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Introduction

Reservoir management is fundamental to the efficient and responsible means of extracting hydrocarbons, and maximizing the economic benefit to the operator, license holders, and central government. All stakeholders have a social responsibility to protect the local population and environment. The process of managing an oil or gas reservoir begins after discovery and continues through appraisal, development, production, and abandonment (Figure 1.1); there is cost associated with each phase and a series of decision gates should be in place to ensure that an economic benefit exists before progress is made. To correctly establish potential value at each stage it is necessary to acquire and analyze data from the subsurface, the planned surface facilities, and the contractual obligations to the end-user of the hydrocarbons produced. This is especially true of any improved recovery methods proposed or plans to extend field life. To achieve all the above requires a multiskilled team of professionals working together with a clear set of objectives and associated rewards. The team's make-up will change over time as different skills are required, as well as the management of the team, with geoscientists, engineers, and commercial analysts needed to address the issues as they arise.

This book is designed as a guide for nonspecialists involved in the process of reservoir management, which is often treated as a task for reservoir engineers alone. It is a task for all the disciplines involved in turning an exploration success into a commercial asset. Most explorers earn their bonus based on the initial estimates of in-place hydrocarbons, regardless

Reservoir Management: A Practical Guide, First Edition. Steve Cannon.

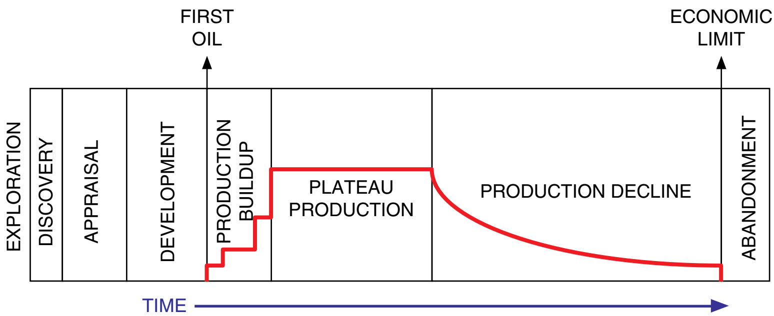

Figure 1.1 Oilfield life cycle from discovery to abandonment with a typical primary production profile in red. The period from discovery to first oil may be short or long depending on economic conditions and infrastructure limitations.

of the ultimate cost of production; the explorers have usually moved on to a new basin before the first oil or gas is produced!

This chapter will look at the basics of reservoir management introducing the main terms and jargon, while subsequent chapters will go into more detail.

- Chapter 2 reviews the life cycle of an oil or gas field after discovery, looks at field development plans, monitoring and data acquisition requirements, and discusses these issues in the light of a number of case studies.
- Chapter 3 looks at the static and dynamic reservoir description around which the initial plans are built.
- Chapter 4 reviews the construction of the integrated reservoir model.
- Chapter 5 addresses reservoir performance and production forecasting, reviewing the dynamic estimation and uncertainty in future resources and reserves.
- Chapter 6 discusses some of the ways to improve or enhance hydrocarbon recovery with examples used to describe the methods.
- Chapter 7 focuses on the economic aspects of a successful field development and how active reservoir management through the field life can improve the returns on investment.
- Chapter 8 considers the way in which the reservoir management plan evolves with time from project sanction to abandonment. We will look at some of these issues in the real world of field development and secondary recovery projects through a series of case studies.

Throughout the book there are relevant examples from real reservoir management projects and field developments across the major hydrocarbon basins of the world. I have also included an Appendix that covers the basics of dynamic reservoir simulation, which is the main tool used by those involved in reservoir management studies.

1.1 The Basics

The main objectives of reservoir management may be summarized as follows:

- Maximizing the ultimate recovery of reserves from an oil or gas field
- Reducing the commercial risk associated with development plans
- Minimizing operating expenditure (OPEX) and capital expenditure (CAPEX)
- Increasing hydrocarbon production from wells
- Increasing the value of reserves through time (net present value – NPV)

To maximize the economic recovery of hydrocarbons requires the identification and characterization of all potential reservoirs in a field so that the optimum development plan can be proposed. This requires a reservoir management plan designed on the basis of location and size of the field, the geological complexity of the reservoir, the type and distribution of the reservoir rock and fluids, the drive mechanism, regulatory controls and contractual limitations, and economics. Different management plans are required for onshore and offshore locations, and also for gas-filled 'tanks of sand' and poorly connected oil reservoirs, especially when natural depletion results in economically low recovery.

