Reservoir Development Plans

Numerous publications have been dedicated to reservoir development planning and integrated reservoir management (Babadagli et al., 2008; Bibars and Hanafy, 2004; Cosentino, 2001; Dudfield, 1988; Fabel et al., 1999; Figueiredo et al., 2007; Gael et al., 1995; Satter and Thakur, 1994; Schiozer and Mezzomo, 2003; Stripe et al., 1993). This book provides a general overview of reservoir development planning to set the context for evaluating and implementing enhanced oil recovery (EOR) projects. In other words, reservoir development planning refers to strategies that begin with the exploration and appraisal well phase and end with the abandonment phase of a particular field to establish the course of action during the productive life of the asset. Figure 1.1 summarizes the phases of a reservoir development plan. The main objective of the complete cycle of a development plan is to maximize the asset value.

![Diagram of Field Development Plan](image-url)

**FIGURE 1.1** The main phases of a field development plan.
Development strategies for new fields are based on data obtained from seismic surveys (which are not always acquired or readily accessible), exploratory wells, and other limited information sources such as fluid properties and reservoir analogues. Based on the information at hand, initial development plans are defined through simulation studies considering either a probabilistic or a stochastic approach to rank options using economic indicators, availability of injection fluids (i.e., water and/or gas), and oil recovery and risk, among other considerations.

Therefore, integrating the information from simulation studies helps to address the multiple and complex factors that influence oil recovery, as well as reservoir development decisions. As new information about the reservoir, its geology, and its degree of heterogeneity becomes available through drilling of new wells (i.e., development and infill wells) and production–injection history, the field can be developed in an optimal way.

In the case of mature fields with a steady decline in oil production, new development plans must be reevaluated or implemented. However, if the decision to implement a new development plan in mature fields is made too late (i.e., fields producing with oil cuts below 5 percent), the number of economically viable options becomes limited. This case relates to the value of time or the window of opportunity for implementing EOR projects in mature fields.

For a variety of reasons, most, if not all, reservoir development plans (RDPs) change or must be adjusted or modified during the productive life of the field. Some of the reasons include the following:

- Lack of reservoir characterization and understanding of production mechanisms at the early stages of development (reduction of uncertainties with time)
- Poor production performance (e.g., production below expectations and early water breakthrough)
- Environmental constraints or drivers (e.g., CO₂ storage, changes in legislation)
- Economics (e.g., low oil prices)
- New technologies (e.g., horizontal wells, multilaterals, and new recovery processes)

Thus, dynamic and flexible reservoir management is required to optimize field production responses that maximize the value of the asset over its full cycle of exploitation.

Considering again the importance of time and reservoir pressure in development plans, Figure 1.2 presents a simple decision tree to evaluate the potential applicability of different recovery processes in light to medium crude oil reservoirs. (We will discuss influence diagrams and decision trees in the Chapter 6, Economic Considerations and Framing.)
Although Figure 1.2 does not show steam injection methods, although it is still a valid recovery process (Perez-Perez et al., 2001).

In general, a particular light or medium oil reservoir can be a suitable candidate for several EOR processes, as we will see later in the book. However, if pressure maintenance (either by water or gas injection) starts below the bubble point pressure ($P_b$), the probability of obtaining lower ultimate oil recovery increases compared to the case of reservoirs in which the secondary recovery initiates at pressures above $P_b$. Additionally, timing for pressure maintenance as part of a reservoir development plan can be critical to control variables such as the following:

- Asphaltene deposition/flocculation because of their impact on reservoir performance, well injectivity, and/or well productivity (Civan, 2007; Garcia et al., 2001; Kabir and Jamaluddin, 2002; Poncet et al., 2002).
- Retrograde condensation, which is typical of gas and condensate reservoirs when pressure goes below the dew point (Belaifa et al., 2003; Briones et al., 2002; Clark and Ludolph, 2003).
- Problems with sand production and wellbore collapse and stability (Bellarby, 2009; Civan, 2007; Nouri et al., 2003; Tovar et al., 1999).

Enhanced oil recovery chemical methods such as alkali-surfactant-polymer (ASP) have gained considerable interest in recent years as these methods have matured and become commercial options to increasing oil recovery in mature waterfloods. To demonstrate the impact of past decisions on the future technical and, most important, economic success of chemical EOR processes, Figure 1.3 shows an example of some of the decisions an operator generally faces when planning a water injection project in a particular field.
Specifically, in recent project evaluations the authors have completed, well spacing has been one of the biggest hurdles of economic feasibility of chemical EOR processes. In some project evaluations, we have found that infill drilling programs are needed or recommended to accelerate oil recovery and thus the rate of return on investment.

We will touch on this type of strategy in association with the larger issue of improved oil recovery, or IOR. However, incremental oil recovery that is estimated during EOR chemical flooding project evaluations is not always sufficient to pay off capital expenditures associated with drilling programs, reducing the upside potential of mature waterflooded reservoirs. The latter combined with the volatility of crude oil prices represents a big challenge in RDPs of mature fields.

On the other hand, reservoir development plans for heavy and extra-heavy crude oil reservoirs, including oil sands, generally differ from those of medium and light crude oil reservoirs. Given the viscosity of heavy oils at reservoir conditions, oil might not flow naturally. This is the case of Canadian oil sands and some tar sands in other areas of the world (viscosities on the order of 10^6 cp). In oil sands, EOR technologies such as steam-assisted gravity drainage, or SAGD, are necessary to produce oil sands at economic rates. In these cases, EOR can be used earlier in the sequence of reservoir development plans of heavy and extra-heavy oils. Thus, EOR methods should not always be associated with tertiary recovery methods as shown in Figure 1.1.

Figure 1.4 shows the elements of a simple decision tree with some of the options of recovery processes that are potentially applicable in heavy to extra-heavy crude oil reservoirs. This particular example is based on the flow of viscous oil at reservoir conditions. It is not surprising that EOR thermal methods represent the most common recovery processes envisioned and applied to develop heavy and extra-heavy oil reservoirs.
However, several pilot tests of chemical EOR processes applied to heavy-oil reservoirs—that is, ASP and alkali-polymer (AP)—have been documented in the literature in recent years. These tests have opened a new window of opportunity for heavy crude oil (14°C ≤ API ≤ 22°C) reservoirs (Arihara et al., 1999; Pitts et al., 2004; Pitts et al., 2006; Pratap and Gauma, 2004; Zhijian et al., 1998).

As you may have realized by now, reservoir development decisions create a history for a reservoir that has a significant impact on decisions down the road for EOR opportunities. We have indicated through examples that a tertiary application of EOR technologies is not a must, and it turns out that the earlier you deploy EOR, the better if the objective is total optimum recovery in terms of volumes of hydrocarbon.

We elaborate on enhanced oil recovery definitions and mechanisms in this book to highlight their impact on decision making, and we would like to demystify some of those “expert opinions.” Despite limited production associated with EOR processes in most productive areas, these technologies are out of the lab and are currently being applied in numerous fields. It is just a myth that EOR represents an opportunity only for the distant future. Enhanced oil recovery not only provides a way to increase reserves, which is loosely defined as oil you can extract by commercial means, but it also might offer an economic way to prolong the productive life of assets and delay the decommissioning stage that most companies abhor.

**FIGURE 1.4** A simplified example of a decision tree to evaluate potential recovery processes as part of the RDP in heavy to extra-heavy (oil sands) crude oil reservoirs.