Journal of Enviromental Economics & Chemical Processes (JEECP)

Journal of Enviromental Economics & Chemical Processes (JEECP)

journal homepage: *WWW.JEECPJournal.com*

Assessing Risks and Uncertainties in Chemical EOR along with Identifying Handling Options

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P A P E R   I N F O

Paper history:
Received 06/12/2024
Accepted in revised form 09/12/2024

Keywords:
Chemical EOR (CEOR) EORC
Risk Assessment
Uncertainty Quantification (UQ)
Mitigation Strategies

A B S T R A C T

Chemical Enhanced Oil Recovery (CEOR) is a complex, multi-phase technique that enhances hydrocarbon recovery by injecting chemicals such as polymers, surfactants, and alkalis into reservoirs. Despite its potential, CEOR faces significant technical, economic, and operational risks, especially during early project development. Effective risk management is essential to ensure success, and pilot testing plays a key role in validating reservoir response and chemical performance before full-scale deployment. This study applies the Risk Failure Modes and Effects Analysis (RFMEA), an advanced version of traditional FMEA, to systematically identify, assess, and prioritize CEOR project risks. Through a comprehensive literature review and expert surveys, 26 key risks were identified and classified into four categories: general CEOR risks, offshore-specific risks, polymer flooding risks, and risks related to chemical combinations. The analysis revealed that permeability reduction, high salinity in offshore settings, reservoir heterogeneities, polymer and chemical adsorption, and polymer yield are the most critical factors affecting CEOR efficiency. These risks can impair fluid mobility, reduce chemical effectiveness, and increase project costs. RFMEA enables a structured evaluation of these risks, helping decision-makers prioritize mitigation actions, optimize chemical formulations, and improve project outcomes. The study emphasizes the importance of integrating RFMEA into the early planning phase of CEOR projects to reduce uncertainties, enhance reliability, and maximize recovery efficiency. By proactively addressing risks, operators can increase the likelihood of successful CEOR implementation and achieve better economic returns. The findings support the use of systematic risk assessment tools in complex oil recovery operations, particularly in challenging environments such as offshore reservoirs.

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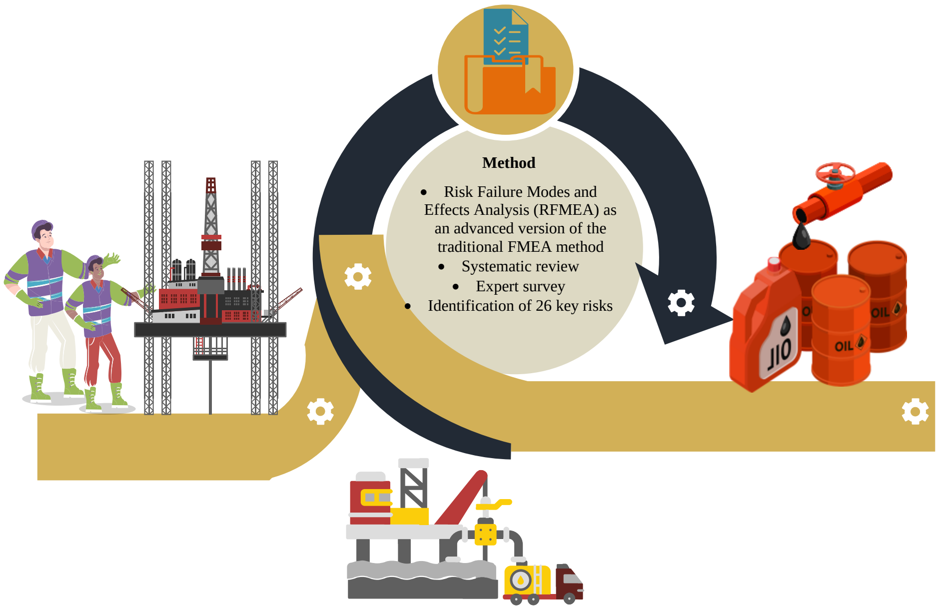

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URL:

Please cite this article as: : M. R, Peyro., & M, Masihi, (2024). *Journal of Enviromental Economics & Chemical Processes (JEECP)*, ?(4), ??-??. https://doi.org/10.30501/................

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1. Introduction

Enhanced Oil Recovery (EOR) has a potential to increase the recovery efficiency for most hydrocarbon fields. The average oil recovery rate for most hydrocarbon reservoirs is 33%. This shows that there is a large potential for EOR technologies [1].

