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Vienna
Austria

ISBN 978-3-319-08400-8 ISBN 978-3-319-08401-5 (eBook)
DOI 10.1007/978-3-319-08401-5

Library of Congress Control Number: 2014950679

Springer Cham Heidelberg New York Dordrecht London

Printed on acid-free paper

Springer is part of Springer Science+Business Media (www.springer.com)

Preface

The preparation of a book has always been a complex and challenging task. This is the third book on energy matters that I have had the opportunity to prepare. The first two books were dedicated to the use of different energy sources for generation of electricity in Latin America and the Caribbean region. One of the books was dedicated to the use of oil, natural gas, and coal for generation of electricity, and the second to the use of different renewable and nuclear energy sources for the same purpose. This book is the first of two books dedicated to the use of conventional and nonconventional energy sources for the generation of electricity in the European region. In this particular book, the role of oil, natural gas, and coal in the regional generation of electricity is presented.

Providing a stable and secure supply of energy is a great challenge for governments seeking to achieve sustainable development goals, since the main energy sources providing economic growth and social development are present in the Earth only in specific locations and in limited quantities. Energy is, undoubtedly, an important element in the struggle of any country to alleviate poverty, promote economic growth, and foster social development. But as the world consumes more and more energy, stress is placed on current level of energy reserves and the environment at national, regional, and international levels.

The world should work together to safeguard the environment without slowing socioeconomic development. Third World countries should look for adequate technological solutions in order to change present unsustainable patterns of consumption and production in developed countries and to seek the low-hanging fruit and the win–win solutions that provide the least costly ways of achieving sustainable development goals.

The book has five chapters. Chapter 1 gives the readers a general overview of the current situation and the future role that could be played by oil, natural gas, and coal in generation of electricity in the European region. According to different expert's opinions, the use of energy at world level will continue to increase gradually until 2030. According to studies made by the French Association of Oil Professionals, it is expected that for 2030, the world energy demand will be double and it is probably that could be triple for 2050. Until 2030, the primary energy demand at world level is expected to increase annually at 1.7 %, which is somehow smaller than the world growth of 2.1 % registered during the past three decades. It is also expected that 90 % of the increase in the world energy demand in the coming decades will be satisfied with fossil fuels. If this forecast is true, then around 15, 300 million tons of oil equivalent (112,500 million of barrels of oil) will be consumed at world level in 2030. Electricity production will account for 32 % of total global fossil fuel use.

In the specific case of Europe, fossil fuels such as oil, natural gas, and coal are by far the largest sources of energy and are widely projected to dominate the European energy mix through to at least 2030. The European Commission's Energy Roadmap 2050 identifies natural gas as a critical fuel for the transformation of the energy system. The substitution of coal and oil to natural gas in the short to medium terms could help to reduce emissions with existing technologies until at least 2030–2035. In Europe, the net growth in the past 11 years of natural gas power (118.2 GW), wind power (75.2 GW), and solar photovoltaic (26.4 GW) was at the expense of fuel oil (down 13.2 GW), coal (down 9.5 GW) and nuclear energy (down 7.6 GW). In the specific case of the EU power sector, countries continue to replace ageing fuel oil, coal, and nuclear power plants with modern technology, while at the same time increasing its total installed capacity to meet the increasing energy demand in the coming years.

Chapter 2 provides readers with the latest information about the current and future role to be played by oil for generation of electricity in the European region. World use of petroleum and other liquid fuels is expected to grow from 85.7 million barrels per day in 2008 to 97.6 million barrels per day in 2020 and 112.2 million barrels per day in 2035; this represents an increase of 14.9 % with respect to 2008. It is important to highlight that most of the growth in liquid fuel use is in the transportation sector, where, in the absence of significant technological advances, liquid fuels will continue to provide much of the energy consumed at least during the coming decades. For the time being, liquid fuels remain an important energy source for transportation and industrial sector processes. Despite rising fuel prices, the use of liquid fuels for transportation purposes is expected to increase by an average of 1.4 % per year or 46 % during the period 2008–2035. The transportation sector will account for 82 % of the total increase in liquid fuel use from 2008 to 2035, with the remaining portion of the growth attributable to the industrial sector. The use of liquid fuel is expected to decline in the other end-use sectors, particularly for electric power generation during the coming years.

To meet the increase in world demand, liquid fuels production (including both conventional and nonconventional liquid fuel supplies) should increase by a total of 26.6 million barrels per day from 2008 to 2035. With the aim to meet this foreseeable increase, OPEC countries will invest in incremental production capacity in order to maintain a share of approximately 40 % of total world liquid fuels production through 2035, consistent with their share over the past 15 years. Increasing volumes of conventional liquids (crude oil and lease condensate, natural gas plant liquids, and refinery gain) from OPEC producers are expected to contribute 10.3 million barrels per day to the total increase in world liquid fuels production during the coming years, while conventional supplies from non-OPEC countries is expected to add another 7.1 million barrels per day during the same period.

The ten top crude oil exporters in 2012 exported 32,618,000 barrels per day. Within this group, there are only two European countries (Russia with 22.1 % and Norway with 5.2 % of the world total). The ten top importers of crude oil in 2012 imported 30,462,000 barrels per day of crude oil. Within this group, there are four European countries (Germany, Italy, France, and Spain).

Chapter 3 provides readers the latest information on the world total natural gas production, consumption, import and export. Natural gas continues to be the fuel of choice in many regions of the world, particularly in the electric power and industrial sectors. The reason is in part because of its lower carbon intensity compared with coal and oil, which makes it an attractive fuel source in countries where governments are implementing policies to reduce greenhouse gas emissions, and also because of its significant price discount relative to oil in many regions. In addition, it is an attractive alternative fuel for new power generation plants because of low capital costs and favorable thermal efficiencies. In the IEO (2011), total world natural gas consumption for industrial uses is expected to increase by an average of 1.7 % per year through 2035, and consumption in the electric power sector is expected to grow by 2 % per year during the same period. The industrial and electric power sectors together account for 87 % of the total projected increase in natural gas consumption.

There are enough reserves of natural gas to satisfy the foreseeable demand during the coming decades. According to EIA sources, the world's total natural gas reserves in 2012 were estimated at 1,317,482 trillion m^3 (6,844.595 trillion cubic feet). The world's total natural gas consumption is expected to increase by 1.6 % per year on average, from 111 trillion cubic feet (3,919.965 billion m^3) in 2008 to 169 trillion cubic feet (5,968.235 billion m^3) in 2035; this represents an increase of 52.2 % with respect to 2008. Increasing supplies of nonconventional natural gas, particularly in North America, but elsewhere as well, will help to keep global markets well supplied.

Chapter 4 provides readers the latest information on the world coal consumption, which is expected to increase by 50.3 %, from 139 quadrillion Btu in 2008 to 2009 quadrillion Btu in 2035; this represents an increase of 50.3 %. In the case of world coal consumption, it is expected to increase at an average rate of 1.5 % per year from 2008 to 2035, but the growth rates by region will be uneven, with total coal consumption in OECD countries remaining near 2008 levels and coal consumption in non-OECD countries increasing at a pace of 2.1 % per year. As a result, increased use of coal in non-OECD countries accounts for nearly all the growth in world coal consumption over the period.

In 2008, coal accounted for 28 % of world energy consumption. Of the total coal produced worldwide in 2008, 60 % was shipped to electricity producers and 36 % of industrial consumers, with most of the remainder going to consumers in the residential and commercial sectors. According to the IEO (2011), coal's share of total world energy consumption is expected to remain relatively big throughout the period 2010–2035, declining slightly from a peak of 29 % in 2010 to 27 % in 2015, where it is expected to remain through 2035.

Coal was the main energy source not only in Europe, but also worldwide until the 1960s. Owing to advances in oil extraction, conversion, and application technologies, coal then began to lose market share to oil. The entry of natural gas and nuclear power into the energy market at the beginning of the 1970s put further pressure on the use of coal for generation of electricity. As a result, despite the rising energy demand, gross coal consumption in the EU-15 has been declining since 1970, while the share of coal in gross inland energy consumption has more than halved, from more than 30 % to approximately 15 %. In contrast, coal retained a 25 % share in gross inland energy consumption globally over the period 1970–2000.

However, in recent years there is renewed interest in the use of coal in the EU, as well as in other countries within and outside the European region for different purposes, based on a wide perception that coal is an abundant, widely available, cheap, affordable, and reliable energy source.

Chapter 5 includes a summary of the main issues includes in previous chapters.

Jorge Morales Pedraza

Acknowledgments

During the preparation of the present book different professionals assisted me in the compilation of relevant information regarding the current and future role of fossil fuels in generation of electricity in the European region. My lovely daughter Lisette Morales Meoqui, M.Sc. has been an extremely helpful assistant in collecting the necessary information and reference materials used in the preparation of the book, in addition of her current job as Head of Finance in the Austrian firm Zeno Track GmbH. My dear son Jorge Morales Meoqui, now a Doctor in Economics, has been also extremely helpful in the revision of some of the initial materials used during the preparation of the book.

Without any doubt, the present book is a reality thanks to the valuable support of my lovely wife, Aurora Tamara Meoqui Puig, who had assumed other family responsibilities in order to give me the indispensable time and the adequate environment to write the book.

Contents

About the Author

Jorge Morales Pedraza Currently works as an Independent Consultant on International Affairs and possesses degrees on Mathematic and in Economic Sciences. Formerly, he was a Cuban Ambassador for more than 25 years. In the 1980s, Morales Pedraza was appointed as Ambassador and Permanent Representative of Cuba to the International Atomic Energy Agency (IAEA) and in the 1990s gained the same title with the Organization for the Prohibition of Chemical Weapons (OPCW). In addition, he was Invited University Professor in Mathematics Science and an Invited Professor for International Relations in the Diplomatic Academy of Cuba. Throughout the 1990s and into the 2000s Morales Pedraza worked for the IAEA as Senior Manager in the Director's office. Over the past years he was involved in the preparation, as author and coauthor, of more than 60 articles published by international publishers houses, as well as 10 chapters for various books focusing on the peaceful uses of nuclear energy, renewable and conventional energy, the use of the radiation for sterilization of tissues, tissue banking, financial investment, among other topics. During this period he also authored 7 books and was invited editor for international journals. Morales Pedraza is a member of the editorial teams of 5 specialized international journals.

E-mail: jmorales47@hotmail.com or jmorales547@yahoo.com

Abstract

Energy constitutes the motive force of civilization and it determines, to a high degree, the level of economic and social development of the countries. Despite the increased use of different types of energy sources, particularly renewable energy sources, fossil fuels are, and will continue to be, the dominant type of energy source within the world energy mix for many countries. However, it is important to know that fossil fuel reserves are declining, particularly oil reserves, and this situation would have a negative impact in the future economic and social development of many countries from all regions. The limited fossil fuel reserves, the negative impact on the environment due to the use of this type of energy source for electricity generation, and the high price of oil, among other elements, is forcing many countries to look for other energy sources, like hydropower, wind, solar, geothermal, hydrogen, including in some cases nuclear energy, for this specific purpose. Nevertheless, one thing is true: There is no other substitute for oil, coal, and natural gas for a stable and secure energy production, both now and in the near future, and alternative ways of producing energy will play only a minor role in the energy balance of many countries at least until the period 2035–2050. For this reason, the stable and reliable supply of oil, carbon, and natural gas is of key national interest to many States.

According to International Energy Outlook 2010 (IEO 2010), the global economic recession that began in 2008, and continued during 2011, 2012, and 2013, has had a profound impact on world energy demand in the near-term. Total world market energy consumption contracted by 1.2 % in 2008 and around 2.2 % in 2009, as manufacturing and consumer demand for goods and services declined. Although the recession appears to have softened in the past months in several countries, the pace of recovery has been uneven so far, with China and India

leading, and Japan and the European Union (EU) member countries lagging. In some EU countries the crisis has deepened significantly.[1]

Liquid fuels remain the world's largest energy source for the coming two decades. To satisfy the foreseeable increase in world liquid fuels expected demand, liquid fuels production should increase by 26 million barrels per day from 2007 to 2035, including the production of both conventional liquid fuel supplies (crude oil and lease condensate, natural gas liquids, and refinery gain) and unconventional fuel supplies (biofuels, oil sands, extra-heavy oil, coal-to-liquids, gas-to-liquids, and shale gas). It is expected that sustained high world oil prices will allow for the economic development of unconventional energy resources and the use of enhanced oil recovery technologies to increase production of conventional energy resources. High world oil prices also incentivize the development of additional energy conventional resources through technically difficult, high-risk, and very expensive projects, including wells in ultra-deep water and the Arctic region. World production of unconventional liquid fuels, which totaled only 3.4 million barrels per day in 2007, should increase to 12.9 million barrels per day (around 3.7 folds) in 2035, and is expected to account for 12 % of total world liquid fuel supply in that year. It is expected also that world liquid fuels consumption during the period 2007–2035 should increase from 86.1 million barrels per day in 2007 to 110.6 million barrels per day in 2035; this represents an increase of 28.4 %.

In the European region, the energy import dependency is rising. Unless Europe can make domestic energy more competitive in the next 20–30 years, around 70 % of the EU's energy requirements, compared to 56 % today, will be met by energy imported products some of them from regions threatened by insecurity. The future energy requirements of the different countries in the world are so high that, for the first time in humanity's history, it is indispensable to consider all available types of energy sources and their proven reserves to plan the economic and social future development of the countries. At the same time, there is also a need to use these energy sources in the most economic and efficient possible manner in order to sustain that development, particularly for electricity generation, in order to reduce, as much as possible, the emission of CO_2 to the atmosphere.

The EU leads the world in power demand management, and in promoting new and renewable forms of energy for the generation of electricity. If the EU backs up a new energy policy with a common voice on energy issues, Europe can lead the global search for energy solutions in the coming decades. However, EU must act

[1] The economic situation of Greece, Spain, Portugal, and Italy, just to mention the most relevant cases, still are very difficult with a high decrease in their GDP, high rate of unemployment, and high public debt.

urgently because it takes many years to bring innovation on stream in the energy sector, as well as to make productive the investments that are needed to update the energy infrastructure in the region.

Keywords Energy · Europe · Oil · Carbon · Natural gas · Energy policy · Energy strategy · Electricity generation

Chapter 1
General Overview

Abstract The different energy sources that humanity has in its hands now to satisfy its energy needs in the future are the following:

- *Fossil Fuels:* Oil (crude and nonconventional), natural gas (including shale gas and other nonnatural gas), and coal;
- *Nuclear energy:* (fission and in the future fusion);
- *Renewables:* Hydro, solar, wind, geothermal, biomass, tidal/wave/ocean energy, and hydrogen.

The mix of primary fuels used to generate electricity has changed a great deal over the past four decades on a worldwide basis. Coal continues to be the fossil fuel most widely used for electricity generation, except in the Latin America and Caribbean region. However, electricity generation using natural-gas-fired power generation plants grew rapidly in the 1980s and 1990s, and is expected to continue growing in the next two decades. The use of oil for electricity generation has been declining since the mid-1970s, when oil prices rose sharply, and this is also expected to continue decreasing during the coming decades.

1.1 Introduction

It is an unquestionable reality that energy production and, particularly, the generation of electricity and their sustained growth, constitute indispensable elements for the economic and social progress of any country. Undoubtedly, energy constitutes the motive force of civilization and it determines, to a high degree, a country's level of economic and social development. To ensure adequate economic and social growth of a country, it is indispensable that all available energy sources be used in all economic sectors in the most efficient and economic manner, particularly for the generation of electricity. It is important to stress that the economy of any country is evaluated according to the development level of its energy infrastructure. For this reason, economic development is directly related to its energy infrastructure, adapted to industrial development possibilities and the supply of different energy resources.

J. Morales Pedraza, *Electrical Energy Generation in Europe*,
DOI 10.1007/978-3-319-08401-5_1

Therefore, the growing price of energy resources and expensive infrastructure is becoming the key issue while solving questions of economic development and integration, and these factors may turn into one that influences the speed of economic growth of the country the most.

The attention of society to energy sector development is related to the need for welfare growth as well as the aspiration to have a safe and ecologically harmonized environment. For this reason, the main task of the energy sector is a reliable generation of safe, ecologically clean, effective, and economically perspective energy, particularly electricity. This objective may be implemented by adopting an energy sector management policy, by changing and defining management and operational costs, and by assessing the impact of energy infrastructure on ecology. Therefore, the need emerges to estimate various aspects of electricity production, transmission, and distribution activity by more exhaustive methods, applying environmental assessment, developing, and establishing ways that may become helpful in the decision-making process (Šliogerien and Krutinis 2008).

According to the opinions of different experts, the use of energy at world level will continue to increase gradually until 2030. Then, the main question that needs to be asked is the following: How much the foreseeable energy demand will increase in the near future and how this demand is going to be met? According to studies by the French Association of Oil Professionals, it is expected that for 2030 the world energy demand will be double and probably triple for 2050. Until 2030 the primary energy demand at world level is expected to increase annually at 1.7 %, which is somehow smaller than the world growth of 2.1 % registered during the past three decades. It is also expected that 90 % of the increase in the world energy demand in the coming decades will be satisfied with fossil fuels. If this forecast is true, then around 15,300 million tons of oil equivalent (112,500 million of barrels of oil) will be consumed worldwide in 2030. Electricity production will account for 32 % of the total global fossil fuel use in that year. For this reason, improving the efficiency[1] at which electricity is produced is one of the most important ways of reducing the world's dependence on fossil fuels, thus helping both to combat climate change and improve energy security.

The different energy sources that humanity has in its hands now to satisfy its energy needs in the future are the following:

- *Fossil Fuels:* Oil (crude and nonconventional), natural gas (including shale gas and other nonnatural gas), and coal;
- *Nuclear energy:* (fission and in the future fusion);
- *Renewables:* Hydro, solar, wind, geothermal, biomass, tidal/wave/ocean energy, and hydrogen.

[1] The energy efficiency (E) of electricity production is defined as: $\mathbf{E = (P + H \times s)/I}$, where: P = electricity production from electricity power plants and CHP plants; H = useful heat output from CHP plants; s = correction factor between heat and electricity, defined as the reduction in electricity production per unit of heat extracted; and I = fuel input for electricity power plants and CHP plants.

The mix of primary fuels used to generate electricity has changed a great deal over the past four decades on a worldwide basis. Coal continues to be the fossil fuel most widely used for electricity generation, except in Latin America and the Caribbean region. However, electricity generation using natural-gas-fired power generation plants grew rapidly in the 1980s and 1990s, and is expected to continue growing in the next two decades. The use of oil for electricity generation has been declining since the mid-1970s, when oil prices rose sharply, and is also expected to continue decreasing during the coming decades.

High fossil fuel prices recorded between 2003 and 2012, combined with concerns about the environmental consequences of greenhouse gas emissions, have renewed interest in the development of alternatives to fossil fuels, specifically of different renewable energy sources and also nuclear energy in several countries,[2] for generation of electricity. The International Energy Outlook 2010 (IEO 2010) reference case indicated that "long-term prospects continue to improve the role of renewable energy sources for the generation of electricity, supported by government incentives and by high fossil fuel prices." However, it is important to highlight that this type of energy source will not satisfy the foreseeable increase in energy demand during the coming decades and other types of energy sources should be included in the energy mix in many countries.

In the specific case of the European region, fossil fuels, such as oil, natural gas, and coal, are by far the largest sources of energy and are widely projected to dominate the European energy mix through to at least 2030. The European Commission's Energy Roadmap 2050 identifies natural gas as a critical fuel for the transformation of the energy system. The substitution of coal and oil with natural gas in the short to medium term could help to reduce emissions with existing technologies until at least 2030–2035 (Pearson et al. 2012). The net growth in the past 11 years of natural gas power (118.2 GW), in addition to wind power (75.2 GW) and solar photovoltaic (26.4 GW), was at the expense of fuel oil (down 13.2 GW), coal (down 9.5 GW), and nuclear energy (down 7.6 GW). In the specific case of the EU power sector, countries continue to replace aging fuel oil, coal, and nuclear power plants with modern technology, while at the same time increasing its total installed capacity to meet the increasing energy demand in the coming years (EWEA 2011).

[2] The nuclear accident at the Fukushima Daiichi nuclear power plant occurred in Japan in March 2011 changed the perception of many countries about the use of this type of energy for electricity generation in the future. Some EU countries canceled all plans to expand the use of nuclear energy for electricity generation or their plans for the introduction of this type of energy for this specific purpose.

1.2 Liquid Fuels

According to the IEO (2011), "the liquid fuels share of world marketed energy consumption is expected to fall from 34 % in 2008 to 29 % in 2035" and to 28 % in 2040 (IEO 2013); this means a decrease of 6 % during the whole period. The current high world oil prices and the reduction of its proven reserves lead many energy users to switch away from liquid fuels for electricity generation, when feasible, and replace them with different types of renewable energy sources and, in some cases, with nuclear energy.

Regarding the possible evolution of Europe's energy mix during the period 2010–2040, it is important to highlight the following: Europe's power mix changed dramatically over the past decades when almost half of Europe's power came from coal and a quarter from fuel oil; back then natural gas was at the level that wind energy is today; less than 3 % of Europe's power came from nuclear energy in 1971. In 2008, Europe generated about one-quarter of its electricity from natural gas, just 3 % of fuel oil and about 20 % of renewable energy sources (EWEA 2011).[3] As regards the structure of electricity production in 2012, the production of conventional thermal electricity decreased by 4.6 % in EU-27 and accounted for 52.3 % of the total production; the production of electricity by nuclear power plants decreased by 2.7 % in EU-27 and accounted for 27.1 % of the total; the electricity production by hydro increased by 9 %, while the production by wind increased in EU-27 by 11.5 % and represented, respectively, 11.7 % and 6.4 % of the total; electricity production by other types of energy sources was 3 %.

In many parts of the world, concerns about security of energy supplies and the environmental consequences of greenhouse gas emissions have spurred government policies that support a projected increase in renewable energy sources. As a result, renewable energy sources are the fastest growing sources of electricity generation expected to grow at 2.8 % per year from 2010 to 2040. After renewable generation, natural gas and nuclear power are the next fastest growing sources of generation, each expected to increase by 2.5 % per year. Although coal-fired generation is expected to increase by an annual average of only 1.8 % over the projection period, it remains the largest source of world power generation through 2040 (see Fig. 1.1). The outlook for coal, however, could be altered substantially by any future national policies or international agreements aimed at reducing or limiting the growth of greenhouse gas emissions (IEO 2013).

The use of liquid fuels grows modestly or declines in all end-use sectors except transportation, where in the absence of significant technological advances liquid fuels continue to provide much of the energy consumed.

In the opinion of the European Commission (EC) President, José Manuel Barroso, the region needs what he called "The Third Industrial Revolution: Oil and

[3] In 2012, around 52.3 % of the electricity generated in the EU was produced using fossil fuels. In 1999, the total electricity generated by fossil fuels was 1,567 billion kWh; in 2012, the electricity generation was a little bit higher than 3,050 billion kWh, an increase of 94.6 % respect to 1999.

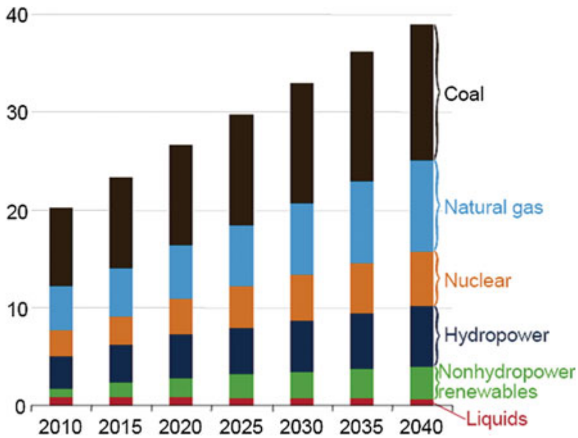

Fig. 1.1 World net electricity generation by energy source, 2010–2040 (Trillion kWh). *Source:* IEO (2013)

other hydrocarbons are a limited resource, and our own internal reserves are dwindling. Today Europe imports around 50 % of its energy needs. By 2030, that will be nearer 70 %, if current energy policies continue to be applied. At the same time, with the rise of new economic giants like China and India, global demand for these hydrocarbons is increasing (…).”

On the other hand, and according to IEO (2010), with world oil prices projected to stay high, liquid fuels are the only energy source for power generation that does not grow on a worldwide basis. Most nations are expected to respond to higher oil prices by reducing or eliminating their use for electricity generation, opting instead to use more economical energy sources for this specific purpose such as renewables, coal, and, in some countries, nuclear energy. It is expected that the generation of electricity from liquid fuels will decrease from 0.9 trillion kWh in 2007 to 0.8 trillion kWh in 2035; this represents a decrease of 11.2 % during that period.

1.2.1 Crude Oil

As of December 2012, proven world crude oil reserves, as reported by EIA sources, were estimated at 1,525.957 billion barrels, which is 52.2 billion barrels (about 3.5 %) higher than the estimate for 2011.[4] In 2013, the proven world crude oil

[4] Crude oil is a complex mixture consisting of 200 or more different organic compounds, mostly alkanes (single bond hydrocarbons on the form C_nH_{2n+2}) and smaller fraction aromatics (six-ring molecules such as benzene C_6H_6). The oil and gas industry classifies “crude” oil by were it was produced of its origin and often by its relative weight (API gravity or viscosity (“light”, “intermediate” or “heavy”); in addition it may also be referred to as “sweet” (it contains relatively little sulfur), or as “sour” (it contains substantial amounts of sulfur) and requires more refining in order to meet current petroleum specifications.

Table 1.1 List of top 20 countries with the highest proven crude oil reserves in January 2013

Countries	Proven crude oil reserves billion barrels	Percentage
Venezuela	297	18.2
Saudi Arabia	265.4	16.2
Canada	173.1	10.6
Iran	154.6	9.4
Iraq	141.4	8.6
Kuwait	101.5	6.2
United Arab Emirates	97.8	6
Russia	80	4.9
Libya	48	2.9
Nigeria	37.2	2.3
Kazakshtan	30	1.8
China	25.6	1.6
Qatar	25.4	1.5
USA	20.7	1.3
Brazil	13.2	0.8
Algeria	12.2	0.7
Angola	10.5	0.6
Mexico	10.3	0.6
Ecuador	8.2	0.5
Azerbaijan	7	0.4
Others	78.4	4.8
Total	1,637.9	100

Source: EIA

reserves were estimated at 1,637.9 billion barrels (IEO 2013); this represents an increase of 7.3 % with respect to 2012.

According to the *Oil and Gas Journal*, 51 % of the world's proven crude oil reserves are located in the Middle East. Just under less than 79 % of the world's proven crude oil reserves are concentrated in eight countries, of which only Canada (with oil sands included) and Russia are not OPEC members.

In 2013, the largest increase in crude oil reserves by far was attributed to Venezuela, as the country now reports its Orinoco belt extra-heavy oil in its totals (Radler 2010). The largest decreases in regional proven crude oil reserves were attributed to Europe, including notable declines for Norway, Denmark, and the United Kingdom (UK), which in combination saw a 14 % decline (1,485 billion barrels) in their proven crude oil reserves from 2010 to 2011 (Table 1.1).

World use of petroleum and other liquid fuels is expected to grow from 87 million barrels per day in 2010 to 97 million barrels per day in 2020 and 115 million barrels per day in 2040. All the growth in liquids use is expected to be in the transportation and industrial sectors. In the transportation sector, in particular, liquid fuels will continue to provide most of the energy consumed. Although advances in non-liquids-based transportation technologies are anticipated, they are not enough to offset the rising demand for transportation services worldwide. Despite rising fuel prices, use of liquids for transportation is expected to increase by an average of 1.1 % per year, or 38 % overall, from 2010 to 2040. The transportation sector is expected to account for 63 % of the total increase in liquid fuel use from 2010 to 2040, and the remainder is attributed to the industrial sector, where the chemicals industry continues to consume large quantities of petroleum throughout the projection. The use of liquids is expected to decline in the other end-use sectors and, particularly, for electric power generation (IEA 2013).

To meet the foreseeable increase in world demand, liquid fuels production (including conventional and non-conventional liquid fuel supplies) should increase by a total of 26.6 million barrels per day from 2008 to 2035. It is important to note that OPEC countries will invest in incremental production capacity in order to maintain a share of approximately 40 % of total world liquid fuels production through 2035, consistent with their share over the past 15 years. Increasing volumes of conventional liquids (crude oil and lease condensate, natural gas plant liquids, and refinery gain) from OPEC producers should contribute 10.3 million barrels per day to the total increase in world liquid fuels production, and conventional supplies from non-OPEC countries add another 7.1 million barrels per day.

Non-conventional resources[5] (including oil sands, extra-heavy oil, biofuels, coal-to-liquids, gas-to-liquids, and shale gas) from all sources are expected to grow on average by 4.6 % per year over the period 2008–2035. Sustained high oil prices will allow unconventional resources to become economically competitive, particularly when geopolitical or other constraints limit access to prospective conventional resources. World production of unconventional liquid fuels, which totaled only 3.9 million barrels per day in 2008, is expected to increase to 13.1 million barrels per day, an increase of 236 %, and is expected to account for 12 % of total world liquid fuels supply in 2035.

According to Table 1.2, the ten top crude oil producers in 2012 produced 2,650 million of tons of crude oil, representing 64 % of the world total production. Within this group there is only one country that belongs to the European region (Russia) with 12.6 % of the world total production of crude oil. The ten top crude oil exporters in 2011 exported 1,408 million tons, representing 71 % of the world total exports. Within this group, there is only one European country (Russia with 12.5 % of the world total). The ten top importers of crude oil in 2011 imported 1,571 million tons of crude oil, representing 75.6 % of the world total imports. Within this group, there are four European countries (Germany, Italy, France, and the Netherlands).

[5] According to some experts' opinions, these sources may eventually more than triple the potential reserves of hydrocarbon fuels. Beyond that, there are even more exotic sources, such as methane hydrates, that some experts claim can double available resources once more.

Table 1.2 Producers, net exporters, and net importers of crude oil*

Producers	Mt	% of world total	Net exporters	Mt	Net importers	Mt
Saudi Arabia	544	13.1	Saudi Arabia	353	United States	500
Russian Federation	520	12.6	Russian Federation	247	People's Republic of China	251
United States	387	9.3	Islamic Republic of Iran	122	Japan	177
People's Republic of China	206	5.0	Nigeria	121	India	172
Islamic Republic of Iran	186	4.5	United Arab Emirates	114	Republic of Korea	125
Canada	182	4.4	Iraq	108	Germany	90
United Arab Emirates	163	3.9	Venezuela	93	Italy	77
Venezuela	162	3.9	Kuwait	89	France	64
Kuwait	152	3.7	Canada	82	Singapore	58
Iraq	148	3.6	Angola	79	Netherlands	57
Rest of the world	1,492	36	Others	574	Others	508
World	4,142	100	Total	1,982	Total	2,079
2012 data			2011 data		2011 data	

* Includes crude oil, NGL, feedstocks, additives and other hydrocarbons. *Source:* IEA (2013)

1.3 Natural Gas

The natural gas used by consumers is composed almost entirely of methane. However, natural gas found at the wellhead, though still composed primarily of methane, is not pure.[6] Raw natural gas comes from three types of wells: oil wells, gas wells, and condensate wells. Natural gas that comes from oil wells is typically termed "associated gas." This gas can exist separately from oil in the formation

[6] While the ethane, propane, butane, and pentanes must be removed from natural gas, this does not mean that they are all waste products. In fact, associated hydrocarbons, known as natural gas liquids (NGL), can be very valuable byproducts of natural gas processing. NGLs include ethane, propane, butane, iso-butane, and natural gasoline. These are sold separately and have a variety of different uses such as raw materials for oil refineries or petrochemical plants, as sources of energy, and for enhancing oil recovery in oil wells. Condensates are also useful as diluents for heavy crude oil.

(free gas), or dissolved in the crude oil (dissolved gas). Natural gas from gas and condensate wells in which there is little or no crude oil, is termed "non-associated gas." Raw gas is processed into various products or fractions:

- Natural gas in its marketable form has been processed for a specific composition of hydrocarbons, sour and acid components, etc., and energy content. Content is typically 90 % methane, with 10 % of other light alkenes;
- Natural gas liquids (NGL) is a processed purified product consisting of ethane, propane, butane, or some higher alkenes separately, or in a blend. It is primarily a raw material for the petrochemical industry and is often processed from the condensate;
- Liquefied petroleum gas (LPG) refers to propane or butane or a mixture of these that has been compressed to liquid at room temperature. LPG is filled in bottles for consumer domestic use as fuel, and is also used as aerosol propellant (in spray cans) and refrigerant (e.g., in air conditioners). Energy to volume ratio is 74 % of gasoline;
- Liquefied natural gas (LNG) is natural gas that is refrigerated and liquefied at below −162 °C, for storage and transport. It is stored at close to atmospheric pressure, typically less than 125 kPa. As a liquid, LNG takes up 1/600 of the volume of the gas at room temperature. Energy to volume ratio is 66 % of gasoline. After transport and storage it is reheated/vaporized and compressed for pipeline transport;
- Compressed natural gas (CNG) is natural gas that is compressed to less than 1 % of volume at atmospheric pressure. Unlike higher alkenes, methane cannot be kept liquid by high pressure at normal ambient temperatures because of a low critical temperature. CNG is used as a less costly alternative to LNG for lower capacity and medium distance transport. Methane for vehicle fuel is also stored as CNG. Energy to volume ratio is typically 25 % of gasoline.

