

Sensitivity analysis of technical and economic parameters for natural gas management in enhanced oil recovery projects

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Abstract

Since oil reservoirs have different properties, each reservoir performs differently during enhanced oil recovery (EOR) processes. In some cases, water injection is the most effective method, while in others, gas injection or other methods will result in better performance. Most reservoir simulations assume that the amount of injection fluid is sufficient. However, in practice, the amount of available gas is enough to supply only a limited number of reservoirs. This study presents a comprehensive model which examines oil reservoirs in concert based on mathematical programming, and considers the competition between them. This model entails sensitive analysis of gas injection projects in order to determine effective factors (technical and economic parameters) on decision-making relating to gas injection projects. Results show that technical and economic parameters such as oil price, gas quality and gas price variation have a marked effect on economic results and may lead to favorable economic conditions. Variations were made in the model regarding changes in interest rate, number of wells and injection pressure, but these variations did not lead to unfavorable economic conditions; in other words, changes in these factors had no significant effect on stability.

Keywords: enhanced oil recovery; comprehensive model; gas injection; reservoir simulation; economical sensitivity analysis

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1 INTRODUCTION

Fossil fuels such as oil and natural gas are used in a variety of energy systems [1–4]. Due to the limited availability of these fuels, it is necessary to maximize recovery from each reservoir. Oil recovery makes it possible to achieve higher production from the resources available. Oil recovery operations have traditionally been subdivided into three stages: primary, secondary and tertiary [5]. Secondary recovery, the second stage of

operations, is typically implemented after primary production has declined [6].

In conventional oil recovery projects, the decline in primary production to an uneconomic level has led to the development of various schemes to improve oil recovery efficiency before the abandonment of a reservoir. The term “enhanced oil recovery” (EOR) principally refers to the recovery of oil by any method beyond the primary stage of production. It is defined as the production of crude oil from reservoir, through processes taken

to increase the primary reservoir drive [7, 8]. These processes may include pressure maintenance, injection of displacing fluids or other methods, such as thermal techniques. Therefore, by definition, EOR techniques include all approaches that are applied to increase the cumulative oil produced (oil recovery) as much as possible [9].

EOR can be divided into two major types of technique: thermal and non-thermal recoveries. Non-thermal recovery can be split into: water flooding, gas injection and chemical processes. There are two types of gas injection including miscible and immiscible. Contrarily, in the cases of using immiscible gas injection, the flooding is performed at lower pressure of MMP. This low pressure is applied in order to keep the pressure of reservoir for preventing the production cut-off and improve the production rate [10]. On the other hand, in immiscible gas injection, flooding by gas is conducted below MMP. This low pressure injection of gas is utilized to maintain reservoir pressure to prevent production cut-off, and thereby increase the rate of production [9].

The use of light crude, in conjunction with relatively high reservoir temperature and relatively low reservoir pressure, suggests that immiscible gas injection is the most appropriate EOR process. Injection of a fluid such as water or gas under particular conditions has become the most common method for recovering additional oil after primary production. These secondary recovery techniques generally recover 5%–20% of the remaining oil after primary production [11].

Since oil reservoirs have different properties, each reservoir performs differently during EOR processes. In some reservoirs, water injection is the most effective method, while in others, gas injection or other methods will result in a better performance [12, 13]. To determine the most appropriate EOR method, in most cases a reservoir is simulated using simulation software such as ECLIPSE and a range of EOR approaches (including miscible and immiscible gas injection and water injection) are investigated under various scenarios [14, 15]. In these scenarios, factors such as injection fluid flow rate, the number of injection or production wells, injection or production bottom hole pressure and injection fluid properties are examined in different configurations. Each of these conditions has different production efficiency. After examining different scenarios for each EOR method, it is possible to compare them in order to select the best method [9]. However, technical comparisons alone cannot determine the best EOR method. While one method may have a higher recovery factor than the others, it may also have higher costs; as a result, that method may be less profitable than other methods, and may not be the best choice overall [6].

As mentioned above, the factors affecting oil recovery are: injection fluid flow rate; produced oil flow rate; the number of injection or production wells; the coordinates of injection and production wells; bottom hole pressure in production and injection wells and injection fluid properties [9]. Generally, during the implementation of EOR projects, parameters such as produced oil flow rate and bottom hole pressure in production and injection wells are adjustable. In addition, the number and

coordinates of production and injection wells will not cause any significant problem; in other words, these factors will not limit the implementation of the project. A significant parameter affecting oil recovery, however, is the injection fluid flow rate, which may cause some constraints [16–18]. This parameter is therefore the focus of investigation in the present study.

