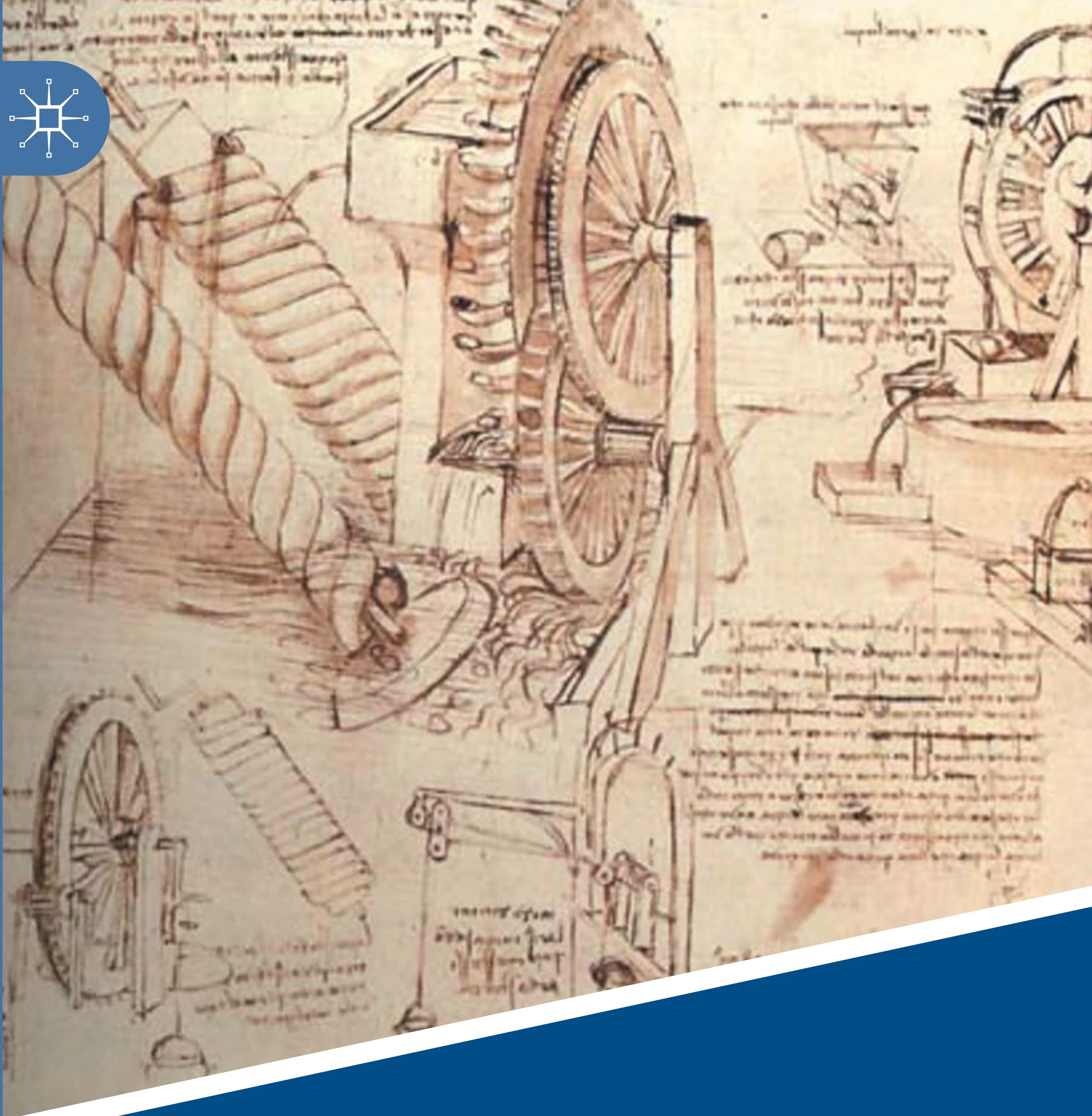

The Palgrave Handbook of International Energy Economics

Edited by Manfred Hafner · Giacomo Luciani

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Foreword

The *Handbook of International Energy Economics* is an exhaustive compendium of the main economic issues related to the energy sector. In a constantly evolving world, our societies face unprecedented challenges, which will have to be tackled in the decades to come. Climate change ranks high among such challenges, and the transition to a low-carbon future will require deep changes to the way we produce, distribute and trade energy. This will have several implications on our economy, which need to be explained, understood and discussed.

It is therefore timely that we shed light on the complexities surrounding the energy transition, as well as on the ongoing transformations affecting the energy industry. This Handbook represents an important step in the right direction. The book provides a comprehensive and easily accessible reference on the structural economic aspects influencing energy policies and their outcomes. By gathering the contributions of leading experts in the field, it delves into some underlying economic factors that are unlikely to change in the short-to-medium term, emphasizing the economic consequences and trade-offs of the technological solutions currently available.

The analysis takes stock of all the technologies composing today's energy sector, avoiding an *a priori* selection between "old" and "new" sources. This all-inclusive approach allows for a thorough assessment of the economics of the different solutions, highlighting the advantages and disadvantages of alternative options against the backdrop of the United Nations Sustainable Development Goals (SDGs). It also offers a punctual analysis of energy markets, illustrating their organization and price discovery processes, as well as some global trends that may influence future supply and demand patterns.

Furthermore, the Handbook has the merit of showing the inherent tension between the global and local dimensions of the energy transition. On the one hand, it recognizes climate change as a global issue, calling for international cooperation and dialogue with a view to promoting a common response from the international community. On the other hand, it underlines the limitations of "one-size fits all"-type solutions.

The world we live in is marked by substantially different perspectives in the energy landscape at the inter-continental level, which influence the way countries and regions look at the transition. This reflects the different availability of primary sources across the globe, creating conflicting visions about which solutions should or should not be encouraged. The energy mix of the future can only stem from a combination of such visions. In this context, the role of the energy industry should be to provide multiple alternative technologies that can deliver abundant, decarbonized and affordable energy to all.

Towards this goal, it is crucial to promote an inclusive conversation about the energy transition, and yet one based on hard facts and realistic measures. Indeed, meeting the targets of the Paris Agreement will require concrete, rapid and economically sustainable solutions, coupled with a widespread understanding of the economic and technological aspects underpinning each and every energy option.

This Handbook should be regarded as an important contribution to improving access to relevant information for both professionals, politicians and the wider public. As Eni, we will continue to support academic efforts as part of our strong commitment to promote a just transition that creates long-term value and allows everyone to access reliable and clean energy.

Rome Eni

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Finally, we are most grateful to Eni for the generous grant that has permitted the publication of this work in open access, thus making it electronically accessible for free to all who might be interested and at a much-reduced price for all who may wish to purchase a hard copy. A special personal thanks to Dr. Lapo Pistelli who supported the initiative.

We hope that they will all be satisfied with the final product.

Manfred Hafner and Giacomo Luciani

Contents

Notes on Contributors

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Abbreviations

AAU	Assigned amount unit
AC	Alternating current
ACQ	Annual contracted quantity
AEEP	Africa-European Union Energy Partnership
AEL	Alkaline electrolysis
AfDB	African Development Bank
AI	Artificial intelligence
API	American Petroleum Institute
API	Automated programming interface
APQ	Average program quantity
ASCM	Agreement on Subsidies and Countervailing Measure
b/d	Barrels per day
BAU	Business as usual
BCA	Border carbon adjustment
BEV	Battery-electric vehicle
Boe	Barrel oil equivalent
BOG	Boil off gas
BOS	Balance of system
BRP	Balance responsible party
BTU	British thermal unit
CAISO	California ISO
CAM	Capacity allocation mechanism
CAPEX	Capital expenditure
CAPP	Central African Power Pool
CBADM	Carbon border adjustment mechanism
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CCUS	Carbon capture, utilization and storage
CDM	Clean development mechanism
CER	Certified emission reduction

CFD	Contracts for difference
CFPP	Cold filter plugging point
CFR	Cost freight
CHP	Combined heat and power
CIF	Costs, insurance and freight
CME	Chicago mercantile exchange
CNG	Compressed natural gas
COB	California Oregon border
CPF	UK Carbon Price Floor
CRI	Coke reactivity index
CSP	Concentrated solar power
CSR	Coke strength after reaction
CTF	Cooking fuel and technology
CV	Calorific values
DC	Direct current
DCE	Discrete choice experiment
DER	Distributed energy resource
DES	Delivery ex ship
DFDE	Dual-fuel diesel electric
DFI	Development finance institution
DH	District heating network
DNO	Distribution network operator
DoD	Depth of discharge
DSM	Demand side management
DSO	Distribution system operator
E/P	Energy/power ratio
EAEC	European Atomic Energy Community
EC	European Commission
ECA	Export credit agency
ECSC	European Coal and Steel Community
EEG	Erneurbare Energien Gesetz
EEX	European energy exchange
EFP	Exchange for physical
EFS	Exchange for swap
EGS	Enhanced geothermal system
EI	Energy intensity
EIB	European Investment Bank
EII	Energy intensive industry
EMEC	European marine energy centre
EPAA	Emergency Petroleum and Allocation Act
EPC	Engineering, procurement, construction
ERCOT	Electricity Reliability Council of Texas
ERU	Emission reduction unit
ESP	Electronic sales platform
ESPP	East African Power Pool

ETS	Emission Trading System
EU	European Union
EU-27	European Union with 27 Member States (after 31.12.2020)
EU-28	European Union with 28 Member States (before 31.12.2020)
EV	Electric vehicle
FCC	Fluid catalytic cracking
FCEV	Fuel cell electric vehicle
FCFS	First-come-first-served
FEED	Front end engineering design
FERC	Federal Energy Regulatory Commission
FIEX	Financial expenditures
FIP	Feed-in premium
FIT	Feed-in tariff
FLNG	Floating liquefaction facilities
FOAK	First of a kind
FOB	Free on board
FPSO	Floating production storage and offloading
FSO	Storage and loading
FSRU	Floating storage and regasification units
FTR	Financial transmission right
FYP	Five-Year Plan
GAR	Gross as received
GDP	Gross domestic product
GHG	Greenhouse gas
GIS	Geographic information system
GPW	Gross product worth
GSA	Gas sales agreement
GT	Gas turbine
GTA	Gas Transportation Agreement
GTCC	Gas turbine combined cycle
GTL	Gas-to-liquids
GTS	Gas-to-solids
HAR	Harmonized allocation rule
HFO	Heavy fuel oil
IBRD	International Bank for Reconstruction and Development
ICE	Intercontinental exchange
IDC	Interest during construction
IEA	International Energy Agency
IFC	International Finance Corporation
IGU	International Gas Union
ILUC	Indirect land use change
IMO	International Maritime Organization
IOC	Independent oil company
IOC	International Oil Company
IOSCO	International Organization of Securities Commission

IPCC	Intergovernmental Panel on Climate Change
IPP	Independent power producer
IRENA	International Renewable Energy Agency
IRR	Internal rate of return
ISO	Independent system operator
ISO-NE	ISO New England
ISV	Independent software vendor
ITO	Independent transmission operator
JBIC	Japanese Bank for International Cooperation
JKM	Japan Korea Marker
JOA	Joint Operating Agreement
JSM	Japanese steel mill
JTF	EU Just Transition Fund
JV	Joint venture
KETS	Korean emissions trading system
KP	Kyoto Protocol
LCA	Lifecycle analysis
LCOE	Levelized cost of electricity
LCOS	Levelized cost of storage
LDC	Load duration curves
LLS	Louisiana light sweet
LMP	Locational marginal price
LNG	Liquefied natural gas
LNGC	LNG carrier
LOHC	Liquid-organic hydrogen carrier
LOLE	Loss of load expectation
LPG	Liquefied petroleum gas
LRF	Linear reduction factor
LSE	London Stock Exchange
LULUCF	Land use, land use change and forestry
MAOP	Maximum allowable operational pressure
MCP	Market clearing price
MCQ	Minimum contracted quantity
MDG	UN Millennium Development Goal
ME	Middle East
ME-GI	Electronically controlled, gas injection
MHV	Material handling vehicle
MIGA	Multilateral investment guarantee agency
MISO	Midwest ISO
MS	Member State
MSR	Market stability reserve
NA	North Africa
NAO	National Audit Office
NAP	National allocation plan
NAR	Net as received

NBP	National balancing point
NBS	China's National Bureau of Statistics
NDC	Nationally Determined Contribution
NEMO	Nominated electricity market operator
NOC	National Oil Company
NP	No price
NPV	Net present value
NREL	National Renewable Energy Lab
NS	North Sea
NYISO	New York ISO
NYMEX	New York Mercantile Exchange
O&M	Operation & maintenance costs
OFGEM	Office for the gas and electricity markets
OPEX	operating expenditures
ORC	Organic rankine cycle
OSP	Official selling price
OTC	Over-the-counter
OTEC	Ocean thermal energy conversion
P2G	Power-to-gas
P2H	Power-to-heat
P2L	Power-to-liquids
P2V	Power-to-vehicle
PA	Paris Agreement
PAYG	Pay-as-you-go
PCI	Pulverized coal injection
PE	Private equity
PEM	Proton-exchange membrane
PEMEL	Polymer electrolyte membrane electrolysis
PEMEX	Petroleos Mexicanos
PJM	Pennsylvania, Jersey and Maryland
PPA	Power purchase agreement
PPP	Public-private partnership
PPP	Purchasing power parity
PRA	Price reporting agency
PSA	Pressure swing adsorption
PSC	Production sharing contracts
PTR	Physical transmission right
PV	Solar photovoltaics
PVT	Pressure, volume and temperature
RAB	Regulated asset base model
RBL	Reserve-based lending
RCS	Regulated cost of service
RES	Renewable energy source
RGGI	Regional Greenhouse Gas Initiative
RLDC	Residual load duration curves

RMU	Removal unit
RoR	Run-of-river
ROW	Right-of-way
RPS	Renewable portfolio standard
RSP	Regulated social and political
RTO	Regional transmission operator
rTPA	Regulated third-party access
RVP	Reid vapour pressure
SAPP	South African Power Pool
SCADA	Supervisory control and data acquisition
SDG	Sustainable Development Goal
SDG 7	Sustainable Development Goal 7
SEC	Specific energy consumption
SECA	Sulphur emissions control areas
SEforALL	Sustainable Energy for All
SEM	Single electricity market
SMR	Small modular reactor
SMR	Steam methane reforming
SO	System operator
SOC	State-of-charge
SOEC	Solid oxide electrolysis cell
SOEL	Solid oxide electrolysis
SPA	Sale and purchase agreement
SPIMEX	Saint Petersburg International Mercantile Exchange
SPR	Strategic petroleum reserve
SPV	Special purpose vehicle
SRMC	Short-run marginal cost
SSA	Sub-Saharan Africa
T&D	Transmission and distribution application
TAN	Total acid number
TBP	True boiling point
TCO	Total cost of ownership
TFC	Total final energy consumption
TFDE	Tri-fuel diesel electric
TO	Transmission operator
TOP	Take-or-pay
TPES	Total primary energy supply
TRL	Technology readiness level
TSA	Temperature swing adsorption
TSO	Transmission system operator
TTF	Title transfer facility
UEC	Unit energy consumption
ULSD	Ultra-low sulphur diesel
UNFCCC	United Nations Framework Convention on Climate Change
UPS	Uninterruptible power supply

US	United States
USEC	US East Coast
USG	US Gulf
V2G	Vehicles-to-grid
VALCOE	value-Adjusted LCOE
VC	Venture capital
VGO	Vacuum gas oil
VIOC	Vertically integrated oil company
VoLL	Value of lost load
VPP	Virtual power plant
VRB	Vanadium redox battery
WACC	Weighted average cost of capital
WAF	West Africa
WAPP	West African Power Pool
WCI	Western Climate Initiative
WCS	Western Canada Select
WEC	Wave energy converter
WTI	Western Texas Intermediate
WTO	World Trade Organization
WTP	Willingness to pay
WTS	West Texas Sour
XDF	Low-pressure slow-speed dual-fuel

Energy Units

bcm	Billion cubic metres
bcma	Billion cubic metres annually
BTU	British thermal unit
gCO_2/kWh	Grams of carbon dioxide equivalent per kilowatt-hour
Gt	Gigatonne
Gtoe	Gigatonne of oil equivalent
GWe	Gigawatt electrical
GWh	Gigawatt-hours
GWth	Gigawatt thermal
kcal/kg	Kilocalorie per kilogramme
kg/min	Kilogramme per minute
kgH_2/h	Kilogramme of hydrogen per hour
kW	Kilowatt
kWel	Kilowatt electric
kWh	Kilowatt-hours
kWth	Kilowatt thermal
mmb/d	Million barrels per day
MMBtu	Million British thermal units
MMT	Million tonnes

Mt	Million tonnes
MT/y	Million tonnes per year
Mtoe	Million tonnes of oil equivalent
Mtpa	Million tonnes per annum
MW	Megawatt
MWe	Megawatt electric
MWh	Megawatt-hours
MWhu	Megawatt-hours useful energy for final users
PJ	Petajoule
tpa	Tonne per annum
TWh	Terawatt-hours
USD/kWh	US dollar per kilowatt-hour
$/boe	Dollar per barrel oil equivalent
€/kWel	Euro per kilowatt electric
€/kWP2L	Euro per kilowatt power-to-liquid
€/MWh	Euro per megawatt-hours
€/t	Euro per tonne

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Introduction

The future of energy has moved to centre stage in the political and economic debate at the national and international levels. Prompted by concerns for global warming, we have entered a phase of policy rather than solely market-driven energy transitions, which have turned energy from a mostly technological and occasionally geopolitical issue into a vital subject of economic policy and area of conflict between opposing interest groups. This book has the ambition to become a reference for readers who wish to be active in the debate and need basic understanding of the economics of energy in its international setting. Presenting a comprehensive overview of the issue, this book aims to be accessible to a wide readership of both academics and professionals working in the energy industry, as well as to graduate students and to general readers interested in the complexities of the economics of international energy.

The energy landscape changes frequently: multiple publications are available that monitor developments, either of the energy environment as a whole or of segments of the same, and these are continuously updated. We aim at complementing this abundant and frequently very professional literature with a reference book that will help readers understand the advantages and disadvantages, the opportunities and limits that characterize alternative solutions in the light of economic, and not just technological analysis. An economic approach and understanding is necessary, because technology offers multiple alternative solutions to our energy challenges (which, of course, is reassuring) but not all come at the same cost or promise the same economic reward. Furthermore, frequently the cost/reward profile of each technological solution is not intrinsic, but depends on circumstances—geographic, meteorological, demographic and social—as well as on the composition of the rest of the energy system, that is, on all other solutions that are adopted in parallel.

Energy is a complex system in which various sources interact and complement or contradict each other, generating end results in terms of availability and well-being for final consumers, or at least some of them. What may be appropriate in one country/region/economy may not fly in another. One needs to understand how the whole system works, that is, develop a holistic vision of energy and environment issues, to be able to identify feasible and appropriate solutions, depending on circumstances.

The reader will find in this volume competent and detailed discussions of the peculiarities of each major energy source, of the multiple energy markets and price formation processes, and of their interrelationships. The volume also covers a selection of the world's macro-regions to highlight how different conditions are in different geographical and meteorological situations.

Some major facts must be recalled to justify the structure of the volume and what it includes. Primary energy demand must be distinguished from final uses: the first includes original energy sources, which are then transformed into usable energy products to meet final uses. In 2019, fossil fuels accounted for 84 per cent of total primary sources: oil for 33 per cent, coal for 27 per cent and gas for 24 per cent. The share of fossil fuels in total primary energy has barely changed at all over the past three decades. Fossil fuels are transformed into usable final products through a process of refining or other chemical transformations. Alternatively, they are used to generate electricity. Electricity generation is also the predominant utilization of the remaining primary sources: hydro (6.5 per cent of total primary sources), renewables (5 per cent) and nuclear (4.5 per cent). The share of renewables has been growing and that of nuclear declining, so these two trends have roughly compensated each other.

Electricity covered 20 per cent of final uses in 2019, and the rest being accounted for by fuels for thermal or mobility purposes. It is widely expected that the share of final uses covered by electricity will increase thanks to greater convenience and improved efficiency. Electricity is expected to play a growing role across the spectrum, in mobility, thermal uses and industry. However, the increased penetration of electricity will perforce be a gradual process, so that the future of energy over several decades cannot coincide with the future of electricity.

Reliance on primary energy sources also varies greatly in different regions. The Middle East and North Africa region relies almost exclusively on oil and gas; other sources are marginal. In contrast, close to 50 per cent of energy consumed in Asia and the Pacific region is provided for by coal. The region with the highest contribution of hydroelectricity is South and Central America (22 per cent), while nuclear energy and renewables are most important in Europe (each accounting for 10 per cent of primary sources). Hence, the global energy landscape is the outcome of a mosaic of quite different tiles, responding to divergent endowments, opportunities and policies.

We know that the current energy system must evolve—it has constantly evolved since the invention of the steam engine and the dawn of commercial energy, but the pace of evolution must speed up, and the direction take a more decisive turn. In planning this Handbook, we have sought a compromise between the present and expectations for the future. Hence, the book does not attribute to "old" sources an attention proportional to their actual contribution, but neither ignores them. This results in relatively little attention to coal, whose importance is widely expected to decline rapidly, and large attention to energy sources which will continue to play a major role in international energy trade for decades (oil and gas) and those whose demand is expected to grow significantly in the future (electricity and renewables), while also addressing sources whose importance is at the moment almost non-existent, such as hydrogen, geothermal or tidal and waves, but which could also play an increasing role in the future.

Economics of Energy Production and Distribution

The book is divided in four main sections. The first is devoted to the economics of energy production and distribution and has separate chapters for all major sources of energy. Chapter 1 is devoted to oil and gas exploration and production, the so-called upstream section of the hydrocarbon industry. The chapter explains the different phases of an exploration-production project in order to highlight the cost structure and the nature of the risks related to each phase. It also discusses rent sharing according to the different taxation systems and points out the profitability problems of this capital-intensive industry.

As it is not possible to know in advance whether oil or gas (or neither) will be found, exploration is necessarily common. Furthermore, gas is frequently found in association with oil in fields containing predominantly oil, and liquids are frequently present in gas in predominantly gas fields; hence, the production of oil and gas is commonly joined. However, once brought to the surface, the paths of oil and gas diverge. The transportation of oil is relatively low cost: oil easily travels over long distances. Therefore, separate discussion of oil transportation was not considered necessary.

In contrast, gas transportation is expensive and has important implications on the industry. Gas tends to be utilized close to where it is produced to reduce the cost of transportation. Hence, the penetration of gas, or share of gas in total energy provision, varies very considerably between countries and regions, depending on whether gas is available (or historically was available) locally. This does not mean that gas is not transported over long distances—this is in fact an increasingly frequent occurrence. However, the high cost of transportation justifies significant differences in the price of gas in different parts of the world, which obviously also affects its relative competitiveness and which final uses it may be demanded for. Gas can be transported either in gaseous form by pipeline or in liquefied form by dedicated ships (LNG carriers). Chapter 2 provides a focus on the economics and commercial aspects of these large, often multibillion-dollar infrastructure projects, characterized by high upfront investment costs and requiring complex risk-sharing mechanisms between all parties involved.

Gas, once brought to the destination where it is demanded, normally does not require further treatment: the separation of higher molecules is made at the production site and what is transported is almost exclusively methane (CH_4). In contrast, oil must be refined in order to be transformed into usable products, depending on the technical characteristics required for each of its multiple uses, such as fuel (gasoline or diesel) in internal combustion engines, in aviation or shipping, in heating or the production of lubricants and so on. The process of refining is sensitive to the quality of the oil fed into the refinery, to the configuration of the refinery, that is, the number and quality of units (processes) available in it, and to the desired composition of the products slate. Refining is discussed in Chap. 3, where the key processes are explained together with their costs and siting issues. Historically, most oil has been refined in proximity of final markets, but this is no longer necessarily true, as producing countries are striving to integrate downstream into refining and petrochemicals to capture more of the value added than is allowed by the exportation of oil in its crude form only. Less demand in Europe and more demand in Asia have deeply changed the structure of the industry with closures of facilities in Europe and development of large, sophisticated plants in the Middle East and Asia.

Chapter 4 is devoted to hydrogen, which, in a sense, constitutes the bridge between the discussion of hydrocarbons and that of electricity that features in the following group of chapters. Hydrogen is not a primary source of energy because it is not found in isolation in nature and needs to be separated using energy: it is therefore an energy carrier rather than a source. At present, it is produced predominantly from hydrocarbons without carbon capture and sequestration, and is therefore a significant source of CO_2 emissions into the atmosphere. It is used predominantly for its chemical properties in refining and the chemical industry, rather than as carrier of energy. But the future is expected to be completely different, because hydrogen can be stored and offers a flexible source of both heat and electricity with no emissions of greenhouse gases. If produced from hydrocarbons with carbon capture and sequestration, it has the potential of "decarbonizing hydrocarbons", allowing the continued use of gas grids where they exist. It can also be produced from water through electrolysis, stored and turned to electricity again at some different time: it is therefore a form of electricity storage which is potentially crucial to facilitate the integration of non-dispatchable renewables into the grid.

We come therefore to the discussion of the electricity industry. Chapter 5 is devoted to the economics of power generation: this is a complex topic, due to the multiplicity of technologies available for power generation. The chapter introduces the major economic differences between the multiple power generation sources, highlighting the comparative advantages and disadvantages of each.

Chapter 6 is devoted to power generation from fossil fuels (coal, oil and gas) which constitute the bulk of global electricity generation (63 per cent of total—of which 36 per cent from coal, 23 per cent from gas and 3 per cent from oil). It covers the various technologies of power production and their key economics characteristics including CAPEX, OPEX, dispatchability, flexibility, location and expected service life.

Chapter 7 is devoted to nuclear energy (10 per cent of global power generation). It starts with the fundamentals of nuclear economics, with first the cost of nuclear operations, and also the revenue side, in both regulated and deregulated markets. Then it goes in depth into analysing the economics of two specific cases: long-term operations of existing nuclear plants and nuclear new build (covering potential for cost reductions and the case of Small Modular Reactors). The chapter concludes with a review of new research to understand the value of nuclear in future decarbonized electricity systems.

Chapter 8 is devoted to hydropower (16 per cent of global power generation), which is one of the oldest power generation technologies and the source of the largest power stations in the world. Despite a phenomenal rise of new renewable generation technologies, hydropower remains responsible for most of the renewable electricity generation around the globe. This chapter explores the economics of power generation from hydro and its advantages as well disadvantages. It describes the characteristics of the three hydropower generation types (run-of-river, hydro storage and pumped-storage) and provides an outlook on the future role of hydropower in modern energy systems.

The following two chapters deal with solar and wind (together accounting for 10 per cent of global electricity). Solar energy (Chap. 9) covers an increasing share of global energy demand. As a renewable source of energy, it will play a major role in decarbonizing electricity supply. The chapter provides an overview on the solar sector from an economic perspective. It describes the technical characteristics of photovoltaic and concentrated solar power and explains how these affect the economic competitiveness of solar energy. Wind power too plays a major role in decarbonizing electricity supply (Chap. 10). The chapter provides an overview on the economics of wind energy and highlights global trends in the wind sector. It describes the technical characteristics of onshore and offshore wind energy and explains how these affect the economic competitiveness of the technology. In both chapters, the authors describe how solar and wind power, as intermittent sources of energy, can be integrated into power systems. They also discuss how renewable energy support schemes contribute in fostering the deployment of solar and wind power.

The remaining two chapters are devoted to geothermal (Chap. 11) and tides and waves (Chap. 12), two renewable sources of electricity which presently play a very limited role, but are believed to offer considerable potential (geothermal in particular). Geothermal energy is emerging as one of the most reliable sources of renewable energy and gaining relevance over conventional and non-renewable sources of energy because of its constant availability and sustainable nature. Besides being a clean and renewable energy source with a low levelized cost of electricity, geothermal reservoirs have huge potential for power generation and thus may become the pillar of local grid systems, meeting baseload.

The above group of chapters deals with the economics of generating electricity, but that cannot be considered in isolation from the economics of electricity transmission and distribution, especially in view of the characteristics of the electricity grid, which requires instantaneous matching of demand and supply at all times. The following chapters deal with these issues from different angles.

Chapter 13 looks at the economics of energy networks (both electricity and gas) including from a regulatory point of view, that is, how the power and gas industries may be organized competitively and what challenges this entails. The chapter describes the physical and economic properties of energy networks, focusing on their monopolistic nature and the implications for electricity and gas systems. It goes onto review how energy networks are treated in competitive energy markets, how access to networks functions and what arrangements are established to ensure efficient economic outcomes and equal treatment of all market participants. Finally, it explains how access to energy networks is charged and how network users exchange energy within a network.

Chapter 14 deals with the challenges and opportunities of energy storage, with a specific focus on the economics of batteries for storing electricity. Storage technologies include a variety of solutions that have been used for different grid services, including frequency control, load following and uninterrupted power supply. Next, Chap. 15 provides an introduction to the main characteristics of sector coupling, which is often referred to as P2X, where "X" may stand for various applications, such as gas (G), heat (H), vehicles (V) or others. The common feature of these technologies is to provide additional flexibility to the power grid by the integration with other energy networks or sectors, through the conversion of electricity into other energy carriers.

In the light of the discussion in previous chapters, Chap. 16 deals with the integration of non-dispatchable renewables (i.e. solar and wind, whose availability cannot be controlled by the producer) into the electricity grid. At low levels of deployment, these technologies typically do not raise significant issues, but to reach high shares of generation within each power system, several measures are needed to integrate them in the overall electricity mix. The chapter reviews various potential approaches and discusses the challenge of reaching high levels of penetration of non-dispatchable renewables, while at the same time maintaining the stability of the grid and avoiding recurrent black-outs.

The last chapter in Part I (Chap. 17) is devoted to the financing of energy investment, which is closely related to the economics of each energy source. Energy projects can vary enormously in scale, risk and potential reward. Accordingly, different financial models need to be applied to optimally finance different typologies of projects. Also, different categories of investors, ranging from low risk to very high risk, must be tapped to succeed in financing projects. In the context of the substantial investments required to sustain the development of world's economies, this chapter reviews the key steps in the financing of an energy project, from the project viability analysis to the choice of financing instruments and structures. The authors highlight how the source of energy and the other characteristics of a specific project impact and shape its financing, using case studies from renewable and conventional energy alike, and conclude by drawing attention to the innovations taking place across all energy segments.

Economics of Energy Trading and Price Discovery

Part II of this Handbook is devoted to the economics of energy trading and price discovery. Energy markets, their organization and price discovery processes necessarily reflect technical features (elasticity of demand and supply, ease of transportation/transmission, potential for storage and intertemporal arbitrage, potential for substitution of one source/form of energy with another). On this basis, organizational and contractual structures are put in place which then shape the process of price discovery and eventually determine market prices.

Oil is by far the most widely internationally traded commodity in the world. Notwithstanding the decline in its price over the second half of the 2010s, crude oil alone still accounted for a significant share of international trade, and its weight has further increased with higher prices since 2021. The price of crude oil is a frequently referred to indicator for gauging global economic conditions. But the organization of the global oil market is very peculiar, as quality differences have significant bearing on the price of individual crudes, and trading takes place on the basis of reference to a limited number of physical benchmarks, whose availability and quality also evolve over time (Chap. 18). In addition, the logistics of trade delivery, whether seaborne by ship or overland by pipeline, also deeply influences the functioning of physical crude oil trading. The time dimension, which reflects delays needed to organize shipping or transit times, creates a demand for hedging instruments, which, in turn, motivates the establishment of a futures (or paper barrels) market that has grown enormously and has become the primary price discovery ground, with multiple ancillary markets linking different contracts and leading to advanced financialization. All of which means that the price of oil is not as straightforward as the price of potatoes in your local market: the complex structure and interrelationships must be understood to validly interpret the daily gyrations in the price of oil.

Oil product prices are discussed in Chap. 19. These obviously not only reflect the underlying price of crude oil, but also respond to the peculiarities of production and use of each product, keeping in mind that all are joint products from a refinery, whose configuration may differ significantly (as explained in Chap. 3) but cannot change in the short run, creating imbalances in the equilibrium of demand and supply of individual products at any moment in time. This chapter explains which hydrocarbons are mixed up inside a barrel of crude oil and how the refining process separates, treats and upgrades the composite to extract the usable products needed. It looks at whole crude properties and what these mean for handling and transporting the oil. It defines the different types of refinery process, from primary distillation to reforming right through to cracking and coking. It describes the range of products that result from refining crude oil and the use to which each product is put.

The pricing of internationally traded natural gas (discussed in Chap. 20) has fundamentally evolved over time, moving from predominant indexation to crude oil or oil products in accordance with various bespoke formulae peculiar to each long-term contract, to growing reliance on gas-to-gas competition and the emergence of gas trading hubs where both physical molecules and financial products are traded. The chapter explains why gas suppliers traditionally defended long-term oil-indexed contracts and analyses the main features of historical contracts. The old consensus on oil indexation, which had been a pillar of international gas trade for a decade, has been eroded in several regions. Beyond Europe and North America, Asia is also gradually moving towards a larger share of hub indexation, although it is still lagging behind in the process of establishing its own hubs. The chapter concludes that gas prices remain regional even if additional convergence is materializing thanks to the globalizing effect of flexible LNG.

The chapter devoted to international coal trading (Chap. 21) offers a view of coal production, consumption and trade at both global and regional levels. Given China's dominance of coal markets, the chapter describes the geography of Chinese coal supply chain in some detail. Some concepts of geology and mining are explained to facilitate a better understanding of the different coal qualities and grades, which play a more important role in coal trading and pricing than for other fossil fuels. The chapter offers a historical perspective of the evolution of the international coal market to describe the current market, very dynamic and liquid, with increasing variety of qualities.

The trading of electricity (Chap. 22) is conditioned by the need to constantly balance the grid, meaning that wholesale prices change almost continuously to reflect the changing balance of demand and supply. Therefore, in competitive markets electricity is traded in intervals that tend to be shorter and shorter (e.g. a new auction is conducted every 15 minutes, but in some markets every 5 minutes) as well as on a day-ahead basis. After a description of the functioning of wholesale electricity markets with a focus on the derivatives and the spot market, the authors analyse not only their main features such as trading venues, traded products, rules and the processes but also some key trends that can be observed. Going forward, electricity systems around the world are undergoing nascent but profound changes as market architecture and regulatory framework evolve to meet ambitious climate targets while maintaining efficient investment incentives and security of supply.

With the growing concern for climate change and based on the conviction that this is due to a market failure linked to the negative externality of emitting greenhouse gases (which the emitter is normally not requested to pay for), policies have been introduced to correct this and impose a monetary charge on emitters. This can be achieved either through the imposition of a carbon tax (i.e. a fixed price for each tonne of CO_2 emitted or equivalent) or through the creation of a market for emission allowances. Chapter 23 explores the concept of carbon pricing, with a specific focus on the trading of carbon via emissions trading systems (ETSs). The analysis starts with an overview of the main design options for a cap-and-trade system, presenting the experience of the European Union (EU) ETS as a real-world example of how such systems work. The history of the EU ETS is thoroughly examined, explaining what the main challenges and benefits of the system are and what lessons can be learnt from the world's biggest ETS. Using the European experience as a benchmark, other major ETS markets are also analysed, highlighting the potential for interconnection of different systems as well as the prospects for international cooperation mechanisms under Article 6 of the Paris Agreement.

The last chapter in Part II (Chap. 24) is devoted to the process of unbundling of vertically integrated industrial structures for the sake of enhancing competitive market relationships in lieu of market dominance on the part of one or few players. Energy market restructuring and liberalization have produced mixed results. While wholesale market design and competition have matured, retail competition has remained static. This chapter discusses the reasons that contribute to the success and failure of energy market unbundling with the use of global examples. The new trends and policies in energy markets are discussed from a regulatory perspective including active investor participation, technological innovation and the growth in renewable energy.

Global Energy Trends

Part III of the Handbook is devoted to the discussion of some global energy trends or transversal issues, which will play a key role in the shaping of the energy landscape in the coming decades.

Chapter 25 attempts at disentangling the multiple contrasting interactions between economic conditions and energy transitions. It goes without saying that the net effect, resulting from the balance of such multiple contrasting interactions, is extremely difficult or even impossible to predict. It very much depends on the specific characteristics of the economy facing the need to decarbonize, notably its current energy system, rate of growth of energy demand, available energy resources and opportunities for decarbonization. All of these parameters are extremely variable country by country. It also greatly depends on the specific transition path pursued and especially the intended speed of the transformation. The chapter lays special emphasis on the need to shift resources from consumption to investment and the consequent increase in the capital-output ratio, which has also consequences for the distribution of income.

Chapter 26 discusses the drivers of energy demand, which is one face of the relationship between the economy and energy (the flip face being how energy availability supports the generation of income). The chapter reviews all final uses of energy and discusses to what extent we may expect that the relationship between income availability or economic growth and energy demand may evolve. We know that energy demand grows less rapidly than GDP, but to what extent can the parameter linking the two be reduced? Is it conceivable that it may ever turn negative, that is, that income may increase while energy demand decreases?

Chapter 27 discusses energy subsidies, which are widespread among OECD and non-OECD countries alike and exist for all energy types. Governments often give noble and legitimate rationales for the introduction and continuation of various energy subsidies, but the reality of energy subsidy policies is nearly always more complex than the stated rationale. Governments have tried to balance the energy trilemma by implementing several types of energy subsidies at once. This has resulted in a complex political economy of pervasive subsidies across energy production and consumption. Even when some policy priorities clearly change, the phasing out of existing subsidies may prove politically challenging when powerful vested interest groups exercise their influence over governmental decision-making. The chapter goes in depth on the types, size, objectives and politics of subsidies to fossil fuel consumption and production and those to renewable electricity.

A closely related issue is that of energy access, which is dealt with in Chap. 28. Providing access to affordable modern energy services represents a key requirement for eradicating poverty and reducing inequalities. This is the reason why the United Nations included the achievement of universal access to affordable, reliable, sustainable and modern energy among the Sustainable Development Goals at the core of its 2030 Agenda for Sustainable Development. Several hundreds of million people especially in sub-Saharan Africa still lack access to modern energy for cooking (worldwide 2.9 billion people) or electricity (840 million), and what better income levels can they attain under these conditions? It is crucially important that energy transitions achieve the strategic goal of universal access to energy.

The remaining two chapters in Part III deal with technological advancement. Chapter 29 explores emerging technologies that may have a disruptive impact on the energy landscape. Disruption denotes an action that completely overhauls the traditional way an industry is working, for instance, by introducing a new technology or new standards. The shorter the transition, the more disruptive the event is considered. History shows that sudden disruptions are very rare in the energy industry, due to the relatively slow diffusion process of new technologies; nevertheless, the chapter argues that some disruption is possible especially in connection with electrification of passenger cars and increasing penetration of electricity in final uses.

Digitalization (Chap. 30) is another possible source of disruption. Previous energy transformations have largely been driven by the exploitation of a new energy source. In contrast, besides delivering cost reductions in the supply of both conventional and renewable energy, digitalization is transformational because it brings the demand-side into play, facilitating the move to a more integrated, highly flexible and customer-centric energy system which will ultimately unlock deep decarbonization of our societies. This transformation comes with risks: increased danger of cybersecurity attacks, threats to privacy especially in non-democratic political systems, increased use of energy and disruption of existing business relationships.

Energy and the Economy: Continental Perspectives

The last part (Part 4) of the Handbook features six chapters dedicated to major inter-continental differences and perspectives in the energy landscape, which profoundly influence the shape of energy transitions—justifying the necessity to speak of transitions in the plural rather than hypothesizing a uniform transition pattern applicable to the entire world.

There are striking differences in the availability of primary sources, with some regions/countries especially rich in coal or hydrocarbon resources, while others have favourable conditions for a major expansion of hydroelectricity or meteorological characteristics especially propitious for wind or solar energy. These differences cannot be ignored and determine vested interests in the existing global energy structures, on the one hand, as well as encouraging exploitation of innovative solutions, on the other.

History of course plays a huge role: energy structures have huge inertia and past decisions influence outcomes for very extended periods of time. Some forms of energy, like hydroelectricity or nuclear, have secular histories or have been profoundly influenced by political and military considerations.

The gap in income levels dividing continents has been narrowing since the end of the Second World War but remains very wide. The consumption of energy per capita in the Indian subcontinent or in sub-Saharan Africa remains at an order of magnitude smaller than in the advanced industrial countries. We have mentioned the importance of achieving universal energy access, but access per se is not sufficient. No bridging the huge remaining income gaps is possible if distances in energy availability per capita are not reduced. Priorities for countries where the population is energy poor cannot be the same as for countries that are major consumers and emitters of greenhouse gases and have been for centuries.

We have not pretended to offer an exhaustive geography of energy, opting rather for selecting a limited number of key cases. We begin with China (Chap. 31) for the simple reason that China is today the largest source of greenhouse gases and the country whose energy production and demand grow more rapidly in absolute terms. Despite large domestic resources of coal, oil and gas, the country has emerged as a key importer of oil and natural gas, exposing it to vulnerabilities associated with import dependence. Over the course of China's economic expansion, its energy policy has been geared towards ensuring adequate supplies at affordable prices to end-users, preferring to use administrative measures to regulate supply and demand rather than market mechanisms. Yet as the country's economic structure shifts away from heavy industry and towards consumer services, its energy needs and choices are changing, while the role of markets is expanding. And the negative environmental impact of China's energy choices has now become a social concern, as well as an industrial opportunity.

Russia (Chap. 32) deserves attention not only because it is the most important exporter of gas as well as one of the three most important producers of oil (with the United States and Saudi Arabia). Russia, ranking fourth in the world in the primary energy consumption and in the carbon dioxide emissions, adheres to the strategy of "business as usual" and relies on fossil fuels. Decarbonization of the energy sector is not yet on the agenda: a sceptical attitude to the problem of global climate change prevails among stakeholders. GDP energy intensity remains high, supported by relatively low energy prices and high cost of capital. The share of solar and wind energy in the energy balance is insignificant and is not expected to exceed 1 per cent by 2040. The challenge for Russia in the coming years is to develop a new strategy for the development of its energy sector, which enters the zone of high turbulence—even in the absence of the influence of the climate change agenda—due to the COVID-19, increasing global competition, growing technological isolation, financial constraints and, since February 2022, ostracism following the invasion of Ukraine.

The Middle East and North Africa (Chap. 33) is the region richest in hydrocarbon resources, but these are very unevenly distributed between countries. The region therefore displays great diversity in opportunities and perspectives. However, most countries remain exceptionally reliant on fossil fuels with a highly limited role played by clean energy alternatives; while the region also lags behind other region's progress in energy efficiency. In the Arab least developed countries (LDCs), energy access remains incomplete, severely obstructing socio-economic progress.

Sub-Saharan Africa (Chap. 34) embodies a paradox. Although the region is blessed with energy resources and has long attracted the oil and gas industry, the majority of its population lacks access to energy, especially electricity, which hinders their economic and social development. For decades the dominant discourse, from governments as well as international development agencies and economic actors, has considered that the exploitation of its energy resources would prompt the economic growth of the continent by giving the countries the financial means to undertake development strategies. Unfortunately, the reality seems much bleaker as most energy-producing countries in sub-Saharan Africa seem to underperform in terms of economic development, plagued by the so-called resource curse. Nigeria, the main oil-producing country on the continent, offers a dramatic illustration of this situation. However, a new approach has recently emerged which focuses on the development of access to energy for the population. As a consequence, all over the continent new initiatives have been put in place to boost the access to energy for the local population. This access has at last been acknowledged as a key driver for economic development.

The last two chapters are devoted, respectively, to North America (Chap. 35) and Europe (Chap. 36). North America is characterized by levels of energy consumption per capita which are double those in Europe or Japan; thus, issues of energy efficiency are extremely important. High energy consumption rates in United States and Canada challenge reaching climate policy goals, under heightened public pressure, and the search for alternatives to fossil fuels. Mexico will be more focused on economic development and energy access. The United States will continue to emphasize energy innovation, driven by public investment in research and development and private capital in commercial applications.

Finally, Europe has tended to occupy the moral high ground of decarbonization and energy transition, not without contradictions and with outcomes not exactly in line with expectations. Popular opinion plays a major role, and in contradictory directions, with simultaneous rise in green and populist political support, which results in hesitations and divergent priorities in individual countries. Progressively, a consensus on many important aspects has been emerging at least within the European Union, although divergences remain very strong on crucial items in the agenda, such as the future role of nuclear energy, carbon capture and sequestration and natural gas. The EU set an energy policy framework based on three pillars (security of supply, competitiveness and sustainability) with the goal to address three different priorities: competitiveness (affordable prices), security (of energy supply) and sustainability (clean energy). These three pillars appear to pursue contradictory goals, especially in the short term, but they are seen as converging in the longer term. This chapter aims to analyse how these different objectives have been key drivers of the European energy policy and economics. To illustrate this, the authors also present five case studies: the United Kingdom, Italy, France, Germany and Poland. Lastly, the chapter presents the "European Green Deal", whose ultimate goal is to reach carbon neutrality by 2050. The chapter analyses how a climate-neutrality goal requires a substantial transformation of the EU economy, which comes with some internal and external frictions.

In Conclusion

This book is the result of the collaboration of numerous authors from different institutions and with different backgrounds and perspectives. We have made no attempt to eliminate differences in opinions and conclusions because the future of energy is open to multiple solutions and the reader should be exposed to all points of view.

As stated at the beginning of this introduction, we have multiple alternative technological solutions that may deliver abundant and affordable energy for the future. The exact mix that will prevail is likely to be country- and region-specific because of structural differences as well as of different priorities and policies. In any case, the basis for rational decision-making is adequate knowledge and understanding of technical and economic opportunities and constraints. Energy is one of several areas in which a sometimes-difficult relationship exists between "experts", politicians and the wider public.

This handbook is the fruit of a lifelong hands-on experience by the editors working for the energy industry, international organizations, governments as well as in academia. We hope that this Handbook will give a modest contribution to improve access to relevant information for energy professionals, for politicians, for scholars and students as well as for a wider public and thus facilitate the adoption of sounder energy policies.

Manfred Hafner
Giacomo Luciani

PART I

Economics of Energy Production and Distribution

CHAPTER 1

Economics of Oil and Gas Production

Nadine Bret-Rouzaut

1 Introduction

Oil and Gas Exploration & Production involves exploring a sedimentary basin to discover a field, developing it to produce the oil or gas that can be extracted from it, and finally reclaiming the site at the end of production.

It is a very capital-intensive industry (the currency unit is one million US dollars, and the budget of many projects is over one billion), entailing multiple and varied risks but, in return, also the potential for high profitability.

Several actors, each with a well-defined role, are involved in enabling the quantities of hydrocarbons needed for consumption to be available on the market. The three main ones are:

- The State
- The oil companies
- The contractors.

To these main actors, one must add banks and insurance companies—to make financing possible—and professional organizations—to discuss and analyze challenges and find the best approaches to confront them.

In addition to these, the local population has gradually asserted itself and acquired influence, although even today in a number of countries the means at its disposal remain limited.

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2 The Main Actors

2.1 The State

As a general rule (with the sole exception of privately owned land in the United States), the State is the owner of all underground natural resources, including hydrocarbons. It controls oil activities and acts as guarantor of the general interest, in particular when it authorizes companies to explore for and produce hydrocarbons or when it decides to introduce into the law an obligation of local content (through employment of local professionals, manufacturing of equipment in the country, or creation of local companies linked to the oil and gas sector).

Depending on the legal regime applicable to ownership of underground natural resources, there are two possible forms of intervention:

- direct: the holder of mining rights directly explores and produces hydrocarbon deposits either as owner of the land (for privately owned land of the United States) or as the State, through national companies, with or without a legal monopoly (such as it exists, e.g., in Saudi Arabia)
- indirect: in this case, the holder of the mining rights, as the State and by virtue of its power, designates who will carry out the exploration and exploitation of hydrocarbon fields within the framework of the legislation in force and the applicable patrimonial agreement and contractual regime (which can be either a concession, a production sharing contract or occasionally a service contract, as explained later).

In petroleum matters, the State is primarily represented by the Ministry in charge of hydrocarbons (Ministry of Petroleum, Ministry of Energy, Ministry of Mines and Subsoil, etc. depending on the country). But other ministries are also involved: the Ministry of Finance and Ministries in charge of security and environment, labor, and fisheries, if it is an offshore field. In some countries, specialized national agencies will support the Ministry in charge of oil affairs. For example, in Norway the Norwegian Petroleum Directorate provides high-level technical expertise to the Ministry.

2.2 The Oil Companies

We may distinguish several different categories of oil companies. A first distinction is usually made between integrated and non-integrated companies, also called independents. An integrated company has assets along the entire value chain from hydrocarbon exploration to the sale of petroleum products to the final consumer. Vertical integration is expected to enable the company to create more value, by adding downstream profits (from refining and distribution/marketing) to profits from the upstream (exploration and production). Vertical integration can also provide a balance when one of the segments of the value chain faces difficult market conditions, because chances are that in this case the other segments experience favorable conditions. For example, when the price of crude oil is high, upstream profits increase while the downstream activities, for which the price of crude oil is a cost, may be challenged.

In contrast, an independent company is only present in a single segment of the chain, that is, with respect to the discussion in this chapter, only in the upstream: its role ends when it sells the hydrocarbons it produces to buyers that are not linked to it. Independents are much smaller than integrated companies, and frequently quite risk-prone explorers.

Secondly, we may distinguish between national companies (NOCs), in which the State is the majority or sole shareholder, and international companies (IOCs) such as ExxonMobil, Shell, BP, Total, and others, which have their equity traded on stock exchanges and own assets in multiple countries.

These diverse companies must in the end work together. Indeed, it is very rare for a single company to be active in an oil field in the absence of any partner. Exploration risks are extremely high, and the probability of finding a commercial field low. The oil companies will therefore join forces in a Joint Venture (JV). Each individual company normally prefers to take a stake of variable importance in several licenses, rather than concentrate its investment on a few prospects, so as not to put “all its eggs in the same basket”. Partners in the same project then sign an association agreement regulating their cooperation, called the Joint Operating Agreement (JOA). This agreement is signed by all the oil companies that come together to ensure the proper execution of the contract. The national company may be one of the partners of this JV when the State wishes to participate directly in operations, assuming the same rights and obligations as other companies, up to its share of participation.

The JOA defines the co-responsibility of the partners, the legal and fiscal transparency of each partner, the financing rules (procedure for calls for funds, invoicing methods, co-financing of expenses), and the sharing of results, as well as the rules for decision-making through a management committee. Operations are initiated, prepared, and directed by the company entrusted with the role of operator, whose responsibilities must be clearly spelled out in the JOA. The operator is also the representative, who communicates on behalf of the Association and represents it in all relations with the State. In the event of disagreement during the commitment period, it is usually the operator who decides. But sometimes some of the partners may decide to work on “sole risk”, that is, to assume full responsibility for the work that the other partners do not want to do.

2.3 The Contractors

In the past, oil companies designed, planned, and carried out the engineering for oilfield exploration and development. This involved the possession of seismic and drilling equipment and the employment of the teams necessary for their operation. Then, in the 1980s, oil companies progressively decided to refocus on what they considered to be their core business, outsourcing activities not considered to be part of the core to oil service companies. The pendulum has repeatedly swung between internalization and outsourcing, but overall the trend has been to outsource more and more activities. The oil and gas contracting sector now carries out much of the work subcontracted by oil companies: geophysical activities (acquisition, processing, and interpretation of seismic data); drilling and related services; as well as engineering activities, such as underwater works (pipe laying) or platform construction (shipbuilding). In addition, there is a multitude of service providers including tool manufacturers (geophysics and drilling), metal construction, mechanical engineering, and engineering companies. The common point for all these companies is that they are service companies for the oil industry, first, second, or third tier providers.

In the past, the oil and gas contracting industry frequently developed in parallel with the exploitation of local hydrocarbon resources (the United States, the United Kingdom, Norway, etc.). In recent years, Chinese companies have entered this sector and have rapidly gained significant market shares. However, the United States is still the reference country for oil activity, which has led to the creation of a powerful oil-related industry, giving some companies a leading position today: examples are Schlumberger, a company that was originally French, or Halliburton. But exploration, development, and production operations involve multiple highly specialized competencies (driller, mud specialist, helicopter company, diver, etc.) so that oil companies must sign many contracts (one contract with each service company), which is a long and management-intensive process. To overcome these disadvantages, oil companies are increasingly opting to deal with only one company and sign integrated service contracts.

Faced with this demand, contractors embarked on a major industrial restructuring process in the early 1990s, mainly through external growth. Many mergers and acquisitions have thus taken place, and the industry has consolidated.

3 The Different Phases of Exploration-Production

3.1 Exploration

The purpose of exploration is to discover an oil and/or gas field. It involves three areas of expertise: geology, geophysics, and drilling.

3.1.1 Geology

The first step in the process is when geologists study the geology of large areas to define specific areas that may contain hydrocarbon accumulations. Then, geologists carry out geographical surface studies to verify the presence of the triplet essential for any conventional deposit:

– a source rock that generated hydrocarbons millions of years ago

- a reservoir rock which, due to its porosity characteristics, may have accumulated hydrocarbons in its pores
- an impermeable overburden rock that retained the hydrocarbon molecules trapped inside the reservoir rock.

Then they will study the topography and visible structures in order to deduce some characteristics of the formations and structures of the subsoil. When the region is mature (proven existence of hydrocarbons), they use many existing sources of information from databases of companies, public agencies, and so on. Geologists then synthesize all the information acquired in the form of subsurface maps at different scales. But knowledge of the characteristics of the surface terrain is not sufficient to extrapolate the properties of the subsoil. In addition, in submerged areas, nothing is visible. This is why geophysical exploration methods are used.

It is difficult to estimate the cost of geology, because geologists are present throughout the upstream chain and the related expenses are treated in association with other expenses.

3.1.2 Geophysics

Geophysics consists of making measurements of physical quantities of the subsoil and interpreting the results in geological terms. These geophysical methods are based on three approaches, two of which are marginal: magnetometry and gravimetry. The main approach is seismic reflection, which makes it possible to carry out a proper echography of the subsoil.

Seismic reflection consists in sending elastic waves into the subsoil, which propagate through the rock masses, then refract and reflect on certain geological discontinuities called mirrors. Like echoes, reflected waves then rise to the surface where they are recorded by sensors (geophones on land, hydrophones contained in a streamer at sea) that convert ground vibrations into electrical voltages transmitted to a recording laboratory. The seismic recordings collected by the geophysicist are then processed by powerful computers to increase the signal-to-noise ratio.

Seismic results provide a good idea of the underground structural formation—layer inclination, continuity, folding—that can make visible possible traps constituting potential target locations for drilling.

3.1.3 Seismic Cost

The cost of a seismic campaign can be broken down into:

- Cost for field data acquisition
- Cost for data processing (computer processing)
- Cost of interpretation (analysis and understanding of results to enable decision-making).

The acquisition of seismic data at sea is easier than on land, due to the ship's ease of movement in all directions. This allows covering a large area at lower cost.

As with acquisition, routine seismic processing is outsourced to service companies. Processing costs are usually significantly lower than acquisition costs. Once the seismic data has been acquired and processed, it must be transformed into information that can be used by decision-makers. The processing of data must be done under the control of specialists. This translates into personnel and IT costs that can range between a few hundred thousand and one million dollars per seismic campaign.

The total cost of a seismic campaign thus amounts to between a few million dollars and a few tens of millions of dollars, depending on the difficulty of access, the type of coverage desired, and the area covered (we can calculate a cost in $/km^2). These costs are also related to the severe competition between service companies in local markets, with the award of seismic surveys being subject to competitive bidding in the countries concerned.

Thanks to geological and seismic data, it is possible to judge the prospect's interest and eventually make the decision to drill an exploration well, because only direct access to the subsoil, through drilling, can provide certainty that a field exists.

3.1.4 Drilling

The objective of drilling is to reach the target by perforating the geological layers over several thousand meters. A hydrocarbon field may be several kilometers from the surface, but never more than eight kilometers. If the hydrocarbon molecules have ventured into greater depths, they have been completely destroyed by the pressure and temperature at these depths. The most common drilling technique is to attack the rock with a rotating drilling tool, the drill bit. The driller must at all times ensure that there is a balance between the pressure inside the well and the pressure in the geological layers traversed. Drilling progresses at a rate of a few meters per hour, more and more slowly with increasing depth, punctuated by difficulties and regular replacement of the drill bit, which requires the entire drill string to be raised.

The main difference between onshore and offshore drilling is the support on which the rig must be installed at sea: platforms resting on the seabed (jack-up platforms used in shallow water), semi-submersible or floating structures (rather reserved for drilling in deeper waters). These devices are moved after each prospect drilled.

Whether the drilling leads to a discovery or not, it provides the geologist with important information in the form of cores, cuttings, and electrical records at the bottom of the well.

3.1.5 Cost of Drilling

Drilling of an exploration well generally lasts two to six months, depending mainly on the depth and hardness of the layers traversed, and 70 to 75% of the cost will be directly proportional to this duration. On the other hand, on average only one in five wells, or even only one in seven in poorly known areas, leads to the discovery of an economically exploitable reservoir, which means that the oil company must take into account the costs of all wells even if they have not led to a discovery.

The cost of drilling is higher than the cost of geology-geophysics and represents the bulk of the costs of an exploration program. The rental of the drilling rig from the contractor alone represents 20 to 40% of the total cost of drilling. The daily cost of renting a rig varies with its power, which depends on the depth of the well and, at sea, the depth of water in which the rig will be positioned. It also varies according to the rig utilization rate, that is, the ratio between the demand of oil companies and the supply of available drilling equipment, which varies with the price per barrel of crude oil.

To this cost must be added the costs of supervising the work, the cost of consumables (tubes, etc.), and the cost of other equipment and expertise required for drilling (logistics, mud, logging, etc.). In the end, a well will generally cost between a few million and a few tens of millions of dollars. An offshore well will often cost between 3 and 5 times more than an onshore well, even with a similar duration. Wells in extreme areas and/or at very great depths can cost several hundred million dollars.

3.1.6 Total Cost of Exploration

Exploration costs include seismic, geological, and geophysical interpretation and exploration drilling, including well testing.

Exploration expenses are, by definition, incurred before discovery and therefore have a direct impact on the company's accounts with two fundamental consequences:

- they will only be "refunded" if there is a commercial discovery; however, the probability of success of an exploration program is only 10 to 30%.
- they can only be financed from equity; given the high risk of failure, no bank will lend money to an oil company for exploration.

Exploration expenditures can vary over a very wide range. They may be limited to the cost of a seismic campaign and a dry well in the case of unsuccessful exploration. In this case, the oil company records a financial loss, even if this exploration campaign allowed the acquisition of additional information on the studied area. We express the cost in $/boe (barrel oil equivalent) by dividing the total amount of expenditures by the discovered reserves in barrels: depending on the region and time, this figure will generally range from $2 to $5 per boe.

3.2 Development

When exploration leads to a discovery, the next step is delineation (of the reservoir boundaries) and reservoir appraisal (e.g., homogeneous reservoir rock characteristics across the deposit). This provides additional information to confirm the discovery and assess with better accuracy the amount of reserves (quantity of hydrocarbons that can be extracted) and production conditions. Economic studies (crude oil/gas price, taxation, etc.) complement the technical studies to answer the essential questions: Is the field commercial? Should it be developed? If so, according to what scheme? Does it fit well into the company's strategy and its financial resources?

Once the decision to bring the field into production has been taken, the field must be developed, that is, all the equipment needed to exploit the field must be put in place: transport networks, production facilities, treatment and metering equipment, drilling of new wells, and so on.

3.2.1 Production Drilling

Unlike exploration drilling, production well drilling is a repetitive operation whose duration is easier to plan, and its costs are often better controlled. On average, production wells are drilled faster than exploration wells (learning curve).

In addition to drilling times, it is necessary to consider the completion times needed to connect the producing area to the borehole. The completion must ensure that the walls of the wellbore are secure. Today, while the vast majority of exploration or delineation wells remain vertical, production wells often use diverted or horizontal drilling techniques, particularly when the drilling area is inaccessible or urbanized or offshore, to limit the number of platforms or to exploit a deposit of low thickness or permeability (the latter being the case of shale oil and shale gas deposits). Multi-drain drilling can also be used when you want to produce several parts of the same reservoir simultaneously.

3.2.2 Production Drilling Cost

The cost of a production well is not very different from that of an exploration well. On the one hand, there is an additional cost due to the fact that the well must be equipped to be able to produce efficiently, but, on the other hand, thanks to experience, the well is drilled more quickly. In the case of a horizontal well, the cost is 20 to 30% higher than that of a vertical well, but in return, well productivity is increased by sometimes a factor of 3. Environmental constraints also can have an impact on well costs. These may be increased by the need to treat drilling waste, such as rock cuttings or various fluids, in order to comply with the country's environmental regulations.

3.2.3 Floating Supports

At sea, the equipment must be installed on floating supports. At shallow water depths, we can use a fixed structure (jacket), but for depths beyond a few hundred meters of water (currently, we are able to produce more than 3000 m of water, to which several thousand meters are added in the subsoil to reach the field), we then use one of three alternatives:

- A semi-submersible platform, anchored to the sea floor to be kept in place, and with a large and deep hull so as to have a low center of gravity and good stability
- A SPAR, a structure consisting of either a solid cylinder or a cylindrical part and a metal mesh with catenary anchor lines
- A Floating Production Storage and Offloading (FPSO): they were initially modified tankers used only for storage and loading of crude oil (FSO). Then, as the available tankers became scarce, new boats were built. By allowing autonomous production, the FPSO are more and more used in deep offshore areas where there are no export networks such as Brazil and West Africa.

Depending on the structure chosen, it will have to be built (or bought, or rented, if it is an existing structure) and installed during this development phase.

3.2.4 Total Development Costs

Development investments include the costs of development drilling (production wells and, where applicable, injection wells) and the costs of production facilities with separation and processing units, storage tanks, pumping and metering units, and discharge systems (pipelines and loading terminals).

Except for marginal cases such as small satellite fields whose development is very rapid, the development phase generally lasts 2 to 4 years.

In the development of an oil field, investments can reach several billion dollars. Identifying and evaluating the key parameters of a development are essential to the proper definition and profitability of the project. Some parameters, such as the situation of the field, the depth of the target, or the ocean-meteorological conditions, have strong influence on costs. Development costs represent between 40% and 60% of the total cost of the project.

Depending on the region, the cost of development varies considerably. In most cases the range will be between 7 and 15 $/boe, but it can be much more for complex fields.

3.3 Production

It is impossible to recover all the hydrocarbons present in a reservoir because of the action of capillary forces. On average, around 80% of the gas and 30 to 40% of the oil originally in place can be recovered. The time profile of production is characterized by a build-up phase, followed by a plateau that can be maintained for a time comprised between a few months and 2–3 years (or longer for large deposits), and finally by a decline phase until the end of the deposit's life.

As production progresses, reservoir pressure drops, reducing the eruptive capacity of hydrocarbons, particularly of oil. Initially, the wells produce spontaneously (i.e. without stimulation), until the production of water becomes excessive. This so-called primary recovery ranges between 25 and 30% of oil in place and in the majority of cases does not allow economically sufficient volumes of oil to be extracted. This is why it is often financially interesting to implement methods of assisted recovery after a certain operating time, such as pressurized water injection (the most widely used) or gas injection. These methods allow higher recovery rates of up to 40 to 60%. To go even further, so-called tertiary recovery processes can be used, such as chemical or thermal methods, to improve spatial scanning and reduce capillary forces. Tertiary methods can provide an additional recovery of 5 to 10% of the oil in place. However, all these methods have a cost, and it will be necessary to verify that their implementation brings an improvement in profitability. This also depends on the characteristics of the company exploiting the field: large companies frequently face higher costs and may divest fields reaching the end of their life to smaller, more nimble companies.

In the particular case of shales (oil or gas), as these formations have low porosity and permeability, hydraulic fracturing will be required to create cracks in the reservoir using high hydraulic pressures and extract significant quantities of hydrocarbons. The introduction of retaining agents such as sand or small marbles keeps these fractures open. But as productivity declines very quickly in these formations, it will be necessary to constantly renew fracturing to maintain an acceptable level of production.

The sum of exploration and development costs constitute total capital expenditure (CAPEX).

3.3.1 Operating/Exploitation Costs

Operating costs (OPEX) are defined as all expenses related to the operation of a production facility. They can be classified as (Fig. 1.1):

- fixed (independent of production level) or variable (proportional to production level)
- direct (production, maintenance of wells, inspection, logistics, safety) or indirect (technical assistance, headquarters staff)
- according to their nature: personnel costs, consumption (fuel, energy, etc.), telecommunication costs, rentals, service, and maintenance contracts.
- according to their object (production, maintenance, security, etc.). This classification allows cost accounting closer to the operator's objectives.

One can find a great diversity of situations, depending on the field: OPEX will generally range widely, between 7 and 15 \$/boe, depending on the difficulty of extraction (gas, oil, heavy oil, etc.), field size, geographical location (land or sea), region (desert, jungle, far north, temperate zones, etc.).

