Power and Energy Series 70

Economic Evaluation of Projects in the Electricity Supply Industry

3rd Edition

Hisham Khatib

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Contents

Preface

The first edition of this book was published in 1997, and the second edition appeared in 2003. In the past ten years significant developments (technological as well as managerial) have taken place in the electricity supply industry (ESI) in most countries in the world. Significant strides in technology and improved efficiency of power generation have materialised during the past few years, as well as advancement in materials, information and telecommunications, which has helped promote electricity markets and trade.

There is a global trend towards liberalisation and privatisation in the electricity supply industry. This is coupled with growing environmental awareness and increasing calls for managing and curbing carbon. All have dramatically affected the ESI worldwide. Developments that have taken place during the past decade outweigh all that has taken place since the middle of the twentieth century.

This necessitated a review and a new edition of this work to take into account these developments that affect the way projects are conceived and evaluated by the industry. With the gradual demise of government-owned utilities, financial and economic evaluation of projects is gaining more importance in competitive and liberalised markets, as is risk management.

Financial and economic evaluation of projects is usually carried out by a team of engineers, economists and financial analysts. In the case of economic evaluation of large projects, there is an involvement of economic and environment disciplines, and the undertaking of an analysis that is beyond the proficiency of most engineers, accountants and financial analysts. Projects in the electricity supply industry are slightly more sophisticated than other investment projects in the industrial sector and more capital intensive. It is not easy to introduce people from other disciplines (economists, accountants, financial analysts) into the intricacies of electrical engineering; however, their role remains very important in the evaluation of projects in the power industry. It may be easier to acquaint engineers with the fundamentals of financial and economic evaluation of projects. This will allow for an easier dialogue between different disciplines in any project evaluation team, and correspondingly lead to better results.

This book is written primarily for engineers to assist them in project evaluation; therefore the treatment assumes some understanding of engineering, particularly the electrical power technology. All the financial and economic analyses and examples are brief and simplified to allow for the quick grasp of ideas and understanding of the subject by the non-specialist. However, the book is also useful for economists and financial analysts in understanding issues encountered in engineering projects and the electricity supply industry and the means of evaluating their economic implications. Chapters 1, 8–14 and 16 are, in particular, power engineering biased.

Simplified techniques for the financial and economic evaluation of projects are not difficult to understand by power engineers with their engineering and mathematical knowledge. There are plenty of simple evaluation rules that have to be grasped by engineers and which will give them a good insight to simple financial analysis and economic evaluation that will sharpen their understanding of the economic implications of investments and allow them to understand concepts such as the time value of money, discounting and the discount rate, rate of return and risk evaluation. Such concepts are essential knowledge for power system planners and others who are involved in project selection and strategies.

The book is mainly concerned with the financial and economic evaluation of projects. Therefore, it does not dwell on the other related aspects of demand prediction, technology, management and the framework of the power sector planning. These are, of course, very important for financial and economic evaluation; however, they are treated in detail in the available literature, and will be referred to when they are of direct bearing on evaluation. The book dwells only briefly on financial projections of a commercial nature. Therefore, the book is mainly concerned with the evaluation of projects, particularly capital-intensive projects like those of the electricity supply industry. Most of the investments carried out by utilities and investors are in the form of individual projects. The evaluation is required to find out the least-cost solution as well as the rate of return on the investment. The whole performance of the investor, as a complex commercial entity, can be assessed through financial ratios and *pro forma* financial statements. These are briefly described in Chapters 4–6.

Many books have been written in the US about engineering economics and evaluation of projects than have been written in the UK. Evaluation is not a universal science; approaches and criteria for assessment differ in the UK and Europe from North American practices in some aspects. The differences are, however, limited and some of them will be pointed out in the book.

International development agencies, particularly the World Bank, the Organisation for Economic Co-operation and Development (OECD), the International Energy Agency (IEA) and different UN agencies and other national and regional development funds, have significantly contributed towards understanding project evaluation, especially the economics of externalities, shadow pricing and costing of environmental damage. This book draws on their work wherever relevant. These basic methods did not change much since their inception and are still the bases for much of the economic evaluation.

This third edition is significantly enlarged compared with the first and second editions. There are four major significant additions. The first concerns more thorough understanding and evaluation of the environmental evaluation and economics of climate change (Chapter 8). The second is the strategies and outlook of the ESI in both the UK and the US (Chapter 9). The third is the evolving technologies to deal with carbon in the industry (Chapter 10) and the fourth is the economics of the new renewables (wind and solar) which are now a centre of concern (Chapter 12).

During recent years there was growing interest in renewables, particularly wind and solar, in dealing with the long-term impacts of carbon emissions and carbon pricing as well as empowering consumers (the smart grid) and opening the ESI to competition. These developments are covered in the aforementioned chapters.

Naturally there is repetition in the chapters, the discount rates, environmental considerations and efficiency and reliability improvements are common to many chapters. This allows some chapters to be read independently from the rest of the book, which will assist the reader. The book contains many statistics related to energy and electricity. These are mainly based on the OECD-IEA *World Energy Outlook 2012* and the US-DOE *International Energy Outlook 2013*, as well as some statistics from the industry such as *BP Statistical Review of World Energy – June 2013*. These statistics are not contradictory but do not exactly match; therefore there may be some slight differences between chapters.

This book will also be useful for post-graduate electrical power engineering students preparing for a higher degree. It will introduce them to the concepts of financial and economic evaluation and the criteria that govern investment in the electricity supply industry.

This book covers a wide ground and could not be written without benefiting from the published effort of others as well as quoting from the literature; therefore every chapter has a list of relevant references, upon which I have drawn, and that will enable the interested reader to sharpen his or her knowledge about the subject.

I am indebted for the assistance I received from Ms Ruwaida Khatib and Ms Tahreer al-Qaq in typing and arranging the manuscript and to Ms Rebecca Ryan for English language editing of some of the chapters. Of course any deficiencies are mine.

Hisham Khatib

Chapter 1

Global electrical power planning, investments and projects

1.1 The value of electricity

Electricity is versatile, clean to use, easy to distribute and supreme to control. Just as important, it is now established that electricity has better productivity in many applications than other energy forms [1, 2]. All this led to the wider utilisation of electricity and its replacement with other forms of energy in many uses. Demand for electricity, although slowed down in Organisation for Economic Co-operation and Development (OECD) economies, is still growing globally at a rate near that of economic growth and, in many countries, at almost 1.5 times that of the demand for primary energy sources. Electricity generation, in 2013, accounts for 40–41 per cent of primary energy use [3]. With the type of technologies and applications that already exist, there is nothing to stop electricity's advancement and it attaining a higher share of the energy market. Saturation of electricity use is not yet in sight, even in advanced economies where electricity production claims a major share of the primary energy use. Other than the transport sector, electricity can satisfy most human energy requirements. Electric vehicles (EV) although still limited in sale, however, may come strongly into the market in the foreseeable future. It is expected that, by the second half of the 21st century, most of the energy needs in industrialised countries will be satisfied by electricity [4].

Electricity has become an important ingredient for human life; it is essential for modern style of living and for business. Its interruption can incur major losses and create havoc in major cities and urban centres. Its disruption, even if transient, may cause tremendous inconvenience.

Therefore, continuity of electricity supply is essential. Also, with the widespread use of cyber technology and other voltage- and frequency-sensitive electronic equipment, the importance of the quality of supply has become evident. A significant proportion of investment in the electricity supply industry (ESI) goes into the reserve generating plant, standby equipment and other redundant facilities needed to ensure the continuity and high quality of the supply. Economics of reliability in the ESI is a very important topic [5], which will be dealt with in detail in a later chapter. With the spread of smart grids and distributed electricity generation, the ESI is changing and consumers will have more say in the supply management. Optimisation of investment in the ESI requires understanding of markets, prediction of future demand and an approach based on integrated resource planning.

1.2 Integrated resource planning

Integrated resource planning (IRP) seeks to identify the mix of resources that can best meet the future electricity-service needs of consumers, the economy and society. It is the preferred planning process for electric utilities. Under IRP, different resource options (incorporating investment and operational costs) are compared using a discounting process, and electrical power is visualised as a sub-sector of the energy sector. In turn, the energy sector is one among many other sectors (agriculture, health, education, transport, etc.) that makes up the national economy. However, energy and electricity permeate the whole economy, electricity linkage with all other sectors and the national economy at large is stronger than any other sector. Energy is also a capital-intensive activity that claims financial resources and investments more than other sectors, particularly if the country has no sufficient indigenous energy resources.

The electricity sub-sector is usually the largest within the energy sector. It claims more than one-half of the total capital investment in the energy sector and, presently on average, consumes 41 per cent of the country's total fuel consumption (ratios vary from one country to another). Capital investments in the electricity sector of the emerging economies amounted to almost 9 per cent of their gross capital formation (total capital investment) in the past two decades. This ratio is increasing owing to the rapid growth of electricity demand in these countries. Besides its direct linkages to almost all other sectors of the national economy, the electricity sub-sector does cause environmental detrimental impacts on national, regional and global levels, which are discussed in Chapter 8 [6].

Investments in the electricity sub-sector are prompted by the requirements of the economic and social sectors and by demography. However, their extent is restricted by the country's financial and capital investment capabilities and the availability of other energy sources, as well as the continuous improvement in efficiency of utilisation. The form and location of electricity production facilities and fuels utilised are being increasingly influenced by environmental considerations. Within the electricity sub-sector itself, limited financial resources have to be optimally distributed between generation extension and network strengthening, between urban and rural areas, and between different geographic locations. Usually the grid and distribution network demand as much, or slightly less, investment as generation facilities. Electrical power production also has to utilise different types of fuel and other resources depending on their local availability, cost and environmental impact. All these factors call for integrated electricity planning in a hierarchical manner (Figure 1.1).

Integrated resource planning in electric power utilities also involves links with the labour, capital and energy markets. It aims at ensuring that the policies (pricing and accessibility to supply) and practices (quality and availability of supply) of the power utilities adequately serve the purposes of the national economy. These purposes include ensuring a reliable supply at the least possible cost while efficiently utilising resources and protecting the environment.

Electricity is a secondary form of energy; usually it is referred to as an energy carrier. It is produced, in most cases, by converting primary energy and nuclear fuel into heat that drives turbine-generators or internal combustion engine-generators. It is also produced directly by hydro-power by driving hydro-turbines, as well as by natural sources (wind, solar). Therefore, electricity is an integral part of the energy scene. Fuels for producing electricity are the major part of the primary fuels that constitute the total primary energy requirements (TPER) in any country. Also, electricity is increasingly substituting other fuels within the energy sector. Any study into integrated resources management in the electricity sub-sector must consider this relationship. The aim is to achieve clean production and efficient resources utilisation in the electricity sub-sector. This will not only help reduce the burden of energy on the national economy, but also allow efficient and clean replacement of other fuels, thus greatly enhancing integrated resource management within the entire energy sector.

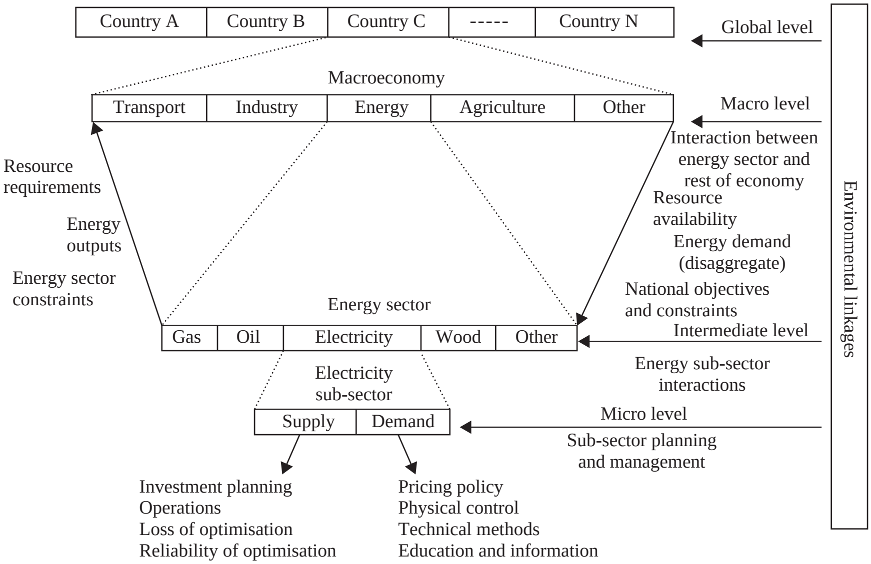

Figure 1.1 *Integrated resource planning in the ESI*
Integrated resource planning in the ESI seeks to identify the mix of resources. Energy is one of the national economy's most extensive sectors and it permeates the whole economy and has linkages practically to all sectors of the national economy that can best meet the future electricity-service needs of consumers, the economy and society. It is presented in the hierarchical framework of economy. Environmental aspects are increasingly linking the electricity sector to the energy sector and through it to the national micro-economy and global environmental management [Sources: IAEA; References [7] and [8]]

1.3 The changing electrical power industry scene

During the last century the ESI worldwide has resisted rapid change. This is mainly because of the inertia of its large size and investments, and being monopolistic in nature in most cases. Until recently, change has been slow technologically and managerially. In spite of the widespread utilisation of information and cyber technology and electronics in almost every electrical power facility, technological change has been gradual. Most electricity utilities continued to be monopolies with, in most cases, government ownership and control.

The oil crises of the 1970s shocked the electricity industry and hence it shifted the emphasis from expansion to conservation and efficiency. From the late 1980s tremendous developments in the management, ownership and control of the ESI began to take place. These changes were prompted by three important factors.

- The changing role of the government and the influence of market economies, and its emphasis on competition which led to restructuring and deregulation, liberalisation and private sector investment and ownership as well as electricity trade. These developments were made possible by the spectacular technological advancement in information technology and communications [9].
- Changes in technology in the generation of electricity with the growing role of renewables (wind and solar), the renewable portfolio standards (RPS) and the introduction of the smart grid. New renewables are sometimes termed as 'disruptive technologies' because they are slowly changing the long-established norms of the industry.
- Growing environmental concerns led to carbon pricing and prompting efficiency, conservation and conversion to cleaner fuels as well as emission-free renewables and distributed generation. Such environmental concerns evolved regulatory measures, and also advanced international agreements and protocols, which may have long-lasting effects on the future of the ESI [10] (see Chapters 8–10).

These three factors, which are practically recent in the history of the industry, are still gaining momentum, and are causing tremendous changes in the ESI. The structural change and technological development in the industry during the last two to three decades outweigh developments from the beginning of the 20th century.

The changing role of governments, and its shying away from investing in power generation, and reduction in the profitability of the market economy, led to greater emphasis on the efficiency of investment and returns on capital. It encouraged competition, and also the partnership of the private sector and independent power producers (IPPs) in the industry. Environmental awareness led to the promotion of renewables and encouraged more efficient electricity production, reduction of losses, utilisation of cleaner fuels, abatement of emissions and control of pollution. In addition, it greatly affected the fortunes of nuclear power. Emphasis has shifted from growth to demand management, from more sales to rationalisation of demand, containment of emissions and better consumer services – the 'services utility'.

These recent developments are analysed in this section and in greater detail in the later chapters with their relevance to the financial and economic evaluation of electrical power projects.

1.3.1 Reform trends in the electricity supply industry

Energy markets worldwide are currently in the midst of a fundamental transformation, as a result of technological change and policy reforms and the introduction of disruptive technologies [11]. The objectives of these reforms are to enhance efficiency, lower costs, increase customer choice, mobilise private investment and consolidate public finances. The mutually reinforcing policy instruments to achieve these objectives are the introduction of competition (often accompanied by regulation) and the encouragement of private participation. As a large number of developed and developing countries have successfully restructured their electricity and gas markets, an international ‘best practice’ for the design of the legal, regulatory, and institutional sector framework has emerged. It includes [9]:

- the corporatisation and restructuring of state-owned energy utilities;
- the separation of regulatory and operational functions, the creation of a coherent regulatory framework, and the establishment of an independent regulator to protect consumer interests and promote competition;
- the vertical unbundling of the electricity industry into generation, transmission, distribution and trade;
- the introduction of competition in generation and trade and the regulation of monopolistic activities in transmission and distribution;
- the promotion of private participation in investment and management through privatisation, concessions and new entry;
- the reduction of subsidies and tariff-rebalancing in order to bring prices in line with costs and to reduce market distortions;
- the growing participation of consumers in system management through the increased private generation and introduction of the smart grid; and
- the increasing cost of electricity in many countries due to subsidies, like feed-in tariffs to enhance prospects of renewables.

These trends greatly widened the scope for financial management in the ESI, introducing to the industry new financial services like risk analysis and risk mitigation, electricity trading and others (see Chapters 13–16).

1.3.1.1 Challenges and trends of the power industry in mature economies

OECD countries are mature economies; they face different challenges than those being faced by emerging and developing economies. The power industry in these countries is experiencing, for the first time, almost zero growth in energy demand and sometimes even negative growth. At the same time it is required to invest to replace ageing and polluting assets, relieve congested grids and meeting regulatory uncertainty. Therefore, power and utility companies are caught between conflicting

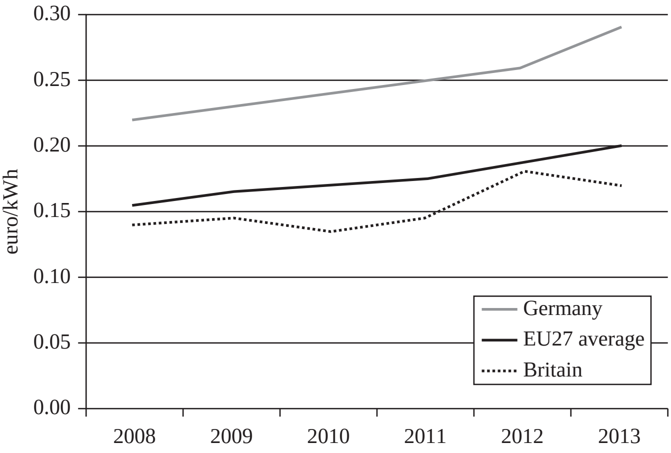

Figure 1.2 Creeping EU electricity prices [Source: Reference [13]]

goals – moderating electricity demand and increased call for capital expenditure. This is a new situation that challenges their historical business models [12]. There are increasingly growing regulatory and financial forces to accelerate the removal of old and vintage coal plants and replace these instead by firing natural gas and renewables. Therefore, many utilities are downsizing and outsourcing, while others are consolidating through mergers and acquisitions. They aspire to have better efficiencies and process improvements. The implementation of the smart grid is taking place in many OECD countries, but the future results are still unclear. It is hoped that the smart grid facilities will encourage consumers to better manage their demand, e.g. peak shaving and better load profile.

All the above are compounded by regulatory uncertainty. In spite of the present global slowdown, electricity tariffs are gradually increasing and becoming more contentious leading to challenges in meeting capital requirements (Figure 1.2). Local and global environmental awareness regarding global warming will affect the power industry through more stringent regulations, carbon pricing and taxation and need to switch to less carbon fuels.

Such new challenges are quite different from the more comfortable monopolistic utility atmosphere that prevailed until recent years. All this require utilities to keep looking for ways to test new methods and activities in order to break away from the existing challenging constraints.

1.3.1.2 Challenges and trends of the power industry in emerging economies

Developing economies, particularly the emerging economies of the BRIC countries (Brazil, Russia, India and China), face different set of challenges to their power industry. These countries constitute majority of the developing world population and their economies are growing at a relatively high rate. While mature economies are almost stagnating or growing at a low rate, China's growth is now around 8 per cent and that of India is 6 per cent; these two countries constitute around 40 per cent of the world population. Rapid economic and population growth is accompanied by almost a rapid rise in demand for energy and electricity, and with that comes the problems of mobilising investment funds and finding enough amounts of the right fuels. Such challenges are summarised below, and also in other chapters.

- The rapid rise in demand for electrical power is well in access of that of total energy, particularly in emerging economies. This poses a challenge to investment potential, both in OECD and non-OECD countries. Increasingly governments are trying to shift such investments to the private sectors so that more governmental resources are devoted to human development activities (health, education, public services, etc.)
- The electrical power sector is a major emitter of detrimental emissions, particularly CO_2. The sector will face increasing demands for imposing carbon price, which will increase the cost of production and hence tariffs. All this will foster development of clean power generation technologies, particularly carbon capture and storage, with their large cost.
- The global power sector suffers from low efficiency. This is less than 30 per cent when all system losses are taken into account, which means that most of the energy of the electricity sector fuels is emitted as waste heat. Gradually, one year after another, the sector efficiency is increasing, but reaching an overall sector efficiency of 50 per cent is still not yet in sight.
- Introducing new renewables (solar and wind) to the power sector will increasingly pose challenges, both technical and financial. New renewables are termed 'disruptive technologies' because of the disruption they cause to the traditional system structure. They can cause major dispatch challenges to existing networks and also require feed-in tariffs to foster their expansion. All this creates problems for system operators and mean higher tariffs to consumers.
- The supply structure and outlook is also changing. The introduction of renewables and smart grids invites the participation of consumers in system management. Some of the consumers are increasingly becoming producers and others now have a say in system management through the smart grid. This requires a new organisation of utilities so that they become more of a service provider. All this is accompanied with a growing role for regulators.
- Currently 1.3 billion people in the world, almost one-fifth, do not have access to electricity. Most of them are in South Asia and sub-Saharan Africa. Providing them with electricity is a necessity for their development as well as for better future for humanity at large.
- Simultaneously many people around the world enjoy power subsidies, i.e. their tariffs are lower than actual supply cost. This leads to wasteful consumption and more emissions. Phasing out subsidies from the sector is a needed reform.

1.3.2 Environmental concerns and the efficiency of generating plant

Electricity generation is an inefficient energy conversion process. The bulk of the existing inventory of generating plant, globally, has a gross generation efficiency of less than 35 per cent. Vintage coal-firing power stations have an efficiency that averages 25 per cent, and these are being phased out. Gross global generation efficiency, which is at present 36–38 per cent, was estimated to be around 31 per cent in the 1980s, 29 per cent in the 1970s and as low as 27 per cent in the 1960s. Significant improvements in efficiency have been achieved during recent years, almost to the extent of 0.1–0.2 percentage points per annum.

Modern, large and efficient super critical thermal generating facilities utilising pulverised coal have an efficiency of approximately 43–45 per cent (Figure 1.3). Modern combined-cycle gas-turbine (CCGT) plants are now claiming efficiency of 60 per cent or even higher, and in the relatively few applications of combined heat and power (CHP), efficiencies of fuel utilisation can exceed 80 per cent [14]. However, owing to the very large inventory of existing inefficient generating facilities worldwide, the average efficiency of electricity generation will not significantly improve in the short term. When the system losses of 6–10 per cent in industrialised countries, and more than 25 per cent in many developing countries, are taken into account, the amount of energy reaching consumers in the form of electricity is less than 30 per cent of the calorific value of the fuel in feed. In some developing countries it may be even lower than 20 per cent. Improving this is a main challenge to the ESI worldwide.

Table 1.1 demonstrates the low efficiency of the generation sector and the disparities in efficiency between OECD and developing economies. These are gross generation efficiencies, in that they do not exclude consumption inside the power plant, which will reduce net efficiency by almost 1–3 percentage points.

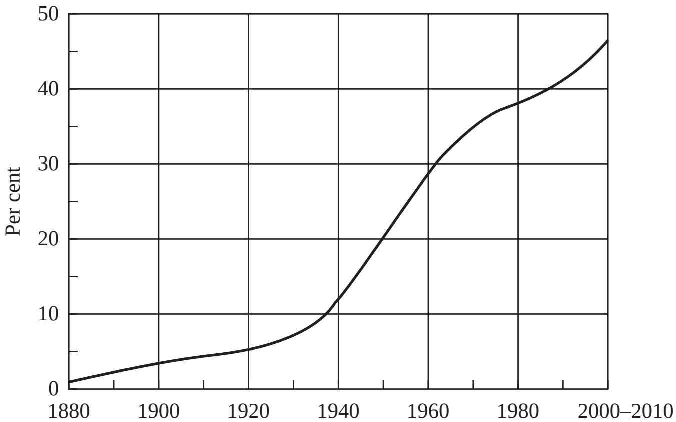

Figure 1.3 Development of electricity generation efficiency in thermal plants utilising pulverised coal [Source: References [14] and [15]]

Table 1.1 Gross generation efficiency 2010

	Generation (TWh)	**Fuel consumption (m.t.o.e)**	**Generation efficiency (%)**
OECD	10 850	2 260	41
Non-OECD	10 560	2 570	35
World	21 410	4 830	37.8

m.t.o.e: million tons of oil equivalent.
Sources: References [14] and [15].

There are many barriers to improve generation efficiency. Some of these are technical caused by limitation in pressure and temperature due to metallurgical constraints, also penalties to efficiency through the application of emissions containing facilities like desulphurisation and carbon capture technologies. But the main problems are financial – the lack of investment funds to replace old low-efficiency plant with modern high-efficiency facilities. Due to this many power stations, mainly in developing economies, which ought to be shut down because of age and low efficiency continue to generate beyond their technical limitations. Shortage of natural gas in many parts of the world is delaying the wide spread use of CCGTs, which are the facilities with the highest generation efficiency.

The problems of low efficiency are exacerbated by high network losses due to inefficient old transformers and antiquated transmission and distribution facilities, which cannot be quickly replaced due to the lack of enough investment funds. Correspondingly the useful electrical energy reaching consumers worldwide is less than one-third of calorific content of the fuel consumed. As already indicated, in some developing economies network losses may reach up to 25 per cent.

Regulatory measures increasingly being enforced in many OECD countries to improve efficiency in generation through specifying minimum efficiency standards for new plants and incentives for CHP increased applications, raising fuel prices and imposing penalties on carbon emissions serve the same purpose. Such measures can be summarised as follows:

- Setting minimum energy efficiency standards which demand the introduction of supercritical, ultra-supercritical or integrated gasification combined cycle (IGCC) high-efficiency plant.
- Introduction of emission standards on existing fossil fuel plants which will shorten the lives of old inefficient plant and discourage their refurbishment.
- Incentive and regulatory measure for the increased introduction and use of combined heat and power (CHP) facilities.
- Setting minimum efficiency standards for transformers.
- Smart grid technologies that optimise power flows and reduce the grid losses.
- Increasing demand to phase out subsidies on electricity consumption, which will lead to better demand side management and improve efficiency of the power sector.

Table 1.2 Energy return on energy invested (EROI)

Source	**EROI**
Coal	20:1–80:1
Natural gas	20:1–40:1
Oil	12:1–40:1
Tar Sands/oil shale	1:4–5:1
Nuclear	5:1–15:1
Large hydro projects	60:1–100:1
Wind	16:1–22:1
Solar photovoltaics	6:1–12:1
CSP/flat plate solar panel	1.6:1–1.9:1
Ethanol (sugarcane)	0.8:1–10:1
Maize-based ethanol	0.8:1–1.6:1
Biodiesel	1.3:1

Source: Reference [16].

1.3.3 Energy return on energy invested (EROI)

Energy is required to produce energy. To produce fossil fuels some energy is needed for mining, and developing the infrastructure and transport. The same applies to renewables and biofuels. EROI is usually defined as the ratio of amount of usable energy acquired from a particular energy source to the amount of energy expended to obtain that energy amount:

$$\text{EROI} = \frac{\text{usable acquried energy}}{\text{energy expended}}$$

This energy return on energy invested is shown in Table 1.2.

From Table 1.2, it is clear that fossil fuels in general have a high EROI; they are highly concentrated and correspondingly their extraction and development do not demand much energy and transport compared to other new forms of energy. Biodiesel and bioenergy in general demand the consumption of a lot of energy to produce a unit of the useful fuel. Large hydro projects have a very high EROI since, once the dam is built, it is almost free energy without the need for much effort or further energy use.

Wind and solar are in between, with wind energy more efficient in energy return. Solar needs a lot of energy in panel manufacturing and producing the material for the solar panels. Concentrated solar panels (CSP) in particular have a low EROI that is detrimental to its economics.

1.3.4 Capacity factor in power generation

In assessing the economics in electricity generation, it is not only the installed capacity that should be the focus but also the capacity factor, which is more important. The capacity factor is simply equal to electricity generation per annum in kilowatt-hours (kWh), divided by the installed capacity in kW and multiplied

Table 1.3 Capacity factors achieved in the UK [17]

Coal-fired stations	42.2%
Combined cycle gas turbines	61.2%
Nuclear	58.1%
Plant biomass	62.8%
Landfill gas	58.9%
Anaerobic digestion	48.7%
Large hydro projects	35.3%
Wind energy	26.5%

by 8 760 hours in the year. The result is the average number of hours that the facility would be running had it been fully loaded. This is different from the actual number of hours in which the facility is actually synchronised to the system, because some/most of the time the facility is partially loaded or not loaded at all.

As far as capacity factors are concerned, electrical generation facilities are roughly divided into three categories: base load, medium load and peaking plant. Base load facilities are that generation plants which are most economical to run, in that the plants need the cheapest fuel per kWh produced. The generation plants defer from one system to another. Usually these are nuclear, coal firing and combined cycles (CCGT) plants. Nuclear and coal fuel needs are cheapest and CCGT has a high efficiency. Therefore, these plants are regarded as base load and have a high capacity factor. Medium load plant can be low-efficiency coal-firing facilities as well as large hydro projects with limited storage facilities. Peak plants are facilities with the least capacity factor because they are usually run for the least hours during the day, usually during peak hours, or run partially loaded to enhance system security, like single cycle gas turbines or generation which fires expensive heavy oil. Biomass plants are run with the highest possible capacity since they utilise almost free fuel. While renewable sources like wind and solar are given priority, the use of these resources, blowing wind or shining sun, depends on the geographical location of the region. It is because of this reason the wind has relatively low capacity factors, around 18–25 per cent, and even less in the case of solar.

A typical list of recent capacity factors for different generation facilities in the UK are shown in Table 1.3.

1.3.5 Growing importance of natural gas and shale gas

The growing importance of natural gas (also liquefied natural gas (LNG) and shale gas) as a source of energy, particularly for electricity production, has enhanced the utilisation and development of the gas turbine and its derivative (the high-efficiency combined cycle plant) at the expense of the capital-intensive traditional steam power stations.

Natural gas was a premium fuel in the past. Recently, however, owing to its rapidly increasing reserves, abundance, relative cheapness and cleanliness, it has become the fuel of choice for electric power generation, whenever available.

Table 1.4 Emissions from fossil fuels [18]

Fuel	Air pollution emissions in million tons (Mt)/m.t.o.e. of fuel			
	SO_2	NO_x	CO_2	PM
Coal (3% S)	0.081	0.018	3.57	0.106
Coal (1% S)	0.027	0.018	3.57	0.096
Fuel oil (residual)	0.060	0.017	3.13	0.004
Fuel oil (distillate)	0.006	0.009	3.19	0.002
Natural gas	–	0.012	2.07	–

Note: m.t.o.e., million tons of oil equivalent.

Environmental considerations have played a considerable part in this regard. Compared with other fuels, natural gas is a benign fuel. It has practically no sulphur, correspondingly no sulphur dioxide (SO_2), and it emits no particulate matter (PM). Its emissions of carbon dioxide (CO_2), which is the main greenhouse gas, and nitrogen oxide (NO_x) are almost half that of coal. This is detailed in Table 1.4. The natural gas is increasingly becoming an important fuel because of its vast proven reserves (Figure 1.4).

Increasingly, more global natural gas production is utilised for electricity generation. Utilisation of natural gas and LNG for power generation will gradually grow at a rate higher than that of any other fuel. However, its usage will continue to be limited by its availability in only a few countries, its high cost of transmission through pipes, the need for long-term contracts and the high cost of LNG. Only one-fifth of the present production of natural gas is traded internationally. Natural gas projects cost more than twice the amount of crude oil projects. Its transport may be six times as expensive. All these factors are slowing the development and utilisation of natural gas as the ideal fuel for electricity production.

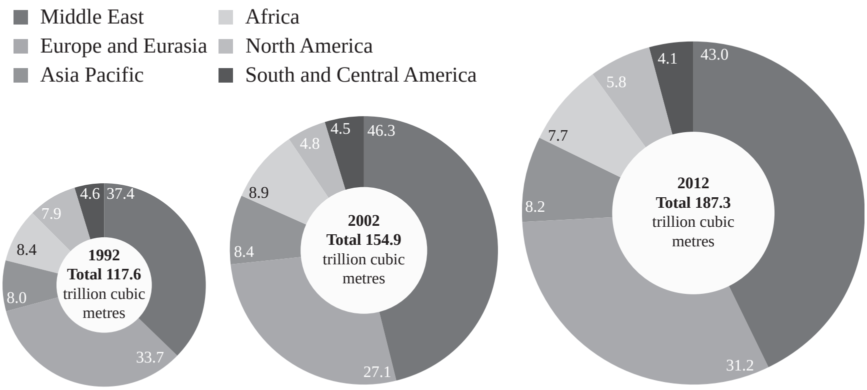

Figure 1.4 Growing global reserves of natural gas [Source: Reference [19]]

In its different scenarios the International Energy Agency-World Energy Outlook (IEA-WEO) [3] estimates that the utilisation of natural gas for power generation will experience a significant demand growth of around 2 per cent annually. However, this prediction matches the demand growth for coal, which due to its cheapness and abundance will continue to dominate power generation, particularly in the growing economies of BRIC countries, claiming almost half of the in-feed fuels for electricity generation by 2035. It is reckoned that renewables will have the strongest growth prospects at an average rate of 5–6 per cent annually.

1.3.5.1 Shale gas

Shale gas is a natural gas that is found in shale formations. However it is unconventional natural gas, as coal bed methane and methane hydrates. It is becoming increasingly important in the US due to its abundance and cheapness. At the beginning of this century shale gas contributed to only 1 per cent of natural gas production, but in 2010 it was 20 per cent; US-EIA predicts that by 2035, 46 per cent of the US natural gas supply will be met with shale gas. Prices of shale gas in the US went down to as low as $2/mbtu, but it has now recovered to about twice that figure [20].

The shale gas boom was made possible by modern technology in directional drilling – horizontal drilling to create maximum borehole surface area and also in hydraulic fracking which creates artificial fractures around the well bore.

The US-EIA has recently published country-wide estimated recoverable shale gas data. The data are summarised in Table 1.5 in trillion cubic feet; however it has to be emphasised that not all recoverable shale gas can be economically extracted and treated as proven reserve.

With this abundance of shale gas in most of the world energy economies, this resource is destined to play an increasing role in electricity production, replacing imported gas or coal in many instances. However, shale gas is not without environmental impact or as benign as natural gas. It emits methane at large quantities than natural gas, but less than coal. The fracturing fluid used for shale gas production is water, in large quantities, added with chemicals. This can cause

Table 1.5 Recoverable shale gas sources [19]

Country	Estimated recoverable shale gas (trillion cubic feet)	Proven natural gas (trillion cubic feet)
China	1 115	124
US	665	318
Canada	573	68
Mexico	545	17
Russia	285	1 688
Brazil	245	14

contamination of clean water aquifers and result in water pollution, and it is also feared that, in few instances, it can lead to earthquakes with induced seismicity potential.

Estimates of UK shale gas resources are around 255 trillion cubic feet. It is expected that only around 10–15 per cent of this resource would be recoverable and treated as reserve. The cost of recovery is also still controversial [21].

1.3.6 Rehabilitating, retrofitting and repowering of existing power facilities

Stringent regulations (environmental and otherwise) and way leaving conditions, which increased the cost of new facilities, led to frenzied attempts to rehabilitate, refurbish and repower existing facilities. Shortages of capital also contributed towards extending the life and improved utilisation of existing sites. Difficulty in licensing new nuclear facilities led to extending the life of existing facilities to 60 years and over.

Repowering involves modification of an existing plant by changing the method used to generate power. This process may modernise the power plant, increase its efficiency, lower operating costs and/or increase output. Evaluation of the economics of repowering and retrofitting existing sites needs more sophisticated evaluation than other projects. This will be detailed in later chapters.

Some markets, particularly the EU energy market, require environmentally compliant and economically competitive plants. Some power plants in Central and East Europe are generally ageing, are not well maintained, have high pollution and have low efficiency. Their technology is outdated. Consumers are direct victims of this ageing infrastructure as they pay a high cost for power.

The business options for an investor in/owner of generation plant in the EU to meet the new pollution limits include demolishing and rebuilding, retrofitting with emission-control equipment, or repowering to make use of low-emission gas-fired CCGT technologies. Demolition and replacement with new, efficient equipment require high capital costs. Retrofitting appears to be a valid option because of the high EU market environmental requirements. If new pollution-control equipment can be retrofitted for a relatively low cost and the plant is still reasonably competitive, then this option should be considered. However, retrofitting is limited to the installation of modern pollution control devices in order to meet emission limits. It does not improve efficiency or reduce the cost of power production.

If the existing plant is not competitive, retrofitting will not help; repowering may be a viable option. Repowering, that is making substantial changes to power plants at the end of their useful economic or environmental life, improves efficiency, decreases environmental emissions and reduces operating cost. If existing equipment can be reused, such as the steam turbines, repowering may be cheaper than rebuilding. Complete replacement of major systems such as boilers and turbines, conversion to combined cycle operation (through the addition of combustion turbines and heat recovery equipment) or introduction of circulating fluidised bed (CFB) boilers are the options to be considered for ageing power plants to comply with the EU standard.

For repowering to be economically attractive, owners must look for repowering returns equal to their expected returns on other options. Depending on the state of the facility, income and investment vary and so do the returns:

- if the existing facility is physically or economically forced out of service, ‘as is’ net operating income is zero;
- if the facility is operable and capable of cycling duty and sales into a competitive market, the ‘as is’ income may be surprisingly high; and
- if the facility requires extensive investment (retrofit) for environmental compliance, ‘as is’ investment may be quite high.

The capital investment required to repower ageing plants is offset by the life extension of the plant, the decrease in operations and maintenance (O&M) costs and increased efficiency and power generation. Repowering with natural gas turbines can be cost-effective compared with building a new combined cycle unit of the same size because existing equipment may be reused.

To improve environmental performance there is a growing interest to fit carbon capture and storage (CCS) facilities in thermal power plant. CCS is quite expensive and reduces the efficiency of generating plant; therefore it is more feasible that such facilities are added to new, highly efficient super-critical coal generating plants than retrofitting existing plants, which will also penalise their already modest efficiency [22].

1.3.7 The importance of demand side management (DSM)

Prompted by the high cost and shortage of capital, many power utilities have found it cheaper and more profitable to invest in efficiency and demand side management (DSM) rather than extending the supply and building new facilities.

DSM activities vary and involve the following:

- Changing the shape of the daily and seasonal peak load curves (reducing peaks and filling the load curve valley).
- Introducing and encouraging the use of more efficient electric apparatus.
- Reducing waste and overuse, through pricing, regulations, and educating the consumers. Under this category falls reducing system loss.
- Conservation: Beyond eliminating overuse, conservation helps manage and reduce demand without affecting the quality of life.
- Substitution: Some electricity benefits can be substituted more economically by other means. For instance, passive solar design of buildings can significantly reduce demand for lighting, electric and water heating. Methods of evaluation of the benefits and economics of DSM projects are referred to later.

Most of these considerations will have beneficial effects on the ESI. They can lead to cleaner and leaner production facilities, more rational and efficient use as well as fostering competition that assist in optimising the use of resources, thus lowering costs and giving greater benefits to the consumer. Investment requirements will be rationalised and electricity costs can be reduced. All this, however, is going to be gradual and will vary from one country to another. The ESI is different to telecommunications industry. Energy systems, particularly electricity systems, have huge inertia; they are highly capital-intensive and live for a long time. They also demand a lot of licenses and way leaving. This, of course, delays reaping the beneficial results of some of these recent developments. Such delays have also been assisted by slow technological change in the way electricity was being produced, transmitted or distributed in the past.

New and renewable energy sources (other than hydro) are taking more time to live up to their earlier promise and expectations. Such sources, which can be mostly only utilised as electricity, will be dramatically boosted in the future if the present worries about global warming are reinforced by more substantive arguments, legislation and carbon pricing. However, liberalisation of the markets is creating a new potential for the power industry. Technological change will increasingly affect the way electricity is being generated and distributed. Distributed generation, renewables, the virtual power plant and similar technological innovation assisted by market liberalisation are gradually, but surely, leading the power industry into a new future.

1.4 The global electrical power scene

Total global electrical power production in 2010 amounted to around 21 400 terawatt-hours (TWh), with an average of 3 125 kWh per capita per annum. The global installed electric power facilities are very difficult to quantify exactly; however they are estimated by the IEA at 5 813 GW [3]. Half of the world electricity production was in OECD countries with an annual average of 8 750 kWh per capita, and another 11 per cent in East Europe and the former Soviet Union. Developing and emerging economies, which account for more than 77 per cent of the world's population, utilised only 39 per cent of the global electricity production, with an annual average of 1 630 kWh per capita. Thermal power, mostly utilising solid fuels, accounted for 67.5 per cent of global electricity production, which is a significantly higher proportion than last years. Hydro-produced power accounted for 16 per cent and nuclear for 13 per cent, which is lower than previous years. Total fuel utilised to produce this electricity amounted to around 38 per cent of the world's primary commercial fuel use. The power sector also emitted 12 500 Mt of the world's 30 200 Mt CO_2 emissions, i.e. 41.4 per cent, which demonstrates the high carbon intensity of the power sector. Detailed statistics of electrical power energy, input fuels used and types are shown in Table 1.6.

The most recently published figures before publication were the US-EIA International Energy Outlook (IEO 2013). These are slightly different from figures published by the IEA-WEO 2012. They are detailed below as presenting another and more recent source.

These EIA predictions are quite revealing and warrant further discussion. Demand for electricity over the 30-year period (2010–2040) is expected to grow at a rate of 2.20 per cent annually against a growth of total primary energy of only

Table 1.6 The electricity sector expected future [11]

	2010	**2020**	**2030**	**2040**
Energy demand (m.t.o.e)	13 100	15 750	18 220	20 500
Annual growth 2010–2040	1.5%			
Electrical (TWh)	20 200	26 600	33 000	39 000
Annual growth 2010–2040	2.2%			
Electrical capacity (GW)	5 061	6 221	7 214	8 254
Annual growth 2010–2040	1.6%			
Global energy emission CO_2 (Mt)	31 200	36 400	41 500	45 500
Annual growth 2010–2040	1.3%			
Power generation CO_2 (Mt)	12 495	15 560	18 330	20 110
Annual growth 2010–2040	1.92%			
Power emissions (global) (%)	41.4	42.9	44.5	45.6
Primary energy for power (m.t.o.e)	4 840	6 170	7 430	8 140
% of global energy	38.0	40.2	42.5	43.6

1.50 per cent; this means that electrical energy growth is on average 1.47 times of total primary energy which demonstrates the growing rate and importance of electrification in the global energy scene. Simultaneously electrical power generation will be a major source of emissions which are likely to increase at a rate of 1.92 per cent annually. This rate is lower than demand growth indicating decarbonisation efforts of the power sector.

Power production which assumed in recent years only 38 per cent of primary energy use will grow to 43.6 per cent in 2035 [3]. Gradually power generation will assume half of the primary energy use in the second half of this century.

Carbon emission from power generation was detailed by EIA [11]. They are expected to be almost 44 per cent of global emissions by 2040 and are likely to assume half of the global emissions in the middle of this century. This emphasises the view that any policy which aims at environmental preservation and curbing emissions must have carbon emissions from the electricity sector as the centre of its interest. The power generation sector has the advantage that emissions are generated at a central point, the power station, which makes dealing with them, by CCS technologies for instance, much easier.

Installed power generation capacity (which is lower in EIA figures compared to IEA predictions) is expected to grow from around 5 060 GW in year 2010 to around 8 250 in 2040, and nearly double 2010 capacity after 2050. This rapid growth is accompanied by improvements in generation efficiency. While each kWh of electricity produced consumed 0.226 kg of oil equivalent in 2010, this is expected to be as low as 0.200 kg by 2035, which is less by over 10 per cent and demonstrates the growing improvement in efficiency in the sector. This will be discussed in more detail in the other chapters.

1.4.1 Electricity and the world economy

There has always been a sort of coupling between energy use and economic growth. Demand for electricity has always displayed good correlation with global economic growth, as measured by gross national product (GNP) in purchasing power parity dollars ($ppp). This strong coupling between electricity and economic growth is clearly shown in Figure 1.5.

During the period 1975–2000, electricity growth averaged 4 per cent per annum, which is a high rate of growth. In the future, electricity demand growth is expected to be less than the growth of the world economy. It is expected to average around 2.2 per cent annually during the next 30 years, while the world gross domestic product (GDP) is expected to grow at a higher rate of 3.6 per cent annually. This indicates a decoupling of electricity growth from world economy, due to saturation of electricity use in OECD countries and improvements in efficiency and demand side management all over the world.

Table 1.7 gives more detailed figure of the future of the electricity sector. These are mainly from the OECD-IEA WEO and may slightly differ from the US-EIA figures presented above.

It is useful to compare these new results with those that appeared in the second edition of this book in 2003.

First column in Table 1.8 is present 2010 electricity source figures. Second column, is predictions for 2010 as were viewed in 2001.

The trends are clear; there is surge in the utilisation of natural gas, a clear drop in nuclear contribution, so also in oil. Other new renewables doubled their contribution; however this is still quite small – it will take many years until new renewables will have a marked impact on the global energy scene. In the meantime thermal generation, bolstered by coal and gas, dominates the global electricity generation scene contributing two-thirds of global output.

The IEA *World Energy Outlook 2013*, published on 12 November 2013, expects the power sector representing more than half of the increase in global

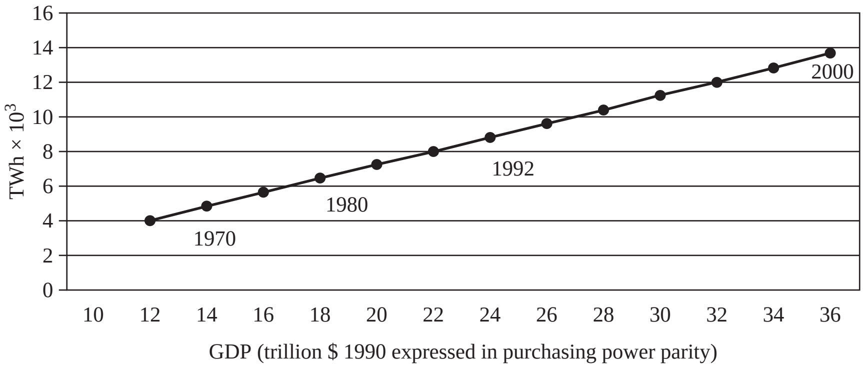

Figure 1.5 Electricity demand as a function of world GNP (excluding former centrally planned economies) [23]

Table 1.7 Global electricity statistics [3]

	Global electricity balance (2010)							
	Population (million)	**Capacity (GW)**	**Production (TWh)**	**kWh per capita**	**%**	**Energy (m.t.o.e.) Total primary energy**	**Energy (m.t.o.e.) Electricity (m.t.o.e)**	**Electricity (%)**
OECD	1 237	2 718	10 848	8 770	50	5 404	2 267	42
East Europe	335	422	1 681	5 018	8	1 137	552	49
DCs	5 271	2043	8 879	1 685	42	6 189	2 020	31
World	6 843	5 183	21 408	3 128	100	12 730	4 839	38

	Sources of electricity generation				
	GW	**TWh**	**% of electricity**	**Input (m.t.o.e)**	**Input (%)**
Nuclear	394	2 756	13	719	15
Hydro	1 033	3 431	16	295	6
Thermal	3 435	14 447	67	3 626	75
solids	1 649	8 687	41	2 249	46
oil	435	1 000	5	275	6
gas	1 351	4 760	22	1 102	23
Other/renewables	321	774	4	199	4
Total	5 183	21 408		4 839	

	Locations of electricity generation (2010)			
	Nuclear (TWh)	**Hydro (TWh)**	**Thermal and other (TWh)**	**Total**
OECD	2 288	1 351	7 209	10 848
East Europe	289	303	1 089	1 681
DCs	179	1 777	6 923	8 819
World	2 756	3 431	15 221	21 408

Sources: References [3] and [11].

Notes:

1. Generation refers to gross generation.
2. Capacity refers to net capacity.
3. Fuel required for production of electricity is estimated at 250 g of oil equivalent per kWh for thermal generation and 226 g/kWh for world average.
4. Fuel equivalent of hydro generation is equal to the energy content of the electricity generated.
5. m.t.o.e., million tons of oil equivalent; DCs, developing countries.
6. Terawatt-hour (TWh) = 1 000 million kWh, gigawatt (GW) = 1 million kW.
7. Global electricity figures are not well documented. The above is a collection and approximation of data from many sources, mostly from above sources with some rounding.

energy use to 2035. Non-OECD countries will account for the bulk of incremental electricity demand, led by China 36 per cent, India 13 per cent, Southeast Asia 8 per cent and the Middle East 6 per cent. (All numbers refer to the IEA's central 'New Policies Scenario'.) In terms of electricity demand per capita, the IEA says that the gap narrows between non-OECD and OECD countries, but only Russia,

Table 1.8 Comparison with earlier predictions

	2010[a]	**2001**[b]
Nuclear	13%	16%
Hydro	16%	18%
Thermal	67%	64%
Solids	41%	39%
Oil	5%	9%
Gas	22%	16%
Other/renewables	4%	2%

[a]Actual 2010 sources.
[b]2010 sources as were predicted in 2001.

Table 1.9 World electricity demand outlook 2011–2035

	1990	**2011**	**2020**	**2025**	**2030**	**2035**	**2011–2035**[b] **(%)**
Gross generation[a]	11 818	22 113	27 999	31 121	34 058	37 087	2.2
Demand	10 085	19 004	24 249	26 974	29 520	32 150	2.2
Industry	4 419	7 802	10 288	11 385	12 268	13 187	2.2
Residential	2 583	5 195	6 507	7 362	8 325	9 336	2.5
Services	2 086	4 560	5 636	6 214	6 698	7 137	1.9
Transport	245	292	408	486	590	734	3.9
Other	748	1 151	1 419	1 535	1 648	1 763	1.8
T&D losses	1 003	1 816	2 308	2 589	2 862	3 138	2.3
Generators' own use	733	1 298	1 434	1 550	1 668	1 791	1.4

Source: IEA-WEO 2013 (New Policies Scenario).
[a]Includes end-use, transmission and distribution (T&D) losses and own use by power generators in TWh.
[b]Compound average annual growth.

China and the Middle East will exceed even half of the OECD average by 2035. Global installed generating capacity will grow by over 70 per cent, from 5.65 TW in 2012 to about 9.76 TW by 2035, with 1.94 TW of capacity being retired. Cumulative total investment of around $17 trillion is envisaged during 2013–2025, with new plants accounting for 58 per cent of the total and the remainder going into transmission and distribution networks.

The IEA expects the share of renewables (hydro, bioenergy, wind, solar and other sources, but not nuclear) in primary energy worldwide to reach 18 per cent of generating capacity in 2035, compared with 13 per cent in 2011. Power generation from renewables worldwide is expected to increase by over 7 000 TWh from 2011 to 2035, making up almost half of the increase in total generation (Table 1.9).

1.4.2 Investments in the electricity sector

Investments in the power sector infrastructure are very high, particularly in the developing economies which are still building facilities. Investments are mostly in new generation in BRIC countries and other developing countries. OECD investments are limited because their power sector has already matured. However, these

Table 1.10 Future investments in the electricity supply industry

	Investment in the electricity supply industry (2012–2035) (based on 2012 dollars in billions)		
	Generation	**T & D**	**Total**
OECD	4139	2648	6787
East Europe	651	531	1182
Developing economies	4896	4002	8898
Total	9686	7181	16867

Source: Reference [3].

countries need to invest in replacing retired and inefficient plant, improving and strengthening the network and absorbing new renewable sources, particularly wind source that requires significant additions to the transmission grid.

Estimations of ESI investments over the next 25 years are presented in Table 1.10. These are required to increase generation from around 5 180 GW in 2010 to 9 480 GW in 2035–2040, i.e. by around 4 300 GW; to this must be added another 10–20 per cent to replace ageing and retired plant making this a total of around 5 000 GW. With an estimated average of $1 500 per kW of new power generation this amounts to around $7.50 trillion. To this must be added a similar figure for transmission, distribution and control, making a total investment in the sector of around $15 trillion over the next 25 years based on 2012 dollar. The IEA carried out detailed evaluation and came out with a figure of $16.87 trillion which is very close to our rough estimation. However, these IEA figures are influenced by a higher capital-intensive nuclear component of around 10 per cent of the total generation, which does not seem to be feasible at this stage.

The OECD figure displays a higher component for generation, 61 per cent of its total investments indicating the need to replace ageing facilities and the difficulty in securing way leaving to network extension. China is expected to spend $3.9 trillion until 2030 in installing 88 GW of new power stations every year, half of them will be hydro-power plants [24]. At the latest World Energy Congress in October 2013, the World Energy Council estimated global electricity investments to average $19–25 trillion over the period to 2050.

Such investment has to be viewed with the global economy trends and capital formation expectations. The world GDP in 2012 was $71.666 trillion [25]. Annual investments in the power sector over the future 23 years will average around 0.7 per cent of the global GDP and around 4.25 per cent of global investments. This is a substantial amount.

1.5 Cyber security of electrical power system

All the components of the power system, particularly control equipment and apparatus, are vulnerable to cyber attacks. It can damage the critical infrastructure particularly the power grid and its controls. With the introduction of smart metering the financial structure of the ESI is now also under threat of hackers. The industry relies increasingly on digital electronic devices and communications to optimise system operation and enhance reliability; therefore cyber security is increasingly becoming an important and a growing challenge [26].

Network security involves the expansive information technology infrastructure which manages the power system operation and protection. With the increasing employment of advanced metering infrastructure, new element of protecting consumers' privacy and simultaneously ensuring demand response are becoming important.

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Chapter 2

Considerations in project evaluation

Projects involve investments that are meant to satisfy a demand, and to achieve an engineering or economic purpose (usually better efficiency or enhanced performance). Therefore, a project is a process of creating specified results. It is a complex effort involving many tasks to achieve a certain objective. A project is a non-repetitive unique process with start and end points, budgets and financial plans, life-cycle phases, and stages. Projects can be capital intensive (electrical power, energy, telecommunications), infrastructural, civil work intensive (transportation, water supply, etc.), and people intensive (agriculture, education, nutrition, etc.) [1, 2].

2.1 Project selection and evaluation

Project selection is a problem of allocation of scarce resources including capital, skilled labour, management and administrative capacity, as well as other resources (land, energy, etc.). In the electricity supply industry, most projects are rather imposed on the industry by rising demand. However, there are many ways of satisfying a demand, through building new generation facilities, repowering existing facilities, strengthening the network or rationalising demand by demand side management (DSM) plans. Many projects are prompted by the need to improve the quality of supply to achieve better continuity or adequate system standards. Some projects, for efficiency improvement, are justified by economic and environmental considerations.

Therefore, the requirements for projects in the electrical power sub-sector are more focused and less diverse than those encountered in other sectors. Recently, with deregulation and privatisation, a wider market has become available for entrepreneurs and investors to sponsor projects, mainly generation projects in electricity utilities. With increased globalisation, investor funds in the electricity supply industry will be seeking global as well as local markets. Although some projects undertaken by independent power producers (IPPs) have enough financial and demand guarantees, like take-or-pay clauses and governmental guarantees, they still contain an element of risk – project cost, delays, plant availability, inflation, etc. Therefore, project selection, analysis and evaluation are becoming more important in the electricity supply industry than at any time in the past [3].

Project analysis is a method of presenting the choice between competing uses of resources, and is done through analysis of information and data. Project evaluation studies are meant to assist in the selection and design of new viable projects. A study will evaluate the extent to which the project produces the intended results, the proper technology, the least-cost alternative process as well as the cost-effectiveness of the project. It will also consider the engineering as well as the financial risk and evaluate the economic (social) cost.

2.2 Project development

The development of projects is a cycle involving three distinct phases: the pre-investment, investment and operational phases. Capital-intensive projects in the electricity supply industry pass through these three phases with each of the first two phases divided into stages of planning, risk evaluation, design engineering and execution [4, 5].

2.2.1 The pre-investment stage

The pre-investment stage begins with the identification of the need for the project (demand that has to be satisfied by new generation facilities, or a bulk supply sub-station, or an investment opportunity from an independent power supplier). This preliminary identification is followed by a pre-feasibility study, which is viewed as an intermediate stage between the identification of the project and a detailed feasibility study. In the pre-feasibility study, a detailed review of the need for the project and demand for its output is undertaken, as well as of the possibilities and alternatives (site, size, fuels, etc.) and also risks. Therefore, at this phase, a lot of support studies are undertaken: market and demand, fuel supply, cooling water, location studies including soil mechanics, environmental impact assessment, as well as financial and economic analysis into the selection of the least-cost facilities, technologies and location, and profitability of the project.

2.2.1.1 The feasibility study

The feasibility study should provide all data and details necessary to take a decision to invest in the project. The feasibility study defines and critically examines the results of the studies undertaken in the pre-feasibility stage (demand, technical, financial, economic and environmental). The results of the feasibility stage are a project where all the background features have been well defined: size and location of the facilities, technical details, fuels, network features, and environmental impact and how to deal with it, timing of the project, and implementation schedule. The financial and economic parts of the feasibility study cover the required investment and its sources, the expected financial and economic costs and returns.

It is not possible to draw a clear dividing line between the pre-feasibility and the feasibility studies. The pre-feasibility study is concerned with defining the alternatives (demand, location, size, technology, fuels, costs and environmental impact), while the feasibility study defines the project in a manner that allows implementation to proceed. A typical outline of a feasibility study is shown in Table 2.1.

Table 2.1 Typical outline of a feasibility study [4]

1. Introduction
2. The sectoral setting
   - (a) The industrial (electrical power engineering) sector and linkages to the rest of the economy
   - (b) The sub-sector (e.g. the generation sub-sector)
   - (c) Issues and problems
   - (d) Proposals for change
3. The market, pricing and distribution
   - (a) The market
     - (i) Historic supply and consumption
     - (ii) Projected demand and supply
     - (iii) Market for the proposed project
   - (b) Transmission, distribution and marketing
   - (c) Pricing
4. The utility
   - (a) Background
   - (b) Ownership
   - (c) Organisational framework
   - (d) Management
5. The project
   - (a) Objectives
   - (b) Scope of the project
   - (c) Technical description
     - (i) Production facilities
     - (ii) Utilities and infrastructure
     - (iii) Ecology and the environment
   - (d) Manpower and training
   - (e) Major inputs
   - (f) Project management and execution
   - (g) Project timing
   - (h) Environmental and social impact and measures for environmental preservation
6. Capital cost and financing plan
   - (a) Capital cost
   - (b) Working capital requirements
   - (c) Financing plan
   - (d) Procurement
   - (e) Allocation of financing and disbursement
7. Financial analysis
   - (a) Revenues
   - (b) Operating costs
   - (c) Financial projections
   - (d) Break-even analysis
   - (e) Accounting and auditing requirements
   - (f) Financial rate of return
   - (g) Major risks and risk analysis
8. Economic justification
   - (a) Economic analysis and economic rate of return
   - (b) Linkages and employment
   - (c) Technology development and transfer
   - (d) Foreign exchange availability and effects
   - (e) Regional development impact
9. Agreements

The feasibility study for large electrical projects (like building a new large power station or a major bulk transmission network and substations) has not only to be confined to the project, but also to look into what we call ‘system affects’ the electrical power sector in which the project will be operating (through undertaking power system analysis), the future demand and market for electrical power. The feasibility study has to undertake an engineering analysis that looks into the technologies, the scope of the project, its timing and implementation arrangements, its management and manpower requirements and its financial and economic viability, and also its environmental impacts [6].

In this book, we are mainly concerned with the financial and economic evaluation of projects to ensure their viability. However, it is essential to understand the impact of the other five considerations in electrical power project feasibility:

1. the sector;
2. the market (demand);
3. technology and engineering analysis;
4. management and manpower; and
5. environmental impact and costs.

These are briefly dealt with below to introduce the project evaluator to the different aspects that need to be considered before undertaking a project. In such capital-intensive projects, the financial plan is of vital importance; it has to ensure that there are enough funds to carry out the project to completion. Funds are needed not only to finance the project cost, but also to provide the working capital and pay for interest during construction, and for ancillary costs and expenses. In most such expensive projects, besides the capital (equity) from the project owner, there are usually large loans provided by banks, financial institutions and development agencies. All of these needs to be investigated, arranged and coordinated in the financial plan.

2.2.1.2 Project appraisal

Apart from the project pre-feasibility and feasibility studies that are carried out by the project owners, more evaluation, which is termed ‘project appraisal’, is executed by the financiers (other than equity owners) such as lending banks or development funds. The idea of appraisal is to satisfy the financiers as to the accuracy and soundness of the feasibility study. Appraisal usually deals in depth with macro-economic matters, environmental impact and externalities. These are costs and benefits that are outside the confines of the project itself, but affect other objectives or policies of the country. Appraisal work is greatly assisted by having a properly prepared feasibility study that covers every facet of the project. However, appraisal goes beyond feasibility into considering policies, regulations, and other macro-economic considerations and externalities. Appraisal undertakes a thorough economic (social) evaluation of the project costs and benefits, as well as carries out detailed sensitivity and risk analysis; this is to ensure the financial and economic viability of the project.

The project appraisal, particularly when carried out by regional international development agencies or independent evaluators, leads to a thorough critical evaluation of the project and the sector. It often comes out with suggestions and proposals that improve the project's setup and enhance the future performance of the sector. Some of these proposals are crucial to the success of the project, so that they are treated as covenants and are incorporated in the financing and loan agreements, and the effectiveness of the loan agreements and its disbursement is conditional on the prior honouring of such covenants. Therefore, appraisal not only is beneficial for the project but also can lead to sector reforms that have a bearing on the economy and the way it is managed. It can affect tariffs, management and importation laws and can also lead to restructuring. This is the case in many developing economies that badly need to finance their power sector and have to borrow extensively from lending development institutions (like the World Bank) for this purpose, or introduce IPPs.

It is not intended to detail each facet of project evaluation and appraisal, since these are detailed elsewhere [7–9]. The emphasis will rather be on the financial and economic (also environmental) evaluation. However, here are some of the aspects and activities that are investigated in the feasibility study and appraisals.

The sector

A study of the power sector involves a study of its development, organisation and its linkages to the rest of the economy, the institutions working in the sector and regulatory setup. In addition, the legislation, regulations and incentive structure inside the sector (that are likely to affect the project) are involved. The tariffs, their structure and their prospect of change and the regulatory system for setting them are included in the study, as are the sector policies and strategies, their effect and the interaction of the project with these. Taxation and importation tariffs and policies are examined for their impact on the project, and also the regulatory system to ensure protecting the rights and duties of the players in the sector. During appraisals there may appear certain shortcomings in the sector or in the regulatory system that warrant pointing out.

The market (demand)

This deals with power demand, its past development, present growth and future demand forecasts, and how the project will enable satisfying these. Project evaluation looks beyond the project into the system and how the electrical power system, as a whole, interacts with the project and with the availability of the new supplies and network. The demand study also looks into the shape of the demand, its timing, how it fits the load curve and prospects for its modification. It also looks into the tariffs that apply, and whether the tariffs are satisfactory, and whether the project will affect these. In the case of system strengthening projects, the study involves an assessment of the existing detrimental financial and economic effects of the supply interruption and its consequences. Future demand and market evaluation involve predictions and, correspondingly, a measure of risk assessment that is important in the financial evaluation and in choosing the right technologies and sizes that minimise the financial risk.

Technical and engineering analyses

These are covered by the detailed studies referred to in the pre-feasibility stage. The feasibility study highlights the least-cost solution to satisfy the project objectives (usually satisfying the demand). Appraisal ascertains that the proposed technical solutions are truly the least-cost ones and that costs, timing, and implementation schedules are satisfactory. The engineering analysis looks into the project timing and implementation schedule. The technical and engineering analyses are related to the financial and economic analysis, since these are intended to evaluate the technical and engineering alternative that satisfies the demand at the least cost.

Management and manpower

This refers to the availability of technical and managerial staff to man the facilities and ensure their proper operation, maintenance and management of supporting facilities: stores and inventories, transport, provision of services, etc. It also defines their availability and costs, the training requirements for the staff and the implication of all this on project costs.

The environmental impacts

Environmental impacts need to study and ascertain the environmental impacts of the project. Also to look into the future prospects for environmental regulation, pricing and limitations of emissions, choice of fuels and their cleanness [10].

2.2.2 The investment phase

Once the project is fully defined, successfully evaluated and appraised and the finance is available, the next phase of project implementation – the investment phase – begins. This has many stages:

- carrying out the organisational, legal and financial measures to implement the project;
- basic, as well as detailed, engineering work;
- land acquisition;
- tendering, evaluation of bids and contracting;
- construction work and installation;
- recruitment and training of personnel; and
- plant commissioning and start-up.

Good project planning and management must ensure the proper implementation of all the above stages well before the project start-up. Delays or gaps in implementation or management can cause increased costs or other damage to the utility, the investors and consumers. Execution schedules of different sections of the project need to be closely prepared, coordinated and monitored. Typically, a network plan with identification of the critical path needs to be drawn out for the procurement, implementation, testing and commissioning of large projects. Various methods have been developed for the effective and balanced organisation of the investment phase, such as the critical path method (CPM) and the project evaluation and review technique (PERT).

This phase involves disbursement and investment expenditures which need careful assessment and evaluation. Such expenditures occur in the earliest years of project implementation and are not significantly reduced by discounting. Therefore, they have considerable effect on the project's financial viability. Their effect can be more important than future financial flows (which occur at the later stages of project operation) whose importance is greatly diluted by discounting. Such disbursements and investment expenditures have to match the financing plan of the investment phase.

2.2.3 The operational phase

If the project is well planned and executed in the pre-investment and investment phases, respectively, a few problems in the operational phase will be encountered, other than the teething problems that are not uncommon in most new facilities. The success of the project and its benefits (profitability), of course, depend not only on good engineering and management, but also on sound financial and economic evaluation during the pre-feasibility and appraisal stages. This sound financial and economic evaluation is the subject of the next few chapters.

Electrical power facilities have a long useful operational life. To ensure that such facilities will survive their useful life demands proper operation and efficient maintenance that can involve high expenditure. All this is to be considered during the evaluation stage. However, as mentioned above, the effect of expenditures in later years of the project operation can have limited significance in evaluation owing to discounting, particularly if high discount rates are applied. It is, however, necessary to define the expected useful life of the project at the evaluation stage. This can be greatly influenced by prospects of technological change and obsolescence, as well as by changes in the fuel market and environmental legislation in the case of power generation. Such unexpected outcomes can be taken care of during risk analysis (see Chapters 15 and 16).

2.2.4 Post-operation evaluation

It is useful, at a later stage, after project completion, to revisit the project to compare the performance and results with project estimates. This mainly applies to demand, cost, execution time and evaluation of impacts, as well as returns. Such post-operation evaluation is routinely carried out by major leading international development agencies, such as the World Bank. However, it also needs to be carried out by utilities and investors. A post-evaluation will educate the project planners and decision makers and widen their scope for future project preparation to minimise pitfalls and risks in the preparation of other similar future projects. Unfortunately, other than for development agencies, not much post-operation evaluation is carried out. Post-operation evaluation is vital to enhance experience and reduce future risks.

2.3 Other considerations in project evaluation

Projects in the electricity supply industry, compared with other industrial and utility projects, have a few distinct features.

- They are highly capital intensive, more so than projects in any other engineering sector. They also can have long ‘lead time’ before they are operational.

Therefore, they demand thorough planning, timing and intensive financial and economic evaluation.

- Power projects, particularly electricity generation, can have serious environmental impacts, whose mitigation can significantly affect capital cost. A thorough environmental assessment and costing are a necessity for all electrical power projects, particularly generation.
- Power projects have long useful lives; however, some of these projects may not remain operational to the end of their useful life because of technological change, public apprehension (nuclear power industry is an example), environmental regulations, shortage in fuel availability, etc., as already mentioned.
- Most of the power projects are an extension or strengthening of an existing large electrical power system and network. New large investments, like a large power station, will have a 'system effect' whose operational and financial impact extends beyond the confines of the project to affect the whole system cost. This is a consideration that has to be accounted for in large projects and demands sophisticated system analysis and simulation.

