Chapter 1
Introduction to Tax and Royalty Regimes

1 Introduction to Tax and Royalty Regimes

1.1 INTRODUCTION

In this book, we treat two principal types of upstream petroleum *fiscal regime* (a collection of individual *fiscal devices*, such as taxes):

- **Tax and Royalty regimes** are introduced here.
- The other major kind, known as a **Production Sharing Contract (PSC) regime**, is covered in Chapters 6, 7 and 8.
- The intervening chapters treat individual fiscal *devices* which are often used in either type of regime.

As the name implies, the main (though not necessarily only) sources of revenue for a government using a Tax and Royalty regime are income tax – payable on profits, if these occur – and **royalties**, which are usually payable as a percentage of revenue (almost always) whether the project is profitable or not.

Fiscal regimes based on royalties and taxes are a cornerstone of how governments extract their **economic rent** – here, meaning share of revenue – from petroleum producing properties. Such regimes, which are also commonly referred to as **concessionary or mineral-interest arrangements**, were the only fiscal regimes, or "fiscal designs," used, until PSCs were introduced in the mid-1960s.

In fact, in the early days of the petroleum and mineral extraction industries, a royalty was the only fiscal device applied that provided a state with any share of project revenue.

Land **rentals**, **bonuses** (both also introduced in this chapter) and income taxes were soon added, to increase the government's economic rent, or "fiscal take" (using "take" as a noun, to mean what revenue the government "takes"). As oil prices soared in the 1970s, governments saw their bargaining power grow at the expense of international oil companies, and introduced other supplementary or "special" petroleum taxes to capture "excess" profits.

Today, concessionary systems with two or more layers of taxation in addition to a royalty are not unusual. Typically there is also a complex set of tax allowances, credits and other incentives designed to encourage investors to invest in high-cost and risky projects. Most OECD countries have concessionary fiscal designs based on a combination of royalty and tax fiscal devices, as do some developing countries.

Our Approach in This Chapter

To keep things simple for the main example model in this introductory chapter – the discounted cashflow model found in the file "Ch1_Tax_and_Royalty_Model.xls" – we use simplified (though still realistic) royalty and tax rates, which are the same every year. Be aware, however, that the rates for income tax and – as we will see in Chapter 3 – royalties can vary over time, according to sophisticated formulas which make them flexible over a wide range of economic and production situations.

In this chapter we concentrate on the most common concepts and components of a basic (but reasonably typical) hypothetical tax and royalty regime, illustrated in a simplified (but reasonably granular) multi-year Excel fiscal model. This approach highlights:

- how various fiscal devices in many tax and royalty regimes are typically applied;
- the input assumptions required; and
- the allowances and deductions used in their calculation.

We include both an abstract-style summary and a flowchart-style "map" of our model for reference as we work through it, section by section.[1]

We will also pester you from time to time, asking you to make changes in the model and to decide whether the results make any sense. The ultimate goal of the model is to show how changes in the fiscal regime affect the hypothetical government's and investor's **discounted net cashflows**, the sum of which equals their **net present values (NPVs)**.

To ensure readers understand both basic and certain nuanced concepts and calculations relating to NPV, we include an introductory section on the time value of money – discounting and inflation – and why they are important in valuing upstream petroleum properties. Even if you are already familiar with discounted cashflow valuation, this section should be worthwhile for you at least to skim, to see which calculation approaches we have adopted as standard in this and other chapters.

Basic key upstream-specific model inputs are introduced in layperson's terms.

We also introduce some useful Excel techniques for making models easier to navigate and view, and ask "what-if?" questions, using interactive charts which show how specific fiscal devices and other key upstream input assumptions impact investor and government cashflow.

This chapter explains the need for, and the calculation of, an **economic limit test (ELT)**, which establishes when a project ceases to be profitable and therefore should be abandoned. The ELT thus determines when production should permanently stop (or be "shut-in") and when the site should be cleaned up and restored, by decommissioning wells and facilities. <u>The ELT is critical in optimizing future cashflow</u>.

[1] The summary is found on the "ModelSummary" sheet of the file "Ch1_Tax_and_Royalty_Model.xls." The "map" is found on the same file's "ModelMap" sheet. Note that this "map" is rather "busy," and might be a bit much to take in all at once. For this reason, we also provide different versions of it, each highlighting only a single section at a time, on pages 48–56 of the file "Ch1_Main_chapter_supplement.pdf."

Sensitivity analysis is often required to establish the impacts on NPV of ranges of uncertain input variables. Spreadsheet "spinner" controls can help make it easy to change variable settings. Excel also provides a one-way and two-way "Data Table" feature, which is more useful and powerful for showing the effects of many different variable settings in a single view. We demonstrate these tools in this chapter's main example model.

1.2 INFLATION AND DISCOUNTING: TIME VALUE OF MONEY BASICS IN THE CONTEXT OF UPSTREAM PETROLEUM MODELING

Introduction

In upstream petroleum fiscal and valuation modeling, there are three considerations which determine whether an oil or gas field is potentially a promising investment. Failure in any one area negates the strengths of the others. These areas are:

1. the parameters affecting the field's underlying performance (e.g., production volumes, commodity prices, and costs);
2. the fiscal system – which is the thrust of this book; and
3. the time value of money – how inflation but, usually more importantly, discounting can impact the investment's value to the investor today. Time value is particularly important in oil and gas field developments because they typically involve several years of upfront capital investments with no revenue, followed by many years of revenue from production.

Because we do not intend this book to be a complete course in petroleum economics – a field which actually brings in a lot of detail from other disciplines within the industry – we treat items 1 and 3 above only in overview. We shall address item 1 later in this chapter. We address item 3 here.

We introduce the time value of money in this section through examples which completely ignore the fiscal issues to which most of the rest of the book is devoted. This is deliberate, in order to isolate for examination:

- the unique "distortions" which the time value of money can have on the value of an oil or gas project to an investor and/or host government; as opposed to
- the (usually) unrelated distortions which fiscal systems (especially complex ones) can have.

Therefore, in this section, we explain the basics of the time value of money in less detail than a standard corporate finance textbook, but enough to help readers unfamiliar with the subject to proceed with this book.

We define the time value of money here, simply enough, as how the value of cashflows spent or received depends on when they occur.

Three Kinds of Money in our Models

US dollars – which generally speaking are the international currency of the upstream petroleum industry – are the "blood" of the examples and models used in this book. You will see that it consists of three "blood types":

- **"Real" dollars**, quite often the form in which a model's forecast input assumptions are denominated;
- **inflated dollars**; and
- **discounted dollars**, the calculation of which is typically our valuation goal when using our (and commonly, much of the upstream petroleum industry's) cashflow analysis approach, which is based on net present value (NPV), as discussed below. (Importantly, we also could have used the term "inflated, then discounted dollars" here, because in this book we only discount inflated dollars, not Real ones.)

Real Versus Inflated Dollars

"Real" dollars, also called "**constant dollars**," are dollars of a constant purchasing power at a given point in time. They ignore changes to purchasing power due to inflation/deflation and exchange rate movements. As such, values expressed in "Real" dollar terms are used to express underlying cost and price trends in terms of monetary values at a particular point in time, e.g., a specific year. This point in time is usually when the cost and price forecasts are made, which is also often the first period of a forward-looking cashflow forecast.

In contrast, **inflated dollars** – also known as "**money-of-the-day**" (**"MOD") dollars**, or as "**current dollars**" – are values expressed with variations in purchasing power (inflation or deflation effects) factored in. Because inflation/deflation and exchange rate movements are facts of life, this makes MOD dollars the *actual* dollar values of, for example, costs incurred, or prices realized, at a particular point in time. They are the only dollars you can ever spend or receive. (For this reason, you might be forgiven for calling these the "real" dollars, but do not – you will confuse everyone.)

Real Versus Inflated: Example

Suppose that, in 2015, a cost engineer is asked to forecast the cost of renting a well-drilling mechanism, or "rig," for drilling a well in 2020. She does not know much about macroeconomics, but she does know about other fundamentals of the drilling rig market.

After considering the most suitable type of rig, she reckons that, today, renting one of these would cost $125 000 per day. Because she is thinking about the price today, she is thinking about prices in today's terms, ignoring inflation.

Then, drawing on future forecasts of likely supply and demand for this kind of rig, as well as her own experience-seasoned judgment, she tries to adjust the price today for expected changes in the underlying rig rental market, to arrive at an estimated price in, say, five years' time. In the end, she forecasts that, due to expected weakening of demand for this type of rig, by 2020 the rate will actually fall, to $100 000 – *as measured in today's 2015 dollars*.

These 2015 dollars have today's constant purchasing power. In a financial modeling context, these are constant or "Real dollars." And this is why the term "Real dollars" on its own is incomplete – it always needs to be specified as **Real dollars at a given point in time**. Therefore we will correct ourselves, and call the currency used in the rig rate forecast "$100 000 Real dollars of 2015 purchasing power" or, for short, "Real 2015 $100 000."

The engineer then hands this price forecast over to the commercial analyst, who does not know much about rig rental rates, but does keep abreast of forecasts for local country and US dollar inflation and exchange rates. (In this book, because all costs and prices are assumed to be in US dollars, we will not deal with exchange rates.)

Because the analyst's job is to forecast *actual* cashflows which occur at *actual* transaction costs and prices – *not* cashflows denominated in some hypothetical unit – he applies a forecast US dollar inflation rate to the "Real" dollar amounts supplied by the engineer. We will assume that after inflating the engineer's forecast of Real 2015 $100 000 per day, the resultant inflated cost he forecasts for 2020 is MOD $115 000. Again, "MOD" is "money of the day," where "the day" is the "day"[2] when the rig rental is paid out. Assuming the forecasts are correct, the company will be writing the actual check for $115 000.

Again, to recap:

- Real dollars are not the actual values of amounts spent or received at the time these transactions occur; rather, they are these values expressed, for convenience, in the monetary value (buying power) of one specific period.
- MOD dollars *are* the values which are actually spent or received at the time these transactions occur.

Discounted Dollars

Just as inflating dollars increases their value, **discounting** decreases their value. By discounting, we mean adjusting the value of a dollar spent or received in the future to its value today, or its **present value**.

(Do not confuse the terms "real value" and "present value," at least as we use them in this book, although we can see why someone might. They are completely distinct.)

Present value in our, and the common, use of the term, is the value of a future dollar today, calculated by applying a **discount rate** to the value of a single future cashflow.

- The higher the discount rate, the lower the present (i.e., discounted) value will be.[3]
- The further from today that the cashflow occurs, the lower the present value will be.

[2] "Money of the day" is a loosely worded expression – it does not necessarily mean the inflated value on a specific day. The expression could be rephrased more precisely as "money of the time when it is paid or received."

[3] The discount rate actually used is likely to vary from one organization to another, as discussed in the section "What Does Discounting and NPV Tell Us?"

Terminology pause

- In this book, we only discount dollars which have already been inflated, i.e., only MOD dollars. (One can also discount Real dollars, but we do not do so here.) This is the most common way that the industry calculates and reports present value.
- Therefore, although we do sometimes go to extra lengths, especially in this introductory section, to specify, for example, that a cashflow is denominated in "inflated, discounted dollars," be aware, whenever you see a reference in this book to "discounted value," "present value" or companion terms such as **net present value** (**NPV**) or **discounted cashflow** (**DCF**), that you should understand that the values in question have been inflated to MOD values, and then discounted.

High-Level View: Using Discounted Dollars in our Valuation Models

We will show the calculations involved in discounting soon. But for the moment, let us jump ahead, and assume that we already have calculated our discounted values, so we can outline here the basic mechanics of how they are used in our valuation models.

Knowing the discounted value (or present value) of one single cashflow item – out of the many which occur in the multi-year endeavor of exploring, developing and/or producing an oil or gas field – is not very useful. Rather, here is how we, and much of the industry, use discounted values. We:

(a) discount every year's **cash inflows** (cashflow received, e.g., revenues);
(b) discount every year's **cash outflows** (cashflow spent, e.g., costs);
(c) subtract each year's (b) from each year's (a), to get annual **discounted net cashflow** values; and
(d) sum each year's (c), to get **net present value**, or **NPV**, which is one of the most commonly used valuation metrics in the upstream petroleum industry.

The basic NPV decision rule is that investments which have a positive NPV are good investments, while those with negative NPV should be avoided. Using this rule is sometimes called the **NPV method**, the **discounted cashflow method** or the **DCF method**. Importantly, **this rule only applies to future cashflows**, where "future" means starting from the date for which you wish to know the NPV (known as the **valuation date**). We ignore any past or **"sunk" costs**, unless for some fiscal reason these influence future cashflows. (We do cover such cases in this book.)

What Does Discounting and NPV Tell Us?

The subject of discounting, and ways to choose discount rates (such as basing them on an investor's weighted average cost of capital), is vast and will not be detailed here.[4] But for a quick and, we hope, intuitive understanding of why we bother discounting future cashflows, think of the process as a way of saying whether an investment is good compared to other investment opportunities available.

In other words, under this view, it is *not* enough to know that the sum of all *undiscounted* future cash inflows, minus the sum of all *undiscounted* future cash outflows – which equals **undiscounted net cashflow**[5] ("**NCF**") – is positive. Rather, you must also consider whether this NCF is more valuable to you today than NCF from one or more other investment opportunities.

One way to do this would be as follows:

- Suppose you already know of one $100 investment opportunity which you are certain is open to you – Project A – which could earn you – in *un*discounted, MOD terms – a return of 10% per year.
- This means that every year your $100 is not invested in this project, but rather in, say, Project B, which offers only 7% annual returns, you will not be losing money in an absolute sense (you will be making 7% per year), but you will be losing money in a wider, comparative sense.
- Thus you should choose investments with returns higher than Project A. The cost to you of being invested in something with lower returns than Project A is called your **opportunity cost** – the cost of a missed opportunity to do better.

Under this opportunity cost view of discounting, Project A's 10% annual returns would become the discount rate you would use to evaluate Project B, or any other investment opportunity. Again, you would use it to discount the future annual MOD net cashflows at this rate (in a way we will show soon), to get discounted MOD future annual net cashflows, which you would sum to reach NPV.

- In essence, to say that when the NPV calculated using a discount rate of 10%, for an investment other than Project A, is positive, this is just another way of saying that its returns are greater than 10%, and therefore better than Project A's.
- Hence the term, the "**time value of money**": assuming that you always have a Project A to invest in, any moment that your money is not invested there, or is invested in something with worse than 10% annual returns, means your capital is losing money compared to that benchmark.

[4] Good introductions can be found in most corporate finance texts. Two which we recommend are *Fundamentals of Corporate Finance* by Richard Brealey, Stewart Myers and Alan Marcus (McGraw-Hill/Irwin, 2011) and, for a more hands-on calculation approach, *Principles of Finance with Excel* by Simon Benninga (Oxford University Press, USA, 2010). An in-depth yet very readable treatment of how to choose appropriate discount rates is *The Real Cost of Capital: A Business Field Guide to Better Financial Decisions* by Tim Ogier, John Rugman and Lucinda Spicer (FT Press, 2004). (Disclosure: Tim Ogier is a former colleague of one of this book's authors.)

[5] Don't confuse **net cashflow** – which means all inflows minus all outflows, regardless of whether the values have been discounted – with **net present value**, which always means that the cashflows have been discounted. For clarity, we often specify "net cashflow" or "NCF" fully, i.e., as being "undiscounted NCF" or "discounted NCF."

There are more terminological nuances to keep in mind. Reflecting common usage, in this book we call undiscounted NCF either "undiscounted NCF" or simply "NCF." We call discounted, *annual* NCF, "discounted NCF"; we call total (all years) discounted NCF, "NPV."

Because we express the returns on a time basis, e.g., 10% annual returns, the further from today that you have to wait to receive a cash inflow, the less it is worth to you today, because in the meantime you could be investing to get at least 10% annual returns.

Timing Matters – a Lot

This is why, as we will see, the math mechanics of discounting are such that the further in the future that an undiscounted cashflow occurs, the lower its discounted (present) value will be today.

This applies whether the cashflow is an inflow or an outflow. All other things being equal:

- the further in the future that inflows occur, the more they will be discounted – which is bad for NPV, because, for example, revenue will be lower in present value terms; and
- the further in the future that outflows occur, the more they will be discounted – which is good for NPV, because, for example, these costs will be lower in present value terms.

In upstream petroleum projects – in which, commonly, there are years of upfront investment outflows before any production revenue occurs – these basic truths can become harsh facts of life from a valuation perspective.

We show a simplistic example in Figure 1.1, in which we assume, from the perspective of January 1, 2015, that:

- there are two cashflows, one a cost (an initial investment, i.e., a cash outflow) and the other, revenue (a cash inflow), each forecast to equal Real 2015 $100;

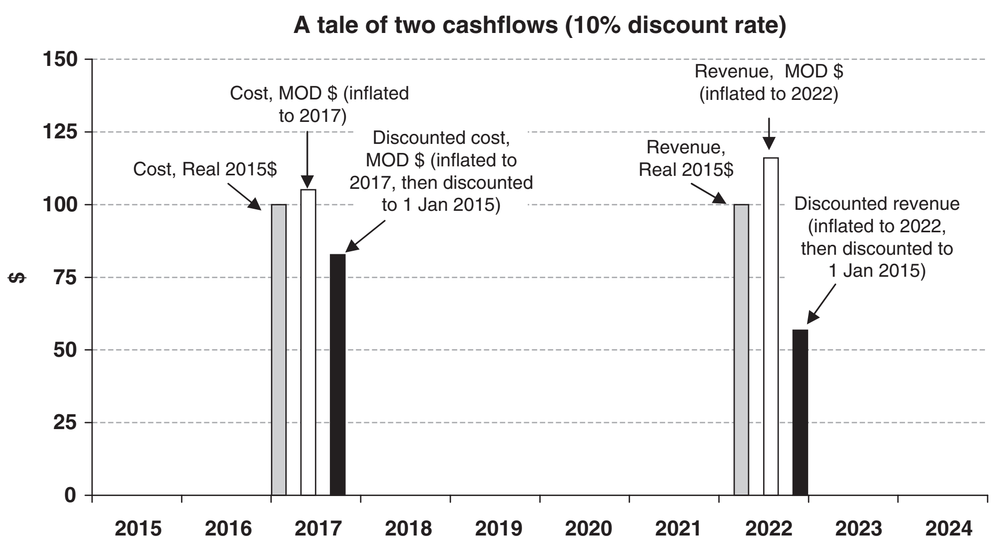

Figure 1.1 The impact of timing on cashflows (i.e., present value), 10% discount rate

- the outflow occurs in 2017 and the inflow in 2022; and
- the annual inflation rate is 2%, and the annual discount rate is 10%. (We will show how to apply these in calculations soon.)

In this example, the investment does not look very good, just knowing that the Real \$ value of the outflows match the Real \$ value of the inflows; after all, why would one bother, on this basis, to invest to achieve a Real net cashflow of \$100 − \$100 = \$0?

In discounted terms, however, it looks even worse. The two black columns show that discounted revenue of around MOD \$55, minus discounted costs of around MOD \$80, would result in a negative discounted net cashflow of around MOD \$(25). Factoring in the time value of money can really hurt sometimes when costs precede revenues, depending on the sums and timing involved. As we will illustrate in a later, more realistic upstream petroleum example, we have seen proposed investments, which look great in Real \$ terms, as well as in undiscounted MOD terms, but *horrible* in discounted MOD terms.

As mentioned, the effect of discounting depends on not only the timing of the cashflows, but also on the discount rate used. Note how much smaller the discounted revenue becomes when we change the discount rate to 15%, as shown in Figure 1.2.

NPV Is the Principle Investment Decision Basis in the Upstream Petroleum Industry

Valuation is an inherently subjective endeavor, in practice sometimes drawing as much on individual judgment (based on experience, or sometimes, unfortunately, whim or bias) as on "science." Hence there are many investment metrics in addition to – and usually used in combination with – NPV. We shall focus on the NPV, i.e., the discounted cashflow method,

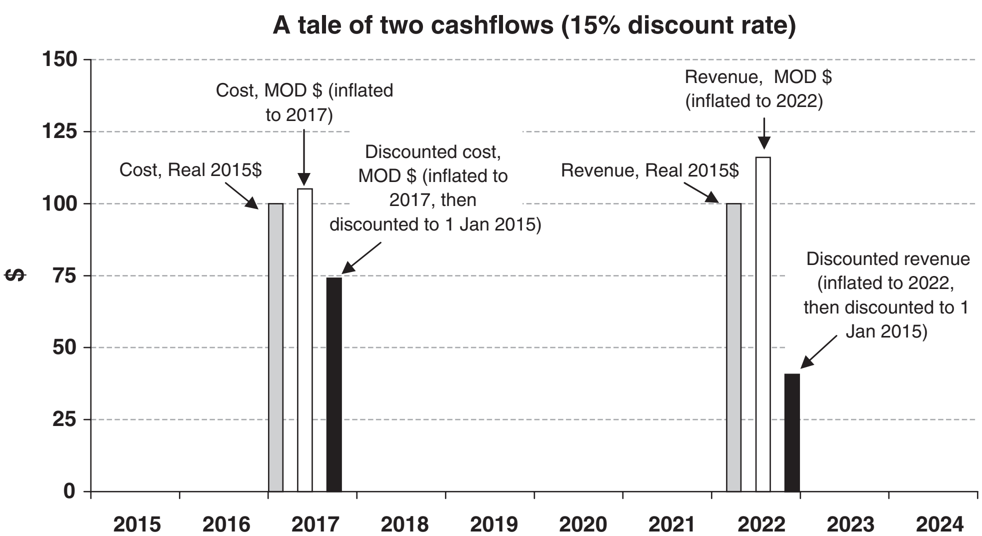

Figure 1.2 The impact of timing on cashflows (i.e., present value), 15% discount rate

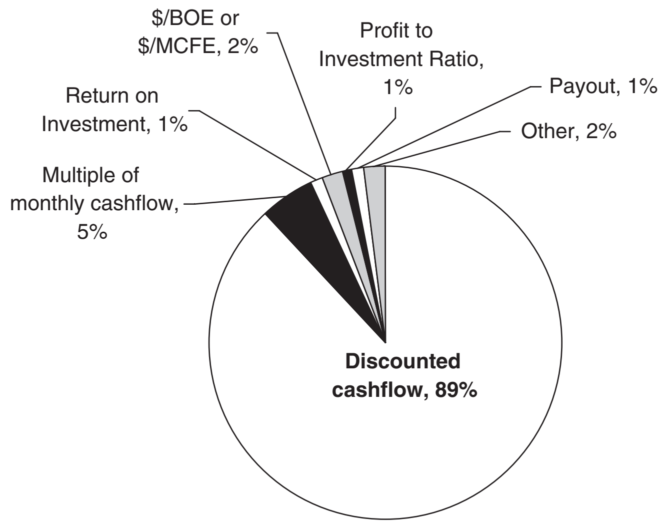

Figure 1.3 SPEE 2011 Survey, "Most Commonly Used Method for Determining Value of Oil and Gas Properties" (Reproduced by Permission of the Society of Petroleum Evaluation Engineers)
Note: (1) Values do not sum to 100% due to rounding. (2) Certain terms in this chart are explained below.

in the valuation-related portions of this book, because we believe it to be one of the most commonly used.

We base this belief on both our combined 52 years of professional experience and the literature, such as the annual *Survey of Parameters Used in Property Evaluation*, published by the Society of Petroleum Evaluation Engineers (SPEE). Results of the edition published in June 2011, presented in Figures 1.3 and 1.4, show the discounted cashflow method's clear prevalence among industry professionals.

Figure 1.3 shows that easily the largest portion of respondents favor the discounted cashflow method. This edition of the survey had 136 respondents, of which 40% were from oil and gas exploration and production companies, 38% from consultancies, 15% from banking/energy finance firms, and 7% from "Other."

Respondents said that when they use more than one investment valuation method, discounted cashflow is still the most common primary one, as shown in Figure 1.4.

Detailing the methods of choosing the discount rate, is again, beyond the scope of this book. We tend to use 10% in our examples for consistency's sake. (US and Canadian regulators require oil and gas companies to report NPVs on a 10% basis, purely to standardize comparisons across companies.) Note, however, that while the choice of discount rate can vary widely, discount rates of around 10% are fairly commonly used for upstream valuations. Again, we base this both on our own experience, and on survey results like those shown in Figure 1.5.

Figure 1.5 shows that most (64%) of the 101 respondents asked used "unrisked" discount rates between 9% and less than 10.5%.