In the case of natural gas, there are enough reserves to satisfy the foreseeable demand during the coming decades. According to EIA 2013 report (see Table 1.3), the world's total natural gas reserves in 2013 were estimated at 239,894.8 trillion m^3 (6,793 trillion cubic feet).[7] According to EIA sources, worldwide natural gas demand grew by 1.71 billion m^3 per day from 2000 to 2007, nearly 25 % during the whole period or 3.6 % as average per year. The EIA also projects global natural gas demand in the coming years to grow over 9.7 billion m^3, representing an increase of 14.8 %, and projects a further growth in demand around 11.2 billion m^3 per day by 2025; this represents a further increase of 16.1 % (see Fig. 1.2). World natural gas consumption is expected to increase by 64 % from 113 trillion cubic feet (3,990.6 billion m^3) in 2010 to 185 trillion cubic feet (6,533.275 billion m^3) in 2040. Although the global recession resulted in an estimated decline of 3.6 trillion cubic feet (127.134 trillion m^3) in natural gas use in 2009, robust demand returned in 2010 with an increase of

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[7] One cubic feet is 35.315 m^3.

Table 1.3 Natural gas reserves by country January 2013

Country	Reserves (Trillion cubic feet)	Percentage
World	6,793	100
Top 20 countries	6,200	91.3
Russia	1,688	24.9
Iran	1,187	17.5
Qatar	890	13.1
Saudi Arabia	288	4.2
United States	273	4.0
Turkmenistan	265	3.9
United Arab Emirates	215	3.2
Venezuela	195	2.9
Nigeria	182	2.7
Algeria	159	2.3
China	124	1.8
Iraq	112	1.6
Indonesia	108	1.6
Kazakhstan	85	1.3
Malaysia	83	1.2
Egypt	77	1.1
Norway	73	1.1
Canada	68	1.0
Uzbekistan	65	1.0
Kuwait	63	0.9
Rest of the world	593	8.7

Source: IEA

7.7 trillion cubic feet (271.93 trillion m^3), or 4 % higher than demand in 2008, before the downturn (IEA 2013).

Natural gas continues to be the fuel of choice for the electric power and industrial sectors in many of the world's regions, in part because of its lower carbon intensity compared with coal and oil, which makes it an attractive fuel source in countries where governments are implementing policies to reduce greenhouse gas emissions. In addition, it is an attractive alternative fuel for new power generation plants because of relatively low capital costs and the favorable heat rates for natural gas generation. The industrial and electric power sectors together account for 77 % of the total projected world increase in natural gas consumption. In 2011, the participation of natural gas in the EU energy mix reached 23.4 % and in the generation of electricity 37.4 %.

According to Table 1.3, the major world natural gas reserves are located in Russia (24.9 % of the total), followed by Iran (15.5 %) and Qatar (13.1 %). Among the

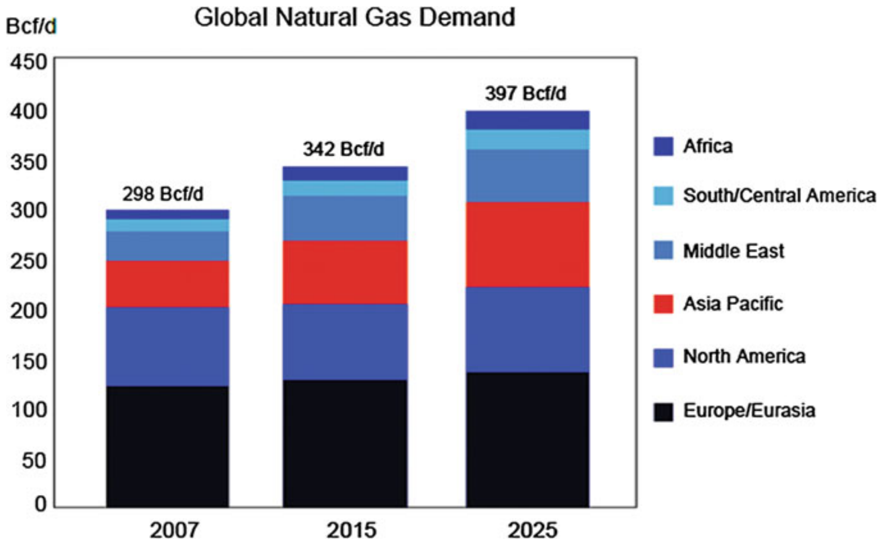

Fig. 1.2 World's natural gas demand projection during the period 2015–2025. *Source:* EIA International Energy Outlook (2010)

20 top countries with the highest natural gas reserves there are only two European countries: Russia and Norway.

Natural gas consumption in OECD Europe is expected to grow by 0.7 % per year on average, from 19.8 trillion cubic feet (699,237 trillion m^3) in 2010 to 24.5 trillion cubic feet (865,2175 trillion m^3) in 2040, the lowest growth rate over the period, both in the OECD region and in the world. The decline in demand for energy from coal and liquids results in an increase in the natural gas share of OECD Europe's total energy consumption, from about 25 % in 2010 to 27 % in 2040. More than half of OECD Europe's 4.7 trillion cubic feet (165,9805 trillion m^3) of growth in total natural gas consumption from 2010 to 2040 is expected to come from the electric power sector at 2.7 trillion cubic feet (95.35 trillion m^3). Although the amount of natural gas consumed for electric power production is expected to increase by an average of only 0.4 % per year from 2010 to 2020, it is expected to increase by 1.7 % per year from 2020 to 2040, as economies recover from the global recession that began in 2008.

Many governments in OECD Europe have made commitments to reduce greenhouse gas emissions to 20 % below 1990 levels by 2020 and have endorsed the objective of lowering emissions to between 80 % and 95 % below 1990 levels by 2050 (European Commission 2013).

Natural gas potentially has two roles to play in reducing carbon dioxide emissions in OECD Europe's electric power sector: as a replacement fuel for more carbon-intensive coal-fired generation and as a backup for intermittent generation from renewable energy sources. Although there are many incentives for using natural gas more heavily in the electric power sector, growth has been hampered by a lack of progress in regulatory reforms in OECD Europe that would make natural gas more competitive in electric power markets. Such reforms would include measures to increase spot trading and make natural gas markets more flexible by making it easier for market participants to purchase and transmit gas supplies. Presumably, the impact of such reforms, as well as the increased use of natural gas to reduce carbon dioxide emissions from electric power generation, would occur for the most part after 2025. Additionally, recent actions by some European governments to reduce their reliance on nuclear power in the wake of Japan's Fukushima Daiichi nuclear disaster will provide an additional boost to both natural gas and renewable energy use in electricity generation. According to IEO (2013), "an increase of 1.7 % per year in natural gas consumption for power generation from 2020 to 2040 is higher than for any other energy source used in the sector".

Many governments in OECD Europe have made commitments to reduce greenhouse gas emissions and to promote the development of clean energy for electricity generation during the coming decades. Because natural gas is less carbon-intensive than either coal or oil, it is a more environmentally attractive option for electricity generation under this circumstance, and thus is likely to remain an important fuel for Europe's electric power sector development in the long term.

The countries of non-OECD Europe and Eurasia currently rely on natural gas for more than 50 % of their primary energy needs, the larger share in the IEO (2011) reference case. Russia is the world's second largest consumer of natural gas after the United States, with demand totaling 593.292 trillion m^3 (16.8 trillion cubic feet) in 2008, representing 55 % of Russia's total energy consumption. It is expected that Russia's natural gas consumption will grow at a modest average rate of 0.1 % per year from 2008 to 2035. In other countries of non-OECD Europe and Eurasia, it is expected that natural gas consumption will grow by 0.4 % annually over the period 2008–2035, from 289.583 trillion m^3 (8.2 trillion cubic feet) in 2008 to 321.367 trillion m^3 (9.1 trillion cubic feet) in 2035.

It is important to highlight that natural gas is the largest component of several other European countries' primary energy consumption. The industrial sector remains the region's largest consumer of natural gas, with a share of approximately 40 % of total natural gas consumption throughout the period 2008–2035. However, in the long term, rising prices for both domestically produced and imported natural gas are likely to moderate the region's growth in natural gas demand.

From Fig. 1.3, the following can be stated: The primary production of natural gas in the EU during the period 2005–2012 decreased from 190,651.8 thousand tons of oil equivalent in 2005 to 133,148.5 thousand tons of oil equivalent in 2012; this represents a decrease of 30.2 %.

The main European natural gas producers in 2012 were Russia with 19.1 % of the world total, followed by Norway with 3.3 % and the Netherlands with 2.3 %. The main European natural gas exporters in 2012 were Russia with 22.3 % of the world total, followed by Norway with 13.1 % and the Netherlands with 4.1 %. The main European natural gas importers in 2012 were Germany with 8.4 % of the world total, followed by Italy with 8.2 %, France with 5.2 %, and Ukraine with 3.9 % (Table 1.4).

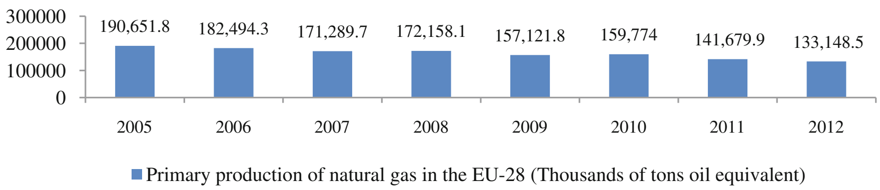

Fig. 1.3 Primary production of natural gas in the EU-28. *Source:* Eurostat data base

Table 1.4 Producers, net exporters, and net importers of natural gas in 2012

Producers	Bcm	% of world total	Net exporters	Bcm	Net importers	Bcm
United States	681	19.8	Russian Federation	185	Japan	122
Russian Federation	656	19.1	Qatar	120	Germany	70
Qatar	160	4.7	Norway	109	Italy	68
Islamic Republic of Iran	158	4.6	Canada	57	Republic of Korea	48
Canada	157	4.6	Algeria	48	Turkey	45
Norway	115	3.3	Turkmenistan	37	United States	43
People's Republic of China	107	3.1	Indonesia	37	France	43
Saudi Arabia	95	2.8	Netherlands	34	United Kingdom	37
Netherlands	80	2.3	Nigeria	27	People's Republic of China	36
Indonesia	77	2.2	Malaysia	21	Ukraine	32
Rest of the world	1,149	33.5	Others	154	Others	283
World	3,435	100	Total	829	Total	827
2012 data			2012 data		2012 data	

Net export and net imports include pipeline gas and LNG. *Source:* IEA (2013)

According to Table 1.5, UK is the country with the highest inland consumption of natural gas for generation of electricity with 994.40 GWh per year, followed by Germany with 853.71 GWh per year, Italy with 791.5 GWh per year, and France with 494.74 GWh per year. The EU countries with the highest production of natural gas for generation of electricity are the Netherlands with 738.90 GWh per year, followed by the UK with 598.57 GWh per year, and Germany with 112.74 GWh per year.

Table 1.5 Gas security of supply—2011

Country	Gross inland production(1) (GWh per year)	National production(2) (GWh per year)
Belgium	197.24	N/A
Bulgaria	26.07	N/A
Czech Republic	93.26	1.94
Denmark	51.45	85.41
Germany	853.71	112.74
Estonia	6.54	N/A
Ireland	54.61	3.68
Greece	37.61	0.08
Spain	362.71	0.6
France	494.74	7.51
Italy	791.50	80.07
Cyprus	N/A	N/A
Latvia	17.00	N/A
Lithuania	28.98	N/A
Luxembourg	13.92	N/A
Hungary	114.15	25.99
Netherlands	457.16	738.9
Austria	95.53	17.28
Poland	148.92	42.95
Portugal	52.20	N/A
Romania	125.47	100.23
Slovenia	10.03	0.07
Slovakia	58.22	1.03
Finland	44.63	N/A
Sweden	15.27	N/A
United Kingdom(3)	994.40	598.57

Sources: National Regulators data Eurostat
Notes: (1) Gross Inland Consumption = Production + Imports − Exports + Storage variations. (2) The maximum quantity of gas consumed in a day during the year. (3) UK numbers include Great Britain only, as gas demand from Northern Ireland and the Republic of Ireland is not possible to differentiate

According to Eurostat sources, in 2012, gross inland consumption of natural gas in EU-27 fell by 3.6 % in comparison with 2011. The biggest falls in consumption compared with 2011 were in Belgium (−30.5 %), Sweden (−12.7 %), Finland (−10.5 %), Portugal (−9.6 %), Denmark (−8.4 %), and Greece (−7.7 %). Increases in consumption in comparison with 2011 were recorded only in Estonia (+11.3 %), Poland (+6.2 %), Germany (+3.4 %), and Luxembourg (+1.5 %).

1.4 Coal

World coal production is expected to increase over the next 10–15 years by about 30 %, mainly driven by Australia, China, Russia, Ukraine, Kazakhstan, and South Africa. Production will then reach a plateau and will eventually decline thereafter (see Fig. 1.4). According to this figure, the production of coal is expected to increase until 2020 and after that year the production of coal will start to decline until 2100. In 2010, the confirmed world coal reserves were around 909.4 billion short tons, enough to satisfy the increase in world energy demands at least for the next 120–130 years at present level of consumption.[8] It is important to highlight that between 85 % and 90 % of global coal reserves are concentrated in six countries: USA, Russia, India, China, Australia, and South Africa. USA alone holds 30 % of the world's coal reserves and is the second largest producer. In the European region, only one country, Russia, is among the six top countries with the highest coal reserves.

However, according to the EWG (EWG Series No. 1, 2007), the historical world coal reserve assessments raise doubts regarding the quality of this information. The reasons are the following:

(a) Proven coal reserves of China have not changed since 1992; those of some other countries not even since 1965;
(b) Proven recoverable coal reserves (as reported by the WEC) for other countries—e.g., Botswana, Germany, and the UK—have been downgraded over the past

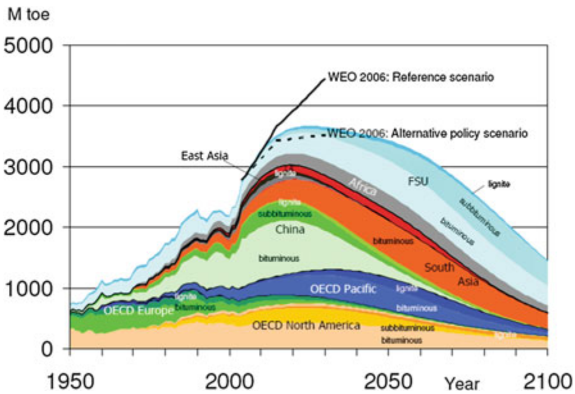

Fig. 1.4 Worldwide possible coal production during the period 1950–2100. *Source:* EWG Series No.1 2007

[8] The first and foremost conclusion from different experts' studies is that data quality of coal reserves and resources is poor, both on global and national levels and, for this reason, it is difficult to confirm the real world, regional, and national coal reserves. The most dramatic example of unexplained changes in data is the downgrading of the proven German hard coal reserves by 99 % from 23 billion tons to 0.183 billion tons in 2004. Poland has downgraded its hard coal reserves by 50 % compared to 1997 and has downgraded its lignite and subbituminous coal reserves in two steps to zero since 1997 (EWG 2007).

years by more than 90 %. Even the coal reserves of Poland are 50 % smaller now than 20 years ago. This downgrading cannot be explained by volumes produced in that period. The revisions are probably due to better data;

(c) Since 1987, the proven recoverable coal reserves (as reported by WEC) of India were continuously revised upward from about 21 billion tons to more than 90 billion tons in 2002. However, India is the only country with such huge upward revisions.

Estimated world coal resources have declined from 10 billion tons coal equivalent to about 4.5 billion tons coal equivalent, a decline of 55 % within the past 25 years. Moreover, this downgrading of estimated coal resources shows a trend supported by each new assessment. Therefore, it is possible that resource estimates will be further reduced in the future (EWG Series No. 1, 2007).

China is by far the largest coal producer, but possesses only half the coal reserves of the USA. Other important coal producers are India, Australia, South Africa, Russia, Indonesia, Poland, Kazakhstan, and Colombia. Therefore, the outlook for coal production in these countries, particularly China and the USA, will dominate the future of global coal production. In addition, it is important to highlight that coal consumption mainly takes place in the country of origin; only 15 % of coal production is exported. The largest net coal exporters are Australia, Indonesia, Russia, Colombia, South Africa, and China. These countries account for 85 % of all exports with Australia providing almost 40 % of all exports (EWG Series No. 1, 2007).

In the absence of national policies and/or binding international agreements that would limit or reduce greenhouse gas emissions, world coal consumption is projected to increase from 139 quadrillion Btu in 2008 to 209 quadrillion Btu in 2035, at an average annual rate of 1.5 %.[9] Regional growth rates are uneven with little growth in coal consumption in OECD nations, but robust growth in non-OECD nations, particularly among the Asian economies (IEO 2011). Much of the projected increase in coal use occurs in non-OECD Asia, which accounts for 95 % of the total net increase foreseeable in world coal use from 2007 to 2035. Increasing demand for energy to fuel electricity generation and industrial production in the non-OECD Asia is expected to be met in large part by coal (IEO 2010).

In 2007 coal-fired power generation accounted for 42 % of world electricity supply; in 2035 it is expected that the coal share will increase slightly to 43 %; this represents a very modest increase of only 1 % in the next 28 years. Sustained high prices for oil and natural gas make coal-fired power generation more attractive economically, particularly in nations that are rich in coal resources. In 2020, the participation of coal in electricity generation is expected to be 40 %; this represents

[9] In the IEO (2010) report, world's coal consumption is expected to increase by 56 % from 2007 to 2035, and coal's share of world's energy consumption is expected to grow from 27 % in 2007 to 28 % in 2035; this represents an increase of only 1 % for the whole period.

2 % lower than the level reached in 2007. In 2035, the participation of coal in electricity generation is expected to be 43 %; this represents 3 % higher than the level reached in 2020 and 1 % higher than the level reached in 2007. In general, the use of coal in the European region (OECD countries[10]) will drop from around 19 quadrillion Btu in 1980 to slightly higher than 10 quadrillion Btu in 2035; this represents a reduction of 9 quadrillion Btu or 47.4 %.

According to the IEO (2010) report, coal is in decline for electricity generation in many countries. It is expected a reduction of 0.3 % per year during the coming years. Nevertheless, coal-fired power plants are expected to supply the second biggest amount of electricity after renewable sources by 2035 and it is expected also to be the second fastest growing source of energy for electricity generation in the projection period, except for the Latin American and Caribbean regions. Undoubtedly, coal is the predominant fuel used for electricity generation worldwide and it is expected to continue playing this role during the coming decades. Coal-fired electricity generation is expected to grow at a 1.8 % annual rate from 2010 to 2040. In 2040, total world electricity generation from coal is expected to be 73 % higher than the 2010 level, although coal's share of the electricity market will fall to 36 % in 2040. China and India alone account for 89 % of the projected growth in coal-fired generation. In contrast, OECD nations reduce their reliance on coal-fired electricity generation with environmental factors, particularly in OECD Europe, playing a sizable role in the reduction (IEO 2013). However, this projection could be altered substantially by any future national policies or international agreements that aim to reduce or limit the growth of greenhouse gas emissions. Finally, it is important to highlight that coal will continue to be, during the coming years, the fossil fuel with the largest share of worldwide electric power production by a wide margin (see Fig. 1.5).

The total coal consumption in the countries of OECD Europe is expected to decline from 12.2 quadrillion Btu in 2010 (27 % of the OECD total) to 10.7 quadrillion Btu in 2040 (25 % of the worldwide total). Although all nations in the region consume coal, 65 % of OECD Europe's 2010 total coal consumption was concentrated in Germany, Poland, Turkey, and the UK, with Germany alone consuming 26 % of the regional total. The electric power sector accounted for 67 % of the region's total coal consumption in 2010, and most of the remainder was consumed in the industrial sector. Electric power demand for coal is declining steadily in the region and driving the downward trend in the region's overall coal consumption (IEO 2013).

The Industrial Emissions Directive (IED), agreed to by the European Council of Ministers and the European Parliament in 2010, as well as regional climate change policy goals, drive this decline. The IED requires use of the best available technology

[10] OECD Europe include the following countries: Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, Slovakia, Spain, Sweden, Switzerland, Turkey, and the UK.

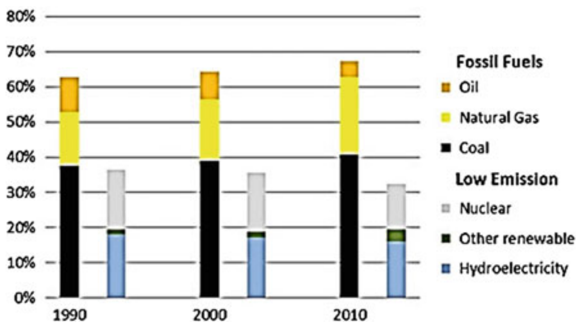

Fig. 1.5 Participation of different energy sources in the generation of electricity during the period 1990–2010. *Sources:* World Energy Outlook 2002 and World Energy Outlook 2012, IEA

for reduction of sulfur dioxide and nitrogen oxides, among other pollutants, beginning in 2016, and is likely to trigger retirements of some coal-fired power plants, especially in the four leading coal-consuming countries (European Commission 2010). The scale of the retirements outweighs the scale of new coal-fired capacity additions in Germany, Turkey, Poland, the Netherlands, and Italy, where new coal-fired capacity is needed to fill the supply gaps left by a nuclear power phase-out (in Germany), to replace less competitive power plants (such as oil-to-coal conversions and replacements in Italy) and to supply more power to meet the demand growth (especially in Turkey) (World Resource Institute 2012). Total installed coal-fired generating capacity in OECD Europe is expected to decline from 204 GW in 2010 to 169 GW in 2040 (a reduction of 17.2 %), and coal's share of total electricity generation is expected to decline from 24 % in 2010 to 15 % in 2040; this represents a reduction of 9 %.

Coal consumption in the OECD Europe industrial sector remains largely flat. The effects of energy efficiency measures in OECD European countries, such as moving away from less efficient processes like open-hearth steelmaking, are more than offset by the effect of the increase in industrial output. For example, the gross output of OECD Europe's iron and steel plants is expected to increase by 26 % from 2010 to 2040 (IEO 2013).

In 2006, Poland (93 %), the Czech Republic (59 %), Greece (58 %), and Germany (47 %) were the European countries with the highest dependency on coal for generation of electricity.[11] This situation has not changed during the past years (Table 1.6).

[11] The dependency factor can be calculated using the following formula: Energy dependency $= \frac{\text{Net imports}}{\text{Production} + \text{Net imports}} \times 100$.

Table 1.6 Producers, net exporters, and net importers of coal in 2012*

Producers	Mt	% of world total	Net exporters	Mt	Net importers	Mt
People's Republic of China	3,549	45.3	Indonesia	383	People's Republic of China	278
United States	935	11.9	Australia	302	Japan	184
India	595	7.6	United States	106	India	158
Indonesia	443	5.7	Russian Federation	103	Republic of Korea	126
Australia	421	5.4	Colombia	82	Chinese Taipei	65
Russian Federation	354	4.5	South Africa	72	Germany	45
South Africa	259	3.3	Kazakhstan	32	United Kingdom	44
Germany	197	2.5	Canada	25	Turkey	29
Poland	144	1.8	Mongolia	22	Italy	24
Kazakhstan	126	1.6	Vietnam	18	Malaysia	22
Rest of the world	808	10.4	Others	23	Others	213
World	7,831	100	Total	1,168	Total	1,188
2012 data			2012 data		2012 data	

* Includes steam coal, coking coal, lignite and recovered cool. *Source:* IEO (2013)

The main European coal producers in 2012 were Russia with 4.5 % of the world total, followed by Germany with 2.5 % and Poland with 1.8 %. The main European coal exporter in 2012 was Russia with 8.8 % of the world total. The main European coal importers in 2012 were Germany with 3.8 % of the world total, followed by UK with 3.7 %, Turkey with 2.4 %, and Italy with 2 %. World recoverable coal reserves as of January 2009 are included in Table 1.7.

From Table 1.7, the following can be stated: The world coal reserves are estimated at 946.1 billion short tons. The countries with the major coal reserves are USA (258.6 billion short tons or 27.3 % of the total); Russia (173.1 billion short tons or 18.3 % of the total), and China (126.2 billion short tons or 13.3 % of the total). The reserves-to-production ratio was estimated in 2009 to be 119 years. In 2012, the world coal reserves were estimated at 865.99 billion short tons; this represents a decrease of 8.5 % with respect to 2009.

Table 1.7 World recoverable coal reserves as of January 2009 (Billion short tons)

	Recoverable reserves by coal rank					
Region/ Country	Bituminous and anthracite	Subbituminous	Lignite	Total	2010 production	Reserves-to-production ratio (years)
World total	445.0	285.9	215.2	946.1	7.954	119
United States[a]	118.4	107.2	33.1	258.6	1.084	238
Russia	54.1	107.4	11.5	173.1	0.359	482
China	68.6	37.1	20.5	126.2	3.506	36
Other non-OECD Europe and Eurasia	42.2	18.9	39.9	100.9	0.325	311
Australia and New Zealand	40.9	2.5	41.4	84.8	0.473	179
India	61.8	0.0	5.0	66.8	0.612	109
OECD Europe	6.2	0.9	54.5	61.6	0.620	99
Africa	34.7	0.2	0.0	34.9	0.286	122
Other non-OECD Asia	3.9	3.9	6.8	14.7	0.508	29
Other Central and South America	7.6	1.0	0.0	8.6	0.085	101
Canada	3.8	1.0	2.5	7.3	0.075	97
Brazil	0.0	5.0	0.0	5.0	0.006	842
Others[b]	2.6	0.8	0.1	3.6	0.015	233

[a] Data for the United States represent recoverable coal estimates as of January 1, 2012
[b] Includes Mexico, Chile, Middle East, Japan, Republic of Korea, and Greenland
Source: IEO (2013)

1.5 Energy Dependency

The overall import dependency of the EU has grown at a lower rate in recent years. Although it increased by 3.5 % between 1995 and 2000, and by 5.8 % between 2000 and 2005, the increase in the period between 2005 and 2010 was only 0.2 %. The impact assessment of the Energy Roadmap 2050 indicates that the EU's import dependency will not change significantly until 2030 (could reach 56.4 % according to available sources).

The participation of the different energy sources in the energy mix of the European countries is shown in Fig. 1.6.

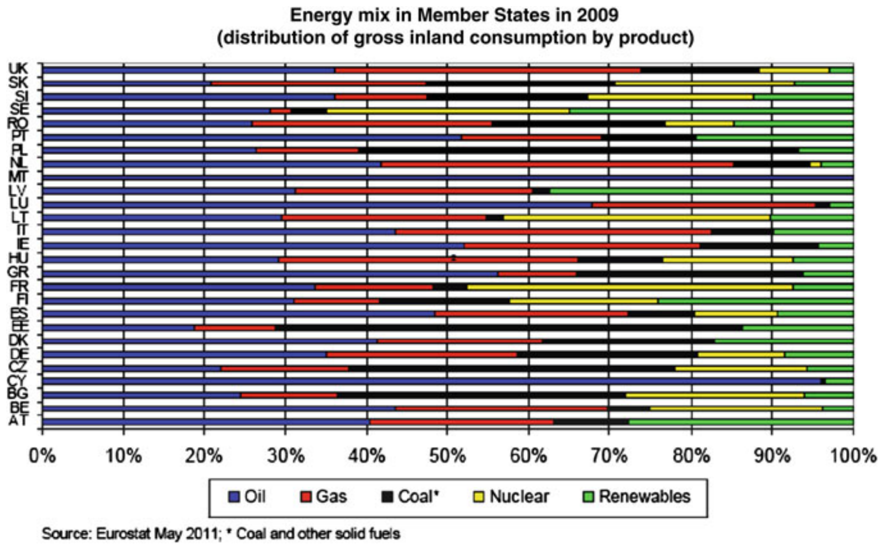

Fig. 1.6 Participation of different energy sources in the energy mix of the European countries

1.6 Electricity Generation

There are three major electricity networks in Europe: NORDEL (Iceland, Denmark, Sweden, Norway, and Finland), IPS/UPS (the entire former Soviet bloc, including Lithuania), and UCTE (all other European continental countries). These three electricity networks are not interconnected.

The purpose of the European power generation system is to satisfy electricity demand with an adequate quality of service at the best cost. In Europe, electricity is generated using different types of energy sources. These sources are, among others, oil, natural gas, coal, hydro, wind, solar systems, biomass, geothermal, and nuclear energy. Several power plants used for generation of electricity in the region are reaching its operational life and, for this reason, should be replaced with new and more efficient power plants with low CO_2 emissions, with the aim of implementing the EC directives on the reduction of emissions of this gas. It is important to highlight that electricity production is responsible for 32 % of total global fossil fuel use, but in several EU countries this figure is lower and continued to decline in recent years. Improving the efficiency of electricity production, therefore, offers economic benefits and a significant opportunity for reducing dependence on fossil fuels, which helps to combat climate change, the reduction of the emission of CO_2, and improve energy security.

Energy efficiency depends, among other factors, on the type of power plants and the number of years in service.[12] If steam power plants are going to be retired after

[12] According to IEA sources, the global average efficiencies of electricity production are 34 % for coal, 40 % for natural gas and 37 % for oil. For all fossil fuels, the global average efficiency is

40 years of service as well as other types of power plants after 25 years of operation, then it is expected that a total of 400 GW of existing power plants will be retired by 2030, bringing the current installed capacity down to 65 GW. The remaining capacity will mainly comprise steam power plants (84 %) and will be fuelled mostly by coal (60 %), followed by oil (21 %) and natural gas (19 %) (Tzamis et al. 2009).

The replacement of old and inefficient power plants should be carried out on the basis of the following goals:

- A significant reduction of CO_2 emissions;
- The generation of electricity at minimal possible cost;
- The reduction of primary energy consumption;
- An increase in the security of energy supply.

For this reason, the expansion of the electricity generation capacity should not be considered an isolated issue that only concerns the electricity sector, but should be treated as a key aspect in the formulation of the overall European sustainable energy strategy (Tzamis et al. 2009).

According to the IEO (2013) report, world net electricity generation is expected to increase by 93 %, from 20.2 trillion Kwh in 2010 to 39 trillion kWh in 2040. Electricity supplies an increasing share of the world's total energy demand and is the world's fastest-growing form of delivered energy. World electricity delivered to end-users is expected to rise by 2.2 % per year from 2010 to 2040, compared with average growth of 1.4 % per year for all delivered energy sources. In general, projected growth in OECD countries, where electricity markets are well established and consumption patterns are mature, is slower than in non-OECD countries, where at present many people do not have access to electricity. The electrification of historically off-grid areas plays a strong role in determining relative growth. The IEA estimates that 19 % of the world's population, or about 1.3 billion people (IEA 2012), did not have access to electricity in 2010. Moreover, almost 57 % of the population in Africa currently remains without access to electric power.

Although the 2008–2009 global economic recessions slowed the rate of growth in electricity use in 2008 and resulted in a negligible change in electricity use in 2009, demand returned in 2010, led by strong recoveries in non-OECD economies. Total net electricity generation in non-OECD countries are expected to increase by an average of 3.3 % per year, led by non-OECD Asia (including China and India), where annually it is expected to increase an average of 4.0 % from 2008 to 2035. In contrast, net generation among OECD nations is expected to grow by an average of

(Footnote 12 continued)
36 %. In absolute terms, the United States and China have the highest production of electricity from fossil fuels and account for 44 % of world production. A further five countries, Russia, Japan, India, Germany, and the UK, account for another 20 % of fossil-fuelled electricity production. Globally, most fossil-fuelled electricity production is from coal (63 %), followed by natural gas (29 %) and oil (9 %).

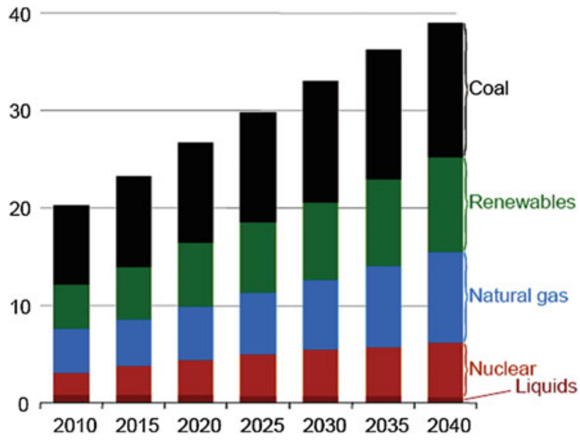

Fig. 1.7 World net electricity generation by fuel type during the period 2010–2040 (Trillion kWh). *Source:* IEO (2013)

1.2 % per year from 2008 to 2035.[13] In the case of Europe, total gross electricity generation in 2011 was 3,558.2 billion kWh, i.e., 3 % higher than in 2009 when it contracted due to the economic slowdown. Prior to the crisis, electricity generation had been growing steadily. It then fell in 2009 to its 2003 level.