Most electrical power technologies are well known and proven, but with the introduction of renewables they are evolving. Demand and markets are available and predictable, and tariffs can be regulated. Therefore the extent of risk for investments in the electricity supply industry, although significant, is lower than the average market equity. Outside the Organisation for Economic Co-operation and Development (OECD) many electricity utilities are still monopolies, although the picture is now changing in most countries. Because of their monopolistic and regulated status they were shielded from most of the market risks (and also market incentives). In such cases the risk of wrong, or non-optimal, decisions are shifted from the utility to others, such as the consumer, through tariffs, but things are changing as explained in Chapter 1. It is therefore essential that proper financial and economic evaluation, in accordance with market criteria, is carried out in order to ensure that the utility projects are viable in competition for resources with the other sectors of the economy.

The above points, as well as other considerations, affect the financial and economic evaluation of projects in the electricity supply industry. They have to be considered and will be detailed in later chapters. The introduction of computer-based design packages (on a large scale) into the design and drafting of specifications and drawings, particularly in case of power stations, have greatly reduced the lead time necessary for designing and executing a power station, thus significantly assisting in reducing risks and lead times for new power stations.

Also, the increasing availability of natural gas, the shorter lead times for the increasingly popular combined-cycle gas-turbine (CCGT) power stations and their smaller sizes, which better fit the load curve, have assisted in reducing risks of investment in new facilities. This is also assisted by the increasing use of modular designs in power station projects where lead times are also considerably reduced.

The increasing role of IPPs has introduced new players into the electricity supply industry. In utilities, the risk of investment is spread over many projects.

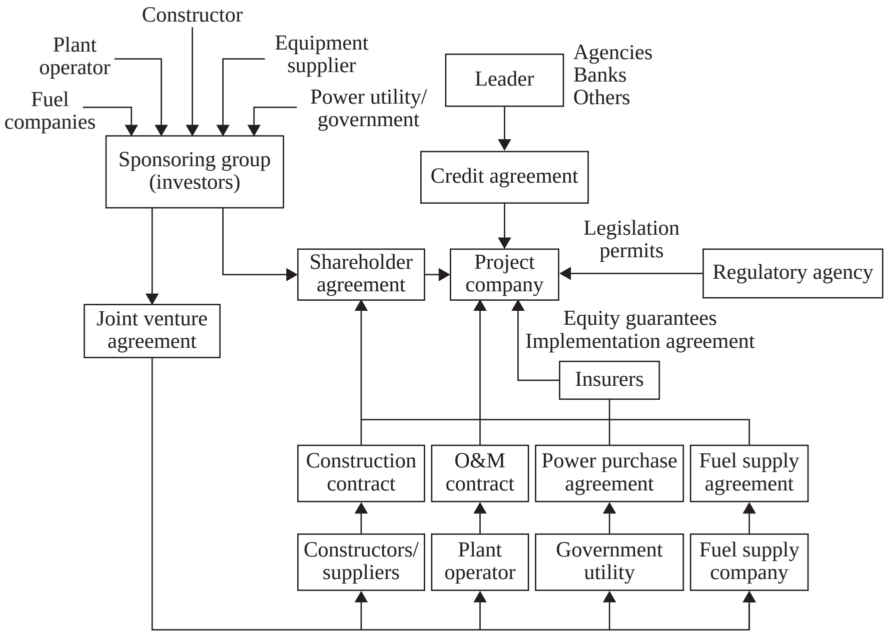

Figure 2.1 Typical project structure [Source: Reference [11]]

The IPP usually deals with a project at a time; therefore risk management is paramount. This can be achieved through all parties concerned agreeing to the mutual share of financial liabilities through a security package, which involves the many agreements defining the project and outlining the obligations of the parties involved (government guarantees, power purchase agreement, fuel supply agreement, insurance, etc.). Legal arrangements are quite important in formulating such a security package. A typical project structure is shown in Figure 2.1. This diagram explains the complexity of a modern generation project [11].

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Chapter 3

Time value of money (discounting)

Projects in the electricity supply industry live for a long time. As already mentioned, 25–30 years is a normal useful life for a conventional power station. Nuclear and the network lives even longer. For power generation projects most expenditures in the form of operational cost (fuel, carbon cost, etc.) and income occur after commissioning. Such future financial flows occur during different times and circumstances. Correspondingly, these have different value of money than flows occurring during project evaluation. Therefore, the time value of money (discounting) and the choice of a proper discount rate are highly important for capital-intensive long-life projects with large (or even modest) operational cost, like that of the electricity supply industry.

Electricity generation can be the source of environmentally detrimental emissions with long-term impact on wealth, health and human welfare, and these can materialise in the very long term, 50 or 100 years into the future, even more. Long-term discounting, as we are going to see, greatly reduces future costs and benefits, particularly that affecting human welfare. Therefore, in this chapter we shall be only concerned with financial discount rates relevant to financial flows. Welfare economics have a different social discount rate, which is introduced in Chapters 4 and 8.

Operational cost (mostly fuel, maintenance and salaries) can vary significantly over time and from one region to another. Therefore, it is not possible to assess long-term costs and performance with great certainty or to accurately compare different generation facilities. What is important is to understand the underlying procedures for analysis and apply them in an intelligent way. This is the purpose of this chapter.

3.1 Discounting

Generally, *financial flows* (streams of expenditures and income) from projects do not occur during the project evaluation [1, 2]. They occur after a year, a few years, or often after many years. Annual *cash flows* are the difference between money received and money paid out each year. Cash flows or financial flows (outlays) occurring at different times cannot be readily added, since £1 today is different from £1 next year, and very different from £1 in 20 years' time. Before dealing with financial flows occurring at different times, these have to be adjusted to the value of the money at a specified date, which is normally called the *base date* or *base year*.

Therefore, an important factor to recognise in project evaluation is the time value of money. A pound today is more valuable than £1 tomorrow and £1 tomorrow is more important than £1 the day after, etc. There are many reasons for this.

- Future incomes are eroded by inflation; therefore the purchasing power of a pound today is higher than a pound in a year's time.
- The existence of risk: an income or expenditure that occurs today is a sure amount. Future income or expenditure may vary from anticipated values.
- The need for a return: by undertaking investment and foregoing expenditure today, an investor expects to be rewarded by a return in the future.

An entrepreneur expects to gain a premium on his or her investment to allow for the following three factors: inflation, risk taking and the expectation of a real return. That is, he or she expects to regain his money, plus a return that matches with the market and his or her estimation of these three factors.

Even if inflation is allowed for, or ignored, money today will still remain more valuable than tomorrow's money because of risk and expectation of a reward by forgoing today's expenditure. To a rational investor, £1 today is more valuable than tomorrow's £1, because it can be invested immediately and can earn a real income, that is a return higher than inflation. Today's £1 will equal tomorrow's £1 plus a real value above inflation.

Present valuing (discounting) is central to the financial and economic evaluation process. Since most of the project costs, as well as benefits, occur in the future, it is essential that these should be discounted to their present value (worth) to enable proper evaluation. Present valuing will be carried out through discounting next year's financial outlay (F_1) to its present value through multiplying it by a *discount factor*. The discount factor is a function of the *discount rate* (r), which is the reward that investors demand for accepting a delayed payment. It is also referred to as the *rate of return* or *opportunity cost of capital*, so that

$$\text{present value (PV)} = \text{discount factor} \times F_1$$

where discount factor $= 1/(1+r)$. The discount factor is sometimes called the *present worth factor*. It is defined as how much a pound in the future is worth today. Therefore, with a discount rate (expected rate of return) of 10 per cent annually, the discount factor for the first year's financial outlay will be $1/(1+0.1) = 0.909$, and £110 materialising after one year will equal to $0.909 \times £110 = £100$ today.

Similarly, an outlay at year 2 will have to be multiplied by $1/(1+r)^2$ and that occurring at a year n will have a discount factor of $1/(1+r)^n$. Therefore, the discount factor, in year n, will be as

$$\text{discount factor} = 1/(1+r)^n$$

and present value $= F_n \times$ discount factor $= F_n \times [1/(1+r)^n]$. Therefore, £1 000 occurring after five years, with a discount rate of 10 per cent, will have a present value equal to £1 000 $\times [1/(1+0.1)^5] =$ £620.92. Similarly, £1 000 occurring after 30 years will be equal to £1 000.0 $\times [1/(1+0.1)^{30}] =$ £57.31 today. This demonstrates how the value of future money is eroded over time by discounting.

In the same way, the process of discounting can be converted to a process of compounding when it is required to present value past payments. The *compound factor* is the reciprocal of the discount factor and is equal to $(1+r)^n$. Therefore, a financial outlay that occurred one year earlier has a present worth equal to $(1+r)$ of the value of that outlay today. A payment of £1 000 that occurred a year from now will have a present value of £1 000 $(1+0.1) =$ £1 100.

Therefore, the discount factor $[1/(1+r)^n]$ is universal, with n positive $(+n)$ for all future years and negative $(-n)$ for all past years' financial outlays, with $n = 0$ for the base year. For the ease of the analysis the term *discounting* will also mean *compounding*, taking into account the timing of the outlay as mentioned above.

It has to be emphasised that present valuing is based on *compounding returns*. That is, the expected return (say interest rate) on the first year's money is also added to the original investment and then the sum reinvested at the same interest rate. This is different from *simple return* (simple interest), where interest is only paid on the original investment. Therefore, in simple interest, with an interest rate of 10 per cent, a £100 invested today is equal to £100 + £10 after one year, £100 + £10 + £10 after two years, and £130 after three years, etc. In compound interest payments, the £100 investment will equal to £100 $(1+0.1)^2$, £100 $(1+0.1)^3$, that is, £121 and £133.10 after two and three years, respectively. Compounding and not simple returns are the basis for present valuing.

When the discounting or compounding procedure is applied to money, the rate (r) is often referred to as a *rate of interest*. When the procedure is applied to economic resources in a more general sense (the electricity supply industry), it is usually referred to as the *discount rate* [3]. The discount rate is, therefore, a more general term than the interest rate. It takes into consideration factors to be discussed later, like opportunity cost, capital structuring and risk. In most of the chapters of this book the term discount rate is used.

3.2 Discounted cash flows

It is better if the net present valuing is stated in terms of discounted cash flows. A cash flow has already been defined as the difference between money received and money paid. Each year's future cash flows can be discounted to their present value by dividing them by the discount factor for that year.

Therefore, extended stream of cash flows $M_0, M_1, M_2, \ldots, M_n$ occurring at years $0, 1, 2, \ldots, n$ has a present value of

$$\mathrm{PV} = M_0 + \frac{M_1}{(1+r)} + \frac{M_2}{(1+r)^2} + \cdots + \frac{M_n}{(1+r)^n} = \sum_N \frac{M_n}{(1+r)^n}$$

In the special case of $M_1 = M_2 = \cdots = M_n = M$

$$\mathrm{PV} = M \sum_N \frac{1}{(1+r)^n}$$

To give a simple example, consider a short-term project involving an investment of £50 000 at the beginning of each year over four years, starting today, with a discount factor of 8 per cent. Its present value is equal to

$$\begin{aligned}\mathrm{PV} &= 50 \times 10^3 \left[1 + \frac{1}{1+0.08} + \frac{1}{(1+0.08)^2} + \frac{1}{(1+0.08)^3}\right]\\ &= 50 \times 10^3 (1 + 0.926 + 0.857 + 0.794) = £178\,850\end{aligned}$$

As already mentioned, present valuing is a process of compounding returns. Therefore, the same principles of discounting (compounding) are applicable for past payments, and their present valuation. For instance, a cash flow M that occurred in a past year n has a present value of $M_n(1+r)^n$ in terms of present value of money. The present value of £100 paid three years before is equal to £100 $(1+0.1)^3 = £133.1$ at a discount (compound) rate of 10 per cent annually.

In the above example, if the investments occurred in the past four years, their present value today will be

$$\begin{aligned}\mathrm{PV} &= £50 \times 10^3\ [(1+0.08)^4 + (1+0.08)^3 + (1+0.08)^2 + (1+0.08)]\\ &= £243300\end{aligned}$$

This approach is quite useful in electrical power projects since, in some project evaluations, the base year (i.e. the year 0, to which all payments are discounted) is usually the year of commissioning. Therefore, future cash flows are discounted to that year, while past flows are also compounded (discounted) to that commissioning year.

Because of discounting, the value of future cash flows becomes eroded significantly year after year, particularly if discount rates are high. In the above example, at a discount rate of 10 per cent, a payment occurring in 30 years will have a present worth of only 5.7 per cent of its value. If the discount rate is 15 per cent, then this present worth is only 1.5 per cent, which is almost negligible. Therefore, in project evaluation, the financial streams of the first few years have great significance. These need to be predicted with accuracy, because it is the money streams of these early years that have greater real value and impact. Discounting greatly helps in reducing the significance of inaccuracies in predicting future long-term cash flows. However, this entirely depends on the discount rate. A low discount rate will help retain a significant value of future cash flows, while a high discount rate will render long-term cash flows almost valueless today. In recent years interest rates and inflation were significantly reduced, therefore long-term financial flows have become significant.

Discount tables, amortisation ratios, etc., are readily available in the literature [3, 4], and through modern financial calculating machines.

Table 3.1 NPV – real terms

I (Year)	**II (Cost)**	**III (Income)**	**IV = III – II (Net benefits)**	**V (Discount factor)**	**VI = V × IV (Net benefits discounted at 10%)**
−1	40	–	−40	1.100	−44.00
0	110	40	−70	1.000	−70.00
1	10	40	30	0.909	27.27
2	10	40	30	0.826	24.79
3	10	40	30	0.751	22.54
4	–	70 (salvage value)	70	0.683	47.81
				Net present value:	£8.41

3.3 Net present value

Along the life of the project there will be two financial streams: one is the costs stream (C) which includes capital and operational cost (also sometimes includes decommissioning) and the other is the benefits stream (B). The two streams must contain all costs and benefits for the same estimated life frame of the project. The costs stream, being outward-flowing cash, is regarded as negative. The difference between the two streams is the cash flows – the *net benefits stream*. The values of the net benefits in certain years can be negative, particularly during construction and the early years of the project.

Discounting the net benefits stream to its present value, by multiplying each year's net benefits by that year's discount factor, will present the net present value (NPV) of the project [5, 6], as detailed in the example in Table 3.1, which utilises a discount rate of 10 per cent. Notice that outward-flowing cash (costs) are negative, whereas inward-flowing cash (income) is positive:

$$\mathrm{NPV} = \sum_{N} [B_n - C_n]/(1 + r)^n$$

Usually projects are undertaken because they have a positive NPV. That is, their rate of return is higher than the discount rate, which is the opportunity cost of capital. The calculation of NPV is the most important aspect in project evaluation, and a positive NPV estimation, at the designated discount rate, is essential before undertaking a project. Competing projects are usually prioritised according to their NPV.

3.4 Accounting for inflation in cash flows

Future cash flows can be estimated either in terms of present value of money and are usually termed *cash flows in real terms* or in terms of the money at any particular date (year) on which they occur, and are termed as *monetary or nominal cash flows*.

It is usually easier to predict future cash flows in real terms, i.e. based on present value of money, because today's information is the best available. Utilising real terms will eliminate the need to predict another future factor – inflation – thereby reducing the number of the unknowns.

Nominal cash flows are quite important for commercial financial statements and accounts. They are used in the prediction of financial statements allocations (depreciation, interest, etc.) in order to arrive at gross profits and net profits (after allowing for taxation and similar outlays). To arrive at nominal cash flows, predicted real cash flows have to be inflated by the expected inflation rate.

In present valuing, a real discount rate has to be utilised if future cash flows are in real terms (in terms of present value of money). A nominal (monetary) discount rate is utilised if cash flows are in monetary terms that are in the money value of the year in which they occur. A nominal discount rate is equal to the real discount rate modified by the inflation rate:

$$\text{nominal discount rate} = [(1 + r)(1 + \text{inflation rate})] - 1$$

Suppose, for instance, that a real discount rate, which allows for real return and a risk of 10 per cent, is adopted. Inflation is expected to be 5 per cent in the future.

Then the nominal discount rate will equal

$$[(1 + 0.1)(1 + 0.05)] - 1 = 0.155, \text{ i.e. } 15.5 \text{ per cent}$$

Because of their small values and as an approximation, a nominal discount rate equals the real discount rate plus inflation. If cash flows are in real terms then real discount rate is utilised. If they are in nominal terms then the nominal discount rate is employed. NPV is the same when utilising both methods.

The cash flows of Table 3.1 can be presented in nominal terms by inflating them by the annual inflation rate of 5 per cent as in Table 3.2.

This is the same result as that of Table 3.1, which indicates that the real and nominal cash flows will give the same NPV if the real and nominal discount rates are properly utilised with each cash flow respectively.

It is to be noted that the expenditure in the year -1, shown in Table 3.1, was £40 in terms of the money of the base year (year 0). This is only equal to £38.1,

Table 3.2 NPV – nominal terms

Year	**Nominal cost**	**Nominal income**	**Nominal net benefits**	**Nominal discount factor**	**Net benefits discounted at 15.5%**
−1	38.1	–	−38.1	1.155	−44.01
0	110.0	40.0	−70.0	1.000	−70.00
1	10.5	42.0	31.5	0.866	27.27
2	11.0	44.1	33.0	0.750	24.79
3	11.6	46.3	34.7	0.649	22.54
4	–	85.1	85.1	0.562	47.81
					Net present value: £8.41

i.e. [£40 $\div$ (1 + 0.05) inflation rate], in terms of the money of year -1. The same applies to the estimate of the salvage value, which is estimated at £70 in terms of money of the base year and is equal to $(70 \times [1 + 0.05]^4) = £85.1$ in terms of the money of year 4.

In most of the analysis of this book, it is the real cash flows and the real discount rate that will be used to discount streams of income and expenditure (past as well as future). When values are available in terms of the money of the day of the transaction (like fixed rent values, payments for fixed rates and tariffs, fixed price fuel contracts, etc.), then these values have to be deflated to the base-year money, by utilising the envisaged inflation rate, and then discounted by the real discount rate to their present worth.

In many power-generation projects it is the commissioning year of the project that is termed as the base year. Prior to the base year many payments, usually project investment cost, are already incurred. Payments are to be made in terms of the money of the commissioning year, by inflating them with the inflation rate, then to be compounded (discounted) to their present value by multiplying them with the compounding factor $(1 + r)^n$. This is the same as multiplying them by the discount factor $1/(1 + r)^{-n}$, where n is negative because it is prior to the base year. Cash streams occurring after the base year (commissioning date) have to be presented in the base-year money and discounted by multiplying them with the discount factor $1/(1 + r)^n$. Therefore, the discount factor $[1/(1 + r)^n]$ is universal for all cash flows with n as negative for all flows prior to the base year, positive for all flows after the base year, and zero for the base year. For the ease of treatment, the term ‘discounting’ will be universally used for both ‘compounding’ and ‘discounting’.

In the past analysis, it has been assumed that price changes of operating costs as well as revenues are going to change over time (inflate) at the same rate. This may not be true in many cases, since relative price changes do often occur. Different cost categories, like fuel costs, may have different rates of change over time from other costs like labour or other materials, the same applies for carbon pricing. In this case, future streams are presented in nominal terms utilising each cost or income item, and its expected inflation rate. Real cash flows are obtained by deflating these by the average annual inflation rate expected during the projected period. Alternatively, the project cash flows are presented in real terms with the stream of the cost or income item(s) expected to significantly deviate from the average annual inflation rate, inflated (deflated) by the inflation differential between its anticipated inflation rate and that of the average annual inflation rate.

3.5 Considerations in present valuing

The above analysis indicated that projects consist of financial streams of benefits (B) and costs (C), which occur at different years through the life of the project. Therefore, it is essential to understand how to deal with these streams, manipulate them to allow for the computation of their projects’ NPV and allow for comparison of the different projects. This section details various present valuing (discounting) formulas and their utilisation. It recapitulates on the above analysis and introduces new concepts. Future and past cash flows are termed M, and the discount rate is termed r. These are all in terms of real money, that is ignoring inflation (if they are represented in nominal terms then the discount rate must incorporate the inflation rate as detailed above). The following are general rules that need to be understood by project evaluators, although all do not necessarily apply to the electricity supply industry.

3.5.1 Future and past valuing

Future valuing (FV), of a present value (PV), means that the base year has been moved into the future by n years. Therefore, the PV is occurring now at $(-n)$ years, from the new base year. The universal discount (compound) factor is maintained, with negative n value, i.e. $\mathrm{FV} = \mathrm{PV} \times [1/(1+r)^{-n}] = \mathrm{PV}(1+r)^n$. A similar approach applies for past valuing, which means that the base year has been moved into the past by n years. The past value will equal $\mathrm{PV} \times [1/(1+r)^n]$.

3.5.2 Annuity factor

Present valuing of a stream of equal cash flows M is

$$\mathrm{PV} = \frac{M}{1+r} + \frac{M}{(1+r)^2} + \cdots + \frac{M}{(1+r)^n} = M \sum \frac{1}{(1+r)^n}$$

If we substitute a for $M/(1+r)$ and x for $1/(1+r)$ then

$$\mathrm{PV} = a(1 + x + x^2 + \cdots + x^{n-1})$$

Multiplying both sides by x we have

$$x\mathrm{PV} = a(x + x^2 + \cdots + x^n)$$

Subtracting the second equation from the first provides

$$\mathrm{PV}(1-x) = a(1-x^n)$$

Substituting for a and x and then multiplying both sides by $(1+r)$ and rearranging gives

$$\mathrm{PV} = M\left[\frac{1}{r} - \frac{1}{r(1+r)^n}\right]$$

The expression in square brackets in the above equation is the *annuity factor*, which is the present value of an annuity £1 paid at the end of each of n periods, at a discount rate r:

$$\text{annuity factor} = \left[\frac{1}{r} - \frac{1}{r(1+r)^n}\right]$$

Therefore, the annuity factor is the summation of all the annual values of the discount factors over the period, i.e. annuity factor $= \sum_N \times$ discount factor, and

$$\text{PV} = M \times \text{annuity factor}$$

Thus, the present value of annual payments of £20 each, paid for ten years, with the first occurring after one year, and at a discount rate of 8 per cent, is

$$\text{PV} = £20\left[\frac{1}{0.08} - \frac{1}{0.08(1+0.08)^{10}}\right] = £20 \times 6.710 = £134.20$$

In the above equation of the annuity factor, if the cash flow is maintained to perpetuity, then the annuity factor is reduced to $1/r$ and the present value of the *perpetuity* will be

$$\text{PV} = \frac{M}{r}$$

In the above example, if a bond has an annual payment of £20, which is permanently maintained, then the present value of all future payments will be

$$\text{PV} = £20/0.08 = £250$$

If the above annual payments to perpetuity are increased one year after another, by an annual percentage g (like reinvesting the annual return by g per cent), then the present value of the perpetuity becomes

$$\text{PV} = \frac{M}{1+r} + \frac{M(1+g)}{(1+r)^2} + \frac{M(1+g)^2}{(1+r)^3} + \cdots$$

It can be proved that the above equation, over a long period, can be reduced to

$$\text{PV} = \frac{M}{r-g}$$

Therefore, and with the same assumptions of the above example, if we consider a bond that pays 4 per cent in annual real return, and if this return is reinvested, then the PV of the perpetuity becomes

$$\text{PV} = £20/(0.08 - 0.04) = £500$$

The above equation assumes that payments are done annually and once. However, if payments are spread over the year and paid m times, then the annual rate of return of r, compounded m times a year, amounts by the end of the year to $[1 + (r/m)]^m - 1$. Thus, an annual return of 12 per cent, paid as 1 per cent monthly, and with a return at the same rate compounded, is equivalent to $[1 + 0.12/12]^{12} - 1 = 12.68$ per cent annually.

Generally speaking, if the benefits are spread continuously, then the equation $[1 + (r/m)]^m$ approaches e^r as m approaches infinity, where e is the base for natural algorithms and is equal to 2.718. For a continuously compounded benefit or cost the end of the year value has to be multiplied by $(2.718)^r$. Therefore, if the interest in the above example is paid daily and reinvested, the compounded return will equal approximately 12.75 per cent annually.

3.5.3 Capital recovery factor or equivalent annual cost

An annuity factor is a means of converting a stream of equal annual values into a present value, at a given discount rate (interest). A capital recovery factor (CRF) performs the reverse calculation. It converts a present value into a stream of equal annual payments over a specified time, at a specified discount rate (interest).

From the above equation of the annuity factor, it is possible to derive the CRF or the *equivalent annual cost*. This is the amount of money to be paid at the end of each year 'annuity' to recover (amortise) the investment at a rate of discount r over n years.

The equivalent annual cost M will be the reciprocal of equation of PV mentioned earlier, i.e.

$$M = \frac{\text{PV}}{\text{annuity factor}} = \text{PV} \times \text{CRF}$$

and

$$\text{CRF} = \frac{1}{\text{annuity factor}} = 1 \bigg/ \left[\frac{1}{r} - \frac{1}{r(1+r)^n}\right]$$

For example, the equivalent annual capital cost of an investment of £1 million over ten years at a rate of interest of 12 per cent will be

$$\begin{aligned} &= £1\,000\,000 \bigg/ \left[\frac{1}{0.12} - \frac{1}{0.12(1+0.12)^{10}}\right] \\ &= £1\,000\,000 \times 0.17698 \\ &= £176\,980 \ \text{ annually} \end{aligned}$$

This is the same as the annual mortgage payment to acquire a house. Thus, a house costing £1 million, which has to be repaid over ten years with an annual interest (mortgage) rate of 12 per cent, will entitle ten annual payments of £176 980 each.

To prove that the CRF is the reverse of the annuity factor, consider these equal annual payments of £176 980 discounted over ten years, at a rate of interest of 12 per cent. Their present value will be

$$£176\,980 \times \text{annuity factor}$$

The annuity factor from the Present Value Tables is 5.6502, so

$$£176\,980 \times 5.6502 = £1\,000\,000$$

which is the original investment.

When such payments are executed on a monthly basis, with a monthly rate of interest equal to 0.01 per cent, and the payments are spread over 120 months, the aforementioned equation becomes

$$£1\,000\,000 \Big/ \left[\frac{1}{0.01} - \frac{1}{0.01(1+0.01)120}\right] = £14\,347 \text{ monthly}$$

For semi-annual payments the annual fee will be

$$£1\,000\,000 \Big/ \left[\frac{1}{0.06} - \frac{1}{0.06(1+0.06)^{20}}\right] = £87\,184 \text{ semi-annually}$$

In fact, the CRF is the sum of two payments. The first is repayment of the principal (amortisation) and the second is the interest on the unrepaid principal.

The annual CRF for £1 at an interest rate of 12 per cent and a period of four years is 0.3292, as shown in the following schedule.

	Principal	**Interest**	**CRF (Total)**
1	0.2092	0.1200	0.3292
2	0.2343	0.0949	0.3292
3	0.2624	0.0668	0.3292
4	0.2941	0.0351	0.3292
	1.0000	0.3168	

It is very important to understand both the CRF and the annuity factor. They are useful in daily financial life and in quick comparison of projects and evaluation of alternatives in the electricity supply industry, as will be demonstrated in Chapter 5.

3.5.4 Grouping monthly and hourly flows

Not all costs and benefits occur at the end of the year. The main benefit of electricity production, which is generation in kilowatt-hours (kWh), occurs continuously every hour of the year. To accumulate these as a single generation figure at the end of the year is an inaccurate approximation. Payments for salaries, fuel, etc. are costs that are incurred monthly and continuously throughout the year. To lump them as a single payment at the end of the year and to discount them will result in an underestimation. To overcome this, such financial flows can be presented in a monthly (or hourly) form, which makes the calculation cumbersome. As an alternative, they can be lumped as an annual flow at the middle of the year, which is a useful approximation.

As an example, consider generation from a plant of capacity of 1 kW. Its annual continuous production is 8 760 kWh, spread throughout the year, with 1 kWh every hour. If this production is grouped as one figure at the beginning of the year, with an annual discount factor of 12 per cent (hourly discount rate of 12 per cent/8 760), it will be equal to

$$1\Bigg/\left[\frac{0.12}{8\,760}\right]-1\Bigg/\left[\frac{0.12}{8\,760}\left(1+\frac{0.12}{8\,760}\right)^{8760}\right]=8\,255\text{ kWh}$$

Grouping this at the end of the year will have a present value equivalent to

$$1\Bigg/\left[\frac{0.12}{8\,760}\right]-1\Bigg/\left[\frac{0.12}{8\,760}\left(1+\frac{0.12}{8\,760}\right)^{-8760}\right]=9\,307\text{ kWh}$$

Neither of these figures matches with the annual generation of 8 760 kWh, which is recorded by the operators.

If both the figures above are discounted to mid-year at 12 per cent annual discount rate, they will be 8 787 and 8 765 kWh, respectively. Therefore, grouping all the annual generation in its physical terms as one lump sum, in the middle of the year, is a useful approximation. The same applies to other expenses (payments for fuel, salaries, benefits, etc.), which are approximately evenly distributed throughout the year. This is the procedure, which was adopted by UNIPEDE in its comparison of the cost of different generating facilities [7] and later by IEA/NEA [8].

Therefore, if the commissioning year is the base year, then the cash flow of the first year has to be grouped at the middle of the first year for present valuing purposes. The second year's cash flow is grouped at 1.5 years from the base year, and so on. Deviation from this, like the common practice of grouping all cash flows at end of the year, causes errors.

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Chapter 4

Choice of the discount rate

4.1 Introduction

The life-cycle costs of a project and its feasibility, for a given output, depend on three factors: (i) the investment cost, (ii) the operational costs and (iii) the discount rate utilised. Many planners think that the discount rate is the most important of these three factors. It greatly affects the whole economics of the project and the decision making, particularly in capital-intensive projects like those of the electricity supply industry [1]. The discount rate almost governs the choice of the least-cost solution. It also greatly affects estimation of the net returns from the project (net present value) during the evaluation stage, the project's feasibility and the decision to proceed with the investment or not. A high discount rate will favour low capital cost with higher operational cost project alternatives. A low discount rate will tend to weigh the decision in favour of the high capital cost and low operational cost alternatives.

In spite of its crucial importance in project evaluation, it is surprising how little effort project evaluators exert to research the proper discount rate needed for their project evaluation. Simultaneously, all the efforts in estimating investment and operational costs are rendered worthless by a wrong deviation in the choice of the discount rates. Many project evaluators usually take a specific discount rate, of their own choice, as appropriate and then try to cover up for its possible inaccuracies by sensitivity analysis. Sometimes, owing to lack of clarity about discount rates, two (or more) discount rates are chosen for evaluation [2]. Often, for government-sponsored projects, the work of the planner is made easier by the authorities fixing the discount rate (sometimes inaccurately).

In many cases, the internal rate of return (IRR) of the project is calculated and if this is considered to be appropriate by the investors (utilising their experience, hindsight and possible available returns and risks of other projects), then a decision is taken to proceed with the investment without having to resort to the detailed calculation of an adequate discount rate. However, such a procedure does not allow the calculation of the net present value of a project, or adequate comparison of different alternatives (see Chapter 5).

It needs to be explained that there are two discount rates. The first is discount rate for investment (or goods). This is a concept that measures the relative price of goods at different points of time. This is also called the real return on capital, the real return and the opportunity cost of capital. This is what we shall be dealing with in this chapter. The second is the discount rate that involves long-term environmental considerations. This measures the relative weight of the economic welfare of different generations over time. This is usually called the ‘pure rate of social time preference’. This will be utilised in Chapter 8 for evaluating environmental and global warming considerations [3].

4.2 The discount rate

The discount rate is the opportunity cost of capital (as a percentage of the value of the capital). The opportunity cost of capital is the return on investments forgone elsewhere by committing capital to the project under consideration. It is also referred to as the *marginal productivity of capital*, i.e. the rate of return that would have been obtained by the last acceptable project. In investment decisions, the opportunity cost of capital is the *cut-off rate*, below which it is not worthwhile to invest in the project [4].

The discount rate connotes the entrepreneur’s indifference to the timing of the return. If it is equal to 10 per cent, then the entrepreneur is indifferent to whether he or she receives £1 today or £1.10 a year from today. This indifference is the basis for engineering economics. To serve this purpose, the nominal discount rate should at least be equal to a value which, after tax, would compensate the entrepreneur for the following three objectives, which have already been mentioned in Chapter 3: (i) reduction in the purchasing power of money which is brought about by inflation, (ii) provision of a real return and (iii) compensation to the extent of risk undertaken by committing capital to this investment. The value of the nominal discount rate is correspondingly a function of the above three factors: inflation, risk-free real return and the extent of risk in the project. A real discount rate, which ignores inflation, is utilised if the cash flows are presented in the base-year money, as explained in Chapter 3. When reference is made just to the ‘discount rate’, it is the real discount rate that is meant.

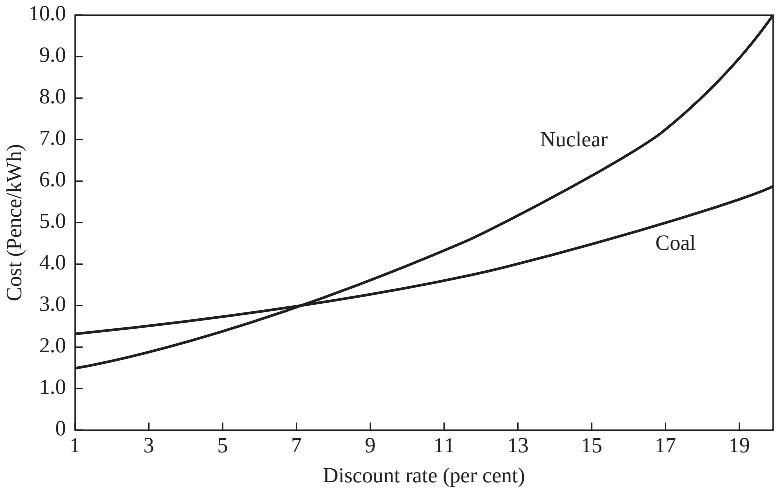

Figure 4.1 Sensitivity of nuclear and coal power stations costs to discount rate [Source: Reference [5]]

To demonstrate the importance of discount rates, the cases for nuclear and coal power stations have been compared. The results of the evaluation are demonstrated in Figure 4.1. The figure gives the price per kilowatt-hour (kWh) of output and shows how the economics of each alternative changes with the discount rate. At low discount rates of less than 7 per cent, the nuclear alternative is cheaper. However, at a discount rate of 9–10 per cent or higher, it is definitely the coal alternative that is in favour, even at high coal prices. Obviously, the discount rate is crucial in such decision making between alternatives [5].

	Nuclear	**Coal**
Investment cost (£ million)	1527	895
Operating cost per kWh	0.37p	0.46p
Fuel cost per kWh	0.45p	1.43p

Note: Figures are only indicative and do not represent today’s cost.

From Figure 4.1 it is clear how, for evaluation purposes, the cost per kWh generated is greatly affected by the discount rate for high capital-intensive investments, like those of a nuclear power station. The cost of 2p per kWh more than doubled when the discount rate was increased from 4 per cent to less than 11 per cent. Between these two discount rates, the cost of each kWh from a coal power station, which is less capital intensive but has a much higher operational cost, increased by less than one-third.

Figure 4.1 demonstrates the important fact of the sensitivity of different types of investment to the choice of the discount rate. It is clear that, because future net benefits are greatly reduced by the higher discount rate, the cost per kWh rapidly rises for capital-intensive nuclear power stations more than it does for the less capital but higher operating cost coal power stations. For low operating cost alternatives, like nuclear, the high net benefits are severely eroded by the high discount rate, while the high front capital investment is compounded by the high discount rate to the base year of commissioning. For the higher operating cost alternative, the net benefits as well as the front investment are smaller, and correspondingly the result is less affected by discounting. The choice of the proper interest rate is crucial in such highly different investment cost alternatives.

Because of the primary importance of choosing the right discount rate in any project evaluation, this subject is dealt with in some detail in this chapter. In this analysis, which is carried throughout utilising the project’s real costs and benefits, at the base-year prices, we are only concerned with the real discount rate (i.e. ignoring inflation). At this stage, taxation is also ignored.

4.3 Calculating the discount rate

In most countries, projects financed by the government use a different discount rate than that used by the private sector investors. Normally, government investments are less risky, because they are mostly in regulated utilities and industries.

The discount rate of the private sector investments is influenced not only by risk, but also by returns in the bond market which can change significantly from one period to another. Both discount rates are, however, significantly influenced by availability of capital for investment and the cost of borrowing.

4.3.1 Government financed projects

For public projects, the discount rate is sometimes decided by the responsible institutions in the government, which greatly eases the work of the planner of government sponsored projects. In the 1978 White Paper guidelines for nationalised industries, the UK Treasury indicated that the required rate of return for the nationalised industries projects should be 5 per cent in real terms (this was at a time when the real returns of risk-free investment, like those of short-term government bonds, were very close to zero). Later, in April 1989, this was increased to 8 per cent and in the mid-1990s this required rate of return was adjusted to 6 per cent annually [6]. Recently, the UK Department of Energy and Climatic Change (DECC) utilised a discount rate of 10 per cent in its study ‘Electricity Generation Cost 2013’. In other countries, hindsight is employed. The cut-off rate is in the background thinking of the decision maker. If the rate of return falls below a certain level (say, 10 per cent), the project is deemed unacceptable. If it is higher than another level (15 per cent, for instance), the project is held in great favour. The level of such rates depends on the availability of capital and public funds for the government utilities to invest, and the number and value of competing projects. It also depends on the availability of loans for the public utilities and the rate of interest of such borrowing. It is usually appropriate for the government to undertake the project as long as its rate of return is higher than the real cost of borrowing. The actual cost of borrowing takes into account the budget deficit, the indebtedness of the government, that is the public local debt as well as foreign, and the capability of the government to repay this in the future as well as other macroeconomic considerations relevant to the role of the government in the economy. Sometimes this discount rate is referred to as the social discount rate.

International development agencies, such as the World Bank and other regional development banks, also consider, during project appraisal, the macroeconomic situation of the borrowing developing country to assess the right discount rate to apply in the case of that particular country. In their studies of the economics of nuclear electricity generation, the International Energy Agency (IEA) chose what it considered to be two logical real discount rates, namely 5 and 10 per cent, and evaluated the economies of different generation facilities utilising both of the discount rates. Of course, this is only indicative [7]. For decision making, a single discount rate has to be chosen as a reference discount rate. This discount rate has to take into consideration most of the points explained below. In case of business decisions it must be equal to the opportunity cost of capital.

4.3.2 Business investment projects

Investors expect a rate of return from projects to compensate them for the following: a minimum acceptable real return available in the market (risk-free rate of interest), the risk of investing in the project, taxation and also inflation. As explained, the rate of return will be calculated in real terms thus ignoring inflation. Therefore, the real returns from the project are estimated to compensate the entrepreneur for the following factors.

4.3.2.1 The risk-free rate of interest

The risk-free rate of interest measures the time value of money. The best measure for measuring market risk-free rates of interest is the index-linked gilt. These government index-linked bonds (linked to the cost-of-living index) yield to their owners, annually, an interest that is equal to a risk-free rate of return and also compensate them for inflation. It is also possible to calculate the real risk-free rate of interest by deducting inflation from the nominal yield on conventional government bonds.

Table 4.1 features the average return on treasury bills and government bonds in the US, as well as US common stocks until 2000. From this table it is clear that government bonds have a real return that averages around 2.6–3 per cent annually, while the common stock has a risk premium of around 7 per cent above government bonds.

A return of around 2.5–3 per cent is therefore the minimum real return expected by an investor when undertaking a risk-free investment, like putting money into government bonds.

Table 4.2 shows the return of US stocks compared to three months treasury bills and ten years treasury bonds, presented in arithmetic average, and the corresponding risk premium, over the period 1928–2012.

4.3.2.2 Premium to compensate for risk

Equity is an ownership right or risk interest in an enterprise. Return from equity (stocks) involves capital gains (or losses) as well as dividends. Investing in equities entails risk, equity prices as well as dividend fluctuations. Therefore, investors in the financial market (stock exchange) expect a premium over investors in

Table 4.1 Average rates of return on treasury bills, government bonds, corporate bonds and common stocks, 1926–2000 (figures in annual percentages)

Portfolio	**Average annual rate of return**		**Average risk premium (extra return versus treasury bills)**
	Nominal	**Real**	
Treasury bills	3.8	0.7	0
Government bonds	5.6	2.6	1.8
Corporate bonds	6.1	3.0	2.3
Common stocks (S&P 500)	13.0	9.7	9.2
Small-firm common stocks	17.7	14.2	13.9

Source: Ibbotson Associates, Inc., Yearbook.

Table 4.2 Annual return in stocks, treasury bonds and treasury bills: 1928–2012

Period	**Arithmetic average (%)**		
	Stocks	**Treasury bills**	**Treasury bonds**
1928–2012	11.26	3.61	5.38
1962–2012	11.10	5.17	7.19
2002–2012	8.71	1.65	5.64

Period	**Risk premium (%)**	
	Stocks–Treasury bills	**Stocks–Treasury bonds**
1928–2012	7.65	5.88
1962–2012	5.93	3.91
2002–2012	7.06	3.08

Source: Aswath Damodaran, January 2013.

government bonds to compensate them for the risk they are undertaking. The amount of this premium depends on their and the market's evaluation of the risk of the investment, as well as the availability of other remunerative outlets for their money.

Return on equities (capital gains plus dividends) fluctuates in the stock market. However, over the long term, the average equity expects to have a higher real return than bonds. Otherwise, there will be no incentive to invest in the risky stock market. The arithmetic mean of the return on the value-weighted index of all equities (the market portfolio) in the UK during the period 1955–1994 was 10.9 per cent on average annually, but this has dropped in recent years.

An almost similar picture exists in the US, where the average risk premium (extra real return of stocks over treasury bills) was around 9 per cent annually over the lengthy period of 1926–2000. Since 1900s, till recently, the market risk premium has averaged 7.6 per cent annually above treasury bills [8]. This figure similarly matches with that of the UK capital market experience, as well as other markets. Therefore, an average risk premium of 7–9 per cent (say 7.5 per cent) above treasury bills, or 6–7 per cent above government bonds, is considered reasonable for the average equity. But with the recent decline in interest rates this also dropped.

The above situation applies to the average equity, i.e. to the market portfolio. However, each category of investment has its own risk measure; investment in new business ventures, depending on its technologies and markets, is much more risky than the average equity. Simultaneously, regulated utilities have a risk, which is lower than the average market risk. A stock's sensitivity to change in the value of the market portfolio is known as *beta*. Beta, therefore, measures the marginal contribution of a stock to the risk of a market portfolio. In a competitive market, the expected risk premium varies in direct proportion to beta. This is the capital asset pricing model (CAPM) [8], simply defined as

$$\text{expected risk premium on a stock} = \text{beta} \times \text{expected risk premium on market}$$

Therefore, treasury bills have a beta of zero because they do not carry out any risk. The average equity in the market portfolio has a beta of 1. Therefore, its risk premium is the average market risk premium of say 7.5 per cent.

Generally speaking:

$$\text{expected risk premium on investment} = \text{beta} \times \text{average market risk premium}$$
$$\text{real discount rate} = \text{real risk-free rate} + (\text{market risk premium} \times \text{beta})$$

Therefore, investment in an asset that has a beta of 0.6 means that the real discount rate for this investment will be equal to 5.2 per cent; (0.7 per cent (which is the risk-free rate) + (7.5 per cent market risk premium × 0.6)).

In addition to capital asset pricing model (CAPM), other methods are also used to calculate cost of equity, including multifactor models such as the Fama–French model (FFM), the Pastor-Stambaugh model (PSM), macroeconomic multifactor models and the build-up method. While consisting of other components (the risk-free rate and the equity beta), in the academic literature, the CAPM is considered to only include one 'factor': the equity risk premium [9].

It is therefore necessary to discuss the beta of the electricity utilities. Utilities, in many cases, are monopolies. They have well-defined markets and also established technologies; correspondingly they have a lower beta than the average equity. Recent beta for electricity generating companies in the UK was around 0.9 and that of the regional electricity companies was around 0.8. Beta of the mean equity for electric generating utilities in the US was much lower, at an average of 0.51. Beta for Japanese utilities fluctuated much more than that of UK and US utilities. Beta was as low as that of the US utilities until the mid-1980s, then increased, and was above 1.0 in recent years. Table 4.3 gives the beta of several large US electric utilities. Past mean equity beta of American and Japanese electric utilities is presented in Figure 4.2.

Apparently, no general global figure can be put into the beta of electricity utilities. Generation utilities have a higher risk and correspondingly higher beta value than distribution utilities. Nuclear installations have a higher risk than other forms of thermal generation and, correspondingly, utilities with nuclear generation have a higher beta than other generating utilities, depending on the extent of their nuclear component. Long-life facilities, like large coal-firing plants, carry more risk than modern CCGT gas-firing facilities. Investments in big long-lead-time pulverised coal-firing generating units are riskier than investment in smaller short-lead-time CCGT plants that easily fit the load curve. Therefore, the risk of investment in electricity utilities in a particular country compared with other equities in the financial market depends on the extent and type of regulation in the

Table 4.3 Beta for some large electric utilities in the US

Firm	Beta	Standard error
Boston Edison	0.60	0.19
Central Hudson	0.30	0.18
Consolidated Edison	0.65	0.20
DTE Energy	0.56	0.17
Eastern Utilities Associates	0.66	0.19
GPU, Inc.	0.65	0.18
New England Electric System	0.35	0.19
OGE Energy	0.39	0.15
PECO Energy	0.70	0.23
Pinnacle West Corp.	0.43	0.21
PP & L Resources	0.37	0.21
Portfolio Average	0.51	0.15

Source: The Brattle Group, Inc.

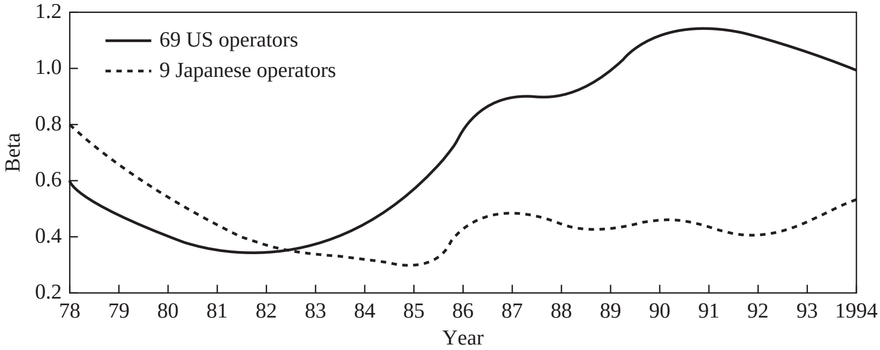

Figure 4.2 Mean beta of electric utilities in the US and Japan [10]

utility market in that country, the sort of business of the utility (generation or distribution or both), the type of facilities utilised and their expected life. Generally speaking, regulated utilities have a lower beta than the average equity. Beta between 0.4 and 0.9 are normal for utilities depending on the type of business and extent of regulation. The regulatory environment, in particular, has a marked influence on the beta of investment in electric utilities. However, beta in different countries reflects local factors and are not necessarily representative of those of other countries. However, the prospects of future carbon pricing will increase the risk of certain generation investors.

Electricity utilities, because of their growing market and established consumer base, have less risk than the market average. This has also allowed them to borrow at lower rates, thus reducing the burden at their consumers. To allow for expansion, their borrowing requirements are at least twice their depreciation allocation.

4.3.2.3 Taxation and its relationship with the discount rates

Most of the previous discussions referred to post-taxation figures, since entrepreneurs are interested in their real returns after taxation. It is, therefore, better to apply the real required rate of return to post-tax rather than pre-tax cash flows. It is, however, necessary to calculate the relationship between pre-tax and post-tax required rate of return, since cash flows are usually presented in pre-taxation figures. This relationship depends on the depreciation policy of the firm (the annual writing down allowance, WDA), as well as the annual cash flows in proportion to the incremental initial investment. The relationship can be expressed by the following equation [8, 9]:

$$\text{pre-tax return} = \text{post-tax return}/[1 - \text{Tax rate} \times (1 - \text{WDA}/p)]$$

where p = incremental annual operating cash flow expressed as the proportion of the incremental initial investment, or to put it in a simpler form:

$$\text{pre-tax return} = \text{post-tax return} \bigg/ \left[1 - \text{Tax rate}\left(1 - \frac{\text{amount of depreciation}}{\text{annual cash flow}}\right)\right]$$

Therefore, the post-tax return depends on the tax rate, tax exemption procedures, the depreciation practices of the firm as well as its annual cash flows. In all cases, pre-tax discount rates should be higher than post-tax discount rates. For instance, for a utility with a real post-tax return of 8 per cent, the required pre-tax return at a corporate taxation of 35 per cent can be as high as 12.3 per cent, but normally less than that after allowing for depreciation deductions.

Consider, for instance, an investment in a power station, which is supposed to cost £100 million and last for 20 years, where the discount rate is 10 per cent and the tax rate is 30 per cent. Such a plant will need to have a net annual income to the investors after tax of £11.7 million to justify their investment (this is the annuity required to amortise an investment at a 10 per cent discount rate over 20 years). The pre-tax returns will have to equal the after-tax return plus the tax, after allowing for a tax allowance for depreciation (assuming a straight-line depreciation of 5 per cent annually, i.e. 100 per cent divided by 20 years).

$$\begin{aligned}
&\text{Pre-tax return} = \text{post-tax return } (£11.7 \text{ million}) + \text{tax} \\
&\text{tax} = (\text{pre-tax return} - \text{depreciation}) \times \text{tax rate of } 0.3 \\
&\text{depreciation} = £100 \text{ million}/20 = £5 \text{ million}
\end{aligned}$$

substituting

$$\text{pre-tax return} = £14.57 \text{ million}$$

Such a sum (from the Present Value Tables) corresponds to a pre-tax rate of return of 13.4 per cent, which is significantly higher than the expected post-tax opportunity cost of money of 10 per cent.

Consider another example that utilises financial statements. A firm that invested £100 million will have an expected annual cash flow forecast as shown in Table 4.4.

Whether the firm will proceed with the investment depends on the evaluation of a positive net present value of future cash flows at the firm's discount rate.

Table 4.4 Forecast cash flows in millions of pounds for the firm

	Year 0	**Years 1–20**
Investment	100	
1. Revenue		300
2. Operational variable cost		250
3. Fixed costs		15
4. Depreciation		5
5. Pre-tax profit (1 – 2 – 3 – 4)		30
6. Tax		9
7. Net profit (5 – 6)		21
8. Operating cash flows (4 + 7)		26
Net cash flow	−100	26

Notes:

1. The assets are depreciated over 20 years in a straight-line method. Tax rate is 30 per cent.
2. All figures of items 1–8 are annual figures.

Suppose that the firm's opportunity cost of capital (discount rate) equals 12 per cent after tax. Then a cash flow of £26 million, over 20 years, at a discount rate of 12 per cent will equal

$$\sum_{20} \frac{26}{(1+0.12)^n} = 26 \times \text{annuity factor}$$

$$= 26 \times 7.47$$

$$= £194.22 \text{ million}$$

where 7.47 is the annuity factor obtained from the Present Value Tables.

The NPV of the investment is

$$-100 + 194.22 = £94.22 \text{ million}$$

Therefore, since the NPV is positive at a discount rate equal to the opportunity cost of capital, the firm will proceed with this investment.

4.3.2.4 Inflation

All the above analyses were in real terms, i.e. ignoring inflation. However, if the cash flows are presented in nominal terms, i.e. in terms of the money of the year in which they occur, then the discount rate should also be in nominal terms.

Generally speaking, in the earlier defined CAPM model the *real* discount rate can be modified to *nominal* discount rate as follows:

real discount rate = real risk-free rate + (market risk premium × beta)
nominal discount rate = market risk-free rate + (market risk premium × beta)

Therefore, a utility operating in a utility market of beta of 0.5, average market risk premium of 8.5 per cent and a nominal market risk-free rate of 8 per cent will have a discount rate of

$$8 \text{ per cent} + (8.5 \times 0.5) = 12.25 \text{ per cent}$$

4.4 Controlling the value of the discount rate

From the above discussion, and after allowing for risk-free returns plus premium for risk, inflation and taxation, the discount rate can assume high values [8]. This can affect investment in utilities like electric power companies. It is, therefore, appropriate to consider ways of controlling the required rate of return for utilities. The most important means is through capital structuring and regulating prices (electricity tariffs).

4.4.1 Capital structuring

This involves raising a proportion of the capital required for investment through debt. Debt, for sound utilities, carries an interest, which can be as low as (or only slightly higher than) the market risk-free return on index-linked bonds, while the equity will require a high return because of risk. Therefore, capital structuring through having a significant part of the investment capital required in the form of fixed-interest loan can significantly reduce risk. However, it has to be realised that if there is a high debt/equity ratio, then this entitles higher risk for the equity. Servicing the debt will be the first priority for the cash flow, which means putting returns to the equity capital at a higher risk. This means raising the beta of the equity, which may end in approximately the same rate of return for the total capital investment, irrespective of the debt/equity ratio.

Consider the case of a situation in which the real risk-free returns are 3.5 per cent, with risk premium on the average investment 10 per cent, totalling 13.5 per cent. If a power utility (with a beta of 0.6) is investing in a project totally by equity, its post-tax real returns should at least equal 3.5 per cent $+ 0.6 \times 10$ per cent $= 9.5$ per cent. If the capital is raised by a debt/equity ratio of 1:1, with a debt of real interest of 3.5 per cent, however, then the theoretical real cost of capital will become 0.5×3.5 per cent $+ 0.5 \times 9.5$ per cent $= 6.5$ per cent. This assumes that beta for the equity has remained constant. This is not the case, because the equity has become riskier owing to the need to service the debt, prior to having any returns to the equity holders. Beta may have to double to 1.2, so that the real return remains roughly equal to the original 9.5 per cent.

Because of the tax deductibility of interest payments (*tax shield*), the main advantage of debt is the tax benefit. This may vary significantly from one country to another. Each country's situation and its taxation system have to be studied independently. Decision on the merits of tax deductibility of the interest rates and reduction of risk (if any) has to be taken when considering capital structuring. This is discussed in more detail in section 4.5.

4.4.2 Transferring risk

It is possible to transfer risk from the utility to consumers, by allowing continuous price (tariff reviews), which ensures that the equity holders will always get a decent pre-agreed target rate of return. This will almost eliminate the risk from the utility. A utility with regulated prices will have little risk and correspondingly a low beta and a low discount rate. This may tempt the utility to invest in higher capital-intensive assets, which will lead to higher costs to the utility and correspondingly higher tariff to consumers. This means shifting utility investment decision risks (whether right or wrong) to the consumers who have to pay, through the regulated tariff, for the utility's decisions, i.e. the consumers now have to bear the additional risk of the investment to allow the utility always to get its target rate of return. Such an arrangement will not only shift the risk to the consumer, but also prejudice the interest of other competing operators and investors in the industry that may not have the same privileges of price adjustments.

It is therefore essential when considering new projects and investments in regulated utilities to insist on using, as a discount rate, the private sector rate of return as employed in profitable taxpaying investor-owned utilities.

4.5 Other forms of the discount rate

4.5.1 Weighted-average cost of capital

For project evaluation in the US, most utilities use the revenue requirements method (RRM). It is a project evaluation method that discounts future costs (revenue requirements) into their present value using the utility's weighted-average cost of capital (WACC). WACC is the weighted-average cost of the firm's equity and debt. WACC rests on four components: the cost of debt, the cost of equity, the optimal capital structure and the corporate tax rate.

$$\text{After-tax WACC} = r_d(1 - T_c)\,\frac{D}{V} + r_e\frac{E}{V}$$

where r_d is the return on debt, r_e return on equity and T_c corporate tax rate, and D is debt ratio, E equity ratio and $V = E + D = 1$.

Consider the case of a utility with debt: equity ratio of 0.6:0.4 and tax rate 25 per cent, with debt interest of 6 per cent and expected equity return of 10 per cent.

$$\begin{aligned}\text{After-tax WACC} &= 0.06\ (1 - 0.25) \times \frac{0.6}{0.6 + 0.4} + 0.10 \times \frac{0.4}{0.4 + 0.6}\\ &= 0.067,\ \text{i.e. } 6.7\%\end{aligned}$$

WACC is a common tool used by utilities for discounting cash flows and assessing the viability of the investment. But as described below this method has some flaws. The least-cost alternative is the project alternative with the lowest present-value revenue requirement (PVRR), which is the lowest-cost alternative using the WACC as the discount rate [11].

This use of WACC is not consistent with methods of evaluation that are advocated by finance textbooks including this book. The WACC is an average between the cost of borrowing and the acceptable return on the investors' equity. Therefore, it reflects the overall cost of the utility's funds at any point in time. It is not the opportunity cost of capital and its utilisation as a discount rate is erroneous in this regard, because the discount rate for present valuing has to be equal to the opportunity cost of capital. The WACC does not reflect risk. Therefore, it is erroneous to utilise it for comparing projects of different risks – like comparing a nuclear plant (high-risk project) with a CCGT plant (low-risk project). The correct risk-adjusted discount rate for project alternatives is their opportunity cost of capital. As defined at the beginning of this chapter, in investment decisions, the opportunity cost of capital is the 'cut-off rate', below which it is not worthwhile to invest in the project. Normally the WACC is below the opportunity cost of capital and it correspondingly favours higher investment-cost project alternatives.

4.5.2 Utilisation of multiple discount rates

Different project alternatives have different risks. For instance, investing in a nuclear power station is riskier than investing in a conventional power station. New technologies have a much higher risk than established technologies. Therefore, for choosing the least-cost alternatives, more than one discount rate can be utilised, each for a different alternative. Each alternative has a different beta, which can be evaluated and incorporated in the CAPM model to obtain a discount rate that is commensurate with the alternative's risk. That will allow for a risk-adjusted discount rate for each alternative, which assists in incorporating risk into evaluation of alternatives to choose the least-cost alternative and also to evaluate the required risk-adjusted returns on investment. Risk assessment will be covered in detail in Chapters 15 and 16.

Multiple discount rates can also be utilised for different components of desegregated costs. Operational costs of a project contain many components: fuel, salaries, consumable and spare parts, local taxes and rates, insurance, etc. Each of these has a different future risk. For instance, local rents and rates can be fixed in real terms and need not be discounted with a discount rate that incorporates a risk element (beta is equal to 0). Fuel prices usually have much higher risk than any other cost parameter, particularly if there are prospects of environmental legislation that may entitle cleaner fuel versions (lower sulphur content, for instance) or plant modifications.

Such prospects are allowed for in the risk assessment. Alternatively, an inflation differential is incorporated in the fuel outlay, in the cost stream to cater for the possible increase in prices of fuel over the general inflation rate. For evaluation purposes, it is much easier to utilise a composite discount rate for the costs stream while allowing for significant cost items (like fuel) to be treated in a manner that matches with their possible variation from the general price increase trends.

4.6 Summary

The discount rate is very important in project evaluation and is a crucial factor in deciding the feasibility of a project. Investments in projects involve risk. Therefore, entrepreneurs expect a post-tax real rate of return on their investment to equal the income of risk-free bonds plus a premium for risk. This premium depends on beta, which is the ratio of the fluctuation in the price of similar assets to the fluctuations in the overall stock market. In recent years, the real returns on government bonds averaged 2.6–3 per cent annually, while the average risk premium in the stock exchange, both in the UK and the US, was around 4–5 per cent [3, 12].

The above post-tax rate of return has to be adjusted to a higher pre-tax rate of return. This takes into account taxation rates and exemption procedures, as well as the depreciation policies of the firm. If cash flows are in nominal, rather than real terms, then a nominal discount rate that incorporates inflation has to be utilised.

Regulated utilities, like power companies, have a lower beta than the average equity. This depends on the type of business (generation or distribution), the type of facilities (conventional or nuclear) and the extent of regulation in the market. Such beta varies from one country to another and usually has values between 0.4 and 0.9.

The extent of risk can be slightly reduced by capital structuring, through increasing debt to equity ratio, and by transferring the risk to consumers in a regulatory system that allows for regular electricity tariff reviews. This will only shift the investment risk from the firm to the consumers. It is, therefore, essential when evaluating investments in power utilities, whether public or private, that a rate of return (the discount rate) that is equal to that utilised in profitable taxpaying investor-owned utilities should be employed. Therefore, in this book we are adopting the widely accepted CAPM model.

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Chapter 5

Financial evaluation of projects

5.1 Introduction

5.1.1 Evaluation of costs and benefits

It is essential to recap on what was said in Chapter 3. During the life of the project, there are two financial streams: one is the cost stream and the other is the benefits (income) stream. The two streams must contain all costs and benefits for the same estimated life frame of the project. In financial evaluation of small projects, the two streams will contain only the estimated actual cash costs and benefits of the project through its life cycle. The economical evaluation will influence the two streams, to include all the economic (social and environmental) costs and benefits of the project that can be evaluated. The difference between the two streams is the cash flow, the net benefits stream. The values of the net benefits can be negative, particularly during construction and the early years of the project. In later years, the benefits will usually exceed costs and the discounted net benefits will be positive, otherwise the project will not be undertaken.

It can be said that evaluation of costs and benefits of large projects (these normally demand equity, loans and other financial instruments) is carried out on three levels [1].

5.1.1.1 Owner's evaluation

This is a straight evaluation. The owner is mainly concerned with cash flow and considers all money flowing in (income from sales, receipt of loans and salvage value) as positive and all money flowing out (project cost, cost of operation, interest and repayment of loan) as negative. The owner is interested in net benefits and their net present value in comparison with the value of the investment (equity). The owner is concerned only with the return to equity.

5.1.1.2 Banker's evaluation

When analysing the project for loan consideration, the banker looks on it as one entity irrespective of the division of the investment cost between loans and equity. The banker evaluates the return on the total investment (equity plus loans) and considers its profitability. Therefore, the banker will consider the net present value of the whole investment and not just the investor's equity. The banker's evaluation integrates the points of view of the loan providers and equity investors.

5.1.1.3 Economic evaluation

This goes beyond the banker's evaluation to include all the economic (social and environmental) costs and benefits that can be evaluated. That includes taxes, subsidies and environmental and other external costs, as detailed later in Chapter 7. Some of these costs are invisible and materialise only in the long term. Therefore, they require a lot of skills for their evaluation. Such economic evaluation is usually done by development banks and similar institutions, and also by the concerned planning departments in the government.

5.1.2 Project financial costs

There are three main kinds of costs: investment costs, operating costs and working capital. These costs are usually broken down into several different items as discussed below.

5.1.2.1 Investment costs

The items included under investment costs are (i) initial costs (ii) replacement costs and (iii) residual values. Initial costs refer to the costs involved in construction and commissioning, including land, civil works, equipment and installations. Replacement costs refer to the costs of equipment and installations procured during the operating phase of the project to maintain its original productive capacity. Residual values refer to the value of these investment items (equipment, land, etc.) at the end of the project's useful life. These are usually positive flows in contrast to initial and replacement costs. However, residual values are usually small and do not have a major impact on decision making. Sometimes, as in the case of nuclear power stations, decommissioning and dismounting represent a negative substantial cost, which can affect evaluation.

5.1.2.2 Operating costs

Operating costs are a combination of fixed and variable costs. Fixed costs will be incurred whatever the level of productions, like salaries, cost of management, some taxes and levies and part of the maintenance cost. Variable costs will depend on the level of production and include items like fuel and energy, water, lubricants and part of the maintenance cost (in the case of industrial projects, the cost of raw materials is also included). In general, production will never start at the maximum capacity of the project. Capacity utilisation may increase over time or may fluctuate according to time of day or to season. The variable cost will increase with the increase in production and will stabilise when maximum sustainable production capacity is reached. The total operating cost is the sum of the fixed and variable costs. The operating cost per unit of production falls as higher-capacity utilisation rates are achieved.

5.1.2.3 Working capital

Working capital refers to the physical stock needed to allow continuous production (spare parts, fuel, raw materials). The stock has to be built up at the commissioning phase and before the beginning of the commercial operation. Usually, stock requirements are defined as one month's worth of production. For power plants and network projects, there is usually one component of working capital, which is the initial stock of material necessary for commercial operation. But for industrial projects, there are three components of working capital: (i) initial stock of material, (ii) work in progress and (iii) final stock of production. Generally, working capital can also be defined as the difference between a company's short-term assets and liabilities.

For evaluation purposes, all project costs are calculated at the estimated constant prices and costs (real terms) existing at a specific year – the base year.

5.1.3 Financial benefits of the project

Financial benefits of the project are brought about by selling the project product. These benefits are usually equal to the amount of production multiplied by the estimated base price. Not all projects in the electrical power industry imply production. Some, like efficiency improvement, lead to cost reduction, which is equal to the benefit. Others can have economic and social rather than financial benefit, as in the case of improvement of the supply reliability, rural electrification and environmental preservation.

In the electrical power industry, calculation of benefits is not easy. A new power station would normally not only increase production, but also contribute towards reduction of the overall system cost of generation. It may also reduce system losses and delay the implementation of some projects for network strengthening. Certain projects are redundant and are made necessary by the need to ensure security of supply. Rural electrification is normally a source of financial loss, but has significant economic benefits. Some improvements in power stations, like inhibition of emissions, incur high investment, reduce electrical energy output and efficiency, and yet have sound economical (environmental) benefits.

Owing to deregulation, privatisation and competition, estimating financial benefits (profitability) of electrical power industry projects is becoming increasingly important. Later into the book, examples will be cited that help in understanding the methodology of estimating financial and economic benefits.

5.2 Least-cost solution

It is necessary to ensure that a project is profitable and that its return is higher than that of the opportunity cost of capital. It is important also to ensure that the project is the *least-cost alternative* for attaining the required output [2–4].

The electricity supply industry (ESI) is one of the best venues for using least-cost solution techniques, since there is always more than one way in which a project can be executed so that its benefits can be secured. The least-cost solution aims at evaluating all realistic alternatives, financially and economically, before deciding the alternative that can achieve the project benefits at the least cost.

Projects in the ESI are, in the main, mutually exclusive; that is the implementation of one project renders it technically or uneconomically feasible to implement another project.

Most day-to-day decisions in the electrical power industry involve financial evaluation to choose the least-cost solution (from mutually exclusive projects) for meeting the demand or rendering the service. For instance, there are many alternatives for meeting the need for more electricity generation: thermal power stations at different sites using small or large units firing coal or gas, gas-turbines and combined-cycle gas-turbines firing light fuel or natural gas, nuclear power stations, and now renewables, etc. Each alternative will have a different cost, cause a different system effect and lead to a new overall system cost. The least-cost solution aims at finding out the alternative technical arrangement that meets the requirements of supplying electrical energy with the least cost to the utility, its site and timing.

The same applies to projects in the electricity network, sizing, timing of extensions and their routes and locations. Adjudication of offers for electricity facilities, like transformers where the high capital cost of an alternative can be traded against its lower losses, is required. The evaluation involves computing the overall cost of each network alternative (capital plus future discounted cost of losses and other operational costs). Trading capital cost against future operational costs and against system security is a main criterion in financial project evaluation and least-cost solution. Therefore, in most electrical power engineering decisions, there is more than one alternative to achieve the required result. The least-cost solution considers all these alternatives, evaluates them and indicates the alternative with the least discounted overall cost over the useful life span of the project.

In choosing the least-cost solution, we are concerned with the differences in the present value of the cost of the alternatives (including their system effects, if any). In many cases, the benefits (output) of each alternative are the same since all the alternatives are supposed fully to meet the project. In this case we are concerned with the evaluation and comparison of costs. However, if there are differences in the amount of the energy output, then comparison of alternatives is carried out per discounted kilowatt-hour (kWh) of electricity output through evaluating over time the overall system cost of the alternatives.

There are many methods for financial evaluation and comparing alternatives. The most important and useful ones are:

- present value method;
- annual cost method (the equivalent uniform annual cost method); and
- levelised cost of electricity (LCOE) generation [5].

5.2.1 Present value method

The present value (PV) method [6, 7] aims at present valuing (discounting) all costs and benefits of the project or cash flows (net benefits) to a specified date, the ‘base year’. In this case, all cash flows prior to or after the base year are discounted to the base year through multiplying by the discount factor $[1/(1+r)^n]$ where n is negative for years prior to the base year. All values are considered to occur at the year end. However, in most instances, the middle of the year may be the more appropriate date for their aggregation, as already discussed in Chapter 3.