Nowadays various recovery methods like water flooding; gas flooding and etc. are widely used in petroleum industry in order to increase hydrocarbon production as much as possible. Despite the fact water flooding is the main technology for maintaining reservoir pressure and enhancing oil production rate, this technology allows us to recover up to 10-40% of original oil from the fields. The rest amount of oil is divided into two categories: the remaining oil beyond water flooding process and bypassed oil. Comparing the engineering activities in different industrial areas, the low recovery efficiency seems to be stunning for outsiders. It is hard to understand that we are able to recover only one-third of a valuable and non-renewable natural resource and two-third of the geological reserve is usually lost forever. For petroleum engineers, however, that fact is self-evident because of the following limiting factors [2]:

•The reservoirs are heterogeneous; viz. the volumetric (horizontal and vertical) sweep efficiency is poor.

•The natural oil/water/gas/rock systems have unfavorable surface, interfacial and capillary properties; viz. the microscopic displacement efficiency is low in the reservoirs.

CEOR is an enhanced oil recovery technology in which chemical solution is injected into the reservoir in order to increase sweep and/or displacement efficiency. Polymer flooding involves injecting polymer solution to decrease water mobility resulting in improved sweep efficiency. Surfactant flooding involves injecting surface-active agents (surfactants) that achieve low Interfacial Tension (IFT) with the displaced oil. The injected chemicals solubilize the displaced oil to form an oil bank that is displaced ahead of the slug. The chemical slug also has a low IFT with formation water. Polymers are usually added to surfactants for mobility control, hence the name Surfactant-Polymer (SP) flood or Micellar-Polymer flood. SP floods have advantage over other EOR methods because of its dual advantage of increasing both microscopic displacement efficiency and volumetric sweep efficiency. Microscopic displacement efficiency is increased as the oil is mobilized by the surfactant and the added polymer increases volumetric sweep efficiency. Chemical floods have been shown to have a huge potential of increasing recovery efficiency in mature water-floods with high residual oil saturation [3].

The main objectives of this thesis are:

1.Reducing damage caused by non-consideration of uncertainties and consequently the risk posed by the implementation of the CEOR operation and the models used.

2.Increasing the efficiency of CEOR in oilfields.

The Research assumptions

This research is done based on the following assumptions:

1.Static model and characteristics data are available

2.The data used in the project are reliable

3.We will focus only on technical risks, which will be considered threats (negative risks).

4.The characteristics of the CEOR projects are considered the same for Iran.

The Research Questions

This study provides answers to two following questions:

1.What are the technical risks and uncertainties in CEOR and what are their priorities?

2.What are the best responses to technical risks and uncertainties in CEOR operation?

Chemical flooding is a term that is used to describe the addition of chemicals to the water. CEOR is used in partnership with water injection programs to mobilize and increase oil extraction. CEOR programs were the most popular in the 1980s, but installations decreased as the price of oil fell in the 1990s. Recently, the number of projects has grown exponentially as the price of oil increases, program designs improve, and the cost of chemicals decreases. Typically, sandstone reservoirs are most frequently utilized for CEOR due to the higher permeability of sandstone compared to limestone reservoirs. The primary depletion and secondary water-flooding of oil reservoirs typically recover only 20–50% of original oil in place and hence the majority of oil still remains trapped after the application of these conventional processes. The low oil recoveries from secondary water-floods are the result of inefficient macroscopic sweep efficiencies caused by lack of mobility control and poor microscopic displacement efficiencies, in turn caused by the capillary trapping of oil, attributed mainly to interfacial forces. By overcoming these inhibiting factors, CEOR processes are currently considered as promising tertiary technologies for increasing oil recovery from depleted oil reservoirs [3].

Chemical flooding was considered for field application until the mid-1980s, with crude-oil prices fluctuating around USD 30 bbl. However, the sharp decline in oil prices at that time resulted in slowing of CEOR field projects as well as resultant increased oil production. Higher sustained oil prices in the last decade as well as steeply declining production rates and higher water cuts, particularly offshore, have renewed interest in CEOR because the extra chemical and equipment costs required for implementation are now often recoverable from the more valuable incremental oil production. Furthermore, CEOR processes also have a smaller CO_2 footprint because of their lower associated energy requirements when compared with other common EOR methods such as miscible gas and thermal EOR. Most fields experiencing reduced production during water-flooding are candidates for some version of CEOR [4].

SP and Alkali-Surfactant-Polymer (ASP) flooding, generally known as CEOR, commonly uses one or more chemical agents, including: surfactant, co-surfactant, Alkali-Co-solvent-Polymer (ACP), and/or electrolytes. Surfactant and co-surfactant reduce oil/water IFT, resulting in the reduction of residual oil saturation, and therefore increasing the amount of mobile oil. Alkali can generate additional surfactant in situ and reduce surfactant adsorption (i.e. loss) on rock, while polymer improves mobility control and ultimately sweep/recovery efficiency [4].