To achieve these objectives requires the integration of static and dynamic models of the reservoir together with gross uncertainties associated with a complex natural system, as well as models of surface facilities designed to optimize production from the field, economic models of OPEX, CAPEX, and price fluctuations throughout field life. The uncertainty associated with each of these inputs leads to a range of potential rewards; determining the relative value of these outcomes is the task of the whole team at the time of evaluation and prior to any investment being made.

The life cycle of an oil or gas field begins after discovery with a clear appraisal plan, to delineate the field, upon which the development program is designed, costed, and approved. Inevitably, surprises will occur during development drilling that require a change to the plan, but these should have been considered and included in the budget. An oil or gas field only begins to make money once production has started: most oil companies expect a return on investment within three to five years of this date. Thereafter, the thoughts move toward improving overall returns through innovative secondary recovery techniques or increasing ultimate recovery using more esoteric tertiary methods. Effective reservoir management should always be proactive, anticipating decline, and investing to maintain production and improve recovery through to abandonment (Figure 1.2). Reacting to decline after it has started may limit the solutions available and ultimately cost more. Both of these phases are often invoked to delay the ultimate stage of the life cycle, cessation of production and then abandonment, the costs of which should also have been included in the original development plan.

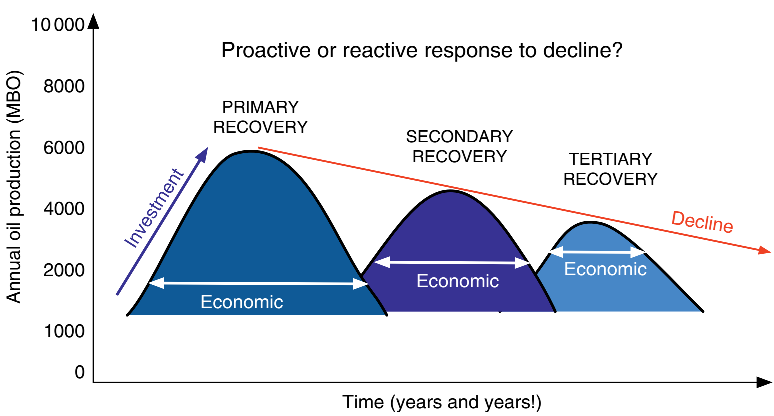

Figure 1.2 Effective reservoir management should always be proactive, anticipating decline, and investing to maintain production and improve recovery through to abandonment. Reacting to decline after it has started may limit the solutions available and ultimately cost more.

1.2 Field Appraisal

As soon as an oil, condensate, or gas field is discovered there is internal and external pressure to monetize what will have been a significant investment in the exploration phase. The appraisal plan is drawn up to try to reduce the major uncertainties in the reservoir description and thus increase confidence in the value of the potential project. A lot will depend on the data collected during the exploration phase: was the reservoir cored and logged to determine rock properties? was a well test carried out and fluid samples collected? was the well suspended or abandoned? Many operators never core or test an exploration well; they delay data gathering to the next phase. In an onshore location this may be understandable, but offshore, where the well cost is much greater, collecting the basic data may ease the subsequent decision on appraisal.

Most fields require one or more appraisal wells to build confidence before investment. In the early days of North Sea exploitation, before modern 3D seismic was available, after making a discovery, several appraisal wells would be drilled to delineate a field. In one case, a well was drilled to the north and south of the discovery and a platform located in the center: the first well drilled to the east crossed a fault that put the reservoir into the aquifer. This near disaster was corrected by locating a second platform 2 km to the west so the whole field could be successful accessed; this was before the days of extended reach wells.

An appraisal program should meet three criteria:

1) Information gathered must be relevant and have the potential to change your belief about a given uncertainty.
2) The data must have a material impact on decision-making.
3) The cost of acquisition must be less than its value (VOI – value of information).

Additional 2D/3D seismic acquisition can be expensive if required for onshore appraisal, and drilling may be less costly. Drilling a well may allow the acquisition of additional core data, well logs, or drill stem tests.

The commonest way of looking at these criteria are to develop decision trees to address the different possible outcomes and their impact on the development. Ideally, appraisal will move smoothly into development planning, and thus reduce the cycle time from discovery to first production. A development team will be put together combining subsurface professionals, facilities engineers, commercial specialists, economists, and legal experts to review each aspect of the proposed project.