In simulating a reservoir and investigating different scenarios, it is usually assumed that the amount of injection fluid (water or gas) is sufficient [9]. However, the problem with this method is that in certain areas (such as Iran), the amount of available injection gas is enough to supply only a limited number of reservoirs. This raises the question of how to distribute the available gas between reservoirs in order to maximize the amount of oil recovered.

In order to achieve the most appropriate condition, reservoir simulations typically examine a single reservoir in isolation; when there are multiple reservoirs, and the amount of injection gas is insufficient, such models lose their efficiency, since they examine each reservoir without considering the others. There is therefore a need for a comprehensive model that examines all reservoirs collectively. The comprehensive model proposed in this study examines oil reservoirs in concert based on mathematical programming, and considers the competition between them. This allows us to determine how to distribute the available gas between reservoirs in order to maximize the amount of oil produced.

2 MODEL DESCRIPTION

In order to analyze this issue, a mathematical programming method is used, which is an optimal model for this investigation. The following definitions apply to this model:

Mathematical programming: a set of quantitative models and techniques associated with optimal resource allocation in order to achieve a desired goal [19].

Model: a simplified form of the real world. In this study, gas transmission from the source and its injection into oil reservoirs is modeled, taking into account both technical and economic factors [9]. Simulation of each reservoir in this project is carried out using the ECLIPSE simulator.

Modeling: the conceptualization of a problem in mathematical terms, such that the relation between variables is expressed in a simple form using a set of mathematical equations [19].

Mathematical model: a model typically written in mathematical language that expresses the relations between phenomena using mathematical symbols. Such models sometimes indicate a fact with high approximation and low error, and sometimes explain facts relatively. The mathematical model used in the present study has been developed by applying mass balance equations and limited available resources.

Objective function: a mathematical function consisting of decision variables, which indicate the goal of the model. This function indicates the priority of the decision maker, such as maximizing earnings (profit) or minimizing costs. In the present

study, the objective function is shown to be maximizing earnings [20].

Decision variables: quantities for which the decision maker seeks to find an optimal number or value. In the present study, the decision variables are the amount of gas transmitted from each gas source to each oil reservoir and the total injection gas allocated to each reservoir [20, 21].

Limitations: a set of equations or non-equations consisting of decision variables which explain the limitations of a model in order to achieve the goals of a model [20, 21].

A noteworthy limitation of the model used in this study is that relating to the maximum exploitable gas flow from each gas source. This is influenced by exploitation facilities, as well as the maximum amount of gas allocated to gas injection projects, since the gas produced from gas reservoirs is not only used for injection in oil reservoirs, but also has other applications in homes, commerce, power plants, transportation and so on. As a result, only the exiting gas is allocated to gas injection projects.

A related limitation on the maximum injection gas flow is the limited permeability of each reservoir.

A further limitation relates to the efficiency of oil production. The oil recovery factor increases along with the rate of injected gas up to a specific point, after which the oil recovery factor cannot be increased further by increasing the rate of gas injection. This point is determined using reservoir simulation.

Related limitation of financial resources: primary investment.

The optimal model for the method used in this study is presented using the GAMS optimization software.

The mathematical structure of the method using mathematical programming: As shown in Figure 1, this study considers a system of two gas sources and four oil reservoirs. The properties of the oil reservoirs and the distance of the gas sources from the oil reservoirs are presented in Tables 1 and 2. It is supposed that these reservoirs are nominated for gas

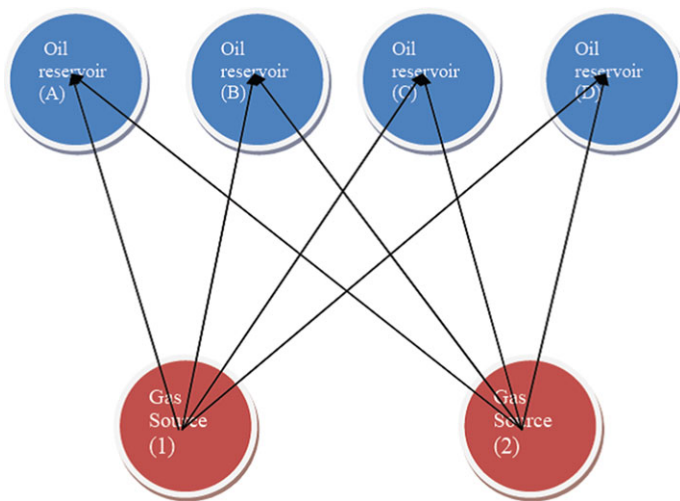


Figure 1. Schematic of oil reservoirs and gas sources.

injection but that there is not enough gas to supply all of them. The goal is therefore to determine the way in which the available gas should be distributed among the reservoirs in order to maximize the profit gained from gas injection.