Screening criteria for broader EOR processes have been discussed by several researchers—for example, Taber et al. (1997a, 1997b), Al-Bahar et al. (2004), and Dickson et al. (2010). This section briefly summarizes several critical parameters regarding CEOR application conditions [5]. Many parameters could affect CEOR processes; however, the most critical parameters should be reservoir temperature, formation salinity and divalent contents, clay contents, and oil viscosity.

The first step is the screening of reservoir where reservoir geometry and fluid, rock features are studied due to the passing criteria. If the properties of suggested reservoir are matched with the screening criteria, further deep investigations like modeling, laboratory works, and reservoir specification can be considered. Eventually these phases result in a technical-economical evaluation. The next phase is to determine targets and structure the pilot test. After successful study on pilot test, the profitable scenario is developed and improved; this involves field scale modeling and an operation strategy that examines realization, observation and operations [6].

Project Risk Management (PRM) includes the processes of conducting risk management planning, identification, analysis , response planning, and controlling risk on a project. The objectives of PRM are to increase the likelihood and impact of positive events, and decrease the likelihood and impact of negative events in the project [7]. be managed proactively and therefore may be assigned a management reserve. A negative project risk that has occurred is considered an issue [8].

The elements of the risk management paradigm are (Identify, Analyze, Response, and Control). These steps take place sequentially but the activity occurs continuously, concurrently and iteratively throughout the project life cycle. Plan Risk Responses is the process of developing options and actions to enhance opportunities and to reduce threats to project objectives. The key benefit of this process is that it addresses the risks by their priority, inserting resources and activities into the budget, schedule and project management plan as needed [9]. Control Risks is the process of implementing risk response plans, tracking identified risks, monitoring residual risks, identifying new risks, and evaluating risk process effectiveness throughout the project. The key benefit of this process is that it improves efficiency of the risk approach throughout the project life cycle to continuously optimize risk responses [9]. Control Risks can involve choosing alternative strategies, executing a contingency or fallback plan, taking corrective action, and modifying the project management plan. The risk response owner reports periodically to the project manager on the effectiveness of the plan, any unanticipated effects, and any correction needed to handle the risk appropriately. Control Risks also includes updating the organizational process assets, including project lessons learned databases and risk management templates, for the benefit of future projects [9].

Identifying and mitigating project risks are crucial steps in managing successful projects. This article proposes the extension of the FMEA format to quantify and analyze project risks [10].

The new technique is labeled the project risk FMEA (RFMEA). The RFMEA is a modification of the well-known process, product, and service FMEA technique. In order to use the FMEA format for projects, the detection value of the standard FMEA is modified slightly for use in the project environment. The new approach is illustrated in a case study from the electronics industry. By adding the detection value to the risk quantification process, another measure beyond the typical risk score is made available to the project team [10]. The benefits of the RFMEA include an increased focus on the most imminent risks, prioritizing risk contingency planning, improved team participation in the risk management process, and development of improved risk controls [10].

Multiplying three values of likelihood of occurrence (or probability), severity (or impact), and detection is the familiar format of the FMEA used for process, design, and service planning [11].

Nowadays, one of the major problems in the dependability field is addressing the system modeling in relation to the increasing of its complexity. This modeling task under lines issues concerning the quantification of the model parameters and the representation, propagation and quantification of the uncertainty in the system behavior [12]. In previous years, the reliability and risk analysis of systems were studied by making assumptions simplifying the study. One of these assumptions is to focus the study only on the technical part of the system. This assumption is no longer valid, since it has been shown the importance of organizational and human factors contributions [13]. Bayesian Network (BN) is a graphical structure for representing the probabilistic relationships among a large number of random variables and performing probabilistic interface with those variables [13]. BN appear to be a solution to model complex systems because they perform the factorization of variables joint distribution based on the conditional dependencies. The main objective of BN is to compute the distribution probabilities in a set of variables according to the observation of some variables and the prior knowledge of the others. The principles of this modeling tool are explained in Jensen and Pearl [13].

A BN is a Directed Acyclic Graph (DAG) in which the nodes represent the system variables and the arcs symbolize the dependencies or the cause–effect relationships among the variables. A BN is defined by a set of nodes and a set of directed arcs. A probability is associated to each state of the node. This probability is defined, a priori for a root node and computed by inference for the others [14].

Since 2001, BN have been used to analyze risky situations. Particularly, BN represent a useful formalism in the risk analyses domain due to their ability to model probabilistic data with dependencies between events [15].

BN is widely used in quantitative risk analysis due to its ability for performing both predictive and diagnostic analysis. The BN consists of qualitative and quantitative components [16].