Glenlivet Field, West of Shetland *A successful exploration well tested a seismic anomaly in 600 m of water during the summer drilling season (Horseman* et al. *2014). Updip of the well the seismic response became tuned, reducing confidence in the in-place gas volume. The vertical well was fully logged and cored over a third of the reservoir sands. Given good weather and time on the rig schedule the operator decided to drill an updip sidetrack to reduce the seismic uncertainty; the sidetrack confirmed a thick reservoir section to*

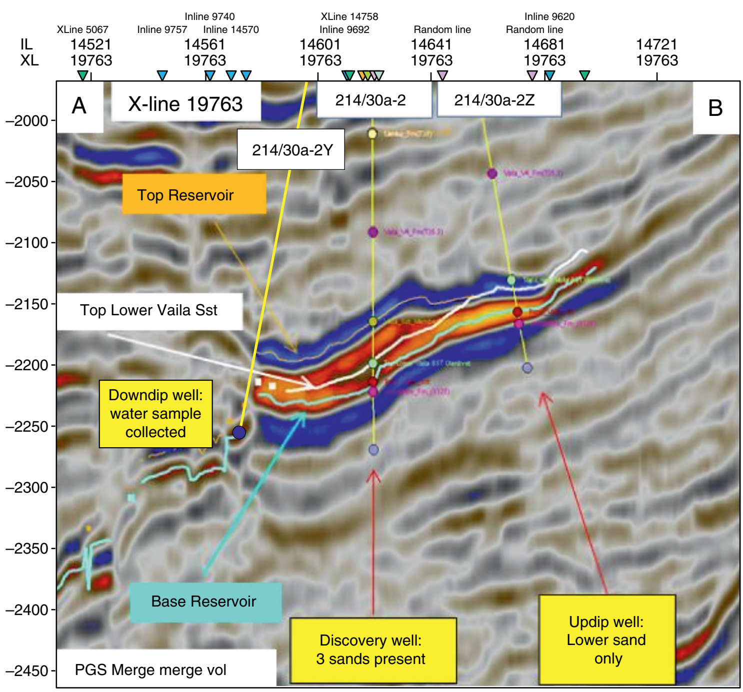

Figure 1.3 The Glenlivet Field, West of Shetland, showing the seismic response of the reservoir plus the discovery well and two sidetracks that were drilled to fully appraise the field prior to development. *Source:* Courtesy of DONG Energy.

*the edge of the anomaly, confirming the optimistic gas volume estimate. To gain access to an export pipeline a sample of the downdip aquifer was required; this sample would represent any produced water. So the operator decided to drill a second sidetrack and recover a water sample. Each sidetrack was logged to establish a reservoir correlation. There was no requirement to test the well because the core and log data confirmed a high deliverability reservoir; the gas in place could be drained by one well alone, and no further appraisal was required (*Figure 1.3*).*

From these results a development plan was written that required the drilling of two vertical wells, each with sand screens to minimize sand invasion and downhole gauges to monitor gas production. Two new wells were planned so that neither well was over produced and there would still be a producer should either well fail. The ultimate production rates from the field would be dependent on the available capacity in the pipeline.

1.3 Volumetrics

The starting point for any field development is an estimate of the in-place hydrocarbon volume. Is there enough oil or gas to make a development economically viable or do the hydrocarbons remain future resources and not reserves?

Conventional volumetric calculations to estimate hydrocarbons initially in-place (HIIP) require a number of simple input parameters, most of which are in the remit of the petrophysicist. The input parameters are related in the following way:

Hydrocarbons initially in-place:

$$HIIP = \frac{GRV.NTG.\phi.\left(1 - S_w\right)}{B}$$

where:

GRV	=	gross rock volume
NTG	=	net : gross
ϕ	=	porosity of net reservoir
$(1 - S_w)$	=	hydrocarbon saturation
B	=	formation volume factor

Gross rock volume (GRV) is the volume of rock between the top reservoir structure and the closing contour or hydrocarbon water contact.

Net : gross (NTG) is that part of the reservoir containing moveable fluids. In a 3D model this can be calculated from a facies model or by the application of a series of cut-off values based on an effective porosity and/or permeability. The ratio of NTG to GRV gives the *net rock volume* (NRV).

Porosity is the capacity of a rock to store fluids; the pore volume of a reservoir model is the total of all cells with an effective porosity and is directly linked to the NRV. Cells with effective porosity may be defined by a facies model or by some cut-off value.