For optimal analysis of this question, the factors related to income and system costs are presented as an objective function. The equation related to the objective function and the economic analysis is as follows:

$$\text{Object function} = \sum_{j=1}^4 (P_j - C_j) \quad (1)$$

Since there are four oil reservoirs, four incomes and four system costs (one for each reservoir) should be considered in the objective function. The income of each reservoir is computed separately as follows:

$$P_j = D_j * \text{IOIP} * (X_{inj,j} - X_{nat,j}) \quad (2)$$

where

P_j is the income from the total oil production of the j th oil reservoir (in USD);

C_j is the total cost of gas injection for the j th oil reservoir (in USD);

D_j is the price of each oil barrel for the j th reservoir (in USD);

IOIP is the amount of original oil in place for the j th reservoir (in STB);

$X_{inj,j}$ is the oil recovery factor for the j th reservoir with gas injection (dimensionless);

$X_{nat,j}$ is the oil recovery factor for the j th reservoir without gas injection (natural production, dimensionless).

The oil recovery factor for the j th reservoir with gas injection is estimated using a reservoir simulator (ECLIPSE software). The simulation considers the fact that different reservoirs have different functions, and that both the volume of residual oil and the price of oil differed in each reservoir.

The gained profit from this project depends on the costs of gas injection. In addition to income, overall costs include fixed costs and variable costs. Costs such as the purchase of equipment, pipelines and the drilling of required wells are fixed values and are not dependent on the injection gas rate, whereas costs such as those of the electricity used by pressure boost stations and the amount of gas consumed are dependent on the rate of gas injection; these costs are therefore stated as a variable. The fixed cost for each oil reservoir is as follows:

$$C_t = CC_{1j} + CC_{2j} + CC_{3j} \quad (3)$$

where

CC_t is the constant total cost for the j th reservoir;

CC_{1j} is the cost of the excavation and completion of the required wells for the j th reservoir;

CC_{2j} is the cost of the purchase and initiation of the required compressors for the j th reservoir;

Table 1. Properties of oil reservoirs.

| Reservoir | Matrix porosity % | Matrix permeability (md) | Fracture porosity % | Fracture permeability (md) | Initial oil in place (MMstb) | API | Initial reservoir pressure (psi) |
|-----------|-------------------|--------------------------|---------------------|----------------------------|------------------------------|-----|----------------------------------|
| (A) | 10 | 50 | | | 202.807 | 43 | 4100 |
| (B) | 20 | 100 | | | 405.78 | 43 | 4100 |
| (C) | 10 | 50 | 0.5 | 100 | 241.93 | 43 | 4100 |
| (D) | 15 | 20 | 0.5 | 50 | 343.2 | 43 | 4100 |

Table 2. Distance between oil reservoirs and gas sources (km).

| | Reservoir (A) | Reservoir (B) | Reservoir (C) | Reservoir (D) |
|----------------|---------------|---------------|---------------|---------------|
| Gas source (1) | 100 | 100 | 200 | 200 |
| Gas source (2) | 50 | 50 | 150 | 150 |

CC_{3j} is the cost of pipeline construction from the j th gas source to the j th oil reservoir.

The variable costs for each reservoir are as follows:

$$VC_t: VC_{1j} + VC_{2j}$$

where VC_{1j} is the cost of consumed gas for the j th reservoir; and VC_{2j} is the cost of consumed electricity in the pressure boost stations for the j th reservoir.

This portion of costs (VC_t) is calculated on an annual basis and should be correlated. It is necessary to divide by an annual coefficient (Green and Perry 2008). The annualized factor is as follows:

$$AF = \frac{i(1+i)^N}{(1+i)^N - 1} \quad (4)$$

where i is the interest rate and N is the useful lifetime of the gas injection project.

The variable n , defined for each oil reservoir in the object function, represents the oil recovery factor with or without gas injection. To determine this variable, each reservoir must be simulated and the oil recovery factor must be characterized. The oil recovery factor (without gas injection) for the simulation conducted for this study is presented in Table 1. It is also necessary to compute the oil recovery factor with gas injection for different injection gas flow rates in the simulation; the equation is as follows:

$$X_{inj,j} = f(Q_j) \quad (5)$$

where Q_j is the injection gas flow rate (MMscf/day).

In the above equation, the oil recovery factor is computed as an equation of the injected gas amount, and the equation is then entered into the general model.