In BN, probability inference of an event is conditional on the observed evidence‖. BN tools and algorithms can implement forward or backward linear prediction analysis as well as diagnosis analysis. Considering the conditional dependencies of variables, BN represents the joint probability distribution P (U) of variables U = {A1…An} [17]; as

P (U) = ∏))

Pa (Ai) is the parent set of Ai in the BN, while P (U) reflects the properties of the BN. In diagnostic analysis, BN takes advantage of Baye's theorem to update the prior occurrence (or failure) with new observations of another set of variables called evidence E. The posterior probability distribution of a particular variable can be computed using different classes of inference algorithms, such as the junction tree or variable elimination, based on Bayes' theorem [18].

$$(U \mid E) = \frac{)}{)} \quad \frac{)}{\Sigma \quad)}$$

Separation of produced oil/water emulsions from polymer flooding is complicated in an offshore environment [19]. High viscosity of the surrounding phase and small particle sizes both inhibit the settling velocity of liquid droplets and solid particles and therefore increase required residence time in gravity separators. Especially for water-in-oil emulsions produced from heavy crude, low separation temperatures caused by cloud-point limitations decrease settling (or rising) velocity of droplets and increase required residence time by increased continuous-phase viscosity and a decrease in the density difference between the oil and water phases. For an offshore polymer flood, the weight and space requirements for the bulk gravity separators may be prohibitive [19]. Conventional filtration with dual media or nutshell filters can be used to remove remaining dispersed oil in produced water to low levels (e.g.,<5 ppm). However, these filters could possibly be affected by the presence of polymer, and the filtration processes also have quite high maintenance and Operating-Expenditure (OPEX) costs and exhibit large footprint and weight requirements, hence making them unattractive for offshore use [20].

Offshore CEOR (polymer and ASP) faces subsurface challenges such as deep-water conditions, high temperature, pressure, and salinity, which limit the use of conventional onshore chemicals. This necessitates advanced R&D to develop salt- and temperature-stable chemistries. Improved sweep efficiency and low well density require tailored well patterns and smart-well technology. A recent study highlights early polymer breakthrough in an offshore polymer flood, causing fluid treatment issues, and the need for injection profile control to manage surface separation problems. The Angsi field is located in the South China Sea, 170 km off the East Coast of peninsular Malaysia. It is the largest integrated oil and gas development in Malaysia, with four drilling platforms and one central processing platform. The Angsi complex consists of a central processing platform ANPG-A) and a bridge-connected drilling/riser platform (ANDR-A). The complex is the host and processing platform for the satellite platforms namely ANDP-B, ANDP-C and ANDP-E [21]. Angsi CEOR application will be the first offshore AS full field injection in the world [21].

Angsi field is slated to be the first in the world for full field AS chemical flooding in an offshore environment whereby treated water mixed with chemical will be supplied from an onshore seawater treatment, chemical mixing and power generation plant located 170km away from the platform in the East Peninsula Malaysia [22]. In their quest to increase oil ultimate recovery and extend field life, PETRONAS spearheaded various EOR initiatives in Malaysia. The CEOR was identified as one of the EOR process that has good potential for the field implementation to increase ultimate recovery in Malaysian oil fields [23].

The pilot operation on a normally unmanned satellite platform with limited facilities added to the challenge and risk that requires a considerable attention during the planning phase. Thus, the primary focus at this point was to properly assess and evaluate the pilot execution to ensure Health Safety Environment (HSE) compliance and reduce risks during pilot execution. A set of specific guidelines and procedures were established to ensure the effective implementation of these recommendations [24]. Project team a multi-disciplinary team was formed to plan and execute the first CEOR pilot project in Malaysia. One of the first tasks for the team was to identify the technical partners that will provide the technical and operational expertise to the project. And it was also crucial for the team to leverage on the technical partners' proven expertise especially in SWCT implementation. The team has succeeded in involving the technical partners in the planning phase, integrating their experiences and knowledge into the project and coming-up with optimized pilot design, field procedures and equipment selection. As any of the previous projects implementation at Angsi field teamwork and communication were vital components in this project and has resulted in the success of the project [24]

2.Methodology

The current study contributes to the current deepening understanding of the value of the application of risk analysis to Operation Company.A qualitative methodology was chosen to answer two research questions with structured interviews being chosen as the primary research method. This process is iterative and continuously performed throughout the duration of the project.

Figure 1. IS upgrade project

The following briefly defines these elements. In using the RFMEA approach, there are a few required modifications to the standard FMEA format. The project RFMEA is a tool to identify, quantify, and remove or reduce risks in a project environment versus with the product's technical aspects as identification in the FMEA. The RFMEA is used in conjunction with the developed FMEAs for product design, process development, and service deployment [25].