Hydrocarbon saturation is the proportion of the pores filled with hydrocarbon rather than water; the volume of hydrocarbon plus the volume of water will be unity, $S_h = (1 - S_w)$, where S_w is the proportion of water in the pore space. Only those cells that have been designated as being NRV will be counted in the summation to give the reservoir hydrocarbon volume.

Formation volume factor accounts for the increase in hydrocarbon volume between the reservoir and the surface; this is a function of the change in pressure between reservoir and surface conditions and depends on the fluid description.

There are a number of dynamic methods used to estimate HIIP such as decline curve analysis, material balance, or reservoir simulation; these will be discussed further in Chapter 5.

1.4 Drive Mechanism

Oil and gas reservoirs have a natural drive mechanism that provides the energy to move the hydrocarbons toward a producing well. The common natural drive mechanisms are water drive, gas expansion, solution gas drive, compaction drive, and gravity drainage. One drive mechanism initially dominates production, but a combination of mechanisms often occurs over the period of field life. Depending on the drive mechanism it is possible to estimate potential recovery factors ranging between 5 and 30% for oil fields and up to 80% for a gas field that depletes naturally (Table 1.1). To improve recovery for any field normally requires a secondary method to maintain the energy in the reservoir.

Table 1.1 Recovery factors for different fields under differing production methods. Rules of thumb!

Recovery factor	Low (%)	Medium (%)	High (%)
Oil field – by natural depletion and without aquifer support	10	15	20
Oil field – by efficient water or gas injection or strong aquifer support	30	50	60
Gas field – by natural depletion	60	70	80

1.5 Field Development

Having delineated the field and acquired the necessary reservoir and production information a development plan can be written. There will always be uncertainties in the reservoir description that will need to be considered in the development plan. The key elements are the number of wells required to drain the reservoir and the surface facilities needed to fulfill any contractual or legislative agreements. In the situation where gas is contracted on an annual basis it is possible to plan a simple rate of production per well to fulfill an agreed annual decline profile. However, if the gas market is liberated, such as in the UK, each well or group of wells is required to deliver production at hourly or daily rates to fulfill the needs of commercial and domestic users. In this latter case, having wells that can be switched on and off like a tap become essential. Oil production is managed on a different monetary basis where value is made on delivery to the refinery and the quality of the oil.

Drilling onshore is usually done on a regularly spaced pattern: initially widely spaced to allow for subsequent infill drilling or water-flooding; these might be in the original plans or form a secondary phase of recovery. Offshore field developments require higher CAPEX including large platform structures and pipelines or storage facilities. The number of wells is often restricted by the surface facilities and wells must be engineered to maximize access to the reservoir.

Field developments are often staged or phased: a subtle distinction where *staged* plans are approved at time of commissioning whereas *phased* plans are based on the results of the initial development. In the past, many offshore fields were over engineered or displayed 'gold plated' solutions to basic issues. Those days are long gone, and every nut, bolt, and piece of pipe must be justified during the economic assessment of a project.

Hyde Field, Southern North Sea: *Planning a new field development is a matter of looking at the potential resource and deciding how best to monetize that resource. When the UK gas market was liberated in the 1990s there was a 'dash for gas' by those companies with export infrastructure. Small fields that previously were uneconomic under fixed*

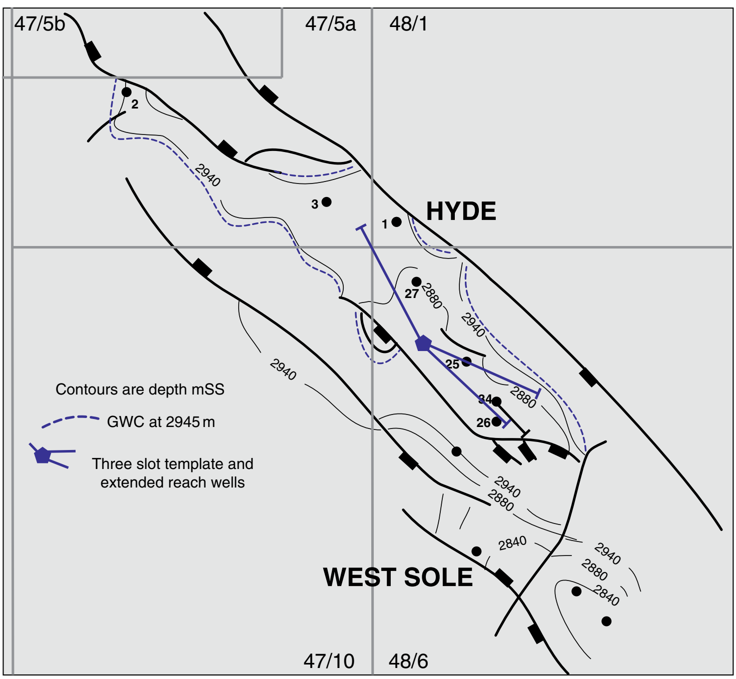

Figure 1.4 The Hyde Field, UK Southern North Sea, showing the main structural features plus the locations of the three extended reach wells drilled from a three-slot subsea template.

