Introduction to Petroleum Economics
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By Chris Hinkin
BS mechanical engineering, University of Bath, UK
MBA, Aston University, UK

Society of Petroleum Engineers
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Society of Petroleum Engineers
222 Palisades Creek Drive
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http://www.spe.org/store
service@spe.org
1.972.952.9393
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Dedication

Dedicated to my parents.
Foreword

I recall with very fond memories my time as a student at Imperial College, London in the late 1970s, studying on the MSc degree course in petroleum engineering. Like all the other students, I absorbed everything I needed to know to begin an exciting career as a petroleum engineer—how to drill wells, analyze the data obtained from those wells (cores, logs, drill stem tests, etc.), understanding the basics of geophysics and seismic interpretation, the mapping of fields, learning the wonders of material balance, poring over the intricacies of offshore platform and pipeline designs, figuring out how the fledgling technology of reservoir simulation worked, etc., etc.

Almost as an afterthought, every week we had a 1-hour lecture on petroleum economics, which we all grudgingly attended, regarding it as distraction from the much more interesting and important subjects we were learning about.

Entering the industry immediately thereafter, it quickly became apparent that economics were a huge focus for petroleum engineers. I so wished I had paid more attention to those 1-hour lectures at Imperial College!

Chris Hinkin, the author of this book, and I worked together for 10 years, between 2005 and 2015. He taught me the importance of deep expertise and understanding of petroleum economics. He created literally many hundreds of millions of dollars of value for the company we worked for by applying his profound knowledge and his painstaking attention to details. Chris demonstrated the need and criticality of petroleum economics experts in our business. I wish I’d come across him 25 years earlier in my career.

I’m delighted Chris has decided to share his skills with a wide audience by writing this excellent book, which I wholeheartedly recommend to anyone wishing to improve their understanding of the subject—a must read.

Howard Paver
Senior Vice President
Hess Corporation, New York City
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Preface

Every year, oil companies spend eye-watering amounts of money searching for and producing oil, and take breathtaking risks that they will be rewarded.

And at the heart of deciding whether they would be wise or foolish to invest their money in drilling an exploratory well, say, or building an oil pipeline are petroleum economists whose job is to determine whether their company should grow richer or poorer by doing so.

So, clearly, what petroleum economists do in oil companies is important. In fact, surely little else that goes on in an oil company is more important.
Introduction

I wish someone else had written this book and I could have read it when I became a petroleum economist nearly twenty years ago.

My background then was relevant enough that both my employer and I were optimistic that, with some training, I would succeed in my new role. So I read a few books and went on some courses to help. And help they did. But only up to a point and not completely. In fact, they reminded me of Mrs. Fotheringham.

Mrs. Fotheringham was one of my math teachers at school, who taught by providing instructions: if the question asks this, you do this; if it asks that, you do that; which worked inasmuch as I passed tests. But I didn’t always understand why I was doing what I was doing.

And the same was true of those books and courses. They provided me with instructions but not always an understanding.

Since then I’ve read more books and gone on more courses that have helped me up to a point but not completely and have reminded me of Mrs. Fotheringham.

But never mind, because after nearly twenty years as a petroleum economist (that has proved to be very far from the relatively small step becoming one was meant to be), I now understand. So what follows is the book that I wish I could have read twenty years ago.

Chris Hinkin
Some Housekeeping

Before we start, I want to make sure that anyone going beyond this point knows what’s in store for them. I want to be clear about what I mean by petroleum economics; I want to be clear about where I’m going to draw the line regarding what I believe is necessary to know and what isn’t; and I want to be clear about how I’m going to say what I’m going to say. That way, no one will be disappointed expecting this book to be something it isn’t.

So let’s begin with the most important question: what is petroleum economics?

What Is Petroleum Economics?
I gave up telling people that I’m a petroleum economist a long time ago after doing so had killed too many conversations stone dead. In a change of tactics since then, my conversations have enjoyed a much better survival rate by my telling people that I’m an economist in an oil company.

Why the change worked, I don’t know. Clearly, in some way, “economist in an oil company” says something more meaningful than “petroleum economist” does. The trouble is that while conversations survive now (albeit, often, left wounded and suffering), they usually take off in a direction that isn’t at all relevant to what I do.

People assume I forecast oil supply and demand, or I estimate countries’ economies’ resilience to oil price, or I’m an oil trader. But I do nothing of the sort.

In fact I’ve already alluded to what a petroleum economist’s job is in the earlier Preface, which I’ll repeat here, paraphrased:

A petroleum economist’s job is to determine whether his or her company should grow richer or poorer by investing its money in, for example, drilling an exploratory well or building an oil pipeline.

I’ll talk about certain aspects of that sentence later on, like why “should,” why the sense of uncertainty? And how do we measure “richer or poorer”? But the definition is good enough for now.

So petroleum economics makes the case to oil companies to spend money on something because to do so should make them better off; and, possibly even more important, it also makes the case to them not to spend money because to do so should make them worse off. Of course, cases are also made at the same time to do one or the other by other parts of the company, which may relate to political issues, or the company’s own strategy, or tactical maneuvering to thwart a competitor; and decision makers have to consider all these things too in coming to their decision.

But this book is about petroleum economics, so I’m going to stick resolutely to that topic and not get distracted.
There’s just one more thing to be clear about here, which is where in the oil industry petroleum economics applies. The oil industry can really be divided into at least two subindustries: the *upstream* part and the *downstream* part. The upstream part relates to oil companies’ activities in exploring for, and producing oil from, oil fields, and the downstream part relates to their activities in refining what the oil fields produce and selling products such as petrol (gasoline in the US).

This book concerns the upstream part of the industry and therefore how petroleum economics contributes to helping oil companies make decisions about searching for oil, producing it, and transporting it only as far as the point at which the downstream part takes ownership of it.

**Where Is the Line Drawn?**

There are actually two lines I want to draw regarding what I believe is important to know and what isn’t: the starting one and the finishing one.

On the finishing one first: I’m not out to boldly go where no petroleum economist has gone before (to coin a well-known phrase). On the contrary, I want to stay within the bounds of common petroleum economics practice and the tools of the trade that most petroleum economists around the world use every day; which are, without doubt, *cash flow modeling* and *discounted cash flow* (much more about these later).