3 RESULTS AND DISCUSSION

As shown in Figure 1, this study considered two gas sources and four oil reservoirs. It was supposed that there was not enough natural gas for injection into all oil reservoirs; therefore, gas was a limited resource, and its allocation to the oil reservoirs was important. The modeling of gas sources and oil reservoirs was conducted based on technical and economic factors.

The model was solved using GAMS software. The gas allocated to each oil reservoir and its economic results are given in Table 3.

3.1 Sensitivity analysis for the comprehensive model

The remainder of this paper focuses on a sensitivity analysis for the presented model. Some of the parameters (such as natural gas flow rate or economic resources) may change in future years. This sensitivity analysis is necessary in order to find the most important parameter.

The model could be used to determine optimal conditions according to the dominant economic conditions in the country, but the effects on this model of certain important parameters are not examined, and this possibility is not investigated here. The objective function consists of two parts that have an impact on gas allocation to the reservoirs, and which are examined separately here: (i) project income; and (ii) project cost.

3.1.1 Sensitivity analysis for effective factors on projected income of the gas injection project

As concerns project income, the effective factors are as follows: oil recovery factor; initial oil in place; and oil price. The initial oil in place was constant for each reservoir and was not subject to change. This parameter must be determined exactly, however, as in case of error the allocation of gas to the oil reservoir would not be optimal. The oil recovery factor for each reservoir was determined and presented as an equation. Given the direct relation between project income and oil recovery factor, an accurate estimation of this parameter leads to better gas allocation. We can therefore conclude that accurate estimation of rock and reservoir fluid, fluid behavior in the well and the diffusivity solving method have a direct effect on gas allocation to oil reservoir in this comprehensive model. An especially

important parameter for determining project income is oil price. Oil price change is divided to two elements: (i) oil price change due to energy price reduction; and (ii) reservoir oil price change due to impurity of the injected gas, leading to a reduction in quality. Various scenarios were considered for examining the effect of oil price change on gas allocation across all reservoirs, the results of which are shown in Table 4.

As shown in Table 4, various scenarios were considered in which the oil price ranged from 100 to 50 USD, and in which final results obtained from integration were determined using the comprehensive model. As can be seen, when the oil price approached 100 USD, payback time was 3.03 years, which is acceptable in engineering projects; when the oil price was reduced to 80 USD, payback increased to 5.69 years, which is similarly acceptable; with the oil price reduced to 70 USD, however, payback was 10.13 years, which is not economical.

A reduction in oil price is related to a reduction in oil quality due to poor gas injection (as is the case, for example, with natural gas including H₂S). Various scenarios were considered to examine the effects of oil price change, in which oil price was reduced in one reservoir with no corresponding price changes in other reservoirs. The results of these scenarios are presented in Table 5.

As shown in Table 5, in the first scenario, the oil price for all reservoirs was 100 USD, while in each of the other scenarios, the oil price for one reservoir was reduced to 70 USD, with

effects on the overall model as shown. The model results suggest that oil price changes for reservoirs (A) and (B) (scenarios (2) and (5)) had little impact on payback, while price changes for the other reservoirs had a profound effect (equal to 50%). Examining changes in oil quality is a very expensive process; if reservoirs were classified based on this model, part of that expense would be reduced. In this respect, reservoirs (C) and (B) reservoirs should be inspected for quality changes and other reservoirs should be prioritized.

3.1.2 Sensitivity analysis for effective factors on projected costs of the gas injection project

The previous section outlined the effective factors on the income gained from the gas injection project. This section, meanwhile, focuses on factors affecting the cost of such projects, the most influential being the price of the gas injected into the reservoir. Various scenarios were considered in which the price of natural gas was changed and the gas was then allocated to the oil reservoirs. The results are presented in Table 6. The gas price in Iran is very low in comparison to consumer countries. For example, the selling price of Iranian gas to Turkey is 13 500 USD/MMscf, but this price includes the cost of pressure reinforcement stations and pipelines; if these costs were to be calculated separately, the selling price in Iran would be 3 USD/MMscf.