contracts suddenly became swing feeders to the existing system: wells that could be switched on and off as required. The Hyde Field was discovered in 1982 but was only brought to production in August 1993 when the economic risk could be mitigated through new technology: extended reach near horizontal wells (Steele et al. *1993). Extensive appraisal of a similar nearby accumulation indicated a number of important constraints on development: a partial gas column (~105 m); low permeability (1 mD mode); high water saturation (40%); low, natural flow rate (12 MMscf/d): effectively the field was in a transition zone. This information indicated that production wells would require some form of stimulation to achieve economic rates. Because of the partial gas column, horizontal drilling was chosen over hydraulically fractured deviated wells (*Figure 1.4*).*

To demonstrate that the field could be best exploited by this method, a pilot well was drilled and cored at the crest of the structure prior to drilling a horizontal sidetrack. The sidetrack was drilled and steered using LWD technology to maintain maximum penetration of the best quality reservoir layer: ultimately 420 m of productive reservoir was penetrated. The well was tested using a predrilled slotted liner to allow future use as a producer. The well tested at a rate of 69 MMscf/d, which was a significant increase on previous vertical/deviated wells. A second horizontal production well was drilled with similar results and the field was developed with a three-slot subsea template and a not normally manned platform.

1.6 Reservoir Simulation

These days, no development manager would consider presenting a project to an investment board without the results of a reservoir simulation to support the assumptions made. Reservoir simulation is a numerical method of representing flow in a reservoir toward the production wells and on to the surface under a number of chosen scenarios. The model can be used to run production forecasts and for assessing uncertainty for each development scenario.

The numerical model usually comprises an upscaled geological model, fluid data (pressure–volume–temperature [PVT]), and relative permeability information and fluid distribution: these form the initial state model prior to running any simulation. Well completion and production information is required plus some knowledge of the surface facilities at least at the wellhead. From these initial simulation runs it is possible to predict rates of production, pressure decline, and ultimate recovery for a given scenario, thus determining the value of the development. Ultimately, the model can be used to 'history match' production and then for prediction. Like all models the results are nonunique and dependent on the quality of the reservoir description. The Appendix has a simplified description of the process of reservoir simulation.

1.7 Field Production

The facilities required to handle the produced hydrocarbons depend on the type of hydrocarbons and the location of the reserves: offshore or onshore. An onshore oil field can be produced to local storage tanks prior to truck or pipeline transportation to a refinery. Onshore gas may be piped directly into local energy generation plant or liquefied for transport. Offshore platform developments for oil and gas usually require a pipeline to an offshore or onshore gathering system for further processing. Further offshore, and in deeper water, floating production and storage vessels (FPSO) are often a preferred solution.

A large part of field development planning addresses these fundamental options and the economic benefits and consequences of one or the other. Before committing to a major deepwater gas development the partner companies will construct a risk assessment based around three options: a deepwater installation to process the gas prior to export, a shallow water processing platform and pipeline, or a subsea development and a pipeline to an onshore gas processing plant. The subsea development and pipeline to shore was selected in part because it allowed for significantly greater processing capacity and opportunity for future gas discoveries to be developed through this infrastructure.

Magnus Field, Northern North Sea: *Magnus was discovered in 1974, but first oil was not until 1983. The field has an estimated 1.54 billion barrels of oil in-place with reserves of around 870 million barrels: around 56% recovery. The field was developed through a single drilling and production platform: the largest single piece steel structure in the North Sea. Initially there were facilities for 17 oil production wells, five water injection wells, and nine spare slots, and the production capacity was 140 000 BOPD and 2.5 MMscf/d of gas. The oil is exported via a 91 km pipeline to the Ninian Central Platform and then to the Sullom Voe terminal on Shetland. Produced gas is exported to Brent A* via *a 79 km pipeline and onwards through the FLAGS pipeline system to St. Fergus gas terminal on the Scottish mainland (Shepard 1991).*