To give a simple example of aggregating flows at the middle of the year, consider a project that is supposed to live for five years after completion, is expected to have the following two streams of cost and income based on the base-year prices, and at two discount rates of 8 per cent and 15 per cent. The project will have a residual value of £60 000 at the end of its useful life of five years.

The example in Table 5.1 demonstrates the present valuing procedure. Costs and benefits are supposed to be evenly distributed over the appropriate months of the years of the project. Therefore, these can be grouped in the middle of the year about the commissioning date (base year). This project will have a net positive value of £35 980, at a discount rate of 8 per cent, but a negative value of £13 990, at a discount rate of 15 per cent. Correspondingly, the project is profitable if an opportunity cost of capital of 8 per cent is considered appropriate. The project needs to be discarded if 15 per cent is the opportunity cost of capital. It is also possible to avoid the discounting for one and a half years by choosing the base date to occur yearly from the middle of each accounting year.

The PV method is suitable for choosing the least-cost solution. The method discounts the capital and future running costs of each considered alternative to its present value, using the agreed discount rate that is the opportunity cost of capital. If there is any salvage value for the alternative, its value after discounting to the base year is deducted from the cost of this alternative. Different alternatives may have different system effects, and correspondingly different costs. These have to be undertaken in the evaluation. The alternative with the least present value cost is the chosen least-cost solution.

In choosing the least-cost alternative, benefits need not be presented in monetary terms. In some cases, benefits are better presented with the physical output of the project such as number of units produced, tons of the output or any

Table 5.1 Present valuing (all values are in thousand pounds)

Year	**Costs**			**Income**	**Net benefits**		
	Capital	**Operational**	**Total**		**Cash flows**	**DR = 8%**	**DR = 15%**
−1.50	100	–	100	–	−100	−112.24	−123.32
−0.50	50	–	50	–	−50	−51.96	−53.62
0	Commissioning date						
0.5	20	20	40	40	0	–	–
1.50	–	30	30	80	50	44.55	40.54
2.50	–	30	30	80	50	41.25	35.26
3.50	–	30	30	80	50	38.19	30.66
4.50	–	30	30	80	50	35.36	26.66
5		Residual value		60	60	40.83	29.83
			Present value of net benefits:			35.98	−13.99

Table 5.2 Comparing alternatives

Year	**Alternative 1**				**Alternative 2**			
	Cost (£)		**Production (kWh)**		**Cost £**		**Production (kWh)**	
	Actual	**Discount**	**Actual**	**Discount**	**Actual**	**Discount**	**Actual**	**Discount**
−1					10	11	0	0
0	100	100	0	0	150	150	0	0
1	50	45.45	500	454.5	50	45.45	500	454.5
2	30	24.79	1000	826.4	10	8.26	1000	826.4
3	30	22.45	1000	751.3	10	7.51	1000	751.3
4	30	20.94	1000	683	10	6.83	1000	683
5					10	6.21	1000	621
Sum	240	213.63	3500	2715.2	250	235.26	4500	3336.2

Cost per discounted kWh for alternative 1 = £213.63/2 715.2 = £0.0787, and for alternative 2 = £235.26/3 336.2 = £0.0705. (As explained earlier the base date was chosen so that the annual costs and benefits grouped at the middle of each year are at yearly intervals from the base date.)

similar output. This is particularly suitable in the case of an electrical power project, since most of the benefits are production of electricity as kWh, its multiples, or reduction of cost as reduced losses or usage in kWh. The method is also particularly useful for comparing alternatives with different lengths of execution time and different outputs (kWh). The evaluated costs (capital and operational) and benefits (in kWh) are discounted to the base year. The least-cost alternative will be the one least discounted cost divided by the discounted energy output. This is demonstrated using a 10 per cent discount rate in Table 5.2. Alternative 1 is the least-cost solution.

5.2.2 Annual cost method (equivalent uniform annual cost method)

This is a useful and quick way for choosing the least-cost solution. It can help in providing the right answer, supposing that certain assumptions and approximations are possible.

In Chapter 3, the equivalent annual cost has been defined as being equal to the amount of money to be paid at the end of each year 'annuity' to recover (amortise) the investment, at a discount rate r over n years. An annuity is a level stream of cash flows that continues for a specified number of time periods (years). The annuity factor is the present value of all the annual values of the discount factors over the whole period (annuity factor $= \sum_N$ discount factor).

The equivalent annual cost M will be equal to

$$\frac{\text{present value of the investment}}{\text{annuity factor}}$$

where annuity factor $= [1/r - 1/(r(1+r)^n)]$.

The same results can be obtained by multiplying the present value of the investment by the capital recovery factor (CRF), since CRF is equal to [1/annuity factor].

Alternatively, the annual benefits (B) of the project, if they are equal throughout the years of the project, can be present valued by the same way:

$$\text{present value of benefits} = \text{annual benefits } (B) \times \text{annuity factor}$$

The same applies to present value the annual fixed operating cost (FC) and annual running operational costs (OC) throughout the life of the project. If these are constant every year (for a known output), these can be present valued as

$$\text{annuity factor} \times (\text{FC} + \text{OC})$$

Therefore, the present value of the total costs of the project throughout its useful life will equal to

$$\text{project cost at base year} + [(\text{FC} + \text{OC}) \times \text{annuity factor}]$$

and the total benefits of the project $= B \times$ annuity factor.

For electricity generation projects, such benefits can be in the form of kWh. If benefits are in monetary terms then annual cash flows (net benefits) are utilised.

The PV of a project with equal annual operational cash flows is equivalent to

$$\text{project cost at base year} + (\text{annual cash flow} \times \text{annuity factor})$$

(Remember that project cost is negative because it is an outward-flowing payment.)

This is a useful and quick way for comparing alternative projects, and for approximately calculating the cost of production and prices. A good example is to compare the cost of production of a power station utilising a combined-cycle gas-turbine (CCGT) plant with that utilising steam-power turbines (ST) of a similar size. Installed cost at commissioning of the CCGT plant is £500 per kW, and it has an expected life of 20 years. The ST plant costs £1 000 per kW with an expected life of 30 years. The fixed and running costs (fuel, operation and maintenance) are also 2.4p per kWh and 2p per kWh, respectively. Each plant operates at full load, approximately 8 000 hours annually for ST and 7 000 hours annually for CCGT. All these costs apply to the same commissioning date.

Then, the production cost of each kWh from these two alternatives, with a discount rate of 10 per cent, can be calculated as follows. The annuity factors for 20 and 30 years at 10 per cent discount rate are 8.514 and 9.427, respectively.

$$\text{For CCGT: } [(\pounds 500 \div 8.514)/7000] + 2.4\text{p} = 3.24\text{p per kWh}$$
$$\text{For ST: } [(\pounds 1000 \div 9.427)/8000] + 2\text{p} = 3.33\text{p per kWh}$$

Obviously, production from the CCGT power station is the least-cost alternative. The above calculation can also assist in the assessment of the tariff to be charged for such a production. An alternate way of calculation is to present value all the future running cost of the alternatives, to present value the output in kWh (as benefits), and make the necessary comparison. Therefore, for the CCGT alternative (per kW of installed capacity)

$$\begin{aligned}\text{PV of operational cost} &= 0.024\text{p} \times 7000\text{kWh} \times 8.514 = £1430.4\\ \text{Total PV of costs per kW} &= £500 + £1430.4 = £1930.4\\ \text{PV of benefits (kWh)} &= 7000 \times 8.514 = 59598\text{kWh}\\ \text{Cost per kWh} &= £1930.4/59598 = 3.24\text{p}\end{aligned}$$

For the ST alternative:

$$\begin{aligned}\text{PV of operational cost} &= 0.02 \times 8000\text{kWh} \times 9.427 = £1508.3\\ \text{Total PV of costs per kW} &= £1000 + £1508.3 = £2508.3\\ \text{PV of benefits (kWh)} &= 8000 \times 9.427 = 75416\text{kWh}\\ \text{Cost per kWh} &= £2508.3/75416 = 3.33\text{p}\end{aligned}$$

This alternative method of assessment yields the same result as above.

This is a quick method that gives rapid results and allows the attention of the evaluator to focus on a few alternatives. However, it involves many assumptions and approximations that need to be handled carefully. Therefore, such quick methods have to be elaborated further to consider other detailed issues (exact commissioning, system effects, environmental impacts, long-term prospects, etc.) to allow accuracy in decision making. System costs are quite important in choosing the least-cost alternative particularly when investments in new renewables (solar and wind) are considered, as detailed in Chapter 12.

The choice of either the PV or the annual cost method for evaluating the least-cost alternative is a matter of personal convenience. In the US, the annual cost method is preferred. Its implications are easier to understand for business decisions, and it is easier to compute for regular annual series of disbursements, particularly if the capital is obtained through loans. In the electrical power industry, annual costs are irregular, utilisation varies from one year to another and most decisions affect the overall system cost. To allow for more detailed evaluation of future costs, the PV method is preferred for identifying the least-cost solution since it allows for variations in output, operating costs over time and other factors.

5.2.3 Levelised cost of electricity

This is the method mainly used to compare the cost of base-load electricity production from different generation technologies (nuclear, fossil, renewables). Actually it is a direct application of the annual cost method, but is only applied to electricity generation.

The DECC (UK) *Electricity Generation Costs of 2013* [5] defines the levelised cost of electricity (LCOE) as 'the discounted lifetime cost of ownership and use of a generation asset, converted into an equivalent unit of cost of generation in £/MWh. The levelised cost of a particular generation technology is the ratio of the total costs of a generic plant (including both capital and operating costs), to the total amount of electricity expected to be generated over the plant's lifetime. Both are expressed in net present value terms. This means that future costs and outputs are discounted, when compared to costs and outputs today.

This is sometimes called a life cycle cost (LCC), which emphasises the 'cradle to grave' aspect of the definition. The levelised cost estimates do not consider revenue streams available to generators (e.g. from sale of electricity or revenues from other sources), with the exception of heat revenues for combined heat and power plant which are included, so that the estimates reflect the cost of electricity generation only.

As the definition of levelised costs relates only to 'those costs accruing to the owner/operator of the generation asset, it does not cover wider costs that may in part fall to others, such as the full cost of system balancing and network investment, or air quality impacts'. Levelised cost estimates are highly sensitive to the underlying data and assumptions including those on capital costs, fuel and carbon costs, operating costs, operating profile, load factor and discount rates. This measure makes no assumptions about how particular generating stations would be financed, or the allocation of risk between parties. A Contract for Difference (CfD) stabilises revenues for a particular generating station at a fixed price level known as the 'strike price' over a specified term, at a rate of return which reflects contract duration and design, financing costs, and risk allocation between parties [5].

The levelised cost measure does not explicitly include the financing costs attached to new generating stations. Therefore, levelised cost estimates are highly sensitive to the underlying data and assumptions used including those on capital costs, fuel and carbon costs, operating costs, load factor and particularly discount rates. As such it is often more appropriate to consider a range of cost estimates rather than point estimates. Sensitivity analysis is explained in Chapter 15.

The LCOE for a generating facility is the real-time price that would equate the net present value of revenue from the plant's output with the net present value of the cost of production.

Therefore, the LCOE can be calculated through the following equation:

$$\mathrm{LCOE} = \frac{\sum (\mathrm{investment}_t + \mathrm{operation\ and\ maintenance}_t + \mathrm{fuel}_t) \times (1+r)^{-t}}{\sum \left(\mathrm{electricity}_t \times (1+r)^{-t}\right)}$$

$(1+r)^{-t}$ being the discount factor for year t, where r is the discount rate which is the opportunity cost of capital. The opportunity cost is the return on investments forgone elsewhere by committing capital to the project. If there is carbon pricing or decommissioning costs, these should be added to the cost section of the above equation.

The IEA *Projected Costs of Generating Electricity* (2010 Edition) [8] explains that the notion of LCOE is a handy tool for comparing the unit costs of different technologies over their economic life. It would correspond to the cost of an investor assuming the certainty of production costs and the stability of electricity prices. In other words, the discount rate in LCOE calculation reflects the return on capital for an investor in the absence of specific market or technology risks. Given that such

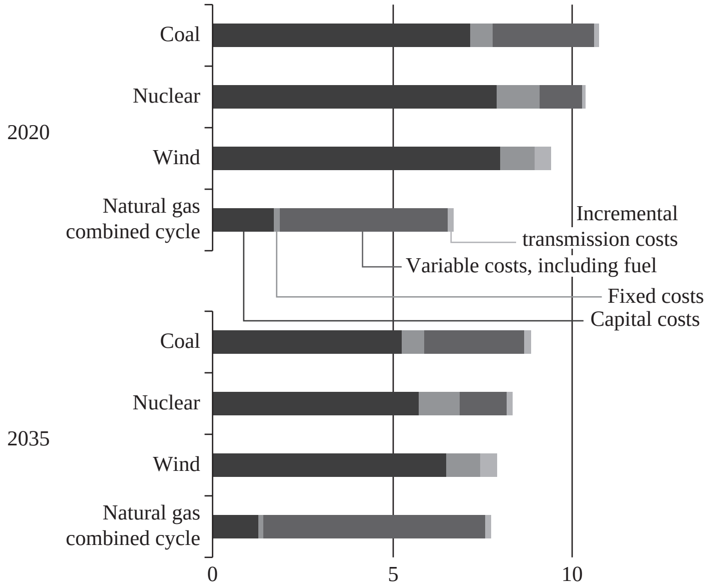

Figure 5.1 Levelised costs of electricity in the US for years 2020 and 2035 [Source: Reference [9]]

specific market and technology risks frequently exist, a gap between the LCOE and true financial costs of an investor operation in real electricity markets with their specific uncertainties is usually verified. For the same reason, LCOE is also closer to the real cost of investment in electricity production in regulated monopoly electricity markets with loan guarantees and regulated process rather than to the real costs of investments in competitive markets with variable prices.

Figure 5.1 details the levelised electricity costs for new power plants, excluding subsidies, for year 2020 and 2035 (2010 cent per kWh) as calculated by the US EIA in *Annual Energy Outlook 2012* [9]. The levelised electricity generation costs in the UK are detailed in Appendix A.

We have to explain that the generation investment cost is the overnight construction cost plus interest during construction. Overnight costs include owner's cost, EPC (engineering, procurement and construction) and contingency, but excludes interest during construction. In the above analysis we did not include the environmental and social costs of electricity generation (emissions, pollution, etc.); this will be dealt with later in Chapter 8.

5.3 Measuring worth of the investment

Many of the projects in the electrical power industry are forced on the planner and are beyond his control; examples are building new power plants to meet load increase and providing new facilities to enhance security of supply, rural electrification, etc. Therefore, many decisions in the electrical power industry are restricted to the choice of the least-cost solution. With the privatisation of utilities and market economies, a more thorough analysis of the profitability of investment is also becoming essential. Projects are carried out because they are needed, they are the least-cost solution and they are profitable. It is now becoming increasingly necessary not only to weigh the benefits of the investment through a cost–benefit analysis, but also to carry out financial profitability projections. This includes forecasting three summary statements: (i) the *pro forma* income statement, (ii) the *pro forma* balance sheet and (iii) the *pro forma* fund flow statement [10]. Such statements will allow assessment of financial profitability to owners.

In this section, we are concerned with the traditional cost–benefit analysis of projects to assess their acceptability to utilities, governments, investment bankers and development funds, as well as investors. There are several ways of assessing whether the project is worth undertaking. The most useful of these are

1. computing the internal rate of return;
2. evaluating the net present value of the project;
3. calculating the benefit/cost ratio; and
4. other criteria (payback period, profit/investment ratio, commercial return on equity capital).

All the above criteria, except the last, involve discounting.

The case of independent power projects undertaken by private investors is discussed in section 5.5.

5.3.1 Internal rate of return

Calculating the internal rate of return (IRR) is a popular and widely used method in the evaluation of projects. The IRR is the discount rate that equates the two streams of costs and benefits of the project. Alternately, it is the rate of return r that the project is going to generate provided the stream of costs (C_n) and stream of benefits (B_n) of the project materialises. It is also the rate, r, that would make the NPV of the project equal to zero, i.e. IRR is such that

$$\sum [C_n/(1+r)^n] = \sum [B_n/(1+r)^n]$$

If IRR is equal to or above the opportunity cost for a private project, or the social discount rate (as set by the government) in public projects, then the project is deemed worthwhile undertaking. Utilities, governments and development funds set their own criteria for the opportunity cost of capital and for the social discount rate below which they do not consider providing funds. Such criteria depend on the amount and availability of required funds. The criteria also depend on the presence and expected return of alternative projects in other sectors of the economy, the market rate of interest and the risk of the project. In Chapter 4, the concepts that govern the choice and fixing of the discount rate have been discussed. For some investors, the discount rate can be viewed as the minimum acceptable rate of return below which a project is rejected. Therefore, if the IRR is equal to or above the

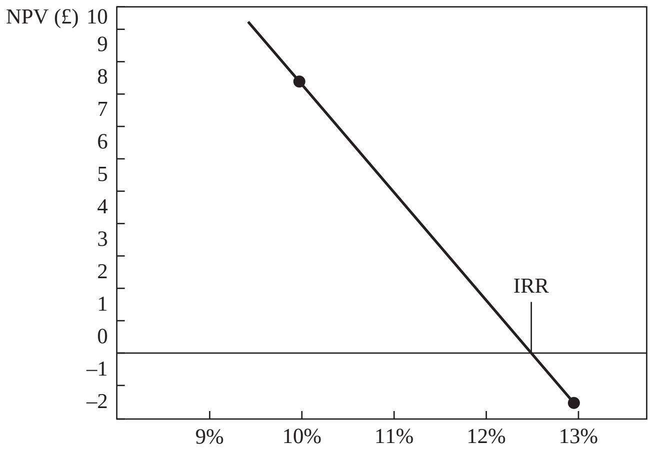

Figure 5.2 Calculating the IRR by interpolation

Table 5.3 Calculating benefits

Year	**Cost**	**Income**	**Net benefits**	**Net benefits discounted at 10%**
−1	40	–	−40	−44
0	100 + 10	40	−70	−70.00
1	10	40	30	27.27
2	10	40	30	24.79
3	10	40	30	22.54
4	–	70	70	47.81
			Net present value:	£8.41

minimum acceptable rate of return, then the project is considered to be worthwhile undertaking. The IRR can be calculated by trial and error calculations, through the utilisation of the above equation until *r* is found or can be interpolated. However, preferably, it can be calculated through the use of a computer program or a modern financial calculating machine.

Alternately, it can be computed using a graphical method. Two points may be plotted on the graph (Figure 5.2) and joined by a straight line. The point at which this line cuts the horizontal axis (i.e. where the NPV is zero) gives the IRR. The IRR for the example in Table 5.3 is shown.

The IRR concept has certain minor weaknesses that have been explained in the literature [6, 11, 12] and can sometimes be defective as a measure of the relative merits of mutually exclusive projects. It also contains an important underlying assumption, that all recovered funds can be reinvested at an interest rate equal to the IRR, which is not always possible. However, the IRR is a widely understood concept and it largely represents the expected financial and economic returns of the project. Also most of the weaknesses referred to do not normally occur in the electrical power industry. The main merit of the IRR is that it is an attribute of the project evaluation. Its calculation does not involve an estimation of a discount rate. Therefore, the evaluator avoids the tedious analysis of Chapter 4. It is satisfactory to calculate the IRR and compare it with the test rate conceived, which is a superficial attractiveness. Therefore, it is a widely used means of assessing the return of the project in the ESI.

5.3.2 *Net present value*

The concept of net present value (NPV) has already been explained in detail. The method discounts the net benefits (cash flows), i.e. project income minus project costs to their present value through the already assigned discount rate. If the net result is higher than zero, this proves that the project will provide benefits higher than the discount rate and is worthwhile undertaking.

For example consider the same project as given in Table 3.1, with the following present-day costs (investment £140, annual running cost £10) and income (benefits) of £40. The project is expected to last four years and the prevailing discount rate of 10 per cent is used.

Calculating the IRR: Since the NPV at 10 per cent is positive, the discount rate is greater than 10 per cent. Trying 12 per cent, the NPV is £1.76; at 13 per cent the NPV equals –1.47. The IRR is, therefore, around 12.5 per cent. Since it is higher than the minimum acceptable return of 10 per cent, the project is acceptable.

Finally, we consider the NPV: Since the NPV > 0, the project is acceptable.

The NPV is a powerful indicator of the viability of projects. However, it has its weaknesses, in that it does not relate the net benefit gained to the capital investment and to the time taken to achieve it. In the above example, it does not matter if £8.41 were obtained through investing £100 or £1 000, or obtained over 4 years or 40 years. However, it is very useful in choosing the least-cost solution, since it is the alternative that fulfils the exact project requirements and has the higher NPV that is preferred.

5.3.3 *Benefit/cost ratio*

This method compares the discounted total benefits of the project to its discounted costs:

$$B/C = \sum_n B/(1+r)^n / \sum_n C/(1+r)^n$$

Only projects of $B/C \geq 1$ are adopted. This criterion is popular and, in some applications, is more useful than the net present value, in that it relates the benefits to costs of the projects. It has also a useful application for capital constraint, when the industry has a lot of feasible projects but limited investment budget. In this case projects are ranked in accordance with their B/C ratio and are adopted accordingly until their combined costs equal the capital investment budget. Therefore, it is useful in comparative analysis.

It has to be remembered that B/C is a ratio, while NPV is a measure of absolute value.

In the example of Table 5.3:

$$\text{value of discounted benefits} = 40 + 36.36 + 33.06 + 30.05 + 47.81 = £187.28$$
$$\text{value of discounted costs} = 44 + 110 + 9.09 + 8.26 + 7.51 = £178.86$$
$$B/C \text{ ratio} = 187.28/178.86 = 1.047$$

5.3.4 Other non-discount criteria for evaluation

There are many other criteria for evaluating the project's worth and return of investments. The most common methods are the payback period and profit/investment ratio calculation.

5.3.4.1 Payback period

The payback period is defined as the time after initial investment until accumulated net revenues equal the investment, i.e. the length of time required to get investment capital back. The method is used as an approximate measure of the rate at which cash flows is generated early in the project life. It is utilised for small investments, like improvements and energy efficiency measures, since it is easy for business managers to understand. However, in isolation, it tells the analyst nothing about the project earning rate after payback and does not consider the total profitability or size of the project. It also ignores inflation and discriminates against large capital-intensive infrastructure projects with long gestation times. Payback is an *ad hoc* rule. Therefore, it is a poor criterion in itself and it must be used in conjunction with other criteria.

In the previous example of Table 5.3 the payback period is higher than three years.

5.3.4.2 Profit/investment ratio

The profit/investment ratio is the ratio of the project's total net income to total investment. It describes the amount of the profit generated per pound invested, and is sometimes referred to as profitability index. The idea is the selection of the project that maximises the profit per unit of investment. The ratio is easy to calculate, but does not reflect the timing at which revenues are received and profits generated. Therefore, it does not reflect the time value of money. Correspondingly, it is not a proper evaluation measure. In the example of Table 5.3 the profit/investment ratio is £50/£140 = 35.7 per cent.

5.4 Owner's evaluation of profitability: commercial annual rate of return

At the beginning of section 5.3 it has been explained that, for an investor to assess commercial profitability, forecasting a *pro forma* income statement through conventional financial accounts is necessary.

Therefore, it is possible roughly to evaluate the profitability of the equity investment from the commercial viewpoint of the investor through calculating the equity's profit by financial accounts. A year is chosen at which the project matures, and the net profit of the project is calculated for that year. Net profit is equal to income minus operational expenses, depreciation, interest, taxes and other expenses. This is compared with the total share (equity) capital invested and is the commercial return to the investors.

The same approach can be utilised for assessing the return on the total investment (equity plus loans). In this case the net profit, for commercial purposes, will be equal to income minus operational expenses, depreciation, taxes and other expenses. Interest is not included, since interest is the return on the loans. This net profit is divided by the total investment to calculate the commercial return of the whole investment.

Such commercial accounts are not the criteria for proper project evaluation for several reasons, mainly because they do not account for the time value of money. Depreciation is used as cost of capital invested, and depreciation does not adequately account for the declining value of money or for inflation. Accountants' measures of profitability are not well suited for *ex ante* project evaluation, especially for non-commercial projects.

Evaluation methods that do not involve the time value of money (discounting) are poor indicators. They provide approximations and should not be utilised for least-cost solutions or evaluating large investments. Evaluation of independent power projects are detailed in section 5.5.

To summarise, the guiding principle for project evaluation is the maximisation of net present value while utilising, as a discount rate, the opportunity cost of capital. The internal rate of return is not the only criterion for evaluating projects for investment decisions. Net present value with a proper discount rate (reflecting the true opportunity cost of capital) is a criterion. With limited budgeting a benefit/cost ratio has to be calculated to assist in prioritising projects.

5.5 Independent power producers

An independent power producer (IPP) is an entity, which is not a public utility, but which owns facilities to generate electric power for sale to utilities and end users. IPPs may be privately held facilities, corporations, cooperatives such as rural solar or wind energy producers, and non-energy industrial concerns capable of feeding excess energy into the system [13].

IPPs are now greatly increasing in numbers encouraged by two factors. The first is that many governments are now unable or unwilling to invest in electricity generation and prefer to devote their limited resources to social activities like education and health, and due to the liberalisation it is widely believed that the private sector is more efficient in such activities. The second is the recent advances in gas turbines and combined-cycle facilities and increased dependence on natural gas for electricity generation. Such facilities are well defined, do not require much capital and only need one or two years for execution. They carry only limited risk and therefore are ideal for private sector investments. Therefore, there are not many IPPs in the nuclear industry which is capital intensive and carry a measure of risk; this is still the domain of governments. Recently, particularly in the Middle East, an increasing interest has been seen among the IPPs to take up projects of water desalination in combination with power production. Therefore, some of the IPPs have now become independent water and power producers (IWPPs).

With the rapidly increasing number of IPPs the procedure and agreement for such activities have become almost well established and are thorough in defining the obligations and rights of each party with liquidated damages. The IPPs usually sell their power under a power purchase agreement (PPA) with the incumbent utility, the single purchaser or large customers. It is common to see the PPA take the form of build-own-operate-transfer (BOOT), which permits an investor to 'build', 'own' and 'operate' the generation facilities and then 'transfer' the facilities to the host purchaser on the termination of the contract.

Usually the IPP contracts are long-term PPA with the off-taker (mostly a public utility) who undertakes to purchase all the IPP's output. The PPA sets the rights and obligations of each side.

Such an IPP project structure is shown in Figure 5.3. It involves many project agreements; usually PPA, Power Purchase Agreement; FSA, Fuel Supply Agreement; LLA, Land Lease Agreement; LA, Loan Agreement; EPC, Engineering, Procurement and Construction; O&M, Operation and Maintenance.

Investments are usually procured by a mix of equity provided by the owner (20–30 per cent of the project cost) and loans (80–70 per cent). In most cases it is the owner who acts also as a project developer. The developer is the manager of the effort to realise the project from its inception to (typically) the financial close, which triggers the start of construction of the facilities for the project.

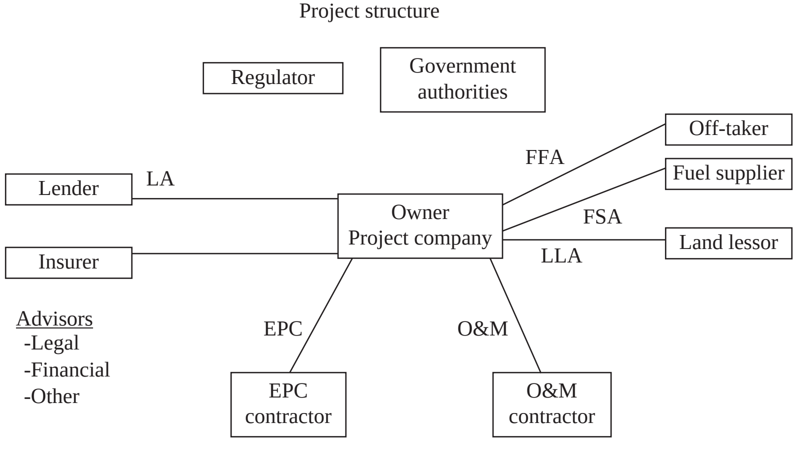

Figure 5.3 IPP project structure [Source: Reference [13]]

The investor PPA expects to attain a reasonable return on its equity and a fair IRR for the project. The IPP revenues are derived from two charges in PPA- fixed charges (capacity charge plus an O&M fixed charge), and a variable charge (fuel charge and O&M variable charges). In increasing number of cases the off-taker assumes responsibility for the provision of fuel and it is not included in the payment. Such arrangement for fuel is termed 'pass-through'. In most cases in developing countries such agreements are guaranteed by the government and usually supervised by a regulatory body.

The risk in generation investment is usually taken care of by investors in calculating the discount rate and weighted average cost of capital. However, the reform in the electricity market and the liberalisation are removing the regulatory risk shield which monopolies enjoyed, where they were capable of transferring financial risks to consumers. In a liberalised market the future power price level is not known. The investor is now required to internalise these risks in his or her evaluation of his or her investment decision. Therefore the private investor rates of return are usually higher than that of regulated integrated monopolies, and the time frame is shorter than the usual 30–40 years of the useful life of the facilities. Also investors now favour less capital-intensive facilities with more flexible technologies, like in investing in CCGT plant rather than investing in nuclear or traditional large coal-firing plant.

Therefore the Department of Energy and Climate Change (DECC) electricity market modelling does not use 'levelised cost estimates' *per se*. It utilises assumptions or investor's foresight over price for fossil fuel, prices of carbon (if any) and wholesale electricity prices and any financial incentive.

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Chapter 6

Considerations in project evaluation

Apart from discounting and least-cost evaluation, there are many considerations in project evaluation. These include allowing for contingencies, timing of expenditures, sunk costs, depreciation and interest charges. There are also other considerations relating to system linkages, dealing with projects of different lives, and expansion projects. Such considerations are discussed in the following sections.

6.1 Base cost estimate and contingencies

The base cost estimate [1] done at the evaluation stage is the best judgement of the cost of all project components at the specified evaluation date. It assumes that these components are accurately known and their costs are set properly. If certain cost estimates are rough, then that indicates the need for further investigations to accurately assess project cost components. The period for project implementation and the commissioning date should be estimated.

The best estimates of project costs can be undertaken from prices available at the time of estimation (date of evaluation). Project implementation can take many years. Hence, the actual cost of the project at the commissioning date will differ from the cost estimated at the time of planning and evaluation. This is the result of inflation and increase in prices and quantities of the project components, as well as sometimes of technology. Such variation is allowed for through the following two contingencies:

1. a physical contingency to allow for the increase in quantities of material and equipment involved in project execution and the change of implementation methods and
2. a price contingency to allow for increase in price of project components, over the base case estimates, during the construction period.

6.1.1 Physical contingency

The physical contingency reflects possible changes in quantities and implementation procedures. The amount of physical contingency depends on the type of the project components. Civil works have a higher contingency than machinery, to the extent of detailing in project estimate preparations. Physical contingencies usually vary up to 10 per cent of the project base cost. Beyond this, a more detailed estimate has to be undertaken in order to reduce uncertainties in project cost estimation. Physical contingencies are distributed along the project's execution life as a percentage of annual cost allocations.

6.1.2 Price contingency

The price contingency allows for the increase in unit prices of the project components, beyond the estimated prices of the planning year. It is highly dependent on inflation rates and other possible price increases. This allows estimating project cost disbursements in terms of the money of the year in which they occur. The sum of these annual disbursements, including price and physical contingency, gives an idea of project cost for formulating a *finance plan*. The full finance plan will include these costs plus the interest during construction and working capital. This indicates the amount of money needed to be raised and procured to finance the project. However, the project cost for financial and economic evaluation purposes is not indicated, since the financing plan involves adding money of different dates and correspondingly different real values. The base project cost is that project cost estimated in terms of the money of the planning year (or the commissioning year).

If the project cost is distributed along the years of the execution period and is desired to utilise the commissioning date as the base year and to present the project cost in terms of the money of that year, then the anticipated annual disbursements, during the project execution period (which include both physical and price contingencies), are compounded to that year by the nominal discount factor (which includes the discount rate plus inflation). Table 6.1 helps in explaining this. An alternative arrangement, if the project is estimated as a lump sum in the money of the planning year and it is desired to have the commissioning date as the base year, is where the planning year estimates are compounded to the commissioning date by the nominal discount rate with the physical contingency added, and these project costs are then represented in terms of the money of the year of commissioning.

For example, consider a project that takes three years for execution, and costs £100 at the base year (the present year of planning). Investment is grouped to be disbursed at 20, 40 and 40 per cent spread over three years starting one year after the cost estimation date. Price contingency is equal to inflation at 5 per cent annually. Physical contingency is 10 per cent and the discount rate is 12 per cent.

Table 6.1 Financing plan

Year	Base	Physical contingency	Price contingency	Total
1	20	2	1.1	23.1
2	40	4	4.5	48.5
3 (commissioning)	40	4	6.9	50.9
		Total project cost for the financing plan purposes = £122.5		

Commissioning date is after three years of execution. The financing plan requirements are given in Table 6.1.

The project cost in terms of the money of the base year is equal to the base cost plus the physical contingency (i.e. £100 + £10). The project cost at the commissioning date is the base cost plus the physical contingency, compounded by a factor of 1.626, i.e. $(1.12 \times 1.05)^3$, where (0.12×1.05) is nominal discount rate. Therefore,

project cost at the base (planning year) = £110 (money of the base year)
project cost at the commissioning year = £178.86 (money of the commissioning year)
project financing requirements = £122.50 (plus interest during construction and working capital if any)

This is elaborated further in section 6.2.

6.2 Interest during construction

An important consideration in project evaluation is how to account for interest during construction. In calculating the IRR (internal rate of return) of the project, the project cost can be considered to be equal to a single evaluated cost at the base year. If this is done, then it is not necessary to account for inflation or interest during construction in calculating the IRR. If the base year is the project execution commencement year, then the project cost at that year is the estimated cost of the project in terms of the money of that year plus the physical contingency. If the project cost is set in terms of the money of the commissioning year, then the price contingency is added to the cost stream of payments for project execution, so as to render it in terms of the money of the respective price contingency year. Then this stream is discounted (compounded) to the commissioning year by the nominal discount (compounding) factor, as already explained in section 6.1. Usually, the nominal discount rate is not much higher than the interest rate utilised for financing construction (interest during construction). The combined price contingency and the discount (compound) rate account for the interest during construction, where the latter is ignored in evaluation.

Therefore, for financial and economic evaluation of projects, the project capital costs can be presented as a lump sum either in terms of the money of the project planning year (commencement of execution) or the project commissioning (completion) of execution year. The latter figure is obtained by compounding the actual annual disbursements on the project to the commissioning year through the nominal discount rate. Alternatively, the project cost, while estimated in the planning year, can be presented as stream of payments along the execution period. In this case the physical and price contingencies are added and this stream is discounted by the nominal discount rate to the base year, whether it is the year of planning or commissioning.

Therefore, interest during construction is not directly considered in the financial and economic evaluation. It is ignored if the above procedures are carried out correctly. However, interest during construction is important for planning the finance of the project. It has to be realised that if the project is financed entirely by equity, then there will be no payments for interest during construction.

In Chapter 5 we introduced the concept of overnight cost. Overnight cost is the cost of a construction project if no interest was incurred during construction, as if the project was completed ‘overnight’. An alternate definition for overnight cost is: the present value cost that would have to be paid as a lump sum upfront to completely pay for a construction project.

The overnight cost is frequently used when describing power plants. The unit of measure typically used when citing the overnight cost of a power plant is $ per kW. For example, the overnight cost of a nuclear plant might be $5 000 per kW, so a 1 000 MW plant would have an overnight cost $5 billion. Interest on the $5 billion spent during construction would be extra [2].

6.3 Sunk costs

Sunk costs are defined as those costs that have been incurred on the project, before commencing the present evaluation. Despite their value to the project, they have already been spent. Therefore, they are not included in the costs of the project for new decision making or for determining whether to proceed with the project or not [3]. An investment is sunk if the asset cannot easily be used for any purpose other than its original purpose. Sunk costs can be different from fixed costs of a project. For instance, an investment in a power station building is sunk because the building has no other use (without great cost and difficulty). On the other hand, an investment in building management offices for a project in the city (although it is a fixed cost) is not a sunk cost, since such an asset can be readily converted for other purposes [4].

When evaluating the costs and benefits of completing or extending a project, the costs and benefits that already exist are not included in the evaluation. It is only the expected future costs and benefits that matter in the decision making today. Therefore, the IRR of completing unfinished projects or extending existing projects would appear to be very high, but that reflects the nature of the decision being made.

So if it is decided to convert or extend an existing installation or to utilise an existing infrastructure, there is no need to include past investments in the new evaluation. These are sunk costs, which should not be considered. However, it may be appropriate sometimes to calculate the returns on the total project (including sunk costs) to evaluate earlier decisions and learn from such experiences. This, however, need not interfere with the present evaluation decision making.

Sunk costs occur frequently in the electricity supply industry, for example in extending or refurbishing an existing power station or substation site, updating an existing transmission line, converting an existing dam into a hydro-power facility, etc. In all such cases, it is only the added costs and benefits of the project that need consideration. In evaluating the original project, the prospects of future extensions and modifications are contemplated. Such prospects should be included in the evaluation of the original project, since the success of the original project evaluation may be contingent on such future prospects.

6.4 Depreciation and interest charges

In evaluation, the cost and benefit streams of the project are reduced to cash flows. As already defined, cash flows are the difference between pounds received and spent out. Therefore, in calculating the internal rate of return, depreciation and interest charges are ignored. Depreciation does not represent actual cash flow and correspondingly is not involved in present valuing or any other economic evaluation criteria. Depreciation is, however, important in the preparation of financial statements (financial projections) of private utilities and firms. It influences the taxation, the profit/loss statement, and hence dividends to shareholders.

With regard to the interest charges, it must be remembered that the IRR is the maximum rate of interest that could be paid for the funds employed over the life of the investment without loss to the project. Therefore, interest charges should also be excluded from calculating the rate of return of the project and other evaluation criteria [4, 5]. This equally applies to interest during construction.

In most projects, like that of independent power producers (IPPs), financing is done by a combination of equity and loans, mainly loans. The investor is interested to know the IRR of the project and the return on equity. In calculating the return on the equity, the amount of loan servicing (interest on the loan and loan repayments) has to appear as cash expenses and deducted in the appropriate years from the current income stream. Simultaneously, the amount of loan has to be deducted from the project cost. Thus, the costs, benefits and net benefits will represent those accruing to the equity only. The IRR calculated will be the rate of return on the equity. It has to be compared with the opportunity cost of the capital, i.e. the return that this equity capital can obtain in the best alternative investment. The investor would undertake the project only if the internal rate of return on the equity in this project is higher than the opportunity cost.

6.5 Financial projections

It is useful to carry out financial projections for a new project. Such financial projections help in calculating the cost and benefit streams and consequently computing the project's IRR. The financial projections [6] necessary are as follows: (a) projected income statement, (b) projected balance sheet and (c) flow of funds statement. The income statement is useful in project evaluation, since it contains most of the information needed for the financial and economic evaluation. The income statement (in nominal terms) would detail for each year the income of sales and services, the cost of products (fixed plus operation), maintenance and capital charges (depreciation and interest). The information will allow the calculation of the profits in any given year and, after deduction of taxes, the calculation of net profits for distribution to the equity owners.

The financial statement can be produced in real terms, usually in the figures of the base year. It is more appropriate to plan the financial projections in current (nominal) terms to ensure coverage of full capital costs by the finance plan. It is also appropriate to evaluate the financial development of the firm and the viability of the project under the realistic situation of inflation. Therefore, the real financial projections (of the base year costs and revenues) are inflated, year by year, with a figure normally equal to the expected inflation rate. This will result in financial projections in current (nominal) terms. Such current projections will enable one to ascertain that the financing available in the form of equity, loans, financial allocations (depreciation) and retained profits will be sufficient to meet financial requirements of the project in current terms, year by year.

A single inflation rate may be useful for the estimation of financial statements. In some cases, and as already mentioned, certain items of costs and benefits may deviate from the expected general inflation level. For instance, expected increases in fuel prices may be higher than the inflation rate. Also, an increase in electricity price may display a trend of being slightly lower than an increase in the general price. In such cases, inflation differentials should be included in drawing out the financial statement to allow more realistic assessment of future trends. Such inflation differentials are also important when drawing out the cost and benefit streams in real terms for calculating the project's IRR. For instance, if it is expected that fuel prices, in the future, will increase at y per cent annually over the general inflation rate, then the real outlay for fuel in the cost stream should increase at a compound rate of y per cent annually over the base year.

The income statement, in current terms, aids in calculating the tax on profits. Most private investors are interested in the *after-tax financial rate of return*. Therefore, the income statement will allow the compilation of tax for each year. This is deducted from the net benefit stream to allow computation of the after-tax financial rate of return. Also, in the case of existence of loans, the deduction of the loan component and loan servicing from the benefit stream will enable the calculation of the after-tax financial rate of return on equity.

It is, however, essential to understand the concepts of financial statements, income statement, balance sheet and funds flow statement, in order to assess the actual performance of the company (firm) in the commercial market and the profits that will be paid to shareholders. It has been explained in section 5.4 that such financial statements (commercial accounts) are not criteria for proper project evaluation or least-cost solution. However, preparation of *pro forma* financial statements and financial projections help not only in computing the cost and benefit streams and consequently the IRR and NPV, but also in projecting the financial and commercial profitability of the project and the actual financial return that is likely to be paid to owners and shareholders. In case of projects, analysing financial performance and the calculation of financial ratios is useful to fully grasp the envisaged performance of the firm, and impact of the project on its financial performance and profitability to owners, and the financial problems the firm is likely to face (availability of funds, debt servicing, liquidity problems, etc.). As well as to undertake comparisons of the firm's performance with market acceptable financial ratios. Such financial performance and financial ratios will affect the ability of the firm to raise funds in the money market and the terms of obtaining these, as well as the price of the firm's share if these are traded in the stock exchange. Sections 6.5.1–6.5.3 offer short explanations of financial statements and ratios.

6.5.1 Financial performance and financial statements

Typical financial statements [7, 8] will look like as presented in Table 6.2, which contains an income statement followed by a balance sheet. These are summary financial statements. Annual reports of companies will show these summary financial statements as well as notes that explain, in detailed tables,

Table 6.2 Summary pro forma financial statement for a power generating company (figures are only indicative and in £ million)

	2013	**2014**
Income statement		
Income of electricity sales	125.0	128.8
Other income	2.0	2.7
Costs of generation (other than fuel)	(18.0)	(18.5)
Fuel costs	(50.0)	(52.0)
Other expenses	(8.0)	(7.0)
Depreciation	(25.0)	(25.0)
Earning before interest and tax (EBIT)	26.0	29.0
Net interest	(10.0)	(9.0)
Tax at 40%	(6.4)	(8.0)
Net income	9.6	12.0
Preferred stock dividend (if any)	–	–
Earnings of the common stock	9.6	12.0
Balance sheet		
Cash and short-term securities	5.5	5.0
Receivables	20.0	21.0
Inventories	15.0	16.0
Other current assets	(2.5)	(2.5)
Total current assets	43.0	44.5
Land, plant and equipment	554.0	544.0
Other long-term assets	20.0	40.0
Total assets	617.0	628.5
Debt due	10.0	10.0
Payables	100.0	95.0
Other current liabilities	5.0	5.0
Total current liabilities	115.0	110.0
Long-term debt	100.0	90.0
Other long-term liabilities	102.0	118.9
Preferred stock (if any)	–	–
Shareholders equity	300.0	309.6
Total liabilities	617.0	628.5

( ) is negative

each of the items that appear in the summary financial statements, including a table for allocation of profits (if any) which explains how profits applicable to common stock will be divided between dividends, reserves and retained profits.

The income statement of Table 6.2 can be a *pro forma* income statement for a power-generating firm that is supposed to commence its full production early in 2013; the figures of 2014 are also *pro forma* figures based on same energy sales, with a higher income of 3 per cent, which is the general inflation index expected for that year. However, prices of fuel have been inflated by 4 per cent in accordance with agreements and general price trend for fuels.

In the income statement, the income from electricity sales as well as from other sources (which can be from selling services or income from other investments) represents the total income of the firm. From this, costs are deducted; these are costs of operation (salaries, consumables, etc.) as well as fuel cost and other expenses (rents, rates, etc.). The allocations for depreciation are also deducted. The result is earnings before interest and tax (EBIT). After deducting interest the taxable income remains. The net income of the firm is the EBIT less the amount of interest and tax. Earnings applicable to the common stock (or to private investors) are the net income minus dividends to the preferred stock (if there are any preferred stocks which do not exist in the case of Table 6.2).

The balance sheet is a *snapshot* of the firm's assets and liabilities at the end of the year. These are usually listed in declining order of liquidity. Usually assets are current assets and long-term assets. Current assets are cash and short-term securities that can be easily liquidated, as well as receivables (which are the electricity bills that have not been paid yet), inventories of fuel, spare parts and other materials and consumables. Long-term assets consist mainly of the stock of generating plant, land, buildings, fuel storage, offices and similar facilities. The balance sheet shows the current value of these assets only in the first year. In later years this value is reduced by the amount of annual depreciation. Also, new assets can be added. Therefore, future balance sheets do not show the current or actual market values of assets, or their replacement values, but rather show their depreciated value for financial statement purposes.

Liabilities of the firm are also current and long term. Current liabilities are payments that the firm will have to pay in the near future (interest payable by the firm as well as debts due in the next year). Bonds, long-term loans and similar financial instruments that will not be paid for many years are the long-term liabilities. After deducting all short- and long-term liabilities, what is left is the shareholders' equity. This equity is equal to common stock plus retained profits. The shareholders' equity, its annual growth and its comparisons with the shareholders' paid-up capital, is important indication of the financial viability of the firm.

Most firms have to expand in the future. They can do that by self-financing, issuing new common stock or preferred stock, or by loans, or a mixture of both. Self-financing is very important for a firm's healthy growth. It is equal to retained profits and reserves plus depreciation allocations.

6.5.2 Financial ratios

Financial ratios are used to understand and test the viability of a firm, and the performance and returns of its investments. In case of evaluation of individual projects, financial ratios greatly help in studying the impact of the new project on the financial and commercial outlook of the firm (see section 6.9). There are many financial ratios of interest, the most important of which are briefly stated below.

Debt-equity ratio is a measure of the leverage of the firm:

$$\text{Debt-equity ratio} = \frac{\text{long-term debt} + \text{value of any leases}}{\text{equity}}$$

In the case of Table 6.2 it equals $100/300 = 0.33$ (for the year 2013).

Times interest earned ratio demonstrates the ability of the firm to serve the interest on its debt:

$$\text{Times interest earned ratio} = \frac{\text{EBIT} + \text{depreciation}}{\text{interest}}$$

Referring to Table 6.2 it equals

$$(26.0 + 25)/10 = 5.1$$

Current ratio is a measure of the firm's potential reservoir of cash and its ability to meet its short-term liabilities:

$$\text{Current ratio} = \frac{\text{current assets}}{\text{current liabilities}}$$

Current ratio, as given in Table 6.2, is $43.0/115.0 = 0.374$.

Net profit margin is the proportion of sales that finds its way into profits:

$$\text{Net profit margin} = \frac{\text{EBIT} - \text{tax}}{\text{sales}}$$

From Table 6.2 it equals $(26.0 - 6.4)/125 = 0.157$.

Return on total assets and return on equity are most important indicators of a firm's performance.

$$\text{Return on total assets} = \frac{\text{EBIT} - \text{tax}}{\text{average total assets}}$$

As per Table 6.2

$$(26.0 - 6.4)/610 = 0.032$$

(average total assets equal sum of assets at the beginning and end of the year divided by 2 and assumed to equal £610 million for year 2013).

$$\text{Return on equity} = \frac{\text{earnings available to shareholders (owners)}}{\text{average equity}}$$

this equals

$$9.6/300 = 0.032$$

Price–earnings ratio (P/E ratio) is a much quoted measure by the financial press. It is the ratio of the price of a firm's share in the stock exchange compared with its earnings. Therefore, it estimates how the firm is esteemed by investors and their expectation of its future performance.

$$P/E \text{ ratio} = \frac{\text{stock (share) price}}{\text{earnings per share}}$$

In the case of Table 6.2, if the number of shares of the firm is 300 million and the price of a share in the market is £1.05 then the earnings per share are 0.032 and the $P/E = 33$.

A high P/E ratio (like above) can indicate that the firm is at low risk, or there is expectation of higher growth in earnings in the future or in the value of the stock (or a combination of these).

$$\text{Dividend yield} = \frac{\text{dividend per share}}{\text{stock price}}$$

In the case of Table 6.2 this equals

$$0.032/1.05 = 0.0305 \cong 3.1 \text{ per cent}$$

6.5.3 Flow of the funds statement: sources and applications of funds

This important financial statement shows how the firm utilises its current assets to fund its investment and distribute dividends to its shareholders.

Internal sources of funds for a firm are operating cash flow income (after tax and interest), plus depreciation. External sources have been explained before. Applications (uses) of funds are utilised for financing new investments, paying dividends as well as increase (decrease) in the networking capital.

Table 6.3 explains a Sources and Applications of Fund Statement, as applied to any firm's income statement.

Such a Sources and Applications of Funds Statement leads, with the information available from the same year's financial statement and the other market and investment data referred to above, to a *pro forma* financial statement for the next year.

Financial planning that necessitates attempts to predict the firms' financial performance involves simulation and many assumptions including prediction of sales, prices, performance of competitors, price of money, depreciation and taxation policies, etc. Such planning has to proceed year after year with the approach followed in Tables 6.2 and 6.3. A manual approach is tedious. Nowadays, standard spread-sheet programs such as the modern version of Lotus and Excel, i.e. LOTUS 1-2-3 and Excel 2007, and more recent versions, greatly ease the work of financial planning managers.

Table 6.3 Sources and applications (uses) of fund statement

	Fund (in thousand pounds)
Income statement	
Income	2 000
Cost of sales	(1 400)
Depreciation	(100)
EBIT	500
Interest	(100)
Tax at 40%	(160)
Net income	240
Sources and applications of funds	
Sources	
Net income	240
Depreciation	100
Borrowing	400
Stock issue	400
Sources	1 140
Applications (uses)	
New investment	1 000
Dividends	100
Increase in net working capital	40
Applications (uses)	1 140

6.6 Evaluation of benefits in the electricity supply industry

Electricity production has one output, i.e. electrical energy in the form of kilowatt-hours (kWh). The benefits of most investments in the industry can be presented in kWh. In selecting the least-cost solution projects, it is wiser to present these benefits in kWh rather than money; then discount these benefits [8]. Benefits in monetary terms are kWh multiplied by the tariff, or other forms of valuation of the kWh (as in the case of reducing electricity interruption). Dealing with kWh will ease the work of the evaluator by avoiding other estimations, e.g. of tariffs, which has been shown in Table 5.2. However, the following paragraphs will deal with it in greater detail.

This approach is particularly suitable for evaluating base-load generation alternatives. The real costs of each alternative (capital plus operation) are discounted to the base year and divided by the discounted net benefits (which are the generated kWh during the project lifetime discounted to the base year). The least-cost solution is the alternative with the least discounted real cost per discounted kWh. Such methods have the advantage of being independent from tariff evaluation and inflation.

Such an approach does not take into account system effects; the contribution of each base load variant (nuclear compared with coal, for instance) must take into consideration its system effect. Nuclear has a much higher investment cost over CCGT (combined-cycle gas-turbine) per kW installed. Its higher utilisation factor would save some more expensive generation, which enhances its attractiveness. This is possible to compute through generation simulation, and assessing the impact of each alternative on the overall generation cost. This is detailed in section 6.8. In addition, not every kWh in the electricity supply industry is measured by the same yardstick. The value of a base generation kWh is different from that of peak generation. A kWh curtailed has a much higher value than the tariff. The same system effects apply to the network. Building a parallel transmission line will increase load transfer capability and reduce system losses, which have a value reflected in the tariff. It can greatly improve supply continuity which would reduce the amount of electrical energy curtailment, where each kWh saved will have an economic value of multiple that of the tariff.

In short, for alternative projects in the ESI, the procedure of evaluating the benefits in terms of discounted kWh to the base year is quite a useful tool. However, it is only accurate if the system effects of each alternative are the same or if different system effects are evaluated and incorporated in the analysis.

6.7 Timing of projects

There is usually great pressure to start publicly owned projects as soon as possible. However, a project should not be started unless the evaluator is certain that the project will have a positive net present value, while utilising the opportunity cost of capital as a discount rate. Even then, it may not be the optimum time to start the project. Assessing the effect of delaying the project has to be undertaken to evaluate whether a possible net present value will be better slightly into the future. If a future higher net present value is possible, then the project has to be executed at the year that provides the highest net present value.

Usually, a project should be executed when the first year net benefits exceed opportunity cost of the investment, i.e. the discount rate times the project cost. If the delay causes a rise in the cost of the project, in real terms, this should be taken into consideration.

6.8 Dealing with projects with different lives and construction periods

Project alternatives may have different lives and execution periods [9, 10]. The effect of the length of execution period is effectively reflected by discounting to the base year. The base year can be the project evaluation year, or the project commissioning year, with the same conclusions. For alternatives with widely different execution times (CCGT plant with typically two years for execution compared with six years for nuclear) system effects have to be considered.

There are various ways for comparing projects with different lives. If we compare a coal plant with an expected life of 40 years with a CCGT alternative with 20 years, then we repeat the investment cost of a new CCGT and add it to the cost stream at 20 years. However, things are not that simple when the expected life of the coal plant is only 30 years. In this case, we have to consider adding an investment in the form of a new fictitious plant (P_2) with a considered cost of 10 years after the end of the 20 years' life of the first CCGT plant. Since the comparison is over 30 years only, we have to calculate the cost of this new plant P_2 (which will actually live for 20 years) over only its first 10 years of service. This cost will be equal to the benefits (over the period 20–30 years) at a discount rate that is equal to the IRR of this investment. Since we know the cost of plant P_2 and can evaluate its benefits over its full life, we can calculate its IRR. This IRR is utilised as a discount rate of the benefits over the remaining 10 years of the project life (the period 20–30 years). It will be equal to the cost of the fictitious plant P_2 that will (for comparison purposes) serve only over the period of 20–30 years. This evaluated cost of P_2 will be added to the cost stream after 20 years.

Discounting greatly reduces the significance of this problem, particularly if high discount rates are concerned. After 20 years, the discounted value of the repeat project is 0.149 of its present cost at 10 per cent discount rate, and only 0.061 at 15 per cent discount rate.

The annual cost method manages the life of the alternative through calculating the discounted cost per discounted kWh. This method, also, does not reflect the technology advantage of the shorter life alternative.

6.9 Expansion projects

For a project expansion (or a firm's activity), it is necessary to carry out a *with and without* project evaluation. This involves estimating the additional benefits brought about by the project and comparing them with the additional costs caused by the project. With and without project evaluation is quite common in the electricity supply industry. It is particularly useful in case of evaluation of the economies of investing in renewables (wind and solar), as detailed in later chapters.

In this case, the analysis is slightly more complex. It is necessary to produce two sets of financial statements over the life of the project: one including the project expansion and another without it. The difference between the two statements indicates the incremental financial benefits brought about by the project expansion. Such incremental financial statements allow the calculation of the incremental financial IRR. After allowing for inflation, the determining factor for proceeding with the project expansion will be the incremental real IRR.

This is different from before and after comparison because even without the project expansion the net benefit in the project area may change.

6.10 System linkages (system effects)

System linkages are important in electrical power systems and have been referred to more than once earlier. However, these need to be handled in more detail. The electrical power industry, more than any other industry, has the distinct peculiarity that most of its major projects have financial and economic impacts that extend beyond the confines of the project to affect the whole electrical power system. This is because of the interconnected system and synchronic performance. Any new major project, or action, will have an immediate impact that is reflected on the economics of the supply, and sometimes on its quality. Building a new modern and efficient power station would contribute to more electrical energy production and reduce the overall system costs. This is through the production reduction from costlier power stations. Halting a generating unit for maintenance can cause (beside the maintenance cost) major system costs, through the need to operate or increase the production of a less economic generation plant. Adding a new transformer or transmission line can, besides enhancing the transfer of power, reduce system losses and increase availability of supply. This, in turn, will reduce the economic and social cost to the consumers of electricity interruptions.

Therefore, in all major power projects, particularly generation, it is advisable to perform a computer simulation over the next few years, with and without the project. The simulation output of the project is integrated in the system performance. This will allow a better evaluation of the financial and economic impacts of the project. Details of the system simulation are fully explained in published literature [11] and will also be covered in Chapter 11. A flow chart of generation costing and expansion simulation is depicted in Figure 6.1.

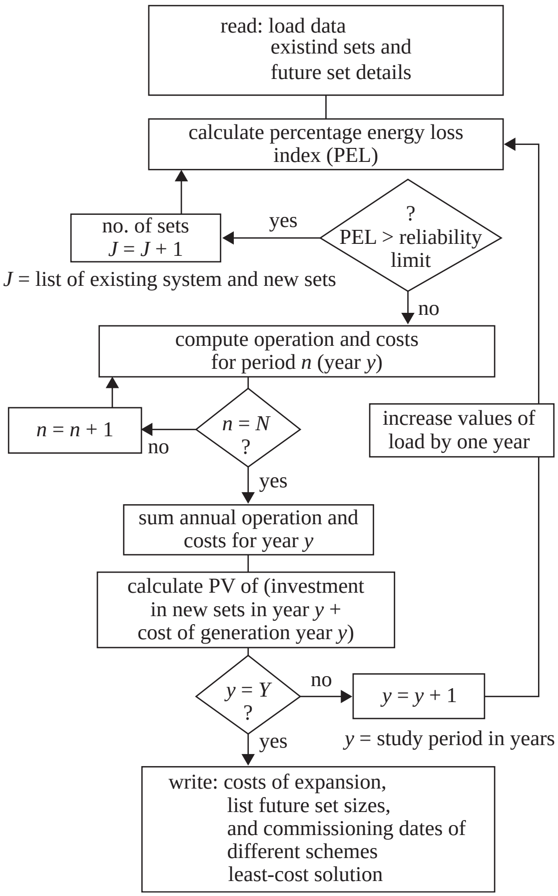

Figure 6.1 Costing of a system expansion plan

Many projects in the electricity supply industry are undertaken to reduce supply interruption and improve service to consumers. In these instances, it is necessary for the electrical utility to put a monetary value on each kWh curtailed. The economics of the network strengthening projects are evaluated through comparing the discounted annual value of the reduction in electricity curtailment (annual kWh saved multiplied by the social cost of each kWh interrupted) with the annual cost. This will be dealt with in detail in Chapter 11.

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Chapter 7

Economic evaluation of projects

7.1 Introduction

The financial evaluation of a project involves studying its performance and return (profitability) from the points of view of the industry (the utility and the firm), the owner and the investor (IPP). Economic evaluation, on the other hand, involves studying project benefits and returns from the national well-being point of view and assessing the effect the project will have on the overall economy and society of the country. While small projects have limited, if any, impact on the national economy, large projects have social and environmental effects, which cannot be ignored (referred to earlier as externalities). The electrical power industry is highly capital-intensive and is also a major emitter. A modern power station normally costs hundreds of millions of pounds, and so do some network projects. In high-capital projects of this nature it is necessary to find the least-cost solution not only from the point of view of the industry but from that of the national economy as well. The project evaluation should not be restricted to its profitability and should also evaluate its national economic and environmental impacts (social impacts) and compare them with those of other competing projects in the resource-limited national economy to ensure economic efficiency.

Economic analysis of major projects involves, therefore, evaluating two things:

1. the priority of the project in the national plans of the country and
2. its effect on the overall economy of the country, and its environmental (social) impacts.

The ultimate purpose of the analysis would be to provide a measure of the impact of the project on the national welfare as exemplified by the increased consumption of goods and services (including electrical energy) that serve as a proxy to increased welfare.

Economic efficiency is important to society. It has four primary components. The first component is the requirement of production efficiency, or incurring the minimum feasible cost in producing goods and services sold. The second component is efficient variety, which means that the menu of goods and services offered is tailored to the wants and needs of customers. The third component is allocative efficiency, which is desired by the society, wherein the goods and services go to customers who value these goods and services most highly. The fourth component is dynamic efficiency, which is desired by the society, which means that the first three types of efficiency are sustained [1].

In the electricity supply industry (ESI) the first purpose is fulfilled through the evaluation and study of the least-cost solution alternative [2]. The second and third purposes are achieved through the implementation of appropriate electricity tariff and security levels to different classes of consumers. The last purpose of sustainability is attained through integrated resource planning. Recently increasing attention is paid to consumer participation and involvement, hence the development of the smart grids [3].

Economic efficiency (which takes into consideration social as well as environmental costs and benefits) should be a fundamental criterion of public investment and policy making. It should also be fundamental for large capital-intensive private-sector investment that replaces, supplements or competes with public investment. This includes investments made by independent power producers. If real costs and benefits of large projects are not addressed from the perspectives of both the industry and the whole economy the wrong projects (or alternatives) may be selected.

The same method of discounting costs and benefits is used for both financial and economic evaluation. Economic evaluation is concerned with estimating the economic rate of return (ERR). Financial analysis, on the other hand, evaluates the internal rate of return (IRR) and considers only financial parameters in the analysis. A project, for example building a power station firing cheap, low-quality coal and located near the load centre, may have a high financial IRR. But when environmental costs of the project are considered, they may result in low (or negative) ERR and may lead to the rejection of the project on economic rather than financial grounds [4].

In many cases market prices do not reflect the real cost of resources, products or services to the economy. Market prices are usually distorted by duties, taxes, subsidies and other trade restrictions. Such instruments have a major influence on the financial profitability of a project from the industry or investor’s point of view but none on its economic viability from the perspective of the national economy. Distortions, particularly subsidies, vary from one country to another but are more prominent in the developing countries than in market economies, where efficient and transparent prices prevail. They do exist in many countries in varying degrees, particularly in energy fuels and products prices. This is most vividly exemplified in the electrical power industry where in some countries prices of local fuels are subsidised and are set at a level less than their true cost to the economy.

A lot of work has already been done during the past three decades to establish the techniques for the economic and social evaluation of projects. Most of this work was done in the past by the international lending agencies like the World Bank, Organisation for Economic Co-operation and Development (OECD), Overseas Development Administration (ODA) and various UN agencies [5–9]. Handling detailed mechanics of economic and social evaluation requires a skilled economist. These are briefly explained below. An important issue, which project planners need to be aware of, is the existence of distortions and the general techniques of dealing with them. Four issues are important: transfer payments, border and shadow pricing, externalities and system linkages. Two other related issues are also important: integrated resource planning (this has been dealt with briefly in Chapter 1) and environmental and health issues. The environmental impact of the ESI is significant. This is an externality that needs thorough evaluation and understanding and is dealt with separately in later chapters.

In most of the analysis that follows it is assumed that the official exchange rate of currency is not artificially fixed (overvalued) but rather is freely adjustable according to international trading links. This is the case in all OECD countries and is becoming increasingly so in most developing countries.

7.2 From financial evaluation to economic evaluation

The two time streams of financial costs and benefits form the starting point for economic evaluation. These financial streams have to be adjusted and modified with regard to the concepts of transfer payments, border and shadow pricing, and externalities. The essence of sound economic evaluation is to remove distortions, particularly price distortions, to improve investment decisions. Such distortions are mainly caused by transfer payments (subsidies, taxes and levies), imperfections in the domestic market (monopolies, restrictive practices etc.) and distortions caused by trade policies (exchange rates, quotas etc.).

In order to shift from financial to economic evaluation it is essential to implement a number of steps:

1. remove direct transfer payments;
2. use border prices in the case of traded goods and services (particularly fuels);
3. use shadow prices, particularly in dealing with non-traded items (such as land; unskilled labour etc.);
4. account for externalities (especially environmental impacts and health costs); and
5. allow for the difference between accounting and the official price of foreign exchange, if any.

Therefore, in economic evaluation, transfer payments (taxes, duties, subsidies) are not included. Costs and benefits are priced in border (international) prices for traded goods and shadow prices for non-traded goods. Externalities, whenever they exist, are added to costs and benefits.

7.3 Transfer payments

A transfer payment is a payment made without receiving any good or direct service in return. In economic evaluation of projects, the most encountered transfer payments are taxes and direct subsidies, as well as loans and debt services (payment of interest and repayment of principal). These are treated as transfer payments because the loan terms only divide the claims to goods and services between borrowers and lenders and do not affect the total amount of true economic return to investment.

Transfer payments represent only shifts in claims to goods and services and are not to the use of new production. They do not increase or reduce national income and are hence omitted when converting financial streams used in financial evaluation to economic values used in economic evaluation [10].

In the ESI, transfer payments normally apply to local duties, fuel subsidies (or taxes) and other subsidies, taxes and interest. Such payments do not represent direct claims on the country's resources but merely reflect a transfer of control over resource allocations from one part or sector of the national economy to another, and should therefore be excluded from economic evaluation. In contrast, they are quite important in financial analysis.

Economic analysis is not concerned with sources of investment funds (equity or loans or a combination of these) and repayment of loans (particularly local loans), since the loan and its repayment are financial transfers and are not part of the economic analysis. The economic cost of a project is its investment cost in the base year minus its discounted terminal value if any, converted into economic terms as detailed below. It is, however, essential to distinguish between taxes that are transfer payments and are ignored in economic analysis, and other taxes that are actual payment for goods and services and should be included. For instance, a road tax can be a payment for the services provided by the road, and a municipality tax can involve a charge for sewerage and should therefore be included in the analysis.

Subsidies are direct transfer payments that flow in the opposite direction from taxes. Fuel subsidies are common in the ESI, particularly for local coal and gas supplies, and renewables. Conversely, imported sources of fuel may be heavily taxed to encourage local energy sources, possibly for environmental reasons, or merely to provide an income for the government. In such cases local energy sources have to be priced at their full actual cost to the economy. If these items are tradable (as will be explained below) then their set prices should reflect border prices (opportunity cost) if they are higher than their production cost.

The same logic applies to credit transactions – loans and loan servicing. Such transactions do not increase national income but again represent the transfer of control of resources from one sector of the economy to another, i.e. they are transfer payments. Foreign loans that impose a burden on foreign reserves or that are subsidised by an undervalued currency have to be considered in the economic evaluation.

7.4 Externalities

An externality is the impact of a project felt outside its confines and is not included in its financial evaluation. Externalities may be either technological or pecuniary. An example of a technological externality might be pollution from a power station that causes direct material and health damage. Economic evaluation usually tries to incorporate technological externalities, especially costs, within the project account and thus change them from externalities to project costs and benefits (internalise them).

For example, costs of the damage to buildings and health by sulphur dioxide (SO_2) emissions, and to water basins caused by the waste discharges from the power station, may be calculated and assigned to the project, so also challenges of climatic change. Pecuniary externalities arise when the project affects the prices paid or received by others outside the project, for example where building a new efficient and clean power station reduces prices of electricity to users. Pecuniary externalities have to be included in both financial and economic analysis of the project.

Externalities are not easy to define and are very difficult to quantify. Their identification and attempt at quantification is an important part of the job of a skilled project evaluator. Some externalities are positive. In the ESI they may be in the form of technology advancement, export promotion, job creation, training etc. Examples of negative externalities include detrimental environmental impacts and congestion.

Most large projects in the electrical power industry have externalities, particularly environmental impacts. These range from minor visual impact and landscaping problems in small transmission and distribution projects to very serious pollution problems, as in low-quality coal power stations. In most cases such environmental aspects are identified in an impact assessment study and attempts are made to rectify them in project design and costing. However, other intangible effects, like visual impact, noise level, congestion, etc. are very difficult to quantify, as are some of the benefits like technological development, technology transfer and human capacity building. Still they should not be ignored and every effort should be made to identify and quantify them whenever possible. Externalities can have a strong influence on the choice of the least-cost solution, particularly when the difference in cost between alternatives is small.

It is important to try to identify all externalities caused by the project. Where there are significant externalities, an attempt should be made to quantify them and include their values in the project costs and benefits. Where it is difficult to quantify them, which is usually the case, they should be cited in the project economic evaluation and they may affect the choice of the least-cost solution. Environmental and global warming externalities of electricity production are particularly important. They involve carbon pricing and a special discount rate, and these are dealt with in detail in the following chapters.