As a general rule, the amount of operating costs in \$/boe is therefore of the same order of magnitude as development costs, but with one major difference: development costs must be financed at a time when there is still no cash inflow,

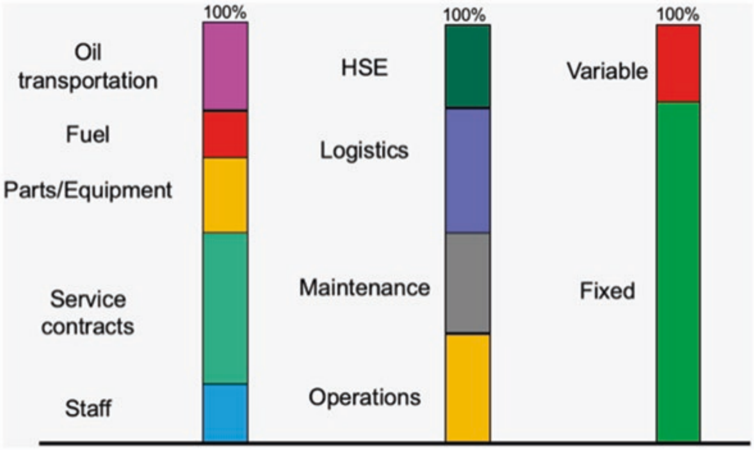

Fig. 1.1 Cost structure according to different types of breakdown by major cost families. (Source: Courtesy of Eric Descourtieux, Trident Energy)

since the field is not yet in production; while operating costs are funded from sales. Nevertheless, controlling operating costs is a daily concern for the operating teams, who must ensure an optimal level of production in complete safety and at the lowest cost.

3.4 Dismantling—Site Restoration

Finally, after a production period often of the order of 15 to 30 years, the limits of economic recovery of hydrocarbons are reached and the production structure is dismantled; if onshore, it is also necessary to rehabilitate the land. These operations can be very penalizing (the cost of dismantling an offshore platform is equal to that of its installation), especially since they occur at a time when the oil company no longer enjoys the cash flow from exploitation. It is therefore necessary to provision and take into account these costs in economic calculations from the start.

3.5 Technical Cost

Technical cost is defined as the total expenditure from exploration to decommissioning, that is, the sum of exploration and development investment, operating and maintenance costs of existing facilities, and decommissioning costs. The respective weights of these different categories of expenditure vary according to the project, but a few orders of magnitude can be given as a percentage of the overall cost of the project:

- 5 to 10% for exploration

- 35 to 45% for development
- 35 to 45% for operating and maintenance
- 5 to 10% for dismantling.

These costs are optimized to achieve the highest profitability. For example, it is sometimes preferable to reduce development investment and let operating costs increase accordingly, by renting the production platform rather than buying it. This will reduce expenses before production begins, and rental expenses will be charged annually during the production phase. Such optimization is aimed at the best possible value creation. In the end, technical costs are highly variable from one project to another, but will generally be in the range of \$10 to \$35/boe, with offshore projects costing more than onshore. The technological challenge of offshore production and more complex logistics explain this difference.

3.5.1 Cost Reduction

Companies must pursue two simultaneous objectives: increase production without endangering the production level of the reservoir and keeping costs as low as possible.

Two factors play a fundamental role in the evolution of costs:

- Technical and organizational innovation
- The level of economic activity, and more specifically the price of oil.

Regarding the first factor, the oil industry is relatively conservative in its technical choices, preferring to use proven methods to reduce the risks associated with the implementation of any new technology that could lead to a delay in the start of field production. However, some companies are ready to innovate, particularly when innovation allows significant gains or when the technical parameters of development require new solutions to reach new reserves. In terms of R & D, in response to the pattern of increasing outsourcing by oil companies, contractors have come to play a more important, and now even indispensable, role on the international oil scene.

Nowadays, a large part of innovation results from access to massive amounts of data, which makes it possible to have more reliable understanding and better forecasts (e.g., of oil prices) or optimize investment costs by managing the exploitation of a field remotely (the platform's size is reduced to a minimum to accommodate only a few people, the majority of the team remaining on land, with remote connections giving access to all the data necessary for the proper functioning of the exploitation).

But innovation is not limited to the technical sphere. Cost reductions can also result from organizational innovations, particularly in logistics. Rethinking the entire organization of a project to optimize each link, eliminating as much as possible redundancies without harming safety or the environment, using every possibility of connecting to existing installations, and finding associations that allow synergies are themes increasingly at the heart of the drive for optimization.

With respect to the influence of the oil price, costs will evolve according to the market situation (balance of demand and supply) of the sector in question (geophysics, drilling, construction, etc.). For example, the price of platforms will be sensitive to the costs of raw materials (steel in particular), the workload of platform-building companies, and the availability of construction sites. For the same type of platform, price differences of 20 to 30% can be observed, depending on the market situation. A construction site may be willing to accept a low price to just cover its operating costs and avoid closure if demand is low. On the contrary, in a situation of overheating, when the order books are close to full, suppliers and manufacturers have the power to negotiate and sign with the highest bidder. Maintaining, at each stage, effective competition between contractors when awarding work contracts helps reducing the final cost of a project. Consequently, there is a correlation between costs and oil prices: when the price of oil is high, companies have abundant cash from their producing fields and are therefore more willing to invest. Since they all have the same reaction at the same time, markets are quickly tightened. When the price of crude oil is low, we have the opposite reaction.

Cost control is now a priority for all companies, whether contractors or producers; they must set up procedures to ensure rigorous budget monitoring and permanent data exchange between the various entities involved in the project, whether with the client or the company's financial department.

4 The Patrimonial Agreement

The State, as responsible for the general interest, owns the natural resources of the subsoil (with the exception of private land in the United States), gives the authorization to explore for and exploit hydrocarbons, and controls oil activities. In each country, there is a law that provides the legal, financial, and fiscal framework for existing or potential exploration and production activity. It defines, inter alia, the applicable legal regime, the authority of the Minister responsible for Petroleum Affairs, the role of the national company (if there is one), and the tax regime.

Two modes of State intervention are possible:

- The State directly develops hydrocarbon fields through its national company, as in Saudi Arabia
- The State designates a company to carry out exploration and exploitation operations. It decides on the regime to which the chosen company will be subject, within the framework of the legislation in force (the regime can be a concession contract, a production sharing contract, or a service contract).

4.1 Procedures for Awarding Mining Titles/Contract

The granting of mining titles or oil contracts in available exploration areas can be decided through one of two alternatives:

- Negotiation process. In this case, companies are encouraged to submit an offer covering the terms and conditions of the proposed oil agreement. The State may then enter into negotiations with the proposing company, in order to reach a mutually acceptable agreement
- International call for tenders (also called "exploration round"). The State opens blocks and sets the conditions of the call for tenders (terms of submission, availability of data). It provides companies with a standard contract in which certain terms (work commitments, expenses, economic terms, participation rates, etc.) are left to the company to propose. After studying the offers, two cases are possible: either acceptance of the best offer, without negotiation (competitive bidding), or negotiation with the company having submitted the best offer, in order to improve the proposed terms and finalize a contract.

The tax system is defined by the State. There are two main alternative solutions: either a concession or a production sharing contract. The State can also offer only service contracts, but oil companies are reluctant to accept this solution, yet are sometimes forced to accept it if they want to work in the country.

5 Concession

In the concession regime, the legislation and regulations define the applicable framework in a detailed and non-discriminatory manner. A concession regime is the rule in Europe, the United States, Canada, Australia and Latin America, with few exceptions.

The concessionaire becomes the holder of an exploration license from the State, followed by an operating license (often called concession) in the event of a commercial discovery of hydrocarbons. The concessionaire exercises the exclusive right to explore for and exploit hydrocarbon fields over a defined area and for a limited period of time.

The concession contract is a document of about a hundred pages, whose various clauses can be grouped into three main categories:

- technical, operational and administrative clauses, covering the practical aspects of the conduct of operations during the various phases
- economic, fiscal, financial and commercial clauses, covering rent sharing between the parties, accounting for oil costs, valuation of production.

Subject to the fulfillment of all contractual obligations, the concession holder may withdraw at any time during the exploration phase or upon its expiry, if no commercial discovery has been made.

Under a concession contract, the oil company:

- owns the facilities until its mining rights expire
- exercises the exclusive right of exploration (in the form of an exploration permit or license).
- obtains a concession or operating permit (lease) to develop a commercial discovery.
- owns and freely disposes of all production at the wellhead, subject to certain obligations such as royalties and sales on the local market
- exercises this right for a limited period of time, at the end of which the exploited fields revert to the State.

Under the concession regime, government revenues are obtained through taxation and are therefore voted by Parliament, meaning that Parliament can decide to change the "rules of the game" at any time.

Government revenues fall into the following main categories:

- bonus: some concession agreements provide for the payment by the holder of an amount payable on the date of signature of the contract, called "exploration bonus". This can range from several million to hundreds of millions of dollars and constitutes a significant financial effort for the holder, especially since this bonus is paid before any discovery, and lost if there is no discovery. For the country, it represents a very attractive, immediate income source. In other cases, the bonus may be paid at the start of development or production. For the same country, there may be several bonuses paid at different times during the project.
- surface fees: the holder may be required to pay annually to the State a rent proportional to the area of his exploration/production permit. The amount of these rents is generally quite low (usually a few $/km^2 per year)
- royalty on production, equal to a percentage of the value of the production paid to the State by the holder, either in cash or in kind. It can be considered as a tax directly proportional to the value of production, in the same way as a tax on turnover, regardless of profits. The calculation of the royalty depends first of all on the applicable rate. Royalty rates are generally different for crude oil and natural gas, and lower for the latter. In order to modulate the royalty according to the characteristics of the fields in exploitation, the contracts may provide for progressive rates according to production volumes.
- the holder's income tax. The holder is subject to a direct tax on the income resulting from his production activities, but also from the transport, refining or liquefaction of natural gas.
- possibly an additional tax on oil profits. The payment of a royalty on production and a direct tax on profits may be considered by the State to be insufficient in times of high crude oil prices. In this case, the State introduces a specific tax on the profits from hydrocarbon production.

6 Production Sharing Contracts

Under the production sharing regime, the relationship between the State and companies is governed by a contract signed after multiple negotiations. Therefore, each contract will to some extent be different.

In this regime, the contractor does not hold a mining title, as the contract with the State does not create such a title. It is often a national oil company that holds the mining title, and the contract is then concluded with this national company, as the representative of the State, in the form of a joint venture. The State's direct participation in the joint venture may be an option.

The oil company that signs the production sharing contract with the State is called a contractor. The company:

- is a simple service provider;
- bears the technical and financial risks of exploration;
- has the exclusive right to develop and exploit the field if there is a commercial discovery;
- does not own the facilities it has paid for, but has the exclusive right to use them free of charge for the duration of the contract. The transfer of ownership can take place either at the time of installation of the facilities, or after full recovery of petroleum costs;
- receives a remuneration limited to a certain fraction of the production and consisting of two parts:
- cost oil, which corresponds to reimbursements of expenses (CAPEX and OPEX) financed by the oil company, but with an annual limit, the "cost stop", equal to a percentage of the production valued. The balance of oil costs not yet recovered in one year is then recoverable in subsequent years. However, any reimbursement should only be made after the control of the ministry in charge, which may reject expenses that it considers illegitimate;
- and a share of the profit oil, the "Contractor profit oil". The other fraction paid to the state is called "State profit oil". Indeed, after deduction of the cost oil, the remaining part, called profit oil, is shared between the State and the oil company according to a percentage indicated in the contract;

It is increasingly common to also see the payment of a royalty envisaged in a PSC, in the form of a percentage of the production valued and deducted immediately from production. Sometimes, a PSC may even include a tax that will be deducted from the Contractor profit oil.

7 Comparison Between Concession and PSC

The Concession and the Production Sharing Contract regimes each have their advantages and disadvantages. Of course, oil companies cannot choose between one and the other: they have an obligation to accept the system in force in the country at the time they undertake exploration. In a nutshell, it can be said that the main advantages of the concession are:

– the oil company owns a mining title and the oil installations, and it becomes the owner of all production at the wellhead (less any quantities corresponding to the royalty, if it is paid in kind)
– it is generally possible to consolidate different mining titles in the same country, and positive with negative pre-tax results, thus minimizing the final tax payable.

The production sharing contract does not have these advantages, but on the other hand:

– it results from a negotiation between the company and the State, which gives the former more latitude to be flexible on points that are less important to it and, on the contrary, rigorous on what is non-negotiable from its point of view
– in most cases, the accounts are prepared in dollars, providing a more accurate view of the results, especially when the activity is located in a country with high inflation.

8 Service Contract

Service contracts are concluded by the national company of the producing country and enlist oil companies as contractors, with the task of carrying out exploration, development, and/or exploitation work on their behalf. Service contracts are mainly used in the Middle East and Latin America, but their spread remains limited because they are of little interest to oil companies, which get only a financial reward (no entitlement to oil or gas), with no possibility of substantial value creation.

Two categories of service contracts exist, depending on the level of risk taken by the oil company:

– risk service contracts (known as agency contracts), under which the contractor is only reimbursed for his financing in the event of production, and risks losing whatever sum investment if no production occurs;
– technical assistance or cooperation contracts, without risk, to carry out specific work in return for adequate remuneration.

9 Economic Studies

Throughout the project, economists will be required to carry out economic studies.

When you are in the prospecting phase, the purpose of the study is to evaluate the commercial interest of an exploration objective. The task begins with a geological study that defines the potential accumulation of hydrocarbons and the probability of success of an exploration well. Based on three geological scenarios, described as “mini”, “mode”, and “maxi”, the team in charge will define, often by analogy with similar fields, the potential development architecture and the investment and operating costs associated. According to these data, an estimate of potential profitability is reached, to help decide whether to implement the proposed exploration program. The relevance of the analogies and extrapolations made in this type of approach will depend on the reliability of the available databases. Therefore, this method of analogy reasoning has limited validity when the assessment must include the use of new technologies. When there is a discovery, the sanctioning of a project will be based on a detailed economic study that integrates four types of data:

- the production profiles, established by the reservoir engineers based on the characteristics of the reservoir and the amount of reserves
- investment and operating costs, assessed by the experts in the estimation
- the valorization of hydrocarbons. Since it is impossible to predict the price of oil and gas over a horizon of several years, scenarios are used. In the past, the focus was on developing complex scenarios with different variations of price each year. Presently, companies rely on fixed price scenarios in constant or current currency and select two or three alternatives, between an optimistic vision (high crude oil price) and a pessimistic one (low crude oil price)
- the contractual and tax conditions that exist in the country in question.

Economic studies focus on studying the profitability of the project by calculating mainly the Net Present Value (NPV) and the Internal Rate of Return (IRR) of the project. The NPV is the sum of the annual and discounted net cash flows. If it is positive, the project is profitable since in this case, the cash flow generated reimburses investment and operating costs plus taxes, taking into account the cost of the capital invested and adding an extra value. The internal rate of return of a project is the value of the discount rate that cancels its NPV. If the project’s IRR is higher than the applicable discount rate, the NPV is positive and therefore the project is profitable. The threshold discount rate chosen by the company is therefore a determining factor. In theory, this rate results from an estimate of the cost of capital used by the company, but in reality, it will depend on the management strategy: choosing a relatively high value leads to selecting only fewer very profitable projects and rejecting opportunities that could then be chosen by the competition. Choosing the lowest value compatible with the cost of capital will allow more numerous projects, but at the expense of profitability.

It is clear that the final decision will be based on many other elements, such as the company's overall strategy or the local strategy in the country in question: for example, if the company is negotiating to obtain new permits, it will be good practice to reach an agreement for fields already discovered. The search for an optimal portfolio requires a diversified portfolio that spreads risks: deep offshore in areas where the geological potential is high, projects in countries with high political risk but high profitability, projects with low profitability but in "safe" countries corresponding to a risk-free investment, and so on. This diversification will be all the more possible as oil companies are used to working in partnerships: multiplying the number of projects reduces the overall risk of the portfolio. However, the risk associated with a fall in the price of crude oil must never be forgotten, because the sensitivity to this parameter is very high, even if in some countries tax mechanisms can serve as shock absorbers (e.g., the royalty rate can be correlated with the price of crude oil).

Upstream Petroleum is a sector that faces many challenges. There are more than enough resources to meet the demand for hydrocarbons in the coming decades. But these resources will have to be developed at lower cost, especially when the price of crude oil is relatively low, which requires the discovery of new technologies, the implementation at all levels of the digital transformation, and the access to more efficient processes. Therefore, investment in R & D must be commensurate with the stakes involved.

Beyond these operational challenges, the main challenge is now the obligation for these companies to decarbonize in order to respond to the imperative need to reduce CO_2 emissions, as hydrocarbons represent a significant portion of these emissions. Depending on the distribution of their assets across the globe, their percentage of oil production versus gas production, the latter being less CO_2 emitting, and local environmental policies, the response will not be the same for all companies; for example, they can put in place procedures to reduce methane leaks (e.g., in maintenance), inject CO_2 into the subsoil, use electricity from renewable energies, and so on. Finally, most companies in this sector have started to diversify by developing their asset portfolio through equity investments or acquisitions of companies in the renewable energy sector. And for all of them, financial pressure is on the agenda of their top management: How to maintain profitability at a good level with an increasingly volatile crude oil price and equally volatile costs? Which niches should be invested in? How to retain the loyalty of current shareholders, some of whom wish to turn away from fossil fuels? How to attract new investors for risky projects in an uncertain environment? and so on.

This industry is undergoing a real transformation, and it will succeed only if the men and women who make it up show intelligence, curiosity, and responsibility.

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CHAPTER 2

Economics of Gas Transportation by Pipeline and LNG

Gergely Molnar

The relatively low energy density of natural gas on a volumetric basis—almost 1000 times lower compared to crude oil—makes it one of the most challenging and expensive primary fuels to transport from the wellhead to the burner tip of end-consumers. Internationally traded natural gas is typically transported either in gaseous form via long-distance pipeline systems or in the form of liquefied natural gas on ships (LNG carriers).

The transport segment alone can account for over 50% of the costs occurring through the value chain of internationally traded natural gas. As a consequence, natural gas remained for a long time a local commodity, consumed relatively close to its production centres. Inter-regional natural gas trade emerged gradually with the start-up of the first commercial LNG export facilities and the construction of long-distance pipelines through the 1960s and 1970s.

The share of inter-regionally traded gas in total consumption rose gradually from below 5% in 1975 to 15% in the early 2000s and reached 21% in 2018. In comparison, around half of crude oil produced has been traded in 2018.

Whilst pipelines have dominated international gas trade for a long time, LNG exports more than tripled since the beginning of the century and accounted for just over half of international gas trade in 2018. This has been driven by a particularly strong gas demand growth in the markets of the Asia Pacific region, which have no or limited alternative supply options to LNG (such as Japan and Korea) (Fig. 2.1).

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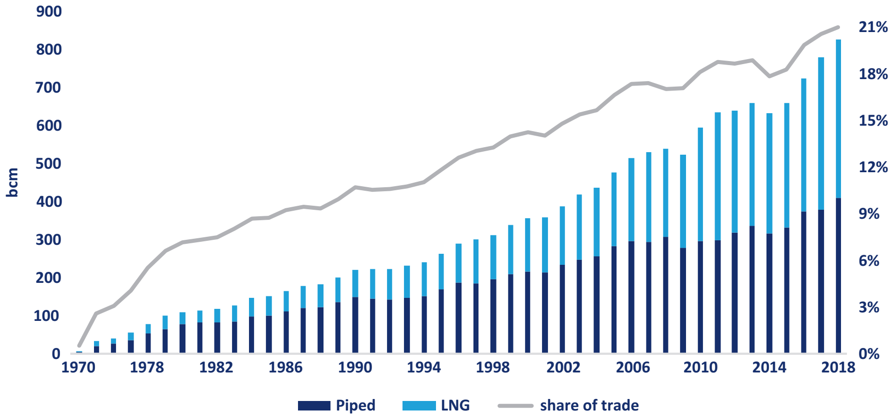

Fig. 2.1 International trade of natural gas (1970–2018). Total LNG exports and intercontinental pipeline trade, including Norway to the rest of Europe. (Source: International Energy Agency)

Besides pipelines and LNG, a number of alternative technologies and methods have been developed to monetize and transport natural gas; however, their utilization remains marginal and is typically serving local markets (see Box 2.1).

This chapter will focus of the economics of large infrastructure projects underpinning the international trade of natural gas, that is, long-distance pipelines and large-scale LNG.

Box 2.1 Alternative Gas-to-Market Transport Options

A number of methods have been developed to transport and monetize the energy value of methane.

This includes the transportation of compressed natural gas (**CNG**) containers and **small-scale LNG** ISO tanks via trucks and rail. These **"virtual pipelines"** can play a crucial role in meeting local natural gas demand in emerging markets with strong consumption growth and a still developing pipeline network. In China, LNG delivered via trucks accounted for over 10% of the national gas consumption in 2017.

Natural gas can also be **transformed into other forms of energy carriers** (gas-to-power, gas-to-liquids, gas-to-solids) close to the upstream source and transported as such to the end-consumers.

Gas-to-wire attracted considerable attention in emerging markets where natural gas is primarily used to meet rapidly growing electricity needs. The largest gas-to-wire project is currently developed in Brazil in the Açu port of Rio de Janeiro. The project consists of a 1.3GW combined cycle plant integrated to an LNG regasification terminal, a transmission line and a substation connected to the national grid.

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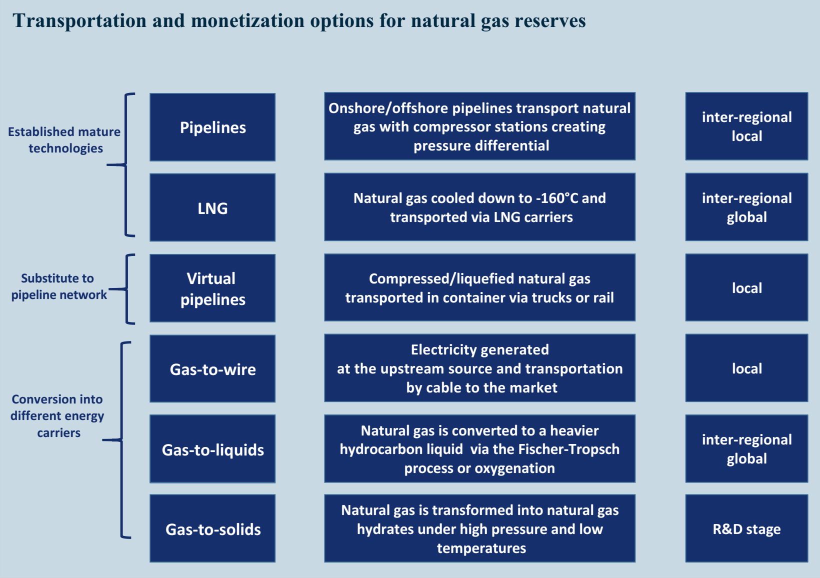
Gas-to-liquids (GTL) is a refinery process transforming methane into a heavier hydrocarbon liquid (such as diesel or gasoline) most commonly using the Fischer-Tropsch (F-T) synthesis. First, methane is converted to syngas (a mixture of hydrogen, carbon dioxide and carbon monoxide). After impurities (such as sulphur, water and carbon dioxide) are removed, syngas is reacted in the presence of an iron catalyst in an environment of high pressure (40 atmospheres) and extremely high temperatures ranging from 260 to 450 °C. Whilst GTL is a technologically proven process, its commercial viability at a large still needs to be proven. There are currently five large GTL projects operating globally, with a total production capacity of close to 250,000 barrels per day (equating to ~0.2% of global liquids production).

Gas-to-solids (GTS) technology processes consist of transforming methane into a solid form called natural gas hydrates (NGH) by mixing natural gas with water at 80–100 bar and 2–10 °C. It is created when certain small molecules, particularly methane ethane and propane, stabilize the hydrogen bonds within water to form a three-dimensional structure able to trap the methane molecule. GTS technologies are still in the state of research and development and no project reached the state of commercial phase.



Transportation and monetization options for natural gas reserves

1 Long-Distance Pipelines

Pipelines have been the natural choice to transport methane in its gaseous form. First historical records of practical usage of natural gas date back to 500 BCE in China, where natural gas was transported via “bamboo pipes” and used to boil ocean water to separate salt and create drinkable water (effectively desalination).

Modern pipeline systems—most often built from steel—can transport natural gas through several thousands of kilometres from the wellhead to the burner tip of end-consumers. Four major types of pipelines can be distinguished along the transportation route:

- Gathering (or upstream) pipelines are typically low-pressure, small-diameter pipelines (4–12 inches) that transport raw natural gas from the wellhead to the processing plan.
- Transmission pipelines are large-diameter pipelines (16–56 inches) operating under high pressure (15–120 bar) and transporting cleaned, dry natural gas through long distances from the processing plant either directly to large end-consumers (such as power plants or industrial sites) or to the city gate where it connects to the distribution system.
- Distribution pipelines are small- to medium-size pipelines (2–28 inches) carrying odorized natural gas under a relatively low pressure (up to 14 bars) from the city gate to its connection with service lines.
- Service lines are small-diameter pipelines (below 2 inches), operating under very low pressure (around 0.5 bars) and delivering natural gas directly to the end users (such as commercial entities and residential consumers).

From an operational point of view, in all cases natural gas flows in the pipelines from one point to another due to the pressure differential existing between those two points. Pressure differential is created and maintained by compressor stations located along the pipeline system (typically located at every 100–200 km of the transmission pipelines).

Compressor stations (containing one or more compressor units) squeeze the incoming natural gas to push it out a higher pressure, allowing pressure to be increased within the pipeline, which is effectively needed to keep natural gas flowing. With the travelled distance increasing, the gas pressure falls due to friction and thus requires further compression. Friction loss (or major loss) results by the movement of molecules against each other and the wall of the pipe.

Other non-linear parts of a pipeline system include metering stations, which measure the flow of gas along the pipeline and enable the operator of the pipeline system to monitor natural gas flow along the pipeline. Operational information (such as flow rate, pressure, temperature and operational quality) from the compressor and metering stations is transmitted to a centralized control station via Supervisory Control and Data Acquisition (SCADA) systems. This allows a permanent monitoring of the pipeline system, ensuring its stable and safe functioning.

This chapter will focus on the large-diameter, long-distance transmission pipelines which enable international trade of natural gas by transiting methane through several countries and borders. The first part of the chapter will provide an overview of the underlying economics of pipeline projects (including CAPEX and OPEX), whilst the second part will focus on the commercial aspects (including contract structuring and tariff regimes).

1.1 Economics of Pipeline Projects

Natural gas pipeline projects are capital intensive by nature. High upfront investment costs typically account for over 90% of total costs occurring through the lifespan of a gas pipeline (~40 years), whilst operating expenses (e.g. fuel costs associated with gas compression, maintenance and repairs, staff, etc.) usually account for up to 5–10% of total costs. Consequently, the initial design of the project and the optimization of capital expenditures needs careful consideration as it has a disproportionate impact on the overall economics of the project.

1.1.1 CAPEX

The investment cost of a natural gas pipeline is ultimately determined by its (1) length, (2) capacity (diameter × operating pressure) and (3) unit investment costs.

The linear part of a pipeline system—commonly called the “line pipe”—accounts for the majority of the CAPEX, whilst the share of the investments into compressor and metering stations typically accounts between 15 and 30%.

Unit investment costs of international pipelines can vary in a wide range from \$30k to over \$200,000/km/inch, depending on a number of factors, including external conditions such as terrain and climatological context, labour and material costs, project management as well as the stringency of the regulatory framework(s) (primarily environmental and safety standards). The unit cost of compressor stations is typically in the range of \$2–\$4 million per MW of installed power.

Figure 2.2 shows the breakdown of the average unit investment costs for the line pipe and the compressor stations, respectively.

Unit investment costs can be broken down into four main categories:

- Material costs:
  - for the linear part of the pipeline system, it includes pipe sections (made usually from high carbon steel and fabricated in steel rolling mills), pipe coating and cathodic protection. It typically accounts for around one-third of total investments costs and is highly dependent of the evolution of steel prices;

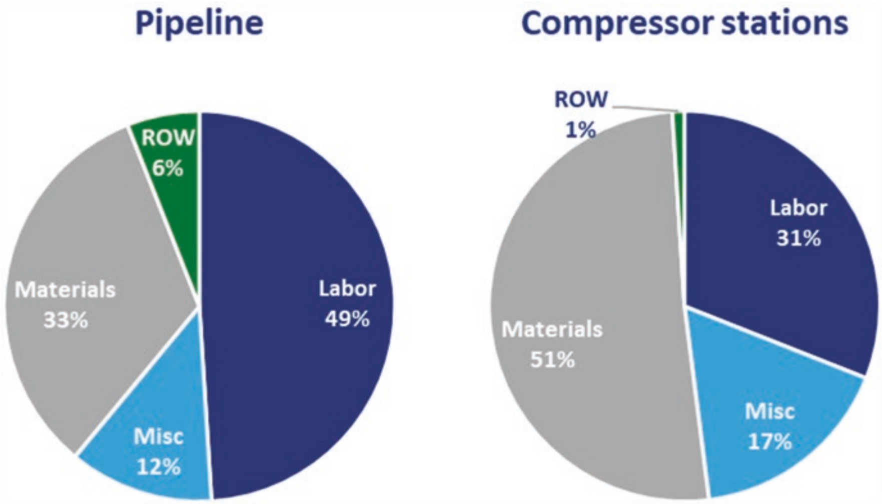


Fig. 2.2 Breakdown of average unit investment costs into pipelines and compressor stations. (Source: based on ACER (2015))

  - for compressor stations, material costs are the most important cost component, accounting for about half of total investment. This includes the pre-fabricated modular functional units of a compressor station (such as gas scrubbing and liquid removal, compressor and driver units, gas coolers, pipes and valves).

- Labour costs:

  - are typically the most important cost component of the line pipe, accounting for over 40% of the unit investment cost. This includes the salaries and wages related to the preparation of the terrain (clearing, grading and trenching) and the construction of the pipeline (stringing, welding, coating pipeline segments, depositing the pipeline and backfilling);
  - the construction of compressor stations includes site preparation, construction of the compressor building(s) and assembling compressor units. It is a somewhat less labour-intensive process compared to pipe laying, with labour costs accounting to around one-quarter of unit investment costs of compressor stations.

- Miscellaneous costs generally cover surveying, engineering, supervision, contingencies, telecommunications equipment, administration and overheads, freight, regulatory filing fees as well as taxes. They typically account for over 10% of total unit investment costs in the case of both the pipelines and compressor stations.
- Right-of-way (ROW) costs include obtaining rights-of-way and allowing for damages.

It is important to highlight that the breakdown of average unit investment costs presented above is purely indicative.

Each pipeline system is unique and hence the cost breakdown will vary by pipeline. For instance, pipes built in more challenging external environments (such as mountainous terrain, rocky soil, wetlands or ultra-deep offshore) will usually have a higher proportion of costs associated with labour and logistics and will depend less on material expenditures. Pipelines crossing high population density areas have in general higher miscellaneous and right-of-way costs and need to abide to more stringent safety standards. Construction of offshore pipeline systems requires both specific line design (wall thickness up to 2 inches to support water pressure, insulation against low-temperature environment and ballasting to provide stability) and a specific set of logistics (including pipelaying vessels with day rates often at several $100k/day), which can increase significantly investment unit costs.

Figure 2.3 provides indicative additions to pipeline construction costs, depending on their respective external environment.

Worth to note that international pipelines—crossing several borders and countries—have to comply with various jurisdictions and regulatory frameworks—which can substantially increase their miscellaneous costs related to administration and regulatory filing fees.

In addition to the cost components related to technical CAPEX, the financial structure and the cost of capital can alter significantly the economics and the profitability of pipeline projects. External financing can account for up to 70% of financing in major international gas pipeline projects. Investors/lenders typically look for LIBOR +3–4% for pipeline investments, depending on the location, the project promoters and their risk appetite. Based on those assumptions, financial expenditures (FIEX) can add 10–15% to the initial technical CAPEX.

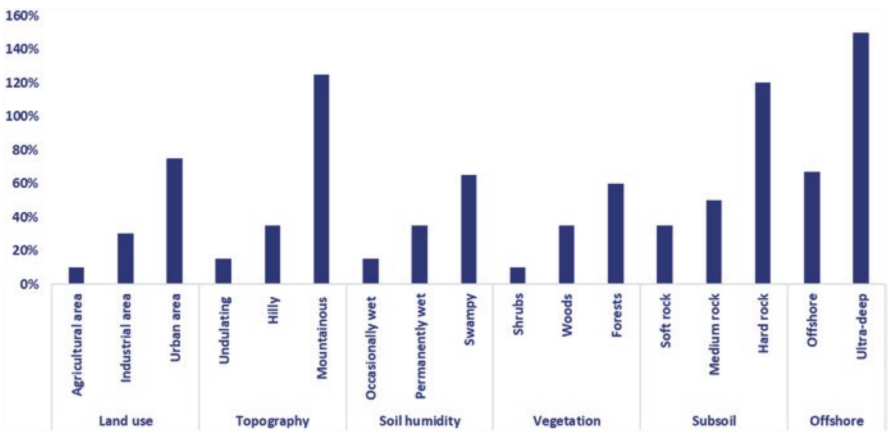


Fig. 2.3 Indicative additions to pipeline construction costs, per difficulty factor. (Sources: based on CEER (2019), Yamasaki (1980) and Author's estimates)

1.1.1.1 Economies of Scale

Natural gas transportation via pipelines naturally results in economies of scale. Whilst the throughput capacity of a pipeline is increasing following the $\pi r^2 L$ formula—where r stands for the radius (half of the diameter) and L for the length of the pipeline—the material costs required for the construction of the line pipe is increasing in line with the $2\pi rL$ formula. Consequently, unit transport costs for the same level of utilization are usually lower for pipelines with larger diameters and built in similar external environment.

Moreover, some of the costs associated with pipeline construction are fixed (design, permits) or increase insignificantly compared to a higher design and working capacity of the pipeline system.

Further, it should be noted that several smaller compressor units will have a higher cost per MW compared to a larger unit with same compressing power due to economies of scale (Fig. 2.4).

1.1.2 OPEX

Operating expenses represent a fraction of the overall costs occurring through the lifespan of a pipeline project, typically accounting for 5–10% of the total costs of natural gas transportation.

Figure 2.5 provides a purely illustrative example of the breakdown of operating expenses, based on the financial reporting of a major European gas transmission company.

Operating costs of a pipeline system can be broken down into four main categories:

- Fuel costs: primarily associated with the energy requirements of compressor stations running either on natural gas or on electricity (see Box 2.2). "Fuel gas" is either provided by the shippers themselves as "fuel gas in kind" or procured by the operator of the transmission system operator via

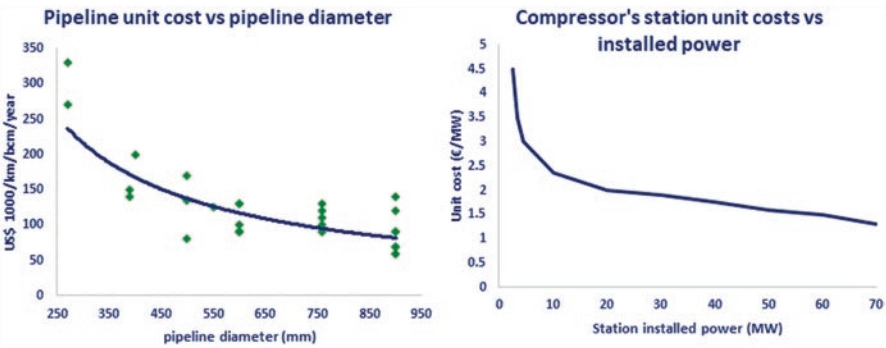


Fig. 2.4 Economies of scale in natural gas pipeline systems. Green dots indicating individual gas pipeline projects. (Sources: International Energy Agency (1994) and CEER (2019))

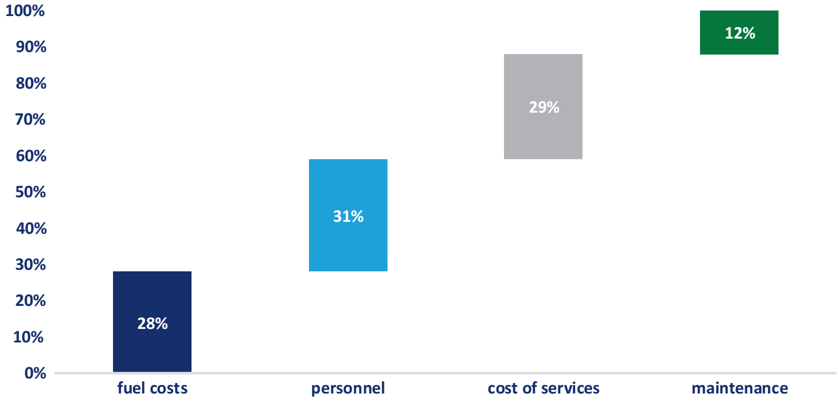


Fig. 2.5 OPEX of gas transmission company

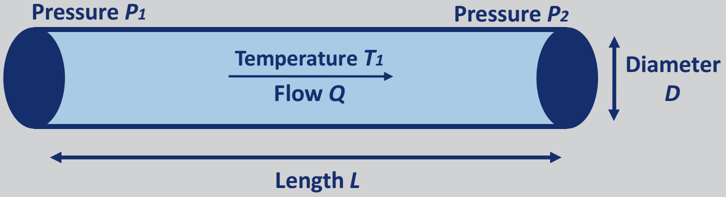
Box 2.2 Compressor Stations

Compressor stations are at the heart of natural gas pipeline systems. The necessary operational pressure needed to transport ("make flow") natural gas is ensured at the starting point of the pipeline system by a **head compressor**.

Natural gas flow in the pipeline can be described with the **general flow equation**:

$$Q = \frac{7.574 \times 10^{-4}}{\sqrt{f}} \times \frac{Ts}{Ps} \times \sqrt{\frac{\left(P_1^2 - P_2^2\right) D^5}{SLZT}}$$

where Q stands for the gas flow rate (m^3/h), f is a general friction factor for gas (determined from the Moody Diagram), T is the temperature in Kelvin, Ps is the standard pressure (in bar), P1 is the inlet pressure, P2 is the outlet pressure, D is the diameter of the pipeline in mm, S is the relative density (air/gas), L is the length of the pipeline (in m) and Z is the compressibility factor of gas (Nasr, Connor 2014).



Steady gas flow in a pipeline

(continued)

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The initial **pressure drops** with the travelled distance due to the friction occurring between the molecules of methane and against the wall of the pipe. Pressure drop can be described from the **Darcy-Weisbach equation** as the following (Menon 2011):

$$H_f = f\frac{L}{D}\times\frac{V^2}{2g}$$

where H_f stands for the head loss due to friction, f is a general friction factor for gas, L is the length of the pipeline (m), D is the internal diameter of the pipeline (in mm), V is the velocity (in m/s) and g stands for the gravitational acceleration constant (9.81 m/s^2).

The loss of pressure requires the installation of so-called **intermediary compressor stations**, typically located at every 100–200 kms of the pipeline system.

The required **compression power** is given by the following equation (Menon 2011):

$$Power(kW) = 4.0639\left(\frac{y}{y-1}\right)QT_1\left(\frac{Z_1+Z_2}{2}\right)\left(\frac{1}{n_a}\right)\left[\left(\frac{P_2}{P_1}\right)^{\frac{y-1}{y}}-1\right]$$

where y stands for ratio of heat of gas (1.4), Q for gas flow rate (million m^3/d), T for temperature (in Kelvin), Z_1 compressibility of gas at suction conditions (when entering the compressor station), Z_2 compressibility of gas at discharge conditions (when leaving the compressor station), P_1 suction pressure of gas (kPa), P_2 discharge pressure of gas (kPa) and n_a is the compressor's isentropic efficiency (typically between 0.75 and 0.85).

A compressor station typically consists of the following facilities:

- **Inlet scrubber**: to clean up the entering natural gas stream from any impurities that may have formed during its voyage in the pipeline;
- One or several **compressor units**: each of which includes drivers and compressors;
- **Gas cooler**: necessary to reduce the temperature of the gas after compression to a level which is tolerable for the pipelines;
- **Outlet scrubber**: to clean the exiting natural gas stream from impurities which might have formed during compression;
- **Control systems**: station control monitors inflow and outflow of natural gas and unit control systems monitor the compression process. All data and information are reported to the central control station via SCADA.

(*continued*)

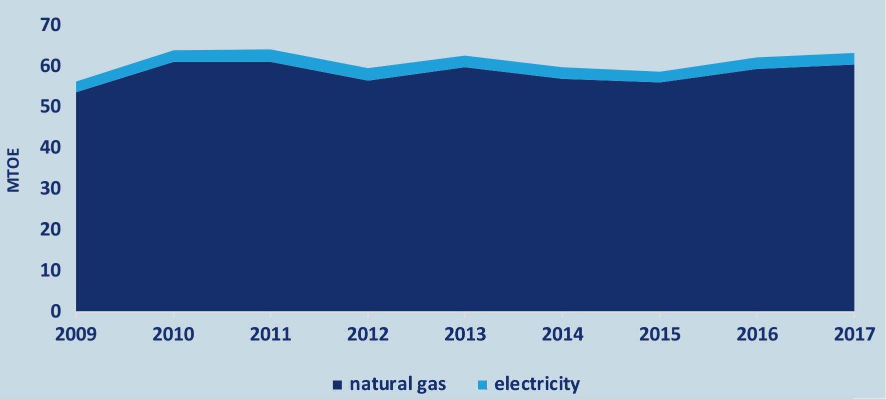
(continued)

Depending on the network configuration and throughput capacity of the pipeline system, aggregate capacity of compressor stations can range from less than 10 MW to several hundreds of MW. The world's largest compressor station is located in Portovaya, Russia, with an aggregate capacity of 366 MW.

Two main types of compressors can be distinguished:

- **Reciprocating compressors**: usually driven by either electric motors or gas engines with a reciprocating moving piston compressing natural gas;
- **Centrifugal compressors** are driven by gas turbines or electric motors, increasing the pressure of natural gas with mechanical rotating vanes.

Compressor stations are using either natural gas (typically taken from the transmission system) or electricity. Data from the International Energy Agency indicate that natural gas accounts for ~95% of energy consumed by natural gas pipelines.



Energy consumption of pipelines per fuel (2009–2017). (Source: International Energy Agency)

Whilst the fuel efficiency of pipeline systems varies depending on their design and external environment, typically, fuel gas usage equates to less than 0.5% of the volume transported per 100 km, that is, less than 5000 cubic metre per 1 million cubic metre transported over 100 km. Pipelines with larger diameters tend to have a lower fuel requirement for the transportation of the same quantity of gas due to lower friction loss.

a competitive tendering process. In the case of vertically integrated companies, where the shipper and the transmission system operator are not separated, fuel costs are part of the company's internal costs.

- Personnel costs include salaries and wages of the employees of the company operating the transmission system, as well as social security contributions and other employee benefits.

- Services costs include all expenses related to services required to manage the pipeline system (such as information technology systems, telecommunication services) and the operating company itself (technical, legal, administrative, personnel-related services) as well as miscellaneous expenses (such as insurance, marketing and consulting).
- Maintenance costs are associated with the inspection, maintenance and repairs of the pipeline system in order to maintain its operational status without necessarily expanding its lifespan.

The breakdown of OPEX cost components can show a high degree of variation depending on technical features and general state of the pipeline system. For instance, an ageing pipeline system running through a challenging environment will naturally have higher maintenance and repair costs. Fuel costs will vary depending on the fuel procurement process, that is, inhouse, "gas in kind" or open tendering process.

1.1.3 Optimal Pipeline Design

Each project developer strives for the most cost-efficient pipeline system design, in terms of both CAPEX and OPEX.

Considering that length and terrain are external and fixed factors, the following considerations are usually taken into account for pipeline system design:

- Quantities to be transported: based on actual market demand and/or expectations, including seasonal variations and modelled peak;
- Internal pipeline diameter: larger diameters reduce pressure drop and hence lower the need for compression power, but necessarily increase the initial CAPEX of the project;
- MAOP (maximum allowable operational pressure): the highest pressure allowed at any point along a pipeline. It is typically between 80 and 100 bar for large transmission systems. There is generally a trade-off between MAOP and pipeline wall thickness. Generally, pipelines running through densely populated areas have a lower MAOP;
- Flow velocity: shall be kept below maximum allowable velocity to prevent pipe erosion (a maximum velocity of ~72 km/h is typically recommended);
- Compressor stations' capacity and spacing, which ultimately influence their fuel consumption (variable OPEX) and performance: a large pressure drop between stations results in a large compression ratio, typically leading to poor compressor station performance.

The techno-economic optimization of the pipeline system design should be based on the hydraulic calculation of the pipeline and followed by a series of NPV calculations (taking into consideration the cost of capital). Typically a software computer program is used for modelling purposes and cost computations before determining the optimal configuration of the pipeline

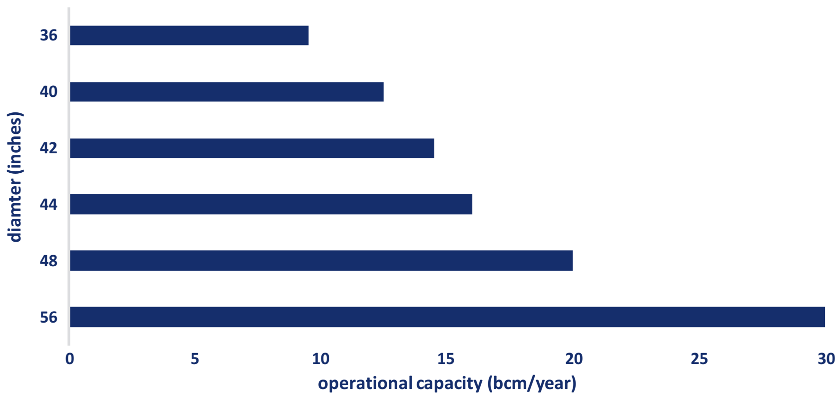


Fig. 2.6 Rule of thumb for optimal pipeline capacity in relation to internal pipe diameter. (Source: based on Brauer (2016))

system in relation to its throughput, diameter and operating pressure. Figure 2.6 provides typical throughput capacities associated with respective internal pipe diameters and assuming an operational pressure of 100 bar.

1.2 Commercial Implications: Contract Design and Tariff Structuring

Natural gas pipeline systems have high upfront investment costs, which become sunk as soon as the pipeline is laid down—due to the inflexible and durable nature of this infrastructure.

Consequently, project developers seek long-term and firm commitments from customers, in order to (1) mitigate investment risk (and hence lower the cost of capital) and (2) ensure a stable revenue flow to recoup capital investment.

Moreover, pipeline system owners have a strong incentive to maximize the utilization of the infrastructure, as it leads to a shorter payback period on capital and allows for a better optimization of fixed operating costs.

These basic considerations are typically reflected in the design and tariff structure of the Gas Transportation Agreements (GTA) concluded between the transporter (the operator of the pipeline system) and the shipper (the customer of the transporter—typically the owner of the natural gas being transported or an agent acting on its behalf).

In the case of the development of new, large gas pipeline systems, GTAs are usually signed before a final investment decision is taken, as they are seen as crucial to address the "capacity risk" of the pipeline project.

GTAs are often underpinned by Gas Sales Agreements (GSAs), between the seller (whose agent is the shipper) and its client(s) (located on the other end of the prospective pipeline). In these cases, GTAs often mimic the contractual arrangements of GSAs. For a detailed review of GSAs, please refer to Chap. 20 of the Handbook (*The trading and price discovery for natural gas*).

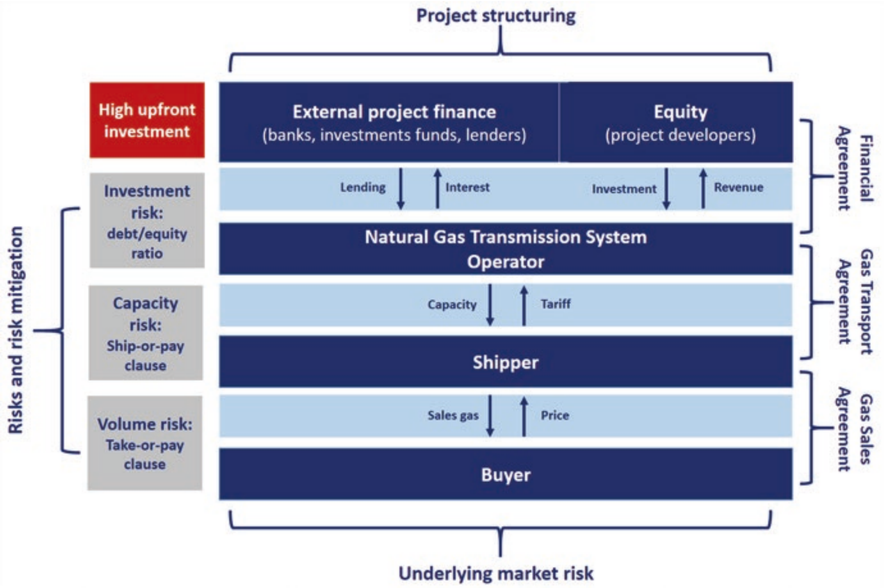


Fig. 2.7 Risk mitigation along the gas value chain. (Source: Author)

Figure 2.7 provides a simplified schematic representation of the interplay between financial arrangements, GTAs and GSAs in mitigating the investment risks associated with natural gas projects.

1.2.1 Characteristics of Gas Transportation Agreements

Under a Gas Transportation Agreement (GTA), the transporter provides a transportation service to the shipper between an input or entry point and one or multiple delivery points, in exchange for a payment made by the shipper and determined by the tariff structure (fixed in the GTA) and the volume transported and/or capacity contracted.

Capacities can be expressed either in volumetric terms (volume/time) or in reference to the energy value of the gas (energy/time).[1]

GTAs underpinning the development of new, large, international gas pipeline systems have typically the following characteristics:

1. Term commitment: GTAs are typically long-term contracts, with a duration of often over 20 years, necessary to recover the initial investment through the revenue from the transportation tariff paid by the shipper(s). The duration of the GTA is commonly aligned with the GSAs of the

[1] In SI units, volumetric capacity would be expressed as mcm/d and energy (thermal) capacity as MWh/d. In USCS, volumetric capacity can be expressed as mcf/d and energy capacity as mmbtu/d.

seller. Term commitments are usually shorter when concluded/renewed in relation to an existing gas transmission system.

2. Tariff commitment: the payments of the shipper for the used and/or reserved capacity will depend on the tariff fixed in the GTA. Tariffs should be non-discriminatory, cost-based and include a reasonable rate of return.
3. Capacity commitment: GTAs typically include a ship-or-pay commitment (often covering the entire firm technical capacity of the pipeline) from the shipper, in order to provide the transporter with a stable revenue stream through the lifespan of the contract. Two main types of GTAs can be distinguished in respect of capacity commitment:

   - Quantity-based: the transporter and shipper agree on the volumes of natural gas to be transported in the pipeline system under the fixed tariff structure. The shipper will typically take a ship-or-pay commitment in relation to the annual quantity (annual ship-or-pay quantity);
   - Capacity-based: the transporter and shipper agree on the capacity the transporter reserves for the shipper in the pipeline system (annual reserved capacity) and for which the shipper is obliged to pay irrespective of the volumes actually being transported. As such, capacity-based transportation agreements inherently have a ship-or-pay component.

In both cases, the shipper shall make a ship-or-pay payment, equating to: (ship-or-pay quantity—unused quantity) × tariff. Make-up provisions (for instance, allowing for a higher capacity usage during the next contract year in order to compensate for the previously unused capacity) might exist, but their occurrence in GTAs compared to GSAs is rare. Worth to mention, in liberalized gas markets the use-it-or-lose-it principle is prevailing: shippers are not allowed to hoard capacity, all unused capacity shall be made available to other, potentially interested shippers via auctions.

1.2.2 Tariff Structures

Alongside the duration of the contract and ship-or-pay commitments, the tariff structure fixed in the GTA is the most important factor underpinning the economic viability of a gas transmission system.

In essence, tariffs shall be structured in way to allow the recovery of the following three components:

- Capital costs related to the initial investment into the gas pipeline system;
- Operating costs occurring during the transportation services provided for the shipper (including fuel gas, personnel, etc.);
- Expected return: the profit element the owner of the transport system is expected to make on its investment.

The different cost elements can appear in a bundled way or separately, including a capacity component (fixed, reflecting the capacity booked) and a commodity charge (variable, reflecting the volumes actually transported). Similarly to capacities, tariffs can be either volume based (payment in relation to volume/time) or energy based (payment in relation to energy/time).

In liberalized gas markets, transport tariffs (1) have to be approved by the regulatory authorities; (2) have to be transparent; (3) should reflect actual costs incurred while including an appropriate return on investments and (4) should be applied in a non-discriminatory manner.

Two main types of tariff structures can be distinguished:

- Distance-based (point-to-point model): the transport tariff is set in relation to the distance between the input and delivery points.

$$C = TDV$$

where C stands for transport cost, T for tariff (€/100 km/1000 cubic metres), D for distance (km) and V for volume (cubic metres).

- Entry-exit system: the total transport costs for the shipper results from the addition of the entry and exit capacity charges it pays when entering and exiting the given transmission network.

$$C = E_n + E_x$$

where C stands for transport cost, E_n for entry fee (€/(m^3/h)/a) and E_x for exit fee (€/(m^3/h)/a).

In an entry-exit system, tariff setting can be based on a uniform approach where tariffs for different network points are set equally (postage stamp) or based on locational differentiation where the tariffs differ for every entry and exit point or zone (locational tariffs).

The tariff formula usually includes an inflation index to protect the investment value of the project (Fig. 2.8).

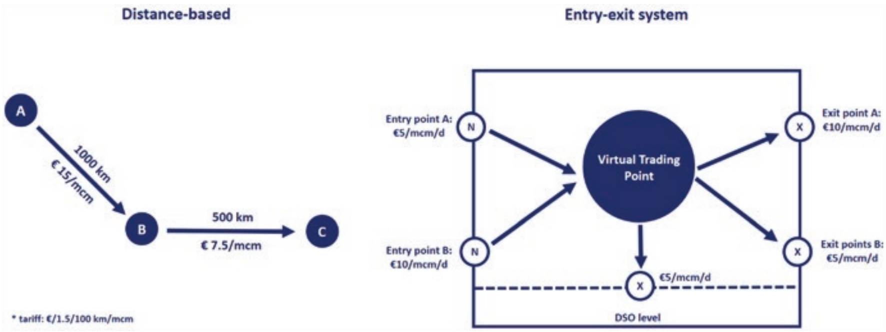


Fig. 2.8 Simplified scheme of tariff structures. (Source: Author)

Distance-based tariffs are typically used in the case of long-distance, intercontinental pipelines with a relatively simple point-to-point structure. Entry-exit models are commonly applied to more complex pipeline systems with multiple branches and interconnections.

The actual level of the pipeline tariff will ultimately depend on (1) initial unit investment cost; (2) expected rate of return and (3) additional transit payments in the case of transit.

Given that capital expenditure accounts usually for over 90% of total costs incurred through the lifespan of a gas pipeline system, tariff rates are intimately linked to the initial unit investment costs. Figure 2.9 illustrates this close interplay. Pipeline systems built in challenging environment (such as mountainous terrain or ultra-deep offshore) and/or with a suboptimal pipeline design will usually have high unit investment costs (over \$80,000/km/inch), which in turn requires higher tariff rates to make the project financially viable. Pipelines with a relatively low unit investment cost (below \$50/km/inch) can offer more competitive transport tariffs.

The transportation tariff is typically reflective of the expected return by the project developers (and lenders). This usually translates to the target return, used to calculate the target revenue. The target revenue will in turn determine the tariff, equating to total annual revenue/annual contracted capacity.

The transit fees paid by the operators of international pipelines crossing third-party countries will depend greatly on the bargaining power between the two countries, their (geo) political relationship and the potential (economic and political) benefits the transit country might receive from the transit pipeline. Transit fee payments can be paid either in cash or in kind. The Draft

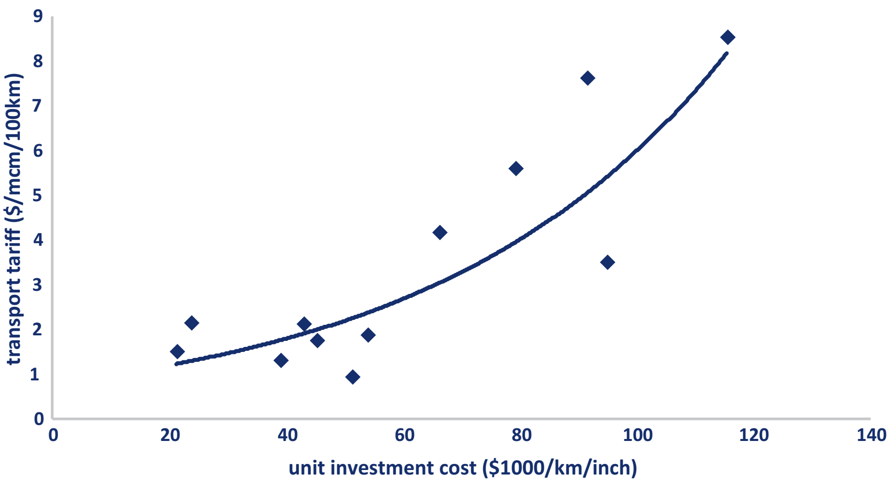


Fig. 2.9 Unit investment costs and transport tariffs of major international pipelines (2000–2020). (Source: Author based on publicly available information and industry estimates)

Transit Protocol of the Energy Charter requires that transit tariffs should be objective, reasonable, transparent and cost-based, "including a reasonable rate of return" (Energy Charter 2003).

Given the high variance of unit investment costs, transportation tariffs of international pipelines will vary in a wide range, from ~$1/mcm/100 km to over $10/mcm/100 km, translating into $0.5/mmbtu/1000 km at the lower end to over $2.5/mmbtu/1000 km for the most expensive pipeline routes.

2 LNG

Liquefied natural gas (LNG) is produced by cooling down methane to -162 °C. This effectively reduces its volume by ~600 times and as such allows for a more flexible way of transportation than through pipelines which have a fixed route by definition. Internationally traded LNG is transported via LNG carriers (LNGCs); however, smaller volumes of liquefied natural gas are also transported via trucks or railroad, typically serving local market as "virtual pipelines" (see Box 2.1).

First experiments with methane liquefaction date back to the beginning of the nineteenth century, when the British chemist Michael Faraday successfully chilled methane into liquefied form. The world's first liquefaction plant was built in 1912 in the United States in West Virginia for peak shaving.[2] An LNG facility was built in Cleveland, Ohio, in 1941. International LNG trade started in October 1964, with the first commercial shipment delivered by the LNG carrier Methane Princess from Algeria's Arzew GL4-Z liquefaction plant to Canvey Island in the United Kingdom (GIIGNL & SIGTTO 2014).

Global LNG trade grew from less than 50 bcm/year in 1970s to an average of 200 bcm/year through the 2000s and overpassed the 500 bcm mark in 2020, accounting for over 10% of global gas consumption and for over half of internationally traded gas.

The LNG value chain—not including upstream development—consists of three main components:

1. the liquefaction terminal: including pre-treatment and liquefaction units, storage tanks and an LNG loading jetty to load the LNG carrier via cryogenic pipes;
2. transportation via large LNG carries either by the buyer (free-on-board) or by the seller (delivery ex-ship);
3. a regasification terminal: including LNG unloading arms, storage tanks, vaporizers, odorization and metering stations and send-out to the transmission system.

[2] LNG peak shaving facilities store liquefied natural gas to meet short-term demand fluctuations.

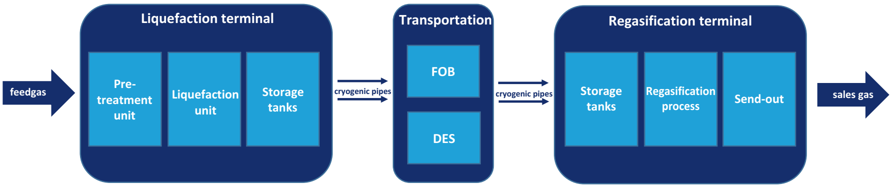


Fig. 2.10 Simplified scheme of the LNG value chain. (Source: Author)

Similarly to long-distance gas pipeline systems, the LNG value chain is characterized by high upfront investment costs and relatively small operating expenses. Consequently, the commercial contracts underpinning the development of LNG projects will show similar traits to the contractual arrangements necessary to mitigate the investment risks associated with pipeline systems (volume, term and tariff commitment) (Fig. 2.10).

Whilst this chapter will focus on the economics of the LNG value chain as described above, it is important to highlight that the costs associated with the upstream development of the reserve base supplying the liquefaction terminal (the cost of the feedgas) can significantly alter the overall economics of a project. The breakeven price of the feedgas can vary in a wide range, from below zero[3] to above \$5/mmbtu in the case of difficult-to-develop reserves (such as coal seam gas). Moreover, the distance between the upstream production facilities and the liquefaction terminal can contribute to the overall costs, in particular if it necessitates the build-up of an additional gas pipeline system.

2.1 Liquefaction Terminals

Liquefaction terminals are arguably the most complex and most costly components of the LNG value chain accounting for over half of total investment costs and operating expenses (when excluding upstream development). The following section provides an overview of their CAPEX structure, recent evolution of unit investment costs and description of typical operating expenses. This will be followed by the presentation of project structures and their contractual features.

2.1.1 CAPEX Structure

The CAPEX of an LNG project will ultimately depend on the liquefaction plant's production capacity (usually expressed in million ton per year, mtpa) and the unit investment cost (expressed in \$/ton per year, \$/tpa).

A liquefaction terminal typically consists of the following facilities, defining its CAPEX structure:

[3] A typical case is when the resource base is sufficiently rich in natural gas liquids (such as ethane, propane, butane, isobutene and pentane) to cover development costs of field.

1. Gas treatment unit: the incoming feedgas needs to be cleaned and purified to obtain pipeline-compatible gas. This includes the removal of CO_2 and sulphur (referred to as "sweetening" of gas), dehydration (to make it water free and hence avoid any icing during the liquefaction process) and the removal of mercury.
2. NGL and fractionation units: natural gas liquids (such as propane and butane) are separated from gas stream to obtain lean gas. Higher value NGLs (such as propane and butane) are separated into individual products for sale, generating additional revenue streams and hence improving project economics. The gas treatment and fractionation units usually account for 10–15% of the CAPEX.
3. Liquefaction unit: the lean, clean and dried gas is cooled down to -162°C through the application of a refrigeration technology, typically consisting of several consecutive cooling cycles (called an "LNG train"). The refrigeration and liquefaction units can account for 30–40% of the liquefaction plant's CAPEX.
4. Storage: liquefied natural gas is stored in large storage tanks before being unloaded via the product jetty through cryogenic pipelines. Besides optimizing production of the liquefaction unit, storage allows for enhanced LNG tanker scheduling flexibility and can serve as a back-up in the case of planned or unplanned maintenance. Most of LNG storage tanks are above ground with a double-walled design and insulated. Storage and unloading facilities account approximately for one-quarter of the CAPEX.
5. Utilities and offsites: due to their remoteness, liquefaction terminals usually rely on their own utilities for power generation, water supply, transport logistics and so on. These additional cost elements typically account for 20–25% of the project CAPEX.

Figure 2.11 provides an illustrative CAPEX breakdown, which could vary substantially depending on a number of factors, including external conditions, such as quality of feedgas, or remoteness of the terminal.

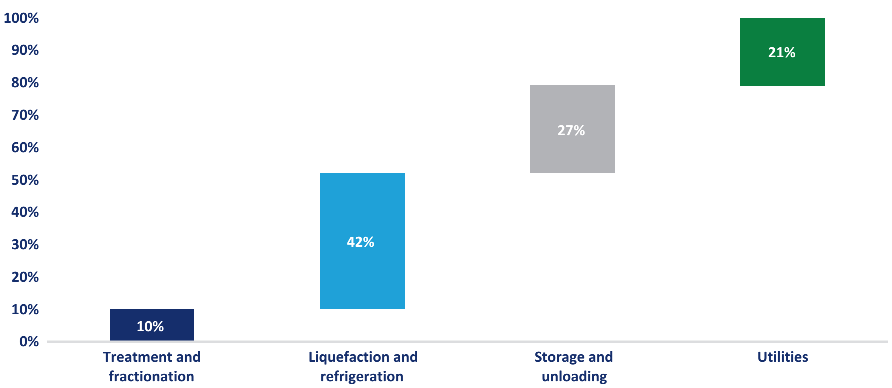


Fig. 2.11 Liquefaction terminal CAPEX breakdown. (Source: based on Songhurst (2018))

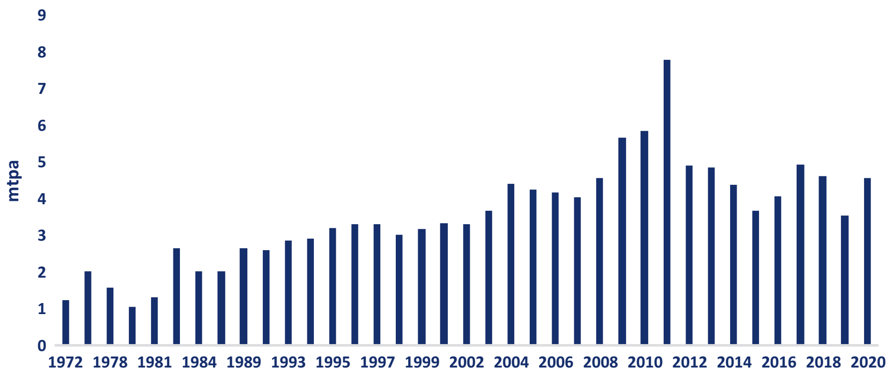


Fig. 2.12 Average nameplate capacity of liquefaction trains by commissioning year. (Source: based on ICIS LNG Edge)

2.1.2 Unit Investment Costs

The evolution of unit investment costs has been cyclical through the last couple of decades. Historical data suggest that the metric cost of liquefaction plants decreased from an average of \$600/tpa during the 1970s and 1980s to below \$400/tpa through the first half of 2000s. This has been partly driven by economies of scale: the average train size more than doubled over that period, from below 2 mtpa in the 1970–1980s to almost 4 mtpa in the first half of 2000s—and eventually reaching their peak of 7.8 mtpa with the commissioning of Qatar's mega-trains in 2009–2011 (Fig. 2.12).