More exotic tools do exist, and I’ve seen some of them in action; and I’ve also witnessed first-hand why they usually fail, which they do for up to two reasons:

- One is that too little attention is paid to basic concepts, basic assumptions, and basic calculations. In other words, someone has built a sophisticated house on foundations that can’t support it. The house can be as sophisticated as you like, but without proper foundations underpinning it, it will fall down. Now that issue can, of course, be addressed through education and training, and so perhaps it isn’t an insurmountable hurdle to overcome.
- The other reason is less surmountable, however, and more tricky to overcome. It’s that senior managers who make decisions, who take ultimate responsibility for approving the multimillion-dollar investment before them, want to understand—no, more than that, insist on understanding—why the petroleum economist’s advice is what it is and how he or she reached that conclusion. And if the senior managers don’t understand, they won’t approve the investment; it’s as simple as that. It won’t do the petroleum economist any good waving a hot-off-the-press PhD thesis in front of them; he or she will quite likely be escorted from the boardroom, and probably from the building as well.

So, this book is restricted to the everyday tools of the trade that petroleum economists use, and anything less commonly used is beyond the line and out of bounds.

As for the starting line, I don’t assume any knowledge whatsoever of cash flow modeling and discounted cash flow. Or any understanding of these individual words even. All I assume is an interest in petroleum economics as I’ve just defined it.

**How Am I Going to Say All This?**

Between these two lines—the starting one and the finishing one—is the contents of this book, and so let me say something about this space.
This isn’t a report or an academic thesis. It’s a book; and one I’d very much like you to have some pleasure in reading. In the hope of achieving that aim, I include little in the way of mathematics. There will be technical language only where it’s completely unavoidable. And I also promise not to use the words “concept,” “framework,” “systematic,” and “methodology.” At the same time, however, I can’t promise you espionage, murder, romance, car chases, or alien invasions. Only the subject of petroleum economics explained as clearly, usefully, and interestingly as I can.

And a Few Last Comments
The very last few housekeeping issues are these:

When I use the word “oil,” I do so for convenience only and I mean any salable product (including, for example, gas) originating from a hydrocarbon-producing field.

Second, terminology may differ among companies and even countries. I know, for example, that what a UK company calls a finance department, an American company calls an accounting group. I hope these differences cause minimal confusion.

And finally, petroleum economists can, of course, be male or female; however, I have to use certain words now and again that prescribe them as one or the other, which I imply nothing whatsoever by doing.

To Summarize
Petroleum economics is the voice that tells oil companies whether, for example, drilling an exploratory well, building a pipeline to connect an oil field to a refinery, or selling gas to a power station ought to make them richer or poorer.

This book is about how petroleum economists provide that voice, which they most commonly do through the use of cash flow modeling and discounted cash flow.
Chapter 1

Introducing Cash Flow

What petroleum economists care about above all else in the world is cash flow (in a professional, not a personal, sense that is; although many, myself included, consider it to be quite important in our personal lives too).

So what is cash flow, and why do petroleum economists care so passionately about it?

1.1 Cash Flow Defined
Cash flow is the flow of cash from someone to someone else, or from one organization to another one; that is, real money changing hands from a provider to a recipient. Providers can be just about anyone and just about any kind of organization, and so can recipients. And it comes in all shapes and sizes: it can matter or it may not, it may be expected or it may be a surprise, it may excite me or it may scare me, it may be in my control or it may not be.

But whether or not it’s any of those things, the first thing we have to do is discover it. That may seem like an odd thing to say. In an oil company, I don’t have to look very hard to discover the cash flow involved when we sell a cargo of oil (obviously, we receive cash from whoever buys it), nor do I have to look very hard to discover the cash flow involved when we pay for a new pipeline (obviously, we pay cash to whoever builds it). I may not know exactly how much we’ll receive and how much we’ll spend, respectively, until the time comes, but I can discover the cash flows alright.

1.2 A Cash Flow Example
Consider this example, then. Your boss asks you what cash flows another company (coincidently called Another Company Inc.) that owns a 10% stake in some oil fields in Russia experiences, which your company (coincidently called Your Company Inc.) owns the other 90% of.

As shown in Fig. 1.1, the ownership structure (in black) and financing (in red) of the oil fields looks like this:

Another Company owns a stake not in the Russian oil fields themselves but in a company (Let’s Be Friends Ltd.) that’s incorporated in the British Virgin Islands. Your Company is incorporated in the Cayman Islands and owns the other 90% of that company. The Russian oil fields are owned by a Russian company, Russia Oil Co., which is owned by a Cypriot company, Russia Holdings Ltd.

Only Your Company has provided the necessary funding to the Russian company to explore for (and, we’ve been lucky, discover), develop, and produce the oil fields, which
it has done by (1) buying preferred stock in another Cayman Islands–incorporated company (Together We Stand Inc.), (2) lending money from there to a company incorporated in Luxembourg (Russia Capital Corporation Sarl), and (3) that company lending the money on to the Russian company. The oil fields are now healthily and happily producing and selling oil.

What answer do you give your boss?

It really isn’t obvious, is it? And the answer isn’t important, in fact; and nor does it matter if you don’t know what preferred stock is and have never seen a corporate structure like this before. My point is that cash flows aren’t always obvious. They can’t always be spotted without the need of even a moment’s thought.

On the contrary, discovering cash flows requires investigation, proper investigation. And that investigation may have to be quite detective-like: talking to suspects you think might be involved, understanding motives, and finding out dates, facts, and figures. It may take you to your company’s finance department, or to engineers or tax experts, or to the project office, or to parts of the company you’ve never seen before and perhaps didn’t know even existed.

1.3 Why Is Cash Flow So Important?

But what makes cash flow so important that petroleum economists are prepared to go to the very ends of the company to discover it? The answer is because establishing cash flows is the start of their journey to measuring whether their company should
become richer or poorer as a result of doing something (drilling that exploratory well, for instance).

1.4 To Summarize
Cash flow is the flow of cash from one person or organization to another. Sometimes its existence is obvious, but other times it isn’t and it has to be sought out.

Discovering cash flows is essential however, because it holds the key to petroleum economists being able to answer the question that’s their responsibility to answer: should doing this (drilling this exploratory well, for example) make our company richer or poorer?
Chapter 2

What Is It About Cash Flow?

So far, I’ve talked about cash flow in the very general sense of what it is and why it matters. Now I’m going to talk more specifically about the cash flows oil companies experience, which will occupy this chapter and the next two.

Some of the cash flows oil companies expect to receive and some of them they expect to incur are cash flows they ought to “know,” although by “know” I don’t mean know for certain. Rather, they’re cash flows that people in the company with particular knowledge and expertise can estimate—for example, how much oil the oil field will produce and what price it will sell for (and so, between them, how much revenue the oil will generate for the company), as well as what it will cost to build everything to do with accessing it (platforms and pipelines perhaps). The next chapter is about that sort of cash flow.