A main externality aspect of a project in the ESI is the system linkage of projects. System linkages are external to the project itself but are internal to the ESI as a whole, and therefore cannot be treated as a true externality. They should be taken into consideration in all financial and economic evaluation of projects.

7.5 Border and shadow pricing

During construction each project incorporates a lot of inputs (resources) such as equipment, materials, land and manpower. During the lifetime of the project, it also consumes inputs, and produces output (product). Among the most important operational inputs in power projects are fuel, manpower and similar resources. In the financial evaluation these inputs are valued at their market prices. Market prices are not ideal and are often distorted to varying degrees in different countries. The industry and investors are mainly interested in market prices of inputs and outputs because that is what they have to deal with and it is these prices that determine financial profitability. Economic evaluation goes beyond this by investigating the true impact of the project on the national welfare. To achieve this, prices of resources must be set at their true cost to the economy [11].

Inputs and outputs can be classified into two categories: traded and non-traded. A project input or output is deemed 'traded' if its production or consumption affects a country's level of imports or exports at the margin. Machinery and equipment, as well as fuel and skilled labour and marketable products, are considered tradable. A project input or output is considered to be non-traded because of its bulkiness, cost consideration and immobility or other restrictive trade practices. Non-traded goods and services include things like land, water, buildings, unskilled labour, electricity (in most cases) and many other services and bulky material. Traded and non-traded goods and services are part of project inputs and outputs. For economic evaluation they have to be priced at their true cost to the economy.

7.5.1 Pricing traded inputs and outputs

Because they can be traded, i.e. imported as well as exported, tradable inputs and outputs create a change in the country's net import or net export position at the margin. They must be valued, in economic evaluation, at *border prices*. Border prices are world prices, free on board (FOB) for exports and cost, insurance and freight (CIF) landed cost for imports, adjusted by allowing for domestic transfer costs. Transfer costs are costs that are incurred in moving inputs and outputs between project site, border and target markets.

Take coal as an example. The border price of imported coal, which will be incorporated in the economic evaluation, will be the CIF price at the nearest port plus handling and transport charges to the generating plant. If this coal is produced locally, its economic price will be its opportunity costs, i.e. FOB price at the port of export minus the cost of transport from the coal mine to the port plus the cost of transport to the generating plant. For bulky materials, like coal, such transport prices are significant and greatly favour local production.

Consider an example in which coal can be imported by country 'y' at \$80 per ton with transport cost between country 'x' and country 'y' at \$20 per ton. If country 'x' would export its production to country 'y', then it has to price it at \$60 per ton (\$80 – \$20 per ton). If the cost of handling this coal and transporting it to the export port of country 'x' is \$15 per ton, then coal at the mine-mouth has to be \$45 per ton. If this coal is used locally instead and with transport plus handling cost of \$5 per ton from the local mine to the local power station, then the economic cost of coal will be \$45 + \$5, i.e. \$50 per ton, irrespective of the actual cost of extraction, which can be much less.

If the cost of production of coal in country ‘x’ increases and it considers importing outside coal from a source with a sea transport cost of \$15 per ton, then its CIF of imported coal will be \$50 + \$15 = \$65 per ton. If transport of this coal to the power station involves another \$8 per ton then the total cost of imported coal to the power station is \$73 per ton.

Country ‘x’ is advised to continue production of coal as long as its production cost is equal to \$68 (\$73 – \$5 per ton local transport cost from the mine to the power station). If country ‘x’ decides to continue producing coal from its mines, even if its production cost reaches \$90 per ton, while selling it at \$70 per ton to the power station, then its coal subsidies will amount to \$20 per ton. Such subsidies are excluded in the economic evaluation. The market price for coal will be \$70 per ton in the financial evaluation of the investors, and \$73 per ton (i.e. the border price) in the case of economic evaluation.

A decision to utilise a local resource (like coal) is not only dependent on production costs and border prices, but also influenced by many other political and social considerations, like utilising local resources, creating local employment, supply security and shortage of foreign exchange, and also environmental considerations. In making such decisions, however, the border price of coal has to be calculated and taken into consideration in evaluating plans and decisions.

7.5.2 Pricing non-traded inputs and services

Non-traded goods and services are priced at their *shadow price*. A lot of research was done in understanding and evaluating shadow pricing [5–8]. With the enhancement of free trade, freely convertible currencies, liberalization and open markets, shadow pricing is still required but not to the extent it was in the past.

In evaluating non-traded goods and services it is essential to differentiate between non-traded tradables and non-tradables. Non-traded tradables are goods and services that can be traded in the international market but are not traded either because of their cost being higher than international prices (e.g. local low-quality coal) or because of trade restrictions and policies (quotas, restrictive import taxes at potential import markets, etc.).

A good example of a non-traded tradable is coal. If the international price of coal is \$50 and its transport to the power station involves an additional \$23, a local coal mine with a high production cost of \$68 (which is above international prices hence rendering its product a non-traded tradable) will continue production protected by the high transport prices. In such cases the economic price of a non-traded tradable commodity is the opportunity cost of the product, i.e. the price it can command in the absence of the project.

Most power projects involve non-tradable inputs, mainly materials for civil works and labour. Such inputs can be decomposed into its components. Large civil works like a power station building contain tradable and non-tradable components. Tradable inputs (cement, steel etc.) can be priced in accordance with their border prices. Non-tradable inputs (gravel, sand, stones, labour etc.) have to be shadow-priced through utilising conversion factors [11]. The most widely used factor is the standard conversion factor (SCF). This factor is the average ratio of border and domestic market prices, and is equal to

$$\frac{M + X}{(M + T_{\mathrm{m}}) + (X - T_{\mathrm{X}})}$$

where M = CIF value of imports, X = FOB price for exports, T_{m} = all taxes on imports and T_{x} = all taxes on exports. Through applying this conversion factor by multiplying it by the non-tradable inputs it is possible to reduce the impact of local distortions. In a way the SCF is the ratio between an official and a shadow exchange rate. In developing countries, it is usually less than unity, signifying that the local currency is overvalued.

Table 7.1 Conversion of financial cost of a power station civil work component into economic cost (in local currency units)

Component	**Financial cost**	**Conversion factor**	**Economic cost**
Traded items			
Cement	10 000	0.90	9 000
Steel	30 000	0.80	24 000
Non-traded items			
Other building materials	10 000	0.88	8 800
Overhead	20 000	0.88	17 600
Unskilled labour	25 000	0.50	12 500
Skilled labour	5 000	1.00	5 000
Total	100 000	0.77	76 900

Table 7.2 Estimation of economic costs and benefits [11]

Project inputs

A. Net imports of tradable items (CIF plus converted port-to-project costs)
B. Diverted net exports of tradable items (FOB minus converted source-to-port plus converted source-to-project costs)
C. Non-traded items
   1. Land (converted opportunity cost)
   2. Labour
      a. Skilled (market wage rate)
      b. Unskilled (converted shadow wage rate)
   3. Goods (converted domestic market price plus converted source-to-project costs)

Project outputs

A. Net exports (FOB minus converted project-to-port costs)
B. Import substitutes (CIF plus converted port-to-market costs and minus converted project-to-market costs)
C. Non-traded items (converted factory-gate price)

Consider a country with imports valued at 100 million currency units and exports of 50 million units, import taxes of 20 million units and export taxes of zero. The SCF is equal to 0.88 (which is $(100 + 50)$ million divided by $[(100 + 20) + (50 - 0)]$ million). It is also usual to have a SCF equal to 1.0 for skilled labour and 0.5 for unskilled labour.

An example is a power station building, which is priced in local currency as shown in Table 7.1. The conversion factors for steel and cement were calculated using border prices as shown. The economic cost of the power station building will be as per local currency. An estimation of economic costs and benefits is given in Table 7.2.

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Chapter 8

Environmental considerations, cost estimation and long term discounting in project evaluation

8.1 Introduction

Electricity utilisation is environmentally benign, and as a carrier electricity is clean and safe. It causes no pollution or environmental emissions at the point of use. It has also been proved that electricity can be more efficient than some other forms of energy as explained in Chapter 1 [1]. Therefore, substituting electricity for other forms of energy can help in reducing global emissions and pollution caused by the use of the latter. In addition, the fact that electricity production is undertaken at a single point, namely the power station site, means that environmental problems associated with electricity production are concentrated at a single point, which makes containing and dealing with them much easier.

Electricity production can cause local and regional environmental impact and also have long-lasting detrimental global consequences. Some of these impacts like the emissions of sulphur dioxide (SO_2), nitrogen oxides (NO_x) and solid particulates, which all have detrimental air quality implications, can be controlled by investing in technology and abatement facilities. These measures can control and reduce such emissions significantly. The process of controlling carbon dioxide (CO_2), which is the main gas suspected of causing global warming (greenhouse effect), is far more difficult and expensive. Fossil fuels account for two-thirds of electricity generation and 45 per cent of total electricity production in 2010 used coal (sometimes low-quality coal and lignite). Coal use for this purpose is increasing particularly in developing economies [2]. These countries, with their limited financial resources, still cannot afford to invest in expensive measures for environmental preservation, particularly those concerned with long-term global effects. Their main concern is the production of the largest possible quantity of electricity to meet shortages and growing local demand in the most extensive manner and as cheaply as possible. Their environmental actions, in many cases, are a late response to an impending major environmental disaster [3].

Employment of abatement technologies is not the only way to control emissions. Substantial emission containment can be achieved through enhancing efficiency in production, conservation of use and use of cleaner fuels (natural gas) and clean technologies (as detailed later), as well as by using zero-emissions energy sources (hydro, nuclear and renewables). The major effort that has taken place recently in the field of improving efficiency of electricity generation has been discussed in Chapter 5. Developments in this field are still taking shape and will ultimately lead to the production of more electricity with less quantity of fuel. Gradual improvements in the energy sector are taking place where electricity is substituting other forms of energy in final use. This will enhance the role of electricity in environmental preservation by reducing emissions from other sources. Clean coal technologies are still being developed [4]; carbon sequestration technologies, although promising, are still quite expensive and it will be many years before they become effective.

Conservation in consumption as well as improved efficiency in energy systems and electricity utilisation is important means for attaining the environmental goals. Conservation and efficiency-in-use measures do not always require large investments and should therefore be the first technologies and methods to be applied. But they do require policies. The main promoter of these measures is the pricing mechanism (tariffs). Another powerful way of promotion is through informing and educating consumers and soliciting their participation in conservation and efficiency measures and in investing in energy-saving technologies. Heat pumps, electric arc melting, induction heating, electric transit and efficient electric house appliances and modern electricity-saving lighting can significantly reduce energy and electricity consumption without compromising consumers' production and welfare. Such electricity conservation, and efficiency in use, plus switching from primary energy use into electricity, lead to substantial reductions in emissions and environmental impacts of electricity and energy without having to invest in capital-intensive environmental abatement technologies [5].

Because of the nature of fuels utilised in the electricity supply industry (ESI) and the rapidly growing utilisation of energy in the form of electricity, the environmental impacts of electricity production are gaining more importance than those of other forms of energy, and this demands a thorough understanding of their nature. Such impacts can have direct financial costs (damage to trees and forests and pollution to land and other resources that can be financially assessed) as well as intangibles (mainly health). There are also the long-term environmental costs and impacts of global warming. These damages can be grouped as social costs. Some of these environmental impacts have to be avoided through investment. A cost/benefit analysis to the costs involved in controlling emissions from the ESI and the benefits derived out of this action have to be undertaken. Unfortunately, a lot of environmental damage costs resulting from electricity production are very difficult to quantify, but the science of environmental accounting is improving [6, 7]. This chapter tries to record the environmental detrimental effects of electricity, methods of quantifying them (where possible), and analyses technologies, investments and other means of control.

Environmental and health consequences are usually seen as external costs – those which are quantifiable but do not appear in the utility's accounts. Hence, they are not passed on to the consumer, but are borne by society at large. These include particularly the effects of air pollution on human health, crop yields and buildings, as well as occupational disease and accidents. Though they are even harder to quantify and evaluate than the others, external costs include effects on ecosystems and the impact of global warming [8].

8.2 Environmental impacts of electricity fuels

Electricity production can have many environmental, health and safety impacts. These occur during the mining phase, using the fuels and dealing with waste. Mining for electricity fuels, their transport and storage also contribute to pollution; so does the disposal of the combustion-process products of ash and other solid wastes. Coal, in environmental terms, represents particular concerns. Its consumption by-products are more polluting than other fuels and they contain higher carbon, SO_2 and NO_x emissions and much more solid waste. Environmental health and other safety impacts of coal mining and transport can be substantial [9].

The main categories of impact of pollution are local, regional and global.

(i) Local impacts are mainly in the form of heavy hydrocarbons and particulate matter (including carbon and sulphur flakes), which are deposited within hours and can travel up to 100 km from the source.

(ii) Regional impacts involve emissions and effluents, the most important of which are SO_2 acid depositions, which have a residence time in the atmosphere of a few days and may travel to a few thousand kilometres, thus causing cross-boundary effects.

(iii) Global pollution is exemplified mainly by CO_2 emissions and to a lesser extent other gases (like methane), which have long residence times in the atmosphere.

Methods of costing the three impacts are described in the following section. The various impacts of the fuel system components are detailed in Table 8.1. Carbon emissions of the fossil fuels are shown in Table 8.2 and the global warming potentials (GWP) of different emissions are in Table 8.3.

Not all impacts of increasing electricity utilisation are detrimental. Most of the time, substituting electricity for other forms of energy helps in improving the efficiency of use of primary fuels. Electricity has replaced most other fuels in urban societies and has improved the quality of urban and built-up environments and of environmental management through various instrumentation and control technologies. The fact that electricity is highly controllable significantly improves the efficiency of heating and cooling systems, as well as machinery and lighting through shorter warm-up and cool-down periods. Therefore, electricity can play a significant positive role in safeguarding local, regional and the global environment if measures to control the detrimental supply side impacts are dealt with in an economically sound manner.

GWPs show that greenhouse gas emissions (GHGs), other than CO_2, can pose a much larger risk to the environment if emissions continue unchecked. GWPs are a measure of the relative radiative effect of a given substance compared to CO_2 over

Table 8.1 Environmental impacts of fuel system components

Electricity generation fuel	**Key impact**
Coal	Groundwater contamination
	Land disturbance, changes in land use and long-term ecosystem destruction
	Emissions of SO_2, NO_x, particulates with air quality implications, heavy metals leachable from ash and slag wastes
	Possible global warming and climatic change from CO_2 emissions
	Lake acidification and loss of communities due to acid depositions
Oil and gas	Marine and coastal pollution (from spills)
	Damage to structures, soil changes, forest degradation, lake acidification from SO_2 and NO_x emissions
	Groundwater contamination
	GHGs impact, e.g. possible global climate change
	Flared gases
Hydroelectric	Land destruction, change in land use, modification of sedimentation
	Ecosystem destruction and loss of species diversity
	Changes in water quality and marine life
	Population displacement
Nuclear	Surface and groundwater pollution (mining)
	Changes in land use and ecosystem destruction
	Potential land and marine contamination with radionuclide
	Possible grave nuclear accidents (Chernobyl, Fukushima)
Renewable	Atmospheric and water contamination
	Changes in land use and ecosystem
	Noise from wind turbine operations and aerodynamic modulation on sleeping patterns
	Possible air quality implications

Source: Reference [6–9].

Table 8.2 Carbon emissions of fossil fuels

	Tonnes of carbon per TOE
Coal	1.08
Fuel oil	0.84
Natural gas	0.64

TOE = tonnes of oil equivalent.
Source: Reference [10].

a chosen time horizon. They are an index for estimating the relative global warming contribution due to atmospheric emission of 1 kg of a particular GHG compared with 1 kg of CO_2. The atmospheric response time of CO_2 is subject to substantial scientific uncertainties, owing to limitations in the understanding of key processes, including its uptake by the biosphere and ocean. The numerical values of the GWPs of all GHGs can change.

Table 8.3 Global warming potentials (GWP)

Gas	**Global warming potential time horizon**		
	20 years	**100 years**	**500 years**
Carbon dioxide (CO_2)	1	1	1
Methane (CH_4)	62 (56)	23 (21)	7 (6.5)
Nitrous oxide (N_2O)	275 (280)	296 (310)	156 (170)
Sulphur hexafluoride (SF_6)	15 100 (16 300)	22 200 (23 900)	32 400 (34 900)

Source: IPCC 2007 [6] (1995 IPCC figures in brackets).

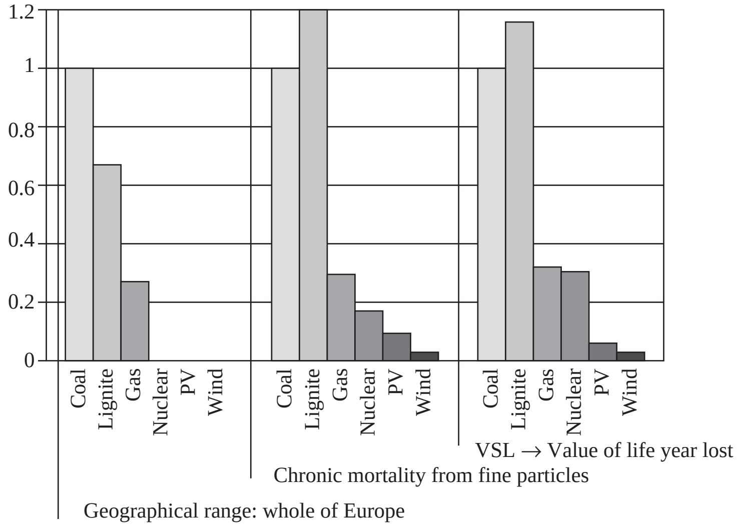

Figure 8.1 Relative ranking of external cost estimates (excluding global warming impacts) for different electricity generation technologies under changing background assumptions. External costs are normalised to the external costs for the coal fuel cycle [Source: Reference [11]]

8.2.1 Environmental impact of different generation fuels

The ExternE project is a major research programme that was launched by the European Commission at the beginning of the 1990s to provide a scientific basis for the quantification of energy-related externalities and to give guidance supporting the design of internalisation measures [11].

In spite of the existing uncertainties, the results of this project were quite robust with regard to the relative ranking of different electricity generation technologies. Figure 8.1 clearly shows that even under different background assumptions electricity generation from solid fossil fuels is consistently associated with the highest external cost, while the renewable energy sources cause the lowest externalities.

8.3 Environmental evaluation

It is not easy to estimate, with a measure of certainty, the cost of environmental impacts of electricity production at local, regional or global levels. Local environmental impacts depend on the quantity and quality of fuel utilised, the site of the power station with regard to population centres and the availability of other amenities. A power station sited in the desert will have much less impact on environmental health than a similar power station close to population centres and forests. A hydro-electric power station in an uninhibited area will have a lot less environmental impact than a hydro-power station that leads to relocating people or to the destruction of villages and agricultural lands.

Environmental impacts that can be quantified in financial terms should be incorporated in the economic evaluation of the project. Those that cannot be directly evaluated (such as loss of bio-diversity, impact on health, etc.) should be researched and quantified, whenever possible, and also incorporated as social costs. Such costs have to be utilised in the economic evaluation used to identify the least cost and in the calculation of the internal rate of return (IRR) and economic rate of return (ERR). Detrimental environmental impacts can be lessened or alleviated through investment, and a cost–benefit analysis of such investments should be performed.

Today, emissions from power stations have been identified and most of them can be evaluated in terms of their environmental impacts (see Table 8.1, also [9]). Therefore, it is now possible, although somewhat difficult, to approximately determine the cost of a power facility’s environmental impact. This cost has to be compared with the capital investment needed for implementing suitable abatement technologies. Benefits of capital investments incorporating different abatement technologies – and thus leading to different impacts – should be compared to help identify the least (economic) cost project alternative.

Long-term global warming impacts are more difficult to assess and cost. These can be included in a carbon price which adds to the cost of electricity production as discussed below (Sections 8.7 and 8.8).

8.4 Health and environmental effects of electricity

The vast majority of the environmental and health effects of electricity are from the generation side, particularly when firing low-quality coal. Hydro-electric and natural-gas fired facilities have lower environmental impacts. It was thought that adequate safeguards have rendered nuclear power stations (almost) safe, but natural disasters (Fukushima) have challenged this. Sections 8.5.1 and 8.5.2 briefly detail the health and environmental impacts of electricity generation facilities.

8.4.1 Direct health effects

8.4.1.1 Fossil-fired generation plants

In the case of gas- and coal-fired plants, a significant public health risk results from exposure to the large amounts of gaseous and solid wastes discharged in the combustion process. These emissions include SO_2, CO, NO_x, hydrocarbons and polycyclic organic matter. Coal-fired stations also discharge fly ash, trace metals and radionuclides. The presence of these pollutants leads to increased incidence of respiratory disease, toxicity and cancer. Disposal of the resulting solid waste leads to health risks associated with leachate and groundwater contamination. Natural gas-fired plants pose a public health risk of NO_x and particulate emissions, but are significantly less hazardous to health than oil- or coal-fired plants [9].

8.4.1.2 Renewable

Large-scale hydro-electric plants pose relatively few health risks compared to fossil-fired plants. However, still water reservoirs create ecological environments favourable to the spreading of parasitic and waterborne disease. Relatively low public risks exist from the low probability of dam failures. Biomass plants emit lower levels of SO_2 compared with gas- or coal-fired plants, but have higher emissions of potentially carcinogenic particulates and hydrocarbons. Other renewables such as solar photovoltaic and thermal, geothermal, tidal and wind power pose no significant occupational or health risks at the generation stage. However, manufacturing and infrastructure building of renewable projects involve emissions and other environmental costs and impacts that can and have to be evaluated and incorporated in the evaluation.

8.4.1.3 Transmission and distribution

The health impacts of transmission and distribution, particularly ultra high voltage alternating current (UHVAC) and high voltage direct current (HVDC), have been documented [12]. It has been verified that human sensitivity to short-term exposure to a strong electrostatic field could be significant. Studies to measure the biological effects of electric fields and of chronic exposure to electric fields on people, animals and plants have been carried out. Since 1981, dozens of studies examined the incidence of cancer among workers exposed to electric and magnetic fields (EMF). Results were inconsistent. While some studies showed a slight rise in mortality of leukaemia or brain cancer among electrical workers, others showed no such tendency. Recent more extensive and detailed studies and research were also inconclusive. Any negative health effects of transmission and distribution may be relatively minor compared to the health effects of the alternative option: sitting power generation facilities closer to population centres [13].

8.4.2 Environmental impact

As mentioned earlier, pollution resulting from electricity generation can be broadly categorised as having local, regional and global environmental consequences. Regional and global impacts are caused primarily by the emission of atmospheric pollutants that have longer residence times, causing dispersal over larger areas. Most important among these gases are SO_2, which causes acid deposition or ‘acid rain’, and CO_2, which is a ‘greenhouse gas’ and contribute to global warming.

8.4.2.1 Local impacts

Purely local impacts include those caused by fossil-fired power plant emissions to the atmosphere (particulates, leaded compounds, volatile organic compounds, dust) that result in air-quality degradation causing damage to crops, structures, local ecosystems and posing a health hazard [9]. This is also the case with emissions from waste-to-energy plants. Effluent disposal from fossil-fired and nuclear plants can lead to groundwater contamination with long-term irreversible pollution implications. The existence of potential carcinogens and mutagens in the waste can have negative impacts on health and agricultural productivity. Improper disposal of radioactive waste from nuclear plants (e.g. discharge of liquid waste into the sea) can cause destruction of fisheries and other health hazards through contamination of the water supply.

Hydro-electric power generation is perhaps the one electricity generation system that has only local, but occasionally major, environmental consequences. These consist of the damage caused by dam construction: destruction of habitats and loss of local/national biodiversity, the inundation of productive land and forests and possibly the loss of cultural sites and mineral resources. Watershed disturbance sometimes leads to increased flooding and low flow in the dry season. On major river systems, this can have inter-regional and/or transitional consequences causing significant political and social unrest over water rights. The existence of still water contributes to the spread of waterborne and parasitic disease. The massive displacement of people that is often required represents a significant social cost and can lead to increased use of marginal lands.

Environmental impacts from other renewables are related primarily to the loss of land use represented by the high space intensity of solar energy, and the noise caused by wind-powered generation. Also the already mentioned emissions during manufacturing and infrastructure materials and building.

8.4.2.2 Regional impacts

Coal- and gas-fired power stations emit significant amounts of SO_2 and NO_x to the atmosphere. The transport of SO_2 occurs over long distances (greater than 1000 km), causing the deposition of emission products over national boundaries. This may result in ecologically sensitive ecosystems receiving depositions of sulphur well above carrying capacity.

Acid deposition caused by SO_2 and NO_x results in damage to trees and crops, and sometimes extends to acidification of streams and lakes, resulting in destruction of aquatic ecosystems. It also leads to the corrosion, erosion and discolouration of buildings, monuments and bridges. Indirect health effects are caused by the mobilisation of heavy metals in acidified water and soil.

While electricity generation accounts for less than half of the total anthropogenic NO_x emissions (the majority of the remainder is caused by motor vehicle exhausts), the portion of SO_2 emitted by electricity generation is substantial. For example, Europe (including Eastern Europe) emitted close to one-third of the worldwide anthropogenic sulphur emissions in the early 1980s. It is estimated that in the last two decades, 60 per cent of European SO_2 emissions were the result of electricity production. Since then, through the utilisation of desulphurisation facilities, such emissions decreased in the Organisation for Economic Co-operation and Development (OECD) countries, also in East Europe, while they are still on the rise on many developing economies.

Other regional environmental impacts are caused by radiation effects on health, and land/water contamination caused by severe nuclear accidents or tsunami. As mentioned earlier, changes in hydrological flow and water conditions caused by dams can also have regional consequences. Thermal-power plants could also have a negative effect on aquatic organisms, fisheries, etc. owing to the increase in the water temperature that could be caused by diffused thermal effluent.

The relative contribution of electricity to overall global emissions (mainly in the form of CO_2 emissions) has been estimated in the US (in 2011) at about 33 per cent and increasing, compared with about 28 per cent caused by transportation. Of the contribution of fossil fuels, coal and oil each contributed about 43 per cent and 36 per cent respectively of anthropogenic CO_2 emissions, and gas contributes about 21 per cent. Electricity generation present contribution to global CO_2 emission is now approximately 43 per cent. The major CO_2 emitter is China, nearing 8 Gt in 2012. Emissions from India and the Middle East are increasing, while that of the US and EU are decreasing [2]. However, power generation is the single largest contributor to GHGs in developing economies. Both China and India are expected to increase coal-fired generation to meet the growing energy needs of their citizens for electricity through utilising domestic energy sources; some of this coal is of low quality with significant local, regional and global impacts.

8.5 Investment costs in reducing dangers to health and environmental impacts

The modification of existing electricity-generation facilities to reduce emissions is achieved through the installation of emissions-control equipment that reduces SO_2, NO_x and particulates, also carbon, though they vary from one country to another. Emission controls add a significant amount to a plant's capital and operating costs and reduces efficiency. For example, in the US pollution control costs are estimated at 40 per cent of capital and 35 per cent of operating costs. For an entire pollution control system in a German power plant, SO_2 control represents 13 per cent of total the capital cost, NO_x control adds 6 per cent and particulate control another 4 per cent. Control equipment in Japan constitutes an estimated 20–25 per cent of total capital costs for a new coal-fired plant, and 15–20 per cent of total electricity-generation costs. Add-on technologies of this nature do not change proportionately with the size of the facility and, as a result, pose relatively high costs to smaller facilities. Therefore their effects on cost of generating facilities in developing countries are larger. Generally speaking, pollution control for large electricity facilities will increase capital cost by 25 per cent and electricity production cost by up to 20 per cent; for smaller facilities the increase can be larger.

Particulate-control technology has a long history of use in power plants. The most cost-effective methods are electrostatic precipitators and fabric filters, both of which achieve 99.55 per cent particulate removal. Costs for both technologies are, for capital costs, about 4 per cent of total cost of plant and, for operating costs, about 5–8 per cent of total plant production cost. Fabric filters are especially relevant for low-sulphur coal use. Other methods include wet scrubbers, which have a high levelised annual cost, and mechanical collectors, which are not efficient enough (at 90 per cent removal) to meet most stringent environmental standards in developed countries.

In terms of electricity production, carbon-sequestration (CS) technologies although proven are not commercial yet, and there are yet no cost-effective pollution-control technologies that can reduce carbon emissions (see Chapter 10). However, natural-gas combined-cycle conversion eliminates sulphur emissions, reduces NO_x emissions by 90 per cent and reduces carbon emissions by almost 60 per cent compared to conventional coal plant. In the UK, it has been estimated that it is cheaper to build and operate a combined-cycle gas-turbine (CCGT) plant as opposed to retrofitting an existing coal-fired plant. CCGT plants are more thermally efficient than conventional fossil-fired plants. They are also more energy efficient and less costly than the new 'clean coal' technology – fluidised bed combustion (which reduces sulphur and NO_x emissions without the installation of emissions control systems).

8.6 Evaluation of the environmental cost of electricity generation

Environmental impacts [14] of electricity generation were detailed in Table 8.1. The most serious impacts, which are difficult and very expensive to deal with, are air pollution damage in the form of emissions of SO_2, NO_x, particulates with air-quality implications and accumulation of greenhouse gases, particularly CO_2. Such emissions will have a detrimental impact on health, buildings and similar properties, forests and can have long-term climate change costs.

8.6.1 Assessing health impacts and costs

The major part of the dose of air pollutants inhaled by the general public is caused by road transport facilities and fuels and not by electricity production. There is remarkable evidence of linkages between very small particulate matter under 10 μm diameter (PM_{10}) and mortality and detrimental health effects. Such very small particulate matter (PM_{10}) is normally produced by transport activities and not by electricity generation utilising coal, which produces the particulate matter of general dimensions.

There are many ways of valuing the impact [15] of air pollution on human health and well-being. Willingness to pay (WTP) involves asking individuals questions about their WTP, through a voluntary contribution or tax mechanism, to reduce air pollution to a safe level. A more direct method is that of *dose–response*, which involves finding a medical relationship between air pollution and observable health. Morbidity effects are valued by the cost of illness (COI) approach. This uses the cost of medical treatment and lost output as the social cost of the air pollution. However, the COI approach may be inferior to the WTP, since it ignores the disutility of illness.

8.6.2 Assessing damage to buildings, properties and forests by air pollution

SO_2 and NO_x are the main air pollutants that are transboundary and can cause damage to buildings and similar properties, as well as to forests. In addition, the deposition of sulphur and nitrogen species causes oxidation of soils and fresh water. SO_2 emissions are mainly caused by firing fossil fuels, particularly for electricity generation without desulphurisation. Brown coals, in particular, have a very high sulphur content and cause more emissions per unit of electricity generated than ordinary hard coal or other fossil fuels. SO_2 emission can be a serious cause of local and regional damage with significant financial cost.

Such emissions, and correspondingly damage cost, can be significantly reduced by either fuel switching or by add-on measures to abate emissions. Fuel switching involves using cleaner fuels. Natural gas (and LNG) is relatively benign, with no SO_2 emissions, and, if economically available, can significantly contribute to the reduction of air pollution. Improving efficiency of generation and utilisation of energy-efficient generation technologies and conservation can also significantly help (see Chapter 10). If fuels such as natural gas are not available, then the alternative for reducing air pollution is to utilise add-on measures. These are technologies and facilities that abate emissions, mostly of SO_2, NO_x and also particulate matter. Utilising these measures should be pushed to the extent that the cost of additional measures should be equal to their estimated environmental benefits.

Sulphur reduction can be achieved prior to combustion by washing or by adding powdered limestone during firing, which can reduce the sulphur emissions by almost one-third. However, major reductions are achievable after combustion by flue gas desulphurisation (FGD), by using limestone (which yields gypsum), or by regenerative techniques that yield sulphuric acid. Utilising all three techniques can reduce the sulphur emission by almost 95 per cent, but at enormous investment and operational cost as explained earlier. In order to assess the extent of these measures, it is essential to know two things: the marginal cost of abatement per each additional unit of sulphur and the cost of environmental damage that additional unit of sulphur causes. *Cost curves* for sulphur abatement can be plotted showing the extent of abatement against cost.

Assessment of environmental damage is much more difficult [9, 16]. Emissions are carried away over wide distances by complex weather patterns. Acidation takes place in dry and wet weather (acid rain), causing the damage described above. In the case of damage to building materials, the extent of damage depends on the extent of emissions and air pollution, and also on the type and quality of materials used. Stone buildings are less affected than brick buildings. The cost of the damage can be assessed by two methods: dose–response functions and the maintenance cycle approach.

In the dose–response functions method, the extent of damage is assessed by dose–response functions that are normally prepared for building stones and metals, where a critical damage level is defined for each material. The value of the national cost of the air pollution will equal the cost for replacement or repair of the damaged material.

The maintenance cycle approach starts with the same assessment of damage to materials by dose–response functions. However, it recognises that a reduction in emissions concentration will lead to a corresponding reduction in maintenance requirements of building material. Therefore, utilising the dose–response functions, an estimation of the saving in maintenance is allocated for a certain reduction in emissions level through a corresponding investment. A value of total national savings is calculated for a given reduction in SO_2 concentration. Utilisation of either method has to be handled with care, taking into consideration the different factors other than SO_2 (like weather) that contribute to material damage.

8.7 Climate change costing

Climate change costing due to emission of greenhouse gases (CO_2, methane) is the most difficult to forecast and to cost aspect of air pollution. This is because of the existence of minimal evidence at present and the fact that damage can only be ascertained in the far future, 50 years or more. CO_2 emissions are the main source of greenhouse gases. These are gases that are supposed to accumulate in the atmosphere with a long residence time, leading to higher long-term atmospheric temperature.

Electricity generation, in 2013, account for about 43 per cent of global greenhouse gases emissions from energy utilisation [2]. With increased growth of electricity generation, at a rate of almost 1.3–1.5 times that of total primary energy utilisation, electricity production will assume a large future proportion of emission of gases, particularly CO_2 that may cause significant climate change in the future. Developing economies, particularly China and India, which have high electricity demand growth potential, depend on local coal supplies that emit increasingly large amounts of CO_2 in the long term; although it is not easy to ascertain the extent and results of such emissions in the future, and correspondingly the extent of damage to human welfare and property. It is wise to adopt the minimum regrets policy, which advocates significant reduction in the rise of greenhouse gases emissions, and preferably their stabilisation as soon as possible, through energy efficiency, conservation and utilisation of relatively benign fuels like natural gas, also renewable and carbon pricing [17, 18]. In the future employing carbon capture and storage (CCS) technologies can significantly help.

It is not possible now to assess, with any exact degree of certainty, the future implications of increased emissions or concentration in the atmosphere of CO_2, and correspondingly to understand the mechanisms of global warming and its social and economic impact. It is, however, certain that whereas other air pollutants have local and regional impact, that of CO_2 is going to be global and can be of much wider reaching. Although the impact of other air pollutants can be contained in a very significant way by technology (also by fuel switching, efficiency and conversation), containment of CO_2 emissions is taking more time. Economies with zero carbon emissions will be possible in the future, but they may prove to be costly; correspondingly, only few industrialised countries will be able to afford them (see also Chapter 10).

In recent years there were many studies that tried to evaluate in monetary terms the cost to humanity (society) of possible climatic change mainly caused by the increasing concentration of CO_2 in the atmosphere. Realising that in the near future at least half of these emissions will be caused by electricity production means that this activity need to be in the centre of any environmental consideration.

The most publicised study is the one presented by the UK government, in November 2006, known as the 'Stern Review on the Economics of Climate Change' [6]. The Review suggests that CO_2 atmospheric concentration should be stablised at 450–550 ppm. In its summary this Review gives a detailed economic evaluation and it 'estimates that if we don't act, the overall costs and risks of climate change will be equivalent to losing at least 5 per cent of global GDP each year, now and forever. If a wider range of risks and impacts is taken into account, the estimates of damage could rise to 20 per cent of GDP or more . . . . Our actions now and over the coming decades could create risks . . . on a scale similar to those associated with the great wars and the economic depression of the first half of the 20th century' [6].

The Stern Review also argued:

- that the social rate of time preference (discount rate) is relevant only for marginal analysis, and therefore is not applicable in taking non-marginal decisions on whether or not to avoid dangerous climate change; and
- for a particular ethical perspective on discounting–essentially that it is unethical to discriminate against future generations simply on the basis of their date of birth, and that the pure rate of time preference should therefore reflect only the small risk that the planet and humanity will cease to exist.

Therefore, there is a need for carbon pricing to transmit the social cost to humanity of GHGs, and help in abating carbon emissions. This carbon pricing needs to be evaluated by environmental economic evaluation. The Stern Review calculates that this implies a social cost of carbon of around £19/tCO_2 in 2000. This was recommended to be adopted as the basics for a shadow price of carbon (SPC) profile for use in policy and investment appraisals across government in the UK. This needs to be updated annually, and it was suggested by the UK Department for Environment, Food and Rural Affairs (DEFRA) in 2007 that this SPC to be [19]:

- uprated each year by 2 per cent a year reflecting the Stern Review's assessment of the rising incremental damage of each unit of carbon as temperatures rise;
- also uprated each year to the year of emissions abatement/release by the GDP deflator (and for future years, by the Government's central inflation target of

2 per cent a year if values in nominal terms are required) – this is so that all costs and benefits being appraised are based on the same year's price level; and

- reviewed in full every five years, in line with the five-year target setting periods specified in the Government's Climate Change Bill.

This means that, in appraising individual policy and investment options, the SPC should be used to value carbon emissions and abatement (reflecting the value of non-marginal impacts) and all costs and benefits should be discounted. The Green Book, of HM Treasury, proposes using the standard annual 3.5 per cent as the environmental (social) discount rate. This applies for the period of 0–30 years. Afterwards the discount rate to be decreased gradually reaching 1 per cent for valuation after 300 years [19, 20].

8.7.1 Environmental impacts and the environmental discount rate

As discussed above, the utilisation of the financial discount rate in evaluating environmental impacts was subject to severe criticism on the grounds that environmental damage and costs appear many years after project execution. As long-term costs they are reduced to insignificance by discounting (at a discount rate of 10 per cent, damage valued at £1 and occurring after 10 years will equal only £0.39 today). At the same time, abatement investments that help the environment will also have long-term benefits, which are greatly reduced by discounting. High discount rates also lead to delay the exploitation of renewable and non-renewable natural resources, such as fossil fuels, because they substantially reduce their long-term value [6, 7].

One strong reason favouring the present valuing of environmental costs and benefits from different perspectives, than the use of the discount rate for investment by individuals, is that individuals are mortal while societies are quasi-immortal. Therefore, individuals, being mortals, tend to value the present in greater terms than societies, because of the prospect of their early death. Such fears do not exist in the community. The community, therefore, has reason to discount the future to a lesser extent than individuals [6].

This argument calls for lowering the discount rate on environmental projects or even not discounting their costs and benefits at all (as advocated in the Stern Review). This, of course, can be a source of difficulty in evaluations, where it will result in having more than one discount rate for different cost/benefit items and implies a different treatment of environmental projects. Another approach would be to properly value, in economic and not just financial terms, environmental costs and benefits and give them the appropriate weight in project evaluation. Projects should be designed not to cause serious environmental damage to irreplaceable critical natural capital. Any long-term change in the expected relative value of environmental assets should also be reflected in their appraised prices.

More thorough research and estimation have to be undertaken of all environmental costs and benefits, particularly those of non-monetary and irreversible consequences, and the values incorporated into the analysis. Having said that, climate change is a long-term problem, so that from an economist's perspective discounting is a very important issue. There is an increasing call to have an environmental discount rate, different and lower than the usual financial discount rate, when evaluating the costs and benefits of projects with long-term environmental impacts. In the Stern Review on the Economics of Climate Change, Stern advocated a discount rate of only 1.4 per cent to support a policy of reducing greenhouse emissions by about 3 per cent annually relative to business as usual. Stern argues that the choice of an environmental discount rate should be based entirely on ethical grounds and not on the opportunity cost of capital. Such low environmental discount rate has been criticised by other economists as being very low [21, 22]. The fact remains that the ESI is a major consumer of fossil fuels and a major emitter of polluting gases, most pronounced is carbon. It is recognised that carbon does harm globally and that there is logic of having a carbon price for it. So also the need to assess accurately the environmental costs and incorporate these in the economic evaluation. These arguments are summarised below.

8.8 Discounting concepts in climate change [23]

8.8.1 The welfare discount rate

In Chapter 5, we explained that long-term climate change impacts needs to be evaluated utilising a discount rate called ‘pure rate of social time preference’ which is different from the real return on capital or the opportunity cost which we already employed in evaluating and comparing investment projects in the ESI and which we utilised to prioritise the levelised cost of electricity generation (LCOE) estimates.

Social welfare economics is not an easy subject and is beyond the realm of this book. However, there is need to mention some considerations in evaluating the social discount rate. The details are in the literature [6, 21, 22] and also in Appendix B.

Defining the social-welfare-equivalent discount rate r_{sw} as the rate that translates a marginal change in consumption at date t into the social-welfare-equivalent marginal change in consumption at time 0, we arrive at

$$r_{sw} = \rho + \eta g$$

where r_{sw} is social welfare equivalent discount rate, it converts future consumption into current consumption equivalent in terms of social welfare; ρ is social rate of time preference, its choice is mainly based on ethical considerations; g is the rate of growth of consumption over time; and η is the elasticity of marginal utility of consumption, i.e. how sensitive is the marginal utility of income is to changes in consumption η, its choice is based mainly on empirical considerations.

The derivation of the above equation is detailed in [21].

Therefore, r_{sw} which is the discount rate utilised in climate change is the sum of two factors: the social rate of time preference (ρ) and the change in the marginal utility of consumption over time.

Ethicists and many economists insist that future utility should not be discounted, that the well-being of future generations should count as much as that of

Table 8.4 *Estimation of the value of the social welfare equivalent discount rate*

	Implicit values of r_{sw} in leading climate policy evaluations			
	ρ	η	g	r_{sw}
Stern	0.1%	1.0	1.3%	1.40%
Cline	0.0%	1.5	1.3%	2.50%
Nordhaus	3.0%	1.0	1.3%	4.30%

Source: Reference [21].

the current generation in a social welfare functions. This suggests a value of ρ from 0–0.001 [6]. However, such a low estimation of ρ is contested by other environmental economists. Table 8.4 gives values utilised in discounting for climate policy evaluation, by three leading environmental economists Stern, Cline and Nordhaus. The three of them agree that the growth rate of consumption can be assessed at 1.3 per cent, while η choice is based on the empirical side, how much increments of consumption lead to higher individual well-being. This leads to wide variations in the estimation of the value of the social welfare equivalent discount rate, as shown in Table 8.4.

8.8.2 The welfare discount rate r_{sw}, abatement policies and carbon pricing

Goulder and Williams [21] point out that the differences in r_{sw} account for much of the difference about the appropriate level of aggressiveness in climate change policy. For example, when the Dynamic Integrated Model of Climate and the Economy (DICE model) was applied, Nordhaus reached a preferred consumption discount rate of 4.3 per cent. This yields an optimal abatement path involving CO_2 emissions reductions of 14 per cent by 2015, 25 per cent by 2050 and 43 per cent by 2100 [19]. When the same model employs Stern's preferred rate of 1.4 per cent, it yields emissions reductions of 53 per cent by 2015. The implied difference in optimal carbon prices is very large as well: $35/ton by 2015 for a discount rate of 4.3 per cent versus $360/ton for a discount rate of 1.4 per cent. These differences reflect the fact that relatively small differences in the consumption discount rate imply large differences in the discounted values attached to events in the distant future. For example, a given loss of consumption 100 years from now is 17 times smaller using a discount rate of 4.3 per cent as compared with the result under a discount rate of 1.4 per cent.

The above analysis implies that using the Stern consumption discount rate of 1.4 per cent will lead to impractical results in terms of optimal abatement policies and carbon pricing. The Nordhaus assessment is more rational and practical in this approach to carbon pricing.

In their analysis Goulder and Williams consider the uncertainties in assigning values to different components of r_{sw}, particularly the economic growth (g).

They reached an important conclusion which implies that when discounting the distant future, one should use a lower rate – potentially much lower – than the rate one would use for relatively short time horizons. And since the longer the time horizon is, the more important the discount rate becomes, this result can have dramatic consequences. This is of special importance for climate policy change because of the long-time horizons involved.

It can also be argued that this applies to the decommissioning cost of nuclear power stations. This decommissioning cost cannot be discounted to present worth by the high discount rate utilised for the present worth of costs and output of nuclear power plant operation. Although technological knowledge and advancement may be able to reduce that long-term decommissioning cost, uncertainty however necessitates the utilisation of a very low discount rate, approaching zero, in order to account for this decommissioning cost.

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Chapter 9

Electricity generation in a carbon-constrained world

Part I – The strategies, national requirements and global agreements

9.1 Introduction: the carbon dilemma

External factors, most importantly the need to pursue the goals of sustainable development, have growing influence on the future of the electricity supply industry. International agreements like the Kyoto Protocol and the anxiety of governments to ensure that future electricity supply is secure, affordable, and also low carbon are modifying the way the business of electrical power is being conducted.

The level of the most important heat-trapping gas in the atmosphere, carbon dioxide (CO_2), has passed a long-feared milestone, reaching a concentration not seen on Earth for millions of years. Scientific instruments have shown that the gas had reached an average daily level above 400 parts per million (Figure 9.1) – it is a sobering reminder that decades of efforts to bring human-produced emissions under control are faltering. The best available evidence suggests the amount of the gas in the air has not been so high for at least three million years, before humans evolved, and some scientists believe the rise portends large changes in the climate and the level of the sea. China is now the world's largest emitter, but Americans have been consuming fossil fuels extensively for far longer, and the US is more responsible than any other nation for the high level of emissions.

From studying air bubbles trapped in Antarctic ice, scientists know that going back 800 000 years, the CO_2 level oscillated in a tight band, from about 180 parts per million in the depths of Ice Ages to about 280 parts per million during the warm periods in between. The evidence shows that global temperatures and CO_2 levels are tightly linked. For the entire period of human civilisation, roughly 8 000 years, the CO_2 level was relatively stable near that upper bound. However, the burning of fossil fuels has caused a 41 per cent increase in the heat-trapping gas since the Industrial Revolution.

Indirect measurements suggest that the last time the CO_2 level was this high was at least three million years ago, during an epoch called the Pliocene. Geological research shows that the climate then was far warmer than today, the world's ice caps were smaller, and the sea level might have been as much as 60 or 80 feet higher. Experts fear with such extreme that humanity may be precipitating a return

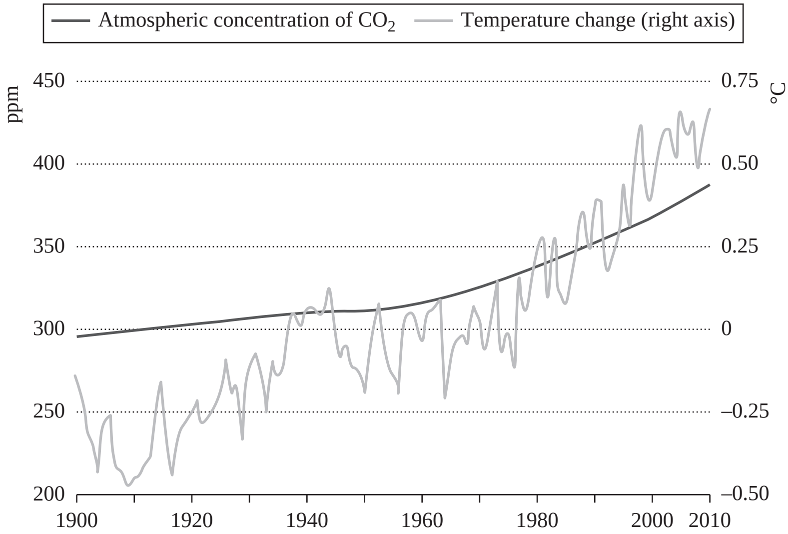


Figure 9.1 The measure of CO_2 concentration [Source: OECD–IEA Redrawing the Energy Climate Map, June 2013]

to near such conditions – except this time, billions of people are going to be adversely affected. Countries have adopted an official target to limit the damage from global warming, with 450 parts per million seen as the maximum level compatible with that goal. Unless things slow down, that level will probably be reached in well under 25 years. Yet many countries, including China and the US, did not yet adopt binding national targets. Unless far greater efforts are made soon, the goal to limit the warming will become impossible to achieve without severe economic disruption [1].

The International Panel for Climatic Change (IPCC) latest report, October 2013, says that atmospheric concentrations of greenhouse gases (GHGs) have increased to levels unprecedented in at least the past 800 000 years, and that the oceans have absorbed about 30 per cent of the emissions to date causing waters to become more acidic and endangering some marine life. The world has already warmed 0.9°C since pre-industrial times and the global mean temperatures are likely to rise by more than 2°C and up to 4.8°C by 2100 if emissions are not reduced quickly and dramatically.

Between 1750 and 2011, human activity released 545 gigatons of CO_2, the main GHG, roughly two-thirds from burning fossil fuels and one-third from land-use change and deforestation. However, in the last decade, 90 per cent of the CO_2 released has come from burning fossil fuels.

Simultaneously, the world is gradually increasingly electrifying. In the not so far future, carbon emissions from the electricity sector are likely to surpass that of the other sectors combined. By the mid-century half of global anthropogenic emissions are likely to be shared by power generation. The growing importance of

Table 9.1 Electricity production contribution to CO_2 emissions

	1990	**2010**	**2020**	**2030**	**2035**
Global CO_2 emissions (Mt) from fossil fuels	20 980	30 190	36 281	41 177	44 090
Emissions from power generation (Mt)	7 481	12 495	15 556	18 329	20 112
Electricity/global (%)	35.7	41.4	42.9	44.5	45.6

Source: IEA-WEO, 2012 (current policies scenario).

global CO_2 emissions from power generation is demonstrated in Table 9.1, adapted from the IEA projections.

From Table 9.1 it is clear that year after another power generation is assuming a greater share of global CO_2 emissions in spite of improvements to generation efficiency and an increase in the share of natural gas in the process. Correspondingly any attempt to curb global emissions will need to have power generation at its centre of interest, without that it will be missing the right target. Therefore, decarbonising the power sector is becoming a focus of interest. Such strategy is demonstrated in the *UK Electricity White Paper 2011*, and US Climate Action Plan 2013, as well as all climate conventions. It also aims at encouraging generation of non-fossil fuels and phasing out harmful subsidies.

9.2 UK Electricity White Paper 2011

In July 2011, the UK government presented to Parliament its *Electricity White Paper*. In its Introduction it mentioned that the aim of the *White Paper* is to reform the market, to ensure future security of supply and to build a cleaner, more diverse, more sustainable electricity mix. The *White Paper* sets out how to encourage investment in the most cost-effective way. However, the *White Paper* is about more than encouraging investment in new generating capacity. It recognises that the most cost-effective way to secure future supplies is not just to build new power stations, but to put demand reduction and energy efficiency at the heart of the policy program.

The *White Paper* package of reforms as outlined means, that by 2030, the UK aims to have ‘a flexible, smart and responsive electricity system, powered by a diverse and secure range of low-carbon sources of electricity, with a full part played by demand management, storage and interconnection; competition between low-carbon technologies that will help keep costs down; a network that will be able to meet the increasing demand that will result from the electrification of our transport and heating systems; and we will have made this transition at the least cost to the consumer’ [2].

The *White Paper* sets out to explain that one of its principal aims is to decarbonise electricity generation to take action now to transform the UK permanently into a low-carbon economy and meet a target of 15 per cent renewable energy by

2020 and 80 per cent carbon reduction target by 2050. To put the UK on this latter trajectory, power sector emissions need to be largely decarbonised by the 2030s.

The *White Paper* explains that the social cost of carbon is not fully reflected in the market price, as this does not take into account all of the damage caused by climate change. A main part of the *White Paper* strategy is contracting for low-carbon generation through a new system of long-term contracts in the form of Feed-in Tariffs with Contracts for Difference (FiT CfD), providing clear, stable and predictable revenue streams for investors in low-carbon electricity generation.

Also, the introduction of a Carbon Price Floor (CPF) to reduce uncertainty, will put a fair price on carbon and provide a stronger incentive to invest in low-carbon generation now. An Emissions Performance Standard (EPS), set at an annual limit equivalent to 450g CO_2 per kWh at base load, to provide a clear regulatory signal on the amount of carbon new fossil-fuel power stations can emit.

Therefore, the aim of the *UK White Paper*, as it defines it, is to:

- provide a more efficient and stable framework for investors, ensuring that the cost of capital required for new low-carbon generation capacity is lower;
- encourage investment in proven low-carbon generation technologies, and also allow new technologies such as carbon capture and sequestration (CCS) to get off the ground and allow them to become cost-effective and compete without support;
- boost competition within the market as it will provide the framework for independent generators and new investors to invest in low-carbon generation;
- lead to competition within and between different low-carbon generation technologies for their appropriate role in the energy mix; and
- achieve these aims at least cost to the consumer.

9.3 US Climate Action Plan 2013

On 25 June 2013, the US President described the Climate Action Plan in a major policy address in Washington, DC. Later that day, the White House released the 21-page written plan. President Barack Obama repeated his pledge, made in 2009, to reduce US GHG emissions by 17 per cent below 2005 levels, by 2020. While acknowledging that US CO_2 levels in 2012 were the lowest in two decades, Obama indicated that much more is to be done [3].

Three key pillars underpin the action plan:

- Cut carbon emissions in the US.
- Prepare for the impacts of climate change.
- Lead international efforts to mitigate and adapt to climate change.

To cut US emissions, five major steps were unveiled:

- Deploy clean energy by reducing emissions from power plants; promote renewable energy and investing in clean energy innovation.
- Create a modern transportation system by increasing vehicle fuel efficiency standards, particularly for heavy-duty vehicles, encouraging biofuels through the renewable fuel standard, and support advanced battery and fuel cell technology.

- Improve energy efficiency by establishing new energy efficiency standards for buildings and appliances; reduce barriers to investments in efficiency; cut energy consumption in commercial and industry buildings.
- Reduce other GHG emissions, specifically hydrofluorocarbons and methane. Also preserve the role of forests in mitigating climate change.
- Improve energy efficiency in US government buildings and operations.

To prepare the US to adapt to climate change, three strategies were defined:

- Encourage resilient infrastructure by removing investment barriers; support state and local preparedness; develop new guidelines for buildings and other infrastructure; learn from experiences with super storm Sandy.
- Protect critical assets, including power plants, fuel distribution facilities, hospitals and other healthcare facilities; maintain sustainable agriculture; reduce wildfires and droughts; prepare for floods.
- Manage impacts through sound science by better understanding the impact of climate change; leverage government climate data to spur innovation; create a 'toolkit' to access resources.

9.4 Climate conventions: Kyoto and beyond

The most significant international environmental treaty ever drafted, the United Nations Framework Convention on Climate Change (UNFCCC), was agreed at the 1992 Earth Summit in Rio de Janeiro and sets out a framework for action to control and cut GHG emissions. A Protocol to the Convention was adopted in 1997 at the Third Conference of the Parties held in Kyoto, Japan. This provides a practical international process to reduce emissions that can contribute to global warming. Under the Kyoto Protocol, industrialised country participants, or parties, agreed to reduce their overall emissions of six GHGs by an average of 5.2 per cent below a 1990 baseline between 2008 and 2012, the so-called 'first commitment period'.

The US's suspicions, particularly its unease about the intentions and commitments of China, did not encourage it to ratify the Kyoto Protocol. The result of the US's refusal to ratify and the absence of Chinese cap meant that the Kyoto Protocol defaulted to a *de facto* European treaty commitment, since it is mainly European Union countries that ratified the Protocol. Therefore, Europe adopted almost unilateral carbon targets [4].

Another climate summit, Copenhagen Climate Conference, was held in 2009. What it achieved was a modest Copenhagen Accord. This proposed that countries could subsequently submit non-binding emissions reductions pledges or proposed mitigation action pledges. The Copenhagen Climate Conference set the limit of global rise in temperature to 2°C, and emphasised on good intentions to cut emissions.

Further climate summits were held in Cancun, Mexico, in 2010 and Durban, South Africa, in December 2011. It was clear that the major emitters the US, China and India would not agree to legally binding commitments. Almost the same could be said for Japan, Canada and Russia. The second commitment period of the Kyoto Protocol after 2012 had lost its three key players. However, the Durban summit reached a mixed outcome despite low expectations and the difficult context of the present global economic and financial crisis. The most significant result is that, for the first time, an agreement was reached involving all major emitters, including the US, China and India. It removed the wall of the 20-year-old two-tiered system in which developed and developing countries were treated differently. However, despite the acknowledgement that time is running out, no additional action to mitigate climate change will be taken before 2020 and with no guarantee for it to happen after that.

However, this outcome, which was actually mixed results, had some positive elements [5]. First of all, there was an agreement to a global binding commitment, covering the Organisation for Economic Co-operation and Development (OECD) and non-OECD countries, to be negotiated by 2015 and to bring these into effect from 2020. Yet this equally means that there will be no additional climate action before 2020, and more importantly, no guarantee of action from 2020.

Second, the Kyoto Protocol will be extended from 2013 for a period of five to seven years. However, this second period is only endorsed by the EU alone. Canada, Japan and Russia declined. On the positive side, it was agreed to add CCS to the CDM. While acknowledging that the current sum of pledges is not enough, there was little progress on closing the gap between the ambitious capping of world temperature rise at 2°C and what is actually taking place in the real world of growing emissions.

Lastly, there was an agreement to put into operation the Global Green Climate Fund to disburse $100 billion per year by 2020 with a fast track approach to spend $30 billion by 2012 to assist developing countries. But there is no agreement on how to finance and operate this fund. Therefore, it will take years to show any effect on mitigation of carbon emissions.

It was clear from the Durban summit that the 2°C cap is no longer feasible. The focus is now on a new summit around 2015. It is increasingly clear that there will be no internationally binding agreement for many years to come, if ever. More national efforts need now to be exerted on containing emissions by advancing clean technologies and clean fuels, improving efficiency and load management.

One of the primary targets for attaining carbon emissions reduction will obviously be the power sector. The efficiency of existing power plants is very low, around 33 per cent, with 41 per cent of them fire coal, and 67 per cent fossil fuels, thus rendering them major emitters. Modern power stations, particularly those operating in a combined cycle mode, have high efficiencies and use relatively benign fuels such as natural gas (see Figure 9.2). Such efficiencies at nearly 60 per cent are almost twice the efficiency of vintage available plants. Emissions from combined cycle high-efficiency plants firing natural gas are only 40 per cent of that of a modern coal-firing thermal power plant (even less in case of brown coal). Shutting down an old coal firing plant and replacing it with a modern CCGT plant will reduce carbon emissions by 3–3.5 times. Significant strides have recently been achieved in higher CCGT plant efficiency (see Figure 9.3).

Also, the power sector itself can expect to face various forms of fiscal tightening to curb emissions, such as carbon taxation and taxes levied on energy used

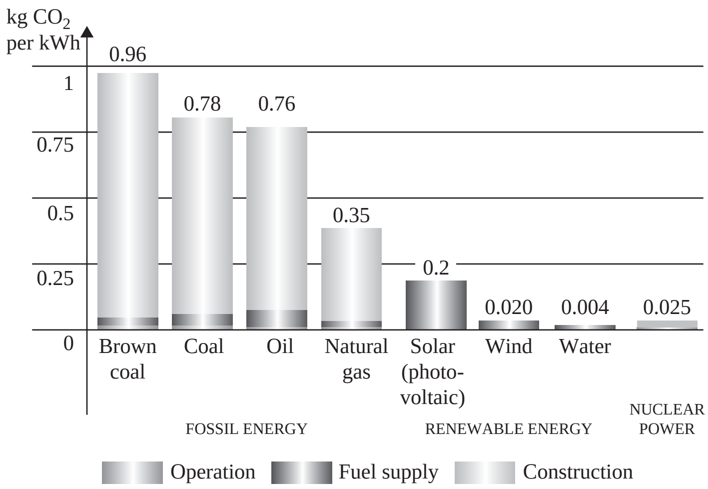
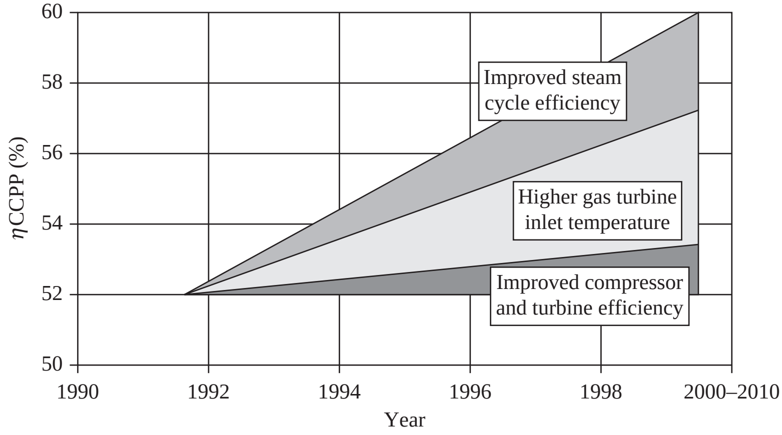


Figure 9.2 Comparison of CO_2 emissions [6]



During the past decade, the efficiency, i.e. the energy utilisation, of combined-cycle power plants has been improved by several percentage points. Improvements in steam turbines and an increase in gas turbine inlet temperature were the key factors behind this gain.

Figure 9.3 Combined-cycle power plant efficiency development [6]

as well as additional and tougher regulatory targets for energy efficiency. The power sector will be able to improve its performance by more efficient and clean generation, lower energy intensity in the economy, encouraging use of clean fuels and clean engineering technologies also furthering renewables and smart grids. These activities are detailed on the following page and in Chapter 10 as well.

9.5 Electricity generation and climatic change agreements

Electricity generation is going to be the primary target for emissions reductions, as agreed upon by climatic change agreements, because of the following factors:

- An increasing share of primary and final energy is being utilised in the form of electricity.
- Prospects for curbing emissions, through improved efficiency, cleaner fuels, renewable and nuclear power and similar means, are easier and produce more significant results in the case of power generation than in other energy conversion processes. New power generation technologies will significantly assist in this regard.
- Emissions from power generation are concentrated in one place – the power station – where they are easier to deal with.
- Electricity lends itself more easily to project mechanisms that allow for emission reductions through ‘carbon taxation’, ‘emissions trading’ and similar ‘flexible project mechanisms’ in the Kyoto Protocol. These are detailed below.

9.5.1 Carbon taxation

If carbon has such a harmful effect, then it should be penalised by taxation. It will set a price for carbon. The two ways to do this are direct carbon taxation and, indirectly, emissions trading.

Emissions are termed by economists as an externality, i.e. external to the market; by setting a carbon price it will be internalised to reflect its cost to the economy and society. Governments can either fix a price for the carbon or fix the quantity of carbon to be emitted by each facility or activity and allow it to be traded to indicate the price. The carbon tax will be approximately equivalent to the carbon permits.

Therefore, a carbon tax is a tax levied on the carbon content of fuels. It sets carbon pricing. The level of emissions of fossil fuels used in electricity generation is related to the carbon content of each fuel. By taxing the carbon content of the fossil fuel, emissions will be taxed [7].

Carbon taxation will significantly affect the economics of electricity generation. It will favour clean renewable sources and nuclear while penalising fossil fuels generation. Coal, having the highest carbon content, will be penalised the most. It will also enhance efforts towards generation efficiency and clean production technologies like CCS. It will increase the cost of electricity, but this depends on the extent of fossil fuels utilisation and also the carbon price. It will also affect the internationally traded commodities, where countries applying carbon tax will be penalised.

Carbon price should reflect the social cost of carbon. This is not easy to calculate and can be controversial (see Chapter 8). It can be done by detailed cost–benefit analysis or by trial and error, i.e. setting an arbitrary price and monitoring market reaction until a near correct price is reached. It is a learning-by-taxing process.

Carbon taxation in the power industry is rather easier to apply, since it is possible to directly tax regulated power utilities and plants by adding a carbon price to their fuel intake or capping their emissions.The economies and price implication of carbon taxation and renewables is dealt with in more detail in Chapter 12.

9.5.2 Emissions trading

This market mechanism is widely seen as a way to help businesses identify the most cost-effective options available to reduce emissions. The trading market should stimulate the development of new technology because it sets a real cost on emissions and provides market incentives to reduce that cost.

Several countries, for example the UK and the Netherlands, are developing national trading systems for GHGs. Trading in atmospheric emissions is not new; both sulphur dioxide (SO_2) and nitrogen oxide (NO_x) emissions have been successfully traded in the US for many years. Emerging systems are based on a 'cap and trade' concept where participants stay within a basic allocated emissions allowance. Where actual emissions of the business are above its total allowance for a given year, it must buy more allowances from the market to ensure compliance. Where emissions are below an allocation, a company can sell allowances. The mechanism for setting allowances requires a 'base year', for which verifiable data can be reported and against which annual allocations can be set. Successful GHG emissions have to be accurate, reliable and independently verified by a qualified third party.

9.5.3 Flexible project mechanisms

These are designed to enable countries to deliver part of their committed emissions targets – 'Assigned Amounts' – through investment in projects that reduce emissions in another country. Power generation is likely to be the most flexible vehicle for the implementation of such projects. There are two project-based mechanisms:

- Joint Implementation (JI) allows for investment by one developed country in a project that reduces GHG emissions in another developing country (like a Western European country investing in a country in Eastern Europe). 'Emissions Reduction Units' (ERUs) generated by such projects can be used to meet the investing country's commitments.
- The Clear Development Mechanism (CDM) is designed to bring development to developing countries through projects that result in a reduction in GHG emissions. The generated 'Certified Emission Reductions' (CERs) units can be purchased by a developed country and used to meet its commitments (Figure 9.4).

To qualify under the CDM, projects put forward for registration to the UNFCCC Secretariat's executive board of the CDM must meet a range of sustainability and environmental criteria set down under the Kyoto Protocol. One of these criteria is the requirement for a verified project emissions baseline.

Likewise, under a verification programme specified in the registration process, independent operational entities (third-party verifiers) will periodically (probably

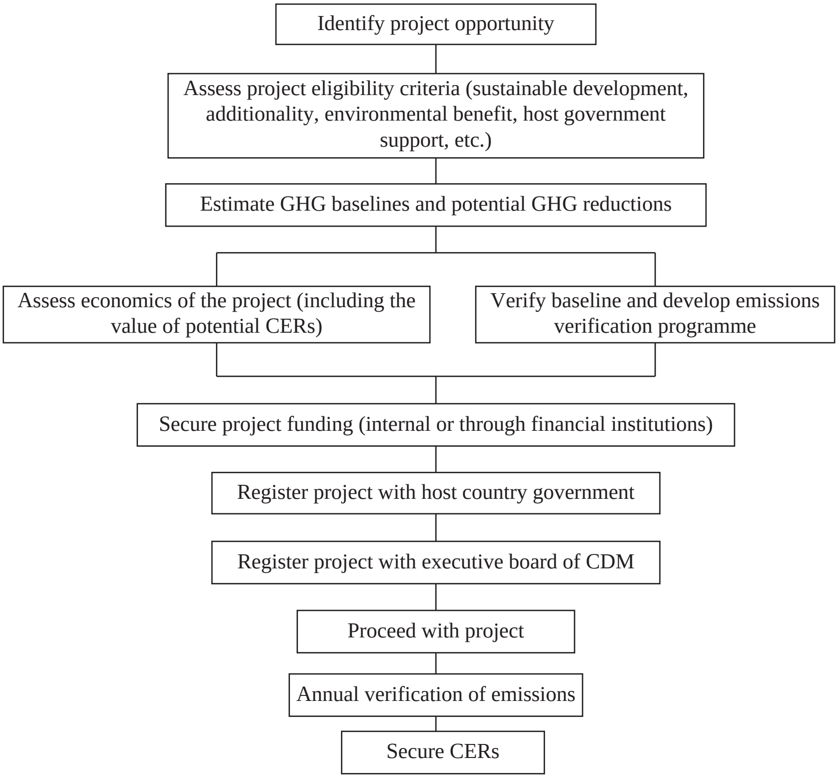


Figure 9.4 The CDM process [8]

annually) verify GHG emissions from the project to enable them to recommend to the executive board of the CDM the number of emissions credits (CERs) that can be issued.