Electricity supplies an increasing share of the world's total energy demand and grows faster than the consumption of liquid fuels, natural gas, and coal in all end-use sectors except transportation. From 1990 to 2007, growth in net electricity generation outpaced growth in total energy consumption (1.9 % and 1.3 % per year, respectively), and it is expected that the growth in demand for electricity will continue to outpace growth in total energy use throughout the projection period.

According to Fig. 1.7, coal will remain the main energy source for generation of electricity during the period 2010–2040.

Owing to the fact that the electricity generation infrastructure in Europe is aging and a large number of power plants are scheduled for retirement in the short and medium terms, the increase in electricity demand, coupled with a reduction in installed electricity generation capacity, could put the European power generation sector under significant strain in the coming years, with negative consequences for the European economy and the standard of living of Europe's citizens, unless new electricity generation capacity is built[14] (Tzimas et al. 2009). The electricity reserve capacity for the period 2007–2020 is shown in Fig. 1.8.

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[13] According to IEA sources, the highest absolute levels of electricity production from oil are in the United States, Japan, Mexico, China and Italy. These five countries now account for more than 36 % of global oil-fired electricity production.

[14] According to public information, the new power capacity to be installed in the next 25 years is almost the same than the current power generation capacity already installed in the region. The total capital investment required for this expansion has been calculated by different sources

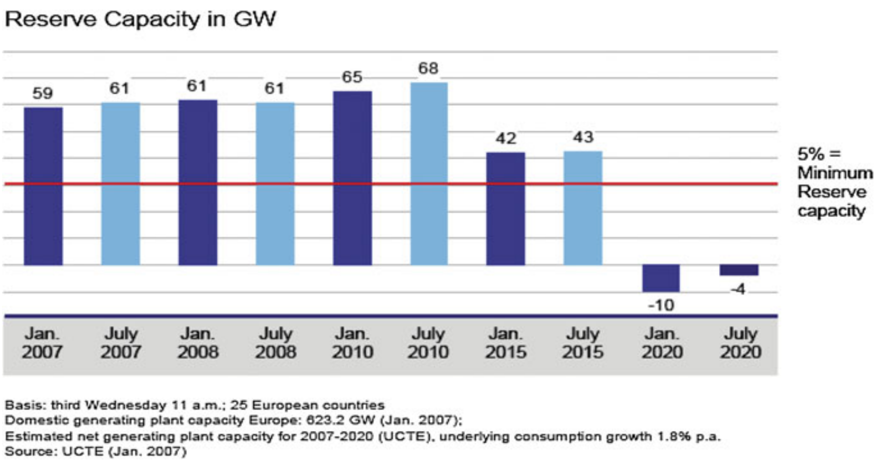

Fig. 1.8 Electricity reserve capacity projected for the period 2007–2020. *Source:* UCTE (Jan. 2007)

It is important to highlight that most of the countries in OECD Europe have relatively stable populations and mature electricity markets and, for this reason, it is expected that there will be no significant increase in the electricity consumption in these groups of countries during the coming years.

The electrification of historically off-grid areas plays a strong role in projected growth trends. The IEA estimates that 22 % of the world's population did not have access to electricity in 2008; a total of about 1.5 billion people. Today, this figure has been estimated at 1.8 billion people; this represents an increase of 20 %.

The participation of the different energy sources in Europe's energy mix is shown in Fig. 1.9. According to this figure, natural gas is the main energy source in the European energy mix, followed by wind and solar photovoltaic. However, this situation could be different during the coming years. In September 2010, the EC published its new EU's energy scenarios called "EU Energy Trends to 2030." The Commission expects 64 % of the total new power capacity to be renewable energy; 17 % natural gas; 12 % coal; 4 % nuclear energy; and 3 % oil. In the case of nuclear energy, the future situation in the use of this type of energy source for generation of electricity could be totally different as a result of the Fukushima nuclear accident. It is expected that the percentage of nuclear energy in the Europe energy mix could be lower than projected.

From Fig. 1.10, the following can be stated: In 2010, natural gas was the only type of conventional energy source that increased its installed capacity adding 28,280 MW to the current level. On the other hand, coal and oil reduced their

(Footnote 14 continued)
between €440 and €1,200 billion. The final amount of capital investment will depends of the electricity generation technology to be used.

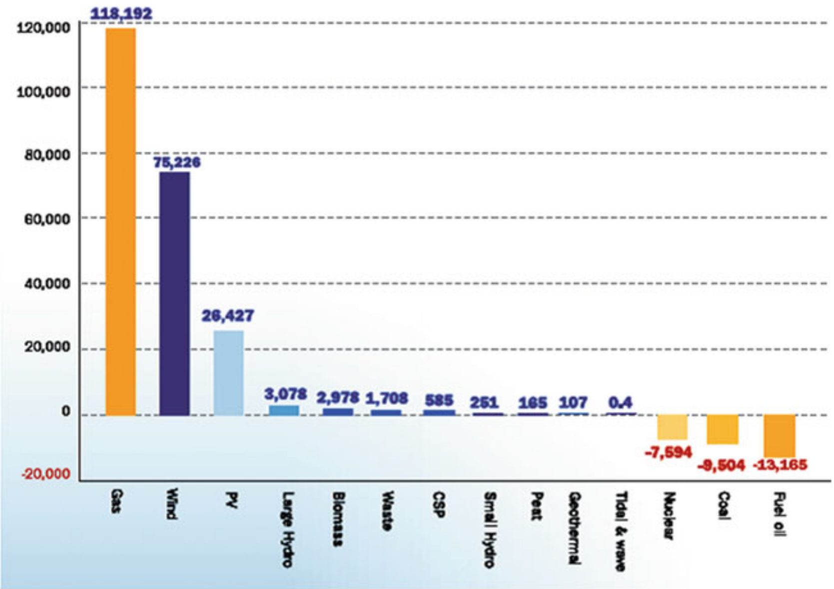

Fig. 1.9 Net electricity generating installations in the EU during the period 2000–2010 (MW). *Source:* EU Energy Policy to 2050

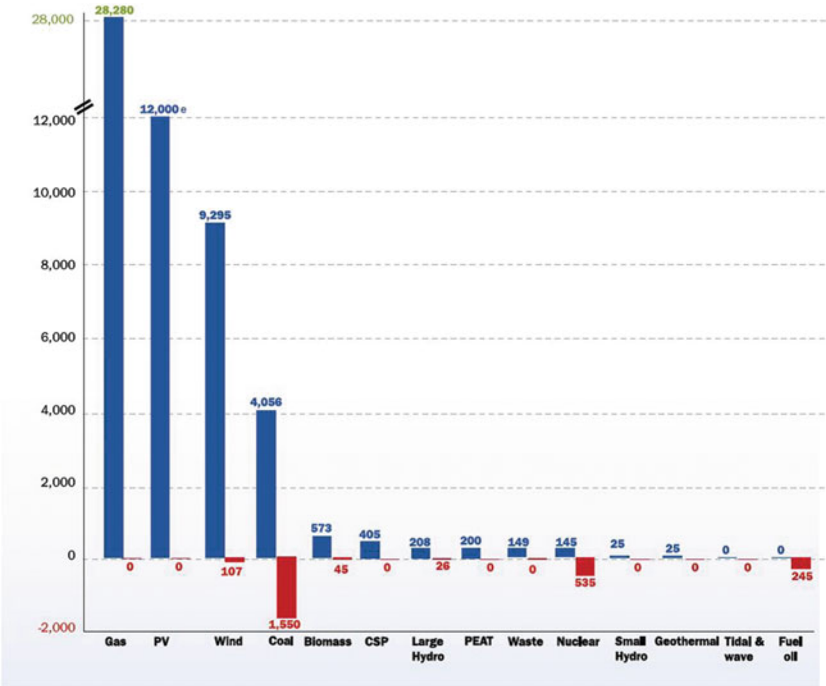

Fig. 1.10 New installed capacity and decommissioned capacity in MW (Total 52,820 MW). *Source:* EU Energy Policy to 2050

installed capacity in 1,550 and 245 MW, respectively. This trend is expected to continue during the coming years.

According to Tzamis et al. (2009), and despite the reduction in the installed capacity during the period 2000–2010, fossil fuel power plants will remain the backbone of the European electricity generation sector as a whole, at least until 2030. For this reason, the energy sector will continue to depend on significant quantities of imported fossil fuels, increasing the vulnerability of the European energy system to disruptions to its energy supply. At the same time, relying on the use of fossil fuels for electricity generation on a large scale will pose a major obstacle to European efforts to curb CO_2 emissions as part of the fight against climate change.

As a result of the effort made by several EU countries, the use of renewable energy sources for electricity generation is expected to increase until 2030, but will not dominate the electricity generation sector before that year. On the other hand, nuclear power plant capacity will either shrink or remain unchanged in some countries of the region in the coming years, particularly after the Fukushima nuclear power plant accident. Undoubtedly, the use of this type of energy for generation of electricity will continue to be a controversial subject within the EU countries. Germany, Switzerland, Belgium, among others, with nuclear power plants currently in operation, already had taken the decision to shut down all of their nuclear power reactors in operation in the coming years, and will not build new nuclear power plants in the future. Other countries such as Italy, Austria, and Denmark, will not use this type of energy source for generation of electricity in the future.

It is important to highlight that the need to expand the European power sector during the coming years will represent a major opportunity for replacement of the current old and less efficient power plants with new ones based on advanced, more efficient, and near-zero CO_2 emission technologies, thus paving the way toward a less carbon intensive power sector.

1.6.1 Impact of the Economic and Financial Crisis in Generation of Electricity

The current economic crisis affecting several EU countries is impacting negatively in almost all economic sectors, but particularly in the industrial sector. Demand in the building sector (the residential and commercial sectors) is less sensitive to changing economic conditions than it is in the industrial sector, because people generally continue to consume electricity for space heating and cooling, cooking, refrigeration, lighting, and water heating, even in an economic recession. As a result of the crisis, in 2010 electricity generation was up by only 1.8 %. In that year, Greece, Norway, Switzerland, the UK, the Netherlands, Ireland, and Italy could not reach the 2009 electricity generation levels. However, Luxembourg, Finland, Turkey, and Sweden had already returned to strong growth in the electricity generation sector.

Despite some growth in the electricity generation sector, the overall situation in this sector was not very encouraging, considering that only 10 countries out of 22

Table 1.8 Indigenous electricity generation in OECD Europe in 2008

Countries	Electricity production in 2008 (GWh)	Share of European electricity production in 2008 (%)
OECD Europe	3,461.369	100
Austria	61.7	1.79
Belgium	80.9	2.35
Czech Republic	77.1	2.24
Denmark	34.6	1.01
Finland	74.5	2.16
France	549	15.94
Germany	613.2	17.8
Greece	57.4	1.67
Hungary	37	1.07
Ireland	29.2	0.85
Italy	304.4	8.83
Luxembourg	3.5	0.1
Netherlands	102.7	2.98
Norway	143	4.15
Poland	141.2	4.1
Portugal	45.2	1.31
Slovakia	27.2	0.79
Spain	287.4	8.34
Sweden	146	4.24
Switzerland	66.9	1.94
Turkey	190.1	5.52
UK	372.9	10.82

Source: IEA (2008)

had reached or exceeded 2008 levels; this represents 45.5 % of the total number considered. In the major natural gas markets, only the Netherlands and Turkey were consuming more, while the other markets were struggling to get back to pre-crisis levels, particularly in France, Spain, UK, Germany, and Italy (Table 1.8).

From Table 1.9, the following can be stated: The EU-27[15] countries with the highest production of electricity were Germany with 18.6 % of the total, followed by France with 17.1 %, and the UK with 11.5 %. In 2010, the Eurozone countries generated 71.3 % of the total electricity produced by the EU-27.

The projection for total electricity generation in 2030 is 0.3 % lower than it was in last year's prediction made by several experts. This is largely because the impact of the economic recession in the near-term was more severe than anticipated in previous projection. According to the new data, liquids-fired generation is expected to be 11 % lower than early projection, but both natural gas and coal-fired power

[15] The EU has from July 2013, a total of 28 members (Croatia is the member 28 of the EU).

Table 1.9 Production of electricity in the EU-27 during the period 2000–2010

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Share In EU-27, 2010 (%)
EU-27	2,863	2,943	2,964	3,050	3,119	3,140	3,182	3,196	3,203	3,045	3,181	100.0
Euro area	1,995	2,040	2,069	2,136	2,194	2,204	2,245	2,258	2,275	2,159	2,268	71.3
Belgium	80.3	76.2	78.1	80.9	81.7	83.4	82.0	85.1	81.4	87.5	91.4	2.9
Bulgaria	36.9	39.6	38.6	38.5	37.5	40.3	41.6	39.1	40.7	38.7	42.2	1.3
Czech Republic	68.0	68.8	70.4	76.7	77.9	76.2	77.9	81.4	77.1	76.0	79.5	2.5
Denmark	34.4	36.2	37.3	43.8	38.4	34.4	43.2	37.4	34.9	34.5	36.8	1.2
Germany	538.5	548.2	549.3	567.9	576.8	581.6	597.2	598.4	598.9	556.8	591.4	18.6
Estonia	7.6	7.6	7.7	9.2	9.2	9.1	8.7	11.0	9.5	7.9	11.7	0.4
Ireland	22.7	23.7	23.9	24.1	24.4	24.8	26.1	26.9	28.9	27.1	27.5	0.9
Greece	49.9	49.7	50.6	54.3	54.9	55.7	56.5	59.1	59.4	56.1	53.4	1.7
Spain	214.4	226.0	232.7	250.2	268.7	282.1	287.7	293.2	301.5	283.4	292.1	9.2
France	516.9	526.3	534.9	542.5	549.7	550.3	549.1	544.6	548.8	515.2	544.5	17.1
Italy	263.3	266.0	270.8	280.2	290.0	290.6	301.3	301.3	307.1	281.1	290.7	9.1
Cyprus	3.2	3.4	3.6	3.8	4.0	4.1	4.4	4.6	4.8	4.9	5.1	0.2
Latvia	3.7	3.7	3.5	3.5	4.2	4.4	4.5	4.4	4.9	5.2	6.1	0.2
Lithuania	10.0	13.2	16.1	17.9	17.7	13.6	11.4	12.9	12.8	14.1	5.3	0.2
Luxembourg	1.1	1.6	3.7	3.6	4.1	4.1	4 3	4.0	3.5	3.8	4.6	0.1
Hungary	32.3	33.7	33.5	31.4	31.3	33.2	33.3	37.2	37.4	33.3	34.6	1.1
Malta	1.8	1.S	1.9	2.1	2.1	2.2	2.1	2.2	2.2	2.0	2.0	0.1
Netherlands	86.0	89.9	92.1	93.0	98.4	96.2	94.4	100.9	103.4	108.9	114.3	3.6
Austria	59.1	60.1	59.9	57.4	61.4	63.5	62.2	63.2	64.6	66.8	68.3	2.1
Poland	132.2	132.7	131.4	138.4	140.3	143.6	147.7	145.4	141.5	137.9	142.9	4.5
Portugal	42.2	44.8	44.4	45.4	43.5	45.0	47.5	45.9	44.6	48.7	52.8	1.7

(continued)

Table 1.9 (continued)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Share In EU-27, 2010 (%)
Romania	48.6	50.4	51.1	51.3	52.7	55.5	58.4	56.2	60.1	52.8	55.6	1.7
Slovenia	12.8	13.6	13.7	12.9	14.3	14.1	14.1	14.0	15.4	15.4	15.4	0.5
Slovakia	27.7	29.6	30.0	28.7	28.2	29.3	28.9	25.8	26.6	24.1	25.4	0.8
Finland	67.3	71.2	71.6	80.4	82.2	67.8	78.6	77.8	74.5	69.2	77.2	2.4
Sweden	141.6	157.6	143.2	132.5	148.5	154.6	140.4	145.1	146.4	133.3	145.3	4.6
United Kingdom	360.8	367.4	370.1	380.1	376.9	380.5	378.8	379.1	372.4	360.2	365.3	11.5
Norway	142.3	121.0	130.1	106.8	109.8	137.4	121.0	136.6	141.5	131.1	123.5	–
Switzerland	65.5	70.3	65.1	65 3	63.6	57.8	62.0	65.8	66.8	66.4	66.1	–
Croatia	10.2	11.7	11.7	12.1	12.8	12.0	12.0	11.7	11.8	12.4	13.6	–
Turkey	118.7	116.3	123.7	135.2	145.1	155.5	169.5	183.3	189.8	186.6	203.0	–

Source: Eurostat (online data code: nrg_105a) generation is expected to be about 5 % higher, nuclear power generation is expected to be 9 % higher, but this could change as a consequence of the nuclear accident at the Fukushima nuclear power plant and the decision of some European countries to shut down all nuclear power plants currently in operation during the coming years. The electricity generated from renewable energy sources is expected to be 10 % higher than the previous projection, but will not be enough to replace the use of fossil fuels in the generation of electricity. Electricity generation specifically in OECD Europe is expected to increase by an average of 1.1 % per year from 3.4 trillion kWh in 2007 to 4.4 trillion kWh in 2030, and 4.6 trillion kWh in 2035[16]; this represents an increase of 35 % respect to 2007.

Undoubtedly, the electric power sector offers some of the most cost-effective opportunities for reducing CO_2 emissions in many countries.[17] Coal is both the world's most widely used source of energy for electricity generation and also the most carbon-intensive energy source. If a cost, either implicit or explicit, were applied to CO_2 emissions, there are several alternatives or low-emission technologies that currently are commercially proven or under development, which could be used to replace some coal-fired power generation plants. Implementing these technologies would not require expensive large-scale changes in the power distribution infrastructure or in electricity using equipment.

1.6.2 The Use of Oil for Electricity Generation

With the current world oil prices between US$90 and US$100 per barrel and with the world oil prices projected to reach US$133 per barrel (in real 2008 dollars) in 2035, liquid fuels are the only energy source for power generation that does not grow on a worldwide basis during the next two decades. With oil prices remaining high, alternative fuels are substituted for liquids-fired generation where possible, and the liquid fuels share of generation is expected to fall from 5 % in 2008 to just over 2 % in 2035. Most nations are expected to respond to higher oil prices by reducing or

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[16] In Europe, indigenous electricity generation was down by 4.9 % in 2009 as a result of the economic and financial crisis that are affecting several countries of the region and in the USA. Contrary to expectations, five EU countries increased their indigenous electricity generation in 2009. These countries are Austria, Belgium, Luxembourg, Netherlands and Portugal. This outcome is somehow surprising due to an important industrial output reduction in all these countries, sometimes sharply (Luxembourg, Belgium and Austria). In other EU countries electricity generation suffered a significant reduction, particularly in Slovakia, Sweden, Hungary, and Greece, in line with a collapse in their industrial production outputs. In Germany, Italy, France, and the UK electricity generation registered a sharp decline while it was less severe in Turkey and Spain.

[17] In 2009, electricity generation in Europe accounts for 33 % of CO_2 production. Globally, the energy sector emits 26 billion tons of CO_2 each year and electricity production alone accounts for 41 % of total emissions (10.7 billons). The IEA expects CO_2 emissions in 2030 to have increased by 55 % to reach more than 40 billion tons of CO_2. The share of emissions coming from electricity generation is expected to increase up to 44 % in 2030, reaching 18 billion tons of CO_2; this represents an increase of 7.3 billons respect to 2009.

eliminating their use for electricity generation, opting instead for more economical sources of electricity generation, including coal and in some cases nuclear energy. For this reason, electricity generation from liquid fuels is expected to decrease from 0.9 trillion kWh in 2007 to 0.8 trillion kWh in 2035, a decrease of 11.2 %. It is expected that this trend will continue the same pattern during the coming years.

1.6.3 The Use of Natural Gas for Electricity Generation

The specific situation regarding the use of natural gas for electricity generation is the following: Over the period 2007 to 2035, natural-gas-fired electricity generation is expected to increase by 2.1 % per year. Generation of natural gas worldwide is expected to increase from 3.9 trillion kWh in 2007 to 6.8 trillion kWh in 2035; this represents an increase of 74.4 %, but the total amount of electricity generated from natural gas continues to be less than one-half the total for coal, even in 2035. According to the IEO (2011) report, the natural gas share of global electricity generation is expected to grow from 22 % in 2008 to 24 % in 2035.

Natural gas is the second fastest-growing source of power generation after renewables in the outlook for OECD Europe, increasing at an average rate of 1.3 % per year from 2007 to 2035, which is 0.8 % lower than the expected increase at world level. Although growth still is strong, considering that total electricity demand increases by only 1.1 % per year, it is slower than the 2.1 % annual increase projected for natural-gas-fired generation in previous reports. The difference results primarily from revised growth projections for the region's nuclear power and, to a lesser extent, renewable generation.

Table 1.10 Electricity produced from natural gas in 2008, 2009 and 2011

	Electricity production from natural gas in billion kWh in 2008	Electricity production from natural gas in billion kWh in 2009	Electricity Production from natural gas in billion kWh in 2011
Eleven European countries	372.5	346	260.73
Austria	10.9	12	11.67
Belgium	23	26.8	23.8
Czech Republic	4.3	4.1	1.42
France	14.6	24	20.42
Greece	13.3	9.4	8.5
Italy	174.5	143.1	142.06
Luxembourg	2.4	2.8	2.34
Poland	3.9	3.9	5.81
Portugal	14.4	13.9	23.8
Slovakia	1.7	1.6	2.2
Spain	109.6	104.5	84.52

Source: Entsoe data

According to Table 1.10, in 2011 Italy was the country with the highest participation of natural gas in the electricity generation in its energy mix within the European region, followed by Spain, Portugal and Belgium. It is expected that the use of natural gas in these group of European countries will suffer no significant changes during the coming years. The participation of natural gas in electricity generation in other European countries is very small.

It is important to highlight that natural-gas-fired-combined-cycle technology is an attractive choice for new gas-fired power plants to be built in the future because of its fuel efficiency, operating flexibility (it can be brought online in minutes rather than the hours it takes for coal-fired power plants and some others generating power plants), relatively short planning and construction times, relatively low emissions, and relatively low capital costs.

1.6.4 The Use of Coal for Electricity Generation

Coal accounted for nearly 25 % of OECD Europe's net electricity generation in 2008, 5 % lower than in 2007, but concerns about the contribution of CO_2 emissions to climate change could reduce that share in the future. Coal is the predominant fuel used for electricity generation worldwide. In 2010, coal-fired generation accounted for 40 % of overall worldwide electricity generation and it is expected to grow at a 1.8 % annual rate from 2010 to 2040. In 2040, total world electricity generation from coal is expected to be 73 % higher than the 2010 level, although coal's share of the electricity market is expected to fall to 36 % in 2040; this represents a 4 % decrease during the next 30 years. The OECD nations will reduce their reliance on coal-fired electricity generation due to environmental factors, particularly in OECD Europe, playing a sizable role in the reduction (IEA 2013). According to the IEO (2010) report, it is expected that electricity from coal slowly loses its prominence in OECD Europe and ultimately falling behind renewables, natural gas and, in some countries, nuclear energy as a source of electricity.

It is important to highlight that coal consumption in the electric power sector is not decreasing uniform in all countries in OECD Europe. For example, in Spain, the Spain's Coal Decree, which went into force in February 2011, subsidizes the use of domestic coal in the country's power plants. The policy is expected to result in more electricity generation from coal-fired plants, at least through 2014, when the subsidy is scheduled to expire (Fig. 1.11).

The use of coal for electricity generation for regions is shown in Fig. 1.12. In OECD America, the use of coal for electricity generation will slightly decrease during the period considered. On the other hand, the use of coal for electricity generation in OCDE Europe will significantly decrease in the same period. In total, the use of coal for electricity generation in OECD countries in 2040 will be higher than in 1980, but it will be almost the same than in 2020.

Finally, it is also important to consider the following reality during any consideration of the future energy balance in the European region. Europe is running out of indigenous energy resources in the form of fossil fuels at a time when a paradigm shift

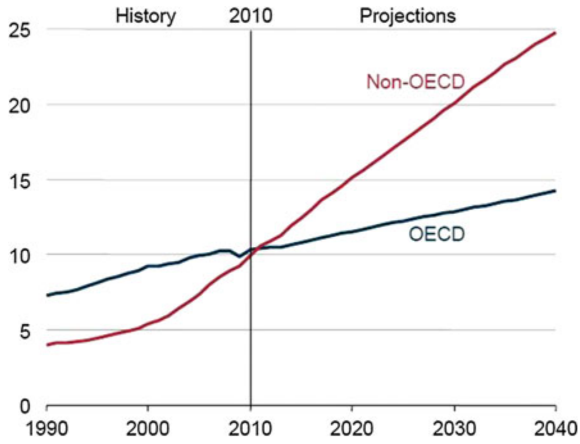

Fig. 1.11 World coal consumption for electricity generation in OECD and non-OECD countries during the period 1990–2040 (Quadrillion Btu). *Source:* IEO (2013)

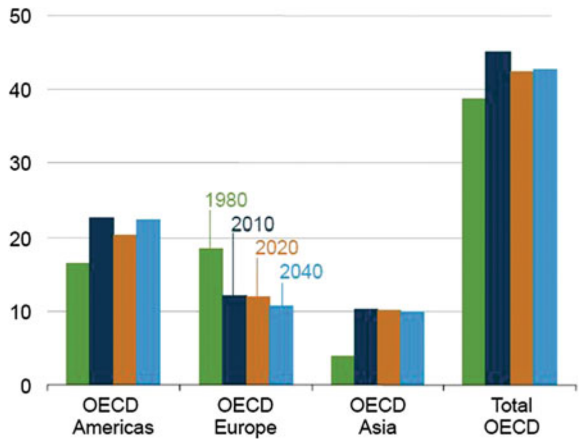

Fig. 1.12 OECD coal consumption by region in 1980, 2010, 2020, and 2040 (Quadrillion Btu). *Source:* IEO (2013)

in energy prices is occurring. At the end of 2012, the oil price was over US$100 per barrel and it is expected that this price will be higher during the coming years. The price of coal and natural gas is also expected to grow in the near future. Most observers agree that the era of cheap fossil fuels is over and signs are emerging that competition for ownership of oil and natural gas is becoming fiercer and will intensify heavily in the coming years. The era of energy uncertainty has come. Wars against Iraq and Libya were fought, in addition to political factors, such as the future political composition of the Middle East, for the future control of important oil and natural gas reserves located in these two countries as well as in other countries of the Middle East region. The controversy around the Iran's nuclear power program includes also the future control of the vast oil and natural gas reserves located in this country.

From Fig. 1.13, the following can be stated: Coal is, and it is expected to continue to be, the fossil fuel with the highest participation in the world electricity generation until at least 2040, followed by the use of different renewable energy

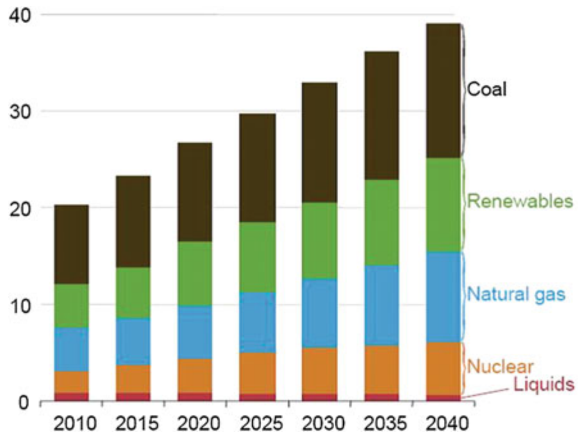

Fig. 1.13 World net electricity generation by fuel during the period 2010–2040 (Trillion kWh). *Source:* IEO (2013)

sources (after 2015 and until 2035), natural gas (will be second in 2035), nuclear energy, and liquid fuels. It is important to highlight that in the European region, switching towards natural gas (against coal) was apparent in the first half of 2010, particularly in some large markets in the North West of the region such as the Netherlands, the UK, France, and even Germany, while the picture was relatively different in Southern Europe where the electricity produced from natural gas was at 2009 levels in Italy and even lower in Spain due to increase hydro and wind electricity generation.

However, a strong shift from coal to the use of natural gas for electricity generation within the EU will have a significant negative consequences for the security of energy supply, due to the amount of natural gas that need to be imported to satisfy future electricity demand, something that cannot be ignored by politicians, government officials, and the energy industry.

According to Fig. 1.14, in the case of OECD Europe, after 2015 the use of renewable energy sources is expected to be the type of energy fuel with the highest

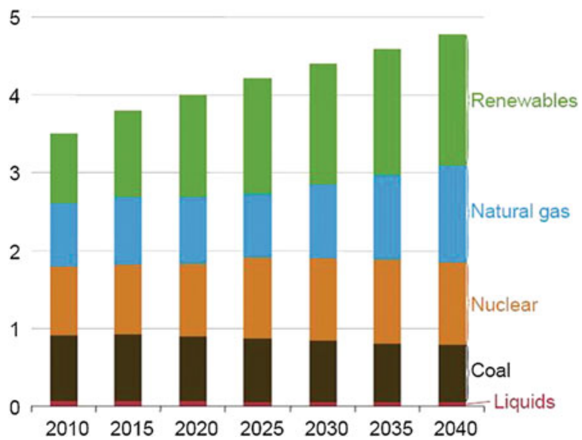

Fig. 1.14 Net electricity generation in OECD Europe by fuel during the period 2010–2040 (Trillion kWh). *Source:* IEO (2013)

participation in electricity generation at least until 2040, followed by natural gas, nuclear power, coal and liquid fuels. However, the negative impact in the public opinion of the Fukushima nuclear accident could reduce the percentage of nuclear energy in the energy mix within the OCDE Europe in the future.

1.6.5 Market Concentration in the Liberalized Power Generation Markets in Europe

The liberalization of the European power market has significantly changed the framework of the electricity industry. The process of market opening and securing fair, transparent, and sustainable third party access is still under way. But incomplete liberalization can be thwarted by concentration trends in the electricity generation market.

The analysis of the situation of markets concentration in Europe shows two very different development patterns. According to the outcome of a study carried out by experts from the Öko-Institut E.V. in 2005, the market concentration in the UK decreased significantly in recent years and lead to electricity generation markets, which could be described as "no concentrated", similar to the Scandinavian power production market. On the other hand, market concentration and its trends are occurring in all other countries of the European region. In markets, which are characterized by former centralized state monopolies, the concentration indicators remain very high. Furthermore, especially in the German market, which is historically characterized by a diversity of power generation, mergers have pushed the concentration indicators to levels that are more and more critical.

Based on this situation, it is necessary to create more strict competition rules in the electricity markets in the European region as a necessary counterbalance to these developments. Key elements of this approach are a stricter unbundling, a premium for decentralized power generation taking into account long-term avoided network costs, the elimination of other market distortions as well as disinvestment obligations for market dominating generators.

The situation for example in Spain, Portugal, and Italy, where a slight decrease of market concentration can be observed, does not lead to a significantly different situation than for instead in France and Belgium where nearly no changes can be identified.

Taking into account the challenge of developing fair, transparent, and sustainable energy markets in Europe, several conclusions can be drawn. These are the following:

- The remaining market concentration in the field of electricity generation has to be seen as endangering fair, competitive, and sustainable energy markets;
- Breaking old monopolies and avoiding new concentration trends in the electricity generation sector must be a central issue for competition policy to be adopted by some EU countries in the energy sector during the coming years;

- The high levels of market concentration in the electricity generation sector must be compensated for by extremely fair, transparent, and coherent rules for third party access;
- Additional measures to decrease market concentration in the electricity generation sector should attract more attention by competent national authorities.

Regarding the last issue the following matters should be addressed:

- Strict unbundling of generation, transmission and distribution is a key issue. Further activities on the EU level should tackle ownership unbundling as the medium-term target;
- Decentralization electricity generation should receive a premium for long-term avoided network costs;
- Additional market distortions (availability of decommissioning funds for activities in the market, fuel cycle cost obligations and liability issues, among others) between electricity generators should be removed;
- The existing approaches to urged market-dominating companies for disinvestments (e.g., in the UK and Italy) or equivalent measures (virtual power plant auctions in Belgium and France, among others) should be strengthened and extended.

Last but not least, the further in-depth evaluation of market concentration in the European electricity sector taking place on a regular basis, should be seen as a key issue for the future improvement of the internal market for energy (Matthes et al. 2005).

1.6.6 Electricity Generation Cost

The annual electricity generation cost associated with a power plant is comprised of two components:

- The *annual fixed costs* that are independent of the amount of electricity that the plant generates in a year. These include fixed charges to the capital expenditure[18] and the fixed operating and maintenance costs[19];
- The *variable costs* that are proportional to the amount of electricity generated, namely the variable operating and maintenance costs[20] and the fuel costs.

[18] These includes the costs of building the plant and bringing it to commercial operation and the costs associated to interest charges accrued during the construction period. The construction costs are further split into direct costs and indirect costs (contingency and spare parts, among others). Capital costs vary greatly among different power plants. The fixed costs should be paid even when the power plant does not operate at all.

[19] These include taxes and insurances, personnel administration costs and, typically, the annual overhaul.

[20] These costs includes the cost of consumables, waste disposal, and of unscheduled repairs, Variable cost could change during the operational life of a power plant, and it will depend of the total hours that the power plant runs over a year.