However, liquefaction costs increased significantly over the last decade. According to the International Gas Union (IGU), the average unit cost of liquefaction plants more than doubled from \$404/tonne in 2000–2008 to over \$1000/tonne between 2009 and 2017 (IGU 2018).

This has been partly driven by the fact that a relatively high number of projects have been developed simultaneously, driving up demand for engineering, procurement and construction (EPC) services and the cost of labour. The cost inflation has been particularly felt by the developers of greenfield projects, for which unit cost practically tripled from \$527/tonne to \$1501/tonne over the same period. Projects in Australia (where unit costs went above \$2000/tpa) have been confronted with availability of skilled labour, high logistic costs, exchange rate shifts and construction delays (IGU 2018).

In the case of brownfield projects, which usually benefit from existing infrastructure, unit costs have been increasing less significantly, by just over 40% from \$320/tpa in 2000–2008 up to \$458/tpa in 2019–2017. This includes LNG terminals in the United States (such as Cameron, Freeport or Sabine Pass), which have been originally developed as LNG regasification terminals. The addition of liquefaction plants on those sites required less important terrain preparation works, whilst further savings could be made on utilities and storage tanks development (IGU 2018).

The average metric cost of projects currently under construction is ~\$850/tpa. This is certainly lower than the highs experienced through the 2010s (mainly due to locational factors), but still considerably higher when compared to the unit investment costs of the early 2000s.

The efforts of project developers to reduce investment costs include:

- Modularization: an increasing number of project developers is choosing to use pre-fabricated modular units to offset some of the onsite construction expenses (where labour costs tend to be higher). Whilst the use of modular units has its own logistical challenges, it has been estimated by various consultancies that modularization can reduce the CAPEX of liquefaction plants built in remote areas by 5–10% (McKinsey 2019).
- **The return of large trains**: whilst mega-trains clearly demonstrated economies of scale through improved capital and process efficiency, they naturally require a larger reserve base and more capital at risk, which hindered their development since the commissioning of Qatar's mega-trains in the late 2000s. The average train size of projects under construction is about 25% higher compared to the ones commissioned between 2012 and 2018, mainly due to projects in Canada, Mozambique and Russia—which all have train sizes over 6.5 mtpa. Moreover, Qatar's announced expansion project (which would increase the country's liquefaction capacity from 77 mtpa in 2020 to 126 mtpa by 2027) will be based on mega-trains with a capacity of ~8 mtpa.
- **Floating liquefaction (FLNG) facilities** allow for a more cost-optimal development of stranded gas reserves. The first FLNG started operations in 2017 in Indonesia (Petronas' PFLNG Satu with a capacity of 1.2 mtpa), followed by Cameroon FLNG in 2018 (2.4 mtpa), Prelude FLNG in Australia (3.6 mtpa) and Tango FLNG in Argentina (0.5 mtpa) both in 2019. Whilst FLNG certainly can optimize upstream development costs, the average unit cost per liquefaction is relatively high (~\$1400/tpa) when compared to onshore liquefaction facilities. One should note that FLNG projects **based on vessel conversions** (such as Cameroon FLNG) can have substantially lower costs (~\$500–700/tpa) than greenfield, purpose-built FLNG vessels, further improving the overall project economics.

As presented in Fig. 2.13, LNG liquefaction costs can vary from ~\$200/tpa to well above \$2000/tpa, which naturally translates into a wide range of break-even costs (usually expressed in \$/mmbtu). On average, liquefaction break-even costs are in the range of \$2–3/mmbtu.

2.1.3 OPEX

As a thumb of rule, operating expenses of a liquefaction plant account between 3 and 5% per year of the initial capital investment. This is significantly higher when compared to the operating expenses of gas pipeline systems and is

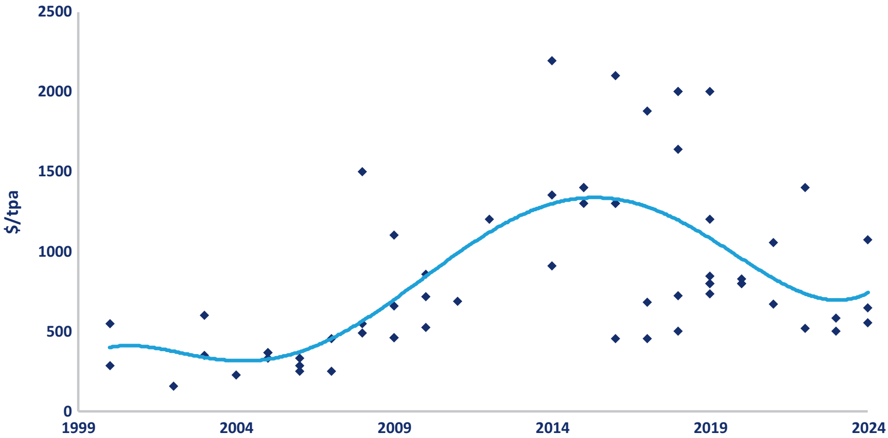


Fig. 2.13 Unit investment costs of LNG liquefaction projects (2000–2024). (Source: Author based on Songhurst (2018), publicly available information and various industry estimates)

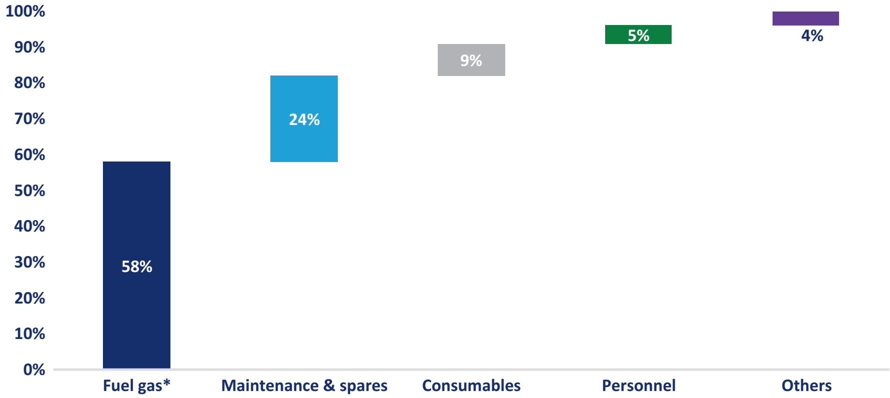


Fig. 2.14 Liquefaction plant OPEX breakdown. Assuming cost of fuel gas at $5/mmbtu. (Source: based on Songhurst (2018))

primarily due to the energy-intensive nature of the liquefaction process (Fig. 2.14).

Depending on the liquefaction process used, plant design and ambient temperatures, between 8 and 12% of the feedgas entering the liquefaction terminal is used to meet the energy requirements of the liquefaction plant (primarily to run the steam or gas turbine drivers powering refrigerant compressors). As such, fuel gas expenses can alone account for over half of the OPEX of a plant.

Other cost elements include expenses related to maintenance works, purchase of consumables (chemical products used for the refrigeration process), salaries of the personnel and insurance.

2.1.4 Project Structuring and Contract Design

Considering the high upfront investment costs of LNG liquefaction plants, project developers will seek to mitigate investment risks through risk sharing mechanisms incorporated in the project structure itself and the design of commercial contracts underpinning the procurement of feedgas on one hand and the market of sales gas/liquefaction capacity on the other hand.

Three basic types of commercial structures can be distinguished:

1. Vertical integration: the production of the feedgas, the ownership and operation of the liquefaction plant and the sale/export of the produced LNG are concentrated in one single commercial entity. The project revenues are derived from the sale of LNG via long-term sale and purchase agreements (SPAs).
2. Merchant model: the owner and operator of the liquefaction plant is a different commercial entity from the developer(s) of the upstream assets and supplier(s) of feedgas. This necessitates the conclusion of a gas sales agreement (GSA) between one or multiple upstream companies and the LNG project company. In essence, the GSA ensures the financial revenue stream of the upstream company on one hand and the supply of feedgas to the LNG project company on the other hand. The revenue stream of the LNG project company is derived from the sale of LNG via SPAs.
3. Tolling structure: the owner and operator of the liquefaction plant provides liquefaction services to its customers. The revenue stream of the LNG project is ensured by the tariff payments received from its customers under (typically) long-term liquefaction capacity agreements. The revenue stream of the customers of the LNG project company are usually ensured through long-term LNG SPAs (Fig. 2.15).

Furthermore, hybrid models can emerge. For instance, an LNG project company might offer in a bundled manner liquefaction capacity (for a fixed fee

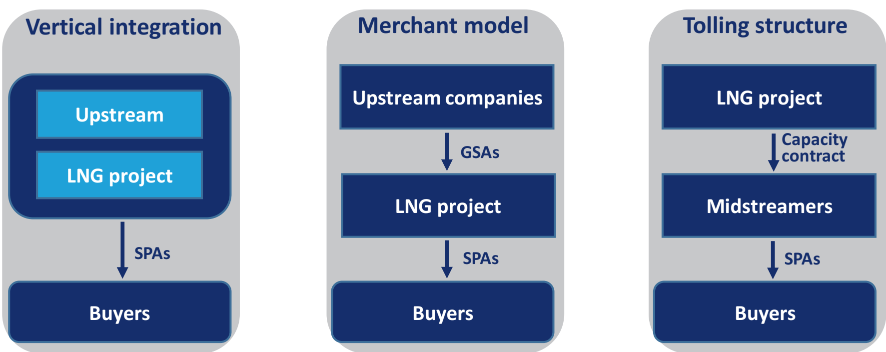


Fig. 2.15 LNG project structuring—basic models. (Source: Author)

indexed to inflation) and sourced feedgas supply (indexed to a given hub) to its customers (e.g. Cheniere's Sabine Pass or Corpus Christi projects)

Both LNG liquefaction capacity contracts and LNG SPAs have similar traits to gas transportation agreements:

- Term commitment: whilst the duration of SPAs went down, from an historical average of over 20 years to below 15 years for the contracts concluded between 2015 and 2019, liquefaction capacity agreements are typically signed for a duration of ~20 years;
- Volume/capacity commitment: both liquefaction capacity contracts and LNG SPAs underpinned by take-or-pay commitments (please refer to Chap. 20 of the Handbook) with limited volume flexibility;
- Price/tariff commitment: SPAs include a negotiated price formula applicable for the entire duration of the contract with eventual revision clauses (please refer to Chap. 20 of the Handbook). Liquefaction contracts are typically based on a fixed tariff (reflective of the breakeven cost of the project and expected margin of the developers) indexed to inflation;
- Destination commitment: historically LNG SPAs typically included destination restrictions (providing market segmentation influence to the seller). Whilst those clauses still exist in legacy contracts, they are becoming increasingly rare in new SPAs due to the resistance of buyers amidst an increasingly liquid and interconnected global gas market. The International Energy Agency's Global Gas Security Review 2019 shows that almost 90% of long-term contracts signed in 2019 had no fixed destination (Fig. 2.16).

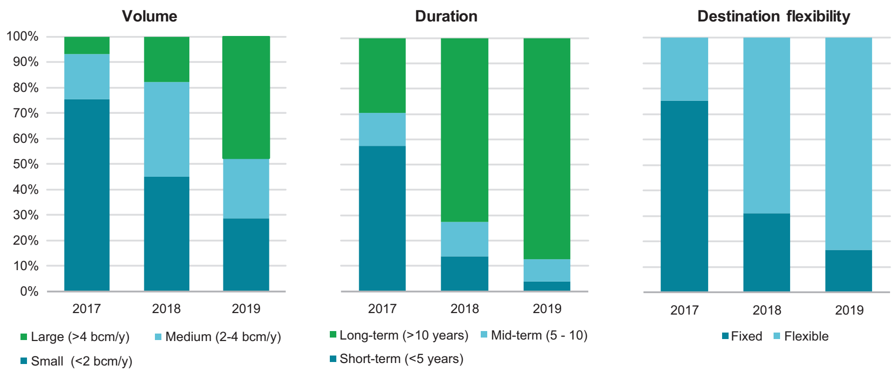


Fig. 2.16 Recent LNG contracting dynamics. (Source: International Energy Agency (2019))

2.2 LNG Shipping

Internationally traded LNG is transported via large, double-hulled vessels, with specifically designed cargo containment systems able to keep LNG at atmospheric pressure and at temperatures close to -162 °C.

The obligation of shipping LNG will depend on the contractual terms fixed between the seller and the buyer in the LNG SPAs and can take the following forms:

- Free-on-board (FOB): delivery takes place at the loading port and the buyer carries the obligation and costs of transportation;
- Delivery ex ship (DES): delivery takes place at the unloading port and the seller carries the obligation and costs of transportation;
- Costs, Insurance and Freight (CIF): the buyer takes title and risk of the LNG at the loading port, but the seller carries the obligation and costs of transportation.

The current section provides an overview of the recent trends in the LNG carriers' fleet, the contractual arrangement underpinning its development and the factors determining the unit cost of LNG transportation by vessels.

2.2.1 LNG Carriers

With a cost averaging at $200 million through the last decade, LNG carriers are fairly considered being amongst the most expensive vessels, second only to the large cruise ships.

By the end of 2019, there were just over 600 LNGCs in operation, including 37 FSRUs (Floating Storage and Regasification Units) and 46 vessels with a transportation capacity of less than 50,000 m³ (Fig. 2.17).

Two main types of cargo containment systems can be distinguished:

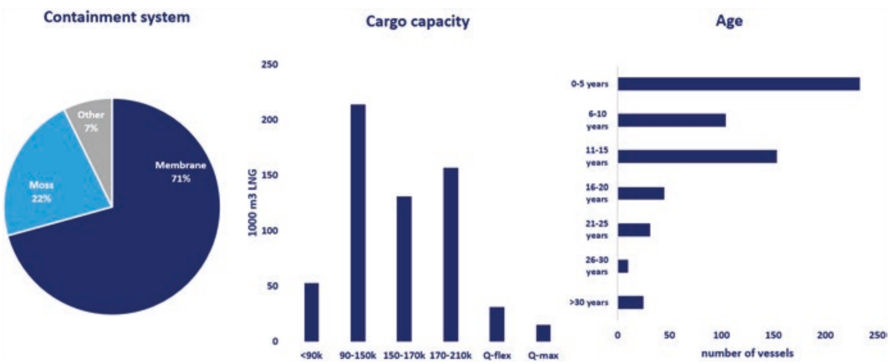


Fig. 2.17 The global LNG fleet. (Sources: based on GIIGNL (2020) and IGU (2020))

- Membrane are practically box-shaped tanks put into the vessel's holds. To cope with the cargo, holds are coated with a cryogenic lining that can withstand the load. Envelopes, known as membranes, contain the LNG at a temperature of -163 °C, sealing it with a totally impermeable layer between the liquid cargo and the vessel's hull, while also limiting cargo loss through evaporation. Membrane-type systems account today for over 70% of containment systems;
- Moss type consists of insulated independent spherical tanks constructed from aluminium alloy and designed to carry LNG at cryogenic temperatures and at a pressure close to atmospheric pressure. The tanks are encased within void spaces and situated in-line from forward to aft within the hull.

Both containment systems aim to minimize the evaporation of LNG (boil off gas, BOG). Typically, between 0.1 and 0.15% of the cargo evaporates per day during the voyage. Newer vessels are designed with lower BOG rates, with the best-in-class purporting rates as low as 0.08% (IGU 2018).

There has been a general trend towards larger cargo capacity, increasing by almost 30% from an average of 125,000 m^3 through the 1970s and 1980s to over 160,000 m^3 since the mid-2000s. The largest LNGCs (Q-max, with a capacity of over 260,000 m^3) were commissioned between 2008 and 2011 in line with the start-up of Qatar's mega-trains. According to the International Maritime Organization (IMO) safety requirements, the tanks can be filled up to maximum 98% of their capacity.

The relatively young age of the LNG fleet—with over half of the LNGCs under 10 years of age—is primarily the reflection of the strong growth LNG trade underwent through the last decade, increasing by almost twofold. LNGCs are typically retired/reconverted after reaching an age of 30–35 years.

In terms of propulsion systems, the following main types can be distinguished (IGU 2020):

- Steam turbines: boilers generate steam to run the propulsion turbines and auxiliary engines. The boilers typically use boil-off-gas and can be partially (or in some cases fully) fuelled with heavy fuel oil. They have been the dominating type of propulsion systems in the past, however are gradually losing their market share due to their relatively low thermal efficiency (resulting in high variable operating expenses). They still account for over 40% of propulsion systems under use in 2020.
- DFDE (Dual-Fuel Diesel Electric) are electric propulsion systems powered by dual-fuel, medium-speed diesel engines, which can run both on diesel and on BOG. They are typically 25–30% more efficient than steam turbines.
- TFDE (Tri-Fuel Diesel Electric) are electric propulsion systems which can be powered by diesel, heavy-oil and BOG. Altogether with DFDE, they represent one-third of propulsion systems in use.

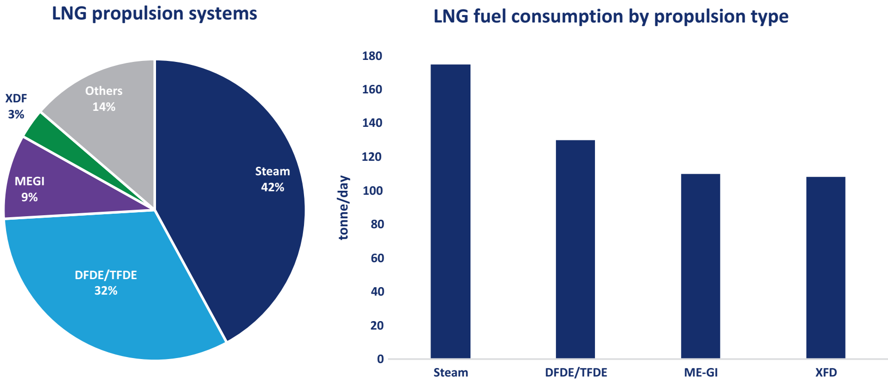


Fig. 2.18 Propulsion systems in use by market share and respective fuel efficiency. (Sources: based on ICIS LNG Edge and IGU (2018))

- ME-GI (Electronically Controlled, Gas Injection) propulsion systems pressurize boil-off gas and burn it with a small amount of injected diesel fuel. They can reach an efficiency 15–20% higher compared to DFDE and currently account for ~10% of propulsion systems in use.
- XDF (Low-Pressure Slow-Speed Dual-Fuel) represents the latest generation of propulsion systems. It burns fuel and air, mixed at a high air-to-fuel ratio, injected at a low pressure. When burning gas, a small amount of fuel oil is used as a pilot fuel. It has a fuel efficiency comparable to ME-GI propulsion systems. Currently, XDF systems account for only a fraction of propulsion systems in use, however they represent almost two-thirds of the vessel orderbook beginning in 2020 (Fig. 2.18).

2.2.2 LNG Chartering

The majority is LNGCs are owned by independent shipowners (with a share of ~70%), who charter LNGCs to market players (including sellers, buyers, aggregators, traders) typically under long-term lease agreements.

The average length of term charter contracts has significantly decreased in recent years, from over 20 years to below 10 years for the contracts concluded between 2008 and 2017. This partly reflects the changing flexibility requirements of LNG players and the shorter duration of LNG SPAs (Fig. 2.19).

Two basic types of long-term charter agreements can be distinguished:

- Time charter: the shipowner provides the LNG carrier and operating services (including the crew, management, maintenance, insurance, etc.). The tariff ("hire rate") hence has two components: a fixed CAPEX-based and a variable OPEX-based. The charterer pays for the voyage-related expenses, including fuel and port costs;
- Bareboat charter: the shipowner simply provides the LNG carrier for which it receives a usually fixed CAPEX-based tariff.

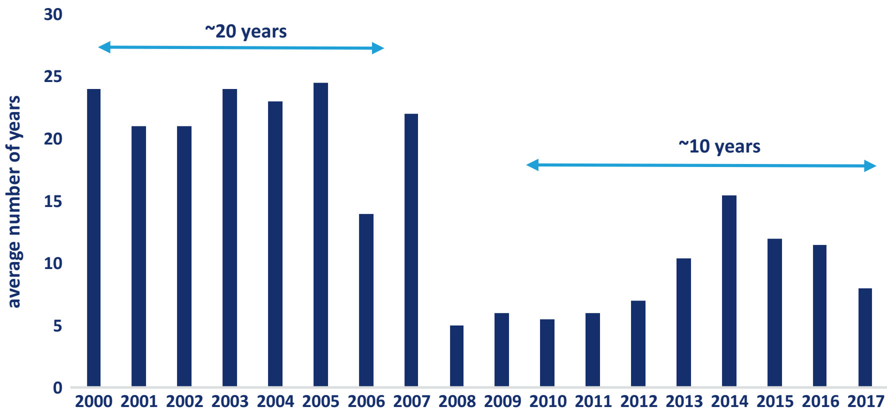


Fig. 2.19 Average length of term charter contracts, per year of contract signing. (Source: based on Adede (2019))

Long-term charter rates remain opaque. Based on the estimates of various price reporting agencies, long-term rates for LNGCs with steam turbine propulsion systems averaged at ~$50,000/day and ~80,000/day for TFDE LNGCs between 2018 and 2019.

Besides long-term charters, there is an increasing number of LNG vessels available (~10% of the global fleet) for short and spot charter deals, supporting further the development of short-term LNG trading. It should be noted that spot charter rates naturally display greater volatility, with charter rates fluctuating between $30,000/day and $200,000/day in 2018.

2.2.3 Unit Cost of LNG Transportation

The unit cost of LNG transportation between a given liquefaction and regasification terminal will depend on a number of factors, including:

- Distance and voyage time: the distance (expressed in nautical miles) typically refers to the length of the entire roundtrip. The voyage time is important given that charter rates are paid per diem and will depend on the speed (expressed in knots=nautical miles[4]/hour) of the vessel. Typically the vessel spends one day at the export terminal and one day at the import terminal with loading and unloading operations, respectively;
- Charter rates typically account for over half of the total transport unit cost. They will vary accordingly to the vessel's size, age, propulsion system and BOG rate, and in the case of spot charters will be largely determined by the prevailing market conditions;
- BOG: will depend on the vessel's BOG rate, the distance and the speed of the vessel;

[4] Nautical miles equate to 1.15 miles and to 1.852 kms.

- Fuel cost is directly proportional to the distance and speed of the vessel. Higher speeds (~19 knots) will naturally translate into higher fuel and/or BOG consumption (vs a vessel running at 14–15 knots can rely purely on natural BOG), whilst lowering the voyage time could reduce chartering costs. The fuel price will depend on market prices for bunker fuel (typically HFO/MDO) and the charterer's procurement strategy. Inclusive of BOG, fuel costs are usually the second most important component of total unit transport costs (over 25% for ST vessels);
- Heel gas requirements of the LNG vessel refer to the minimum inventory level to keep the tanks cool after unloading and potentially necessary for unladen voyages if running on boil-off. It is typically assumed to be ~2–4% of the initial cargo;
- Canal costs has to be paid when transiting through the Suez and Panama canals. They are set by Canal Authorities and are typically in the range of $300–500,000/transit;
- Port costs: paid per diem during the loading and unloading operations and are usually assumed ~$100,000/day;
- Brokerage fee: spot charters are typically arranged through specialist brokers, usually attracting 1–2% of the total charter cost;
- Insurance: typically covers the vessel and the cargo, either separately or bundled.

Illustrative LNG shipping costs are provided in Fig. 2.20, for major transport routes. Altogether, the approximative unit transport cost in the case of a DFDE vessel with a cargo capacity of 160,000 m^3, chartered for $80,000/day and sailing at 18 knots, without the need to transit via canals, would be $0.04/mmbtu/1000—significantly cheaper than transportation via pipelines (with tariffs ranging between $0.5 and 2/mmbtu/1000).

2.3 *Regasification Terminals*

Regasification terminals can be located onshore (representing almost 90% of global regasification capacity in the beginning of 2020) or offshore on Floating

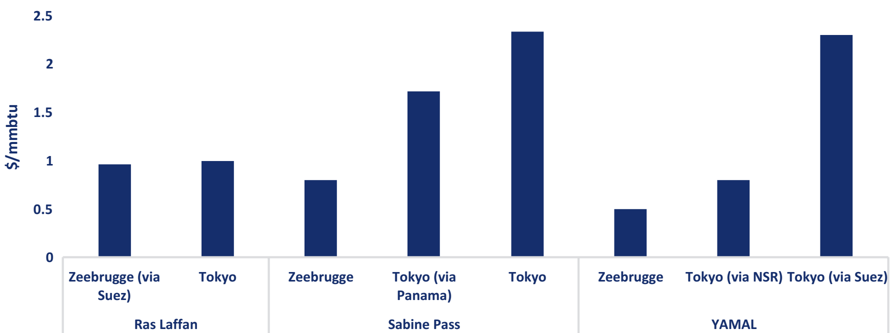


Fig. 2.20 LNG shipping costs for major transport routes for a DFDE vessel. (Source: based on ICIS LNG Edge)

Storage and Regasification Units (FRSUs or FRUs—in the absence of storage capabilities).

A regasification terminal consists typically of the following facilities:

- Unloading arms: LNG is delivered from the LNG carrier via unloading arms, establishing the connection between the vessel's manifold system (piping connection) and the terminal. There are usually several unloading arms and one vapour return arm. It is necessary to send back vapour to the LNG carrier to avoid vacuum conditions. Unloading typically takes 12–16 hours, and the carrier stays about one day in the port.
- Storage: once unloaded, LNG is transported via cryogenic pipelines to storage tanks. Storage tanks allow for tanker scheduling flexibility and optimization of send-out to the downstream market. They have similar design to the ones located at liquefaction terminals and primarily serve tanker scheduling flexibility and optimization of send-out (and hence sales). It is worth to note that in markets with no significant underground storage capacities, LNG storage can enhance security of supply.
- Vaporizers: the LNG sent from the storage tanks is regasified with vaporizers. Four basic types can be distinguished: (1) open rack vaporizers using seawater for the heat necessary to vaporize LNG; (2) submerged combustion vaporizers using natural gas produced by the terminal and pass the hot gases into a water bath containing a tubular heat exchanger where LNG flows; (3) intermediate fluid vaporizer has two levels of thermal heat exchange, first between LNG and an intermediate fluid such as propane and between the intermediate and a heat source (typically seawater); (4) ambient air vaporizers using the heat from the air (usually applied at smaller regasification terminals).
- Send-out: once regasified, natural gas flows to the pressure-regulating and metering station, before being sent-out to the national gas transmission system. Depending on the configuration of the LNG regasification terminal, natural gas can be odorized in an odorizing station before leaving the terminal.

Onshore regasification terminals have significantly lower unit investments costs compared to liquefaction terminals, averaging at ~$250/tpa between 2013 and 2017. However, one should note that this represents a significant cost-escalation compared to the projects commissioned between 2006 and 2012, with an average unit investment cost of $115/tpa. The rise in unit costs has been driven by higher expenses associated with EPC contracts and by the general trend towards larger storage tanks.

Offshore regasification terminals have usually lower metric costs (~$100/tpa), as they require less terrain preparation and ground work. FSRUs are often reconverted LNG carriers, which tend to lower their unit costs as well. They typically have shorter lead times (e.g. Egypt's second FSRU project has been implemented in a record time of 5 months) compared to conventional onshore

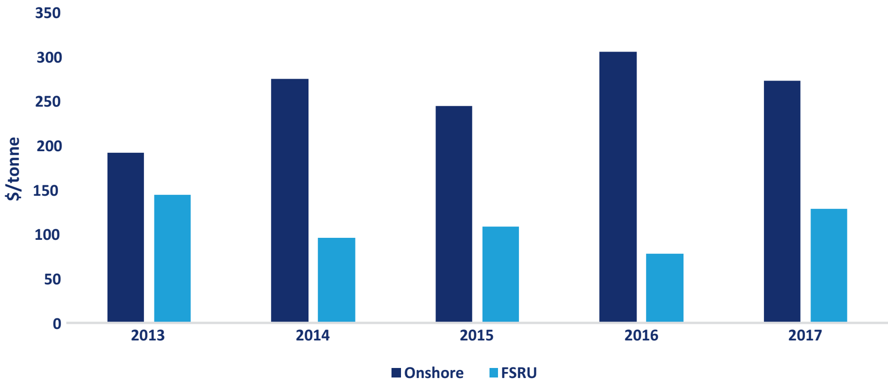


Fig. 2.21 Regasification unit investment costs (2013–2017). (Source: based on IGU (2013–18))

regasification terminals. This can be of particular interest in markets which experience near-term gas demand growth or potential supply-demand imbalances. On the flipside, they tend to have higher operating expenses (as the vessel is most commonly leased), lower storage capability and no option for future expansions. Since the first FSRU has been commissioned in 2005, offshore regasification has been growing considerably to over 100 mtpa by the beginning of 2020 (Fig. 2.21).

Regasification capacity is usually booked under long-term capacity contracts. In liberalized markets, under the principle of use-it-or-lose it, unused capacity has to be offered on the secondary market, for instance, via auctions. Regasification fees typically range between $0.3 and $1/mmbtu.

3 Conclusion

Transportation typically accounts for over half of total costs occurring through the value chain of internationally traded natural gas and hence greatly influences its cost competitiveness.

Both long-distance pipeline systems and LNG have high upfront investment costs, requiring risk sharing mechanisms being incorporated either in the project structure itself (primarily via vertical integration) and/or into the design of commercial contracts between the project developers and their customers.

Risk sharing typically translates by the buyers' long-term commitment to pay a fixed tariff (reflective of the breakeven cost of the project and expected margin of the project developers) for the liquefaction/transportation capacity purchased on a firm basis and underpinned with ship-or-pay clause. Whilst gas sales contract structuring has been evolving towards a greater commercial flexibility (allowing for shorter term deals with less firm commitments and more diverse price formulae), transportation contracts—especially when underpinning the development of new infrastructure—have largely retained their conservative design, allowing project developers (and their lenders) to recover the initial high upfront investment cost through a stable revenue stream.

When comparing transportation costs via LNG vs long-distance pipeline systems, one should note that in the case of LNG the majority of costs—both initial investment and operational expenses—occur upfront, at the stage of liquefaction and then increase relatively slowly (less than $0.05/mmbtu/1000 km) during the transportation phase via LNGCs. In contrast, in pipeline systems transportation costs increase more swiftly ($0.5–2.5/mmbtu/1000 km) with the travelled distance.

Consequently, LNG becomes cost competitive with pipeline transportation only on long distances, typically beyond several thousand kms. This is illustrated in Fig. 2.22, comparing the delivery costs of LNG (assuming an average ~$2.4/mmbtu liquefaction and 0.4/mmbtu regasification fee) transported via an LNGC with a typical long-term hire of $80,000/day versus pipelines operating under a relatively low tariff rate of $0.5/mmbtu/1000 km and a higher tariff of $1/mmbtu/1000 km.

Considering the above-described assumptions, LNG becomes cost competitive with pipeline transportation for distances above 3000–7000 kms. However, as discussed through the chapter each pipeline and each LNG project is unique and unit investment costs vary in a wide range for both type of infrastructure, which can significantly alter the “breakeven distance” between LNG and long-distance pipeline systems.

The high transportation costs of natural gas compared to other primary fuels (such as coal or crude oil) is severely weighing on the cost competitiveness of methane molecules. The gas industry will need to continue to work on optimizing transportation costs.

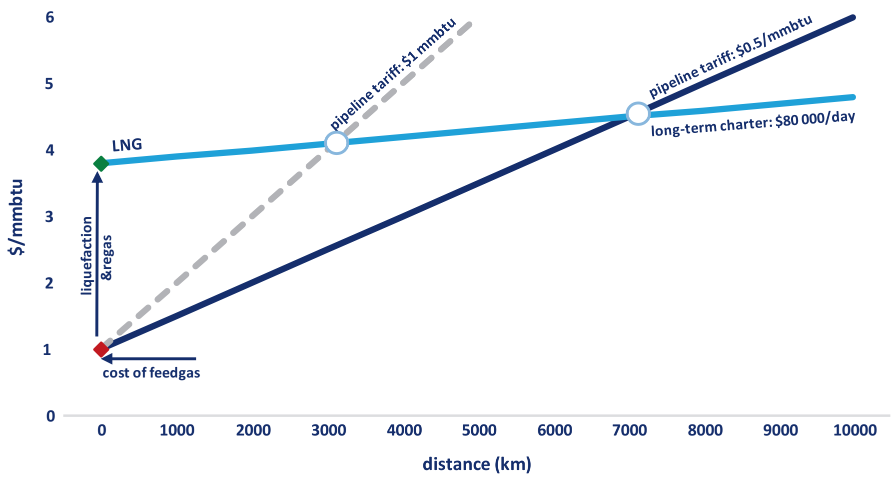


Fig. 2.22 LNG versus pipeline transportation costs. (Source: Author)

The unit investment cost of liquefaction plants has been decreasing since the highs (over $2000/tpa) reached in the early 2010s. However, the average metric cost of projects currently under construction (~$850/tpa) is still approximately twice the unit investment cost of projects commissioned between 2000 and 2008. This highlights the potential cost reductions which might be reached through improved project management, plant design optimization and usage of innovative construction approaches (e.g. modularization, vessel conversions to FLNG).

Given the maturity of technology, the cost reduction potential in gas pipeline systems is considered to be rather limited. The design of newly built pipelines will increasingly need to take into account the requirement of improved compatibility with low-carbon gases, including hydrogen (see Chap. 4 of the Handbook, *Economics of hydrogen*), biomethane and synthetic gas.

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CHAPTER 3

Economics of Oil Refining

Jean-Pierre Favennec

1 Introduction

Refining is a key step in the oil industry, as we do not directly consume crude oil. A petroleum refinery is a set of installations intended to transform crude oil, generally unusable as such, into petroleum products: motor gasoline, jet fuel, diesel fuel, fuel oil, lubricants, liquefied petroleum gases, naphtha, and so on.

The products consumed in largest volumes are motor gasoline, motor diesel, and heavy fuel oil. The products with the fastest growing consumption are jet fuel and diesel fuel (Table 3.1).

1.1 Crude Oil

Crude oil is composed mainly of hydrocarbon molecules formed from carbon and hydrogen atoms. Impurities, particularly sulfur and metals, are also found in oil. Sulfur is found in the products and gives SO_2 by combustion, which is dangerous for the environment. Metals are present in very small quantities (a few parts per million—ppm), but, even in very low concentrations, their presence in petroleum products can be harmful to the processes that use them (especially catalysts).

There are probably more than 400 different crude oils in the world. While the annual production of Arabian Light, a crude oil extracted mainly from the Ghawar field in Saudi Arabia, exceeds 250 million tons per year (Ghawar, from where it is produced, originally contained more than 10 billion tons of crude oil), many crude oils are produced in very small quantities. Only about a hundred crude oils are traded on a significant international scale.

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Table 3.1 Global consumption of refined products (million tons)

	1973	*2017*	*2017 vs 1973*
LPG/Naphtha	199	517	260%
Gasoline	559	1112	199%
Jet	114	371	325%
Diesel oil	592	1422	240%
Fuel oil	747	371	50%
Others	196	605	309%
Total	2407	4337	180%

Source: Adapted from International Energy Agency

So many deposits, so many raw materials. Each crude oil is characterized in particular by its density, which is commonly measured in American Petroleum Institute (API) degrees.[1] The current crudes have a density between 0.8 (about 45° API) and 1 (10° API). A light, low-density crude oil will produce relatively high levels of gasoline and diesel fuel and low levels of fuel oil. On the other hand, a heavy crude oil will give a lot of heavy fuel oil.

1.2 The Main Steps of Refining

The refining of petroleum, that is, the transformation of crude oil into finished products, requires several operations that can be grouped as follows:

- the separation of crude oil into different fractions, which are the basis for the manufacturing of finished products
- the improvement of the quality of some cuts
- the transformation of heavy cuts into light cuts
- the final preparation of the finished products by blending

A refinery consists of several distinct parts:

- the process units where oil is separated into fractions or cuts; some cuts undergo additional processing for improvement in order to reach commercial requirements; heavy fractions can be converted into light fractions,
- utilities, that is, all units of production of fuel, electricity, steam, and so on, necessary for refining processes
- storage facilities
- reception and shipping facilities,
- blending facilities.

[1] The formula for API gravity is: (141.5/Specific Gravity)-131.5. Hence water, which has a specific gravity of 1, has an API degree of 10. All crude oil is lighter than water, and the lighter it is, the higher is the API degree.

The area covered by a refinery can reach several tens of hectares, but a large part of this area is covered by storage facilities

2 History and Evolution of Refining

The use of oil goes back to the earliest times. The Mesopotamian king Sargon refers to bitumen in the cuneiform texts that have come down to us. Reference is also made to the bitumen in the Bible, whether it is the caulking of Noah's Ark or the coating of Moses' cradle to allow it to float on the Nile.

Very early on, the Chinese refined crude oil. Many texts mention the use of petroleum-based products as lubricants.

More than one thousand years ago, oil fields were already being exploited in the Baku region (which was the main oil production region at the beginning of the intensive exploitation era, during the Russian Tsar's empire in 1900).

Around the year 1000 Arab chemists used the distillation of oil to make different products, like lubricants.

Oil was also widely used as a weapon of war. The famous "Greek fire" spread terror in many naval fleets from the beginning of our era in the Mediterranean area. Arab and Persian chemists, then Chinese chemists, also used highly flammable products in the same way.

However, the modern history of the oil industry is said to have begun with the production of kerosene for illumination. For many years, the use of lamp oil (mostly whale oil) was the best way to illuminate a room, until the whale population decreased rapidly. In 1846, Abraham Gessner of Nova Scotia, Canada, developed a process to produce kerosene from coal. Shortly afterwards, in 1854, Ignacy Łukasiewicz began producing kerosene from hand-dug oil wells in Poland.

In the United States, the indigenous Indians used seepages of oil in different ways, including lighting. Some specialists considered that probably oil could be found in the ground, and the oil industry began in 1859, when Edwin Drake discovered oil near Titusville, Pennsylvania, by digging a 20-meter deep well. Very rapidly, John D. Rockefeller, a young smart accountant, built several refineries to produce mainly kerosene and took monopolistic control of the oil refining and marketing industry in the United States. He created Standard Oil, a company capable of manufacturing kerosene of standard—that is, constant—quality, from different crude oils with different characteristics. The company was an association of several corporations, more or less one per US state. However, in 1911, Standard Oil was taken to court because it was a monopoly, prohibited under the newly approved Sherman Act, and was broken up into 34 companies including Standard Oil of New Jersey, now Exxon, part of Exxon Mobil; Standard Oil of New York, now Mobil, the other part of Exxon Mobil; Standard Oil of California, today's Chevron, and so on. At the beginning of the twentieth century, the introduction of the internal combustion engine and its use in automobiles created the gasoline market, which became the driving force behind the relatively rapid growth of the oil industry. Early oil discoveries, such as those in Ontario and Pennsylvania, were quickly overtaken by large oil "booms" in Oklahoma, Texas, and California.

From a technical point of view, the refining industry really began in 1863 with the construction of the first distillation unit in Boston, USA. Certainly, this unit has nothing to do with the refineries we know today. Still, it made possible to extract from crude oil the kerosene or lamp oil consumed at the time. The development of electricity by Thomas Edison introduced a competitor to kerosene, but the development of electricity consumption was very slow. Shortly afterwards, the appearance of the automobile led to an increase in the consumption of petrol and diesel. Then fuel oil found an outlet in the navy, just before the First World War.

The refining industry was booming, and on the eve of the Second World War, distillation capacity reached 364 MT/y—Million Tons per year—worldwide, two-thirds of which in the United States and only 4% (16 Mt./year) in Europe.

More distillation units, but also more so-called secondary treatment units were built. First of all, thermal reforming was developed to increase the production of gasoline. Then came thermal cracking to reduce the production of heavy fuel oil and increase the production of light products, especially gasoline and diesel. Finally, after Second World War, catalytic reforming was introduced to improve the quality of gasoline. Many other processes developed in parallel, but the refining industry can now be considered a mature industry.

Rockefeller initially focused on crude oil processing and product distribution operations, leaving oil production, which he considered too risky, to other players. But gradually, within the major oil companies, refining has become integrated with oil exploration and production on the one hand, and distribution on the other. Integration provides the company with its sources of crude oil and its outlets, thus promoting the smooth physical operation of the oil chain. Gradually, however, and in particular because of nationalization of the oil fields in several counties in the 1970s (Algeria, Libya, Iraq first, Venezuela, Kuwait, Saudi Arabia some years later), international companies became mainly refining and distribution companies, with crude oil production being largely in the hands of the national companies of producing countries. This trend has been partially reversed: some producing countries opened their oil exploration and production in order to attract the large international oil companies (the Majors), which can bring expertise and financing. Very often this has been carried out through associations (joint ventures) between the national oil company and the foreign companies.

On the other hand, some OPEC countries now play a key role in refining. The countries of the Persian Arab Gulf and Venezuela have developed significant capacities, which are largely export-oriented. For strategic reasons, some of them (Saudi Arabia and Venezuela) have also taken control of important capacities abroad (especially in the United States).

3 Refining Capacities Around the World

Refining capacity, measured by atmospheric distillation capacity, increased from just over 1 billion tons per year in 1950 to over 4 billion tons per year in 1980. It declined to less than 3.60 billion tons in 1985, following the second oil crisis. After the fall in oil prices in 1986, capacity increased again and is currently of the order of 5 billion tons per year, or 100 million barrels per day.

- *Asia* (from Pakistan to Japan, and including Australia and New Zealand) is now the world's largest refining area, with a distillation capacity of 1.7 billion tons per year. Japan and China have the largest facilities, but South Korea and India also have a significant tool. Capacity has increased very rapidly in recent years due to the very strong growth in demand, especially in China and India.
- *North America* (the United States, Canada, and Mexico) also has a very large refining base, representing more than 20% of the world's capacity. The United States has more than 80% of the capacity in this region. It should be noted that the number of US refineries has fallen from 320 to 135 in 40 years, while total capacity increased. Small refineries in the middle of the United States have been closed for lack of crude oil at the time, while large refineries developed on the coast.
- *Western Europe and Turkey*, with 17% of the world's capacity, remains a major refining area, despite the very sharp capacity reductions in the early 1980s. The number of refineries has decreased from 160 to about 100, with a 30% reduction in total capacity. Capacity in Eastern Europe is around 13% of global total. Most (80%) of this capacity is located in the former USSR, but these figures should not be misleading: facilities in this region are generally old, unsophisticated, and currently much underutilized.
- *Central and South America* is well equipped with refineries, with Brazil and Venezuela having the largest capacities. Large-scale refineries are located in the Caribbean and Venezuela: they are often export-oriented and the United States is a privileged market for refineries in this sub-region. However, it should be stressed that at the time of writing US sanctions on Venezuela are impacting the refining industry there.
- *The Middle East* is also an important refining center with several large refineries for export, particularly to Asia. The largest exporters are Kuwait, Saudi Arabia, and Abu Dhabi. The strong growth in demand, driven by economic growth and rather low product prices, requires a rapid increase in capacity. In addition, large new refineries have recently been built in Saudi Arabia, for example, SATORP, a 20 million tons very sophisticated refinery built by Total and Aramco. Sinopec and Aramco are building a similar refinery.
- Finally, *Africa* has only limited capacity. Four countries (Algeria, Egypt, Nigeria, and South Africa) represent more than 60% of the continent's

> capacity. Apart from Algeria, Libya, and Egypt, which export finished products to Europe and the United States, refineries in this area are mainly used to supply local markets. In many sub-Saharan countries, there are small refineries (of about 1 to 3 million tons) to supply local markets of the same size. The profitability of these refineries is precarious, but they give autonomy in terms of products, which can be precious, to the countries where they are located.

However, many of these refineries have closed more or less recently (Mauritania, Sierra Leone, Liberia, Togo on the West Coast; Mombasa, Dar Es Salaam, and Maputo on the East Coast). These refineries are finding it increasingly difficult to compete with products that arrive in large quantities from large refineries built in the Persian Gulf or in India.

In total, there are currently approximately 700 refineries worldwide with a total processing capacity of approximately 100 million barrels per day. The average capacity of a refinery is therefore around 150,000 b/d or nearly 8 Mt./year.

The Jamnagar refinery is the largest oil refinery in the world since 2008, with a processing capacity of 1.24 million barrels per day (more than 60 million tons per year, almost equivalent to the capacity of a major European country!). Located in Gujarat, India, it is owned by Reliance Industries.

Among other very large facilities, we find the Paraguana refinery in Venezuela, which is the result of the merger of the Amuay and Cardon refineries (pipe connections have been established between the two refineries). Its capacity totals 980,000 barrels per day. There are also the South Korean refineries in Ulsan (two refineries) and Yeosu, whose combined size exceeds 2 million barrels per day. Other very large refineries are found in Saudi Arabia and the United States.

On the other hand, there also are small refineries adapted to small and isolated markets. Inland countries (Mali, Niger, Chad, Uganda, Rwanda, and so on) are very difficult to supply with finished products from the African coast, which can be more than a thousand kilometers away. In Chad and Niger, which have domestic oil resources, two similar 20,000 barrel per day refineries were built by Chinese companies just after 2010.

4 Refining Structure and Evolution of Demand by Product

As we have seen, the strong growth in the consumption of oil (and therefore petroleum products) dates back to the 1950s and 1960s. At that time, the switch from coal to liquid fuels led to an impressive increase in demand for heavy fuel oil and heating oil. Until the early 1970s, a simple refinery (composed of Distillation + Catalytic Reforming + Desulfurization Units), which processed a medium crude oil of the Arabian Light type, was perfectly adapted to demand, producing 40 to 50% heavy fuel oil, used in the industry and for electricity production, in line with the demand.

The 1973 and 1979 oil shocks, by increasing the price of oil tenfold, led to a sharp drop in demand for heavy fuel oil, replaced by coal, gas, or nuclear power. On the other hand, demand for gasoline, diesel oil, and jet fuel, for which there were no substitutes, continued to grow. To cope with this change in the structure of demand, it was necessary to build many conversion units, which are capable of transforming heavy distillation fractions into lighter fractions, petrol or diesel components. Most of the units built were of the FCC type (fluid catalytic cracking) because they have the dual advantage of very high fuel efficiency and a "moderate" investment cost compared to that of alternative solutions, such as a hydrocracker. The conversion rate, measured by the ratio of the weighted sum of a refinery's conversion capacity to its distillation capacity, increased in all regions of the world. The development of conversion has been significant in Western Europe, where the conversion rate of around 5% in 1975 increased to more than 50%. In 1977, Western Europe had 143 refineries, but only one-third of them had FCCs. Ninety percent of the remaining 100 refineries are now equipped with FCCs (or equivalent process units).

Similar trends have been observed in other regions of the world. The latest refineries built in Asia and recent extensions in the Middle East include many cracking units.

4.1 Recent Developments

Refineries must constantly adapt to major changes, for example, switch to unleaded petrol around 1990; general reduction in the sulfur content of fuels; and reduction in sulfur dioxide emissions from ships, which requires the installation of scrubbers or switching to LNG.

Thus, we have witnessed the construction of units capable of supplying gasoline components with increased octane number (regenerative catalytic reforming, isomerization, alkylation, etc.) to meet the demand for unleaded petrol and remodeling—rather than new construction—of desulfurization units to cope with the mandated reduction in the sulfur content of products, and in particular diesel fuel.

The decrease in heavy fuel oil production—which is imperative given market trends—is being achieved through improvements to existing FCC-type units capable of handling "heavier" loads and recent or future projects in deep conversion units, and remains a major challenge for refiners. The construction of very expensive deep conversion units (residue hydrocracking, coking with coke gasification) requires a considerable spread between the prices of diesel oil and that of heavy fuel oil. The changes to the FCCs also allow heavier loads to be handled. The transformation of residues into electricity via gasification is also an interesting option.

The refining industry in the United States is characterized by a particularly high conversion rate. Traditionally, the American refining industry has had to face very strong demand for motor gasoline. US demand for gasoline is in the order of 400 million tons per year, or about 45% of total US demand for petroleum products and 40% of total world demand for gasoline. The size of the car fleet, the high unit consumption of cars in the United States, and the fact that part of the commercial vehicle fleet is equipped with gasoline engines explain the strong demand for this product. On the other hand, abundant gas and coal resources have reduced the market for heating and heavy fuel oil. As a result, American refineries—or at least the largest ones—are equipped not only with FCC units but also with cokers. Eighty percent of cokers in the world are located in the United States. The average gasoline yield of US refineries exceeds 55%.

5 Refining Investment Costs

The investment cost of a completely new refinery depends on its size, complexity, and location. It is generally estimated that a 160,000 b/d (8 million tons per year) refinery, equipped with catalytic cracking, visbreaking, and gasoline units and built in Europe, would currently cost more than $6 billion. This cost can be significantly increased in the event of extremely stringent emission regulations, in terms of both the refinery's environment and the product quality.

A simple refinery (atmospheric distillation and catalytic reforming, plus distillate hydrodesulfurization) of a smaller size (100,000 b/d or 5 million tons per year) would cost half of this amount, or $3 billion. But the construction of such small refineries, which are no more profitable because they produce too much heavy fuel oil, is no longer on the agenda. Conversely, the investment required for a very large refinery, equipped with a deep conversion unit in order to reduce the production of heavy fuel oil to very small quantities, would cost more than $10 billion.

The analysis of investment costs shows the very high proportion of "off-sites" (production of utilities, storage, receiving and shipping facilities), which can represent more than half of the cost for simple refineries. All other things being equal, the degree of autonomy of the refinery in electricity (whether or not it is purchased externally), the size of the tank farm, the size of the reception and shipping facilities are, among many others, important parameters in the total amount of the investment.

Two characteristics are essential in determining the investment cost:

- *Size*: The volume of a vessel (which determines its production capacity) is a function of the cube of the radius, while the surface (which determines its cost) is a function of the square of the radius. As the size of the vessel increases, its production capacity therefore increases faster than its cost. There are therefore significant economies of scale in a refinery. These savings are limited by the maximum size of some units. Thus, an atmospheric distillation unit will usually not exceed a dozen million tons per year of capacity. A larger refinery will therefore have at least two atmospheric distillation columns.

- *Location*: The cost of transporting the equipment and the cost of assembly are significant elements of the construction cost. A refinery located at a site far from the manufacturing plants for the main components (columns, reactors, etc.) will therefore be more expensive than the same refinery located near suppliers (North America, Europe, and Southeast Asia). The scarcity of local labor, forcing the movement of specialized teams, also has a significant impact on investment. Finally, particular climatic conditions can also have an impact on the price of the equipment.

6 Refining Costs

For ease of analysis, a distinction is made between variable costs (proportional to the quantities of crude processed), fixed costs (independent of the quantity of crude oil processed: personnel, maintenance, overheads) and capital costs (or depreciation).

6.1 Variable Refining Costs

These are proportional to the quantities of crude oil processed: they are mainly related to chemicals and catalysts.

Chemicals: A large number of chemicals are used in refining processes, but the costs involved remain limited. For a long time, the main focus was on lead additives (tetra-ethyl lead) to improve the octane number of gasoline. The gradual disappearance of these additives led to a reduction of the total cost for "chemicals". However, the increasing use of other additives (cetane improvers, additives improving cold resistance for diesel fuel, "pour depressants", etc.) slightly increases costs.

Catalysts: Most refineries—with the exception of refineries which have just a single distillation column—include catalytic process units: reforming, cracking, isomerization, alkylation, hydrodesulfurization, catalytic cracking, hydrocracking, and so on. The catalysts used are very diverse. The reforming process uses noble metal catalysts, whose cost exceeds several hundred dollars per kilo. However, these catalysts are regenerated (continuously in recent units, periodically in older units): at the end of the use cycle, the noble metals are recovered and reused.

For catalytic cracking, catalyst losses are continuously compensated by an injection of new catalyst. The cost of the catalyst is limited.

In total, the cost of chemicals and catalysts, per barrel of crude oil processed, is in the order of one dollar.

6.2 Fixed Costs

These costs include personnel, maintenance, insurance, local taxes, overheads, and so on, which are almost independent of the quantity of crude processed. Indeed, whether the refinery operates at 60% or 100% of its nominal capacity, personnel costs, for example, are the same.

Staff: The number of people working in a refinery varies greatly. It is at least about 200 to 250 people for a simple refinery. It can be much higher for a complex refinery, equipped with several atmospheric distillation units and cracking. For example, a large refinery (with two atmospheric distillations, two reformers, one catalytic cracker, one hydrocracker, one visbreaking unit, but also hydrodesulfurization units and an oil chain) directly employs more than 1000 people. The staff numbers therefore depend very little on size, but mainly on complexity. Personnel costs range from about $15 million/year for a simple refinery to $40 million/year for a refinery equipped with deep conversion. As a reminder, it should be noted that some refineries, particularly in the former Soviet Union countries, had a very large number of employees, several times higher than the number of employees in a Western European refinery. This is due to both the multiplication of small units in the same refinery and the existence of highly developed ancillary services (some factories even had spare parts manufacturing workshops, health services, and agricultural production cooperatives).

Maintenance: Maintenance is more or less proportional to the initial investment cost. A rule of thumb considers that the annual maintenance cost represents approximately 1 or 2% of the initial investment, that is, between about $50 million/year (simple refinery) and $100 million/year (deep conversion refinery). In Western refineries, most of the maintenance services, which are not considered part of the core business, are now outsourced.

General costs: These cover taxes, insurance, miscellaneous operating costs, overheads.

Total fixed costs are in the order of $2 to $3 per barrel processed (if the refinery operates at or close to capacity).

6.3 Recovery of Capital Costs

Capital, whether it is the cost of initial capital investment for a new refinery or the cost of new units in an existing refinery, must be recovered as depreciation. For a 160,000 barrel per day refinery equipped with conventional conversion, the initial investment, as we have seen, is about $6 billion. If this unit is new, the incidence of capital depreciation (which can be interpreted as the sum of interest and repayments assuming the money needed to build the refinery is fully borrowed) will be in the range of $8 to $9 per barrel of crude processed (again, if the refinery operates at or close to capacity).

6.4 Total Refining Cost

In total, the costs and charges (excluding utilities) for a new conventional conversion refinery operating at full capacity would amount to just over $10 per barrel. But the majority of refineries in operation is largely amortized and therefore operates with lower refining costs, in the order of $3 to $5 per barrel of crude oil processed.

6.5 Factors That Influence Refining Costs and Profitability

As we have seen, fixed costs (personnel, maintenance, and overheads) and capital costs represent the bulk of the total cost of processing crude oil. This has a very significant impact on the economics of refining.

(a) *Operating Rate*

This is the most important parameter. It is essential for a refinery to operate at a rate close to the maximum. This is of course true not only for atmospheric distillation but also for other units. A running rate of 66% translates, compared to full capacity operation, into a 50% increase in fixed costs per ton of crude oil processed.

This reasoning can be tempered by the fact that the full capacity operation of all refineries in an area where distillation capacities exceed overall product demand can result (and generally results) in a collapse of prices and therefore margins. This is why some refiners in such circumstances sometimes decide to decrease the quantity of crude oil processed. These measures are generally of short duration because a strengthening of margins immediately translates into a return to full capacity.

(b) *Size*

For a given utilization rate, the refining cost per ton of crude decreases as the size of the refinery increases. Indeed:

- Personnel and overhead costs are almost independent of the size of the refinery.
- Maintenance costs and capital charges increase less quickly than size.

For this reason, refineries with a size of less than about 5 million tons of distillation per year are no longer built, except in very special cases. Only geographical reasons (proximity to crude oil, e.g., in the United States; proximity to isolated markets, e.g., in Africa) can justify the existence of small refineries.

(c) *Complexity*

The degree of complexity of a refinery naturally increases the cost of processing a ton of crude oil. This is mainly due to higher cost of capital and maintenance. Two important remarks, however:

- a complex refinery will generate a higher margin than a simple refinery, all other things being equal (size, location, market, etc.) due to higher yields of light products

- a complex refinery will effectively generate a higher margin than a simple refinery if the crude oil is adapted to the processing in the conversion units. In other words, it will have to deal with heavier loads allowing it to fully utilize its crackers.

(d) *Location*

A refinery whose investment cost was increased by the distance from equipment suppliers, the scarcity of labor and extreme climatic conditions will of course have a higher operating cost per ton of crude oil.

(e) *Synergy with Petrochemicals*

The juxtaposition of refining with other activities, in particular, production of petrochemicals, is a very important asset, not only for the direct provision of charges for the steam cracker (the main process unit to make olefins which are the basis for the manufacturing of plastics, synthetic fibers, and synthetic rubber), but also because of the potential for common support services (maintenance, laboratory, general services, shipments, etc.) for all the site's activities.

7 Costs and Margins

The refining (gross) margin is the difference between the value of products (excluding taxes and distribution costs) leaving the refinery and the cost of crude oil entering the refinery. The net margin is equal to the gross margin less variable costs. The refining margin depends on many parameters and in particular on the refining scheme. We will thus speak of a TRCV margin for a refinery equipped with Topping, Reforming, Cracking (catalytic) and Visbreaking. Refining margins also depend on the region in which the refinery is located. A good geographical location translates into increased product value and therefore a better margin. In the United States, for example, refining margins in the interior of the continent are higher than those on the coast.

As previously discussed, total, refining costs for a newly built conventional refinery with 160,000 barrels per day of capacity and standard conversion units would be about $10 per barrel of crude processed, taking into account capital costs (interest and loan repayments). But most refineries, at least in North America and Europe, were built more than 20 years ago and are now depreciated. Their operating costs are in the order of $3 per barrel.

While production costs are relatively stable, margins are highly variable. They will depend on the market situation. Refining margins were very low until around 2000. They have improved over the past few years due to rationalization of capacity, which has involved many closures. Current margins, without generally allowing full cost coverage, make it possible to cover the limited cash costs and depreciation of recent investments. Indeed, most of the refineries in operation were built before the first oil crisis. In most Western countries, the most recent refineries date back to the 1970s. The initial installations are therefore largely amortized. Of course, new investments are constantly being made in refineries. But the economic depreciation associated with these new investments is only a small fraction of that that would result from the construction of a new refinery.

7.1 Margins by Region

Margins in the United States vary widely from one region to another. Around the Gulf of Mexico, the refining margins of the large, sophisticated refineries built to maximize gasoline production are fair. Margins in this area, which is very open to imports, are affected by product arrivals, particularly from Europe and Latin America. On the other hand, margins are much higher in the Midwest and even more so in California due to a better supply-demand balance on the one hand, and higher product prices on the other. Higher quality standards for products are reflected in prices. We should stress that the price of crude oil in the center of the United States is referred to the quotation of WTI (West Texas Intermediate crude) in Cushing, Oklahoma. Cushing is a place supplied with crude oil from many different origins (including synthetic crude from Canada) and equipped with large storage facilities. The price of WTI, which is a reference for other US crude oils, is normally low compared to Brent because of the large inflow of crude and limited pipeline facilities to transfer the crude. This is the main reason for better margins in the United States.

Refining margins in Asia were relatively high before the Asian crisis of 1997. Margins in this region were then more favorable than elsewhere due to continued growth in demand and the protection of certain markets. Margins collapsed in mid-1997 due to the region's economic problems, which slowed demand growth just while very large capacities were built. They rebounded in 2000, but remain relatively low if calculated on the basis of spot prices. However, we should remember that product prices are controlled by the government in many countries, allowing some profitability of the industry.

In Europe, the margins of a complex reference refinery located in Rotterdam were in the order of $1 to $2 per barrel in the 1990s, before recovering in 2000. Rapid variations in crude oil prices can also lead to very significant variations in the level of the margin.

7.2 Future Margins and Costs

Margins published by oil companies or trade journals are typical margins for fictitious refineries. This is called a margin indicator. In Europe, margin indicators generally correspond to the case of a refinery located in Rotterdam and operating in a highly competitive environment. These "Rotterdam calculated" margins do not cover the full costs of a new refinery.

A number of factors improve the economic situation of refining:

- Very significant productivity progress has been made in terms of costs: a few years ago, a large French company announced that it would lower its refining "break-even point" by around $1 per ton of crude oil processed per year. This trend continues: improvement in operating rates, efforts on the various items, reduction of inventories, and strict selection of investments are among the elements that explain this improvement;
- The generally published margins only take into account major products (gasoline, jet fuel, diesel, fuel oil). The so-called specialties products (lubricants, bitumen, LPG, or even petrochemical products) are not taken into account. However, these products often generate positive results that contribute to improved refining margins;
- The prices at which some refineries can actually sell their products are often higher than those taken into account in the calculation of margin indicators, because of a possibly more favorable geographical situation: a refinery located in Europe inland in an importing area will sell its products at a much higher price than Rotterdam, the difference reflecting transport costs;
- In a number of countries, refiners offset low refining margins with their presence in the distribution sector
- In order to better cope with competition and poor market conditions, restructuring is taking place in cooperation between operators.

Capacity restructuring in the face of a market that is likely to continue to grow for a few years suggests a good situation for global refining.

8 Oil Demand for Tomorrow

In a base scenario, the International Energy Agency (IEA) forecasts that oil demand—100 Million b/d in 2018—could exceed 110 Mb/d (5.5 Gtoe) in 2030, with most of the increase in demand coming from emerging countries, which will account for more than 60% of world consumption in 2030 compared to slightly more than 50% today. The share of motor fuels in oil consumption will continue to rise to more than 60%. Of course, in this baseline scenario, global carbon dioxide emissions will increase in contradiction with the Paris agreements of 2015.

However, the IEA proposes a second scenario, reflecting the impact of proactive energy policies and measures by governments and leading to a modest demand reduction of 10% in 2030 compared to the baseline scenario. In the latter scenario, oil consumption is therefore reduced to 99 Mb/d and the share of biofuels in total fuels increases from 4 to 7%, which seems unambitious but can be explained, at least in Europe, by the difficulties encountered in harmonizing the actions of the 27 Member States.

The increase in oil-related carbon dioxide emissions will greatly increase pressure on governments to limit demand growth, but the implementation of measures with a significant impact will require real political will.

Oil will increasingly be used for fuels and petrochemical bases, to the detriment of uses for heating and power generation.

The development of oil substitutes: agro fuels, synthetic fuels obtained by the Coal to Liquids (CTL), and Gas to Liquids (GTL) processes will be limited because they are expensive in energy and the improvements of the catalysts make it possible to manufacture products of excellent quality in refineries. The only GTL units recently built were in Qatar but no new units are planned.

9 The Future of Refining

The steady increase in the consumption of petroleum products requires increased refining capacity. Given the disappearance of refineries, often of small size, because unprofitable, the construction of new capacities is inevitable. These capacities will be built mainly in Asia, to cope with growing demand, and in the Middle East, where the availability of crude oil is a major factor. The refineries to be built will have to take into account the constant decrease in the demand for heavy products, because of price and the need to reduce pollution. The shift of ships to use of low sulfur fuels, which became mandatory in 2020, illustrates this perspective. New refineries will also face increasingly stringent specifications for light products.

Refineries will benefit from a favorable factor, rarely anticipated by forecasters. While in the 70s and 80s it seemed inevitable that the oils to be discovered would be increasingly heavy and sulfurous, this trend never materialized. For example, the crude oils found in Saudi Arabia after the discoveries of the large deposits around the Second World War were lighter than the oils of the first discoveries. Of course, the massive production of shale oil, called Light Tight Oil because their density (API degree between 40 and 45) is very low, goes in the same direction. The development of refining will no doubt be limited by the uncertain future of demand for petroleum products. Why build a refinery today if demand is to decline in 20 or 30 years?

The economic situation of refining is however better today than it was 30 years ago. The recurring weakness of margins—and profits—in the 1980s led to restructurings that paid off. We can therefore expect a slow but certain evolution toward refineries on average larger and more sophisticated, with a fair profitability.