But some cash flows can’t be estimated like that. Some of them must be derived from separate—and often quite complex—calculations. These cash flows relate to a country’s “fiscal terms,” which is an important expression that warrants definition straightaway. “Fiscal,” according to my dictionary, is defined as “pertaining to the public treasury or revenue,” and “terms” conveys what “pertaining” means in practice. In other words, fiscal terms are taxes, although “tax” is actually far too blunt a word.

Over the years, governments have invented ways of sharing in oil revenues that the word “tax” simply doesn’t do justice to. So a more helpful definition of “fiscal terms” is “what the government takes,” in all its varied and inventive forms. It’s the cash flow that goes to the government (or governments, plural, as we’ll see later). Chapter 4 is about that sort of cash flow and the calculations that derive it (I bet you can’t wait).

Before any of that though, we should consider a few things that petroleum economists have to establish about cash flows first, however they’re derived and whatever they relate to.

2.1 Cash Flow: Beyond Discovery

Petroleum economists need to answer three questions about a given cash flow:

1. Is it relevant?
2. How big is it?
3. When does it occur?

We’ll consider these individually and in that order.
2.1.1 Is a Cash Flow Relevant? The number of cash flows that take place in even a small oil company can be many, never mind in a large international organization, in which the number is truly immense. Luckily, though, petroleum economists don’t have to care about all of them. In fact, they don’t have to care about many of them. They only have to care about cash flows that pass two tests.

The first test is that cash flows must be brought about by the new activity the company is considering doing (I’ll continue using the same example: drilling an exploratory well). So these are cash flows that would newly come into the company or would newly exit it directly as a result of the company doing this new thing, whatever it may be. They may be brand-new cash flows that are created, or they may be changes to cash flows that already exist. Either way, the brand-new cash flows and the changes in already existing ones must be completely attributable to the new activity.

The second test is best described with the aid of a picture (see Fig. 2.1). Here’s an oil company with a border around it.

Once again, the company is shown as a corporate structure. Boxes represent companies that are owned by other companies higher up and ultimately are owned by the parent company at the very top. All companies can be depicted like this, and large international oil companies may have hundreds of boxes representing their various businesses doing various things in various parts of the world.

Beyond the border is the rest of the world; that is everything that isn’t the company. To pass the second test, cash flows must cross this border; they must move from inside the company to outside it or from outside it into the company.

Any cash flows that remain completely inside the border (and therefore completely inside the company)—for example, a cash flow from one box to another one—and any cash flows that remain completely outside it fail the test.

A way to think of this is in terms of bank accounts. Cash flows that cross the border go from one of the company’s bank accounts (companies usually have more than one bank account) to someone else’s, usually one that belongs to another company or to the government. Or, of course: to one of the company’s bank accounts from someone...
What Is It About Cash Flow? 7

else’s. Cash flows between bank accounts that both belong to the company don’t cross the border.

If a cash flow passes both tests, it qualifies as a “relevant” cash flow. Passing only one test, no matter how admirably, isn’t enough. It must pass both. Petroleum economists are interested only in relevant cash flows. If a cash flow isn’t relevant, then they aren’t interested in it and they can ignore it.

2.1.2 Cash Flow Example. An example, as ever, is helpful. Here’s the situation. An oil field of ours in Denmark has been producing oil successfully for several years. Now, our explorers have discovered another oil field nearby (as we speak, they are in the pub yet again, though this time with good reason: to celebrate). The new discovery can be produced through the existing field’s production facilities, although we’ll have to lay a pipeline back to them and also add extra equipment to them in order to do so.

You are the petroleum economist and so must advise the company’s board of directors regarding whether to develop the discovery into a producing field (having determined if the company should become richer or poorer in doing so, although we’ve only just begun talking about how petroleum economists do that, so the board will have to wait a few more chapters yet).

You start by thinking about what the relevant cash flows would be if we developed the field, as follows:

i. The new field would produce oil that we’d sell to another company (one that owns a refinery, given that we don’t have one of our own). Is the money we’d receive for the oil a relevant cash flow? Yes it is, you conclude, because it crosses the border from outside the company into it; and if we don’t develop the field, we won’t otherwise produce the oil and sell it. So, the oil production and the incoming cash flow associated with it occur as a direct result of our decision to develop the field.

ii. But developing the new field would cost money. You’re told that we would need to drill three new wells, and those wells would be connected back to the existing field’s production facilities by a new pipeline, all of which work would be carried out by a contractor company that is completely separate from us.

Regarding the extra equipment for the existing production facilities, however, it turns out that we acquired identical equipment last year for another project in Indonesia that won’t, after all, use it and is unable to sell it. “So,” the project manager tells you, “we shouldn’t have to pay full price for that because it’s secondhand now.” You think about that over a cup of coffee afterwards. “Hmmm,” you ponder. “The cost of the wells and pipeline is relevant cash flow. It crosses the border from inside the company to outside it, and it wouldn’t occur if we didn’t develop the new field. But if we already own the extra equipment and paid for it last year, then while our new Danish project may have to buy it from our Indonesian project to preserve the integrity of each project’s own accounts, that wouldn’t be relevant cash flow. True, cash flow may occur that wouldn’t have occurred had we not chosen to develop the new field in Denmark, but it doesn’t cross the border. It would be ‘from one box to another one,’ between bank accounts that both belong to the company.
It would be different,” you ponder further, “if the equipment could be sold by the Indonesian project. In that case the Danish project is therefore depriving the company of that opportunity, which means the Danish project must assume responsibility for, effectively, costing the company money, real relevant cash flow money, the money it would otherwise have received from the equipment’s sale.” Economists call that an “opportunity cost” for the company and, in this scenario, it would count as a relevant cash flow, a cost, for the company’s Danish project.

“And then there would additionally be relevant cash flow in transporting the equipment from Indonesia to Denmark and installing it there.”

You finish your coffee and head back to the project manager’s office.

iii. Not only would developing the new field cost money, so would producing it. There’d be costs to transport the oil to the place where we’d actually sell it, there’d be costs to ensure that the new wells and pipeline are maintained in good condition, and there’d be some additional costs associated with the existing production facilities, given the extra equipment it would have and the more oil production it would handle. Without going into any more detail than that, just for now let’s say you satisfy yourself that all these costs are relevant; they all cross the border, and they wouldn’t occur at all were it not for us developing and producing the new field.

iv. If the new field made a profit, we’d have to pay tax. (We haven’t talked about tax yet. That’s for Chapter 4. So, until then, we won’t talk about it in any great detail.) You visit the tax department, and the heads of the half dozen or so people who work there turn around as you walk past. You go to the head of tax’s (Mr. Smith’s) office and explain your task. Mr. Smith tells you that from a tax point of view, it should be straightforward, but he adds, “We’ll probably finance the development by lending money down from our Bermudan holding company. We can offset the interest we pay in Denmark against the tax we pay there. So you’ll need to take that loan and interest into account.” He then asks you, “Will you stay to have a cup of tea with us? We don’t get many visitors.” You say that you’re sorry, but you’re on your way to see the project manager and so, unfortunately, you don’t have time. He looks disappointed. As you leave, the whole department gathers to see you off, and they all wave as you disappear around the corner and out of sight.