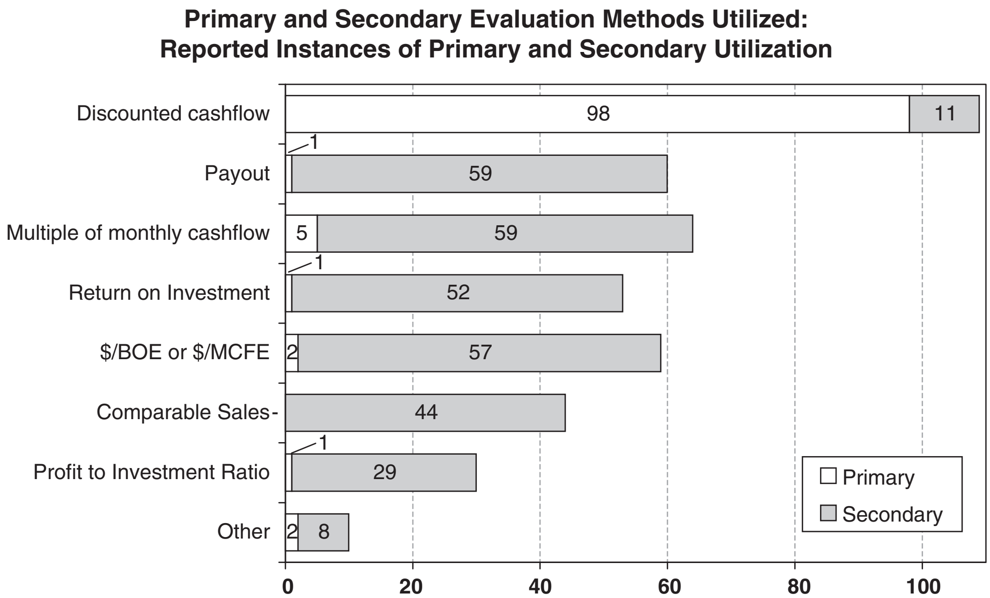

Figure 1.4 SPEE 2011 Survey, "Most Commonly Used Method for Determining Value of Oil and Gas Properties" (Reproduced by Permission of the Society of Petroleum Evaluation Engineers)

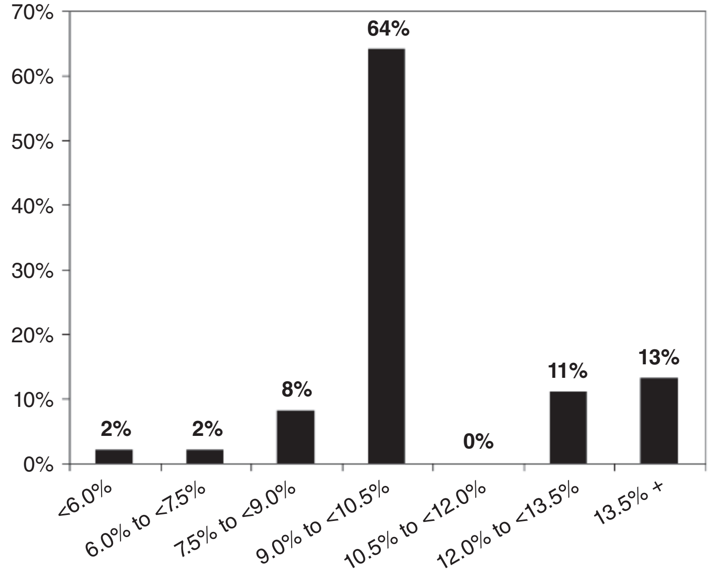

Figure 1.5 SPEE 2011 Survey, "Unrisked Discount Rate Applied to Cash Flows, Composite (101 Respondents)" (Reproduced by Permission of the Society of Petroleum Evaluation Engineers)

An Aside: Risked and Unrisked Discount Rates

"Unrisked," as used in Figure 1.5, means, in effect, that the discount rate has not been adjusted for probabilistic uncertainty. To explain with an example:

- The discount rates we use in this book – and which, unless described otherwise, is how the term is commonly understood – are "unrisked discount rates." They are used to discount (in a way we will illustrate soon) a series of future cashflows, assuming the cashflows are 100% certain to happen as forecast.
- Whereas a "risked discount rate" reflects a specialized adjustment made to the unrisked discount rate, to take into account uncertainty that the cashflows might *not* occur as forecast. For example, one could try to adjust the unrisked discount rate so that it somehow accounts for the likelihood that actual production volumes, prices, costs, timing, etc., could differ from what is forecast; or for whether certain events (such as a commercial oil or gas discovery) will even occur at all.

We do not cover risked discount rates in this book, and in fact would question whether this is the best technique for accounting for risk in valuation models. For an alternative approach to adjusting valuation models for uncertainty and risk, see the material in the "Appendix V" folder on the disk, relating to the use of the included trial version of Crystal Ball software.

Terminology pause: equivalent petroleum units

Note that "BOE" (or "boe") as used in Figures 1.3 and 1.4 means "**barrel of oil equivalent**." This unit measures combined quantities of oil, when it (as normally) is expressed in barrels, with gas, which in volumetric terms is usually measured in cubic feet or cubic meters. Looking at volumes on a BOE basis is useful because it is awkward to express, for example, total petroleum reserves as "3 million barrels + 12 billion cubic feet of gas." Instead,

- the gas is converted to BOE using a factor which depends on its energy content ("calorific value"). Although this varies according to the composition of the gas in question, common rules of thumb are that there are 6000 cubic feet per BOE, and 35.315 cubic meters per cubic feet.
- In our example, the 12 billion cubic feet of gas/6000 = 2 million BOE of gas; and this 2 million BOE of gas + 10 million barrels of oil = 12 million BOE of total petroleum reserves (or total **hydrocarbon** reserves).

"MCFE" (or "mcfe") in Figures 1.3 and 1.4 means "**1000 cubic feet equivalent**." In the upstream petroleum industry, "M" or "m" *usually* means 1000, and "MM" or "mm" *usually* means 1 million:

- We use these conventions in this book. Unfortunately, they are not universal. In fact we have even seen "M" used to be mean thousands of barrels, and "m" used to mean millions of dollars, on the same page. Ensure you know what is meant.

- We convert 3 million barrels of oil to gas equivalent units as follows. Using the same rule of thumb stated above, 3 million barrels of oil equals 3 million × 6000 = 18 billion CFE (or cfe), or 18 million MCFE.

The investment measures and methods, in addition to discounted cashflow, which appear in Figures 1.3 and 1.4 are, again, beyond our scope here. Because none, except for value per BOE or values per MCFE, are specific to the upstream petroleum industry, they can be found in many corporate finance texts.[6]

Traffic control: this section continues in PDF and Excel formats

Due to considerations of space and formatting, we continue Section 1.2 in the file "Ch1_time_value_of_money_supplement.pdf" on the disk. Its subsections are as follows:

- Basics of time value of money. Calculation of annual inflation and discounting (uses the file "Ch1_Time_value_of_money_intro.xls").
- Interactive analysis. Mechanics of inflation rates, discount rates and cashflow timing (uses the file "Ch1_Discounting_vs._inflation.xls").
- Time-shifting oil field example (uses the files "Ch1_time_shifting_example.xls" and "Ch1_IRR.xls").
    - Exercise. Guessing the impact of timing differences.
    - Sensitivity analysis. Discount rate impacts on NPV; internal rate of return.
- Monthly inflation and discounting (uses the file "Ch1_monthly_discounting.xls").
- Dealing with partial years in annual models. Annual inflation/discounting when the valuation date is not January 1 (uses the file "Ch1_Changing_the_valuation_date.xls").
- Discounting and the "Behavior" of NPV (uses the file, "Ch1_Discounting_and_NPV behavior.xls").
- Details of special formulas and Excel methods used.

Even if you are comfortable with the basic time value of money concepts and calculations, we suggest you at least "skim" this document, because in it we:

(a) explain some of the standard terms and methods we use throughout the rest of the book; and
(b) draw basic lessons from examples of some representative (albeit simplified) upstream petroleum situations. In particular, the section on the time-shifting oil field example – based loosely on a real situation – shows how the typical pattern of oil field cashflows can mean that timing can make or break a project's investment-worthiness.

[6] For coverage of many of them within an upstream petroleum context, good sources include: *The Economics of Worldwide Petroleum Production*, by Richard D. Seba, (OGCI Publishing, 2008), and *The Acquisition & Divestiture of Petroleum Property: A Guide to the Tactics, Strategies and Processes Used by Successful Companies,* by Jim Haag (PennWell Corp., 2005). (Disclosure: One of us is a former colleague of Jim Haag.)

1.3 INTRODUCING BASIC COMPONENTS OF UPSTREAM PETROLEUM CASHFLOW UNDER A SIMPLE TAX AND ROYALTY REGIME

The screenshot shown in Figure 1.6 is of the chart which starts in cell B603 on the "Model" sheet of **the main example model for this chapter, found in the file "Ch1_Tax_and_Royalty_Model.xls."** If you set the model to its Base Scenario ("factory settings") by clicking the button in cell I1 (or its duplicates in cell I21), and then use the spinner control in cell G23 to raise the oil price multiplier to 150%, you should see the same results.[7]

This "**waterfall chart**" [8] assembles all the primary components of the investor's undiscounted NCF.

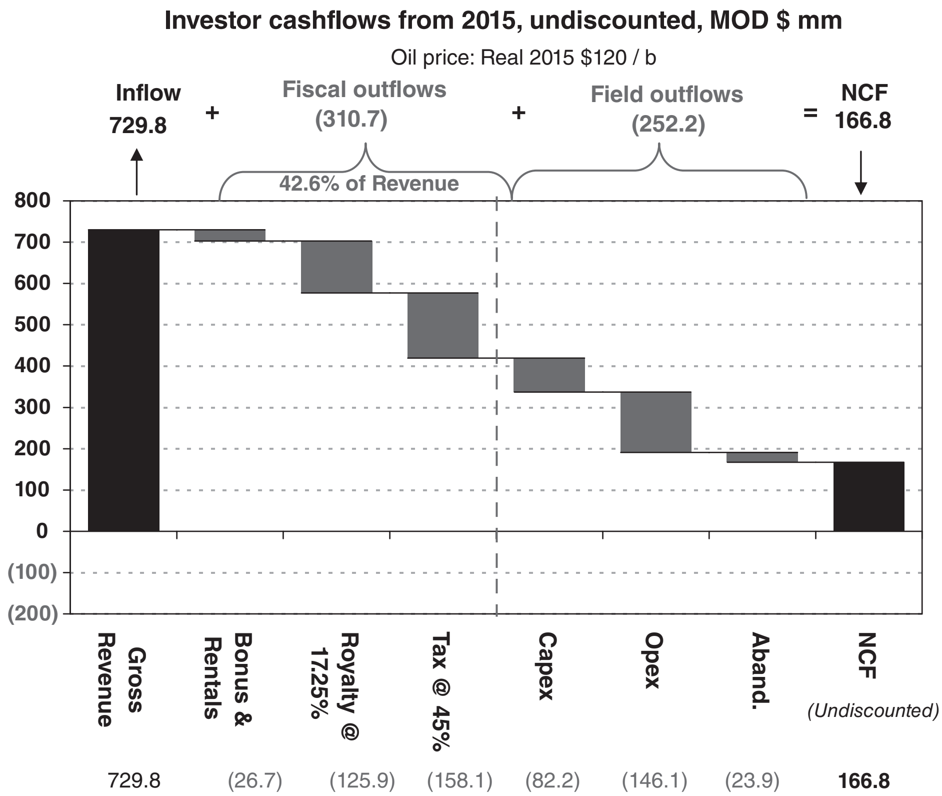

Figure 1.6 From the file "Ch1_Tax_and_Royalty_Model.xls"
Notes: Reflects Base Scenario, with oil price multiplier then set to 150%. "Aband." means abandonment costs.

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[7] We will discuss some easier ways to change assumptions and view the results shortly.

[8] We made this "waterfall" chart using a method developed by Jon Peltier of Peltier Technical Services. A demo version of an Excel add-in which enables you to make such charts quickly and easily can be found at http://peltiertech.com/. The underlying data for the chart shown in this example, and for the discounted version to the right of it in the Excel file, are in rows 842–860 (the method is used by permission of Jon Peltier of Peltier Technical Services, Inc., http://peltiertech.com).

The chart is a perhaps useful reminder as we work though the model in the sections to follow that – despite its moderate complexity – ultimately, we are just looking at revenue minus seven cost items.

Let us briefly introduce the main components of NCF shown in Figure 1.6. (We shall discuss them in more detail later.)

Gross revenue is field revenue, i.e., production volumes times the price. Here we mean "gross" as in before any deductions (sometimes the term "net revenue" is used to mean "net of" (i.e., after the deduction of) royalty).

Fiscal Outflows

A **bonus** is a kind of fiscal payment made, often when some production milestone is reached.[9] Regulations usually express the amounts payable in MOD terms, as we have done in the model's assumptions section, discussed further below.

Rentals are periodic fees payable, based on the area of the license, and sometimes varying depending on what kind of activity (e.g., exploration, development or production) is occurring. Again, we (and, usually, regulations) express the sums due in MOD terms.

Royalties are fiscal payments which are usually calculated as some proportion – in this example, 17.25% – of gross revenue.

Income tax is payable as a percentage of taxable income, which is calculated as gross revenue less certain deductions, or **tax allowances**.

Note from the caption for the chart that, under these settings, the sum of the fiscal payments to the government amounts to 42.6% or gross revenue. Under a tax and royalty regime, this is known as the "**Government revenue take**" (when "take" is used as a noun, to mean "portion").

Field Outflows

Capex is capital expenditure. In this example, it is the cost of getting the field ready to produce by drilling wells and building infrastructure such as pipelines and processing facilities.

Opex is ongoing operating costs during the production years. (Opex is sometimes incurred in the pre-production years, when capex is being spent, consisting of things like administrative and managerial costs; we ignore these in our simplified example model.)

Abandonment costs are the costs of removing equipment, plugging wells and otherwise restoring the production site after production ends.

[9] Other kinds of bonuses, called signature bonuses, are paid when an agreement is executed. See Chapter 4 for a fuller treatment of bonuses.

A discounted view

Notice to the right of this chart (starting in cell I603) the same total (all-years) cashflow items, only discounted at the Base Scenario's default discount rate of 10% (using the mid-year discounting convention, and assuming a January 1, 2015 valuation date).

As we would expect, each discounted item is lower than its undiscounted counterpart.

But notice also – referring to the value captions at the bottom of the chart if needed – that not all items seem to be discounted to the same extent. For example, discounted gross revenue of MOD $546.9 mm equals 75% of undiscounted gross revenue of MOD $729.8 mm, whereas discounted capex of MOD $76.6 mm equals 93% of undiscounted capex of MOD $82.2 mm, and discounted abandonment costs of MOD $12.9 mm equal 54% of undiscounted abandonment costs of MOD $23.9 mm. Why is this so?

Get Acquainted with the Model by Playing with it

Depending on your monitor's size, if you **click the "Console View" button in cell F1** – and then perhaps the "Full screen on . . . " button row in cell F21 – you should be able to see a split view, with:

- most of the main input assumption controls and input cells visible above the split (scroll down a bit to be able to see the last few, which end in row 67); and
- a scrollable area below the split, which should be large enough for you to see analysis charts and other items of interest. In this bottom area, scroll so that the top row visible is row 602. Adjust the view as necessary (by moving the splitter bar, using Excel's full screen mode, and/or adjusting the zoom) so you can see both of the waterfall charts.

The "Console View, with waterfall charts" screenshot on page 2 of the file "Ch1_Main_chapter_supplement.pdf" shows what you should see.

In light of the basic introduction to the time value of money, and to the components of NCF, watch the waterfall charts update as you play around with the various input assumptions, many of which should be understandable. Here are a few items, however, which might not be obvious:

- The last year of the license (cell C63) is the last year of legally permitted production by the investor.
- The distinction between tangible and intangible capex (cells I59:J60), as well as tax-related balances from prior activity in row 70, have income tax implications which we shall discuss later.

Be sure you are comfortable with how the **sensitivity multipliers** in cells F23:023 work. These provide a quick way to ask "what-if?" questions by changing an assumption for a given parameter across all years. They multiply the variables which we have input in the

	A	B	C	D	E	F	G	H
10	**Future (from 2015) field and price input assumptions; monetary items in Real 2015 $**							
11	Pre-sensitivity basis:		Oil production	Capex (tangible & intangible)	Abandonment	Variable Opex	Fixed opex	Oil price
12	(multiplied by)							
13	Sensitivity multiplier for :		Oil production	Capex		Opex		Oil price
14	(equals)							
15	**Post-sensitivity basis (used in model):**		**Oil production**	**Capex (tangible and intangible)**	**Abandonment**	**Variable Opex**	**Fixed opex**	**Oil price**

Figure 1.7 From the "ModelSummary" sheet of the file "Ch1_Tax_and_Royalty_Model.xls"

space below them (i.e., starting in row 33) by the percentages shown. A somewhat cleaner, diagram-style view of what we mean here is shown in Figure 1.7, which is a screenshot from the "ModelSummary" sheet in the file "Ch1_Tax_and_Royalty_Model.xls."

This is the reason that many of these items – namely, the non-fiscal ones – have cells in two formats: pre-multiplier and post-multiplier. The multipliers are rather "crude" in that they each apply to their respective items equally in every year. As we shall see later, they are a quick and dirty way to analyze how changes in input assumptions affect model results:

- For example, when building our Base Scenario, we decided that Real 2015 $ capex would be 61.0 mm and 20.0 mm in 2015 and 2016, respectively, so we entered these as pre-multiplier values, using the spinners in cells I57:J57. We also entered our assumption of a Real 2015 $ 21.0 abandonment cost in cell O57. These are our pre-multiplier forecasts.
- All three of these values equal the ones immediately below them, i.e., the post-multiplier basis values in row 58, under the Base Scenario, when all multipliers are set to 100%. Raise the capex/abandonment cost multiplier (cell J23) to 105%, and you will see each of the three post-multiplier values in row 58 increase accordingly. The post-multiplier basis values are what get used in the model.

To be clear, each multiplier acts on all relevant years. Thus the oil price multiplier will affect each year's price.

Think of setting pre-multiplier inputs as fine-tuning, while setting the multipliers is a rough way of scaling a set of input assumptions up or down quickly.

With these points in mind, in the console view, vary each input from its setting under the Base Scenario (which can be restored at any time within the Console View by clicking the button in cell I21), while watching the waterfall charts, just enough for you to get a sense of whether the model behaves "sensibly":

- Do NCF and NPV increase when prices (cell G23) or production (cell O23) rise, or when the various costs fall – and vice versa?
- Get destructive: find four or five ways – using one variable, or combinations of them – to turn NCF and NPV negative.

- What is the impact on NPV of delaying the start of production to 2017 (using the spinner control in cell C43)? How about delaying the abandonment payment by a year (cell L60)?
- Do the tax deductibility switches for the rental and the bonus (cells J67 and L67) have much effect? What if you increase the bonus (cell O63) and the rentals (row 65) themselves?
- Does the difference between the discounted and undiscounted items change as you expect when you change the discount rate (cell C23)?
- Something strange, for which we have not prepared you:
  - Reset to the Base Scenario (cell J21).
  - Focus only on the undiscounted version of the waterfall chart.
  - Now lower the oil price multiplier (cell G23) from 100%, in steps of 5%. As you do, watch the left chart's undiscounted gross revenue column and data label.
  - At each multiplier setting step down through 60%, gross revenue falls – as you would expect – and by about the same amount (roughly, MOD $20–25 mm). (To see how the multiplier changes the oil price used by the model, refer to the chart which starts a bit below the waterfall charts, in cell L633.)
  - Change the oil price multiplier to 55%. Now undiscounted gross revenue falls sharply, by over MOD $50 mm. Keep lowering the multiplier. Between 50% and 45% is another, steeper drop. What is happening here?

Technical note: waterfall chart axis scales

It can be useful to view the two waterfall charts side by side when they use the same Y-axis scales, to clearly see the effects of discounting. For this reason, we have set them to the same scales manually (by right clicking them and making changes in the Excel dialogue boxes which appear).

One drawback of doing so, however, is that the scales might then be too small under some assumption settings (causing some columns to hit the "ceiling" or "floor"), or too large to show things in enough detail. A solution to this is to right click the Y-axis and have Excel set the scale minimum and maximum automatically; this, however, will mean that sometimes the two chart scales will not match, and/or the charts will "jump" at certain settings.

1.4 ANOTHER (IMPORTANT) MULTIPLIER – INTRODUCTION TO MODELING COMMERCIAL BEHAVIOR WITH THE ECONOMIC LIMIT TEST

Let us investigate why, as we just saw, gross revenue fell unusually sharply at certain oil price multiplier settings:

- Reset the model to the Base Scenario and, in the Console View, scroll as needed so that the oil price multiplier in cell G23 is visible above the horizontal split bar, and the small undiscounted NCF summary chart starting in cell B661 is visible below it.

- Again, lower the multiplier from 100%. Note that:
  - from 100% through to 60%, there are five years of revenue (the black columns in the chart) and thus five years of production;
  - at 55%, there are four years of revenue/production; and
  - at 45%, there are three years of revenue/production.

These three views are reproduced in screenshots on page 6 of the file "Ch1_Main_chapter_supplement.pdf," entitled "Undiscounted net cashflow, considering the economic limit test, under different oil price assumptions."

Why Is Our Production Lifespan Shrinking?

Before answering, first, let us review. In Section 1.2 we noted that:

- ultimately, the results we are most interested in are monetary values which are inflated, then discounted; and
- we implement this by multiplying all inputs which are originally expressed in Real $ by two "multiplier arrays," i.e., the annual inflation index and the annual discount factor.[10]

There is in fact a third "multiplier array" which is fundamental to our valuation models. It is based on what is called the **economic limit test (ELT)**. The ELT is a way of bringing commercial logic to our models. It is used to simulate shutting down a field when – or preferably, just before – continued production would result in losing money. "Money" as defined by the most commonly used ELT methods is a form of operating cashflow, on which we will elaborate later. For the moment, consider the example below, from the file "Ch1_Economic_Limit_Test_ELT.xls."

Consider the simplified oil field investment shown in Figure 1.8, in which all monetary values have already been inflated, i.e., put on a MOD basis. It looks like a good investment, at least initially – after an initial, "enabling" investment of $100 mm (cell E15), production starts, resulting in positive cashflow (by this simplified measure) for the next four years.

You can see that the positive cashflows of $75 mm and $55 mm in the first two production years mean that, on this basis, the investor (assumed to have a 100% equity stake, or "working interest"(WI)) makes back the initial $100 mm investment sometime by the end of 2017.

But after two more years, cashflow turns irreversibly negative in 2020, as cash costs exceed dwindling revenue. Annual cashflows are also shown in Figure 1.9.

It would be hard to imagine that a profit-minded investor would choose to continue production after 2019.

To maximize its cashflow, the investor needs to abandon the field at some point before losses can occur. The investor therefore injects some "policy" into the simplistic cashflow model, as shown in Figure 1.10.

[10] Note that input assumptions which are originally expressed in MOD terms – such as the bonus and rentals in this example model – are already inflated, and therefore only need to be discounted, by multiplying them by the discount factor array.

	B	C	D	E	F
11	Constant oil price, $/b				100
12		**Pre-ELT basis**			
13		Production	Revenue	Cash Costs	Cashflow
14		mm b	MOD $mm	MOD $mm	MOD $mm
15	2015	0.0	0	100	(100)
16	2016	1.0	100	25	75
17	2017	0.9	90	35	55
18	2018	0.8	80	45	35
19	2019	0.7	70	55	15
20	2020	0.6	60	65	(5)
21	2021	0.5	50	80	(30)
22	2022	0.4	40	80	(40)
23	2023	0.3	30	80	(50)
24	2024	0.2	20	80	(60)
25	**Total**	**5.4**	**540**	**645**	**(105)**

Figure 1.8 From the file "Ch1_Economic_Limit_Test_ELT.xls"
Notes: Oil price, production volumes and cash costs are assumed; revenue = price × production; cashflow = revenue − cash costs; "mm" means million; "b" (or "bbl") means barrels.

As seen in Figure 1.10, the array of 0s and 1s in column H, i.e., this **binary array**, acts like a gate – or like a bouncer at the door of a nightclub – keeping undesirable things from "passing through" by multiplying them by 0. The result is that:

- although total life-of-field production volume falls from 5.4 mmb on a pre-ELT basis (cell C67) to 3.4 mmb on a post-ELT basis (cell I67),
- the exclusion of the unprofitable barrels starting from 2020 improves total life-of-field cashflow from a loss of MOD $(105) mm (cell F67) to a profit of MOD $80 mm (cell L67).

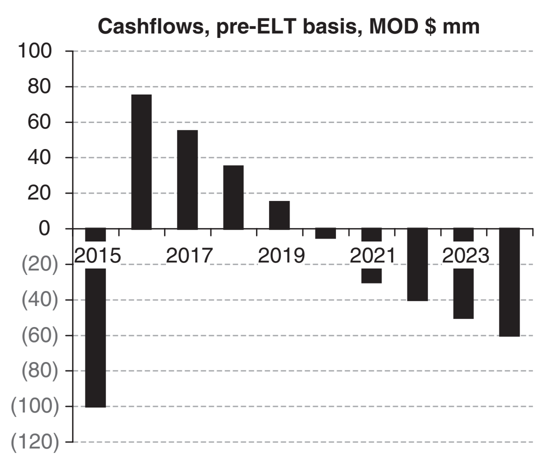

Figure 1.9 From the file "Ch1_Economic_Limit_Test_ELT.xls"

These get multiplied... → ... by this... → ...resulting in these

	B	C	D	E	F	G	H	I	J	K	L
54		Pre-ELT basis				ELT -- Economic Limit Test		Post-ELT basis			
55		Production	Revenue	Cash Costs	Cashflow	Continue or	Continue (1)	Production	Revenue	Cash Costs	Cashflow
56		mm b	$mm	$mm	$mm	Quit?	or Quit (0)?	mm b	$mm	$mm	$mm
57	2015	0.0	0	100	(100)	Continue	1	0.0	0	100	(100)
58	2016	1.0	100	25	75	Continue	1	1.0	100	25	75
59	2017	0.9	90	35	55	Continue	1	0.9	90	35	55
60	2018	0.8	80	45	35	Continue	1	0.8	80	45	35
61	2019	0.7	70	55	15	Continue	1	0.7	70	55	15
62	2020	0.6	60	65	(5)	Quit	0	0.0	0	0	0
63	2021	0.5	50	80	(30)	Quit	0	0.0	0	0	0
64	2022	0.4	40	80	(40)	Quit	0	0.0	0	0	0
65	2023	0.3	30	80	(50)	Quit	0	0.0	0	0	0
66	2024	0.2	20	80	(60)	Quit	0	0.0	0	0	0
67	Total	**5.4**	**540**	**645**	**(105)**			**3.4**	**340**	**260**	**80**

Figure 1.10 From the file "Ch1_Economic_Limit_Test_ELT.xls"
Note: All annual post-ELT basis values in columns I–K equal their pre-ELT counterparts in columns C–E, times the corresponding year's value in column H.

Multiplying the pre-ELT basis values by 0, thus shortening their lifespan, is known as "**truncating** them **to the economic limit**."

Does the truncation of the economic field life shown in Figure 1.11 – in this case, from 2024 to 2019 – look vaguely familiar? Recall how changing the oil price multiplier in our main chapter model "Ch1_Tax_and_Royalty_Model.xls" to 55% and then to 45% shaved years off the production life. That was the model's ELT doing its job.