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CHAPTER 4

Economics of Hydrogen

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1 Introduction

Concerns about the growing greenhouse gas emissions and associated anthropogenic climate change call for new solutions for developing a decarbonized and more sustainable energy system. Hydrogen can be a versatile non-fossil energy carrier and has substantial potential to enable such a

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transition. This chapter provides an extensive overview of the technical and economic characteristics of hydrogen and outlines the necessary background to foster the discussion of the role of hydrogen in a decarbonized energy system. First, we review potential applications of hydrogen and estimate its market potential in a typical industrialized nation in the year 2050. Subsequently, hydrogen-related policies and regulations are discussed. Then, we describe the most important facets of hydrogen supply, including its production, storage, processing and conditioning, delivery, and refueling. Then, the public acceptance and security aspects of hydrogen fuel supply chains and use are addressed. Finally, we analyze consumer willingness to pay for hydrogen technologies.

2 Hydrogen Use and Markets

Hydrogen can be used in many different sectors, including transportation, households, commerce and trade, chemical and heavy industry, and power sectors (Fig. 4.1). Therefore, hydrogen is increasingly considered a highly promising energy carrier necessary to achieving a fully decarbonized energy system (Robinius et al. 2017a; Henning and Palzer 2013; Knor et al. 2014). To provide a brief overview of hydrogen applications and related market potentials, anticipated hydrogen utilization in different sectors of the energy system will be described. More than 99% of the current worldwide hydrogen demand of 74 million tons arises from the heavy and chemical industry sector (SRI 2007; IEA 2019). Thus, hydrogen already plays today a vital role in this sector.

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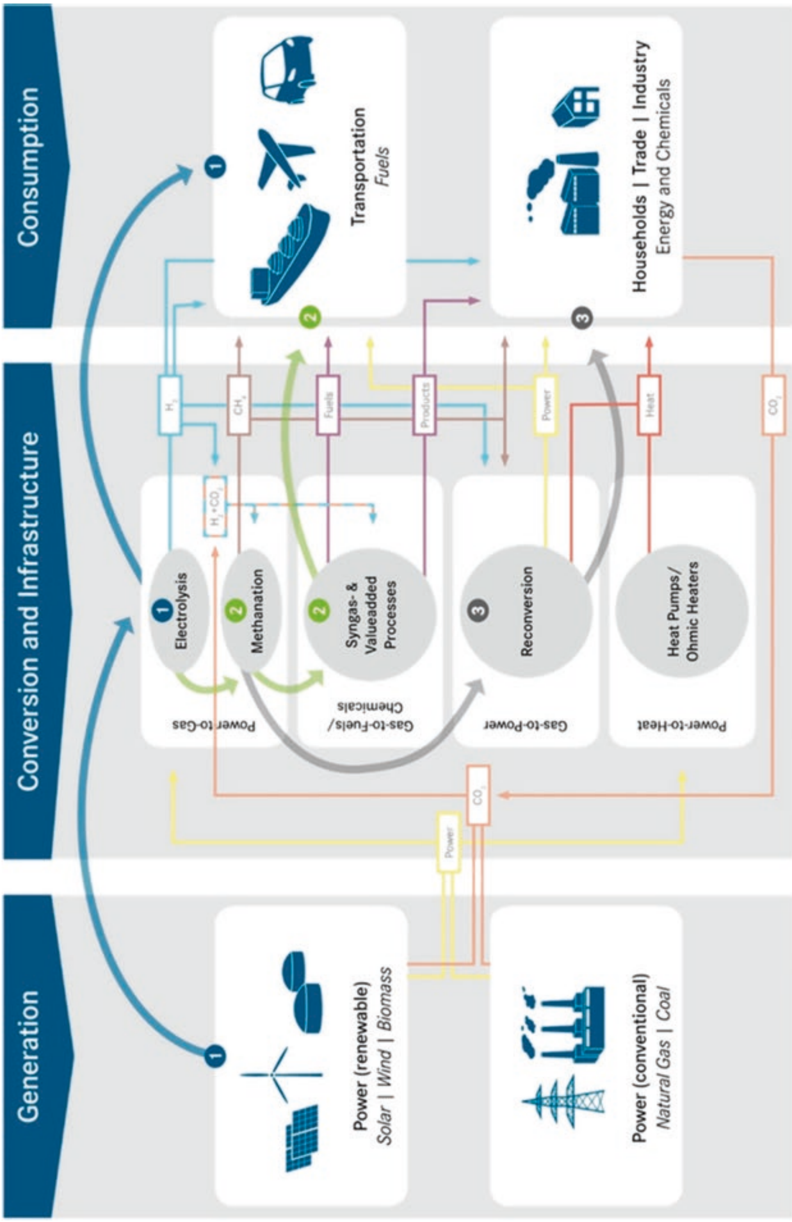


Fig. 4.1 Overview of hydrogen's potential role in the energy system (Robinius et al. 2017b)

2.1 Transport

In the transportation sector, hydrogen can be utilized in conventional combustion engines or, more prominently, to supply fuel cells, which have significantly higher efficiencies than combustion engines and, unlike diesel or gasoline engines, emit no CO_2 and NOx into the atmosphere. Compared to alternative zero emission drivetrains, fuel cell-electric vehicles (FCEVs) offer the advantages of long range (>500 km) and short refueling times (less than 3–5 minutes), as well as comparably high power capacity for heavy duty and commercial applications (Offer et al. 2010). However, the high cost of fuel cells and underdeveloped hydrogen infrastructure has until now limited the market penetration of FCEVs (Gnann et al. 2015). Due to its size and high willingness to pay, the most prominent target market for FCEVs historically was that of passenger cars. To fulfill the high vehicle space and design requirements of passenger vehicles, FCEV cars are generally equipped with 700 bar of onboard hydrogen storage. The first prototypes of FCEVs had already entered development in the 1960s (Fuel Cells Bulletin 2016). The technology has been continuously developed, and today, under the support of various market introduction policies, there are approximately 11,000 FCEV passenger cars on the road worldwide (Fukui 2019).

Despite the slow progress of FCEVs in the passenger car segment, the technology is attracting growing interest in various other applications, such as public transportation and commercial vehicles (Wulf et al. 2018a). Due to their space and design constraints, these vehicles are generally operated with onboard hydrogen storage at 350 bar. Range constraints, limiting the functionality of battery-electric vehicles (BEVs) for commercial vehicles, create a market opportunity for the introduction of fuel cells in local buses, smaller passenger trains and freight vehicles (Ritter 2016; Alstom 2018; Roland Berger 2015; FCH JU 2016). Another application that has been exhibiting significant growth in recent years is the material handling vehicle (MHV) market (Micheli and Hanke 2015). Fast refueling, emission-free operation, and a wide range of possible operating temperatures (i.e., harsh weather conditions) enable fuel cell MHVs to save costly space in logistics centers and operate indoors also at low temperatures as, for example, typically found in cold storages (Fischedick 2017). Other potential FCEV applications expected to play a role in the future energy system include motorbikes, ships, airplanes, railways, and agricultural machinery (Hart et al. 2015; New Holland Agriculture 2014; Hof et al. 2017).

It was found that the associated market potential of captive fleets, such as public transport and forklifts, is sufficient to provide a cost-competitive, countrywide hydrogen supply (Cerniauskas et al. 2019a). From infrastructure perspective, larger mobility markets, such as those for freight vehicles and passenger cars, require a public hydrogen refueling station network, and therefore, these markets are more challenging to enter. Finally, green hydrogen could play a key role in the future production of synthetic fuels, such as synthetic gasoline, synthetic kerosene, and so on, which are among the main options for decarbonizing air travel and high-power vehicles such as locomotives.

2.2 Private Households and Heat

Hydrogen can be flexibly used in the heating sector to achieve various inlet temperature levels, thus giving it a broad range of applications (e.g., space heating, hot water preparation), from single-family houses to large, multistorey commercial and residential buildings. Existing natural gas boilers can be retrofitted to use hydrogen, as it has a similar Wobbe index as natural gas (Hodges et al. 2015). Given sufficient hydrogen supply infrastructure, this approach would allow rapid decarbonization of the heating sector, as a successful large-scale retrofit of heating appliances has already been demonstrated during the shift from town gas to natural gas in the first half of the twentieth century and during the still ongoing shift from low- to high-calorific natural gas (Dorrington et al. 2016; Fernleitungsnetzbetreiber 2017). Nevertheless, the blending of hydrogen with natural gas is currently limited by natural gas quality requirements, which vary significantly among countries, from 0.01 to 12%vol. (ITM Power PLC 2013; Dolci et al. 2019). The thermal use of admixed hydrogen and the cost-competitiveness of natural gas make this market more difficult to penetrate than is the case of mobility applications.

In fact, due to its low exergetic efficiency, the combustion of hydrogen is the less preferred utilization option. Alternatively, hydrogen can be used to operate combined heat and power units (CHPs), which are increasing in importance in decentralized energy systems (Weidner et al. 2019). Fuel cell CHPs enable an even higher overall efficiency (equivalent to a coefficient of performance (COP) of >5) than an all-electric solution, which combines the highest efficiency combined-cycle gas turbine (efficiency of >50%) with the highest efficiency heat pump (COP 3–4) (Staffell 2015). In Rigas and Amyote (2013), the effectiveness of support schemes for micro fuel cells in Germany is analyzed against the latest market conditions, support schemes, and legislative changes. The study shows that the technology is still far removed from competitiveness in domestic applications in Germany and that PEMFC system costs must be halved for the representative system considered (viz. from €19,500 to €10,500), including all auxiliary devices, before the technology can compete on the market without any form of subsidy.

2.3 Chemical and Heavy Industry

Hydrogen already plays a vital role in the heavy and chemical industry sector. However, instead of being used as an energy carrier, hydrogen is mostly utilized as a chemical feedstock for ammonia and methanol production and in the refining of oil (SRI 2007). Smaller hydrogen demand can also be found in the food-processing sector and in glass manufacturing (Schenuit et al. 2016).

Furthermore, hydrogen can be used for the direct reduction of iron ore and thus foster the decarbonization of the still very GHG-intensive steel industry (Otto et al. 2017).

However, the penetration of green hydrogen in the chemical and heavy industry sector, which encompasses the use in current chemical processes as well as novel applications such as the direct reduction of iron (Power-to-Steel) and the production of synthetic fuels (Power-to-Fuel), is more difficult than in transport. The high cost-competitiveness of the global commodity markets, as well as technological and market development uncertainties, significantly diminish the willingness of industrial consumers to shift to green hydrogen in the short- to medium-term perspective. Therefore, the large-scale adoption of green hydrogen in the industry is generally anticipated during the later stages of the hydrogen market development (Fraunhofer ISI and Öko-Institute 2015; Hydrogen Council 2017). Finally, green hydrogen could play a key role in the future production of synthetic fuels, such as synthetic gasoline, synthetic kerosene, and so on, which are among the main options for decarbonizing air travel and high-power vehicles such as long-haul trucks.

2.4 Power Sector

The growing capacity of variable renewable energy sources, such as wind and solar PV, increases the need for storage systems to buffer energy production fluctuations and provide sufficient flexibility to meet current supply security requirements. Short-period hourly and daily fluctuations can be absorbed by conventional pumped hydro power and more novel solutions, such as state-of-the-art compressed air and battery storage technology. However, the seasonal variation of renewable energy technologies requires long-term storage spanning weeks to months, which can be provided by underground chemical storage by means of hydrogen or synthetic methane (Welder et al. 2018). The stored energy can be shifted to transportation, heat, and heavy industry sectors or converted back into electricity with dedicated open-cycle gas turbines. However, the higher electrochemical conversion efficiency of fuel cells (60%) than of gas turbines (40%) favors coupling with other sectors over repowering. On this, various studies have suggested that hydrogen electrification would play a pivotal role in the power sector with a high degree of renewable power penetration (Henning and Palzer 2013, 2015; Knor et al. 2014). The economic feasibility of power-to-gas (P2G) systems in combination with hydrogen (and renewable methane), as well as underground storage used for load-balancing, is analyzed in Roche et al. (2010) employing a techno-economic model. The authors found that in none of the cases investigated (i.e., base case; storage and arbitrage; storage and balancing) was the P2G system economically viable under present market conditions, and so it requires substantial financial policy support.

3 Potential Applications of Hydrogen

3.1 Hydrogen Policy and Regulation

The literature on hydrogen policy and regulation has been growing in recent years, especially regarding green (Fig. 4.2) hydrogen in transport (Ajanovic and Haas 2018; Bleischwitz and Bader 2010; Collantes 2008; Rodrígueza et al. 2019; Pique et al. 2017). The economic prospects and necessary policy framework for green hydrogen used in passenger car transport are investigated by Ajanovic and Haas (2018), taking into account hydrogen production costs from variable renewable energy technologies and learning curve effects concerning fuel cell vehicles. The authors conclude that the prospects for hydrogen, apart from the need to become economically viable, depend a lot on the prevailing policy framework (to foster low-emission vehicles), for example, in terms of vehicle taxation/subsidization (purchase and use), non-monetary measures (entry to city centers, use of bus lanes, the free use of public parking spaces, etc.), and fuel economy standards. Bleischwitz and Bader (2010) review the current EU policy and regulatory framework for the transition toward a hydrogen economy, with a particular focus on prevailing barriers and inconsistencies. The authors conclude that the present policy framework does not hinder hydrogen development but that it does not forcefully compel it either. The most substantial impact is on hydrogen and fuel cell research and development. Regulatory policies are found to have a weak but positive impact on hydrogen, whereas EU funding policies show some inconsistencies. In their view, the large-scale market diffusion of hydrogen and fuel cells will require a new, technology-specific support approach, with a supportive policy framework that takes the regional dimension explicitly into account. However, recent changes in the EU Renewable Energy Directive, which includes green hydrogen

Brown	Coal gasification
Grey	Water electrolysis using power from fossil fuels
	Reforming of natural gas
White	By-product of industrial processes
Blue	Coal gasification with CCS
	Reforming of natural gas with CCS
Turquoise	Methane pyrolysis
Yellow	Water electrolysis using nuclear power
Green	Reforming of biogas
	Gasification and fermentation of biomass
	Water electrolysis using regenerative power sources

Fig. 4.2 Color coding for origins of hydrogen

as a feedstock switch in refineries, indicates the increasing consistency of EU policy (European Parliament and Council 2018).

The manifold dimensions of the policy debate over transportation fuels, with a particular focus on hydrogen, are analyzed in Collantes et al. (Collantes 2008) for the US, based on a web-based survey involving 502 individuals from 323 different stakeholder organizations. Policy beliefs and policy preferences of stakeholders are collected in order to identify, and obtain measures of, the main dimensions of the policy debate related to the use of hydrogen as a transportation fuel in the US, thus greatly reducing the complexity of the policy picture. Three policy preferences found are (i) command-and-control approaches; (ii) addressing externalities with technology-neutral approaches; and (iii) facilitating technological progress and innovation. Another effort to translate the potential contributions of hydrogen technology into public policy schemes was undertaken in Rodrigueza et al. (Rodríguez a et al. 2019) in the case of the legal framework for hydrogen regulation in Mexico. The study found that the lack of hydrogen storage, lack of regulation on the use of hydrogen in final applications, and lack of safety regulation are essential barriers that must be overcome before the hydrogen economy can unfold. Finally, Pique et al. (2017) report on a comparative study on regulations, codes, standards, and practices on hydrogen fueling stations in nine different countries, namely, the US (California), the UK, Italy, Germany, Canada, Sweden, Norway, Denmark, and Spain. The authors find that countries often have no national regulation specific to hydrogen fueling, have no specific regulations other than their own technical guidelines, and that international standards (such as ISO 17268 or ISO 20100) are the references applied in almost all countries.

Leibowicz (2018) develops policy recommendations for the transition to sustainable mobility and transport system by investigating the historical dynamics of this sector, and in particular, regularities concerning the relative timing of infrastructure, vehicle, and travel diffusion processes across systems. In doing so, he analyzes technological lock-ins, techno-institutional complexes, technology transitions, barriers to adoption, and the historical diffusion of transport systems.

4 Hydrogen Infrastructure

4.1 Production

Hydrogen can be separated from water or hydrocarbon compounds found in various fossil fuels and biomass. The element hydrogen is colorless, but due to the broad spectrum of possible production alternatives, there exist different names to classify the hydrogen according to its CO_2 emissions, like gray, blue, and green hydrogen (IEA 2019) (see Fig. 4.2). In general, the term gray hydrogen refers to hydrogen production via fossil fuels, with the most common process being the steam methane reforming (SMR). Depending on the CO_2 intensity of the electricity mix, production via electrolysis from the grid electricity may also be called gray hydrogen due to the high associated CO_2 emissions. Nonetheless, additional sub-classes to the CO_2 intensive production, such as brown and white hydrogen, have been proposed. Brown hydrogen stands for hydrogen production from coal and is the most CO_2 intensive among the production sources. By-product hydrogen that is not used as feedstock but is exploited thermally near its source was proposed to be referred to as white hydrogen. In the case of other use cases, the thermal utilization on-site can be substituted by the combustion of natural gas, thus leading to a smaller CO_2 intensity than in the case of the gray hydrogen. Blue hydrogen generally refers to non-renewable hydrogen production meeting low CO_2 intensity criteria. Application of carbon capture and storage (CCS) to coal gasification and SMR enables these processes to sufficiently reduce the associated emissions to meet this criterion. However, additional classes of the turquoise and yellow hydrogen have been proposed. Turquoise hydrogen is produced by methane pyrolysis, in which methane is split in a thermochemical process into solid carbon and hydrogen, and if the heat supply of the high-temperature reactor is provided by renewable energy sources, the process yields low CO_2 emission intensity, whereas hydrogen production via electrolysis from nuclear power is called yellow hydrogen. Green hydrogen is produced exclusively from renewable energy sources. Typically, green hydrogen is produced by water electrolysis. Further possibilities are the gasification and fermentation of biomass and the reformation of biogas. The following sections will explore the key features of the essential hydrogen production processes defining the described classification.

Currently, the most widely utilized options to retrieve hydrogen from hydrocarbons are SMR, partial oxidation, and gasification (gray hydrogen) (SRI 2007). SMR comprises a high-yield endothermic reaction of natural gas and steam to allow high-purity hydrogen production (Gupta 2008). The partial oxidation of hydrocarbons has lower material efficiency and hydrogen purity but can utilize a larger variety of fuels, including oil residues (Gupta 2008). Gasification has the lowest material efficiency and hydrogen purity; however, it allows the use of more widely accessible fuels, such as coal (brown hydrogen) and biomass (Gupta 2008) [43]. Against the background of CO_2 emissions reduction policies, these processes can be extended with subsequent CCS (blue hydrogen), thus enabling to diminish the CO_2 footprint of hydrogen production, which is expected to be the key bridge technology to the widespread low-emission hydrogen production (IEA 2019). Another possibility of providing hydrogen while avoiding CO_2 emissions is methane pyrolysis (turquoise hydrogen), which uses the thermal non-catalytic splitting of methane into hydrogen and carbon at high temperatures. However, despite up-and-coming applications, due to its low technology readiness level (TRL), methane pyrolysis is not expected to become commercially available within the next 10–20 years (Geres et al. 2019). To put the state of technology's development into perspective, the latest pilot project aims to reach a production capacity of up to 12 kg_{H2}/h (ARENA 2019) which is approximately equivalent to production of an electrolyzer with 600 kW_{el} capacity with running on full load

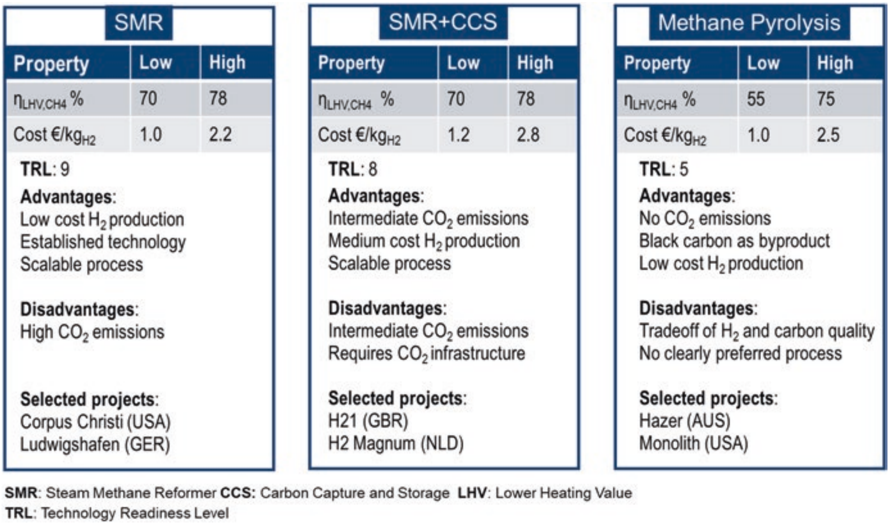
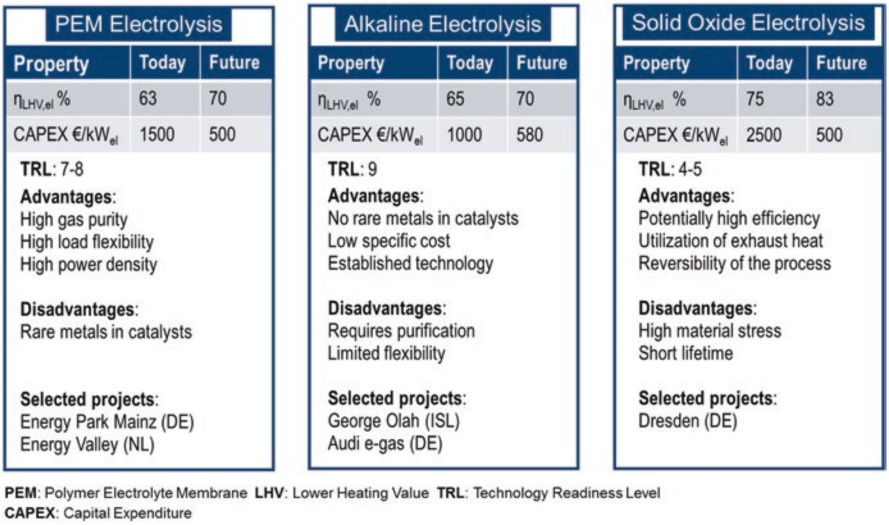


Fig. 4.3 Comparison of natural gas-based hydrogen production methods (Geres et al. 2019; ARENA 2019; Monolith Materials 2018; Parkinson et al. 2019; Sarsfield-Hall and Unger 2019; Eikaas 2019; Machhammer et al. 2016; Abánades et al. 2013)

at all hours in a year. Figure 4.3 provides an overview of the most promising low CO_2 intensity production options from natural gas.

Alternatively, with expanding decarbonization of electricity production (green and yellow hydrogen), by using electrolysis hydrogen can be retrieved from water. The main electrolysis processes currently being discussed are alkaline (AEL), polymer electrolyte membrane (PEMEL), and solid oxide (SOEL) electrolysis. AEL is the most mature technology and is already implemented on an industrial scale of several MW and is used for 4% of current hydrogen production (SRI 2007). Due to its typical application for chlorine production instead of variable renewable energy integration, AEL has important constraints on the operating range, requiring a minimal load of 20% and relatively slow dynamics between operating points of <30 s (Schmidt et al. 2017a; Brinner et al. 2018). Alternatively, PEMEL has a wider operating range of 0%–150% and dynamic operation between operating points of <2 s, thus enabling the coupling of PEMEL with highly intermittent power sources such as solar PV and wind (ITM Power 2018; Bayer et al. 2016; Kopp et al. 2017) [55–57]. Another alternative is SOEL, which operates at high temperatures (700–1000 °C with ZrO_2 ceramic as electrolyte) that allow higher efficiency than in the case of other electrolyzer systems (Brinner et al. 2018). However, the high operating temperature also increases the thermal inertia and thus feasible size of the cells, which poses significant challenge for larger scale SOEL deployment and integration with variable renewable energy technologies. Furthermore, current SOEL must overcome important deficiencies, such as



PEM Electrolysis

Property	Today	Future
$\eta_{LHV,el}$ %	63	70
CAPEX €/kW$_{el}$	1500	500

TRL: 7-8
Advantages:
High gas purity
High load flexibility
High power density
Disadvantages:
Rare metals in catalysts
Selected projects:
Energy Park Mainz (DE)
Energy Valley (NL)

Alkaline Electrolysis

Property	Today	Future
$\eta_{LHV,el}$ %	65	70
CAPEX €/kW$_{el}$	1000	580

TRL: 9
Advantages:
No rare metals in catalysts
Low specific cost
Established technology
Disadvantages:
Requires purification
Limited flexibility
Selected projects:
George Olah (ISL)
Audi e-gas (DE)

Solid Oxide Electrolysis

Property	Today	Future
$\eta_{LHV,el}$ %	75	83
CAPEX €/kW$_{el}$	2500	500

TRL: 4-5
Advantages:
Potentially high efficiency
Utilization of exhaust heat
Reversibility of the process
Disadvantages:
High material stress
Short lifetime
Selected projects:
Dresden (DE)

PEM: Polymer Electrolyte Membrane **LHV**: Lower Heating Value **TRL**: Technology Readiness Level
CAPEX: Capital Expenditure

Fig. 4.4 Comparison of electrolytic hydrogen production methods (Wulf et al. 2018a; Brinner et al. 2018; Schmidt et al. 2017b; Saba et al. 2018; Glenk and Reichelstein 2019; Smolinka et al. 2018)

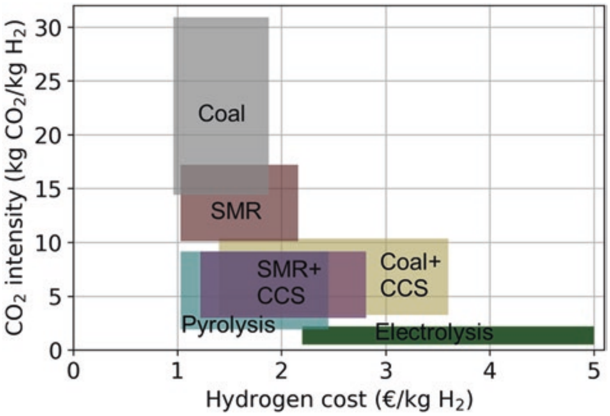


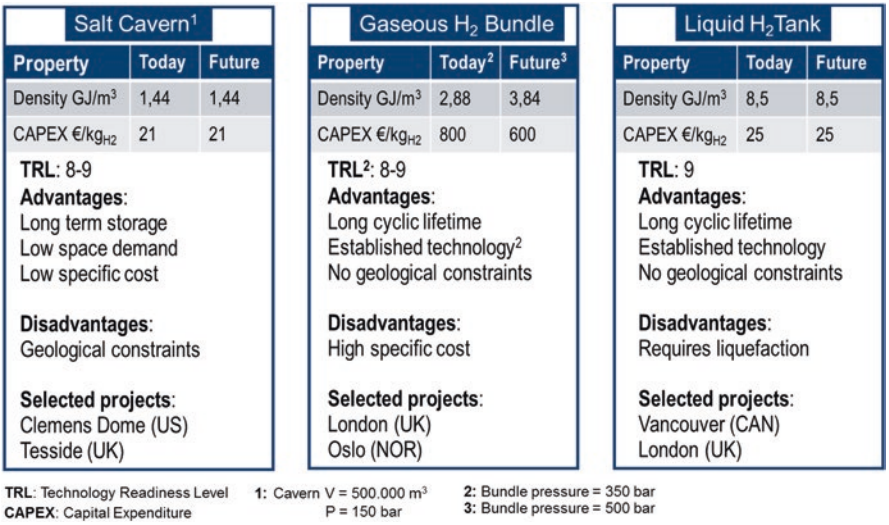
Fig. 4.5 Hydrogen production cost and intensity (adapted from the literature (Parkinson et al. 2019; Heuser et al. 2019))

short lifetimes and material degradation (Schmidt et al. 2017a). Figure 4.4 provides an overview of the most important features of electrolytic hydrogen production technologies.

Figure 4.5 summarizes the literature review of the CO_2 intensity and the cost of hydrogen production for a selection of the most promising technologies. The results consider estimates of life-cycle emissions of the production and primary energy sources. In the case of coal-based processes, underground mined coal, and in the case of electrolysis, renewable electricity is considered in the analysis. Furthermore, emissions occurring in the natural gas supply chain are additionally considered for SMR and SMR+CCS (Munnings and Krupnick 2018). The respective technologies are displayed as areas encompassing underlying uncertainties and variations of the data in the literature. The displayed variation of fossil fuel-based production is mainly affected by efficiency and the costs of primary energy and CCS where applicable, whereas in the case of electrolysis, the uncertainty appears primarily due to different renewable energy availability and anticipated future technological development of electrolysis and renewable energy generation technologies. It can be observed that moving from top to bottom along the y-axis, these technologies display a Pareto frontier of both hydrogen production cost and associated CO_2 intensity. Whereas, on the one hand, coal and SMR lead to not only lowest cost but also highest CO_2 emissions, on the other hand, green electrolytic hydrogen enables the lowest CO_2 emissions at the cost of higher production costs. In between, one can observe pyrolysis and coal as well as natural gas-based hydrogen production with CCS. Nevertheless, as mentioned above, pyrolysis is still at an early stage of development. Thus, the initial transition to less CO_2 intensive production will potentially not be able to rely on this technology.

4.2 Storage

Seasonal variations of renewable energy sources such as wind and solar PV require long-term storage solutions to cope with intermittent power production. The long-term storage requirements of renewable energy integration can be fulfilled with hydrogen. Hydrogen storage can be facilitated by the storage of pure hydrogen or by using hydrogen carriers (Reuß et al. 2017). Pure hydrogen can be stored in specialized steel containers in a compressed, liquid state or, alternatively, compressed hydrogen can be stored in underground facilities. The high storage capacity and relatively low costs of underground storage make it an especially attractive solution for seasonal renewable energy variations. Gaseous and liquid storage options, by contrast, are more suitable as buffer systems at hydrogen refueling stations. Since the 1960s, the utilization of underground storage in industrial facilities has proven the technical feasibility of GWh-scale underground hydrogen storage (Crotogino et al. 2010). However, despite large potential in Europe and some other regions, the geological limitations of the required rock formations for salt caverns and porous rock diminish the global availability of hydrogen underground storage (and multiple media may compete for underground storage, such as compressed air, CO_2, and hydrogen itself). Alternatively, hydrogen can be stored in the form of synthetic fuels or by making use of specialized energy carriers. While the use of synthetic fuels would allow the existing infrastructure to be used, drawbacks include high energy losses during the conversion and the cost of CO_2 separation from the air, as it is anticipated to decarbonize the energy



Salt Cavern[1]

Property	Today	Future
Density GJ/m^3	1,44	1,44
CAPEX €/kg$_{H2}$	21	21

TRL: 8-9
Advantages:
Long term storage
Low space demand
Low specific cost

Disadvantages:
Geological constraints

Selected projects:
Clemens Dome (US)
Tesside (UK)

Gaseous H_2 Bundle

Property	Today[2]	Future[3]
Density GJ/m^3	2,88	3,84
CAPEX €/kg$_{H2}$	800	600

TRL[2]: 8-9
Advantages:
Long cyclic lifetime
Established technology[2]
No geological constraints

Disadvantages:
High specific cost

Selected projects:
London (UK)
Oslo (NOR)

Liquid H_2 Tank

Property	Today	Future
Density GJ/m^3	8,5	8,5
CAPEX €/kg$_{H2}$	25	25

TRL: 9
Advantages:
Long cyclic lifetime
Established technology
No geological constraints

Disadvantages:
Requires liquefaction

Selected projects:
Vancouver (CAN)
London (UK)

TRL: Technology Readiness Level
CAPEX: Capital Expenditure
1: Cavern V = 500.000 m^3, P = 150 bar
2: Bundle pressure = 350 bar
3: Bundle pressure = 500 bar

Fig. 4.6 Features of hydrogen storage (Wulf et al. 2018a; FCH JU 2016; Brinner et al. 2018; Reuß et al. 2017; Hua et al. 2014; Acht 2013; Yang and Odgen 2007)

system by 2050. Specialized energy carriers, such as hydrides and liquid organic energy carriers, can offer advantageous energy density properties under low pressure, thus mitigating potential hydrogen risks (Reuß et al. 2017). However, these technologies also feature drawbacks in terms of efficient energy discharge and must still be proven in day-to-day operation to demonstrate the technology's readiness for commercialization (Fig. 4.6).

4.3 *Hydrogen Processing and Conditioning*

The varying technical characteristics of the components along the hydrogen supply chain with respect to the hydrogen's state, purity, and pressure necessitates conversion steps, such as compression, liquefaction, and purification. In the case that energy carriers are used for the storage and transport of hydrogen, charging and discharging units must be taken into consideration.

Electrolytic hydrogen production output is typically conducted between 1 and 20 bar, while to accommodate sufficient quantities of hydrogen and to save space, mobile hydrogen fuel cell applications operate at 350–700 bar. This creates a significant pressure increase that must be maintained and operated along the supply chain. Furthermore, hydrogen supply chain components, such as high-pressure pipelines and 500-bar trailers, have additional hydrogen pressure constraints. To fulfill the aforementioned hydrogen pressure requirements, the compression can be facilitated via mechanical, electrochemical, hybrid, and ionic means. However, only the former is an established technology with proven operational viability. Alternatively, for the gradual pressure increase along the supply chain, hydrogen can be liquefied at the production point and subsequently evaporated and compressed to the required pressure level at the refueling station.

As with the pressure, hydrogen purity is defined by the hydrogen quality requirements of the final consumer; for example, PEMFCs have a 99.97% purity requirement (ISO 2012). However, depending on the hydrogen supply chain pathway used, additional hydrogen purity constraints can arise when SMR and by-product hydrogen or hydrogen liquefaction are considered (Berstad 2018; Zhu et al. 2018). The most widely adopted hydrogen purification methods encompass temperature swing adsorption (TSA) and pressure swing adsorption (PSA). Special membranes also are promising for smaller throughput applications.

4.4 Hydrogen Delivery

The three main routes of hydrogen distribution are gaseous hydrogen trailers and pipelines, as well as liquid hydrogen trailers. The choice of the most effective delivery method depends on the chosen means of storage, as changes in the state of hydrogen increase energy losses, delivery distance, and throughput (Reuß et al. 2017; Yang and Odgen 2007).

Gaseous hydrogen trailers offer a cost-effective solution during the introduction phase, marked by low and sparsely distributed demand. They become less economical in the later market stages when hydrogen demand increases. Nevertheless, even with significant hydrogen demand, the last mile distribution from the hydrogen pipeline to the refueling station remains a cost-effective option (Reuß et al. 2019). Alternatively, hydrogen can be liquefied or transported in the form of liquid organic hydrogen carriers. Both options enable cost-efficient, long-distance hydrogen transportation, which is especially interesting for overseas hydrogen trade (Heuser et al. 2019). Challenges related to the transport of liquified hydrogen are comparable to those of LNG, which requires high insulation to avoid boil-off losses. Therefore, as with LNG transport, LH_2-transporting ships and trucks can be operated on the boil-off losses of hydrogen. In the case of liquid organic hydrogen carriers (LOHCs), transportation is very similar to liquid fuels, and therefore, few modifications to current fossil fuel pipelines and trailers would be necessary. However, studies have shown that economic viability of LOHCs delivery depend strongly on the availability of low-cost heat energy (Reuss 2019), constraining LOHCs to more specific environments (Fig. 4.7).

Hydrogen pipelines are often considered as the most cost-efficient and environmentally favorable means of delivering large volumes of hydrogen over medium to large distances (Wulf et al. 2018a; Tlili et al. 2020; Emonts et al. 2019). This makes it especially attractive for a transmission network and the connection of industrial sites. Currently, there are already several insulated hydrogen pipeline networks supplying industrial sites with a total length of 3000 km in Europe and the US. The risk of low pipeline utilization and

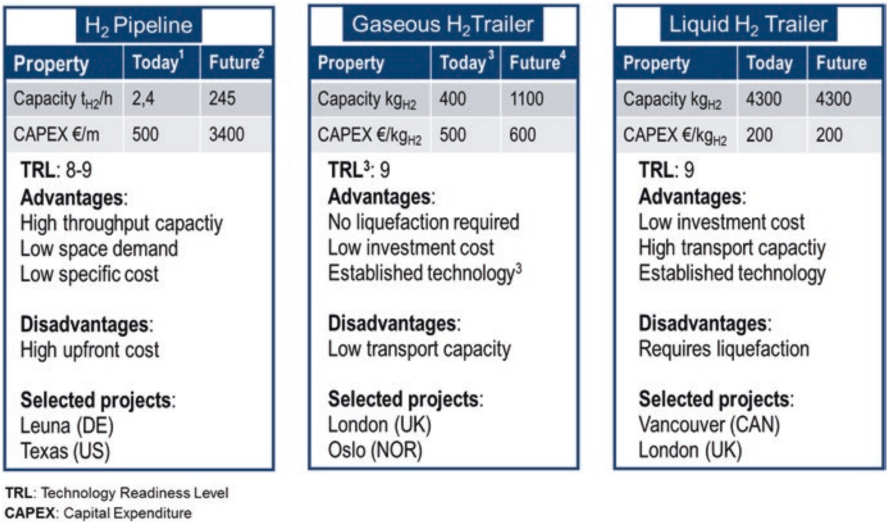


Fig. 4.7 Features of hydrogen delivery methods (Wulf et al. 2018a; FCH JU 2016; Brinner et al. 2018; Reuß et al. 2017; Hua et al. 2014; Tractebel and Hinicio 2017; Krieg 2012)

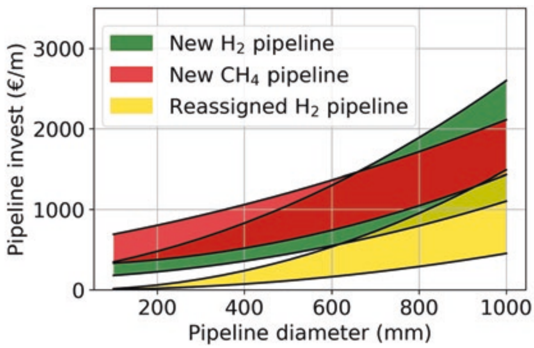


Fig. 4.8 Pipeline investment cost overview (Robinius et al. 2017a; Fernleitungsnetzbetreiber 2017; Krieg 2012; Cerniauskas et al. 2019a; Mischner et al. 2011)

elevated initial investment in the steel pipelines (Fig. 4.8) challenges the implementation of hydrogen pipelines during the market introduction phase. However, pipeline costs can be alleviated through the reassignment of existing natural gas pipelines, which, with the increasing electrification of the heating sector and the shift from low- to high-caloric natural gas, will increasingly become available. Initial investigation of the German natural gas transmission grid has shown that, despite additional measures for handling hydrogen-related material embrittlement, pipeline reassignment can reduce yearly pipeline expenditures by up to 80% in comparison to a new, dedicated hydrogen pipeline (Cerniauskas et al. 2019a). Another option to use hydrogen in the natural gas grid is to blend hydrogen with natural gas. Historically, there have been many cases of utilizing hydrogen-rich town gas (50–60% of H_2), which were abandoned in favor of natural gas in the 1960s (Williams 1981). Currently, different countries make use of hydrogen gas admixtures with natural gas of up to 10% w\m (ITM Power PLC 2013), which can be further increased if heating devices and natural gas turbines and CNG vehicles, which currently allow 2%vol max, are adapted for higher hydrogen concentrations (DVGW 2019). Comparable large-scale change in consumer devices was already observed during the transition from town gas to natural gas in the 1960s, as well as during the ongoing shift from low- to high-caloric natural gas (Fernleitungsnetzbetreiber 2017; Williams 1981). Nevertheless, despite the apparent benefits of the widespread availability of natural gas infrastructure and the avoidance of new infrastructure implementation, hydrogen blending might lock in hydrogen to thermal use, as any other hydrogen applications would require subsequent hydrogen purification (ISO 2012).

4.5 Hydrogen Refueling

Currently, all hydrogen-powered vehicles prefer gaseous over liquid onboard hydrogen storage, as the latter would inevitably lead to boil-off losses in the vehicle. For use in passenger cars, the current state of the art is a gauge pressure of 700 bar, while 350 bar is the prevailing pressure for hydrogen use in buses and other commercial applications. The underlying structure of hydrogen refueling stations is comparable to that of current fossil fuel refueling and consists of a buffer storage, dispenser, cooling unit, and fuel-processing unit that creates the necessary pressure gradient to facilitate refueling. This principle holds for gaseous as well as liquid and LOHC delivery (Pratt et al. 2015). Additional cooling of hydrogen is required to compensate for the temperature increase during refueling, which is caused by the Joule-Thomson effect. Detailed hydrogen refueling station designs generally differ concerning the form of hydrogen delivery and the chosen method for creating the required pressure gradient. For the 700-bar hydrogen refueling of passenger cars, the pressure is increased to 875 bar to enable rapid refueling rates of 1.8–3.6 kg/min (FCH JU 2016; SAE 2014). To achieve this, hydrogen is generally either stored in high-pressure vessels that facilitate the refueling process or medium pressure vessels, with a small additional compressor, which covers the highest pressure-gradient requirements, being installed. In the case of liquid or LOHC hydrogen delivery, hydrogen is evaporated or discharged from the hydrogen carrier and compressed to the required pressure. In the case of 350-bar vehicles, rapid refueling requires a lower pressure gradient, and therefore, 500-bar trailers can be employed as high-pressure hydrogen storage media for vehicle refueling (Elgowainy et al. 2014; Reddi et al. 2017).

5 Hydrogen Safety

In general, concerns about hydrogen safety are different but not more demanding than those pertaining to fossil fuels such as natural gas, gasoline, or diesel (Rigas and Amyote 2013). Most hydrogen hazards relate to the fact that, like methane, hydrogen gas cannot be detected with human senses (Rigas and Amyote 2013). In the case of methane, gas leakage detectability increased with the addition of odorants to the methane gas. However, the current high hydrogen purity requirements of fuel cells preclude the use of odorants (Rigas and Amyote 2013). Nevertheless, hydrogen-related material degradation is a well-understood and -managed hazard, as it is among the main causes of equipment failures in the oil and gas industry (Popov et al. 2018; Shehata et al. 2008). Hydrogen also has positive features when compared to fossil fuels. In contrast to methane and gasoline, hydrogen rapidly disperses to incombustible concentrations and has less explosive energy (Hess Corp 2007; Linde AG 2018; Air Liquide AS 2018). Furthermore, unlike gasoline, hydrogen is neither toxic nor carcinogenic (Hess Corp 2007; Linde AG 2018).

Hydrogen-related incidents are constantly tracked and analyzed to improve the safety of hydrogen system operation. The major causes of hydrogen-related incidents can be classified into the following categories (Federal Institute for Materials Research and Testing 2002):

- Mechanical and material failure
- Corrosion and embrittlement
- Incidents of over-pressurization
- Incidents of expanding liquid hydrogen boil-off
- Hydrogen-unrelated incidents
- Human error

An overview of more than 240 historical incidents revealed that 95% of these were not associated with any fatalities, while 34% did not result in any damage (Rigas and Amyote 2013; Weiner and Fassbender 2011). It could also be identified that most of the accidents occurred as a result of simple equipment, such as valves and fittings, which often relates to human error during assembly and maintenance (H2 Tools 2019). Therefore, despite the fact that most of the accidents were directly caused by equipment failure, the most frequent direct and indirect cause of the accidents was a lack of situational awareness and human error (Rigas and Amyote 2013; H2 Tools 2019).

Markerta et al. (2017) advocate the use of a holistic approach for analyzing the risk and sustainability of hydrogen infrastructures, proposing the use of the "functional modeling" method and combining this with life-cycle analysis (LCA) and geographic information systems (GIS). They consider risk assessment as part of a more general decision plan needed to design and establish sustainable supply chains that are economical, efficient, reliable, safe, and secure. By using functional decomposition (from an early design stage onward), it is possible to analyze and compare alternative supply chain solutions that provide the required system functions with regard to safety, reliability, environmental impact, and costs.

5.1 The Public Acceptance of Hydrogen

The public acceptance of hydrogen technologies has been the subject of research for several decades. Varying levels of acceptance were examined in broad, methodological studies. The following comments highlight only a few selected criteria that relate predominantly to the perception of the general population in Germany (Zimmer 2013a; Spillet and IFOK 2016). An overall positive basic attitude toward hydrogen transportation is often found due to its tailpipe emission-free nature and status as a futuristic technology. One exception was civil society actors surveyed who were reasonably skeptical about hydrogen transportation applications. Citizen surveys focused in particular on expectations of the technology in terms of vehicle usability, health and noise, climate and environmental protection, and safety sensitivity (Zimmer 2013a; Spillet and IFOK 2016). With regard to usability, the interviewees largely assumed current conditions with regard to range, performance, vehicle size, and filling station availability (Zimmer 2013a).

According to the report for Germany, noise abatement played a minor role in the assessment (Zimmer 2013a). The most important added value was considered the technology's contribution to environmental protection. The often critical issue of safety perception due to the chemical-physical properties of hydrogen played hardly any role in the study. The report noted that this was demonstrated by the fact that the hazardous nature of hydrogen was not once addressed. Also, in a citizen conference, after an initial discussion of safety concerns on the part of citizens, the assessment was expressed that hydrogen vehicles are safe. Furthermore, a representative survey was carried out in which approximately 1000 people were asked about their view of the statement, "I would be more afraid to live next to a hydrogen filling station than next to a conventional filling station," with 6% replying that this would be "fully applicable," 17% that it would be "rather applicable," 43% that it would be "rather not applicable," and 34% that it would be "not applicable at all." An overwhelming majority of 77%, therefore, rejected the statement. Zaunbrecher et al. interviewed 182 people about their attitude and acceptance of hydrogen storage in Germany (Zaunbrecher et al. 2016). Of the 141 answers supplied, it could be concluded that hydrogen, in contrast to other currently discussed technologies of the energy system transformation, is generally viewed positively in terms of social acceptance. The construction of necessary facilities is also supported in principle, although there are uncertainties about the risks if hydrogen is stored near residential areas.

Studies on similar questions have also been carried out in other nations. Despite this study's focus on Germany, the results of studies in other countries will be presented briefly, as hydrogen-based passenger car transport can only be successful if it can be implemented worldwide. Iribarren et al. investigated the social acceptance of hydrogen in Spain as a fuel for road traffic (Iribarren et al. 2016). Some central questions included the public perception of hydrogen itself, hydrogen as a fuel in public transport, and its environmental friendliness. All three questions were answered in the affirmative, in some cases at more than 70%. On the question of the acceptance of hydrogen fueling stations, it is striking that more than 50% of those questioned had no objections to these but preferred that they be built away from residential areas. Only about 3% of the respondents were against hydrogen fueling stations. The aspect of supporting the market introduction of hydrogen was examined on the basis of the question of an appropriate ("affordable") tax. A total of 74% responded positively, but around 60% felt that this transition should not be undertaken with the help of a direct tax. Similar findings were found in a trans-European study on hydrogen acceptance as well, thus indicating the underlying societal acceptability and support for hydrogen and fuel cell technology applications (HYACINTH 2013).

A study by Bögela et al. (2018) investigates the implications of prior attitudes for public-facing communication campaigns related to hydrogen technologies in seven European countries, finding low attitude strength and low stability of attitudes with regard to hydrogen fuel cells for both stationary and mobile applications. The implications of these findings are that information campaigns in early stages can help increase awareness among those with no or low prior knowledge about hydrogen technologies and positively influence attitudes toward the technology. At a later stage, when public knowledge and awareness increase, psychological research on prior attitudes becomes more relevant and should address the context-specificity and empirical testing of the theoretical models used.

An interesting question is whether the provision of quantitative risk information on hydrogen infrastructure increases or decreases acceptance (behavior toward the technologies) and acceptability (attitudes). In a repeated Japanese online survey (Ono and Tsunemi 2017; Ono et al. 2019) regarding the scenario of constructing a hydrogen fueling facility at the gas station in the vicinity to the home of the respondents, the public acceptance of hydrogen fueling was investigated on the basis of risk perception scales. The provision of quantitative risk information and risk acceptance criteria increased the acceptability of hydrogen refueling stations in proximity to the homes of respondents but decreased acceptability at the nearest gas station.

Roche et al. (2010) review the various conceptual frameworks and methodologies used for studying public attitudes toward new transport technologies. They review the findings of recent literature on acceptance, attitudes, and preferences for hydrogen and fuel cell end-use technologies from a vehicle perspective. The authors recommend using approaches that build knowledge and familiarity with the technology prior to the exploration of attitudes. They advocate further studies that take a whole-system perspective on hydrogen technologies, looking at (green) hydrogen in the context of other competing CO_2-free fuel technologies, and which aim to identify the early signs of possible social acceptance barriers (to be prepared if opposition arises in the course of increasing the penetration of hydrogen, and in particular concerning growing numbers of hydrogen refueling stations).

5.2 Willingness to Pay

For the broad adoption of hydrogen-based transportation, in addition to the right conditions for supply with FCEVs and hydrogen, the question arises of whether or not consumers are willing to opt for hydrogen-based transport by purchasing an FCEV. According to economic theory, a customer purchases a product or service if (a) the utility it provides exceeds the so-called total cost of ownership (TCO), that is, its net utility is positive, and (b) if its net utility is the highest among all available alternatives (Zweifel et al. 2017). While utility itself is subjective and dependent on the personal preferences of consumers, its influencing factors are measurable. In the case of hydrogen-based transportation, primary drivers certainly take mobility itself (e.g., distances one can travel in a specific timeframe) into account. However, as Hackbarth and Madlener show, there are other factors, such as a reduction of CO_2 emissions, that might add to a consumer's perceived utility of hydrogen-based transportation (Hackbarth and Madlener 2016). With respect to TCO, one can differentiate between fixed and variable costs for consumers. In terms of fixed cost, the most substantial impact is the cost of the vehicle itself. Other fixed costs might include expenditures for taxes or insurance. With variable cost, the most significant factor is the cost of hydrogen as a fuel. Additionally, the maintenance costs depend on the use of FCEVs.

The monetary value of consumers' willingness to pay (WTP) can be quantified using different analytical methods. In general, these approaches can be divided into the actual (revealed) or hypothetical (stated) market behavior of the consumers. On the one hand, the preferences of customers can be revealed through their actual purchasing behavior in the markets. Using observations of actual market transactions, highly reliable and valid data on consumer preferences can be obtained (Schmidt and Bijmolt 2019). From volumes purchased as a function of market prices, one can derive the WTP of the consumers. However, such revealed preference methods require sufficiently liquid markets for the good or service in question in order to obtain the necessary data on actual consumer behavior. In the case of hydrogen-based transportation, markets with sufficient liquidity for such analyses are yet to be formed. On the other hand, analysts can use stated preference-based methods to study WTP. Particularly for goods or services where liquid markets are yet to be formed, as in this instance, such methods are the most frequently used. Among these methods are the so-called discrete choice experiments (DCE). Here, surveys are used where respondents chose their favorite option out of a set of alternative choices where different attributes (e.g., CO_2 emissions, refueling time, etc.) vary. Of these choices, analysts can derive the WTP for the good or service in question through the choices of the respondents.

For consumers to choose hydrogen-based transportation services over the available alternatives (i.e., fossil-fueled ones), its individual net utility must be the higher of the two. Currently, the TCO of hydrogen-based transportation exceeds the TCO of alternatives employing other fuels. In this case, either the WTP for hydrogen-based transportation must substantially exceed the WTP for fossil-based forms (i.e., because consumers are willing to pay more for environmentally friendlier transportation) or the TCO of hydrogen-based transportation must be substantially decreased until it is about on par with fossil-based alternatives. In either case, state regulation could lead to a situation in which the net utility of hydrogen-based transportation is maximal either by increasing net utility for hydrogen-based transportation (e.g., through subsidies) or by decreasing the net utility of fossil-fueled alternatives (e.g., through taxes). In accordance with the aforementioned observations (see Hydrogen Policy and Regulation section), a successful reduction in CO_2 emissions will require a balanced mix of these two measures.

A representative survey by Zimmer (2013a) for Germany indicates that about 83% of the population would be willing to spend about 5000 EUR more for environmentally friendlier alternatives. Translating the results of this study into TCO, environmentally friendlier mobility can exceed the TCO of fossil-fueled transportation but only by about 5000 EUR in the German case. Figure 4.9 illustrates some further results from studies on WTP for transportation. It indicates that WTP may vary greatly depending on location (country) and other characteristics (e.g., environmental concerns, refueling time, and the

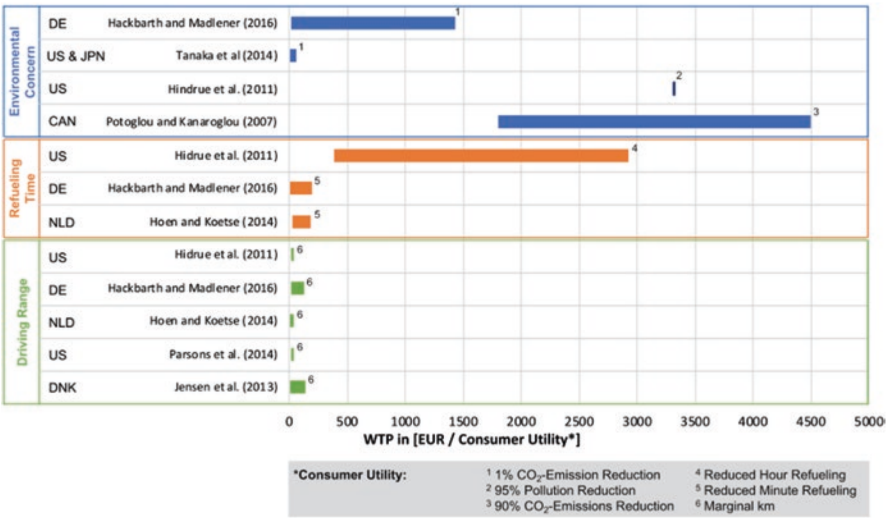


Fig. 4.9 Study results of the willingness to pay for different user aspects (Hackbarth and Madlener 2016; Tanaka et al. 2014; Hidrue et al. 2011; Hoen and Koetse 2014; Parsons et al. 2014; Jensen et al. 2013; Potoglou and Kanaroglou 2007)

driving range). According to the results, customers are willing to pay more for an alternative-fueled vehicle with reduced CO_2 emissions. Both FCEVs and BEVs might meet these requirements. However, compared to BEVs, FCEVs can offer the customer a higher degree of pain flexibility through a faster refueling process of only a few minutes, resulting in a driving range of several hundred kilometers. Although most average daily journeys are well below the range of BEVs, this flexibility remains an important criterion for vehicle purchases. Figure 4.9 shows that this directly translates into a higher WTP.

6 Conclusions

Hydrogen is a versatile energy carrier that offers numerous possibilities to decarbonize various sectors of the economy. To date, hydrogen has been used on an industrial scale worldwide but has been produced almost entirely from natural gas or coal. Hydrogen production from low-carbon energy resources is still costly, but its costs are expected to decline rapidly due to the falling costs of renewable energy and to realizing economies of scale and economies of mass production for electrolyzers (Dodds 2015). Green hydrogen is favorably received by the public and is less hazardous than fossil fuels, thus providing beneficial conditions for the technology's acceptance. Furthermore, many prospective consumers express a positive willingness-to-pay for green hydrogen services, which further reduces the utility gap for the adoption of hydrogen technologies. For these reasons, green hydrogen market entry and commercialization is receiving increasing attention from policymakers and businesses alike.

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CHAPTER 5

Economics of Power Generation

Manfred Hafner and Giacomo Luciani

Electricity can be generated either chemically (as in photovoltaic panels) or, more frequently, mechanically, through the rotary movement of a generator (a magnet moving within a net of cables). The needed rotary movement can be obtained by the force of steam expanding at high temperature, water flowing, or wind blowing in a turbine; or even by using a regular internal combustion engine. The high temperature needed to raise steam can be derived from burning coal, oil, gas, waste and biomass; from controlled fission in a nuclear reactor; by concentrating solar radiation; or by extracting heat from the earth crust. The bottom line is that there are numerous solutions to generate electricity, and each of them has specific characteristics that render it more adapted to the specific conditions and circumstances where and when electricity is required.

In order to provide a satisfactory treatment of power generation technology and economics, a single chapter would have expanded beyond a practical dimension: accordingly the discussion has been divided into a general

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introduction and a sequence of specific chapters each devoted to a different generation solution: thermal power based on fossil fuels (coal, oil, and gas)—Chap. 6; thermal power based on nuclear fission—Chap. 7; hydroelectricity—Chap. 8; solar power—Chap. 9; wind power—Chap. 10; geothermal power—Chap. 11; and power from tides and waves—Chap. 12. In this introductory chapter, we touch upon the major economic differences between these multiple solutions, highlighting the comparative advantages and disadvantages of each. In the end, a well-functioning electricity system will always necessitate a combination of different technologies assorted in an appropriate way to satisfy a range of situations that are expected to arise in time.

When discussing electricity and comparing different power generation technologies and their properties, the reader must first and foremost keep in mind the distinction between *capacity* (or power) and *energy (or electricity generated* or consumed). Capacity (or power) is the electricity that a generation plant produces (or an electricity device consumes) instantaneously. It is measured in watts, kilowatts (1 kW = 1000 watts), megawatts (MW: 1 MW = 1000 kW), and gigawatts (1 GW = 1000 MW). The installed (or nominal) capacity of a power plant is (generally) the maximum capacity of a power plant. The amount of electricity a power plant produces (or an electricity device consumes) over a given time is measured in kilowatt-hours (kWh). Kilowatt-hours are determined by multiplying the number of kW produced (required) by the number of hours of production (use). Energy is thus the amount of electricity generated (consumed) over time and is measured in watt-hour, kilowatt-hour (kWh), megawatt-hour (MWh), gigawatt-hour (GWh), and terawatt-hour (TWh).

Unlike coal, oil, or gas, electricity cannot be stored easily. It must thus be generated and delivered at the precise moment it is needed. The most important element to be considered when addressing power generation is the *demand load curve*. A load curve shows the variation of load (in kW or MW) over time (in hours). The load curve can be plotted for 24 hours a day, it is then called a daily load curve; if one year is considered, it is called annual load curve. The load curve is important because the electricity capacity demanded by consumers (industry, residential, and commercial) varies over time. Typically, industrial activities are the highest during the day, commercial activities are high during the day and the early evening hours, and residential activities are high mainly in the evening when everybody is at home and turns on the lights, watches television, and uses other electric devices.

The resulting daily load curve of a country is one with a low level during the night and a higher level during the day with some peaks either during the day or in the evening hours. Moreover, the load curve differs from day to day (on weekends and festivities when industrial activities are reduced, the load curve is generally lower) and across seasons (in cold climates, electricity load is higher during the winter months due to heating, while in hot climates, it may be highest in summer months due to cooling). Some high-income countries with a relatively temperate climate may nowadays have two seasonal peaks: a winter peak due to heating and a summer peak due to cooling. The load curve thus differs from country to country due to cultural and meteorological differences. The integral (surface) below the load curve represents the electricity demand (electricity demand = capacity × time = kW × h = kWh).

All of this is of utmost importance because the load curve will define the amount of the electricity demand which is *base load* (load needed all year), *peak load* (load needed only a few hours a day), and *intermediate load (or mid-load)* for operating hours between base load and peak load. Different power plants with their different repartition of capital cost and operating cost will be used to satisfy different load segments.

All power generation plants are relatively capital-intensive, in the sense that the initial investment costs are a significant and frequently dominant component of total cost; however, the *ratio of capital vs. operating costs* varies significantly: it is highest for nuclear, wind, solar, large coal-fired, and some hydropower plants and smallest for gas turbines or plants based on internal combustion engines. Nuclear, coal-fired, and hydropower plants with large reservoirs are available for many hours, and it is convenient to keep them in use for as many hours as possible, in order to amortize the very high capital cost over the maximum number of hours and reduce the unit cost of producing each kilowatt-hour. The same would be true for solar and wind, except that these plants are non-dispatchable; therefore, the operator cannot control the extent of their use. Consequently, nuclear, coal-fired, and some hydropower plants are optimal to meet base load demand. In contrast, gas turbine power plants or generators based on internal combustion engines are typically preferred for meeting demand peaks or dealing for emergency situations, for example, in islands or other isolated tourist destinations during the high season, or in hospitals in case electricity from the grid is no longer available. Hydroelectric plants with small storage will be used during peak hours due to the high opportunity cost of these plants.

A further distinction of importance is between *indirect* and *direct* operating costs. Indirect costs are related to the upkeep of the plant independently of how much the plant is being used and are typically incurred on a yearly basis. In contrast, direct costs are directly related to the utilization of the plant, for example, the cost of fuel in a coal- or oil-fired thermal plant or in a gas turbine plant. Indirect costs are fixed and fundamentally unavoidable, while direct costs are directly related to the production of power. Hence, both capital and indirect costs are not part of *marginal* cost, which is the cost of producing one additional KWh of power, and exclusively reflects direct costs. Hence, some technologies, notably solar, wind, and most hydropower plants, have zero marginal costs, and nuclear has low marginal costs because the cost of fuel per kWh produced is very small. To the opposite extreme, gas turbines or internal combustion engine-based plants have significant marginal costs and will only be started if demand justifies it.

A generation plant will not always generate at full capacity: there will be times when it generates at less than full capacity, and times when it is not in use and does not generate at all. This may be due to the load curve or intrinsic non-availability by some plants (the most obvious are solar and wind availability for plants relying on these energy sources).

How much electricity will be produced by a plant of a given installed (or nominal) capacity depends on the number of hours that the plant is available for production (*availability*) and the number of available hours that the plant is actually in use.

There are 8760 hours in a year, and no power plant can be available throughout the year. Some plants may be available most of the time in a year (coal-fired, nuclear, biomass, geothermal, run-of-river hydroelectric plants, or hydroelectric plants with a very large reservoir of water) and may be relied upon for close to 8000 hours (due to maintenance and other outages they cannot operate all hours of the year).

Other plants, in contrast, are necessarily limited in their availability: for example, solar photovoltaic panels only produce electricity during the day and will produce very little when the sun is low over the horizon or it is covered by clouds, meaning that even in the best imaginable conditions, a photovoltaic panel cannot possibly reach 3000 hours of availability, and in many locations may be available for as little as 1000 hours. Similarly, a hydropower plant with a small reservoir (e.g. in the Alps) may only be able to produce electricity at nominal capacity for 2–3000 hours in the year.

The difference between the last two cases is that in the case of a hydropower plant the operator may normally decide when to use the plant using an opportunity cost approach (i.e. to decide when to "spend" the limited plant's hours of availability in order to maximize revenues), while in the case of solar photovoltaic the operator has no control at all on the availability, and electricity may be produced when it is needed, but possibly also when it is not needed. Hence a further key difference between various technologies is *dispatchability*. Some technologies (notably thermal power plants, independently of the source of heat, and hydropower plants with large reservoirs) are fully dispatchable, in the sense that the operator decides when the plant is in operation. At the opposite extreme, some technologies are not dispatchable at all (wind, solar, and hydro run-of-the-river, i.e. with no reservoir), and electricity is produced when the appropriate natural conditions exist, and not at other times.

This distinction is important because, as already mentioned, the demand and supply of electricity in a grid must be balanced at all times in real time. The power producer (or the manager of the grid, called a Transmission System Operator or TSO) has little or no control over demand and must adjust supply to demand—a task made considerably more difficult if power is produced from non-dispatchable technologies. The details of this are discussed in Chap. 13 on the economics of networks, and the integration of non-dispatchable renewables is discussed in Chap. 15. The issue of non-coincidence of demand and supply highlights the importance of electricity storage, which is limited and expensive: this is discussed in Chap. 14 as far as battery storage is concerned and in Chap. 8 as far as pumped storage is concerned (so far the only way to store electricity by converting it to potential energy).

Producing peak load electricity is more expensive than producing base load electricity; in the first case, an equipment needs to be built which only runs a few hours a day, and in the latter case, investments can be amortized producing electricity almost all year. Even though in physics a kWh is equal to a kWh regardless when and where it is consumed, in economic terms a kWh is not equal to a kWh. The cost of producing a kWh depends on the moment when it is consumed and thus when it needs to be produced since it cannot be easily and cheaply stored.

This time element of demand (and thus production) is relevant not only for *power plant dispatching*, but also for *future capacity planning*. If overall demand of electricity in a country increases by a certain amount of TWh but most demand increase is expected to happen during peak hours, the required power plant investments will be fundamentally different compared to the case where the demand increase happens mainly during low load hours thus increasing base load.

A distinction needs to be made between capacity investment planning in order to satisfy future electricity demand evolutions and dispatching existing and available power plants for the hour or day ahead. For future capacity planning, a full cost (or *long-run marginal cost*) approach needs to be taken (including investment cost, operating and maintenance cost, fuel costs, and possibly the cost of carbon emissions—as well as possibly other costs aimed at internalizing environmental and other externalities), while for dispatching purposes, only the short-run marginal costs (fuel costs and other unit-based environmental costs) are taken into account. The choice of power generation technology (and thus energy) being used on a given moment of the day depends thus on the merit order (marginal costs) of the different power plants to satisfy demand. For dispatching purposes, all fixed costs are to be considered sunk cost.