A major project to increase recovery and extend field life was proposed in 2000 and implemented three years later. The project required importing gas from two West of Shetland oilfields via a pipeline to Sullom Voe where liquefied petroleum gas was added before being delivered by another pipeline to the field where it was reinjected into the Magnus reservoir to aid pressure support and hence recovery as a water–alternating gas (WAG) project. It was expected that an additional 50 million barrels would be recovered, and the field life extended by a further 5–10 years. The whole IOR project cost around £320 million. Ten years on, another field rejuvenation project was initiated to maximize the ongoing depletion strategy and to build a better understanding of the plant and well reliability both of which were successful in managing to achieve planned voidage replacement and plant restoration. The field operating efficiency has grown from 40% in 2013 to over 70% in 2017. At the end of last year, the company estimated remaining 2C resources at around 50 MMboe, but it has also identified various drillable targets that could lift remaining mobile oil in-place to 270 MMbbl. These, and a potentially large gas discovery made by the former operator, could form the basis of a long-term, low-cost development program.

1.8 Reservoir Monitoring and Surveillance

Monitoring the key reservoir indicators of hydrocarbon production is essential for both reserve estimation and management during the field life. Essentially, oil or gas production on a well-by-well basis, or by gathering station and by total field production, is required for basic economic valuation: the value of how much oil or gas is produced is the reward for the investment. How much water or gas is injected is monitored to estimate the pressure maintenance strategy, and the pressure decline in each well or reservoir unit may also be recorded to determine the wells that might need more support. Modern methods of reservoir monitoring include permanent gauges to measure real-time oil, water, and gas flow, sending the data to central data-gathering centers for analysis and for further intervention. This area of reservoir management is where many of the greatest advances have been made in recent years.

1.9 Improved Hydrocarbon Recovery

As hydrocarbons are produced the reservoir loses energy due to a decline in pressure, unless there is an active aquifer helping to support production; when this not the case it is necessary to provide that extra boost to the reservoir. This is commonly done through water injection into the aquifer, or gas injection into the crest of the field; gas compression may be a means to extending the life of a naturally depleting gas field. All of these methods require additional expenditure at some point in field life; sometimes this is built into the original development plan if appropriate. The economics must drive these decisions; there must be sufficient added value in extending field life, but the inventiveness and imagination of petroleum engineers never ceases to amaze me.

Beryl Field, Northern North Sea: *Brought on stream in 1976, and designed for a 25 year field life, the Beryl Field is still a location for near-field exploration and production over 40 years later. At a peak production rate of 200 000 BOPD an early phase of satellite developments slowed down the subsequent decline, however by 2012 the end was in sight. Following the acquisition of 3D broadband seismic in 2012–2013, PSDM seismic processing of the data has resulted in a better understanding of the structural and reservoir complexity. In view of this, a portfolio of near-field exploration targets was drilled in 2015–2016 with four commercial discoveries in two years, a 66% success rate. A key element of* *these wells was the planned sidetrack to evaluate different structural elements: one sidetrack penetrated a 200 ft column of oil that was greater than the original Beryl oil column. Production from these wells started a year later and, because of the existing infrastructure and its capacity, improved their economics significantly and halted the production decline. These results have arrested the production decline and extended field life by a further 5–10 years (Helgeson* et al. *2019).*

1.10 Cessation of Production: Field Abandonment

All oil and gas fields will eventually cease to be economic and must then be abandoned incurring a final cost to the overall CAPEX: hopefully this will be after long-term financial growth of profits. Around the world there are many oilfields still active after 50–100 years of production; indeed, many have long-term investment plans to continue their profitable life. However, some fields have had very short lives because of unforeseen circumstances: usually a matter of under-appraisal or having been under managed.

An example of such would be a trio of gas fields in the Southern North Sea that were abandoned after less than 10 years of production because of an unexpected influx of highly saline formation water that effectively blocked the pore space around the wellbore reducing gas flow completely. The fall in pressure toward the wellbore resulted in salt coming out of solution and crystallizing. Some remedial steps were taken to flush out the salt, but these were ultimately unsuccessful and the fields ceased production well before the expected ultimate recovery was achieved (Ketter 1991).

1.11 Summary

Developing and managing an oil or gas field requires a multidisciplined approach that can address the multiplicity of technical, commercial, and environmental issues. Hopefully, the rest of this book will demonstrate some of the challenges faced by oil companies, their staff, and stakeholders.