Table 1. Standard FMEA and the RFMEA forms

Typical FMEA Columns	Failure ID	Failure Mode	Occurrence	Severity		Detection	RPN
Typical RFMEA Columns	Risk ID	Risk Event	Likelihood	Impact	Risk Score	Detection	RPN

Source: See Ref [25]

In this research after interview with specialists this result achieved, the effect of cost, time and schedule in impact of risks approximately equaled together.

Table 2. Guidelines for assigning the likelihood

9 or 10	Very likely to occur
7 or 8	Will probably occur
5 or 6	Equal chance of occurring or not
3 or 4	Probably will not occur
1 or 2	Very unlikely

Source:See Ref [26]

The largest deviation from the standard FMEA is the technical—changes are not noticeable. Definitions used for detection attribute. In the standard FMEA, the highest detection value means that the organization has no detection

capability available for the fault, whereas a low detection number in the standard FMEA means that the organization has a way to detect the fault before it ships from the operation almost 100% of the time

The largest deviation from the standard FMEA is the technical changes are not noticeable. Definitions used for detection attribute. In the standard FMEA, the highest detection value means that the organization has no detection. The RFMEA procedure is outlined Step one is for the team to brainstorm risk events. The team is coached that each risk event must be identified in the form of, If x happens, then y will occur,‖ where x is the risk event and y is the impact of the event happening. The impact might be serious time delay, an increase in costs, or both. A given risk might have multiple impacts, and in those cases, a risk Identification (ID) is given for each impact identified. While the impact and subsequent contingency plans for a particular risk are likely to be different, the likelihood value and the detection value for the event will typically be the same.

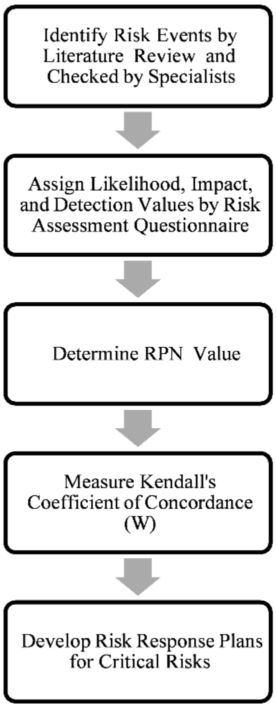

Figure 2. RFMEA procedure

In this section, the risk analysis for all of the risk groups is presented. First risks with their identification shown in Table 3. All the risks according to the experts' answers to the risk assessment questionnaire.

Table 3. Risk Identification

ID	Risk	Group	ID	Risk	Group
R1	Chemical formulation effectiveness	CEOR General Risks	R14	Polymer yield	Polymer Flooding Risks
R2	Produced fluids		R15	Polymer adsorption	
R3	Sweep efficiency		R16	Permeability Reduction	
R4	Injectivity		R17	Shear degradation	
R5	Scaling		R18	High salinity	
R6	Chemical supply and handling logistics		R19	High temperature	
R7	Logistics of handling large volumes of chemicals offshore	CEOR Offshore Risks	R20	Micro emulsion viscosity	Chemical Combination Risk
R8	Platform space limited		R21	Chemical adsorption	
R9	High salinity in offshore		R22	Chemical performance	
R10	Large well spacing		R23	Localized heterogeneities	
R11	Space and weight limitations on the deck		R24	Impact of free gas on the ASP process	
R12	Seawater as the only available injection- water source		R25	Unconstrained Fracture Growth	
R13	Limited disposal options		R26	Securing a continuous supply of chemical	

Source: Researcher's findings

The presence of the initial gas in the porous medium does not influence the displacement efficiency of the ASP flooding. When the ASP solution is injected after a gas flood, a large fraction of gas is trapped, as a consequence of which the effective volume for liquid flow of the ASP solution and oil is reduced and therefore the oil breakthrough occurs earlier. This has favorable impact on the economics of the ASP projects because of the accelerated production.

The presence of trapped gas results in different results depending on conditions before the injection of the ASP solution. Seemingly, the efficiency of the ASP flood decreases with the increasing trapped gas saturation, i.e., smaller oil saturation. The pressure drop or injectivity could be an operational limit when ASP is applied in a reservoir with large amount of trapped gas. Higher injection pressure required to inject the more viscous fluid could potentially result in chemical being injected out of zone, reducing its effectiveness in the target zone and complicating evaluation of the pilot results.

The surfactants used in a chemical combination flood are generally not off the shelf chemicals. It will be necessary to obtain a secure supply for the entire pilot time frame. This includes having enough back-up supply to cover any delivery disruptions.