Glancing back, you think you can see a tear in Mr. Smith’s eye.

As you walk back along the corridor, you think to yourself, “Tax is a relevant cash flow. It crosses the border, and we wouldn’t pay tax on the new field’s profits if we hadn’t developed the field in the first place.” Then you remember Mr. Smith also saying something about financing the project. “Hmmm,” you ponder once again. “But surely the loan isn’t a relevant cash flow? All that happens is cash moves from one box inside the company to another one (from our Bermudan holding company to our Danish company) when the money is lent, and then it moves back again in the form of interest and when it’s repaid. It doesn’t cross the border. That makes sense,” you decide, and you nod your head as you walk along.

“But what about what Mr. Smith said about us offsetting the interest on the loan we pay in Denmark against the tax we pay there? What does that mean?” you ponder some more. “So what happens is the tax we pay in Denmark is
reduced because those interest payments can be offset against our tax bill. So,” it dawns on you, “whilst the loan itself isn’t relevant cash flow, I do have to take into account how it affects the tax we pay, because the tax we pay is a relevant cash flow.”

You walk on with a smile on your face and someone you pass asks you if you’re feeling alright because nobody ever comes away from the tax department smiling.

2.1.3 How Big Is the Cash Flow, and When Does it Occur? Of course, petroleum economists have to know the answer to the second question, how big the cash flows coming into and going out of the company would be as a result of it doing something new. Naturally it matters whether the sums involved are thousands of dollars, millions of dollars, tens of millions, hundreds of millions, or billions.

But almost as necessary for petroleum economists to know is when these cash flows would occur, the answer to the third question. Briefly, because a whole chapter is going to talk about this later on, it’s why utility companies encourage us to pay our bills monthly rather than at the end of each 3-month period, and why “buy now, pay next year” offers for new sofas appeal to so many people. But more about that later on.

So where does all this talk about relevant cash flows and the size and timing of those cash flows leave us? The answer is in a very important place. It leaves us in the place where we know how our whole company’s cash flow profile would change from now into the future if it did the new thing. We’ve isolated what difference doing it would make to our company’s present and future cash flows. And that’s vitally important to know in our challenge to understand whether our company might become richer or poorer as a result of doing it.

2.2 To Summarize

While there are many cash flows that take place in an oil company, petroleum economists care only about the ones that are relevant.

Relevant cash flows are those that, first, are created by the company doing something new, such as drilling an exploratory well or developing an oil discovery into a producing field. These cash flows may be brand-new or they may be a change in an already existing cash flow. And second, they’re cash flows that cross the company’s border with the outside world: they come into the company from completely outside it or exit the company to completely outside it. Cash flows that don’t pass these two tests aren’t relevant cash flows and petroleum economists can ignore them.

Petroleum economists also need to establish the size of relevant cash flows and determine when they occur (the latter of which we’ll talk much more about later).

All this information together tells petroleum economists how their company’s overall cash flow profile from now into the future would change as a result of it doing the something that’s new, and it’s a vital stepping stone that allows them to begin to determine whether their company should become richer or poorer as a result.
Chapter 3

The Relevant Cash Flows Oil Companies “Know”

This chapter is about the kind of relevant cash flows that experts in the company can estimate. Such cash flows are distinct from those that are derived from often quite complex calculations relating to countries’ fiscal terms—in other words, the cash flows that governments take from oil fields’ profits. The next chapter will cover that kind of relevant cash flow. Here, I’ll talk briefly about the relevant cash flows that are typical of each phase of an oil field’s life, which are:

1. Exploration—that is, the original search for an oil field.
2. Appraisal—that is, gaining an understanding of what has been discovered (of course, providing something has indeed been discovered) before deciding whether to develop it.
3. Development—that is, providing all the wells and production facilities so that a discovered field can produce its oil.
4. Production—that is, operating the wells and facilities safely and maintaining them in good order, ensuring the produced oil is fit and ready for sale, and transporting it to the place where it’s sold.
5. Decommissioning—that is, removing as much evidence as possible that an oil field was ever there and returning the locality to what it looked like beforehand.

In no way is it my intention to explain how such cash flows are estimated. I couldn’t if I tried, and I take my hat off to those who do it. But petroleum economists mustn’t be ignorant of the process either. We use the numbers that these experts produce, which makes us their customers; and when a customer, it always pays to be an informed one. So in this chapter, simply making more informed customers of us regarding these cash flows is my hopeful goal.

I ought to make a few obvious points first, however. Oil fields are found in very different places, come in very different shapes and sizes, and present very different challenges to make them work. So generalizing is difficult when we talk about them, but I don’t think that matters for this chapter’s general purpose. Also, the phases of an oilfield’s life aren’t necessarily as neatly sequential as I’ve just suggested. In practice, different phases sometimes merge together into one, and it isn’t uncommon for activities of previous
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phases, or even whole phases themselves, to be repeated later on in a field’s life, and sometimes more than once.

Here are the typical relevant cash flows that oil companies know.

3.1 Exploration

1. For onshore exploration, investigation of geological features on the surface that may indicate the presence of an oil field below it, for example, through fieldwork and satellite studies.

(I don’t intend, by the way, to say much about the activities and processes I’m mentioning here that give rise to these cash flows. Once again, I couldn’t if I tried. But good books exist on each one of these subjects and, of course, courses too; so I delegate to them for that.)

2. Geophysical surveys that penetrate below the surface and indicate what may lie beneath it, for example, seismic, gravity, and magnetic.

The preceding two areas of work are often referred to as “G&G,” for geology and geophysics.

3. Drilling an exploratory well, including all the services needed to support the operation (provision and transportation of supplies, materials, equipment, and crews for and to the drilling site); gathering information “downhole” that will indicate what’s there; collecting material, including cores (“plugs” of rock), from it; and testing (if a discovery is made) by producing from it for a short period of time. Note that not all these activities may be carried out for every well.

4. Study of what we can learn from the well by evaluating material recovered from it and processing information gathered during and after drilling.

5. Usually payment of annual fees to the government for the ongoing rights to explore over an area.

6. Office and onshore operations base costs, which I’ll talk more about later on.

3.2 Appraisal

7. Drilling an appraisal well or wells, commentary about which is similar to that for drilling an exploratory well (point 3).

8, 9, and 10. Same as points 4, 5, and 6.