Table 3. Economic results of gas injection after reservoir integration.

| Reservoir | Station cost (USD) | Well cost (USD) | Pipe cost (USD) | Fuel cost (USD/year) | Gas cost (USD/year) | Production (USD/year) | Total annual cost (USD/year) |
|-----------|-----------------------|-------------------|----------------------|-----------------------|----------------------|-----------------------|------------------------------|
| (A) | 11.4751×10^8 | 1.5×10^8 | 4.5000×10^7 | 4.6054×10^6 | 2.7363×10^8 | 4.7548×10^8 | 6.9152×10^8 |
| (B) | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (C) | 18.2067×10^8 | 6.0×10^7 | 4.5000×10^7 | 7.307×10^6 | 3.7979×10^8 | 2.4469×10^8 | 9.6384×10^8 |
| (D) | 3.0878×10^8 | 6.0×10^7 | 12.000×10^7 | 12.3923×10^6 | 4.3737×10^8 | 2.1080×10^9 | 1.2207×10^9 |

Table 4. Economic results of sensitivity analysis of oil price (due to energy price reduction).

| Scenario | Oil price (USD/stb) | Capital cost (USD) | Total annual cost (USD/year) | Income (USD/year) | Benefit (USD/year) | Payback (year) |
|----------|---------------------|----------------------|------------------------------|----------------------|----------------------|----------------|
| (1) | 100 | 6.5369×10^9 | 2.8762×10^9 | 5.0304×10^9 | 2.1542×10^9 | 3.03 |
| (2) | 90 | 6.5365×10^9 | 2.8761×10^9 | 4.5273×10^9 | 1.6512×10^9 | 3.96 |
| (3) | 80 | 6.5359×10^9 | 2.8761×10^9 | 4.0242×10^9 | 1.1481×10^9 | 5.69 |
| (4) | 70 | 6.5353×10^9 | 2.8760×10^9 | 3.5211×10^9 | 6.4512×10^8 | 10.13 |
| (5) | 60 | 6.5344×10^9 | 2.8759×10^9 | 3.0180×10^9 | 1.4211×10^8 | 45.98 |
| (6) | 50 | 6.5333×10^9 | 2.8758×10^9 | 2.5149×10^9 | -3.609×10^8 | |

Table 5. Economic results of sensitivity analysis for oil price (due to oil quality).

| Scenario | Reservoir (A) oil price (USD/stb) | Reservoir (C) oil price (USD/stb) | Reservoir (D) oil price (USD/stb) | Reservoir (B) oil price (USD/stb) | Capital cost (USD) | Benefit (USD/year) | Payback (year) |
|----------|-----------------------------------|-----------------------------------|-----------------------------------|-----------------------------------|----------------------|----------------------|----------------|
| (1) | 100 | 100 | 100 | 100 | 6.5369×10^9 | 2.1542×10^9 | 3.03 |
| (2) | 70 | 100 | 100 | 100 | 6.7751×10^9 | 2.1891×10^9 | 3.09 |
| (3) | 100 | 70 | 100 | 100 | 6.5178×10^9 | 1.4249×10^9 | 4.57 |
| (4) | 100 | 100 | 70 | 100 | 6.5369×10^9 | 1.5218×10^9 | 4.4 |
| (5) | 100 | 100 | 100 | 70 | 6.5369×10^9 | 2.1542×10^9 | 3.03 |

As shown in Table 6, gas allocation to oil reservoirs was determined for gas prices ranging from 1000 USD to 6000 USD/MMscf. The results suggest that gas price has a significant effect on economic performance, and that an increase in gas price increases payback. The results also suggest that a gas price increase to 4000 USD/MMscf improves the profitability of the gas injection project, but if the price exceeds 6000 USD/MMscf, the project would show an annual loss; in other words, the total annual cost would be greater than the project income. A portion of the gas required for injection projects is consumed in the turbo compressor in order to increase the injection gas pressure, with the remainder entering the reservoir. For this reason, these two quantities should be examined individually, because the consumption of gas in the turbo compressor is irreversible, with the gas disappearing after burning, while the gas injected into the reservoir is able to be reused. Particularly useful in this respect is a parameter termed the ratio of injected gas value. The ratio of injected gas value refers to the value of the portion of the injected gas that could be reused in the future in relation to the value of the current quantity of gas. For example, a ratio of injected gas value of 0.3 means that the reusable portion of the injected gas has a value of 0.3 of that of the current quantity of gas. In this study, various scenarios were considered in which the ratio of injected gas value was changed after optimal gas allocation using the comprehensive model. The economic results are presented in Table 7.