The Kyoto Mechanisms offer the power generation sector an incentive to invest in emissions reduction projects because ERUs and CERs should be fungible with permits issued as ‘Assigned Amounts’ that can subsequently be monetised through emissions trading. The potential size of the CDM market remains uncertain (especially given the uncertainty over supplementary). But the best forecasts made to date suggest it will be between 700 and 2 100 million tons of CO_2 per year.

9.6 The negative effect of power sector subsidies

We have to start by defining what we mean by ‘subsidy’. A subsidy implies selling an energy product (refined fuels or electricity) at prices lower than the product’s opportunity cost. The opportunity cost is the price which the product would have obtained had it been exported instead of local firing or utilisation in the local market.

Subsidies are a big problem in the energy sector. IEA *World Energy Outlook 2011* (WEO, 2011) estimated subsidies to be worth $409 billion in 2010, mainly in oil exporting countries of the Middle East and Russia, and to a lesser extent in India and China. These subsidies are mainly in cheap refined oil products (almost 50 per cent) followed by electricity (almost 30 per cent); see Figure 9.5. OECD countries have also subsidised new renewable energy sources to the extent of $66 billion in 2010 [9].

Subsidies lead to waste, misallocation of resources, and excessive and unnecessary carbon emissions. Electricity is provided at highly subsidised tariffs in many oil exporting countries and some developing countries, leading to wasteful consumption. Some of these countries even use crude oil in electricity generation, which greatly increases the extent of subsidies and emissions.

Water is now increasingly being produced by desalination, utilising electricity for reverse osmosis technology, in the Middle East oil exporting countries, costing almost a dollar per cubic metre, mainly due to electricity costs, but sold at a subsidised price of only few cents leading to waste and unnecessary high consumption of water and electricity.

For the sake of equity there are always calls for the need to provide electricity in subsidised manner to certain limited income consumer groups as well as industries. If there is real need for this, then the subsidy should be made in cash and not in electricity bills. Electricity subsidies lead to inefficient use and waste. Assisting the poor is through progressive tariff, mainly in electricity and water. Basic consumption can be subsidised; higher consumptions are increasingly higher priced, thus substituting for the subsidies and cutting waste. Correspondingly, it is essential to charge fair electricity prices that cover actual cost in order to avoid waste and unnecessary environmental impacts.

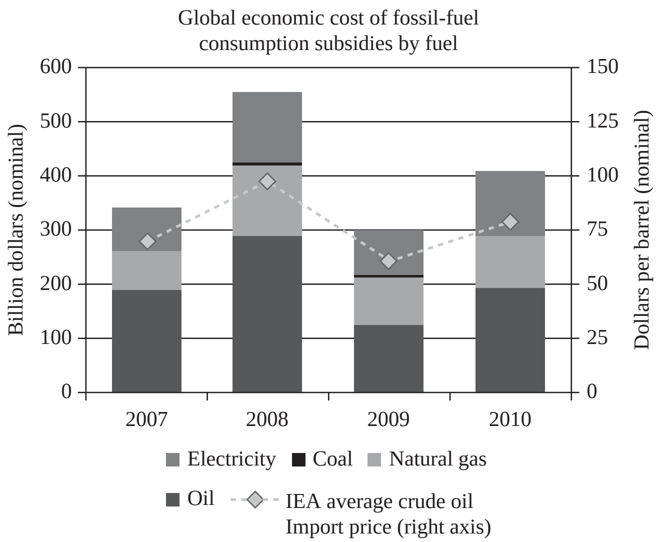


Figure 9.5 Energy and power subsidies [Source: OECD/IEA-WEO, 2012]

Table 9.2 Global subsidies (2012)

Subsidy	Worth ($ billion)
Energy subsidies	500
Agricultural, food, fishing subsidies	400
Water subsidies	300
Total	1 200

Electricity and gas subsidies are also leading to relocation of heavy industries. Energy intensive industries (aluminium, petrochemicals, cements and others) are being relocated into regions of the world where energy and electricity prices are cheap. This is making these products cheaper than what is necessary, thus increasing their use beyond what is optimal and misleadingly shifting emissions from OECD countries to non-OECD countries as has already been explained. The global business of subsidies amounted, in 2012, to almost $1 200 billion and increasing (Table 9.2).

Not all subsidies are direct price subsidies. Overlooking electricity and water theft is a form of subsidy, so is under-billing or no billing for consumption. Phasing out fossil fuels including that of electricity consumption subsidies would:

- slash growth energy demand by 4.1 per cent;
- reduce growth in oil demand by 3.7 mb/d; and
- cut growth in CO_2 emissions by 1.7 Gt.

Subsidies to the electricity sector, in 2012, amounted to almost $130 billion. The commercial value of these subsidies will amount to almost 6.5 per cent of the commercial value of the global electricity market, which has a total value of almost $2 trillion at commercial prices of electricity. Phasing out these subsidies can hopefully reduce emissions from the sector by 3 per cent, i.e. by almost 400 Mt of CO_2 annually.

9.7 Prospects for non-fossil-fuel power generation

9.7.1 Prospects for nuclear energy

Nuclear energy, in 2012, accounted for around 13 per cent of global electricity production. However, during the last quarter of the twentieth century there has been no significant addition to nuclear power in the US and very few plants were built elsewhere. Public awareness and opposition to new nuclear plants, as a consequence of the 2011 Fukushima incident in Japan, are no doubt the most significant factors in the recent demise of nuclear power. It is going to delay the new contributions from this sector by few years. However, alarm about carbon emissions and the emissions-free character of nuclear power rekindled hopes for a revival of such facilities, but to little avail in OECD countries. In the first half of 2002, Finland decided to proceed with its fifth nuclear reactor, the first such decision in Europe for after a long time. The commissioning date for this plant has been extended and its cost is escalating [10].

Nuclear power has many positive attributes that make it appealing to a balanced electricity-generation mix. These include a very large potential energy resource, demonstrated performance of maintaining very high levels of safe operation and public and workforce health and safety, no atmospheric pollution, low and stable fuel cost and very high reliability. The substantial capital cost for new nuclear plant capacity, however, remains a significant, negative attribute of nuclear power.

This penalty cost of nuclear power has been aggravated by the rising efficiency and continuous fall in the cost of a modern CCGT plant. Recent cost assessments of a nuclear power plant are around $5 000 per kW and possibly twice as much in highly regulated markets. Only governments can afford such high risk and investment cost. Therefore, new plants are now restricted to China, Russia, India, South Korea and markets where governments are in charge of the sector.

Significantly higher natural gas prices and/or the imposition of a hefty carbon tax will improve nuclear power plant's competitiveness. However, for nuclear, the potentially large consequences of a beyond-design accident and the long-term impacts of radioactive waste are the main drivers that led to decisions for a moratorium or the phasing out of nuclear power in most European countries. The problem of proliferation also remains a critical issue.

Nuclear power generation is free from carbon emissions. This should encourage their utilisation, particularly with the prospect of carbon taxation, but nuclear energy is becoming increasingly unpopular, particularly in Western Europe, owing to antagonistic public opinion, whether this is justified or not. Also, the high upfront investment cost, long lead times and prospects of future legislation render nuclear energy a high-risk alternative for private utility investors. Only governments or state institutions with state guarantee can at this stage undertake such investments. Some European countries (Germany for instance) decided to phase out nuclear, particularly after the Fukushima incident, others like Italy decided against adopting such technology. However, countries with rapidly rising demand, like China, India, the Gulf countries, Russia, Turkey and Korea, are still pursing the nuclear alternative even at a modest pace. Global attitude towards nuclear energy and its economies is on the whole not encouraging. It will take a lot of effort and optimism for nuclear to maintain its present share of electricity generation of 13 per cent. According to the IEA-WEO 2012 (current policies scenario), such a share is likely to drop to less than 10 per cent by 2035.

9.7.2 Prospects for wind power

Wind power is the most rapidly growing renewable energy source. Demand for it is expected to increase significantly over the next 20 years.

The cost of wind power is still high compared with fossil fuels, but declining capital costs and improved performance are likely to reduce generating costs. Wind is expected to become cost competitive with fossil-fuels-based generation on the

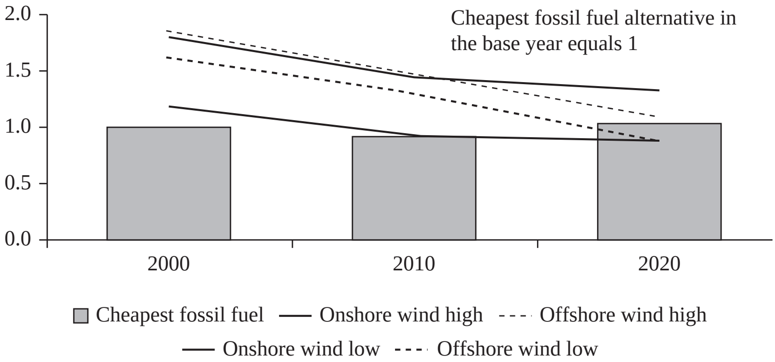


Figure 9.6 OECD-Europe electricity generating costs for wind and fossil fuels [11]

best sites on land over the next decade, but dispatching problems will persist. Figure 9.6 shows how electricity generating costs for wind power and fossil fuels may evolve in OECD-Europe up to the year 2020.

Large land requirements and competition among different land uses could constrain growth. The intermittence of wind power and the unsightliness of wind turbines could further limit site availability. The effects of intermittence must be taken into consideration at the early stages of wind-power development, as the effects may become more obvious with higher shares of wind in the electricity mix. Such limitation and prospects are discussed in detail in Chapter 12.

9.7.3 Future prospects for solar cells

Continued strong growth suggests that the solar-cell market will play a future prominent role in providing renewable, non-polluting sources of energy in both developing and industrial countries. A number of policy measures can help ensure the future growth of solar power. Removing distorting subsidies of fossil fuels would allow solar cells to compete in a more equitable marketplace. Expanding net metering laws, to other countries and the parts of the US that currently do not have them, will make owning solar home systems more economical by requiring utilities to purchase excess electricity from residential solar systems. Finally, feed-in tariffs, revolving loan funds and other providers of micro-credit are essential to the rapid spread of solar-cell technologies.

The economics of solar power will be discussed in detail in Chapter 12. However, the cost of electricity for grid-connected customers from solar cells remains higher than from wind or coal-fired power plants, but it is falling fast owing to the economies of scale as rising demand drives industry expansion.

A few million homes worldwide, mainly in villages in developing countries, now get their electricity from solar cells. For the 1.7–2 billion people not connected to an electrical grid, solar cells are typically the cheapest source of electricity. In remote areas, delivering small amounts of electricity through a large grid is cost-prohibitive, so people who are not close to an electric grid are likely to obtain electricity from solar cells. If micro-credit financing is arranged, the monthly payment for PV systems is often comparable to the amount that a family would spend on candles or kerosene for lamps. After the loan is paid off, typically in two to four years, the family obtains free electricity for the remainder of the system's life.

In low-income countries, PV systems provide high-quality electric lighting, which can improve educational opportunities, provide access to information and help families to be more productive after sunset. A shift to solar energy also brings health benefits. Solar electricity allows for the refrigeration of vaccines and other essentials, playing a part in improving public health. For many rural residents in remote areas, a shift to solar electricity improves indoor air quality. Photovoltaic systems benefit outdoor air quality as well. The replacement of a kerosene lamp with a 40 W solar module eliminates up to 106 kg of carbon emissions a year.

In addition to promising applications in the developing world, solar energy also benefits industrial nations. Even in the UK, a cloudy country, putting modern PV technology on all suitable roofs would generate more electricity than the nation consumes in a year. Recent research surrounding zero-energy homes, where solar panels are integrated into the design and construction of extremely energy-efficient new houses, presents a promising opportunity for increased use of solar cells.

9.7.4 The virtual power plant

Different private generating facilities are likely to proliferate in the future. Beside conventional plants, these include large on-shore and off-shore wind farms, biomass power plants, district heating, fuel cells, CSP and PV plants. Connecting many energy suppliers together to form a virtual power plant poses a special challenge for information and telecommunications technology. Numerous set points and actual values must be compared in a decentralised energy management system, automation units have to be controlled, and forecasts of sun, wind and consumer behaviour must be obtained. Prospects for such a virtual power plant will also be discussed in later chapters.

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Chapter 10

Electricity generation in a carbon-constrained world

Part II – The technologies

10.1 Introduction to clean electrical power

As has been explained in the last few chapters, the global drive for clean power is mounting. The emphasis is of course on clean generation with minimum emission of pollutants, particularly CO_2. There are many technologies available for this, however, most of them are still expensive and not yet mature. Clean power generation and decarbonisation of the power sector is attained through the following approaches and technologies:

- Wider adoption of renewable generation and technologies
- Increasing utilisation of nuclear power
- Cleaner fossil fuels and efficient generation technologies
- The smart grid
- Conservation and demand side management (DSM)

The economics and prospects of renewable generation are covered in detail in Chapter 12. It is obvious that the prospects of renewables attaining the major share in electrical power generation, is limited at least in the foreseeable future (until 2040). The limited future prospects of nuclear power were discussed in Chapter 9. Therefore, global electricity generation is therefore likely to continue to depend on fossil fuel as its principal infeed. This is particularly true in rapidly growing economies like those of China, India (and the other BRIC countries) which are anxious to utilise local resources, like cheap coal, to the maximum extent possible. Simultaneously cleaner fossil fuels generation is advancing through different avenues: greater utilisation of natural gas as a relatively benign fuel, improving the efficiency of generation, future introduction of clean fossil fuel technologies like CCS.

All through past chapters, we referred to the growing role of natural gas as clean infeed to electricity generation, and also the improved efficiency of CCGT facilities. In this chapter, we shall concentrate on efficient electricity generation, clean fossil fuel technologies, carbon capture and storage (CCS) and the smart grid.

These aspects are dealt with in detail in the following sections.

10.2 Improving efficiency of the generation sector

Electrical efficiency is most important because the world is electrifying. Energy services are now being increasingly offered in the form of electricity, rather than in any other form – mechanical or human. Although energy demand is expected to grow at an annual rate of 1.5 per cent over the next 25 years, that of electricity is expected to grow at a rate of around 2.3 per cent, reflecting this growing electrification [1, 2]; that is why improving the efficiency of electricity production figures so highly in any effort to improve global energy efficiency. Any environmental policy that does not have electricity efficiency as the centre of its interest will be missing the target.

The efficiency of electricity generation is a complex phenomenon. It depends on many factors and varies from one country to another. National primary energy endowments plays a prominent role; countries with viable hydro-electric sites try to exploit these as a priority, so they will also exploit local coal resources in spite of their environmental impacts. The endowment of national (or imported) resources of natural gas presents opportunities for high efficiency, low emissions and relatively inexpensive electricity generation. Nuclear is limited to a few countries with relatively advanced financial and human resources, its efficiency is below average; also below average is the efficiency of new renewable generation – like solar.

Energy losses occur in every activity in the electricity sector, not only in the utilisation of electricity, but mainly in the electricity supply industry – electricity production (generation), its transmission to consumer centres as well as its distribution to users and consumers. The majority of losses occur mainly in electricity generation. Until today the average net efficiency of electricity generation worldwide is around 34 per cent, with almost two-thirds of calorific content of primary fuel input into electricity generators lost as waste heat. It has to be emphasised that there are no exact dedicated data on global net electricity generation and its exact consumption of fuels. So we have to rely on published data in the global annual energy surveys, the latest of which is the ‘International Energy Outlook 2013’ of the US Energy Information Administration [2]. Efficiency of electricity generation, which was as low as 25 per cent in the 1950s, significantly improved to around 34–35 per cent today, and is continuously but slowly improving mainly through the increasing use of combined cycle facilities firing natural gas and improved technologies in material use. In this chapter, when we are referring to electricity generation efficiencies, we are only accounting for net power sent out from the station, thus ignoring the energy use by the plant auxiliaries which can be as high as 5–6 per cent of generated power in case of steam plants and 1–2 per cent in gas turbine plants.

Figure 10.1 shows how the efficiency of coal firing power stations was held steady at almost 34 per cent over the last 20 years, while that of gas firing facilities improved from 34 per cent in 1990 to an average of 43 per cent in 2010 through the wide introduction of combined cycle gas turbine plant (CCGT) facilities firing natural gas.

There are also major losses in the electricity grid – the transmission network as well as distribution lines. The transmission network that delivers bulk electricity

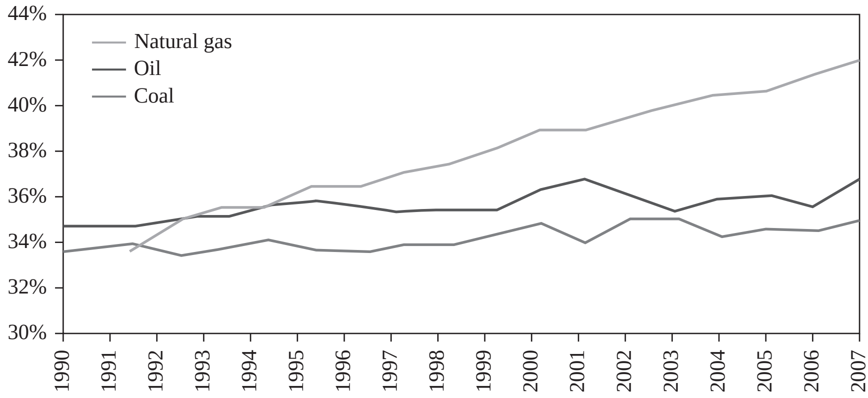

Figure 10.1 Development of efficiency of thermal generating plant [Source: OECD/IEA/ETP 2010 [3]]

from major power stations into bulk supply substations, can incur losses as high as 1–3 per cent of transmitted energy (depending on the length and voltage of the network). Other 6–10 per cent losses occur in the distribution networks (also depending on the network configuration – length and conductors). Therefore, world average transmission and distribution (T and D) losses are around 8–10 per cent of energy sent out from the power station [3]. When this is taken into account, of the primary energy input into the power plant only 30–32 per cent of this energy reaches consumers, i.e. less than one-third. This demonstrates the efficiency dilemma of the electrical power system. It has been suggested that only 3 per cent of the energy content of coal fired to generate electricity for lighting will be utilised as light in an incandescent lamp.

10.2.1 Improving efficiency of electricity generation

Efficiency of the electricity generation depends on the mode of generation. Hydroelectric production has an efficiency of over 90 per cent; whereas some vintage thermal plants firing coal have efficiencies of no more than 25 per cent. Modern steam plant, firing coal, is becoming the preferred means of generation, particularly in China and India, where thermal plants represent 80 per cent of production due to availability of cheap coal. Steam generation, mainly firing coal, presently represents slightly less than half of the world's electricity generation; future improvements in efficiency of electricity production depend on technology advancement in this quarter. Major losses mainly occur in the thermal plant itself, in condensing steam; also in auxiliaries and generators and these can be as high as 5–6 per cent of the generated electricity.

There are two approaches to improve steam power generation efficiency: one is by increasing live steam parameters (pressure and temperature) to develop supercritical (SC) and ultra-supercritical (USC) technologies; another is by system integration, a typical example is integrated gasification combined cycle (IGCC). In the next 10 years, SC and USC will be built in significant numbers, and these new plants are likely to remain in use until 2050 for electricity production from coal because of their flexibility and general advantages of lower cost, reliability, high availability, maintainability, and operability. IGCC currently looks promising in its ability to produce large CO_2 reductions at the lowest cost while maintaining high generation efficiency.

The production of district heating besides electricity generation (combined heat and power plants) greatly improves energy efficiency. Utilising waste heat from electricity generation to produce district heat, as well as heat for industrial processes, an efficiency of 90 per cent can be achieved. However, such successes can only be achieved in certain countries (that require district heat) and in some industrial applications.

Pulverised coal combustion (PCC) is currently the predominant technology for generating electricity from coal and represents 43 per cent of fuels used in electricity generation. It also accounts for more than 97 per cent of the world's coal-fired electrical capacity. Most existing plants operate at less than SC steam conditions, i.e. less than 34 per cent efficiency, with best examples reaching 39 per cent efficiency.

New pulverised coal power plants – utilising SC and USC – operate at increasingly higher temperatures and pressures, and therefore achieve higher efficiencies than conventional units. Supercritical power generation has become the dominant technology for new plants in industrialised countries. Now considerable efforts are underway in the US, Europe, Japan and also China, to develop 700°C-class advanced ultra-supercritical (A-USC) steam turbines. If successful, this will raise the efficiency of the A-USC units to about 50 per cent by 2020 [4].

Natural gas (NG) presently accounts for 20 per cent of electricity production. The increasing availability of NG and its prices are favouring the utilisation of NG in high efficiency combined cycle gas turbines (CCGT) where efficiencies of over 50 per cent are becoming common with as high as 60 per cent already available. This increasing CCGT trend and improvements in the efficiency of thermal plant through the increasing use of critical and supercritical steam turbines means that the efficiency of electricity generation is destined to continue to improve, although slowly, in the future.

10.2.2 Future trends in efficiency of electricity generation

As already indicated the efficiency of electricity generation is destined to continue to very slowly improve year after another. Such improvements are prompted by the rising cost of primary fuels, but also and as importantly by environmental considerations. Mitigating carbon emissions from generating plants is a global environmental concern. Carbon trade and taxation, also carbon legislation, are becoming common in most Organisation for Economic Co-operation and Development (OECD) countries and few other countries, and will enhance the already mentioned technological trends to improve efficiency of coal plants and switch to cleaner renewable resources, particularly hydro and wind, also the more efficient CCGT plant firing natural gas.

However, such global improvements are going to be very slow due to the existence of a vast inventory of vintage low-efficiency plants which have long lives; the high investment cost of introducing new plants and also the efficiency penalty of mitigating emissions through the introduction of clean technologies, like that of carbon capture and storage (CCS) which tend to significantly reduce efficiency of new plants fitted with such facilities.

Table 10.1 gives a prediction of the future development of electricity generation in the coming 25 years and its rising proportion of primary energy sources. This is also demonstrated in Figure 10.2

The fact is that the annual amount of fuels destined to electricity generation will grow at a rate of almost 2.1 per cent annually, while net electricity generation will grow at a higher rate of around 2.3 per cent, indicates an annual improvement of efficiency of 0.2 per cent percentage points. Over a period of 25 years (2011–2035) this means that the efficiency of electricity generation is likely to improve by 5 per cent as indicated in Table 10.1.

Table 10.1 Future electricity generation trends

Year	**Expected net generation (TWh)**	**Fuel consumption (Quad Btu)**	**Electricity fuels % of global energy use**
2005	19 125	194	38.4
2015	22 652	227	39.4
2025	28 665	281	41.8
2035	35 175	337	43.8

Source: Reference [2].

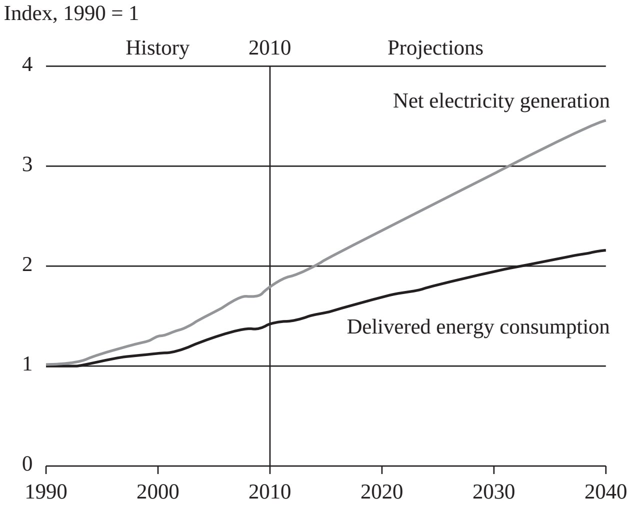

Figure 10.2 Growth in world total electricity generation and total delivered energy consumption, 1990–2040 [Source: EIA, International Energy Outlook 2013]

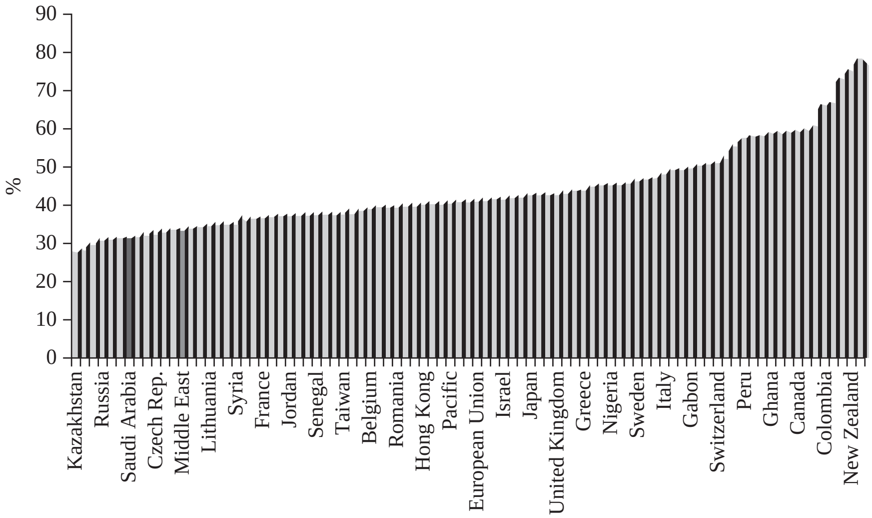

Figure 10.3 Energy generation efficiency worldwide measured by dividing total net electricity production by energy inputs [Source: 'Trends in Global Energy Efficiency', ABB, 2011]

The above Figure 10.3 depicts power generation efficiency in different world economies.

10.2.3 Carbon emissions from electricity generation

Thermal power stations firing coal are major emitters of CO_2 with around 750–1 000 g CO_2 per kWh in 2010. With net electricity generation of 20 500 TWh in that year, total CO_2 emissions from the electricity sector amount to around 12 000 million tons, this is around 40 per cent of global carbon emissions. With each one percentage point of improvement in efficiency of electricity generation, CO_2 emissions can be reduced by as much as 350 Mt annually.

It must be realised that slow but continuous progress has been achieved in reducing emissions from generation plant during recent years. Earlier vintage plants of the late twentieth century burning coal operated at an efficiency of 25 per cent while emitting 1.30 tons CO_2 per MWh. New thermal generation operating at an efficiency of 45 per cent and burning coal is emitting only 0.720 tons CO_2 per MWh, while a new CCGT burning NG can has an efficiency of 60 per cent and emits only 0.320 tons CO_2 per MWh. This is only one quarter of the emissions per unit of electricity one quarter of a century ago.

Nuclear plants, due to security reasons, have to operate at relatively moderate temperatures and pressures. Correspondingly its efficiency tends to be at 35 per cent or lower. This is a low efficiency value compared to modern thermal plants. However, a nuclear plant has the advantage of producing no emissions. The same applies to hydro-electric generation, also new renewable resources (wind and solar) that tend to have low or no emissions but operate at low efficiency in comparison to hydro plants, which have high efficiency.

10.2.4 Factors affecting the efficiency of generating plant

Power plant efficiencies are typically defined as the amount of heat content in (Btu) per the amount of electric energy sent out (kWh), commonly called a heat rate (Btu/kWh). Such efficiency is affected by [5]:

- design choices that present a trade-off between capital cost, efficiency, operational flexibility and availability;
- operational practices that aims at a full load, avoiding steam leakages and utilising integration systems;
- fuel, particularly utilising hard dry coal that possesses less water and ash;
- environmental control, to reduce emissions (NO_x and SO_x); represent *parasitic loads* that decrease efficiency. Similar penalties are introduced by applying CCS technologies that significantly increase cost and reduce plant efficiency;
- ambient temperature – colder cooling improve efficiency of generating power; however, high altitude negatively affect output and efficiency of gas turbines;
- method of cooling – methods for cooling steam turbine effluent can be through once-through cooling, wet cooling tower and indirect dry cooling. There are penalties to utilise wet cooling towers that can range 0.8–1.5 per cent and as can be as high as 4.2–8.8 per cent with a dry cooling tower and dry cooling.

To this must be added penalties brought about by aging, normal deterioration and bad operation, low maintenance and management practices. Deterioration can be addressed by: refurbishment, replacement in kind, upgrade with advanced design, modifying the original design, repowering and retirement with replacement by new construction.

10.2.5 Improving efficiency of the generating cycle [6]

The main consideration in improving the efficiency of the generating cycle is through utilising the heat content of the exhaust gases and cooling water. This is done mainly with combined cycle gas turbines (CCGT) in which the exhaust gases of the GT are fed into a steam boiler and steam turbine generator – thus increasing efficiency of the generating cycle by 50 per cent. A typical CCGT plant now operates in the range of 45–55 per cent, but efficiencies as high as 60 per cent are already achievable.

The other means to improve the efficiency is by combined electricity and heat production where the condensed steam from the steam turbine outlet is not only utilised as a heat source mainly in industry but also various applications including district heating. This also considerably improves the efficiency of utilising fuels. An average efficiency of around 50 per cent can be reached in the EU by conventional thermal electricity and heat production. Tremendous strides have been achieved in this regard

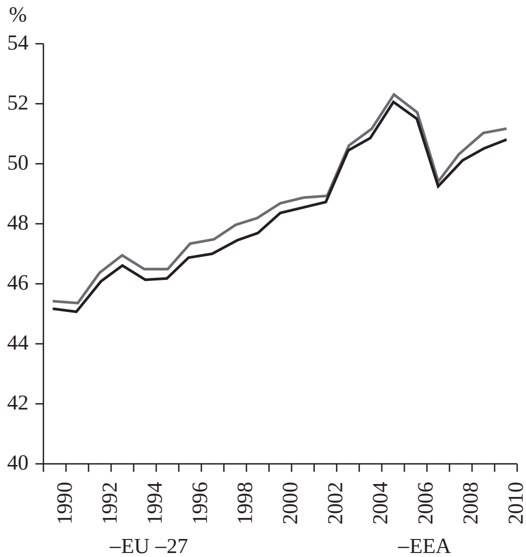

Figure 10.4 Development of efficiency of conventional thermal electricity and heat production [Source: EEA 2013 [5]]

during the last 20 years as demonstrated in Figure 10.4. Combined with district heat, over all efficiencies as high as 90 per cent have been achieved in Denmark.

Improvements in the efficiency of the utilisation of generation fuels can be attained through the combined production of power and water, in which the steam from the generating process is utilised for desalination by the flashing process, thus significantly improving the utilisation of the generation fuels. Further improvements in output and efficiency are obtained by many new technologies, such as cooling the input air to gas turbines and direct steam injection heaters.

10.3 Clean fossil fuel technologies [7]

10.3.1 Clean fossil-fuel-based power technology

Programmes are underway to develop power plants of the future, using coal and natural gas as the primary fuel, that:

- are essentially pollution free;
- nearly double the current generating efficiency;
- have the capability to produce a varied slate of co-products, such as chemicals, process heat, and clean fuels.

Gasification technologies are an essential part of this effort because they provide the means to vastly expand the clean fuel base to more-abundant and lower cost resources (including biomass and wastes) and enable co-production of power and high value by products.

Gasification breaks feed stocks down into basic constituents so that pollutants can be readily removed and clean fuels or chemicals can be produced. Aiming at:

- Resultant clean fuels can be used to power highly efficient and clean gas turbines, fuel cells, and fuel cell/turbine hybrids.
- Gasification concentrates the CO_2 constituent, which facilitates capture and recycle or sequestration.
- A clean-coal technology programme has sponsored integrated-gasification combined-cycle (IGCC) projects, representing a diversity of gasifiers and clean-up systems that are helping to pioneer the commercial introduction of this next generation power concept.
- Circulating fluidised bed (CFB) combustion: Because CFBs have unique advantages with regards to fuel adaptability, load following, emission reductions, and operating costs, it is likely that the utilisation of CFBs will continue. New CFBs are becoming increasingly efficient, larger, more reliable, and have decreasing emissions. The world's largest and most efficient 600 MW supercritical CFB was placed into operation at the end of 2012. It can be expected that, within this century, coal-fired CFB technology will experience continued development, and become increasingly important for obtaining high-efficiency coal-fired power generation.
- Polygeneration based on coal gasification: Generating synthesis gas after gasification of coal is the foundation for polygeneration (or coproduction). Using coal as the feedstock, polygeneration technologies can result in a range of products, such as electricity, chemicals, heat, liquid fuels, and natural gas. Both electricity and higher value products (e.g. chemical products and fuel gas used by urban residents) can be produced at the same facility. Integrated gasification and combined cycle (IGCC) technology is a combination of gasification used for the production of clean coal-based electricity production. Electricity generation based on IGCC has demonstrated significantly lower emission levels and can also facilitate the separation of CO_2. Power plants that implement polygeneration operate in such a way that they achieve the goals of efficient electricity production and full utilisation of coal as a resource. This technology offers benefits across multi-disciplinary fields, and it is one of the best options for the high-efficiency, clean, and low-carbon-utilisation of coal. Therefore, development and demonstration of polygeneration facilities should be supported in such a way to promote the technology and increase the number of demonstration projects.

Gas separation membranes are important for enhancing the cost and performance of technologies on many fronts, by offering the promise of displacing energy-intensive, costly cryogenic and chemical means of separating out selected constituents from a gas stream, such as oxygen, hydrogen, CO_2, or pollutants.

- Separation membranes have the potential to significantly enhance the cost and performance of gasification-based technologies.
- Ion transport membranes for oxygen separation are in an advanced stage of development.

- In addition to gasification applications, ion transport membranes create the possibility of combustion with oxygen rather than air to eliminate nitrogen-based pollutants and to concentrate the CO_2 constituent, which enables capture.
- High-temperature ceramic membranes hold the promise of making a hydrogen-based economy feasible and have immediate application to fuel cells, and fuels and chemical production.
- CO_2 separation membranes have the potential to significantly reduce the cost of CO_2 capture, which is the most costly facet of the carbon sequestration process.

Advanced gas-turbine development is essential because gas-turbines will be a mainstay in the power-generation industry for the foreseeable future, operating on natural gas in the near- to mid-term and on gasification-derived synthesis gas in the longer term. Advanced turbine system programmes for the future aim to:

- improve the efficiency and overall performance of the smaller gas turbines in electric-generation service that are subjected to highly cyclic loads, and
- link these gas turbines to fuel cells to push efficiency and environmental performance even higher.

Fuel cells have the potential to revolutionise future power generation because they:

- operate on a range of hydrogen-rich fuels (natural gas, methanol, and gasification-derived synthesis gas);
- represent a bridge to a hydrogen economy;
- offer inherently high efficiency and are essentially pollution free (emitting water, CO_2 and heat);
- lend themselves to distributed generation applications because of low emissions and quiet operation (owing to few moving parts).

Phosphoric acid fuel cells are offered commercially and are penetrating niche markets, with efficiencies of 40 per cent – a many 250 kW units have already been sold.

Second-generation, high-temperature molten carbonate fuel cell and solid oxide fuel cells are poised to enter the market, with efficiencies approaching 60 per cent when operated in a combined-cycle mode that uses the process heat to produce steam.

Fuel cell/turbine hybrids that have the potential to raise efficiencies up to 70 per cent by using the process heat from high-temperature fuel cells to drive a gas turbine are under development. Fuel cell energy announced the start-up of a 250 kW molten carbonate fuel cell/capstone micro-turbine system, and a solid oxide fuel-cell-based system is soon to follow.

Fuel cells are unlikely to take the power markets by storm. As long as a developed hydrogen infrastructure is not available (and it may take decades), fuel cells are just another fairly efficient means of converting gas into power and heat; no more, no less. To succeed, manufacturing costs must first drop to a level that allows prices barely to exceed the \$2 000 kW^{-1} threshold. This may take quite some time.

Distributed generation alleviates electricity transmission and distribution constraints (enhancing the reliability of electrical grids), enables combined heat and power applications (boosting thermal efficiencies upwards of 80–90 per cent), and offers an option to central-power generation.

10.4 Carbon capture, usage and storage (CCS)

10.4.1 Introduction

Carbon capture and storage (CCS) covers a wide range of technologies that are being developed to allow the capture of carbon dioxide (CO_2) emissions from burning fossil fuels at large point sources (mainly electricity generating power stations) and preventing them from being emitted to the atmosphere by gainfully using these emissions or storing them in safe geological sites. Presently annual CO_2 emissions amount to 30 gigatons (Gt). Under 'business as usual' scenarios they will likely to go up to 43 Gt by 2035 [1]. Half of anthropogenic emissions come from dispersed activities that thwart collection. There is now interest in carbon utilisation. Therefore, there is a growing inclination towards carbon capture, utilisation and storage (CCUS) activities [7].

CCUS is considered to be technically feasible and commercially viable in many existing injection activities in the oil and gas industry to enhance oil recovery (EOR). Currently, it is proposed for deployment in more than 20 large worldwide electricity generation projects in order to improve the technologies and reduce costs. Presently there are eight large scale CCUS project operating worldwide, six more are under construction. Six of the operating projects are in natural gas processing. The other two are in synthesis fuel and fertiliser production. Five of these projects use EOR. The execution of some of these projects has been delayed by funding shortages and the need for an approved regulatory framework for transport and storage of CO_2 [8, 9].

10.4.2 The technologies and storage

CO_2 capture is technologically viable. There are mainly three processes: post-combustion capture, pre-combustion capture and oxy-fuel (CO_2/CO_2 recycle combustion) capture technologies. Currently, post-combustion technologies on coal or gas fired power plant use wet scrubbing of the flue gases with a solvent. The pre-combustion process involves fuel reaction at high pressure with oxygen or steam to produce CO_2 and hydrogen. When applied to coal it is usually associated with integrated gasification combined cycles (IGCC). Capital costs and performance parameters for all three routes are based on projected scale-ups in future plant and so are still not firmly established. These projections tend to be relatively close to each other so no clear favourite technology has emerged. Second generation technologies are being researched which hold out prospects of significantly electricity production cost reduction.

There are three major CO_2 capture technologies, pre-combustion (for IGCC plants), oxy-fuel combustion, and post-combustion capture.

10.4.2.1 Oxy-fuel combustion

Oxy-fuel combustion of coal is a process of burning coal using O_2 with a recycle stream consisting mostly of CO_2 and O_2 instead of air. Because nitrogen from air does not enter the boiler, production of NO_x is greatly reduced. Oxy-fuel combustion generates a flue gas consisting primarily of CO_2 and H_2O. After a purification process, including ash separation, desulphurisation, denigration, drying, and possible further CO_2 pressurisation, it is liquefied and stored.

10.4.2.2 Pre-combustion CO_2 capture

IGCC power plants dynamically integrate the benefit of coal gasification and the high efficiency of combined cycle power generation technology. The thermal efficiency of IGCC power plant has been improved to the point that it is the same as ultra-supercritical power units (≈43 per cent). Furthermore, with the development of gas turbine technology, the efficiency of IGCC can be further improved.

10.4.2.3 Storage

Storage is mainly in geological formations at depths of more than 1 000 m and pressures higher than 100 atmospheres. Such storage can take place in deep saline aquifer and depleted oil and gas formations, as well as below coal beds. There are on-shore and off-shore viable storage sites that can safely accommodate long term global emissions. IPCC estimates global storage capacity to be in the order of 1 000–10 000 Gt CO_2 which gives sufficient storage capacity.

Transportation of CO_2, to storage or usage sites, can be developed in the future through a network of secondary pipelines to carbon emission sites with a main pipe line feeding storage or usage facilities.

10.4.3 Carbon usage

Presently, the greatest commercial demand for CO_2 comes from the oil industry for EOR. Carbon has more commercially viable uses: it provides bubbles in soda, is used in greenhouses to make plants grow quickly and it is made into dry ice. There are other possible commercial usages. A long-term vision visualises successful air capturing of carbon, say by solar technologies, and then combine the captured CO_2 with manufactured hydrogen to make gasoline or diesel fuels which are carbon-neutral hydrocarbons for transport. Some of these forms of storage are more permanent than others but all are helpful in getting the CCUS technologies into wider deployment.

10.4.4 The economics

Application of CCS to industries, particularly power stations, will always result in significant added cost. They will reduce efficiency by 6–9 percentage points and increase cost of electricity by arrange of 20–30 per cent, some of which can be compensated by usage of the captured CO_2. Therefore, CCS technologies can become economically viable only if carbon is adequately priced. It can be gainfully employed in new highly efficient 45 per cent coal-fired power stations, which employ super or ultra-supercritical pressures and temperatures to 700–750°C. CCS is not economically viable in older low efficiency pulverised coal (PC) plants. New power stations can now be built with ‘capture-ready’ concepts to allow easy retrofitting with capture equipment if needed in the future.

For CCUS to commercially develop there is need for:

- regulatory and legal obligations that mandate all future PC power stations to incorporate CCS technologies, and/or
- higher pricing of carbon with CO_2 beyond $50/ton, even to $100/ton.

In the future, and if the EU 2050 vision of carbon-free economies develops, this means decarbonising natural gas which will ensure the extensive and wide application of CCS technologies. Major energy intensive industries such as cement, iron and steel production are also likely to be required to reduce CO_2 emissions considerably.

10.5 Smart grids

Since its inception progress in electrical power technologies has been slow and the inertia, to continue with business-as-usual, is high. The power business with its slow technological progress has been contrasted with the electronics and telecommunication businesses where rapid technological progress is taking place every day.

The development of the electrical power sector suffered from a few main drawbacks. One of them is the unchanging hierarchy of the electricity system (Figure 10.5). Large inefficient central power stations, feeding into high-voltage grids, transfers electric power to users through a myriad of distribution networks.

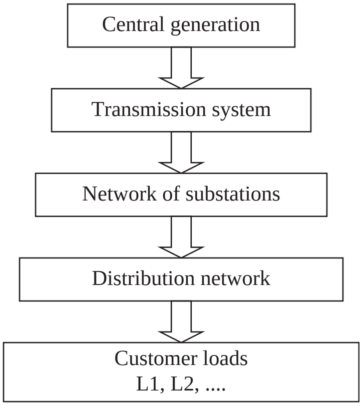

Figure 10.5 The existing grid [Source: Reference [10]]

Consumers have few, or practically no choices, and live communication between users and producers is almost nonexistent.

Therefore the existing electricity grid is inefficient. Only 30 per cent of the energy content of primary fuel input reaches consumers. Practically a third of the grid facilities are used for only few hours each year. Almost 20–25 per cent of the installed capacity is idle most of the time and is only needed for emergencies that may or may not occur for a long time. Also interruptions are not uncommon. The system hierarchy can lead, in certain circumstances (like loss of major generation supply or breakdown of a transmission line), into major supply interruptions or blackouts that affect a large number of customers. Therefore the existing electricity grid is not optimum. Over the last few decades it has well-served consumers' requirements well, but at relatively low efficiency and high cost and with lot of emissions.

Now with advancement in electronics and communications, as well as environmental awareness, things are changing at a relatively significant pace compared to the past stagnation. We are now slowly entering the age of smart grids that are more efficient, interactive for consumers and environment friendly. This is going to gradually transform traditional grids into 'smart grids'. The transformation will be gradual and sometimes slow, but it is a significant departure from the past stagnation. Electric power is not the electronics and communication business; due to its capital intensive nature, it is a slowly evolving technology, but the results can mature over time.

Smart grids, in the minds of many power engineers and planners, are only associated with distribution. Here we will present a broader view to cover electricity production (generation) as well. There are many definitions for the smart grid but I chose this one: 'the collection of all technologies, concepts, topologies, and approaches that allow the silo hierarchies of generation, transmission, and distribution to be replaced with an end-to-end, organically intelligent, fully integrated environment where the business processes, objectives, and needs of all stakeholders are supported by the efficiency exchange of data, service, and transactions' [11].

A smart grid is therefore a grid that accommodates a wide variety of generation options and forms. It allows consumers to interact with the energy management system to optimise their use. It is a self-healing system that predicts looming failures and mitigates problems. It relies on IT to optimise its economical performance. Therefore, a smart grid incorporates four new activities which are not familiar to the existing electrical power grid.

- It empowers consumers to interact with the energy management system in order to manage their demand and reduce their bills.
- It utilises information technology and telecommunications to optimise the use of its capital assets, particularly generating facilities, in order to minimise operational cost.
- It is a 'self-healing system', which can predict looming failures and take preventive action to limit interruptions and mitigate serious system failures.

- It accommodates a wide variety of generation options which, beside traditional generation, incorporate new and renewable sources including distributed generation and consumer premises, intermittent new sources like solar, wind, etc. and also future possible mobile sources (like electric cars).

Most importantly smart grid aims at efficiency and also environmental sustainability.

10.5.1 Metering

A central component in the smart grid is metering. Until now the most widely used electricity metering worldwide are the electromechanical meters. These meters have been in existence since the inception of electricity distribution. They have proved to be resilient, relatively accurate and served the purpose of the industry relatively well. However, they required frequent reading and manual billing. Correspondingly, the introduction of the new smart meters remotely measuring energy consumption provided a direct communications link between energy suppliers and their consumers. That removes the need for meter readings at the premises and ensures accurate bills based on actual, not estimated, consumption. However, this is one way communication from the consumer to the utility. It is termed one-way automated meter reading (AMR). What is more important is to move from this into two-way automated metering infrastructure (AMI). With this domestic customers will be able to see the information about their energy use through an integrated in-home display. More important than the real-time billing information, that will also give consumers more control over their energy use and carbon emissions, and create new opportunities for energy retail services, infrastructure management and renewable energy generation. Such AMI smart metering is crucial in the effort to make future energy saving and to tackle climate change. It is a major step forward in the development of the smart grid as well as in overcoming bottlenecks in the operation of the generating system through load management with available generating capacity, and allows pervasive control.

The European Union EC has now mandated that, by 2020, all existing electromechanical meters at consumers premises should be replaced by smart meters. This is the AMR step. As explained above it is only a first step in the long path to the smart grid. The next step is the installation of the two-way AMI. It will allow consumers to communicate with the grid to obtain live information on costs and tariffs and to make choices that will not only reduce their costs but also help optimise the grid operation [12].

10.5.2 Storage issues [13, 14]

Electrical energy storage is the biggest problem that has besieged the electricity supply industry since its inception. Of course, limited storage in batteries and similar facilities are available, but here we are concerned with the availability of massive storage of energy in the form of gigawatt hours. The only available large facility is the well-known pumped hydro storage schemes, which have been available for decades. They are, however, capital intensive, with an efficiency of only 70–80 per cent and require certain topographical and geological formations, which does not necessarily exist everywhere.

Viable large storage is important for the functioning of the smart grid; correspondingly interest in developing such storage technologies is growing. There are few ideas being investigated and developed.

The first major development is the likely introduction of large batteries. A Japanese firm NGK currently sells a large room sized, sodium-sulphur battery. Each large battery can provide 1 MW for 6 hours. When clustered in grid requirement standards they are still small and not cheap ($2 500 per kilowatt). However, it is an encouraging start.

The second development is that of the provision of efficient lithium-ion batteries for plug-in hybrid electric vehicles (PHEV). They have the ability to store vast amounts of cheap off-peak electricity for use during the next day during peak demand, with the possibility of releasing it to the grid during system shortages.

The third possibility is the large thermal storage. In the long term, particularly after 2030, concentrating solar power plants (CSPs) provide means of indirect electricity storage by storing heat. CSPs are able to store heat during the day and convert it to electricity at night, thus providing flexible round-the-clock electricity from solar power. The following graph (Figure 10.6) demonstrates this, in which excess heat collected in the solar field is sent to the heat exchanger and warms the molten salts going from the cold tank to the hot tank. When needed, the heat from the hot tank can be returned to the heat transfer fluid and sent to the steam generator.

Another of these storage facilities is the concept of the isentropic pumped heat electricity storage system (PHES). According to its developers, the isentropic

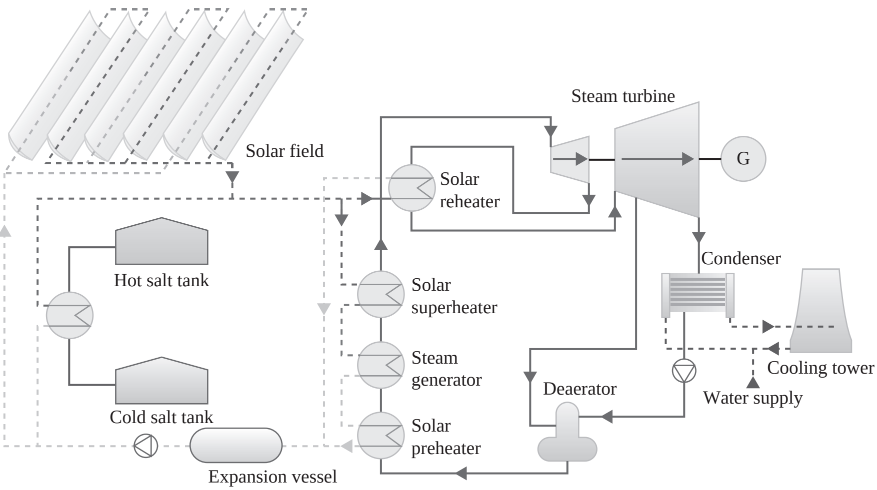

Figure 10.6 Layout of the Solana (Abengoa Mojave Solar Project) [14]

PHES system uses a highly reversible heat engine/heat pump to transfer heat between two insulated storage vessels containing a particulate mineral (in its simplest form, gravel). A gas circulates through the machine and, to store energy, is first compressed, which raises its temperature to 500°C. It is then passed through one of the stores, in which the mineral is heated by direct contact, which also cools the gas to close to the original temperature. It is then expanded back to its original pressure, which cools it to around −160°C, and then passed through the other store where it cools the mineral by direct contact and is warmed back to close to its original temperature. This process requires energy that can be supplied electrically via a motor, and is thus an energy storage process. Discharge is the opposite of the charge process and releases energy, in which situation the machine drives an electrical generator. This results in an electricity-in to electricity-out (round trip) efficiency in the range of 72–85 per cent. This compares favourably with a typical pumped-hydro value of 74 per cent [14].

There have been never ending attempts to store energy by pressurising air into salt caves or similar facilities, also in form of inertia in flywheels, etc. However, one must admit that success until now has been modest. There is no economical large-scale solution yet, in sight.

However, the smart grid is providing alternatives to the problem of storage. Storage is needed to store cheaply produced energy (say off-peak) and release it during shortages and peak demand. The smart grid can provide the same results, but in a different manner. Many appliances, and also batteries of PHEV, can be made to utilise cheap off-peak electricity. Such supplies will be interrupted during peak and shortages, for a prescribed time, without causing users undue inconvenience; thus ‘restricting demand’. Such facilities can only be made widely available through the smart grid, correspondingly the smart grid will provide ‘demand management’ alternative that can allow optimal operating and economical supplies without the need for large bulk energy storage.

10.5.3 Evolution of the smart grid

It is not expected that the new smart grid will replace the existing electricity grid soon; it would rather slowly complement it, improving its performance and adding to its capabilities. This necessitates a topology for the smart grid with compatibility of the existing traditional grid, but allowing for incorporation of innovative technologies and organic growth.

This can happen through the integration of ‘intelligent micro-grids’. Such micro-grids are defined as ‘interconnected networks of distributed energy systems (loads and resources) that can function whether they are connected to or separate from the electricity grid’.

This micro-grid will incorporate micro generation mainly renewables, local and distributed storage capability and load management facilities, all of which are essential to smooth the intermittent performance of renewables. Therefore, smart meters, as described above, capable of remote controlling of the load, are an integral part of the smart grid. An intelligent core communication infrastructure,

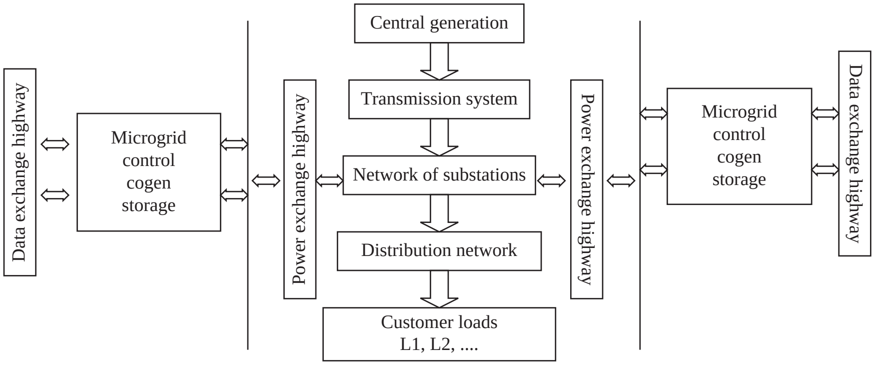

Figure 10.7 Incorporating the smart grid into the existing grid [Source: Reference [10]]

capable of exchanging information and undertaking micro-control, is also a basic requirement of the micro-grid.

Many observers think that we are new in transition to widely distributed electricity systems, often labelled as 'micro-power' in which the customer owns and operates their small (micro) generation facilities. Their devices are also connected to the distribution grid for exchange of power. The availability of storage facilities (electrical or thermal) will greatly enhance the prospects of micro-power facilities.

Such micro-grids will be incorporated to a smart grid through dedicated highways for command, data and power exchange. The smart grid will coexist alongside the existing traditional grid, gradually expanding and eventually, over the long term, replacing a lot of the infrastructure and functions of the already existing traditional grid (Figure 10.7).

10.5.4 Summary

The technology of the electricity supply industry which suffered from low efficiency and stagnation in the last century is now in the process of evolution through the introduction of more efficient generation and smart grids. Smart grids rely on two-way AMI that will give consumers more control over their energy use and create new opportunities for energy retail services, infrastructure management and renewable energy generation.

Beside improved technologies for energy storage, the smart grid will provide an alternative through demand management of consumer's appliances and possible PHEV energy exchange with the grid.

At the core of the smart grid lies the development of the intelligent micro-grid. Such micro-grid will enhance distributed generation and will be incorporated to a smart grid through dedicated highways for command data and power exchange. The ultimate results will hopefully be more efficient supply that better serve consumer needs and lowers costs and help mitigate undue harmful emissions.

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Chapter 11

Economics of reliability of the power supply

11.1 Introduction

Reliability of the power system is generally defined as the overall ability of the system to perform its function [1]. It can also be defined as the ability of the power system to meet its load requirements at any time. Two distinct aspects of system reliability are identifiable: system security and system adequacy. System security involves the ability of the system to respond to disturbances arising internally, whereas system adequacy relates to the existence of sufficient facilities within the system to satisfy the customer-load demand [2].

As mentioned in Chapter 1, reliability of the electricity supply is of paramount importance. Interruptions (even transient supply problems) can cause serious financial and economical (social) losses. Electricity shortages can affect any country in two ways: they can handicap productive activities and seriously affect consumers' welfare. From the productivity standpoint, electricity shortages discourage investors by affecting production, increasing its cost, and requiring more investment for on-site electricity production or standby supplies. For small investors, the cost of operation is increased, since electricity from small private generation is more expensive than public national supplies. Electricity interruptions at home also cause consumers great inconvenience, irritation, loss of time and welfare [3].

To any economy, an unreliable power supply results in both short- and long-term costs. Costs are measured in terms of the loss of welfare and the adjustments that the consumers (such as firms), facing unreliable power supplies, undertake to mitigate their losses.

Service interruptions may trigger loss of production, costs related to product spoilage and damage to equipment. The extent of these direct economic costs also depends on a host of factors such as advance notification, duration of the interruption and timing. The latter refers to the time of day or season and to the prevailing market conditions regarding the demand for the firm's output. These direct costs can be very high, particularly under conditions of uncontrolled load shedding and transmission and distribution outrages, i.e. sudden interruptions in service without advance notification. In addition to the direct costs noted earlier, there are indirect costs to the economy because of the secondary effects that arise as a result of the interdependence between one firm's output and another firm's input.

Chronic electricity shortages and poor reliability of supply trigger long-term adjustments. If a firm's expectations are that shortages and unreliable service will persist, then they will respond in one or more ways. The installation of back-up diesel generator sets is the most common long-term adjustment taken by commercial consumers and small industrial firms. It was estimated, and until recently, that a substantial amount of the total installed generating capacity in many developing countries (in the order of more than 20 per cent) is in the form of standby generation on customer premises [4].

Shortages of electric power and supply interruptions occur because of either of the following two reasons:

(i) Unreliability of the supply due to the non-availability of generating plants, or breakdowns in the transmission and distribution system. Such unavailability can occur in varying degrees in any power system in the world: *system security*.

(ii) Shortfalls of delivered electric power even under the best conditions of the electric system. Such shortfalls usually occur in developing economies. Most of these suffer capital shortages owing to inadequate number of generating facilities capable of matching the peak demand, and with limitations in the transmission and distribution system, particularly to rural areas: *system adequacy*.

The ability of a power system to meet demand and deliver adequate electric energy to the consumers is termed above as system adequacy. To provide such adequacy and to overcome supply shortages and interruptions, there is a need for investment. Most investments in the electricity supply industry (ESI) are meant to reduce the prospect of shortages, and maintain and improve reliability. Most of the shortages can occur as a result of the growth in the demand, which necessitates generation extension and network strengthening. However, and in spite of large investments, interruptions are inevitable. Costs of improving continuity of the supply can be very high after a certain level of reliability. As shown in Figure 11.1, such costs can increase at an exponential rate beyond a certain level of reliability [5].

The function of the power system is to provide electrical energy as economically as possible and with an acceptable degree of reliability and quality. Economics of reliability tries to strike a reasonable balance between cost and quality of service. Such balance varies from one country to another, just as from one category of consumers to another. Most developing countries cannot afford the high costs of ensuring the high reliability of supply, taken for granted in industrialised countries. Gradually, however, quality of supply is improving worldwide.

11.2 The value of reliability

By value of reliability, we mean the estimation (in monetary terms if possible) of the benefits and the utility derived by the consumer from achieving (or improving) a certain level of availability of the supply. The cost of unreliability over a certain

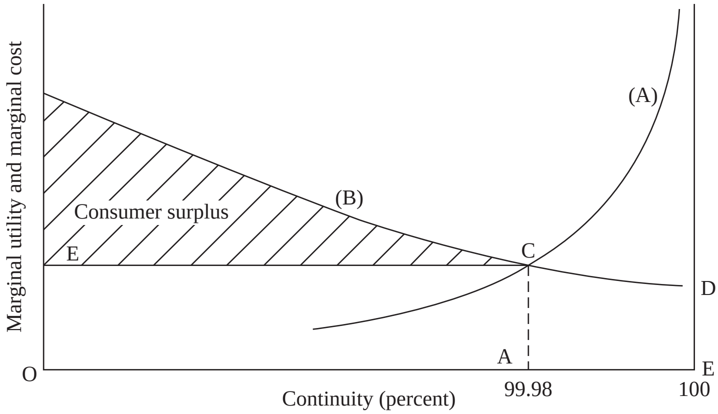

Figure 11.1 Marginal utility and marginal cost of electric availability

period is the social cost (financial and economic) suffered by consumers as a consequence of supply interruption during that period. Cost–benefit analysis of reliability economics in planning of the power system has not advanced in the way it has in some other public services, e.g. transport. This is because of the great difficulty of obtaining comprehensive assessment of the reliability of supply from the generating system down to the consumer terminals. Even more difficult is the evaluation of consumer financial and economic loss, and the inconvenience due to interruptions [6].

The electricity tariff does not reflect the benefits that consumers (the society and the economy) derive from the existence of the electricity supply. In Figure 11.1, the tariff, if it is fixed at a long-run marginal cost, is equal to CA. What the consumer pays for is the annual quantity of consumption multiplied by the tariff (area OECA). The benefits are the entire area under curve (B) and to the left of CA. This is much higher than what is paid. The difference is called the *consumer surplus*, which is the extra benefit that the consumer derives out of the presence of the supply over what is paid in tariffs, which is usually substantial. The consumer loss of utility due to interruption is depicted by area ACDE.

It is possible, however, to assess the contribution of different schemes towards the continuity of supply and to choose the one with the maximum contribution within economical cost. The problem still remains of what is the ‘economical cost’? Because of these difficulties, empirical design rules and national standards for supply security have been set to guide and limit the planners, without resorting into actual monetary valuation of reliability benefits. In a few countries, however, monetary values have been fixed for evaluating the cost of loss of supply. These values are utilised to evaluate cost of interruptions and compare these with the system strengthening cost, in order to justify its execution.

What the planner would aim at is not a completely uninterruptible supply; the cost of such a system would be prohibitive as shown by curve (A) of Figure 11.1. The aim should, however, be the point of ‘optimum reliability’ point C in the figure. Point C is the intersection of the reliability marginal cost curve to the electricity supply industry (curve (A)) with the marginal cost of interruptions to the consumer (curve (B)). The intersection point is where the optimum reliability is obtained. It is where the marginal utility of the extra increment of reliability improvement to the consumer is equal to the marginal cost spent in achieving it by the supply industry.

It is possible to draw curve (A) over a wide range. This curve, which can be evaluated by modelling, is the least-cost system strengthening scheme as chosen from many schemes, which would lead to the same reliability but involve higher cost. It is, however, very difficult to draw curve (B). It is now possible, through studies and consumer surveys to obtain information and build tables of interruption cost data applicable to certain categories of consumers and certain areas [7]. Such data are valuable in estimating the value of reliability to assist in cost–benefit analysis for system strengthening.

11.3 Reliability in system planning

In order to understand the value of this approach, it is advantageous to review the existing methods that guide reliability planning and are applied by most of the electricity supply utilities worldwide. These can be summarised as follows [5]:

- Empirical planning rules
- Supply design standards
- Simplified cost–benefits analysis
- Detailed financial and economic evaluation

The first three methods will be discussed in sections 11.3.1–11.3.3, and the fourth method will be discussed in detail in section 11.4.

11.3.1 Empirical planning rules

In this case, the planner, based on his experience and practice in dealing with similar situations, decides on the desired reliability level. This is achieved through the evaluation of the importance of the system and network and correspondingly the extent of redundancy to be incorporated, taking into account the following: the part of the system it is dealing with, voltage level and nature of the network, number and category of consumers, financial constraints, and past reliability records and past experience in handling a similar situation.

Almost all systems that do not have drawn out and written supply design standards, or probabilistic planning, employ such criteria. The empirical rules for generation involve a percentage reserve-margin method, without a loss of load expectation (LOLE) calculation; or for a small system, a firm generating capacity with the biggest set(s) out-of-commission. For the main network the '$n - 1$' rule is employed, which means that the loss of a main line from n parallel lines, or a transformer of n transformers, should not affect continuity of supply, with more emphasis being placed on important networks. In the distribution, and lower-voltage networks, ‘rules of thumb’ are employed in accordance with the consumer category and investment constraints mentioned earlier.

11.3.2 Supply design standards

Supply design standards are a step forward from the empirical approach, where the amount of past experience, performance, economical limitations and individual separate rules are reduced to a set of detailed guidelines for utilisation by planners to reliably design the system.

In generation, this involves a LOLE target, which stipulates that in any year the probability of capacity shortage should not exceed a certain value; usually a fraction of a day. Correspondingly, plans are drawn out in advance for the generation system strengthening so that LOLE would not exceed a certain standard. In the network, consumer groups and supply areas are classed in accordance with their demand, the minimum number of circuits available, and the target time for restoration of supply is specified. For interruption duration not to exceed a certain level, the network may need strengthening.

11.3.3 Cost–benefit analysis

Generally, not all cost–benefit analysis of the power system should necessarily involve monetary valuation of the cost of interruption. An increasing amount of work is being undertaken to evaluate the cost of different schemes and the probable amount of interruption. Further engineering judgment is used to choose the right plan, within the constraints mentioned, utilising empirical rules.

A simple actual example commonly encountered is that of choosing the method of protection of rural single feeders (Figure 11.2). Three methods are discussed and costed: expulsion fuses (EF), auto reclose circuit breakers (AR) and AR with automatic sectionaliser (AS), in the middle of the line. The cost and predicted continuity performance of these schemes when applied to a particular rural network are summarised in Table 11.1.

Cost–benefit engineering judgment can now be applied. The employment of EF with an expenditure of only £500 on network protection will involve 12 000 consumer-hours lost and an interruption of 24 hours per consumer per annum (plus main network interruptions). An expenditure of £3 500 will save 10 000 consumer-hours; an extra £2 000 investment can still reduce interruptions by a further 1.8–2.2 hours and consumer-hours lost by 900. The problem is which plan to choose? The

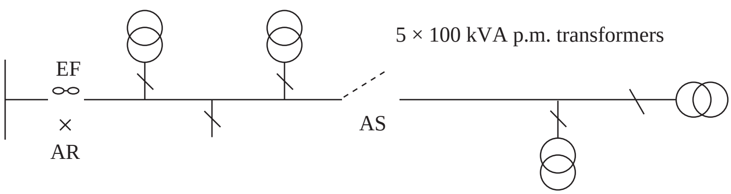

Figure 11.2 Rural network protection schemes

Table 11.1 Rural network protection costs

Scheme	Protection	Cost	Probable consumer-hours per annum	Hours per consumer
1	Expulsion fuses	£500	24 h $\times$ 500 cons. $=$ 12 000	24
2	Auto reclose	£3 500	4 h $\times$ 500 $=$ 2 000	4
3	Auto sectionalise	£5 500	$1 \times 300 + 4 \times 200 = 1\,100$	2.2

Note: Probable consumer-hours interrupted per annum are calculated based on experience of annual interruption duration for such networks.

estimation of interruption length is obtained through experience in operating such systems.

It is doubtful if any system planning will accept scheme 1 in Table 11.1 (except if there is acute capital shortage). The question is whether the extra cost of scheme 3 justifies the expenditure. In a mature supply, the engineer will empirically decide that the 4 hours are excessive and its reduction to 2.2 hours justifies the expenditure.

Proper cost–benefit evaluation involves valuing the social cost of interruption to the consumers over the next 20–30 years, also the cost of the fuses repair, the AR and AS maintenance over the same period, and discounting these costs to their present value. If with scheme 2 the present value of the social cost of interruptions plus the discounted cost of maintenance is higher than £3 500, then scheme 3 is chosen. Alternatively, in case of a lower cost, then scheme 2 is adopted. If the cost of interruptions is much higher, then a more reliable supply should be provided through an alternative source. This, of course, necessitates detailed evaluation of the cost to the consumer of aborted energy (curve (B) in Figure 11.1).

One interesting feature of this simple example is how the marginal cost per consumer-hour saved, increased considerably after making the first step, from £0.30 to £2.22. Thus, the dominant feature is the accelerating cost of higher reliability (curve (A) in Figure 11.1).

11.4 Detailed financial and economic evaluation

11.4.1 System adequacy and economics

The power system consists of three functional zones: generation facilities, transmission facilities and distribution. From the reliability point of view, it can be looked at in three hierarchical levels. The generation facilities, the generation and transmission and the third hierarchical level of the generation, transmission and distribution [1].

The adequacy of the generating system is the most important aspect in system planning to ensure the system-function performance. A shortage in the ability of generating facilities to meet demand can cause serious and sometimes widespread supply interruptions, particularly during peak demand. This leads to immense financial losses, inconvenience and disturbance to consumer welfare. Therefore, the adequacy of generation is paramount in power-system reliability. Adequacy of the bulk transmission network is also important. However, its reliability is usually much higher than that of other parts of the electrical power system. Although faults and inadequacies in this network can cause serious interruptions, they are less frequent than those of the other facilities of the system. Distribution system disturbances and inadequacy cause only localised interruptions, which are less serious than generation and transmission inadequacies.

11.4.2 Assessment and economics of generation adequacy

Sufficient reserve is essential to ensure the adequacy of the generating system. This reserve was determined, in the past, by methods such as ensuring that the generating system had enough percentage reserve, usually not less than 10–15 per cent of system peak, depending on the size of the system and regional interconnections, in order to meet maintenance requirements, unscheduled breakdowns of generating facilities or higher demand than anticipated. In small systems, generation reserve was assessed to be equal to the largest or the two largest sets out of commission. Such deterministic methods cannot ensure the optimisation of investment in the system nor can they determine to a fair degree of accuracy the extent of system adequacy, and that this is the economically optimum adequacy. Correspondingly, simulation utilising probabilistic methods, which can more faithfully predict system performance and assist in the economical evaluation of investment, have become common in planning most large generating systems. The introduction of new generation facilities into the system reduces expected shortages and has system results that affect the whole economics of generation and the cost per unit of electricity produced. Such system effects can only be assessed through probabilistic simulation techniques.