The criteria, or tests, which the investors in both the chapter model and the simplified example in "Ch1_Economic_Limit_Test_ELT.xls" use to decide which should be the final production

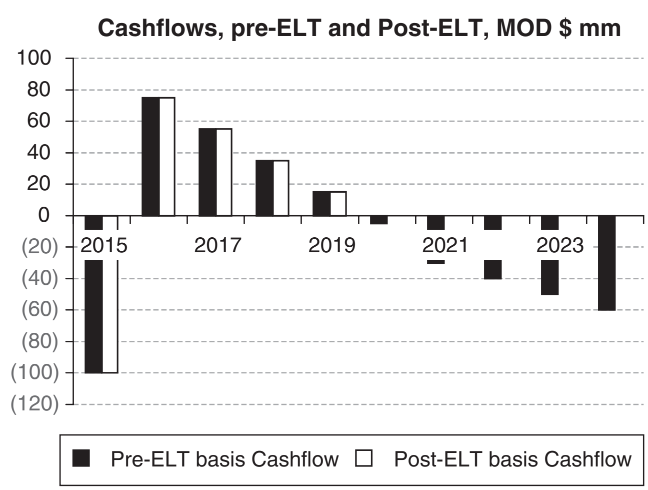

Figure 1.11 From the file "Ch1_Economic_Limit_Test_ELT.xls"

year are examples of ELTs. The ELT is there to simulate how an economically rational actor, i.e., one which wants to maximize cashflow, would behave when faced with the prospect of losses which could be avoided by abandoning the field. We consider some variant of the ELT to be essential in any serious multi-period forecast valuation model.

Note that in the underlying model in "Ch1_Economic_Limit_Test_ELT.xls" we have manually typed in the "Continue," "Quit" and 1 and 0 values columns G and H. Later we will show how to calculate these formulaically. We just note for now that while this is relatively easy, it is not necessarily done in the way that this simple example might suggest.

ELT-related terminology

The **ELT** (again, Economic Limit Test) is, as the name indicates, a test, not a point in time.

Rather, the ELT *determines* a point in time, i.e., when a field should be shut down on economic (or "commercial") grounds, sometimes called the **cutoff**. In our annual models, we call this point in time the end of the **last economic year** or **last economic production year**. In the Base Scenario of "Ch1_Economic_Limit_Test_ELT.xls" it is the end of 2020.

Therefore, the term "**pre-ELT** production" as we use it does *not* denote production occurring before the end of 2020. To be on a "pre-ELT" basis means ignoring the calculation of when the last economic year should be. Thus we use the term "pre-ELT production" to mean production in *any* year, ignoring (not applying) the ELT cutoff. In the simple example above, "pre-ELT production" could be used to describe any value in cells C57:C66. Thus we use "pre-ELT" in the same way we use "pre-tax" in the term "pre-tax cashflow" – that is, meaning cashflow in any year, ignoring (not deducting) tax.

Similarly, "post-ELT" should be understood to mean *any* value after considering (applying) the ELT cutoff, and not, in this example, as meaning after the end of 2020.

The measure of cashflow which the most commonly used variant of ELT aims to maximize, i.e., the analogue to the simplistically termed "cashflow" in Figure 1.11 – is what we term **gross operating cashflow**, or **GOCF**. We'll detail its calculation later.

The ELT is expressed in the binary array in cells H57:H66 (Figure 1.10), which we will term the similarly named **economic life flag ("ELF")**.

Calculation Flow in our Example Model – "Built Around" the ELT

Open the main example model for this chapter, found in the file "Ch1_Tax_and_Royalty_Model.xls." Look at the outline of the model found on the "ModelSummary" sheet. There is a lot of detail here; for now, what is relevant is the overall structure: calculations (which are summarized starting in row 21) are split into three main categories: pre-ELT (rows 21–33), ELT (rows 35–37), and post-ELT (starting row 39).

Pre-ELT calculations. Because the standard version of the ELT we use in this book is based on maximizing GOCF, most of the pre-ELT calculations are of items needed to determine GOCF. These include revenue, operating costs ("opex") and all fiscal costs except (for reasons we explain later) income tax.

ELT calculations. Here we determine when the last economic production year will be, and express this in the model as the binary ELF array.

Post-ELT calculations. Here, we:

- Get post-ELT versions of previously calculated pre-ELT items, by multiplying them by the ELF.
- Deal with a special item – the abandonment cost:
  - We time, based on the last economic year, and thus inflate, the abandonment payment (i.e., for removing equipment, plugging wells and restoring the site).
  - Note that the abandonment cost is on a "post-ELT basis" – not because it has been multiplied by the ELF (it has not), but rather because it has been timed to take into account when the economic production period ends.
- Calculate income tax. Income tax is on a post-ELT basis – not because it has been multiplied by the ELF (again, it has not), but rather because it is calculated using only post-ELT components.
- Calculate net cashflow (NCF) and discounted NCF, using only the post-ELT basis components determined above. Therefore our NCF and NPV results will be on a post-ELT basis as well.

1.5 CHAPTER MODEL HOUSEKEEPING NOTES

In the next few sections of this chapter, we will discuss how the model is built, section by section, and occasionally ask you to make certain changes and observe the results. Before proceeding, here are some useful points to bear in mind.

Read This in Front of the Computer, Actively

Although we try to be generous with explanatory screenshots from the model, both in the text and in the file, "Ch1_Main_chapter_supplement.pdf" on the disk, we have designed the discussion which follows assuming you will be following along while viewing the open Excel model.

You will greatly benefit from using Excel's auditing commands – as well as the shortcut keys we have designated for some of them, as explained on the "AuditingTools" worksheet of the example model file.

Essentially, these commands cause temporary blue tracer lines to appear between formulaically linked cells which are on the same sheet. (Most of our models are contained within one sheet.)

They make it much easier and quicker to follow some of our many detailed discussions about formulas, because instead of having to locate all relevant cells by their cell address, these lines point to all of them at once. When used in split-screen mode, this can be very helpful. Their use is demonstrated in the short video tutorial "Ch1_Good auditing habits.wmv" on the disk.[11]

Custom View Setting Within the Model

The model's underlying calculations, interactive charts and special analysis sections make it rather large. To ease navigation and the use of the interactive charts, we have created a number of buttons in rows 1–10 (with some duplicates elsewhere) of the "Model" sheet which trigger custom views, split the screen horizontally, and/or hide certain rows. (These custom views can be undone using the "Show all rows" buttons in cell C1 or D21.) Be sure you have set Excel to enable macros, or these will not work.

The view when you click the "Group rows" button in cell D1 is a useful format when first surveying the model's layout. The view is "semi-condensed." This means you will see:

- the most commonly used assumption input cells and controls (starting in row 22);
- starting row 83, two charts and a table for reference when making assumptions (for which you will probably have to split the screen);
- starting in row 108, many calculation subsections which show only their section headings and final results, with underlying calculations hidden; and
- the interactive charts and analysis tables which start in row 597.

We will often refer to another custom view, the Console View, which we introduced above and which you can see by clicking the button in cell F1. Although you might need to slightly adjust the horizontal split bar at times, this view should provide a convenient way to change assumptions and see the effects elsewhere in the model.

Spinner Controls

Many inputs may only be changed with spinner controls (switches) such as the one in cell C22. In cases where the variable is expressed as a percentage or contains a decimal – things which Excel's spinners do not permit directly – we have used an indirect solution, which is explained in the "Use of extra cells with spinner controls" section (page 7) of the file "Ch1_Main_chapter_supplement.pdf." This explains, among other things, what the table starting in cell Q1 is for.

If you have not built a model with spinners before, take a moment to watch the video tutorial "Ch1_Making and using spinners.wmv" on the disk in the Chapter 1 folder.

[11] Two other powerful auditing tools that we would urge you to investigate, both for use with this book and generally, are (a) Excel's Evaluate Formula tool (explained in the standalone file "Ch3_Evaluate_Formula_Excel_tool.xls," found in the Chapter 3 folder); and (b) a third-party Excel add-in called RefTreeAnalyser, which – provided you freeze or split the screen in half, vertically, at the right edge of the last caption column on the left – is like Excel's auditing commands on steroids. Rather than following blue lines between cells, it "flies" you past each formula component cell (this is easier to understand when it is used). A free demo and a paid version are available from the developer, JKP Application Development Services, at http://www.jkp-ads.com/RefTreeAnalyser.asp.

Only Type in Cells in Blue Font

Do not type in any cell other than those in blue font, (when permitted – note that some of these have been locked to certain values using Excel's Validation feature.)

Named Cells and Ranges

The model uses many named cells and ranges, to make formulas easier to read. These have red borders. Select a named cell or range and see its name in the box in the upper left hand corner of the Excel screen, to the left of the formula bar. You can also refer to the file's "NamedCellsAndRanges" worksheet, which lists the cell addresses of all named cells and ranges.

Be sure especially to check those named items which are visible in the assumptions part of the Console View, as many are used often in the calculation sections below.

For a quick overview of important points about how we use named *ranges* in particular – and how one should not – see "How Excel understands references to named ranges" on pages 4 and 5 of the file "Ch1_Main_chapter_supplement.pdf."

Checksums and the ROUND Function

Notice the red 0 values in column A, including the one in cell A1, as well as elsewhere in the model, and the "No errors detected" message in cell B1. The red zero cells contain formulas called "checksums," which are used to detect errors. A red zero in a gray-shaded cell means no error has been found. Often these checksum formulas use Excel's ROUND function. For details, see the Checksum pages (8 and 9) of the file "Ch1_Main_chapter_supplement.pdf."

1.6 CHAPTER MODEL ASSUMPTIONS

1.6.1 Assumptions: General Remarks

Our Assumptions Are Simplified

In real-world upstream petroleum economic models, field assumptions are the combined product of the efforts of earth scientists and petroleum reservoir and cost engineers. Each of their disciplines is a specialty in its own right and is thus beyond the scope of this book, which focuses on how to turn technical data into meaningful financial data.

Therefore, here and in other example models used in this book, we will just provide you with the raw technical data assumptions, with no attempt to make them any more detailed than needed to make our fiscal and valuation modeling points. Frequent simplifying shortcuts we have taken include:

- assuming very brief (often one- or two-year) development periods, i.e., when initial capex is spent, to enable production;

- limiting example fields' **technical production** schedules, or **profiles** – here "technical" means pre-ELT, or ignoring the economic limit – to 10 years or less (whereas many actual fields produce for decades);
- aggregating the many types of opex and capex into just a few, fiscally relevant categories;[12] and
- assuming that the Investor (which, under a type of fiscal regime called a production sharing agreement – covered in Chapters 6–8 – is also referred to as a "Contractor") has a 100% equity stake, or **working interest**, in the project in question. Note, however, that in reality often there are multiple partners, sometimes using complex shareholder/financing agreements. While these can be fiscally relevant to the individual parties, they are something of a sub-science of their own, and thus beyond our scope here.

Therefore, bear in mind the old Modeling Law: "garbage in means garbage out." The quality and validity of the input data are paramount. In real life, the analyst would get these data from in-house discipline experts if he or she is working for a petroleum company, whereas outside analysts working for banks, investment funds, potential production partners, or host governments will have to get these data from the operating company's team, from their own in-house expertise if available, or from outside consultants.

1.6.2 Assumptions: Time and the Time Value of Money

These assumptions are summarized in the screenshot from the "ModelSummary" sheet shown in Figure 1.12.

The inflation and discount rates can be input using the spinners in the "Model" sheet's cells C22 and C23. The corresponding arrays for the annual inflation index and discount factor are found in rows 28 and 29, and are named "Infl_index" and "Disc_factor" respectively. They are calculated using the mid-period method described in Section 1.2.

The valuation date, i.e., the date from which values are inflated, and to which they are discounted, is assumed to be January 1, 2015 (not changeable in this version) of the model.

	A	B	C	D	E
3	**Time related assumptions**				
4	• Inflation rate			• Inflation index	
5	• Discount rate	expressed as	--->	• Discount factor	
6	• License length			• License flag	
7	Production and Abandonment delay factors				

Figure 1.12 From the file "Ch1_Tax_and_Royalty_Model.xls"

[12] A wide-ranging and very readable introduction to the different kinds of equipment and processes (and thus kinds of capex and opex) involved in upstream petroleum projects is Norman J. Hyne's *Nontechnical Guide to Petroleum Geology, Exploration, Drilling and Production* (Penwell Books, 2012).

Note that the model lets you delay, compared to the Base Scenario assumptions, the start of production,[13] as well as when the abandonment payment is made, by one year, using the spinners in cells C43 and L60, respectively. The Base Case assumes production will start one year after the first capex year of 2015, and that the abandonment payment will be made in the last economic year.

Sense checks

Start each of the two checks described below by showing the Base Scenario:

(a) In the Console View, be able to see the inflation and discount rate input cells (C22:C23) above the split, and, below it, either the waterfall charts (starting in row 602) or the annual basis undiscounted and discounted NCF charts (row 661). Do you understand why these charts change as they do when you adjust the rates? Do the discounted results match their undiscounted counterparts when the discount rate is set to 0%? What (approximately) is the discount rate at which NPV equals 0 (i.e., what is the internal rate of return (IRR))?

(b) In the Console View, be able to see rows 43 and 60 in the top part of the screen, and, in the bottom part, rows 502–511 from the investor's undiscounted NCF section. Use the spinners in C43 and L60 to adjust the timings. Do the NCF components seem to shift in time appropriately?

We explain the time-shifting calculations in the sections covering production inputs and the abandonment calculation, below.

1.6.3 Assumptions: Commodity Prices[14]

Price Forecasts: General Thoughts

The oil price is one of the single most powerful parameters in an oil field valuation model in terms of its effects on NPV. In the model's Console View, note how much more a 5% increase in the oil price multiplier (cell G23) improves NPV in the waterfall chart, compared to a 5% decrease in the capex or opex multipliers (cells J23 and L23, respectively).[15]

The oil price is, however, also notoriously hard to forecast. Over the few years of writing this book, we have seen the benchmark Brent crude price range between approximately MOD $40 and $150. If we knew what the oil price would be, we would have probably dictated this book to attractive assistants from the deck chairs of yachts, if we had bothered to write at all.

[13] Although in this example model we express our annual production profiles (discussed below) in mmb (millions of barrels per year; also mm bbl), be aware that quite often such data are expressed in barrels per day (b/d, or bbl/d) or thousands of barrels per day (mb/d or m bbl/d). This requires an assumption about the number of days per year. One approach uses the actual number of calendar days for each year; others assume that each year has 365 days, or 365.25 days to approximate the effect of leap years.

[14] As most of our models and examples in this book assume the fields in question produce only oil, the following discussion is about oil prices, not gas prices. The main points made here, however, also apply in large measure to gas prices, except that whereas oil markets are global, gas markets tend to be more localized, and gas prices tend in many regions to vary seasonally.

[15] The degree of difference will of course depend on the field and fiscal assumptions in question, but usually the price is more influential than other input assumptions.

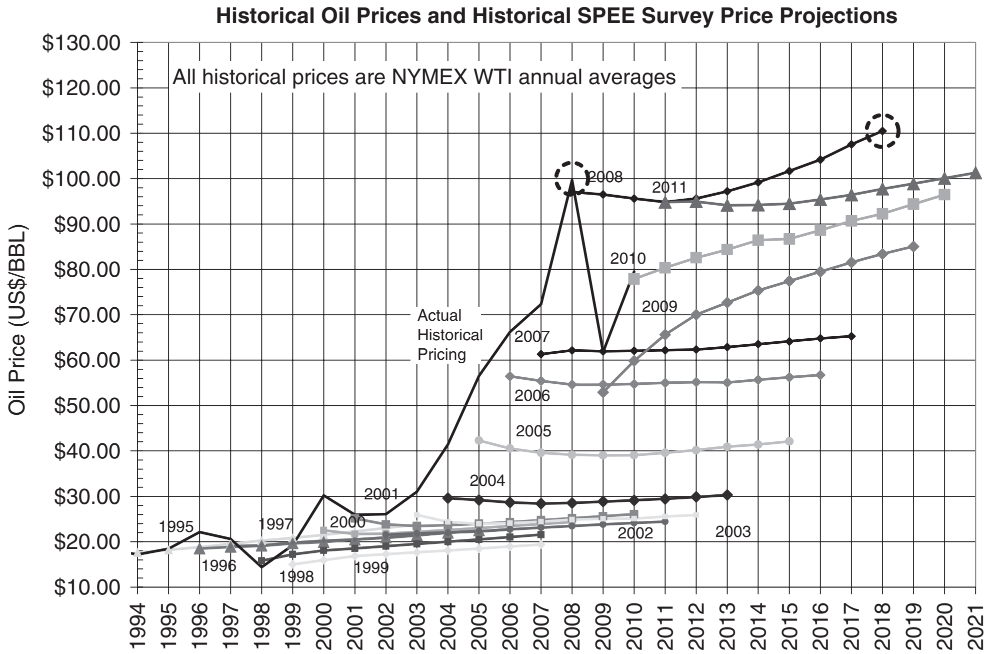

Figure 1.13 SPEE survey: respondents' oil price forecasts over time (From *Society of Petroleum Evaluation Engineers Thirtieth Annual Survey of Parameters Used in Property Evaluation, June 2011*). (For clarity, we have also reproduced this graphic on page 3 of the file "Ch1_Main_chapter_supplement.pdf")

Figure 1.13 is a screenshot from the 2011 SPEE survey we mentioned in Section 1.2. It shows respondents' average forecasts for their "NYMEX WTI" (West Texas Intermediate, the main US crude oil benchmark price, traded on the NYMEX exchange) price forecasts, made at different points in time. For example, the two blue circles, which we have added to start and end the "2008" series in the SPEE's graphic, show that:

- the average forecast made in 2008, for the 2008 oil price, was (approximating from the chart) around $98/b; and
- the average forecast made in 2008, for the 2018 oil price, was around $110.

The contrast between the forecasts and the plain black line, which represents actual historic prices, is instructive.

- The actual price is volatile – or as John Browne, former CEO of BP put it, "inherently unpredictable."
- Forecasts, on the other hand, with some variation, generally tend to "chase" the actual price as it moves up and down – that is, they tend to start at a price close to the actual price seen at, or not long (roughly 0–1.5 years) before the date the forecast was made, and then move horizontally.

This inherent volatility of the oil price is due to the fact that it is – except where governments impose local price controls – determined:

- by supply and demand; and
- due to the role of speculation, by *perceptions* of future supply and demand.

Therefore, it would seem that the most rigorous way to try to forecast global oil prices from first principles would require you to:

- assemble a base case supply/demand projection, drawing on a view of every country's future production, consumption and storage volumes;
- anticipate and quantify the impact on supply and/or demand of disruptions to the base case, e.g., on the supply side, things like wars, civil unrest, vandalism, geopolitical crises, hurricanes, accidents and their fallout, and, on the demand side, anything affecting future consumption, such as the state of the global economy;
- anticipate to what extent speculators and other buyers will themselves anticipate and respond to these disruptions; and
- then back-test the model with historic data, to see how well whatever algorithm you have devised to incorporate all these factors would have predicted actual prices. If the model passes this credibility test – and you are happy to assume that relationships which held true over the historic test period will remain in the future – you have yourself a price forecast model.

This of course is a caricature of a method we have not actually seen used, but which we cite just to show why medium- and long-term forecasts are so often wrong.

Investors, governments and other actors respond to the challenge of forecasting prices for use in valuation models in different ways. Some use quite detailed and "scientific" methods; others use probabilistic approaches;[16] while at the other extreme, others just use a price based on a consensus (often an average) of third-party forecasts, including those forecasts which are implied by exchange-traded commodity futures prices.

A common, pragmatic approach is to accept that the price is unknowable, and to use a base case, however arrived at, as well as low and high alternative cases, to try to get a feel for "expected" (however that is defined) bad and good scenarios. Sensitivity analysis, whereby one calculates NPV across a broad range of oil prices, is a prudent practice to "stress-test" a valuation.

> The oil price issue alone brings into focus the fact that, ultimately, the goal of valuation modeling is not to be able to state "NPV will equal $X," but rather to be able to answer the question "What will NPV be under any given set of explicit assumptions?" Until we learn how to see into the future, it is the best we can do.

[16] We provide an introduction to probabilistic modeling, including exercises for use with the trial version of Crystal Ball on the disk, in the standalone files in the Appendix V folder on the disk, and in Section 8.2 of Chapter 8.

Price Forecasts in Our Example Model

To simplify our model and keep the focus on fiscal analysis, we make no pretence of even trying to forecast the oil price. Rather, for our Base Scenario, we have pulled a number out of the air – Real 2015 $80/barrel (cell D33) – and assumed this will be the field's received oil price each year. We have also created a row for you to input your own annual price(s) in Real 2015 $ terms, and a way to choose between them. Whichever price is used will then be subject to the oil price sensitivity multiplier and inflated to MOD terms, for use in the model.

We do this in rows 33–41 of the example model:

- The spinner control in cell D33 lets you change the assumed (all-years) price in 2015 $/b which will be used, *if* you have chosen to use the Base Scenario oil price. The value in cell D33 then determines every annual cell in row 36.
- You can enter any values for the Real 2015 $/b "User custom oil price" case in cells F37:O37.
- The spinner in cell I33 lets you choose between the two forecasts to use. The selected, Real MOD $/b forecast series will appear in row 39, in which the annual cells use Excel's CHOOSE function (explained on pages 82–83 of "Ch1_Time_value_of_money_supplement.pdf).
- The selected price case in row 39 then gets multiplied in row 40 by the oil price sensitivity multiplier (or "factor," which, again, under the Base Scenario, always equals 100%).
- The resultant values in row 40 get multiplied in row 41 by the inflation index. This is what will feed the model.

Do Not Forget What "Real 2015 $" Means

Bear in mind, as we discussed in the "Real Versus Inflated Dollars" subsection of Section 1.2, above, that the term "Real 2015 $/b" on its own does *not* mean the oil price in 2015. Rather, it means an oil price – which could be for any period specified – expressed in dollars of constant 2015 purchasing power. Thus, for example, under the Base Scenario:

- the value of 80 in cell F36 means an annual average oil price of $80/b for 2015, expressed in Real 2015 dollars; and
- the value of 80 in cell I36 means an annual average oil price of $80/b for 2018, expressed in Real 2015 dollars.

These values are then inflated in row 41 for later use in the model.

Price Forecasts in Models: Differentials

Even assuming the modeler takes the "quick and dirty" approach of using a consensus forecast for a crude benchmark such as Brent crude, unless the field being modeled is one contributing physically to the Brent blend, the price in the model will likely need some adjusting. <u>To keep our model simple, we do not make such adjustments, but you should be aware of them when building real-world models</u>.

Adjustments are needed because Brent is only a benchmark crude, whereas there are many different grades of crude oil around the world, each with its own price. A **benchmark crude** is one:

- which is sold at a specified location; and
- for which prices are published in the public domain. Other examples include West Texas Intermediate, or "WTI" (USA), Urals (Russia) and Forcados (Nigeria).

In general, all oil prices – benchmark and non-benchmark – tend to "move together" in terms of period-on-period percentage change, but they have different dollar values, due to differences in, among other things, a crude's quality (e.g., high-sulfur or "sour" crude tends to be priced lower than low-sulfur or "sweet" crude).[17]

Therefore the modeler should base the price forecast on:

- a benchmark which has in the past shown some meaningful relationship, i.e., similar dollar pricing and percentage change trends over time, to the historic prices realized by the field being modeled; or, if the field being modeled has not produced yet,
- a benchmark of similar quality, i.e., one whose price movements could be expected to parallel those received by the field in question, once it starts producing.

In either case, an adjustment, or **price differential**, would need to be assumed. If, for example, the crude in question has historically sold at a price 10% lower than, say, Brent crude, then one might assume that, in the future, the differential will continue to be equal to 10% of Brent, i.e., the crude in question would sell at a 10% discount to Brent. If on the other hand the crude has historically traded at 10% higher than Brent, the assumed differential could be an assumed "10% premium to Brent."[18]

Price Forecasts in Models: Where Is This Price Realized?

Crude is priced at a specific location. The location matters from a fiscal and valuation standpoint:

- Most fiscal devices such as royalties, which are calculated as some percentage of revenue, specify that the location where the sales price is realized is to be used in their calculation. This could be at the **wellhead** (right were the crude comes out of the ground), or it could be somewhere outside the license area, such as a third-party pumping station, or a pipeline juncture. To correctly calculate royalties and other fiscal devices based on the received price, you need to know this price.
- Location also matters because the cost of transportation to a selling point costs money. In such a case, for cashflow purposes, the cash inflow should be the price received at the selling

[17] Note that in some cases, though, regional differences in inventory values can and do lead to benchmark oil prices moving in opposite directions. In such a case, you need to "take a view" as to which trend should be assumed for forecasting purposes.

[18] Note, however, that differentials between oil price benchmarks may vary significantly over short periods of time (e.g., Brent and WTI over the 2010–2012 period).

point, and the cash outflow would be the handling (i.e., transportation and storage) opex incurred in getting it there.

In our example models in this book, we assume that the assumed oil prices, i.e., those chosen for use in row 39, are the same prices used by fiscal devices, and that these are the wellhead prices, so the investor incurs no transport costs.

1.6.4 Assumptions: Production Profile

Up to seven years of annual oil production volumes, in mmb, can be entered on a pre-multiplier, pre-ELT basis in the gray-shaded cells F46:L46. To enable time-shifting,

- These annual volumes are entered on a generic year basis, i.e., for production year 1, production year 2, etc.
- They are then converted to a calendar year basis in row 49, based on the starting calendar year of production which you specify in row 43.

The method used to shift the production profile to the specified timeframe is explained on pages 11–13 of the file "Ch1_Main_chapter_supplement.pdf."

1.6.5 Assumptions: Capex

Capex Scheduling Issues

For a given production "stream," **capex** or **capital expenditure** consists of the costs of services and/or long-life assets incurred:

- before production starts, as an initial enabling investment, i.e. to find and appraise oil and gas and to get commercial production up and running; typical items include wells and ancillary items, pipelines and treatment/storage facilities; and
- after production starts, to maintain production; this includes certain categories of maintenance/reinvigoration of wells though "recompletions" and "workovers"; these costs are usually incurred only occasionally (i.e., they are not a recurrent annual expense).

In such a simplified single "stream" view, often most of the capex will be spent before production starts (meaning the investor starts off "in the red" – see for example the cumulative undiscounted and discounted NCF charts which start in cells B669 and L669).

Often, however, large and/or complex fields will require a phased approach, i.e., consisting of different "streams" starting at different times, meaning pre-production capex for one stream might be incurred at the same time that another is in its post-production phase. Some "streams" will also share common facilities. Multi-"stream" capex scheduling can get complex, and require solving timing and capacity optimization problems.[19] In nearly all the examples used in this book, we have kept things simple by using the single "stream" assumption.