Table 6. Economic results of sensitivity analysis for gas price.

| Scenario | Natural gas price (USD/MMscf) | Capital cost (USD) | Total annual cost (USD/year) | Income (USD/year) | benefit (USD/year) | Payback (year) |
|----------|-------------------------------|----------------------|------------------------------|----------------------|----------------------|----------------|
| (1) | 1000 | 6.5371×10^9 | 1.4190×10^9 | 5.0304×10^9 | 3.6114×10^9 | 1.81 |
| (2) | 2000 | 6.5370×10^9 | 2.1476×10^9 | 5.0304×10^9 | 2.8828×10^9 | 2.27 |
| (3) | 3000 | 6.5369×10^9 | 2.8767×10^9 | 5.0304×10^9 | 2.1542×10^9 | 3.03 |
| (4) | 4000 | 6.5368×10^9 | 3.6048×10^9 | 5.0304×10^9 | 1.4256×10^9 | 4.59 |
| (5) | 5000 | 6.5367×10^9 | 4.3334×10^9 | 5.0304×10^9 | 6.9703×10^8 | 9.38 |
| (6) | 6000 | 6.5366×10^9 | 5.0625×10^9 | 5.0304×10^9 | -3.156×10^7 | |

Table 7. Economic results of sensitivity analysis for ratio of injected gas value (all reservoirs).

| Scenario | Ratio of injected gas value | Capital cost total (USD) | Total annual cost (USD/year) | Income total (USD/year) | Benefit (USD/year) | Payback (year) |
|----------|-----------------------------|--------------------------|------------------------------|-------------------------|----------------------|----------------|
| (1) | 0.0 | 6.5369×10^9 | 2.8767×10^9 | 5.0304×10^9 | 2.1542×10^9 | 3.03 |
| (2) | 0.1 | 6.5369×10^9 | 2.6572×10^9 | 5.0304×10^9 | 2.3732×10^9 | 2.75 |
| (3) | 0.2 | 6.5369×10^9 | 2.4382×10^9 | 5.0304×10^9 | 2.5922×10^9 | 2.52 |
| (4) | 0.3 | 6.5369×10^9 | 2.2192×10^9 | 5.0304×10^9 | 2.8112×10^9 | 2.33 |
| (5) | 0.4 | 6.5369×10^9 | 2.0002×10^9 | 5.0304×10^9 | 3.0302×10^9 | 2.16 |
| (6) | 0.5 | 6.5369×10^9 | 1.7812×10^9 | 5.0304×10^9 | 3.2492×10^9 | 2.01 |

Table 8. Economic results of sensitivity analysis for ratio of injected gas value (each reservoir).

| Scenario | Gas value ratio for reservoir (A) | Gas value ratio for reservoir (C) | Gas value ratio for reservoir (D) | Gas value ratio for reservoir (B) | Capital cost (USD) | Benefit (USD/year) | Payback (year) |
|----------|-----------------------------------|-----------------------------------|-----------------------------------|-----------------------------------|----------------------|----------------------|----------------|
| (1) | 0 | 0 | 0 | 0 | 6.5369×10^9 | 2.1070×10^9 | 3.03 |
| (2) | 0.5 | 0 | 0 | 0 | 6.5178×10^9 | 2.4374×10^9 | 2.67 |
| (3) | 0 | 0.5 | 0 | 0 | 6.5597×10^9 | 2.5411×10^9 | 2.58 |
| (4) | 0 | 0 | 0.5 | 0 | 6.5369×10^9 | 2.5922×10^9 | 2.52 |
| (5) | 0 | 0 | 0 | 0.5 | 6.7933×10^9 | 2.4750×10^9 | 2.74 |

As shown in Table 7, ratios of injected gas value ranging from 0 to 0.5 were considered. The economic results suggest that this parameter is an effective factor on economic performance: when the ratio increases from 0 to 0.5, the profitability of the project changes to the extent that payback falls from 3.03 to 2.01. Given the high volume of investment in a project of this sort, this difference is significant. Also, relevant is the fact that different reservoirs have different properties; the ratio of injected gas value is therefore different for each reservoir.

An additional feature of this comprehensive model is that when the ratio of injected gas value is considered for a single reservoir, economic variations for the gas injection project can be calculated. For this purpose, various scenarios were considered in which the ratio of injected gas value was given a fixed value for one reservoir and set at zero for the remaining reservoirs. The economic results of these scenarios are presented in Table 8.

As shown in Table 8, in the first scenario the ratio of injected gas value for all reservoirs is zero, while in the other scenarios 2 to 6 this parameter is changed for one reservoir each time. The gained profit of the gas injection project is increased. The results therefore show that the effect of the ratio of injected gas value for specific reservoirs is observable. The ratio of injected gas value is important for all four reservoirs in this model, but its effect on reservoir (C) is more pronounced

than its effect on the other reservoirs, with payback falling further with the change in the ratio of injected gas value for this reservoir than with the others. This factor would become more important in situations in which technical and economic reasons prevent determination of the ratio of injected gas value for all reservoirs. By using this model, reservoirs could be classified and prioritized, and the ratio of injected gas value for the higher priority reservoirs could be determined first.