11. Appraisal may involve producing from a well for an extended period of time to understand the field better than can be concluded from a short test. To do so can generate cash flows both out of and into the company, involving both the costs to collect, process, and transport the oil and the receipts from its sale.
3.3 Development

12. Drilling a development well or wells, commentary about which is similar to that for drilling of an exploratory well (point 3).
13. Study of what we can learn from the well (see point 4).
14. Preparation of an early engineering design to establish how to develop the field, to agree on the specifications of plant and equipment that will be needed, and to better understand the project’s execution plan and what it might cost to fully design, build, install, and commission it.
15. Creation of a detailed design that can be given to manufacturers to build.
16. Manufacture of everything necessary to receive production from the well(s) and deliver salable products.
17. Connecting all the manufactured parts together and making sure the whole system works as expected.
18 and 19. Payment of fees and costs (see points 5 and 6).

3.4 Production

20. The day-to-day cost of the whole production operation, including paying the people who make it work, getting them to and from the field, and looking after them when they’re there; fuel and power for all systems of the production operation; provision of supplies and their transportation to and from the field; and routine maintenance.
21. Chemical treatments, especially in pipelines to maintain the flow of production and prevent the buildup of substances that might hinder it and also to preserve the condition of the pipelines.
22. Wells, which can fail either partially or completely for a number of reasons, require maintenance that may, depending on circumstances, be costly.
23. Plant and equipment must be regularly inspected and maintained to keep it in good working order and preserve a safe working environment.
24. Oil may be transported through systems that aren’t owned by the field that produced it (pipelines, for example) and may also be subjected to further processing. Owners of those systems charge a fee—a “tariff,” usually per unit of volume—for providing those services.
25 and 26. Payment of fees and costs (see points 5 and 6).
27. Receipts into the company from the sale of oil.
28. Just as we may pay tariffs to transport and process our oil in other fields’ systems, other fields may pay tariffs to us to transport and process their oil in ours.
29. Royalties (sums of money) that oil companies have agreed to pay other oil companies and individuals for a variety of reasons, which I’ll expand on in the next chapter.
3.5 Decommissioning

30. The cost of taking the field’s wells out of service.
31. The cost of taking away all plant and equipment and returning the environment to a safe, clean, and natural condition.
31 and 32. Payment of fees and costs (see points 5 and 6).
33. Possibly the sale of certain plant and equipment to another company for further use or for scrap.

3.6 To Summarize
Here’s a diagram (Fig. 3.1) by way of a summary of all these cash flows.

![Fig. 3.1 — Summary of cash flows.](image-url)
Chapter 4

The Relevant Cash Flows Oil Companies Have to Calculate

This chapter is about the kind of relevant cash flows oil companies calculate as opposed to the kind they estimate (which were discussed in the last chapter). So, basically, I’m going to talk about tax and the various other forms of income that countries’ governments receive from oil fields and oil companies.

But here’s a short story first. I always imagined tax was such a complex subject that you had to have a PhD in physics, or something like it, to understand it; and that was especially a concern of mine in my early years as a petroleum economist because tax involves such large sums of money. Well, one day back then, I didn’t understand some calculations relating to tax, and so I wandered along to the tax department for some help. There I met a young gentleman who, it turned out, hadn’t been with the company for long either. Before I sought his help, we chatted for a few minutes. “So what’s your background,” I asked. “I’ve just finished my PhD in physics,” he replied.

True story.

But don’t be afraid. There’s nothing to be frightened of, I promise. As long as we stick together and stay alert, we have nothing to fear.

This chapter is divided into four parts. The first part covers fiscal terms in the country in which an oil field resides (as a reminder: fiscal terms are simply the rules that determine what the government earns from an oil field or oil company). The second part talks about taxes when profits generated by an oil field in one country leave that country for another one (which happens all the time in international oil companies). The third part covers how that money is treated by the other country’s tax authorities when it gets there. And the fourth part covers indirect taxes, the meaning of which I’ll explain when (and I’m confident it’s “when” and not “if”) we get there.

This brings me to a plain and simple fact however: I can’t in the space of just several pages provide a detailed explanation of what is a fantastically complex subject. To do so would be an impossible undertaking and my ambition for this chapter is much more modest than that. Every country’s fiscal terms vary around some common, basic principles, and all I aim to do is explain what those common, basic principles are so that you can go and talk intelligently to your own tax department about your project. They can then tell you if your project varies from those principles and, if so, how, and describe the applicable fiscal terms with more precision.
Petroleum economists aren’t tax experts, and because of that, and also because taxes are such important and often complex cash flows in petroleum economics, going to talk to their tax departments is something that petroleum economists simply have to do—and they have to do it a lot.

So, here we go with just one last piece of advice: stay calm at all times. If you feel yourself starting to panic at any point, stop reading and breathe deeply for a few moments; and if that doesn’t work, take a break and make a cup of tea before continuing.

4.1 Fiscal Terms in the Country in Which an Oil Field Resides

Tax authorities in most countries have one set of fiscal terms for oil companies and another set for other, non-oil companies. They generally treat oil companies differently. They may use a completely different approach to what most of us might immediately understand by the word “tax” (as much of Africa and Asia do, for example, in the form of production sharing contracts, which we’ll talk about later), or they may just charge oil companies extra tax over and above what every company already pays (which Norway, Denmark, Russia, and Australia do, for example).

I’m not going to discuss the rights and wrongs (in my humble opinion) of oil companies’ differential treatment by countries’ tax authorities, nor about the relative merits of how they achieve it, because countries’ fiscal terms are, generally, what they are and it’s unusual that petroleum economists can design or change them. We can moan that they’re too severe or that they don’t make sense, but usually our opinions don’t matter. So I’d much rather spend our limited time together simply talking about how they work.

I alluded just now to there being two broad approaches to fiscal terms that countries’ tax authorities apply to oil companies:

- An extension of the ones that apply to every company
- A completely different approach to the ones that apply to other, non-oil companies

It’s this distinction that produces the two broad types of fiscal terms that are used across the oil industry: “concession,” also called “tax/royalty,” which is applied in countries that fit the first bullet point, where some more tax is added to the tax that every company already pays; and “contractual,” which is used in countries that fit the second bullet point, where a very different approach is taken. Some countries use both types of fiscal terms, although only one type ever applies to an individual oil field save in just one or two instances in the world.

The next few pages talk about these two broad types of fiscal terms one at a time, although it might be helpful to describe them briefly first, just to illustrate the fundamental difference between them. And from now on in this chapter I’ll boldface certain words that I think would benefit from explaining, which I’ll do as soon as possible after I’ve used them for the first time.