With increasingly large shares of non-dispatchable power generation sources in electricity producing systems, flexibility mechanisms become of utmost importance. Non-dispatchable power generation means (e.g. wind and solar) are always first in the merit order, thanks to their zero short-run marginal cost, but they are largely not reliable in the sense that whenever the sun shines and the wind blows, you will use them, but whenever the sun does not shine and the wind does not blow, they are not available. In fact, dispatchable power plants no longer need to follow the "demand load curve" as defined by consumers, but the so-called net load curve, that is, the difference between the load curve as demanded by consumers and the electricity produced by non-dispatchable zero marginal cost electricity (mainly solar and wind). The net load curve is much less predictable and has much higher ramp up and ramp down requirements compared to the load curve of consumers. Needed *flexibility* mechanisms include (i) the capability of power plants to ramp up and ramp down quickly (storage hydroelectric and, to a slightly lesser extent, gas turbine power plants can ramp down/up very quickly, while steam turbine-based power plants [in particular large coal and even more so nuclear plants] are not well suited for fast ramp up/down of power output), (ii) interconnections to neighboring electricity systems, (iii) storage (so far mainly pump-storage, but in the future possibly to some extent also batteries), (iv) electricity demand side management (in particular demand response), and (v) sector coupling (e.g. power to heat, power to gas, power to vehicles).

A further differentiating characteristic is *size*, as measured by the plant's capacity. For some technologies, notably coal-fired and nuclear plants, economies of scale are potentially very important, favoring the construction of very large power plants (in excess of 1 GW of capacity). However, nuclear power plants can also be medium or small size (including less than 100 MW), and in fact, there is growing interest toward such smaller nuclear alternatives. Gas turbine-based plants can be small (gas turbines—GT) or medium size (combined cycle power plants—GTCC). Individual wind turbines are small (today up to 10 MW) and individual photovoltaic panels very small. Hydropower plants can be of all sizes: the largest power plants in the world are hydroelectric, but hydro solutions are available also for very small applications in locations where the grid does not reach.

Another relevant dimension of size is *space occupation* and the physical impact on the immediate environment. Hydropower plants with large reservoirs may entail the flooding of vast surfaces and the need to relocate large numbers of people, an obvious drawback. Large solar power plants also occupy very large surfaces for relatively limited capacity, an obstacle to their deployment in cultivated, forested, or inhabited spaces that are in demand for other purposes. This is one of the reasons why large solar power plants tend to be proposed for desert regions, where space has limited alternative potential use (the other reason is that in dry desert areas solar radiation is very high). To the opposite extreme, nuclear power plants are very small relatively to the very large capacity that they can reach, especially where several plants are grouped in a single location, as is frequently the case.

A final important characteristic is *locational constraints*. Some technologies are available only in specific locations, this being most evidently the case of hydro, but conditions for wind and solar are also greatly variable depending on latitude, meteorology, and orography. This is important because electricity is expensive and difficult to transport over long distances, and plants must be sized in view of the total demand that they can effectively reach and satisfy economically. Thus, some very promising locations for hydro, wind, and solar remain underexploited or unexploited because no demand is geographically close enough to justify creating transmission capacity and a generation plant.

In contrast, thermal power plants are extremely flexible from the point of view of their localization, as they basically only need proximity to a body of water for cooling purposes. Historically, this has allowed industry to be localized in the proximity of markets, or where other factors of production, notably labor, are present at low cost; while in past centuries, when energy was predominantly available in kinetic form, industry clustered in the proximity of energy sources (mostly flowing water). With increased reliance on renewable sources (solar, wind, and hydro) the pendulum may, at least to some extent, swing back to localizing industry close to the source of energy, with potentially momentous consequences on the international distribution of industrial production, especially in sectors that are highly energy-intensive.

CHAPTER 6

Power Generation from Coal, Oil, Gas, and Biofuels

Arash Farnoosh

1 Introduction

This chapter provides an introduction to the economics of electricity generation based on four different energy sources: coal, oil, natural gas, and biofuel. It covers the various technologies of power production and their key economics characteristics including CAPEX, OPEX, dispatchability, flexibility, location, and expected service life. The formula and calculations are provided for further analysis of power generation projects in view of optimizing the choice of technology. Some conclusions are drawn from comparative analysis of coal-, oil-, gas-, and biofuel-fired power generation units.

Thermal power has always accounted for a large proportion of the world's power generation. It has been above 60% since the 1990s. Since 1875, when the world's first thermal power plant was built at the *Gare du Nord* station in Paris, which supplied the lighting nearby, the world's power industry has gradually evolved toward better performances and larger capacities.

Currently, the world's largest coal-fired power plant by installed capacity is the Toketo power plant in China, the largest gas-fired power plant is Russia's Surgut plant, and finally, the largest oil-fired power plant is Saudi Arabia's Shoaiba power station (Table 6.1).

Coal, oil, and natural gas have always been the main energy sources to produce electricity (Fig. 6.1). Although with the increase of environmental

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Table 6.1 The world's top 10 thermal power plants

Power station	*Fuel*	*Installed capacity (MW)*
Toketo, Inner Mongolia, China	Coal	6720
Taian power station, South Korea	Coal	6100
Tanjin power station, South Korea	Coal	6000
Taichung power station, China	Coal	5700
Shoaiba, Saudi Arabia	Oil	5600
Surgut-2 power station, Russia	Natural Gas	5597
Belchiatov, Poland	Coal	5300
Jebel Ali Power and Desalination Plant, UAE	Natural Gas	5163
Higashi-Niigata power station, Japan	Natural Gas	5149
Jiaxing power plant, China	Coal	5120

http://dy.163.com/v2/article/detail/EEM9SO3F05484WS6.html

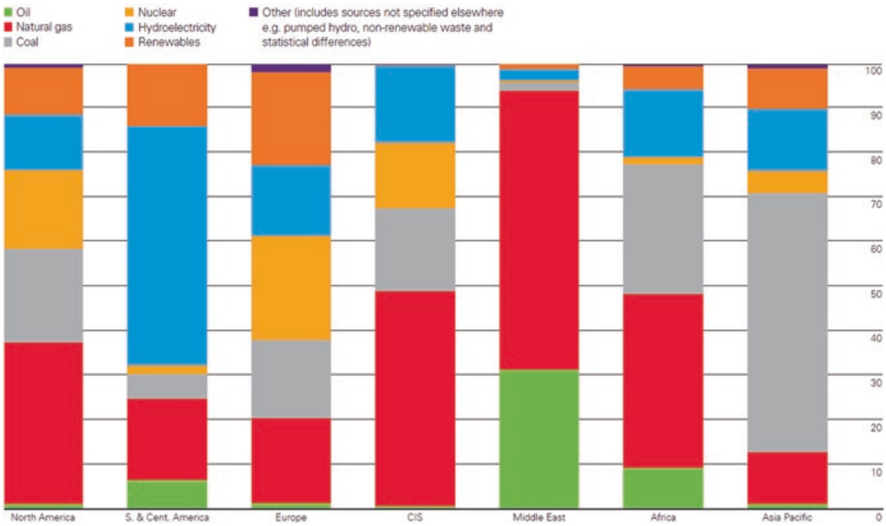

Fig. 6.1 Regional electricity generation by fuel (in percentage) in 2019. BP Statistical Review of World Energy 2020

protection awareness, renewable energy has gradually come into play, the position of fossil energy sources in producing electricity is still unshakable.

Coal accounts for around 40% of electricity production globally, making it the most important power generation fuel in the world, and is a major source of carbon dioxide emissions. It has achieved its pre-eminence because it is cheap and widely available. Coal has been used as a source of energy for over 4000 years, but electricity production from coal only began at the end of the nineteenth century. Initially, it was based on steam engines, but with the development of the steam turbine, coal became the major means of electricity generation during the twentieth century. Many nations have built their prosperity based on coal. The largest users of domestic coal for power generation are China, the United States, and India.

Currently, natural gas power accounts for 23.23% of total electricity generation and is forecasted to grow constantly. Due to the growth of global carbon emissions and the intensification of greenhouse effects around the world, several countries are actively taking measures to abate emissions. These have frequently used natural gas to replace coal, as its associated carbon dioxide emissions are 54% of those originating from coal-fired plants on average.

In a gas-fired power station, air goes through a compressor, is mixed with natural gas in the combustion chamber, and burned. The hot combustion gases expand, driving the gas turbines and turning the generators to produce electricity. The waste gases are emitted to the atmosphere through the stack but can also be recycled in a steam generation unit so as to run a steam turbine in parallel. (This is called a combined cycle gas turbine plant, or CCGT.)

Oil can be used for power generation in a plant very similar to a natural gas one.

Whether it is coal, natural gas, oil, or biomass energy, they all have a common feature, that is, they turn the turbine through combustion so that thermal energy can be converted into mechanical energy and then further converted into electric energy, thus realizing the transition from primary to secondary energy. Natural gas can be recycled through air cycling and condensation.

From the environmental protection point of view, natural gas and biomass are cleaner than coal concerning CO_2 emission. However, from the perspective of the total cost of electricity produced, a coal plant is the cheapest, and a gas-fired plant comes just after, because gas is more expensive to produce, transport, and store, even though it is the most efficient among all other types of power plants.

In the following, we discuss the power generation process of these different types of power plants in details.

2 Alternative Electricity Generation Options

2.1 Coal Power Plants

2.1.1 The History of Coal-Fired Power Generation

The use of coal for power generation began in the United States in the 1880s, based on the same technology that was then used to create mechanical power from the steam engine. Coal was burned to raise steam and the steam used to drive an engine, which in turn drove a dynamo or alternator, which produced electricity. The first fully commercial electric power station was the Pearl Street station in New York, which was built by Thomas Edison and started operating in 1882. The Pearl Street plant used a Porter Allen reciprocating steam engine and dynamo to produce a direct current, which supplied power only for lighting.

The next major advancement was the steam turbine, which was invented by Charles Parsons in 1884. Steam turbines allowed more efficient energy conversion and higher outputs. During the twentieth century, coal-fired power stations using steam turbines became the most important source of electricity across the globe. They remain the single most important source of electricity in the second decade of the twenty-first century.

2.1.2 Global Coal-Fired Electricity Generation

World coal production increased in 2018 by 250 Mt., an increase of 3.3%, driven by increases in steam and coking coal production.

Global coal production increased by 4.3% in 2018, significantly above the 10-year average of 1.3% (Fig. 6.2). Production growth was concentrated in Asia Pacific (163 Mtoe) with China accounting for half of global growth and Indonesian production up by 51 Mtoe. China has been the world's leading coal producer since 1985 and retained the top spot in 2018, producing 3550 Mt. of coal in total, 4.5% higher than in 2017. Production in the United States decreased by 2.5% in 2018, continuing the long-term trend that has seen it fall by more than one-third since 2008.

Coal consumption increased by 1.4% in 2018, the fastest growth since 2013. Growth was again driven by Asia Pacific (71 Mtoe), and particularly by India (36 Mtoe). This region now accounts for over three-quarters of global consumption, while 10 years ago it represented two-thirds.

At a global level, coal still accounts for 38% of power generation, the same share as two decades ago. Coal continues to be primarily used, at 66.5%, for electricity production and commercial heat. However, in OECD countries, the share of electricity and heat produced from primary coal as a fuel fell to 25.2% in 2018, down from 44.4% in 1985.

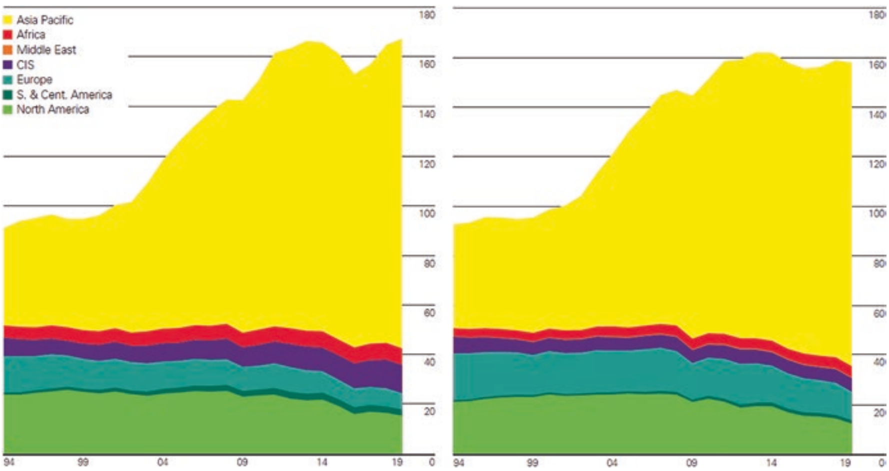

Fig. 6.2 Coal: Production (left) and Consumption (right) by region (Million tonnes oil equivalent). BP Statistical Review of World Energy 2020

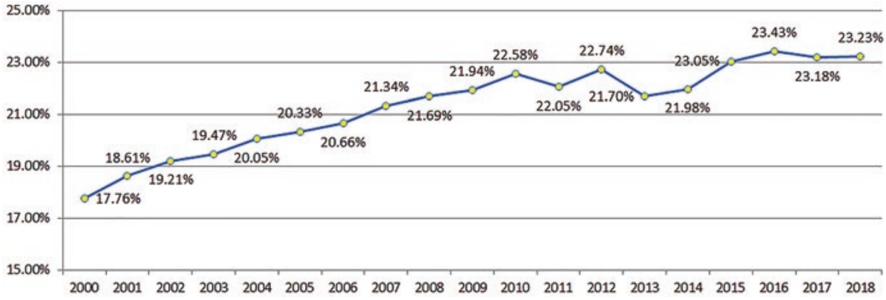

Fig. 6.3 The share of natural gas power generation in global total electricity generation. BP Statistical Review of World Energy 2020

2.2 *Global Gas Power Generation*

2.2.1 Status Quo

It can be seen from the line chart (Fig. 6.3) that the share of natural gas compared to other power generation sources globally has shown a gradual upward trend in the past two decades. Due to the growth of carbon emissions and intensification of the greenhouse effect around the world, several countries have used natural gas to replace coal.

The shale gas revolution in the United States has led to a sharp increase in natural gas supply and drop in prices, thus significantly reducing the cost of natural gas; this, coupled with the fact that natural gas power plants are easier and lower cost to build than coal-fired power plants and have less pollution emissions, resulted in a sharp increase in the proportion of natural gas power generation. In 2019, the United States gas power generation accounted for 27% of the world's total generation from gas, and for 6% of world's total power generation.

Russia is also rich in natural gas resources and suitable for gas power generation but ranks second in the world. Ranked third, Japan uses imported liquefied natural gas to boost its gas power generation, which itself has stimulated the development of the global LNG industry. However, Japan has the largest number of gas-fired power stations, which began using imported liquefied natural gas to generate electricity as early as the 1970s. Seven of the world's top 10 gas power stations are situated in Japan.

There are great differences in the share of natural gas power generation in the energy mix in different regions of the world (Table 6.2). The share of natural gas in power generation is the highest in the Middle East (around 63%) followed by the CIS countries (mainly Russia and Ukraine). Due to the great differences in oil and natural gas reserves among different countries, the proportion of natural gas power generation in each country is also quite different (Table 6.3). In 2019, natural gas power generation accounted for 3%

Table 6.2 Share of natural gas power generation in total power generation in the world in 2019

	North America	*S. & Cent. America*	*Europe*	*CIS*	*Middle East*	*Africa*	*Asia Pacific*
Total power generation (terawatt-hours)	5426	1329	3993	1431	1264	870	12,691
Gas power generation (terawatt-hours)	1976	245	768	693	793	340	1483
Percentage	36%	18%	18%	48%	63%	40%	12%

BP Statistical Review of World Energy 2020

Table 6.3 Share of natural gas power generation in the total power generation in 2019 (in selected countries)

	US	*Canada*	*Germany*	*UK*	*Russia*	*Iran*	*South Africa*	*China*	*Japan*	*India*
Total power generation (terawatt-hours)	4401	660	612	324	1118	319	253	7503	1037	1559
Gas power generation (terawatt-hours)	1701	69	91	133	520	200	2	236	362	71
Percentage	38%	10%	15%	40%	47%	63%	1%	3%	35%	5%

BP Statistical Review of World Energy 2020

of China's domestic electricity generation, compared with 38%, 47%, and 35% in the United States, Russia, and Japan, respectively.

This is also related to domestic resources and energy policies. For example, in countries such as Turkmenistan, Qatar, and Malaysia, natural gas production is quite high, while coal and water resources are limited, and natural gas power generation accounts for more than 70% of total electricity production. Countries such as Argentina and the Netherlands, despite their high natural gas production, have other sources of electricity, and around 50% of their electricity is produced by gas. Countries with 20% to 40% of power production from gas are the United Kingdom, Japan, and Italy, while countries such as South Korea and Hungary account for 10% to 20%.

2.2.2 Future Plans

The trend of global natural gas power generation in the future may depend on the policy adjustment of countries to deal with global climate change and the flexibility of natural gas power generation required by the instability of new renewable sources (wind and solar), but the price of natural gas is high and discourages its larger application to power generation.

On the whole, natural gas power generation has many advantages, such as energy saving and emission reduction, improving power supply security, cutting peaks and filling valleys of power and gas supply, and promoting the development of a circular economy, which is an irreversible trend in the field of modern energy. With the growth of global power consumption in the future, the absolute amount of natural gas consumption for power generation is bound to grow further. Although the growth rate has slowed, it will still account for the largest share of added power generation capacity in the world in the next decade or so.

According to multiple scenarios, the overall rise in global electricity demand drives the rise in natural gas demand; notwithstanding the fact that the proportion of natural gas in the power industry is likely relatively flat at about 20%.

2.3 Biofuel-Based Power Generation

2.3.1 Current Situation

Biomass, which is a renewable energy source that has the potential of being CO_2 neutral, is normally used for power generation in association with other fuels in so-called co-firing systems.

There are several successful co-firing projects in many parts of the world, particularly in Europe and North America. However, despite their remarkable commercial success in Europe, most of the biomass co-firing in North America is limited to demonstration levels.

Biofuels can be divided into four categories. First-generation biofuels can be produced from rapeseed, grains, potatoes, sugar beets, and canes. These biofuels are made from oil-based plants, starch crops, and sugar. The fuel industry has to compete with the nutrition and fodder industries for these products. On the other hand, the production of second-generation biofuel is essential for limiting food versus fuel competition by using non-edible oil feedstock such as agricultural waste and residues. Second-generation biofuels are produced from non-nutrition products, mainly from straw, miscanthus, sedges, and energetic plantations, mostly from agriculture and forestry residues. The third-generation biofuels derived from oleaginous microorganisms have also gained attraction recently as the potential feedstock in generating fuel for energy production. They do not compete with food crops on arable land. Algae can be cultivated in wastewater and other residual water. Finally, fourth-generation biofuels are produced from genetically modified (GM) algae to enhance biofuel production. Although GM algae biofuel is a well-known alternative to fossil fuels, the potential environmental and health-related risks are still of great concern.

2.3.2 Process and Technology Status

Co-firing is regarded as the most attractive short-term option for power generation from biomass. It is defined as the blending and simultaneous combustion of biomass with other fuels, such as coal or natural gas, to raise steam and generate electricity. Biomass co-firing in coal power plants is by far more widespread and extensively proven than in gas-fired plants. Co-firing can play an important role in increasing the share of biomass and renewable sources in the global energy mix and reducing greenhouse gas (GHG) emissions. It also creates opportunities in industries like forestry, agriculture, construction, manufacturing, food processing, and transportation to better manage large quantities of agricultural and wood waste. The cost of adapting an existing coal power plant to co-fire biomass is significantly lower than the cost of building new systems relying only on biomass. Although a biomass dedicated plant offers significant environmental benefits, relying solely on biomass is risky due to unpredictable feedstock supply. Other constraints of generating power solely from biomass are the low heating values and the fuel's low bulk densities, which create the need to transport large volumes of biomass.

Co-firing includes three major technologies: direct, indirect, and parallel. The approaches differ in terms of the boiler system design as well as the percentage of biomass to be co-fired.

Direct co-firing is the simplest, cheapest, and commonest option. Biomass can either be milled jointly with the coal (i.e. typically less than 5% in terms of energy content) or pre-milled and then fed separately into the same boiler. Common or separate burners can be used, with the second option enabling more flexibility with regard to biomass type and quantity. Figure 6.4 shows that in direct co-firing technology, biomass is fed directly into the furnace after being milled either together with the base fuel or separately.

Indirect co-firing is a less common process in which a gasifier converts the solid biomass into a fuel gas that is then burned with coal in the same boiler. Though more expensive because of the additional technical equipment (i.e. the gasifier), this option allows for a greater variety and higher percentages of biomass to be used. Gas cleaning and filtering is needed to remove impurities before burning, and the ashes of the two fuels remain separate.

Finally, parallel co-firing requires a separate biomass-fired boiler that supplies steam to the same steam cycle. This method allows for high biomass percentages and is frequently used in pulp and paper industrial facilities to make use of by-products from paper production, such as bark and waste wood. In parallel, biomass co-firing technology, as shown in Fig. 6.5, biomass

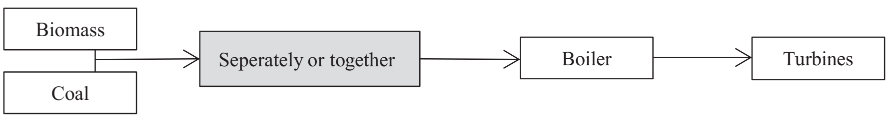

Fig. 6.4 Direct biomass co-firing technologies

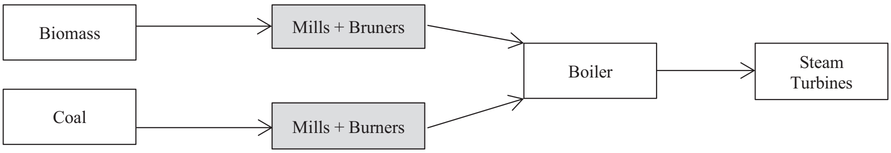

Fig. 6.5 Parallel biomass co-firing technologies

pre-processing, feeding, and combustion activities are carried out in separate biomass burners. Parallel co-firing involves the installation of a completely separate external biomass-fired boiler in order to produce steam used to generate electricity in the power plant.

2.4 Oil-Fired Power Stations

2.4.1 Role at Present

Similar to natural gas, oil is burned at power plants to create heat, which is then used to raise steam and turn turbines and create electricity. There are three kinds of oil products mostly used as power plant fuel: crude oil, diesel oil, and heavy fuel oil.

Crude oil is extracted directly from the oil well in the purest condition. It forms the basis of all petroleum products, and it has more than 500 components. According to its sulfur content, crude oil can be "sweet" (low sulfur content) or "sour" (high sulfur content).

Diesel oil is a blend of different middle distillates derived from the crude oil refining process. It is usually composed of light and heavy gas oil, light and heavy cycle oil, as well as vacuum gas oil.

Heavy fuel oil (HFO), also known as "residual fuel oil", is based on the high viscosity, tar-like mass, which remains after the distillation and subsequent cracking of crude oil in the refining process. As a residual product, HFO is relatively inexpensive—it typically costs 30% less than distillate fuels and less than crude oil.

Oil-fired power plants commonly emit nitrous and sulfur oxides, methane, mercury compounds, and significant amounts of carbon dioxide. Similar to gas-fired and coal-fired plants, oil-fired plants require large quantities of water for the production of steam and for cooling. The use of oil at power plants also results in residues called sludge that are not completely burned and therefore require disposal in landfills.

Roughly, 70% of oil-fired electric generating capacity that still exists today was constructed prior to 1980. Utility-scale generators that reported petroleum as their primary fuel comprised only 3% of total electric generating capacity at the end of 2018 and produced less than 1% of total electricity generation.

Power plants that burn petroleum liquids (such as distillate or residual fuel oils) are generally used for short periods during peak electricity demand. Otherwise, oil-fired power plants operate mostly at low capacity factors because of the high price of petroleum relative to other fuels, air pollution restrictions, and lower efficiencies of their aging generating technology. Most oil-fired generators are either turbines or internal combustion engines used to supply power only at peak electric power demand or when natural gas prices rise due to local natural gas demand.

2.4.2 Oil-Fired Plants in Different Countries

In the United States, more than 68% of the 36.4 GW of domestic oil-fired generating capacity is located in 10 states, primarily in coastal states with access to marine ports. When these plants were built around the 1970s, coal-fired generators were the main sources of electricity. However, coastal states (e.g. Florida) are relatively far from coal production areas. Since coal is primarily transported by rail, the cost of long-haul coal transport may not be competitive in these areas compared with oil delivered by marine modes. A fundamental shift in the perception of oil as a utility fuel occurred not only in the United States but in the whole world during the 1970s, when world oil markets experienced sharp price increases. Supply shortages during the main oil shocks (Arab Oil Embargo, the Iranian Revolution, and the Iran-Iraq war) also discouraged oil-fired electricity generating capacity additions globally.

However, in Saudi Arabia, the Shoaiba oil-fired power facility, located on the Red Sea coast, is the largest oil-fired power plant and second largest thermal power plant in the world. The Shoaiba project is a distinctive Saudi Arabian one. As a matter of fact, currently, very few countries are building oil-fired power plants, in part because of environmental concerns as oil burning is a significant contributor to greenhouse gas emissions. They are also unpopular because of price and supply uncertainty, which is not at all the case of Saudi Arabia, with huge domestic oil supplies.

Iran, possessing significant fossil fuel resources, has also consequently invested in utilization of thermal systems for electricity generation. Almost 90% of the required electric energy is produced via thermal power plants. Natural gas (66%) is the largest source of fuel for electricity generation (which is also the case in most other Persian Gulf countries) followed by heavy oil (17.4%) and gas oil (6.6%) (Table 6.4).

Last but not the least, Japan is also among the large users of oil-fired power plants mainly due to its geographical situation. For example, the Kashima Power Station located on Japanese coast, about 50 miles north-east of Tokyo, is the world's second largest oil-fired (and gas-fired) thermal power station with 5204 MW of installed capacity.

Table 6.4 The world's largest oil-fired power plants

No.	*Power station name*	*Countries*	*Installed capacity (MW)*	*Fuel*	*The company of affiliation*
1.	Shoaiba oil-fired CCGT power plant	Saudi Arabia	5600	Crude oil	Saudi Electricity Company
2.	Kashima Power Station	Japan	4400	Fuel oil, natural gas	Tokyo Electric Power Company
3.	Anegasaki Power Station	Japan	3600	Crude oil, fuel oil, natural gas	Tokyo Electric Power Company
4.	Hirono Power Station	Japan	3200	Crude oil, fuel oil, coal	Tokyo Electric Power Company
5.	Yokosuka Thermal Power Station	Japan	2276	Light oil, natural gas	Tokyo Electric Power Company

http://dy.163.com/v2/article/detail/EEM9SO3F05484WS6.html

Source: https://www.power-technology.com/features/feature-giga-projects-the-worlds-biggest-thermal-power-plants/

3 Economic Characteristics

3.1 Economic Analysis

3.1.1 Fixed and Variable Costs

The fixed costs of an electricity plant project consist of capital expenditure (CAPEX) and fixed operating and maintenance cost (OPEX).

1. **CAPEX**

Capital expenditure occurs during the construction phase of the project before its commissioning and is expressed in monetary units (Euro, US dollar, or whatever currency is selected) per kW of installed or nominal capacity. Capital expenditure must be broken down by its components based on various technical life durations and equity investors (e.g. utility company, private equity holder, consumer…).

CAPEX varies for different projects and technologies. As it can be seen in Table 6.5, capital expenditures for coal and biofuels plants are far greater than those for other traditional fossil fuel power plants, and among all technologies, natural gas power generation is the most competitive.

2. **OPEX**

Operating expenses (OPEX) are cash expenditure that occur every year and may be either fixed (if independent of production) or variable (if linked to production). They are expressed in monetary unit per annum and per kW of installed or nominal capacity for fixed OPEX and per kWh of produced power for variable OPEX.

Table 6.5 Range of CAPEX for mid-scale generation projects

		Coal	*Natural gas*	*Biomass combustion electricity plant*	*Biogas digester and electricity generator*	*Diesel generator*
CAPEX ($/kW)	Min	3600	900	2500	3000	1000
	Max	5000	1300	4500	6500	1300

Source: Sustainable Energy Handbook, simplified financial models module 6.1, 2016

Table 6.6 Range of OPEX for mid-scale projects

		Coal	*Natural gas*	*Biomass*	*Biogas*	*Diesel*
Fixed OPEX(% of CAPEX)	Min	1.0%	0.5%	4.0%	5.0%	2.0%
	Max	1.5%	1.6%	6.0%	8.0%	4.0%
Variable non-fuel OPEX ($/kWh)	Min	–	–	0.002	0.020	0.014
	Max	–	–	0.004	0.030	0.028
Variable fuel OPEX ($/kWh)	Min	0.004	0.002	0.005	0.014	0.300
	Max	0.007	0.006	0.022	0.058	0.500

Source: Sustainable Energy Handbook, simplified financial models module 6.1, 2016

It is clear in Table 6.6 that both fixed and variable OPEX is higher for a biofuels plant than for a fossil fuel plant, and again natural gas plant is most advantageous. Part of the OPEX cost is variable (per kWh of output) as it is linked to the consumption of basic commodities such as cooling water, chemicals, lubricants, replacement of wearing parts and of course fossil fuel. Due to fixed operating cost, if the plant's output is lower than expected, the project owner/operator is exposed to the risk of a higher average cost per kWh; the latter may exceed the revenue from the power purchase agreement that is usually strictly proportional to the kWh output. For a new project, the OPEX is the full operational cost of the project. For a rehabilitation/strengthening or an expansion/extension project, the OPEX is the marginal operational cost incurred by the project.

3. **Total Cost**

The total cost of production of an installed technology (€/MWh) includes fixed and variable costs:

$$C_{total} = \frac{C_f}{\eta} + \left[\frac{P_{CO2}}{\eta} * \frac{1}{E}\right] + VCOM + \frac{FCOM}{U} + \frac{aI}{U.}$$

where
C_f is the fuel cost given in €/MWh,
η is the total thermal efficiency,[1]

[1] Efficiency of thermal power plants are different for various technologies and could be also different within the same technology as it depends on the design and engineering of the thermal

P_{CO2} is the emitted CO_2 price in €/t, in jurisdictions where a carbon tax or emission trading system is in force,

1/E is the emission factor of the considered fuel in t/MWh,

VCOM is the variable cost of operation and maintenance in €/MWh

and *FCOM* is the fixed part,

a is the annuity corresponding to the *i* (interest rate), and *I* is the unit investment cost in €/MW,

U is the utilization ratio in hours/year.

We understand easily from the formula that the total cost of a power unit with heavy investment cost is much more sensitive to the utilization time compared to that of a unit with lower initial investment cost, even if the latter's fuel cost is more expensive.

It is the same for the sensitivity to the interest rate *i,* or the number of years over which the power unit is amortized.

3.1.2 Life Duration and Revenue

For some technologies, capital expenditure (CAPEX) may be a recurrent expense as reinvestment has to be factored periodically (e.g. every 5 or 10 years), in order to replace specific components that have a shorter life than the useful life of the project. This is the reason why CAPEX is broken down by components with shorter technical life duration than the economic life of the project. It may also be useful to separate components that receive a performance guarantee from the manufacturer for a shorter period than the economic lifetime of the project. In this latter case, it is assumed that the component must be replaced at the extinction of the guarantee period.

The revenue generated by the project is calculated on an annual basis and starts at the commercial commissioning of the project. This revenue will offset the project costs and is usually calculated as a physical quantity of energy generated by the project (or off-taken by a paying consumer) multiplied by a unit price.

3.1.3 Basic Economic Indicators

1. Pay-Back Period

The pay-back period calculates how many years are necessary to cover the CAPEX with the net annual revenue that consists of the annual income minus the annual OPEX charges. The economic sustainability of a project is subject to the pay-back period being shorter than the project economic life.

units. On average, it is between 40% and 44% for coal plants, 20% to 25% for biofuel/gas plants, 35% to 40% for single gas turbines (oil or gas-fired), and from 55% up to even 63% for combined cycles which are the most efficient thermal power plants. (IEA 2018).

2. Internal Rate of Return

The internal rate of return calculates the interest rate that makes equal to zero the net present value of all cash flows, both negative (costs) and positive (revenue), over the period of revenue certainty.

$$\sum_{t=1}^{n} \frac{(R_t - C_t)}{(1+i)^t} = I_0$$

where R_t is the revenue in year t; C_t is the total cost in year t; i equals to internal rate of return, and I_0 is the initial investment (or overnight cost in the electricity jargon).

In the first year, the cash flow consists of the CAPEX and is negative. From the second year until the end of the time series, the cash flow consists of the revenue minus the OPEX (minus the reinvestment cost if applicable). To be financially viable, the investment should have an internal rate of return exceeding the weighted average cost of capital (WACC).

3. Net Present Value (NPV)

The last, but absolutely not the least, criteria is the Net Present Value (NPV) of the project over its economic lifetime. The cash flow schedule is the same as for the calculation of the internal rate of return from second year onward.

$$NPV = \sum_{t=1}^{n} \frac{(R_t - C_t)}{(1+i)^t} - I_0$$

where R_t, revenue in year t; C_t, costs in year t; i, discount rate; I_0, initial investment. For the project to be economically viable, the NPV must be positive.

3.2 *Financial Analysis*

The total amount to be financed includes the capital investment cost as described in the economic analysis section plus the specific financing cost that occurs during the construction period, which is called interest during construction (IDC). During the construction period, the project cannot reimburse financial charges from revenue. Therefore, this cost has to be factored in the project cost used to calculate the funding requirements.

There are three types of sources for funding: equity, loans, and in some cases grants. Equity is the money committed by the owners of the project from their own sources or through an equity partner. Loans are funds committed by banks against a predetermined repayment schedule. Grants are funds provided by a donor with no obligation of repayment (assuming that such a donor is available).

1. Weighted Average Cost of Capital (WACC)

The Weighted Average Cost of Capital (WACC) is the equivalent discount rate applicable to the project cost that will be sufficient to repay the loans and generate the expected return on equity. The WACC is calculated over the loan duration as follows:

$$\text{Share of loan} \times \text{loan interest rate} + \text{share of equity} \times \text{duration of loan} \times \text{expected return on equity} + \text{share of grant} \times 0$$

In the above formula, the higher is the share of grant, the lower will be the WACC (as a result of a lower share of loan + equity).

2. Levelized Cost of Electricity (LCOE)

The Levelized Cost of Electricity (LCOE) is calculated by adding the annuitized capital cost to the annual operating expense, and dividing by the quantity of electricity generated. The LCOE should be inferior to the electricity price—otherwise, the project will generate a loss.

$$PV\ of\ Total\ Costs = \sum_n \frac{total\ capex\ and\ opex\ costs}{(1+i)^n}$$

$$PV\ of\ Electricity\ Generation = \sum_n \frac{total\ net\ electricity\ generation}{(1+i)^n}$$

$$LCOE = \frac{PV\ of\ Total\ Costs}{PV\ of\ Electricity\ Generation}$$

where i is the discount rate and n the lifetime of the power plant.

3.3 Dispatchability and Flexibility

There are two main types of power station in the world: base-load generator units and peaking stations. Base-load generators (the majority of coal power plants) are useful where there is a steady demand and a stable source of fuel, such as coal or gas, to power the generators. Electricity peaking stations (Table 6.5), also called peak-lopping plants, are power plants designed to help balancing the fluctuating power requirements of the electricity grid. Peaking stations typically operate in standby mode, and when there is a peak in demand for power from the electricity grid, they receive a signal to commence operation. Due to their flexibility and robustness, they are able to provide a rapid response to fluctuating demand. They are then turned off as demand declines.

For example, oil-fired generators tend to be used to meet electricity demand during peak hours, and they generally have lower capacity factors and higher heat rates than most other types of power plants. They are installed in places where there is no easy access to alternative power sources and are mainly used as backup for uninterrupted power supply whenever there are outages. Moreover, these plants require only a small area to be installed and offer higher thermal efficiency compared to coal-fired power plants.

In general, liquid fuel power plants have great dispatchability to supply electricity to the grid within seconds and can reach full capacity in minutes. Additionally, they have tremendous fuel flexibility, with the possibility of running with heavy fuel oil, light fuel oil, crude oil, emulsified fuels, or liquid biofuel. Some oil-fired power plants are capable of switching between fuels, potentially complicating the calculation of capacity factors. For instance, plants that normally burn natural gas may choose to burn oil (or oil products) during times of high natural gas demand.

Natural gas power stations are also very flexible and their ramping time (from zero to full capacity) is short. The operation of single cycle mode, in which only one gas turbine is running, takes only about 10 minutes from start-up to full load and the combined cycle (running simultaneously both gas and steam turbines) takes 40–50 minutes. A natural gas power plant has good regulation performance and can operate in the range of 25% to 100% output without any problem. For example, a GE HA class gas combined cycle plant with an installed capacity of 570 megawatts can start in less than 30 minutes and increase or reduce the load at a rate of 60 megawatts per minute. Under some load conditions, provided that the load is at least 200 MW, it can still meet the emissions standard and stabilize the power supply and can also form a reliable backup with intermittent sources (e.g. wind & solar) to promote the rapid growth of renewable energy. Besides, it can operate as flexibly as a liquid fuel power plant. It is also available in multi-fuel versions. When the gas supply is uncertain, or prices are volatile, it is possible to switch from gas to liquid fuel, and vice versa, even during operation.

It is worth to mention that at present, gas power generation has some unique advantages compared to all other source of electricity. An example is the world's first battery-gas turbine hybrid power generation system deployed by GE and Southern California Edison. It integrates a 10-megawatt lithium-ion battery energy storage system and a LM6000 aviation gas turbine, as well as the corresponding control system, allowing the gas turbine to be in rotating standby mode without using fuel and responding immediately to changing power dispatching requirements. When peak shaving is not needed, the gas turbine is in a rotating standby state (connected to the battery), and when the peak shaving is required, the gas turbine is immediately awakened from the rotating standby state through the advanced control system, and the gas turbine is quickly started with load, and the power is immediately transmitted to the power grid.

3.4 Location

Coal power generation location is more restrictive compared to other technologies because coal is a solid and its transport cost is high, while its combustion efficiency is lower than for other technologies. Usually coal plants are located near coal mines and the choice of different means of transport will affect the location of the plant area as well as the size and form of the required land plot, especially for a large power plant. The transportation mode should allow for large volume, low freight, high speed, and flexibility, which will make the location of coal plant all the more difficult.

On the contrary, oil is easy to transport with multiple transportation options including by pipeline and by ship; therefore, oil-fired plants are usually located in coastal areas. A gas-fired power plant is characterized by little land occupation and is very suitable for countries and areas with dense population and scarce land resources. Compared with coal-fired power plants, gas power generation equipment is more compact and does not occupy a large area. Besides, it consumes one-third of the water needed for a coal-fired power plant.

3.5 Expected Service Life

Thermal power plants are designed for an economic lifetime of 30 to 40 years, but some plants have been also used beyond their design life in certain areas. The critical components are the boiler and the turbine. The operation of thermal power generation is faced with both tangible and intangible aging processes. Tangible or physical aging refers to the equipment operating under high pressure and temperature, and bearing mechanical stress, resulting in physical and chemical changes, such as wear, creep, corrosion, and so on, gradually making the equipment unable to continue operating safely under the required design parameters. Invisible aging refers to technological progress. The advent of more efficient or less labor-intensive production equipment means that older equipment will operate under less and less economic conditions. The physical aging of some equipment (such as condenser copper pipes, heater pipes, boiler heating surface pipes, turbine blades, furnace walls, etc.) can be removed during overhaul. However, it is often the aging of these important equipment components that determines the technical and consequently economic lifetime of thermal power plants. Operating experience shows that the service life of equipment operating under 450 °C is between 40 and 50 years. For equipment operating at temperatures above 450 °C, the operating hours could even be reduced to 100,000 hours.

Both gas and steam turbines are devices that drive the rotor to rotate at high speed through high-pressure gas with high temperature and humidity.

The difference is that the pressure and temperature of gas in the gas turbine is higher than in the steam turbine. Taking the GE PG9351FA Class F gas turbine as an example, the gas temperature entering the turbine from the combustion chamber is 1327 °C and the exhaust gas temperature is 609 °C. This working environment at such high temperature and thermal stress aggravates the periodic damage to gas turbines. The material of thermal parts is deformed due to low cycle fatigue[2] and thermal stress, which increases the failure probability of different components and seriously affects the service life of the equipment. Moreover, for two-shaft peak shaving generators, frequent start-up and shut-down is also one of the main causes of shorter life. For gas-steam combined units, the life of the gas turbine, waste heat boiler, and steam turbine could be seriously affected by peak shaving operation. Finally, we should mention that the reliable operation and reasonable maintenance of gas turbine affects not only the safety but also the economy of the whole unit.

4 Conclusion

This chapter illustrated the fundamentals of power generation economics from different fossil sources. It started with the largest fossil-fuel-fired power plants in the world followed by introduction and technology performance of each source (coal, natural gas, biofuels, and oil) of electricity generation. Then economic analysis is introduced and discussed regarding the CAPEX, OPEX, indicators like NPV, IRR, and LCOE in addition to other techno-economic characteristics like dispatchability, flexibility, and expected life service of each technology. The conclusion that can be drawn from the above discussions and the related recommendation is as follows:

While general technology cost assessments can provide rough estimates, the actual cost of each technology is highly dependent on project-specific factors. Power sector planners should not underestimate the level of uncertainty when it comes to technology costs or future operating costs. Country-level analysis can provide a more accurate picture of the relative costs of each technology, but even then any forecast should be treated with care. Rather than attempting to pick the "best" technology, they should instead determine which technologies and fuels are well suited to their particular circumstances and then seek to create a diversified portfolio of options. Doing so can protect against major disruptions in any technology or fuel and help to balance capital and operational costs while mitigating environmental impacts.

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[2] Low-cycle fatigue is the regime associated with a load amplitude high enough to cause the fracture of a part after a limited number of cycles (typically less than 10^5 cycles).

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CHAPTER 7

Power Generation from Nuclear Energy

Valerie Faudon

Nuclear is recognized by the Intergovernmental Panel on Climate Change (IPCC) as a low-carbon energy source, along with renewables and fossil fuels with carbon capture and sequestration (CCS). As of today, it is available in more than 30 countries and deployable on a large scale. Public opinion toward nuclear varies a lot from one country to another, with strong influence on energy policies: some countries, like the United Kingdom, are developing nuclear to meet their climate goals and insure security of supply, while others, like Germany, have decided to phase it out.

At a 2019 conference, the IPCC Chairman pointed out that "there is considerable potential, as well as considerable uncertainty for nuclear power" (Lee 2019). He added that, beyond public opinion, the real challenge in the years to come for nuclear power was "to be cost competitive with other non-fossil fuel technologies and to deploy nuclear power much faster than in the past". He addressed the representatives of the nuclear community: "I wish you success in meeting these challenges because climate needs all the help it can get".

This chapter discusses the economics of nuclear. It covers the fundamentals of nuclear economics and reviews the cost drivers for the long-term operation

This chapter leverages a lot of recent work done with my colleagues at SFEN and OECD-NEA, with special thanks to Michel Berthélémy.

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of the existing fleet and new nuclear projects. It then reviews the latest research related to the value that nuclear can bring to the overall electricity system and in wholesale price formation in deregulated markets.

1 Reminder: Current and Expected Role of Nuclear in Decabonization Scenarios

Today, nuclear makes a significant contribution to low-carbon global electricity supply:

- As of 2020, about 450 nuclear reactors operate in the world (IAEA n.d.), with a combined capacity of more than 400 GWe. Nuclear energy accounts for more than 10% of worldwide gross electricity production (OECD-IEA 2019) and 25% in the European Union.

- Thanks to nuclear, more than 60 Gt of CO_2 emissions have been avoided since 1970 (OECD-IEA 2019), equivalent to five years' worth of CO_2 emissions from the electricity sector. Nuclear is the second largest source of low-carbon energy in the world behind hydropower and the number one source in the OECD.

International institutions have stated that all low-carbon technologies, including nuclear, will be needed to achieve carbon neutrality by 2050.

- According to the IPPC, "the strategy for reducing energy related CO_2 emissions are robust and well-known: very ambitious efficiency improvement, increased electrification, and decarbonization of electricity supply" (Lee 2019). The SR1.5 report describes four "1.5C" trajectories in its "Summary for policymakers", envisaging nuclear production two to six times higher by 2050, compared to today.
  - According to the IEA, to meet climate goals, the expansion of clean electricity would need to be three times faster than at present (OECD-IEA 2019). Along with massive investments in efficiency and renewable energies, the trajectory should deliver an 80% increase in global energy power production by 2040.
  - The latest reference scenarios from the European Commission confirm that the combination of nuclear and renewables will be the basis of a carbon-free energy mix in 2050 (European Commission 2018). By this time, nuclear would represent about 18% of the total.

2 Fundamentals of Nuclear Economics

2.1 Cost of Production

The cost of nuclear power production, as for any other energy source, includes generally three different components:

- *Capital costs*: These have a very high contribution to the LCOE of new plants, as they include the initial investment in building the plant. Nuclear, like wind and solar, is a highly capital-intensive industry. The share of capital costs decreases after the initial depreciation period, specifically in the case of long-term operation of nuclear plants.
- *Plant operating costs*: These include the fuel costs and operation and maintenance costs (O&M). The share of fuel costs, which is usually high for fossil fuel and biomass, and zero for wind and solar, is considered low for nuclear, with uranium estimated on average at 5% of total nuclear production cost. As a result, nuclear plants are less subject to fuel price volatility than fossil fuel plants: a 50% rise in the fuel cost would only result in a 5% increase in the overall generation cost (Cour des Comptes 2014).
- *External costs*: As opposed to coal or gas plants, nuclear is a low-carbon technology and provides little to no air pollution. Also, as it is highly regulated, it must include costs provisions for funding the plant decommissioning and the management and disposal of used fuel and wastes. External costs could however include the costs of dealing with a serious accident that are beyond the insurance limit: in practice, this type of risk (high potential cost with very low probability) is picked up by governments.

2.2 Revenues from Nuclear Plants

The cost of power generation is one of the three components of the retail price of electricity, together with the cost of the transmission and distribution infrastructures, and taxes.

In so-called regulated markets, revenues from power generation are determined through a regulatory process, under the supervision of a Public Utility Authority. In "deregulated" markets, the electricity produced is traded in a wholesale market, where prices are set, on an instant basis, by the "merit order" (economic precedence) logic: as electricity cannot be stored on a large scale, to meet a given level of demand, the various power generation units are called according to their increasing marginal cost.

Nuclear power plants, as we have seen, have low fuel costs, and therefore low marginal costs: they are usually called second after the units with zero to no fuel costs, such as hydro, wind, and solar. Nuclear is called before thermal power plants (coal or gas). The wholesale price for electricity, which will determine the nuclear plant revenue, will be given by the variable cost of the marginal plant, usually a thermal one.

3 Economics of Nuclear Long-Term Operations

In advanced economies, most of the nuclear power plants now in operations were built before 1990, and the average age of nuclear capacity stands at 35 years (OECD-IEA 2019). Most existing nuclear plants have been built with an initial design lifetime of 40 years, but engineering assessments have established that they can operate much longer (60 or even 80 years in the United States). One of the fastest and cheapest ways for these countries to support low-carbon production capacity is to undergo "long-time operation" programs (Fig. 7.1).

In the past years, operators of many older nuclear plants have been investing in such programs, in some cases increasing capacity at the same time (so-called uprates). In the United States, 95 nuclear reactors are currently in operations (IAEA n.d.). They account for 20% of the nation's total electric energy generation and about 50% of US low-carbon generation. About 88 have already renewed their operating license once, extending their lifetimes from 40 to 60 years (Patel 2019). However, since the majority of these will be nearing the end of that 20-year extension by 2029, it is expected that many will seek to renew their license a second time for another 20-year period. In December 2019, the US Nuclear Regulatory Commission (NRC) has for the first time issued license renewals that authorize nuclear reactor operation beyond 60 years and up to 80 years for 2 units in Florida.[1]

3.1 Cost Drivers for Long-Term Operation of Nuclear Plants

Cost estimates are impacted by reactor type, plant situation, and regulatory requirements (IAEA 2018). Most of the costs are related to plant refurbishment and, in particular, replacement of major components to mitigate aging or

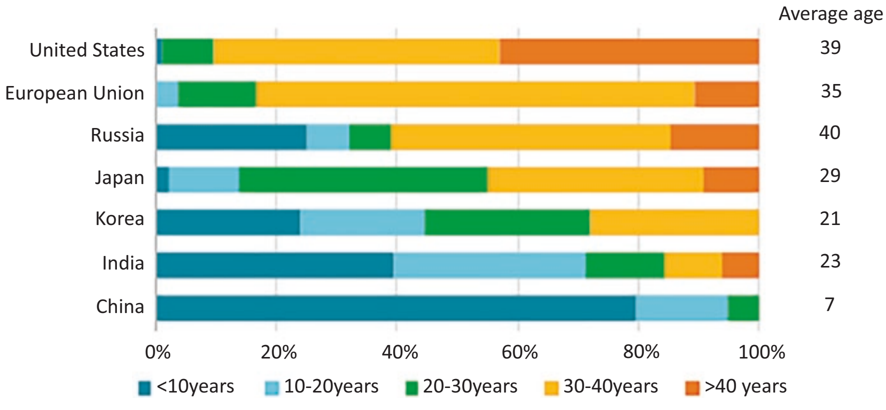

Fig. 7.1 Age profile of nuclear power capacity in selected countries/regions. (Source: OECD-IEA [2019])

[1] Units 3 and 4 at Florida Power & Light's Turkey Point Nuclear Generating plant.

obsolescence. But they also come from safety enhancements to meet the changes in national licensing requirements: these come, for instance, in response to lessons learned from operating experience, changes in industry practices and operating experience feed-back, or studies and lessons learned from accidents (such as Fukushima Daichi). Many new plant systems or systems configuration that were not considered at the time of plant commissioning may be added. In some cases, refurbishments and safety enhancements will come with power uprates, which include new licensing costs, changes in the fuel cycle, and replacement of some other components.

3.2 *Competitiveness of Long-Time Operations of Nuclear Power Plants*

According to OECD-IEA (2019), nuclear lifetime extensions are "one of the most cost-effective ways of providing low-carbon sources of electricity through to 2040". The capital costs of extending the operational lifetime of light water nuclear power plants generally range from USD 500 million per GW to USD 1.1 billon per GW, for a duration between 10 and 20 years. The levelized cost of electricity (LCOE) associated with a nuclear long-time operations project generally falls into the range of USD 40–60 per MWh.[2] The competitiveness of nuclear plant extensions is even more favorable when the full value of nuclear power as a dispatchable, high-availability (on average the capacity factor for nuclear has consistently been between 78 and 83% over the last 20 years), low-carbon source of electricity is taken into account, as we will see in part IV. In the graph below, the "value adjusted LCOE (VALCOE)" is a new IEA metric which combines a technology's costs with estimates of these values (Fig. 7.2).

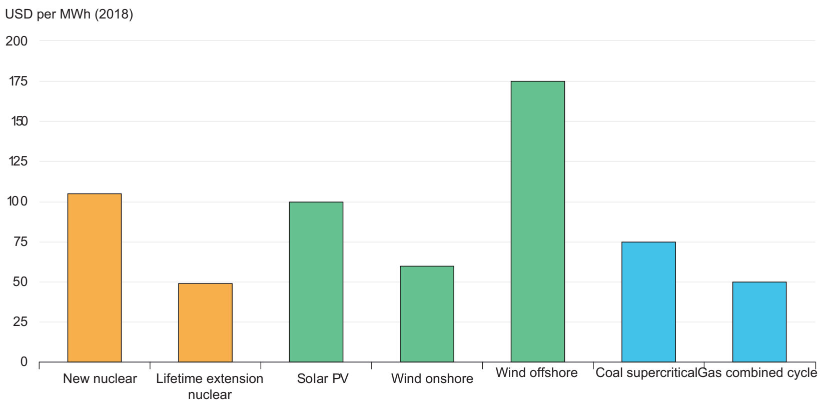

Fig. 7.2 LCOE by technology in the United States, 2018. (Source: IEA, LCOE by technology in the United States, 2018, IEA, Paris https://www.iea.org/data-and-statistics/charts/lcoe-by-technology-in-the-united-states-2018)

[2] Based on investment of USD 500 M-1.1 Bn and an extension of 10–20 years, assuming an 8% WACC.

4 Economics of New Nuclear Projects

The number of nuclear reactors in construction worldwide is 54 (OECD-IEA 2019), the majority of them in Asia, with some in Europe and America.

4.1 Challenges Associated with Delays and Cost Overruns in Recent Projects

Over the last decade, as mentioned by William Magwood, Director General of OECD's Nuclear Energy Agency (NEA), "significant cost overruns and delays in a number of OECD countries have challenged the competitiveness of nuclear power and are driving the risk perception on future projects" (OECD-NEA 2020). As the industry transitioned from "generation 2" reactors to "generation 3" reactors, which present an increased level of safety but are more complex to build, most "First of a Kind" (FOAK) projects worldwide have shown significant delays compared to initial estimates, as shown by Table 7.1:

This situation is quite common for the delivery of large complex infrastructure projects, specifically FOAK projects, and is well documented in the economic literature. A well-known example is the construction of the Channel Tunnel, whose initial budget doubled by completion. Many studies (McKinsey 2013; Merrow et al. 1981; Yemm et al. 2012) have also highlighted the "optimism bias" upstream of these projects, as well as the "rapid learning" phases on the subsequent projects.

Delays for nuclear projects vary according to two country profiles. On one side, there are countries which have been building new reactors in a continuous manner over time, either because they are still in the process of building their initial fleet (China) or because they have begun renewing part of their fleet (Russia). It is symptomatic that the first of third-generation reactors put into service was in Russia and that the first European Pressurized Reactor (EPR) to start was in China. On the other side, there are countries (France, Finland, the United States) which had stopped building for 10 to 15 years: these countries not only have had to face the challenges associated with the first projects (FOAK), but also had to bring their skills and supply chain back again up to the standards required for the construction of nuclear reactors.

4.2 Cost Drivers of New Nuclear Projects

As for renewable energy projects (wind, photovoltaic, and hydraulic) nuclear production costs are very largely dominated by the cost of investment during the construction phase. In an average case (see Fig. 7.3), it is estimated that the cost of investment will make about two-thirds of the production cost. More than half of the investment cost will be the construction cost. Furthermore, the cash flow structure of nuclear projects requires large amount of capital to be mobilized upfront. Construction lead times and costs, together with the cost of capital, determine a plant's economic performance. Once a plant is built, its O&M and fuel costs are low and predictable.

Table 7.1 Construction costs of recent FOAK Gen-III/III+I projects

Type	*Country*	*Unit*	*Construction start*	*Initial announced construction time*	*Ex-post construction time*	*Power (MW_e)*	*Initial announced budget ($/$kM_e$)*	*Ex-post construction cost ($/$kM_e$)*
AP 1000	China	Sanmen 1,2	2009	5	9	2 × 1000	2044	3154
	USA	Vogtle 3,4	2013	4	8/9	2 × 1117	4300	8600
APR 1400	Korea	Shin Kori 3,4	2012	5	8/10	2 × 1340	1828	2410
EPR	Finland	Olkiluoto 3	2005	5	16	1 × 1630	2020	>5723
	France	Flamanville 3	2007	5	15	1 × 1600	1886	8620
	China	Taishan 1,2	2009	4,5	9	1 × 1660	1960	3222
VVER 1200	Russia	Novovoronezh II-1 & 2	2008	4	8/10	2 × 1114	2244	No data available

Source: Author's elaboration on NEA

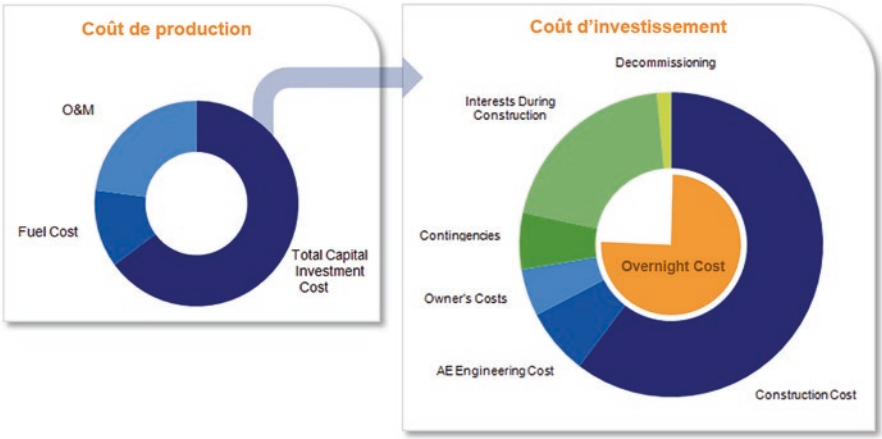

Fig. 7.3 Production and Investment Cost. (Source: OECD, SFEN)

When evaluating the cost of a new nuclear project, the discount rate, which varies a lot depending on whether the borrower is the government or a private party, has a major impact on LCOE. A sensitivity analysis by the OECD-NEA (2015) shows that average plant construction expenses would account for 45€/MWh with a 7% discount rate, but only 20€/MWh with a 3% discount rate.

4.3 Potential for Reduction in the Cost of New Nuclear Projects

Several reports and studies (OECD-NEA 2020; SFEN 2018), in recent years, have looked at lessons learned from projects as well as cost reduction drivers to reduce construction and capital costs on new nuclear projects. We will draw from them in this section.

The most important lesson learned, and cost driver, from FOAK projects has been that detailed designs must be complete and ready before the construction starts, in order to translate design specifications into detailed supply chain requirements and plans for each construction stage. For example, for the EPR construction in Finland, where anticipation of a nuclear renaissance and hopes to benefit from a first mover advantage had led Areva-Siemens to bid with an unfinished design, reveals the need for numerous adjustments which, given the complexity of the project, were responsible for the major part of the delays and cost overruns. Conversely, the construction of the EPR in Taishan benefited from the design and first level of lessons learned from Flamanville: according to the Folz report (2019), while the final cost of construction of Flamanville 3 in France is estimated at 12.4 Bn€, the total cost for the two EPRs in Taishan are estimated at 12.3 Bn€, that is 6 Bn€ per unit.

Besides this key lesson, recent studies have identified numerous cost reduction opportunities, as described in Fig. 7.4:

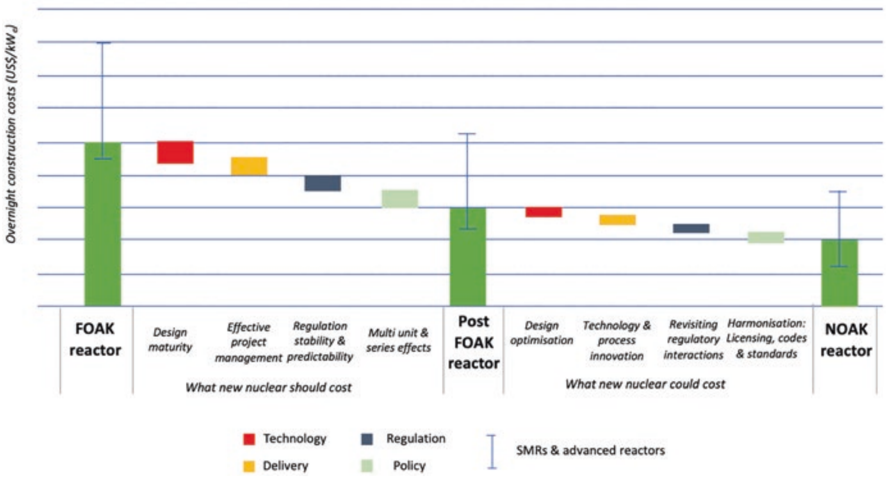

Fig. 7.4 Nuclear cost and risk reduction drivers. (Source: Author's elaboration on OECD-NEA 2020)

In the FOAK stage, the interplay between plant design and effective project management presents a range of cost reduction opportunities: one key example is the engagement in the supply chain early in the design process to integrate all requirements necessary for construction. In the post-FOAK stage, continuous improvement and innovation can yield additional opportunities: one example is the expected introduction into the nuclear industry of the "system engineering" and "project life management" methods, which have been successfully implemented in aeronautics and allow all players involved in a given project to share the same data, from design to construction.

In the longer term, as in any other kind of project, product, or service, the main driver for cost reduction in construction is the series effect. When adequate design maturity has been achieved, the design configuration should be frozen and systematically replicated as many times as possible. We can see then first a program effect (studies, qualifications, and testing work are shared across several units) and productivity effects in the supply chain: thanks to the visibility obtained from a guaranteed order, suppliers can plan and optimize their resources and production tools. Feedback from the construction of the French nuclear fleet in the 80s showed that the maximum series effect can be reached by building reactors in pairs (15% of cost reduction for one pair on a single site), with a 30% reduction for a series of a minimum of three pairs (Cour des Comptes 2014; SFEN 2018). The recent Barakah 4-unit project in the United Arab Emirates, whose first unit achieved first criticality in July 2020, is reported to have achieved more than 50% cost reduction between the first and the fourth unit (Gogan 2019). Probably drawing from these conclusions, India recently confirmed the construction of a total of 16 identical 700 MW reactors (IANS 2020), with, after the first units being built, a "set up in fleet mode" for the units to be completed progressively by 2031.

Finally, we have seen above how sensitive the LCOE is to the discount rate. In the case of the Hinkley Point C project in the United Kingdom, the National Audit Office (NAO) has shown the potential for very significant savings on financial costs, via a better distribution of risks between the various stakeholders (NAO 2017). For example, should the required return on capital (after tax) drop from 9% (value close to the rate used by EDF Energy for the project) to 6% (considering the project as a public infrastructure with the associated investment framework), this would result in a reduction by one-third of the cost per kilowatt hour for consumers. Further studies must be carried out to determine the best project governance allowing the distribution of risks between the various actors. In 2019, the UK government launched a consultation on a so-called regulated asset base model (RAB)—used for other forms of infrastructure such as energy networks. This would lower the cost of capital of the scheme because consumers would have a surcharge added to their energy bills before the plant was completed (FT 2020). However, some have suggested that direct government funding would be a more logical and effective solution (Ford 2020).

The EDF CEO has declared that his company's objectives for future nuclear projects in France, through leveraging all the cost drivers, should be in the 50–70€/MWh range, far below the recently announced Flamanville 3 latest estimate of 110–120€/MWh (Cour des Comptes 2020).

4.4 A Case for Disruptive Innovation: Small Modular Reactors (SMRs)

The delays and cost overruns in large Gen3 projects generated increased interest for a new, disruptive concept of smaller units with simpler designs. Defined as reactors of 300 MWe equivalent or less, Small Modular Reactors (SMRs) would not necessitate as large upfront capital costs per reactor and would be designed for serial construction. In fact, they could potentially be manufactured in an offsite dedicated facility to improve the level of construction quality and efficiency, and then later be installed independently on site or assembled module by module to form a large nuclear power plan.

In addition to traditional baseload power, SMRs would be able to address new markets and applications: their small size and passive safety features would be better suited for countries with smaller grids and less experience of nuclear power. In large countries, they could power islands (e.g., in Indonesia), isolated sites (mines), and remote areas (Northern Canada or Siberia). In the United States, they could target the brownfield sites to replace decommissioned coal plants. Finally, they could be used as well as an alternative to storage, to load follow on grids with a high share of variable renewable energies, to produce heat and decarbonize local district systems (China or Finland), to desalinate water (Saudi Arabia), or to provide low-carbon industrial heat and decarbonize complex industrial processes.

Several projects of SMRs, with different sizes and designs, are underway worldwide. The most advanced is probably the Nuscale project in the United

States, which is supported by the US Department of Energy, has reached several licensing milestones, and is currently preparing for its FOAK project in Idaho.

For SMRs to be a credible option by the early 2030s, successful prototypes must be developed in the 2020s to demonstrate the announced benefits. Specially, they will need to deliver on the ambition with regards to the series effect, as well as simplification and standardization, all the more so because they will need to counterbalance some diseconomies of scale, for instance, on safety systems. Having access to a global market is necessary to foster series-production economies, but this will be possible only with regulatory and industrial harmonization.

5 New Research on the Value of Nuclear in the Future Low-Carbon Mix

To maintain a constant balance of electricity supply and demand, in face of constant demand changes and uncertainties, conventional electricity systems have relied on dispatchable generation such as thermal power plants and hydro power, that in some cases provide a lot of flexibility, as they can ramp up and down on short notice.

According to all decarbonization scenarios, future systems will need to integrate more and more variable capacity—essentially wind and solar power—to meet climate objectives. However, at the same time they will need to shut down traditional dispatchable coal and gas plants, to achieve net zero emissions in the electricity sector. This is a true paradigm shift that will have a major impact on how electricity systems are managed, and how much they cost.