These two main cost components are used to calculate the total electricity generation cost of a power plant during a given period of time. The annual costs are typically expressed in relation to the capacity of the plant as Euro/kWh per year. The relation of the two main components is the following:

$$\text{Annual Cost} = \text{Fixed Costs} + \text{Variable Costs}$$

In Table 1.11, the electricity generation costs of the different power plants (Euro/MWh) without emission trading are included. From Table 1.11, the following can be stated: Wood is the energy source with the highest electricity generation costs, following by wind, natural gas, coal, peat and nuclear energy. From the cost point of view, a nuclear power plant shows the lower total costs in comparison to natural gas, coal, peat, wood and wind power installations.

It is important to highlight that the price level of power plant construction has risen remarkably during the recent years. The price increase has been caused by the growth of construction costs, the increase prices of different metals (steel, copper, and aluminum) and power plant components as well as the imbalance between demand and supply in the field of power plant construction. In addition, the fuel prices have risen rather strongly during the recent years. The general cost growth increases the operation and maintenance costs. Nuclear power plants show the highest capital and operation and maintenance costs in comparison to other power plants that have been included in Tables 1.11 and 1.12.

Summing up, the following can be stated: Renewable energy is the fastest-growing source of electricity generation within OECD Europe and the type of energy source used to limit the greenhouse gas emission in the IEO (2011) report. Natural gas is the second fastest-growing source of electricity generation within OECD Europe. It is important to highlight that natural gas is less-carbon incentive than coal and, for this reason it will be a part of the less carbon emission policy of OECD Europe in the future.

The EC estimates that in 25 of the total EU Member States electricity demand has increased by an average of 1.7 % per annum since 1990. In 15 of these States, electricity demand had an annual growth rate of nearly 1.9 %. In the new EU Member States electricity demand initially exhibited limited annual growth (from 1990 levels) of around 0.2 %, but in the second half of the past decade, it increased to around 1.6 % per annum. The EC expects that total electricity generated in 25 of the

Table 1.11 The electricity generating costs of the power plants (Euro/MWh) without emission trading (5 % real interest rate)

Cost items	Nuclear	Natural gas	Coal	Peat	Wood	Wind
Capital cost	20	6.2	11.5	13.3	23.9	41.9
Operation and maintenance	10	5	8	8	9	11
Fuel	5	40	26.2	22.3	40.6	0
Total	35	51.2	45.7	43.6	73.6	52.9

Source: Risto and Kivistö (2008)

Table 1.12 Input data January 2008

	Nuclear energy	Natural gas	Coal	Peat	Wood	Wind
Electric power (MW)	1,500	400	500	150	30	3
Net efficiency rate (%)	37	58	42	40	33	–
Investment cost (millions of euros)	4,125	280	650	225	81	3.9
Specific investment cost (€/kW)	2,750	700	1,300	1,500	2,700	1,300
Fuel price (€/MWh)	1.85	23.20	11	8.90	13.40	–
Fuel cost of electricity production (€/MWh)	5	40	26.19	22.25	40.61	–
Operation and maintenance costs when 8,000 h/a (€/MWh)	10	5	8	8	9	11
Share of variable operation and maintenance costs (%)	50	65	70	50	40	40
Economic lifetime (a)	40	25	25	25	25	25
Real interest rate (%)	5	5	5	5	5	5
Annuity factor (%)	5.83	7.10	7.10	7.10	7.10	7.10
Emission price (t/CO_2)	23	23	23	23	23	23
Fuel load utilization time (h/a)	8,000	8,000	8,000	8,000	8,000	2,200
Capacity factor (%)	91.3	91.3	91.3	91.3	91.3	25.1

Source: Risto and Kivistö (2008)

Table 1.13 Electricity generation during the period 1990–2030

	TWh					% Annual growth rate				
	1990	2000	2010	2020	2030	90/00	00/10	10/20	20/30	00/30
NMS	317	324	392	498	551	0.2	1.9	2.4	1.0	1.8
EU-15	2,139	2,574	3,027	3,450	3,846	1.9	1.6	1.3	1.1	1.3
Total	2,456	2,898	3,419	3,949	4,397	1.7	1.7	1.5	1.1	1.4

Source: EC
Note: NMS means "new EU Member States (excluding Croatia)"

total EU Member States will grow by 1.4 % annually from 2000 to 2030 (see Table 1.13).

Regardless of the effort carried out up to now by many countries, in particular by the European industrialized countries, in the development and use of renewable energy sources for electricity generation, the use of these technologies has not substantially modified up to now, the energy balance of several of these countries. Fossil fuel stays as the main energy sources for many of them, and it is expected that this situation will not change drastically before 2050. According to conservative projections, new technologies will begin to influence the energy balance of the different countries, particularly in Europe, around 2050. To achieve this long-term goal, European government should adopt an appropriate energy policy and strategy that guarantee a successful development of these technologies during the coming decades.

In Fig. 1.16, the foreseeable participation of the different types of energy sources in electricity generation until 2030 is clearly reflected.

According to Figs. 1.15 and 1.16, coal will continue to be the main energy source for the generation of electricity until 2030, followed by natural gas, renewables,

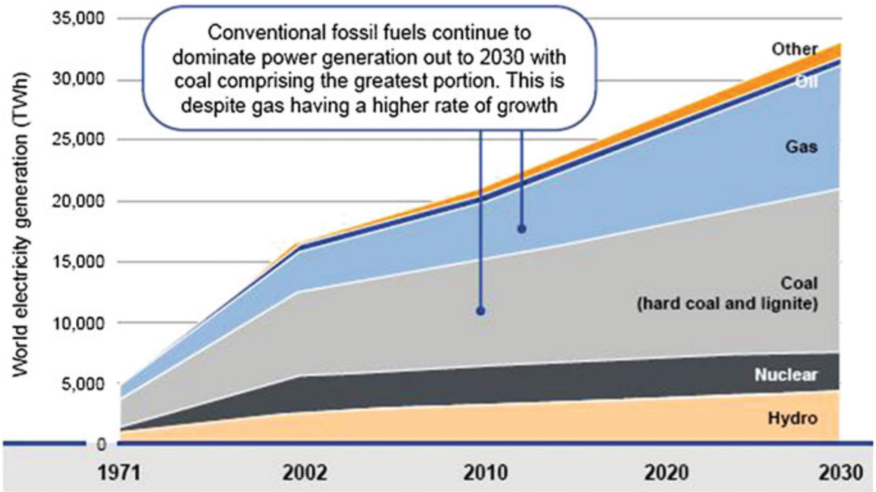

Fig. 1.15 Participation of different types of energy sources in the generation of electricity and projection until 2030. *Source:* Factbook—Generation Capacity in Europe (2007)

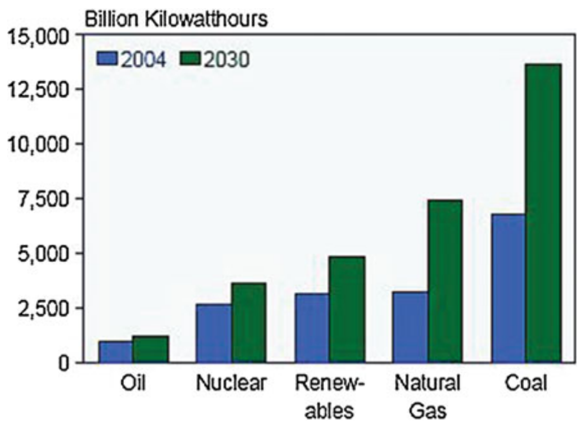

Fig. 1.16 World electricity generation by fuel 2004–2030. *Sources:* Derived from EIA, International Energy Annual 2004 (May–July 2006), web site www.eia.doe.gov/iea.2030: EIA System for the Analysis of Global Energy Markets (2007)

nuclear energy and oil. The major increase in the use of coal for the generation of electricity is expected to occur during the period 2004–2030, followed by natural gas, renewables, nuclear energy, and oil.

1.6.7 The Situation of the Energy Sector in the European Region

The Third World and other countries, including Russia and China, where live around three-quarter of the humankind, consume around 42 % of the world energy, while the industrialized countries consume 58 %.[21] However, this last group of countries has to satisfy only the energy needs of around 18 % of the whole population of the planet, while the other group around 82 %. Has been estimated that near 1,800 million of people lives today without electricity in the world and it is expected that in 2030 around 1,400 million of people will continue to live without electricity; this represents a decrease of 400 million in 18 years.

Several countries in the developed world depend on the import of fossil fuel to satisfy its fundamental energy needs. In almost 67 % of them, this dependence reached between 70 % and 75 % of its energy needs. In the specific case of Europe, the import energy dependency is rising. The region currently imports 56 % of its energy needs, and is on track to reach 70 % or more in the next 20–30 years, if some immediately actions are not implemented to change this trend during the coming years.

Europe's fossil fuel resources are running out fast, fuel prices are increasing and the environment is suffering as a result of the current energy supply structure. In 2030, if the current trend does not change, the EU will be importing 84 % of its natural gas needs, 59 % of its coal needs, and 94 % of its oil needs (Zervos and Kjaer 2008).[22] If Europe cannot make domestic energy more competitive in the next 20–30 years, then around 70 % or more of the EU energy requirements, compared to 56 % today (an increase of 14 %), will be met by imported products from regions threatened by insecurity and political instability.

The EU energy import dependency, combined with the increased influence of politics over the energy market, makes Europe very vulnerable to disruptions in the supply of energy. For this reason, secure access is becoming a national security priority worldwide and the pursuit of secure supply disrupts the free trade regime (Huiskamp 2007). Taking into account the fact that the EU holds extremely modest shares of the world's crude oil and natural gas reserves—around 1.2 % and 2.9 %, respectively—and that oil and natural gas are the largest components in the EU's

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[21] Third World countries consume only 13 % of the world's energy production.

[22] The EC expects a 73 % decline in EU oil production between 2000 and 2030; natural gas production will fall by 59 % and coal by 41 %.

gross inland energy consumption, the region is being very vulnerable to market and price trends.

According to conservative calculations, more than 60 % of the increase in the demand of world primary energy up to 2030 will come from Third World countries, mainly from the Asian region, particularly China and India. Many of these countries have to dedicate around 50 % of their total export income to import the energy resources that they need to guarantee their economic and social development, spending around US$74,000 million for this concept. It is expected that this figure can reach US$170,000 million in the first decades of the twenty first century (Morales Pedraza 2008).

By the contrary, the participation of the OECD countries in the world energy demand is expected to diminish from 58 % to 47 % in 2030; this represents a decrease of 11 %. In the cases of Russia and Central and Eastern Europe countries, the energy demand will decay until 10 %.

It is important to highlight that the industrialized nations of Europe are not free from of the negative effect in their economies of the limited crude oil reserves and the current level of oil price. This is despite of their high economic development and the use of several sources of energy with much more efficient than almost all countries in the developing world.

According to some expert's projections, oil and natural gas prices will continue to grow in 2010s. In the specific case of oil, it is expected that the price could go beyond the current level of between US$90 and US$110 per barrel, creating a very difficult situation for the majority of the countries.[23] However, if the USA or if Israel alone, or both, carries out a military attack against Iran, then oil price could increase even further (up to US$200 per barrel) according to some expert's calculations.

With increasing global demand for fossil fuels, stretched supply chains and increasing dependence on imports, high prices for oil and natural gas are probably here to stay with important negative economic effects in many countries, particularly in developing countries. Just to confirm what has been said before "every 10 % increases in the price of oil causes a loss of 0.5 % of global GDP; this represents approximately €255 billion," according to calculations made by the IEA.

The limited reserves of fossil fuels, the negative impact on the environment due to the use of this type of energy source and the high price of oil, among other elements, are forcing almost all countries to look for other energy sources, like wind, solar, hydrogen, biomass, inclusive nuclear energy, as primary sources of energy, particularly for electricity generation.

The IEO fuel fossil projections and the level of its reserves raise serious concerns about the following four issues: (a) Security of energy supplies; (b) Investment in energy infrastructure; (c) Environmental impact of the use of fossil fuels for electricity generation; and (d) Use and the unequal access of the world's population to electricity.

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[23] In March 2012, the price of oil barrel was around US$120.

1.7 Security of Supplies

Keeping in mind the weight of energy in any country's strategy for its sustained development, particularly for the European countries, and the current level of indigenous fossil fuel reserves, the energy security has become one of the main concerns of the European governments. For this reason, the world energy security was not only one of the main topics included in the G-8 Summit's agenda, celebrated from 15 to 17 on July 2006 in San Petersburg, Russia, but in the agenda of all G-8 Summits held in the past 5 years. The leaders of the G-8 countries agreed in 2006 that "the dynamic and sustainable development of our civilization depends on reliable access to energy" (IAEA 2006). There should be no doubt that energy security, energy price, and energy reserves, among other relevant energy issues, will be on the agenda of regional and international forums to be organized in the future.

There are many drivers governing the secure supply of energy. According to the World Coal Institute (2005), these are some of them:

- *Prices:* The provision of affordable energy to the consumer is dependent on the cost of generation, transmission and distribution. The impact of oil shocks on national economies—such as seen in the 1970s—is well documented. The interruption of supply networks can negatively impact prices and create economic difficulties for countries exposed by over-reliance on one energy source. Sustained price rises and short-term spikes in oil, natural gas or electricity can trigger inflation and recession;
- *Levels of investment required:* To meet the forecast growth in energy demand, the IEA in 2003 has predicted a need for US$16 trillion in investment during the coming years. The availability of that investment will be a significant factor in many countries over the coming years. Policy incentives above and beyond those in place (e.g., Kyoto mechanism) will be required to ensure a secure energy mix;
- *Ease of transport:* Energy must be readily available, and thus the ease and safety with which fuels and electricity can be transported is a key driver for energy security. Oil and gas can be transported through pipelines and tankers or LNG vessels. Coal can be readily transported via ship or rail. Transmission and distribution networks must be capable of carrying electricity to the consumer and able to handle the load demands placed upon them;
- *Concentration of suppliers:* The reliance on imported fuels from a limited number of suppliers may increase the risk of adverse market influence. Where suppliers are particularly from politically unstable countries, there may also be an increased risk of supply disruption with a negative impact in the economy of several countries, particularly developing countries without sufficient energy reserves;
- *Availability of infrastructure and expertise:* To achieve a diverse energy mix, countries must have access to different energy sources, requiring both infrastructure and expertise, whether in generation technologies, fuel handling, access to delivery systems such as pipelines, ports or electricity interconnections and transmission lines, among others;

- *Diversification of generation capacity:* Avoiding over-reliance on one energy source is a fundamental of energy security, reducing exposure to supply disruptions. A well balanced energy system, comprising various power generation technologies, and with suitable capacity, allows the advantages of each to be maximized, allows prices to remain reasonably stable, and ensures a continuing supply to the consumer;
- *International trade and availability of foreign direct investment:* While reducing import dependence may be seen as a key aspect of energy security, the availability of a variety of fuels in a well-functioning and geographically diverse market can be equally important. In developing nations, the availability of foreign direct investment to develop energy resources either for domestic use or for export earnings is also very important;
- *Interconnection of energy systems:* The interconnection of energy systems, particularly electricity, must also be considered in terms of security. A limited market or connection increases the risk of supply disruption by reducing the options available to meet demand. The liberalization of electricity markets must also be considered, while reducing costs and increasing efficiency in the short-term, liberalization may create situations where overall capacity is reduced, increasing the risks of supply shortage;
- *Fuel substitution:* Diversification in the uses of fuels may also be important for energy security. Fuel transformation—such as coal to gas, gas to liquids and coal liquefaction—can meet demand even when conventional supplies may be affected;
- *Political threats:* Recent world events have highlighted the vulnerability of energy supply systems to political interests and even terrorist attacks, motivated by economic, religious or other concern;
- *Industrial safety:* Incidents at mines, oil and gas platforms and refineries, whether caused by human error, weather or geological conditions, may disrupt supply chains and impact fuel availability.

1.8 Investment in Energy Infrastructure

Due to its aging energy infrastructure and constant demand growth, massive investment in electricity generation plants and grids are required. Over the next 12 years, 360 GW of new electricity capacity—50 % of current EU electricity generating capacity—needs to be built to replace several aging power plants in order to meet the expected increase in energy demand. Since energy investments are long-term investments, today's decisions will influence the energy mix for the next decades. Until 2030, the new electricity capacity should be 435 GW.

Among the various types of power plants operating in the European region, coal-fired power plants are the oldest. Around 54 % of the total coal-fired power plant capacity (93.3 GW) that exist in the European region has already 25 years old and almost 10 % (16 GW) are over 40 years old. The situation is similar for oil-fired power plants, although their capacity is much lower than coal: Around 52 GW of oil capacity is over 25 years old and 4.2 GW is over 40 years old. The situation is quite different from natural-gas-fired power plants: Just 17 % of the installed capacity (22.2 GW) is over 25 years old, most of the steam type. Most natural gas electricity generation capacity is relatively young, including the highly combined cycle power plants built during the past decades (Tzimas et al. 2009).

Undoubtedly, the investments that need to be carried out in the current energy infrastructure in several European countries are enormous.[24] In Europe alone, in order to meet expected enezrgy demand and to replace aging infrastructure, the level of investments that needs to be made is around €1 trillion over the next 20 years (COM 2006a, b). It is expected that the EU should invest €100 billion in transmission networks and €340 billion in distribution networks for reinforcement, asset replacements, and new connections over the period from 2001 to 2030 (EWEA report 2005).[25] The task of modernizing the power grid to integrate more distributed generation units and smart technologies to allow better demand management and to absorb large amounts of renewable energy generation beyond 2020, must become a top priority for the EU. It is also essential to ensure that all EU Member States are able to benefit from the new energy resources being developed in the EU, such as offshore wind and photovoltaic and concentrated solar power, through more inter-regional links.

The electricity sector will account for 60 % of total energy investment until 2030. If the investments in the oil, natural gas, and coal industries that are needed to supply fuel to power plants are included, the share of electricity reaches 71 %. Total oil investment will comprise 19 % of global energy investment, natural gas a further 19 % and coal a mere 2 %. The projected increase in world oil demand from 77 million barrels a day in 2002 to 120 million barrels a day in 2030 will require new production capacity to be brought on-stream. Most of the new capacity will be needed to replace depleted wells that are already producing or that will be brought into production and subsequently depleted during the next three decades. Bringing all of new capacity on-stream will entail up-stream investment of US$2.2 trillion.

Oil field decline rates will be a key factor in how much investment will be needed. Investment in non-conventional oil (including gas-to-liquid power plants)

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[24] In the period 2005–2030, the EU needs to install 862 GW of new electricity generating capacity. A total of 427 GW of generating capacity will be retired in the EU and an additional 435 GW will be needed to satisfy the growing demand for power. The required capacity exceeds the total capacity currently operating in Europe (723 GW) (Zervos and Kjaer 2008).

[25] According to World Energy Investment Outlook 2003 report, the total investment requirement for energy supply infrastructure worldwide over the period 2001–2030 is US$16 trillion, or US$ 550 billion a year. This investment is needed to replace existing and future supply facilities that will be exhausted or become obsolete during the period 2001–2030, as well as to expand supply capacity to meet projected primary energy demand growth of 1.7 % per year. Capital needs will grow steadily through the mentioned period. The average annual rate of investment is projected to rise from around US$450 billion in the period 2001–2010 to US$630 billion in the period 2021–2030. The level of investment represents only 1 % of global gross domestic product on average foreseeable over the next 30 years.

will amount to US$205 billion or 7 % of total oil investment. Canada and Venezuela will need to spend in excess of US$160 billion on developing their extra-heavy oil and bitumen resources, while gas-to-liquid power plants, most of which will be built in the Middle East, will cost around US$40 billion. The construction of tankers and pipeline will cost US$260 billion. Inter-regional trade in crude oil and oil refined products is projected to double to 66 million barrels a day over the period 2001–2030. Investment in refining, with new capacity concentrated in the Middle East and Asia, will be US$410 billion dollars (Birol 2003).

Upgrading the European electric power network infrastructure at the transmission and distribution level is perhaps the most fundamental step on the way to reaching the EU's mandatory target to meet 20 % of energy from renewable energy sources, including increasing the share of renewable electricity from 15 % to 34 % by 2020. Equally, renewable energy—together with security of supply, energy independence, and developing the internal market—has become a significant driver for expanding, modernizing, and interconnecting the European electricity networks.

However, EU must act urgently because it takes several years to make productive the investments that are needed to update the current aging energy infrastructure of the region. Today, Europe's energy networks—that is, the infrastructure to transport electricity, gas, oil and other fuels from producers to consumers—are aging. They are based on traditional fossil fuel supplies, and large centralized production, with cheap and plentiful energy. The lack of suitable network links is a barrier to investment in renewable energy and decentralized generation. The enlarged EU has inherited poor east-west and south-north connections. This makes it more difficult for energy to move freely around the EU and makes some regions more vulnerable to supply disruption. With energy imports set to rise under almost all scenarios, new import routes are urgently needed to give the EU greater flexibility in its supplies (COM 2008). The new capacities to be built in 2012 in order to satisfy the foreseeable increase in electricity demand in EU countries are shown in Fig. 1.17.

From Fig. 1.17, the following can be stated: The country with the highest power capacity to be built in 2012 is Germany with 16 GW, followed by the Scandinavian countries with 12 GW, Spain and Portugal with 11 GW, the UK with 10 GW, and the Balkan sub-region with 7 GW. The aging of the different power facilities in the EU in 2007 is shown in Fig. 2.1.

It is important to highlight that all types of power facilities operating in the EU in 2007 were in the second half of their life cycle. In the case of hard coal facilities, 70 % of the total are above 25 years of exploitation; in the case of lignite, 60 % of the total are above 25 years of operation; in the case of natural gas/oil, around 50 % of the total are above 20 years of exploitation, and in the case of nuclear energy around 70 % of the total are above 20 years of operation.[26]

[26] It is important to highlight the following: The last boom for the construction of conventional and nuclear power plants in the European region was in the 1980s. Since then mainly gas-fired power plants have been built. For this reason, around 40 % of thermal and nuclear power plants are

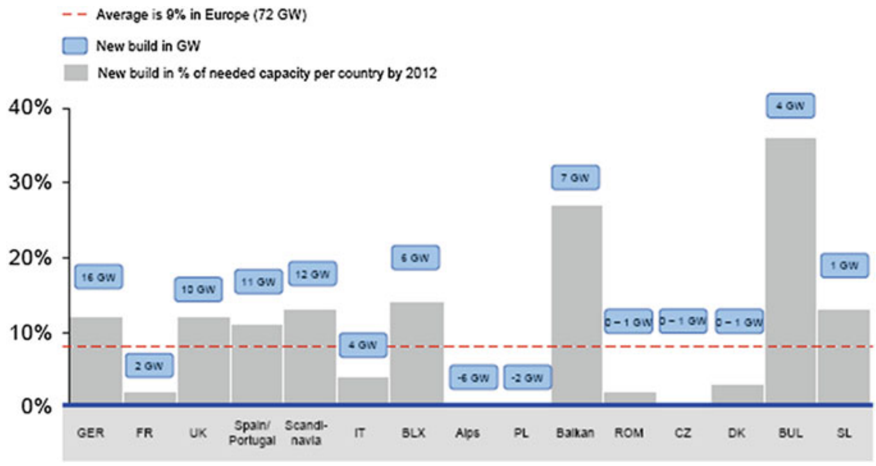

Fig. 1.17 New power capacities to be built per country and group of countries in 2012 in the EU. *Source:* Factbook—Generation Capacity in Europe (2007)

Finally, it is also important to highlight that the network development is an important element of energy policy. The emphasis of EU's network policy has been plugging gaps in networks or deal with bottlenecks for internal security of supply reasons. This is important, but not enough to deal with global security of supply challenges, to benefit from new technologies, to diversify energy sources, and to assure solidarity in an energy crisis. EU network policy needs to be fully aligned with EU energy policy (COM 2008).

1.9 Environmental Impact

When politicians and experts discuss energy demand, energy supplies, level of energy reserves, energy price, investment in energy infrastructure, among others energy issues, the impact on the environment must be present. There is no doubt that the world climate is getting warmer. Greenhouse gas emissions have already made the world 0.6° warmer. If all countries take no action, especially higher consumer energy countries, then there will be an increase of between 1.4 and 5.8° by the end of the century. All regions in the world—including Europe—will face serious consequences for their economies and ecosystems, if appropriate energy policies and strategies are not adopted and implemented as soon as possible, in

(Footnote 26 continued)
older than 25 years and around 60 % of hard coal plants are older than 25 years. The replacement of all these power plants is needed by 2030.

order to reduce the negative impact on the climate that the use of some of the current energy sources has.

Getting the energy we need affects our environment in many different ways. Some energy sources have a greater impact than others. Fortunately, the energy industry has become increasingly aware of this situation. Great strides have been made to ensure that oil and gas producers make as little impact as possible on the natural environments in which they operate. These include drilling multiple wells from a single location to minimize damages to the surface, using environmentally sound chemicals to stimulate well production and restoring the surface as nearly as possible to pre-drilling conditions as required by landowners and State or federal agencies, who often must approve the company's completion of restoration activities.

When many people think of oil and the environment, they think of oil spills. The reality is that the exploration and production of oil rarely create an oil spill. The oil and gas industry takes safety and environmental stewardship very seriously. Most oil spills occur primarily during transportation, mostly involving the tankers that are used to move oil from where it is produced to where consumers need it. But oil spills from transportation have declined significantly during the past few years, and the growing use of double-hulled tankers provides extra protection. Another source of oil spills during transportation is pipelines. Unfortunately, a major reason for spills from pipelines in developing countries is civil unrest. Weather, such as hurricanes, is another factor in pipeline-related spills. Urban runoff and natural seeps are large sources of oil pollution. Urban runoff comes from rain washing away oil drips from cars or machinery and people pouring used oil into the gutter and using other improper disposal methods. Natural seepage is actually the largest single source of petroleum inputs in marine environments totaling 47 %. When burned, petroleum products emit carbon dioxide, carbon monoxide and other air toxins, all of which have a negative effect on the environment.

In the case of coal, mining has the potential to harm air, water and land quality if it is not done with proper care. Acidic water may drain from abandoned mines underground, and the burning of coal causes the emission of harmful materials including carbon dioxide, sulfur dioxide and mercury. Clean coal technology is being developed to remove harmful materials before they can affect the environment, and to make it more energy-efficient so less coal is burned. The coal industry also restores mined land to or prepares it for more productive uses once surface mining is done.

1.10 Energy Efficiency

Improved energy efficiency is often the most economical and readily available means of improving energy security and reducing greenhouse gas emissions. If countries can increase further energy efficiency for the generation of electricity, then a reduction of 36 % in the emission of CO_2 can be reached. For this reason, the EC adopted an energy efficiency plan with the objective of controlling and reducing energy demand, and to take targeted action on consumption and supply in order to save 20 % of annual energy consumption by 2020. Although substantial steps have been taken towards this objective (mainly in the appliances and building sector), recent estimates suggest that the EU is actually only on course to achieve half of the desired savings. It is, therefore, essential for the EU to act now to get back on track to achieve the 2020 targets. The EC has recently published a comprehensive energy efficiency plan, which aims to provide a holistic approach to identifying and realizing the savings potential.

The EC has outlined a two-step approach to targeting in the energy efficiency plan. The first stage will assess the national energy efficiency targets and programs set by EU Member States and how they might contribute to the overall EU target. In 2013, the EC will provide an assessment of the results obtained and whether the programs will deliver the European 20 % objective. If the 2013 review shows that the overall EU target is unlikely to be achieved, then as a second stage the EC will propose legally binding national targets for 2020.

It is important to highlight that the EU action against climate change is an integrated energy and climate change policy. The goal is to set Europe on the right track towards a sustainable future with a low-carbon energy-efficient economy by:

- Cutting greenhouse gases by 20 % (30 % if international agreement is reached);
- Reducing energy consumption by 20 % through increased energy efficiency;
- Meeting at least 20 % of Europe energy needs from renewable energy sources.

Finally, it is important to note that power generation efficiency can be calculated using the following formula:

$$\text{Power generation efficiency} = \frac{\text{Output power energy}}{\text{Total power energy}}$$

1.11 Energy Savings

Every family and citizen can save a lot on the electricity bills every year. Some of the measures than can be adopted with this purpose are the following: One of the major sources of consumption of electric energy is household appliances and, for this reason, they should be used in the best way possible. People should buy household appliances available in the market with the lowest possible power consumption.

In addition, it is good practice to shut off the TV from the stand-by button because by leaving it on all the time it consumes a lot of power on a yearly basis. The refrigerator, which is always on, must be kept clean and at a temperature, which is not too low, because it would be useless, and people should look for the no-freeze, low consumption models. Try not to use electric water heaters, which use a lot of power. It is important to change regular light bulbs to the energy saving ones. Although they cost more when the people buy them, they give the chance to save a lot on the electric bill giving the same light. It is important to shut off the lights where the people do not need them.

It is also important to highlight those general cross cutting measures such as energy taxation, energy investment, fiscal deduction, and the European emission trading scheme forms a general base for stimulating energy efficiency. Voluntary sectorial or sub-sectorial agreements were made with industries, services, major transport organizations, and key players within the household sector with the aim of increase energy efficiency. Energy efficiency standards have been introduced for most economic sectors and a set a lower limit for efficiency. In order to improve energy efficiency innovations and the front-runners, both should be financially supported.

1.12 Access to Modern Energy Technology

Access to modern technology for the production of electricity is not appropriate distributed among countries and regions. The most advanced countries from the economic and technological point of view with only 18 % of world population are consuming 58 % of world energy production, while the rest of the world with the 82 % of the world population are consuming only 42 % of world energy production. This situation must be changed in the future, if the majority of the countries wish to give better live to their citizens, particularly in the case of China and India, countries with the greater world population. Table 1.14 shows the relationship between energy consumption and population by region or group of countries.

1.13 European Internal Energy Market

According to Morales Pedraza (2008), one of the current problems that Europe is facing is the following: Europe has not yet developed fully competitive internal energy markets. Only when such markets exist, will EU citizens and businesses enjoy all the benefits of security of energy supply and lower prices. To achieve this

Table 1.14 Relationship between energy consumption and population by region or group of countries

Region	Energy consumption (%)	Population (%)
USA and Canada	32	6
Europe and Japan	26	12
Former USSR countries	26	32
Other countries	16	50

Source: Author's compilation from different sources aim, interconnections should be developed, the necessary energy infrastructure should be built, effective legislative and regulatory frameworks must be in place and fully applied in practice, and community competition rules need to be rigorously enforced in all EU countries.

According to EC (2003), today's electricity network is the result of technological and institutional development over many years, with most of the electricity generated in large central power plants and transmitted through high-voltage transmission systems. The power is then distributed to consumers via medium and low-voltage local distribution systems. In this paradigm, power flows only in one direction: From the central power plant to the network and to the consumers. The system from power generation to consumers is often controlled by a monopoly national or regional supplier acting as both transmission system operators (TSO) and distribution system operator (DSO).

As the market is liberalized, monopoly control of the system will change with multiple TSOs and DSOs operating it transparently to enable the market, and without discrimination, operate under the governance of a regulator. To operate successfully, all players in the system must have a common set of guidelines. It will also require a more active role for DSOs in controlling network stability, optimizing central and distributed power inputs, interconnection and, of course, metering and billing.

The drivers for these changes are multiple and symbiotic. However, they all have their basis in the common concerns to use primary energy as efficiently as possible, with the least possible negative environmental impact whilst ensuring that energy supply is secure, safe, and supplied at an agreed quality and at a competitive cost.

In general, distributed generation[27] reduces energy transmission losses—estimates of power lost in long-range transmission and distribution systems are of the order of 7 % in OECD countries—and helps to bypass "congestion" in existing transmission grids. It enables the use of waste heat (via CHP) improving overall system efficiency. Power quality and reliability can also be enhanced. From an investment point of view, it is generally easier to find sites for renewable and other direct generation than for a large central power plant and such units can be brought online much more quickly. Capital exposure and risk are reduced and unnecessary capital expenditure avoided by matching capacity increase with local demand growth.

Furthermore, the consolidation of the energy sector should be market driven if Europe wishes to respond successfully to the many challenges it faces and to invest

[27] Distributed generation can be defined as a source of electric power connected to the distribution network or the customer site. This approach is fundamentally distinct from the traditional central plant model for energy generation and delivery. The wide development of distributed generation requires a thorough examination of all technical and non-technical aspects of an increased use of renewable energy resources and other decentralized generation units in distribution networks. A recent survey undertaken by ENIRDGNET to assess the driving forces creating demand for distributed generation in European countries indicated that the most important drivers are environmental concerns, deregulation of the electricity market, diversification of energy sources, energy autonomy, and energy efficiency.

properly for the future. The EU has the tools to help. It is the world's second largest energy market with over 450 million consumers and, for this reason, actions promoted by the EU within the European region will have an enormous impact in the world energy sector.

EU countries are making good progress in several areas within the energy sector. The EU leads the world in demand management, in promoting new and renewable forms of energy, and in the development of low carbon technologies. If the EU backs up a new common policy with a common voice on energy questions, Europe can lead the global search for energy solutions (COM 2006a, b).