Capex Classification for Fiscal Purposes: Intangible vs. Tangible

For fiscal purposes, a key distinction is whether capex is classed as intangible or tangible:

- Intangible capex consists of items, the essence of which cannot be touched – for example, seismic data and its processing and interpretation; a facilities plan; the drilling of a well bore, etc. Intangible capex is usually "expensed for tax purposes." This means that, for example, the full value of a $10 mm intangible capex item is eligible to be an income tax deduction, or **tax allowance**, in the year that it is incurred.
- Tangible capex, on the other hand, can be touched – for example, the steel casing which is placed in the well bore; well platforms and facilities, pipelines, compressor stations, etc.
- Often – though not always – tangible capex is "capitalized for tax purposes," which means that the tax allowances which arise from tangible capex will be phased over time via depreciation. For example, under a common variant known as "straight line" depreciation:
  - if the depreciation rules in the country's tax code state that a $10 mm tangible capex item has a 10-year "useful life" for depreciation purposes,
  - then for each of the 10 years, starting with the year the item is first used, there will be 10 equal annual tax allowances of $1 mm each.

This is a simplification. We treat depreciation in more detail below.

In our example model, capex is assumed to be incurred only in 2015 and 2016. Assumptions are input in pre-multiplier, Real 2015 $ terms, along with an assumed tangible/intangible percentage split each year, as shown in Figure 1.14.

	F	G	H	I	J
55	**costs (Real 2015 $)**				
56	**Capex , $mm**			**2015**	**2016**
57	Pre-multiplier			61.0	20.0
58	**Post-multiplier**			**61.0**	**20.0**
59	of which tangible, %			60.0%	90.0%
60	of which intangible, %			40.0%	10.0%

Figure 1.14 Capex inputs under Base Scenario (Real 2015 $ mm), from the file "Ch1_Tax_and_Royalty_Model.xls"
Note: Reflects Base Scenario.

[19] A good source on generic project timing modeling in Excel is *Spreadsheet Modeling and Applications: Essentials of Practical Management Science*, by S. Christian Albright and Wayne L. Winston (South-Western, 2005). In addition, the trial version of Crystal Ball on the book's disk contains tutorials for solving schedule optimization problems using the included OptQuest software.

1.6.6 Assumptions: Opex

Field operating expenses, or **opex**, are the ongoing costs incurred once production has begun. Opex is usually often divided for modeling purposes into two categories:

- fixed opex; and
- variable opex.

Fixed field opex (cell C57) is usually forecast in terms of total cost per accounting period. In our example model, it lives up to its name, i.e., the cost is a "fixed," or constant, amount incurred for each period of operation, regardless of how much oil is produced.

Be aware, however, that in the real world, the amount is only "fixed" *within certain ranges* of production volumes involved:

- For example, a processing facility might cost Real 2015 $10 mm per year to operate, when the annual volumes processed are between, say, 0 and 1 mmb, but $15 mm per year when they are between 1 and 2 mmb etc.
- Thus what is commonly called "fixed opex" is actually "fixed" only over certain ranges of production, and can vary in a step-like manner between thresholds.

Other examples of such fixed field opex include administrative overheads, operating staff, safety, security, environmental monitoring and facility insurance.

In contrast, **variable field opex** (cell D57) always varies continuously according to production volumes. For oil production, variable field opex is normally expressed on a unit basis, which in the case of an oil-only development would mean cost per barrel of oil production.[20]

Simplifications Used in Our Example Model

We have ignored any operating costs incurred in the pre- and post-production years. In real life there would be, at minimum, managerial and administrative overheads incurred to consider.

In our Base Scenario, fixed opex of Real 2015 $15 mm per year (cell C57) is assumed incurred in all production years, i.e., it is truly "fixed," and does not vary depending on a year's production volume.

> While this assumption might be plausible in light of the Base Scenario's assumed volumes, be aware that it might not make sense in the real world, for example, to increase the oil production sensitivity multiplier in cell O23 from 100% to 500%, while leaving fixed opex unchanged.

[20] With fields producing a significant amount of water, variable operating costs are sometimes expressed as cost per barrel of total fluid production (i.e., oil plus water). So be sure you are clear what "per barrel" means!

To remedy this in a real-world Excel model, one would need to ensure that fixed opex charges vary formulaically with the appropriate production thresholds – using, for example, IF statements, or LOOKUP tables.[21] Note that while writing the formulas might be easy, the underlying inputs would likely require somewhat detailed cost engineering expertise.

1.6.7 Assumptions: Abandonment

The assumptions for the **abandonment costs** – also called **decommissioning costs** and/or **site restoration costs** – are input on a Real 2015 $, pre-multiplier basis in cell O57. Under our Base Scenario, they are Real 2015 $21.0 mm.

Abandonment costs are the costs incurred to meet the requirement for oil and gas producers to clean up after themselves when production has finished, usually by plugging disused wells and dismantling facilities. By definition, much of this constitutes the last activity in the life of the field, most of which occurs after revenue from production has ceased.

In our example model, the abandonment cost is paid in a single "lumpsum," either in the last year of economic (i.e., post-ELT) production, or one year later, as the user specifies using the spinner in cell L60.

Note that:

- The relevant sensitivity multiplier is the combined capex/abandonment multiplier in cell J23. We use a combined multiplier as a simplification, though one which makes some sense, as the size of abandonment costs is often linked to the scale of capex involved in developing a field.
- We do not inflate the abandonment cost at this stage in the model. We cannot, because we do not yet know when it will be paid – we will know this only after we determine when the last economic production year will be, which is calculated later, in the model's ELT section. We will inflate the abandonment cost there.

Looking ahead: abandonment costs' impact on NPV

Discharging abandonment obligations via such a single, end-of-life lumpsum is fairly common practice, but there are several variations used as well. One is to require payments from the producer in advance, i.e., while the field is still producing. This and other abandonment funding arrangements are important as they can impact cashflows in a number of ways:

- As cash outflows in their own right, which in some cases can be quite material. For example, a long-producing field, nearing the end of its life, can have large accumulated "lumpsum" abandonment liabilities due in the near future, "looming on the horizon."
- The timing of abandonment payments influences their discounted cost to the investor, and thus the investor's NPV; this aspect of the time value of money can, in fact, sometimes

[21] See the standalone file "VLOOKUP_HLOOKUP_examples.xls" in the Chapter 1 folder for more details on LOOKUP tables.

give investors incentives to seek legitimate ways to delay abandonment payments, when permitted.

- Abandonment costs are usually tax deductible, as we assume in our example model.
  - Abandonment costs paid as an end-of-life lumpsum, however, will be incurred at a time when the field will have little or no revenue, and thus little or no taxable income. When there is no taxable income, a tax deduction does not benefit the taxpayer (unless there are special fiscal mechanisms in place to help remedy this, which our example model does *not* assume).
  - Whereas if, in contrast, abandonment costs are paid over the producing life, when there *is* (hopefully) taxable income, then the abandonment costs paid will benefit the taxpayer as tax deductions.

Thus the impact of how abandonment costs are funded will depend on the interplay between the size of the costs, their timing, the ability to make use of the associated tax benefits, and the effects of inflation/and discounting on both the outflow itself and on any tax benefits.

Chapter 5 is devoted entirely to abandonment funding.

Coming Up: Overview of Fiscal Assumptions

The screenshot reproduced in Figure 1.15 shows the main items which we shall introduce in the next few sections.

1.6.8 Assumptions: Royalty

	A	B	C	D	E	F	G	H
16								
17	**Fiscal assumptions**							
18	Usable as tax allowances?	Royalty rate %	Rental amount, MOD $	Bonus amount, MOD $	Tax loss end of 2014	Income tax rate, %; Depreciation rules	Prior balances: Tax loss and Undepreciated balance end of 2014, MOD $	Capex as tax allowances: Intangible is expensed; Tangible is depreciated
19		Yes	Maybe	Maybe	Yes			

Figure 1.15 From the "ModelSummary" sheet of the file "Ch1_Tax_and_Royalty_Model.xls"

The royalty payment is one of a few "off-the-top" fiscal devices in our example model.

Royalties are payments to the government – and sometimes to third parties ("overriding royalties") – based on a rate which is a percentage of the value of commercial production. Their cash value per barrel (in the case of oil) is usually based on the producer's received sales price. Hence the term "off the top" – such royalty payments are usually made from revenue before any other deductions are made.

Government royalties provide a guaranteed revenue stream for the state, regardless of a field's profitability. (In formal petroleum economics terminology, this means they are **regressive** devices.)

Royalties can take many different forms – Chapter 3 is devoted to some of the most common ones. For this chapter's introductory model, we have used the simplest version – a constant percentage of the wellhead price in all years. Under the Base Scenario, it is 17.25%, input in cell H63 of the "Model" sheet.

Sense check

Set the model to the Base Scenario and, in the Console View, move the oil price multiplier above and below 100% while watching the waterfall charts below the split. Do the royalty columns (and value captions at the bottom) update as you would expect?

Reset the oil price multiplier to 100%, and then scroll down in the top part of the screen, so that you can see the royalty rate (cell H63). At which royalty rates do the investor's NCF and NPV – shown in the waterfall charts' captions – turn negative?

Note that in cell N67 we have assumed that the royalty is tax deductible. This is not changeable in the model. We have never seen a case where royalty was not tax deductible. It would be cruel indeed for a government to tax an investor based on income which was taken "off the top," i.e., never actually received by the investor.

1.6.9 Assumptions: Rentals

Area rentals – not to be confused with opex, which can include the costs of renting equipment or facilities – are a second fiscal device in our example tax and royalty regime which takes money "off the top" of the investor's cash inflows, without any direct link to field profitability or the lack thereof.

As the name implies, area rentals are periodic, area-based fees payable to the government, usually based on the area of the acreage[22] in question, and the phase of the fields' lives, which in our example is divided for these purposes into the pre-production phase and the production phase.

Rental assumptions for the area and the annual rental rates payable during each type of period are entered in row 65 of the model. Note that:

- as is common in many fiscal regimes with rentals, the annual per-unit payments required are small relative to project cashflows – in this case MOD $50 000–100 000, depending on the period – and are expressed in the regulations (and thus in the model) in MOD terms; and

[22] Note that in upstream petroleum, the term "acreage" is sometimes used to mean "area," even when the regulations use other units, such as square kilometers in our example model.

- we simplify in our example model by assuming that the license area is the same every year. Be aware, though, that often in real exploration licenses which result in a discovery, the investor is required to **relinquish**, or give back to the government, any acreage it no longer needs for further exploration and/or development and production. In some cases, relinquishments are required after certain deadlines. At all events, the license area can shrink over time.

Sense check

Note that, in cell J67, you can assume whether rentals are tax deductible. Reset the model to the Base Scenario. Then in the Console View, arrange the split so that rows 65–67 are visible above it and, below it, the waterfall charts (including the value labels at the bottom of the charts, which should be possible in full screen mode). Make the rentals non-deductible by changing the value in cell J67 from 1 to 0, while noting the changes in the waterfall charts. Note that doing so will not change the amounts shown in either chart for “Bonuses & Rentals,” but it will have a modest impact on the income tax charge, and thus on NCF and NPV.

1.6.10 Assumptions: Bonuses

Bonuses are the third “off-the-top” fiscal device in our example model’s assumed tax and royalty regime. Bonuses are payments – again, usually denominated in MOD terms – made to the government which correspond to some project milestone.

Bonuses take many forms. A few common ones include:

- Signature bonuses (paid when the investor formally joins a license, or signs a production sharing contract).
- Bonuses payable upon first commercial[23] production (like the one in our example model). While not always large, they can have symbolic/“public relations” value to governments which wish to show the public, early in a project, that the host country is receiving cashflow.
- Bonuses based on reaching a level or levels of cumulative production.

Chapter 4 is devoted entirely to bonuses.

In this chapter’s example model, the assumed bonus amount is entered using the spinner in cell O63. Bonuses are not always tax deductible; therefore the user may decide whether this one is or not, using the spinner in cell L67.

[23] “Commercial production” in this sense usually means production which is sold during a field’s main production period, as opposed to early volumes produced on a test basis during the preceding appraisal period.

Sense check

In the Console View, make row 43 – where you decide when first production will be – visible above the split, and the timed bonus payment in row 160 visible below the split. Change the production date and be sure the bonus timing changes appropriately. Note that because we have entered the assumed bonus assumption in MOD terms, its MOD value in the model does not change according to when it is paid.

Assumptions: per-barrels basis "reality check" table

If you click the "Show all rows" button in cell C1, and then click the "Console View" button in cell F1, you should see below the horizontal split (perhaps most clearly in full screen mode) a table starting in cell G83. This expresses all the results of all the assumptions, excluding income tax and related items, on a (take a deep breath) post-sensitivity multiplier, pre-ELT, life-of-field, Real 2015 $/barrel basis. The table is shown in Figure 1.16. It reflects the Base Scenario.

In other words, we get a "raw" or "underlying" view of the weighted average field economics, based on assumptions feeding the model, but before the model "acts" on them by introducing "distortions" due to the economic limit, taxation and the time value of money.

	G–I	J	K
82	Reflects post-multiplier basis assumptions		
83	**Memo: Total (all years) results of assumptions, IGNORING the economic limit, in Real 2015 $**		
84	**Item**	**Real 2015 $/b**	**% of gross revenue**
85	**Gross field revenue**	**80.00**	**100.0%**
86	Capex	13.79	17.2%
87	Fixed opex	17.88	22.3%
88	Variable opex	8.00	10.0%
89	Abandonment	3.58	4.5%
90	**Field costs**	**43.24**	**54.1%**
91	**Field operating cashflow**	**36.76**	**45.9%**
92	Royalty @ 17.25%	13.80	17.3%
93	Rentals	2.12	2.6%
94	Bonus	2.48	3.1%
95	**Fiscal costs**	**18.39**	**23.0%**
96	**Field pre-tax cashflow**	**18.36**	**23.0%**

Figure 1.16 From the "Model" sheet of the file "Ch1_Tax_and_Royalty_Model.xls"
Note: Reflects Base Scenario.

This per-barrel view puts into perspective the relative size of different cost items in relation to revenue, which otherwise would be hard to do, since we are inputting our assumptions in so many different formats, namely:

- variable opex in Real 2015 $ per barrel;
- fixed opex in real 2015 $ mm per producing year;
- capex per year in Real 2015 $ mm in specific years;
- abandonment costs in Real 2015 $ mm (to be spent in a year we do not know yet);
- royalty as a percentage of the oil price; and
- rentals and the bonus in MOD $ mm.[24]

The "raw" view in this table is only a starting point for analysis – after all, we are building a fiscally detailed valuation model, so we will only discount and thus derive a value from inflated, post-ELT, post-tax cashflows. But the "raw" view still can give useful insights, and help check the credibility of some of the inputs.

- For example, if you reset the model to the Base Scenario and, in Console View, lower the oil price (cell D33), you will see that the field's "raw" pre-tax cashflow (cell J96) first goes negative at Real 2015 $(0.67) mm, when the price is Real 2015 $57.00/b.
- You will also see why. Field operating cashflow (i.e., ignoring fiscal costs) in cell J91 is positive at this oil price; therefore the loss shown in cell J96 must be due to the fiscal costs.
- If you continue lowering the oil price you will see that at Real 2015 $43.00/b, cashflow goes cash negative on a field basis as well, i.e., the result in cell J91 also turns negative, to Real 2015 $(0.24) mm.
- Getting such a feel for the field's "underlying" (i.e., non-fiscal) "breaking point" can help inform investors who have an opportunity to negotiate aspects of the fiscal regime.

1.6.11 Assumptions: Income Tax and Related Items

Before detailing our Base Scenario's specific income tax assumptions, first let us get a sense of how they will ultimately be used in the model, by jumping ahead to look at the outline of the income tax calculation. Refer to the screenshot from the "ModelSummary" sheet shown in Figure 1.17. Note that income taxes are calculated on a post-ELT basis, meaning that all the components of the calculation are on a post-ELT basis.

Conceptually, the income tax calculation is quite straightforward. The investor's **tax position** in any given year equals gross revenue minus the sum of **tax allowances** (i.e., deductions). When the annual result is positive, the tax position is one of **taxable income** (or **taxable**

[24] In order to get the rentals and bonus from their input format of MOD $ into the "reality check" table's Real 2015 $ format, we had to go a bit further down, into the calculations section of the model, to where we time and sum these items in MOD terms (as discussed below), and then deflate them to get them in Real 2015 $ terms. We deflate them by *dividing* each annual MOD result by the appropriate year's inflation index. We do this in the workspace in rows 142–146. Note also how we have calculated the fixed opex cost per barrel in cell J87, using the COUNTIF function. See the comment in this cell, or Excel's online help, regarding how this function works here.

	A	B	C	D	E	F	G	H
47	**(Post-ELT) Income tax calculation**							
48	**Income tax allowances (i.e., deductions) MOD $ =**							
49	(Post-ELT, MOD $:	Royalty + Rental (maybe) + Bonus (maybe)	+	Total Opex + Intangible capex + Aband. costs	+	Depreciation of Tangible capex	+	Tax loss carryforward)
50	Tax position, MOD $	=	(Post-ELT, MOD $:		Gross Revenue	-	Income tax allowances)	
51	**Income tax liability, MOD $**							
52	• if Tax position > 0,	=	Post-ELT, MOD $:		Tax position, MOD $	x	Income tax rate, %	
53	• if Tax position < = 0,	=		0				

Figure 1.17 From the “ModelSummary” sheet of the file “Ch1_Tax_and_Royalty_Model.xls”
Note: Reflects Base Scenario.

profit), which gets multiplied by the tax rate (45% in our Base Scenario (cell C67 of the “Model” sheet)) to result in the income tax charge. When the annual result is negative, the tax position is an **untaxable loss** (or **tax loss**), so the investor pays no tax. All inputs are on a post-ELT basis, because we only want to forecast tax liabilities for the years of actual activity, based on the shutdown date which the ELT will tell us (once we’ve calculated the ELT.)

We have already detailed some of the tax allowances: opex; intangible capex (assuming, as we do, that all intangible capex is expensed for tax purposes); abandonment costs; royalty; and – depending on the user’s choice – the rental and bonus payments.

Tax allowances: two “funny ones”

There are, however, two other types of tax allowance which require a bit more explanation. These are depreciation and tax loss carryforwards:

- Depreciation, as already mentioned, is a way of spreading over multiple periods the tax allowances arising from tangible capex, once this capex has been incurred in a particular period. Under our Base Case, the number of periods over which costs are depreciated is assumed to be eight years (cell C75).
- Tax loss carryforwards are historic tax losses which can, under certain circumstances (i.e., depending upon prevailing tax regulations), be used to reduce future taxable income.

Thus these two items – uniquely among the tax allowances shown in Figure 1.17 – sometimes require us to directly take certain *historic* costs into account:

- This might at first sound unusual, because, as discussed in Section 1.2, the NPV result we are working toward is the sum of discounted *future* net cashflows.
- There is in fact no inconsistency; this is because the historic costs in question (under our Base Scenario, as we will detail in a moment) have a direct impact on future tax

payments, which of course do influence future net cashflow. Their impacts, under our Base Scenario, are as follows:

- It is assumed that before the valuation period, some tangible capex was incurred, and partly depreciated; that as of December 31, 2014, the undepreciated amount remaining is MOD $6.0 mm (cell 070) and that this sum has two more years (during which there is production) to fully depreciate (cell G77). This, as we shall see more clearly later, means that there is the potential for the investor to benefit from up to $6.0 mm in deductions to offset future tax bills.
- It is assumed that before the valuation period, losses for tax purposes were made from prior activity, which as of December 31, 2014 totaled MOD $10.8 mm (cell I70). Again, as we will detail later, this means that there is the potential for the investor to benefit from up to an additional $10.8 mm in deductions to offset future tax bills.

While the basic ideas at work here are clear, there are some nuances to consider and a few, perhaps not obvious, calculation steps involved. We will deal with these in later sections.

For now, just be aware that these assumed two prior balances in row 70:

- are exceptional among our other assumptions, because they are historic; and
- can end up having a material effect on NCF and NPV.

In a real-world model, you will need to know details of any such "prior" (i.e., pre-valuation date) items.

Where We Are Heading: Pre-ELT Calculation of GOCF (Gross Operating Cashflow)

Over the next few pages we will cover the steps in calculating the components of GOCF, which, as defined in row 33 of Figure 1.18, is gross field revenue minus the cash royalty, rentals, bonus and opex. As mentioned in Section 1.4, GOCF is the basis for the version of the ELT we will calculate later.

	A	B	C	D	E	F	G	H
21	**Pre-ELT (Economic limit test) calculations**							
23	(For later use): Total Capex , MOD $	=	(Post-sensitivity, Real 2015 $:		*Capex)*	x	Inflation index	
25	**Cash items for GOCF (Gross operating cashflow) calculation MOD $**							
27	Opex MOD $	=	(Post-sensitivity, Real 2015 $:		*Total Opex)*	x	Inflation index	
28	Fiscal cost: Royalty MOD $	=	Gross Revenue MOD $	x	Royalty rate (%)			
29	Other non-tax fiscal costs MOD $	=	*Rental MOD $*	+	*Bonus MOD $*			
31	Gross Revenue MOD $	=	(Post-sensitivity, Real 2015 $:		Oil price x Inflation index)	x	Post-sensitivity Oil production	
33	**GOCF MOD $**	=	(MOD $:	Gross Revenue	-	(Royalty + Rentals + Bonus + Opex))		

Figure 1.18 From the "ModelSummary" sheet of the file "Ch1_Tax_and_Royalty_Model.xls"
Note: Italics indicate a timing adjustment is made at that calculation stage.

1.7 PRE-ELT CALCULATIONS

1.7.1 Pre-ELT Calculations: Opex and Capex Timing/Inflation

The calculations for timing, in a dynamic model, of opex – relative to production– and of capex – as determined by our assumed spending schedule – are straightforward, although two formulas initially look imposing. Refer to Figure 1.19.

	B	C	D	E	F	K	L	M	N	O
113	**Timing/inflating of opex and capex**									
115			**Total/other**		**2015**	**2020**	**2021**	**2022**	**2023**	**2024**
116	Field production	mm b	**5.9**		-	0.6	0.2	0.2	-	-
118	Fixed opex	MOD $ mm	**114.9**		-	16.7	17.1	17.4	-	-
119	Variable opex	MOD $ mm	**50.1**		-	5.1	2.1	1.4	-	-
120	**Total opex**	**MOD $ mm**	**165.0**		**-**	**21.8**	**19.1**	**18.8**	**-**	**-**
121										
122	Tangible capex	Real 2015 $ mm	**54.6**		36.6	-	-	-	-	-
123	Intangible capex	Real 2015 $ mm	**26.4**		24.4	-	-	-	-	-
124	Tangible capex	MOD $ mm	**55.5**		37.0	-	-	-	-	-
125	Intangible capex	MOD $ mm	**26.7**		24.6	-	-	-	-	-
126	**Total capex**	**MOD $ mm**	**82.2**		**61.6**	**-**	**-**	**-**	**-**	**-**

Figure 1.19 From the "Model" sheet of the file "Ch1_Tax_and_Royalty_Model.xls
Notes: Reflects Base Scenario. Some columns (for 2016–2019) are hidden.

Key/typical formulas used ("•" indicates the end of the formula):
K116. =K53 K118. =(IF(K116>0, Fixed_opex_per_year_real, 0)) * Infl_index •
K119. =(K116 * Variable_opex_real_per_bbl) * Infl_index • K120. =SUM(K118:K119) •

F122. =IF(year = First_Capex_Year, Capex_year1_real_total *
Capex_year1_real_percent_tang,
IF(year = Second_Capex_Year, Capex_year2_real_total *
Capex_year2_real_percent_tang, 0)) •

F123. =IF(year = First_Capex_Year, Capex_year1_real_total *
Capex_year1_real_percent_Intang,
IF(year = Second_Capex_Year, Capex_year2_real_total *
Capex_year2_real_percent_intang, 0)) •

F124. =F122*Infl_index • F125. =F123*Infl_index • F126. =SUM(F124:F125) •

We defined fixed opex in the model's assumptions section as an annual charge, equal in Real 2015 $ terms, incurred only during production years.[25] We named the post-multiplier version of this assumed value, found in cell C58, Fixed_opex_per_year_real. This named cell is referenced by the annual formulas in row 118, to mean that, if it is a production year, the answer equals Fixed_opex_per_year_real, times the corresponding annual inflation index, to give us the answer in MOD $; otherwise, the answer is $0.

Annual variable opex (row 119) in MOD $ mm is calculated as annual production in mmb, times our assumed post-multiplier Real $ per-barrel cost in cell D58 (named Variable_opex_real_per_bbl), times the corresponding annual inflation index.

Capex

We will shortly use the opex results just calculated in the GOCF calculation. We do not use capex in the GOCF calculation, so we shall time and inflate capex in this section just to get the task "out of the way"; we will use these timed/inflated capex results soon enough.

Whereas for opex we combined the timing and inflation of each item into a single formula, for capex, we split things up to keep the formulas from getting too long.

First, in row 122, we calculate tangible capex in Real 2015 $ mm. The typical formula, e.g., the year 2015 in cell F122, is the long and – at first – slightly hostile-looking IF statement:

```
=IF(year = First_Capex_Year, Capex_year1_real_total * Capex_year1_real_percent_tang,
IF(year = Second_Capex_Year, Capex_year2_real_total *
Capex_year2_real_percent_tang, 0))
```

Because our example formula in cell F122 is for 2015, and the input assumption in the cell named "First_Capex_Year" is also 2015, let us just focus on the first line of the formula.

In a somewhat friendlier format, the formula means that if it is the first year in which capex is spent – which we assumed to be in 2015 – then, in 2015, Real 2015 $ tangible capex equals total real 2015 $ capex, times the percentage of that which is tangible:

- Under our Base Scenario, total 2015 capex – Capex_year1_real_total (cell I58) – is assumed to be real 2015 $**61.0** mm,
- of which **60%** – Capex_year1_real_percent_tang (cell I59) – is assumed to be tangible,
- so that the 2015 tangible capex outflow is Real 2015 $61.0 mm × 60% = Real 2015 $**36.6** mm (cell F122).

The second IF statement in the formula works the same way, except that it only gives an answer when the year is the assumed second year of capex spending, i.e., 2016, and it references the capex inputs relevant to this second year. The results are shown in cell G122 of the model (which is hidden in the screenshot).