5.1 Beyond the Cost of Power Generation, the Notion of "System Costs"

When shares of variable renewables (wind and solar) are low, the variability can be easily absorbed by the system. However, as their share increase, the introduction of variable renewable energies (wind, solar photovoltaic) will require additional back-up (such as storage) and adjustment capacities (such as demand flexibility) in order to guarantee the quality of electricity and the supply-demand balance. It will also involve strengthening the electricity networks. These effects lead to additional costs for the power system to be integrated when comparing the production costs of different technologies. A recent OECD-NEA study (2019) shows that these "system costs" can increase from €7/MWh to almost € 45/MWh when the share of variable renewables increases from 10 to 75% of the electricity mix.

In this new paradigm, the question of the competitiveness of each means of production can no longer be asked without consideration of the characteristics of the system where it operates: we will have to take into account the interdependencies within the electricity system (share of non-dispatchable sources, limits of storage facilities, and other sources of flexibility) and the structure of the electricity market. New nuclear power, a low-carbon source that can be controlled 24/7 and offers great flexibility (possible variation of 5% of nominal power/min), must in fact be compared, with respect to the services it provides to the system, to other controllable means such as hydroelectricity or to fossil means (coal, gas) equipped with carbon capture and sequestration.

5.2 MIT Study Shows That the Least-Cost Carbon-Neutral Portfolio Includes a Share of Nuclear

A recent MIT study (2018) explored in detail how imposing a carbon constraint affects the optimal electricity generation mix in different regions of the world (the United States, the United Kingdom, China). Should the carbon constraint not be a determinant factor, fossil fuels, whether coal or natural gas, are generally a lower cost alternative for electricity generation. Under a modest carbon emission constraint, renewable generation usually offers a lower cost alternative. However, as the world seeks deeper reductions in electricity sector carbon emissions, the cost of incremental power from renewables increases dramatically.

The study concludes that the least-cost portfolios include a significant share for nuclear, the magnitude of which significantly grows as the cost of nuclear drops. The levels of 'deep decarbonization'—meaning emissions target for the electric sector that is well below 50 gCO_2/kWh—including nuclear in the mix of low-carbon solutions, help to minimize rising system costs, which makes attaining stringent emissions goals more realistic (in comparison, worldwide, electricity sector emissions currently average approximately 500 gCO_2/kWh). Lowering the cost of nuclear technology can help reduce the cost of meeting even more modest decarbonization targets (such as a 100 gCO_2/kWh emissions target).

5.3 Toward Major Changes in the Regulation of Electricity Markets

Several studies (OECD-NEA 2019; SFEN 2020) have shown that, as a consequence of the increased share of variable renewables in the electricity mix, the volatility of electricity prices will increase substantially with periods of very high production of solar and wind (with episodes of very low and sometimes negative prices) alternating with very low production (with episodes of very high prices). As a result, the studies conclude that, as their deployment increases, the value of variable resources for the system decreases: this has important implications on their ability to be financed in energy-only markets.

In this environment, a recent SFEN study in France shows that a significant share of nuclear in the low-carbon mix plays an important role in stabilizing electricity prices; as its marginal cost is not zero, it is dispatchable and capable of load-following to support the integration of solar and wind production. It also provides frequency services to the network and operates in the long-term (60 years at least).

In general, as most generation technologies would have to rely on a limited number of hours with high market prices to recover their investment costs, it will make it even more difficult for investors to predict future revenues from their investment and will require changes in the regulation of electricity markets.

6 Conclusion

In its 2019 report, the OECD-IEA makes a few major recommendations directed at countries that intend to retain the option of nuclear power. The first one is to keep the nuclear option open and authorize lifetime extensions of existing nuclear plants as long as safely possible. The second one is to value dispatchability and design the electricity market in a way that properly values the system services needed to maintain electricity security, including capacity availability and frequency control services. In general, the Agency recommends to value non-market benefits and remunerates them accordingly.

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CHAPTER 8

Hydropower

Eike Blume-Werry and Martin Everts

1 Introduction

Hydropower has been used by mankind for centuries, with early references dating back to the Han Dynasty in China and the ancient Greeks. Whilst it was then predominately used to grind grains, it later became a source of power for spinning frames to spin cotton during the industrial revolution.

Turbine technology innovations in the nineteenth century paved the way for modern uses of hydropower. In 1827, the French engineer Benoît Fourneyron developed the first waterwheel that is referred to as turbine, capable of producing approximately 6 horse powers or 4.5 kW. Later versions of his turbines spread across Europe and the United States. The most commonly used turbine, the Francis turbine, was developed shortly after, in 1849, by British-American engineer James Francis. In the late 1870s, American inventor Lester Allen Pelton invented an impulse water wheel, the Pelton turbine.

These innovations enabled to utilise hydropower for electricity generation whereby the first installation lit a single light bulb in 1878 in Northumberland, England. Many more followed, first in Europe and North America and by the turn of the century also elsewhere around the globe. During the twentieth century, increasingly larger hydropower stations were developed, and some projects' purposes extended from electricity generation to flood control and irrigation. In 1936, in the middle of the Great Depression, the Hoover Dam started production with an initial capacity of 1345 MW.

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Today, hydropower is the source of the largest power stations in the world, the Three Georges Dam in China, with a capacity of 22.5 GW, and the Itaipu Dam at the border of Brazil and Paraguay, with a capacity of 14 GW. Globally, with over 4000 TWh generated in 2018, hydropower accounts for approximately 16.3 per cent of electricity generation and installed capacities exceed 1000 GW (International Energy Agency 2018). This makes it, at the time of writing, by far the most important renewable energy source, providing approximately 67 per cent of all electricity generated from all renewable sources (International Energy Agency 2018). Hydropower stations are located all over the world and in all climate zones as Table 8.1 illustrates. However, hydropower stations are predominantly installed in regions with favourable topographies.

Whilst in the developed world the best and most suitable sites for hydropower generation have long been exploited, there remain significant hydropower potentials in the developing world, in particular in Africa. There has been substantial hydropower growth in the last decades in East Asia, almost exclusively due to growth in China, which has the highest installed capacity and production of any country. Altogether, hydropower has been a competitive source of electricity generation for over a century, yet it requires certain geographical features, which will be explored in more detail later. As a result, suitable locations in the developed world have mostly been exploited, and during the last decades, growth has taken place primarily in the industrialising economies.

One can differentiate between three hydropower generation types: run-of-river, hydro storage and pumped storage. The following chapters describe the characteristics of the three technologies. The generation in all three types follows the same principle, as water is used to turn one or multiple turbines. One can calculate the power output of a hydroelectric turbine with the following formula:

$$P = \eta \times \rho \times q \times g \times h$$

Table 8.1 Installed hydropower capacity by regions (2016)

Region	*Installed hydropower capacity (in GW)*	*Share of total*
Africa	22.3	2.1%
Middle East & North Africa	18.1	1.7%
Latin America & The Caribbean	140.4	13.2%
North America	171.3	16.1%
Europe	259.6	24.4%
South & Central Asia	63.8	6.0%
East Asia	336.2	31.6%
South East Asia & Pacific	51.1	4.8%
Total	1064	100%

Source: World Energy Council

where P is the power output, η the efficiency of the turbine (generally between 0.8 and 0.95), ρ the density (approximately 1000 kg/m^3 for water), q the site-specific water flow in m^3 per second, g the gravity (9.81 m/s^2) and h stands for the hydraulic head, that is, the falling height in metres.

2 Run-of-River

Run-of-river hydroelectricity describes hydro generation plants using the water stream of a river to generate electricity without any, or only limited storage, referred to as pondage. The volume of water flowing down the river and the drop of the riverbed level determine the amount of electricity that can be generated. The larger the drop of the riverbed level and the volume of water, the greater the potential energy that can be converted into electricity. Run-of-river power plants usually divert water from the river into a canal or pipe that directs the water to the powerhouse. The so-called penstocks lead the water through turbines which generate electricity. Afterwards the water flows downstream through pipes or canals referred to as tail race back into the river.

Due to the fact that run-of-river power plants do not store water in a reservoir, they are somewhat limited in their scalability and flexibility. Capacities range from micro installations with a capacity of only a few kilowatt (kW) to large-scale plants, which may have a capacity of up to several hundred megawatt (MW). Typically, plants with a capacity of 100 kW up to 1 MW classify as mini installations, with plants up to 10 MW (or up to 50 MW depending on national jurisdiction) are labelled as small and anything larger as large-scale plants. Generally speaking, large-scale plants between 10 and 1000 MW capacity dominate global installed capacities and production volumes.

The lack of water storage makes run-of-river power plants dependent on river flows that can have significant daily and seasonal fluctuations. Plants by alpine rivers, for instance, experience considerable larger production volumes in spring and summer months following the snow melt (see Fig. 8.1). In other parts of the world, freshets, monsoon seasons or other weather phenomena such as El Niño can cause similar production fluctuations in other months. Run-of-river power plants are therefore an intermittent power generation technology that is only partially dispatchable and cannot always adjust its power output according to the demand, as, for instance, hydro storage plants.

Since run-of-river power plants do not require large dams that store water, construction is simpler and avoids accompanying issues that are associated with the construction of dams (see next section).

The environmental impact of any hydropower plant ought to be regarded on an individual basis as it depends on the location as well as the type and size of the plant. Generally speaking, run-of-river power plants have a lower environmental impact on human and aquatic life than hydro reservoirs or pumped-storage plants, given that no dam construction and flooding of land areas is required. Nevertheless, run-of-river power plants still have a negative impact

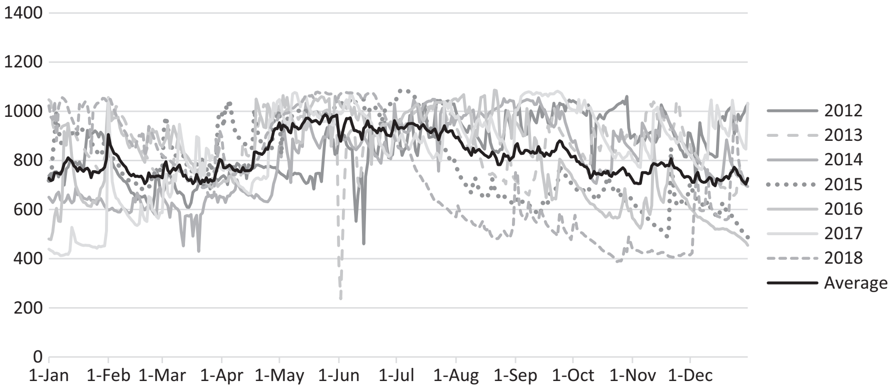

Fig. 8.1 Production profile (daily average produced megawatt hours) of a run-of-river power plant in Switzerland shows yearly and seasonal variations. (Source: Authors' elaboration on Axpo Holding AG data)

on (often fragile) river ecosystems. The plant represents a physical barrier for fish populations, especially migratory fish, and depending on turbine design and operating mode, passage can often be lethal or sublethal for the fish.[1] In recent decades, improvements have been made in terms of turbine designs and bypassing options such as fish ladders, yet legislative requirements vary significantly by country or jurisdiction.

Run-of-river power plants have very long lifetimes. Some key equipment such as turbines last about 25 years before they are replaced, yet the power plant typically has a long lifetime of approximately 80 years. Often power plants approaching the end of their lifetime are modernised rather than dismantled, since suitable locations are limited and hydropower is still an economic source of renewable energy today. Some of the older hydropower plants, especially in Europe, are listed buildings of cultural heritage.

3 Hydro Storage

Hydro storage power plants typically use a dam to store water in a reservoir. The reservoir acts as energy storage, using the gravitational potential energy of water at higher elevation. To generate electricity, gates let water flow into penstocks, which in turn lead the water to one or multiple turbines in the powerhouse. Afterwards the water flows downstream into a basin and/or river. In essence, the general concept works like in a run-of-river power plant with the key difference that the water flow is controlled by the plant operator. This means that hydro storage is—unlike run-of-river hydro—a dispatchable source

[1] See Anderson et al. (2015) for a detailed analysis of run-of-river hydropower's impact on ecological conditions of rivers.

of energy. Operators can choose the quantity and timing of electricity to be generated within given regulatory restrictions.

Hydro storage power plants and dams can be colossal in size and capacity and form some of the largest man-made structures on earth. The Three Gorges Dam in China, for instance, is the largest power station in the world with an installed capacity of 22,500 MW. In terms of electricity production, only the Itaipu Dam on the border of Brazil and Paraguay surpasses the Three Gorges Dam (depending on hydrological conditions) with recorded production volumes of over 96 TWh annually in the late 2010s. Aside those enormous-sized hydro storage plants, there are also comparably small hydro storage installations of only a few MW. Micro or mini hydropower plants, however, usually do not classify as hydro storage but as run-of-river.

The operational nature of hydro storage power plants differs significantly. Some, such as the two named above, produce baseload power and have comparably high capacity factors. Others are peak-load power stations with much lower capacity factors and operate only in times of high demand or high prices. The size of reservoir, the water flow into the reservoir and the turbine capacity are factors that determine how a hydro storage power plant operates. Depending on the site, further factors such as legally required minimal water flows and reservoir levels also play a role.

Most hydro storage power plants in liberalised European power markets function as peak-load plants. During spring and summer months, following the snow melt, the reservoirs fill up. Peak demand, and with it high prices, usually occurs in Europe during winter months, which is why operators of hydro storage power plants discharge the majority of water then (see Fig. 8.2: Weekly water levels of Swiss hydro reservoirs (in per cent) illustrate the seasonal usage of hydro storage plants in the Alps. Source: Authors' elaboration on Swiss Federal Office of Energy data). Given that each unit of stored water can only

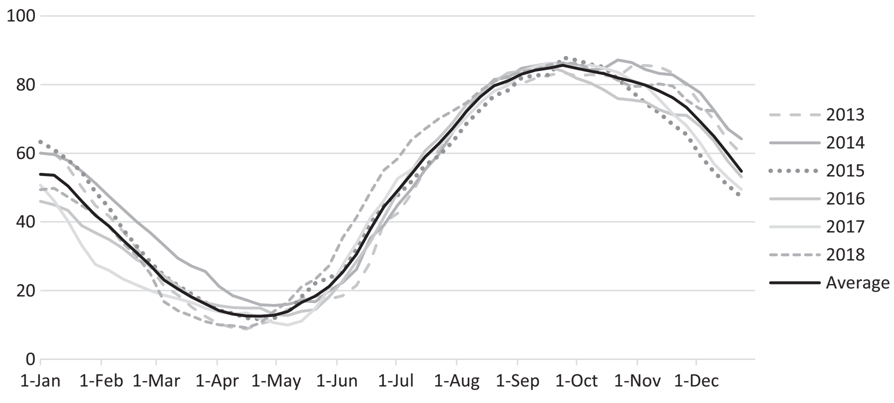

Fig. 8.2 Weekly water levels of Swiss hydro reservoirs (in per cent) illustrate the seasonal usage of hydro storage plants in the Alps. (Source: Authors' elaboration on Swiss Federal Office of Energy data (2019))

be discharged once, the discharging, that is, selling of hydro storage, reflects a bet against higher prices in the future. A certain amount of water (site-specific, see formula mentioned earlier) in an upper reservoir is equal to a call option of generating a unit of electricity. The opportunity costs of releasing water are equal to the expected future value of electricity. Hydro storage power plant operators use modern option pricing theories to optimise the dispatch of their plants. Put simply, operators try to serve the highest priced hours a year with the limited amount of water available in their reservoirs. Unlike other generators who bid with their marginal costs on energy-only markets, the dispatch of hydro storage power plants is not marginal cost based. Instead, operators use shadow prices—reflecting the marginal costs of additional alternative (thermal) power plants—to place their bids on the market.

Hydro storage power plants require certain geographical and geological features. Usually they are located in mountainous areas where elevation levels of river drop sharply, and the topography enables storing water in a reservoir. The reservoirs of hydropower plants often cover vast areas of formerly dry land. The construction of dams and creation of reservoirs thus have far-reaching consequences for river ecosystems and surrounding areas. Reservoirs do not only flood large areas of land, converting valleys into lakes, but also alter the river ecosystem further downstream. Natural seasonal floods no longer occur and altered flow rates lead to losses in biodiversity as well as changes in sedimentation, as dams may hinder the flow of sediments downstream. There is also an ongoing academic debate on the greenhouse gas emissions (first and foremost methane) of reservoirs, especially in tropical climates, due to microbial decomposition of organic material in the water under anaerobic conditions.[2]

It is important to note at this point that the construction of (large) dams and reservoirs has an impact on not only the natural environment but also the people living there. At the turn of the century the ‘World Commission on Dams’, a global governance forum researching controversial issues of large dams under patronage of Nelson Mandela presented a final report (World Commission on Dams 2000). A key motivation was to solve and prevent human conflict associated with the construction and use of dams especially in developing countries. The final report highlights inter alia that in too many cases an unacceptable price in social and environmental terms has been paid for the considerable benefits of dams by communities downstream and by people displaced, whose number is estimated at 40–80 million (World Commission on Dams 2000).

Just like run-of-river power plants, hydro storage power plants have very long lifetimes of approximately 80 years. Hydromechanical elements usually have shorter life spans and are replaced accordingly, whilst the structure of the dam can have a longer lifetime than 80 years, depending on the design. Regular assessments of the structural safety of dams are essential, given catastrophic consequences of a dam failure. In Europe, a governing body grants operators

[2] See Prairie et al. (2018) for a detailed discussion on greenhouse gas emissions from reservoirs.

concessions that typically cover a period of 25–75 years (Glachant et al. 2014, p. 21). Once a hydro storage power plant with dam and reservoir is built, it is usually there to stay. Dismantling a hydroelectric dam with a reservoir is a complex and costly task. In Europe, dams approaching the end of their lifetime undergo a modernisation in most cases and only comparably small dams have been removed thus far. Hydropower dam removal has been more significant in North America, yet no dams with considerable large power productions have been dismantled to date.

4 Pumped-Storage Hydroelectricity

Pumped-storage hydropower plants use two or more reservoirs at different elevation levels to store electricity in form of gravitational potential energy of water. During low-priced hours, water is pumped to a reservoir with a higher elevation level, and in times of high prices, it is discharged to generate electricity. The power generation process is the same as for hydro storage power plants, the only difference being that discharged water is collected in a reservoir at lower elevation.

Since the pumping process consumes electricity, pumped-storage hydropower plants both consume and produce electricity. Pumped hydro is to date the only (grid scale) economically viable and mature form of storing electricity, yet significant progress has been made in different battery technologies in recent years. The round-trip efficiency (pumping up water and discharging it to generate electricity) of pumped-storage hydropower is typically between 70 and 80 per cent (Rehman et al. 2015).

In general, pumped-storage hydropower plant reservoirs tend to be smaller than those of hydro storage power plants without a pumping component. This is due to different use cases. Whereas many hydro storage power plants serve as seasonal storage with reservoirs filling up during spring and summer months, pumped-storage plants function first and foremost as daily or weekly storage units. There are, however, also pumped-storage plants with comparably large reservoirs and conventional hydro storage plants that have had a pumping component and lower-elevation reservoirs added. Economies of scale apply to pumped-storage hydropower plants, which are why installations are commonly large scale, with typical capacities between 1000 and 1500 MW, the largest installation being the 3003 MW Bath County Pumped Storage Station in the United States. Globally, installed pumped-storage hydro capacity reached approximately 160 GW at the end of 2018, accounting for over 94 per cent of installed energy storage capacity (Henley 2019).

The aforementioned location constraints of hydro storage power plants apply also to pumped-storage installations, yet reservoirs tend to be smaller. Consequently, pumped-storage hydropower plants are typically located in mountainous areas and have an elevation difference between reservoirs of a few hundred metres. The first pumped-storage hydropower station was developed

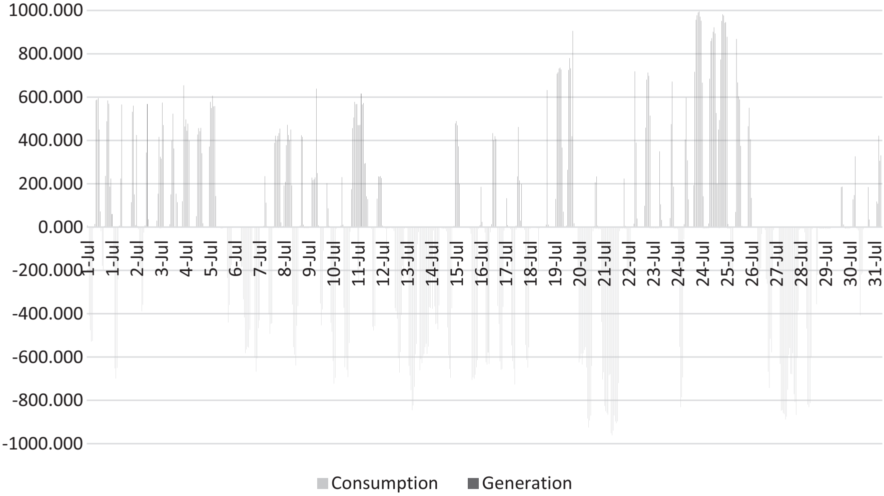

Fig. 8.3 Monthly pump/generation profile of a pumped-storage hydropower plant in MWh. (Source: Authors' elaboration on Axpo Holding AG data)

in the Swiss Alps over 100 years ago. Today, China, Japan and the United States are the countries with the highest installed capacities of pumped storage.

Economically, pumped-storage hydropower plants use price spreads on electricity markets. During low-priced hours (e.g. during night-time, weekends or at times of excess supply), water is pumped up in the upper reservoir, and during high-priced hours, it is discharged to generate electricity (see Fig. 8.3). The greater the price spreads on a given market, the higher the profitability of pumped-storage power plants. This operating nature contributes to balance markets, especially at high penetration rates of intermittent renewable energies, which is a matter that will be explored in more detail in the following section.

Given the similarities of conventional hydro storage and pumped-storage power plants, environmental concerns of conventional hydro storage (see above) apply also to pumped-storage installations. In addition, pumped-storage power plants have been criticised for the fact that they consume more electricity than they generate (unless there is a considerable natural inflow). This criticism neglects the fact that pumped-storage plants generate electricity during times of peak demand that would otherwise be covered by dispatchable conventional fossil fuel-based generation sources. Indeed, operators of pump-storage power plants use shadow prices of additional conventional fossil fuel-based power plants in the merit order for their dispatch strategy and bids on power markets. There is little doubt amongst experts that energy systems with (very) high penetration of intermittent renewables require storage solutions such as pumped storage and batteries, highlighting the importance of pumped-storage hydropower plants for decarbonising power systems.

5 Role of Hydropower in Generation Portfolios and Flexibility

Hydropower has been an economically viable generation technology for over a century. The role of hydropower in countries' generation portfolios has therefore developed slowly over time without the radical changes observed in other renewable energy capacities. Wherever the natural environment enabled the use of hydropower in the industrialised world, then hydropower capacities were often deployed. Today, hydropower benefits from the fact that it is a renewable and emission-free power generation technology, something that was not deemed particularly relevant in the early days of hydropower development. The role of hydropower in countries' generation portfolios is therefore typically set by how well a given country is suited for hydropower. Some countries such as Norway, Albania or Paraguay cover virtually all or even more than their domestic electricity needs by hydropower sources.

It is fair to note that the role of hydro in a generation mix is more a result of the natural environment than of policy decision, as hydropower typically offers an economically viable and sustainable source of power if suitable waterways with considerable elevation drops are available. As a result, hydropower potentials in developed nations are largely exploited, and global hydropower growth is less substantial than that of other renewable energies such as wind and solar photovoltaics (PV). China accounts for most of the global growth of hydropower and has a share of approximately 19 per cent in its generation mix (International Energy Agency 2018). In the United States, around 7 per cent of the power generation comes from hydropower sources, and in the European Union (EU-28), it is approximately 10 per cent with considerable differences between member states (Eurostat 2019; International Energy Agency 2018).

As aforementioned, hydropower plants can be used to meet near baseload demands with high capacity factors. They can also be designed to cover peak demand with high installed capacities and lower capacity factors and everything in between. Be that as it may, even when the share of hydropower is small in any given country, the flexibility of hydro storage and pumped-hydro is often crucial for the stabilisation and balancing of the power grid. Hydro storage and pumped-storage plants can ramp up production within seconds to react to market signals and grid demands. In other words, the flexible plants help to keep the frequency stable at sudden changes of supply or demand, by adjusting the power output accordingly. In a decarbonising world with increasing penetration of variable renewables in power grids, this flexibility is critical for security of supply. Pumped-hydro flexibility is twofold and comes handy, as it not only can provide additional generation capacity during times of high demand but also acts as a consumer to store surplus electricity. Whilst pumped hydro functions as a daily storage unit in most cases, conventional hydro storage plants typically serve as seasonal storage units. The use case therefore differs from the one of grid-scale batteries, which have been experiencing significant cost reductions over the last years, but are adapted only for shorter flexibility. Aside batteries, hydro storage is currently the most flexible generation technology that can follow the load without the efficiency losses of conventional thermal power plants at lower loads. Power systems with considerable shares of flexible hydro units can therefore integrate variable renewable production more efficiently.

6 Hydropower Costs and the Financing of Hydropower Plants

Construction costs for hydropower plants are very site-specific. Large and small-scale plants can differ significantly in their costs per unit of installed capacity and per unit of electricity generated. Yet not just the size of the power plant but also the legal/regulatory requirements (e.g. fish passages) and the location (e.g. remote mountainous areas) are key factors that determine the costs of a specific plant and may vary drastically from site to site. Anyhow, compared with other power generation technologies hydropower plants are typically characterised by high to very high capital expenditures (capex). The International Renewable Energy Agency (IRENA) sets the installation cost range for large hydropower at 1050 to 7650 USD_{2010} per installed kW and slightly higher for smaller plants as they are less likely to profit from economies of scale (IRENA 2012).

In contrast to the high capex, the operating expenditures (opex) of hydropower plants are very low, since the fuel, that is, the water, is usually free. The operating costs of hydropower plants stem primarily from maintenance costs of mechanical equipment and labour costs for operating the plant resulting in very low overall opex.[3] IRENA describes the annual operation and maintenance costs of large hydropower projects as 2 to 2.5 per cent of investment costs per installed kilowatt and slightly more for smaller installations (IRENA 2012). Put together, hydropower can be a very economic source of electricity when analysing the costs over a lifetime. In this context, scholars refer to the so-called levelised costs of electricity (LCOE) that describe the average lifetime costs of electricity generation. Following IRENA's hydropower installation and operating costs, the agency gives large hydropower an LCOE range of 0.02 to 0.19 USD_{2010} per kilowatt hour (and up to 0.27 USD_{2010}/kWh for small hydropower) assuming a 10 per cent cost of capital (IRENA 2012).

The relatively high capital expenditures (capex) combined with a typically rather long lifetime of hydropower plants make investments in hydro power difficult. During the first wave of hydropower, in the first half of the twentieth century, many hydropower plants were built by state owned companies or quasi monopolies. Nowadays most hydropower plants have to be financed by privately owned companies with no or very limited subsidies or securities from governments or states. However, financing infrastructure investments with

[3] It should be noted that this is subject to varying national jurisdictions that may increase operational expenditure, for instance, by charging hydropower plant operators for the use of the water.

high capital expenditures, long lifetimes and uncertain future revenues can be challenging.

Other renewable energy sources such as wind and photovoltaic also have high capex compared to their operating expenditures. But similar to hydropower plants, many governments and states helped building the first wave of wind and photovoltaic plants with subsidies such as fixed tariffs or with other forms of securities for future revenues. Over the last decade, most governments and states reduced securities they offer for new wind and photovoltaic plants. With this reduction of subsidies and securities, the market developed new instruments for financing renewable plants, first and foremost power purchase agreements. However, these power purchase agreements typically have a duration of only 10 years. For power plants with lifetimes of approximately 20 years, a security for the first half of their duration is typically enough to enable private financing. But for hydropower stations with significantly longer lifetimes, power purchase agreements with a duration of 10 years do not cover enough uncertainties regarding future revenues to allow for significant private investments.

7 Outlook for Hydropower

As a renewable and clean generation technology, hydropower should continue to play an important role in future low carbon power systems. Even though further sites for hydropower deployment are limited in the developed world, there are significant untapped technical potentials in the developing world, especially in Africa (Henley 2019).

Unlike other renewable energy technologies such as wind and PV that experienced substantial technical innovation during the last two decades, no such drastic innovations or cost reductions can be expected for hydropower. However, it can be expected that the benefits of flexible hydropower technologies will be challenged by other storage technologies such as batteries. Moreover, one can assume that the benefits of renewable run-of-river plants will be challenged by other renewable technologies.

However, at a broader picture one can assume that geography will always be a driving factor behind renewable energy sources. In windy regions, some form of wind power plants will be used (as it was already used for at least two centuries), sunny regions will try to harvest the power of the sun, and in wet and mountainous regions, some form of hydropower will continue to play an important role in the power generation.

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CHAPTER 9

Solar Power Generation

Laima Eicke, Anselm Eicke, and Manfred Hafner

1 Introduction

In less than two hours, enough sunlight strikes the earth to satisfy the world economies' annual energy demand. Despite this abundance of solar energy, the conversion of sunlight into usable energy forms only represents a tiny fraction of today's global energy supply. Yet, the share of solar energy in global energy supply, especially in the electricity sector, is rising rapidly. Unprecedented deployment has taken place in the last decade, stimulated by efforts to improve energy access, security of supply and mitigate climate change. Between 2010 and 2017, the global installed capacity of solar generation increased more than

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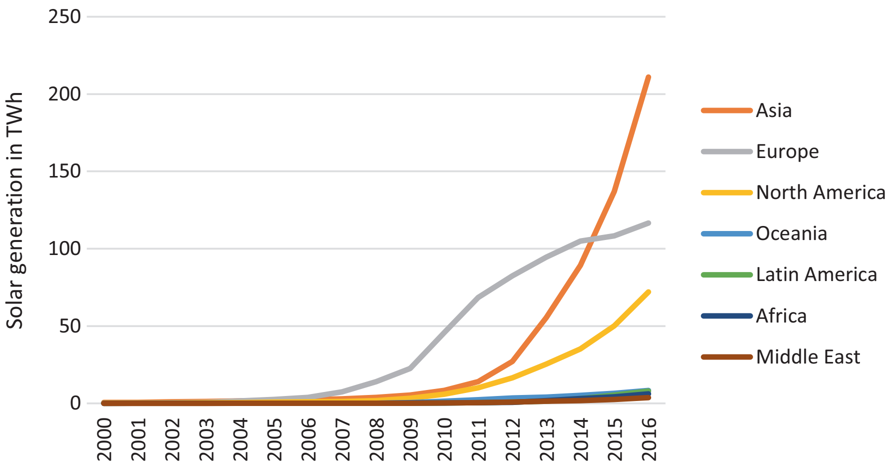

Fig. 9.1 Power generation from solar energy by region (in TWh). (Authors' own elaboration, data from IRENA 2020)

tenfold from 34 GW to 437 GW (IRENA 2020). Steep learning curves and the economies of scale enabled technological improvements and, in consequence, have led to massive cost reductions.

Solar photovoltaics (PV), the conversion of light into electricity using semiconducting materials, were one of the most expensive electricity-generating technologies when first employed in astronautics in the late 1950s. By 2020, it has become an economically viable energy source for many applications. An alternative technical process to generate electricity from solar radiation is concentrated solar power (CSP). Yet, the latter, accounted for less than 3% of all solar power in global electricity generation in 2017 (IRENA 2020).

PV is the third most important renewable energy source in terms of global capacity after hydro and wind power. Globally, solar energy is mostly used in Asia, Europe and North America with the strongest rise in Asia, mostly driven by China and India (Fig. 9.1). According the World Energy Outlook of the International Energy Agency, solar PV may become the largest technology in terms of global installed capacity in the Stated Policies Scenario by 2035 (IEA 2019).

2 Technical Characteristics of Solar Energy

A brief introduction to the technical characteristics of solar energy provides the necessary background information to better understand its economics.

2.1 *Solar PV*

The main components of photovoltaic cells are semiconducting materials such as silicon and germanium. In these materials, sunlight releases charge carriers (electrons), which create an electrical field. As source of electricity generation, this field induces a direct electrical current. This process is known as the photovoltaic effect. Electricity generation exploiting this effect is not only possible from direct sunlight, but also from its diffuse components, implying that PV cells also generate electricity with cloudy skies.

Photovoltaic cells are integrated in solar arrays. Inverters (to invert DC current from solar panels into AC), transformers, electrical protection devices, wiring and monitoring equipment are summarized as balance of system (BOS). In some cases, BOS also includes sun-tracking systems, which increase the yield by positioning the panels towards the sun.

The three major types of solar PV technology are monocrystalline cells, polycrystalline cells and thin firm cells, of which the first two make up more than 95% of global module production (Fraunhofer ISE 2019).

Monocrystalline solar cells have the highest efficiency rates, typically 15–20% but the highest quality panels can reach up to 23% efficiency. As for all solar panels, the efficiency of monocrystalline panels depends on ambient temperature. On average, efficiency declines by about 10% when the ambient temperature rises by 25 °C (Quaschning 2019). Featuring high efficiencies, monocrystalline solar panels are space efficient, i.e. they require smaller ground areas to generate the same amount of electricity compared to other technologies. They also live the longest with most manufacturers putting a 25-year warranty on monocrystalline solar panels. Their main disadvantage is the high cost, because manufacturing requires the highest-grade silicon.

Polycrystalline silicon cells are cheaper because of a simpler production process and the amount of waste silicon is less compared to monocrystalline cells. The efficiency of these panels is typically lower (13–16%). They also have a slightly lower heat tolerance, which means that polycrystalline perform slightly worse in high temperatures than monocrystalline panels.

Thin film solar cells deposit one or several thin layers of photovoltaic material onto a substrate. Most thin-film modules have efficiencies of around 9–11%. Their mass production makes them cheaper than crystalline based solar cells. Thin film solar panels are mostly used in applications where panel sizes are not an issue. Another advantage is that they can be more easily integrated into facades and roofs.

When comparing efficiencies, it is important to differentiate between efficiencies of single cells, of panels and of the entire installation including converter and transformer. In the last 10 years, the efficiency of average commercial silicon modules increased from about 12% to 17% (Fraunhofer ISE 2019). Lab cell efficiencies of close to 50% when concentrating light rays and applying new materials demonstrate the potential for further efficiency increases at the production level (Geisz et al. 2020).

2.2 Concentrated Solar Power

Concentrated solar power (CSP) does not exploit the photovoltaic effect. Instead, mirrors are used to focus solar rays to heat a fluid. Similar to

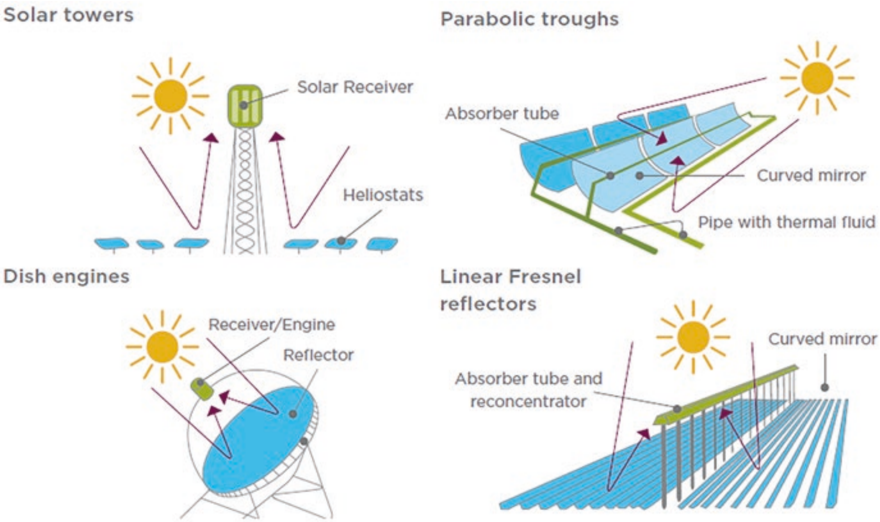

Fig. 9.2 Concentrated solar power technologies. (Source: Qader and Stückrad 2016)

conventional power plants, the thermal energy then drives a turbine to generate electricity. A downside of the CSP technology is that direct radiation is required for the process, because diffuse radiation cannot be focused. CSP plans are therefore mostly sited in countries with high direct radiation and a dry climate (see section on solar potential), for example, in northern Africa and the Middle East.

One major advantage of the CSP technology compared to solar PV is that heat can be stored at comparatively low cost. Equipped with molten salt vessels as thermal energy storage, most CSP plants have a steadier generation profile during the day and extend electricity generation long beyond sunset.

The four main construction types of CSP plants are solar towers, parabolic troughs, linear Fresnel reflectors and small-scale dish engines (Fig. 9.2). Parabolic trough and solar tower CSP plants are the most mature CSP technologies and lead new installations by far (REN21 2019).

CSP technologies can be grouped into point concentration systems (solar towers and dish engines), and linear concentration systems (parabolic troughs and linear Fresnel reflectors). Technologies based on point concentration systems achieve higher temperatures (up to 1200 °C) than linear concentration technologies (300–550 °C), and thus yield higher thermal efficiencies. However, focusing a large number of mirrors on a single point is highly complex and leads to high construction and maintenance costs. By contrast, linear concentration technologies require less land than point concentration systems.

Parabolic troughs and tower systems have first been built commercially in the 1980s. Whereas learning potentials in well-developed, mature steam processes, such as steam turbines, condensers and generators have been exhausted, further technological improvements are expected in other components. For example, higher storage potentials could be reached by using new fluids or particles that enable transfer and storage of sun energy at higher temperatures; enhanced mirror materials could reduce costs and increase reflectivity; and information technology can be used to detect system failures, reducing operation and maintenance costs, in particular of complex point concentration systems; such technological innovations could further improve the technology's efficiency and further reduce costs (Desai and Bandyopadhyay 2017; Islam et al. 2018).

3 Applications of Solar Energy

Photovoltaic systems have long been used in specialized applications as standalone installations (island systems). Grid-connected PV systems were first constructed in the 1990s. Nowadays, solar energy for electricity generation is applied on the wide range between small roof-top PV systems and large utility scale solar parks. In contrast to the modular solar PV, CSP is mostly deployed in large-scale power plants.

PV and CSP in large-scale solar parks, directly connected to the high voltage grid, are used to generate electricity on a commercial-scale. The largest solar power plants around the world are PV parks with installed peak capacities of up to 2 GW per site, the order of magnitude of a large nuclear power plant. The largest solar PV parks are located in India, China and the Middle East.

The modularity of solar PV (and dish engine CSP plants) also allows small-scale deployment. Roof-top PV systems have increased significantly, fostered by falling costs and governmental support policies. On a small-scale, roof-top PV serves self-consumption or supplies local mini-grids. In most countries, distributed residential systems already have generation costs below (the energy portion of) retail electricity prices, making the deployment of solar PV for self-consumption economically attractive (IEA 2020b). Behind-the-metre business models, increasingly comprising battery storage, allow to self-consume electricity generated by roof-top PV. In remote off-grid rural areas, particularly in developing countries with good solar resources, decentralized solar power feeding into local mini-grids may provide electricity access in places where a connection to the national grid is too expensive. In urban areas, roof-top PV could provide a back-up for an unreliable grid supply. In these applications, roof-top PV does not compete against large-scale power plants but against other small-scale generation units such as diesel generators. Often, solar is not only the most sustainable alternative but also economically viable. This increasing economic attractiveness of small-scale PV systems could lead to rapid expansion of decentralized PV capacity.

Aside from power generation, CSP can also generate steam, which can be used in other sectors, for example, in enhanced oil recovery or steam-using industry processes. Thus, CSP technologies could be elements of sector coupling to enable further decarbonization of economies.

4 Costs of Solar Energy

Investment costs are by far the highest cost component of solar energy. Variable operation costs of solar energy are close to zero because it uses no fuel other than solar radiation, which is free of charge. This cost structure is structurally different compared to conventional generation technologies. In this section, we discuss the development of investment and maintenance costs.

4.1 Declining Investment Costs of Solar Energy

Between 2010 and 2018, the average total installation costs of solar PV declined by 74% (Fig. 9.3). These exceptional cost reductions were made possible by extraordinarily high growth rates of PV capacity. The compound annual growth rate of PV installations was 36.8% between 2010 and 2018 (Fraunhofer ISE 2019). The learning curve (or experience curve) is another indicator of cost reduction. It describes how prices decline when the number of manufactured goods increases. Learning curves of solar PV modules were particularly steep: they have followed a 20–22% cost reduction for each doubling of capacity during the last four decades (Fraunhofer ISE 2019). Within the module, PV cells

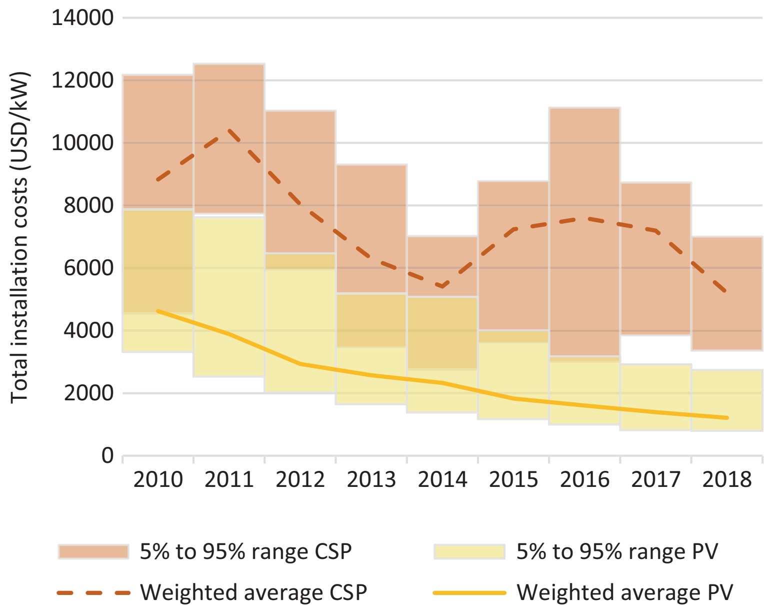

Fig. 9.3 Development of installation costs for solar PV and CSP. (Authors' own elaboration, data from IRENA 2020)

account for the highest cost shares. The three main factors driving the cost reductions of PV cells were (i) increasing sizes of manufacturing plants (economies of scale), (ii) improved module efficiency (technological advances), and (iii) a decline in costs of purified silicon. A high share of the recent cost reductions can be traced back to the rapid expansion of cell manufacturing in China, where about 70% of all PV modules are produced (Fraunhofer ISE 2019). Due to the modularity of PV panels, long distance transportation of the panels is easier than for most other generation technologies, such as, for example, blades and towers of wind turbines, which are usually manufactured locally. The market for solar panels is therefore a global market, characterized by large-scale manufacturing sites and high competition with cost-cutting effects.

The decline in balancing of system costs was led by inverter cost reductions. While PV modules historically had the largest share in total cost, in 2020 the overall BOS costs account for up to 40–60% of total PV investment costs (IEA 2020b).

Similar to solar PV, high upfront capital investment costs are also a major barrier for CSP technologies. They account for almost four fifth of the total costs. Throughout the past decade, average installation costs of CSP plants have been falling from 8800 USD/kWh in 2010 to 5,200 USD/kWh in 2018 (Fig. 9.3), albeit less constantly than they have been for solar PV. The uneven trajectory can be explained by a much lower number of new installations and an uneven buildout among countries. Until 2013, most capacity additions occurred in Spain and the United States, incentivized by generous past incentive schemes. But no new capacity has entered commercial operation in Spain since 2013 and in the United States since 2015. Current capacity extensions are led by China and Morocco (REN21 2019).

4.2 Operation and Maintenance Costs of Solar Energy

A second relevant cost driver of solar energy is the operation and maintenance (O&M) costs. To ensure high levels of technical performance of the solar system, it is necessary to identify and replace broken modules of a PV plant, or receivers and mirrors of a CSP plant. Particularly dusty areas (e.g. deserts) require regular cleaning of mirrors and modules. Both tasks make up for significant costs (IRENA 2020). Large-scale solar plants benefit from significant economies of scale in these O&M costs.

The development of large-scale power plants has increased the demand for tools for inspection and monitoring. Drones are often used in the solar industry due to their wide range of surveillance and monitoring capabilities. The formerly manual process of monitoring is increasingly replaced by data driven monitoring solutions. With sensing elements, drones capture the necessary data in less time and a more accurate form, which is then digitally processed. This enables long range inspection and easy control of plants and thereby reduces operation and maintenance costs significantly.

4.3 LCOE of Solar Energy

The levelized cost of electricity (LCOE) combines investment and operation costs. It is defined as the average cost of electricity per unit of electricity output. The LCOE is a good metric to measure cost reductions and technological improvements of a technology. However, this indicator should not be used to compare different technologies. It is highly sensitive to the number of full load hours of a technology and it neglects the value of electricity, i.e. how much electricity is valued at the time when generated (see Chap. 15 on system integration).

In 2018, the LCOEs of Solar PV ranged from 60 to 210 USD/MWh with a global average of 85 USD/MWh (IRENA 2019c). Further cost declines are expected to reach 20–80 USD/MWh in 2030 and 14–50 USD/MWh in 2050 (IRENA 2019a). The LCOEs of CSP technologies have also been falling throughout the last decade. In the US, the LCOE of CSP halved from 340 USD/MWh in 2010 to 190 USD/MWh in 2018 (IRENA 2019c), and is even expected to fall to 50 USD by 2030 (US Department of Energy 2020).

LCOEs decline when costs are reduced but also when the electricity output increases. Such increase is reflected in rising capacity factors (also utilization rates or load factors), describing the ratio of generated electricity to installed capacity. A capacity factor of 20% implies that the electricity generation is equivalent to this generator operating 20% all hours in the year at full capacity. As we will discuss in the following sections, capacity factors strongly depend on the location of solar energy installations and the natural resources.

5 Generation Pattern of Solar Energy

Solar generation is highly variable. Power generation with solar energy is limited to daytime given that the sun does not shine at night. Consequently, capacity factors of solar power plants (without storage) are lower compared to other technologies and typically range between 10% and 20% in most regions, reaching up to 25% at the best spots in desert locations. Since 2010, the global weighted average capacity factor of utility scale PV systems has been constantly increasing (Fig. 9.4). Three major drivers explain rising capacity factors (IRENA 2019c). First, solar PV is increasingly deployed in regions with higher irradiation levels. Second, tracking systems that follow the movement of the sun are increasingly employed, which increases the yield. And third, system losses have been reduced, for example through improvements in the efficiency of inverters.

Figure 9.4 shows that the capacity factors of CSP experienced a significantly stronger increase compared to PV. The main reason for this development is the increasing combination of CSP plants with thermal storage. This helps shifting generation into hours without sunlight, thereby allowing capacity factors exceeding 30–40%. Storage and turbine dimensioning allow to theoretically achieve capacity factors of over 90%, which is however not economical. The

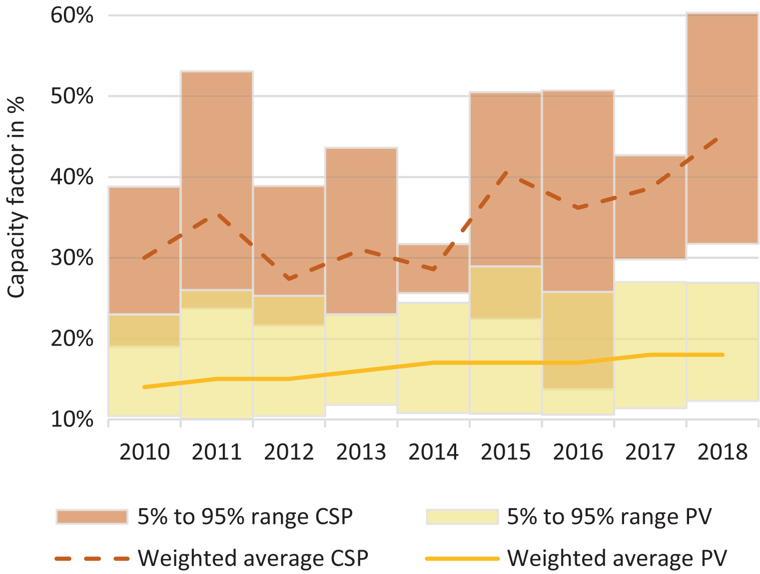

Fig. 9.4 Capacity factors of solar PV and CSP. (Authors' own elaboration, data from IRENA 2020)

high fluid temperatures of solar power CSP plants are best suited for storage. This technology has therefore the highest realized capacity factors of up to 70% (IRENA 2020). Due to the extension with thermal storage, generation patterns of CSP plants differ from solar PV. This flexibility provides an additional value compared to the non-dispatchable solar PV (Pfenninger et al. 2014).

Because of its comparatively low capacity factors, the share of solar energy in the generation mix of a country is usually lower than its share in terms of total installed capacity. A second relevant effect resulting from its generation pattern is the high concentration of solar energy generation in few hours of the day. In these hours, most PV plants of an area generate electricity. The high simultaneous electricity supply of solar generation has a depressing effect on electricity wholesale prices. In countries with high shares of solar energy, solar market values are significantly lower than for other technologies, implying that revenues from selling electricity from solar generation are, on average, lower than average wholesale electricity prices (Hirth 2013). This effect is known as merit order effect and it applies in particular to solar PV because its generation is most concentrated in time.

6 Potential of Solar Energy

The potential of solar energy varies strongly across the globe (Fig. 9.5). Depending on solar irradiance levels, solar capacity factors are highest close to the equator and decline towards the poles. The highest potential for solar

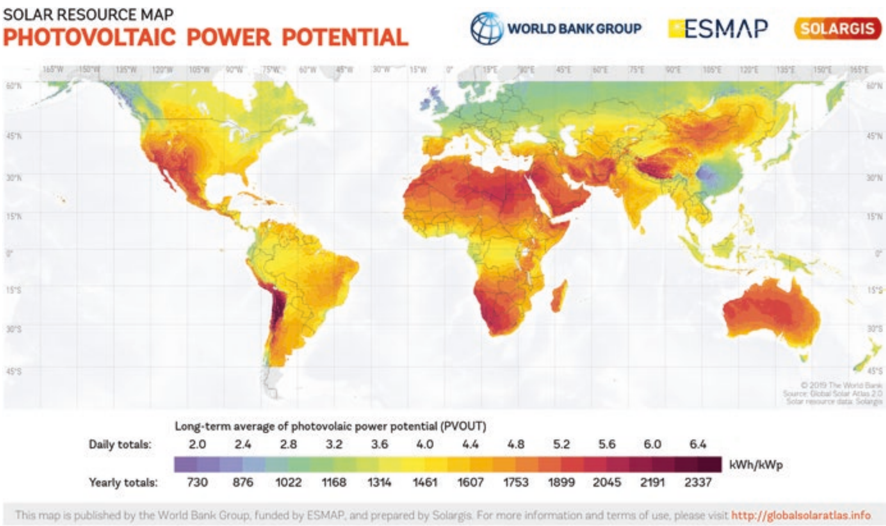

Fig. 9.5 The geographical potential of solar energy. (Source: Global Solar Energy Atlas 2019)

energy lies in the Atacama Desert in South America, the Sahara region, in the Middle East, the Gobi desert in western China, Australia and the western part of the United States. Solar irradiation in these areas is more than twice as strong as in eastern China and most northern European countries where large parts of global solar energy installations are located. Consequently, the electricity output, and with it the electricity generation costs, varies by a factor of up to two depending on the location.

CSP technologies are even more dependent on direct solar radiation than Solar PV plants and need direct normal irradiance values of at least 1800 kilowatt-hours per square meter per year. Their applicability is thus much more limited. However, well suited conditions can be found on all continents, including regions in south-western United States, the Middle East and North Africa, South Africa, Australia, Mexico, Chile and Southern Europe.

In addition to daily patterns, solar generation features seasonal patterns, especially at higher degrees of latitude, i.e. towards the poles. Close to the equator, solar irradiance increases but also cloud cover tends to be higher. In these areas, solar energy output remains relatively stable throughout the year; the position of the sun varies less and the time of sunrise and sundown remain similar.

7 Policy Instruments and Support Schemes

The strong increase in solar buildout would not have been possible without enabling government policies. These include research and development funding and development policies, which led to the development of a solar industry. This development was in particular driven by guaranteed feed-in tariffs which were first implemented in Germany in 2000.

The design of effective support schemes for solar energy needs to take into account the cost and finance structure of solar generation: as discussed in previous sections, solar plants are very capital intensive. Most expenses of solar power generation occur during construction, early in the project's lifetime. Higher cost of capital, for example due to high interest rates, strongly affects the project's profitability because expenditures in these years are recovered a decade later. The economic viability of solar therefore strongly declines with increasing cost of capital. Gas-fired power plants, in comparison, have comparatively low construction costs and a significant share of the expenses, fuel costs and emission costs, are settled when revenues from power generation accrue.

One main target of support schemes is thus to reduce the cost of capital, for example by lowering risks for project developers. Initially, feed-in tariffs were the primary support scheme for solar energy, which was mostly built on a small-scale by private households. By guaranteeing fixed feed-in tariffs, uncertainty about future revenues declined. Also, the risk of electricity price variations is mitigated for investors. With these support schemes, solar projects became profitable. Starting in 2010, many countries began to determine the level of feed-in tariffs for large-scale projects in auctions. In these auctions, projects compete for a predefined amount of supported capacity and only the most cost-efficient ones get financial support. Since the late 2010s, a shift from subsidy driven development to a competitive pricing model becomes visible in many markets. This also includes bilateral Power Purchase Agreements (PPA) between producers and off-takers, such as utilities and industry, absent of governmental support.

The less mature CSP technologies are still dependent on policy support in order to be economically viable. Due to their higher LCOE compared to solar PV, support schemes would need to reflect better the system benefits provided by CSP's dispatchability to foster a further development of CSP technologies. System stabilizing effects such as the ability to generate electricity during demand peaks will become increasingly important as energy systems decarbonize and move towards high shares of renewable energy sources.

8 Outlook

Unleashing the huge potential of solar energy will be key to achieve global climate targets and to limit global warming (IRENA 2019a). Continuous policy support is thus granted in many countries around the globe. In addition to support schemes, further cost declines and innovations drive the rapid expansion of solar energy. As in many other markets, digitalization drives cost reductions in the solar sector. Predictive algorithms based on big data and artificial intelligence enable an optimized adjustment of solar PV modules and CSP mirrors to the sun's position in order to maximize the power output. New monitoring and control systems reduce maintenance costs. Further improvements in terms of sustainability and cost reductions could be achieved by recycling materials, for example, silicon.

Driven by increasing cost competitiveness and policy support, solar energy is highly dynamic. Between 2019 and 2024, the IEA predicts solar to be the fastest growing energy source worldwide with an increase in total installed capacity of around 700 GW (IEA 2020a), more than doubling the 2018 level of 490 GW (IRENA 2019b). China, the European Union, the United States, India and Japan are expected to drive this development (IEA 2020b). By 2050, IRENA expects the total installed capacity of Solar PV to exceed 8000 GW—equalling 16 times the 2018 level (IRENA 2019b). The solar industry needs to prepare for this rising global demand—scaling up investments is therefore key in the next decade.

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CHAPTER 10

Wind Power Generation

Anselm Eicke, Laima Eicke, and Manfred Hafner

1 Introduction

Wind energy has been deployed for several thousand years. The kinetic energy of moving air was driving propeller boats in ancient Egypt, pumping water in ancient Persia and later employed to grind grains across the Eurasian continent. The first windmill for electricity production was built in Scotland in 1887. Pioneer projects followed in the US and several European countries. Wind turbines as known today were only developed in the second half of the twentieth century.

Since the early 2000's, global wind energy installations have experienced high growth rates. Globally installed wind capacity grew more than six-fold in the past decade from 100 GW in 2008 to more than 620 GW in 2019. Worldwide, wind power is the second largest deployed renewable energy

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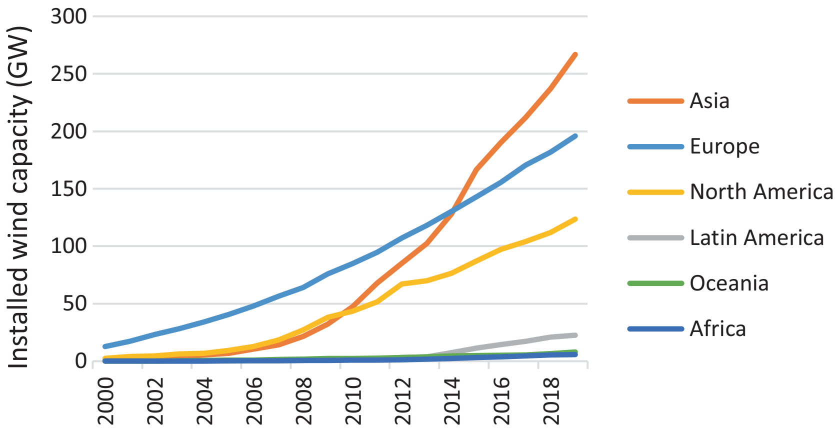

Fig. 10.1 Installed wind capacity per region (onshore and offshore combined). (Authors' own elaboration, data from IRENA 2020)

technology after hydropower, and is placed second in terms of capacity additions with 51 GW added in 2018, only surpased by solar energy (IEA 2020). Wind energy is distinguished between onshore and offshore depending on the location of turbines. Yet, as of 2018, offshore wind accounts for only 4.1% (24 GW) of the total installed wind capacity (IEA 2019).

The global wind energy market is dominated by Asia, where 41% of the global capacity is installed (Fig. 10.1). Asia overtook Europe in 2014, which was previouosly driving the expansion of wind power and accounted for 75% of global capacity in the early 2000's. North America ranks third with 112 GW installed in 2018. Despite huge potential, wind energy currently plays only a minor role in other continents (IRENA 2020). Wind energy makes up merely 6% of the world's electricity generation in 2018; yet, the international renewable energy agency (IRENA 2020) expects wind power to become the largest source of power generation in 2050, when about 35% of electricity supply may stem from wind energy (IRENA 2019).

Compared to onshore wind, offshore wind energy technologies had their technological break-through significantly later. The first larger-scale wind parks were installed along the coast lines of the North Sea and the Atlantic Ocean only in 2010. These two areas still encompass 90% of installed offshore wind capacity (IRENA 2020). Between 2010 and 2018, the global offshore wind market grew nearly 30% per year and it is expected to expand significantly in the upcoming years, with most capacity additions in 2018 located in China, North America, and Oceania (IEA 2019). IRENA projects the strongest growth of wind power in Asia where more than 50% of global wind energy capacity will be located in 2050. According to these projections, 23% of total installed onshore capacity will be located in North America and about 10% in Europe (IRENA 2019). For the offshore wind sector, projections also see Asia at the forefront in 2050, accounting for 60% of total installed capacity, followed by Europe (22%) and North America (16%).

2 Technical Characteristics

Wind turbines convert the kinetic energy of moving air into electricity. As the blades of a wind turbine are set in motion, their rotation turns a turbine. This rotational energy moves the shaft connected to the generator, producing electrical energy.

Modern wind turbines consist of three key components: the tower, the nacelle, and the rotor blades. The nacelle serves as the heart of the turbine. It encompasses the machine set, which includes the rotor hub, a generator, and the gearbox. The rotor blades are connected to the gearbox, or sometimes also directly to the generator, via a shaft. Electrical equipment allows adjusting the angle of the blades to limit electricity generation at high wind speeds and to optimize the output at changing wind speeds.

Abstracting from technical details, the power output of wind turbines mostly depends on two parameters: the wind speed and the length of the rotor blades. Because the electricity output of wind turbines is proportional to the swept area of the rotor blades, a doubling of the blade length squares the wind power potential. The energy output also raises proportionally to the third power of the wind speed. Doubling the wind speed thus leads to an increase in power potential by a factor of eight. This indicates that the hub height, that is, the length of the tower, is a crucial design parameter of wind turbines because wind speeds usually increase with height from the ground. In general, higher towers therefore improve the yield of wind turbines. Aside from height above the ground, wind speed also varies strongly across regions. The location of the installation is thus of key importance for the economics of wind energy. In general, coastal areas benefit from higher wind speeds compared to landlocked regions. This drives the deployment of offshore wind turbines despite the significantly higher technical complexity and costs. Offshore wind turbines are mostly fixed, and still rarely floating. Fixed turbines have their foundation on the ocean ground and they are therefore only deployed in shallow coastal areas. Floating offshore turbines are a less mature technology based on experiences made in the oil and gas sector. They allow harvesting wind energy farther offshore in deep waters. Only in 2017, the world's first commercial floating wind farm started operating in Scotland.

Technological improvements focus on increasing rotor diameters and the hub height to increase the power output of wind turbines. Yet, there is a tradeoff between these two parameters: the higher the tower, the less weight it can hold due to turbulences caused by higher wind speeds. The firmness of construction materials sets limits to these efforts. The efforts to increase efficiency have been guiding technological development and led to significant cost reductions during the past decades: tower heights vary between 50 and 200 m, and average rotor diameters have more than doubled from 50 m in 2000 to 110 m in 2018. These improvements led to an increase in the average capacity by 250% (IRENA 2019). This trend is expected to continue: in the early 2020s, the largest windmills are expected to reach capacities of 12.5 MW and rotor diameters of up to 220 m. Nameplate capacities of future wind turbines are expected to further increase (GE Renewable Energy 2020).

The development of wind energy markets started in windy countries, including Denmark, Germany, and the UK. While the windiest locations are gradually filled by wind farms, renewable energy developers increasingly focus on locations with medium and low wind speeds (see below, the section on technical potential). Manufacturers have started developing new turbine designs specifically for these lower wind-speed sites. This is mostly achieved by increasing the height of towers. But the size of the generator also yields trade-offs: combining a small generator (with low rated capacity) with large blades, leads to a higher capacity utilization at low wind speeds, resulting in a more constant generation profile. This facilitates the integration of wind energy into the power system (see Sect. 10.5). The downside of such low wind-speed turbines is that not all the kinetic energy of wind is converted into electricity at high wind speeds. In turn, bigger (and more costly) generators produce significantly more electricity in times of high wind speeds, but are oftentimes underused. By now, wind turbine manufacturers offer a wide range of turbine sets, optimized for specific wind conditions.

Trends going beyond rising average tower heights and rotor diameters include new, aerodynamic profiles of blades and new materials, in order to increase durability and reduce maintenance costs also in demanding locations such as deserts or high seas (IRENA 2019). Digitalization drives predictive algorithms based on big data. These optimize the positioning of turbines in the wind and improve monitoring and control systems, further reducing maintenance costs (Wood Mackenzie 2019). Improvements in terms of sustainability and cost reductions could be achieved by recycling various materials. Pioneer projects have shown promising results for example, by recycling expensive fiberglass components of wind turbines (IRENA 2019).

3 Technical Potential of Wind Energy

Wind energy potential, often expressed as the mean wind speed of a location, is unequally distributed around the globe (Fig. 10.2). The power output of wind turbines thus varies strongly between locations. Generally, wind resources of higher quality for energy production are close to the poles; the lowest potential is close to the equator. The most promising areas in Europe are in the north, for example, in the North and Baltic Seas; the coasts of South America and New Zealand equally bear large potentials (Fig. 10.2).

Today's wind installations are far from tapping this huge theoretical potential. In theory, the most lucrative sites could provide more than today's total electricity consumption worldwide (IEA 2019). In practice, land usage conflicts, citizens' opposition, and environmental regulations limit deployable

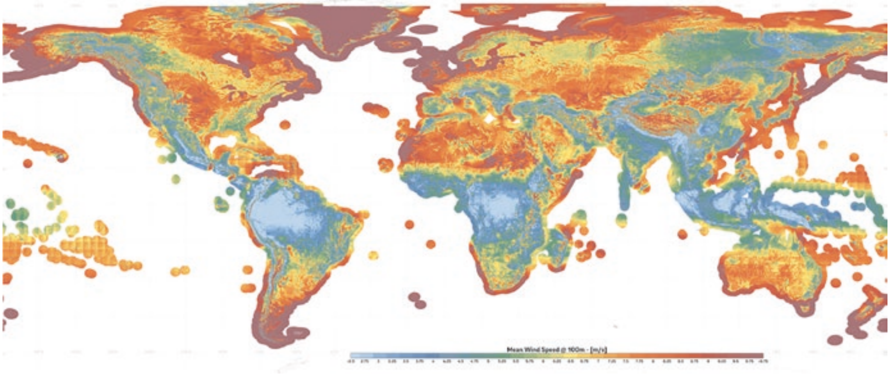

Fig. 10.2 The global wind energy potential shown as mean wind speeds 100 m above ground. (Source: Global Wind Energy Atlas 2019)

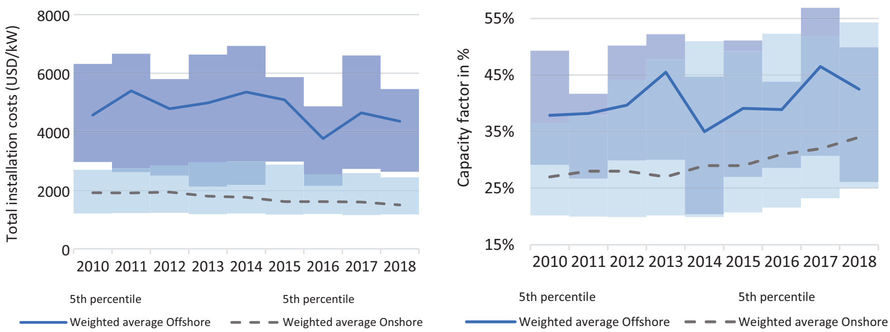

Fig. 10.3 Global average installation cost and capacity factors of onshore and offshore wind energy between 2010 and 2018. The shaded areas show the 5% to 95% quantiles in each year. (Authors' own elaboration, data from IRENA 2020)

land. These limitations are in particular hindering the rapid deployment of onshore wind and are often less relevant for offshore wind.