4.1.1 The Difference Between Concession and Contractual Fiscal Terms. From a petroleum economist’s point of view, the difference between concession and contractual fiscal terms lies in how the profits an oil company makes from an oil field are determined for the purpose of deciding how much of it the oil company keeps and how much the government takes.
Take a producing oil field. In a concession world, the oil company that owns the oil field spends money finding it, developing it, and producing it; it sells the oil the field produces and pays tax on any profits it makes from the whole venture.

Regarding the word “owns”: strictly speaking, oil companies don’t own oil fields. Ownership usually rests with countries’ governments, which award oil companies the rights to explore for, produce, and sell oil from one or more of them for a period of time in return for assurances that they’ll honour any promises they’ve made (for example, to drill a certain number of exploratory wells) and abide by rules regarding their conduct. Not always, however; onshore in the US, for example, ownership rests with individual landowners. So when I use the word “owns” in this context, I use it loosely.

Back to the fundamental difference between concession and contractual fiscal terms: in a contractual world, however, the oil that an oil field produces is divided up between the oil company and the government according to a procedure that’s set out in a contract between them.

In both cases the oil company makes a profit, it hopes, but the profit is just calculated differently; and that profit—whichever approach is used—can be taxed. In that respect, therefore, it’s a shame that concession fiscal terms were ever also called “tax/royalty” because tax doesn’t apply only to that approach; but they are and that’s that.

4.1.2 Concession, or Tax/Royalty, Fiscal Terms. As its other (unfortunate) name suggests, concession fiscal terms have two parts: a tax part and a royalty part, although they don’t necessarily include both; some concession fiscal terms have only a tax part.

Royalty. We’ll begin with royalty because it comes first in computations of concession fiscal terms.

Royalty is a proportion of an oil field’s oil that the government takes as its own, without paying for it. The payment may be provided by oil companies “in kind” (meaning in actual oil) or “in cash” (meaning money; the cash equivalent of the relevant amount of oil), or more commonly as either and the government chooses which method of payment it wants when a royalty payment is made. The payment is invariably defined as a proportion and not a fixed amount of oil production, so it would be, say, 5%, rather than, say, 100,000 barrels in a year. It’s a proportional slice of whatever’s produced.

The amount typically ranges from 5 to 15% and can apply to any product the field produces. That amount goes straight to the government authorities. It belongs to them from the start and the oil company has no claim whatsoever to the income from it when it’s sold. In Monopoly speak: it goes straight to the government; it does not pass go and does not collect two hundred pounds (ignore this sentence if you’re not familiar with the game of Monopoly).

In practice, governments like royalty and oil companies don’t.

Oil companies first: like anyone else, oil companies prefer to be taxed (if they have to be taxed at all, that is) on the profits they make. But oil fields pay royalty whether they’re profitable or not. So long as they produce oil, a portion of it is taken by the government. Even if an oil field makes no profit at all, the oil company owning it still pays royalty.

In particular, royalty hurts oil companies in the early years of an oil field’s life when they’ve just spent a great deal of money drilling wells and building platforms and so on, which they’re eager to recoup as fast as they can; yet as soon as an oil field begins producing, royalty is immediately due.
Governments, on the other hand, like royalty, and pretty much for the same reasons that oil companies don’t like it. They have the certainty that they’ll receive income from an oil field whether or not it’s profitable for the oil company; and not only that, they’ll receive it straightaway, as soon as production starts.

So what’s the difference between royalty and tax? (That isn’t a joke by the way, like what’s the difference between a tax accountant and a coconut? Answer: you can get a drink out of a coconut.) For petroleum economists, there isn’t one really, except in the nature of their calculations. Apart from that, the difference between them may boil down to nothing more than the way they’re both reported in the company’s accounts, but that isn’t important here.

Before we leave this section, it’s worth noting that the word “royalty” is also used to describe payments that oil companies sometimes make to, and receive from, other companies or even private individuals. Royalty of this sort may come about because one oil company has sold an unexplored area to another one and they’ve agreed that should oil be found there by the buyer, the buyer will pay the seller a “royalty”—a fee—when that oil is produced. It may also result when an oil company makes use of property owned by a private individual, who is then compensated in the form of a “royalty.” Although these so-called royalties represent relevant cash flows, they aren’t a part of a country’s fiscal terms.

**Tax.** There are two kinds of tax that I’ll talk about next: production taxes and profit-based taxes, and I’ll talk about them in that order.

*Production Taxes.* Of course, strictly speaking, all taxes on oil companies—at least in relation to their ownership of oil fields—are production taxes because it’s producing oil that earns oil companies the profits they pay tax on. Here, though, by production taxes I mean taxes that are based on the oil an oil field produces rather than on any measure of the profit it makes.

In that respect, these taxes are therefore quite royalty-like in the way they work, although they differ from royalty in their mechanics. Whereas royalty is a slice of whatever oil is produced, production taxes are a cost per barrel, ton, or other measure of oil produced, although the cost may be adjusted by factors that increase or reduce it, taking into account, perhaps, the oil field’s size or location or other more or less challenging circumstances that make it more or less profitable. And that means that even taxes as relatively straightforward as these follow no common algorithm in the countries that use them.

Despite the fact that they can be made more or less sensitive to oil companies’ fortunes than royalty, at the end of the day they still bear the hallmarks of royalty (by not being profit based) however, and so they have similar advantages and disadvantages in the eyes of oil companies and governments.

*Profit-Based Taxes.* Whereas not all concession countries have a royalty or production taxes, they all have some kind of profit-based taxation. “Profit” is a word we use all the time, of course: we make a profit when we sell something for more than we paid for it and we sustain a loss when we sell something for less than we paid for it.

About the most important feature of profit-based taxation is that we pay tax when we make a profit and we don’t pay tax when we don’t make one. It’s important enough to say again: if we make money, we pay tax; if we lose money, we don’t.
A former tax teacher of mine (I say “tax teacher”; the company I worked for thought of him more as someone they employed to manage their tax department) always used to say that paying tax isn’t a bad thing; at least it means you’re making money.

Profit-based taxes work like this:

1. We take the **value** of what we’ve received.
2. We subtract, in the form of **deductions**, what it has cost us to create that value.
3. We multiply what’s left, which is our **taxable income**, by a **tax rate**; and the answer is the **current tax** that we have to pay.

Again, I’ll spend a moment on each of these terms.