There are two main limitations remained in ASP flooding field tests. Firstly, the strong alkali might cause scaling and erosion which shortened the pump checking cycle and increased the maintenance work. Such phenomenon frequently occurred when high concentration alkali existed in production liquid. Though physical and chemical scaling inhibition measures could extend the average pump-checking interval from 90 days to 160 days, the average pump-checking cycle for ASP flooding was only half of that of polymer flooding.

Secondly, the emulsified level of produced liquid was very high. The treatment process was difficult and the cost was high. In South-5 and North-1 East ASP flooding industrial tests, water and oil were hardly separated being strong emulsification. The electric field of electric dewatering unit was unstable, leading to both water contents in exported oil and suspended solids content in water exceed the standard specifications. This situation was even worse with the presence of high concentrations of alkali and surfactant in the produced fluid. demulsification and dehydration of produced liquid could be resolved by a series of measures, including modification of electrodes of electric dewatering unit, and higher dosage of demulsifier and defoamer. However, the costs of these techniques were relatively high.

Risk response refers to identifying, evaluating, selecting, and implementing actions in order to reduce the likelihood of occurrence of risk events and/or lower the negative impact of those risks. The risk response plays a proactive role in mitigating the negative impact of project risks. Once risks of a project have been identified and analyzed, appropriate risk response strategies must be adopted to cope with the risks in the project implementation. Therefore, there is wide agreement that the risk response strategy selection is an important issue in PRM, but study on selecting risk response strategies is the weakest part of the PRM process so that many organizations fail to gain the full benefits from PRM. Many of reservoir challenges usually have a simple solution, but if reservoir management team could not identify detection correctly, cannot request reservoir challenges .Development of a quality assurance program involves a careful identification of risk scenarios, determination of appropriate monitoring methods, and determining appropriate corrective actions for each plausible scenario.The integration of risk analysis and production history matching is also a subject that has recently been receiving special attention. The general idea is to integrate the processes of reservoir development when uncertainties exist and the reservoir management process in order to mitigate risk gradually as production is observed and used to reduce uncertainties in geologic attributes. This type of procedure has a great potential of improvement as new tools are being developed to speed up the process, which requires high computational effort. When a potential CEOR opportunity has been screened for study and potential implementation, a staged development process is important for de-risking uncertainties. discuss several key stages for project development, which include: laboratory testing, piloting, and full-field development. Each of these stages contains several sub-stages important for de-risking, which are explained further in the following sub-sections.

Typically after a field has been screened as a potential CEOR candidate, chemical formulations are screened through various laboratory experiments (phase behavior, aqueous stability, rheology, etc.) on how they perform with the crude oil and formation and/or injection brine from the reservoir/field of interest. Chemical formulation performance is validated using core floods for a variety of feasibility and de-risking factors. Laboratory testing and core flooding help calibrate models in a chemical flood simulator to optimize pilot and full-field development designs .Pilot projects are a crucial intermediate de-risking step between laboratory study and full-field implementation. They are essentially field experiments used to prove technical feasibility of the laboratory findings in the field, and to better define and optimize the full-field development. Several types of pilots exist (single well, pattern pilot, etc.) and one or more can be selected to prove feasibility with respect to injectivity, desaturation, and/or recovery among other things. Full field development and deployment occurs after the Final Investment Decision (FID) has been made. It consists of the delivery of all the wells, materials, and facilities, as well as implementing the injection schedule and reservoir surveillance strategy. However, although post-FID may seem like a point-of-no-return, there is still opportunity for de-risking and optimization. For example, a phased approach can be used to develop, say, one part of the field first, then apply learning to other parts of the field later.

Pilot projects can provide information of significant value for a CEOR project; however, it is important to define the objectives of a pilot, and aim to accomplish those objectives in as short a time as possible. Pilots will contain either a single well or multiple wells, with each scenario having different advantages and objectives. The length of time and cost of a single well pilot compared to a producing multi-well pilot typically differs by an order of magnitude. Depending on whether the project is onshore or offshore, a single well pilot can last one to a few months and cost several hundred thousand to a couple million dollars, while a multi-well pilot lasts one to a few years and costs a few million to tens of millions of dollars. For de-risking purposes, CEOR projects will typically run a single-well pilot first, assess feasibility (e.g. de-saturation, injectivity), then run a multi-well pilot before making the final investment decision for commerciality.