Wind speeds vary not only by region but also over time. Most of the time, wind farms do not generate electricity at full capacity. The capacity factor indicates how much electricity a wind turbine generates on average per year. It is defined as the actual electricity generation divided by the maximum theoretical electricity generation, that is, the power output if the turbine always generated at nameplate capacity. The higher the capacity factor, the more electricity a wind turbine produces. Typical capacity factors of onshore wind power range between 30% and 40%, with an average of 34% in 2018 (Fig. 10.3). The highest values are achieved in favorable sites and with newer wind turbine designs. In particular, coastal areas feature higher levels of wind speeds than landlocked regions, and offshore wind power's electricity generation is usually significantly higher per unit of capacity installed. Capacity factors of offshore wind farms range between 35% and 65% with an average of 43% in 2018. Some of the highest levels are reached in the North and Baltic seas in Europe (IEA 2019). Next to sites, also the turbine's design affects the capacity factor as we have discussed in the previous subsection.

4 Costs of Wind Energy

In comparison to electricity generation from fossil fuels, wind power is much more capital-intensive. Because wind power has no fuel cost and has comparatively low cost for operation and maintenance, the largest cost-components of wind turbines are investment and finance costs. This makes wind power plants particularly dependent on good financing conditions and low cost of capital.

The installation cost of wind energy varies strongly between countries. For example, the average total installation costs for onshore wind farms ranged between USD 1170 per kW in China and USD 2030 kW in the UK in 2018 (IRENA 2019). The main reason for this difference is the market structure of wind energy components. Blades and towers of wind turbines are bulky and difficult to transport; they are therefore usually produced locally. Consequently, their prices vary strongly among countries. By contrast, electrical equipment such as the nacelle, including generator and transformers, is shipped around the world and cost differences for these parts are smaller. The most expensive component of wind power plants is the turbine, followed by grid connection and the foundation (EWEA 2009).

On average, installation costs of onshore wind projects have been falling by 22% between 2010 and 2018 (Fig. 10.3, left) and are expected to further decline. The cost decline for onshore wind was mainly driven by technological advancement in turbine technologies, measured by high learning rates (IRENA 2017; Williams et al. 2017). These were fostered by public investment in research, development, and demonstration in several key markets (Klaassen et al. 2005; Zhou and GU 2019). Especially larger generators and longer blades increased power output and led to a decline in the specific (per capacity) costs. At the same time, average capacity factors of onshore wind turbines increased from 27% to 34% (Fig. 10.3, right). This is due to better-informed selection of sites and to developments of new turbine designs, better adapted to lower wind speeds.

Offshore wind parks are much more costly to construct than onshore installations. Grounding wind turbines on the sea requires expensive equipment, including for example specialized ships. Similarly, maintenance throughout the turbine's lifetime is more complex than for onshore installations due to the challenging accessibility. In terms of installation costs, the average cost of offshore energy is about three times higher than for onshore energy (USD 4360 per kW compared to USD 1500 per kW, Fig. 10.3, left panel) (IRENA 2019). But the costs of offshore wind projects have also been decreasing in recent years, for reasons similar to onshore wind. Particularly strong improvements were achieved in reducing operation and maintenance costs. Further cost decreases of offshore wind energy are expected due to high investment plans in China, likely to result in further technological improvements.

The levelized cost of electricity (LCOE) is a metric for the average cost of power generation. The LCOE is the ratio of all costs divided by the generated electricity produced over the lifetime of the plant. It therefore captures declines in costs and also technological improvements in the form of higher capacity factors. Note that LCOE is a useful metric for the cost improvements within a technology, but it should not be used to compare different generation technologies because it neglects the time-value of electricity, that is, the value that wind power offers to the electricity sector in terms of offsetting other electricity costs. LCOE of wind energy declined as technological improvements had a decreasing effect on cost (in the denominator) and increasing capacity factors improved the electricity yield (in the nominator). IRENA expects a continued decline of onshore LCOE from USD 60 per MWh in 2018 to USD 40 per MWh by 2030 (IRENA 2019). Due to the different generation profiles, a cost-benefit comparison between the two technologies exceeds the comparison of LCOE, which are significantly lower for onshore than for offshore wind (55 USD/MWh compared to 186 USD/MWh, IRENA (2020)). As discussed in the previous section, offshore wind power has significantly higher capacity factors than onshore (Fig. 10.3, right) and thereby, steadier generation profiles. This implies offshore wind also generates electricity when onshore wind does not. Because wind generation often has a depressing effect on wholesale prices, their steadier generation profile allows offshore wind to produce electricity when the wholesale electricity price is higher, which generally leads to higher market values.

As more and more wind parks that have been installed 20 to 30 years ago reach their technical lifetime, repowering old wind farms entails further cost-saving potential. Full repowering describes the replacement of entire wind parks whereas partial repowering implies that single components, such as rotors or gearboxes, are replaced while foundations and towers remain in place. The replacement or upgrading of older components with more advanced technologies can enhance the power output of wind parks and increase their operating time. This strategy allows installing the most advanced technologies at locations with best wind resources, which often had already been covered by installations. Higher rates of social acceptance by local communities, already accustomed to wind power, and existing environmental assessments decrease risks and costs in comparison to new sites. Repowering may also require grid extension due to more powerful turbines (IRENA 2019).

The installation costs of onshore and offshore wind projects are expected to continue their past decline during the next decades (IRENA 2019). Further technological advancement, more competitive supply chains, and economies of scale in production are the main drivers of these developments. Limitations to further reductions in cost are cost of materials, transportation, and the costs deriving from regulatory processes.

5 System Integration

The rapid expansion of wind power imposes new challenges on power systems. The four main characteristics of wind power hindering its system integration are the temporal variability, rapid changes in generation, difficult predictability, and regionally diverging wind energy potentials. These characteristics impose additional costs on the power system.

Changing wind speeds cause wind generation to vary over time. The replacement of dispatchable energy sources with variable wind energy raises the question of generation adequacy. Will there always be sufficient generation capacity to meet electricity demand? The contribution of wind energy to the system's generation adequacy is called "capacity value", that is, the amount of dispatchable generation capacity that it can replace without reducing security of supply. The capacity value of wind energy depends on how much wind resource is available during times of peak loads. As a rule of thumb, the capacity value is close to the average power produced by wind power when the share of wind power in the system is small (Milligan et al. 2017). This implies that offshore wind power tends to have higher capacity values than onshore wind due to its higher capacity factors. With an increasing share of wind in the system, its capacity value declines. The capacity factor can become higher if wind conditions systematically correlate with electricity demand, for example, when high wind speeds in winter time cause higher electricity consumption for heating.

High shares of wind power may cause rapid changes in electricity generation, for example, due to a weather front rapidly changing wind speed. This requires dispatchable generators to quickly adapt power output, and it imposes steep ramping gradients. Most conventional generators in today's power systems are not designed and optimized for such operational mode, in particular nuclear and coal plants. But simultaneity in wind generation is also a problem for wind power plant operators. An oversupply of electricity leads to a declining value of wind energy, reflected in low prices in liberalized markets (known as merit order effect).

The difficult predictability of wind generation has raised concerns about increasing balancing costs due to the deployment of wind energy. Yet, practical experience has shown decreasing balancing costs despite growing shares of wind power (e.g. Hirth and Ziegenhagen 2015). In several countries in Europe and the United States, wind power provides frequency support services (IEA Wind Task 25 2017). Measures to enhance flexibility with high shares of wind power include the introduction of new electricity markets, demand-side flexibility, and storage. Electricity markets that have cross-border trades of intraday and balancing resources and emerging ancillary services markets are supporting the integration of wind power.

All three issues (variability, rapid changes, and difficult predictability of wind power) are strongly reduced through interconnecting multiple power systems. Such geographical smoothing reduces extreme variations. For example, all wind plants in Europe generated less than 5% of their installed capacity in 2017 only in two consecutive hours. The maximum duration of less than 10% of capacity was 38 hours (IEA Wind Task 25 2017).

The fourth major challenge for integrating wind power into power systems are regionally diverging wind energy potentials. Wind farms, usually in remote lowly populated areas or offshore, require a grid connection to load centers. Aggravating the challenge, wind turbines are typically built in large wind farms to benefit from economies of scales. A large wind farm may consist of several hundred individual wind turbines, ranging up to a total of 1.5 GW, equivalent to a large conventional power plant. The construction of additional transmission infrastructure is a time-consuming process in many countries. A lack of grid infrastructure implies that electricity from wind cannot be transmitted and is consequently curtailed. The required network reinforcement for wind power significantly varies between regions, depending on where wind power plants are located relative to load and existing grid infrastructure. Grid connection is often a major component of the integration cost of wind energy. Yet, in most countries, these costs are usually not paid by wind plant operators (Eicke et al. 2020), also because the network costs are difficult to attribute to individual assets.

6 Policies Supporting Wind Energy

In this chapter, we have discussed various barriers hindering wind energy. Technological challenges include harsh environmental conditions, variability, and uncertainty of generation and infrastructure needs. Economic barriers are the high upfront capital costs and long payback periods which impede the access to finance in many countries. In addition, wind turbines are often confronted with limited social acceptance, increasing investment risks and prolonged installation processes. To address these challenges and to advance the deployment of renewable and domestic energy sources, countries around the world introduced support policies for wind energy, which can be grouped into deployment policies, integration policies, and enabling policies (IRENA 2019).

Deployment policies address economic barriers. They are based on fiscal and financial/economic instruments: in Europe, several countries introduced feed-in tariffs in the early 2000s, while the US and India deployed renewable portfolio standards, and introduced tax incentives. Since the late 2010s, renewable auctions have been increasingly introduced across the globe (IRENA 2019). Competitive auctions brought down installation costs and are meant to create incentives for technological advancements. This even led to extremely low auction results with bids for offshore wind energy without guaranteed feed-in tariffs in the Netherlands, Germany, and the UK (IRENA 2019). In technology neutral auction designs, wind energy often won; many countries therefore started using technology specific auction designs (Steinhilber 2016; Mitchell and Connor 2004). Furthermore, the deployment of offshore wind energy is often supported through financing grid connections and redeveloping sites.

Technical integration policies for wind energy tackle technological challenges by improving the flexibility of power systems. These comprise the enhancement of existing grid infrastructure, and promoting research and development of sector coupling and electricity storage. Several countries with high shares of wind energy generation, including Denmark and Germany, encourage the transformation into hydrogen of electricity at peak wind generation. The EU is supporting the strategic build-up of battery cells and hydrogen solutions within its Green Deal (Eicke and Petri 2020). Social integration policies improve public acceptance for wind energy. They include participatory processes in the planning stage of projects, and the engagement of local communities via ownership models or the provision of local services. Policies fostering local co-ownership or financial benefits for nearby communities have been shown to increase the acceptance of wind parks in the population (Wolf 2019).

Enabling policies address several of the above-mentioned challenges in an integrated manner, taking the whole economy into account. Examples are climate targets and industrial strategies that provide medium and long-term guidance and investment security. They foster the development of wind projects and the build-up of domestic wind industries. Such industrial policies for the wind energy sector have been part of recovery packages in response to the COVID-19 pandemic, for example in China and Germany (Weko et al. 2020). These measures are based on strong economic growth prospects and job creation potentials (Helgenberger et al. 2019). Enabling policies also encompass labor market measures, research programs and education policies to build up well-trained and skilled personnel for wind energy. Economic/financial policies might change the cost of electricity from wind generation in relation to fossil fuels significantly, for example, by introducing carbon pricing (IRENA 2019).

The design of supporting policies differs significantly by country context and policy objectives. In combination, development, integration, and enabling policies aim to tackle the technological, economic, and social challenges we discussed in this chapter. This helps further improving wind energy technologies and taping their huge potentials across the globe.

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CHAPTER 11

Geothermal Power Generation

Isabella Nardini

1 Introduction

The word *geothermal* comes from the Greek *gê* and *thermòs*, which literally means *Heat of the Earth*.

Geothermal energy derives from thermal energy that is contained within the Earth. The main sources of this energy are the radiogenic heat produced by the radioactive decay of isotopes (atoms of a given element, in this case potassium, thorium and uranium, with the same number of protons but different numbers of neutrons) in the mantle and crust, and the primordial heat left over from the formation of the Earth. This heat is constantly transferred from the interior of the Earth to its surface: due to this heat flow, the rock temperature increases by about 30 °C for each km of depth (geothermal gradient). Rainwater circulating underground through porous, fractured, permeable rocks is heated up. The hot water (or steam), rising through faults and fractures, can reach the surface and form hot springs, fumaroles and geysers but most of it, instead, remains underground, trapped in fractures and porous layers of rock between impermeable surfaces. Drilling wells connect the geothermal resource with the surface for using the thermal energy contained in the fluid.

The total estimated thermal energy of the Earth is immense but only a fraction can be recovered and utilised by humankind.

Geothermal energy from natural pools and hot springs was known since ancient times. More than 10,000 years ago, Native Americans used geothermal energy for cooking, bathing and warming. The beneficial effects of baths

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heated by hot springs and thermal waters were considered sacred gifts by Egyptians, Israelites, Hindus. Also Greeks and Romans used the water for bathing, cooking and curative purposes and one of the best-preserved evidence is the Roman city of Pompeii during the first century CE, where the water supply and the heating system were constantly updated with the most advanced techniques of that time. Such uses of geothermal energy were initially limited to sites where hot water and steam were accessible.

The world's pioneer district heating system was installed at Chaudes-Aigues (France) at the beginning of the fourteenth century, but only in the late nineteenth century, it was commercially introduced in several cities of USA and industry began to realize the economic potential of geothermal resources. Today the world's largest geothermal district heating system is in Reykjavik (Iceland), which has utilized natural hot water to heat its buildings and houses since 1930. Early industrial applications included the extraction of boric acid from geothermal fluids in Larderello (Italy) during the early nineteenth century. The first attempt at geothermal electric power generation took place in Larderello, with the successful development of an experimental plant in 1904. The first geothermal well was drilled in Japan in 1919, and at the Geysers in northern California in 1921. Geothermal power plants were then commissioned in New Zealand in 1958, in Mexico in 1959, in the USA in 1960, and later in many other countries.

2 Geothermal Energy Technology and Utilization

Geothermal energy can be found around the globe and is not conditioned by external conditions (whereas e.g. solar and wind energy present higher variability and intermittence) but upon the depth to the resource and economic convenience to produce it. Growing awareness and interest in renewable resources has raised the need to homogenize the reporting requirements for geothermal resources so that they can be applied worldwide. As no internationally agreed standards, guidelines or codes exist, the ambiguity inherent in the definition of geothermal assessments leads to increased resource uncertainty, more investment risk and less confidence in development Beyond the fact that the classification of a geothermal resource is strongly dependent on different approaches (i.e. by temperature, use, type and status, accessibility, electric power generation, stored heat, specific energy, recoverable volume, recoverable heat, recoverable power, net profit) (Falcone et al. 2013), it can be used to generated clean electricity, for heating and cooling or for industrial purposes. However, for electricity generation, medium- to high-temperature resources, which are usually close to volcanically active regions, are needed. A simplified scheme based on reservoir temperature, fluid type (water or steam), applications and technology is shown in Fig. 11.1.

Geothermal energy utilization is commonly divided into two categories: electric energy generation and direct uses. Deep geothermal technologies generally take advantage of a much deeper (commonly more than 2 km depth),

RESERVOIR TEMPERATURE	FLUID TYPE	APPLICATION	TECHNOLOGY
HIGH -T >150°C	water, vapour	electricity generation direct heat use	▪ DRY STEAM TURBINE ▪ SINGLE/DOUBLE/TRIPLE FLASH ❖ HEAT EXCHANGER
MEDIUM-T 90-150°C	water	electricity generation direct heat use	▪ BINARY CYCLE ❖ HEAT EXCHANGER ❖ GEOTHERMAL HEAT PUMP
LOW-T <90°C	water	direct heat use	❖ HEAT EXCHANGER ❖ GEOTHERMAL HEAT PUMP ❖ DIRECT HEAT USE

Fig. 11.1 Simplified scheme of geothermal resources, application and technology

higher temperature geothermal resource to generate electricity, while ground source heat pumps and direct use geothermal technologies utilize shallower, lower temperature geothermal resource for heating, cooling and industrial applications.

2.1 *Dry Steam Power Plants*

These plants draw from underground resources of steam. The conversion device is a steam turbine designed to directly use the low-pressure, high-volume fluid produced in the steam field. The steam is piped directly from underground wells to the power plant, where it is directed into a turbine/generator unit. Dry steam plants commonly use condensing turbines. The condensate is re-injected (closed cycle) or evaporated in wet cooling towers. This type of geothermal power plant uses steam of 150 °C or higher. Direct dry steam plants range in size from 8 MW to 140 MW (S&P Global Platts 2016).

2.2 *Flash Steam Power Plants*

These conversion facilities are the most common type of geothermal electricity plants in operation today. They are similar to dry steam plants; however, the steam is obtained from a separation process called flashing. They use geothermal reservoirs of very hot water that flows up through wells in the ground under its own pressure. As it flows upward, the pressure decreases and some of the hot water boils into steam. The steam is then separated from the water and directed to the turbines. The fluid fraction exiting the separators, as well as the steam condensate (except for condensate evaporated in a wet cooling system), is usually re-injected. The temperature of the fluid drops if the pressure is lowered, so flash power plants work best with well temperatures greater than 180 °C. Flash plants vary in size depending on whether they are single-(0.2–80 MW), double—(2–110 MW) or triple-flash (60–150 MW) plants (S&P Global Platts 2016).

2.3 Binary Cycle Power Plants

These plants operate on water at lower temperatures. The primary resource fluid is used, via heat exchangers, to heat a secondary working fluid, usually an organic compound with a low boiling point (i.e. ammonia/water mixtures used in Kalina cycles or hydrocarbons in Organic Rankine Cycles—ORC), in a closed loop. Typically, binary plants are used for resource temperature between 100 °C and 170 °C. Although it is possible to work with temperatures lower than 100 °C. Binary plants range in size from less than 1 MW to 50 MW (S&P Global Platts 2016).

2.4 Combined-Cycle or Hybrid Plants

Some geothermal plants use a combined cycle, which adds a traditional Rankine cycle to produce electricity from what otherwise would become waste heat from a binary cycle (ORMAT 2017). The typical size of combined-cycle plants ranges from a few MW to 10 MWe. Hybrid geothermal power plants use the same basics as a stand-alone geothermal power plant but combine a different heat source into the process; for example, heat from a concentrating solar power (CSP) plant. This heat is added to the geothermal brine, increasing the temperature and power output.

Geothermal electricity generation relies mainly on technologies that exploit conventional geothermal resources, such as: dry steam plants, flash plants, binary plants, and combined-cycle or hybrid plants. However, as high-quality conventional resources become harder to access, deeper resources may become accessible in the future through the development of Enhanced Geothermal System (EGS).

2.5 Enhanced Geothermal System (EGS)

A large part of the geothermal potential is heat stored at depths greater than commonly drilled.

The principle of the EGS is to create artificial fractures to connect production and injection wells by hydraulic or chemical stimulation. Stimulation is accomplished by injecting water (natural water flow is absent) and a small amount of chemicals at high pressure to create or reopen fractures in the deep rock. The EGS uses binary plants to produce power from the hot brine, which needs then to be totally re-injected in order to keep the pressure and production stable. During EGS reservoir creation and stimulation, rocks may slip along pre-existing fractures and produce micro-seismic events, which is one of the major controversial issues for the development of these systems.

2.6 Heat Pump and Direct Use Systems

A ground source heat pump utilizes the naturally occurring difference between the subsurface ground temperature (average temperature at depth of 20–100 m is 14 °C depending on the site) and the subsurface ambient air temperature. Geothermal hot water can be used for many applications that require heat. In these systems, a well is drilled into a geothermal reservoir to provide a steady stream of hot water. The water is brought up through the well (horizontally or vertically drilled), and a mechanical system (piping, heat exchanger and controls) delivers the heat directly for its intended use. A disposal system then either injects the cooled water underground or disposes of it on the surface. The heat pump can also operate in reverse, moving heat from the ambient air in a building into the ground, in effect cooling the building. A supplementary advantage of this system is that hot water can also be supplied to the building using the same loop. During the heat exchange, the excess heat from the building is transferred to its hot water system before reaching the ground loop. No additional energy is required to heat the water and no gases are released as everything is in a closed loop.

Beyond the heat pump systems for heating and cooling buildings and district heating, direct use systems have a wide range of applications such as greenhouse operations, heating the sidewalks and roads to melt snow, hot water supply, aquaculture and other industrial uses like laundries, drying, biological processes, waste management, resorts and spas in tourism industry. With some applications, researchers are exploring ways to effectively use the geothermal fluid for generating electricity as well.

3 Geothermal Power Generation Worldwide and Market Overview

The renewable power capacity data shown in the tables and figures below represent the maximum net generating capacity of power plants and other conversion facilities that use renewable energy sources to produce electricity. For most countries and technologies, the data reflect the capacity installed and connected at a given year. The capacity data are presented in megawatts (MW) and the generation data are presented in gigawatt-hours (GWh).

Geothermal installed capacity worldwide has continued to grow in the last decade (Fig. 11.2). In 2020, global geothermal installed capacity has increased up to 14,013 MW, representing approximately 0.5% of renewable power capacity worldwide. Tables 11.1 and 11.2 and Figs. 11.3 and 11.4 show data of the total installed geothermal capacity respectively per region and per country. The Asian regions share 32.4% of the total geothermal installed capacity due to the remarkable contribution of Indonesia (2131 MW) and the Philippines (1928 MW) followed by Japan (481 MW). North America shares 24.9% of the total with the highest contribution per country given by the USA (2587 MW). Europe shares 11.8% of the total and the major contribution is given by Italy

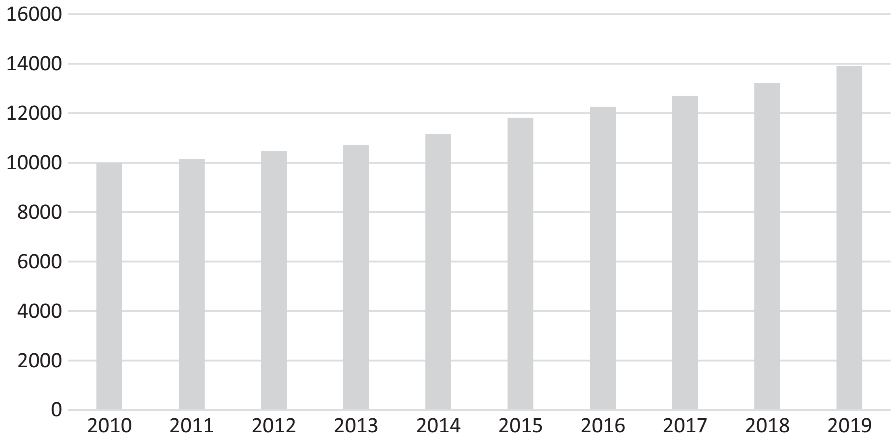

Fig. 11.2 Total Geothermal Installed Capacity (MW). (Source: IRENA_Renewable_Energy_Statistics_2021)

Table 11.1 Geothermal installed capacity by region

Region	*Geothermal Installed Capacity (MW)*	*Share of Total*
Asia	4540	32.4%
N America	3492	24.9%
Europe	1652	11.8%
Eurasia	1695	12.1%
Oceania	1040	7.4%
Africa	831	5.9%
C America + Carib	723	5.2%
S America	40	0.3%
Total	14013	100.0%

Data Source: IRENA_Renewable_Energy_Statistics_2021. The data refer to 2020 obtained from a variety of sources, including: the IRENA questionnaire; official statistics; industry association reports; and other reports and news articles

(797 MW) and Iceland (756 MW). Eurasia (Russian Federation and Turkey) shares 12.1%, almost all in Turkey (1613 MW), with only a minor estimated contribution by the Russian Federation (81 MW). In Oceania, a major contribution is given by New Zealand (984 MW). The African countries share 5.9% of the total, basically concentrated in Kenya (824 MW) and Ethiopia (7 MW). Central America and the Caribbean are mainly represented by Costa Rica (262 MW), El Salvador (204 MW) and Nicaragua (153 MW). The geothermal installed capacity in South America is completely concentrated in Chile (40 MW).

Table 11.2 Geothermal Installed Capacity by country in 2020

Country	*Geothermal Installed Capacity (in MW)*	*Share of Total*
United States	2587	18.5%
Indonesia	2131	15.2%
Philippines	1928	13.8%
Turkey	1613	11.5%
New Zealand	984	7.0%
Mexico	906	6.5%
[a]Kenya	824	5.9%
Italy	797	5.7%
Iceland	756	5.4%
Japan	481	3.4%
Other	1006	7.2%
Total	14,013	100.0%

Data Source: IRENA_Renewable_Energy_Statistics_2021. Data obtained from a variety of sources, including: the IRENA questionnaire; official statistics; industry association reports; and other reports and news articles

[a] Data estimated by IRENA from a variety of different data sources

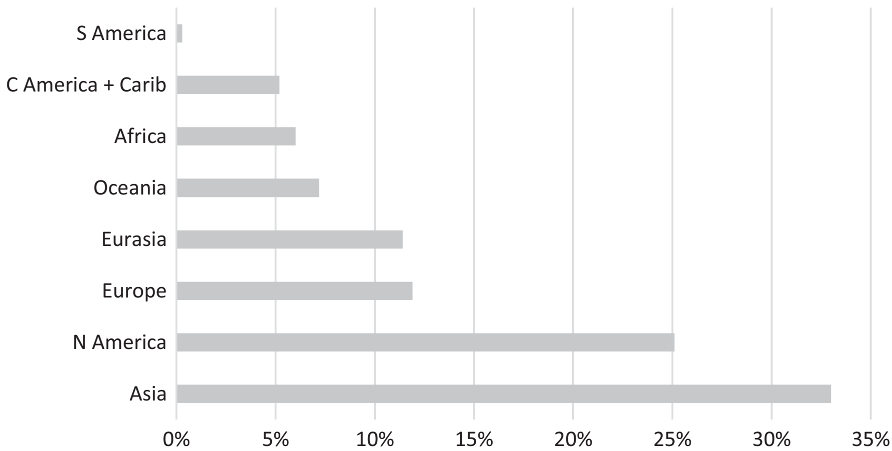

Fig. 11.3 Share of Total Geothermal Installed Capacity by region in 2020. (Source: IRENA_Renewable_Energy_Statistics_ 2021)

Coherently also the electricity generation from geothermal has grown from 69,856 GWh in 2011 to 92,047 GWh in 2019. The top ten countries are listed below in Table 11.3 and shown in Fig. 11.5.

At the end of 2020, there were 139 geothermal power plants with 3.5 GWe of geothermal electricity capacity across Europe. In 2020, Turkey has become the most active geothermal power market in the world with 8 new plants which added 165 MWe of geothermal electricity installed capacity. Moreover, a profitable development is driven by the confirmation from the Turkish government on the extension of the feed in tariff program applicable to plants entering in

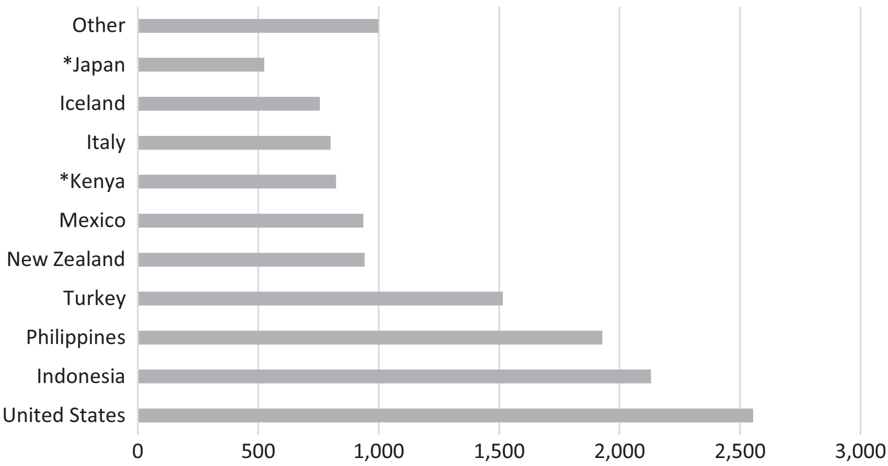

Fig. 11.4 Installed Geothermal Capacity by country in 2020 (MW). (Source: IRENA_Renewable_Energy_Statistics_ 2021)

Table 11.3 Geothermal electricity production by country in 2019

Country	*Electricity Production (GWh)*	*Share of Total*
United States	18,364	20.0%
Indonesia	14,100	15.3%
Philippines	10,691	11.6%
Turkey	8952	9.7%
New Zealand	8041	8.7%
Mexico	5330	5.8%
[a]Kenya	5384	5.8%
Italy	6075	6.6%
Iceland	6018	6.55%
Japan	2830	3.1%
Other	6262	6.8%
Total	92,047	100.0%

Data Source: IRENA_Renewable_Energy_Statistics_2021. Data obtained from a variety of sources, including: the IRENA questionnaire; official statistics; industry association reports; and other reports and news articles
[a] Data estimated by IRENA from a variety of different data sources

operation by 2025 (EGEC 2020). The European geothermal electricity market remains highly dominated by Italy and Iceland. The geothermal power potential is large and could cover, or exceed, the actual electricity demand in many countries. The EU Member States' National Energy and Climate Plans (NECPs) indicate as their target to reach the electricity production of 8 TWhe by 2030.

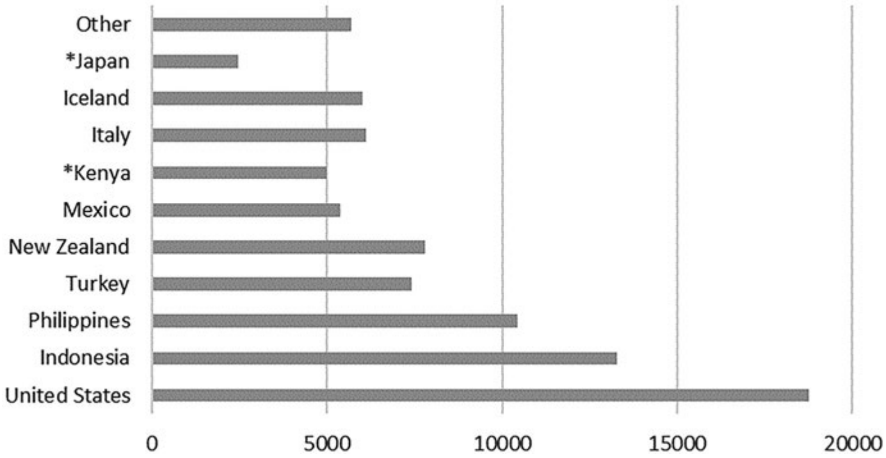

Fig. 11.5 Geothermal Electricity Production by country in 2019 (GWh) (Source: IRENA_Renewable_Energy_Statistics_2021)

Europe is a principal global market for geothermal district heating and cooling for buildings, industry and other services. In 2019, there were 5.5 GWht of installed geothermal district heating and cooling capacity in 25 European countries, corresponding to 327 systems. In 2020 a total of 350 geothermal district heating and cooling systems in operation plus 232 under development ready to be operational by 2025 (EGEC 2020). The status of geothermal district heating and cooling in Europe reflects a strong interest for this renewable resource and the possibility to implement it almost everywhere in Europe. The Netherlands continues to be the driving European market for deep geothermal heating and cooling.

The European geothermal heat pump market reached the milestone of 2 million units installed, as it is becoming a major heating and cooling solution in some regional or national markets because of its high efficiency and decreased costs due to the distribution of bigger systems in large edifices. Mature market for geothermal heat pumps in Europe include Germany, France and Switzerland. In colder climate countries, geothermal heat pumps are closer to market maturity and Sweden is the only country qualified as a mature market.

4 Geothermal Energy Costs and the Financing of Geothermal Power Plants

The overall cost of a geothermal project is extremely site-sensitive in the broadest sense, depending not only upon the geological setting but also, to a large extent, on market and policy from national to local scale. There are however, economic factors common to all projects such as provision of fuel (resource type), conversion technology, revenue generation and financing. The investment cost is basically divided into the cost of surface infrastructures and operations and the cost of subsurface activity. The surface costs include the cost of surface exploration and resource assessment and the cost of conversion technology (design and construction of the conversion facility and related surface equipment, such as electrical generation plant with required transformers and transmission lines, roads, buildings), while the cost of subsurface investment is that of drilling (exploration drilling, drilling of production and injection wells). While surface costs can be predicted with a certain degree of accuracy, higher uncertainty is represented by the drilling cost. The drilling cost for a low-temperature geothermal development typically is 10–20% of the total cost, and that for a high-temperature field is usually 20–50% of the total cost. Although drilling costs have a strong influence on the overall cost, the uncertainty driving the geothermal development cannot be exclusively attributed to them.

Typical costs for geothermal power plants range from 2000 USD/kW to 6000 USD/kW (depending on the site, if installing additional capacity at existing brown field or new green field). The data for recent projects shows that global weighted-average total installed costs were USD 4468/kW in 2020, slightly lower than in 2019, but broadly in line with values seen over the last four years.

The LCOE from a geothermal power plant is generally calculated by using the installed costs, operations and maintenance (O&M) costs, economic lifetime, and weighted average cost of capital. The global levelized cost of electricity (LCOE) of geothermal power of commissioned plants in 2020 was USD 0,071/kWh, having slightly declined from previous years (IRENA 2021, Renewable Power Generation Costs in 2020). O&M costs are high for geothermal projects, because of the need to work over production wells on a periodic basis to maintain fluid flow and hence production.

Capacity factors for geothermal plants, are the highest with respect to all other renewables, typically expected in the range of 70–90%, but lifetime capacity factors, considering a 25-year economic life, will depend heavily on well performance and ongoing investment to maintain production wells or drill new ones as the reservoir responds to the extraction and reinjection of fluids.

Costs for geothermal technologies are expected to continue to drop through 2050 (Sigfusson and Uihlein 2015). The economics of geothermal power plants may be improved by exploiting by-products such as silica, carbon dioxide and other chemicals.

Geothermal power plant development is capital-intensive due to exploration and drilling costs, for which it can be difficult to obtain bank loans. Since geothermal exploration is considered high risk, developers generally need to obtain some type of public financing. This risk is derived from the fact that capital is required before confirmation of the presence of the resource and therefore before project profitability can be determined. Policy makers can surely contribute to decrease the risk and the capital cost for private developers by deploying economic and financial instruments for example, by cost-sharing for drilling and by the activation of public-private risk insurance schemes; by data sharing with developers (including seismic events/fractures and deep drilling data owned by national or local governments).

5 Outlook for Geothermal Energy

The transition from current fossil-fuel energy system towards a sustainable one-based requires renewable energy technology. The potential of geothermal energy is huge and can be used globally. Given the somewhat unique nature of geothermal resources, geothermal power generation is very different to other renewable power generation technologies. Geothermal is a mature, commercially proven technology and with advances in technology and processes, it can become increasingly competitive as expected by 2050. Moreover, advantages of geothermal energy are not only the generation of electricity in different plant configurations but also the direct application of heat in industry, the heating and cooling. It is well positioned to play an important role in mitigating global climate change, increasing national energy security, and making the economy more competitive.

There are significant risks involved with initial exploration and drilling, but favourable regulatory environments (including tax incentives and land permitting and licensing legal framework) can do much to facilitate further developments in the sector. Besides, from being a clean and renewable energy source, geothermal power is also suitable for base load electricity generation and thus has the potential to become the backbone of local grid systems.

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CHAPTER 12

Power Generation from Tides and Waves

Dhruv Bhatnagar, Danielle Preziuso, and Rebecca O'Neil with contribution by Jan Alam, Saptarshi Bhattacharya and Sarmad Hanif

1 Introduction

Ocean waves and tides have the potential to supply a significant portion of the world's energy needs. Water is denser than air, ocean forces are powerful, and significant population density and corresponding electricity loads occur near ocean environments around the world. Yet commercial development of energy capture technologies from marine resources has been limited to date, generating only 1.2 TWh of electricity across the globe in 2018 while global electricity demand was 23,000 TWh (International Energy Agency 2019a, b).

Currently, cost and technology uncertainty of marine energy devices remain the primary barrier to expansion. However, as renewable energy technologies mature and become more viable through policy intervention, economic development, generation incentives, and robust research and development programs, marine technologies increasingly hold promise of commercialization.

This chapter discusses the development of marine energy projects to date, economic factors for deployment and operations, and commercialization pathways for the future. While marine renewable technologies include a range of devices such as ocean thermal conversion technologies and ocean current devices, the chapter focuses on the wave and tidal energy sectors.

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M. Hafner, G. Luciani (eds.), *The Palgrave Handbook of International Energy Economics*, https://doi.org/10.1007/978-3-030-86884-0_12

2 Resources, Technologies, Deployments

Tidal current energy capture devices and wave energy converters (WECs) can vary greatly in design, scale, stage of development, and technology readiness level. Given this range, the most useful common references for economic potential are tidal and wave energy resource characteristics and occurrence.

2.1 Tidal Current Devices

Tidal current is generally driven by the Earth's rotation, the relative positions of celestial bodies to the Earth, and local bathymetry (i.e., ocean depth and topography). Tidal currents are bi-directional but generally one-dimensional, as a given tide typically ebbs and flows along one vector. Tidal devices may be mounted to the ocean floor and elevated to the current or may be suspended from the surface. Ultimately, the amount of energy that can be harnessed is dictated by the velocity of the tidal current.

The simplest and most dominant form of a tidal current device is the horizontal axial-flow turbine, which roughly resembles a horizontal axis wind turbine and operates in a similar manner. A variety of other device types are being developed, including tidal kites, oscillating hydrofoils, ducted turbines and screw turbines (Roberts et al. 2016; U.S. Department of Energy 2015). All of these technologies differ from tidal barrages, which are configured to extract energy from changes in tidal elevation rather than the horizontal current of tides, and have been in commercial use for decades.

Due to the nature of the resource, tidal energy is considered variable but highly predictable in its variability, unlike other renewable resources (e.g., wind and solar), which require extensive short-term forecasting and energy reserves to compensate for weather conditions. Tidal patterns are generally sinusoidal but can show great variation in intensity and pattern within short distances. Less than 20 miles apart, the maximum velocity at Admiralty Inlet, Washington (Northwest USA) can be more than double the maximum velocity at Sequim Bay, Washington over the course of a day and display significantly different resource patterns over time as shown in Fig. 12.1.

2.2 Tidal Current Device Deployment

Although tidal devices have not been deployed at utility scale, there have been successful grid-connected deployments and prototype tests. The most developed tidal stream turbine installation to date, SIMEC Atlantis Energy's SeaGen device, was installed in Strangford Lough, Northern Ireland, United Kingdom and connected to the grid in 2008 (MacEnri et al. 2013). Over the course of its lifetime, the 1.2 MW system produced over 11.6 GWh of electricity, which ESB Independent Energy bought through a power purchase agreement before the device was fully decommissioned in 2019 (SIMEC Atlantis Energy 2019; Renewable Technology 2017).

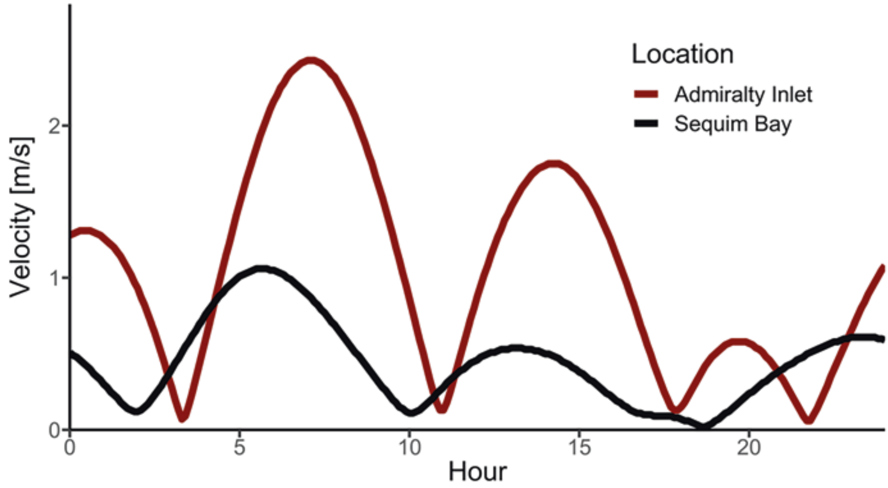

Fig. 12.1 Tidal current velocity [m/s] at Admiralty Inlet and Sequim Bay in Washington, USA. Data are from the Assessment of Energy Production Potential from Tidal Streams in the United States (Haas et al. 2011)

The European Marine Energy Centre (EMEC) has hosted and tested several prototypes in recent years, including Orbital Marine Power's SR2000 tidal turbine, which was launched at the facility in 2016. During its first 12 months of operation at EMEC, the 2 MW floating twin-turbine system produced over 3 GWh of electricity (Orbital Marine Power 2020). Pilot projects have also taken place in North America, with Sustainable Marine Energy testing its 280 kW PLAT-I tidal energy platform in Grand Passage, Nova Scotia in February of 2019. The project has successfully generated electricity with no noticeable negative marine wildlife impacts to date. It is however not connected to the grid (Sustainable Marine Energy 2019a).

In September 2019, Sustainable Marine Energy announced that it had been awarded a license by the Nova Scotia Department of Energy and Mines to sell power via a power purchase agreement to Nova Scotia Power. The company anticipates the development of 9 MW of tidal capacity in the Bay of Fundy in a joint venture with Minas Tidal LP (Sustainable Marine Energy 2019b). The Faroe Islands' electric utility, SEV, awarded a power purchase contract to Minesto in November 2018 to deploy two installations of its tidal kite devices. The European Commission's SME Instrument Programme in June 2019 issued a €2.5 million grant to Minesto and SEV to support the installation of the devices (Minesto). As of April 2020, all siting permits have been approved for the two tidal kites in Vestmannasund as part of the Deep Green Island Mode Project (Minesto 2020a).

2.3 Wave Energy Converters

Waves are a fundamentally fluctuating energy source. Ocean surface waves are created by the movement of wind over the ocean. Once produced, they can travel large distances. When they arrive at a location far from the area of production, they are called swells. While waves express high variation between their peak intensity and average intensity, they also display seasonal patterns. The behavior of ocean waves is classified by amplitude, phase, and directionality.

Unlike tidal energy devices, there is a variety of WEC designs (Falcão 2010; Drew et al. 2009). Point absorbers, oscillating wave surge devices, attenuators, and oscillating water columns are among the most common device classifications, with the first three technology types often consisting of one or more bodies that generate power from the wave-induced relative translation motion and/or rotational motion between the body and a reference frame (e.g., seabed). Oscillating water columns differ from these devices in that they instead consist of a column of air trapped on top of a column of water; the rise and fall of the water column due to incident waves pushes the air through a turbine, thus generating power. Most devices are wave-to-wire, generating power within an individual device, then aggregating within an array and sending power to shore via an export cable. Other hydraulic devices are designed for near-shore environments and they pump water to onshore power generation equipment.

2.4 Wave Energy Converter (WEC) Deployment

As with tidal current devices, WECs have not yet reached commercial development, yet a variety of WECs have been deployed and tested around the world, many of which have been connected to local grids. In 2011, the Spanish utility Ente Vasco de la Energía supported the deployment of a 300 kW oscillating water column system integrated with the breakwater of the harbor in Mutriku, Spain. The system was also the first multi-turbine WEC system tested in the world (International Energy Agency—Ocean Energy Systems 2016). In Australia, Carnegie Clean Energy has deployed several successful pilots. The Perth project off Garden Island included three fully submerged buoys that were connected to the grid and operated continuously for 12 months. The project incorporated a desalination plant to produce freshwater (Carnegie Clean Energy), and the Australian Department of Defence contracted for the electricity generation under a power purchase agreement (Sawyer 2017). North America has also seen grid-connected WEC deployments. The first grid-connected device in the United States was an 18 kW Azura technology deployed by Northwest Energy Innovations at the U.S. Navy's Wave Energy Test Site in Hawaii in 2015 (Whitlock 2015).

3 Cost Drivers

3.1 Technology Cost Drivers

Anticipated deployment costs for wave and tidal devices are relatively high to other existing generation technologies. As described above, deployments have consisted of small-scale projects or pilots intended to test technologies in the water, their electricity production, interaction with the marine environment and integration into power systems. Device development for projects is a custom process, introducing construction costs and delays without manufacturing standardization, supply chain alignment, or cross-over with maritime sector applications for economies of scale and availability.

The marine operating environment introduces specialized hazards, which accordingly introduces novel and unavoidable costs. Saltwater contains minerals that can corrode materials and coatings. Aquatic life will interact with the deployment, raising environmental concerns and triggering regulatory requirements. Wave energy devices are intentionally mobile with exposed mechanics and changing levels of submersion. Tidal and wave devices will require special protections with advanced coatings, corrosive resistant materials, or protective casings. Deployment in the ocean can be limited due to customized supply chain, specialized vessels and equipment, and limited operational windows. Technology developers must design devices to withstand strong and multi-directional forces. Research and development programs across the world have promoted strategic investments to drive down these costs (U.S. Department of Energy 2019b; International Energy Agency 2019b). Individual wave energy conversion devices must be built for a significantly higher power output capacity than their average power output to handle the natural fluctuation in wave intensity (Yu et al. 2018).

3.2 System Costs: Levelized Cost of Electricity

The levelized cost of electricity (LCOE) is the most common metric for comparing the cost-benefit of different energy generation technologies. For example, the often-cited Lazard estimates compare technologies on an LCOE basis (Lazard 2019). Compared to simple representations like installation cost per unit of rated power, LCOE offers a more holistic representation of an energy project by considering actual generation.

The LCOE metric creates a ratio between the present value of a project's lifetime costs and the amount of energy that the project will produce throughout the project's lifetime. LCOE is in units of currency per amount of energy, or in the United States, dollars per kilowatt hour. It is calculated as (Fig. 12.2):

The metric recognizes that project costs vary over time and that the siting of renewable energy projects dictates resource strength and energy available. The differences in energy production impact the denominator of the LCOE equation: the more energy the project can produce each year, the lower the cost of

$$LCOE = \frac{cost\ to\ generate\ (capital\ and\ O\&M\ over\ project\ lifetime)}{total\ amount\ of\ energy\ generated}.$$

Fig. 12.2 Simple formula for Levelized Cost of Energy

electricity becomes. LCOE has largely been the metric of choice when governments consider incentivizing new technologies and it is a primary screen for gauging which innovative technologies are nearing commercial viability and if they can be considered for out-year investment.

LCOE estimates for small and early developments of tidal current and wave energy projects are within the range of \$400/MWh to \$800/MWh for tidal (Jenne et al. 2015; IEA-OES 2015) and \$250/MWh to \$2000/MWh for wave (IEA-OES 2015). This can be compared to \$49/MWh for solar, \$57/MWh for wind and \$119/MWh for combined cycle natural gas power plants sited in California (Neff 2019).

The highly variable range of wave and tidal LCOE values is mirrored in the estimates used by the electric utility sector in planning documents. From a review of U.S. utility integrated resource plans (IRPs), with values escalated to 2019\$ U.S., tidal and wave sectors both have over 6-to-1 cost ratios from the lowest to the highest. The range for offshore wind is lower at 5-to-1. This range is still expressed with very few data points: tidal values only have 4 observations from which to generalize, while there are 8 observations for offshore wind and for wave energy. See Fig. 12.3.

Estimated LCOE for tidal and wave devices is higher by an order of magnitude relative to other generating resources. As tidal and wave devices are not yet commercially available, and as evidenced by the broad range in value, these cost estimates remain guesswork and are not considered reliable comparators or gages for future levelized costs. Both solar panels and wind turbines in the early stages of development had similarly high levelized costs. In 2010, the global weighted average LCOE of utility-scale solar photovoltaic (PV) was approximately \$370/MWh. Since that time, the levelized cost has dropped by 77% (IRENA).

Research has shown potential for wave energy devices to be co-located with offshore wind plants, as the generating resources can be complementary and co-location reduces the cost per energy generation for both resources (Reikard et al. 2015; Chozas et al. 2012). Similarly, energy storage is particularly well suited for pairing with tidal energy projects. Tidal energy's inherent predictability and periodicity lend itself well to coupling devices with a limited amount of storage. Hybridization with energy storage has the potential to change the competitiveness of a tidal project by decreasing the fluctuation in power output over time; however, introducing storage increases project costs and slightly reduces the net energy produced onsite due to round-trip efficiencies (Zhou et al. 2013; Ben Elghali et al. 2019).

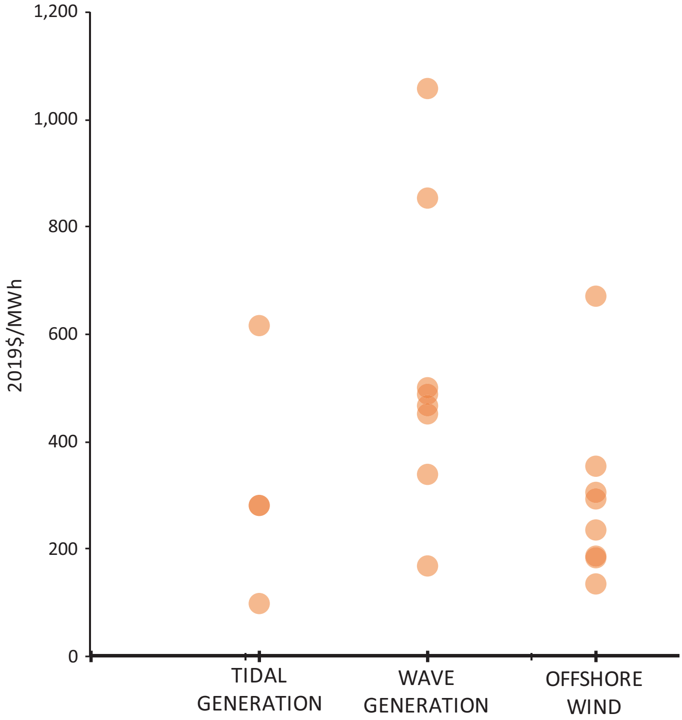

Fig. 12.3 LCOE (converted to $2019) for tidal generation, wave generation, and offshore wind as reported in U.S. utility integrated resource plans (IRPs). Points are partially transparent such that darker points represent more than one IRP reporting an LCOE of the indicated value. (Cooke et al. 2020)

While LCOE is widely used and covers a renewable energy project's economic lifetime, it represents an incomplete picture of the *value* of a particular energy project. LCOE fails to capture a range of other potential value streams that generators supply, most notably services critical to the operation of the grid (The University of Texas at Austin Energy Institute 2020; Ueckerdt et al. 2013). In the past, when the energy system was composed of entirely dispatchable resources—where output could be modulated to meet load and technology attributes varied little (i.e., large central scale power plants that operated for decades and required similar amounts of land and fuel supplies)—LCOE was an appropriate metric to directly compare across technologies. Today, there is an increased recognition of the range of technology attributes and differentiators, as well as contributions to grid reliability beyond simple energy that need to be measured and accounted for.

On a simple cost basis, an energy project in the ocean will always be challenged to appear competitive with a land-based energy project. The economic competitiveness of tidal and wave energy resources to future electric grid conditions is better evaluated, then, by these resources' unique values and attributes rather than its costs alone. In order to review potential future development markets and economic opportunities, the remainder of this chapter discusses unique or competitive value that tidal and wave energy devices can provide to global energy systems.

4 Economic Value: Relevant Markets and Applications

While operation in a marine environment has cost implications, in certain markets this attribute of wave and tidal resources may provide a competitive edge. Opportunities for development may exist in a wide variety of markets, particularly remote and island communities, military bases, and constrained grids and grids with high contributions from renewable energy sources. Further, maritime applications, may also provide market opportunities.

4.1 Remote and Island Communities

Tidal and wave development are more promising in locations where the cost of electricity is high and access to a consistent fuel supply (e.g. diesel fuel) is challenging. These are often remote and island communities with small grids.

Island and coastal communities are often at the forefront of climate impacts and have a strong driver to move to cleaner energy sources (Dornan and Shah 2016). Beyond providing clean energy, the development of renewable resources in remote communities can have benefits in job creation, economic development, and emissions reductions (Shirley and Kammen 2013). Tidal and wave resources can help avoid the impacts of fossil fuel use and address challenges associated with other renewable technology integration (i.e., solar or wind variability, intermittency and a lack of predictability). Research suggests that marine energy resources can avoid transmission investments to remote, coastal locations (Robertson 2010; Moazzen et al. 2016); that as a predictable resource, marine energy would require a fraction of associated integration costs and support the integration of other resources; and that to achieve high physical penetration levels of renewable energy, winter peaking resources with seasonal variation such as marine energy could be valuable. The use of marine energy in a portfolio increases resource diversity, reducing vulnerability to grid and fuel supply disruptions and exposure to fuel price volatility.

The following examples highlight the unique value associated with tidal and wave devices and illustrate broader potential market opportunities.

4.2 Faroe Islands (Resource Complementarity)

The utility in the Faroe Islands, SEV, has evaluated the use of tidal energy as part of its approach to achieve a 100% renewable energy generating portfolio. SEV finds that tidal energy can provide a consistent and predictable output, complementing other seasonally variable resources of wind, hydroelectric generation, and solar photovoltaic. These resources, in combination with pumped storage and batteries, SEV predicts, can enable it to successfully and reliably achieve a 100% clean generation portfolio. Doing so otherwise would require a significant overbuild of wind and solar resources (Katsaprakakis et al. 2019). The utility is presently working on the pilot project previously mentioned to showcase the use of tidal energy, and if successful, intends to expand this effort with larger tidal turbine units (Minesto 2020b).

4.3 Alaska (Fuel Supply and Resource Availability)

The U.S. state of Alaska has several remote communities. Many of these communities are not connected to a large electric grid and are self-sufficient for their energy, reliant mostly or entirely upon diesel generation for electricity (Beatty et al. 2010). There is significant interest in the use of renewables to provide reliable and fuel-independent electricity to these communities in order to lessen the high costs of using diesel generation that result from high fuel costs (due to transportation) and supply chain uncertainty. Shipped diesel fuel may be disrupted due to weather or other factors, creating a potential resilience benefit from the use of local, reliable, and available resources. The community of Igiugig in Alaska has deployed a river current device, similar to tidal energy, and the community of Yukatat is evaluating the potential for a wave energy converter to test the provision of electricity from these resources and reduce their use and dependence on fossil generation (Alaska Center for Energy and Power 2016; ORPC 2020).

4.4 Caribbean & Indian Ocean Islands (Land Use)

Another advantage of wave and tidal devices is their small terrestrial footprint, which is limited to an electric cable and auxiliary on-shore equipment for interconnection. Land is a scarce commodity on islands and subject to competing uses. With the expectation that renewable resources will need to be significantly increased to meet climate goals, there is increasing benefit to siting renewable energy resources offshore in areas where available land is scarce. In its 2017 Integrated Resource Plan for the Caribbean Utilities Company, Pace Global found an advantage in utilizing marine energy, specifically ocean thermal energy conversion (OTEC), as significantly less land was required for its development relative to other resources (Pace Global 2017). Similarly, the Seychelles Energy Commission approved a 25-year power purchase agreement for a 4 MW floating solar development in a lagoon off Mahé island, with the African Legal Support Facility citing that the plant provides clean energy generation while avoiding the challenge of land constraints on the island (Bellini 2020).

4.5 *Military Bases*

There are several remote military bases around the world: remote outposts within a nation's mainland borders that are not grid-connected, or remote outposts on islands or another nation's territory. Energy is a critical need for military operations and these bases must have reliable power at all times, especially during severe weather events and military conflicts, which is problematic when these bases are heavily reliant on imported diesel (Defense Science Board 2016). Similarly, there are numerous grid-connected bases that are reliant upon grid-delivered electricity that is susceptible to interruption in contingency events (Samaras et al. 2019). For example, in April 2011, a tornado left the U.S. Army's Redstone Arsenal base in Huntsville, Alabama without power for eight days, leading to a base closure and a reliance on diesel backup generators for critical activities. By the end of the outage, the generators had almost emptied their fuel reserves (Marqusee et al. 2017).

Recently militaries have explored the use of alternative resources, particularly renewable resources with energy storage, to reduce reliance on diesel, which not only avoids costs and emissions but also achieves their primary goal of ensuring continued operations if diesel supplies are no longer available (Samaras et al. 2019). Tidal and wave energy devices can act as a replacement to fossil generation as a result of their improved predictability and periodicity, supporting load when implemented in conjunction with intermittent renewable technologies and energy storage, in a microgrid, for example. Further, tidal and wave devices can provide resilience by offering an improved level of uninterrupted generation relative to solar or wind (Newman 2020). Figure 12.4 below highlights this value using the output of a microgrid dispatch model. The box and whisker plot indicates the percentage reduction in renewable energy capacity, battery capacity, diesel generator capacity, and diesel fuel consumption for a microgrid ensuring the delivery of energy during different electric grid outage lengths using the addition of a tidal energy resource instead of a solar PV resource across 100 simulations.

4.6 *Constrained Grids and Grids with High Renewable Energy Contributions*

Electric generation sources can be located at great distances from both large and remote coastal electric loads, which means that transmission infrastructure is needed to assure reliable electric delivery over these long distances. Transmission services can be capacity constrained along the coasts, making it difficult to add new electric loads to the system, inhibiting economic growth. Installing new transmission infrastructure is an expensive and spatially constrained proposition (ScottMadden 2020). Further, coastal transmission and distribution lines may be single points of failure, providing no redundancy for these communities if a line is suddenly unavailable (Hasan et al. 2013).We see examples of this in coastal cities of North Carolina, USA, where extreme

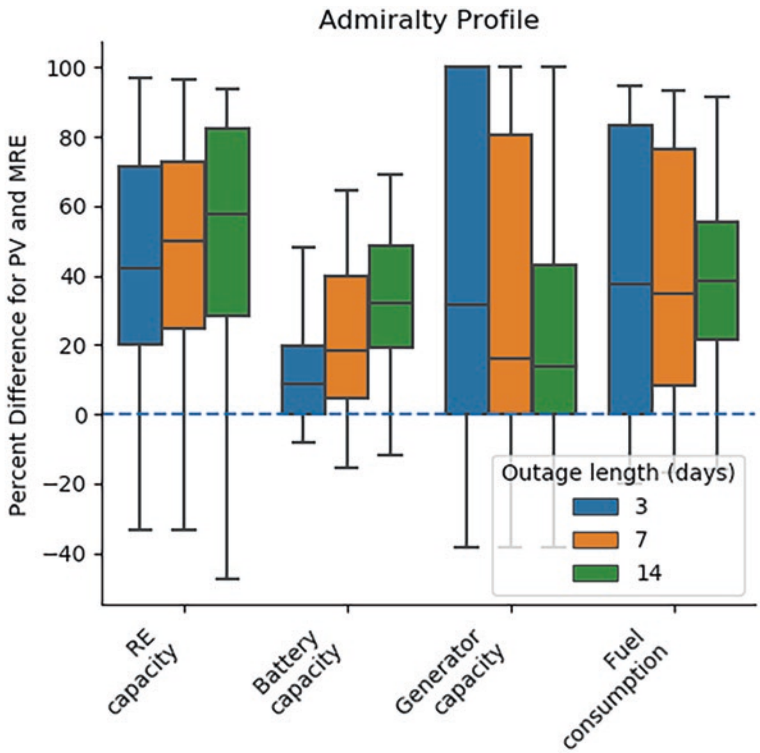

Fig. 12.4 Percent reduction in the required RE capacity, battery capacity, generator capacity, and fuel use resulting from adding additional MRE instead of PV capacity to meet 100% uptime during different outage lengths, across 100 simulations for a hypothetical load served by a microgrid with a diesel generator, battery, solar PV and tidal energy. (Newman 2020)

weather events, like hurricanes, and unforeseeable contingencies result in widespread power outages in major tourist locations (Bohatch 2017; Dalesio 2014).

Siting tidal and wave energy devices in such constrained areas could provide both clean renewable energy and unique benefits to the system, such as a deferral or reduction of investments in the distribution and transmission system, provision of ancillary services (e.g., frequency and voltage support), and local power quality benefits. Another benefit could be supporting economic development in otherwise energy constrained areas (Oregon Department of Energy 2012). Finally, the infrastructure build-out required to meet renewable energy goals, especially when policy includes a resource proximity requirement, such as direct interconnection to a state or particular utility's electric system, may have unacceptable demands on available land, creating another opportunity for tidal and wave resources (ScottMadden 2020).

Wave and tidal device output will be more predictable than their solar or wind renewable counterparts. This advantage enables tidal and wave resources to provide benefits to the grid in several other ways, including accommodating optimal amounts of complementary resources, distribution and transmission system management, and reduced costs in holding fewer operating reserves. Wave and tidal energy have electricity generation profiles that complement wind and solar resource availability over annual, seasonal, and daily periods. These resources fill critical resource timing gaps in grids with increasingly high levels of renewable energy generation. A wider portfolio of diverse contributing renewable energy brings geographic diversity, supports resource adequacy, and reduces reliability risks.

4.7 Scotland (Energy Storage Integration)

In 2018, Nova Innovation integrated a Tesla battery storage system with the Shetland Tidal Array in Scotland and expanded the generating capacity at the site (Renewable Energy Magazine 2018). The system allows for storage of excess tidal energy during energy production peaks and then discharges stored tidal energy during low to no device output periods. The facility is claimed as the world's first "baseload" tidal power facility (Nova Innovation 2019) due to its relatively flat net production.

By coupling with storage, tidal or wave facilities could achieve better controllability and offer a scaled version of dispatchable generation. Researchers have explored the coupling of non-battery storage solutions with marine energy. Though of relatively small scale, an electrolyzer, which splits water using electricity to generate hydrogen gas (H_2), with a generation capacity of 220 kg of H_2/day was developed using tidal current device prototypes for its electric input (ITM Power 2017). The resulting hydrogen from this system could be used to generate electricity when demand increases, potentially for much longer timeframes than the typical four-hour limitations that standard commercial battery technologies currently allow. Such a system could also be used to supply fuel cell-based vehicles and additional transportation systems (U.S. Department of Energy 2019a). These developments suggest that coupling marine energy devices with various types of energy storage can enable new value streams.

4.8 Australia (Renewables Integration)

As Australia deploys more renewable resources on its electric system, the country has recognized a need for supporting technologies and resource diversity to help integrate this renewable energy. Wave and tidal energy use could reduce system capacity and balancing requirements by reducing the overall variability of the energy generation profile. The diversity could also provide a natural resiliency effect: the more geographic diversity of the overall generation profile, the less likely it is to be interrupted by contingency events. As renewable resources reach higher levels of deployment, seasonal and daily ramps of generation will cause significant reliability management challenges. In contrast, wave energy will maintain consistent production over seasonal periods and could fill the production gaps to provide reliable electric service. Australia's Commonwealth Scientific and Industrial Research Organization has evaluated Australia's wave energy potential and finds that the southern coastline of the country has a wave resource that could contribute up to 11% of Australia's total energy needs (CSIRO 2020).

4.9 Powering the Blue Economy

One strategy to advance commercialization of wave and tidal energy technologies in the near-term is to develop these technologies for electric demands within existing and emerging maritime sectors, called the "blue economy." Meeting the electricity needs of maritime sectors requires targeted technology development at small scales with specialized characteristics to fit the demands of the maritime environment. These markets include ocean observation, desalination, seawater mining, and aquaculture (LiVecchi et al. 2019). While this approach may advance commercialization of marine energy technologies, the largest economic opportunity still remains in serving traditional electric grids under the circumstances described above.

5 Conclusion

Considering the magnitude of tidal and wave resources and the policy drive toward a cleaner, decarbonized electricity system, it is reasonable to anticipate that tidal and wave energy will be able to commercialize and deploy around the world. This may be especially true in environments where there are limited clean energy resource options, the marine nature of these deployments provides additional value, or grid conditions require the unique attributes of tidal and wave energy resources.

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CHAPTER 13

The Economics of Energy Networks

Andrea Bonzanni

1 Wires and Pipes: Electricity and Gas as Network-based Energy Sources

In spite of their many differences and specificities, electricity and gas are two energy carriers unequivocally associated with the existence of large and complex transportation networks to move energy from production to consumption points. While long-distance transportation is common for other energy sources (see, for instance, the global seaborne coal trade) and networks to connect producers to consumers are not unusual (see, for instance, the extensive pipeline systems for crude oil and refined products), only electricity and gas display networks as a fundamental feature, without which they would be rendered almost worthless and unable to play a role in modern energy systems. Electricity and gas are network energies par excellence. For this reason, in this chapter we will simply refer to 'energy networks' to indicate the infrastructure to transport electricity and gas.