1.13.1 Integrating National Markets

One of the most compelling arguments for regional integration is usually made on the basis of the fragmentation of a specific region in different countries of different sizes. The small domestic markets, combined with generally high production costs and deficient investment climates result in limited investments.

From the literature and experience, some traditional and non-traditional gains from regional integration arrangements could be identified. Some of them are the following:

1. **Traditional Gains from Regional Integration Arrangements:**
    a. *Trade gains:* If goods or services are sufficiently strong substitutes, regional trade arrangements (RTAs) will cause the demand for third party goods and services to decrease, which will drive down prices. In addition, more acute competition in the trade zone may induce outside firms to cut prices to maintain their present in the region. This will create a positive terms of trade effect for member countries. The risk of trade diversion could be mitigated if countries implement very low external tariffs ("open regionalism" arrangements);
    b. *Increased returns and increased competition:* Within a small market, there may be a trade-off between economies of scale and competition. Market enlargement removes this trade-off and makes possible the existence of larger firms with greater productive efficiency in any industry with economies of scale, and increased competition that induces firms to cut prices, expand sales and services, and reduce internal inefficiencies. Given the high level of fragmentation in a given region, it is expected that market enlargement would allow firms in some sectors to exploit more fully economies of scale. Competition may lead to the rationalization of production and the removal of inefficient duplication of power plants. However, procompetitive effects will be larger if low external tariff allows for a significant degree of import competition from firms outside the zone. Otherwise, the more developed countries within the regional integration scheme would most probably dominate the market because they may have a head-start. On the

other hand, current energy technology may be obsolete in these countries compared to current and future needs of the regional market. Firms may then decide to re-deploy new energy technology and relocate in other areas depending on factor costs. In this case, countries with the most cost-effective infrastructure and human resources would be the beneficiaries;

c. *Investment:* RTAs may attract new resources, both from within and outside the regional integration arrangement as a result of market enlargement (particularly for "lumpy" investment that might only be viable above a certain size), and production rationalization (reduced distortion and lower marginal cost of production). Enlarging a sub-regional market will also bring direct foreign investment, which will be beneficial, provided that the incentive for foreign investors is not to engage in "tariff-jumping". This advocates once again for the necessity to reduce protection and more specifically external tariffs.

   According to Word Energy Council (2010) report, for the electricity market, the central danger of the current economic recession is that countries could revert to national thinking and protectionism to the detriment of Europe as a whole. Increased protectionism will almost certainly stop further investments into the European grid infrastructure, and it will slow the exchanges between different national markets that Europe so desperately needs. Grid improvements are the core challenge for the European electricity sector, and the successful completion of these improvements is necessary, if regional markets are going to take the next steps towards a truly common European market;

2. **Non-Traditional Gains from Regional Integration Arrangements:**

   (a) *Non-traditionally gains:* The theoretical as well as applied literatures indicate that there are several "non-traditional gains" from regional integration arrangements. These are: (i) Lock into domestic reforms; (ii) Entering into RTAs may enable a government to pursue policies that are welfare improving, but time inconsistent in the absence of the RTAs (e.g., adjustment of tariffs in the face of terms of trade shocks, confiscation of foreign investment, among others). There are two necessary conditions for RTAs to serve as a commitment mechanism. One is that the benefit of continued membership is greater than the immediate gains of exit and the value of returning to alternative policies. The other is that the punishment threat is credible. Regional integration arrangements work best as a commitment mechanism for trade policy;

   (b) *Signaling:* Though entering RTAs is costly (investment in political capital and transaction costs), a country may want to do so in order to signal its policy orientation/approach, or some underlying conditions of the economy (competitiveness of the national industry) in order to attract investment. This may be especially important for countries having a credibility and consistency problem;

(c) *Insurance:* RTAs can also be seen as providing insurance to its members against future insecurity of supplies and regional solidarity for the solutions of the problems a country could face in a given moment;
(d) *Coordination and bargaining power:* Within RTAs, coordination may be easier than through multilateral agreements since negotiation rules accustom countries to a give-and-take approach, which makes tradeoffs between different policy areas possible. The collective bargaining power argument is especially relevant for small countries within a sub-region. It may help countries to develop common positions and to bargain as a group rather than on a country by country basis, which would contribute to increased visibility, credibility, and even better negotiation outcomes;
(e) *Security:* Entering RTAs may increase intra-regional trade and investment and also link countries in a web of positive interactions and interdependency. This is likely to build trust, and hence reduce the risk of conflicts between countries.

1.13.1.1 NordPool

According to Hooper and Medvedev (2008), in 1991 Norwegian electricity market was deregulated and competition was introduced in electricity generation and supply.[28] Five years later (1996), Sweden took the decision also to deregulate their electricity market. These two countries established a common spot-market, called "NORDPOOL", becoming the first multinational power exchange in the European region. Additional steps were taken to reduce barriers to cross-border trade. Finland completed their deregulation process in 1997 and, finally, in 2000 the Nordic market was fully integrated when Denmark East became a NORDPOOL power exchange area.

The Nordic Electricity Market is an advanced regional market with one regional power exchange and TSO cooperation above the European standard. NORDPOOL offers a physical day-ahead market based on day-ahead auctioning for hourly delivery over the 24 h of the following day, as well as a continuous hour-ahead ELBAS market. As of March 4, 2009, ELBAS covers Finland, Sweden, Western Denmark, Eastern Denmark, Norway, and Germany. The supply and demand bids in the day-ahead market from the system price from the supply and demand curve for every hour. Using the day-ahead price as the reference price, NORDPOOL also offers clear forwards, futures, and options contracts and cleared contracts for price area differentials (World Energy Council 2010).

The Nordic Electricity Market has more than 350 generation companies. The three largest generators in the region have a combined market share of about 40 %.

[28] Transmission and distribution remained regulated monopolies.

There are several important things to highlight about this integration process and local conditions. These are the following:

- It took almost 10 years to complete integration, and as late as 1998 the Nordic Electricity Market was regarded as an “emerging” market;
- Prior to 1991, trade between Norway and Sweden was conducted through bilateral contracts, and while NORDPOOL spot is now a liquid market and trading volumes, is over 60 % of total electricity consumption in the Nordic countries. In 1998, less than 20 % of total electricity consumption of Norway, Sweden, and Finland was traded in the spot market;
- The key driver for integration was legislated by the EC. However, there is increasing recognition of the view that the establishment of the Nordic Electricity Market was the outcome of a gentleman’s agreement; it suited the strategic plans of the market participants and governments concerned;
- The integration of the Nordic Electricity Market was initiated at a time of relative surplus in electricity generating capacity and transmission constraints were not generally binding.

1.13.1.2 Trilateral Coupling

Integration of electricity markets in Belgium, France, and the Netherlands, the so-called “Trilateral Coupling (TLC)”, started in November 2006. It allows an optimal allocation of the cross-border capacities that are submitted by the TSOs through an implicit auctioning mechanism. This initiative produced a sharp decrease of hourly price differences benefiting the consumers in these countries. Market coupling is a method for integrating energy markets in different areas. With market coupling the daily cross-border transmission capacity between various areas is not explicitly auctioned among the market parties, but is implicitly made available via energy transactions on the power exchanges on either side of the border.

In this system the results from the day-ahead markets of France, Belgium and the Netherlands will be coupled. There will be a local matching per country. Each country determines the local clearing price and a curve that indicates the price dependency per changing import/export volume. Using these curves and the known transport capacity a coupling is applied that without congestions results in a single price.

1.13.1.3 Western European Market

According to the EC, the Western European Market consists of Germany, France, Belgium, the Netherlands, Luxembourg, Switzerland,[29] and Austria. Some of these

[29] Switzerland is not a member of the EU and generally falls outside of the EU’s regulatory frameworks.

countries also provide a bridging function to the new EU Member States situated on their Eastern borders. Such overlaps between different markets will emerge as markets develop further and become more integrated. As liberalization advances, market-based solutions will become common.

The market structures in the different countries of this region vary considerably. In some of the countries, the generation structure is diversified, but in other markets only a small number of companies are operating.

In Germany, France, the Netherlands, and Austria, power exchanges have been established, all of them with a day-ahead markets and some with a futures market. Belgium, meanwhile, is currently in the process of building up an electricity exchange. In all of these countries, wholesale trading has been evolving.

Despite the lack of politically driven market integration, a Western European Market is clearly emerging through the activities of the market actors and the TSOs themselves. Upon closer inspection, the following two wholesale regions can be observed already, if one compares wholesale prices in the national markets: (a) Austria, France, Germany, Luxembourg; and Switzerland; and (b) Belgium and Netherlands.

There is very seldom congestion on the cross-border lines between Austria, France, Germany, Luxembourg, and Switzerland. As a result, the day-ahead and forward prices of these five national wholesale markets are converging. During the past years the spread of the forward prices between France and Germany has been continuously decreasing. The same development can be observed for the day-ahead prices. In fact, the prices on the German, French, and Austrian power exchanges are developing almost in parallel, and the end prices are very close to each other (World Energy Council 2010).

1.13.1.4 Central West European Market

In February 2007, proposals were announced for Germany and Luxembourg to establish the so-called "Central West European Market (CWEM)". The CWEM includes the Netherlands, Belgium, France, Luxembourg, and Germany—a single price coupling was launched successfully as of November 9, 2010. For several years now, the CWEM-TSOs have been working on the 'next-step' coordinated capacity calculation method, the 'flow-based methodology' (FB), and reported on their work in 2008. The methodology, that was still in a theoretical stage at that time, has evolved by extensive experimentation and some theoretical improvements, and is now operational. This means that the implementation of a flow-based market coupling (FBMC) in CWEM, as a next revolutionary step in the European market integration, is now envisaged.

According to Hooper and Medvedev (2008), it is worth noting that the time taken to make operational the integration of electricity markets appears to be significantly different. A single price area in the Nordic Electricity Market was established over many years, while it apparently evolved in a matter of months in the TLC. There may be many reasons for this difference, but critically the TLC involved the integration of markets where actors were already accustomed to trade-in electricity; wholesale market competition was introduced in 1998 and, perhaps more importantly, the market infrastructure and rules were well established and market participants had built up a body of experience. It is, therefore, arguable that the integration process took place over a comparable period of time.

The fundamental motivation for trade is to minimize costs by dispatching the cheapest plant available for each period, and the rationale for integrating national electricity markets is to maximize cross-border capacity and to adopt rules and procedures for efficient cross-border trade such that the consumers of the nations concerned benefit. Benefits accruing from the effects of market integration can be thought of as falling into three groups. These groups are the following:

- *In terms of developing competitive* (*cost-reflective*) *prices:* Where vertically integrated systems are too small for intranational competition to be workable, integrating national networks inevitably reduces market concentration and may constrain the potential to exercise market power. According to the opinion of many experts, the presence of market power and monopolistic pricing, free trade in electricity between nations might provide an effective substitute for competition at the national level, particularly where there is considerable variation in prices. Additionally, larger markets can support more liquid wholesale markets, which discipline market participants and encourage cost-reflective pricing;
- *Security supply:* In terms of security of supply, in a centrally coordinated dispatch over a region with a non-synchronous peak requires, on average, a lower reserve margin than is required under national operation. Similarly, diverse resource endowments and generating technologies across the region could offer greater resilience to external shocks, given adequate interconnection capacity;
- *Sustainability:* Stewardship of scarce (fossil fuel) resources can be improved, if the optimal fuel mix is considered at a regional level. For example, nations relying heavily on coal generation could import from nations with surplus power generated from, say hydro, simultaneously minimizing CO_2 emissions and utilizing a renewable energy source. An expanded market also offers increased opportunities for innovation and the adoption of low-carbon technologies that may not be feasible for small systems.

1.13.1.5 Regional Integration in South East Europe

The history of regional integration in South East Europe (SEE) started in 2005 with the adoption a legally binding agreement, the so-called "Energy Treaty", which established the Energy Community of South East Europe (ECSEE), and committed the parties to the formation of a regional electricity market. All are new or aspiring members of the EU at that time, and are therefore implicitly or explicitly required to implement the EU Energy Policy, and to pursue its three fundamental objectives: (a) Competitiveness; (b) Security of supply; and (c) Sustainability.

Regarding this new integration process, it is important to highlight the following: According to Kennedy and Besant-Jones (2004) and GIS (2005), there was very limited investment in generation capacity in the SEE during the 1990s. For this reason, currently the average age of electricity generation power plants in SEE is around 35 years (see Table 1.15). Therefore, without significant investment in refurbishment of old power plants currently in operation in the sub-region, the construction of new power plants, and the improvement of interconnections between countries, the sub-region will become increasingly dependent on imported electricity.

Table 1.15 Largest power plants in each country in 2005 by installed capacity, approximate market share, and type of fuel used

	MW	Percentage
Albania		
Total	1,520	
Komani	600 hydro	39
Fierze	500 hydro	33
vauDejes	250 hydro	16
UlzaShkopet	50 hydro	3
Total		92
Bosnia		
Total	3,714	
Tuzla 3, 4, 5, 6	715 lignite	19
Kakanj 5, 6, 7	450 brown coal	12
Capljina	420 hydro	11
Visegrad	315 hydro	8
Total		51
Bulgaria		
Total	10,917	
Maritsa East 1-3	2,280 lignite	21
Kozloduy 5, 6	1,440 nuclear	13
VarnaTPP	1,260 coal	12
Chaira	864 hydro	8
Total		54
Croatia		
Total	3,984	
Zakucac	486 hydro	12
Sisak	420 oil/gas	11
ZagrebTE-TO	345 oil/gas	9
Rijeka	320 oil	8
Total		39
Macedonia		
Total	1,486	

(continued)

Table 1.15 (continued)

	MW	Percentage
Bitola	675 lignite	45
Negotino	210 oil	14
Vrutok	150 hydro	10
Oslomej	120 lignite	8
Total		78
Romania		
Total	17,589	
Turceni	1,650 lignite	9
Portile de Fier	1,398 hydro	8
Mintia-Deva	1,274 black coal	7
Rovinari	990 lignite	6
Ludus	800 gas	5
Cemavoda 1	700 nuclear	4
Total		39
Turkey		
Total	38,802	
Ataturk	2,405 hydro	6
Karakaya	1,800 hydro	5
Afsin-Elbistan	1,715 lignite	4
Gebze	1,595 gas	4
Total		19
Serbia		
Total	7,647	
NikolaTesla 1-8	2,892 lignite	38
Djerdap 1	1,058 hydro	14
Kostulac 1-4	1,008 lignite	13
BajinaBasta 1, 2	978 hydro	13
Total		78
UNKosovo		
Total	1,513	
Kosovo 1-7	1,478 lignite	98
Total		98
Montenegro		
Total	840	
Piva	342 hydro	41
Perucica	307 hydro	37
Pljevlja	191 lignite	23
Total		100

Source: GIS (2005) and national electricity regulators' websites

From Table 1.15, the following can be stated: In smaller countries of the sub-region there are just a few electricity generation facilities. The big four producers control a significant proportion of the total sub-region installed electricity generation capacity. For example, in Montenegro there were only three producers in 2005 and in Kosovo only one. In Albania, Macedonia, and Serbia the largest four producers hold 92 %, 78 % and 78 % of the total electricity generation capacities, respectively, while in Turkey, Romania, and Croatia the top four producers hold less significant proportions of the total electricity generation capacity in 2005 (19 %, 30 % and 39 %, respectively).

It is important to stress that difference in countries' resource endowment and the possibility of inter-temporal substitution in the fuel mix could stimulate a sub-regional trade in electricity, potentially reducing the required investment in new electricity generation capacity. According to the structure of the sub-regional energy mix, the most convenient substitution is between hydro and thermal power in peak and off-peak periods. Such substitution would facilitate matching supply and demand at peak periods, so improving system reliability and region-wide capacity reserve. In addition, the GIS (2005) reports differences in fuel costs across countries, so there is potential to utilize the comparative advantages of some countries in the production of relatively cheap electricity for later consumption in other countries. Such types of sub-regional electricity cooperation and trading could provide great benefits to consumers through lower prices and more reliable electricity supply (Hooper and Medvedev 2008).

The sub-region currently experiences a winter peak, though there is considerable variation at national level (Greece and Turkey are summer peaking systems). In the long-run, there is an expectation that ECSEE nations will converge on the Croatian seasonal pattern: Summer demand as a proportion of the total increasing, winter as a proportion falling, and fairly stable demand in autumn and spring. This greater seasonal variation, which may be exaggerated by variance in the speed of convergence to a regional pattern, will depend on both macroeconomic factors, notably realized economic growth and structural shifts, and the degree of effective energy market restructuring (Hooper and Medvedev 2008).

1.13.1.6 North East Market

According to World Energy Council (2010) report, Poland, the Czech Republic, the Slovak Republic, Hungary, and Slovenia are included in the North East Market. It is important to highlight that the market structure differs considerably from country to country. For example, Poland has a rather fragmented generation structure, however, still mainly State owned, but the structures in the Czech Republic and Hungary are much more centralized. The electricity markets in these countries are still in development. Despite the liberalization of these markets is not as advanced as it is in the markets of most of the EU-15, considerable progress has been made, and there are ongoing efforts to develop even more competitive markets.

1.13.1.7 Baltic Market

The three Baltic countries (Estonia, Latvia, and Lithuania) are currently linked to other European countries through a cable between Estonia and Finland, which has been operating since January 2007. The Baltic countries are also still synchronously connected to the Russian/CIS electricity system. The power systems of the three countries work in parallel with those of Russia and Belarus, operated by the common organization of system operators BRELL.

On June 17, 2009, Estonia, Latvia and Lithuania, together with countries surrounding the Baltic Sea, reached an agreement on further development of a single sub-regional energy market. The EC, Denmark, Germany, Estonia, Latvia, Lithuania, Poland, Finland, and Sweden signed a joint memorandum of understanding of Baltic Energy Market Interconnection Plan based on the principles of the development of a single Baltic Energy Market around the Baltic Sea and based on the respective roadmap of actions necessary for integrating Baltic countries into European energy markets in the coming years (World Energy Council 2010).

1.13.1.8 Iberian Electrical Energy Market

The Iberian Electrical Energy Market (MIBEL), a unique wholesale market in Spain and Portugal, came into force on July 1, 2007. The legal framework for this market is based on the "Agreement between the Portuguese Republic and the Kingdom of Spain relative to the constitution of an Iberian Electrical Energy Market". Signed by the respective governments on October 1, 2004, the MIBEL agreement established the general principles for the organization and management of this market and, in particular, the framework for the organization of the spot market and the derivatives market. This spot market is run by the Iberian Energy Market Operator- Spanish Pole (OMEL). When congestion appears at the Spanish–Portuguese interconnection, market splitting goes into effect. When the MIBEL came into being, it featured a single daily market and a mechanism for the allocation of capacity by implicit auction. Around 27 % of OMEL's electricity was sold in the liberalized market, and the other 73 % of the volume was moved through regulated suppliers.

The launch of the MIBEL daily market, which is managed by OMEL, was one of the most important developments in the Portuguese wholesale market in 2007. On June 15, 2007, all power purchase agreements held by the incumbent EDP Group with the power plants were terminated. This led to the implementation of a compensation mechanism for the stranded costs resulting from the loss of the contracts, with only two power purchase agreements with two power plants remaining in force. The operation of these power plants and the placement of the power generated in the market are handled by an enterprise called "Ren Trading". It was created as a subsidiary of the parent company (Ren SGPS) that owns the transmission grid operator. On July 1, 2007, shortly after the termination of the power purchase agreements, the standard regime electricity generators began making their sales offers in a market context.

1.14 New Initiatives

The EU adopted in 2008 a group of new initiatives in the energy sector. These initiatives were the following:

1. *European Wind Initiative:* This initiative focus on large turbines and large systems validation and demonstration (relevant to onshore and offshore applications);
2. *Solar Europe Initiative:* This initiative focus on large-scale demonstration for solar photovoltaic and concentrated solar power;
3. *Bioenergy Europe Initiative:* This initiative focus on next generation biofuels within the context of an overall bioenergy use strategy;
4. *European CO_2 Capture, Transport and Storage Initiative:* This initiative focus on the whole system requirements, including efficiency, safety, and public acceptance, to prove the viability of zero emission fossil fuel power plants at industrial scale;
5. *European Electricity Grid Initiative:* This initiative focus on the development of the smart electrical system, including storage, and on the creation of a European Centre to implement a research program for the European transmission network;
6. *Sustainable Nuclear Fission Initiative:* This initiative focus on the development of Generation-IV nuclear technologies (COM 2007a, b).

The energy requirements of the different countries are now so high that, for the first time in the history of the humankind, there is a need to consider different types of energy sources and their level of reserves to plan the country energy needs to ensure their future economic and social development. At the same time, the use of different energy sources, particularly for electricity generation, should be done in the most efficient and economic possible manner in order to sustain that development. To achieve this goal, in the particular case of the EU, it is indispensable to adopt and implement a correct European Energy Policy and Strategy. A summary of the EU policy and strategy can be found in Morales Pedraza (2008).

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Chapter 2
The Role of Oil in the Regional Electricity Generation

Abstract Overall European oil production is projected to plateau at around 6 million barrels per day in the next few years and to decline thereafter to around 2.3 million barrels per day in 2030. On the other hand, in 2011 total oil production in the European region reached 4.273 million barrels per day and oil consumption of 15.085 million barrels per day. Due to this huge difference between the production and consumption of oil, Europe was forced to import 10.812 million barrels per day in 2011. The total crude oil refinery capacity in 2011 was 16.187 million barrels per day, more than enough to process all the crude oil that the region needed. If the status quo prevails, then the EU may need to import an additional 2.8 million barrels per day by 2012–2013. This represents a rise of 29 % in imported oil over a 6 year period that needs to be set against a backdrop of falling production in many oil exporting countries.

2.1 General Overview

Crude oil is a naturally occurring substance found trapped in certain rocks below the Earth's crust formed more than 300 million years ago. It is a dark, sticky liquid which, scientifically speaking, is classified as hydrocarbon; this means, it is a compound containing only hydrogen and carbon.

According to International Association of Oil and Gas Producers, in more than 150 years of intensifying use,[1] the world has consumed about 1 trillion barrels of oil and 66 trillion m^3 of natural gas—which provided the energy equivalent of another 430 billion barrels of oil. Thanks to growing investment in exploration, production, and innovative technology, oil and natural gas proven reserves have been increasing steadily since the 1980s. However, according to different expert's calculations the world newly-increased reserves had reached the summit and it is expected to start

[1] The first well was drilled in Ploiesti in Romania. It was followed by a well drilled in the United States in 1859, in Italy in 1860, in Canada in 1862, and in Russia in 1863. Other sources considered that the first well drilled was in the United States in 1859.

J. Morales Pedraza, *Electrical Energy Generation in Europe*,
DOI 10.1007/978-3-319-08401-5_2

decreasing in a spiral manner in the following years. The prediction model used to calculate recoverable reserves stated that the global ultimate recoverable reserves are about 400 billion tons; during the period 2008 and 2035, the world newly increased reserves were supposed to be about 410 billion tons, 10 billion tons more than today. By the end of 2008, the cumulative global oil production was 167 billion tons, which account for 42.27 % of the ultimate recoverable reserves of the world. At the same time, annual global consumption was approximately 31 billion barrels. Therefore, at that rate of consumption, the world has enough oil for some 40 years at present level of consumption, if no important recoverable reserves are found. This figure of consumption has remained almost constant for the past 20 years.

In 2013, the world's total oil reserves reached the amount of 1,637.9 billion barrels according to IEO (2013) report. The situation of world oil exploitation has been worsening in recent years. Presently, there are 60 super-giant oil fields with reserves more than 5 billion barrels per field in the world. Meanwhile, the oil production from 16 of top 40 fields has continually decreased and another six oil fields just struggle to maintain the stable production. Among 48 major oil producing countries, 20 of them have overall declined production. Along with an expected decline of oil production in more and more countries after 2015, it is a tough challenge for increasing the total global capacity of oil production. According to the Hubbert Model, the world oil production will meet the comprehensive decline from 2025 to 2030. The possibility of remarkably increase of world oil production in the future will be quite dim.

The year 2013 was a decidedly uninspiring year for oil exploration. Worldwide, there were no discoveries as big as 1 billion barrels. Indeed, there were expensive disappointments all around the globe. According to analyst Anish Kapadia of Tudor, Pickering and Holt, of his 25 high-impact "wells to watch" in 2013 only four were discoveries. Having monitored 400 total exploration wells drilled last year, Kapadia's rough estimate is that the industry discovered 20 billion barrels of conventional oil (and equivalent natural gas) last year, against global consumption of 50 billion barrels worth.

The big discoveries that were made tended to contain more natural gas than anticipated. Gas is simply not as desirable as oil because it's harder to get to market (especially when in far flung locales), and on an energy equivalency basis it sells at a deep discount to oil.

The year's biggest discoveries were all over the place, from Malaysia, to Mozambique, Egypt, Angola, and Canada, but none of them in the European region.

World oil production rose about 2.5 % last year, from 4,019 million tons in 2011 to 4,119 million tons in 2012, according to the recently issued BP Statistical Review of World Energy 2013. Meanwhile, gas output rose 2.2 %, from 3,291 billion m^3 in 2011 to 3,364 billion m^3 in 2012.

Saudi Arabia holds first place in global oil production ranking, with 547 million tons produced in 2012. Russia sits second—slightly behind Saudi Arabia—with 526 million tons in 2012. Both leaders significantly outpaced the USA, which ranked third, with 395 million tons of oil produced last year. Eight out of ten countries increased their oil output and only two—Iran and Mexico—fell. The USA is the leader in terms of oil production growth in 2012 (+14 %), whereas Iran output is down 16 %, which is the worst rate among competitors.

Overall European oil production is projected to plateau at around 6 million barrels per day in the next few years and to decline thereafter to around 2.3 million barrels per day in 2030. On the other hand, in 2011 total oil production in the European region reached 4.273 million barrels per day and oil consumption of 15.085 million barrels per day. Due to this huge difference between the production and consumption of oil, Europe was forced to import 10.812 million barrels per day in 2011. The total crude oil refinery capacity in 2011 was 16.187 million barrels per day, more than enough to process all the crude oil that the region needed. If the status quo prevails, then the EU may need to import an additional 2.8 million barrels per day by 2012–2013. This represents a rise of 29 % in imported oil over a 6 year period that needs to be set against a backdrop of falling production in many oil exporting countries.

There are two regions in Western Europe, which are the main oil producers. One of them is the North Sea, a mature oil producing region and the second is the Norwegian region. UK production is already in decline, more than offsetting a continuing modest increase in Norwegian output. According to the Department of Energy and Climate Change, the estimate of crude oil reserves based on proven plus probable crude oil reserves now stands at 751 million tons, which is a decrease of 18 million tons compared to 2009. Proven crude oil reserves at the end of 2010 stand at 374 million tons, which is 4 million tons less than at the end of 2009. The main contributing factor to this reduction was the reallocation of probable crude oil reserves into the proven category in some producing fields, although development approval during 2010 of several new oil fields including Maule, Bacchus, Athena, and Huntington also contributed.

Another important indicator is the reserves-to-production (R/P) ratio, which represents "burning rate" of proven oil reserves in situ for any given country when applying current levels of domestic oil production. Canada is the wealthiest country by R/P ratio, with 153 remaining years of oil production secured by oil reserves. Iraq (132 years) and Iran (126 years) hold the second and third places, respectively. The USA, China and Mexico are the most "unthrifty" countries with only about 11 years before they exhaust their current proved oil reserves.

The global total oil consumption in 2008 was 3.928 billion tons, which was decreased 0.3 % compared to 2007 and it had the first negative growth after 1993. The OECD oil demand increase ended in 2000 after consecutive increase for 14 years. From 2001 to 2008, the year-to-year rate of oil demand from OECD countries averagely decreased by 0.08 %, and this number was down 3.2 % in 2008. It is predicted that the oil consumption demand will keep dropping in the future, according to the national energy policy of OECD and new energy development trend. The prediction shows that the consumption of OECD will decrease between 1.78 and 1.97 billion tons in 2020 from 2.18 billion tons of 2008 with average year-to-year dropping of almost 1.2 %. However, the oil demand of emerging economies, such as BRICS, has been increased strongly at the average growth rate of

3.69 % since 1995. The oil demand of Middle East countries has also kept rising rapidly since 1965 with an average year-to-year rate of about 5 %. Oil demand of other developing countries is growing at the average rate of 1.76 % and the rate is expected to rise up more than 1 % after 2015.[2]

The world's average level of oil consumption per habitant and per year is now around 1.6 tons. However, the level of consumption varies significantly between countries and regions. For example, in the USA and Canada, average oil consumption per habitant per year is around eight tons; this represents 500 times world average. In Third World countries, that average level could be around 500 kg only; this represents 0.8 times world average (Morales Pedraza 2008).

After so many years of discriminatory oil consumption in the world, now this type of fuel faces a serious problem that can limit, in a future not very distant, the possibilities of economic growth of several countries, particularly those without significant reserves of this and other types of energy sources. In addition, the availability of oil for electricity generation and for other uses is more limited now than in the past due to the following reasons:

- A decrease of the world's crude oil reserves;
- The current high level of oil consumption;
- The ongoing high world's oil price;
- The negative impact on the environment caused by the burn of oil for the generation of electricity.

Growth remained robust in China and Middle East countries, with Chinese consumption growing by 860,000 barrels per day or 10.4 %. Driven by the economic recovery, middle distillates (over 4.4 %) were the fastest-growing refined product category globally. Global oil production increased by 1.8 million barrels per day or 2.2 %, but did not match the rapid growth in consumption. The gains in production were shared between OPEC and non-OPEC producers. OPEC production cuts implemented late in 2008 were maintained throughout 2010, although relaxed production discipline and rising output not subject to production allocations resulted in an increase of 960,000 barrels per day or 2.5 %. It is important to highlight that in 2012 OPEC countries controlled around 72.6 % of the world's total crude oil reserves. Non-OPEC countries accounted for 58.2 % of global oil production in 2010, roughly the same share as in 2000. Non-OECD countries accounted for 85 % of the oil increase reported, and for the first time accounted for a majority of global throughput.

Summing up the following can be stated: According to BP Statistical Review of World Energy 2011, after falling for two consecutive years, global oil consumption grew by 2.7 million barrels per day or 3.1 % to reach a record level of 87.4 million barrels per day. This was the largest percentage increase since 2004, but still the weakest global growth rate among fossil fuels. OECD consumption grew by 0.9 %

[2] Oil remains the world's leading fuel at 33.6 % of global energy consumption, but oil continued to lose market share for the 11th consecutive year.

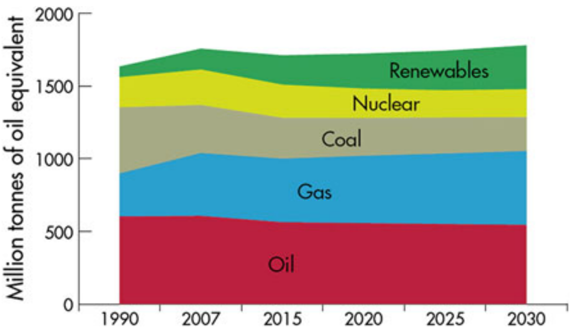

Fig. 2.1 Participation of the different energy sources in the generation of electricity in the EU energy mix for the period 1990–2030. *Source:* IEA World Energy Outlook, Reference Scenario, assuming the implementation of current climate legislation and policy

(480,000 barrels per day), the first increase since 2005. Outside the OECD, consumption growth was a record 2.2 million barrels per day or 5.5 %.

The expected participation of the different energy sources in the generation of electricity in the EU energy mix for the period 1990–2030 is shown in Fig. 2.1.

From Fig. 2.1, the following can be stated: Natural gas and renewable are the energy sources that will increase their participation in the EU energy mix during the coming years, while oil, nuclear, and coal will reduce their participation in the EU generation matrix by 2030. In the specific case of nuclear energy, the reduction expected could be higher than predicted due to the decision of some countries in the European region to shut down all nuclear power reactors currently in operation before 2022, as a direct consequence of the nuclear accident at the Fukushima nuclear power plant.

Global crude oil refinery[3] capacity utilization rose to 81.5 %. Refining capacity increased by 720,000 barrels per day in 2009, the slowest growth since 2003. However, the aggregate growth figure hides net reductions in the OECD markets of Europe, Japan, the USA, and Canada. Capacity additions were concentrated in the non-OECD countries. Installed refining capacity in the non-OECD countries now exceeds that of the OECD countries by 1.5 million barrels per day.

After two consecutive declines, global oil trade grew by 2.2 %, or 1.2 million barrels per day, with net Asia Pacific imports accounting for nearly 90 % of the growth. Net imports grew robustly in China (over 14.6 % or 680,000 barrels per day) and Japan (over 7.1 % or 280,000 barrels per day), as a result of the shutdown

[3] Installations where oil and condensates are processed into marketable products with defined specifications such as gasoline, diesel or feedstock for the petrochemical industry (these products are chemical products where the main feedstock is hydrocarbons. Examples are plastics, fertilizer, and a wide range of industrial chemicals). Refineries off-site such as tank storage and distribution terminals are included in this segment, or may be part of a separate distribution operation. The economic success of a modern refinery depends on its ability to accept almost any available type of crude oil. With a variety of processes such as cracking, reforming, additives, and blending, it can provide product in quantity and quality to meet market demand at premium prices.

of all nuclear power reactors operating in the country after the Fukushima Daiichi nuclear accident. Net export growth was largely from the former Soviet Union (over 7.2 % or 570,000 barrels per day) and the Middle East (over 2.6 % or 470,000 barrels per day). The growth in global trade was roughly split between crude oil and refined products, though crude oil still accounts for 70 % of global oil trade.

