use of Net Present Value. J_{NPV}, is defined by Eqs. (1)–(3). Revenue is obtained from gas sales and oil sales. The daily cost of oil extraction is

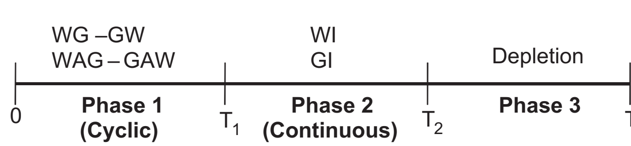

Fig. 1. Possible gas and water injection strategies in three phases: (1) cyclic, (2) continuous and (3) depletion.