[25] In our simplified version used in this example, we ignore fixed general and administration (G&A) costs in the Base Scenario's single pre-production period year of 2015.

If the year is neither of the two years of capex spending, the answer in the annual cells of row 122 is **$0**.

Annual MOD $ tangible capex is calculated in row 124, by multiplying the annual Real 2015 $ tangible capex just calculated in row 122, by the inflation index. We inflate these values in a separate step here, because the formulas in the first step are already long enough.

Intangible capex in Real 2015 $ and MOD $ is calculated in rows 123 and 125, respectively, in exactly the same way as tangible capex, except that the formulas reference the intangible percentage of total capex.

Each year's MOD $ tangible and intangible capex is summed in row 126 to give total MOD $ capex, which in our example year of 2015 is MOD $61.6 mm (cell F126).

1.7.2 Pre-ELT Calculations: Bonus and Rentals

To calculate the bonus and both kinds of rental payments in rows 132–139:

- we create timing rows, which return a 1 in the year when a payment is due; and
- in the next rows, we multiply the corresponding year's 1 or 0 by the amount of the payment.

Recall that we assume, as is common, that the fiscal regulations express the amounts due in MOD $, so there is no need to inflate them.

In light of this, Figure 1.20, and the formulas beneath it, should require little explanation. Note, however, that:

- the checksum in cell A132 uses the formula `= 1-D132` to ensure that the one-time bonus is indeed paid only once;
- the named cell `Bonus_MOD` referenced in row 133 is the cell O63 in the assumptions section, where we input the Base Scenario bonus of MOD $15.0 mm;
- cells D134 and D135 are named `Rental_pre_production_MOD` and `Rental_production_MOD` respectively; they calculate each rental as the assumed area of the license, in km^2 (square kilometers) times the appropriate per-km^2 MOD payment due each year;
- in each annual cell of row 140, we use a checksum formula to ensure that in any given year, only one type of rental is paid.[26] The formula for the typical year of 2016, for example, is `= IF(G116=0, 0, 1-G138-G136)`.

[26] Note that this approach, simplified for use in our annual model, assumes that a calendar year will be either 100% pre-production period or 100% post-production period. Therefore only one kind of rental will be paid in any given year. When – as is common, and therefore assumed in our example model – rentals are usually rather small relative to other cashflows, this approximation should not result in material error. If desired, however, when first production is expected to start at specific point *within* a calendar year, you can adjust the rental calculation for the first production year (assuming that the license terms provide for charging rentals on a fractions-of-period basis). For example, if production were to start at the end of the first calendar quarter, you could calculate the total rentals payable for that year as (the pre-production period's annual rental charge × 25%) + (the post-production period's annual rental charge × 75%).

	A	B	C	D	E	F	G	H	I
				Total/other		**2015**	**2016**	**2017**	**2018**
116		Field production	mm b	**5.9**		-	1.8	1.4	1.0
129		**Calculation of Rental and Bonus payments**							
131				**Total/other**		**2015**	**2016**	**2017**	**2018**
132	0	Is it the first year of production?	1 = yes	**1**		-	1	-	-
133		**Bonus, payable first production year**	**MOD $ mm**	**15.0**		**-**	**15.0**	**-**	**-**
134		Annual Rental, pre-production period	MOD $ mm	0.9					
135		Annual Rental, production period	MOD $ mm	1.8					
136		Is it the pre-production period?	1 = yes			1	-	-	-
137		**Rental payment, pre-production period**	**MOD $ mm**	**0.9**		**0.9**	**-**	**-**	**-**
138		Is it the production period?	1 = yes			-	1	1	1
139		**Rental payment, production period**	**MOD $ mm**	**12.6**		**-**	**1.8**	**1.8**	**1.8**
140	0	Check	(0=ok)			0	0	0	0

Figure 1.20 From the file "Ch1_Tax_and_Royalty_Model.xls"
Notes: Reflects Base Scenario. Some rows and columns are hidden.

Key/typical formulas used ("•" indicates the end of the formula):
G132. =IF(year=Production_first_year, 1, 0) • G133. =Bonus_MOD*G132 •
A132. =1-D132 •

D134. =M$65*G65 • D135. =M$65*J65 • F136. =IF(year<Production_first_year, 1, 0) •
F137. =F136*Rental_pre_production_MOD •
G138. =IF(G136=1, 0, IF(year<=Production_last_year_pre_ELT, 1, 0)) •

G139. =G138*Rental_production_MOD • G140. =IF(G116=0, 0, 1-G138-G136) •

1.7.3 Pre-ELT Calculations: GOCF

The calculation of GOCF (again, gross operating cashflow) is shown schematically in Figure 1.21 and in detail in the model screenshot in Figure 1.22.

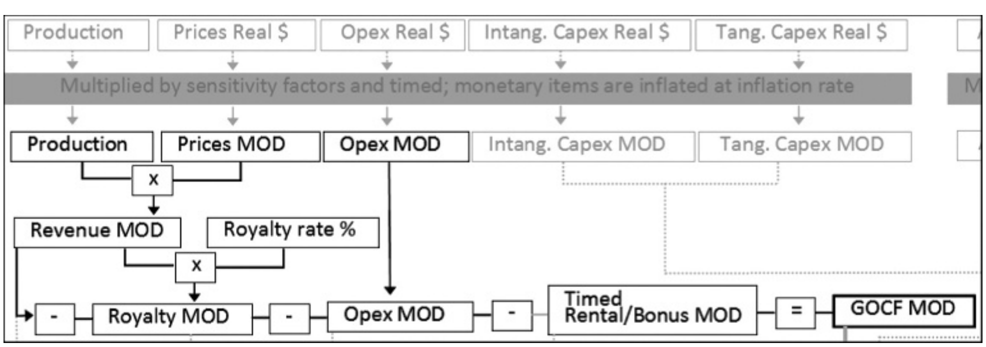

Figure 1.21 Detail from page 49 of the file "Ch1_Main_chapter_supplement.pdf"

	B	C	D	E	F	G	H	I
116	Field production	mm b	5.9		-	1.8	1.4	1.0
149	Calculation of GOCF (Gross Operating Field Cashflow)							
151			Total/other		2015	2016	2017	2018
152	Oil price	MOD $/b			80.80	82.41	84.06	85.74
154	**Gross field revenue**	MOD $ mm	**500.9**		**-**	**148.3**	**113.5**	**86.6**
156	Royalty @ 17.25%	MOD $ mm	**86.4**		-	25.6	19.6	14.9
157	Fixed opex	MOD $ mm	**114.9**		-	15.5	15.8	16.1
158	Variable opex	MOD $ mm	**50.1**		-	14.8	11.3	8.7
159	Rentals	MOD $ mm	**13.5**		0.9	1.8	1.8	1.8
160	Bonus	MOD $ mm	**15.0**		-	15.0	-	-
161	**Total costs (for GOCF purposes)**	**MOD $ mm**	**279.9**		**0.9**	**72.7**	**48.5**	**41.5**
163	**Field gross operating cashflow (GOCF)**	**MOD $ mm**	**221.1**		**(0.9)**	**75.7**	**65.0**	**45.1**
164			**Maximum**					
165	**Cumulative GOCF**	**MOD $ mm**	**233.5**		**(0.9)**	**74.8**	**139.8**	**184.9**

Figure 1.22 From the file "Ch1_Tax_and_Royalty_Model.xls"
Notes: Reflects Base Scenario. Some rows and columns are hidden.

Key/typical formulas used ("•" indicates the end of the formula):
H152. =H41 • H154. =H116*H152 • H156. =Roy_rate*H154 • H157. =H118 •
H158. =H119 • H159. =SUM(H137,H139) • H160. =H133 •
H161. =SUM(H156:H160) • H163. =H154-H161 • D165. =MAX(F165:O165) •
H165. =G165+H163 •

Let us look at the annual GOCF calculation shown in Figure 1.22 as consisting of three basic steps:

- *Collection of previously calculated MOD $ (i.e., inflated) components.* These include the oil price (row 152), fixed and variable opex (rows 157–158) and rentals and the bonus (rows 159–160).
- *Calculation of remaining components: gross field revenue and royalties*:
  - Annual gross field revenue, in MOD $ mm (row 154), equals annual field production, in mmb (row 116), times the year's oil price, in MOD $/b (row 152).
  - Annual royalty payments, in MOD $ mm (row 156), equal gross field revenue in MOD $ mm, times the assumed royalty rate, which is in the cell named Roy_rate (cell H63, in the assumptions section).
- *Calculation of GOCF.* Annual GOCF, in MOD $ mm, is calculated in row 163 as gross revenue (row 154) minus all relevant cash costs (row 161). Note that we calculate cumulative GOCF in row 165. This will be the basis of our commercial shutdown mechanism, the ELT, in the next section.

1.8 ELT CALCULATION AND ROLE IN ECONOMIC MODELING

The ELT calculation is summarized schematically in Figure 1.23.

ELT calculation		
Last economic production year	=	Year, occurring when license is valid, that total future (i.e., cumulative) GOCF MOD $ is maximized
ELF (Economic Life Flag), annual	→	Used below as a multiplier; Equals 1 when field is "alive", otherwise equals 0

Figure 1.23 From the “ModelSummary” sheet of the file “Ch1_Tax_and_Royalty_Model.xls”

The ELT in Action – Knowing When to Quit

Refer to the “ELT calculation” screenshot on page 14 of the file “Ch1_Main_chapter_supplement.pdf” for the following discussion.

As discussed earlier, the ELT is used to determine when to shut down the field. The goal in doing so is to maximize cashflow – in particular, GOCF.

Before we detail the formulas used in the ELF (i.e., economic life flag) section, first let us “jump ahead”, and watch an already-completed ELF do its job.

In essence, the ELF is just a multiplier applied to annual pre-ELT cashflow items, i.e., revenue, royalty, opex, rentals, the bonus and total capex. These are all are multiplied by a 1 when the field is economically “alive,” or by 0 afterwards, to result in their post-ELT equivalents.

If this sounds a bit abstract, refer to the “ELT calculation” screenshot on page 14 of the file “Ch1_Main_chapter_supplement.pdf” for the following discussion. (Note that certain columns are hidden to make the screenshot fit the page, but all relevant years are shown.)

- First, focus on row 203 – the binary “ELF” or economic life flag – which simply implements the (similarly named) ELT. This is the main result we are working toward in this section of the model. We will explain its calculation soon, but, for now, recall our analogy likening the ELF to a bouncer, implementing the “orders” of the ELT, to only let annual items occurring during the economic lifespan “pass through.”
- According to the ELT, the last year of economic life is 2020 (cell D204). Therefore the ELF equals 1 up to and including that year, and 0 thereafter.
- Thus, for example, in 2015, pre-ELT basis GOCF of MOD $(0.9) mm (cell F163) occurs while the field is considered economically alive; therefore it is multiplied by the 1 in cell F203 to give a post-ELT basis of MOD $(0.9) mm (cell F206).
- But the pre-ELT basis GOCF of MOD $(3.7) mm in 2021 (cell L163) occurs after the last economic year of 2020, and so is multiplied by the 0 in cell L203 to give a post-ELT basis of GOCF of $0.

Thus we can say that <u>the ELF truncates the field’s lifespan to the economic limit</u>. In doing so, it maximizes the field’s total (all years) GOCF, i.e., its cumulative GOCF at the end of the field life.

This truncation by the ELF maximizes project GOCF as follows:

- Before considering the ELT, the field produces through the end of **2022** (cell M163), achieving a total GOCF of **MOD $221.1 mm** (cell D163), which is the same as the cumulative GOCF value at the end of that year (cell M165).
- This is less than the maximum pre-ELT basis, cumulative GOCF of **MOD $233.5 mm**, which occurs earlier, in **2020** (cell K165, and captured in cell D165). It is less than this maximum because, after the maximum is reached in 2020, the field goes on to produce two years of losses (cells L163:M163). If only the field had stopped at that maximum!
- The ELF does just that – subject to the license term being valid, which it is (as detailed below): it stops the field life at the end of the period (2020) in which post-ELT GOCF has reached its cumulative maximum, hence the MOD $0 values in cells L206:0206. The result is that post-ELT GOCF totals **MOD $233.5 mm** (cell D206), which is the same as the cumulative GOCF value at the end of 2020 (cell K208).
- In other words, the ELF stops production before the loss-making years of 2021 and 2022 can occur, and thus maximizes project GOCF.

ELF Calculation Details

Because the investment's lifespan depends not only on its commercial viability, but also on how long it is permitted to occur, our calculation strategy is to combine:

- the information that 2020 is the year of peak cumulative GOCF, with
- the information about the length of the license period, to determine the ultimate answer to the question, **when will the field be shut down?**

We do this by calculating two "sub-multipliers," one considering the year of peak cumulative GOCF (row 201) and the other considering the license length (row 202). Both of these determine our "final" multiplier, i.e., the ELF, in row 203:

- First, we capture in row 200 the fact that 2020 is the year of peak cumulative GOCF:
  - In each annual cell of this row, we use a formula which answers with the year, if the year in question is the year when this peak GOCF value occurs; otherwise, the answer will be the text, "n.a."
  - For example, the typical annual formula used in 2020 (cell K200) is `= IF(K199 = $D199, year, "n.a." ),` where `K199` is cumulative GOCF in 2020, and `D199` is the maximum cumulative GOCF of all years. Since in this example 2020 is in fact the year when maximum cumulative GOCF occurs, the answer in cell K200 is 2020, while the answer in all the other years is "n.a."
  - We then capture the information, that 2020 is the peak year, in cell D200, which uses the formula `=MIN(F200:O200)`. This formula ignores the "n.a." text in the annual cells, and so only records the answer of 2020.
- We express that 2020 is the last economic year – *ignoring the license length* – in row 201, in which each annual cell uses the formula `= IF(year < = $D200, 1, 0)`, where `D200` is

the year of peak cumulative GOCF. In our Base Scenario, this results in values of 1 in each year up to and including 2020 (cell K201), and values of 0 thereafter. This **binary range** or "binary array" is the first of the two "sub-multipliers."

- Similarly, we use a binary range in row 202 to create a license flag, i.e., a row where the annual cells show a 1 when the license term is ongoing, and a 0 otherwise. Each annual cell in row 202 uses the formula =IF(year <=Last_license_year, 1, 0), where Last_license_year is the named assumption cell C63. Because our Base Scenario assumes the license is valid through to the last year in our timeline, i.e., 2024, every annual cell in row 202 shows a value of 1. The license flag thus becomes our second "sub-multiplier."
- Next, we express **the economic lifespan, *considering* the license length** – that is, the most sensible commercial lifespan which is permitted by the license length – with a "final" third binary range, in row 203. Each annual cell in row 203 just multiplies the relevant year's value in row 201 by the one in row 202. Thus the annual cells in row 203 make up the **economic life flag (ELF)**,[27] which we have already seen "in action."
- We have named the red-bordered range F203:O203, "ELF." We will use the ELF in the next section of the model as a multiplier to truncate the field inputs (production, costs, etc.) to the economic lifespan, considering the license length. In other words, under the Base Scenario, the ELF will remove various post-2020 items from the model by multiplying them by 0, which will have **the effect of modeling a field which shuts down in 2020**.

Finally, we capture, as a "memo" (information) item, the last year of economic life, considering the license length, i.e., our "ultimate" stopping year, which from now on is what we will call the **last economic year** for short – in cell D204. We can see that the answer is 2020 just by noticing that the last year in the ELF range which contains a 1 is 2020 (cell K203), but it will be useful to have this recorded it in a cell. Therefore we calculate as follows:

- In each of the annual cells in row 204, we use a formula which, in essence, says, "If this year is the last year when the ELF equals 1, then the answer is this year; otherwise, the answer is 'n.a.'" To frame this as a formula:
  - we could expand this into, "If this year, the ELF equals 1, and in each of the following years, the ELF equals 0, then the answer is this year; otherwise, the answer is 'n.a.'";
  - which in turn expands into, "If this year, the ELF equals 1, and the sum of the ELF values in all following years equals 0, then the answer is this year; otherwise, the answer is 'n.a.'";
  - which we write as the following Excel formula (using the typical example of cell K204, for 2020): =IF(AND(K203=1, SUM(L203:$P203)=0), year, "n.a.") .
- Under the Base Scenario, this results in a value of 2020 in cell K204, and the text "n.m." ("not meaningful") in the other annual cells in row 204.

[27] To reclarify terminology: "ELT" is the economic limit test, which tells us the economic limit (i.e., the last year when it makes economic sense to produce); "ELF" is the economic life flag, i.e., the mechanism which communicates the ELT's findings to the rest of the model.

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- We capture this result of 2020 in cell D204 with the formula = MIN(F204:O204), and name cell D204 "Production_last_economic_year." Again, the MIN function ignores the text and captures only the numerical value of 2020.

Why Base the ELT on **Peak Cumulative** *GOCF?*

Some analysts use a version of the ELT which is not based on peak cumulative GOCF, but rather a version which shuts down the field the *first time* GOCF goes negative. This is incorrect, because it ignores the possibility that the field could recover in subsequent periods, generating enough GOCF to offset the loss.

Let us consider an example. Reset the model to the Base Scenario. Then set up the view as follows:

- Use the button in cell C1 to show all rows on the "Model sheet," split the screen using the button in row 4, and adjust the view so that rows 33–37 are visible in the top part of the screen, and the chart starting in row 170 is visible in the bottom.
- Right click the chart's Y-axis, and manually set the scale to a minimum of −125 and a maximum of 375, if this is not already the case.

In the top part of the screen, change the chosen oil price scenario to the "User Custom price" using the spinner in cell I33. This will use the Real 2015 $120/b price assumption for each year, which we have supplied as a default value. You will notice that the chart's cumulative GOCF line (white, with black diamonds) goes off the scale; that will change in a moment.

Now let us assume the oil price collapses in 2018. In cell I37, enter 20 (i.e., Real 2015 $20/b).[28] The chart will appear as shown in Figure 1.24.

The impact is that annual GOCF in 2018 is negative – the underlying value is MOD $(8.6) mm, which you can see either by hovering the cursor over 2018's white triangle, or by looking at the underlying value a bit below the chart, in cell I187.

Would you really want to shut down the field at the end of 2018 (or the end of 2017, to avoid the 2018 loss), when GOCF, as noted in the chart's caption, recovers enough to reach a cumulative peak of MOD $341.5 mm in 2021 (cell L188)?

You might reply that we are ignoring the time value of money, since GOCF here is undiscounted. You would be right.[29] We prepared for that. In this example, discounted cumulative GOCF also peaks in 2020 (at MOD $263.5 mm (cell L190)). So, again, why would you shut down before then? It would be a mistake to shut down the field just because there has been one year of GOCF losses.

[28] This is not far-fetched; note that the benchmark Brent crude price reached close to MOD $10/b in 1998.

[29] Basing ELTs on undiscounted values appears to be rather common in practice, although NPV maximization "purists" might argue that this is wrong.

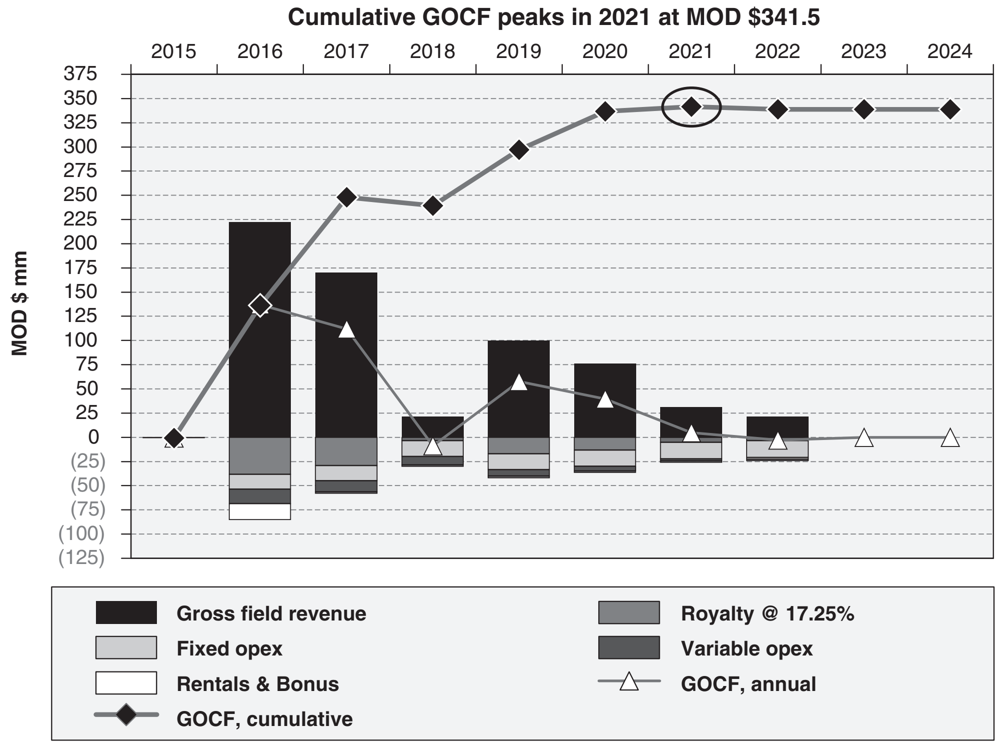

Figure 1.24 From the file "Ch1_Tax_and_Royalty_Model.xls"
Note: The chart's Y-axis scale has been manually set to a minimum of (125) and a maximum of 375 for this screenshot. Not all the colors reproduced here match those in the Excel file.

Another, similar approach – also incorrect, in our opinion – tries to set a number of periods of GOCF losses which can be tolerated before shutting down. This approach is intended to prevent being "fooled" by a single, perhaps exceptionally bad period, like 2018 in the case just described.

For example, suppose an analyst modeled such that one period of GOCF losses is tolerable, but any more are not.

Suppose further that the oil price crash is forecast to continue into 2019. Change the price in cell J37 to $20. The chart will now look like the screenshot in Figure 1.25.

Even after two years of annual GOCF losses, cashflow starting in 2020 is still strong enough to recover: cumulative GOCF goes on to peak in 2021 at MOD $272.7 mm (cell L188, as does discounted cumulative GOCF, at MOD $218.7 mm (cell L190)).

An analyst could, effectively, say, "Ok, then, let's tolerate *three* years of annual GOCF losses, to avoid getting fooled by two exceptional years." At which point it becomes clear that setting a number of periods of tolerance for losses before finally shutting down the field is an arbitrary

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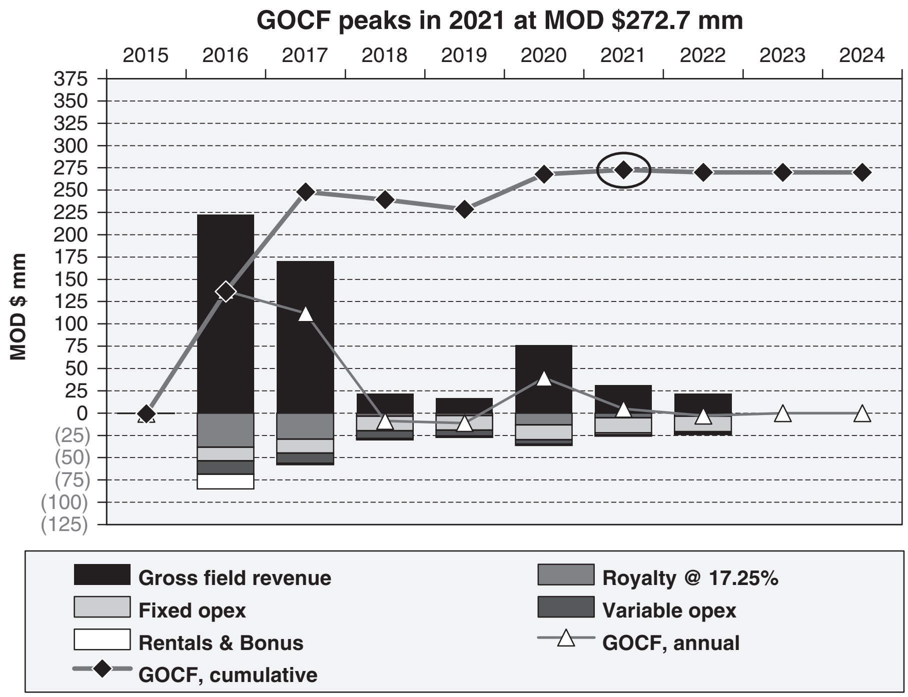

Figure 1.25 From the file "Ch1_Tax_and_Royalty_Model.xls"
Note: The chart's Y-axis scale has been manually set to a minimum of (125) and a maximum of 375 for this screenshot. Not all the colors reproduced here match those in the Excel file.

approach, because what matters is not the number of periods of production, but rather the value of the cashflow you are trying to maximize.

Therefore, the best version, in our opinion, of the GOCF method for determining the economic limit is based on the maximum *cumulative* GOCF, which takes into account all years, including those which follow perhaps exceptional losses. If there is any positive cumulative GOCF to be generated, this method will maximize it.

(Do not forget to change the custom prices in row 37 back to $120, unless you want to keep the $20 years in place for your own custom price scenario.)

ELT Exercise: Playing with the Field Life

For this exercise, first set up as follows.

Reset the model to the Base Scenario. Show all rows, then use the Console View (cell F1) and full screen mode (cell F21).

In the bottom part of the screen, scroll so that, again, you can see the chart which starts in row 170. Right click the Y-axis, and set the Y-axis scale's minimum and maximum values to automatic.

Now, make changes to various assumptions in the top, console part of the screen which will cause GOCF to peak earlier than under the Base Scenario's result of 2020. (You can see the peak year at each setting in the chart's caption.) Stop and inspect at each setting what causes this to happen, and try to explain why it has happened.

For example, let us re-enact the exercise we did earlier in the chapter, by lowering the oil price sensitivity multiplier in cell G23 to 60%, and then to 55%. (Note that you can see the resultant average (all-years) received oil price, for reference, change in the "thermometer" chart in column D, to the left of the GOCF chart.)

As we cross these oil price thresholds, we cause GOCF in 2020 to turn negative enough to lower peak cumulative GOCF from:

- MOD $79.3 mm, occurring in 2020, when the multiplier is 60%, to
- MOD $60.5 mm, occurring in 2019, when the multiplier is set to 55%.[30]

Inspect the chart at each of the two settings. What seems to be the "culprit" causing cumulative GOCF to peak a year earlier, when the multiplier is set to 55%?