**Value**. The value of what we’ve received is what everything we’ve received is worth in the eyes of the tax authorities. The “in the eyes of the tax authorities” part is important. Let’s say we sell a barrel of oil on the open market for USD 92.74. The tax authorities would agree that it’s worth USD 92.74 because of the very fact that we sold it on the open market. That’s what the open market was prepared to pay us for the barrel of oil, and so that must be its fair value. If we sell the oil cheaply, as a favour to a friend, say, the tax authorities’ alarm bells would ring, concerned that they’re missing out on some tax revenues; which may result in their assuming, for tax purposes only, that we did sell the barrel for USD 92.74, or a price much more like it. This is a concern that some countries circumvent completely by applying an ‘approved price’ to any barrel of oil that’s sold (Norway does, for example, with their “norm price”) which is a price set by the tax authorities that producers must use for tax purposes.

Another Scenario. Let’s say we agree with the owners of another oil field that we’ll transport their oil in our pipeline and in return they’ll give us 5% of the oil we transport for them. Do we pay tax on the oil we receive? Most certainly we do. Paying us in oil is still paying us, and so we have to calculate the oil’s equivalent value, and that’s the amount we declare to the tax authorities that we’ve received.

Usually, we’ve had to spend some money in order to create value, and profit-based taxation allows us to subtract the money we’ve spent from the value of what we’ve received in order to arrive at the amount we have to pay tax on. But what we subtract isn’t generally as simple as what we’ve spent, when we’ve spent it. What we subtract are deductions, although, strictly speaking, I ought to say “allowable deductions” because whatever it is we’ve spent money on, we can deduct only what we’re allowed to, what the tax authorities say we can, which are the legitimate costs of being an oil company and carrying on an oil company’s business; no more, no less.

**Deductions**. Deductions are **what** we’ve spent but not necessarily **when** we’ve spent it. When the tax authorities let us deduct what we’ve spent depends on what we’ve spent the money on. We can deduct certain amounts we’ve spent all at once, straightaway, if we’ve spent them on the kind of things that we buy, use immediately, and then they’re gone, lost, and we don’t have the benefit of them anymore. Examples are salaries, consumables that are immediately used up, the rent of an office perhaps, interest on a loan, and oil transportation costs when we use someone else’s pipeline and pay a tariff (a transportation fee) in return. There are other amounts that we can’t deduct all at once, straightaway, however, and we have to deduct them a bit at a time over several years; and, what’s more, usually starting only when we actually begin using whatever it is we’ve
bought. That would be the case if we’ve spent the amounts on the kind of things that we buy and keep on using year after year. Examples are wells, platforms, and pipelines (our own pipelines, the ones that we own, that is).

The former sort of costs (of things we buy, use immediately, and then they’re gone) are called “operating costs,” or “revenue costs” (because they’re usually met out of the revenue that a company earns), and the latter sort (things we buy and carry on using year after year) are called “capital costs.” Operating costs are the costs that are deducted all at once, straightaway, and capital costs are the ones that are deducted a bit at a time over several years, usually starting only when we begin using whatever it is we’ve bought—all of which translated into tax speak is that operating costs are expensed and capital costs are depreciated, usually starting only when the asset is placed into service (“the asset” being the well, platform, or pipeline, for example).

So “expensed” means deducted all at once, straightaway, and “depreciated” means deducted a bit at a time over several years. “Expensed,” therefore, needs no further definition; “depreciated,” however, does.

Individual countries explain how they apply depreciation. It may be a fixed proportion each year over a number of years of the total amount we’ve spent: so a capital cost of USD 100 million might be depreciated (and deducted) as USD 10 million per year over 10 years; which is called “straight-line” depreciation (because USD 10 million per year over 10 years looks like a straight line on a graph that shows deductions on the y-axis and years along the x-axis). Or it may mean a proportion of whatever’s still left to be depreciated each year—say, 25% per year: so a capital cost of USD 100 million would be depreciated as USD 25 million in the first year (25% of USD 100 million, leaving USD 75 million still to be depreciated), then USD 18.75 million in the second year (25% of USD 75 million, leaving USD 52.25 million still to be depreciated), and so on; which is called “declining-balance” or “reducing-balance” depreciation.

There are several other depreciation methods, some of which are derivatives of the preceding two and some of which are different, and I don’t intend to talk about all of them. Suffice it to say that countries’ tax authorities make clear what method oil companies must use. But be aware that different methods may be used for different kinds of things or parts of assets (different parts of a well or production facility, for example)—and your tax department will know, or can find out, the rules that apply in a given country.

The moment an asset is placed into service is when it actually starts working, not when it’s manufactured, nor even when it’s installed, and it may sound trivial to make the distinction. So we have to wait a year or two after we pay for the asset before we can start depreciating it and claiming deductions. It’s a nuisance, but it isn’t a big deal. Or is it?

Another Story. I was the petroleum economist for a potential acquisition of a small additional interest in an oil field in which the company I worked for already owned a significant interest. So the tax calculations for the oil field already existed in the company. However, I noticed when I looked at them that deductions for capital costs were starting immediately when the costs were incurred rather than, as they should have been, starting only when whatever had been bought was placed into service.

The country in which the oil field resided had two profit-based taxes: a fairly standard one, but also another potentially quite brutal one that was, however, triggered only when certain quite rare circumstances occurred. These circumstances were when how much income an oil field had earned divided by how much money had been spent developing...
and producing it reached a certain trigger value. Both parts of that ratio were defined specifically—and somewhat curiously I might add, but I won’t go into that.

Our calculations as they were being done (deductions relating to capital costs starting immediately when the costs were incurred) showed the trigger value not to have been reached yet and, in fact, never being reached in the oil field’s lifetime. However, when the calculations were corrected, they showed that it would be reached in the following year and the only way to prevent that happening was to acquire the small additional interest that was for sale (because most of the acquisition cost could be added to the denominator of the ratio, thereby decreasing it and moving it away from the trigger point). So we did that, and had we not done so, my company would have paid an extra USD 1 billion in taxes over the oil field’s remaining lifetime.

The moral to the story is that when it comes to tax, never prejudge what may or may not be important.

But let’s get back on track.

Operating costs and capital costs are common language in oil companies. You hear them all the time. But sometimes classifying costs as either one or the other and then deducting them according to the above general rule (that operating costs are deducted immediately and capital costs are deducted over time) is risky. Some costs may be difficult to classify, and some you may think are clearly one or the other but aren’t according to a particular country’s rules. An example is drilling, which some countries treat entirely as a capital cost, whereas others treat it as part capital cost and part operating cost.

So it really is advisable, at least if and when in doubt, to let your tax department tell you how a cost is treated in the context of a tax deduction: whether it’s expensed like an operating cost or depreciated like a capital cost (and if so how), or a combination of the two.