2.2 Reserves, Production, and Consumption of Crude Oil in Europe

Proven world's crude oil reserves were estimated on 1,668.9 billion barrels at the end of 2012.[4] Of the proven world's total crude oil reserves, 51 % are located in the Middle East, 14 % in North America, 16 % in Central and South America, 8 % in Africa, 7 % in Eurasia, 3 % in Asia, and 1 % in Europe (12 billion barrels).[5] Just less than 79 % of the world proven crude oil reserves are concentrated in eight countries, of which only Canada (with oil sands included) and Russia are not OPEC members. The crude oil reserves per country are shown in the Table 2.1. The table includes the 20 top countries with the largest world crude oil reserves and Fig. 2.2, the world proven crude oil reserves by geographic region as of January 1, 2013.

Table 2.1 Countries with the largest proven crude oil reserves (Billion barrels) 2013

Countries	Proven crude oil reserves Billion barrels	%
Venezuela	297	18.2
Saudi Arabia	265.4	16.2
Canada	173.1	10.6
Iran	154.6	9.4
Iraq	141.4	8.6
Kuwait	101.5	6.2
United Arab Emirates	97.8	6
Russia	80	4.9
Libya	48	2.9
Nigeria	37.2	2.3
Kazakhshtan	30	1.8
China	25.6	1.6
Qatar	25.4	1.5
USA	20.7	1.3

Source: IEO (2013)

[4] Considering crude proven oil reserves in Venezuela of around 296 billion barrels confirmed in 2011.

[5] Europe is running out of indigenous fossil fuels at a time when fossil fuel prices are high, as is the volatility of those prices.

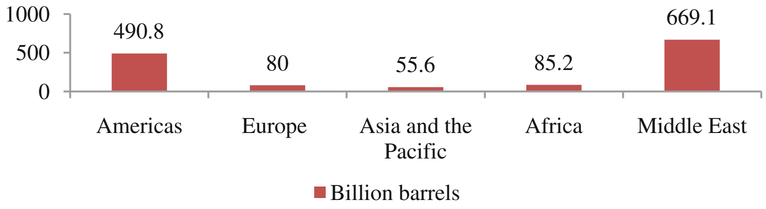

Fig. 2.2 World's proven crude oil reserves by geographic region 2013 (Billion barrels). *Source:* IEO (2013)

From Table 2.1, the following can be stated: The only European country in the list of the top countries with the world largest proven crude oil reserves is Russia with 4.9 %. In other words, Europe has no important proven crude oil reserves and this situation is forcing almost all countries in the region to rely on the import of oil, natural gas, and coal in order to satisfy their energy needs.[6] The region with the highest crude oil reserves is the Middle East followed by the Americas (Fig. 2.2).

It is expected that the total world's oil demand will be around 110,600 million barrels a day in 2035 from 86,100 million barrels registered in 2007 (IEO 2010). However, it is important to know that the majority of this increase is not going to be used for electricity generation, but mainly in the transport and industrial sectors. It is also expected, taking into account the current level of oil consumption in Europe, that imports of oil will increase from the current 82 % to 93 % in 2030; this represents an increase of 11 %. There are several reasons for this increase in the consumption of oil. These are:

- The continued substantial and growing oil consumption of the rich countries, including the EU as a whole and the USA, in combination with greatly increased energy needs in China and India;
- Fewer and fewer new major sources of crude oil are being discovered in the past decades;
- Security of supply may be jeopardized by increased political unrest in the Middle East and elsewhere and, for this reason, countries are increasing their oil storage in order to face without interruption the potential cut off the supply of oil from unstable regions.

From Table 2.2, the following can be stated: Total crude oil supply in the EU-27 decreased from 2,794.7 thousand barrels per day in 2007 to 2,168.2 thousand barrels per day in 2011; this represents a decrease of 23 % in 5 years (4.6 % per year as average).

Probable crude oil reserves have decreased by 13 million tons to stand at 377 million tons. This reflects the fact that the reallocation of possible crude oil reserves to probable crude oil reserves has not kept pace with that from probable to proven

[6] Most of Europe's oil supply comes from the Middle East.

Table 2.2 Total crude oil supply in the European region (thousand barrels per day)

Countries	2007	2008	2009	2010	2011
EU-27	2,794.7	2,668.4	2,520.2	2,382.6	2,168.2
Austria	27.7	27.9	28.2	28.7	30.4
Belgium	11.2	11.2	12.6	12.7	10.5
Bulgaria	2.9	2.9	2.9	2.9	2.9
Cyprus	0	0	0	0	0
Czech Republic	13.7	11.6	10.4	10.3	13.0
Denmark	313.9	288.7	262.6	247.7	223.5
Estonia	7.4	7.6	7.6	7.6	7.7
Finland	9.8	8.7	9.5	9.4	10.0
France	74.6	80.0	77.4	78.6	94.6
Germany	120.4	130.3	133.1	125.0	141.0
Germany (offshore)	25.2	20.8	23.7	20.9	24.1
Greece	5.1	6.6	6.4	8.5	7.6
Hungary	32.8	37.7	35.4	34.5	27.6
Ireland	−0.5	−0.4	−0.3	−0.2	−0.4
Italy	168.6	164.2	145.5	156.1	161.3
Latvia	0	0	0	0	0
Lithuania	6.8	6.7	5.7	5.7	5.7
Luxembourg	0	0	0	0	0
Malta	0	0	0	0	0
Netherlands	51.8	43.3	37.8	34.8	44.6
Netherlands (offshore)	43.9	34.1	25.6	20.3	17.6
Poland	35.2	36.3	34.2	28.7	28.3
Portugal	6.4	7.5	5.4	5.6	5.2
Romania	115.0	116.0	112.4	107.1	105.1
Slovakia	8.6	10.7	7.5	7.7	9.9
Slovenia	–	–	–	–	–
Spain	28.2	27.6	27.5	30.3	37.4
Sweden	3.6	4.7	4.7	2.9	2.9
United Kingdom	80.6	80.7	82.1	78.1	73.7
United Kingdom (offshore)	1,601.8	1,502.9	1,422.1	1,318.7	1,084.1

Source: EIA

crude oil reserves. Possible crude oil reserves have decreased by 1 million tons to stand at 342 million tons. Maximum crude oil reserves (remaining), combining proven plus probable plus possible crude oil reserves figures, have decreased by 18 million tons to 1,093 million tons.

In Norway, where most of the remaining Western European crude oil reserves are found, there is scope for increasing oil production from the Norwegian Sea and the Barents Sea. It is important to highlight that Norway is now the largest oil producer and exporter in the whole Western Europe, covering 12 % of Europe's oil needs in 2011.

However, the Norwegian Petroleum Directorate's estimate of remaining proven crude oil reserves fell for the first time ever since 2003. In 2012, remaining Norwegian crude oil reserves amount to 5.32 billion barrels, a decrease of 0.35 billion barrels respect to 2011.[7] In that year, the crude oil reserves were estimated at 5.67 billion tons. It is important to highlight that higher output from these two areas is not expected to be sufficient to offset declines in oil production elsewhere after the middle of the current decade.

The other European country with high crude oil reserves is Russia. There are seven oil bearing basins in Russia. It is worth mentioning that different estimations and prognosis about Russia's crude oil reserves are based on current geological, economic, technological, and political factors. Calculations provided are done in accordance with real situation at the first decade of the 21st century. Nowadays, the condition of potential reserves of crude oil in Russia means that they can afford to maintain production of more than 500 million tons annually until the middle of the century. In order to achieve this figure, it is necessary to implement new ways to search and explore new oil fields, improve current technology and technical base, among other measures. Such measures will require substantial State and private investments and improvement of the current legislation. If Russia could successfully achieve the above mentioned goals, then the country will become of great strategic importance in enhancing the world's energy security. The country still holds substantial crude oil reserves and with a well-considered approach to oil production, will keep playing a lead in the crude oil supplying role for decades (Grama 2012).

2.3 Oil Pipelines

Oil import to the EU is significant and it is assumed to increase from 84 % in 2006 to more than 90 % of total oil demand in 2020 when only 53 million tons equivalent will be produced in the EU, due to the depletion of its own indigenous crude oil resources. According to Eurostat sources, in 2006 crude oil and oil products covered 37 % (673 million tons equivalent) of the EU-27 primary energy demand. In the same year, the EU indigenous production of oil was 123 million tons equivalent. It is expected that oil with 702 million tons equivalent will still represent more than 35 % of the EU's primary energy demand in 2020; this represents 2 % less than in 2006.

[7] The Norwegian government has placed a moratorium on exploration in these areas until it completes an environmental impact assessment. In the longer term, the government aims to strike a balance between encouraging oil companies to extend the life of existing fields and gradually opening up access to new ones. The aim is to prolong offshore production and allow time for development of production technology that is less environmentally harmful.

Oil import through pipelines, however, only accounts for a limited share of the total EU oil import. Most of the imported crude oil (80 %) is brought in by tankers and vehicles, and only 20 % arrive through two pipelines: Druzhba and Norpipe. Oil pipelines from third countries are therefore currently of limited importance for the energy supply in the EU.

2.3.1 Oil Pipelines Within the EU

The whole oil pipeline system comprises about 33,000 km of pipelines in the EU-27 (see Fig. 2.3). The owners of the oil infrastructure in the EU are typically joint ventures with companies from the countries crossed by the infrastructure. For example, Trans Alpine Pipeline (TAL) bringing oil from Trieste in Italy to Austria and Germany is owned by a consortium from these three countries.

The EU internal oil pipeline network is characterized by the limited connections between the Western European pipeline network and the Eastern oil infrastructures. Currently, the only pipeline connection between Eastern and Western EU oil

Fig. 2.3 Oil pipelines in territory of the EU and neighboring countries. *Source:* Commission Staff Working Paper: Oil Infrastructures. 2008 (COM (2008) 782)

networks is the Ingolstand-Kralupy-Litinow (IKL) pipeline with a length of 349 km and a capacity of 10 million tons per year, corresponding to less that 2 % of the EU oil consumption in 2006. An additional short link between Bratislava and Vienna has been discussed, but it crosses environmentally sensitive areas around the Danube and no decision has been taken regarding the future construction of this pipeline.

Two other major internal oil pipelines are the South European Pipeline (SPSE, 23 million tons per year) connecting the French port of Fos sur Mer to the French refinery of Feyzin and further up to the German refineries, and the Rotterdam-Antwerp Pipeline (RAPL, 32 million tons capacity), which connects Rotterdam with Antwerp and Germany.

Another important feature of the internal EU oil network is that the Western part is connected via pipelines to major European ports while most of the Central and Eastern European crude oil refineries are supplied through the Druzhba pipeline. If the Russian policy of redirecting its oil export from the Druzhba pipeline continues, Central European countries might face difficulties and increased costs of their supply of crude oil and oil products through alternative routes. This point out to the fact that there a clear need for upgrading the oil pipeline infrastructure in the Eastern European countries, which today is left to the market actors to solve.

Another important network of pipelines is managed by NATO, which has operated its own pipeline system since 1950. It covers 11,500 km and operates in 13 countries. The NATO network consists of ten separate military storage, transport and distribution systems for oil products. Eight is single nation systems. Two are transnational North European pipeline system covering Denmark and Norway, and a large Central European pipeline system covering Belgium, France, Germany, Luxembourg, and the Netherlands.

2.3.2 New Pipelines and Supply Routes for Oil

New oil pipeline projects have been proposed to bring additional Caspian oil production to the international market and the EU (see Fig. 2.3). The advantage of these projects is that they will permit diversification of routes and sources of supply to the EU and to the international oil market, and some of them link directly to the EU's internal network. One of these projects is the Burgas-Alexdroupolis, which represents the first transport pipeline in the territory of the EU controlled by a Russian consortium.

2.3.2.1 The Druzhba Oil Pipeline

The Druzhba oil pipeline, the longest pipeline in the world (around 4,000 km), was put in operation in 1964 with the aim of supplying oil to the Western regions of the former Soviet Union and to countries of Central and Eastern Europe members of the former socialist block (see Fig. 2.4).

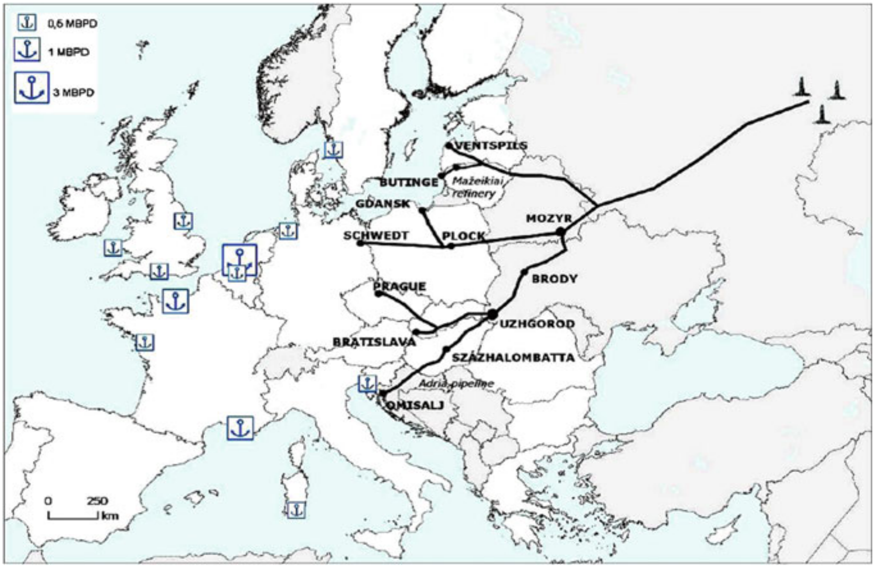

Fig. 2.4 Druzhba and Norpipe oil pipelines. *Source:* Commission Staff Working Paper: Oil Infrastructures. 2008 (COM (2008) 782)

The Druzhba oil pipeline begins in Southeastern Russia, where it collects oil from Western Siberia, the Urals, and the Caspian Sea. It runs to Mozyr in Belarus, where it splits into a Northern and a Southern branch. The Northern branch crosses the remaining part of Belarus across Poland and Germany supplying the oil refineries in Poland, Germany, and the Baltic countries. The Southern branch runs through Ukraine and splits into two lines to Slovakia and to Hungary. Druzhba oil pipeline is also connected to the Adria pipeline via Croatia and to the Odessa Brody oil pipeline.

The Baltic oil pipeline system (BPS) was completed in 2001, and in 2006 reached a capacity of 65 million tons per year, allowing Russia to divert oil export to the Russian port of Primorsk.

The full capacity of the Druzhba oil pipeline is between 85 and 100 million tons per year and is not fully utilized due to leaks that have not been repaired yet because of disagreements between Lithuania, Belarus, and Russia, and due to decreasing oil consumption in Hungary, the Czech Republic, and the Balkan States. The current capacity usage level is between 65 and 70 million tons per year.

Due to the dispute in 2007 on oil transit through Belarus, Russia is planning other pipelines (Baltic Oil Pipeline System-2, BPS-2) from Unecha to Primorsk with a transport capacity of 50 million tons and an enlargement of the Primorsk oil terminal, further diversifying their export routes. The construction of the BPS-2 has started in 2009 and is expected to be finalized before 2014. The implementation of the BPS-2 will increase the tanker traffic in the Baltic Sea considerably, creating a risk of accidents and leaks in environmentally sensitive areas. The other concern is that oil targeting Eastern Europe will be more expensive, as the cost of transportation by tanker is higher than that done by pipeline. Russian plans to connect Russia with the EU via the Baltic Sea have not yet been developed.

Finally, it is important to highlight the following: Currently the potential capacity of the Russian oil pipeline network allows for a supply of about 226 million tons of crude oil per year (or roughly 4.5 million barrels per day) aimed at the Western European States outside the former Soviet Union. During 2006, Russia exported roughly 204 million tons of crude oil (4 million barrels per day), and over 2 million barrels per day of oil products. A total of 1.3 million barrels per day were exported via the Druzhba oil pipeline, another 1.3 million barrels per day were sent via the port of Primorsk near St. Petersburg, and around 900,000 barrels per day via the tankers from the Black Sea port of Novorossiysk. Exports of both oil and natural gas that occur through the use of pipelines fall under the sole authority of the State pipeline monopoly.

2.3.2.2 The Norpipe Oil Pipeline

The Norpipe oil pipeline (354 km) starts in Norway and lands in the UK, carries oil from different Norwegian and British oil fields. The capacity is 45 million tons per year, but due to capacity limitations at the receiving point in the UK only 40 million tons are utilized. By 2020, it is foreseeable that the North Sea production will decline, and for this reason, 90 % of the oil products in the EU will be imported from third countries. Currently, most oil is arriving via ports and tankers, and this trend is expected to continue during the coming years. As increased tanker traffic can be foreseen in the next decades, this raises concerns in relation to the environment: greenhouse gas emissions, air quality, oil spills, and accidents. Special attention thus needs to be drawn to mitigate further environmental impacts from oil transportation.

Construction of new oil pipelines can contribute with environmentally viable alternatives. In particular, Eastern European countries are facing security of supply problems, which could be mitigated by a better oil pipeline infrastructure, improving the security of supply. Due to the lack of regulation of the oil sector in the EU, it is left to the private sector to take initiatives to create new oil infrastructures. It could be considered, however, whether it is not in the interest of the EU to take complementary political and investment initiatives due to their importance for the security of supply and the environment.

In total, European oil refineries represent a little over 12 % of the world's oil refining capacity. There are around 130 oil refinery establishments currently in operation in Europe, taking into account EU candidate countries, Switzerland and Norway (Murray et al. 2006).

2.4 Oil Demand in the Transportation, Industrial, and Electricity Generation Sectors

It is a fact that oil became, overnight, in the main source of energy at world level, with great impact on the development of the industrial and transportation sectors in all countries. In the 1930s, oil covered 10 % of the world energy needs. Forty years later, this percent was five times higher. Little by little, the oil displaced coal in two of the activities in which the use of energy is fundamental: (a) Production of heat; and (b) Electricity generation.

The growth in the automobile and transportation industry was a consequence, among other reasons, of a bigger use of oil as an energy source. There is no doubt that the impetuous development of countries within the European region was achieved due, among other factors, to the massive use of oil in the industry and in the transportation sectors, and to the control that a reduced group of European and North American companies exercised in the extraction, sell, and use of this type of fossil fuel (Morales Pedraza 2008).

In the 1960s, the industrial sector consumed around 1,600 million tons of oil. At the end of the 1970s, this figure rose to 2,280 million of tons; this represents an increase of 42.5 % in only 10 years or 4.25 % per year as average. During the same period, the role of coal in the world's energy balance diminished from 57 to 25 %, a decrease of 32 %, and the use of natural gas increased from 12 to 23 %, an increase of 11 %.

In the transportation sector, the energy use includes the energy consumed in moving people and goods by road, rail, air, water, and pipeline. Currently, the transportation sector is second only to the industrial sector in terms of total end-use energy consumption. According to the IEO (2011) report, almost 27 % of the world's total delivered energy is used for transportation, most of it in the form of liquid fuels. It is expected that transportation energy use increases by 1.4 % per year during the period 2008 to 2035.

With the expected increase of oil energy demand in the coming years, the transportation sector will be responsible for 82 % of it and the industrial sector for the rest (18 %). For this reason, it is projected that in 2020 the transportation sector will displace the industrial sector as the one with the higher level in the final use of oil. In the case of the European region, it is predictable that the oil demand in the transportation sector will grow to a slower rhythm, due to market saturation. In the residential and service sectors, it is expected that the growth in oil energy consumption will be around 1.7 %, a little bit higher than in the industry, where the level of energy consumption it is expected to grow only 1.5 %.

With the significant rise in oil prices during the period 2008–2013, the reduction of crude oil reserves, and the growing concern about stable, secure, and environmentally friendly energy supplies, the promotion of the use of biofuels in the transportation sector should become a priority in the European political agenda. It is important to highlight that today's biofuels are the only type of energy that could significantly reduce oil dependence in the transportation sector. For this reason, the

EC is adopting additional measures in order to increase the participation of biofuels in the energy balance in the transportation sector. However, the production of biofuels could have a negative impact in the production of cereals for food and in its price, affecting very seriously the already fragile economic situation of many Third World countries (Morales Pedraza 2008).

2.5 Oil Price Evolution

In the case of electricity generation, the situation at world level in the coming years is expected to be the following: "Worldwide oil-fired electricity generation is projected to increase by an average of 0.9 % per year from 2004 to 2030 but, in the OECD countries, it is projected to decline by 0.3 % per year. Only the non-OECD Middle East region, with its ample crude oil reserves and a current one-third share of total electricity generation fueled by oil, is projected to continue relying heavily on oil to meet its electricity needs" (IEO 2007). According to the IEO (2010, 2013) reports, the use of oil for electricity generation has been declining since the mid-1970s, when oil prices rose sharply. It is expected that this trend will continue until 2040.

The total amount of electricity generated by oil-fired power plants during the period 2000–2010 is shown in Fig. 2.5.

From Fig. 2.5, the following can be stated: The electricity generated from oil-fired power plants decreased significantly during the period 2007–2010 as a result of the economic and financial crisis that are affecting many countries in the European region; the total decrease was 16.6 %. It is expected that the use of oil for electricity generation will continue decreasing during the coming years at world level, and could reach only 2 % of the world electricity generated in oil-fired power plants in 2035.[8]

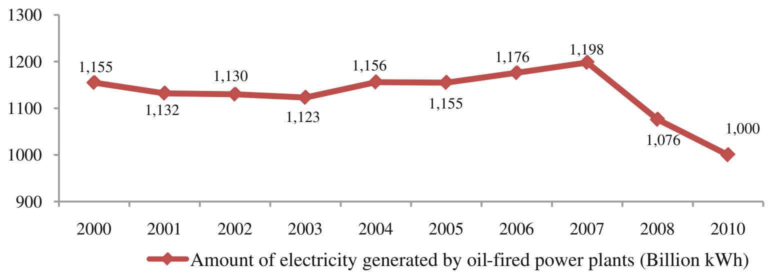

Fig. 2.5 Amount of electricity generated by oil–fired power plants at world level during the period 2000–2010. *Source:* IEA Energy Balances of non-OECD countries 2010 and EIA World Energy Outlook 2012

[8] According to EIA 2012 report, the participation of oil-fired power plants in the world generation of electricity was in 2010 around 5 %.

Table 2.3 Fluctuations of oil prices in the 20th century

Year	1900–1970	1979–1981	1985	1990–1999	2007	2008	2012	March 2013
Price	<$2	>$35	~$10	Max $25	+$98	+130	~120	+100

Source: Author own compilation

The vertiginous use of oil at world level was motivated initially by its low price during so many years. The fluctuations of the world's oil price during the past century could be seen in Table 2.3.

During the first 70 years, the oil price stayed below US$2 per barrel; between 1979 and 1981, the oil price stayed above US$35 per barrel, motivating a change in the energy strategy in Europe; in 1985, oil price collapsed and reached around US$10 per barrel; in the 1990s, oil prices went up to a maximum of US$25 per barrel. For 2007, the foreseeable oil price was US$40 per barrel, that is to say, around US$58–59 less than the oil price of US$98–99 per barrel reached in November 2007. During the first semester of 2008, the oil price reached US$140 per barrel, the maximum level reached during the whole period 1900–2008. At 2012, oil price reached US$120 per barrel in the period January–March and over US$100 per barrel in March 2013.

2.6 The Participation of Oil in the Energy Balance in the European Region

Two major events have shaped Europe's geopolitical and economic development since 1945. The first was the establishment of the EU in 1957, and the second was the fall of the Berlin Wall followed by the fall of the Soviet Union in 1989/1991. The big European economies, Germany, the UK, France, and Italy, all display similar patterns of oil consumption. Sharply rising consumption in the 1960s and early 1970s was curtailed by the twin oil shocks of 1973, the oil embargo declared by the Arab States, and the Iranian Revolution of 1979. Following a period of adjustment and reduction in oil consumption (e.g., closing of oil-fired power plants) oil consumption stabilized during the mid-1980s and has remained fairly constant ever since. The population of these countries is rising slowly, is aging and per capita consumption of oil is, therefore, falling slowly. It is noteworthy that oil consumption in Germany, France, and Italy has been decreasing in recent years. This may be related to on-going de-industrialization combined with growing introduction of renewable energy sources and the adoption of conservation measures related to environmental awareness.

Between 1965 and 1985, the Northern and Benelux countries displayed a similar pattern of oil consumption. After 1985, oil consumption in the Northern countries remained stable, but in the Benelux countries began to rise steadily. Today, oil consumption in the Benelux countries stands at 25.2 barrels per capita per annum—the highest in the EU by far. The reason for this steady growth in oil consumption in this group of countries may be related to the growth of petrochemical industries in the Netherlands and Belgium, the presence of large transport hubs such as Schiphol airport, and affluence flowing from the location of the European parliament in Brussels, among others.

The small countries of the EU such as Ireland, Portugal, and Greece, who like Spain, have benefited from EU membership and have had steadily growing oil consumption during past two decades. In terms of oil consumption, the East European group is perhaps the most significant. Six countries were admitted to the EU in 2004 (along with Latvia, Estonia, and Slovenia). The oil consumption of these countries plunged with the fall of the Soviet Union and the introduction of market prices for fuel. Today, their per capita consumption of oil, 5.2 barrels per annum, is less than half the EU average. With a population of nearly 68 million and ambition to reach West European living standards, this group of countries represents a powerful driving force for EU oil demand. For East Europe to reach per capita consumption of 10 barrels per annum would add around 1 million barrels per day to EU oil consumption in the past 20 years.

In summary, over the period 1999 to 2009, there was a gradual decline in the share of crude oil and oil products and solid fuels in Europe's total gross inland consumption, while an increasing share of EU-27 consumption accounted for by natural gas and renewable energy sources. The combined share of crude oil, oil products and solid fuels fell from 57.5 % of total consumption in 1999 to 52.3 % in 2009, reflecting changes in the EU-27's energy mix and a move away from the use of the most polluting fossil fuels, particularly for the generation of electricity. It is expected that this trend will continue during the coming years and the role of oil in the energy mix of the European countries will decrease even further, particularly for the generation of electricity.

According to predictions of experts, it is expected that with the current level of oil consumption, the production of oil will begin to present signs of exhaustion in some regions around 2025 (in specific regions even before). For example, oil production from Norway, OECD Europe's largest oil producer, appears to have peaked at about 3.4 million barrels per day in 2001, and it is expected to continue declining to about 1.4 million barrels per day in 2030 as the larger and older oil fields mature. Oil production from the UK, which peaked in 1999 at 3 million barrels per day, is expected to fall to 0.5 million barrels per day in 2030 (IEO 2007).

Taking into account the analyses made by different experts, it is expected that for 2020 the oil participation in the global energy balance will diminish sensibly reaching half of the level reached at the beginning of the 1980s. It is very likely that oil participation in the global energy balance continues to diminish until reach 10 % at some moment in the 21th century. The European countries will have a decisive influence in the reduction of oil participation in the global energy balance, if this group of countries continuing to apply appropriate energy policies and strategies, increase the use of renewable energy sources for electricity generation, and develop and use new technologies that make more efficient and less polluting the use of fossil fuels, particularly coal as an energy source.

According to Fig. 2.6, the Middle East will continue to be the region with the highest share of crude oil production with 32.2 % of the total, followed by the OECD

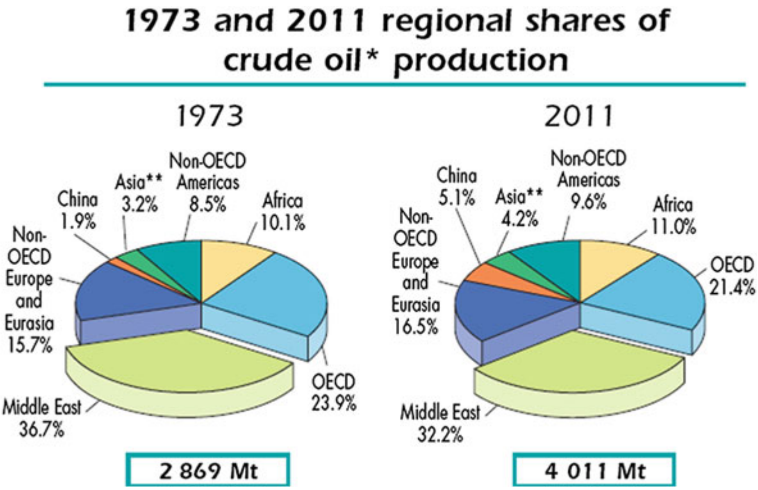

Fig. 2.6 Key world energy statistics 2012. *Source:* IEA (2012)

countries with 21.4 % and non-OECD Europe and Eurasia with 16.5 %. However, it is important to highlight that during the period 1973–2011, the share of crude oil production increased in all regions, except in the Middle East. At world level the increase was almost 40 %.

2.7 Future Trends

By 2020, it is foreseeable that the North Sea oil production will decline and 90 % of the crude and oil products in the EU will be imported from third countries. Currently, most oil is arriving via ports and tankers and this trend is expected to continue in the near future. As increased tanker traffic can be foreseeable in the next decades, this raises concerns in relation to greenhouse gas emissions, air quality, oil spills, and oil accidents. Special attention thus needs to be drawn to mitigate further environmental impacts from oil transportation.

Construction of new pipelines can contribute with environmentally viable alternatives. In particular, Eastern European countries are facing security of supply problems, which could be mitigated by a better oil pipeline infrastructure, improving the security of supply. Some initiatives that could be considered in relation to oil infrastructure are, among others, the following:

- Carry out investigations of the functioning of the internal market for crude oil and oil products in order to define possible new policy measures regarding the improvement of the current oil infrastructure that needs to be adopted in the future;
- Undertake an independent study of the pro and cons of different alternative oil pipeline options;

- Develop an oil dimension in the energy community; so far, only electricity and natural gas are included;
- Include oil infrastructure in Trans-European networks; only natural gas and electricity are now included;
- Investigate whether the current environmental obligations are sufficient to mitigate increased environmental pressure, due to the increased maritime transport of crude oil and oil products;
- Consider the climate change impacts on the oil pipelines and oil infrastructure in order to integrate increasing climate risks;
- Ensure that the EU's current energy dialogue with the major oil suppliers also pays attention to the issue of oil transportation.

A summary of the oil situation and on the future role to be played by this type of energy source for the generation of electricity in a selected group of European countries during the coming years is included in the following paragraphs.

2.8 Austria

Austria's energy policy rests on three pillars—security of supply, energy efficiency, and renewable energy sources. The country's decarbonization drive has strengthened as the economy and renewable energy use have continued to grow, while fossil fuel use has decreased, particularly for the generation of electricity. Notably, Austria has more than tripled the public funding for energy research, development, and demonstration since 2007.

Greenhouse gas emissions from energy use, which peaked in 2005, still need to be reduced further, and the transport sector offers prime opportunities for this. In the context of EU negotiations on an energy and climate policy framework to 2030, Austria should develop a strategy that also integrates security of supply and internal market dimensions.

Closer cross-border integration of both electricity and natural gas markets and systems is required to build a single European market. This calls for increased coordination and cooperation with neighboring countries. Austria should also encourage investment in networks, optimize demand response and integrate variable renewable energy supply in a cost-effective and market-based manner.

A well-functioning internal market can help reduce the growing concerns over energy prices and costs, both for industry and for citizens. Austria could address these concerns also by implementing more energy efficiency measures and facilitating greater retail market competition.

Oil first production occurred in Austria in 1863. Crude oil was found in two different locations in the country: Upper Austria, near Wolfsegg am Hausruck, and in Lower Austria, in the vicinity of Vienna. After reaching a peak of about 3.7 million tons in 1955, oil production gradually declined to 22,000 barrels per day in 2000. According to EIA sources, in 2012 the production of oil in Austria was 29,500 barrels per day; this represents an increase of 34 % respect to 2000, but still very low respect the level reached in 1955.

2.8.1 Crude Oil Reserves

According to EIA sources, Austrian crude oil proven reserves reached 0.047 billion barrels in 2013; this represents a decrease of 6 % respect to 2012.

2.8.2 Production and Consumption of Oil

The evolution of Austrian oil production and consumption during the period 2008–2012 is included in Figs. 2.7 and 2.8.

According to Fig. 2.7, the production of oil increased 10.9 % during the period 2008–2011. After 2011, the production of oil decreased 3 %. It is expected that the production of oil in Austria will continue to be very small during the coming years.

According to Fig. 2.8, the consumption of oil in Austria during the period 2008–2012 decreased 8.5 %. It is expected that the consumption of oil in Austria will continue decreasing during the coming years, particularly for the generation of electricity.