3.1.3 Flow rate sensitivity analysis for amount of produced gas

The injection fluid used in this model is natural gas, which is produced from gas reservoirs or rises to the earth's surface with produced oil, separated by two or three phase separators. The method of gas production is not investigated here; any oil or gas reservoir from which gas is produced is considered a gas source. It should also be noted that, as mentioned above, natural gas is used not only for injection into oil reservoirs, but also has other applications, such as in power plant or domestic consumption and in the petrochemical industry, among others. As a result, only a portion of available natural gas is allocated to oil reservoir injection. It is therefore worth analyzing the effect of a change in the amount of available natural gas on the economic performance of the gas injection project. For this purpose, various scenarios were considered in which the flow rate of produced gas was changed. The results are presented in Table 9.

As shown in the table, the results of the model suggest that variations in the gas flow rate could have a significant effect on profit, investment, income and the total cost of the project. For the reservoirs modeled here, when the gas flow rate was 2000 MMscf/day, payback was 3.03, whereas when the gas flow rate was changed to 1700 MMscf/day, payback fell to 2.56. This result does not necessarily mean that 1700 MMscf/day would be preferable to 2000 MMscf/day, as certain countries sell oil more easily than gas, and at a more convenient price. It is therefore possible that some governments would favor the scenario that entails a higher rate of gas injection, higher income,

more investment, less profit and higher payback, rather than the scenario that offers lower income, less investment, lower annual costs, more profit and higher payback.

3.1.4 Sensitivity analysis for injection pressure and number of wells

A part of primary investment is related to the cost of well drilling and completion, and has a direct relation to the number (quantity) of wells in an oil reservoir. The number of wells required for each reservoir was determined according to each reservoir simulation and a comparison of different scenarios. The stability of the comprehensive model was examined in comparison to the proposed number of wells. Various scenarios were considered in which the number of wells was changed and the gas allocated to the reservoirs. The economic results are presented in Table 10.

In Table 10, a new parameter referred to as well number is defined as the ratio of the number of real-world wells required to the number of required wells according to the reservoir simulations. For example, in scenario (2), the well number is 1.5, meaning that if the required well number determined by the simulation was 10 ring per reservoir, a value of 15 ring was investigated in this scenario and its economic results calculated.

As can be seen in the table, an increase in the well number ratio did lead to variations in the model, but these variations did not cause unreasonable conditions without economic justification. In other words, a change in the number of wells would not have a significant effect on stability. The possibility for changing the number of wells is of course very low, but in some cases it would be essential to examine its effect.

Another parameter which could be effective on economic results is injection pressure. The required wellhead pressure is 3000 psi, although it is possible to increase this. The economic results of increasing wellhead pressure are presented in Table 11.

In Table 11, scenario (1) is the main scenario used in the previous discussions, while the other scenarios assume wellhead

Table 9. Economic results of sensitivity analysis for source gas flow rate.

| Scenario | Gas flow rate (MMscf/day) | Capital cost (USD) | Total annual cost (USD/year) | Income (USD/year) | Benefit (USD/year) | Payback (year) |
|----------|---------------------------|----------------------|------------------------------|----------------------|----------------------|----------------|
| (1) | 2000 | 6.5369×10^9 | 2.8762×10^9 | 5.0304×10^9 | 2.1542×10^9 | 3.03 |
| (2) | 1900 | 6.2404×10^9 | 2.7360×10^9 | 4.9161×10^9 | 2.1801×10^9 | 2.86 |
| (3) | 1800 | 5.9867×10^9 | 2.6003×10^9 | 4.8106×10^9 | 2.2104×10^9 | 2.7 |
| (4) | 1700 | 5.7494×10^9 | 2.4664×10^9 | 4.7116×10^9 | 2.2451×10^9 | 2.56 |

Table 10. Economic results of sensitivity analysis for well number ratio.

| Scenario | Well number ratio | Capital cost (USD) | Total annual cost (USD/year) | Income (USD/year) | Benefit (USD/year) | Payback (year) |
|----------|-------------------|----------------------|------------------------------|----------------------|----------------------|----------------|
| (1) | 1 | 6.5369×10^9 | 2.8762×10^9 | 5.0304×10^9 | 2.1542×10^9 | 3.03 |
| (2) | 1.5 | 6.6719×10^9 | 2.8900×10^9 | 5.0304×10^9 | 2.1405×10^9 | 3.12 |
| (3) | 2 | 6.8069×10^9 | 2.9037×10^9 | 5.0304×10^9 | 2.1267×10^9 | 3.2 |
| (4) | 3 | 7.1351×10^9 | 2.9379×10^9 | 5.0889×10^9 | 2.1510×10^9 | 3.32 |
| (5) | 4 | 7.3469×10^9 | 2.9587×10^9 | 5.0304×10^9 | 2.0717×10^9 | 3.55 |