Keep lowering the oil price multiplier. What happens when it reaches 45%, and, again, why?

Continue lowering the oil price multiplier. Notice what happens when it reaches 35%, or lower:

- Cumulative GOCF never becomes positive. (Why not?)
- As the caption shows, cumulative GOCF "peaks" at MOD $(0.9) mm in 2015. Notice that this value equals the amount of the rental paid that year (cell F186).
- If this is the best the field can do, the advice to stop at a negative "peak" GOCF year is another way of saying, this investment, under this price outlook, should not be made at all.

> Play with other variables in the console section and see what else you can do to change the year of peak cumulative GOCF, i.e., to change the field's economic lifespan.

Sensitivity Analysis with Excels' Data Tables Feature: The Impact of Fixed Opex on Economic Field Life

As you did the last exercise, or went on to practice finding ways to shorten the economic field life, you might have noticed that the level of fixed opex has a big impact. This is to be expected in situations like our Base Scenario, where a constant, material cost is incurred in each production year, regardless of the volume – meaning that at low enough volumes, or prices, fixed opex can push GOCF into negativity.

[30] Note that in cases when the multiplier is set to 55%, it can be hard to see from the chart's cumulative GOCF line exactly where the peak cumulative GOCF year is – in this case, 2020 or 2019. Although the chart's caption records the peak value, you can check this and in fact see any year's value by hovering your mouse over the line's black diamonds.

Let us focus a bit more on how fixed opex can impact the economic lifespan. Open the file "Ch1_Tax_and_Royalty_Model_Small_Data_Table.xls." This is a duplicate of our main chapter example file, except that in rows 235–256 it has an array of values produced by Excel's **Data Tables** feature, and a chart based on it.

Behind the rather unremarkable name, "Data Table", is a fast and powerful way to conduct sensitivity analysis. If you wished to see in a single view, e.g., NPV at every oil price assumption between MOD $0 and $200/b, in increments of MOD $5/b:

- you could do it the long way, i.e., change the oil price 40 times, and copy and paste the result 40 times as values into a table somewhere; or
- you could do the same thing with the Data Table wizard in a few mouse-clicks.

The tradeoff is that Data Tables use a lot of computer resources, and so can slow down the calculation of models, so much so that we are putting this one in its own file, to allow our main example file to work faster.[31]

In this case, our Data Table shows the length in years of the field's economic life – on a post-ELT basis – under fixed opex assumptions ranging from Real 2015 $0 to $100 mm per production year, in increments of Real 2015 $5 mm. (We show how to create Data Tables like this one in the short video file "Ch1_Using_Data_Tables.wmv" in the Chapter 1 folder.)

The results are shown graphically in Figure 1.26.

Notice that when the annual fixed opex per production year is between Real 2015 $0 and $5 mm, the last economic production year is 2022. This is the same last production year of

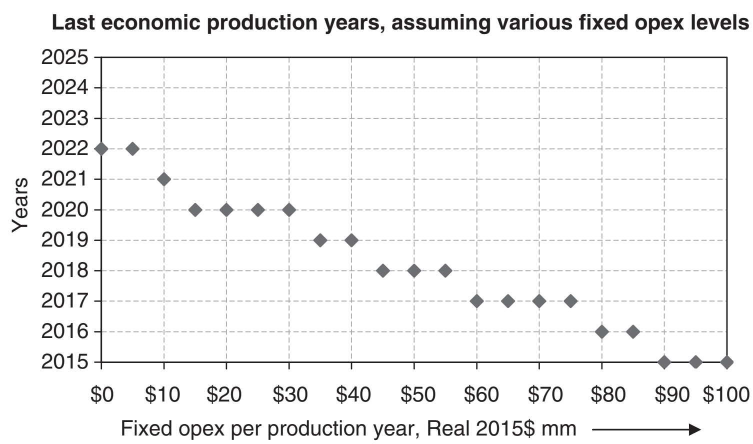

Figure 1.26 From the file "Ch1_Tax_and_Royalty_Model_Small_Data_Table.xls"
Note: Reflects Base Scenario except for different opex assumptions.

[31] When you open "Ch01_TaxRoyModel_v05_with 1 data table.xls" be sure that Excel's calculation mode is set to Automatic, otherwise the results in the Data Table might not display/update as expected.

our Base Scenario *pre*-ELT field production life shown in cell D54. In other words, under these two particular fixed opex assumptions, the field shuts down on technical grounds (i.e., it is out of oil), not on economic grounds.

But rising levels of fixed opex steadily shorten the economic field life so that, by the time we reach the extreme assumptions of Real 2015 $90–100 mm, the ELT's advice is that the economic field life ends in 2015, which is before production even starts. In other words, again, the ELT's "advice" is not to produce (i.e., not to invest) at all.

Can we trust a Data Table?

Note that, due to how Data Tables work, the chart will *not* update when you change the fixed opex assumption in cell C57. (It will change when you change other assumptions, depending on the changes you make.) You can, however, check the Data Table's results against the "live model."

Starting from the Console View, arrange the split so you can see row 57 above the split, and, below it, rows 204–229. Use full screen mode if necessary.

Pick a fixed opex value from the chart, e.g., Real 2015 $50 mm, and note from the chart that the Data Table tells us that this would result in an economic lifespan ending in 2018.

Use the spinner to enter Real 2015 $50 mm in cell C57. Now inspect cell D204. It shows that the last economic year has indeed changed to 2020. You can check any other Data Table result this way.

What Is Missing from Our GOCF Calculation?

Note that in arriving at GOCF, we ignore some cashflow items which we do consider when calculating NCF (net cashflow).

One of these is capex. Why exclude such an often very material cash outflow? The reason for doing so, under the commonly used ELT approach, is that the ELT is supposed to measure the commercial viability of an upstream petroleum investment based on its *operating* cashflows, i.e., once the field is *already* "up and running." Capex – specifically upfront development capex – is what *gets it* up and running, and thus, the reasoning goes, should not be considered.

Two other very real cash outflows which are not deducted from revenue when calculating GOCF under common methods are the abandonment cost and income taxes.

We have some ideas why this is so. Regarding abandonment payments:

- One cannot know the inflated value of an abandonment payment, or series of payments, until one knows when it, or they, will be made. But one does not know when it, or they, will be made until one knows when the field has reached the economic limit, which in turn is knowable only by calculating GOCF.

- Thus trying to deduct timed and inflated abandonment payments from GOCF, which tells us when to quit and thus when to time the abandonment payments, is a circular calculation.
- It is circular because, to know when to quit, one must know the inflated value of the abandonment payments. But to know the inflated value of the abandonment payments, one must know when to quit.

Regarding income taxes, we suppose that these are excluded from the standard approach to GOCF calculation due to the problem with abandonment payments just mentioned. Abandonment payments are, as mentioned, often tax deductible. If one cannot include abandonment as an outflow in the GOCF calculation, then one cannot correctly calculate the tax position and thus the tax charge, in order to count the tax charge as an outflow in the GOCF calculation. The tax calculation would be wrong, as it would ignore the tax deductions from abandonment payments.

Whatever the reasoning, this approach – that is, to ignore abandonment costs and income taxes when calculating GOCF in order to determine the economic limit – has been codified as recommended practice by an unofficial but influential group of upstream petroleum industry associations,[32] most recently in reporting guidelines published in November 2011, from which we quote below.

From *Guidelines for Application of the Petroleum Resources Management System, November 2011*

Sec. 7.4.1. Economic limit is defined as the production rate beyond which the net operating cashflows (net revenue minus direct **operating costs**) from a project are negative, a point in time that defines the project's economic life.

The project may represent an individual well, lease, or entire field.

Alternatively, it is the production rate at which net revenue from a project equals "out of pocket" **cost to operate** that project (the direct costs to maintain the operation) as described in the next paragraph . . .

Operating costs should include property-specific fixed overhead charges if these are actual incremental costs attributable to the project and any production and property taxes **but (for purposes of calculating economic limit) should exclude depreciation, abandonment and reclamation costs, and income tax**, as well as any overhead above that required to operate the subject property (or project) itself. [Emphasis in bold added] (Yasin Senturk, "Evaluation of Petroleum Reserves and Resources," *Guidelines for Application of the Petroleum Resources Management System*, Society of Petroleum Engineers, Richardson, Texas, USA (November 2011), p. 112. This can be found online on at www.spe.org/industry/docs/PRMS_Guidelines_Nov2011.pdf.)

[32] The Society of Petroleum Engineers, the Society of Petroleum Evaluation Engineers, the American Association of Petroleum Geologists, the World Petroleum Council, and the Society of Exploration Geophysicists.

We shall revisit this topic later, in Section 1.11. For the time being, be sure that you are able to calculate the ELT and the ELF according to the common industry approach as we have shown above.

1.9 POST-ELT CALCULATIONS

1.9.1 Post-ELT Calculations: Abandonment

Having calculated the ELT, we will now apply it, directly or indirectly, to every component of NCF. The method for calculating all items except for income tax and tax-related depreciation is summarized in the screenshot from the "ModelSummary" sheet of our example file, shown in Figure 1.27.

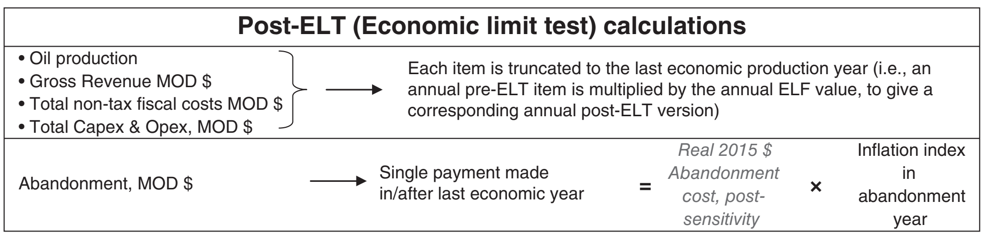

Figure 1.27 From the "ModelSummary" sheet of the file "Ch1_Tax_and_Royalty_Model.xls"

The actual calculations of the items shown schematically in Figure 1.27 – *except* for the abandonment payment – can be found in the section of the "Model" sheet which starts in row 276. These calculations are straightforward – as you can see from the typical formula captions in column P, we simply multiply each item's pre-ELT counterpart by the ELF.

Calculating the abandonment cost is only slightly more involved, due to the simplicity of the single "lumpsum" abandonment funding arrangement which the Base Scenario assumes. The method used is shown in Figure 1.28.

	B	C	D	E	F	G	H	I	J	K
264	**Abandonment calculation**									
265 266			**Total/other**		**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
267	Abandonment payment made in ..	year	2020							
268	Abandonment payment	Real 2015 $ mm	**21.0**		-	-	-	-	-	21.0
269	Inflation index				1.010	1.030	1.051	1.072	1.093	1.115
270	**Abandonment payment**	**MOD $ mm**	**23.4**		**-**	**-**	**-**	**-**	**-**	**23.4**

Figure 1.28 From the file "Ch1_Tax_and_Royalty_Model.xls"
Notes: Reflects Base Scenario. Some columns are not shown.

Key/typical formulas used ("•" indicates the end of the formula):
D267. =Production_last_economic_year + Abandonment_delay •
D268. =Abandonment_cost_real •
K268. =IF(year=Abandonment_payment_year, $D268, 0) • K269. =Infl_index •
K270. =K268*K269 •

The purpose of the abandonment calculation section, shown in Figure 1.28, is to time the abandonment payment and then inflate it appropriately to give a MOD value.

We time the payment based on the year in cell **D267**, which we have named Abandonment_payment_year. This is calculated as:

- the last economic production year, which we calculated in cell D204 (named Production_last_economic_year) as 2020 under the Base Scenario; plus
- any delay we assumed in cell L60, which we named Abandonment_delay. Under the Base Scenario, this is a "delay of 0 years," hence no delay. Therefore Abandonment_payment_year equals **2020** (cell D267).

The "formula flow" of row 268, in which we time the Real 2015 $ abandonment payment, is atypical. Usually, the value in the Total column is determined by (is the sum of) the annual values. In this case, however, the Real 2015 $21.0 mm in cell D268 is the starting point, i.e., it is our assumed value, which determines values in the annual columns:

- The value in cell **D268** brings down the assumed **Real 2015 $21.0 mm** from the named cell, Abandonment_cost_real (cell O58).
- The annual cells in row 268 capture the timing with the typical formula (using 2020 as an example) of IF(year = Abandonment_payment_year, $D268, 0). Thus the Real 2015 $21.0 mm abandonment payment appears in 2020 (cell K268), while the rest of the annual cells in row 268 return zero values.
- We inflate the timed abandonment payment by multiplying each annual cell in row 268 by the inflation index, which we brought down to row 269 for clarity of presentation. The inflated value of the abandonment payment is thus MOD $21.0 mm (cell K268) × 1.115 (cell K269) = MOD $23.4 mm (cell K270). The total in cell D270 is a "normal" total.

Note that we do not multiply the abandonment payment by the ELF. This is because the way we have calculated it, it is already on a "post-ELT basis," in that it is already timed in relation to the field's shutdown year.

Sense check

Reset the model to the Base Scenario, use the Console View, and arrange the screen so that you can see row 60 above the split and the waterfall charts, starting in row 603, below it. As you change the assumed abandonment timing from 0 to 1 year post-production (cell L60), you will see that NCF and NPV – recorded in the charts' captions – change as follows:

MOD $ mm	NCF	NPV
0-year delay	61.3	37.4
1-year delay	60.8	38.4

The later the abandonment occurs, the lower NCF will be, but the higher NPV will be. Why?

1.9.2 Post-ELT Calculations: Depreciation

We have now calculated every cashflow item needed to calculate NCF, with the exception of income tax. To calculate income tax, we need to calculate two more items, both tax allowances: namely, depreciation and tax loss carryforwards. We treat depreciation here.

Notice that the model actually calculates depreciation two ways, and lets the user choose, using the spinner in cell B433, which method's results will be used by the model:

- The first is calculated in the section entitled "Method 1) Straight line depreciation charge, SIMPLIFIED method, for demonstration ONLY (i.e., "quick and dirty")" which starts in row 294.
  - Be forewarned – as the heavily qualified title suggests, this is not fully correct. Among other things, it fails to get the timing quite right for a model like ours, which uses the mid-year inflation and discounting conventions. It is useful, at best, as a starting point approximation of the depreciation charges.
  - The simplified method is used here because it provides a way for us to show you most of the important calculations in a reasonably small space.
- The second method is calculated in the section entitled "Method 2) Straight line depreciation charge, "proper" version (ok for real models)" starting in row 339. This method involves some details omitted from the quick and dirty method. This "proper" method has one clear advantage – it is right. Otherwise, it is rather involved and frankly tedious.

We detail the "quick and dirty" method on pages 15–18 of the file "Ch1_Main_chapter_supplement.pdf."

We detail the proper method in "Appendix I: Depreciation.pdf." It is not strictly necessary for you to turn to this now – you will still benefit from this chapter without doing so. It is, however, something you will need to tackle at some point, especially as we will see it again – a lot – in our production sharing contract example models in Chapters 7 and 8. Although we do not discuss this method here, we include it as an option in the example model, so that when you do turn to it, you will have a working example for a basic tax and royalty regime.

> Take a moment to review the depreciation assumptions in cell O70 and in rows 74–77, and then turn to the "Quick and dirty depreciation calculation" (pages 15–18) from the file, "Ch1_Main_chapter_supplement.pdf." (Return here when you are done.)

Now that you have seen how to do the quick and dirty method, we do not want you to get too comfortable with it. To encourage you to eventually learn the proper one, we will show you – a bit later, after covering the income tax calculations, below – that under the Base Scenario assumptions, the choice of method can in fact make a material difference to the investor's tax liability.

1.9.3 Income Tax: Basic Concepts and Calculations

Income tax is one of the key sources of revenue for a state applying a tax and royalty regime.[33]

In this section we will step away temporarily from the main example model in the file "Ch1_Tax_and_Royalty_Model.xls" in order to explain some important basics of income taxation, and then return to the example model in Section 1.9.4.

Here we will show how to calculate two basic versions of income tax. These are income taxes both without and – as is more common – with **income tax loss carryforwards**.

Loss Carryforward: Simple Example

The idea behind tax loss carryforwards is straightforward. Suppose that a company is started in 2015, during which its costs – all assumed to be tax deductible – are $12 mm and its revenues are $10 mm. It has made a **$2 mm tax loss**, so it will pay no income tax.

This loss not only prevents it from paying taxes in 2015, but also will provide, under a tax regime which permits it, a form of future tax relief – that is, the **$2 mm** loss will be *carried forward* as a tax deduction for the 2016 tax year. Thus:

- if in 2016 the company generates $10 mm in taxable profit, then its taxable 2016 income will be $10 mm − **$2 mm** = $8 mm (and if the tax rate is 50%, it will pay $4 mm in taxes);
- if in 2016 the company generates $2 mm in taxable profit, then its taxable 2016 income will be $2 mm − **$2 mm** = $0 (and will pay no taxes);
- if in 2016 the company generates $1 mm in taxable profit, then its taxable 2016 income will be $1 mm − **$2 mm** = $(1) mm, i.e., a tax loss (on which no income tax will be payable). In this case, $1 mm of the $2 mm tax loss from 2015 gets used up, leaving $1 mm in unused tax losses from the 2015 tax year.
  - If the tax rules permit carrying forward tax losses for one year only, then that is the end of the story for this remaining $1 mm tax from the 2015 tax year – it will not be used for any future tax relief, and so "dies on paper";
  - If, however, the tax rules *do* permit carrying forward tax losses for more than one year – and, say, the company's 2017 operations generate $5 mm in taxable income – then taxable income for 2017 will be $5 mm – the remaining $ 1mm loss from 2015 = $4 mm (and so taxes payable, at a 50% tax rate, will be $2 mm).

Indefinite and Time-Limited Carryforwards

Most regimes permit tax loss carryforwards, and usually permit them to be carried forward indefinitely, until the tax loss is fully used up ("amortized"). We show how to model such loss carryforwards these in this section.

[33] As we shall see in later chapters, income taxes also feature in some production sharing regimes.

We discuss a less common variant – in which there is a time limit on how far into the future tax losses may be carried – later in this section.

Generic Income Tax Equations and Terminology

Income Tax Liability

Income tax liability = Income tax rate × Taxable profit

where the **income tax liability** – which we use interchangeably with the term "income tax charge"[34] – is the income tax payment due.

Taxable Position

We use "tax position" to mean either a **taxable profit** – sometimes called "pre-tax profit" – or an **untaxable loss**, which is also called a "tax loss":

Taxable profit = (Taxable revenue) – (Tax deductions) when the result if positive

Untaxable loss = (Taxable revenue) – (Tax deductions) when the result if negative

Following common practice, our examples assume that royalty payments are tax deductible.

Therefore "taxable revenue" – in our examples which feature royalties – is field revenue minus royalty. (This is also called "revenue, net of royalty" or sometimes "net revenue," though we do not like the latter term, because sometimes "net revenue" is used to mean net of royalty, but at other times, to reflect a net working interest (equity) share. It is therefore often best to clarify what is meant by the prefix "net.")

Tax Deductions

Tax deductions = (Costs and charges occurring in the present year)
+ (Any prior period tax losses, carried forward)

Income **tax deductions** are also called "income **tax allowances**." Different income tax regimes define income tax deductions in different ways, but they usually include components of the cost of supply (e.g., operating expenses, or "opex"), other production costs, and, as mentioned in Section 1.6.5, above, intangible capex. (We treat intangible capex in more detail when discussing depreciation.)

Let us now look at some simple calculation examples.

[34] Our examples in this book assume that all tax liabilities are paid, so we consider the liabilities to be cash charges. In addition, as some tax regimes require a given year's tax liability to be paid in instalments throughout that year, we effectively assume in our annual models that total tax charges for the full year – like any other cashflow, using our standard mid-period inflation/discounting method – are actually made in the middle of that year. Therefore, be aware that if you wish to assume later payment – for example, that taxes owed for the full year 2015 are paid sometime in 2016 – you will need to adjust the example templates we provide.

	B	C	D	E	F	G
1	**Assumptions**					
2	Item	Unit	Value			
3	Revenue	$	100			
4	Opex	$	160			
5	Annual tax rate	%	**50%**			
6	Only profit is taxed; losses are not taxed					
8	**Calculations -- single year's tax liabilty**		Income tax liability		Formulae used	
9	Item	Unit	Wrong	Right	Wrong	Right
10	Revenue	$	100	100	D10. =D3	E10. =D3
11	Tax deduction: opex	$	160	160	D11. =D4	E11. =D4
12	Taxable profit / (untaxable loss)	$	(60)	(60)	D12. =D10-D11	E12. =E10-E11
13	Annual tax rate	%	50%	50%	D13. =D5	E13. =D5
14	**Tax liability**	**$**	**(30)**	**0**	D14. =D12*D13	E14. =IF(E12<0, 0, E12*E13)

Logic to prevent taxing losses

Figure 1.29 From the file "Ch1_tax basics.xls"

Excel Logic to Prevent the Taxation of Losses

In Figure 1.29, which comes from the example file "Ch1_tax basics.xls," we show a simple one-year model, in which we ignore loss carryforwards for the moment.

> Note that, in this and the following examples in this section 1.9.3, all revenue is assumed to be taxable revenue.

In the Assumptions section, we can see that there is only one deductible item, opex, which has been set in cell D4 to $160. Revenue is $100, and the tax rate is 50%.

Column D shows what happens without any adjustment to the tax liability formula in cell D14. Even though the $(60) loss in cell D12 is untaxable, it gets taxed at 50% anyway, resulting in the "negative tax liability" of $30 (cell D14).

What does a "negative income tax liability" mean? That the government will write the loss-making company a check for $30 in that year? That would be very unusual – imagine the strain on public finances and perverse business incentives if this were the case. Most of the time, the term "negative income tax liability" is meaningless.[35] Usually, the maximum benefit a company can expect when it makes an income tax loss – again, *ignoring* loss carryforwards for the moment – is that it will not be charged for income tax that year, but it will not be *rewarded* for losing money.

[35] Some governments in certain circumstances do issue companies with tax credits associated with certain qualifying losses (e.g., for exploration expenditures in Norway and Alaska), but these are exceptions to the general rule.

The formula in cell E14 fixes the mistake seen in cell D14. The IF statement in cell E14 = IF(E12 < 0, 0, E12 * E13) means that:

- if the pre-tax position value in cell E12 is less than 0 (i.e., is a loss), then the tax liability is 0;
- otherwise (i.e., if the pre-tax position is positive (a profit), or equals 0) the income tax liability equals the tax position in E12 times the income tax rate in cell E13, in this case correctly resulting in a tax liability of $0 (cell E14).

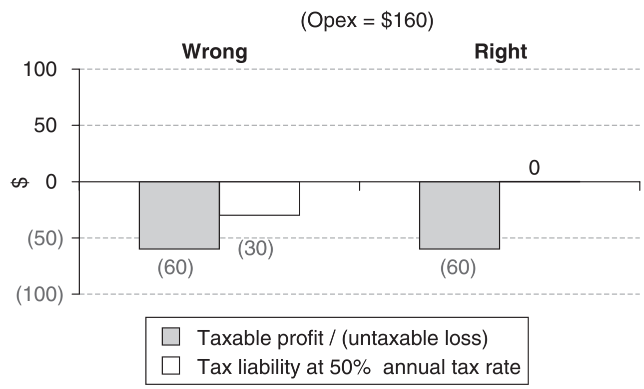

Figure 1.30 From “Ch1_tax basics.xls”

Figures 1.30 and 1.31 reproduce a chart from the Excel file under two different opex settings. Take a moment to use the spinner in cell D4 to scroll from the minimum opex permitted ($40) to the maximum ($160) and back again, to check that the “Right” method logic works.

We know the “Right” formula logic is working when:

- losses are not taxed (Figure 1.30), but
- taxable profits are taxed (Figure 1.31, in which case the “Wrong” method also happens to give the right answer).

Figure 1.31 From “Ch1_tax basics.xls”

Calculating Indefinite Income Tax Loss Carryforwards

Our model in the file "Ch1_tax basics.xls" was only for a single year. In the following, still much simplified, two- and three-year examples, we have assumed that:

- there were no tax losses before Year 1; and
- when tax losses may be carried forward, they may be carried forward indefinitely.

But first, let's look at another example which ignores loss carryforwards.

Income tax without carryforwards	**Year 1**	**Year 2**
Revenue	100	100
Tax deduction 1: current year opex	160	20
Taxable profit/(untaxable loss), ignoring loss carryforward	(60)	80
Tax rate	50%	50%
Tax liability	0	40

Figure 1.32 Tax calculation without loss carryforwards

Because the example in Figure 1.32 assumes tax losses may *not* be carried forward, there is no connection between the two years' calculations. The Year 1 tax loss of $60 "goes nowhere," and so provides no tax relief. Having calculated each year's tax liability, our work is done.

Now let us try an example with loss carryforwards.

First, let us just focus on the vertical flow of calculations *within* years in Figure 1.33, below, ignoring for the moment the flow *between* years. In either year, note the two-stage calculation which results in the final annual tax position in row 6. There is one stage for each of the two types of tax deduction:

- Tax deduction 1 relates to underlying operations (opex in row 3). The tax position, considering only this deduction, is calculated in row 4.
- Tax deduction 2 relates only to carried forward losses (row 5). These are subtracted from the corresponding year's result in row 4, to give the year's "final" tax position in row 6.

Now let us turn to the flow between years, i.e., tax loss carryforwards. There is assumed to have been no loss in "Year 0" (not shown) to carry forward, so this means only Year 1's $60 tax loss (cell B6) gets carried forward to cell C5. This happens via the formula in cell C5, =IF(B6 < 0, (-B6), 0), which means:

- if the prior year's final tax position in B6 is negative i.e., is a loss, then the answer is the value of that loss, expressed as a positive;
- otherwise, the answer is 0 (i.e., there is no loss to carry forward).

Year 1 “final” pre-tax position – a $60 loss – is carried forward to Year 2, expressed as a positive, and subtracted from this (i.e., from C4)…

	A	B	C
1	**Income tax with carryforwards, Example 1**	**Year 1**	**Year 2**
2	*Revenue*	*100*	*100*
3	*Tax deduction 1: current year opex*	*160*	*20*
4	Taxable profit/(untaxable loss), ignoring loss carryforward	(60)	80
5	Tax deduction 2: tax loss from prior year (shown as a positive)	*0*	60
6	**Taxable profit/(untaxable loss), considering loss carryforward**	**(60)**	**20**
7	*Tax rate*	*50%*	*50%*
8	Tax liability	0	10

… resulting in this final taxable profit for Year 2.