This chapter will provide an overview of the economics of transporting electricity and gas through networks. In Sect. 2, we will describe what energy networks are, with a focus on their physical and economic properties. In Sect. 3, we will discuss the monopolistic nature of energy networks and the implications for electricity and gas systems. In Sects. 4, 5 and 6, we will review how energy networks are treated in competitive energy markets, how access to networks functions and what arrangements are established to ensure efficient economic outcomes and equal treatment of all market participants. In Sect. 7, we will explain how access to energy networks is charged and how network users exchange energy within a network.

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2 Physical and Economic Properties of Energy Networks

The movement of electricity and gas through networks are very different phenomena from a physical perspective.

Electricity networks are made up of *electrical conductors* (most commonly aluminium wires wrapped around a steel core) through which electrons flow as a result of a difference in electric potential between two points (called *voltage*), creating an electric current. Modern networks are based on *alternating current (AC)* with variable voltage oscillating with a frequency of 50 or 60 cycles per second (Hertz). *Direct current (DC)* elements are sometimes used to flow electricity between separate AC networks. Rectifiers are used to covert AC into DC and inverters are used to covert DC into AC. The amount of electricity a set of wires (referred to as a *line*) can transport over a given distance is a function of its thermal capacity (measured in Watts) and peak voltage (measured in Volts). Lines are usually placed above ground on steel towers, wood H-frames, wood or concrete single poles of differing structures and heights depending on their voltage and external environmental conditions. Lines can be buried underground and even submerged in water in areas where overhead lines are technically unfeasible or unacceptable for environmental reasons. The complex physics of electricity requires electricity networks to be equipped with numerous instruments and devices that control and regulate the system. *Switching stations* and sub-stations housing *transformers* are disseminated through the networks to ensure that the voltage of the current flowing through the lines is always appropriate. *Circuit breakers* are necessary so that flows can be rapidly disconnected from networks to avoid disruptions and equipment damage.

Gas networks consist of pipelines (usually buried underground), valves, compressor and metering stations. *Pipelines* can be made of carbon steel, high strength plastic or composite material depending on their diameter and the pressure level at which they are operated. *Compressor stations* (fired by turbines, electric motors or engines) pressurise the gas to reduce its volume and propel it through the pipelines by creating a pressure differential so that gas will flow from the high- to the low-pressure points in the network. They are installed at regular intervals of 50 to 160 km to ensure the right level of pressure and a constant flow rate are maintained. The speed at which gas moves within the network ranges from 15 to 32 km per hour. *Valves* work like gateways, blocking the flow of gas and directing it where required. *Metering stations* are used to monitor, manage and account for the gas flowing through the pipelines. They are often associated with other control components such as filters and odorisation equipment.

A vital element of both electricity and gas networks is the *control room*, or control centre. It is a physical central location where staffs operating 24 hours a day and 365 days a year monitor the functioning of networks and makes the necessary decisions to ensure its stability and safety. Advancements in data technologies have led to an increased importance of the control room in energy networks as information availability and quality have improved and more elements and processes can be managed remotely.

In spite of these key fundamental differences, electricity and gas networks are structured and classified in a similar manner. We conventionally divide energy networks into transmission and distribution networks. *Transmission* refers to the movement of electricity and gas over long distances, through high-voltage lines in electricity and large diameter high-pressure pipelines in gas. *Distribution* refers to the networks connecting transmission systems to end users through low-voltage lines and low-pressure pipelines. There is no conventional dividing line between transmission and distribution. In electricity, most distribution networks operate below 50 kV, but some are operated at up to 132 kV and some transmission lines are operated as low as 66 kV. Likewise, in gas, parts of transmission and distribution networks operate at similar pressure levels around 200 psi, but some transmission pipelines operate at above 1000 psi and pipelines connected to end users operate at below 10 psi. The connection points between transmission and distribution networks, however, are well identified and are usually called *city gates*. In both electricity and gas, some large consumers (such as industrial sites and gas-fired power stations) are able to connect directly to the transmission network, bypassing the distribution stage.

Energy networks have been planned to accommodate flows from a few dozens of large injection points (thermal or nuclear power plants, import pipelines, gathering pipelines connecting gas production fields) to a few dozens of large withdrawal points (distribution networks, large consumption sites) and most transmission lines and pipelines have operated on a one-way basis. However, the evolution of energy systems has increased the need to have energy networks that can accommodate *bi-directional* flows. In electricity, especially, the rapidly growing output from distributed renewable energy sources (DERs) connected to distribution grids is increasing the instances in which electricity flows from low-voltage to high-voltage lines. In gas, energy security and diversification objectives have prompted investment to enable some networks to operate more flexibly.

Networks are a complex and costly undertakings. Several estimates of the cost of gas pipelines and electric lines per kilometre or per unit of energy transported have been made but they are reliant on a huge number of assumptions that render these calculations of little general use. It is, however, possible to identify some key features about the cost of energy networks:

- Construction costs are highly variable and dependent on external factors, such as the cost of land, environmental conditions and constraints, the complexity of the permitting process;
- Fixed costs are much higher than variable costs, so the total cost of a network is largely independent of the amount of energy that flows through it;

- Capital costs are much higher than operations and maintenance (O & M) costs, so the largest share of costs is incurred during the planning and development stage of a network, rather than during its operation;
- The costs of ensuring orderly flows through the networks are heavily dependent on the rules governing the behaviour of network users but, as a general principle, are much greater for electricity than for gas.

3 Natural Monopoly and Vertical Integration

A remarkable consequence of the economic properties described above is the ability to generate a rare consensus within the economics profession—energy networks are unanimously considered natural monopolies. The concept of *natural monopoly* has been discussed in economics since the nineteenth century and is formally defined as a particular activity in which a firm can serve the market at a lower cost than any combination of two or more firms.[1] In essence, the economies of scale of energy networks are so large that, whatever the level of output, the long-run average cost of transporting electricity and gas is continuously decreasing (and is always above the long-run marginal cost). This creates a decisive prime mover advantage and an insurmountable barrier to entry for latecomers. Any attempts to introduce competition in natural monopolies would result in a wasteful duplication of assets and the failure of the new entrant, unless it is continuously subsidised. Competition in energy networks is therefore neither sustainable nor desirable (Fig. 13.1).

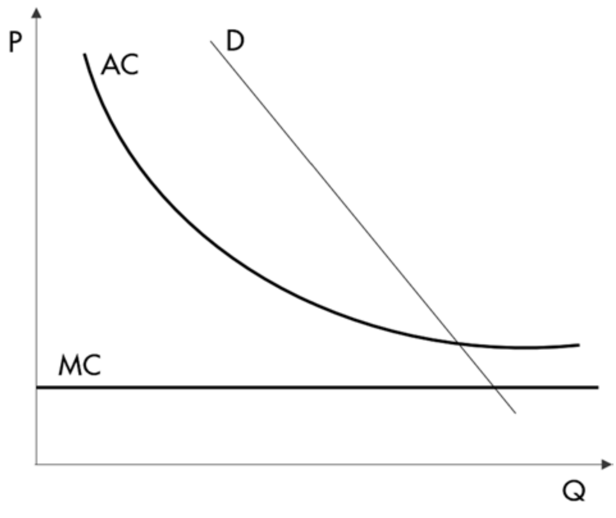

Fig. 13.1 Natural monopoly. (Source: Author's elaboration)

[1] OECD (2003).

Some exceptions to this general principle are represented by relatively simple DC lines and long-haul pipelines in which multiple competing providers can serve the market profitably if demand is sufficiently high. These are commonly called *merchant transmission investment*. Successful examples are very rare in practice.[2] Many of the merchant transmission lines in Australia in the early 2000s and the IUK and BBL pipelines connecting the UK with mainland Europe have subsequently applied for regulated status following changes in market conditions and the expiration of the long-term contracts that initially triggered the investment.

The ownership of energy networks, if unchecked, provides exorbitant *market power* and gives rise to opportunities to foreclose markets to competitors and discriminate between firms engaging in activities for which network usage is necessary, such as gas production, electricity generation, gas and electricity supply. While economic theory has shown that long-term contracts can be used to govern the unequal relationship between network owners and network users,[3] in practice, this enormous advantage has discouraged investment and market entry, resulting in the establishment of monopolistic market structures beyond transmission and distribution. Since the early days of energy networks, *vertical integration* along supply chains emerged as the dominant industry structure and the provision of electricity and gas rapidly became the prerogative of vertically integrated local or national monopolies (Fig. 13.2).

When acting purely on the basis of profit-maximising considerations, monopolists inevitably take advantage of their market power and hike prices to

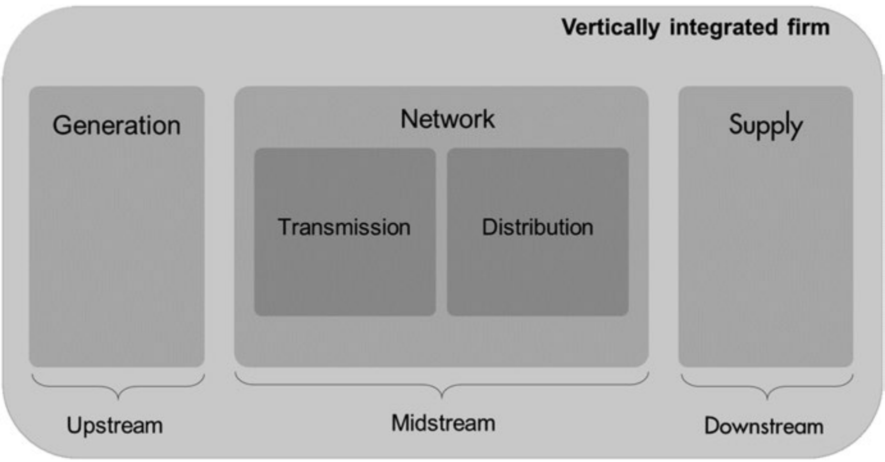

Fig. 13.2 Vertical integration in network energies. (Source: Author's elaboration)

[2] For a theoretical discussion of the merchant model and its practical shortcomings, see Joskow and Tirole (2005).

[3] Joskow (1984).

a level significantly above marginal cost. The impact of such a decision is particularly severe in the energy sector given the very low price elasticity of energy demand and the large spill-overs energy costs have on other economic sectors and society at large. Hence, public intervention is warranted and it can take the form of changes in ownership or regulation. While conceptually very different, the impact of the two models is very similar. In both cases, public authorities ensure that the monopolist no longer acts as a profit maximiser but sets its prices and makes key decisions taking broader welfare impacts into account.

Public ownership is the simplest and crudest measure that can be taken to avoid abuse of market power by a monopolist. It has been the preferred options for governments across the world for much of the twentieth century. Public ownership of energy assets, including but not limited to energy networks, has long been the norm, either as the result of acts of nationalisation (such as in France in 1946 or in the United Kingdom between 1947 and 1949) or due to the direct involvement of central or local governments in the establishment of these industries (as in the cases of Eni in the Italian gas sector or the *stadtwerke*, or municipal utilities, in Germany). A variant of public ownership is co-operative ownership, whereby network owners are fully or partially private actors but their interest is not profit maximisation from the natural monopoly activity. Cooperatives (such as agricultural or industrial consortia) were very common in the early days of the energy industry and are experiencing a revival with the proliferation of DERs and microgrids.

Regulation is an alternative model in which assets continue being owned by private firms but their pricing policies, revenue requirements, terms of service as well as any other key decisions around operations and investment are defined by public authorities through legislation and regulatory acts. A firm subject to this regime is called a *regulated entity*. In order to guarantee their technical competence and neutrality, the competence for rulemaking is usually allocated to a technocratic *regulatory authority* that is formally independent from government departments. This is the case, for example, of investor-owned utilities in the United States or the UK National Grid after its privatisation in 1990, whose activities are tightly monitored and regulated by the competent state public utilities commissions and the Office for the Gas and Electricity Markets (Ofgem) respectively. Most countries in the world have adopted this model in recent decades after a process of privatisation of state-owned assets, but there are cases of early adoption. The United States, for instance, regulated private inter-state transmission companies with the Federal Power Act of 1935 and the Natural Gas Act of 1938.

The choice between public ownership or regulation of private assets have often been determined by ideology, with nationalisations commonly implemented as part of a programme of sweeping economic reforms by left-leaning or socialist governments and more conservative administrations favouring regulation without impinging on existing property rights. The level of capability within public agencies also plays a role. Governments with limited know-how tend to favour public ownership due to its simplicity—once the nationalisation process is completed, they will have full control over decision-making processes in the industry. On the other hand, regulation of private assets requires constant monitoring and a deep understanding of industry functioning to ensure rules are always fit for purpose and keep pace with change.[4] For these two reasons, the pendulum has decidedly swung from public ownership to regulation from the late 1980s to the 2000s as free-market doctrines imposed themselves as the mainstream ideology in economic policy and governments had built up more sophisticated expertise. Even in countries where government ownership was retained, vertically integrated firms were incorporated as limited companies and independent regulatory authorities were created to regulate and oversee them. More recently, with state intervention experiencing newfound intellectual popularity and decarbonisation policy objectives posing unprecedented challenges to energy systems, calls for public ownership have resurfaced.

4 The Unbundling of Energy Networks

Perceived shortcomings of vertically integrated firms, either government-owned or regulated, led to attempts by policymakers to introduce competition in the electricity and gas sectors. This process has conventionally been termed *liberalisation*, restructuring, reform or, with a misnomer, deregulation. A prerequisite for effective competition is the separation of the natural monopoly element from the other segments of the value chain where competition can exist. Such a vertical de-integration is termed *unbundling* and it consists of the creation of separate network companies that cannot engage in other activities along the electricity and gas value chain. These network companies continue to be regulated entities, whereas firms active in other segment of the value chain are left free to operate as profit-maximising entities. The rationale for unbundling is to avoid conflicts of interest and ensure that both operational and long-term strategic decisions regarding networks are taken in an independent and transparent manner treating all firms active in the sector in a non-discriminatory fashion. With no dominant player benefitting from the enormous advantage provided by the control over networks, firms could compete on an equal footing and, the theory goes, invest and provide consumers with better services and cheaper prices.

After unbundling, ownership and operation of networks usually coincide, even though there are cases in which the two functions are performed by separate entities. Unbundled firms are conventionally called *Transmission System Operators (TSOs)* or *Distribution System Operators (DSOs)* in Europe. The use of the term Distribution Network Operators (DNOs) is also common,

[4] The extensive academic literature and anecdotal evidence on regulatory capture, a process whereby regulatory authorities become unable to perform their tasks due to a disproportion in financial and cognitive means between them and the industries they should regulate, are indicative of how difficult it is to deliver effective regulation, even in the most advanced economies.

especially in the United Kingdom. In the United States, gas TSOs are simply called pipeline companies, whereas in electricity we distinguish between Independent System Operators (ISOs), which are company that operate networks they do not own, and Regional Transmission Organizations (RTOs), which are multi-state network operators. In this chapter, we will use the generic term 'network operator' to indicate the companies operating an energy network, regardless of ownership arrangements.

Conceptually, four types of unbundling can be distinguished (Table 13.1):

- *Ownership unbundling*. The network is transferred to a newly created company, which becomes the owner and operator of the network. This is the purest form of unbundling. The new company retains no links to the previously vertically integrated undertaking it belonged to and it is forbidden from engaging activities other than the transmission and distribution of energy. This is the case of the United Kingdom, where National Grid plc. has been created as an independent TSO for electricity and gas.
- *Legal (or functional) unbundling*. Network ownership and operation is transferred to a separate subsidiary of the vertically integrated undertaking. If implemented correctly, it should guarantee operational and managerial independence, but it is seen as a shallower form of unbundling. This is the model adopted in France, where the electricity and gas networks have been transferred to RTE and GRTgaz respectively, but the sole shareholders of these companies remain the former vertically integrated monopolists EDF and Engie (formerly GDF).
- *Operational unbundling*. Network ownership and operation are separated, with the former usually remaining with the former vertically integrated undertaking and the latter performed by an independent entity, which is usually called Independent System Operator (ISO). This is another shallow form of unbundling. It is common in electricity markets, especially in North America where nine ISOs and RTOs operate large parts of the electricity networks in the United States and Canada. It is very rare in gas, even though there are no fundamental reasons that make this form of unbundling unsuitable for the gas industry.
- *Accounting unbundling*. Network ownership and operation remain within a vertically integrated firm but separate financial statements are

Table 13.1 Unbundling models

	Network owner	*Network operator*	*Legal separation*
Ownership	Separate company	Separate company	Full
Legal	Separate subsidiary	Separate subsidiary	Shallow
Operational	Vertically integrated firm	Separate company or separate subsidiary	Shallow
Accounting	Vertically integrated firm	Vertically integrated firm	None

Source: Author's elaboration

produced for the activities of transmission and distribution. This is a very mild form of unbundling, which does not deliver independent decision-making but at least provides regulators with sufficient information to monitor the behaviour of vertically integrated firms and intervene if deemed necessary. It is the model adopted for distribution networks in several European countries.

Attempts to liberalise energy markets and unbundle networks have often, but not always, coincided with the *privatisation* of energy assets. The two processes, however, are conceptually distinct and do not need to go hand in hand. A case in point is Poland, which fully unbundled its electricity and gas TSOs PSE and OGP Gaz-System and from PSE and PGNiG respectively, even though all four companies remain under state control.

The first country to pioneer unbundling was Chile in 1981,[5] followed by the United Kingdom between 1986 (for gas) and 1989 (for electricity). Unbundling has subsequently been the cornerstone of the liberalisation of European energy markets promoted by the European Commission in the 1990s and 2000s. International financial institutions routinely include unbundling in their set of recommendations and make support conditional to its implementation. The separation of Ukrtransgaz from Naftogaz completed on 1 January 2020 in the Ukraine following pressure from the IMF, the European Bank for Reconstruction and Development (EBRD) and the European Commission is the most recent example. Some form of unbundling has now been implemented in most of Europe and Latin America but vertical integration still dominates in Africa, much of Asia as well as, somewhat surprisingly, North America.

Numerous studies have attempted to demonstrate the effectiveness of unbundling using econometric techniques, but evidence has been inconclusive, and often contradictory.[6] In most of these studies, end user prices are used as the metric of success for unbundling with a very simple logic—if prices in the period following unbundling are lower than in the period preceding it, unbundling is considered successful; if prices are higher, it is a failure. In reality, too many intervening variables are at play, reducing the explanatory power of these analyses. First, low end user prices cannot be reliably used as a proxy for functioning markets as too many factors contribute to their formation. Electricity and gas prices are highly dependent on global commodity cycles, which in turn depend on industry specific and macroeconomic trends. Moreover, the period following unbundling have coincided, at least in Europe, with early attempts to decarbonise energy systems, which resulted in direct support for renewable energy sources and higher system costs, most of which have been passed on to end users. Second, unbundling in isolation cannot be used to define the success of market liberalisation. Even after the separation of networks from the rest of the value chain, one or a handful of dominant firms can still have tools to

[5] Pollitt (2004).

[6] For an overview of empirical studies, see Growitsch and Stonzik (2011, pp. 6–7).

exercise market power, collude and restrict market entry. If this happens, additional policy measures are necessary, either through horizontal de-integration (breaking up large generation and supply companies) or direct support and facilitations for new entrants.

When these elements are taken into consideration, the debate over the effectiveness and benefits of unbundling blends into the broader debate about the effectiveness of liberalisation and competition in network energies.[7] The separation of networks from the rest of the value chain is a necessary element for the creation of functioning competitive energy markets, but it is not sufficient alone. On the other hand, it is difficult to envisage competitive energy markets without some form of network unbundling.

5 Third-party Access to Unbundled Networks

As a result of unbundling, gas producers, electricity generators and suppliers have to become customers of transmission and distribution networks, or network users, to continue operating their businesses. Access to unbundled energy networks and all interactions between the networks and their users are governed by a set of detailed rules that ensures that all network users are treated equally. These rules, usually called *network codes*, are reviewed and approved (if not drafted) by regulatory authorities. This is the principle of *regulated third-party access (rTPA)*.

A key element covered by rTPA is *network connection*. Gas producers, electricity generators and consumers (either directly for large users or through a supplier for households and small businesses) must be connected to networks to partake in energy systems. The connection process is managed by the network operator, which performs all the necessary actions to physically connect the new network point in exchange for a fee, which is usually cost reflective. The network connection cost would depend on elements such as the capacity of the requested connection, its distance from the existing network and the cost of any upgrade to the rest of the network that it may trigger. rTPA rules ensure that this process is well-defined and prevents the network operator from discriminating between network users. Network connection is a much more complex process in electricity than in gas given that the additional injections or withdrawals at the newly connected point are deemed to have a greater impact on the rest of the network. Under rTPA systems, network operators have usually been under an obligation to grant a connection to all network users who request it. However, some electricity systems are increasingly under pressure due to an excess of connection requests for DERs which the network operator

[7] While the benefits of competition are widely discussed, a fair assessment should recognise some of unquestionable advantages that a vertically integrated monopolistic market structure provides, such as better coordination of operational and investment decisions (which in turn can improve system reliability and security of supply), limited allocation of capital to marketing activities, lower financing costs due to capital availability and better creditworthiness of vertically integrated undertakings.

struggles to manage, so alternative models are being evaluated. In Spain, for instance, a proposal to set a maximum threshold to connections of new generators and allocate them to the highest bidders through an auction mechanism is under discussion.

Another key element governed by rTPA is the ability to dispatch energy to various points within the network. This is done through the reservation of the right to transport a defined amount of energy through a pipeline or a transmission line over a specified period of time. Reserved network capacity is called a *transmission right* in electricity, whereas in gas the phrase *capacity booking* is preferred. The two concepts, however, are not fundamentally different. rTPA rules ensure that all prequalified parties can reserve network capacity and become network users.

Network capacity is allocated in the form of standardised products allowing to transport a fixed amount of energy over a period of a year, a month, a day or an hour. Half-yearly and quarterly products are also allocated by some electricity networks. Multi-annual capacity bookings (up to 15 or 20 years ahead) were once common, especially in gas, but their use is now increasingly rare.

Network users book in advance the amount of capacity they need based on their estimated peak demand over the relevant period. If their capacity needs are predictable, they can try to profile their bookings through a combination of products of different durations (Fig. 13.3).

The process through which network users can obtain transmission rights or capacity bookings is termed *capacity allocation*. It can take several forms:

- *First-come-first-served (FCFS)*. Capacity is allocated to the first user who formally requests it (and pays the corresponding fee). This is the simplest and most rudimentary form of allocation. It has gradually been abandoned as rTPA systems have become more sophisticated. However, it is

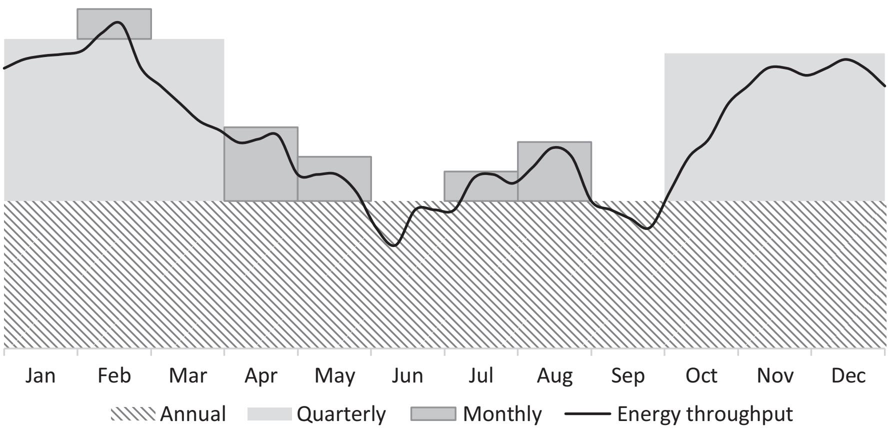

Fig. 13.3 Illustrative profiled capacity booking. (Source: Author's elaboration)

sometimes still used. For instance, within-day transmission capacity in most European electricity markets is still allocated on a FCFS basis.

- *Pro-rata*. It is a process in which the network operator collects binding requests from all interested parties. If the total amount of requests does not exceed available capacity, all requests are fulfilled. If they exceed available capacity, all requests are rebased so that each network user receives an amount of capacity equal to its request reduced by a fixed percentage. Such a mechanism is seen as fairer than FCFS as it does not grant excessive first mover advantages. However, it is prone to gaming and may lead to inefficient outcomes.
- *Auctioning*. Capacity is allocated to the highest bidder after an auction is held. Auctions can take various forms. Auctioning is the standard mechanism to allocate capacity in European electricity and gas markets following the implementation of the EU network codes on Capacity Allocation Mechanism (CAM) and Harmonised Allocation Rules (HAR).
- *Open seasons*. This method is used to allocate capacity that does not yet exist. Network users bid for prospective capacity, which is then realised if sufficient bookings are guaranteed to underpin the necessary investment. Open seasons are by nature used to allocate long-term capacity (from a minimum of 5 years to 20 years or more) and are iterative processes, normally including an initial non-binding phase and a binding phase in which users commit to book (and pay for) the new capacity.

Capacity allocation can be either explicit or implicit. *Explicit allocation* is the most intuitive process, whereby the network operator first allocates the capacity, then requests the holder of the capacity booking to communicate the amount of energy it intends to flow through that capacity. Such a communication is called *nomination*, or scheduling. Explicit allocation is used almost universally in gas markets and is common in electricity markets for timeframes of one month or longer. On the other hand, when an *implicit allocation* mechanism is in place, network capacity is assigned automatically to the network users flowing energy between two network points. It is very rare in gas markets, while it is used to allocate capacity for timeframes of a day or shorter in most competitive electricity markets in Europe and North America. Day-ahead cross-network capacity within the EU is allocated through an implicit auction mechanism called flow-based *market coupling* whereby an algorithm determines the most efficient flows through the European networks given available capacity within the networks. Implicit auctioning is considered a more efficient allocation method as it ensures that capacity is allocated to the highest bidder and all allocated capacity is actually utilised by the network user.

An important feature of network capacity is their *firmness*. Firm capacity gives the user that books it a firm right to flow energy through it. However, this cannot be guaranteed in practice as flows of energy through the network are not always reliably predicted and *network congestion* may occur. In these situations, network operators can prevent holders of capacity from using it and block any scheduled flow of energy. Such an action by the network operator is called *curtailment*. The problem is obviously more acute in electricity given the greater complexity of managing flows for this energy carrier, but it is not uncommon in gas, especially in case of exceptional events such as unplanned maintenance or unseasonal cold snaps. Holders of firm capacity that is curtailed are entitled to receive compensation from the network operator. Rules around curtailments and compensations are amongst the most controversial aspects of rTPA regimes. A common practice in gas networks is to allocate *interruptible capacity*. Holders of this type of capacity do not have a firm right, so network operators can curtail their flows without compensation. Such capacity products are very rare in electricity.

Another important distinction between types of capacity products is the one between physical and financial transmission rights. *Physical transmission rights (PTRs)* give their holder the right to physically dispatch energy between two locations. On the other hand, *financial transmission rights (FTR)* are financial options that replicate the economic outcome of holding actual network capacity. In practice, a holder of an FTR between two locations will sell energy in one location, buy energy in the other location and receive the difference (spread) between the two market prices, if positive, from the network operator that allocated the FTR. While PTRs cannot guarantee full firmness for the reasons described in the previous paragraph, FTR are financially firm, meaning that the network operator is obliged to correspond the price spread under all circumstances, irrespective of whether the flow of energy was physically possible. The allocation of FTR is therefore very complex for network operators and requires a deep understanding of network flows and high computational abilities to allocate the right amount of FTRs at the right price. All capacity bookings in gas are PTRs. FTRs are common in electricity markets in North America and are gradually being introduced in Europe.

Allocation of network capacity in derogation to the principle of rTPA is exceptional but commonly foreseen for new infrastructure projects that would otherwise not be realised. The rationale behind *TPA-exempted* capacity allocation is that network users would not commit to the level of capacity bookings necessary to make the project viable unless they are granted the privilege of exclusive access to the new infrastructure. TPA exemptions are usually approved by regulatory authorities with strict conditions attached and for a limited period of time (Fig. 13.4).

6 Revenue Regulation in Energy Networks

As regulated monopolies, energy networks are subject to stringent *revenue regulation*. The basic principle of revenue regulation is that the remuneration that can be accrued by a network operator (usually called *allowed revenue*) is constrained by rules and parameters set by the regulatory authority. In order to provide stability to both network operators and network users, allowed revenues are set and held stable for a period of several years (usually five), which is

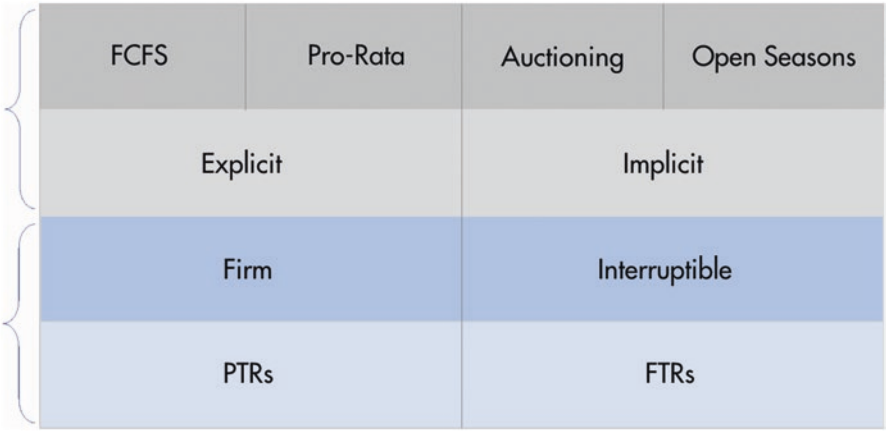

Fig. 13.4 Features of capacity allocation by network operator. (Source: Author's elaboration)

called *regulatory period*. Significant changes can only take place between different regulatory periods. Revenue regulation is arguably the most crucial and complex task energy regulatory authorities have to perform in a liberalised market.

No two revenue regulation regimes are alike, but the methodologies used by regulatory authorities can be classified into two broad families: rate-of-return (also called cost-of-service) regulation and incentive regulation, in which we distinguish between price-cap regulation and revenue-cap regulation. In a *rate-of-return regulation* regime, the regulatory authority sets a target rate of return the network operator is entitled to receive on the capital invested. The revenue of the network R will be equal to:

$$R = (\mathrm{RAB} \times r) + E + d + T$$

where:

- RAB is the regulatory asset base, or the total amount of capital and assets the network operator employs to perform its activities;
- r is the permitted rate of return set by the regulatory authority;
- E is the operating expenses incurred by the network operator to perform its activities;
- d is the expenses incurred to account for the depreciation of capital assets; and
- T is the tax paid by the network operator.

The crucial variable in the formula above is r, which must be set at a level that is sufficient to attract the necessary level of investment. In accounting terms, it is said that r must be above the network's weighted average cost of capital (WACC), that is the firm's cost of servicing its debt and making its equity investable.[8] Rate-of-return regulation is effectively a form of *cost-plus pricing*, as the network operator is guaranteed a fixed margin (in this case a fixed percentage of the RAB), irrespective of the level of its costs. Whilst this system guarantees stable long-term returns to investors, which in turn tends to lower financing costs, it provides the network operator with no incentive to reduce its operating expenses. Moreover, given that the remuneration is directly proportional to the level of the RAB, it incentivises networks to over-invest in capital assets, a phenomenon that is pejoratively referred to as gold-plating. In spite of these shortcomings, rate-of-return regulation has been the standard methodology to regulate monopolies in the energy sector for most of the twentieth century and its use to regulate energy networks is still widespread, especially in the United States.

Price-cap regulation was developed in the United Kingdom in the 1980s in response to the above-mentioned inefficiencies of rate-of-return regulation. Its origin is conventionally traced back to a 1983 report for the UK Department of Industry on the recently privatised telecommunication industry.[9] As the name suggests, this methodology is aimed at directly capping the prices the network operator can charge, by limiting the increase Δ P by the following formula:

$$\Delta P = \mathrm{RPI} - X$$

where:

- RPI stands for Retail Price Index, a measure of inflation published by the UK Office for National Statistics; and
- X is a parameter intended to capture the efficiency gains the network operator was expected to achieve over the relevant period.

The objective of price-cap regulation (often simply referred to as 'RPI minus X') is to incentivise the network operator to operate more efficiently by letting the firm keep the additional revenue generated in case the efficiency gains it achieves are greater than the parameter X. The implicit assumption behind this idea is that, due to information asymmetries, the regulatory authority is unlikely to correctly assess the value of the network's asset base and its operating costs (which are key parameters in determining the network's remuneration in a rate-of-return regime). By adopting price-cap regulation, one could expect that the network operator's full efficiency capabilities would be revealed and

[8] It is worth noting that in case the network owner is a government entity, r could, at least in theory, be set at a level below the firm's WACC due to government policy favouring a less efficient allocation of public capital in exchange for lower energy costs.

[9] Littlechild (1983).

the regulatory authority could eventually set regulated prices at a lower level by adjusting the parameter X in the following regulatory periods. Due to its theoretical attractiveness and simplicity, the uptake of price-cap regulation across the world was rapid. Price-cap regulation proved particularly popular in Latin America and Asia during the privatisation wave of the 1990s and early 2000s. However, empirical evidence of the superiority of price-cap regulation is limited and the extra-profits it allows network operators to retain have frequently triggered political backlashes. Even in the United Kingdom, the pure RPI minus X system was rapidly abandoned in favour of hybrid regimes that monitored the behaviour of network operators more intrusively.

Revenue-cap regulation shares many of the elements of a price-cap regime, with the exception that, as the name suggests, the variable on which a cap is imposed is the total revenue the network operator is entitled to earn. In a stylised representation, the revenue R_1 a network operator can accrue over a period is equal to:

$$R_1 = \left(R_0 \times \pi\right) + I_1 + d \pm A_0$$

where:

- R_0 is the allowed revenue over the preceding period;
- π is a measure of inflation;
- I_1 is the expenses to be incurred for investment the network operator has committed to make over the period;
- d is the expenses incurred to account for the depreciation of capital assets; and
- A_0 is the discrepancy between the allowed revenue R_0 and the actual accrued revenue, which can be positive (over-recovery) or negative (under-recovery).

While conceptually very similar to price-cap regulation, one crucial feature of revenue-cap regulation is that it decouples the network's revenue from the amount of services sold.[10] As such, this regime insulates network operators from demand fluctuation, making it particularly apt for activities whose costs are overwhelmingly fixed and in which public policy objectives often favour lower network utilisation (see, for instance, the promotion of energy efficiency, self-consumption and demand response). The majority of networks in Europe are currently subject to some form of revenue-cap regulation.

In practice, incentive regulation is accompanied by additional rules and mechanisms attempting to make them fairer and fit for purpose, albeit ever more complex. Detailed reporting obligations on business plans and investment, tight monitoring of costs and mechanisms providing network operators

[10] Jamison (2007).

with incentives or penalties depending on the performance against certain targets (including those related to transparency and conduct) are common features of modern revenue regulation regimes. *Benchmarking* remuneration against the performance of a best-in-class operator (a regulatory practice referred to as yardstick competition) is also used.

As much as accumulation of experience and improvements in computational ability will continue refining the capabilities of regulatory authorities, revenue regulation is deemed to remain an area prone to errors and controversy. On the one hand, network operators tend to have better insight than the regulatory authority over some of the key parameters and may be tempted to game the process. On the other hand, the inherent uncertainty of other input factors does not depend on information asymmetries. For instance, neither the network operator nor the regulatory authority is able to forecast with precision demand trends and interest rates, which significantly affect network utilisation and the viability of investment. Under these circumstances, the accuracy of revenue and cost forecasts for several years ahead is inevitably low, prompting the occurrence of situations in which the network gets either overcompensated, thus undermining the credibility of the regulatory authority, or gets undercompensated, resulting in harmful under-investment or even endangering the financial viability of the network operator.

7 Network Tariffs and Market Structures

In accordance to the principles of revenue regulation and rTPA discussed in the previous sections, the fee a network operator can charge network users for each service it provides (such as a network connection or the booking of capacity at a network point) must be set at an equal level for all network users, called *regulated network tariffs*. In case a service is allocated through an auction, the regulated tariff will be the auction starting price. The calculation or approval of network tariffs, which result from the application of a predefined methodology (also called *charging regime*), is another key task of energy regulatory authorities. Tariffs are a politically sensitive topic as they determine the allocation of network costs among different categories of network users, which in turn significantly influences the energy costs paid by different end users.

Like revenue regulation regimes, network tariffs methodologies vary greatly from one to another. The main distinction that can be observed is between zonal and nodal tariff systems. In a *zonal tariff system*, network users pay fees to the network operator when they book capacity to enter and exit the network, while they are not charged for moving energy within it. For this reason, they are also called *entry-exit* systems. From a practical perspective, a network user injecting energy at network point A and withdrawing it at network point B will book entry capacity at point A and exit capacity at point B, pay the corresponding tariffs, then schedule energy flows at these two points. The movement of energy between point A and point B is solely managed by the network operator. Zonal tariff systems are divided into *postage-stamp* regimes and methodologies that take into account *locational signals*. In the former, like in traditional postal systems, tariffs at all entry and exit points are the same regardless of the costs incurred to move the electrons or gas molecules between network points. In the latter, such costs (which are usually driven by the distance between points) are taken into account when determining the tariffs. The majority of electricity transmission networks and the near totality of gas transmission networks apply a zonal tariff system. Distribution networks, both in electricity and gas, usually charge according to a zonal postage-stamp system.

A *nodal tariff system* is a more complex regime in which network operators charge users a tariff for each movement of energy between two nodes of the network. Such a granular charging of network capacity can potentially lead to the emergence of a different price for energy at each point of the network. For this reason, these systems are also called *locational marginal pricing (LMP)* systems. In practice, in a nodal tariff system capacity between any two network nodes is usually auctioned with a reserve price of zero, so there will be a positive price for capacity between two nodes only if there is more demand than capacity available, or network congestion. The difference of price between two locations is therefore called *congestion revenue*. There is a broad academic consensus on the benefits of nodal systems over zonal ones because they allow for more efficient pricing of energy within networks and, consequently, more efficient network utilisation.[11] However, zonal systems are still more common as they are generally simpler to operate and less politically controversial.[12] Nodal tariffs have been adopted in several electricity transmission networks in the United States over the 1990s and 2000s, but their uptake outside North America has been slow.

Network tariff methodologies also influence how network users exchange energy between themselves. In zonal tariff systems, it is common for the network operator to manage *virtual trading points* (also called virtual hubs), either directly or through an appointed third-party provider, at which transactions notionally take place. The alternative for network users would be to trade at the interconnection between two networks (called flange trading). Across Europe, for instance, all networks (or cluster of networks) have their own virtual trading point, which tends to be given a specific name in gas (for instance, TTF, NBP, NCG, PSV), while is simply called with the name of the network in electricity. Flange trading has been actively discouraged by policymakers since the early 2000s and has almost disappeared. In nodal systems, on the other hand, market participants can in theory buy and sell energy at each node of the network. In practice, trading coalesces at some key locations, or *physical hubs*, either because they are key infrastructural interconnections or because trading activity has conventionally focused there over time. In the United States, most

[11] Hogan (1999).

[12] The application of locational marginal pricing (LMP) and the resulting differences in the energy price paid by consumers on the basis of their location, while economically efficient, has proved to be politically unacceptable in most countries.

exchanges of electricity take place at approximately ten major physical hubs. Likewise, the North American gas market is based on trading at Henry Hub (a physical location in Louisiana) and several satellite regional hubs.

8 Conclusion: The Future of Energy Networks

This chapter has provided an overview of the structure and functioning of energy networks. Many of the key concepts outlined, such as unbundling, rTPA and revenue regulation, are currently at the core of the energy policy debate. Established wisdom in the field of the economics of energy networks is being revisited by academics and practitioners in the attempt to devise appropriate solutions and organisational models for the unprecedented policy and environmental challenges energy networks need to tackle. Current trends only superficially appear to be impacting electricity and gas networks in different manners. Instead, both share a future where rapid transformation and massive investment are necessary. Electricity networks are expected to cope with large increases in throughput due to the electrification of many energy uses (primarily road transport), while being able to manage more volatile and unpredictable energy flows resulting from the replacement of dispatchable thermal generators with non-dispatchable renewable installations. On the other hand, the gradual phase-out of fossil gas in power generation, industry and heating puts gas networks at risk of demise unless they promote a conversion of their infrastructure to low-carbon gases, such as biomethane and hydrogen. Closer interaction between electricity and gas networks (including joint infrastructure planning and operation) is also likely to take place.[13]

In spite of a much-publicised push to off-grid solutions made possible by rapid improvements in DERs and digitalisation, it is difficult to envisage a future in which networks do not continue to play a fundamental role in modern energy systems. Even in the plans of the most enthusiastic proponents of self-generation, continued reliance on network connection, either to supply energy or to evacuate excess on-site production, remains essential. Energy networks are therefore likely to be going through a rapid but incremental evolution of their role and functioning, rather than a full-blown revolution. Despite the radical uncertainty crippling the energy sector, we can confidently state that energy networks are here to stay.

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[13] A full integration of electricity and gas networks is a distinct possibility in a scenario where electrolysers turning electricity into hydrogen (which would provide both electricity storage and low-carbon gas) become a significant feature of energy systems.

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CHAPTER 14

Economics of Electricity Battery Storage

Michel Noussan

1 Introduction

The energy consumption related to human activities always involved a specific energy supply chain, which provided to the final users the exact amount of energy required at a specific time. Since it is not always possible to match the energy supply with the user's demand, there is a need for storing energy to compensate this mismatch. The storage may be required with a large diversity of durations, ranging from fraction of seconds to months or even years. Different energy carriers involve multiple storage solutions, based on limits and opportunities related to the form of energy that is stored (chemical, potential, kinetic, electro-static, etc.), as well as on technical and economic features of the available storage technologies.

The easiest energy storage usually happens with fuels, especially solid and liquid, which can be generally stored in their normal form without the need of specific solutions. While attention must be paid in avoiding potential self-combustion, chemical degradation, or phase change, solid and liquid fuels are usually stored in simple tanks (eventually cooled or heated in particular climate conditions).

Additional requirements are usually needed for gaseous fuels, mainly natural gas. Due to its low volumetric density, its transportation and storage are usually performed either by compressing it at high pressures or by liquefying it with the need of providing continuous cooling. Natural gas storage is usually

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performed on a seasonal basis, to match the continuous supply with the fluctuating demand driven by different weather conditions throughout the years. Such storage strategies usually involve large-scale underground formations, either depleted reservoirs or saline formations. The low energy and fuel losses are generally compensated by the significant economic savings that can be obtained with continuous upstream operations for natural gas.

Another energy carrier that is commonly stored is heat, usually in the form of warm or hot water, either in large-scale facilities connected to district heating networks or industrial users or at small-scale heat storage systems for domestic users. Heat storage is mostly used to exploit the better efficiency related to heat generators operating at constant load, especially biomass boilers and heat pumps. However, large seasonal underground systems are being used in some countries to store solar energy in summer and supply district heating in winter. Some systems exploit the ground as storage medium, while others rely on very large water volumes (Bott et al. 2019). For small-scale storage, alternative technologies based on phase-changing materials are the objective of multiple research efforts, although commercial applications are still limited.

Electricity stands out among the most difficult energy vectors to be stored. Electricity storage solutions are usually relying on its conversion to another form of energy. With the exception of superconductivity, other current technological solutions rely on chemical, mechanical, gravitational, or electro-static forms of energy. Nevertheless, electricity storage systems are strongly needed to guarantee the continuous balance of the power grid and provide reliable and effective service to the final users. For this task, a wide range of services is required, which are usually categorized with respect to storage duration: from few seconds or minutes for frequency control; to energy transfers across weeks, days, or day-night (also called arbitrage); and to the need of providing UPS (Uninterrupted Power Supply) for industrial consumers connected to the grid (Crampes and Trochet 2019).

Each available storage technology is usually tailored to a preferred application, based on technical limitations, design choices, and economic features. Today, most electricity storage worldwide is performed by pumped hydro systems, which rely on a mature technology with lower costs in comparison with the alternatives. Although pumped storage may be used also for frequency regulation, the flexibility provided by its potentially long discharge time (up to a few dozens of hundred hours) is usually exploited for arbitrage. Frequency control is provided through flywheels but more often by backup power generators. Batteries are somewhat in between, since they have discharge times that usually reach some hours, but at the same time they are responsive enough to provide frequency regulation services. Compressed-air storage systems have similar applications than pumped hydro, but due to limited available sites few applications exist.

While most storage systems are mature technologies, there is currently an interesting potential in the deployment of electric batteries, especially based on lithium-ion. The two leading drivers are the additional flexibility required by non-dispatchable renewable sources (mainly solar and wind) and the strongly decreasing cost expected by massive upscaling of battery manufacturing for electric vehicles. Although other chemistries may prove to be disruptive in the future, the current choice appears to be firmly oriented toward Li-ion, which is the preferred choice of numerous large-scale factories worldwide (so-called gigafactories). Their modularity also allows a large range of applications, from utility-scale grid storage to beyond-the-meter batteries for final users, usually coupled with distributed PV generation.

For these reasons, this chapter focuses on Li-ion batteries, given their expected central role in the future power systems. Alternative chemistries will be briefly mentioned, with the aim of highlighting the potential advantages they may provide. Section 2 provides a technological perspective to highlight the main aspects that are involved in battery design, deployment, and operation. Section 3 focuses on battery economics, with attention on the manufacturing supply chain and on the sizing and operational logics. Finally, Sect. 4 closes the analysis by recapping the main take-aways, together with some policy implications.

2 Battery Technologies

Different technologies exist for electric batteries, based on alternative chemistries for anode, cathode, and electrolyte. Each combination leads to different design and operational parameters, over a wide range of aspects, and the choice is often driven by the most important requirements of each application (e.g. high energy density for electric vehicles, low cost for stationary storage, etc.). The current rise in battery manufacturing capacity worldwide is associated with Li-ion batteries, which are meeting the requirements of the electric vehicles (EVs) industry and offer a viable solution also for stationary storage applications, both for utility-scale batteries and behind-the-meter distributed storage.

The historical trend of global stationary storage capacity (see Fig. 14.1) shows an increase in recent years, from around 0.6 GWh in 2010 up to 3.5 GWh in 2017. While up to 2010 most of the capacity was relying on sodium batteries, in 2017 almost 60% of the total capacity is made up of Li-ion batteries (figures may slightly differ when considering output power, since the energy/power ratio is usually different from one technology to another). This rise is due to different factors, but the most important is surely declining costs driven by manufacturing upscaling of this technology for use in EVs, as is further explained later.

Figure 14.1 is limited to utility-scale capacity, while there is also a growing, although much more difficult to quantify, amount of behind-the-meter storage.[1] Estimates for 2016 range from 0.5 to 2.4 GWh, depending on the source, limited to distributed storage operated by residential, industrial, and

[1] Behind-the-meter storage refers to the distributed battery storage installed by private users, mostly residential. It is often coupled to distributed generation systems, such as photovoltaics.

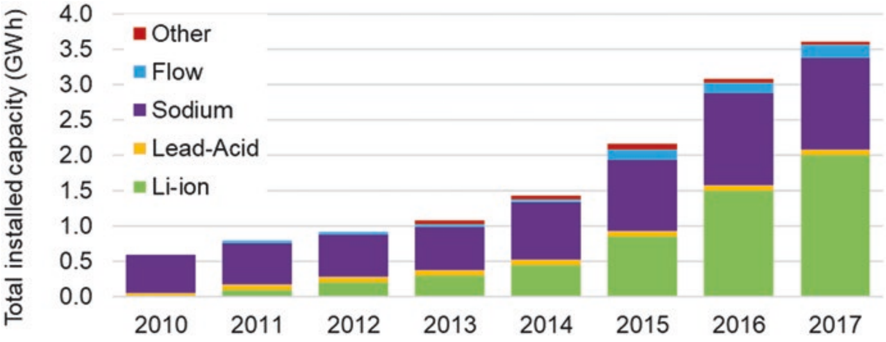

Fig. 14.1 Evolution of installed capacity for stationary storage (utility scale), per technology. (Source: Author's elaboration on (Tsiropoulos et al. 2018))

commercial users. This capacity is made up of a large number of storage systems with small capacity, usually coupled with local generation from RES (mostly solar). While utility-scale batteries are usually managed centrally, an optimized operation of the distributed energy systems requires the operation of smart grids and networks supported by digital platforms (such as virtual aggregators[2]).

It is important to highlight that stationary storage may refer to different services for the power network, at both the transmission and the distribution levels, which differ based on the response time of the batteries, the discharge duration, and the size of the system. The applications may include services for the transmission grid (arbitrage, frequency regulation, peak shaving, black start, and ramping[3]) or for the distribution grid and users (voltage support, balance management, uninterruptible power supply (UPS), and support to self-consumption from PV generation[4]).

[2] Virtual aggregators are digital platforms that coordinate the operation of multiple systems, including generation units, energy storage systems, and demand response, with the aim of reaching the minimum threshold of power required to participate to wholesale markets (usually higher than 1 MW).

[3] Arbitrage is the practice of purchasing electricity from the grid when it has a low price and storing it for later use when the price increases. Frequency regulation is a service provided to the grid that ensures that alternate electric current is maintained within the required tolerance bounds by synchronizing the power generators. Peak shaving is the practice of using available storage capacity to limit the maximum power demand during peak hours, to optimize the generation units and avoid excessive variations. Black start is the process of restoring the operation of an electric grid after a partial or total shutdown, while ramping is the operation of increasing or decreasing the output power of a generation unit.

[4] Voltage support and balance management are flexibility services provided to the distribution grid that allow a proper operation of all the network within the tolerance boundaries. UPS units guarantee that in the case of a network failure the electricity supply is not interrupted, and it is usually required by expensive machineries that may be sensitive to power shortages. Support to self-consumption from PV generation may be required to maximize the local use of electricity to improve the energy efficiency of the system and/or decrease costs for the users.

Table 14.1 Main characteristics of different battery technologies

	Unit	*Li-ion*	*Pb-A*	*Na-S*	*V-R flow*
Cycle life	(cycles @ % SOC variation)[a]	3000 to 10,000 @ 80%	200 to 1800 @ 80%	4500 @ 80%, 2500 @ 100%	10,000 to 12,000+ @ 100%
Specific energy	Wh/kg	75 to 200	30 to 50	150 to 250	10 to 30
E/P ratio	kWh/kW	0.025 to 0.6	0.13 to 0.5	6	1.5 to 6+
Cycle efficiency	–	80% to 98%	63% to 90%	75% to 90%	75% to 80%
Daily self-discharge	–	0.1% to 0.3%	< 0.5%	20% (thermal)	Negligible

Source: Author's elaboration from Leadbetter and Swan (2012)

[a]SOC—State of charge. Cycle life is often measured considering the number of cycles that can be performed with respect to a specific variation of the state-of-charge of the battery

The following section will describe the main characteristics of the most significant available technologies, not only with a strong emphasis on Li-ion batteries but also with a discussion of the main alternatives: lead-acid (Pb-A) batteries, sodium-sulfur (Na-S) batteries, and vanadium redox (V-R) flow batteries. The main characteristics of different technologies are summarized in Table 14.1.

As already anticipated, each battery shows peculiar parameters that are tailored to specific applications. Particularly, the energy/power (E/P) ratio is crucial for the choice of the application, and while there is some room for adjustment by considering specific design parameters (such as electrodes thickness in Li-ion batteries), each technology usually fits best in a specific application as presented hereafter.

2.1 Li-Ion Batteries

Li-ion batteries are a recent technology, initially developed at Bells labs in the 1960s and first commercialized by Sony in 1990. The Nobel prize in Chemistry in 2019 has been awarded to J. B. Goodenough, M. S. Whittingham, and A. Yoshino for their crucial role in the development of Li-ion batteries at different steps (Nobel Media AB 2019). Their success for portable electronics has been mainly triggered by high cycle life, high energy density, and high efficiency, although at a higher price in comparison with other solutions.

Li-ion batteries were mostly applied to portable electronics (including laptops, phones, etc.), until the rising interest in EVs triggered a significant deployment of batteries, whose price decreases also helped their increased sales for stationary energy storage and other applications (including medical devices, gardening tools, and electric bikes) (Fig. 14.2).

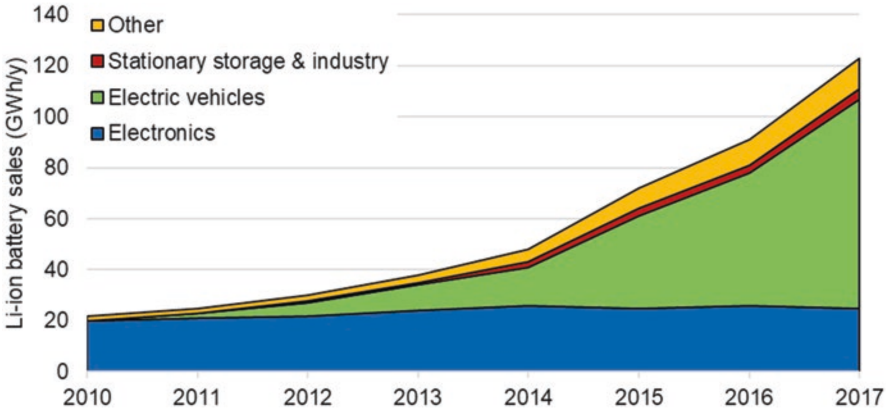

Fig. 14.2 Evolution of Li-ion battery sales worldwide. (Source: Author's elaboration on (Tsiropoulos et al. 2018))

Thanks to their superior performance, they represent the most interesting technology for research and development. In particular, most research is focusing on alternative cathode chemistries to improve energy density and safety or reduce cost through limited use of specific materials (especially cobalt). Other areas of research include anode and electrolyte materials and manufacturing processes.

2.2 Other Battery Technologies

2.2.1 Lead Batteries

Pb-A batteries are the most mature and diffused battery technology in the world, with their first applications dating back to the 1860s. The extensive research that has been made on many different aspects now guarantees low costs, although with limited life cycles and energy density. Specific additives are available to reach specific objectives, such as reducing the self-discharge or decreasing corrosion issues (Leadbetter and Swan 2012). Lead batteries are seldom used for heavy cycling applications, but they are generally suitable for infrequent cycle applications such as peak shaving or uninterruptible power supplies. Large batteries have been installed as case studies in different countries, up to 20 MW and 40 MWh, demonstrating good performance over several cycles, although requiring appropriate energy management methods. Notwithstanding the technology maturity, research is still active in different domains with the aim of decreasing costs and addressing specific challenges, such as longer lifecycles or more accurate determination of the state of charge (SOC).

2.2.2 Sodium-Sulfur Batteries

Na-S batteries are another relatively new technology, having been developed from the 1960s to the 1990s. While they were initially investigated for electric vehicles without much success, they eventually became among the lowest-cost options for grid storage and renewable applications. The operation of Na-S batteries involves peculiar aspects, including the need of high temperature operation for liquid sodium (300–350°C) and the potential very high reactivity of sodium with air in case of containment losses. While the inefficiency during the operation is generally enough to keep the sodium at the right temperature without the need of an external energy supply, in case of non-operation the battery records up to 20% of daily capacity losses due to heat dissipation. Existing installations have grown rapidly in the last decades, with the largest system for stationary storage reaching to date a capacity of 34 MW and 245 MWh coupled with a 51-MW wind farm to stabilize its power output (Leadbetter and Swan 2012).

2.2.3 Flow Batteries

The most diffused technology for flow batteries is the vanadium redox battery (VRB), whose development began in the early 1980s. Its peculiar features include a very long life cycle, the possibility of independently designing the required power and energy output, very low self-discharge losses, and moderate efficiency and costs. In a flow battery, two electrolytes are stored in two separate tanks, and an electrical current is created through a redox reaction by circulating H^+ ions through a membrane. Storage capacity can be raised by increasing the size of the tanks, at constant power output, while increasing the membrane area has the only effect of expanding the power output (i.e. with constant storage capacity). A significant issue is the limited temperature operational range (10–35°C), which usually requires the installation of a temperature control system, although additions to the electrolytes can increase this range. VRB batteries are at a lower technology readiness level in comparison with other solutions, and there are few and small commercial applications to date. An example of application is a 500 kW/1 MWh VRB installed in a wind power research and testing center in Zhangbei, China (IRENA 2015). Its main objective is to support wind generation by storing excess production and delivering it to the grid in hours with higher demand, and the battery can also provide services over a shorter timeframe, such as load following and voltage support. However, experts warn that significant cost reductions would be required to compete with Li-ion or advanced Pb-A technologies, which in turn would require increasing manufacturing and development funding, which may not be the case without increasing revenues (Fisher et al. 2019).

3 Economics of Li-Ion Batteries

Batteries are still an emerging technology in the framework of power systems management and face high upfront costs and regulatory constraints due to lack of technical know-how in governments and public authorities. The investment costs include the battery pack, balance-of-system (BOS) costs and engineering, and procurement and construction (EPC) costs. Battery pack prices are strongly decreasing, driven by economies of scale related to EVs deployment, and the remaining costs are also expected to decrease sharply, thanks to increased standardization of storage modules and increased competition on the market.

The economics of Li-ion batteries can be quantified by defining a levelized cost of storage (LCOS), in analogy to the well-known definition of the levelized cost of electricity (LCOE), with the aim of accounting for all technical and economic parameters affecting the lifetime cost of discharging stored electricity (Schmidt et al. 2019). This metric has been defined to improve the limitations of considering only the investment cost, which is often the only indicator that is analyzed, by including replacement and disposal costs, maintenance and operation costs, as well as performance parameters such as capacity degradation over time. LCOS is thus defined as the total lifetime cost of the investment in an electricity storage technology, divided by its cumulative delivered electricity (Schmidt et al. 2019); the calculation involves a more in-depth analysis on the expected performance of the unit.

A general formulation of the LCOS is represented in Eq. (14.1), defining the discounted cost per unit of electricity delivered by the batteries, in line with the most recent publications on the subject (Jülch 2016; Lazard 2018; Schmidt et al. 2019). The main aspects included in this formulation are the investment cost, the operation and maintenance cost, the charging cost, and the end-of-life cost, all divided by the sum of the electricity discharged by the storage system over the entire economic lifetime (N), discounted by the discount rate (i).

$$LCOS\left[\frac{\$}{MWh}\right] = \frac{INV_{cost} + \sum_{n=1}^{N} \frac{O\&M_{cost}}{(1+i)^n} + \sum_{n=1}^{N} \frac{Charging_{cost}}{(1+i)^n} + \frac{EOL_{cost}}{(1+i)^{N+1}}}{\sum_{n=1}^{N} \frac{E_{discharged}}{(1+i)^n}} \tag{14.1}$$

The LCOS is generally defined with respect to the energy discharged, but for specific applications that focus on services related to active power, a more suitable definition would consider the available output power rather than the energy delivered. Some literature works evaluate also an LCOS based on power, by considering the net power capacity that can be provided each year (Schmidt et al. 2019).

The investment cost is usually parameterized on both power output and energy capacity of the battery, and some components need to be replaced in the lifetime of the battery. The replacement costs may be included in the investment cost, properly discounted based on the estimated year of replacement, or they may be considered part of the maintenance costs, without any difference on the final calculation of the LCOS.

Annual costs include O&M costs and charging costs, both affected by the annual number of cycles of the battery. Charging costs are also related to the specific price of electricity, which can show large variations, and the round-trip efficiency, for which a degradation over time should be considered. End-of-life costs are usually calculated as a fraction of investment costs, but the evolution of recycling procedures (and dedicated regulations) may have a significant impact.

The following sections will focus on the main economic aspects involved with investment, operational, and maintenance costs, as well as on the performance parameters that affect the LCOS both on the annual charging cost and on the electricity discharged.

3.1 Investment Cost

The investment cost of Li-ion batteries significantly declined in recent years, and the trend is expected to continue in the future. As already discussed, the most important trend is currently the strong demand of batteries for the EV sector, which is leading to factory capacity expansion in different regions of the world. While this trend is pushing toward a decrease of battery packs cost, Li-ion batteries for stationary storage also include additional components, such as balance of system, power conversion system, energy management system,[5] engineering, procurement, and construction. Some of these additional components may face similar cost decreases in the future thanks to potential synergies with other industries (e.g. inverter costs decrease thanks to their application in the PV deployment).

Detailed information on the investment cost breakdowns is usually not available, due to confidentiality restrictions. Moreover, due to the high variability of both technologies and battery configurations related to specific applications, it is difficult to draw conclusions related to the weight of each component of investment costs. Material-related costs analyzed in different literature studies range from one-third to almost two-thirds of the total system costs, depending on the source, as illustrated in Fig. 14.3 (IRENA 2017).

However, when considering the breakdown of material costs, the figures show less variability: electrode materials (anode, cathode, and electrolyte) constitute roughly half of the cost, with the main contribution related to cathode (between 31% and 39% of the total cost of materials). Notwithstanding the variable impact of materials in the total investment cost of batteries, the increase of the energy density driven by technology innovation will eventually lead to cost savings, thanks to the lower material input required for the same output capacity.

[5] The balance of system includes the components that monitor the battery operation to avoid that specific parameters reach values outside the acceptable range, including the calculation and reporting of indicators. The power conversion system includes the components that allow to convert electricity from one form to another, such as from direct current to alternate current, and modifying voltage or frequency. The energy management system includes the software and operational logics that guarantee the interaction between the battery and the power grid, to support the charging and discharging phases and ensure an efficient operation of the energy storage system.

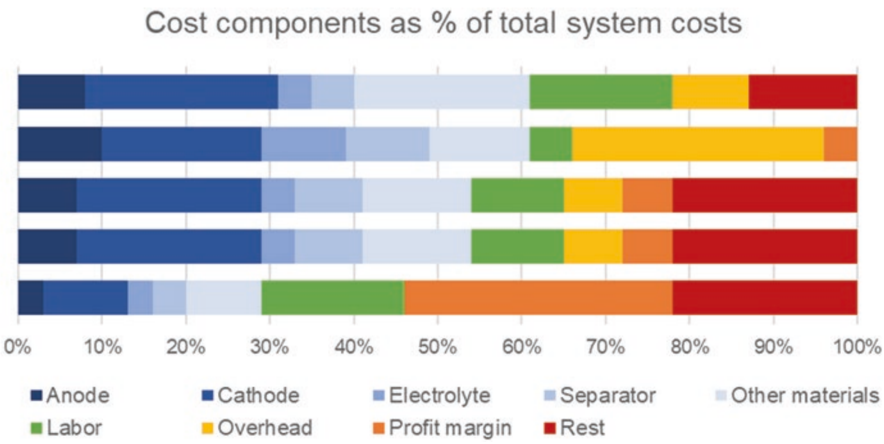

Fig. 14.3 Investment cost breakdowns from five different sources. (Source: Author's elaboration on (IRENA 2017))

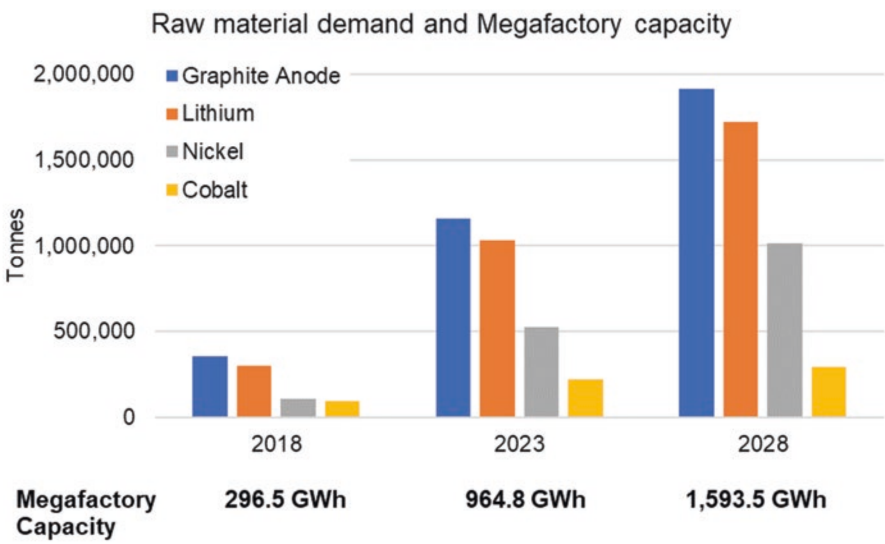

Fig. 14.4 Expected increase in raw material demand for global Li-ion batteries manufacturing. (Source: Author's elaboration on (Benchmark Mineral Intelligence 2018))

Many authors calculate learning curves based on the historical trend, assuming that the cost decrease has no significant limitations related to external constraints (Berckmans et al. 2017; Kittner et al. 2017; Schmidt et al. 2017). However, other works highlight the fact that the cost of active materials, especially under rising global demand, may act as a strong constraint to further reduce battery costs and may slow down the learning curves (Hsieh et al. 2019).

The rise of battery demand will translate to fast-increasing raw materials requirements, as estimated in the chart of Fig. 14.4 with reference to the