The most widely utilised methods of assessing adequacy of generation are: the loss-of-load expectancy (LOLE) index, percentage energy loss index, and the frequency and duration method. These indices are used to assess probabilistic generation adequacy by convolution of the generating capacity model with the load model [8].

11.4.2.1 Loss-of-load expectation (LOLE) method

The LOLE may be the most widely used probabilistic index for generation reliability assessment. It is based on combining the probability of generation capacity states with the daily peak probability so as to assess the number of days during the year in which the generation system may be unable to meet the daily peak:

$$\text{LOLE} = \sum_{L} n_L A_G$$

where n_L is the number of occurrences of peak demand L during the year, and A_G is the cumulative probability of being in capacity state j, such that $C_{j-1} \geq L > C_j$.

The reciprocal of the above equation is the LOLE in years per day. This means the probable number of years, or fraction of a year, during which the generation system will be unable to meet the peak demand of that day.

The LOLE index has gained recognition because it provides a probabilistic figure that can be computed and employed in system planning. It combines a generation and a load model. It is relatively simple to compute, understand and apply. However, this index suffers from the following shortcomings:

- It gives no indication of the extent of load shedding in megawatt (MW) or percentage wise, nor does it give any indication of its duration or frequency regarding the average consumer, which is what reliability assessment should be mainly concerned with.
- The LOLE, in days per year, mainly indicates the number of days in the year in which the generating system would not be able to meet the load. The frequency of load shedding may be higher than this figure in case of double peaked daily load curves and in systems that employ units with high failure rates but short repair duration.
- Since such an index is not capable of assessing the actual damage, it is not very useful for comparing the reliabilities of different utilities or national systems, particularly if they have different shapes of the load curve and peak durations.

The above arguments, particularly the first one, have been recognised by the many users of this index. However, it is argued that for the same system, the use of the LOLE index would be adequate and correct for investigating different expansion plans and annual maintenance scheduling. This is correct only if the duration of peak demand is static over the years of study. This is not the case in many systems, with the continuous increase in the middle of the day load being experienced in most cases, particularly in developing economies.

To give an example, suppose that for a certain system with a typical daily load curve and annual load duration curves ‘A’ and ‘a’, respectively in Figure 11.3. The LOLE would be associated with the probably curtailment of the portion of the energy higher than the line ‘C’. If over a few years, the shape of the load curve changes to that of ‘B’ and ‘b’, while the LOLE is maintained constant, then the probable amount of energy curtailment, area $c + c''$, increases faster than the growth of peak demand. This signifies a disutility to the consumer and an actual

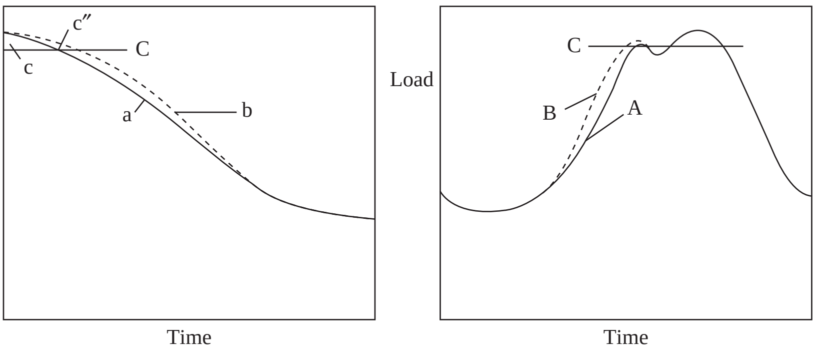

Figure 11.3 Effect of change of load curve on electricity curtailment

increase (probably small) in the unreliability of supply, which the LOLE cannot measure and defeats the purpose of maintaining the LOLE constant.

The effects of the change in the shape of the load curve and pattern of consumption, although they take place slowly over years, may change significantly from one season to another in the same year.

Besides the significant arguments against the LOLE mentioned above, it can be misleading in long-term planning and annual maintenance scheduling in systems of non-stationary load curves where significant changes in the duration of the peak load are expected to be encountered between seasons and over years.

11.4.2.2 Frequency and duration method with a load model

The theory of the frequency and duration analysis of the generation states with a load model is detailed in reference [8].

The generation frequency and duration approach, when coupled with the proper load model, will lead to the computation of a comprehensive reliability data. It will indicate the probable existence of all possible negative margin states, their frequency of occurrence, cycle time and mean duration.

However, the model does not yield a single reliability index. Two indices are calculated: an availability index and another frequency index. Here also the frequency index is of similar value to that of the LOLE and the sound arguments against its application for system expansion and medium-term operation can be applied. The availability index will account for the duration of load shedding but not its extent and magnitude.

This was recognised by the developers of this method and the following index of percentage energy loss (PEL) [9] was suggested as being more representative of the actual reliability of the system for planning purposes.

11.4.2.3 Percentage energy loss (PEL) index

The method involves the generation capacity states availability table and the daily load curve. The probable energy curtailment, during one year, divided by the energy requirement of the load and multiplied by 100, yields the PEL index:

$$\mathrm{PEL} = \frac{\text{probable energy curtailment}}{\text{energy requirement}} \times 100$$

The probable energy shedding is obtained by combining the generation states availability table with the segments of the load curve. By summing up all load segments, the probable energy curtailment will be computed.

The percentage energy loss index comes nearer than any other single index to assessing the true reliability of generation, because it reflects the ratio of energy curtailment (disutility) to the consumer to his consumption (utility) [5]. Hence, it can measure the amount of inconvenience and loss to the consumer, which is the principal concern of any reliability criterion. However, it also suffers from the fact that it is not useful in a dynamic load curve. If the generation expansion scheme is aimed towards maintaining the index constant, then with the load factor improvement with time, owing to an increase in base load (say by an increase in off-peak space heating), the amount of energy permitted curtailment, which usually occurs during peak hours, would increase in proportion more than the growth in peak demand. This indicates deterioration in the 'actual' reliability of the supply and an increase in consumers' disutility and inconvenience, which defeats the purpose of maintaining the index constant.

We have demonstrated the computational methods of various reliability indices that are widely utilised for power system projects planning. What is important is how to use them intelligently. This calls for a better assessment of the social costs of power system unreliability, particularly those caused by the generating system.

11.5 Financial and economic evaluation of quality of electrical power

The cost of electrical power interruptions [10] to facilities utilising electricity has been detailed earlier. However, these facilities can be sensitive to a wider range of power quality disturbances other than just outages that are counted in utility reliability statistics. In the new digital economy, momentary interruptions or voltage sags lasting less than 100 ms can have the same impact as an outage lasting many minutes.

To overcome the damage caused by these transient disturbances it is essential sometimes, for certain facilities (like banks, data and customer service centres), to invest in technologies for equipment protection and improving power quality. Such investments can be very high, and correspondingly a cost–benefit analysis is required before embarking on them.

Such a cost–benefit analysis will have to:

- analyse the power system quality performance,
- correspondingly estimate costs associated with power disturbances,
- look into technological solutions in terms of effectiveness and cost, and
- perform the cost–benefit analysis.

Voltage sags and monetary interruptions have most important impacts on performance of facilities. There is equipment that is usually sensitive only to magnitude of voltage variation; others are sensitive to both magnitude and duration of an RMS variation.

IEEE Standard 1159 defines voltage sags lasting between 0.5 and 30 cycles as 'instantaneous', those lasting between 30 cycles and 3 s are identified as 'momentary', and those lasting between 3 s and 1 min are defined as 'temporary'. In addition to magnitude and duration, it is often important to identify the number of phases involved in the sag.

The costs associated with sag events vary widely according to facilities and market conditions. Such costs can be product-related losses, labour-related losses and other costs like damaged equipment and loss of income. Costs will vary with magnitude, duration and frequency of power quality disturbance.

Cost of power quality improvement technologies depends on the alternative category involved, its investment cost as well as operating and maintenance cost.

For small control protection (less than 5 kVA) CUTS, UPS and dynamic sag protectors are employed. For machine protection (up to 300 kVA): UPS, flywheel as well as dynamic sag corrector are employed. For large facility protection in the 2–10 MVA range, beside the UPS and flywheels, dynamic voltage regulators as well as static and dynamic transfer switches are employed.

To perform the required economic analysis, the solution effectiveness of each alternative must be quantified in terms of the performance improvement that can be achieved. Solution effectiveness, like power quality costs, typically will vary with the severity of the power quality disturbance, and the type of activity.

Once the costs of the quality improvement technologies and their effectiveness have been quantified, a normal cost–benefit analysis exercise, like the ones explained in this book; have to be undertaken before decision making.

11.6 Evaluation of investment in generation

Optimisation of investment in the generating system is important for the economics of the electricity supply industry. Generation facilities constitute almost two-thirds of all new investments in the electric power system and the vast majority of the operational cost. The losses due to their unavailability are widespread in contrast to the network problems, which have localised consequences. Therefore, it is essential to optimise these to ensure the economic as well as the technical adequacy of the power system.

The most important points to be addressed when investing in power generation are as follows:

- *Selecting the location* – many technical and economic considerations govern selecting the location (fuel availability, cooling water requirements, availability of land, proximity to the load centre, configuration of the transmission network and environmental considerations).
- *Timing* – this is influenced by the criteria for generation adequacy as well as load growth prospects and lead time for the new facilities. Such issues were addressed in Chapters 5–7.
- *Type, size of the new facilities and fuels* – there are many and increasing types of new generation facilities (conventional thermal units firing pulverised coal or other fuels, nuclear, hydro or other renewables, gas-turbines in a simple or combined cycle, etc.). What is important is not only the type of facility and fuel consumed, but also the optimum set size that fits economically, to the growing load curve, in order to reduce risk.

There are several established algorithms to assist in generation planning and its economics. All of these are based on a decision-making framework expressed in economic terms aiming to schedule least-cost investments for power generation expansion. Some of these are Wein Automatic System Planning (WASP) Model [11] and the UNIPEDE Model [12]. Such models, however, fall short of achieving proper financial and economic evaluation of generating planning because of weaknesses in the system adequacy criteria that they utilise, as explained above. It is necessary to undertake detailed financial and economical evaluation, with proper economic adequacy criteria. More about that is given below and in Chapters 12 and 15.

11.6.1 Valuing cost of interruptions

The cost of electricity to a consumer, i.e. the consumer's evaluation of the worth of the electricity supply (while ignoring consumers surplus), is equal to payments for electricity consumed plus the economic (social) cost of interruptions.

Supply interruptions cause disutility and inconvenience, in varying degrees and in different ways, to different consumer classes, domestic, commercial and industrial. The costs and losses (L) of these interruptions to the average consumer are a function of the following:

- Dependence of the consumer on the supply (C)
- Duration of the interruption (D)
- Frequency of its occurrence in the year (F)
- Time of the day in which it occurs (T)

that is

$$L = (D^d \times F^f, T^t) \times C$$

where d, f and t are constants, but vary from one consumer category to another.

It is becoming increasingly necessary to assess the cost of interruptions to consumers in monetary terms and to use this assessment as an input in the project evaluation to arrive at the system plans that minimise total overall financial and economic cost to the utility and the consumer (payment in tariffs plus the cost of interruptions). Many problems are encountered.

- Consumer cost is not only a function of the frequency and duration of the interruptions, but also the day and the time of the day in which they occur as well as consumers' category and expectations. An interruption that occurs after midnight and causes a considerable amount of energy curtailment of off-peak heating may pass unnoticed by the consumer, while a similar interruption that involves much less energy during peak hours and household maximum activity will cause enormous consumer irritation and inconvenience.
- Consumer costs due to interruption are not a linear function. It is highly likely that they will be similar to curve (B) in Figure 11.1, i.e. the marginal utility of an extra incremental improvement in reliability decreases slightly as reliability improves.
- Generation shortages usually occur during peak hours where system demand is highest and value of electricity is most important to consumers. Most network-caused interruptions are random in occurrence and can happen any time during the day. Therefore, interruptions caused by generation shortages are more costly to consumers than network problems.

- The amount of energy curtailed is no indication of the value of electricity to consumers. The value of operating little-energy consuming sensitive machinery for a firm, or TV and light to a household, far out-weights the value of high-energy consuming apparatus and machinery, at least for short interruptions.

Until now and in most countries, the determination of the level of reliability is based on experience, judgment and also the availability of funds to invest in standby plant and redundant systems. Increasingly in Europe and North America, a lot of techniques are used to assess the financial losses to consumers as a result of supply interruptions, i.e. the worth of reliability in monetary terms. There are many ways to assess such costs; most of these can be obtained from the established techniques of *consumer surveys*. The purpose of consumer surveys is to assess consumer *willingness to pay* (WTP) for extra reliability of supply. From consumer surveys it is possible to draw out consumer *damage functions* (consumer cost). These functions reflect the costs that consumers of different categories are likely to endure as a consequence of supply interruption, based on their demand, category of use and the frequency and duration of these interruptions. Such costs are weighted with regard to the respective energy utilisation in the district (or country). The weighted costs are then summed to provide the total cost for the district for each specified duration. These are termed as *composite consumer cost function* for the district or country. From these the total annual cost of interruptions is computed and compared with the energy curtailed to arrive at an average economic cost per kWh of electrical energy curtailed [13, 14].

There are some uncertainties that surround such an approach, but it is closer than anything else in assessing the actual cost to consumers of supply unreliability. This method can be refined further to assess a rate for generation interruptions and a different rate for network interruptions, taking into account that most generation shortages occur during peak hours. Therefore, energy curtailment at peak times is more valuable than that resulting from transmission and distribution network problems, which are random in nature. The total financial cost of electricity to a consumer is the amount of the payments made by the consumer, in the form of tariffs, plus the social cost of electricity interruptions, as valued by the consumers' willingness to pay.

Financial cost of electricity $=$ (energy consumed in kWh $\times$ tariff) $+$ social cost of energy interruptions (kWh interrupted $\times$ average cost to consumer per kWh curtailed).

11.6.2 Incorporating reliability worth in generation planning

The economic planning of electricity production will try to minimise this cost by striking the right balance between electricity production cost (tariff) and supply continuity, as detailed in Figure 11.4.

Such a calculation will indicate the percentage continuity figure that minimises total generation system cost (including interruptions cost), and correspondingly the amount of percentage reserves required to attain such a continuity.

This cost factor is useful for power system planning in order to minimise the system cost to consumers. In such cases, a generation simulation model like that of

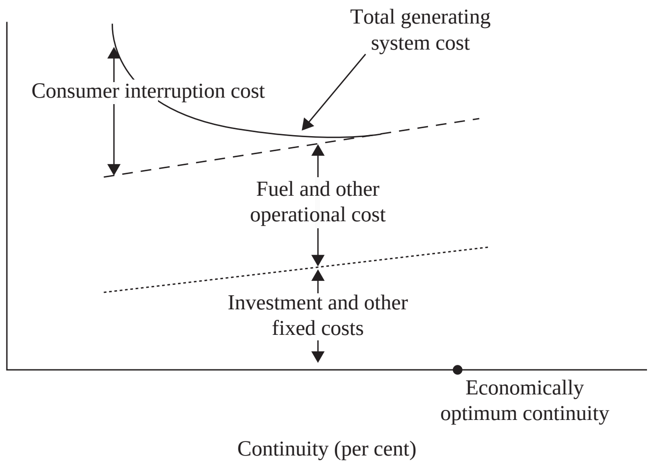

Figure 11.4 Total cost of the power system including cost of interruptions

Figure 11.5 is utilised to assess the annual expected cost of generation at a future year (cost of electricity (fixed and operational) + cost of interruptions to the consumers). Sets are added until the optimum continuity is obtained. This will occur when the above sum is at a minimum. Such simulation is carried out for many years into the future, utilising different generation-extension scenarios, in order to plan a programme for generation strengthening over time.

The same approach applies to the planning and the timing of network strengthening, where the economic cost of electricity supply to a particular area is equal to the cost of energy utilised by the area plus the cost of interruption to the consumers in that area, as caused by network problems. A network-strengthening exercise is carried out to assess the economic cost of each new network-strengthening configuration in order to compute the discounted net benefits of each scheme. The net benefits in this case will be the discounted reduction in consumer economic cost due to interruptions plus reduction in losses minus the discounted cost of the network-strengthening scheme (including any other system cost). If these net benefits are positive, then the strengthening scheme is undertaken. It has to be recalled that the discounted reduction in consumer economic cost is equal to the discounted amount of reduced energy curtailment in kWh multiplied by the average economic (social) cost of each kWh curtailed.

Many attempts were made to assess the economic cost of each kWh curtailed in order to utilise this in system planning. In the 1990s, the UK electricity supply industry assessed the value of lost load (VOLL) to be £2.345 per kWh [15]. The VOLL is defined as the value that customers place on the amount of energy they would have consumed during a supply interruption. A study [13] in North America in 1985, based on the computation of consumers damage function, assessed this to be equal to almost $5 per kWh (£3.00), which is not very different. Recent studies value VOLL at much higher rate of $12 per kWh in 2010 [16]. However, such values are much lower for developing economies, where electricity is valued by the

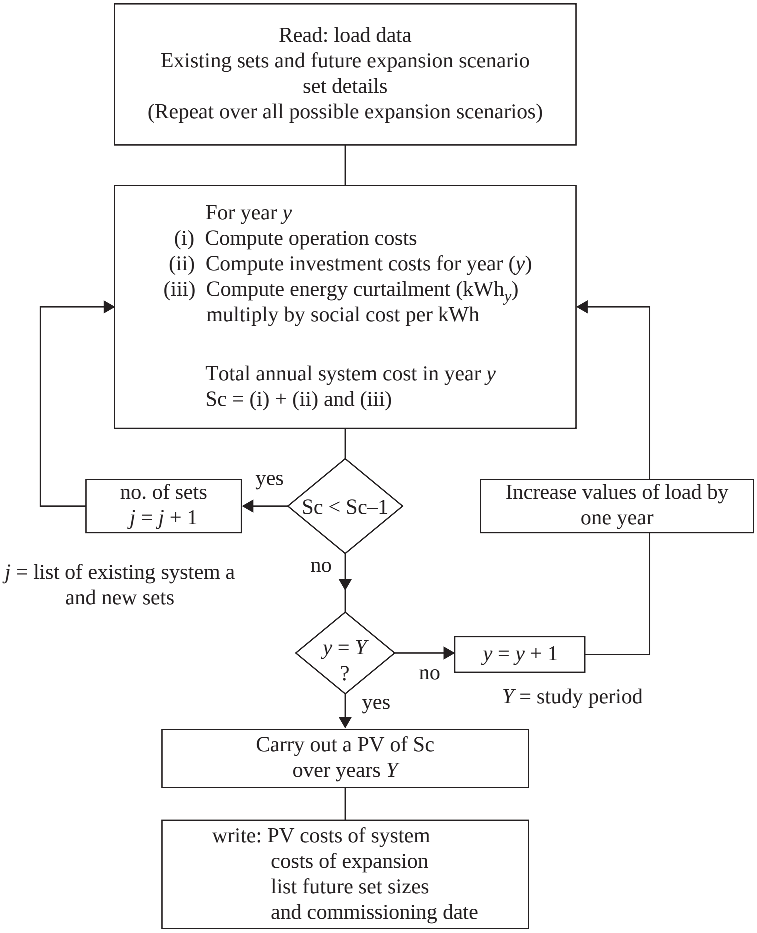

Figure 11.5 System expansion plan (to minimise total system cost (operation + investment + interruptions))

consumer at a lower value owing to their limited WTP, and the shortage of funds, particularly investment prospects in foreign currency, necessities that lower levels of reliability be tolerated.

It has to be realised that such values are based on certain supply continuity standards and consumer expectations. These are likely to change with changes in continuity as demonstrated by curve (B) in Figure 11.1.

11.7 Renewables and reliability of supply

In recent years, for environmental and similar considerations, there is growing interest in introducing new renewable sources (NRs) into the power generation system. New renewables are mainly solar and wind generating plant. Their value and economics are covered in Chapter 12; however we are concerned here with their impact on power system reliability [17–19].

NRs are intermittent, they produce when the sun shines or wind blows. Therefore, they are not dispatchable generation sources, like a thermal plant, in that the power system operator cannot reliably control them. If NRs are a minor component of the power generation system, then their impact on the performance of the power system is negligible [19]. However, if they assume a significant component of system installed capacity, like that in some European systems where wind power is a significant component of system capacity, they can become a major problem to generation dispatchers, and also system reliability. Wind power can appear and disappear suddenly. Since they are free energy they have priority in dispatching over other generation facilities. To accommodate them, the system operator must ramp up and down, rather quickly, other thermal generation (including nuclear). But this is not easy. Thermal plants (coal firing, nuclear and CCGT) need time and cost, to vary their loading or to shut down and restart. Their output can be controlled (ramped) but rather slowly. Therefore, unpredictable energy sources like NRs disturb the traditional performance of the power system. Correspondingly, they are termed ‘disruptive technologies’. The extent of their disruption to power system operation and reliability depend on the extent of their contribution to power system installed capacity and the existence of hydro-electric sources in the generating system, the extent of interconnection with an adjacent network and the amount of rapidly dispatchable and flexible components in the generating system, like single cycle gas turbines and large diesel engines.

The existence of significant hydro-electric sources (including pump storage) in the generating system eases the dispatcher operation since hydro-electric facilities can be easily and quickly ramped up or down to account for NRs output fluctuations. But hydro facilities are limited in many systems. Therefore, the power dispatcher needs to rely on other rapidly responsive plant. This most likely will be in the form of single cycle gas turbines (SCGT) which are rather more responsive to variations in system demand rather than large thermal plant. The existence of interconnection with neighbouring systems can help ease the problem in that these systems can absorb some of the extra generation or meet part of the deficit. But the problem persists when these neighbouring systems have the same renewable component and almost the same weather conditions, as is the case in western and central Europe.

Due to the above mentioned considerations, NRs affect the power system economics and its reliability as well. The science of weather forecasting is improving, which can help in dealing with these dispatching problems, but the answer in the future may lie in improving and extending energy storage facilities, and in interruptible load controlled by the smart grid (Chapter 10). Future development in large batteries and electrical vehicles (EV) that can be charged or discharged quickly to support generating system capacity is another promising future prospect.

The existence of large NRs in the system can, sometimes, be detrimental to system economies. When the wind suddenly peaks thermal plant may not operate at their optimum loading in order to absorb the sudden variation in NRs contribution. When wind blows load on other generating facilities in the system need to be ramped down below their optimum efficient loading thus increasing their fuel consumption and carbon emissions per kWh generated. Therefore, it has to be concluded that NRs contribution to power system economies and reduction of emissions does not extend to their full output, but in some instances can be only 75–80 per cent of their contribution due to the above explained economic loading problem.

Solar presents less of a challenge to dispatchers than wind. Solar is predictable particularly in sunny environments and therefore can be easier to be accommodated in dispatching. However, there may be a problem in systems where there are two peaks, a day time and evening peak that occurs after the sun disappears. Concentrated solar power with some storage is meant to accommodate for this.

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Chapter 12

Economics of new renewables: is there viable energy at the end of the renewables tunnel?

This chapter is presented in two parts. The first part details the debate about new renewables, particularly wind and solar, and the value of these technologies to the power system. The second part presents in simple terms examples and financial and economic methodologies for evaluating them.

Part I: Debating the value of the new renewable technologies

12.1 Introduction

By renewables we mean a wide array of energy sources – traditional: hydro and geothermal, and new renewables: wind, solar and biofuels. The traditional sources are well established in technologies and feasibility. In 2010, RE provided almost one-fifth of global electricity supply of which 80 per cent came from hydro-electric sources. Biofuels are limited and they tend to compete with food production. Their contribution to global energy consumption in 2011 was only 0.5 per cent, almost the same as that of 2010, indicating their modest future prospects. Therefore, here we are mainly concentrating on these new renewables (NRs) – wind and solar energy which are growing and gaining wider acceptance in almost all the world's societies, without yet proving their economic value.

The Organisation for Economic Co-operation and Development (OECD)-International Energy Agency (IEA) says global power generation from hydro, wind, solar and other renewables will exceed that from gas and may be twice that from nuclear by 2016. 'Total renewable energy capacity is expected to grow from 1 579 GW in 2012 to 2 351 GW by 2018', says the report [1]. 'While hydro-power remains the largest renewable source, a portfolio of non-hydro renewable sources – bioenergy, wind, solar PV, solar thermal electricity from CSP plants, geothermal and ocean power – grows more rapidly'. The US-EIA estimates global renewable electricity capacity in 2013 at 1 693 GW, of which the main contributors are hydro-power 1 138 GW, wind 321 GW, solar PV 128 GW and bioenergy 89 GW [2]. By 2018, global renewable electricity capacity of 2 351 GW is expected still to be dominated by hydro-power 1 330 GW, followed by wind 559 GW, solar PV 308 GW, bioenergy 125 GW. In the most recent statistics (2013), solar considerably increased its new installations by 36.6 GW added that year and for the first time surpassed that year's wind installations of 35.5 GW (33.8 GW onshore and 1.7 GW offshore).

Interest in NRs had three major milestones. It started with the oil shock in late 1973. Fossil fuels, particularly oil, were deemed depletable and new sources, preferably sustainable, were advocated. Solar came to the forefront, but with the abundance of cheap energy, particularly fossil fuels (oil, gas and coal) and also nuclear, little progress (other than academic or experimental) was achieved. The next major event commenced with the Rio 1992 Conference (Earth Summit). There it was stressed that greenhouse gases, mainly CO_2, through anthropogenic actions of growing energy consumption are likely to cause permanent damage to the human habitat. The answer is gradual curtailment of the use of the traditional sources of polluting fossil fuels and increasingly resorting to clean energy in the form of non-polluting energy from hydro and nuclear, but mainly new renewables. A third stage commenced with the 2011 Fukushima accident, which caused an aversion to nuclear in most western economies. With limited large economic hydro sites still available, NRs came out to be the main clean viable solution to global energy environmental challenges. The importance and need for the development of new renewables figured out highly not only in many energy forums and future planning, but also in political statements from world leaders like President Obama to the heads of low income African States [3]. Renewables research and advocacy groups sprang up in almost every country, even in countries rich with fossil fuel resources like the UAE, and billions of dollars were earmarked to its future development and the building demonstration projects. Subsidised investment in NRs projects proliferated mostly in Western Europe particularly in Germany, Spain and Denmark and few other European countries. New renewables became the darling technology in almost every economy worldwide.

After four decades of interest and development, new renewables represent only 3.9 per cent of global electricity (in Europe 7 per cent) and only 1.9 per cent of global energy consumption in 2012. That is 237 million tons of oil equivalent (Mtoe) out of global primary energy consumption of 12 476 Mtoe [4, 5]. Wind energy contribution represents now almost half of the new renewables, and it grew 26 per cent in 2011. In recent years, more than half of the market for wind power installations was accounted for by China and India combined, with China taking about 43 per cent of the market. The global wind power generation capacity expanded rapidly from 10 MW in 1980 to 282 GW by the end of 2012, with a remarkable average growth rate of 27 per cent annually. However, it took less than 30 years for nuclear to reach 17 per cent of the world electricity generation, gas turbines developed into sizable proportion of generating electricity facilities during the same period [6]. But not new renewables, their progress seemingly has been much slower. Highly exaggerated declarations that NRs will dominate the world energy scene by 2030 and the more modest projection that it will supply half the world energy consumption by 2050, now seem to any intelligent energy observer to be over optimistic wishes rather than attainable goals. It is appropriate at this stage to have a realistic outlook on new renewables, their potential and economics and how to evaluate them.

To relate a case of the problems encountered in integrating NRs, on Sunday, June 16, 2013, solar and wind were producing 60 per cent of Germany's electricity.

The German system could not economically ramp down to accommodate this sudden very high NRs contribution. Also, Germany could not export its extra generation to its neighbours. Correspondingly generating companies had to pay customers to take their surplus power [7].

12.2 Economics of renewables and the role of the state

There are many aspects detailed below that negatively affect the economics of NRs. One of these are their high investment cost per unit of energy output, the another is their low utilisation factor compared to other energy/electricity generation modes, their intermittent nature and problems in integrating them in national grids, and particularly the issue of dispatching. Accumulation of dust and sand also affect the efficiency of solar panels. The IEA estimates that subsidies to NRE electricity totalled $64 billion in 2011 and are expected to reach $170 billion 2035 [5].

In spite of this, and as already indicated, their percentage growth in recent years was very high; but from a relatively modest base. Most of this was only achieved by state subsidies, direct as well as regulatory. Without these subsidies, NRs on their own economics and technical features, would not have achieved that much. Although they may be the feasible answer for providing electricity in certain applications they are yet no match to traditional sources in securing large scale bulk electricity supplies to national grids.

Subsidies to NRs, mostly in OECD countries, take many forms both direct and regulatory. They are mainly in:

- Capital subsidies and loan guarantees to manufacturers.
- Feed-in tariffs (FiT) to consumers. These provide financial encouragement to convert small electricity consumers (mainly households) into produces.
- Production tax credits (PTC) for investors.
- Renewable portfolio standards (RPS) that ensures that a segment of electricity production goes to NRs (mandatory targets).
- Tradable energy certificates.
- Priority in dispatching, guarantee to access transmission lines and long term contracts.
- Carbon pricing and taxation.

Feed-in tariffs (FiT) provided the best inducement towards encouraging investment in NRs particularly to individual domestic suppliers. Feed-in tariffs are a generic class of polices that guarantee a set payment for electricity production from certain sources that feed the grid. This provides home owners as well as many establishments an incentive to invest in solar panels, with a secured return on their investment. In 2004, the German government, which was in the fore front of such subsidy providers, guaranteed investors almost 60–70 cents per kilowatt-hour (kWh) they generate for the next two decades from photovoltaic generation (PV). This compares most favourably with German retail prices of 21–24 cents per kWh. Germany was not the only country to adopt FiT; similar practices were adopted by many European countries leading to expansion of uneconomical individual and community PV generation. However, such bonanza cannot go on as market realities and economic hardships began to dawn. Recently, Germany decided that solar PV incentives will fall to 19.5 cents per kWh for smallish installations, 16.5 cents for installations up to 1 MW and 13.5 cents for larger installations with gradual cuts of 0.15 cents per kWh per month [8–10].

The cost of solar panels, particularly rooftop systems has been dropping recently, particularly due to the reduction of cost of Chinese panels. In Germany, the cost was around 2 900 euros per kW in 2010, this dropped to around to 1 900 euros in 2012. This was mainly due to the drop in the cost of manufactured panels which recently went down from 1 500 euros per kW to less than half of that. Yet it must be realised that the cost of labour, connections and other infrastructure did not significantly drop. These now constitute more than half cost of the system and are not likely to significantly improve in the future [9].

Subsidies for PV facilities have, since their inception until 2012, generated over 100 billion euros to consumers in Germany, despite the fact that PV plants only account to 3 per cent of electricity generation in Germany. Correspondingly, the cost of this huge subsidy increased the bill of German households by around 25 per cent between 2007 and 2011, putting a large burden on low income and seniors in the country. The domestic tariff in Germany now is 25.3 euro cents (32 US cents per kWh), one of the world's highest. Taxes and FiT account for almost half of this [10].

Many wind energy investors now claim that they can produce electricity at a cost comparable to that of the national grid. This may be true in abstract terms but it ignores system effects, the multiple restrictions and other expenses, particularly new transmission investments, grid reinforcement and dispatching restrictions, associated with such generation, some of these are detailed below. What is important is system cost, how much (positively or negatively) is the system affected by the introduction of the NRs. These costs do not allow wind energy to provide competitive electricity without subsidy in one form or another of the many incentives mentioned above. Solarbuzz data for solar electricity cost in the US ranges from 28.91 cents per kWh in sunny climates to a very high 63.60 cents per kWh in cloudy ones. This is many times the 11–12 cents per kWh cost of grids utilising fossil fuels generation [11].

The fact remains that most new renewables, without governmental subsidies and intervention cannot compete, in most cases, with traditional thermal power generation practices and facilities. No new private NRs investment would venture into the market without support or encouragement of some form or another. With the present global economic challenges, future renewable projects may not continue to enjoy the type of governmental favours of the past. The market future of renewables is challenging to new investments, and need careful assessment as detailed below.

With the increasing amount of variable-output NRs in the network, there is a need also to increase flexible generation. This can be not only in the form of hydro-electric plant or pump storage schemes if they exist, but also in the form of rapidly dispatchable single cycle gas turbines and diesel generation which can rapidly respond to load variation.

12.2.1 UK renewable energy strike prices

There is mounting effort by the UK government for renewables to contribute more than 30 per cent of the UK electricity market mix by 2020. In mid-2013, the UK government revealed its 'strike prices' for renewable energy that it proposes to pay under its 'contracts for difference scheme'.

Contracts for difference form a key part of the government's Electricity Market Reform. Varying in amount for each form of power generation, they guarantee to pay generators a fixed sum – or strike price – for the electricity they generate. Figures cover each year from 2014 to 2019 and reveal that some forms of renewables will get the same strike price for that period while others will see the price fall. For projects with a potential deployment capacity of more than 1 GW, the government plans to pay £155 per MWh for offshore wind in 2014, falling to £135 per MWh by 2019; onshore wind will get £100 from 2014, dropping to £95 by 2019, while large solar PV will receive £125 in 2014 and get £110 by 2019. Hydro and biomass conversion will get the same amount across the 2014–2019 period: £95 and £105, respectively.

The government also revealed details of its proposed capacity mechanism, another pillar of its Electricity Market Reform package. The government confirmed that – subject to EU state aid approval – the capacity market will be launched, with participants such as existing generators and investors in new plant bidding in auctions to provide the total amount of electricity that the UK is predicted to need from 2018–2019. Successful bidders will receive a steady payment in the year they agree to make capacity available. In exchange, they will be obliged to deliver electricity in periods of system stress or face financial penalties [12].

12.3 Debating new renewables

New renewables, as all other energy sources, have their advantages and drawbacks. Let us start by considering their strong advantages:

- NRs are clean, no GHGs emission.
- Provide a measure of local energy security.
- Sustainable, no depletion problems.
- Costs are going down all the time.
- Interconnections and improved wind prediction are reducing the problem of intermittency.
- Limited storage is becoming increasingly possible through concentrated solar panels (CSP).
- Very popular with the public, can be installed quickly in small sizes by individual consumers.

However, they are also:

- Intermittent.
- Low concentration and low efficiency (requiring large space and storage).

- Require (many times) expensive transmission and grid reinforcement, particularly in case of wind.
- Serious dispatching problems to the network operator, if wind component is large.
- Annual utilisation (output) per unit of capacity is low, so also is energy return on investment (EROI).
- Panels need continuous cleaning particularly in deserts and dusty environments.
- They (wind and solar) are mainly available in electricity form.
- They are not without some environmental impacts, during manufacturing and installing. There is also visual impacts and noise of wind facilities.

Renewables, not unlike conventional technologies, also come with some although less adverse side effects, including environmental degradation, particularly due to their substantial footprint, a by-product of the diffused nature of the resource, with the possible exception of hydro and geothermal.

Correspondingly, they are expensive and require incentives and subsidies in order to compete. But they also have other quite few handicaps. All this requires pragmatic evaluation of the virtues of NRs compared to their higher cost. In this regard, we have to consider the following main features:

- The low utilisation factor.
- Dispatching and transmission costs.
- The cost of electricity production.
- The implications of abatement of GHGs emissions.
- The inertia of existing energy systems.
- Smart grids.

12.3.1 The utilisation factor (capacity factor)

NRs generate electricity only when the sun shines (in case of solar) or the wind blows (in case of wind energy). This only happens for limited hours of the year. Therefore, the utilisation hours (utilisation factor) of NRs and their electricity output, per KW of installed capacity, is much lower than dispatchable facilities that operate all the time, like nuclear and base load thermal generation. Table 12.1 shows capacity factor for different generating facilities as follows.

The economic and cost implications are quite serious. This means that a traditional base load power plant (nuclear or fossil) can produce as much as four times

Table 12.1 Capacity factor of generating facilities

Generation mode	**Capacity factor (%)**
Nuclear	90
Base load (coal, natural gas) generation	70–80
Hydro-electric power plants	40–50
Large wind farms	19–28
Solar (thermal and PV)	10–17

the kWh per KW of installed capacity as that of a new renewable plant. In power system economics it is not the investment cost per installed KW which is of importance; it is the energy cost per kWh which is more relevant.

We also need to realise that energy return on investment (EROI) of solar systems is rather low. EROI was introduced earlier in Chapter 1 and is the energy yielded by an energy activity divided by the energy invested in that activity. In the case of wind it can be a high 18, while it drops to 6.8 for PV and 1.6 only for concentric collectors. In case of oil and gas it can be as high as 30–35 [13].

12.3.2 Dispatching and transmission cost

The problems of NRs are compounded by the intermittency and unpredictability of the timing of production. PV installations produce power during sunshine hours, which are usually high demand periods (except during the weekends), this enhances system security and economics. They do that more on sunny days, but this is not the case of wind energy which is the more favoured and increasingly utilised new renewable. It is not easy to predict well in advance when the wind blows and for how long. It mostly does that after evening peak hours when system demand drops and generation costs are low adding to system problems and cost. So to say that wind electricity cost is comparable to power system costs is not always relevant. Also system electricity generation costs change continuously, every hour all through the year, we need to be clear about what system costs are we talking about!

Wind energy is not dispatchable, in that it must be used immediately, even on the expense of other operation facilities on the system. Here the intermittency creates serious problems to the load dispatchers in control centres. How to accommodate this surge of relatively large amount of energy that suddenly appears (or disappears) at the national grid? Can the grid and existing generating facilities accommodate such sudden surges of power by taking or dropping load that quickly? The problem is minor when wind installations are small, but when they become a sizable 5–10 per cent or higher of system size the implications become quite serious. The problem can be eased in system with a large hydro-electric component; it also can be eased by energy storage and regional inter connections, which improve prospects for accommodating sudden surges of wind energy. Weather and wind prediction technologies are continually improving but electricity storage still represents a formidable problem. Other than that of pumped storage schemes which are limited to few geographical sites, bulk electricity storage facilities are still in their infancy. It will be many years, probably decades, before a solution is found to cater for the need for large electricity storage. Concentrated solar panels, with storage, which utilise heavier liquids like super heating of molten salts for few hours of heat storage, provide limited heat storage that improves the economics of solar concentrated panels. But the problem of intermittency rests mainly with wind energy. In a day of February 2012, wind power produced almost one third of Germany’s electricity, four days later (being a calm day) nothing. This imposes a heavy task on other generating plant in the system, which cannot be ramped up and down that quickly, significantly affecting its performance and efficiency [13–15].

Integrating renewables power system operators face two major problems:

(a) Renewable generation capacity is non-dispatchable, in that its production cannot be controlled or increased upon the request of the operator.
(b) Their intermittency necessitates the availability of more fast-responding generating units to maintain system integrity and stabilise the frequency.

To overcome such challenges there is need to:

- Improve local as well as regional interconnections.
- Increase fast responding and dispatch able capacity, like SCGT.
- Foster storage capacity if possible.
- Introduce and expand smart grids.
- Encourage demand side management.

The increase in renewable generation in many European countries, than originally planned, jeopardises the economics of other established facilities and also means their early retirements, which can cause power system security problems. To overcome this few European countries are implementing capacity remuneration mechanisms (CRMs). This mechanism creates additional revenue to owners of thermal plants to prevent their closure; all this negatively affects the economics of power generation.

Transmission line costs are another challenge to NRs. Favourable wind energy sites are usually far from load centres and not easily or cheaply reached by the existing grid. Transmission lines to connect wind farms, some of which are off-shore and require expensive submarine cables, add significantly to the cost; as does strengthening the existing grid to accommodate the wind energy surges. System cost for the injection of each new kWh of new renewable generation can, most of the time, be higher than the renewables' LOLE generation cost.

The flexibility of the contribution of renewables to the electricity supply varies. Although hydro-electricity is reliable and flexible supply, it can also store huge amount of water/power to be used when necessary. This advantage is also assisted by pumped hydro storage, which involves pumping water uphill into the reservoir at off-peak and then releasing it when needed. Biomass and geothermal can provide reliable renewable sources. However, NRs (solar and wind) present formidable challenges to the transmission supply operators due to their intermittency, unpredictable and changing meteorological conditions. This intermittency is delaying/preventing electricity markets from accommodating and meeting the ambitious renewable goals set by energy planners in many countries.

The flexibility of national electricity grids to accommodate variable power sources is enhanced by: achieving geographic and technological diversification of variable energy sources, improving local energy management and increasing prospects of energy-storage schemes and also by trading with other electricity grids.

12.4 Considerations in costing of renewables generation

It is usual to calculate the levelised cost of electricity (LCOE) in order to compare the costs and economics of different generation technologies, that is the cost comparison of nuclear versus fossil base load generation (coal or gas steam units), combined cycle plant as well as peaking units and hydro (see Chapter 5) [16, 17, 18].

Such costing methods cannot be directly applied to NRs technologies, due to their intermittency, dispatch ability issues, also their green nature. The main considerations are valuing of the generation, through its timing and contribution to dispatching and contribution to system cost.

Here we have to differentiate between the unpredictable wind energy and solar which is generated during day peak hours and which is relatively predictable, in both timing and hours of sunshine, particularly in sunny locations. Such solar generation is also, due to its green nature, highly valued and can compete favourably, saving the high cost of peaking plants (like single cycle gas turbines). Correspondingly, it will have a relatively less risk and has higher value than wind, but suffers from a low utilisation factor.

Wind generation falls into a different category. It is unpredictable, mostly it happens in night during low load, and it is intermittent and in case of large installations can cause serious problems to load dispatchers. The extent to which it can be of benefit to the generation system depends on many factors, the most important of which are presence of regional interconnections, or large hydro plants which try to moderate and absorb the large surges of power that accompany gusts of wind or compensate for its absence by importing power or quick release of hydro if it exists. Besides its high cost, there are dispatch ability issues that govern the extent of incorporating wind and similar intermittent generation in the national grid.

The effective productivity of wind plants (ECF), i.e. the utilisation factor, is defined as the annual quantity of electrical energy dispatched into the network relative to total installed capacity of that specific technology (wind). It is a function of wind speed as well as grid flexibility and transmission capacity. The global capacity factor for wind farms till now has been a disappointing 19.6 per cent [19].

The conclusions are that REs costs and economics are not easily grasped by LOCE like other generating facilities. They are dependent on many factors which vary between individual systems – like system size, interconnection capability, amount of sunshine and wind intensity and its intermittency, also hydro-electric presence and storage. In fact, because of these factors, the claims we often hear that a new renewable technology is competitive or at par with traditional generation need further evaluation. Each system has its own generation costs which change by the hour. NRs have to compete with these sources. However, renewables, being green energy producers also invite the consideration of carbon pricing, which can improve their competitiveness. This is an issue discussed below.

The presence of NRs capacity does not always significantly reduce the capacity of other components of the generation system and need for safe reserves. It has been suggested that reserves saving is only limited to 20 per cent of the wind capacity [19]. In order to assess the true value of NRs contribution it is better to simulate the generation system, using stochastic modelling like the Monte Carlo method, with and without renewables, and compare total system costs as explained in Chapter 15 and detailed in Part II of this chapter.

One of the issues in renewables is costing energy from residential PV systems, and similar small solar installations. These, of course, save some fuel particularly during the valuable daytime peak hours, but how do they compare with grid cost. Is the fair price that of the grid generation cost at that time plus any green energy subsidy component, or is it the marginal cost? It must also be understood that the distribution system is there to cover the intermittency of the renewable source and its cost need to be taken into account when valuing residential PV as explained in Part II.

12.4.1 Economic value of green energy

One of the large perceived advantages of new renewables is that they are clean energy, with no local or global pollution, particularly no carbon emissions during production. No doubt this is true but only to a certain extent. NRs cause noise pollution as well as visual impacts. Wind installations can also endanger birds. Solar farms need a lot of space some of which can be valuable land. NRs do not cause pollutant emissions, during electricity generation; however, manufacturing and building of these facilities do cause some environmental impacts. It was also ascertained that emissions mitigation benefits, from new renewables, do not extend to their full value of generation because of dispatching problems that lower the efficiency of other operating plant in the system which have to be operated at partial load to accommodate the NRs, particularly the sudden and unprogrammed presence of wind energy. Correspondingly, it has been suggested that the value of NRs carbon mitigation, to the power system, can only be three quarters of their generation.

12.4.2 New renewables as a disruptive technology

One of the main features of global energy systems, including electricity generation, is their huge inertia. Change and replacements, if they happen, are slow. Electricity facilities, generation and grid, are highly capital intensive and live for a long time. It is not easy to affect rapid change in power systems. These, besides their huge investment cost, need a long building and digestion time. Gradually new renewables are becoming disruptive technologies that may force the power system to reinvent itself.

12.4.3 Net energy metering

In order to encourage NRs and investment in distributed generation, most US states as well as many European countries and elsewhere have introduced the net energy metering (NEM) laws. These were intended to encourage distributed generation particularly rooftop solar PVs. NEM obligates the utility to buy the excess generation from customers who invest in small scale renewable energy system. Customers sell excess generation to the grid and buy back what they need from the grid at other times. Many customers ended up with zero or even negative volumetric consumption, which means that they receive a credit from the utility. With this small scale self-generation, business is taken of the utility. The benefits of the self-generators have to be compensated by increasing the tariff to other consumers. Increasingly distributed generation by PV panels is proving to be a growing disruptive technology, its financial consequences to utilities, also the rest of consumers, have to be dealt with.

This may necessitate a change in the NEM laws. One of the ideas being considered now is the introduction of a fixed charge on each distributed generator (DG) to recover the costs associated with maintaining the grid and providing backup service. These DGs benefit from their connection to the distribution grid and they have to be billed for this.

12.4.4 Smart grids value to new renewables

Smart grids (Chapter 10) incorporate wide variety of generation options – particularly new renewable sources. The wider use of smart grids will assist in incorporating individual PV systems into existing grids, as well as demand side management during shortages caused by, for instance sudden disappearance of wind, and other instances of high supply cost. It will also assist in limiting damage and interruptions caused by network faults and unprogrammed shortages in generating capacity which is likely to occur in systems that incorporate a large renewable component.

12.5 Part I conclusions

New renewables are clean, indigenous and sustainable source of energy; therefore, they are favoured by many governments and the public as a whole. However, their present contribution to global energy consumption is still limited (less than 2 per cent in 2013), because their economics are not yet favourable. In most instances they need to be supported by state subsidies and regulations. They suffer from high investment cost and their intermittent and diffused nature, with low utilisation factor. They are also not free from some environmental impact.

Incorporating NRs into power grids pose challenges due to dispatching problems and the need for expensive transmission extension and grid reinforcement. Wider introduction of smart grids and the likely demise of nuclear in some OECD countries will enhance the prospects for NRs. However, their immediate future expansion will depend on continued subsidies, which is becoming difficult to sustain in the present economic circumstances. Development of large energy storage facilities and carbon pricing will significantly enhance future NRs prospects.

Correspondingly NRs, in spite of their popularity with governments and the public, are likely to face challenges which will slow their progress. This also poses problems to power system planners. Their long term future cannot yet be viewed with certainty. It will be many years before they become a major source of energy to our universe. Their economic evaluation is presented in Part II and Appendix C.

Part II: The financial and economic evaluation

12.6 Assessing the returns on investment in renewables

In earlier sections we have indicated that LCOE, which is the traditional method for assessing and listing dispatchable generating facilities according to their annual costs, does not directly apply in case of non-dispatchable technologies, like renewable, due to their intermittency, timing and unpredictability. Developing the necessary algorithms for such purpose, particularly in case of wind energy, is not easy because of the difficulty in forecasting the timing of the wind blowing, its intensity and for how long [19].

To assess the viability and economics of new renewables (solar and wind) it is necessary to compute the future stream of the electrical system cost with renewables and compare it with the system cost without the incorporation of renewables. This has also to be weighted with the carbon saving and other intangibles of the renewables. The electric system cost does not only apply in here to generation facilities but also to the transmission system extension and reinforcement as well, which can be substantial in case of wind technologies. In most cases the electric system cost per kWh delivered with the presence of renewables is going to be higher than in the absence of renewables. The extra cost indicates the extent of the subsidy which needs to be provided, or increase in tariff to consumers to compensate, for these extra costs (renewables penalty). Calculating and present worthing of system costs without renewables is straight forward and indicated in coming chapters. With the incorporation of renewables there is need for more sophisticated approach. Below we are developing simple, but effective, means to compute the financial and economic effect of incorporating renewables. We have, however, to distinguish between solar energy which is relatively predictable in timing, duration and extent and that of wind which has only short term (if any) predictability in timing, duration and extent; and which can cause disruption to dispatching. Also, we need to differentiate if the investment is done by a regulated utility which can pass the extra cost of renewable electricity to consumers or it is executed by independent investors selling in the spot market. These need to fully comprehend the financial implications before committing themselves to a risky renewables investment.

The economic evaluation of power generating technologies should aim at evaluating their market value that is the revenue they generate to the provider. This particularly applies to NRs. Market value of NRs is lower than their LCOE due to integration costs. A new concept of ‘System LCOE’ has been developed. It is composed of generation cost plus integration costs. This new term system LCOE is the standard LCOE plus the indirect costs that occur at system level [20]. Integration cost of NRs is additional system costs that are not direct generation cost of NRs. Integration costs of NRs have three cost drivers: variability, uncertainty, and location. It can be said that all generation technologies have integration cost. This is true but it is more specific and pronounced in NRs due to variability and unpredictability in dispatching.

The above three mentioned components of the integration cost (variability, uncertainty and location) are shown in Figure 12.1 and are defined as follows:

Profile (variability) costs occur because wind and solar PV are variable. In particular at higher shares this leads to increasingly inappropriate load-matching properties. Backup capacities are needed due to variability of NRs. The full-load hours of capital-intensive dispatchable power plants decrease while these plants need to ramp up and down more often.

Balancing (uncertainty) costs occur because renewable supply is uncertain. Day-ahead forecast errors of wind or solar PV generation cause unplanned intra-day adjustments of dispatchable power plants and require operating reserves that respond within minutes to seconds.

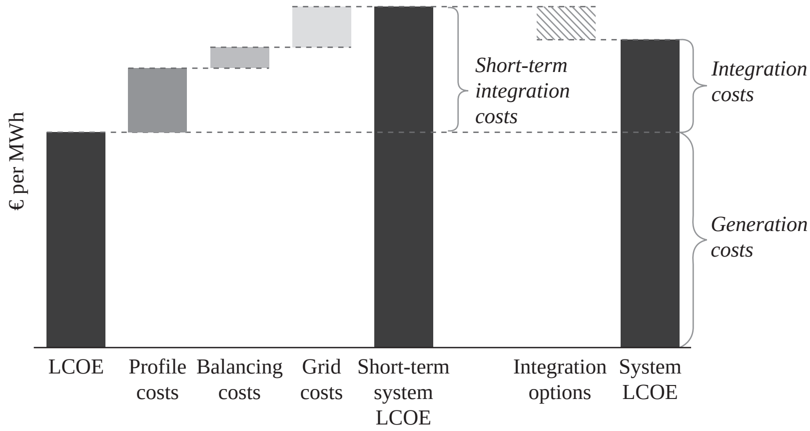

Figure 12.1 System costs of new renewables [Source: References [20] and [21]]

Grid-related (location) costs occur not only because NRs are mostly located far from load centres and large investments in transmission might be necessary, but also because of grid constraints and congestion management.

System LCOE are defined by adding the three components of integration costs to standard LCOE that reflect generation costs. Such integration costs vary from one system to another depending on the extent of penetration of NRs, location and the composition of the dispatchable plant in the generation system. They need to be computed separately for any national grid in order to compute the true market value of NRs. Therefore, the system costs of NRs can be significantly higher than their LCOE as demonstrated in Figure 12.1.

There are now many investors in renewables ranging from regulated utilities to private investors in the spot market, and large facilities and investments into individual households investing in small roof top PV installations. New sophisticated ways in investing in renewables are being developed: individual investors, leasing, net metering, etc. Therefore, it is not possible to deal with each case but general simple guidelines for assessment must be developed as indicated below.

12.7 The value factor

The value factor in the market of NRs is its relative price compared to a constant source of electricity. It is the ratio for the generation – weighted average electricity price with a certain time profile relative to a flat profile. In other words, the wind value factor compares the value of power with varying wind with the value if winds were invariant. [21].

Model study results of the European system indicated that as the market share of wind power increases from zero to 30 per cent of total electricity consumption its value factor will drop from 1.1 to 0.5.

A 2012 study [21] concluded that the average value factor during recent years for wind was 0.95 and for solar 1.18; solar being valued higher due to its stronger positive correlation with demand. At low penetration rates both value factors were above unity, which can be explained by the correlation effect. With wind power increasing its market share from 2 to 7 per cent from 2001 to 2011 and solar from 1 to 3 per cent from 2006 to 2011, the perspective value factors dropped by 0.10 and 0.14, which is due to the merit-order effect. The wind value factor increased slightly during 2007–2010, despite installed wind capacity continuing to grow. Three potential reasons are:

(a) A flatter merit-order curve due to a shift in the gas-to-coal-price ratio and CO_2 pricing,
(b) More efficient international trade due to market coupling, and
(c) The impact of solar power which reduces the base price more than the average revenue of wind power.

To conclude, market data suggest that the merit-order effect significantly reduced the market value of NRs even at quite modest market shares in the single digit range.

12.8 Effects of new renewables on the merit-order (merit-order effect)

NRs influence the merit order of dispatching, if they are non-marginal they also influence system price. During their generation periods they shift the merit-order curve to the right, thus reducing the equilibrium price of electricity. This effect depends on REs installed capacity; the higher they are the higher will be the shift. This implies that the market value of NRs falls with higher penetration [21–23]. These considerations have important market and system effect:

1. In case of fixed feed-in-tariff renewables get a constant price. Yet in case of green certificates obligations investors receive subsidies on top of market price. Therefore, market value directly affects NRs investors.
2. Market data confirms that the merit-order effect significantly reduced the market value of NRs. These fall quickly with increased penetration of NRs. This will significantly limit the extent to which NRs can be integrated into the power system.

12.9 Calculating benefits in investing in renewables

A utility can invest in solar or wind facilities; however, the benefits are quite different. The main features, pros and cons of such investment can be summarised in the following points:

- Investment in renewables will not save the need to invest in extending the generating system. To ensure security of supply the generating system need to meet peak load with and without renewables. Wind is unpredictable and the generating system with minimum reserves must meet the peak load, with and without presence of wind. Solar is more predictable in timing and extent, but the sun is not there all the time (unless in some sunny regions and deserts). Therefore, the generating system must ensure its integrity (that is meeting peak demand) with and without renewables. Saving in the installed capacity can extend only to 20 per cent of the installed wind capacity and almost the full solar capacity if the peak occurs during sun shine hours, or storage hours of CSP installations with storage.

- The value of NRs' electricity depends on the time of its production. Solar is much more valuable energy than that of wind. It occurs during day hours where system peak exists; therefore, its contribution is significant in reducing generation of expensive peaking plant like that of single cycle gas turbines.
- Wind's main contribution, when available, is to reduce fuel consumption of the generating system. Both solar and wind will reduce generating system emission of GHGs, mainly carbon. Therefore, NRs economies are greatly enhanced by high carbon price; the higher carbon emissions are penalised the more NRs become feasible.
- The carbon saving benefits of renewable, particularly wind, does not extend to their full contribution. When renewable output is available there is only partial loading of other facilities on the system thus reducing their efficiency. Therefore, the benefit of renewable is reducing emissions and system fuel consumption may only be 75–90 per cent of their energy contribution.

Concentrated solar power (CSP) technology captures solar energy through troughs or mirrors (also called heliostats), which are set on trackers and concentrate the sunlight to generate power. Mainly used in utility-scale power generation projects, the technology also holds promise for other applications, including process heat and enhanced oil recovery operations. CSP technology can also be coupled with energy storage. Plants that include energy storage with molten salt can store solar power and dispatch it in the early evening and into the night during system peak hours; therefore, they significantly contribute to installed system capacity [24].

In Appendix C, we shall try to develop simple mathematical examples for the evaluation of NRs.

12.10 The challenge of net energy metering (NEM)

Customers, who install solar rooftop PVs or other forms of distributed self-generation on their premises, typically generate a significant percentage of their total electricity needs, which means they end up buying far less from the 'grid'. This reduces the number of kWh they buy, and consequently the revenues flowing to the local utility.

Under most prevailing NEM laws, customers who generate power in excess of their need at the time, can sell the 'excess' to the grid and get a credit for every kWh exported at the prevailing retail tariff. This becomes problematic in cases when customers have high excess generation.

Since the utility business is essentially a zero-sum game, what NEM customers save – or avoid paying – has to come from the remaining customers who have not invested in distributed self-generation. Under rate of return regulations still prevalent in many parts of the world, to keep the local utility whole, average retail tariffs must be raised. That simply encourages more customers to bypass the grid-supplied electricity.

The utility revenue collection business is also a zero-sum game with predominantly fixed costs. What little may be saved when NEM customers consume less is negligible compared to the loss of revenues from lower volumetric kWh sales. Moreover, as they point out, with justification, that most NEM customers become free riders by paying little or none for the upkeep of the grid while benefiting from the valuable services that it provides.

Since most NEM customers remain connected to the grid and use it for back-up and for balancing their variable self-generation against internal consumption, they gain disproportionately without contributing to its maintenance.

The average solar PV owner generates 70 per cent of the electricity needed, pulling the remainder from the grid at night and on cloudy days. Most utilities credits customers for the power they generate based on the prevailing retail rate, which wipes out most of the customers' utility bill. However, residential customers must pay a monthly service charge which partially compensates for this. [25].

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Chapter 13

Electricity trading

13.1 Introduction

The energy sector is undergoing a major transition worldwide [1, 2]: competition, restructuring, privatisation and regulation are at the core of the current revolution, driven in part by new technological developments and changing attitudes towards utilities. The objectives of these reforms are to enhance efficiency, to foster competition in order to lower costs, to increase customer choice, to mobilise private investment and to consolidate public finances. The mutually reinforcing policy instruments to achieve these objectives are the introduction of competition (supported by regulation) and the encouragement of private participation. An international approach for the design of the legal, regulatory and institutional sector framework has emerged. It includes the following:

- The corporatisation and restructuring of state-owned energy utilities.
- The separation of regulatory and operational functions, the creation of a coherent regulatory framework and the establishment of an independent regulator to protect consumer interests and promote competition.
- The vertical unbundling of the electricity industry into generation, transmission, distribution and trade (services).
- The introduction of competition in generation and electricity trade and the regulation of monopolistic activities in transmission and distribution.
- The promotion of private participation in investment and management through privatisation, concessions and new entry.
- The reduction of subsidies and rebalancing of tariffs in order to bring prices in line with costs and to reduce market distortions.
- The creation of a spot market for local cross-border trading.

One of the most significant features of the electricity supply industry in recent years has been the emergence of electricity trading in liberalised electricity markets; this has also fostered risk management practices. Such activities, particularly risk management, are not particularly worrying in regulated markets with fixed prices; it is only in liberalised markets, where prices are changed in accordance with supply and demand and future expectations with possible price volatility that risk management flourish. This is enhanced by the introduction of customer choice. Such features manifest themselves to a varying degree in various liberalised markets; however, they are more prominent in the US, where prospects for electricity price volatility exist, owing to supply and delivery restrictions, than in the UK and Europe, where there are abundant reserve margins and strong interconnected transmission networks. Market players include generators producing electricity, suppliers who buy electricity to sell on to groups of consumers, traders and marketers, who do not own generating assets but have active roles in the market, and other players who provide, for example, risk management, hedging and brokerage.

Power marketing (or trading in the spot market) refers to any number of financial and/or physical transactions associated with the ultimate delivery of a host of desirable energy-related services and products to wholesale and, increasingly, retail customers. Power marketers, those engaged in such trade, however, need not own any generation, transmission or distribution facilities or assets. They rely on others for the physical delivery of the underlying services. Moreover, power marketers operate primarily as contractual intermediaries, usually between one or more generators and one or more customers.

The physical nature of electricity does not allow a true spot market (instant pricing and delivery), so financial transactions must be scheduled some time in advance of physical delivery, with pools or power exchanges thus substituting for a true spot market.

Electricity market trading is quite different from commodity trading (or other forms of energy trading) because of the nature of electricity – it cannot be stored, its availability must be instantaneous and absolute, as well as the technical complexities of the expertise, knowledge and planning capabilities that only power engineers can make it different. For electricity markets to perform successfully, two types of expertise must converge:

- a high level of technological expertise in the domain of power engineering, and
- financial and business expertise allowing market trading.

Only after the power engineers have set the parameters for physical delivery, both short term and the future to meet foreseeable conditions, can the financial market trading element of the electricity markets come into play. Risk in electricity trade is detailed in Chapter 16.

13.2 Electricity trading worldwide

Trade in electricity can be local, inside the country, or regional – cross border. Cross-border trade faces many restrictions and challenges – geographical and interconnectivity of grids. In addition to this, regulatory and administrative issues can hinder such trade. With the liberalisation of electricity markets in many Organisation for Economic Co-operation and Development (OECD) countries, regulations and rules were created, which are country specific and none conducive to cross-border trade.

In recent years there has been a significant increase in cross-border trade in electricity due to liberalisation and integration of European electricity markets. This was also helped by increasing demand, as demonstrated in Figure 13.1.

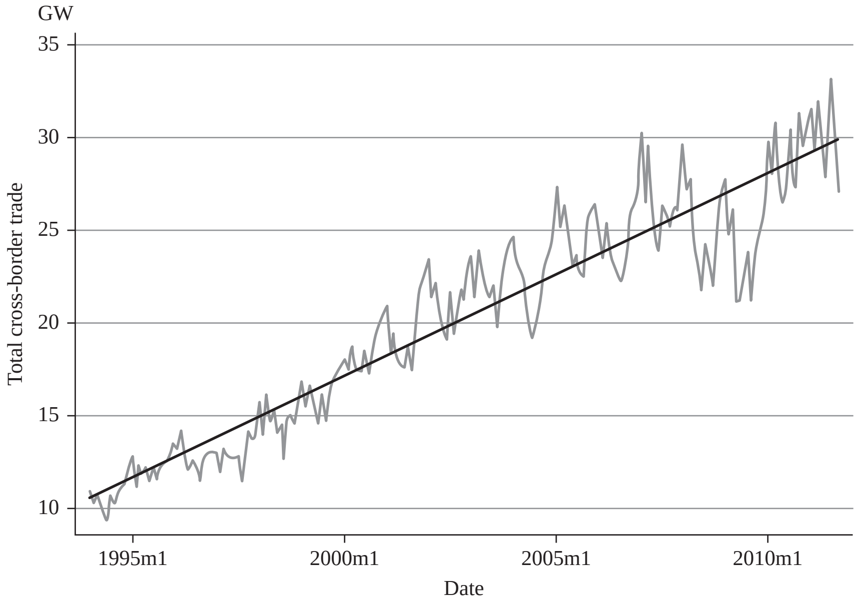

Figure 13.1 Cross-border trade in electricity [Source: Reference [3]]

Electrical energy is considered a 'good' according to the WTO, and attributed the HS code of 271600 by the World Customs Organization. Only 31 countries in the world apply import tariffs on electrical energy, and those tariffs are generally less than 15 per cent on an *ad valorem* basis. Consequently, import tariffs are not considered an important barrier to cross-border trade in electricity in most regions.

Cross-border trade in electricity is fostered by competition of generators to dispatch electricity from low-cost to high-cost areas. It is security of supply and price differentials that are the main drivers for electricity trade. Limited cross-border transmission capacity does not always allow regional electricity to the extent desirable. There are basically four different methods for allocating available cross-border transmission capacity to market participants. The *first-come-first-served* method requires the transmission system operators (TSOs) to have a co-ordinate schedule for allocating net transfer capacities (NTCs) through bilateral agreements on a regular basis (daily, weekly, monthly or yearly). TSOs normally accept requests until the NTC is fully committed in both directions. With pro-rata allocation, TSOs continue to accept requests when demand exceeds available capacity but, having calculated the level of congestion, they then reduce each bid proportionally, so that no congestion remains. By contrast, market-based allocations involve *auctions* conducted either by TSOs or PXs during which each market participant offers a price for the use of cross-border transfer capacity in one direction. There are mainly two auction types: explicit auction and implicit auction. An *explicit auction* is used when the transmission capacity on an interconnector is auctioned off to market participants separately and independently from the marketplaces in which electrical energy itself is being auctioned, while in *implicit auctions* the auctioning of cross-border transmission capacity is included (implicitly) in the auctions of electrical energy in a given power market. For regulators, the creation of trading exchanges can offer the chance to build a truly open and competitive market, guided by a global knowledge base of the successes and failures of other exchanges in other industries around the world [4].

Energy exchanges enable the development of the wholesale business. In addition to the trading of physical quantities, 'future' markets are created making extensive use of financial products. Many exchanges offer multi-energy (i.e. electricity, gas and oil) services, sometimes extending to other commodities as diverse as metal, pulp and paper.

There is a lot to be gained for all parties through these new markets. But it can be a complex process, and companies should evaluate participation in a trading exchange against the current market trends, the drivers in energy markets and the broader developments in financial and commodity trading.

Such considerations are unlikely to lessen the pace at which trading exchanges in the energy sector are growing. Instead, market forces, technology and legislation will shape the new exchange landscape, creating an environment in which competition increases rapidly and consolidation occurs. It is vital that this molding influence be allowed to continue, as for a market to successfully move to a deregulated mode, the basics such as maintaining an adequate balance of regional supply and demand must be established.

Across the world, competition in energy markets has driven the development of wholesale energy trading. There is an enormous variety in the speed and willingness of markets to deregulate, from country to country, and even from state to state. Many countries already have fully competitive and mature markets while other countries still do not plan to deregulate their gas and electricity industries. The US is the most important market for electricity trade; this market and its development will be explained in section 13.2.1, and then the UK and other markets will be discussed in sections 13.2.2–13.2.5.

13.2.1 Electricity trading in the US

During the past decade or so, and particularly since 1992, the growth of electricity marketing, particularly in the US, has been phenomenal [1]. The year 1978 saw the passage of the Public Utilities Regulatory Policy Act (PURPA), which opened the power-generation sector to new players, mostly independent power producers (IPPs). For IPPs to prosper and succeed, they needed access to the national transmission network in order to deliver their product to large consumers. This was provided for in the Energy Policy (EP) Act of 1992, and was supported by two significant orders, in 1996, in which the US Federal Energy Regulatory Commission (FERC) spelt out the modalities for implementations on how an open access transmission system would work in practice. More specific orders were issued in 1999 and 2001 encouraging and calling for the creation of regional transmission organisations (RTOs). Such major milestones in the development of the liberalised US electricity markets are summarised in Table 13.1.

Table 13.1 Electricity milestones: major laws with significant impact on US electricity markets

1935 Federal Power Act
Created the FERC and established principles for regulating wholesale electricity pricing.
1978 Public Utility, Regulatory Policy Act (PRUPA)
Allowed IPPs to flourish.
1992 EP Act
Introduced the premise of a non-discriminatory open access transmission network.
1996 FERC orders 888 and 889
Spelt out FERC's long-standing policy on how an open access transmission system would work in practice; order 889 spelt out the details of the Open Access Same-Time Information System (OASIS).
1999 FERC Order 2000
Encourages the establishment of RTOs.

Sources: Energy Informer (July 2001), Reference [1].

In North America, the electricity market is deregulating at a variable pace. In the US, each state moves forward independently from the others. California, which is further along the process, has experienced significant difficulties (see section 13.2.4) that have influenced the pace of deregulation in other states. For example, states such as Oregon, Nevada and Arizona have put the decision to deregulate on hold. Some Canadian provinces are taking a comparable path to deregulation.

13.2.2 UK electricity market trading

In England and Wales [2] before privatisation began, the electricity industry was a classic, vertically integrated, government-owned monopoly, seen at that time as the best way to provide a secure electricity supply. Consumers had no choice of supplier and had to buy electricity from their local regional electricity company (REC), so that price competition was not possible.

The UK is one of the pioneer countries in developing a free market electricity trading system. On 27 March 2001, New Electricity Trading Arrangements (NETA) for England and Wales were launched. The stated objectives of NETA are to benefit electricity consumers through lower electricity prices resulting from the efficiency of market economics. Promotion of competition in power generation and electricity supply, in order to use market forces to drive consumer costs down, was, and remains, a key objective of actions to liberalise and 'deregulate' electricity markets in the UK.