Table ٤. Comparing the rank of each risk according to each expert

RANK	EXPERT 1	EXPERT 2	EXPERT 3	EXPERT 4	EXPERT 5	EXPERT 6	EXPERT 7	EXPERT 8	EXPERT 9	EXPERT 10
1	R23	R9	R9	R23	R23	R16	R15	R24	R23	R15
2	R12	R14	R10	R10	R10	R14	R14	R14	R16	R22
3	R21	R16	R21	R3	R24	R18	R1	R16	R20	R14
4	R9	R10	R11	R12	R25	R13	R22	R20	R25	R13
5	R11	R21	R17	R25	R19	R19	R16	R23	R2	R10
6	R16	R23	R12	R19	R17	R15	R17	R21	R1	R5
7	R13	R11	R16	R9	R20	R21	R21	R9	R15	R24
8	R22	R15	R23	R20	R15	R2	R19	R25	R21	R7
9	R8	R17	R13	R24	R18	R9	R18	R22	R12	R11
10	R1	R13	R22	R18	R22	R26	R24	R15	R13	R9
11	R2	R8	R8	R5	R12	R3	R25	R18	R18	R2
12	R15	R7	R25	R13	R9	R10	R23	R19	R8	R8
13	R25	R1	R14	R16	R16	R4	R9	R10	R24	R1
14	R18	R20	R15	R17	R3	R1	R6	R13	R5	R3
15	R19	R3	R1	R14	R2	R11	R4	R17	R3	R12
16	R20	R18	R19	R21	R5	R7	R5	R5	R4	R25
17	R7	R12	R20	R22	R21	R22	R10	R12	R9	R21
18	R10	R4	R24	R15	R8	R6	R20	R1	R14	R6
19	R14	R22	R3	R11	R11	R17	R8	R7	R7	R19
20	R17	R19	R6	R26	R1	R5	R11	R2	R19	R17
21	R24	R25	R7	R8	R13	R12	R3	R3	R17	R18
22	R26	R5	R4	R7	R14	R8	R7	R26	R22	R23
23	R6	R2	R18	R2	R7	R24	R26	R8	R11	R20
24	R4	R6	R5	R6	R6	R23	R12	R11	R10	R4
25	R3	R24	R26	R4	R26	R20	R2	R4	R26	R26
26	R5	R26	R2	R1	R4	R25	R13	R6	R6	R16

In order to determine rank any risk to other risks totally, the ranks of a risk in each of the columns summed together. Finally, the risks ranked according to lowest total rank and actually according to highest RPN.

Table 5. Total rank of each risk

ID	Risk	Total Rank
R16	Permeability Reduction	79
R9	High salinity in offshore	81
R23	Localized heterogeneities	81
R15	Polymer adsorption	85
R21	Chemical adsorption	89
R14	Polymer yield	98
R10	Large well spacing	99
R25	Unconstrained Fracture Growth	116
R13	Limited disposal options	117
R22	Chemical performance	118
R12	Seawater as the only available injection- water source	126
R19	high temperature	126
R18	high salinity	127
R24	Impact of free gas on the ASP process	130
R17	shear degradation	135
R20	Micro emulsion viscosity	135
R1	Chemical formulation effectiveness	138
R11	Space and weight limitations on the deck	145
R3	Sweep efficiency	158
R8	Platform space limited	158
R2	Produced fluids	166
R5	Scaling	171
R7	Logistics of handling large volumes of chemicals offshore	179
R4	Injectivity	208
R6	Chemical supply and handling logistics	217
R26	Securing a continuous supply of chemical	223

Source: Researcher's findings

2. Results and Discussion

The results of this dissertation are crucial in the future decision making for a large-scale full field and CEOR technology implementation with reduced technical risk. The result may be one of the keys in deciding the fate of the CEOR implementation in oilfields. The RFMEA technique was introduced as a way to systematically capture risk events, score them, and then respond to those that posed the most threat to the project. For the evaluation of the full project RFMEA, total 26 risks identified, there are six above the RPN value. Creating adequate risk plans for six risks is a challenge; planning for all 26 risks is nearly impossible, given the typical project environment.

In this illustration, the risks of R16, R9, R23, R15, R21 and R14 that shown in Table 6 will require that a response plan will be generate and revise RPN values calculated. Also prioritize risks shown in Table 6.

Table 6. Prioritize risks

Rank	ID	Risk
1	R16	Permeability Reduction
2	R9	High salinity in offshore
3	R23	Localized heterogeneities
4	R15	Polymer adsorption
5	R21	Chemical adsorption
6	R14	Polymer yield
7	R10	Large well spacing
8	R25	Unconstrained Fracture Growth
9	R13	Limited disposal options
10	R22	Chemical performance
11	R12	Seawater as the only available injection- water source
12	R19	high temperature
13	R18	high salinity
14	R24	Impact of free gas on the ASP process
15	R17	shear degradation
16	R20	Micro emulsion viscosity
17	R1	Chemical formulation effectiveness
18	R11	Space and weight limitations on the deck
19	R3	Sweep efficiency
20	R8	Platform space limited
21	R2	Produced fluids
22	R5	Scaling
23	R7	Logistics of handling large volumes of chemicals offshore
24	R4	Injectivity
25	R6	Chemical supply and handling logistics
26	R26	Securing a continuous supply of chemical