Table 11. Economic results of sensitivity analysis for wellhead pressure.

| Scenario | Wellhead pressure (psi) | Capital cost (USD) | Total annual cost (USD/year) | Income (USD/year) | Benefit (USD/year) | Payback (year) |
|----------|-------------------------|----------------------|------------------------------|----------------------|----------------------|----------------|
| (1) | 3000 | 6.5369×10^9 | 2.8762×10^9 | 5.0304×10^9 | 2.1542×10^9 | 3.03 |
| (2) | 3500 | 6.7799×10^9 | 2.9019×10^9 | 5.0304×10^9 | 2.1285×10^9 | 3.19 |
| (3) | 4000 | 7.1149×10^9 | 2.9370×10^9 | 5.0304×10^9 | 2.0935×10^9 | 3.4 |

Table 12. Economic results of sensitivity analysis for interest rate.

| Scenario | Interest rate (%) | Annualization factor (1/year) | Capital cost (USD) | Total annual cost (USD/year) | Income (USD/year) | Benefit (USD/year) | Payback (year) |
|----------|-------------------|-------------------------------|----------------------|------------------------------|----------------------|----------------------|----------------|
| (1) | 4 | 0.0736 | 6.5379×10^9 | 2.6913×10^9 | 5.0305×10^9 | 2.3392×10^9 | 2.79 |
| (2) | 6 | 0.0871 | 6.5374×10^9 | 2.7795×10^9 | 5.0305×10^9 | 2.2510×10^9 | 2.90 |
| (3) | 8 | 0.1019 | 6.5369×10^9 | 2.8762×10^9 | 5.0304×10^9 | 2.1542×10^9 | 3.03 |
| (4) | 10 | 0.1175 | 6.5364×10^9 | 2.9781×10^9 | 5.0303×10^9 | 2.0522×10^9 | 3.19 |
| (5) | 12 | 0.1339 | 6.5358×10^9 | 3.0852×10^9 | 5.0303×10^9 | 1.9451×10^9 | 3.36 |
| (6) | 14 | 0.1510 | 6.5353×10^9 | 3.1969×10^9 | 5.0302×10^9 | 1.8333×10^9 | 3.56 |
| (7) | 20 | 0.2054 | 6.5336×10^9 | 3.5520×10^9 | 5.0299×10^9 | 1.4778×10^9 | 4.42 |

pressures of 3500 and 4000 psi, respectively. The results show that the differences in pressure have considerable impact, but that this impact does not lead to significant changes in economic conditions.

3.1.5 Sensitivity analysis for interest rate

One effective economic factor on all engineering projects, including but not limited to gas injection, is the interest rate, assumed to be 8% in the base model. The interest rate may change for each project; sensitivity analysis for this parameter is therefore essential. Various scenarios are considered in which different interest rates are assumed, and economic results obtained from natural gas injection and allocation are presented in Table 12.

As shown in Table 12, interest rates ranging from 6% to 20% were investigated. The results suggest that an increase or decrease in the interest rate of up to 2% would not have a marked impact on payback and project profit, while a more substantial increase in the interest rate would affect project profit far more significantly. For instance, if the interest rate is increased to 20%, payback time will be increased by 50%; in other words, project profit will fall by 50%, but model decisions for the reservoirs in question will be stable.

4 CONCLUSION

- This model would improve the reliability of decision-making in the management of a country's oil reservoirs, because it offers reasonable gas allocation based on the final profit of gas injection into reservoirs, and considers all relevant economic parameters.
- Sensitivity analysis for gas sources has the potential to improve macromanagement within a country. In cases in which other short- and long-term programs are dependent

on the oil industry, the management of numerous sectors would benefit from a more fact-based approach.

- The economic results of other industrial consumers (the petrochemical industry, refineries, power stations and so on) could be compared with the economic results of this model. This model incorporates all reservoirs. This could be effective in developing or stopping decision-making relating to gas injection projects.
- By using the economic results obtained from increasing the capacity of gas sources, governments would be able to reach more informed decisions about natural gas exports. This situation would need to be reviewed, as with an increase in available gas sources, economic parameters would be exposed to significant changes.
- The cost of wells required for gas injection projects is very high, but this model shows that a change in well numbers or an increase in costs would not have a significant effect on decision-making. In other words, model decisions for the reservoirs in question would be stable.
- Variations in interest rate (up to 20%) would not have a significant effect on decision-making. In other words, model decisions for the reservoirs in question would be stable.

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