In England and Wales, the electricity market was progressively opened to competition in generation and supply over a period of 10 years, with retail competition for the smallest consumers completing full market liberalisation in 1998. A regulatory body, the Office of Gas and Electricity Markets (OFGEM), oversees market operations, licensing and competition, and actively seeks to make changes to benefit consumers and bring their electricity costs down while promoting competition between players in the electricity market. Sweeping away old thinking has led to electricity being regarded as a tradable commodity and revolutionised the business environment bringing new market participants, new business opportunities and rapid change.

Initially, market reforms involved creating an Electricity Pool for England and Wales with a single wholesale electricity price. Producers sold to the Pool and licensed suppliers purchased electricity from the Pool. Pool participants were able to negotiate bilateral contracts. However, the Pool performances did not allow the development of full competition. The UK White Paper on Energy Policy and the Utilities Act 2000 incorporated proposals for trading arrangements similar to those in commodity markets and energy markets elsewhere. NETA provided new structure and rates for England and Wales electricity market. Under NETA there were major developments in which electricity is bought and sold, with major competition in generation and supply, with a wide range of new players competing in the liberalised energy market, as detailed in Figure 13.2.

NETA aims to develop a marketplace in which buyers and sellers can participate through a variety of contracts and agreements within the framework set by NETA. The transactions taking place within the NETA market are electricity price–quantity transactions on a half-hourly basis.

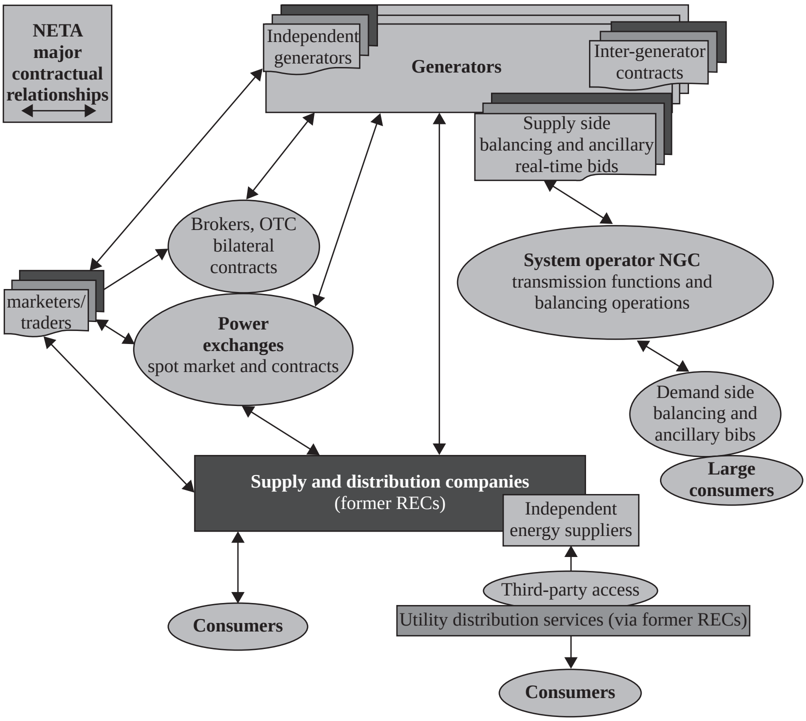

Figure 13.2 NETA electricity market – major contractual relationships [Source: Reference [2], OFGEM]

Market players include generators producing electricity, suppliers who buy electricity to sell on to groups of consumers, traders and marketers who do not own generating assets but have active roles in the market place, together with other players who provide, for example, risk management, hedging and brokerage.

NETA is a new wholesale market, comprising trading between generators and suppliers of electricity in England and Wales. Under NETA, bulk electricity is traded forward through bilateral contracts and on one or more power exchanges. NETA also provides central balancing mechanisms, which do two things: they help the National Grid Company (NGC) to ensure that demand meets supply, second by second; and they sort out who owes what to whom for any surpluses or shortfalls. The majority of trading (98 per cent in the first year) takes place in the forward contracts markets. A very small percentage of electricity traded (2 per cent in the first year) is subject to the balancing arrangements.

Under NETA the market provided through power exchanges replaces the previous Pool arrangement, allowing market players to trade electricity up to one day ahead of the requirement for physical delivery. The NGC operates as a system operator for England and Wales, managing the HV transmission system and also providing all the technical and operational services normally demanded by the system to ensure its integrity including load forecasting, ensuring system security and stability, frequency control and reactive power control. NGC acts on both a physical and a financial level through the balancing mechanism, selecting bids and offers for incremental or decremental supply of electricity in order to achieve physical balance between generation and demand.

It is not intended here to go into the way the financial and settlement activities are undertaken in the England and Wales electricity market trading since these are explained in detail in the literature [2].

13.2.3 The Nordic market

This involves Norway, Sweden, Finland and Denmark. The deregulation of the electricity market in these countries is complete with customers free to choose their supplies. Trade of electricity (mainly generated by hydro-power) between the four countries is extensive. In this market, generation and retail sales are competitive while transmission and distribution are regulated. Third-party access to the transmission network is regulated; therefore there are equal access rights to all users. The Nordic network experience provides an excellent experience to European Electricity market development. The Nordic electricity market general relationships are in Figure 13.3.

13.2.4 Electricity markets across Europe and elsewhere

The European Commission Single Market Directive for Electricity came into effect in February 1999. The directive obliges EU member states gradually to open their power sectors to competition, to vertically unbundle the sector and to ensure non-discriminatory access to the transmission network.

Energy markets across Europe are expected to be fully liberalised, privatised and integrated across borders by 2010. European companies and households will

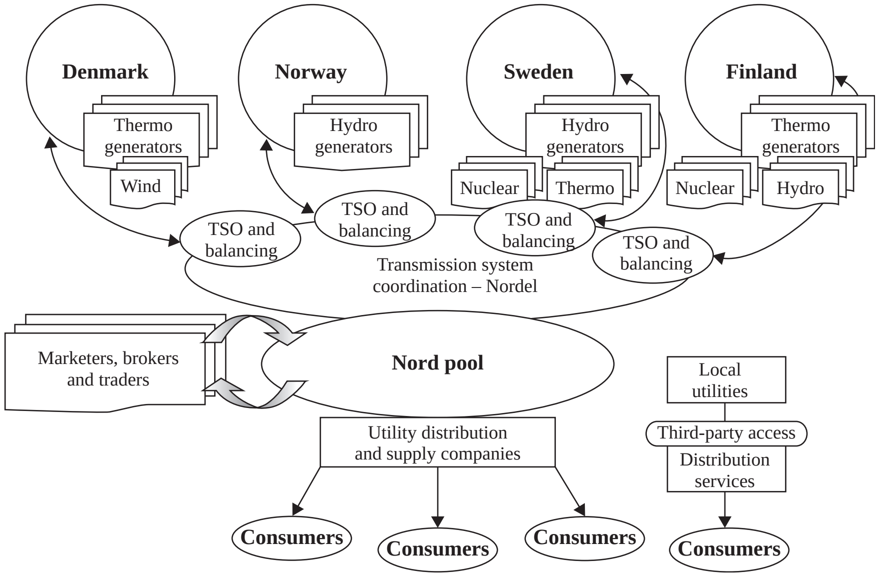

Figure 13.3 The Nordic market – major contractual relationship [2]

benefit from lower prices, better services and free choice between alternative providers. European utilities will be highly competitive as a result of cost cutting and consolidation. The EU Single Market for energy is expected to be the largest in the world, comprising the current member states, and accession countries, with a total of more than 400 million consumers.

Germany leads the European countries in progress towards deregulation and is the region's largest electricity market by consumption. It is strategically important as a base for further European expansion, with physical interconnection to many more European markets than the UK. The country has two regulated exchanges, which have merged into one entity. However, there is little liquidity on this market and brokers have been more successful in trading, most notably through electronic trading in the form of Alternative Trading Systems (ATS).

Australia and New Zealand were among the first deregulated countries, and have almost completed their transition and are refining and adjusting the implementation of the new market rules. Singapore and Malaysia were expected to experience a full opening of their markets since the third quarter of 2002, whereas Japan is only now seeing a partial opening to competition in the construction of merchant power plants and the electricity supply to large customers.

North America pioneered reforms in the 1980s, but owing to its federal structure has not yet completed the process in all states. Except for the UK and the Nordic countries, Europe has embraced reforms relatively late but vigorously, and is now arguably the fastest reforming continent. Latin America, the first developing region to liberalise and privatise its energy sector, has largely completed the reforms agenda. Many countries in Asia that introduced IPPs without liberalisation suffered from the consequences during the recent financial crisis, and are now moving towards the Latin American model. Together with sub-Saharan Africa, the countries of the southern Mediterranean are lagging considerably behind international reforms trends.

At the beginning of 2002, there were approximately ten regulated electricity exchanges in Europe, with eight ATS trading electricity in the region and at least three more regulated exchanges and a further three ATSs close to introduction. With wholesale markets at very different stages of development in each country it is only fair to describe the European picture as fragmented and largely immature, characterised by the number of regions and exchanges; the lack of appropriate instruments; issues around transparency and liquidity; and restricted inter-regional trading.

But the immaturity of electricity trading in most countries has not prevented the creation of new trading exchanges. Indeed, in some new territories, particularly those in which legislation supports competition, an under-developed market offers greater potential gains once maturity and liquidity is reached.

The UK is a good example of this. At the beginning of 2002 there were four exchanges competing for market share in a region where electricity consumption is below the European average. The fight is on between these exchanges, partly not only because the region presents a considerable reward, but also because it will act as a good proving ground, offering a chance for exchanges to cut their teeth before moving on to markets that are less developed.

Generators, wholesalers and retailers access exchanges through the trading activities of internal business units or by outsourcing to trading companies. As electricity prices are extremely volatile, successful trading activity depends on a good risk management policy and implementation. The number and nature of players will evolve, as the electricity market continues to open and the liquidity of exchanges increases. The increase in electronic trading of all forms has resulted in the need for companies to reassess the way in which they trade and the way in which electronic trading impacts on their risk policy.

13.3 Trade in electricity – the spot market

The main motive for liberalisation and electricity market reforms in recent years is to create competition in order to foster economic efficiency. Because of competition, electricity prices tend to be lower, and thus improve investment decisions. This leads to the creation of the wholesale market in electricity that aims to set prices through market mechanism on bid-based spot-market pool. This is managed by system operators who are independent of market participants so as to ensure equal treatment. This also requires equal access of all generators to the transmission system.

System operators forecast their requirements one day ahead. Generators bid their marginal cost to the whole sale market pools and such wholesale electricity prices are usually defined on hourly basis, according to the usual merit order of committing generation. There can also be intraday auctions conducted an hour before electricity dispatch, in order to refine the marginal cost and merit of commitment. Recently independent companies are being created to manage such auctions. They are called PXs.

Beside the day-ahead and intraday trade there is electricity trade in the forward markets. Such forward markets are usually traded from two days to five years ahead. They allow for over-the-counter (OTC) confidential contracts, which are bilateral contracts between generators and retailers. Alternatively companies can trade contracts with forward products offered by the PXs. Such contracts are publicly reported.

13.4 Cross-border trade in electricity

Cross-border trade in electricity is a growing activity encouraged by regional networking and interconnections, the European network, as well as the Nordpool of the Nordic countries. Regional networking is driven by economic as well as security of supply. Recently, the increasing share of new renewable sources, particularly wind power had added an increasing importance to cross-boundary electricity exchanges.

The benefits of cross-border electricity trade are:

1. Better use of complementary resources, e.g. to use flexible hydroelectric generation to export peak power and import thermal power during off peak hours.
2. International interconnections allow balancing of annual demand variations, e.g. if little rain reduced hydro reserves and thermal output in a specific year.
3. International electricity trade allows countries to balance historically grown generation with current needs.
4. It allows the pooling of reserve capacity thereby reducing costs for extra power stations and limiting inefficient dispatch of power stations required for provision of reserves [4].
5. It adds to security and continuity of supplies during emergencies and generation shortages.

The amount of electricity that can be traded is dependent on net transfer capacity (NTC) of the interconnector. In order to trade and electricity exchange, there need be access to the interconnector. This access is usually referred to as third part access (TPA) to the cross-border transmission system.

Allocation of available interconnection capacity in the OECD is usually by market and non-market methods. Many countries utilise market-based methods, like auctions, as the method to allocate cross-border capacity. Non-market-based method that include first come, first served and pro-rata allocation is utilised in other instances. Dealing with congestion issues in the interconnectors is the main consideration.

The first come, first served method is a co-ordinated schedule for allocating NTC by TSOs through bilateral agreements on a regular basis (daily, weekly, monthly or yearly).

In pro-rata, allocations apply in case of congestion. TSOs reduce individual requests to the extent that no congestion remains. In auction-based allocations, prices are offered for the use of cross-border transfer capacity, and after allowing for congestion prioritise the bids from the highest price offered to the lowest. The mechanisms for cross-border trading arrangements are detailed in the literature [5].

13.5 Electricity traders

Because of price volatility in the bulk supply markets the importance of electricity traders has increased during recent years. Correspondingly, risk management and hedging against such volatility is one of the critical services offered by electricity traders. This is likely to be extended soon from the bulk supply market to the retail competitive markets. Electricity traders have access to valuable information (prices, options, etc.), which will also assist their clients in reducing costs, increasing profits and improving performance. They can also broker and undertake transaction management and assist in providing liquidity by helping their customers to change position quickly.

The electricity-related services provided by power traders include physical delivery of power and/or a financial obligation or promise to do so. Such services extend beyond electricity into other energy-related services like natural gas. The delivery may be firm or non-firm, short- or long-term, one time or stretching over time. Prices may be firm or indexed to other commodities or derived from combination of underlying commodity prices, hence 'derived markets'. Many operators in the electricity business will not be able to function successfully in the liberalised competitive electricity market without the help of an electricity marketer.

Electricity marketing has to investigate customer needs, decide on the prices to offer and must take into account the considerable risks and the ways to manage them through mitigation and hedging strategies. Small, uncorrelated risks may simply be managed through risk pooling. Aggregating a large number of small risks, which are not correlated, is the easiest way to manage risk (see Chapter 16).

As from the beginning of the 21st century, electricity trading is growing at a phenomenal rate. In the US the annual volume of wholesale electricity commodity trading reached $2.5 trillion by the year 2003 and online transactions reached $4 trillion by 2005 (see Figure 13.4). Such amounts will make electricity the single largest traded commodity in the US. By 2003 the $2.5 trillion are about 10 times the retail value of electricity trade in the US. This is made possible by the developments in financial trading instruments such as futures, forwards, swaps and options that allow the same electrons to be bought and sold several times before they are actually generated and consumed. The volume of trade is typically many times the physical number of kWh generated or consumed because many times an electricity trader will be buying from or selling to another trader. Correspondingly, the same kWh is usually bought and sold a number of times until it is finally delivered and consumed.

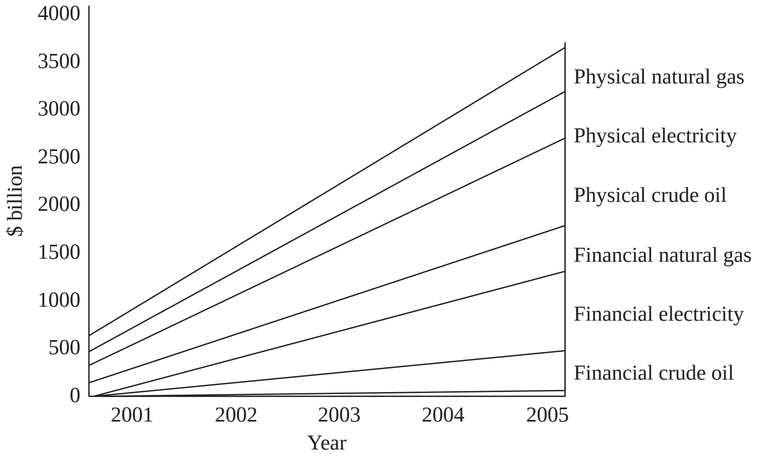

Figure 13.4 Online energy trading [Source: Forrester Research and Reference [1]]

13.6 Value of cross-boundary electricity trade to renewables

Electricity from hydro scheme is both stable and reliable and can improve system stability. But new renewables, particularly wind and PV solar, represent challenges to TSOs. They are intermittent, peak and disappear in few minutes, or seconds in certain instances. The problems are minor if NRs are only a small percentage of the system's generating capacity, but if they become more significant, say more than 10 per cent, they present a challenge to load dispatchers. Such challenges can be met in two ways. The first is by improving load management and interruptible supplies, making use of energy storage systems (like pump-storage if available); also increasing the share of plants that quickly ramp their output up and down when needed, such as single-cycle gas turbines and hydroelectric. These respond quickly to system demand in contrast to coal and other steam power plants and combined cycle gas turbine (CCGT) which needs quite a time (sometimes hours) to ramp up or down their output. The second challenge is from geographic and technological diversification and trading with other interconnected electricity grids [6]. Cross-border trade in electricity is the means for achieving this, and interconnections that facilitate such trade already exist among most neighbouring OECD countries. Facilitation of such trade needs harmonising of rules across interconnected electricity markets and help these countries to accommodate more new renewable energy technologies, which are being driven by environmentalists and ambitious politicians.

Cross-border trade in electricity enable countries to gain access to more flexible power plants located in a wider geographical area, which can then reduce the costs of balancing power due to increased renewable energy power output. However, under some circumstances, intermittent renewables deployed across a wider geographical area may actually serve to balance the power variances that can arise from

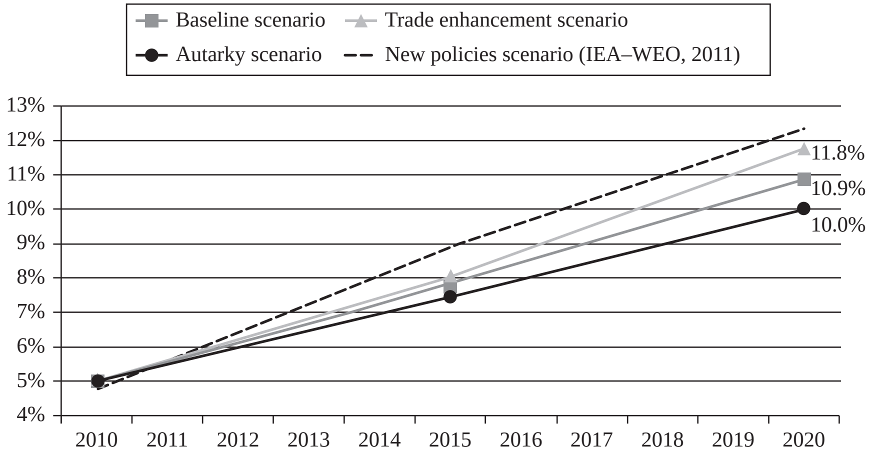

Figure 13.5 Share of wind power relative to total power generated in the EU [Source: Reference [3]]

conventional plants or sudden increases in demand in interconnected countries. To the extent that it does help grids better respond to short-term load variability, increased trade could therefore allow greater penetration of intermittent renewable-energy-based power plants and a more efficient utilisation of conventional ones [3].

With the increasing share of wind power in the EU grids, the accommodation of the intermittency of this power is becoming more challenging (see Figure 13.5).

This can greatly be assisted by cross-border exchanges and trade. Such cross-border trade in electricity is also mainly driven by price differentials between interconnected electricity markets.

13.6.1 Pricing cross-border RE trade

In merit order dispatch the NREs are at the bottom of the supply curve since their marginal generating cost is close to zero. Bahar & Sauvage [3] explain that with greater penetration of renewables, a combination of factors such as high power output from low-marginal-cost renewables and low demand in a given hour or dispatch period can lead to negative wholesale prices. A negative price simply means that generators, rather than consumers, pay for the electricity fed to the grid. This situation arises for two reasons. First, the output of power-generating result-it makes more sense for such generators to keep their plants running by bidding in negative prices, since it is still cheaper to pay somebody to take the electricity than to stop the plant and start it again shortly afterwards. Second, financial incentives for renewable-energy technologies encourage generators using these technologies to produce even if market prices happen to be low or negative. Renewable-energy producers that are eligible for financial incentives will thus continue to produce as long as the negative price level is no greater in absolute terms than the subsidy level.

Bahar and Sauvage also emphasise that where market-based incentive schemes are used, renewable-energy generators are fully or partly exposed to market prices.

They usually bid in the wholesale electricity market along with all other generators, and receive the market price for the electricity they generate in addition to the value of green certificates or premiums. Although these schemes may increase investment risk for investors due to price volatility in both the electricity and the green-certificate markets, and thus may have an impact on the deployment of renewable-energy technologies, they facilitate the integration of renewables into wholesale electricity markets. A fixed feed-in tariff does not entail any price risk, whereas both quota obligations and a premium support scheme involve a market-price risk since relevant generators have to sell their output directly either in the electricity market or through bilateral contracts.

The cross-border allocation of interconnector capacity is usually auctioned off yearly, monthly and day-ahead. Only a few country pairs have established some intraday allocation of cross-border capacity. Intraday cross-border allocations can be helpful for generators to respond to cross-border balancing needs, especially those caused by variable renewables. Such allocations can also allow unexpected surplus generated by variable renewables to be traded across borders [3].

13.7 Future strategies and growth

For cross-border exchange there is a need to adopt a portfolio approach that encompasses corporate strategy, the market environment of each country and the competitive landscape. The legislative environment and regulatory regime of each country need to be considered, as well as the differences in the country's market potential, market participants and competitors. Potential partnerships and alliances can be vital and these opportunities should not be overlooked [7].

The surge in the development and growth of electricity exchanges around the world has largely been driven by the triumvirate of market forces: legislation, competition and technology. This trend is likely to continue in the short term as legislation in Europe and North America increases the number of new markets opening. In the medium and long term, however, customer demand and increasing competition will be the driving forces.

The world's electricity markets are fragmented and immature; and the European electricity industry, for all its successes, is typical of the global situation. While there are already many exchanges, both of the regulated exchange and the ATS varieties, there will be continued growth in the number of exchanges in the short term.

Much of this growth in numbers could be reversed in five years' time, as a strong period of consolidation results in the birth of mega-exchanges. During this time, there will be unprecedented access to new markets through deregulation, better integration of the fragmented markets in Europe and North America and truly mature markets will develop in these regions, both in electricity and gas. This represents a significant change and an unprecedented opportunity for energy traders and exchanges alike. Being successful requires the right strategy, the right partnerships and the ability to execute those plans globally and on a portfolio basis.

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Chapter 14

Evolvement of the electricity sector – utility for the future

14.1 Introduction

During the last decade of the 20th century the electricity supply industry (ESI) underwent major evolvement and restructuring [1]. Until very recently most network industries (mainly the ESI, and also gas, water and telecommunications) were considered to be natural monopolies. Their size, networks, capital-intensive nature and their sensitive services to the public meant, in most cases, exclusive government ownership and control. Recently, however, technological progress, particularly in information technologies and telecommunications as well as development of regulatory instruments, has enabled the introduction of a market mechanism into these traditional monopolies. One main consideration is that governments no more have the resources and intention in financing the capital-intensive projects like power stations. Governments are now more interested in financing social services rather than electricity services, which the private sector can more profitably handle. Developments vary from one country, or region, to another but a general pattern of five phases has developed.

14.1.1 Phase I: Early 20th century – private sector investment and monopolistic market behaviour

The infrastructure investments in the late 19th and early 20th centuries were largely undertaken by private companies. Private firms developed and commercialised the technologies for the production and delivery of electricity and natural gas. Local monopolies, and national and international oligopolies that used their market power to extract economic rents from captive customers, dominated the new industry. Delivery to users was generally confined to urban communities, with limited development of distribution grids in rural areas. There was little competition in the sector during this period of rapid innovation and industry expansion.

14.1.2 Phase II: Mid-20th century – public sector intervention and inefficiency

Around the time of World War II, a trend towards the nationalisation of energy assets or at least strong government regulation of privately owned monopolies became the norm, in an attempt to limit abuses of market power. In many countries, governments also played an important role in rural electrification, since returns were too low to attract private capital. Elsewhere, state ownership of the electricity industry became the rule. Over time, however, public ownership and the absence of competition increasingly undermined effective management, innovation and operational efficiency. Governments used the power sector, like other state-owned industries, artificially to create employment and as an instrument to deliver hidden subsidies to parts of the economy.

14.1.3 Phase III: Late 20th century – unbundling, competition, regulation and privatisation

The economic costs of public ownership and monopolistic market structures became more and more apparent. In the 1970s, the US began to experiment with power sector reforms. By the 1980s, policy makers in Europe, the Americas and elsewhere realised that electricity, natural gas and telecommunications were no longer natural monopolies. Thanks to advances in technology, economic theory, and increasingly sophisticated regulatory instruments, it became feasible to introduce competition with the same effect as in other industries. Substantial improvements in operational and investment efficiency, the reduction of costs to end-users, an improvement of services and a higher rate of innovation thus became possible. During the 1990s, electricity and natural gas sectors were transformed through the overhaul of regulatory frameworks, the introduction of competition and increasing private participation. These policy reforms have been implemented in developed and developing countries alike. Private power producers (independent power consumers (IPPs)) mushroomed to the relish of government and profits to the private sector.

14.1.4 Phase IV: Recent developments – industry convergence and globalisation

The fourth phase, which is now overlapping with the third, is characterised by convergence in the electricity, natural gas and more generally the utility sector. ‘Multi-utilities’ are being formed to offer comprehensive service packages to clients and reap the associated economies of scale. As liberalisation and privatisation are taking hold, the industry is rapidly globalising through international mergers and acquisitions, cross-border trade and the creation of regional power pools. Another facet of the fourth phase is the emergence of a new ‘service’ sector in the power industry, quite distinct from physical distribution, classified now as the ‘wires’ business, involving electricity markets and trade.

14.1.5 Phase V: Empowering the consumers, through the encouragement of small power (mainly in renewables) both among investors and households

The advancement of distributed generation and its declining prices, though mainly subsidised by governments (feed in tariffs, renewable portfolio etc.), has not only led to the proliferation of small power installations, mainly by households (rooftop PV panels) but also by other entrepreneurs in spreading the introduction of individual small power producers, who are increasingly gaining ground in small installations that are increasingly taking larger share of production by utilities. All of this is assisted by the smart grid with smart meters that are increasingly empowering consumers and involving them in power production and management.

14.2 Reorganising the ESI

The ESI worldwide is being restructured, liberalised, privatised, corporatised and deregulated [2], all with the empowerment of consumers. The meaning and differences of these terms [3] are explained here.

Restructuring. A broad term that refers to attempts to reorganise the roles of market players and/or redefine the rules of the game, but not necessarily deregulate the market. California, for example, restructured its market, deregulated its wholesale market by lifting nearly all restrictions, but kept its retail market fully regulated. Many problems ensued.

Liberalisation. This is synonymous with restructuring. It refers to attempts to introduce competition in some or all segments of the market, and remove barriers to trade. The European Union, for example, refers to their efforts under this umbrella term.

Note that ‘liberalisation’ is essentially a misnomer. No electricity market has been (or, in fact, can be) fully deregulated. Experience suggests that even well-functioning competitive markets need a regulator, or as a minimum, a market monitoring and anti-cartel authority. Germany is the only major country attempting to do without a regulator. Even in this case, there is an anti-cartel office, monitoring the behaviour of the market participants.

Privatisation. This generally refers to selling government-owned assets to the private sector, as was done in Victoria, Australia and in England and Wales. It must be noted that one can liberalise the market without necessarily privatising the industry, as has successfully been done in Norway. The experience in New South Wales (NSW) in Australia, has been a mixed success.

Corporatisation. This generally refers to attempts to make state-owned enterprises (SOEs) look, act and behave as if they were for-profit private entities. In this case, the SOE is made into a corporation with the government treasury as the single shareholder. For example, former SOEs in NSW, Australia, have been corporatised. They vigorously compete with one another, while all belong to the same, single shareholder, namely the Government of NSW.

Empowerment of consumers. This is a recent development made possible and easier by the dissemination of the smart grid and its facilities like smart meters, as explained above and in previous chapters.

Liberalising (restructuring) splits off two lines of the power business that until now were controlled by the monopoly utilities – the generation of electricity and the billing and metering of it – and allows new players to compete in providing these services. Further, it allows these competitors to directly negotiate with certain large consumers set their own prices, rather than negotiating with state regulators on a fixed rate.

Only a handful of companies are competing to provide billing and metering services. But many are looking to be the biggest and the best at owning and operating power plants. Those players are usually unregulated subsidiaries of holding companies for traditional utilities, or independent companies and IPPs that own only power plants.

Eventually, these companies will sell most, if not all, of the electricity into the wholesale market, where utilities and power marketers that distribute to retailers will purchase the power. The wholesale market is growing, and is considered crucial to liberalisation because buyers will pay prices based on supply and demand. That means, liberalisation proponents argue, that power-plant owners will attempt to operate the most efficient plants possible, and then sell electricity at the cheapest rate to marketers. They also argue that, currently, utilities have little incentive to operate efficiently because they get a guaranteed rate of return from regulators based on how much the plant costs to build and maintain. This is true but only to a certain extent.

As we will see there is a need for an alert regulator to avoid market volatility and ensure fair play of the markets. Disaggregation of the value chain and benefiting of new technologies, particularly in information and renewables, help create electricity trading and markets. Liberalisation and technology advances are driving industry transformation and a new vision of the digital utility, which is able to gain business advantage through:

- focusing on a few segments of the energy production and delivery value chain such as generation, transmission, customer care and billing or new areas like energy trading and risk management;
- achieving efficiencies through economies of scale gained from concentration on building best-in-class, core, mission-critical, business systems and partnering, outsourcing or procuring the other less critical or more contextual business services required for business operations; and
- the smart grid and the ability to manage loads, utilise small producers and limit interruptions.

While liberalisation may be viewed as a driving force, the power of software and the emerging capabilities for increased collaboration and integration through open Internet-based standards are enabling and simplifying this transformation. Truly excellent software and smart grid platform and applications environment provides the ability to:

- visualise, by delivering the right information to consumers in real-time where needed within a personalised portal view on any device including mobile wireless devices;
- optimise, by taking this information and combining it with other information seamlessly to get a complete picture, finding individuals with expertise that one can collaborate with and using the information to do analysis;

- automate, by executing processes and transacting business, which may require orchestration among many systems and processes and interoperability with many different heterogeneous systems; and
- trade locally and across borders.

14.2.1 The opportunities presented by liberalisation

Figure 14.1 outlines five possible (but not exhaustive) models for the future organisation of the electricity industry [2]. The five models range from the most conservative, which enables all players in the industry to intervene (model 1), to the solution that rules out all intermediate stages (model 5). A distinction is made between network distribution (physical transportation of electricity) and marketing distribution (supply). Third-party access (TPA) enables all players in the industry to be potential suppliers, whether they are producers, transporters, network distributors or marketers (physical traders). Marketers have a unique status, as they are the only participants to focus on supply, since they buy electricity in bulk and sell it to eligible clients.

In model 1, eligible buyers are supplied by marketers, who themselves are supplied by (network) distributors. The distributor buys the electricity from the transporter, who is the only player to have direct contact with the producer.

In model 5, eligible buyers skip all the intermediate stages between themselves and the producer, and negotiate their supply directly with the producer. This can also happen in reverse order, i.e. the producer may directly approach an eligible customer. Under this model, the transporters and distributors only handle the physical transportation of electricity, as stipulated in the directive.

There are several intermediate stages between these two extremes – three of which are models 2, 3 and 4. Model 2 represents the situation that dominated the European electricity industry for a long time, with two slight differences: first that the producer was often also the transporter, and even the distributor; and, second, that some major consumers were supplied directly from the transporter's network.

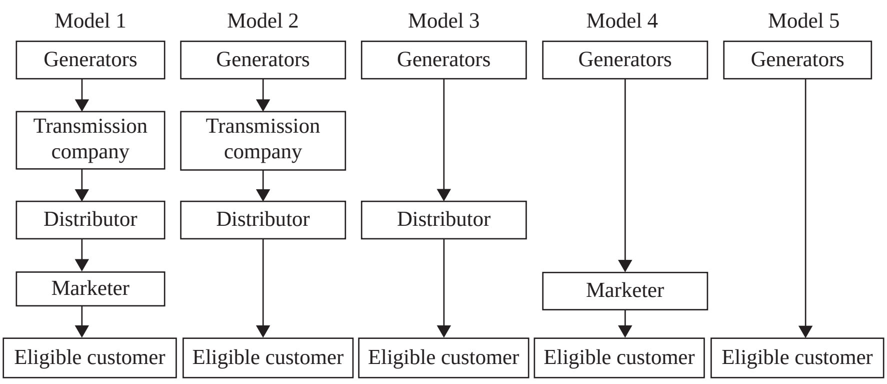

Figure 14.1 Possible models for the organisation of the electricity industry

With liberalisation, the three main players (producers, transmission and distributors, marketers) are likely to have different fortunes.

1. *Enhanced opportunities for producers.* Producers have the advantage of controlling the resource in question. Liberalisation of the market will enable them to sell directly to consumers and to maximise their profits, as they will only pay the transmission company and the distributor the cost of using the networks. Alongside these opportunities in terms of direct contact with the customer, electricity producers are benefiting from increasing synergies between natural gas and electricity at the production level.
2. *New challenge and reduced role for transmission companies and distributors.* At first sight, transporters and distributors are the main losers from liberalisation. As they are forced to open their networks to competitors, they will lose control of a key link in the chain, which afforded them control over supply. The challenge facing these players is to combine their traditional expertise in network management (and production in certain cases) with expertise in supply. This is the condition that will enable transporters and distributors to retain their position as key players in the market, capable of handling their own electricity production as well as that bought from other producers on increasingly competitive markets. In this respect, the opening of the markets constitutes a sizable opportunity. These opportunities are local as well as global.
3. *Traders as the link between producers and consumers.* The main advantage that these traders have regarding final consumers is their understanding of the market (i.e. their knowledge of the cheapest sources of supply) and their capacity to buy large volumes of electricity, which provides them with access to competitive supply tariffs. Similarly, producers, who do not have the expertise needed to ensure sufficient penetration of consumer markets, will prefer to work with external traders who are able to offer such market penetration.

In the new developing markets the customer is no more the traditional one. Some of them are becoming consumers – producers. They are connected to the network for security of supply when their self-production is not there. They also sell electricity to the network through net metering. Besides they are more in control of their suppliers and demand through smart metering and smart networks.

14.3 Barriers in liberalised markets

Monopolies exist because other firms find it unprofitable or impossible to enter the market. Correspondingly, monopolies exist because of barriers [4]. However, under deregulation and in order for perfectly competitive prices to develop, fundamental assumptions of competitive markets must be met. One of these assumptions – the ease through which firms are able to enter markets – plays an important role in the development of competitive markets. Market entry assures (1) that long-run profits are eliminated by the new entrants as prices are driven to be equal to marginal cost and (2) that firms will produce at the low points of their long-run average cost curves. Even in oligopolistic markets, long-run profits and prices exceeding marginal cost can be eliminated if entry is costless.

The California experience in the last decade has highlighted the full extent of barriers facing new generation, and the cost to society when entry is constrained. However, until the barriers to entry are relaxed, prices will not be set at marginal cost. Because entrepreneurial merchant generation is unable to quickly enter the market to capture excess rents, existing generation is able to charge prices exceeding marginal cost.

There are several reasons why entry is constrained, including: difficulty in raising capital, site development and permitting delays, turbine availability and construction lead-time. Both advanced and conventional combined-cycle technologies require three years' construction lead-time, while coal and nuclear plants require four years and more. Once the facility is built, transmission rights and fuel availability constraints can limit market participation. Finally, scheduled maintenance and physically operating constraints can limit real-time market participation. It is apparent that physical generation by itself will not provide real-time market entry and exit required to assure marginal cost pricing.

14.4 The changing utility of the future

Until almost recently the ESI was a highly capital-intensive industry with only few players – governments, large utilities and IPPs that could afford the high capital requirements of the industry. The ESI that had a high inertia to continue with business as usual was contrasted with the telecommunications/telephone industry with its rapid technological change, miniaturisation and rapidly declining costs and tariffs. However, at last, change is coming to the traditional structure of ESI, with its monopolistic, large capital requirements and capital-intensive nature. This is due to the already referred to disruptive challenges mainly brought about by distributed energy resources (DER), which are allowing small investors and individual households to invest profitably in producing their own energy and trading with the utility. The trend is still slowly growing, mainly in China, India and other developing economies. The impact on the utility is still limited but it is beginning to become notable; it is affecting the growth of demand, the access to capital and return on the industry investments. A recent report by the Edison Electric Institute highlighted this trend, which has already affected US and some European utilities, as follows [5]:

> 'Recent technological and economic changes are expected to challenge and transform the electric utility industry. These changes (or "disruptive challenges") arise due to a convergence of factors, including: falling costs of distributed generation and other distributed energy resources (DER); an enhanced focus on development of new DER technologies; increasing customer, regulatory, and political interest in demand side management technologies (DSM); government programs to incentivise selected technologies; the declining price of natural gas; slowing economic growth

> trends; and rising electricity prices in certain areas of the country. Taken together, these factors are potential "game changers" to the U.S. electric utility industry, and are likely to dramatically impact customers, employees, investors, and the availability of capital to fund future investment. The timing of such transformative changes is unclear, but with the potential for technological innovation (e.g. solar photovoltaic or PV) becoming economically viable due to this confluence of forces, the industry and its stakeholders must proactively assess the impacts and alternatives available to address disruptive challenges in a timely manner.'

We are now passing a stage in which consumers are slowly but increasingly becoming producers (through their private installations) and have more say in managing the grid (utilising the smart grid facilities). This is still limited and manageable but it is a trend that is growing and growing rapidly. Bloomberg estimates US PV solar growth to be 22 per cent annually through 2020 [6]. In Australia, there were only 20 thousand rooftops in 2008. In March 2013, they went up to one million. The trend will become a watershed if it spreads to developing economies (like China, India, Brazil, etc.)

This trend will become a 'Big Bang' to electricity distribution, if there is significant future development in the prospects of electricity storage. Then some consumers will contemplate disconnecting from the grid. This reduces demand to utilities and decreases their sales. Also net metering, with the existing consumer cross subsiding the new DER providers, will slowly erode profitability and income of existing utilities and necessitate increased tariff to existing consumers through cost-of-service regulation. This naturally will tempt more consumers to start their own private installation, which will only aggravate the problem [7].

In the future there will be a need for a solution that preserves the financial and commercial integrity of the existing utility. Most likely this will be through the utility's fixed costs being recovered through a service charge tariff structure to cover all costs with DER installation connected to the grid and benefiting out of its services as a backup supply when the sun is not there or during emergencies and for security of supply.

In developed economies and increasingly in emerging markets, the utilities of the present and future have significantly developed their services from the economy of the past. Once there were hundreds of central power stations managed for one way supply, now there will also be hundreds of thousands, even millions of small-scale technologies, moving and transporting power around multi-directional networks. Tariffs are becoming more sophisticated; increasingly, utilities are choosing time-of-use pricing that varies many a time around the day. Electricity utilities are now moving into selling a variety of energy services. Besides security of supply, which was paramount in the strategy of utilities, more attention is being paid to carbon content, voltage quality and structure and ownership.

Regulators need now to take important decisions as to the worth of access to the grid, value of DER, value of net-metering, value to give to demand response, avoided costs and value of dispatch ability.

Distributed generation of electricity will change the role of the grid, a future significant part of the power will not need transmission or distribution, but the grid as we know it will not disappear. The grid will continue to serve those who hook to it as their primary source of power; it will also provide backup power to the DERs. It will also remain as a resource to DER generation to monetise their excess electricity by selling it through the grid. The utility of the future will also have the role of balancing the needs of all the stakeholders connected to it including DERs. Electricity storage, if and once it is developed, will become one of the principle tools of the utility to manage the grid [8].

14.5 Electricity and the new digital economy

The 20th century was characterised by the industrial analogue economy. The economy of the 21st century is the networked digital economy [9], which only runs on electricity characterised by a real-time flow of information. Electricity-based innovation lies at the heart of economic growth.

Digitisation of the global economy has proceeded in three phases. First came computers, which revolutionised information processing and fundamentally transformed the way most businesses operate. Next, as the cost of microprocessors plunged, individual silicon chips began appearing in many applications – from industrial process equipment and medical instrumentation to office machines and home appliances. Now, the third phase involves linking these computers and microprocessors together into networks. There are, at the beginning of the 21st century, millions of websites available on the Internet, potentially available to probably billion computers around the world. Eventually, many stand-alone microprocessors will also be linked to networks, supplying critical information on equipment operations and facilitating even more profound changes in daily life.

This proliferation raises two challenges: quantity and quality. Quantity has to be met not only in building new power stations and generating plants but also in enlarging and strengthening the transmission network, building new interconnections, as well as enhancing the distribution system. Quality was dealt with in Chapter 11.

In 2001, the information technology (IT) itself accounted for an estimated 13 per cent of the electrical energy consumed in the US, a proportion that may grow to as much as 50 per cent after 2020, as shown in Figure 14.2.

The new digital-quality power needs are as explained above in terms of quantity as well as quality. Such needs can be fostered by:

- leveraging the advantages of distributed resources,
- defining and facilitating value-added electricity services,
- providing new direct current (DC) electricity supply technologies,
- developing and employing advanced power conditioning, power quality devices and power electronics and
- establishing new service quality standards for electricity and related products.

Most of these needs have already been discussed in the book.

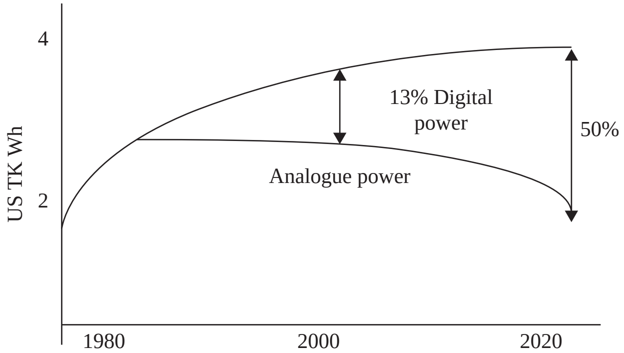

Figure 14.2 *In recent years information technology accounted for an estimated 13 per cent of the electrical energy consumed in the US, a proportion that is growing rapidly*

14.6 The utility of the future

Liberalisation provides for TPA to the electricity grid and the establishment of independent grid operations [9–11]. In doing so, it will also provide for an increased retail competition, starting with the largest electricity customers. Another feature is the unbundling of the vertically integrated value chain, creating different roles for current utility industry entities and allowing new players to enter the market.

The utility companies of the past ran the entire process, from generation to retail settlement. The new unbundled value chain breaks out the functions into four basic entity types; different factors define success within each of these four distinct functions.

- Generators will need to optimise generation outputs according to market demand, comply with environmental rules, prepare for new investments and decrease maintenance and operation costs.
- Energy network owners and operators will concentrate on new ways to secure physical delivery, decrease maintenance and operation costs, plan new investments and ensure compliance with regulatory authorities.
- Energy traders, brokers and exchanges should focus efforts on creating trading vehicles and market liquidity, managing risk exposure, lowering transaction costs and developing new wholesale offers that make the best use of connectivity technologies.
- Energy service providers and retailers will establish ways to reduce energy-sourcing costs, manage client portfolios and risk profiles, bundle and market new services and launch innovative offerings to large clients.

Liberalisation forces a disaggregated business model for each separate element of the value chain, even if the specific models differ from country to country and region to region. This disaggregation promotes the inclusion of new participants with a new combination of roles into the market, participants (such as asset managers, wholesalers, traders and transmission system operators) who did not exist a few years ago in the utilities landscape.

Many of the structural changes that must take place during the transition will be driven by new technologies, such as electronic exchanges and online trading. Today's focus is on external communication needs to interconnect all of the participants, including suppliers, customers and partners, in the value chain.

The large utility of the future must be able to thrive in a competitive, global market for energy [11]:

- it is multinational;
- it can carry its expertise over into emerging parallel businesses;
- it has the flexibility and willingness to unbundle;
- it adapts readily to new structures and concepts;
- it goes beyond its traditional geographic borders to grow; and
- it is an expert manager of risk.

The utility has to learn to operate in different cultures, regulatory environments and markets. The big challenge is in the huge transitions that occur when the industry is transformed by privatisation, consolidation, liberalisation and the introduction of real free-market competition, not to mention the convergence of energy, capital and reinsurance.

The utility of the future will have the flexibility and willingness to unbundle, whenever doing so can add value and competitive advantage as well as improve service to the customer. Risk management will be more important than ever in tomorrow's more deregulated energy markets because it protects businesses, municipalities and other entities affected by change in the energy market, the weather or other factors. The utility of the future will manage commodity price risk with options, swaps and other derivatives. Increasingly, it will be bundling energy, capital and actuarial risk products to manage a broader array of client risks. The benefit is that it will be able to manage risk for itself and its clients, commercialising or producing risk management services. The utility of the future will be an expert manager of risk and help customers determine and achieve an acceptable risk level.

14.7 The 'virtual utility' of the future

Gradually more distributed generation is going to evolve, and most of it will be small units connected to the grid. Such small and decentralised electric energy sources can be operated over the Internet as one large generating plant, a 'virtual utility' [12]. Such development is being enhanced by environmental considerations that are encouraging small renewable energy sources, the fastest growing of which is wind power and rooftop PV systems, small hydro, microturbines and in the future, fuel cells. Such systems may be interconnected by DC transmission systems through low-cost cable network.

This is accompanied by a trend towards neater and aesthetically more appealing arrangements of the network; underground cables are growing while overhead lines are shrinking in size. Cable technologies are allowing for economical and easy-to-install systems. Substations are becoming more compact and easier to conceal. Major advances and cost reduction are also taking place in HVDC light technologies.

These multi-sources will need extended and sophisticated control of all the components and the power flow. The decentralised electric power generation and related revenue flows will most likely be handled by the Internet for direct control, and also for maintenance of the grid as well as for financial and administrative transactions.

14.8 DSM programmes in deregulated markets

In regulated markets, the cost and responsibility of DSM programmes were built into the rate-base or funded through green energy surcharges. In deregulated markets, where DSM programmes or renewable energy investment must be recoverable through market-based pricing, these programmes have been considered uneconomic and thus neglected [4].

Theoretically, real-time load management is analogous to physical ancillary generation markets. Rather than dispatching and curtailing generation, real-time load management curtails and dispatches load. However, owing to the high cost of monitoring and telemetry equipment and current limitations in market design, practical real-time load management is only available to large industrial consumers.

However, residential consumers can also participate in load-curtailment markets. Residential customers can be encouraged to shift demand from peak to off-peak hours via a multi-tier tariff. For example, a simple two-tier system that prices peak power consumption differently from off-peak would provide incentives to shift non-essential activity to off-peak hours. Although limited, the opportunities for residential consumers provide a significant potential source of peak-load reduction. However, the current system of load profiling is fundamentally inconsistent with real-time load measurement and pricing.

Demand responsiveness markets will be most effective when shedding peak load. Experience has shown that a small demand reduction could effectively bring wholesale prices way down. In many service territories, peak demand for the system, which may represent only 100 hours or so per year, creates the need for 10–25 per cent greater system capacity. For peak-load shedding markets to develop, peak-load price signals must be passed to end-use customers. As price signals become apparent, more end-users will find the flexibility and desire to sell back megawatts into the grid.

The most successful programmes avoid much of the downside price risk through voluntary participation. Instead of threatening users with the possibility of extreme energy costs, voluntary programmes pass the price signals to the consumer and, therefore, the incentive to curtail. However, if the consumer chooses not to respond and continues current consumption, they pay the conventional stable rate for electricity. Under voluntary load curtailment, the energy user pays a standard rate that is designed to average out the highs and lows but, during a price spike event, the user can 'sell back' the curtailed energy to the electricity supplier.

Ideally, the electricity supplies would be indifferent to either paying the generating company the spot market price for wholesale energy or paying the large load reducing negawatt participant for load curtailment. Under this scenario, the end-use customer receives the full benefit of equivalent spot market prices for participation in the negawatt market. The benefit to the supplier is less apparent. If the load curtailment generates enough savings, the market would face a less-expensive marginal unit setting market price. In this case the supplier would receive a higher return on power sold to fixed tariff customers.

Load responsive negawatt markets can provide system capacity through either reducing consumption or switching to backup-generation. For the purpose of calculating the cost to shed system load, the two options are equivalent. Both switching to backup-generation and shedding load represent opportunity cost. However, the advantage of focusing on the cost of backup-generation is that it effectively sets an upward bound on cost. The annualised cost of backup-generation effectively caps the power market annualised price. At the point where system cost exceeds the cost of new generation, negawatt market participants would be better off installing new backup-generation than purchasing from the power market. Negawatt markets would compete directly with the generating company, creating a demand response cap to market price and volatility.

Although negawatt market participation can be either through reducing consumption or switching to backup-generation, for the purpose of market pricing, we consider all participation as if through backup-generation.

Participants in an energy reduction programme receive a corresponding premium payment and an energy credit for curtailed energy. The premium payment is based on the 'strike price', the option load contracted and the operational plan selected. A 'call option' in this case gives the supplier the right to purchase energy from the end-use customer at the agreed upon strike price. The call option is exercised when the supplier marginal cost of electric energy, including all variable cost associated with delivering the energy, is projected to be equal to or greater than the strike price.

Theoretically, real-time load management is analogous to physical ancillary generation markets. Rather than dispatching and curtailing generation, real-time load management curtails and dispatches load. Responsive load negawatt markets can be developed to create real-time entry and exit fundamental to competitive priced electric power markets. Negawatt markets would compete directly with generating companies, creating a demand response cap to market price and volatility. Generators would compete with backup-generation, the cost of which sets the market cap.

Using a market-based method of pricing real-time load curtailment, based on real-option valuation of participant opportunity costs, price incentives exist for negawatt market development. The strike price is given by a contractually agreed upon threshold price between the energy provider and energy consumer. From price volatility determined from historic price data or implied from forward markets, a premium value is calculated for the right to curtail future load. Option premiums, profit sharing and limit orders can provide financial incentives for functioning demand responsiveness markets [13].

14.9 The need for a regulator

It is thought that liberalisation will eliminate the need for a regulator [14]. It is also thought that powerful price signals – emanating from fluctuations in supply and demand – are generally adequate to regulate competitive markets. There are cyclical shortages, which result in higher prices, which encourage increased supplies and, which bring prices back to normal levels. So self-correcting competition obviates the need for a regulator to monitor prices and signal when additional supplies are needed and so on. Such arguments do not seem to apply adequately to electricity markets.

An alert and all-powerful regulator appears to be needed particularly during the critical early years of market reforms because the market may not function properly from the beginning. But even after the initial difficulties in the system are worked out, there appears to be a continuing role for the regulator to enforce the rules, and to ensure competitive behaviour among market participants.

One of the key questions for policy makers and regulators is whether there are adequate incentives for investment in generation, transmission and distribution networks in competitive electricity markets. This is an issue that a regulator has to monitor, providing encouragement and incentives for the market to invest to cover for a gradual increase in demand. However, encouraging adequate private investment in transmission is not easy. Costs are reasonably well known, but benefits are difficult to measure and harder to collect because they may accrue to third parties. An alert regulator will have to monitor the network and ensure that there are rewards and incentives to invest in transmission strengthening.

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Chapter 15

Investment projects analysis: evaluation of risk and uncertainty

15.1 Introduction

From a practical point of view there is no project without risks. Risk taking is normal to entrepreneurs, to lending and funding agencies and also to government while making development plans. Such risks and their extent can be reflected in choosing the discount rate of the project (see Chapter 4), where investors expect higher returns to compensate them for risk taking. Because of the regulatory nature of the industry, the limited number of players and the unique nature of electricity and its continuous rise in demand, the average project in the electricity supply industry (ESI) is less risky than the average investment in the stock exchange [1, 2]. However, each project has its own risk; projects that involve new technologies (renewable and clean-coal technologies), or projects with lengthy lead times (nuclear and hydro-power), involve a lot of investment and have more than the average level of risk. Some of the risks are related to engineering and technology; however, market risks equally exist. For example, the demand may not turn out to be as estimated, the tariff is lower than expected and project execution may take more time and involve more cost than planned. Future fuel prices are one of the riskiest aspects in evaluating investments in the ESI projects. Variation in fuel (and carbon) prices may surpass expectations, or supplies may turn out to be insecure and more expensive alternatives have to be sought. For projects with lengthy lives, like coal-firing and nuclear power stations, the problems of obsolescence (due to technological change) and environmental legislation exist; these may cause such projects not to survive their full life or end up with heavy and expensive modifications. Cost overruns, which are caused by project delays, or inaccuracies in estimation do not only significantly change project costs but also substantially reduce net benefits. Such risks are mainly encountered in generation planning and investments.

Recently, two other risk factors are affecting the ESI. The first relates to carbon pricing and legislation – discussed in more details in earlier chapters. Long-term investments in carbon-intensive generation like coal firing plants are highly vulnerable to variations in possible carbon pricing and trading as well as future legislation. Another risk factor is that provided by the wider investments in renewables, particularly wind and solar energy. These as already explained provide distribution to the operation of the generating system and its economics, thus providing another risk to the system investors. Both these two risk elements as well as many others are discussed in detail below.

15.2 Generation investment

Investments in generation extension or replacement are risky decisions that involve many future variables which can change over the planning horizon – load predictions may be inaccurate, fuel price may change, price of carbon can vary etc. This section describes how generation investments are taken, their different methods and tools and how these are adopted to allow for these risks. It starts with the deterministic optimisation techniques and then moves to describe existing electricity industry investment methodologies and finally detailed generation investments project risk allowing for uncertainties of key assumption and their correlations through Monte Carlo Simulation (MCS) tools.

15.2.1 Deterministic generation investment decisions

These are controversial decision support tools for generation extension and strengthening. These are optimisation techniques that endeavour to pick up the least-cost mix of additional generating plants. There are many forms of deterministic generation planning [3] and all suffer the weakness that they rely on deterministic assumptions about uncertain variables.

1. models that compute the expected annual cost of capital and operating costs of different generation options and match them to the expected future demand as modelled by the load duration curve, and then choose the least-cost model [4];
2. apply a levelised cost methodology based on discounted cash flow to compute the cost of each generation technology with its expected capacity factor, and fit this to the load duration curve;
3. fit the generation options to the load duration crude (LDC) to determine their mix and their capacity factors.

Realising the weakness of these deterministic methodologies, improvements were introduced by applying sensitivity analysis and allowing for correlation between critical risk inputs and factors. Few tools are now being used to assess and optimise generation investments based on probabilistic assumptions of the inputs and their risks and correlation, also the role of different generation technologies. These new methodologies are optimisation models that rely on linear programming to obtain the least-cost solution. Many of these are commercially available and include the well-known Wien Automatic System Planning Program (WASP-IV), Long-range Energy Alternative Planning (LEAP) system and MARKAL. LEAP goes beyond these conventional models to incorporate an overall energy strategy [5] of these generation planning tools. WASP is the most well known and it simulates power generation system expansion up to 30 years [6]. These tools are highly powerful and useful; however, they also suffer from the fact that they are deterministic in nature and are based on the planner's assumptions of demand, fuel prices, cost of technologies, etc. They are improved by sensitivity analysis; however, these methodologies do not fully account for the interacting uncertainties associated with the generation sector of the ESI, hence the need to allow for project risks.

15.3 Project risks

Project evaluation involves assumptions about inputs with varying degrees of uncertainty; in some cases these individual uncertainties can combine to produce a total uncertainty of critical proportions [3]. The risks can come from unexpected legislation and regulatory aspects, both price and environment and also from three sources: uncertainty in project planning and specifications, uncertainty in the design coefficients (engineering and technology, economic, income prediction, etc.) and uncertainty in exogenous project inputs (mainly fuel availability and carbon prices). Sensitivity and risk analysis affect the choice of the least-cost solution as well as the internal rate of return (IRR) and correspondingly the decision to proceed with the project altogether.

Most of the financial and project evaluation of Chapters 5 and 7 was on a *deterministic* basis, i.e. all inputs of costs and benefits and corresponding cash flow forecasts were assumed to be accurate. Risks were only incorporated in the discount rate and in allowing for contingencies in project cost, and when net present values were calculated. As already explained, in the real world things never work out that nicely. Therefore, it is prudent to account for such uncertainties by carrying out some project risk analysis. Such analysis involves the following:

- Evaluation and judgement of the behaviour of certain uncontrollable inputs of the project. Calculating, instead of a single return, a whole set of possible returns for the project based on the behaviour of the uncontrollable inputs.
- Criteria for choosing the least-cost solution among the different alternatives based on the likely set of returns for each. A less-risky project alternative with modest returns may be preferred to a more-risky alternative with probably higher returns.

Apart from giving a more realistic and accurate assessment of the likely outcome of the project, a risk and uncertainty analysis has many other advantages. It enables more accurate analysis and evaluation of project inputs and outcomes by many experts and with more factual evidence. This will also lead to an insight into restructuring or redesigning the project in light of this evaluation and analysis. It also enables focusing on those uncertain inputs that affect the likely outcome so as to mitigate or reduce their uncertainty in a number of ways. Project analysis is greatly assisted by modern computers and statistical analysis packages, which allow undertaking of such evaluation in a short time and at a limited cost. However, it needs a lot of insight and accurate understanding of the project structure and details.

Uncertainties faced by power utilities are both *internal* factors, which can be controlled even to a certain extent by the utility, and *external* factors, which are

Table 15.1 Major uncertainties faced by electricity utilities [4]

External uncertainties

- national and regional economic growth and its corresponding effect on future electricity demand;
- structure of energy demand and rate of substitution of other fuels by electricity;
- unpredictable future fluctuations in local and global fuel prices, also carbon pricing;
- insecurity in imported fuel sources;
- future environmental regulations and legislation;
- technological innovations and development of more efficient and clean plant;
- future inflation and cost of financing.

Internal uncertainties

- project cost overruns;
- project execution schedules and delays;
- reliability of the system and availability of generating plant;
- system losses;
- operation and maintenance costs;
- risks brought by high renewables component in the generating system.

outside the control of the utility (see Table 15.1). Internal factors can be managed by better handling of the projects' design, execution and operation; outside factors have to be incorporated into the planning process in order to reduce their uncertainty. The experience of planners and designers greatly assists in defining uncertainties and their handling. Post-evaluation of projects to compare the planning assumptions (costs, execution period, demand prediction, etc.) with actual events builds experience that helps planners to reduce risk and uncertainty in future project assumptions and plans. For instance, most power projects financed by the World Bank proved to cost more and take lengthier times to implement than planned, and detailed sensitivity analysis does not adequately capture or account for such differences [4].

There are many ways to handle and deal with uncertainty and risk. These can be grouped under the following headings:

1. delay and defer decisions until the uncertainty is reduced;
2. plan and allow for possible short-term contingencies;
3. sell risk to others through turnkey projects, long-term fuel contracts, insurance etc.;
4. flexible strategies that allow for relatively inexpensive changes like designing the system to allow for possible future fuel conversion, executing the network to allow for operating at higher voltage, etc.;
5. cross-border agreements to exchange energy and reduce risk of wind generation.

Therefore, recent trends in generation planning try to avoid investing in large units with long lead times and concentrate instead on smaller sets with short construction periods and limited investment. No private entity will contemplate investing in nuclear units at this stage. This will greatly reduce capital risks of utilities, as already explained in Chapter 1.

For simple and small projects, uncertainties can be adequately evaluated by a simple sensitivity analysis, through measuring the response of the IRR or net present value to predictable variations in the project inputs. Alternatively it may need a full risk analysis utilising a *probabilistic* approach to assess the combined net effect of changes in all variables or the likelihood of various changes occurring together. Such a probabilistic approach is particularly useful, indeed necessary, in the case of large capital-intensive and risky projects.

Generally speaking, there are several procedures for project risk analysis, mainly: sensitivity analysis, decision analysis, break-even analysis and the MCS [5]. The incorporation of renewables in the system and the prospects of future carbon legislation and pricing necessitate more sophisticated analysis than that common in the past.

15.4 Sensitivity analysis

Sensitivity analysis involves calculating cash flows under the best estimate of input variables, and then calculating the consequences of limited changes in the value of these inputs. It assists the evaluator in identifying the variables that significantly affect the outcome and correspondingly needs more information and investigation. Sensitivity analysis is carried out during practically every financial and economic evaluation of projects; it is simple and informative. It is a review of the impact that changes in selected project inputs, costs or benefits, or a combination of these, can have on the project's net present value or IRR. In this case one or more variables are changed independently or collectively, within reasonable limits (say, 10–20 per cent) to see the likely effect of the change on the net present value of the project and its likely IRR. Alternatively the aim may be to calculate the change in one variable, like the selling price per unit or project cost that will reduce the net present value of project benefits to zero. This will indicate the selling price per unit or project cost below or above which, respectively, it is not worthwhile pursuing the project. Another alternative may be *break-even analysis*, to work out values of inputs and outputs that will reduce the project benefits to below the *cut-off rate*, which is a rate established as a 'threshold' below which projects should not be accepted. The cut-off rate depends to a large extent on the riskiness of the project. A project with a high volatility in some inputs will therefore need a much higher acceptable cut-off rate than a project with almost sure estimates. Carbon pricing is a consideration for sensitivity analysis.

One of the most important exercises in sensitivity analysis is to review the impact of the discount rate on the project's net present value and its profitability. In this case, and if there is no single firm discount rate, more than one discount rate is tried and the outcome with each discount rate is described. The UNIPEDE/EURELECTIC study into the projected cost of generating electricity considers two discount rates, 5 per cent and 10 per cent, each applied with different outcomes [7].

Sensitivity analysis is therefore an essential and easy means of evaluating the vulnerability of the project to likely future deviation from best-input estimates. It can also greatly help in assessing the extent of risk in the project, and the particular inputs that significantly affect the project outcome. Once these are identified, then a more careful study should be undertaken of these particular items to enable better estimates and a firmer calculation of the net present value and the project's IRR. For the electrical power industry the most important items affecting a project's financial performance are the electrical tariff and fuel prices, also carbon prices. With the increasing availability of electronic calculating facilities it has become much easier to undertake many sensitivity analysis scenarios and to analyse the effect of various parameters on the project's financial and economic feasibility.

One of the major weaknesses of sensitivity analysis is that the changes are, most of the time, ad hoc (10 per cent change in price of fuel or 10 per cent change in demand, etc.), without regard to the expectancy and probability of these happening. Such ad hoc assumptions do not assist decision makers to fully examine the likelihood of the event. Fuel price changes, in the future, may be much more likely to occur than other operational costs; therefore, dealing with these two on equal terms can lead to wrong impressions and conclusions. So it can also effect of a change of one input on other inputs; a significant change in fuel (or carbon) prices will not only affect the net present value (NPV) and IRR, but will also affect demand, prices and merit order and can cause significant implications, which are not captured by sensitivity analysis. What is important is not only the prospect of change of a fundamental input assumption but also the probability of this happening and its extent, and also the interrelationship between variation in one variable and other input. Such prospects can only be adequately evaluated by proper risk analysis.

To demonstrate this, consider a 100 MW combined cycle gas turbine (CCGT) set, firing LNG, that consumes 6 000 btu/kWh generated, at a cost of £2.60 per million btu. The set will cost £100 million at commissioning and is expected to act as a base-load generating unit at full load for 7 000 hours annually. There is a fixed annual cost of £1 million.

With a 10 per cent discount rate, over 20 years, the equivalent annual cost of investment is

$$\frac{\text{Investment}}{\text{20 year annuity factor}} = \frac{\pounds 100\,\text{million}}{8.514} = \pounds 11.74\,\text{million}$$

The fixed annual cost of capital and operation will equal

$$11.74 \text{ million} + 1 \text{ million} = 12.74 \text{ million}$$

with an annual generation of

$$100 \text{ MW} \times 7000 \text{ h} = 700 \text{ GWh}.$$

The fixed annual cost per kWh will be

$$12.74\text{ million} \div 700\,\text{GWh} = 1.82\text{p}$$

Fuel cost per kWh is

$$(£2.6 \times 6000)/10^6 = 1.56\text{p}$$

Total cost of generation is

$$1.82 + 1.56 = 3.38\text{p}\,\text{kWh}^{-1}$$

Consider the case of a sensitivity analysis of a possible double in fuel cost, and then the fuel cost will become 3.12p kWh^{-1} and total cost of generation 4.94p kWh^{-1}.

With such a fuel price and operational cost, the set most likely will not remain a base-load set and correspondingly the energy output of the set will change and its cost per kWh will be higher (depending on the position of the set in the merit order). Sensitivity analysis fails to capture such correlation between fuel cost, energy contribution of the set and correspondingly system cost. It is only simulation that can give the generation cost, capture the system effect and evaluate the true economics of investing in such a plant compared with other alternatives firing other fuels.

15.5 Break-even point analysis

In all industrial production projects a financial break-even point analysis is essential in order to assess the relationship between production volume, production cost and profits. The break-even point is the level of product sales at which financial revenues equal total costs of production; at higher volume of sales financial profits are generated. The detailed break-even analysis will vary depending on what type of profits (gross, net, before or after tax, etc.) and what type of costs (cost of money, cost of certain input items) it is required to test. It is usual to carry out such testing through sensitivity analysis in order to demonstrate how variations in different components of production cost or demand affect this break-even point.

Break-even point analysis is essential in industrial projects [8]. It can be carried out rather easily by equating fixed costs and variable costs to income from sales at a certain sales level so that

$$\begin{aligned}&\text{Fixed (capital and fixed operation) costs}\\&\quad + (\text{sales volume} \times \text{variable production cost per unit})\\&\qquad = \text{sales price} \times \text{sales volume}\end{aligned}$$

One important point to remember in break-even analysis is that it has to be carried out through proper financial evaluation, like that in Chapter 5, rather than through financial accounting statements, which is a common error that most firms fall into.

For example, consider a firm that will invest £10 million to produce a product that has a market price of £2 per unit and a £0.5 variable cost per unit. The firm will face £0.25 million fixed expenses annually. The business is going to remain for 10 years and the company employs a straight-line depreciation method, where sales equal production. It is required to find out the break-even point.

The annual fixed costs of the company are

Depreciation (£10 million per 10 years)	£1.00 million
Other fixed costs	£0.25 million
Total	£1.25 million

The break-even sales are now calculated according to the earlier equation:

$$\text{£}1.25\text{ million} + (\text{£}0.5 \times \text{volume of sales}) = \text{£}2 \times \text{volume of sales}$$
$$\text{£}1.25\text{ million} = \text{£}1.5 \times \text{volume of sales}$$
$$\text{Break-even volume of sales} = 833\text{ thousand units}$$

Therefore, this firm will go into business only if it is guaranteed that its sales will exceed 833 thousand units, on the average, annually.

This accounting approach basis is quite misleading since it ignores the opportunity cost of capital. As mentioned in Chapter 6, depreciation is accounting cost that should not go into financial evaluation. The real cost of money is its opportunity cost; assuming that this is 10 per cent, the equivalent annual cost of the investment is

$$\frac{\text{investment}}{\text{10-year annuity factor}} = \frac{\text{£}10\,\text{million}}{6.145} = \text{£}1.627\,\text{million}$$
$$\text{annual fixed cost} = \text{£}1.627\,\text{million} + \text{£}0.25\,\text{million} = \text{£}1.877\,\text{million}$$
$$\text{£}1.877\,\text{million} + (\text{£}0.5 \times \text{volume of sale}) = \text{£}2 \times \text{volume of sales}$$
$$\text{Break-even sales} = 1251\,\text{thousand units}$$

(This new break-even volume of sales is more than 50 per cent higher than the earlier figure, which displays the importance of financial evaluation and having proper assumptions. Depreciation does not reflect the true cost of money and it is quite misleading in evaluation in that it leads to a lower break-even point.)

To assess the effect of production cost per unit, a sensitivity analysis is carried out by increasing this by 20 per cent, to £0.6 per unit, and measuring the effect on the break-even sales volume. This will mean increasing the break-even sales volume into 1 341 thousand units, i.e. 7.2 per cent more.