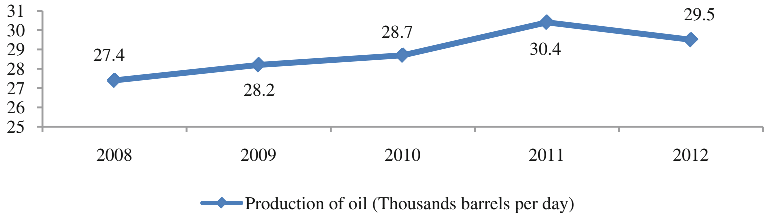

Fig. 2.7 Production of oil in Austria during the period 2008–2012. *Source:* IEA

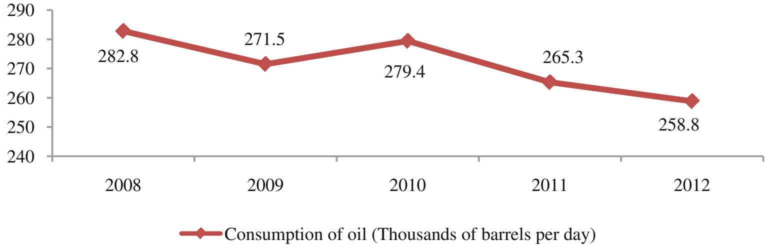

Fig. 2.8 Consumption of oil in Austria during the period 2008–2012. *Source:* EIA

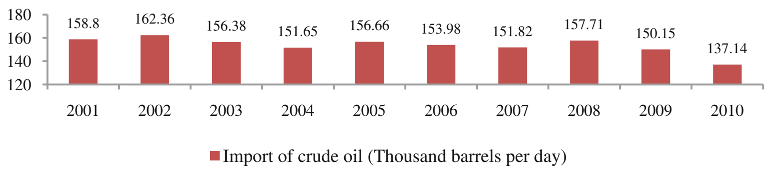

Fig. 2.9 Imports of crude oil, including lease condensate, from Austria during the period 2001–2010. *Source:* EIA

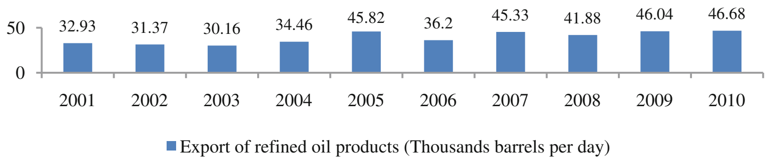

Fig. 2.10 Exports of refined oil products from Austria during the period 2001–2010. *Source:* Eurostat

2.8.3 Import and Export of Oil

According to Wolfgang Ruttenstorfer, President of the Austrian Petroleum Industry Association, oil deliveries to Austria comprised 7.43 million tons, sourced from seventeen countries. The chief crude oil supplier to Austria's domestic petroleum system in 2009 was Kazakhstan with 2.78 million tons, followed by Iraq (1.22 million tons) and Libya (1.11 million tons). In addition to crude oil, Austria in 2009 imported some 6.2 million tons of oil products, such as petrol, diesel or fuel oil, mostly from Germany, Italy, and the Slovak Republic. The imports and exports of crude oil during the period 2001–2010 is shown in Figs. 2.9 and 2.10.

From Fig. 2.9, the following can be stated: The imports of crude oil, including lease condensate, from Austria during the period 2001–2010 decreased 14.5 %. In general, the trend is to reduce the imports of crude oil during the coming years, particularly due to the reduction of the participation of oil in the energy mix of the country, and to the increase in the use of other energy sources for electricity generation.

In the case of crude oil, Austria is not exporting this type of product since 2001. The exports of refined oil products from Austria during the period 2001–2010 increased 41.8 %. It is expected that the exports of refined oil products from Austria will continue increasing during the coming years, but this increase will be small.

2.8.4 Electricity Generation and Consumption

According to Hofbauer (2006), in Austria, the process of reorganization of the energy sector started in 1998, in which—under EU Directives—there was a gradual liberalization according to customer groups and individual value-creation chains in electricity provision. Today, the areas of electricity generation and electricity distribution are subject to competition and since October 1, 2001 the market has been opened to all customers. Austria has thereby liberalized faster than called for by the EU.

The first stages in the liberalization process were introduced in Austria on the basis of the EU Directive on electricity liberalization (96/92/EG). The implementation in Austrian law took place in 1998. As a result of the passing of the new act about the liberalization of the electricity market the implementation of the terms of the EU Directive was completed, and for the first time a standardized law for the regulation and organization of the Austrian electricity sphere was created (Mayer 2002). In the new act, the government laid down the statutory conditions for the reorganization of the electricity business, but the precise implementation conditions are the implementation acts of the individual provinces (Energie Control 2003). In 2003, the EU passed a new directive (2003/54/EC), which obliged all Member States to gradually open the electricity market to all customers by July 1, 2007 at the latest, and furthermore also contains a set of public service obligations (consumer protection, security of supply, and environmental protection). The Austrian act was comprehensively amended in 2000.

Since liberalization, the areas of generation and supply/sales have been opened up to competition. Although liberalization led to the dissolution of the one-time area monopolies, the electricity business in Austria is still characterized by a heavy federal structure of the providers, owners, and markets and, as before, is marked by the powerful dominance of the respective companies in their old provider areas. Owing to the smallness of the Austrian market, this is hardly of interest to foreign suppliers. In addition, in electricity generation Austria has a competitive advantage over other EU countries as a result of the extensive hydroelectric power plants, because electricity can be generated more cheaply and the low power-plant costs can only be undercut with difficulty by foreign providers.

At over 7,200 kWh, electricity consumption per capita in Austria is about 30 % higher than the EU average. Electricity consumption rose by 45 % between 1990 and 2007, but has been declining since (0.9 % per year). However, the electricity's share of final consumption remained stable at around 18 % between 1990 and 2009. Industry is the largest consuming sector, with 48 % of electricity consumption, closely followed by the households and the services sector (47 %). In 2010, the per capita consumption of electricity was 7,797.42 kWh. In 2011, the per capita consumption of electricity increased to 8,356 kWh (1.7 % of increase respect to 2010). It is expected that the per capita consumption of electricity in Austria continues to increase at low rates during the coming years.

In 2008, the total electricity generated in Austria reached 66.88 billion kWh. The participation of conventional fossil fuels in the generation of electricity in 2008 was 29.37 %; the consumption per capita of electricity in that year was 7,546 kWh. In 2011, the generation of electricity reached 71,642 billion kWh, which is 4.762 billion kWh higher that the amount produced in 2008 (an increase of 7.1 %). It is expected that this trend will continue during the coming years.

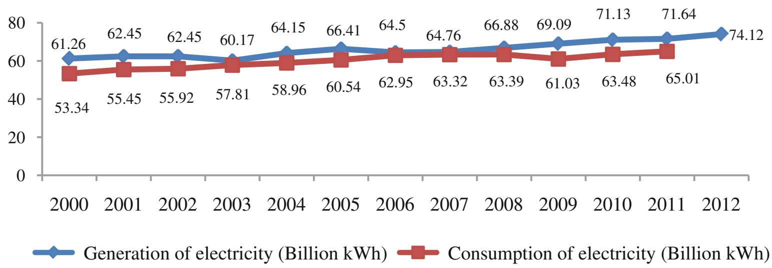

Fig. 2.11 Generation and consumption of electricity in Austria during the period 2000–2012. *Source:* EIA

In 2010, the electricity generated using oil as fuel represented only 2 % of the total electricity produced in the country in that year. It is expected that the participation of oil in the generation of electricity in the country will continue to be very low during the coming years.

From Fig. 2.11, the following can be stated: The generation of electricity in Austria during the period 2000–2012 increased 16.9 %; the total electricity generated in the country during that period is a little bit higher that the consumption of electricity. During the past years, the generation of electricity increased 10.3 %. On the other hand, the consumption of electricity during the same period increased 21.9 %, which is 5 % higher that the increase in the generation of electricity reported by EIA. It is expected that the generation and consumption of electricity in Austria continue to increase during the coming years. The difference between the level of electricity production and consumption in 2011 was around 10 %, which is high enough to allow an increase in the consumption of electricity without the need to invest in the construction of new generating power plants, at least during the coming years.

2.8.5 Import and Export of Electricity

The imports and exports of electricity from Austria during the period 2000–2012 are shown in Fig. 2.12.

During the period 2001–2012, each year the level of import of electricity was higher than the level of export of electricity. It is expected that this trend will continue to be the same during the coming years. The imports of electricity by Austria during the period 2001–2012 increased 60.7 %. Exports of electricity from Austria during the same period increased 43.5 %, which is 17.2 % lower than the level of the imports of electricity reported by EIA.

It is important to highlight that the current trend in the reduction of the use of fossil fuels for the generation of electricity, particularly oil, will not change during the coming years, and for this reason, the participation of oil in the electricity

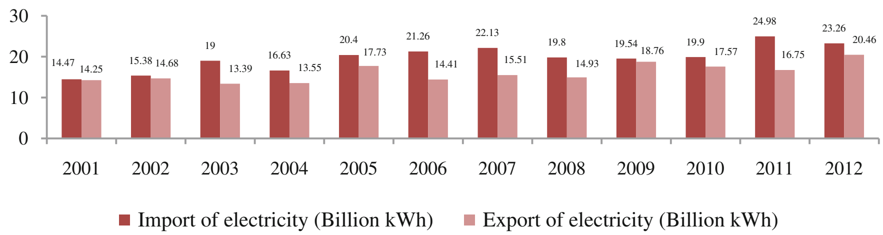

Fig. 2.12 Imports and exports of electricity from Austria during the period 2001–2012. *Source:* Eurostat

generation will continue to decrease. The adoption of different efficiency measures by the Austrian government and the energy sector, and an increase in the use of renewable energy sources for the generation of electricity, will reduce even further the need to use oil for this specific purpose.

2.9 Belgium

According to IEA sources, the three main industry associations in Belgium are the Belgian Petroleum Federation, the Belgian Petroleum Union, and the Federation of Oil Product Wholesalers and Retailers (BRAFCO). The Belgian Petroleum Federation possesses four crude oil refineries, one storage company, and seven main distributors of oil products covering all of the refining activity and 80 % of fuel sales in the country. The Belgian Petroleum Union represents independent importers, distributors, and retailers. Its sixteen members account for some 30 % of Belgium's product imports. BRAFCO represents nearly 800 small-to medium-sized companies and roughly 10 % of the service stations in the country.

2.9.1 Crude Oil Reserves

According to governments sources, Belgium has no crude oil proven reserves reported in 2013.

2.9.2 Production and Consumption of Oil

Belgium has no domestic crude oil and lease condensate production. During the period 2000–2012, oil consumption increased 1.8 % (see Fig. 2.13). The adoption of additional efficiency measures and the reduction of the use of oil for the generation of electricity are key factors in the decrease of the consumption of oil expected during the coming years.

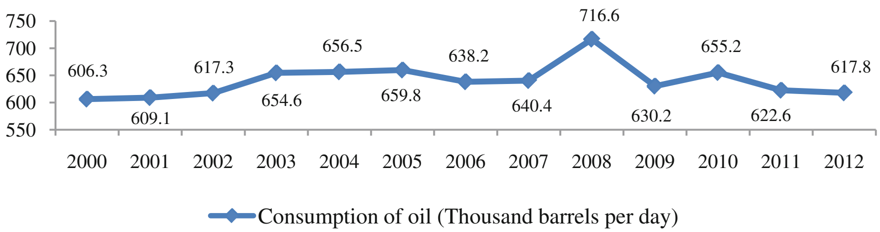

Fig. 2.13 Consumption of oil in Belgium during the period 2000–2012. *Sources:* EIA

2.9.3 Export and Import of Oil

The export and import of oil from Belgium are shown in Figs. 2.14 and 2.15. While fully dependent on oil imports, Belgium is an overall net-exporter of refined oil products within the European region. At the same time, Belgium imports significant quantities of gas/diesel oil from the Netherlands and, to a lesser extent, from Russia. Furthermore, Belgium is increasingly becoming a net importer of fuel oil to meet growing international bunker fuel demand.

According to Fig. 2.14, the imports of oil from Belgium during the period 2006–2012 increased 14.2 %. The peak in the imports of oil during the period under consideration was reached in 2008. Due to the impact of the economic and financial crisis that are affecting the country, and the decrease in the participation of oil for

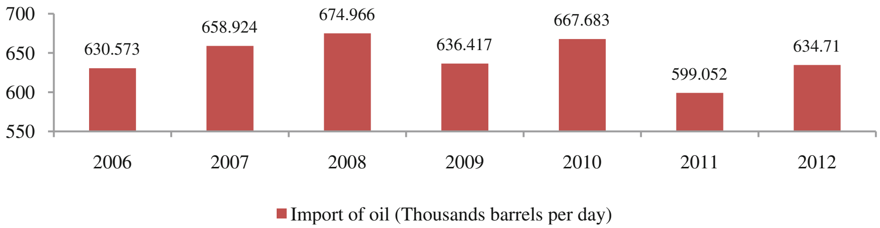

Fig. 2.14 Imports of oil from Belgium during the period 2006–2012. *Source:* EIA

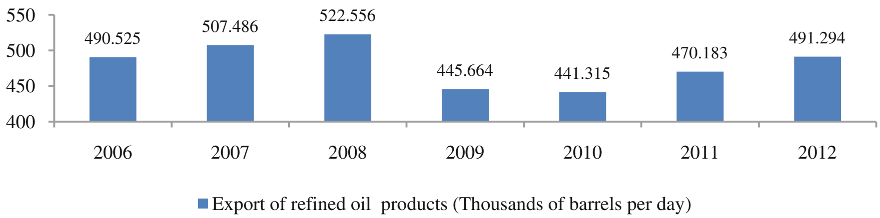

Fig. 2.15 Exports of refined oil products from Belgium during the period 2006–2012. *Source:* EIA

the generation of electricity, it is expected that the imports of crude oil and oil products from Belgium will decrease during the coming years.

On the other hand, the exports of refined oil products from Belgium during the period 2006–2012 increased slightly (0.1 %). The peak in the exports of refined oil products during the period under consideration was reached in 2008. It is expected that the exports of refined oil products from Belgium will continue the same trend during the coming years.

2.9.4 Electricity Generation and Consumption

According to Eurostat sources, in 2010, the total electricity produced by the country was 95.12 billion kWh and 39.3 % of this electricity was produced by fossil fuel power plants. In 2011, the total electricity generated in the country was 90.17 billion kWh, a decrease of 5.3 % respect to 2010. In the specific case of oil, its participation in the electricity generation accounts for less than 1 % and is expected to be eliminated completely in the near future. It is expected also that the participation of other fossil fuels in the generation of electricity will continue decreasing during the coming years, while the use of different renewable energy sources will increase significantly. The generation of electricity in Belgium during the period 2000–2012 is shown in Fig. 2.16.

The generation of electricity in Belgium during the period 2000–2012 decreased 5 %, but after 2010 the generation of electricity dropped significantly 16.4 %. It is expected that the generation of electricity will increase once again during the coming years. On the other hands, the consumption of electricity in Belgium during the period 2000–2011 increased 5.9 %, which is 0.9 % higher than the increase in the generation of electricity registered during 2000–2012. It is expected that the consumption of electricity in Belgium will continue to increase during the coming years.

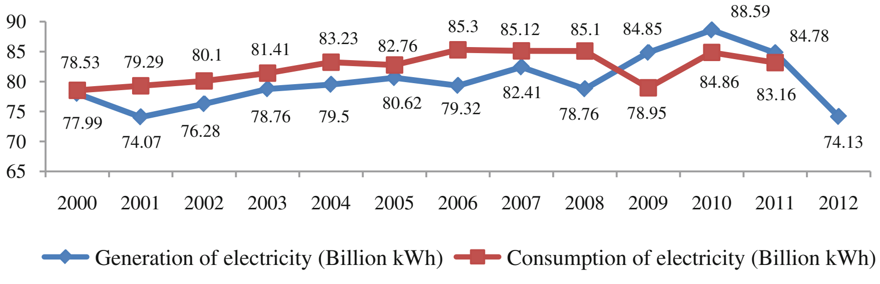

Fig. 2.16 Generation of electricity in Belgium during the period 2000–2012. *Source:* EIA

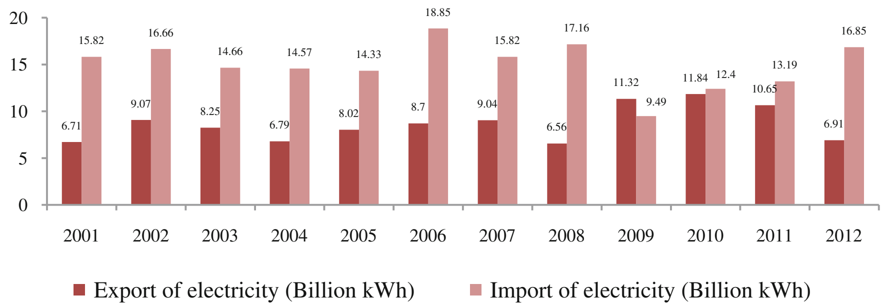

Fig. 2.17 Exports and imports of electricity from Belgium during the period 2001–2012. *Source:* Eurostat and EIA

2.9.5 Import and Export of Electricity

The evolution of the imports and exports of electricity from Belgium during the period 2001–2012 is shown in Fig. 2.17. During the period 2001–2012, the exports of electricity from Belgium increased 2.9 %, and the imports of electricity 8.6 %, which is higher than the exports of electricity reported during the same period. It is expected that the country will continue importing and exporting electricity during the coming years.

2.10 Bulgaria

Bulgarian energy sector is relatively small in global terms, but significant in the country's industrial portfolio. The energy sector primarily comprises of electricity generation and transit of oil and natural gas to other countries within the EU. The energy sector has traditionally been viewed as strategic for the country's economic development and national security. For this reason, the government approved large investments in the energy sector during the past 7–8 years, particularly in building additional capacities, rehabilitating old power plants and expanding the distribution network. The Bulgarian Energy Strategy 2020 sets ambitious plans of turning Bulgaria into the leading power exporter in the Balkans.

Undoubtedly, Bulgaria has the chance to build an energy bridge between its traditional Western and Eastern partners. Currently, a member of the EU, Bulgaria has long-term trade relations with Russia, the Caucasian region, and some Middle East countries. Some of the trade relations have been lost during the transition to a market economy in the period after 1989, but others have been strengthened over the past several years.

Currently, Bulgaria is dependent on foreign oil for almost 100 % of its consumption and on foreign natural gas for over 90 %. However, because of the

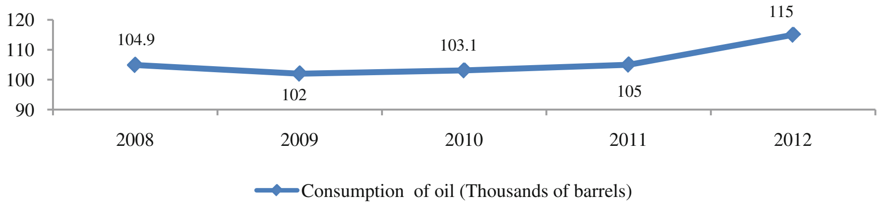

Fig. 2.18 Consumption of oil in Bulgaria during the period 2008–2012. *Source:* EIA

Kozloduy nuclear power plant, Bulgaria's overall energy dependency in 2008 was only 46.2 %, which is a little lower than the EU-average for the same year (53.8 %).

2.10.1 Crude Oil Reserves

Bulgaria crude oil proven reserves are very modest. Have been estimated at 15,000,000 barrels in 2013, according to EIA sources.

2.10.2 Production and Consumption of Oil

According to EIA sources, during the period 2008–2012 Bulgaria produced between 3,400 and 3,600 barrels per day. The oil consumption in the same period is shown in Fig. 2.18.

The consumption of oil during the period 2008–2012 increased 9.6 %, but in the period 2010–2012, the consumption increase in 11.5 %. It is expected that the consumption of oil will continue this trend during the coming years.

2.10.3 Import and Export of Oil

Bulgaria is dependent on imports for 70 % of its energy supplies. During the period 2006–2010, Bulgaria imported and exported oil in quantities shown in Fig. 2.19.

Considered the whole period 2006–2010,[9] the imports of crude oil decreased 18.5 %. Bulgaria does not export crude oil in the period considered. During the same period, the total refined oil products exported decreased 3.7 %. These trends in both parameters are expected to continue during the coming years.

[9] There is no report on the import and export of crude and refined oil products from Bulgaria in 2011 and 2012.

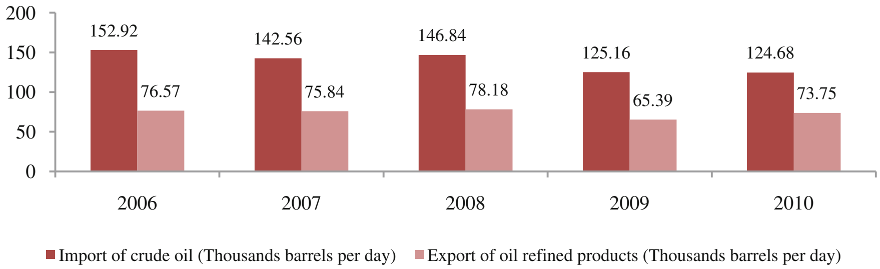

Fig. 2.19 Imports crude oil and exports of oil refined products from Bulgaria during the period 2006–2010. *Source:* EIA

On the other hand, and according to Business Monitor International's Bulgaria Oil and Gas Report 2012, Bulgaria will import between 110,000 and 122,000 barrels per day of crude oil annually over the next 5 years, implying costs of around US$4.32 billion in 2012, easing slightly to US$4.17 billion by 2016. The purpose of this oil import is to satisfy the foreseeable increase in the demand until 2016. According to the same report, the main trends and developments in Bulgaria's oil sector during the coming years are the following:

- Oil demand growth, already modest before the current economic downturn, will make little progress until GDP growth accelerates, which suggests consumption may reach just 122,000 barrels per day by 2016. Imports are expected to grow in line with consumption, as exploration efforts by small independent oil companies are likely to deliver increased domestic crude oil volumes;
- In January 2011, LUKOIL restarted a major investment program at the Burgas crude oil refinery, which had been put on hold during the global economic downturn. France's TECHNIP was awarded a €70 million contract for the first phase of the heavy residue hydrocracking complex at the refinery. The contract award is part of the delayed US$1.3 billion project to transform the plant into a deep refining complex. LUKOIL invested US$240 million in the plant in 2011, but has been battling with local authorities over its operating license;
- Bulgaria is set to import an annual average between 112,000 and 122,000 barrels per day of crude oil over the next 5 years, implying costs of around US $4.17 billion, which will remain unchanged for 2016.[10]

[10] BMI assume an OPEC basket crude oil price for 2011 of US$101.90 per barrel, falling to US $99.40 barrel in 2012. Global GDP in 2011 is forecast at 3.2 %, down from 4.3 % in 2010, reflecting slowing growth in China, a faltering recovery in the USA and a worsening Eurozone debt crisis. For 2012, growth is put at 3.6 %.

2.10.4 Electricity Generation and Consumption

In 2009, fossil fuel power plants generated 55.69 % of the total electricity produced by the country. The total electricity generated using fossil fuels in that year was 24.16 billion kWh, which is a little bit lower than the electricity generated in 2008 (25.9 billion kWh). The participation of oil in the electricity generation in that year was only 0.38 billion kWh (0.88 %). Bulgaria's electricity balance has stabilized since the country stopped exporting electricity as of midnight on February 2014, announced Bulgarian Minister of Economy, Energy, and Tourism Traicho Traikov. "By terminating the exports of electricity, Bulgaria benefitted with the stability of its own system," Traikov told Darik Radio Saturday. On February, Bulgaria's government discontinued all electricity exports in order to make up for the increased domestic electricity consumption caused by the freezing temperatures over the past couple of weeks. According to Traikov, Bulgaria's annual electricity exports equal 1,000 MW, but in early February 2014 the cold weather strained the country's energy capacity. The Energy Minister said that Bulgaria was not faced with an electricity shortage, but that the termination of exports was a necessary measure, because the country energy system has not been built in a way facilitating the export of electricity. The country is exporting just what it has as production surpluses. Bulgaria traditionally exports electricity to Greece and Macedonia; in 2011, electricity exports to Turkey were resumed after an 8 year pause.

The electricity balance of Bulgaria in 2009 is contained in Table 2.4.

Table 2.4 Electricity balance of Bulgaria in 2009

	Billion kWh
Gross production, of which	43.38
Hydro	3.65
Nuclear	15.21
Wind	0.36
Thermal of which	24.16
Coal	22.09
Oil	0.38
Gas	1.67
Biomass	0.02
Net production	39.13
Imports	2.66
Exports	−7.74
Transport/distribution losses	−5.26
Total consumption	27.92
Energy sector consumption	0.34
Final consumption	27.58
Industry	10.48
Transport	0.31
Households services	16.80

Source: EIA

The consumption of electricity in the past 3 years was the following: 30.4 billion kWh in 2009, 32.5 billion kWh in 2010 and 31.3 billion kWh in 2011. It is expected that in 2020, the consumption of electricity could reached 52.7 billion kWh; this represents an increase of 68.4 % respect to 2011.

It is expected also that the participation of oil in the generation of electricity in the country during the coming years will continue to be very small.

2.11 Croatia

The principal objectives of the energy policy in Croatia are stated in the Energy Development Strategy of the Republic of Croatia (Official Gazette 38/2002) which was adopted by the Croatian Parliament in March 2002 for the period of 10 years. The main objectives to be reached are the following:

- Improvement of energy efficiency of the production, transformation, transmission, and transport to distribution and consumption of energy, which includes encouraging the process of natural gas pipeline installation and possibilities of natural gas usage, as well as generation of energy outside public networks;
- Safe, energy provision and supply, inclusion in the international energy market, ensuring several lines of connection to international networks and the provision of energy from several directions for all energy network systems, development of transmission and transport networks, development of distribution networks, observation of safely limitations, and State interests;
- Diversification of energy-generating products and sources, which includes the selection and provision of energy-generated products with the aim of ensuring a safe supply to the consumers and spatial arrangement of sources, which will ensure the safety of supply of each area;
- Utilization of renewable energy sources, which will be in accordance with sources, technological development, and economic policy as a whole;
- Realistic and market-related prices of energy and development of the energy market and entrepreneurship, and privatization processes in accordance with the interests of the Croatian State, which should encourage energy efficiency and better energy management with the aim of including Croatia into the European energy market;
- Environmental protection, which in the energy sector implies the primary action in connection with energy efficiency, the increase use of renewable energy sources, choice of energy-generating products and application of state-of-the-art protection technologies, quality legislation and supervision, the public opinion and education, and promotion of best practices.

Table 2.5 Total oil production and consumption in Croatia in 2011 and 2012 (Thousand barrels per day)

	Croatia 2011	Europe	World	Rank	Croatia 2012
Total oil production	21.29	4,273	87,040	74	20.1
Crude oil production	13.49	3,418	74,051	70	11.8
Consumption	113.00	15,085	87,290	74	93.5

Source: EIA

2.11.1 Crude Oil Reserves

According to EIA sources, in 2009 crude oil reserves in Croatia was estimated at 79 million barrels, which represent around 0.01 % of the world's proven crude oil reserves. In 2013, these reserves were estimated at 71 million barrels; a reduction of 10.2 % respect to the level registered in 2009.

2.11.2 Production and Consumption of Oil

Total oil production and consumption in Croatia in 2011 and 2012 is shown in Table 2.5.

According to Table 2.5, the total oil production, including lease condensate, in Croatia in 2012 was 20,100 barrels per day (11,800 barrels of crude oil per day) and the consumption was 93,500 barrels per day, around 4.5 times the domestic production of oil. According to government sources, the country will account for 1.7 % of Central and Eastern European (CEE) regional oil demand by 2014, while contributing just 0.14 % to regional supply. CEE regional oil use of 5.42 million barrels per day in 2001 is expected to rise to around 6.68 million barrels per day by 2014; this represents an increase of 23 %.

Consumption of oil is set to grow more slowly than the underlying economy, increasing around 1.5 % per annum over the forecast period and reaching 114,000 barrels per day by 2014, which is 0.09 % higher than the level of consumption reached in 2011. Former State oil group INA is attempting to raise local supply in partnership with major shareholder, but it is expected to see a steady decline in oil and liquids production from the estimated 2010 level of 24,000 barrels per day to no more than 20,000 barrels per day by 2014; this represents a decrease of 17 %. Between 2010 and 2019, it expects an increase in Croatian oil consumption by 15.5 % (1.72 % per year).

2.11.3 Import and Export of Oil

Oil import volumes are rising steadily from an estimated 82,000 barrels per day in 2010 to 105,000 barrels per day by the end of the 10 year forecast period. In 2011,

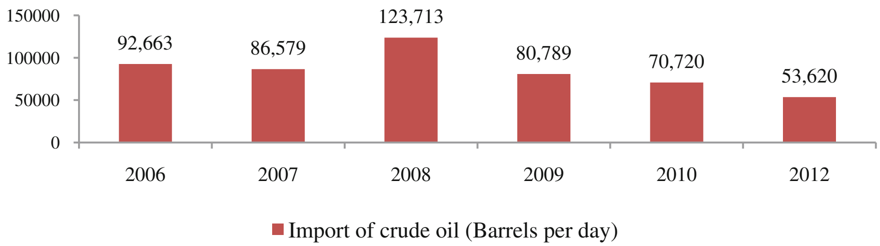

Fig. 2.20 Imports of crude oil from Croatia during the period 2006–2012. *Source:* EIA and other sources (2012)

oil import reached 91,710 barrels per day; this represents an increase of 12 % respect to 2010.

The evolution of the imports of crude oil during the period 2006–2012 is shown in Fig. 2.20.

According to Fig. 2.20, the imports of crude oil from Croatia decreased 42.2 % during the period 2006–2012. The peak in the imports of crude oil, during the period considered, was reached in 2008. Since that year the imports of crude oil has decreased and it is expected that this trend will continue during the coming years. Croatia did not export crude oil during the period considered.

2.11.4 Electricity Generation and Consumption

Electricity generation and consumption in Croatia during the period 2005–2012 is shown in Fig. 2.21.

The generation of electricity in Croatia during the period 2005–2012 increased 17.3 %. The peak in the generation of electricity was reached in 2012 and it is expected that since that year the trend is to produce more electricity due to an

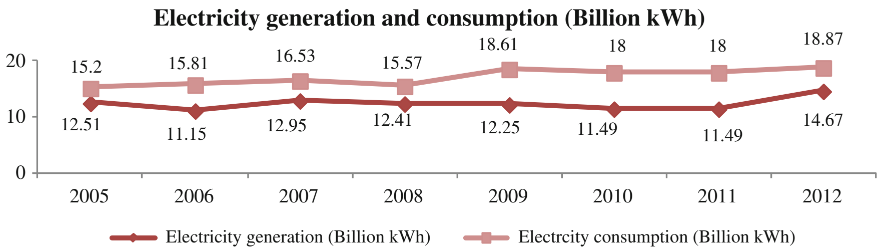

Fig. 2.21 Electricity generation and consumption in Croatia during the period 2005–2012 (Billion kWh). *Source:* Index Mundi and EIA (2008 and 2009)

increase in the electricity demand, particularly after the end of the economic crisis, which is still affecting the whole European region, but now with less intensity.

On the other hand, the consumption of electricity in Croatia is higher (6.7 %) than the generation of electricity and increased 24 % during the period 2005–2012. The peak in the consumption of electricity was reached in 2012, the year with the highest level of electricity production in the period considered. According to the Croatia government, it is expected that the production of electricity increase from 11.49 billion kWh in 2010 to 28 billion kWh in 2020 (13.5 % of increase per year as average) to 36.9 billion kWh in 2030 (36.6 % of increase respect to 2010). In 2010, around 74 % of the total domestic electricity demand were satisfied with national generation.

The government adopted in 2010 a decision to invest in the energy sector a total of €3,050 million during the coming years. From this total, the government will invest €2,200 million to add new electricity capacity. During the period 2009–2020, the government will invest in the generation of electricity €9 billion.

The total installed capacity in 2008 was 3.91 GWe. In 2009, the electricity capacity increased to 4.02 GWe; this represents an increase of 3 %. During the period 2010–2011, a total of 120 MW of new capacity was added. The capacity of the thermal power plants is 1.8 GW (43.4 % of the total capacity installed). In 2006, the generation of electricity using oil as fuel was 11 % of the total electricity generated in the country. In 2009, this percentage was 13.1 %, an increase of 2.1 % respect to 2006. It is expected that the participation of oil in the generation of electricity in the country will continue to be almost the same during the coming years or could be even reduced.

2.12 Czech Republic

The Czech Republic, rich in coal resources, is the third-largest electricity exporter in the EU. The energy sector plays an important role in the country's economy and for the regional energy security. Since the last IEA in-depth review in 2005, the Czech Republic has strengthened its energy policy, further liberalized its electricity market, and made laudable efforts to enhance oil and natural gas security While the focus on energy security is praiseworthy, energy policy could be further improved. For example, energy policy should be better integrated with climate change considerations.

At the same time, economic efficiency should be another key pillar of energy policy. To improve its energy security while reducing greenhouse gas emissions and enhancing economic development, the Czech Republic could take some additional measures in order to improve further energy efficiency and broaden demand-side measures such as focus on low-carbon technologies, integrate electricity and natural gas markets regionally, and optimize needed new energy infrastructure.