One deduction worth special mention is the costs associated with decommissioning an oil field. Decommissioning means ceasing the oil field’s production, “plugging and abandoning” its wells so that they can’t produce anymore, removing all its production facilities and returning the locality to its former, natural condition. Although at least some of the cost relating to its wells and probably all of it relating to its production facilities would have been depreciated for tax when the oil field came into being, the cost of decommissioning it all is expensed for tax (at least, I don’t know of any country that applies concession fiscal terms where it isn’t).

Now you may be thinking, “Wait a minute, it’s all very well letting me deduct my decommissioning costs, but I’m not producing anything anymore, so I don’t have any revenue from selling oil to deduct them against.” And you’d be right. Good thinking.

Concession fiscal terms deal with that in two ways, both of which I’ll explain in a minute.

Before I do that, the last point I want to make about deductions is that where they relate to capital costs that are depreciated, they aren’t cash flow anymore. We’ve taken a cash flow—a cost—and transformed it into something else, so it’s no longer an amount of money we pay someone; it’s now an artificial stream of numbers that’s been created for the sole purpose of calculating tax. It’s become, and is called, a “non-cash cost.”

Now, carrying on with our definitions from earlier (which I hope isn’t starting to seem like a lifetime ago).

Taxable income is the difference between the value of what we’ve received and the deductions we can subtract from it.
Needless to say, if the value of what we’ve received during the year is greater than the deductions we can claim, then our taxable income is positive and we’ll have some tax to pay. (Tax is usually assessed over a period of a year, although it isn’t uncommon that interim payments are made, say, every quarter.)

If, however, it’s the other way around and the deductions we can claim in the year are greater than the value of what we’ve received, then our taxable income is negative and we don’t pay any tax. In that case, our losses (remember, we haven’t necessarily lost real money; these are losses only in the context of establishing whether we have to pay tax this year) can usually be carried forward into future years. Then, they become an extra deduction in the following year, and our taxable income in that following year is therefore less than it would otherwise have been, and so is the tax that we’ll have to pay in that year. And if, in that following year, our taxable income is negative again, then our losses are carried forward once again, and so it goes on (though not necessarily forever; note the paragraph after next).

Some countries also allow these losses to be carried back, meaning brought back in time to earlier tax periods. Previous years’ taxes are then revisited and recalculated, resulting in repayments being made by the tax authorities for, in this case, overpaid taxes in earlier years. And this is one way that concession fiscal terms deal with the decommissioning costs mentioned a little while ago. Those costs may be able to be carried back to earlier tax periods, and so we can still deduct them, but against earlier years’ taxable income when the oil field was still producing. Not all concession fiscal terms allow this to happen, however; and in that case, there’s only one hope for deducting decommissioning costs—which is coming up in another minute.

The rules about what happens in the case of negative taxable income differ, as ever, among countries and, like most things relating to tax, can be complicated. Countries may apply a limit to how long a loss can be carried forward—and if the loss hasn’t been used by then, it’s lost—or on how far in time it can be carried back. In the spirit of the aim of this chapter, further information is available from your local, friendly tax department.

The tax rate is simply the proportion of taxable income that is paid in tax, so it could be 20% or 40% or whatever it happens to be in the country we’re in.

The tax that results from multiplying a company’s taxable income by the applicable tax rate is called its current tax liability. Current tax is the tax an oil company owes the government from a given tax period’s activity as a result of what it’s sold, what it’s spent, and anything else that has contributed to taxable income. Cash tax, on the other hand, is the tax that’s actually paid during a period of time, which may not be the same as the tax that’s calculated as owed for that same period. Often, some of the owed (current) tax is paid in the same tax period and the rest is paid in the following one, after all the relevant information has been collected and the calculations have been done so that it’s clear what the tax bill for the period actually was. It’s cash tax, therefore, rather than current tax that represents relevant cash flow.

The last question I’m going to address in this section is to what do profit-based taxes apply? Is it an individual oil field, is it a whole company (that might own several oil fields), or is it something else?

Again, I’m afraid, there isn’t a clear answer. Some taxes apply to an individual oil field, and some apply to as many oil fields all together that a company owns in a country, as if they were just one big oil field. The term tax people use when they talk about this is a “ring-fence.” A ring-fence defines the scope of the tax calculation—how many oil
fields it includes—and is so called because you can draw an imaginary ring-fence around one or more oil fields and then treat whatever’s inside it in aggregate, all added together, for calculating tax.

If a tax has a ring-fence around an individual oil field, then it applies just to that oil field and that one alone. If the ring-fence is around, say, the whole country, then the tax applies to all the oil fields a company owns in the country lumped together, although instead of “lumped together” tax people say “consolidated” because they like to use long words and therefore sound more clever.

Even where a ring-fence is around a whole country, however, for oil companies it usually also exists only around their upstream activities (that are connected with oil exploration and production) so that those activities can’t be consolidated with anything else the company does. In other words, oil companies’ upstream activities are usually kept separate for tax purposes.

I’m sure I don’t need to say where to go for information about what ring-fence applies to your tax calculations.

Consolidation is also the second way that concession fiscal terms deal with the decommissioning costs mentioned a little while ago. If a tax is consolidated at the country level and there are other oil fields inside the ring-fence generating taxable income between them that’s greater than the decommissioning costs of the oil field at the end of its life, then those decommissioning costs can be deducted there and then. All that happens is that those costs reduce the company’s taxable income for that tax period and so it pays less tax.

In exactly the same way, consolidation is also helpful at the other end of an oil field’s life, especially for exploration and appraisal costs that are expensed. Again, if a tax is consolidated at the country level and if other oil fields inside the ring-fence are generating enough taxable income, then those costs can be deducted immediately, and certainly much sooner than if their deduction has to wait for the new oil field to generate taxable income of its own (which could be up to several years later).

Achieving deductions for tax is a good thing because when we deduct costs, we pay less tax. Achieving deductions as soon as possible is also a good thing because we pay less tax sooner rather than later: we pay less tax today and more tomorrow rather than the other way around. I’ve mentioned this idea once already, at the end of Chapter 2. To paraphrase what I said then: when cash flows occur is important for petroleum economists to know. We place more value on cash flows occurring sooner than on those occurring later, which is why utility companies encourage us to pay our bills monthly rather than at the end of each three-month period, and why “buy now, pay next year” offers for new sofas appeal to people. That’s the whole subject of the next chapter.

And that’s all I’m going to say about concession fiscal terms.

So far so good.

For those of you for whom numbers speak louder than words, Appendix 4.1 shows two worked examples of everything covered in this section: one that assumes an individual oil field isn’t consolidated with other oil fields and another that assumes it is (and that those other oil fields always generate more positive taxable income than the individual field generates negative taxable income). I encourage you to replicate these examples in a spreadsheet of your own.

Those of you for whom numbers do no such thing, by all means ignore these examples and move on.