Source: Researcher's findings

After ranking f risks Kendall‘s W calculated, Suppose that object i is given the rank ri,j by judge number j, where there are in total n objects and m judges. Then the total rank given to object i is:

$R_i = \sum$

And the mean value of these total ranks is:

$\bar{} = \sum$

The sum of squared deviations, S, is defined as:

$S = \sum \quad \bar{})$

And then Kendall's W is defined as:

W =_________

Ri, ‾and S calculated for each risk and shown in Table 7. Based on these values, Kendall's W calculated and equals to 0.5.

Table 7. Kendall's W parameter values

ID	Risk		‾	S
R16	Permeability Reduction	79.0	3.0	3114.5
R9	High salinity in offshore	81.0	3.1	2895.3
R23	Localized heterogeneities	81.0	3.1	2895.3
R15	Polymer adsorption	85.0	3.3	2480.8
R21	Chemical adsorption	89.0	3.4	2098.3
R14	Polymer yield	98.0	3.8	1354.8
R10	Large well spacing	99.0	3.8	1282.2
R25	Unconstrained Fracture Growth	116.0	4.5	353.7
R13	Limited disposal options	117.0	4.5	317.1
R22	Chemical performance	118.0	4.5	282.5
R12	Seawater as the only available injection-water source	126.0	4.8	77.6
R19	High temperature	126.0	4.8	77.6
R18	High salinity	127.0	4.9	61.0
R24	Impact of free gas on the ASP Process	130.0	5.0	23.1
R17	Shear degradation	135.0	5.2	0.0
R20	Micro emulsion Viscosity	135.0	5.2	0.0
R1	Chemical formulation effectiveness	138.0	5.3	10.2
R11	Space and weight limitations on the deck	145.0	5.6	103.9
R3	Sweep efficiency	158	6.1	537.9
R8	Platform space limited	158	6.1	537.9
R2	Produced fluids	166	6.4	973.0
R5	Scaling	171	6.6	1309.9
R7	Logistics of handling large volumes of chemicals offshore	179	6.9	1953.0
R4	Injectivity	208	8.0	5357.1
R6	Chemical supply and handling logistics	217	8.3	6755.6
R26	Securing a continuous supply of chemical	223	8.6	7777.9
Summation			134.8	42630.0

Source: Researcher's findings

3. Conclusions

The main objective of this thesis was reducing damage caused by non-consideration of uncertainties and consequently the risk posed by the implementation of the CEOR operation and the models used, also increasing the efficiency of CEOR in oilfields. To do this, first, we was investigated that what are the technical risks and uncertainties in CEOR and what are their priorities? And second, what are the best responses to technical risks and uncertainties in CEOR operation?

The most important conclusions of this research are:

1.Chemical flooding has gained little traction as a tertiary recovery strategy despite many mature onshore reservoirs existing that could be potential candidates.

2.Twenty-six risks associated with CEOR operations were identified in this research, which was classified into four groups as follows:

a.CEOR general risks

b.CEOR offshore risks

c.Polymer flooding risks

d.Chemical combination risks

3.The risk analysis in each group helped to improve the results of the analysis.

4.The prioritization of risks led to the selection of appropriate response methods..

5.Permeability Reduction, High salinity in offshore, Localized heterogeneities, Polymer adsorption, Chemical adsorption and Polymer yield are the main basis risks in CEOR.

6.Since the risk factor is high in most of the risks, it must be secured before its operation (CEOR) to guarantee its safety.

7.Due to the CEOR is complex method, it is necessary to know your experience in other areas and check your results.

8.CEOR is a very complex technology requiring a high level of expertise and experience to successfully implement in the field.

9.The pilot operation on a normally unmanned satellite platform with limited facilities requires a proper assessment of risks and additional safety measures during the pilot operation to ensure a safe operation.

10.Several factors have been investigated to find the best scenario. The RFMEA is an advanced risk tool that is simple and intuitive. It is based on the well-known FMEA technique, modified for PRM.

11.The RFMEA is based on evaluating both the risk score and the RPN value to find the critical risks that require immediate risk response planning.

12.If properly utilized, the RFMEA can greatly reduce risks on a project, create team ownership in risk planning, and act as a resource for future projects in terms of knowledge management and lessons learned.

13.The engineering manager can use this method and format as a simple and concise way to capture project and program risks. The ability to reuse the data and anything learned from the RFMEA enhances organizational learning. The project manager and engineering manager can use this information to improve project success by focusing on key risks by using the simple risk management RFMEA process.

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