Figure 1.33 Indefinite income tax with loss carryforward, Example 1

Note: All values in italics are *assumptions* (including cell B5). The “•” symbol marks the end of a formula.
Typical formulas used (e.g., in Year 2): **C4.** = C2-C3 • **C5.** = IF(B6 <0, (-B6), 0) • **C6.** = C4 – C5 • **C8.** = IF(C6 < 0, 0, C6 * C7)

Thus in this example, $(60) in cell B6 becomes $60 in cell C5.

Regarding this change in sign (from negative to positive):

- The tax loss is negative in cell B6 because. . .well, that is how losses are calculated! This has the bonus here of telling us whether cell C5 should consider it to be a loss to be carried forward to Year 2, which should only happen when B6 is negative.
- The reason we change any loss in B6 into a positive value in cell C5 is that we – almost uniformly in this book – format both revenues and costs/other deductions as positives, and then obtain results by subtracting the latter from the former (as opposed to formatting revenues as positives; costs etc. as negatives; and obtaining results by adding the two). Therefore we express both types of deductions (carried forward losses) as positives.[36]

Let us look at another example.

[36] This applies to how we *calculate* items. Some charts we use, however, draw on data which are reformatted so that costs and other outflows are shown as negative. In our models and examples, such reformatting is normally done under the heading “For chart”.

	A	B	C
1	**Income tax with carryforwards, Example 2**	**Year 1**	**Year 2**
2	*Revenue*	*100*	*100*
3	*Tax deduction 1: current year opex*	*160*	*160*
4	Taxable profit/(untaxable loss), ignoring loss carryforward	(60)	(60)
5	Tax deduction 2: tax loss from prior year (shown as a positive)	*0*	60
6	**Taxable profit/(untaxable loss), considering loss carryforward**	**(60)**	**(120)**
7	*Tax rate*	*50%*	*50%*
8	Tax liability	0	0

Figure 1.34 Indefinite income tax with loss carryforward, Example 2

Note: All values in italics are assumptions (including cell B5). The "•" symbol marks the end of a formula.
Typical formulas used (e.g., in Year 2): **C4.** = C2-C3 • **C5.** = IF(B6 <0, (-B6), 0) • **C6.** = C4 – C5 • **C8.** = IF(C6 < 0, 0, C6 ∗ C7)

In Example 2 (Figure 1.34), we use the same formulas, but revise our scenario:

- As before, we have a Year 1 untaxable loss of $60 (cell C6). But now suppose that Year 2's *operations* result in another tax loss of $60 (cell C4).
- When we carry forward the Year 1 tax loss of $60, it combines with the Year 2 tax loss from current year operations of $60, to result in a total Year 2 tax loss of $60 + $60 = $120 (cell C6).
- Because we end Year 2 with an untaxable loss of $120, the Year 2 tax liability is **$0** (cell C8).

Let us add another year.

In Example 3 (Figure 1.35):

- Year 3's operating pre-tax profit of $100 (cell D4), minus the $120 *cumulative* tax loss carried forward from the end of Year 2 (cell C6), equals a Year 3 end-period tax loss of $20 (cell D6).
- Because it is an untaxable loss, the Year 3 tax liability is $0.
- This $20 tax loss at the end of Year 3 would then be carried forward to any fourth business year. If there were no fourth year, the $20 tax loss would "die in the books."[37]

[37] When we say that the Year 3 tax loss never gets used as a benefit, in a scenario in which there are only three tax years, we are assuming that a special variant of tax loss benefit transfer, called a **tax loss carryback**, is *not* applicable. Tax loss carrybacks are discussed at the end of this section.

	A	B	C	D
1	**Income tax with carryforwards, Example 3**	**Year 1**	**Year 2**	**Year 3**
2	*Revenue*	*100*	*100*	*200*
3	*Tax deduction 1: current year opex*	*160*	*160*	*100*
4	Taxable profit/(untaxable loss), ignoring loss carryforward	(60)	(60)	100
5	Tax deduction 2: tax loss from prior year (shown as a positive)	*0*	60	120
6	**Taxable profit/(untaxable loss), considering loss carryforward**	**(60)**	**(120)**	**(20)**
7	*Tax rate*	*50%*	*50%*	*50%*
8	Tax liability	0	0	0

Figure 1.35 Indefinite income tax with loss carryforward, Example 3

Note: All values in italics are assumed (including cell B5). The "•" symbol marks the end of a formula.
Typical formulas used (e.g., in Year 2): **C4.** = C2-C3 • **C5.** = IF(B6 <0, (-B6), 0) • **C6.** = C4 – C5 • **C8.** = IF(C6 < 0, 0, C6 * C7).

In Example 4 (Figure 1.36):

- The Year 3 operating pre-tax position is positive \$120 (cell D4). This \$120, minus the \$120 cumulative tax loss carried forward from the end of Year 2 (cell D5), is \$120 − \$120 = \$0, i.e., a Year 3 taxable position of \$0 (cell D6). The Year 3 tax liability is therefore \$0.

	A	B	C	D
1	**Income tax with carryforwards, Example 4**	**Year 1**	**Year 2**	**Year 3**
2	*Revenue*	*100*	*100*	*300*
3	*Tax deduction 1: current year opex*	*160*	*160*	*180*
4	Taxable profit/(untaxable loss), ignoring loss carryforward	(60)	(60)	120
5	Tax deduction 2: tax loss from prior year (shown as a positive)	*0*	60	120
6	**Taxable profit/(untaxable loss), considering loss carryforward**	**(60)**	**(120)**	**0**
7	*Tax rate*	*50%*	*50%*	*50%*
8	Tax liability	0	0	0

Figure 1.36 Indefinite income tax with loss carry forward, Example 4

Note: All values in italics are assumed (including cell B5). The "•" symbol marks the end of a formula.
Typical formulas used (e.g., in Year 2): **C4.** = C2-C3 • **C5.** = IF(B6 <0, (-B6), 0) • **C6.** = C4 – C5 • **C8.** = IF(C6 < 0, 0, C6 * C7).

	A	B	C	D
1	**Income tax with carryforwards, Example 5**	**Year 1**	**Year 2**	**Year 3**
2	*Revenue*	*100*	*100*	*300*
3	*Tax deduction 1: current year opex*	*160*	*160*	*100*
4	Taxable profit/(untaxable loss), ignoring loss carryforward	(60)	(60)	200
5	Tax deduction 2: tax loss from prior year (shown as a positive)	*0*	60	120
6	**Taxable profit/(untaxable loss), considering loss carryforward**	**(60)**	**(120)**	**80**
7	*Tax rate*	*50%*	*50%*	*50%*
8	Tax liability	0	0	40

Figure 1.37 Indefinite income tax with loss carryforward, Example 5

Note: All values in italics are assumed (including cell B5). The "•" symbol marks the end of a formula.
Typical formulas used (e.g., in Year 2): **C4.** = C2-C3 • **C5.** = IF(B6 <0, (-B6), 0) • **C6.** = C4 – C5 • **C8.** = IF(C6 < 0, 0, C6 * C7).

- In Example 4, the cumulative $120 **tax loss** carried forward from the end of Year 2 gets "used up," or **amortized**, in Year 3, so there is no tax loss to carry forward to any fourth business year.

In Example 5 (Figure 1.37):

- The Year 3 operating pre-tax position of positive $200 (cell D4), minus the $120 cumulative tax loss carried forward from the end of Year 2 (cell D5), is $80, i.e., a Year 3 taxable profit of $80 (cell D6). At 50%, the Year 3 tax liability is $40 (cell D8).
- Again, the $120 tax loss gets amortized at the end of Year 3, so there is no tax loss to carry forward to any fourth business year.

In Example 6 (Figure 1.38, below):

- The Year 2 operating pre-tax position is positive $80 (cell C4), and the Year 3 operating pre-tax position is positive $200 (cell D4).
- In Year 2, the $80 pre-tax position, minus the $60 cumulative tax loss carried forward from the end of Year 1 (cell C5), is $80 − $60 = $20, i.e., a Year 2 taxable *profit* of $20 (cell C6), on which tax of 50% × $20 = $10 is payable (cell C8).
- Because Year 2 ends with a taxable profit, there is no loss to carry forward to Year 3, so the carried forward tax loss for Year 3 is $0 (cell D5). Year 3's taxable profit = $200 – $0 = $200 (cell D6), 50% of which makes for a Year 3 tax liability of $100 (cell D8).

This is how indefinite tax loss carryforwards work. They are a quite common investment incentive for petroleum producers in many countries. We will use them as standard assumptions in many of the models in this book.

	A	B	C	D
1	**Income tax with carryforwards, example 6**	**Year 1**	**Year 2**	**Year 3**
2	*Revenue*	*100*	*100*	*300*
3	*Tax deduction 1: current year opex*	*160*	*20*	*100*
4	Taxable profit/(untaxable loss), ignoring loss carryforward	(60)	80	200
5	Tax deduction 2: tax loss from prior year (shown as a positive)	*0*	60	0
6	**Taxable profit/(untaxable loss), considering loss carryforward**	**(60)**	**20**	**200**
7	*Tax rate*	*50%*	*50%*	*50%*
8	Tax liability	0	10	100

Figure 1.38 Indefinite income tax with loss carryforward, Example 6

Note: All values in italics are assumed (including cell B5). The "•" symbol marks the end of a formula.
Typical formulas used (e.g., in Year 2): **C4.** = C2-C3 • **C5.** = IF(B6 <0, (-B6), 0) • **C6.** = C4 – C5 • **C8.** = IF(C6 < 0, 0, 6 * C7)

Changing Formats – Same Calculations, Different Presentation

We chose the modeling format used in the preceding examples to help ease explanation. This format, however, is not one we have commonly seen or used ourselves in real-world models. Therefore, **from now on in this book, we shall use (a more common) standard format**. We introduce it by showing an Excel screenshot of Example 6 in both formats, in Figure 1.39. Note how they result in the same tax liabilities (rows 8 and 21).

Exercise: Calculate These Yourself

Enough passive learning! On the "Exercise_setup" worksheet of the file "Ch1_Indefinite_tax_loss_carryforward_format.xls" find a version of the "Model" sheet which has new input assumptions, but no formulas. Supply the formulas at least in the standard format version. Check your answers against those in the "Exercise_solution" sheet.

Tax Loss Carryforwards: Calculation and Analysis – The Value of Prior Tax Losses

In the preceding examples, we had assumed that activity starts in Year 1, and that therefore there was no prior tax loss arising before Year 1, to carry forward to Year 1. We represented this by using values of $0, e.g., in cells B5 and B14 in Figure 1.39.

But if, for example, a model's timeframe starts in 2015, and there *has* been activity before then, we need to know the value of any tax loss as at the end of 2014, to carry forward to 2015.

Our next example shows how to model this. It also gives a graphic view of how tax losses can grow, shrink and have "ripple effects" across multiple tax years.

	A	B	C	D	E	F	G
1	**Income tax with carryforwards, Example 6 – introductory format**	**Year 1**	**Year 2**	**Year 3**	**Typical formulae**		
2	*Revenue*	*100*	*100*	*300*	**(using Year 2**		
3	*Tax deduction 1: current year opex*	*160*	*20*	*100*	**as example)**		
4	Taxable profit/(untaxable loss), ignoring loss carryforward	(60)	80	200	C4. =C2-C3		
5	Tax deduction 2: tax loss from prior year (shown as a positive)	*0*	60	0	C5. =IF(B6<0, (-B6), 0)		
6	**Taxable profit/(untaxable loss), considering loss carryforward**	**(60)**	**20**	**200**	C6. =C4-C5		
7	*Tax rate*	*50%*	*50%*	*50%*			
8	Tax liability	0	10	100	C8. =IF(C6<0, 0, C6*C7)		
9							
10	**Income tax with carryforwards, Example 6 – standard format used elsewhere in this book**	**Year 1**	**Year 2**	**Year 3**			
11	*Revenue*	*100*	*100*	*300*			
13	*Opex*	*160*	*20*	*100*			
14	Tax loss from prior year (shown as a positive)	*0*	60	0	C14. =(-B19)		
15	Total tax deductions for current year	160	80	100	C15. =SUM(C13:C14)		
17	**Taxable profit/untaxable loss**	**(60)**	**20**	**200**	C17. =C11-C15		
19	Tax loss, to be carried to next year (shown as a negative)	(60)	0	0	C19. =IF(C17<0, C17, 0)		
20	*Tax rate*	*50%*	*50%*	*50%*			
21	Income tax liability	0	10	100	C21. =IF(C19<0, 0, C20*C17		

Figure 1.39 Indefinite tax loss carryforwards: introductory and standard formats, from the "Model" sheet of the file "Ch1_Indefinite_tax_loss_carryforward_format.xls"

Notes: (1) The arrows are Excel audit ("trace precedent") lines. (2) It should be understood that "Taxable profit/untaxable loss" in row 17 is the final tax position, which considers the tax loss carryforward, even though this is not stated explicitly. (3) Italics, which here indicate hard-coded values, will not normally be used this way in the Excel files; rather, this is the job of the blue font in the Excel files. We used italics here and in the preceding examples because blue is not distinguishable in this black and white book.

The **main points** to take away from this are that:

- one always needs to **know the value of any such prior carried forward tax loss**; and
- this **focus on past** (pre-valuation date) activity is an **exception to the general rule** that we normally **ignore the past** in a NPV model, which by definition discounts only future cashflows occurring starting from the valuation date. We make this exception precisely **because the past in this case can impact future cashflows** – that is, the end-2014, carried forward tax loss can impact future tax payments.

This section is continued on the disk

For formatting reasons (relating to size and the use of color), we have put the material for this example into a PDF file on the disk. Go to the file "Ch1_Indefinite_tax_loss_carryforward_examples.pdf" which uses the model in the file "Ch1_Carryfoward_prior_losses.xls."

Related Topics and Techniques: Fiscal Consolidation; Time-Limited Tax Loss Carryforwards; Loss Carrybacks

It is important that you feel comfortable modeling indefinite tax loss carryforwards. As mentioned earlier, they are a very common incentive for investors which we use in many of the example models in this book.

In fact, we will soon see in Chapter 2 that the ability to apply tax loss carryforwards from one license to the pre-tax positions of another is a key feature of **fiscal consolidation** regimes.

In addition, there are two "cousins" of the indefinite tax loss carryforward. Neither are used in this chapter, but we introduce them here and then detail them later in standalone files:

- One is the **time-limited loss carryforward**. So far we have covered indefinite loss carryforwards, whereby tax losses may be carried forward until they are amortized. This is a very common approach. Some regimes, however, use time-limited loss carryforwards. For example, a loss may be carried forward for a maximum of three years, but no more. This would be a case of "use it (in time) or lose it." Although the idea is simple, time-limited loss carryforwards can be quite tricky to model (so much that you might consider this device to be more like an "evil twin" than a "cousin"). We show how in the supplemental file "Appendix III_time_limited_tax_loss_ carryforwards.pdf."
- Another is the **tax loss carryback**:
  - Assume a field produces for 10 years, and that in the last year it has a tax loss of $100. Because it is the last year of business, the loss cannot be carried forward to a next year, and so there are no future taxable profits which this tax loss can reduce.
  - If loss carrybacks are not allowed, this tax loss cannot benefit the producer – the producer has not used it, and therefore has lost it.
  - But if loss carrybacks *are* allowed, the loss can be carried back to offset any *prior* taxable profits. How is this done, if one cannot travel back in time? Essentially, the tax man compares:
    - the producer's total (from all-years) tax position, ignoring the tax loss carryback, to
    - the producer's tax position if the producer *had* been able to deduct $100 from any prior taxable profits.
  - If the second option would have resulted in a lower tax liability than the first, then at the end of Year 10, the tax man would write the producer a check for an amount equal to the amount of the reduction.
- Again, this is harder to model than it sounds. We give an example in the file "Appendix II_ tax_loss_carrybacks.pdf."

1.9.4 Returning to Main Model – Post-ELT Calculations: Income Tax

The income tax calculations format will be the same as that shown near the end of Section 1.9.3, from which we repeat, for reference, part of the screenshot shown in Figure 1.40.

The only difference is that in this simplified example, there are only two kinds of tax allowance – opex, and tax loss carryforwards – whereas, as seen in Figure 1.41, below, under our main chapter model's Base Scenario, we have not only opex and tax loss carryforwards, but also royalty, the bonus, rentals, expensed intangible capex, abandonment and the depreciation of tangible capex. (Recall that the Base Scenario uses the option to make the bonus and rentals tax deductible.)

	A	B	C	D	E	F	G
10	**Income tax with carryforwards, Example 6 – standard format used elsewhere in this book**	**Year 1**	**Year 2**	**Year 3**			
11	*Revenue*	*100*	*100*	*300*			
13	*Opex*	*160*	*20*	*100*			
14	Tax loss from prior year (shown as a positive)	*0*	60	0	C14. =(-B19)		
15	Total tax deductions for current year	160	80	100	C15. =SUM(C13:C14)		
17	**Taxable profit/untaxable loss**	**(60)**	**20**	**200**	C17. =C11-C15		
19	Tax loss, to be carried to next year (shown as a negative)	(60)	0	0	C19. =IF(C17<0, C17, 0)		
20	*Tax rate*	*50%*	*50%*	*50%*			
21	Income tax liability	0	10	100	C21. =IF(C19<0, 0, C20*C17		

Figure 1.40 From the "Model" sheet of the file "Ch1_Indefinite_tax_loss_carryforward_format.xls"

The calculation principles are the same, however. Again, revenue minus the sum of all tax allowances equals the tax position, which:

- if it is a taxable profit, is taxed at the income tax rate; and
- if it is a loss, is not taxed, but carried forward as a tax allowance to the next year.

	A	B	C	D	E	F	G	H
47	**(Post-ELT) Income tax calculation**							
48	**Income tax allowances (i.e., deductions) MOD $ =**							
49	(Post-ELT, MOD $:	Royalty + Rental (maybe) + Bonus (maybe)	+	Total Opex + Intangible capex + Aband. costs	+	Depreciation of Tangible capex	+	Tax loss carryforward)
50	Tax position, MOD $	=	(Post-ELT, MOD $:	Gross Revenue	-	Income tax allowances)		
51	**Income tax liability, MOD $**							
52	• if Tax position > 0,	=	Post-ELT, MOD $:	Tax position, MOD$	x	Income tax rate, %		
53	• if Tax position < = 0,	=	0					

Figure 1.41 From the "ModelSummary" sheet of the file "Ch1_Tax_and_Royalty_Model.xls"
Note: Reflects Base Scenario.

Take a quick look at pages 52–53 of the file "Ch1_Main_chapter_supplement.pdf," in which this section's income tax calculations are highlighted on a version of the "model map" introduced earlier.

Then, for the following discussion, refer to the "Income tax calculation" page (page 19) of "Ch1_Main_chapter_supplement.pdf," which reproduces a view of rows 476–495 of the model. (Note that some columns are hidden in this screenshot.)

Some of the items in the income tax calculation section are essentially just carried down from above, including:

- gross field revenue;
- intangible capex;

- the abandonment payment;
- depreciation; and
- the tax position at the end of 2014 (cell F489, i.e., the MOD $10.8 mm tax loss which we input as an assumption in cell I70).

All of these items are on a post-ELT basis.

Total opex in row 483 is the sum of post-ELT fixed opex and post-ELT variable opex in rows 284 and 285, respectively.

The three fiscal items – royalty, rentals and the bonus – take into account whether or not they are in fact tax deductible:

- Each one equals its post-ELT version, multiplied by the relevant, named, binary (0 or 1) tax deductibility assumption cell in row 67.
- For example, each annual rental charge in row 485 equals the corresponding annual post-ELT rental charge in row 286, times the cell "Tax_deduction_rental" in cell J67, which equals 1 when rentals are assumed to be tax deductible, and 0 when they are not.
- The royalty and bonus calculations in rows 482 and 486 work the same way as the rentals.

The actual tax calculation, including the carryforward of tax losses, is done in rows 489–495, in the same way as described in Section 1.9.3, resulting, under the Base Scenario, in a total, post-ELT investor tax charge of **MOD $66.6 mm** (cell D495).

Unused Tax Losses at Project End

Notice that under the Base Scenario, at the end of the project in 2024, the field life has an accumulated carried forward tax loss of **MOD $36.9 mm** (cell L489). We capture this as a memo item in cell D493. Under our Base Scenario's assumed fiscal regime, that is the end of the story, i.e., this represents MOD $36.9 mm of potential tax benefits, in the form of tax allowances, which will never get used, because the "dead" field will never produce any more taxable income for these allowances to reduce.

Be aware, however, that – as mentioned at the end of Section 1.9.3 – some regimes have ways to let the investor benefit from such unused, end-of-project tax losses:

- One is known as a **tax loss carryback**, which we treat in "Appendix II_Tax_loss_carrybacks.pdf" on the disk.
- The other is a very important mechanism for "sharing" tax losses among fields or reservoirs, when the investor has more than one field or reservoir generating revenue. This is known as **income tax consolidation**, and is the focus of Chapter 2.

Sense check

With the model set to the Base Scenario, split the screen so that above the split you see rows 67–70, and below it, the waterfall charts. Increase the MOD $ values for the historic tax losses and the undepreciated balance, using the spinners in cells I70 and 070, while watching the charts' columns and/or value labels. Does the income tax charge, and thus NCF/NPV, behave as expected? The point to take away is that these historic items can have real value to an investor.

Reset to the Base Scenario (there is a duplicate switch for this just above the left waterfall chart, in cell B600), and then set the tax rate to 75%, using the spinner in cell C67. Then make the same increases to the prior balance items in row 70 as before. For each click of the spinner, is the dollar impact on the tax charge greater or smaller than when the tax rate was 45%?

Once again, reset to the Base Scenario, and set the tax rate to 0%. Again, change the values in I75 and O75 while watching the charts. Nothing happens. Why not?

Assumptions about the "Cashiness" and Timing of Tax Liabilities

In this example model, we assume that the investor pays 100% of tax liabilities in cash, which is why we use the terms "tax liability," "tax charge" and "tax payment" interchangeably.

We also assume that the tax year is the same as the calendar year, and that tax is paid in installments throughout the year (which in fact is common practice in some oil-producing countries, such as Nigeria). This approach is consistent with the mid-year discounting convention which we use in the model, because this convention, you will recall from Section 1.2, approximates cashflows occurring throughout the year. If in your own models the time-related assumptions and/or discounting methods differ from those used here, you will need to adjust the timing of tax payments accordingly.

Variations among Income Tax Regimes

Be aware that we are focusing on the tax liabilities arising only from field activity. In real life, some tax regimes have comprehensive provisions which can greatly complicate the picture, such as:

- tax treaties between the host country and an investor's home country for tax purposes;
- tax incentives focused on specific activities or geographic areas;
- time-limited tax incentives;
- general tax allowances applied to all industries within a specific jurisdiction;
- loopholes; etc.

These are beyond the scope of our book (and in fact, for some countries, could make a book of their own). Bear in mind, however, that these exist and can result in differences between the field-based tax liabilities we calculate here and the investor's final corporate tax bill paid.

To keep our model simple, we have assumed that a single tax rate is applicable each year. In practice, however, in some countries, annual income tax rates can vary: for example, according to how many years a license has been producing; the period's production rate; cumulative production levels; commodity prices; and a device known as an "R-factor," which is some measure of cumulative revenue divided by some measure of cumulative costs.

Because some of these same tax rate-setting mechanisms also apply to royalties – and to prevent overloading this chapter – we detail their calculation in Chapter 3 on royalties. You will find the methods shown there transferrable to income tax calculations.[38]

Analysis: Comparing the Impacts of the "Quick And Dirty" and "Proper" Depreciation Methods on the Tax Liability

As seen in the boxed caption of the chart reproduced in Figure 1.42, the two methods' (all-years) *total* depreciation charges are the same at MOD $61.51 mm, but the timing of *individual,* annual depreciation charges differs under the two methods. As the data labels show, the quick

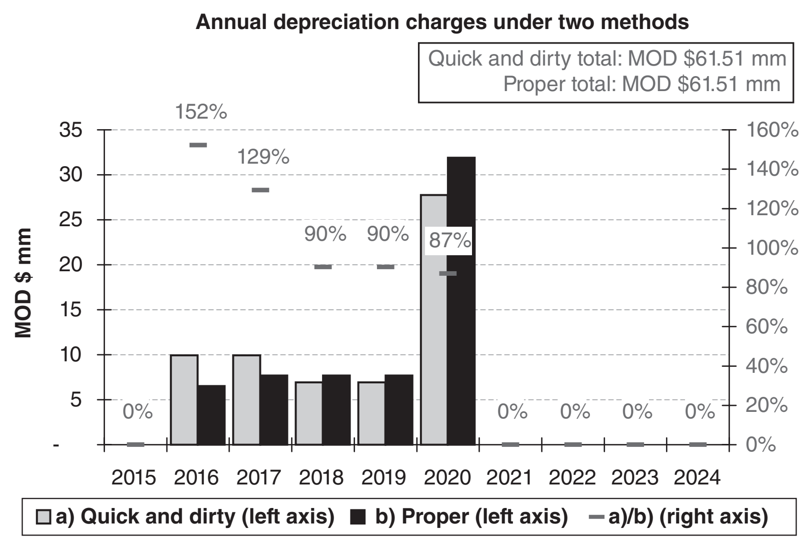

Figure 1.42 From row 436 of the file "Ch1_Tax_and_Royalty_Model.xls"
Note: Reflects Base Scenario.

[38] (1) Some regimes offer tax benefits based on these factors, not by lowering the tax rate, but by using them as the basis for creating additional tax allowances; by excluding certain portions of revenue from taxation (in which case the exempted portions would need to be subtracted from the values found in row 479 of our example model); and / or by creating tax credits (amounts subtracted from the tax liability). (2) Some regimes base a period's tax rate on the period's IRR. This can be problematic in cases where IRR is incalculable, as discussed earlier on pages 55–56 of the file, "Ch1_time_value_of_money_supplement.pdf".

and dirty method overstates the properly calculated depreciation charges for 2016 and 2017 by 52% and 29%, respectively, and understates it by 10–13% in the remaining years.