Sensitivity analysis, as has been proved by experience, is not adequate for large capital-intensive projects. However, it remains a simple and widely used tool for assessing the risk in project valuation and in drawing the attention of planners to particular project inputs that warrant special attention, so that these can be investigated better, or so that certain arrangements are made beforehand, to reduce their risk. Sensitivity analysis through varying the discount rate (the opportunity cost of capital) can have great impact on the outcome particularly when comparing a capital-intensive project with limited-future long-term operational cost (nuclear) with less capital-intensive alternatives, but higher cost of operation (CCGT and single cycle GT). It is much wiser to undertake an extensive exercise to find the right discount rate that commensurate with the risk, as explained in Chapter 4, rather than to undertake a discount-rate sensitivity analysis, which may lead to confusing results.

15.6 Decision analysis

A more comprehensive approach to uncertainty than sensitivity analysis is decision analysis [8, 9]. In its simplest form it involves selecting scenarios: the base scenario, an optimistic scenario and a pessimistic scenario. The base scenario will demonstrate the most likely inputs and outputs from the point of view of the project evaluator. The optimistic scenario will incorporate future parameters that are more favourable to the project success than they appear at the time of evaluation, while the pessimistic scenario will have an opposite view expecting that future events may be less favourable than they appear today. A decision analysis can be undertaken where each of these scenarios can be assigned an explicit probability and be represented as decision tree. A question about the discount rate to be applied arises; a pessimistic scenario will have much less risk than an optimistic scenario, so will the same discount rate be applied in both cases? This is a valid argument that will be dealt with later.

Detailed decision analysis involves the construction of a set of mutually exclusive scenarios of an event, the sum of probabilities of these scenarios adding up to unity. Only one of these mutually exclusive scenarios must take place. Decision analysis is a way of dealing with prospects for future variation of key inputs. Each input can have exclusive scenarios with these scenarios covering all possible future states (N), each state with a probability (P), such that the sum of all these probabilities equals unity $\left(\sum_N P_n = 1\right)$. If the possible values of each input quantity are small, then uncertainty can be expressed as a discrete probability distribution of the output.

The probability of the input quantities can, in most cases, be better presented as continuous, rather than discrete distribution. It is possible, as an approximation, to express a continuous probability function by a discrete distribution and use the probability tree approach. But with many input variables, proliferation of the tree will occur, and this makes the analysis rather cumbersome.

Setting up mutually exclusive scenarios with a probability distribution assigned to each is a rather difficult task. These are usually based mainly on the judgement of experts and other project designers. It involves a lot of estimation and future guessing. Decision analysis is an improvement on sensitivity analysis; however, its weakness lies in the selection of discrete assumptions and probabilities, which are arbitrary in many cases. Also the method does not capture the co-variation that may exist among different variables.

Decision analysis, therefore, is a step forward from sensitivity analysis, yet it has its shortcomings, which have already been explained. However, if the likely input probabilities are few and discrete and can be presented in a simple decision tree, then this can assist in better risk evaluation of the project. Such decision trees are very helpful in sequential decisions. The sophisticated approach to risk assessment is to characterise the uncertainty in the project inputs by assigning a probability distribution to each important input and to simulate the project output – IRR or net present value – by a sophisticated probability distribution as described in Section 15.7.

15.7 Risk analysis (the Monte Carlo simulation)

In sensitivity analysis the impact of change of one variable at a time is evaluated; decision analysis allows the evaluation of the effect of a limited number of plausible combinations of variables. Risk analysis is the tool for considering all possible combinations. As already explained, because of uncertainty about major inputs the selection of a single value for the input variables (as is the case in the deterministic evaluation) could lead to misleading outputs. Risk analysis is basically a method of dealing with uncertainty. Recent trends in the ESI, particularly the growing importance of competition and markets and independent power producers, as also volatility in fuel and carbon pricing have strengthened the need to resort to risk analysis in order to deal with uncertainty. Uncertainty is characterised by trends, events and developments that are not known in advance but are likely to happen, and whose occurrence can affect the outcome of planning decisions. The fundamental risks that are encountered in the ESI have already been mentioned. They are primarily market (demand growth, future fuel and carbon prices, cost of money, tariffs and other income prospects) and technical (breakdowns and non-availability of plant, intermancy of renewables technological change and prospects for future environmental legislation and enforcement). During project implementation there are also the risks of cost overrun, delays in implementation and teething troubles in commissioning. Also the changing structure of the ESI worldwide is creating uncertainties about regulations, trade, renewables, the introduction of new players, the phasing out of monopolies and possible competition.

For most small projects, sensitivity analysis (or the more sophisticated decision analysis) can be enough to satisfy the investor as to the vulnerability of the rate of return to reasonable variations in the values of key inputs of the project, and hence the risk extent in the investment. However, in the case of more capital-intensive investment projects, also in new ventures with little past experience, a proper risk analysis has to be undertaken. Risk analysis calls for sophisticated knowledge of expectancy and probability theory and the undertaking of value judgement.

In the deterministic approach, the NPV and the IRR for the project were presented as single figures. In actual fact each is a single point on a continuous curve of possible combinations of future happenings. Therefore, it is much more accurate to calculate the IRR in a form of schedule (or curve), which will not only give the most likely value of the IRR but also the chance of this value happening and the chance of its being lower (or higher) than the likely value, as shown in Figure 15.1. This analysis would give the investors a much better knowledge as to the prospect of their investment achieving the expected return, or any variation of this, with the probability of it happening. This will not only sharpen the investors' knowledge of the profitability of the investment but in some cases it may also affect their choice of the least-cost solution.

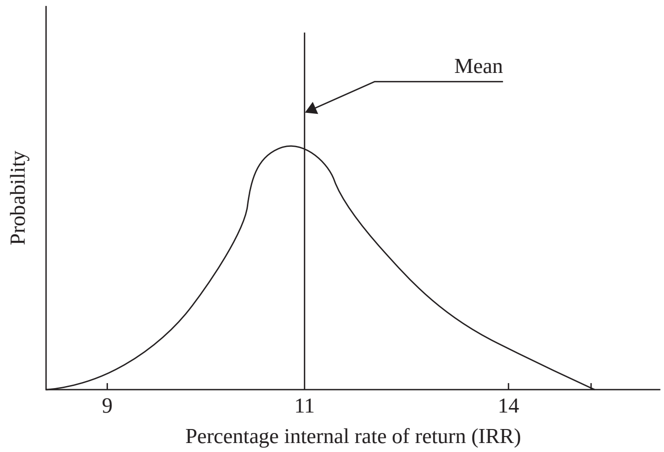

Figure 15.1 Probabilistic presentation of the rate of return (IRR)

The idea of risk analysis is to try to present each of the main values of inputs and outputs of the project in the form of a probability distribution curve with each event having a chance of happening. For instance the most likely cost of the project is *C*, but the likelihood of this happening is 50 per cent, the chance of it becoming 1.5 *C* is 10 per cent, but it is impossible to exceed 2 *C*, while the prospect of it becoming 0.95 *C* is 20 per cent and can never be below 0.90 *C*. Such information will allow the drawing of a distribution curve similar to that in Figure 15.1. Such distribution curves can be drawn not only for the project cost but also for most of the input variables: future fuel prices, the project execution time, the cost of operation, the size of sales and the likely sale price of the output, etc.

There is no precise or standard way of drawing such curves; the curves, however, are either based on past statistics (like wind probability) or present the best-value judgement of the project planners and estimators as to the likely values concerning these main elements of costs and benefits. Such valuation depends on the estimator's value judgement, which is derived from experience and understanding of the market and knowledge gained from previous projects. By utilising the Monte Carlo method in selecting, at random, input sets of these components each with its probability of happening and calculating the IRR for each combination, and repeating this a few times, an IRR curve can be established with its peak, indicating the most likely IRR value and the chance of it happening and also the likely deviation from this return, each with its probability. Thus, the extent of risk in the project becomes clear. A similar curve can be drawn out for the NPV, with each value having a probability of it happening; the same applies to similar required outputs [5,6].

The MCS is a powerful tool in risk assessment. Besides identifying the important input variables, a probability distribution is assigned to each input while identifying any relationship (covariance) among inputs. Sets of input assumption are repeatedly drawn from each input distribution. This will lead to outputs characterised by probability distribution, with the possibility of calculating the mean outcomes, variances and other required parameters.

The MCS involves the following three steps.

Modelling of the project. The complete model of the project will contain a set of equations, the details and data for each of the important input variables (for instance, in the case of generation system expansion modelling – load, generation availability states, futures set sizes and set costs, fuels and carbon maintenance scheduling, reliability criteria and cost of interruptions). The set of equations illustrates how to describe interdependence between different inputs and interdependence over time.

Specify probabilities. A probability distribution has to be drawn out for each of the inputs other than those that are known to have deterministic values (for instance fixed price fuel contracts or turnkey key projects). Such probability distribution can take one of the shapes specified in Figure 15.2 that is drawn by experts using their experience and expectations or through knowledge of past performance and data, as

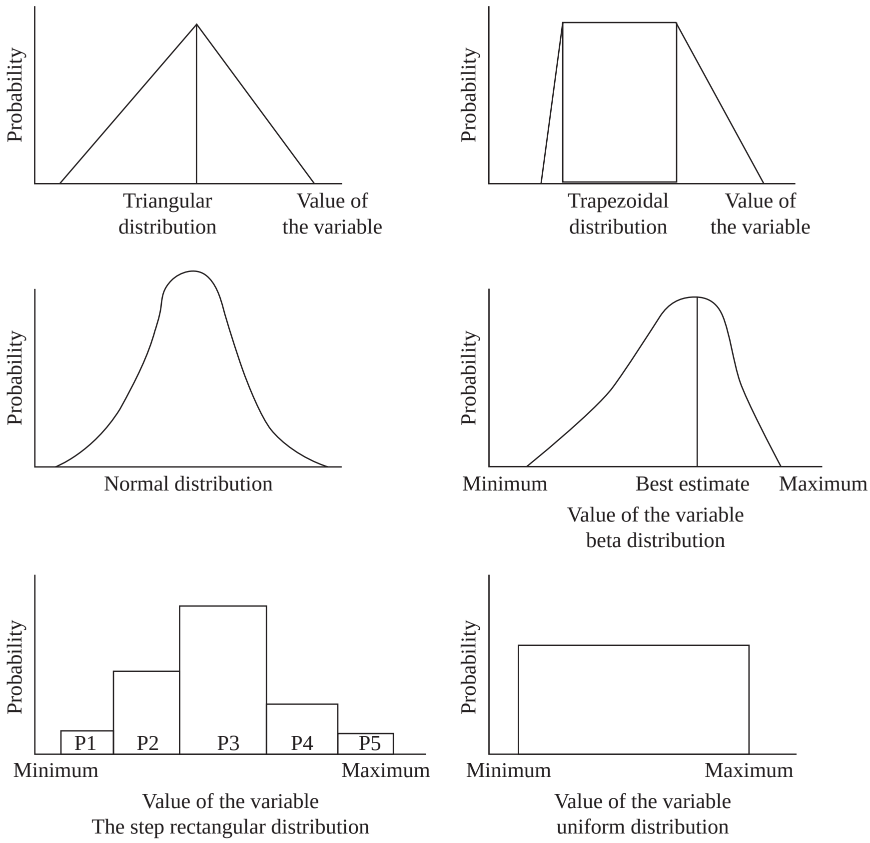

Figure 15.2 Probability distribution curves (to be used in presenting the probabilities of different input variables)

in the case of simulation of generation capacity states. The results are sensitive to the form of input distribution; therefore, choosing the most relevant distribution is quite important. Normal distribution is not always the appropriate distribution form unless there is supporting evidence.

Simulate cash flows and calculate output. The computer samples from each of the input variables, each input value with a probability, calculating the resulting output cash flows and through them a probability distribution of NPV and IRR.

Such a simulation process is tedious and complicated; however, it has many advantages. Not only does it lead to better results with the associated probability of achieving these, but it also enables the forecasters and planners to face up to uncertainty and interdependencies and investigate input values in greater detail. The discipline of simulation can in itself lead to a deeper understanding of the project.

Once the input distribution curves have been completed, the computer, utilising the MCS, generates random values for each of the parameters, calculates the rates of return (NPV or other required output) in each run, and then repeats the process with new random inputs. After many runs (say 10 000) an output distribution is obtained with a mean and a standard deviation.

Unlike sensitivity analysis, this probabilistic risk simulation gives a complete picture of the project outputs and their chance of happening, thus quantifying the project risk. This is not necessarily the true risk that is going to occur in the future, but the risk that is the best judgement of the project evaluators and appraisers. Therefore it goes nearer to define and point out the risks of the project and its output parameters. These, together with the mean and standard deviation, are the best definition of the project's likely output.

One of the most important values of risk analysis is that it assists in reducing the risk of the project by considering in detail inputs that increase the output risk and studying these risks with methods designed to minimise them. Sensitivity analysis can assist in pointing out the inputs that have a major impact on the project output; therefore, risk analysis can concentrate on studying these. It has also to be noticed that normal contingency allowances have to be incorporated in the probability distribution.

The results of the analysis usually focus on calculating the rate of return. A few results are expected:

1. the mean internal rate of return and the standard deviation;
2. the probability of achieving a minimum return;
3. the shape of the distribution and the 95 per cent range confidence level.

15.8 Consideration in risk analysis

15.8.1 Building up probability distributions

The first and most important step in risk analysis is to assign to each input variable a suitable probability distribution. These distributions are based essentially on subjective judgement. The amount of input variables involved depends on the extent of disaggregation referred to in Section 15.8.2. The subjective judgement of the probability distribution of each input will involve a small team of evaluators and appraisers who are familiar with the inputs and their likelihood variations and also with probability simulation [5, 6, 9]. Opinions are exchanged among the team members until a probability distribution, from among classical probability distributions, is chosen as being a better fit to the case. Of particular importance are the extent of skew and the probability of the interval. The approach aims at interaction between quantitative and qualitative judgements. A quantitative judgement involves assigning tentative figures; these in turn are judged qualitatively and modified, and the process is repeated until a probability distribution curve of the input is agreed upon, by all those concerned in the process, as representing the most likely possible distribution.

As explained above, the probability distribution to be utilised has to represent the best judgement of the evaluation and appraisal teams. There are many forms that a probability distribution curve can take. These are:

- Step rectangular distribution
- Discrete distribution
- Uniform distribution
- Beta distribution
- Trapezoidal distribution
- Triangular distribution
- Normal distribution

The form of these probability distribution curves is presented in Figure 15.2. The choice of the most appropriate distribution curve depends on the judgement of the evaluation team. There is tendency to use the normal distribution because of its neatness. Experience, however, has shown that this is probably not the best distribution curve in every case. Other forms like the step rectangular or discrete distribution are also quite useful (sometimes more useful) and easier to formulate.

Two major issues have to be considered in risk analysis: disaggregation and correlation.

15.8.2 Disaggregation

Disaggregation refers to the extent of detail in which an input has to be analysed. For instance, the cost of a power station involves civil works, turbine, generator, boiler, switchyard, fuel handling and storage. The civil works can be disaggregated into great detail of foundations, buildings, cooling arrangements, control room building, storage and workshop building etc. Each item can be disaggregated into further details involving quantities of cement and concrete, steel reinforcements, aggregates, labour, other inputs etc. It is important to understand where to stop disaggregating in order to construct a reasonable probability distribution for each item, and correspondingly of the project cost.

Incomplete and inaccurate results usually happen from lack of disaggregation. Through disaggregation it is possible to obtain better cost estimates, a more realistic demand prediction and a better probability distribution for the inputs. However, too much disaggregation will make the work of the evaluation team cumbersome in having to construct too many probability distribution curves. Therefore, it is wise to concentrate on disaggregating those uncertain input items that can have greater impact on project viability and evaluation.

15.8.3 Correlation

Correlated variables are variables that are likely to move together in a systematic way. They are not easy to detect and are difficult to measure. They appear in practically every project and if ignored can lead to the wrong conclusions. In the ESI, demand is correlated to economic growth and the tariff; operational costs are in turn very strongly influenced by possible variation in fuel prices; and carbon pricing in turn is correlated with demand and economic activity and fuel choice.

Correlation is often hidden and difficult to detect, also it does not appear in the deterministic approach. Disaggregation helps greatly in building up and complicating the problem of correlation, and by limiting disaggregation to an adequate and reasonable level, correlation can better be dealt with. Also acquisition of more data and relating inputs can discover serious correlation that may exist and will allow accounting for this. Correlation is a much more serious problem than the choice of the probability distribution curve. It is not possible to give a general rule for the ESI, particularly the movement of fuel prices and its relationship with other inputs (like carbon pricing). Each large project has to be studied separately and its features, disaggregation and correlation, adequately dealt with.

15.8.4 Effect on the discount rate

In the ESI different projects have different risks. Investing in a power station is riskier than investing in transmission and distribution; nuclear and new technologies power stations (including some renewables) are riskier investments than conventional power stations. All this can be incorporated in the discount rate, which can vary in accordance with the extent of risk in the project.

The second consideration is whether a closer study of the project including presenting input variables in a stochastic manner, with disaggregation and appropriate correlation, will reduce investment risk and hence lead to a reduction in the discount rate. It has to be remembered that the discount rate also reflects the risk of the project. However, in spite of the care in identifying accurately the project inputs (demand, project cost and fuel prices), risk still exists. The discount rate can never be equal to the risk-free discount rate, although it gets near to it in the case of fully regulated electricity distribution utilities where there are frequent tariff adjustments.

Simulation is more realistic in predicting the future performance of the project. However, there will still be inaccuracies in representing the input variables. Also, not all variables can be accounted for and be adequately represented in a probability distribution.

Therefore, it has been advocated that instead of calculating the NPV through simulation it is sufficient to calculate the IRR and represent it in a probability distribution curve similar to that of Figure 15.1 with a mean and a range containing 95 per cent of the expected values of the IRR. This will avoid the problem of assigning a previous discount rate for the project to obtain the NPV. However, if the mean IRR is computed by simulation with a standard deviation this still has to be compared with a discount rate that reflects the risk of the project as advocated in Chapter 4. Calculation of the discount rate that considers the impeded risk of the project is required.

15.9 The value of risk management in liberalised markets

Liberalisation intensifies competition; this will lead to price volatility and greater risk [10] to producers. In the past, accidents and increased costs over a short period owing to unavailability of a low-cost plant were not reflected in immediate price increases. Producers were able to delay reflecting their increased production costs in their prices. There was a time adjustment on prices, which enabled producers to distribute sudden cost increases over a longer period. Clients who consumed electricity at the time when the marginal cost of production was the highest paid roughly the same price as clients who consumed electricity when the marginal cost was at its lowest. With the advent of competition, this is no longer the case: competition has introduced true pricing. Tariffs are applied in real-time (producers must submit their supply bids for the following day), which tends to heighten price volatility.

Indeed, prices can be highly volatile on the spot markets, incurring price risk for the different players and sparking the need for a new function–risk management. As with physical sales, price risk can be hedged in two ways.

- Transactions can be made over-the-counter. This is notably the case when there is no organised market.
- Transactions can be made in organised financial markets, which offer derivatives (futures and options). In general, these organised financial markets are created as a natural complement to organised spot markets.

The first example is illustrated by the market that existed few years ago in England and Wales. Owing to the high levels of price volatility on the Pool, the majority of market participants have contractual relationships in the form of Power Purchase Agreements (PPA). These can be forward contracts where the supplier agrees to deliver a certain volume of electricity to the consumer in the future, at a price agreed in advance. The contract may also be a Contract for Differences (CFD), which is a purely financial contract. A supplier and a consumer agree on a price for electricity to be supplied over a given period (the strike price). If the Pool price is above the strike price, the consumer pays the supplier the difference between the two prices, while if the strike price is below the Pool price, the supplier pays the difference to the consumer. Options are also available.

The second example is illustrated by the Nord Pool. In addition to the spot market (Elspot), the Nord Pool comprises a financial market (Eltermin) with a view to offering operators heading and risk management services. Eltermin contracts comprise three major categories; forward contracts, futures contracts and options. These concepts are explained in detail in Chapter 16.

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Chapter 16

Risk management – in electricity markets

16.1 Introduction

Risk is the hazard to which we are exposed because of uncertainty [1]. Risk is also associated with decisions. Where there are no uncertainties and no alternatives, there is no risk. Decisions that we make can affect these uncertainties and can reduce hazards.

Under regulated markets there were fewer uncertainties and risks because tariffs were almost fixed. With deregulation, electric power markets are volatile, prices change within a short time, and risks can be serious. In the deregulated market of electric power, electricity is a commodity and consumers have choices, correspondingly generators are competing among each other. This has created opportunities mainly for consumers and risks for producers, which need to be hedged.

Trading refers to transactions that take place directly between two parties or through an organised exchange. Although commodities trading in agricultural products have been established since the middle of the 19th century, it was only in 1996 that electricity future started to be traded in the New Year Mercantile Exchange in the US.

It is believed that the California electricity crises of 2000-2001 and its serious financial and economic consequences were due to inadequate proper hedging through long-term supply contracts. The last two or three decades of electricity market reforms have shifted most of the financial risks from consumers to producers. Such restructured electricity market can pose large financial risks to producers. Therefore, to limit these risks regulatory mechanisms were introduced, such as price caps and various capacity market mechanisms, through balancing risks between consumers and producers, limiting price volatility and ensuring investments recovery to producers.

The proliferation of new renewables, particularly wind, in the European electricity market and also in the US, introduced another serious risk factor into the market that can have both serious technical challenges (availability, dispatching) and financial risks (trade price as well as electricity export). These challenges are explained in Chapter 15 and will not be repeated here.

Financial risk management is a rather specialised and sophisticated subject that is now adequately covered in the literature [2].

16.2 Qualifying and managing financial risks

Participants in the deregulated generation market can face significant price risks through unpredictable 'price spikes' when there is shortage of generating capacity due to plant outages or unpredictable high demand brought about by extreme weather. Energy 'volume risks' can also occur when market participation have uncertain volumes or quantities of consumption or production.

Electricity retailers and generators are particularly exposed to such risks and in order to protect themselves they enter into 'hedge contracts' with each other. There are many forms of hedge contracts; however, the two most common are simple 'fixed price forward' for physical delivery and 'contracts for differences' where the parties agree a strike price for future periods. Many other forms of hedging are traded in the electricity markets, such as: 'Virtual Bidding', 'Swing contracts', 'Financial Transmissions Rights', 'Call options and put Options', etc. [3]. All these are designed to manage and transfer financial risks between market participants.

The price index in the market is usually referred to as the 'spot' or 'pool' price. In case of contract for difference, if the price index is higher than the 'strike price' the generating utility will refund the difference. Simultaneously, the electricity distributor (retailer) will refund the difference when the actual price at the moment is less than the 'strike price'.

16.3 Quantifying and managing risk

We have to start by trying to quantify risk and methods for reducing and managing such risks by hedging or other means. This needs understanding of the risk management terminology and jargon, which is summarised below.

Robustness, the most fundamental measure of risk, is the likelihood that a particular decision will not be regrettable. If the decision-maker's choice turns out to be optimal no matter what nature chooses, his choice is robust. (Use of the term 'optimal' implies that the decision-maker has a single objective. Robustness is also defined in multiple-objective situations.) More often, his choice is optimal only for a subset of nature's possible outcomes. Suppose that there is a probability of 0.60 that an outcome or realisation materialises. Then the choice is robust with probability 0.60.

Exposure is a measure of loss if an adverse materialisation of uncertainties occurs for a particular choice. Sometimes exposure can be measured in dollars, but often not. It is difficult to attach a dollar value to loss and inconvenience for a power breakdown.

A hedge is an option that reduces risk. *Derivatives* are instruments to achieve this hedging. A derivative is a financial instrument (such as futures or options contract). It is so-called because it derives its value from a related or underlying asset. An underlying asset is the specific asset on which a financial instrument is based. Derivatives are not securities at all. They are just agreements between two parties with opposite views on the market to exchange risk. For the hedger, derivatives ultimately help protect against price increases and assist in lowering funding costs and obtaining better currency exchange rates in the international financial markets. Derivatives are a form of insurance against market swings that affect the value of underlying assets. Examples of derivative instruments are forwards, futures, options and swaps [4, 5].

Traded option is an option that gives the firm the right (but not the obligation) to buy or sell an asset in the future at a price that is agreed upon today. There is a huge volume of trading in options that are created by specialised options exchanges. For example, you can deal in options to buy or sell common stocks, bonds, currencies and electric power as a commodity.

Futures – a futures contract is an order that you place in advance to buy or sell an asset or commodity like electricity. The price is fixed when you place the order, but you do not pay for the asset until the delivery date. Futures markets have existed for a long time in commodities such as wheat, soya beans and copper. The major development in the 1990s occurred when the futures exchanges began to trade contracts on energy and electricity (see Section 16.3.2).

Forwards – futures contracts are standardised products bought and sold on organised exchanges. A forward contract is a tailor-made futures contract that is not traded on an organised exchange. The principal business in forward contracts occurs in the foreign exchange market, where firms that need to protect themselves against a change in the exchange rate buy or sell forward currency through a bank. Such forward contracts are increasingly being used in electrical power.

Traders in derivatives are usually referred to as hedgers. *Hedging* is taking a position in one security or asset to offset the risk associated with another security or asset. They are meant to gain protection and have some control over risk. Hedging instruments include forward sales contracts, future concepts, swaps and options. Hedging is meant to reduce risk and improve returns. This is achieved by balancing the gain/loss (in the physical market with the loss/gain in the derivative market).

Derivatives are the best way to hedge against adverse risk. Two types of hedging schemes allow protection in falling or raising markets.

Short hedge – a short hedge is a commitment to sell a product in the future at an agreed price. A decline in cash market prices is offset by profits in the futures market. The opposite applies when prices rise. A short hedge offers protection against falling prices.

Long hedge – a long hedge involves a commitment to purchase a commodity in the future at a fixed price. A long hedge locks in the price of the commodity (gas, electricity). It offers protection against rising prices.

16.3.1 Forward contracts

A forward contract is an agreement between two parties to buy or sell an asset at a certain future time for a specified price.

Price for a forward contract is

$$F = S\,e^{r(T-t)}$$

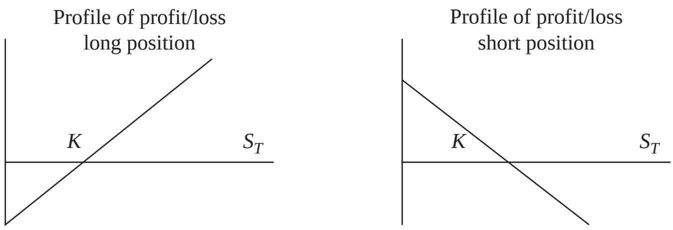

Figure 16.1 Profit of long and short positions

where F is forward price, S is price of the asset at time t, K is delivery or strike price, T is time of maturity of the contract, t is current time and r is risk-free rate of the economy.

Figure 16.1 depicts the profit/loss of a forward contract. The payoff depends on whether the investor took a long or short position. For a long position, the forward contract has a profit if the price S_T is larger than the strike price K. The contract ends with a loss otherwise. In contrast, for a short position, the contract makes a profit if the price S_T is smaller than the strike price K. This is because the writer of the contract receives a price higher at delivery than the current market price.

The forward contract allows customised expiration dates and requires no performance bond.

16.3.2 Futures contract

A futures contract is an agreement between two parties that has standardised terms and conditions, where the seller guarantees to deliver an asset at a specified price at a specified time in the future and the buyer guarantees the acquisition of that asset at the specified price.

Prices of future contracts are calculated with the same formula above. Therefore, both future and forward priced contracts are similarly priced. The future price of the derivative depends on the underlying price of the asset, the maturity date of the contract and the risk-free rate of the economy. In ideal situations and under the same terms, futures prices are equal to forward prices. However, future contracts differ from forward contracts, because future contracts have specified maturity dates whereas a forward contract could have any maturity date. With a forward contract the outcome is usually currency cash while in futures contract it is a physical deliverable. Also, futures contracts require a down payment (like a performance bond) and forward contracts require no performance bond.

The following example is kept simple with the purpose of illustrating how a futures contract is used to hedge the risk in a rising market and how to avoid or minimise one's losses in a declining market.

An energy company sells electricity in the spot market. The company sells blocks of 500 MW at an hourly price.

(a) Assumption I: the party sells a futures contract (short hedge) to protect against falling markets.

1. *Electricity prices fall*. Next month, the energy company will be selling 500 MWh in the spot market. The current price is \$50 MWh^{-1}, and in order to lock in this price, it sells a futures contract of 500 MWh through the exchange at \$50 MWh^{-1} for the next month. The company targets revenue of \$25 000.00.

   The electricity prices fall to \$40 MWh^{-1}. The company receives from the spot market (500) (\$40) = \$20 000. At the same time, the company buys back the futures contract that had a strike of \$50 at the new market value of \$40, realising a gain of (\$10)(500) = \$5 000. Total revenue is \$25 000.

   Following the market conditions, the company incurs a loss in the physical market, which is offset by a gain in the futures market.
2. *Electricity prices rise*. The electricity prices rise to \$60 MWh^{-1}. The company buys back the futures contract that had a strike set at \$50 MWh^{-1} at a loss of \$5 000 and sells the 500 MWh on the commodity market for \$30 000. The total revenue is \$25 000.

(b) Assumption II: the party buys a futures contract to lock in a future price.

1. *Electricity prices rise*. An energy broker commits to buy 500 MWh for February delivery from an energy producer. The broker enters into a futures contract for \$50 MWh^{-1} for a total cost of \$25 000.

   The energy company buys energy from the spot market at \$60 MWh^{-1} and sells the electricity futures contract for \$60 MWh^{-1}. The energy producer makes a \$10 MWh^{-1} profit in the futures market, which offsets his loss in the physical market.
2. *Electricity prices fall*. A large industrial user commits to buy 500 MWh of firm power that follows the spot market price for the next month. The user buys a futures contract for \$50 MWh^{-1} for a total cost of \$25 000.

   The electricity prices fall to \$40 MWh^{-1}. The large industrial user buys electricity directly from the spot market. The large industrial user sells its futures contract at a loss of \$10 MWh^{-1}.

   The loss in the futures contract is offset by the gain in the spot market.

16.3.3 Options

An option is a type of contract that gives the purchasing party the right to buy or to sell for a certain price (called the exercise or strike price) and at a certain date (called the expiration date *T*, exercise date or maturity date). The right to perform a financial transaction has a financial value called a premium. The buyer of the option pays a premium for the right (but not the obligation) to buy or sell the underlying asset (unlike the right or obligation to buy or sell a forward or futures contract, options are more versatile). Only a small percentage (approximately 30 per cent) of all purchased option contracts is exercised, the remaining bulk of which serves to hedge the exposure to the changes in the market price.

16.3.4 Swaps

A swap is an agreement between two parties to exchange one set of cash flows based on a notional amount linked to a floating index in exchange for another set of cash flows based on the same notional amount linked to a fixed index.

Swaps have revolutionised financial risk management and represent one of the greatest business opportunities in this area. Following the futures market in popularity, swaps are greatly utilised in the commodity markets; unlike the participants in a derivative exchange who have no knowledge of their counterparties and are willing to extend credit to them over a period of time.

There are fixed-fixed, fixed-floating and floating-floating swaps. The most common ones are fixed-floating swaps, which help a company that takes a loan at an adjustable interest rate to lock in the rate and thus eliminate any risk. The underlying asset of a swap could be a currency, interest rate, equity or commodity.

Fixed to floating commodity swaps are common. An example will be a mining company that supplies coal to a generation utility. The mining company enters into an annual swap contract where it agrees to receive from the generation utility monthly payments based on delivery of 1 000 tons of coal per month at the rate of \$1 per one million BTU (\$28 ton^{-1}).

In such an arrangement the mining company delivers coal each month with the spot market price per ton multiplied by 1 000 and each month the company receives \$28 multiplied by 1 000.

Such an arrangement allows the mining company to receive fixed amounts. Simultaneously the mining company will deliver its coal at spot market value, which translates into negative or positive cash flow, as the spot market value is in excess or less than the fixed amount of \$28 000.

There are several types of swap.

Commodity swap. This is an agreement between two parties to exchange cash flows based upon the difference between the fixed and floating prices of the same underlying principal. The exchange is done in a common currency.

Interest rate swap. One party agrees to pay to the other party a cash flow equal to a fixed interest rate on a notional amount. The exchange is done in the same currency. This is the most common swap.

Currency swap. This form of swap involves exchanging principal and fixed-rate interest payments on a loan in one currency for principal and fixed-rate interest payment on an approximately equivalent loan in another currency.

Differential swap. This is a swap where a floating interest rate in the domestic currency is exchanged with a floating interest rate in a foreign currency as applied to the same notional principal.

There are endless combinations of swaps and other derivatives.

An example of a fixed-floating commodity swap contract is shown here. Suppose that an energy and services company supplies energy to a large industrial customer, in the form of 100 gas units each month for the next five years. The energy company enters into a semi-annual swap contract where it agrees to receive

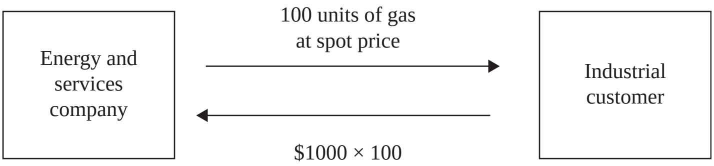

Figure 16.2 Fixed-floating commodity swap contract

from the industrial customer a fixed monthly charge at the price of $1 000 per unit in return for 100 gas units supplied. This swap is illustrated in Figure 16.2.

The exchange of payments takes place as follows:

- the company delivers gas each month with unit spot market value multiplied by 100 units;
- the company receives $1 000 multiplied by 100 units each month.

This swap allows the company to receive a fixed amount, and in return the company will deliver its product at spot market value that translates into negative or positive cash flow as the current market value is in excess of, or less than, the fixed amount of $100 000.

Typically, this type of transaction is made through a financial institution that has the role of transforming a floating price (spot market) into a fixed value. Hedging allows the risk manager to reduce the risk exposure in highly volatile markets. Futures and options are often-used tools to manage financial risk.

16.3.5 Political risk

Political risk is very difficult to hedge. Such risk can come through changes in legislation and environmental agendas. In some cases, as in environmental legislation for SO_2 reduction where there is market for emission permits, hedges can be constructed. The same prospects exist for possible carbon taxation legislation. Political legislation for closing nuclear plants is a major political risk.

16.4 Decision making

A large part of engineering work involves making decisions [4] of various kinds. In fact, decision making ranks with innovation in its importance to the design process. The aim of a decision-making process is to come up with a decision that is optimal in some sense – i.e. the most cost-effective, giving the longest life, involving the lowest operating cost, leading to the most aesthetically pleasing product, and so on. Often, when such decisions are made, the decision maker is confronted with the problem of uncertainty. Intuition and past experience play a prominent role in the engineering decision-making process, but as important as they are, they are often

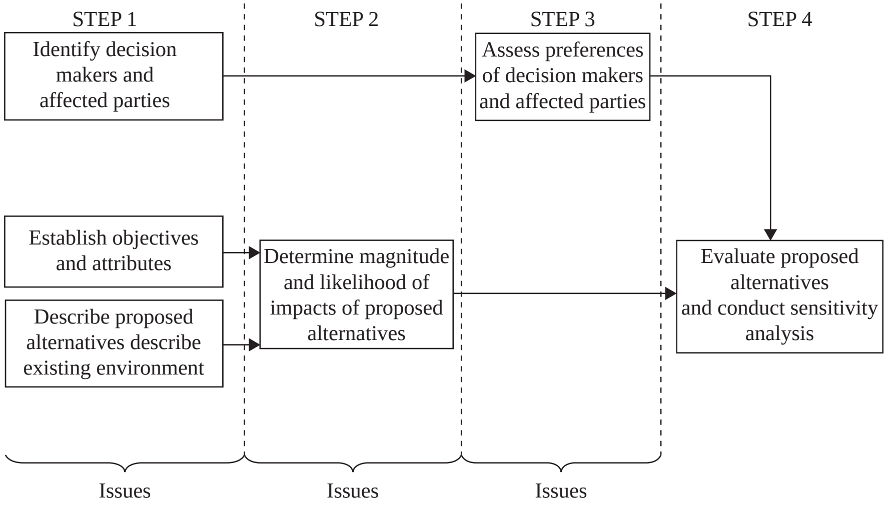

Figure 16.3 Schematic representation of the components of decision analysis [4]

insufficient vehicles to bring us to the best decision. In such cases, a rational approach using probabilistic tools permits proper modelling and analysis of uncertainty.

In any decision analysis, the set of decision variables should first be identified and defined. In a decision-making context, the engineer identifies courses of action or alternatives. Next, a prediction is made of the result of each course of action. For alternatives, we predict the initial cost, the maintenance costs, the life, the risk of failure and other important variables. Each course of action results in a selection of certain maintenance policy or, in terms of the decision analysis, results in certain outcome.

Before a decision is made, we attempt to decide on the desirability of each outcome by attaching some value to it. Finally, we make our decision by selecting the outcome with the greatest value; i.e. the entire decision-making process can be viewed as an optimisation exercise.

16.4.1 The decision-making process

Any decision-analysis problem can be broken into four steps: (1) structuring the problem, (2) assessing the possible impacts of the alternatives, (3) determining the value structure and (4) synthesising the information obtained in steps (1) to (3) to evaluate and compare the alternatives. There are usually several issues that have to be addressed in any particular problem. In any specific case, the resolution of these issues may be crucial to success. Therefore, all of these issues have to be addressed in the decision model. Figure 16.3 summarises the basic steps in the decision-analysis approach and shows some major issues related to a technology choice in power systems [4, 6].

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Appendix A

Levelised cost of electricity generation

Table A.1 Demonstration of how levelised costs are calculated

Step 1 Gather plant data and assumptions

Capex costs:	**Opex costs:**	**Expected generation data:**
- Pre-development costs - Construction costs* - Infrastructure cost* (*adjusted over time for learning)	- Fixed opex* - Variable opex - Insurance - Connection costs - Carbon transport and storage costs - Decommissioning fund costs - Heat revenues - Fuel prices - Carbon costs	- Capacity of plant - Expected availability - Expected efficiency - Expected load Factor (all assumed baseload)

Step 2 Sum the net present value of total expected costs for each year

$$\text{NPV of total costs} = \sum_n \frac{\text{total capex and opex costs}_n}{(1 + \text{discount rate})^n}$$

n = time period

Step 3 Sum the net present value of total expected generation of each year

$$\text{NPV of electricity generation} = \sum_n \frac{\text{net electricity generation}_n}{(1 + \text{discount rate})^n}$$

n = time period

Step 4 Divide total costs by net generation

$$\text{Levelised cost of electricity generation estimate} = \frac{\text{NPV of total costs}}{\text{NPV of electricity generation}}$$

Table A.2 Levelised cost estimates for projects starting in 2013, at 10% discount rate, values in £ per MWh

	CCGT	**OCGT**	**Nuclear-FOAK**	**Onshore >5 MW (UK)**	**Biomass conversion**	**Offshore R2**	**Offshore R3**	**Large scale solar PV**
Pre-development costs	0	5	6	7	1	4	6	0
Capital costs	9	54	64	70	9	77	78	134
Fixed O&M	4	23	11	18	10	31	36	24
Variable O&M	0	0	3	5	1	1	0	0
Fuel costs	49	73	5	0	86	0	0	0
Carbon costs	18	26	0	0	0	0	0	0
CO_2 capture and storage costs	0	0	0	0	0	0	0	0
Decommissioning and waste fund	0	0	2	0	0	0	0	0
Total levelised costs	80	181	90	101	108	113	120	158

Source: Department of Energy & Climate Change: *Electricity Generation Costs 2012*, July 2013.
All estimates are in real 2012 prices. FOAK: First Of A Kind

Table A.3 Load factor assumptions for selected technologies

Technology	**Average lifetime load factor (net of plant availability)**
CCGT	93%
OCGT	7%
Nuclear-FOAK	91%
Gas-CCGT with post-comb. CCS-FOAK	93%
Coal-ASC with oxy-comb. CCS-FOAK	93%
Coal-IGCC with CCS-FOAK	90%
Onshore >5 MW (UK)	28%

Appendix B

Social discount rate for climate change evaluation

The social discount rate to utilise for climate change evaluation is the one decision makers utilise to maximise a social discount function that is the discounted value of utility of consumption over some indefinite time span. It refers to discount future welfare and not future goods or income.

The intergenerational social welfare we are trying to maximise is

$$W = \int_0^{\infty} U[c(t)]e^{-\rho t}dt$$

Here, $c(t)$ is the per capita consumption of generation, $U[.]$ is the utility function used to compare the relative value of different levels of consumption per generation and ρ is the time discount rate applied to different generations. For simplicity constant population is assumed to be normalised to 1.

Optimising the social welfare function with constant population and constant rate of growth of consumption per generation, g^*, yields the standard equation for the relationship between the equilibrium real return on capital, r^*, and the other parameters: $r^* = \rho + \alpha g^*$. α is the consumption elasticity, which is the elasticity of the marginal utility of consumption.

In other form, the social welfare function W can be presented as

$$W_0 = \sum \left(\frac{1}{1+\rho}\right)^t U_t C_t$$

where W_0 is the social welfare evaluated at time zero, ρ is the social rate of time preference (sometimes referred to as the utility discount rate), C_t is the consumption in year t, and U_t is the utility at time t.

Sources:
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Appendix C

Calculating the economic benefit of renewables

The following is a simplified short computation methodology for assessing the economic benefit of renewables. It is meant to assist in evaluation of such benefits for quick decision making. Power system simulation (with and without renewables), as explained in Chapter 12, with more sophisticated Monte Carlo algorithm is necessary for accurate assessment.

C.1 Wind energy-benefits and costs

It is proposed that winds blow haphazardly and are difficult to predict in short term (minutes or few hours). Therefore, the security of the power generation dictates that installed system capacity will be adequate to meet peak demand with or without wind capacity. However, when wind capacity is large, say higher than 5 per cent of the generating system, wind contribution to reliable system capacity can extend to only 20 per cent of wind capacity. Therefore, the benefits of wind facilities are for reducing fuel consumption, reducing carbon emissions and exporting to other regions across border if and when profitable; this is besides fringe benefits, like enhancing energy independence.

Annual cost of wind generation can be assessed from the methodologies detailed in earlier chapters and are as follows:

1. Annual cost:

   (a) annual levelised cost plus fixed O&M cost per kW per year + annual operational O&M cost. (The construction cost will include any transmission and/or strengthening of the grid.)

   (b) the impact of the renewable facility on the other dispatched facilities in the generating system, in reducing their load and correspondingly their efficiency. Since dispatching cost of wind is almost zero, it will replace other forms of generation, mostly nuclear and dispatchable facilities like CCGT and coal plants that cannot be shut down or ramped up and down that quickly.

2. Benefits can be assessed as follows:

   annual reduction in fuel cost + annual value of carbon abated + net income of energy export (if any and if higher than fuel cost)

C.1.1 Example of a regulated utility investment

Let us now consider a wind plant that costs \$2 000 per kW (including transmission and fixed O&M cost).

Such plant has an expected capacity factor of 25 per cent; therefore it will generate 2 190 kWh per annum for 20 years.

The discount rate (opportunity cost) is 8 per cent.

Utilising the annuity factor tables, the annual fixed cost will be \$2 000 $\div$ 9.82 (discount factor) = \$ 204, plus an assumed \$36 annual fixed O&M cost. That is \$240, equivalent to 10.95 cents per kWh

Annual operational cost (O&M) is to be estimated at \$20 per MWh (i.e. 0.91 per kWh).

$$\begin{aligned}\text{Total cost per kWh} &= 10.95\text{c} + 0.91\text{c}\\ &= 11.86\text{c per kWh}\end{aligned}$$

Now consider benefits. Assume such wind generation will mainly reduce the output of fossil plants in the system by 2 190 kWh for every kW of wind facility. Also assuming average efficiency fossil plant generation of around 35 per cent, then fuel requirement is 9 750 btu/kWh. With a cost to the utility of \$10 per mbtu, this will be c9.75 per kWh.

As indicated earlier, due to intermittency of wind and difficulty in shut down and restarting other plant, the other plant will work at partial load and will result in reduced efficiency. The amount of this efficiency reduction will depend on the composition of the system, extent of nuclear and base-load coal and CCGT sets and the extent of wind penetration in the system (it can be neglected if penetration is limited (<5 per cent)). This efficiency penalty can be between zero (with low wind contribution) and 20 per cent in case of major wind system component. Let us assume in this case it is 10 per cent.

Correspondingly, the wind benefits will be

$$9.75\text{c per kWh} \times 0.9 = 8.8\text{c per kWh}$$

To this must be added carbon costs and income from electricity exports. If both of these do not exist, then the benefits of wind of 8.8c per kWh will be less than its total cost of 11.86c per kWh.

This means that the plant will not be built unless there is subsidy for the difference or there is feed-in tariff imposed on consumers to cater for the difference.

In case of a system with an average carbon emission of 0.75 kg of CO_2 (per kWh) and with carbon price of \$40 per ton (4c per kg), the value of carbon reduction will be $0.75 \times 4\text{c} \times 0.9 = 2.7\text{c}$.

So the economic value of wind is $8.8 + 2.7 = 11.5\text{c}$ per kWh, which is comparable to the cost that will encourage, taking invisibles into consideration, to invest in wind energy.

C.1.2 A private investor investing in wind installation

In this case the investor will be selling in the spot market. The spot market price will depend on the marginal cost of electricity at that particular time and which can vary by a wide margin all through the day and also all through the year. If the wind component in the system is high (say >5 per cent) the sudden appearance contribution of wind will considerably reduce the marginal cost of the generating system and will also reduce the load on other operating facilities that are connected, thus slightly reducing their efficiency and increasing their fuel cost per kWh.

It is not possible to do approximate calculation here, but the risks for the private investors are high. They can only be mitigated if (1) there is a high carbon price and/or a high subsidy paid to the investor for his output or (2) the investor is getting a fixed price per kWh delivered to the network, and the investor reckons that this price, with his or her expected output, will be higher than his annual cost.

C.2 Cost and benefits of solar energy

There are wide arrays in investing in solar plants – by utilities, private investors, individual households, leasing photo-voltaic (PV) plants on roofs, etc. and the varieties are increasing and investments proliferating. Also investments can be in PV plant or concentrated solar panel (CSP). Therefore, it is not possible to cover all varied possibilities, but we shall consider here a few of them presented in simple terms to allow developing into more sophisticated cost–benefit analysis by investors.

C.2.1 A utility investing in PV plant

Consider the case of a utility investing in a solar plant in a relatively sunny area, with an equal day and evening peaks, but mostly high summer demand.

Assume cost of investment and system connections at \$2 500 per KW.

annual fixed cost = \$2 500 ÷ 9.82 (annuity factor) = \$245 per kW per annum,
plus \$55 per kW per annum annual O&M, i.e. total of \$300 per annum

Such a plant will operate at an average capacity of 15 per cent during the winter half of the year and 35 per cent during the other half of the year – the summer. During summer months, because of variation in timing between PV output and peak system demand, half the solar plant output will save the operation of peak plant (single-cycle gas turbine (SCGT) at 20c per kWh) and the other half will save output of medium-load plant (at 12c per kWh). In winter mostly medium load plant will be saved.

PV plant output during the winter half of the year will be

$$1 \text{ kW} \times 4380 \text{ hours} \times 15\% = 657 \text{ kWh}$$

With a cost of (\$300 ÷ 2) ÷ 657 = 22.8c per kWh

During the summer months

Output = 1 kW × 4 380 hours × 35% = 1 533 kWh

With a cost of ($300 ÷ 2) ÷ 1 533 kW = 9.78c per kWh

Benefits to the utility will be saving of fuel in winter months of 657 kWh × 12c = $79.

Also saving fuel in summer month of [(1 533 kWh ÷ 2) × 20c] + [(1 533 kWh ÷ 2) × 12] = $245.

Total benefits = $245 + $79 = $324 per annum + cost of carbon saved.

These will be contrasted with the costs of $300. Therefore, the utility will be advised to go ahead with this profitable PV investment.

Note that we did not allow here for any generation system efficiency reduction, because of the relative dependability of solar particularly during summer. Other thermal facilities will be programmed and dispatched taking into consideration the reliability of the solar presence.

C.2.2 A utility investing in CSP plant

The CSP plant, with storage, will significantly improve the capacity factor since it will allow meeting both day and evening peaks. Depending on the technology of the plant, and location, production at varying degrees can stretch to 12 hours in winter and 16 hours in summer with average load factors of 25 per cent of capacity in winter and 50 per cent in summer.

Assuming cost of the plant with infrastructure and system connections is $4 000 per kW installed.

Annual fixed cost = $4 000 ÷ 9.82 (discount factor) = $407 per kW per annum, plus annual O&M costs estimated at $70 per kW per annum, i.e. a total of $477 per kW per annum.

The benefits in production will significantly increase. They will amount to:

production during winter of 4 380 hours × 25% = 1 095 kWh
production during summer of 4 380 hours × 50% = 2 190 kWh
i.e. a total of 3 285 kWh

As expected the amount of the CSP production will replace fossil fuels production which vary from one system to another. Here we shall maintain earlier assumptions that the CSP plant in winter will only replace medium-load plant at a fuel cost of 12c per kWh and in summer its output will save 50 per cent of peaking plant and the other 50 per cent of medium plant (average 16c per kWh).

Therefore, savings in winter will be

1095 kWh × 12c = $131

and in summer savings will be

2190 kWh × 16c = $350

i.e. a total of $481 per annum + carbon cost

This is against an annual cost of $477, i.e. with net benefits of $4 per kW installed, plus carbon cost savings, which can be significant.

The adoption of CSP plant investment in this simplified example is highly recommended.

C.2.3 Domestic PV installations

Let us consider the case of a household investing in a private rooftop PV facility of 5 kW at a cost (including installation and connection) of $3 000 per kW.

The owner will expect a return of 10 per cent and amortising his or her investment over 10 years.

His or her levelised annual cost will be

$$(5 \times \$3000) \div 6.14 \text{ (discount factor)} = \$2443 \text{ per annum}$$

To be added to this is the fixed monthly fee (if any), which the utility will impose on his or her connection to the distribution grid, so that he or she draws on the grid's electricity during periods of no sunshine. Let us assume this fee to be $75 per month.

Therefore, total annual cost $= 2\,443 + (12 \times 75) = \$3\,343$.

The benefits:
The main benefits of course are saving on the utility bill assuming his or her consumption to be 1 000 kWh/month at a flat tariff of 20c per kWh. Also assume that the plant operates at full load for an average of 5 hours in winter and 10 hours in summer.

energy savings in winter $= 5$ kW $\times$ 5 hours $\times$ 30 days $\times$ 6 months $= 4\,500$ kWh
Summer savings will be twice as much.
Total savings $(4\,500 + 9\,000)$ kWh $\times$ 20c $= \$2\,700$ per year

Therefore, it is not worthwhile to undergo this PV installation.

But consider that the utility charges are in increasing tariff tiers, as is usually the case in most countries, i.e. the higher the monthly consumption the higher is the tariff per kWh. Part of this household consumption falls in the 30c per kWh tier. It is expected that the installation output will fall within this high tier and correspondingly save the consumer.

$$(4500 + 9000) \text{ kWh} \times 30\text{c} = \$4050 \text{ per annum}$$

This is well above the consumer's levelised annual cost. Therefore, the consumer is well advised to go ahead with this PV rooftop installation.

This is a simple example based on net energy metering (NEM) arrangement. There are many variations such as leasing arrangements and selling to the grid. Such possibilities are proliferating and it is not possible to cope with the increasing variations in erecting roof-top PV installations. However, two points need to be stressed:

1. The utility need to impose a fixed monthly fee for connecting the household and his or her rooftop installation to the grid. This fee is a fair charge for allowing the household to benefit from the grid facilities during the unavailability of the rooftop output.

2. NEM is beneficial to the consumer; but once it is widely used, it poses serious financial problems to the utility, and also to other consumers, which have been explained in section 12.10.

Recently, rooftop PV installations are increasingly been provided by long-term leasing, for as low as $70 per month. If the household reckons that his monthly bill will drop, at least, by this amount it will be beneficial for him to go ahead with this leasing arrangement; however the consumer will bear any tariff change risks.

Appendix D
Glossary

The following is a glossary of financial, economic and technical terms used in this book as well as few other terms that are of interest. Sources for definition are in References [1], [2] and [6] of Chapter 3.

Amortisation Gradual repayment or writing off of an original amount. Depreciation is a form of amortisation. The capital recovery factor (see below) is composed of an interest component and an amortisation component.

Annual equivalent A stream of equal amounts paid or received annually for a period such that by discounting at an appropriate interest rate it will have a specified present worth. Determined by multiplying an initial value by the capital recovery factor for the appropriate interest rate and period. To ‘annualise’ is to find the annual equivalent of a value.

Annuity Investment that produces a level stream of cash flows for a limited number of periods.

Annuity factor The present value at a discount rate r of an annuity of £1 paid at the end of each n periods:

$$\text{annuity factor} = \left[\frac{1}{r} - \frac{1}{r(1+r)^n}\right]$$

The annuity factor is obtained from annuity tables in the Financial References.

Appraisal Analysis of a proposed investment to determine its merit and acceptability in accordance with established decision criteria (mostly carried out by banks and developmental agencies).

Arbitrage Purchase of one security and simultaneous sale of another to give a risk-free profit.

Basis risk Residual risk that results when the two sides of a hedge do not move exactly together.

Benefit–cost ratio (B/C ratio) Discounted measure of project worth. The present worth of the benefit stream divided by the present worth of the cost stream. Often abbreviated to ‘B/C’, also frequently called the ‘cost–benefit ratio’.

Benefits The incremental value of product sales or cost reductions attributable to an investment. In case of the ESI, benefits can sometimes be represented in the form of kilowatt-hours (kWh).

Beta Measure of market risk.

Bond Long-term debt.

Border price The unit price of a traded good at a country's border. For exports, the free-on-board (FOB) price; for imports, the cost–insurance–freight (CIF) price.

Break-even point The level of product sales at which financial revenues equal total costs of production. At higher volumes of production and sales financial profits are generated.

Call option Option to buy an asset at a specified *exercise price* on or before a specified exercise date (cf. *put option*).

Cap An upper limit on the interest rate on a *floating-rate note.*

Capital budget List of planned investment projects, usually prepared annually.

Capital rationing Shortage of funds that forces a utility to choose between projects.

Capital recovery factor (CRF) or equivalent annual cost Can be used to convert a sum of money into an equivalent series of equal annual payments, given a rate of interest and total period of time. The CRF for £1 at an interest rate of 12 per cent and a period of four years is £0.3292, as shown in the following schedule:

$$\text{principal amortisation} + \text{interest} = \text{CRF}$$

	Principal	**Interest**	**CEF (total)**
1	0.2092	0.1200	0.3292
2	0.2343	0.0949	0.3292
3	0.2624	0.0668	0.3292
4	0.2941	0.0351	0.3292
Total	1.0000	0.3168	

The use of the CRF to compute annual capital charges is generally superior to the use of accounting depreciation allowances and interest expenses for project appraisal purposes.

CAPM Capital asset pricing model.

Cash flow In its simplest concept, this is the difference between money received and money paid out. As used in benefit–cost studies, the net benefit stream is anticipated for a project. Net benefits are available for the service of borrowed funds (amortisation, interest and other charges), payments of dividends to shareholders and the payment of profit taxes.

CCS Carbon capture and storage

CIF The landed cost of an import (cost, insurance and freight) on the receiving country's dock, including the cost of international freight charges and insurance, before the addition of domestic tariffs or other taxes and fees.

Compound interest Reinvestment of each interest payment of money invested to earn more interest (compare with *simple interest*).

Compounding The process of finding the future value in some future year of a present amount growing at compound interest.

Constant prices or **real prices** Prices that have been adjusted to remove general price inflation.

Contract for difference (or **CFD**) is a contract between two parties, typically described as 'buyer' and 'seller', stipulating that the seller will pay to the buyer the difference between the current value of an asset and its value at contract time.

Contingency allowance An amount included in a project account to allow for adverse conditions that will add to baseline costs. Physical contingencies allow for physical events and unexpected costs; they are included in both the financial and the economic analyses. Price contingencies allow for general inflation; in project analysis they are omitted from both the financial and the economic analyses when the analysis is done in terms of constant (real) prices.

Continuous compounding Interest compounded continuously rather than at fixed intervals.

Covariance Measure of the co-movement between two variables.

Covenant Clause in a loan agreement.

Conversion factor (standard conversion factor) A number, usually less than 1, that can be multiplied against a domestic market price of an item to reduce it to an equivalent border price. The simple version of the standard conversion factor is the ratio between a country's foreign trade turnover before and after import and export taxes (or subsidies).

Concentrated solar power (**CSP**) Systems that use mirrors or lenses to concentrate a large area of sunlight, or solar thermal energy, onto a small area. Electrical power is produced when the concentrated light is converted to heat, which drives a steam turbine connected to an electrical power generator, or powers a thermo-chemical reaction.

Correlation coefficient Measure of the closeness of the relationship between two variables.

Cost of capital Opportunity cost of capital.

Costs Costs are incurred to acquire project inputs such as buildings, electrical facilities and machines, materials, labour and utilities. In economic evaluation certain outlays, such as the payment of profit taxes, are costs to the project but not the country. Such outlays are properly treated as transfers of project surplus rather than costs for the purpose of calculating net present value or internal rate of return.

Covariance Measure of the co-movement between two variables.

Crossover discount rate The rate of discount that equalises the net present value of benefit or cost streams, often applied to the cost streams of mutually exclusive project proposals. At a lower rate of discount 'A' is superior, whereas at a higher rate of discount 'B' is superior.

Current prices or **nominal prices** Prices that have not been adjusted (deflated to eliminate general price inflation).

Cut-off rate A rate of return established as a 'threshold' below which projects should not be accepted. See *opportunity cost of capital*.

DCF Discounted cash flow.

Debt service A payment made by a borrower to a lender. May include one or all of the following: (1) payment of interest, (2) repayment of principal and (3) loan commitment.

Decision tree The diagram used in an analytical technique by which a decision is reached through a sequence of choices between alternatives. It is also a method of representing alternative sequential decisions and the possible outcomes from these decisions.

Deflation The act of adjusting current to constant prices. The arithmetic (division) is the same as for discounting.

Depreciation The anticipated reduction in an asset's value brought about through physical use or gradual obsolescence. Various methods are used: straight line, declining balance, accelerated, etc. The important thing to remember is that depreciation charges do not represent cash outlays and should not be included in financial or economic cash flows.

Discount factor How much 1 at a future date is worth today. Also called the 'present worth factor' and the 'present worth of 1'.

Discount rate A rate of interest used to adjust future values to present values. Discounting a future value to the present value is the exact opposite of compounding a present value forward to a future value.

The social-welfare equivalent discount rate (r_{sw}) is the rate that translates marginal change in consumption on the date onto the social-welfare-equivalent marginal change in consumption at time zero.

Discounted cash flow analysis Analysis based on the net incremental costs and benefits that form the incremental cash flow. It yields a discounted measure of project worth such as the net present worth, internal rate of return, or net benefit–investment ratio.

Discounting The process of finding the present worth of a future amount.

Distortion A distortion exists when the market price of an item differs from the price it would bring in the absence of government restrictions.

Dynamic pricing – time-based pricing Refers to a type of offer or contract by a provider of a service or supplier of a commodity in which the price depends on the time when the service is provided or the commodity is delivered. The rational background of time-based pricing is expected or observed change of the supply and demand balance during time. Time-based pricing includes fixed time-of use rates for electricity and public transport, **dynamic pricing** reflects current supply–demand situation or differentiated offers for delivery of a commodity depending on the date of delivery (future contract). Most often time-based pricing refers to a specific practice of a supplier.

EBIT Earnings before interest and taxes.

Economic prices Also known as ‘efficiency’ prices. Prices believed to reflect the relative scarcity values of inputs and outputs more accurately than market prices, owing to the influence of tariffs and other distortions in the latter.

Economic rate of return The internal rate of return of a cash flow expressed in economic prices. It reduces the net present value of the cash flow to zero.

Equity An ownership right or risk interest in an enterprise.

Exercise price (*striking price*) Price at which a *call option* or *put option* may be exercised.

Expected return Average of possible returns weighted by their probabilities.

Externality In project analysis, an effect of a project felt outside the project and not included in the valuation of the project.

Factor of production The inputs required to produce output. Primary factors of production are land, labour and capital; secondary factors include materials and other inputs.

Feed-in tariff A policy mechanism designed to accelerate investment in new renewable technologies. It achieves this by offering long-term contracts to renewable energy producers, typically based on the cost of generation of each technology.

Financial leverage (gearing) Use of debt to increase the *expected return on equity*. Financial leverage is measured by the ratio of debt to debt plus equity (operating leverage).

Financial prices Synonymous with market prices.

Financial rate of return The internal rate of return of a cash flow expressed in market prices. It reduces the net present value of the cash flow to zero.

First-year return An analytical technique to determine the optimal time to begin a proposed project. The optimal time to begin the project is the earliest year for which the incremental net benefit stream for a project begun in that year has a first-year return exceeding the opportunity cost of capital.

Fixed costs Costs that do not vary with changes in the volume of output.

FOB The 'free-on-board' price of an export loaded in the ship or other conveyance that will carry it to foreign buyers.

Hedging Buying one security and selling another in order to reduce risk. A perfect hedge produces a riskless portfolio.

Income statement A financial report that summarises the revenues and expenses of an enterprise during an accounting period. It is thus a statement that shows the results of the operation of the enterprise during the period. Net income, or profit, is what is left over after expenses incurred in production of the goods and services delivered have been deducted from the revenues earned on the sale of these goods and services.

Incremental Refers to the change in the production or consumption of inputs and outputs attributable to an investment project. Measuring project benefits and costs on a 'with/without' incremental basis rather than a 'before/after' basis is essential.

Intangible In project analysis, this refers to a cost or benefit that, although having value, cannot realistically be assessed in actual or approximate money terms.

Interest during construction (IDC) Interest charges occurred during project execution and normally capitalised up to the point in time when the plant starts commercial operation. However, neither interest during construction nor operation is included in the internal rate of return calculation.

Internal rate of return (IRR) A discounted measure of project worth. The discount rate that just makes the net present worth of the incremental net benefit stream, or incremental cash flow, equal to zero.

IOU Investors owned utility.

IPCC International Panel for Climatic Change.

IPP Independent power producer.

Liabilities, total liabilities Total value of financial claims on a firm's assets. They equal (1) total assets or (2) total assets minus net worth.

LIBOR (London interbank offered rate) This is the interest rate at which major international banks in London lend to each other. LIBID is London interbank bid rate; LIMEAN is mean of bid and offered rate.

Marginal productivity of capital The economic productivity or yield of the last available investment money spent on the least attractive project.

Money terms The monetary prices of goods and services. Money terms are distinguished from real terms, which refer to the physical, tangible characteristics of goods and services.

Mutually exclusive projects Project alternatives that provide essentially the same output; if one is done the others are not needed or cannot be done.

Net benefit In project analysis, the amount remaining after all outflows is subtracted from all inflows. May be negative particularly in the early years of the project. It is the net cash flow.

Net energy metering (NEM) The difference between a consumer's electricity consumption and his or her own local generation, mostly through a PV rooftop system.

Net present value (NPV) The sum of discounted future benefits and costs at a stated rate of discount. It is an absolute measure of project merit.

Net working capital Current assets minus current liabilities.

Nominal Stated as an amount of money. Compare with *real*.

Non-traded A project input or output that is not traded by a country either because of its production cost, bulkiness or restrictive trade practices.

Opportunity cost Value lost by using something in one application rather than another. The opportunity cost of employing a worker in a project is the loss of net output that worker would have produced elsewhere. The concept of opportunity cost is the cornerstone of benefit–cost analysis.

Opportunity cost of capital The return on investments foregone elsewhere by committing capital on the project under consideration. It is also referred to as the marginal productivity of capital, a rate of return that would have been obtained by the last acceptable project. The opportunity cost of capital is normally used as a 'cut-off rate' in investment decisions.

Option See *call option, put option*.

Payback period Time taken for a project to recover its initial investment in monetary terms.

P/E ratio Share price divided by earnings per share.

Perpetuity Investment offering a level stream of cash flows in perpetuity.

Present value Discounted value of future cash flows.

Present worth (PW) (1) The value at present of an amount to be received or paid at some time in the future. It is determined by multiplying the future value by the discount factor. (2) The sum of the present worths of a series of future values.

Price elasticity Price elasticity refers to the relationship between the percentage change in the quantity demanded or supplied of an item with respect to a stated percentage change in the item's unit price.

Cross-elasticity refers to the influence of the price of one item on the demand for another. If a reduction in the price of X leads to increased demand for X and decreased demand for Y, the two are 'competitive'. Zero cross-elasticities indicate perfect complementarity, and infinite cross-elasticities indicate perfect substitutability.

Pro forma Projected.

Profit Financial profit is the difference between financial revenues and costs. Economic profit is the surplus of benefits over costs when economic prices are used, after deducting the opportunity cost of capital.

Protection Measures that protect domestic producers from foreign competitors, including import tariffs, quotas and administrative restrictions that effectively limit or prevent foreign competition. Most accurately measured as the difference between border prices and market prices, after allowing for domestic transfer costs.

Put option Option to sell an asset at a specified *exercise price* on or before a specified exercise date (cf. *call option*).

Rate of return Remuneration to investment stated as a proportion or percentage. It is often the internal rate of return. The financial rate of return is the internal rate of return based on market prices; the economic rate of return is the internal rate of return based on economic values.

Real interest rate Interest rate expressed in terms of real goods, i.e. nominal interest rate adjusted for inflation.

Real prices See *constant prices*.

Renewable portfolio standard (RPS) A regulation that requires the increased production of energy from renewable energy sources.

Return on equity (1) The internal rate of return of the incremental net benefit after financing. It is used as a measure of project worth. (2) Net income divided by equity.

Return to capital The rate of return received by the investor on capital engaged in a project.

Risk premium Expected additional return for making a risky investment rather than a safe one.

ROI Return on investment.

Salvage value (residual value) Scrap value of plant and equipment.

Sensitivity analysis A systematic review of the impact that changes in selected benefits and costs have on a project's net present value or internal rate of return.

Shadow price (accounting price) A price that is computed rather than observed in a market place.

Simple interest Interest calculated only on the initial investment.

Smart grid The collection of all technologies, concepts, topologies and approaches that allow the silo hierarchies of generation, transmission and distribution to be replaced with an end-to-end, organically intelligent, fully integrated environment where the business processes, objectives and needs of all stakeholders are supported by the efficiency exchange of data, service and transactions.

Standard deviation A measure of the dispersion of a frequency distribution. Obtained by extracting the square root of the arithmetic mean of the squares of the deviation of each of the class frequencies from the arithmetic mean of the frequency distribution.

Strike price *Exercise price* of an *option*.

Sunk cost A cost incurred in the past that cannot be retrieved as a residual value from an earlier investment.

Swap An arrangement when two companies lend to each other on different terms, e. g. in different currencies, or one at a fixed rate and the other at a floating rate.

Traded A project input or output is said to be traded if its production or consumption will affect a country's level of imports or exports at the margin. A partially traded item will also affect the level of domestic production or consumption.

Transfer payment A payment made without receiving any good or service in return.

Treasury bill Short-term discount debt maturing in less than 1 year, issued regularly by the government.

Unique risk (residual risk, specific risk, unsystematic risk) Risk that can be eliminated by diversification.

Variable costs Costs that vary with changes in the level of output, such as costs for fuel.

Variance Mean squared deviation from the expected value – a measure of variability. Standard deviation is equal to the square root of the variance.

Weighted-average cost of capital Expected return on a portfolio of all the firm's securities. It is used as hurdle rate for capital investment.

With and without Refers to the situations with and without a proposed project. In project analysis, the relevant comparison is the net benefit with the project compared with the net benefit without the project. This is distinguished from a 'before and after' comparison because even without the project the net benefit in the project area may change.

Working capital Difference between current assets and current liabilities. The term is commonly used as being synonymous with net working capital.

Index

Economic Evaluation of Projects in the Electricity Supply Industry

3rd Edition

In the highly capital-intensive electricity supply industry, it is essential that both engineers and managers understand the methodologies of project evaluation in order to comprehend and analyse investment proposals and decisions. This updated and expanded edition of *Economic Evaluation of Projects in the Electricity Supply Industry* takes a broad introductory approach, covering planning and investment, financial analysis and evaluation, risk management, electricity trading, and strategies, technologies, national requirements and global agreements for electricity generation in a carbon-constrained world.

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