To overstate a tax allowance is to understate tax liabilities, and vice versa.

Importantly, the fact that the total (all-years) allowances from depreciation, calculated both ways, are equal, does *not* mean these annual distortions "even out in the end," as far as the investor's tax charges, and thus NCF, are concerned. There are too many other "moving parts" in the model to support such a generalization.

For example, from Section 1.9.3 on tax loss carryforwards, we know that how much – if any – of a tax allowance can be used to reduce taxable income in a given year depends on that year's level of taxable income, which in turn depends on many factors unrelated to depreciation, such as annual prices, volumes and costs, as well as any prior tax losses.

Total (all-years) results		
MOD $ mm	Tax charge	NCF
a) Quick and dirty	64.7	63.2
b) Proper	66.6	61.3
a) – b)	(1.87)	1.87
a)/b)	97.2%	103.1%

Figure 1.43 From row 465 of the file "Ch1_Tax_and_Royalty_Model.xls"
Note: Some columns not shown. Values in the table are hard-coded, reflecting the results of each depreciation method under the Base Scenario.

The Tax charge column of Figure 1.43 shows that, in this case, the quick and dirty method's distortions of tax allowances from depreciation would lead the investor to believe that its tax charge would be MOD $1.87 mm lower than if depreciation were calculated properly.

(Notice, by the way, that the "a) – b)" row highlights that the only effect which the depreciation method has on cashflows is via the tax charge.)

Another reason *not* to assume that the annual distortions even out in the end is that the depreciation charges shown in Figure 1.43 are undiscounted, and therefore ignore the time value of money:

- Of course, it only makes sense to calculate them on an undiscounted basis – the taxpayer has to, because they are used to calculate tax liabilities, which are payable on an undiscounted basis. (Imagine trying to get away with declaring "discounted income" on your annual personal tax return.)
- Irrespective of how tax liabilities are actually calculated, the fact remains that the timing of when tax benefits are available, and thus the timing of any taxes paid, can – like anything with a cash impact – affect discounted results.
- All other things being equal, the earlier a tax benefit occurs, and can be used to reduce taxable income, the greater its discounted value to the taxpayer will be, and vice versa.

- From row 29, using a 10% discount rate and the mid-year discounting convention, note that the present values of a (MOD) $1.00 tax benefit arising in 2015 or 2016 are $0.95 or $0.87, respectively, but for one arising in 2020, it is $0.59.

Just knowing this, and looking at the undiscounted values in Figure 1.42, you might guess that the net effect of the quick and dirty method's distortions is to overstate the discounted sum of all-years discounted depreciation charges, reasoning that the two big overstatements are in the early years, and so get discounted less than the one big understatement, which is in 2020.

If this guess is correct, the quick and dirty method's overstated (compared to the proper method) discounted tax benefit would show up as an understated discounted tax charge. In fact, this is what we see in the discounted results added to Figure 1.44.

MOD $ mm	Tax charge	Disc. tax charge	NCF	NPV
a) Quick and dirty	64.7	**49.3**	63.2	**39.1**
b) Proper	66.6	**51.0**	61.3	**37.4**
a) – b)	(1.87)	**(1.67)**	1.87	**1.67**
a) / b)	97.2%	**96.7%**	103.1%	**104.5%**

Figure 1.44 From row 465 of the file "Ch1_Tax_and_Royalty_Model.xls"
Note: Values in the table are hard-coded, reflecting the results of each depreciation method under the Base Scenario.

The main point of this analysis is that:

- although we have used and explained the quick and dirty depreciation method in this chapter, because it covers most of the steps needed to calculate depreciation correctly, and
- we have placed the full explanation of the proper method outside this chapter, in "Appendix I_Depreciation.pdf" for reasons of space,

the differences between the methods are not merely academic, as they can give materially different results. For this reason, you should be sure to familiarize yourself with the material in Appendix I. We shall use the proper method in a number of the production sharing models in Chapters 7 and 8.

1.9.5 Post-ELT Calculations: NCF and Discounting

The calculation of both the investor's and government's NCF and discounted NCF is outlined in Figure 1.45 and implemented in the model as shown in Figure 1.46.

Because we have finished calculating all post-ELT components of the cashflow, the undiscounted NCF calculations are entirely straightforward, consisting mainly of collecting these components, and then subtracting all the costs from gross revenue.

(Post ELT) Investor net cashflow, discounted net cashflow and NPV calculation						
Net cashflow, MOD $	=	(Post-ELT, MOD $;		Gross Revenue	−	(Rentals + Bonus + Tax + Opex + Capex + Abandonment))
Discounted Net cashflow, MOD $	=	Annual net cashflow, MOD $	×	Annual discount factor		
NPV	=	Sum of annual discounted Net cashflows				

Figure 1.45 From ModelSummary sheet of the file "Ch1_Tax_and_Royalty_Model.xls"

The undiscounted NCF calculations, shown in Figure 1.46, below, using the typical annual formulas for 2020 (column K) as examples, are as follows (all items are on a post-ELT basis):

- Gross revenue, royalty, the abandonment payment and income tax are all just carried down from above.
- Total opex (row 506) is the sum of fixed and variable opex.
- Total capex (row 507) is the sum of tangible and intangible capex.
- Bonuses and rentals are summed into one line item in row 508.
- The investor's undiscounted NCF in row 514 equals gross revenue less all costs.
- Because in this example model we assume that the investor bears all costs, the government's undiscounted NCF (row 515) is the sum of its undiscounted revenues, i.e., royalty, rental, bonus and tax income.

If we only wanted to know the investor's and government's NPVs, we could multiply the annual values in rows 514 and 515, respectively, by the annual discount factors, and sum the resultant discounted annual values.

But as we mentioned in Section 1.2, the time value of money is a sometimes subtle, sometimes powerful "distorter" of the "story" of the field's underlying undiscounted cashflow generation. Different components of cashflow get discounted to different degrees, making it at times hard to understand the "discounted story" – that is, why NPV behaves as it does under different assumptions – by just comparing two lines, undiscounted and discounted NCF.

Therefore, to aid our analysis, we calculate NPV "the long way" by:

- multiplying each undiscounted cashflow component by the discount factor, as seen in rows 540–547;
- subtracting total annual discounted cash outflows from discounted annual revenue to get discounted annual investor NCF (row 551), and summing the discounted annual royalty, rentals, bonus and income tax to get discounted annual government NCF (row 552);

	B	C	D	E	F	G	H	I	J	K	L	P	Q	R
501	**Undiscounted net cashflow (NCF)**													
502	**Undiscounted net cashflow (NCF)**		**Total**		**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**			
503	**Gross field revenue**	**MOD $ mm**	**465.7**		**-**	**148.3**	**113.5**	**86.6**	**66.5**	**50.8**	**-**	K503. =K279		
505	Royalty @ 17.25%	MOD $ mm	**80.3**		-	25.6	19.6	14.9	11.5	8.8	-	K505. =K281		
506	Total Opex	MOD $ mm	**127.0**		-	30.3	27.1	24.7	23.0	21.8	-	K506. =SUM(K284:K285)		
507	Total Capex	MOD $ mm	**82.2**		61.6	20.6	-	-	-	-	-	K507. =SUM(K282:K283)		
508	Bonus & Rentals	MOD $ mm	**24.9**		0.9	16.8	1.8	1.8	1.8	1.8	-	K508. =SUM(K286:K287)		
509	Abandonment payment	MOD $ mm	**23.4**		-	-	-	-	-	23.4	-	K509. =K270		
510	Income Tax @ 45%	MOD $ mm	**66.6**		-	13.8	25.8	16.8	10.1	-	-	K510. =K495		
511	**Investor's total cash outflows**	**MOD $ mm**	**404.4**		**62.5**	**107.1**	**74.3**	**58.3**	**46.4**	**55.8**	**-**	K511. =SUM(K505:K510)		
514	**Investor NCF**	**MOD $ mm**	**61.3**		(62.5)	**41.2**	**39.2**	**28.3**	**20.0**	(5.0)	**-**	K514. =K503-K511		
515	**Government NCF**	**MOD $ mm**	**171.8**		**0.9**	**56.2**	**47.2**	**33.6**	**23.4**	**10.6**	**-**	K515. =SUM(K505,K508,K510)		
537	**Discounted NCF and NPV**													
539	**Discounted NCF**		**Total**		**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**			
540	**Gross field revenue**	**MOD $ mm**	**353.4**		**-**	**128.6**	**89.4**	**62.0**	**43.3**	**30.1**	**-**	K540. =K503*Disc_factor		
542	Royalty @ 17.25%	MOD $ mm	**61.0**		-	22.2	15.4	10.7	7.5	5.2	-	K542. =K505*Disc_factor		
543	Total Opex	MOD $ mm	**93.3**		-	26.3	21.4	17.7	15.0	12.9	-	K543. =K506*Disc_factor		
544	Total Capex	MOD $ mm	**76.6**		58.7	17.9	-	-	-	-	-	K544. =K507*Disc_factor		
545	Bonus & Rentals	MOD $ mm	**20.4**		0.9	14.6	1.4	1.3	1.2	1.1	-	K545. =K508*Disc_factor		
546	Abandonment payment	MOD $ mm	**13.9**		-	-	-	-	-	13.9	-	K546. =K509*Disc_factor		
547	Income Tax @ 45%	MOD $ mm	**51.0**		-	12.0	20.3	12.1	6.6	-	-	K547. =K510*Disc_factor		
548	**Investor's total cash outflows**	**MOD $ mm**	**316.0**		**59.6**	**92.8**	**58.5**	**41.8**	**30.2**	**33.0**	**-**	K548. =SUM(K542:K547)		
550			**NPV**											
551	**Investor Discounted NCF**	**MOD $ mm**	**37.4**		(59.6)	**35.7**	**30.9**	**20.3**	**13.1**	(2.9)	**-**	K551. =K540-K548		
552	**Government Discounted NCF**	**MOD $ mm**	**132.3**		**0.9**	**48.7**	**37.2**	**24.1**	**15.2**	**6.3**	**-**	K552. =SUM(K542,K545,K547)		

Figure 1.46 From the file "Ch1_Tax_and_Royalty_Model.xls"
Notes: Reflects Base Scenario. Some rows and columns are hidden.

- and summing the annual NCF values to get investor and government NPV of MOD $ 37.4 mm and MOD $132.3 mm, respectively (cells D551 and D552).

1.9.6 Post-ELT Calculations: Financial Metrics

Starting in row 518 of the model, we calculate the following metrics.

Internal Rate of Return (IRR)

Under the Base Scenario, the investor's IRR of 42% in cell D518 is, as described in Section 1.2, the discount rate at which the investor's NPV equals 0. (When the IRR is incalculable, the formula used returns "n.m." ("not meaningful").)

Recall that IRRs need to be treated with some caution, as it is possible, when a series of undiscounted net cashflows changes signs (i.e., goes from positive to negative, or vice versa), more than once, for there to be more than one correct answer. Note that the investor's Base Scenario NCF in row 514 changes signs twice: in 2015–2016 and 2020–2021.

Breakeven

The investor's **breakeven** – also known as **payback** – is the point in a field's life when the investor's cumulative net cashflow first turns positive. In our Base Scenario, this happens sometime in 2017, giving that year the first black column in the cumulative undiscounted investor NCF chart, reproduced in Figure 1.47.

All other things being equal, the sooner breakeven occurs, the better for the investor.

While knowing the time it takes to break even is useful both in and of itself, and when comparing competing investment opportunities, it is only *so* useful, because it ignores what

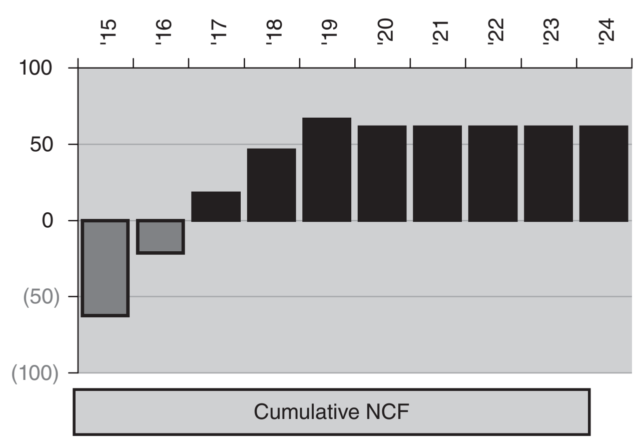

Figure 1.47 Investor's cumulative undiscounted NCF, MOD $ mm, from row 668 of the file "Ch1_Tax_and_Royalty_Model.xls"
Note: Reflects Base Scenario.

happens *after* the field breaks even. Does it go on to generate years and years of positive NCF? Is it abandoned as loss making immediately after breaking even? Or something in between? It is therefore used by some in capital budgeting, but usually as a secondary metric.

We calculate the investor's undiscounted breakeven year in rows 521–525. We explain the method on page 20 ("Approximate breakeven calculation") of the file "Ch1_Main_chapter_supplement.pdf," to which you should now turn. We call the approach shown the "approximate" method because it tells you in which period breakeven occurs, but not when within that period.[39]

Maximum Exposure

An investor's undiscounted **maximum exposure** is the most negative level of investor undiscounted cumulative NCF over the investment lifespan. It is meaningful when – as in our example model, and in many other upstream petroleum situations – an initial investment is required before production can start.

Maximum exposure thus measures the deepest that the investor is "in the hole," and tells us how much of a loss it would sustain if, in a worst case scenario, it made its full enabling investment, but then for some reason had no chance to recoup it by generating positive cashflow.

In our example model, undiscounted maximum exposure is calculated in cell D530 as being **MOD $62.5** mm in the Base Scenario. It is seen as the lowest column in the chart shown in Figure 1.47.

The formula used to calculate it in cell D530 is `=IF(MIN(F529:O529)>=0, "n.m.", -MIN(F529:O529))` where `F529:O529` is each year's cumulative undiscounted NCF:

- The second expression is the "main" part of the formula; note how the minus sign means the maximum exposure will be expressed as a positive.
- The first expression is an error trap, which returns `"n.m."` in cases where cumulative undiscounted NCF is never negative, in which case the investor is never "exposed" in the sense of this metric.

[39] Sometimes it is not enough to know only that breakeven, as measured by some item – whether it is NCF, or another measure of profitability – occurs "sometime" within a period; it is necessary to know more about *when* within the period. This is because some countries base royalty, income tax and other fiscally relevant rates on the *quantified* extent to which an investor has broken even, e.g., whether it has only 50% broken even (i.e., cumulative revenues are only half of cumulative costs); it has fully broken even; or it has 150% broken even (i.e., cumulative revenue equals 1.5 times cumulative costs). In such a case, knowing the specific breakeven date is necessary to calculate correctly when a specified breakeven milestone is reached.

For example, if a tax rate is stated to be 30% before breakeven, and 50% after, and if the company breaks even at the end of the first quarter of the tax year, then it would only enjoy the 30% tax rate for the first 25% of the tax year, and be taxed at 50% thereafter.

This linkage of some measure of breakeven to another fiscal device is a "sub-device" often known as an "R-factor." We cover R-factors in detail as they apply to royalties and production sharing contracts in Chapters 3 and 8, respectively.

We show how to calculate an estimate of a specific breakeven time-point in the standalone file "Ch1_breakeven_methods.pdf" and its companion Excel files in the "Ch1_breakeven" sub-folder on the disk.

Note that in row 531 we determine the year in which undiscounted maximum exposure occurs, using simple logic in the annual cells. This logic:

- returns the calendar year if cumulative undiscounted cashflow equals the maximum exposure, and otherwise returns "n.a."; and
- captures, in cell D531, this year of maximum exposure, by taking the minimum value of the annual cells. The MIN function used ignores the text in the annual "n.a." cells.

(This will make more sense when you inspect the actual model!)

Thus under the Base Scenario, maximum exposure occurs in 2015 (cell D531), which in this case is the first capex year.

Sense check

Reset the model to the Base Scenario. In the Console View, adjust the split so you can see row 43 above the split and rows 661–684 below it.

Production starts in 2016. Change this to 2017, using the spinner in cell C43 (i.e., changing it to the value of 2).

What happens to (a) the amount and timing of maximum exposure, and (b) the timing of the breakeven year (shown in cells B681:B682)?

Experiment with how at least five other input assumptions in the Console View affect each of these two metrics.

Two other undiscounted metrics calculated are:

- **The PIR**, or **profit–to-investment ratio**. It is calculated in cell D534, with the formula =IF(D507<0, 0, D514/D507), which divides total (all-years) investor NCF by total (all-years) capex, subject to a 0 denominator "error trap." Under the Base Scenario, PIR is 0.75, which means that over the field's economic life, each dollar of undiscounted capex invested generates an undiscounted 75 cents of economic profit, measured as undiscounted NCF – in other words, a NCF undiscounted 75% cash return on cash invested.
- **NCF per barrel**. This is calculated as MOD $11.17/barrel[40] in cell D535. The formula is straightforward – on a post-ELT, total, life-of-field basis, it divides undiscounted investor NCF (cell D514) by post-ELT field production in mmb (cell D276), again, subject to a zero-denominator error trap.

[40] Note that the volumetric unit used reflects the fact that our example model produces only oil, whereas a gas field would use NCF per MCF, and a mixed oil and gas field would use NCF per BOE or NCF per MCFE.

In parallel calculations using discounted components, we calculate in rows 555–569 the discounted breakeven year, discounted maximum exposure, discounted PIR ("DPIR") and NPV per barrel.

These ratios are most commonly used for capital budgeting purposes, i.e., for making decisions which affect a portfolio of investments. While capital budgeting is not the focus of this book – except indirectly, in that capital budgeting models rely on inputs from properly executed fiscal models of individual investments – we calculate them in our example model here to make readers who are new to the subject aware of them.

Many analysts prefer to calculate discounted breakeven metrics. Discounted breakeven often occurs later than undiscounted breakeven. Whereas fiscal instruments tend to be linked to undiscounted breakeven metrics, it is the discounted breakeven measures that are more useful for capital budgeting, project performance evaluation and investment decision making.

1.9.7 Post-ELT Calculations: Volumetric Outcomes

In Figure 1.48 (from the section of the model starting in row 629), we show four different ways of measuring the field's total (all-years) production (a term which some might loosely refer to as "reserves," although we hesitate to do so here, as "reserves" is often a legal/reporting term which means different things in different jurisdictions). They are calculated in the section of the model starting in row 572:

- Gross pre-ELT volumes consist of the "technical production" volumes which we entered, and timed and applied a sensitivity factor to, in the assumptions section of the model.
- Gross post-ELT volumes are the gross pre-ELT annual volumes multiplied by the ELF, i.e., truncated to the economic limit.

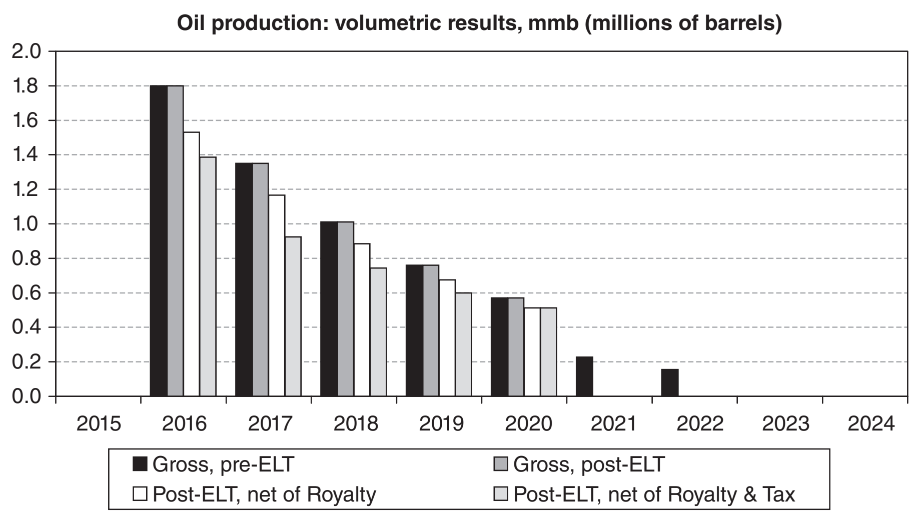

Figure 1.48 From the file "Ch1_Tax_and_Royalty_Model.xls"
Note: Reflects Base Scenario.

- The post-ELT volumes, net of royalty deduct the volumetric equivalent of the royalty payment:
  - Here is a "shortcut" calculation example: if gross post-ELT production is 10 mmb, and the royalty rate is 20%, then the royalty equivalent in barrels is 2 mmb; therefore, post-ELT, net of royalty volumes equal 8 mmb.
  - Some jurisdictions require that investors' reports to stock exchanges provide data on a net of royalty (also called "after-royalty" or "post-royalty") basis. The reasoning is that because the government takes a royalty – either in cash or "**in kind**" (i.e., as volumes) – from "off the top" of the gross revenue stream, the investor is never entitled to the royalty component of the volumes to begin with. Therefore, the investor should deduct the royalty component from reported reserves; otherwise, the investor would overstate the volumes to which it is actually entitled. Under such definitions, the investor's **working interest** volumes would equal the investor's equity stake in the license (assumed 100% in this model), multiplied by the post-ELT volumes, net of royalty volumes.[41]
- The post-ELT volumes, net of royalty and tax, deduct the volumetric equivalent of both the royalty and the income tax charge. The latter is calculated in row 581 of the model as the period's tax charge in MOD $ mm, divided by the period's oil price in MOD $/b. This is also a reporting requirement in some jurisdictions.

The total (all-years) Base Scenarios volumes under each of these four measures are shown in the "Ignored" row (we will explain in a moment) in Figure 1.49, which starts in row 631 of the model.

Note that many jurisdictions require reporting future production volumes on a post-ELT basis as one requirement for them to be called "Reserves" in a strict, regulatory sense. This means that changing economic conditions – or changing forecasts of *expected* economic conditions – can be one factor causing companies to revise their reported reserve estimates from year to year.

For example, suppose that in 2015, a company forecast that the ELT would cause the last expected economic production year to be 2020, but in 2016 the company raises its oil price forecast, which would make two more years of production appear in its model to be commercially viable. In this case the reported reserves would increase by an amount equal to the company's working interest (however defined) in the volume from those two extra years worth of production.[42]

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[41] It is always good to ask whether what a company claims to be its "working interest" reserves have had the royalty component deducted – that is, to ask whether the reserves quoted are "net of royalty" – as reporting standards vary, and some companies will publish figures which do not deduct the royalty component, i.e., they publish reserves, gross of royalty, as this can make the reserves look larger.

[42] Conversely, the company's reported reserves could fall, if in 2016 it lowered its oil price forecast enough to cause the forecast last economic year to occur before 2020.

Note that some reporting jurisdictions such as the US – in order to limit the scope for manipulating reported reserve volumes by "playing" with the commodity price forecast – require that all companies calculate economic reserves using price forecasts which reflect the *historic* average prices realized in the reporting year. This does have the effect of putting each company's reported reserves on an "equal footing" in this respect. However, the resultant reserves volumes reported will not necessarily be that meaningful – unless you happen to believe that, for example, a 20-year oil price forecast, made at the end of 2016, somehow gains "realism" by being based on the average 2016 historic received price.

Points to Consider Regarding Reported Volumes

Although royalty and income tax are both fiscal cash outflows from the investor's point of view, so are other fiscal costs, such as rentals and bonuses; yet stock exchange and other rules seldom (if at all) require that investors deduct the volumetric equivalents of these other fiscal costs to arrive at reported working interest volumes.

- On the one hand, it strikes us as inconsistent to require the deduction of volumes corresponding to some fiscal costs but not others.
- On the other hand, it might be just as well not to require things like volumes net of all fiscal charges.
- One reason is that too many volumetric measures would be likely to confuse outside investors.
- Another is that, from a valuation point of view, calculating ever more finely sliced measures of volumes is only so useful. It is important not to lose sight of the fact that in fiscally detailed upstream petroleum cashflow valuations, volumes are usually not "the point"; rather, they are stepping stones to reach "the point," which is the monetary value of those volumes, as measured by NCF and ultimately NPV and related discounted metrics. From a cold investment perspective, an oil field investment is not about oil, it is about cashflows.[43]

The Positive-NPV Test for Reporting Reserves

Another adjustment to reported production volumes is the positive-NPV test, which, simply put, means that if the project is NPV-negative, the investor may not report *any* future production volumes. The thinking behind this is that if the investment is NPV-negative, the investor will not proceed with the project, and so will not ever produce.

Total (all years) oil production, mmb				
	Pre-ELT	Post-ELT		
Positive-NPV test:	Gross of royalty	Gross of royalty	Net of royalty	Net of royalty & tax
Ignored	5.9	5.5	4.8	4.2
Applied	Not relevant		4.8	4.2

Figure 1.49 From rows 631–635 of the "Model" sheet of the file "Ch1_Tax_and_Royalty_Model.xls"
Note: Reflects Base Scenario.

The model provides the option whether to apply this test, using the spinner in cell C590. If the test is selected, simple formula logic is applied to the post-ELT volumes, net of royalty, and the post-ELT volumes, net of royalty and tax, in cells D594 and D595, respectively. These are the values in the "Applied" row of Figure 1.49. Note that under the Base Scenario, NPV is positive, and so the results are the same, whether the positive-NPV test is applied or ignored.

[43] For further discussion on volumetric outcomes, see Sections 6.5 and 6.7 of Chapter 6 on PSCs.

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Note that in Figure 1.49 we have written “Not relevant” because the positive-NPV test is not usually applied to pre-ELT, gross of royalty volumes, or to post-ELT, gross of royalty volumes.

Sense check

Reset the model to the Base Scenario. In the Console View, be able to see row 23 above the split, and rows 590–595 below the split. Apply the positive-NPV test by selecting “Yes” with the spinner in cell C590. Now lower the oil price multiplier (cell G23) from 100% until the values in cells D594 and D595 equal 0. Scroll down below the split to check, in the discounted waterfall chart just below, that NPV is indeed negative at this multiplier setting.

Concluding sections

Turn to pages 21–46 of the file “Ch1_Main_chapter_supplement.pdf” on the disk for the following three, concluding sections of this chapter:

- 1.10 Multivariable Sensitivity Analysis Using a Two-Way Data Table
- 1.11 The ELT – Questions to Consider
- 1.12 Review Exercise: Key Calculations