2.12.1 *Crude Oil Reserves*

According to EIA sources, the country has total proven crude oil reserves of 0.02 billion barrels in 2013. This figure has been the same during the past 5 years.

2.12.2 *Production and Consumption of Oil*

The total oil production and consumption in 2012 in the Czech Republic is included in the Table 2.6. According to that table, the total production of oil in the Czech Republic in 2012 reached 10,000 barrels per day and the production of crude oil 3,000 barrels per day. The consumption of oil in the same year was 195,500 barrels per day, which is 19.5 folds the level of production reported for that year. It is expected that the relationship between oil production and consumption will not change significantly during the coming years.

The evolution of the production and consumption of oil in the Czech Republic during the period 2008–2012 are shown in Figs. 2.22 and 2.23.

The production of oil in the Czech Republic decreased 8.3 % during the period 2008–2012. The peak in the production of oil, during the period considered, was reached in 2011 and after that year the production of oil decreased 23.1 %. It is

Table 2.6 Production and consumption of oil in the Czech Republic in 2011 and 2012 (Thousand barrels per day)

	Czech Republic 2011	Europe	World	Rank	Czech Republic 2012
Total oil production	13.01	4,273	87,040	81	10
Crude oil production	3.08	3,418	74,051	80	3
Consumption	192.41	15,085	87,290	58	195.5
Net export/imports (−)	−179.40	−10,811	–	33	−144.35
Proven reserves (Billion barrels)	0.015	12	–	76	0.015

Source: EIA

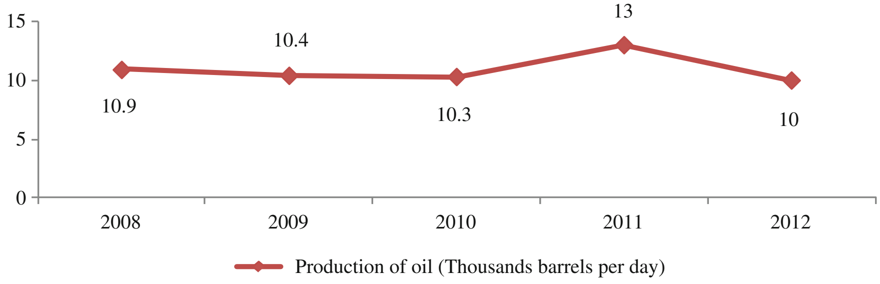

Fig. 2.22 Production of oil in the Czech Republic during the period 2008–2012. *Source:* EIA

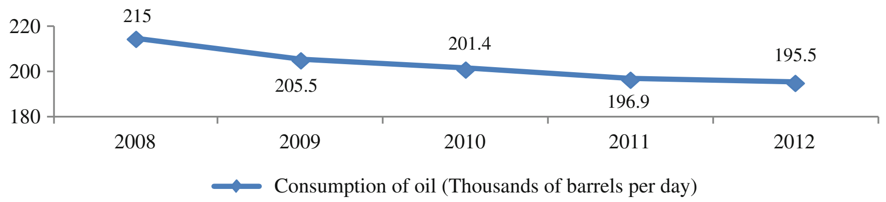

Fig. 2.23 Consumption of oil in the Czech Republic during the period 2008–2012. *Source:* EIA

expected that the production of oil will continue the current trend unless new oil fields are found.

On the other hand, the consumption of oil in the Czech Republic during the period considered decreased 9.1 %, but it is still much higher than the domestic oil production. It is expected that the consumption of oil in the Czech Republic will continue the current trend during the coming years, particularly due to a decrease in the participation of oil in the generation of electricity.

2.12.3 Import and Export of Oil

In 2011, the Czech Republic imported 179,400 barrels of oil in order to satisfy its internal demand. The country does not export oil in that year. The evolution of the imports of crude oil, including lease condensate, during the period 2001–2012 is shown in Fig. 2.24.

According to Fig. 2.24, the imports of oil from the Czech Republic during the period 2001–2012 increased 17.2 %. The peak in the imports of oil was reached in 2008, the year of the beginning of the financial and economic crisis, which is still affecting several countries in the European region. However, it is expected that the imports of oil will decrease during the coming years due to the foreseeable reduction of the use of oil for the generation of electricity. The exports of crude oil from the Czech Republic during the period 2006–2012 is shown in Fig. 2.25.

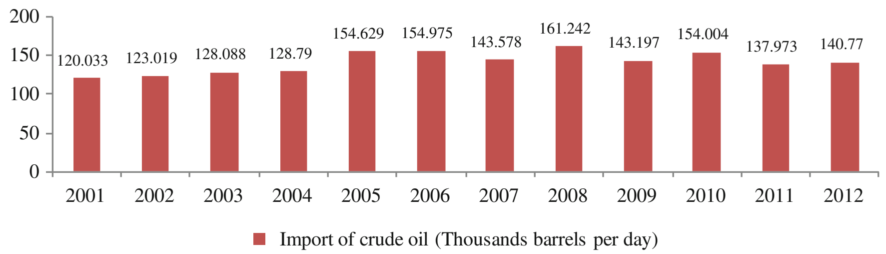

Fig. 2.24 Imports of crude oil, including lease condensate, from the Czech Republic during the period 2001–2012. *Source:* EIA

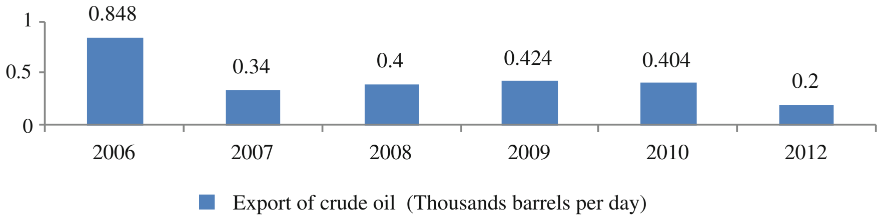

Fig. 2.25 Exports of crude oil from the Czech Republic during the period 2006–2012. *Source:* EIA and Eurostat (2012)

The exports of crude oil from the Czech Republic is very little and decreased 23.5 % during the period 2006–2012. It is expected that the exports of crude oil from the Czech Republic will continue the current trend at least during the coming years as a result of the reduction in the domestic oil production.

2.12.4 Electricity Generation and Consumption

The generation of electricity in the Czech Republic during the period 2000–2012 is shown in Fig. 2.26.

The generation of electricity in the Czech Republic during the period 2000–2012 increased 11.2 %. The peak in the generation of electricity was reached in 2007. It is expected that the generation of electricity in the Czech Republic will continue to be stable during the coming years, but could increase in response to an foreseeable increase in the demand in the industrial and residential sectors.

The participation of oil in the generation of electricity was 0.1 % and is not expected that the current level of participation will increase in the coming years. It is possible that oil could be excluded from the generation of electricity during the coming years.

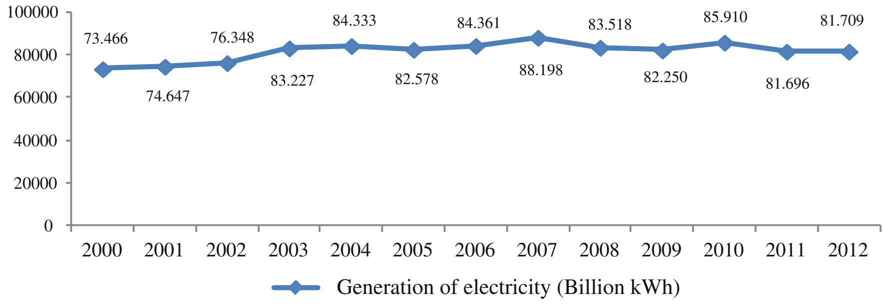

Fig. 2.26 Generation of electricity in the Czech Republic during the period 2000–2012. *Source:* Eurostat and EIA (2011, 2012)

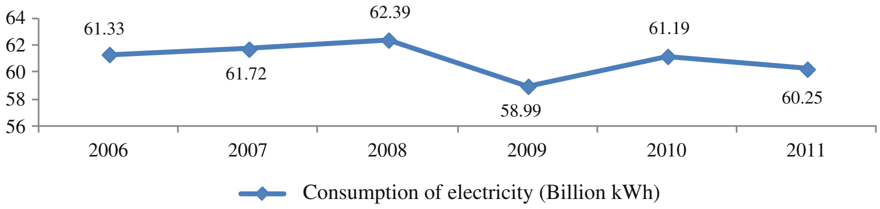

Fig. 2.27 Consumption of electricity in the Czech Republic during the period 2000–2011. *Source:* EIA

The consumption of electricity by the Czech Republic in the period 2000–2011 is shown in Fig. 2.27.

The Czech Republic decreased very little (1.8 %) the consumption of electricity during the period 2006–2011, except from the period 2008–2009. In this period the consumption of electricity dropped 5.5 %. The peak in the consumption of electricity during the period considered was reached in 2008, the same year in which the world economic crisis started. However, the consumption of electricity started to increase once again after 2009 with the beginning of the economic recovering of the country, but dropped 1.6 % once again during the period 2010–2011. Fossil fuel power plants generated 60.6 % of the electricity produced by the country in 2009.

The electricity generation capacity installed in the country in 2011 was reported at 19.98 GWe; this represents an increase of 10.5 % respect to 2010.

2.12.5 *Import and Export of Electricity*

The exports and imports of electricity from the Czech Republic during the period 2001–2012 are shown in Fig. 2.28.

The imports of electricity from the Czech Republic increased in the past 12 years around 17.9 %. The peak in the imports of electricity, during the period considered,

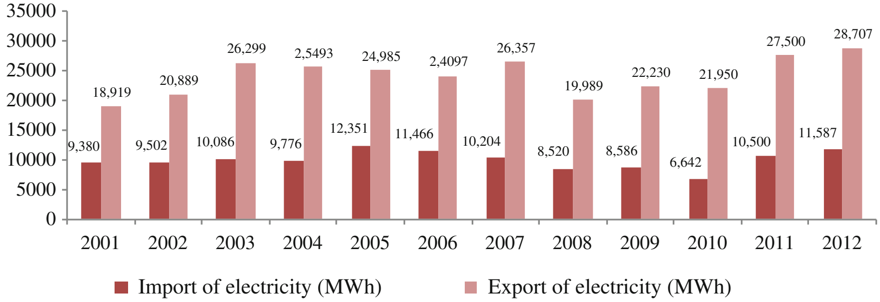

Fig. 2.28 Imports and exports of electricity from the Czech Republic during the period 2001–2012. *Source:* Eurostat

was reached in 2005. As a result of the measures adopted by the government to increase the efficiency in the energy sector and the economic crisis affecting the whole European region since 2008, among others, it is expected that the imports of electricity will continue the current trend at least during the coming years. As can be seen in Fig. 2.28, the exports of electricity increased significantly in the past 12 years, around 51.7 %. The peak in the exports of electricity, during the period considered, was reached in 2012. The Czech Republic is a net exporter of electricity to other countries and it is expected that this status will continue to be the same during the coming years.

2.13 Denmark

According to IEA sources, oil production in Denmark began in 1972 and rose steadily until reaching a peak in 2004, when production averaged nearly 390,000 barrels per day. Oil production has since declined steeply and in 2011 it averaged 220,695 barrels per day; a decrease of 43.5 % respect to 2004. Danish oil production comes exclusively from offshore installations in the Danish North Sea, where there are 19 producing oil fields.

It is important to highlight that Denmark's oil and natural gas production has been in progress for almost 40 years, and oil companies continue to show interest in securing future production from these fields. This was again apparent in 2011, when the government approved five plans for the further development of existing oil fields and the development of an entirely new field, the Hejre Field. Additionally, there have been comprehensive maintenance activities offshore in order to optimize production from existing oil fields, and new wells have also been drilled.

While Denmark has one of the lowest energy intensities in the world, the government is considering the introduction of a long-term (e.g., 2050) target of becoming fully independent of fossil fuels for the generation of electricity, a policy which would further encourage greater energy efficiency, growth in renewable energy production and electrification of energy end use (e.g., transport).

Oil represented 36 % of the Denmark's total primary energy supply in 2009. While the combined share of oil and natural gas in the supply mix has remained relatively stable over the past three decades, at around 60 % of total primary energy supply, oil's share has been reduced dramatically from the nearly 90 % it represented in the early 1970 to 36 % in 2009; this represents a reduction of 54 % (IEA 2011). The Danish Administration is now considering the introduction of a long-term target of becoming fully independent of fossil fuels by 2050.

2.13.1 Crude Oil Reserves

During the period 2002–2005, crude oil reserves increased from 1.230 billion barrels in 2002 to 1.300 billion barrels in 2005; this represents an increase of 5.7 %. Since that year, however, crude oil reserves have started to decline and went down from 1.300 billion barrels in 2005 to 1.060 billion barrels in 2010 and to an estimated of 812 million barrels in January 2011; this represents a further decrease of 27.6 %. In 2013, according to EIA sources, the proven crude oil reserves were estimated at 805 million barrels a further decrease of 0.9 % respect to 2011. Without the discovering of new crude oil fields, and with the current level of extraction, the total crude oil reserves of the country will continue to decrease during the coming years.

2.13.2 Production and Consumption of Oil

Oil production in Denmark in 2010 reached 245,500 barrels per day and in 2011 totaled 220,695 barrels per day, a 10.2 % decline respect to 2010.[11]

The oil production of the Danish sector of the North Sea started to decline since 2004. The main reason for this trend is that over the past years, the majority of oil fields has already produced the bulk of the anticipated recoverable oil.[12] In addition, these aging fields require increasing maintenance of wells, pipelines, and platforms. This maintenance work frequently involves production losses or delays as the wells, and possibly also entire platforms, need to be shut down while the work is taking place. The development of existing and the discovering of new oil fields can help counteract the decline in production in existing oil fields. In addition, the implementation of both known and new technologies can aid in optimizing production from existing oil fields.

However, technological developments and any new oil discoveries made as part of ongoing exploration activity, including under the licenses from the 6th Licensing Round, are expected to curb the decline in oil production. The evolution of the production and consumption of oil in Denmark during the period 2008–2012 are shown in Figs. 2.29 and 2.30.

[11] In 2011, production in the Danish part of the North Sea derived from a total of 278 active production wells, of which 199 were oil wells and 79 were gas wells. In addition, 109 active water-injection wells and 6 gas-injection wells contributed to production.

[12] In 2011, production was suspended in some fields due to safety or environmental issues. Such shut downs may become more frequent in future in step with the increasing age and obsolescence of platforms and pipelines. Summer shut downs have been planned in recent years on several platforms in order to undertake overhauls and maintenance of wells and offshore installations to prevent unplanned shut downs.

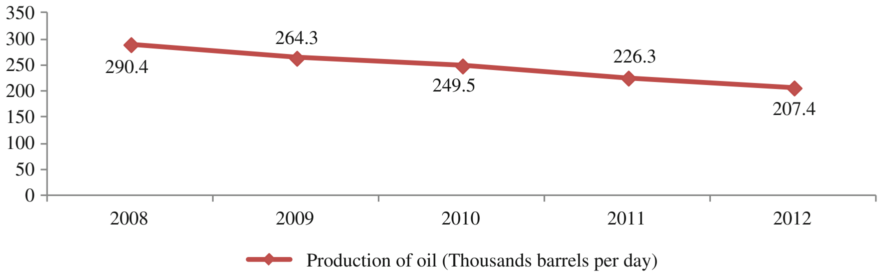

Fig. 2.29 Production of oil in Denmark during the period 2008–2012. *Source:* EIA

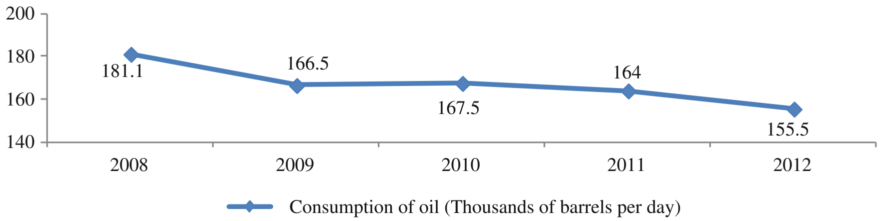

Fig. 2.30 Consumption of oil in Denmark during the period 2008–2012. *Source:* EIA

The production of domestic oil in Denmark has been decreasing since 2008. According to Fig. 2.29, during the period 2008–2012, the production of oil declined 29 %. It is expected that the production of oil in Denmark will continue decreasing, unless new oil fields are found during the coming decades.

On the other hand, the consumption of oil in Denmark dropped 14.6 % during the past 4 year. This trend is expected to continue during the coming years, but overall oil consumption forecast for the period until 2030 is for a small increase, averaging 0.4 % per year (IEA 2011).

2.13.3 Import and Export of Oil

Denmark has been a net exporter of crude oil since the mid-1990s. In 2010, roughly 155,000 barrels per day of the 245,500 barrels per day of domestic production was exported; this represents 63 % of the total consumption of crude oil. It is expected that Denmark continues to be a net exporter of crude oil at least until the end of 2018. Extending self-sufficiency beyond that year will for the most part depend on future technological developments upstream, but even once the country becomes a net-importer, this would likely only be marginal in the period prior to 2035 (IEA 2011). In the same year, Denmark imported just over 55,000 barrels per day of crude oil, primarily from Norway, for domestic refining. In terms of refined oil

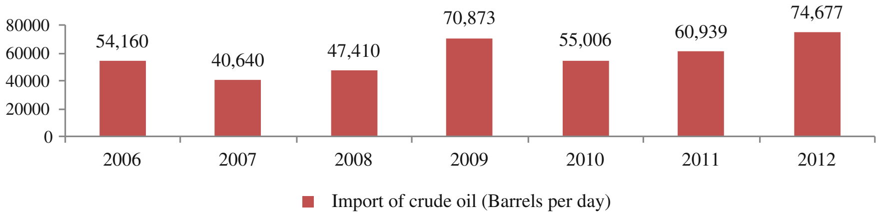

Fig. 2.31 Imports of crude oil from Denmark during the period 2006–2012. *Source:* EIA

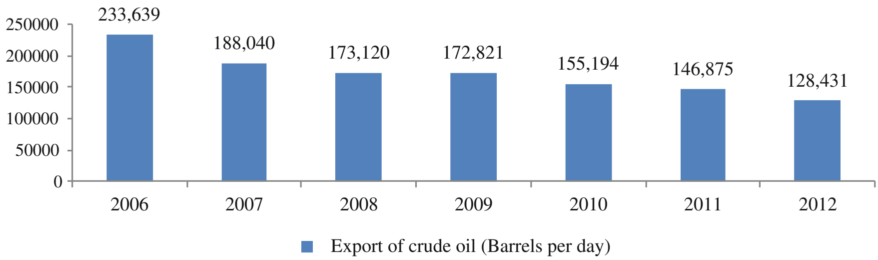

Fig. 2.32 Exports of crude oil from Denmark during the period 2006–2012. *Source:* EIA

products, Denmark is marginally a net importer. In 2010, refined oil product net imports were less than 20,000 barrels per day.

Generally, Denmark is a net exporter of gasoline and fuel oil and a net importer of middle distillates. In 2010, Denmark's total net-exports of oil, including both crude oil and refined oil products, equated to 82,000 barrels per day.

The evolution of the imports and exports of crude oil from Denmark during the period 2006–2012 is shown in Figs. 2.31 and 2.32.

As a result of the reduction of the domestic oil production, the imports of crude oil from Denmark during the past 7 years increased 37.8 %. The peak in the imports of crude oil during the period considered was reached in 2012. It is expected that Denmark will continue importing crude oil during the coming years.

On the other hand, the exports of crude oil from Denmark during the period 2006–2012 decreased 45.1 %. It is expected that this trend will continue during the coming years. However, it is important to highlight that according to the energy policy adopted by the government, Denmark is a net exporter of oil and will remain so at least until end of 2018.

2.13.4 Electricity Generation and Consumption

In Denmark, fossil fuels generate 70.5 % of the total electricity produced in the country in 2009. In that year, the country generated 36.2 billion kWh of electricity using all available energy sources, which is 2.7 billion kWh less that the level

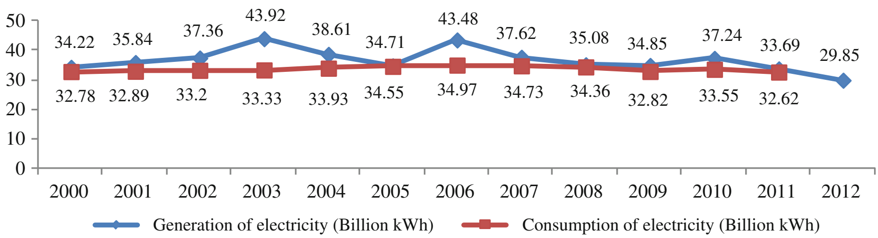

Fig. 2.33 Generation and consumption of electricity in Denmark during the period 2000–2012. *Source:* EIA

reached in 1999. The participation of fossil fuels in the energy mix dropped 8.5 billion kWh during the period 1999–2009. The participation of oil in the generation of electricity in 2009 was 3 % and is expected to be 0 % no later than 2050. According to IEA sources, the installed capacity of the country in 2010 was 13.71 million kW an increase of 2.2 % respect to 2009. The electricity consumption per capita fell from 6,668 kWh in 2007 to 6,246 kWh in 2009, this represented a reduction of 6.4 % only in the past 3 years.

It is the intention of the government to reduce the participation of oil in the electricity generation and to increase the use of renewable energy sources for this specific purpose during the coming years. Important measures have been adopted with this aim.

The evolution of the generation and consumption of electricity in Denmark during the period 2000–2012 is shown in Fig. 2.33.

The generation of electricity in Denmark during the period 2000–2012 decreased 12.8 % as a result of different measures adopted by the government. The peak in the generation of electricity during the period considered was reached in 2003. However, it is expected that the generation of electricity will increase during the coming years as a result of an increase in several economic sectors. On the other hand, the consumption of electricity during the period considered decreased 0.5 % and the government expect that the consumption of electricity in Denmark continue the current trend during the coming years.

2.13.5 Import and Export of Electricity

The exports and imports of electricity from Denmark during the period 2001–2012 is shown in Fig. 2.34. The exports of electricity from Denmark during the period 2001–2012 increased 22 %. The peak in the exports of electricity during the period considered was reached in 2003 when the country exported 15,568 million kWh to Sweden and Germany, among other countries. The government expect that the country will be able to continue exporting electricity during the coming years. On the other hand, the imports of electricity from Denmark during the same period

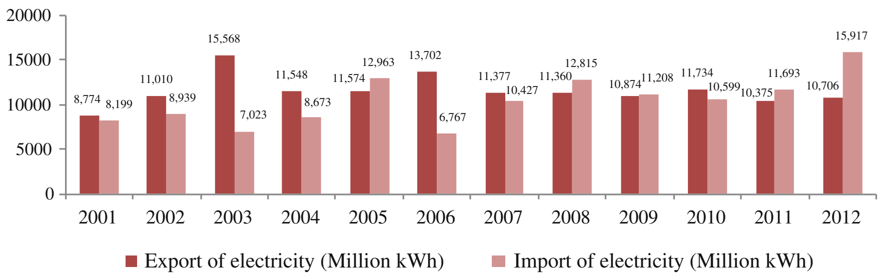

Fig. 2.34 Exports and imports of electricity from Denmark during the period 2001–2012. *Source:* Eurostat and EIA

increased 94.1 %. The peak in the imports of electricity, during the period considered, was reached in 2012. The government expect to reduce the imports of electricity from other countries by increasing the domestic generation of electricity as a result of an increase in the use of renewable energy sources for this purpose.

2.14 Finland

The energy landscape of Finland can be described as versatile. Unlike most countries that rely heavily on one or two main energy sources, in Finland several different energy sources make up the total energy mix. The share of oil in total energy consumption is slightly above 20 %, followed by wood-based energy with close to 20 % share, and by coal and nuclear energy, each representing an approximately 15 % share of the total. Natural gas and peat are also important energy sources, together contributing close to 20 % of the total energy consumption.

The objectives of the Finnish energy policy are: Security of supply; effective energy markets and the economy; environmental acceptability and safety. In Finland, energy supply decisions on energy systems take place at a fairly decentralized level with the exception of nuclear power. A substantial proportion of energy is imported and produced by private enterprises. The energy companies with majority ownership by state are also run on a purely commercial basis. There are about 400 power plants in Finland and about half of these are hydroelectric.

It is important to highlight that Finland has no domestic fossil energy resources and this means that the country is fully dependent on imports. The main source for imported fossil fuels is Russia. Over 80 % of oil products, over 90 % of coal and a full 100 % of natural gas comes from Russia. In addition to fossil fuels, a notable amount of the annual consumption of electricity, over 10 %, is also imported from Russia. Finland imports electricity also from the Nordic electricity markets and from Estonia to satisfy its remaining energy requirements.

2.14.1 Crude Oil Reserves

According to public sources, Finland has no proven crude oil reserves reported in 2013.

2.14.2 Production and Consumption of Oil

In Table 2.7, the total oil production and consumption in Finland in 2011 and 2012 are included. The country did not produce crude oil in 2012.

According to Table 2.7, Finland produced 14,200 barrels per day in 2011 and consumed 207,700 barrels per day; in other words, the country's oil production reported in 2011 satisfied only 6.8 % of the total oil consumption of the country in that year. In 2012, this figure was almost the same. For this reason, and in order to satisfy its internal oil demand, the country imported 199,030 barrels per day in 2012. It is expected that in the future Finland will continue to import a significant amount of oil in order to satisfy its energy needs.

The evolution of the production of crude oil and other liquids in Finland during the period 2000–2012 is shown in Fig. 2.35.

Table 2.7 Total oil production and consumption in Finland in 2011 and 2012 (Thousand barrels per day)

	Finland 2011	Europe	World	Rank	Finland 2012
Total oil production	14.2	4,273	87,040	86	13.5
Crude oil production	0.00	3,418	74,051	92	0
Consumption	207.07	15,085	87,290	54	196.5
Net export/imports (−)	−199.03	−10,811	–	31	NA
Refinery capacity	259	16,787	88,097	53	261
Proven crude oil reserves (Billion barrels)	0.00	12	–	88	0.00

Source: EIA

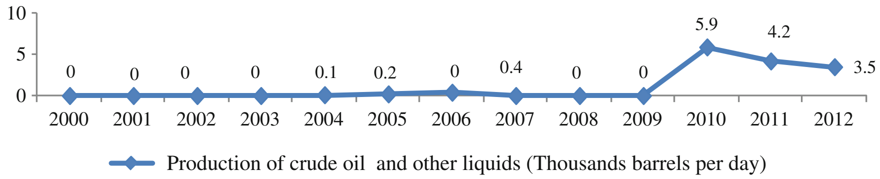

Fig. 2.35 Production of crude oil and other liquids in Finland during the period 2000–2012. *Source:* Eurostat and EIA

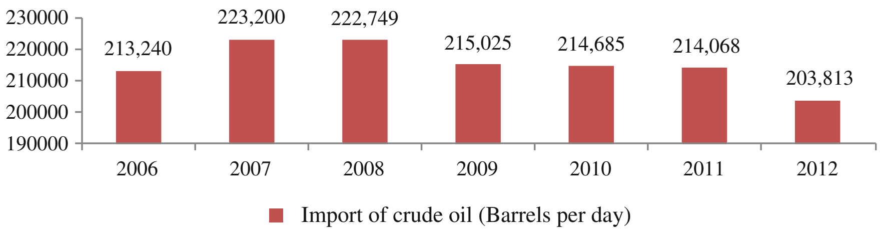

Fig. 2.36 Imports of crude oil from Finland during the period 2006–2012. *Source:* EIA

The production of crude oil and other liquids in Finland during the period 2000–2012 was very small. The peak in the production of crude oil and other liquids during the period considered was reached in 2010. The government expect that the production of crude oil and other liquids will continue to be very small during the coming years. Finland, in general, is not an exporting crude oil country.

2.14.3 Import and Export of Oil

The evolution of the imports of crude oil from Finland during the period considered is shown in Fig. 2.36. Finland needs to import almost all its energy needs. The imports of crude oil from Finland during the period 2006–2012 decreased 5.4 % as a result of the implementation of measures to keep the import of oil as low as possible. The peak in the imports of crude oil, during the period considered, was reached in 2007 and since that year the import of crude oil is decreasing year by year. It is expected that Finland will continue to import an important amount of crude oil in order to satisfy its energy needs during the coming decades, but a lower rate. During the period 2006–2012, Finland does not export crude oil, but exports more than 124,000 barrels per day of refined petroleum products. In 2012, the exports of refined petroleum products reached 150,442 barrels per day, an increase of 8.5 % respect to 2008.

2.14.4 Electricity Generation and Consumption

The power system in Finland is part of the Inter-Nordic power system together with the systems in Sweden, Norway, and Eastern Denmark. Moreover, there are direct current transmission links to Finland from Russia and Estonia for the connection of their systems. Similarly, the Inter-Nordic system is connected to the system in Continental Europe by means of direct current transmission links. Between 2010 and 2020, the government will spend a total of €1,600 million on upgrading the transmission grid, which means annual capital expenditure between €100 million and €200 million. The objective is to build almost 3,000 km of new transmission lines and about 30 new substations. The grid capital investment program covering the whole of Finland is based on the long-term climate and energy strategy of Finland. The aim is to reduce the greenhouse gas emissions, to shift from a dependence on electricity imports to self-sufficiency, and to replace electricity generation based on fossil fuels. The transmission grid must be able to receive the new production, but the development of the grid is also affected by other factors, such as changes in electricity consumption, decommissioned production capacity, and renovations required by the existing grid.

According to government sources, domestic production of electricity in 2012 amounted to 70.4 billion kWh, a decrease of 9 % respect to 2011. The use of fossil fuels for the production of electricity in 2012 decreased 21 % compared to 2011. In Table 2.8, the total electricity generated and consumed in Finland in 2008, 2009, 2010 and 2012 are included.

From Table 2.8, the following can be stated: Electricity net generation in 2012 decreased 12.6 % respect to 2008. The electricity net consumption also decreased from 87.25 billion kWh in 2008 to 81.055 billion kWh in 2011; this represents a decrease of 7.2 %. The installed capacity increases slightly in the period considered from 16.65 billion kWh in 2008 to 16.76 billion kWh in 2011, an increase of 0.6 %. It is expected that in the future the consumption of electricity in Finland will continue increasing, but in a very moderate manner.

According to government sources, 27 % of the total electricity produced in the country in previous years was generated using fossil fuels. From this total only 0.6 % is produced today using oil as fuel, a decrease of 26.4 %.

The evolution of the electricity generated in Finland during the period 1999–2012 is shown in Fig. 2.37. The generation of electricity in Finland during the period 1999–2012 increased 1.2 %. The peak in the generation of electricity was reached in 2004.

The consumption of electricity in Finland during the past 6 years decreased 4.3 %. It is important to highlight that the consumption of electricity decreased during the period 2007–2009 in response to the implementation of additional

Table 2.8 Total electricity generated and consumed in Finland in 2008, 2009, 2010, and 2012 (Billion kWh)

	Finland 2008	Europe	Rank	Finland 2009	Finland 2010	Finland 2012
Net generation	77.4	3,607	37	72.1	80.7	67.69
Net consumption	87.25	3,364	33	81.29	87.46	81.055 (2011)
Installed capacity (million kW)	16.65	916	40	16.32	16.68	16.76 (2011)

Source: EIA and Eurostat

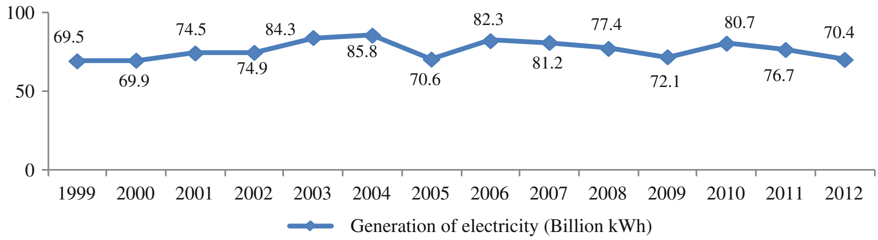

Fig. 2.37 Generation of electricity in Finland during the period 1999–2012. *Source:* Eurostat

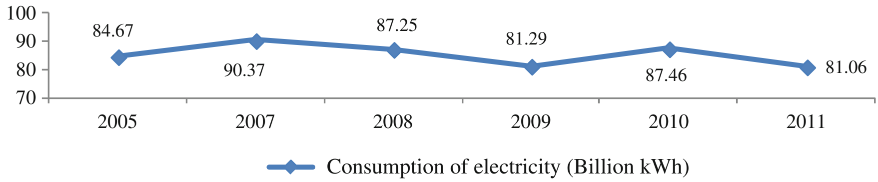

Fig. 2.38 Electricity consumption in Finland during the period 2005–2011 (Billion kWh). *Source:* Eurostat and EIA (2011)

measures adopted by the government with the aim of increasing energy efficiency in all economic sectors. During the period 2009–2010, the consumption of electricity increased by 7.6 %, but decrease once again during 2010–2011 (Fig. 2.38).

2.14.5 *Export and Import of Electricity*

The exports and imports of electricity from Finland during the period 2001–2012 are shown in Fig. 2.39. The exports of electricity from Finland during the period 2001–2012 decreased 9.2 %. The peak in exports of electricity during the period

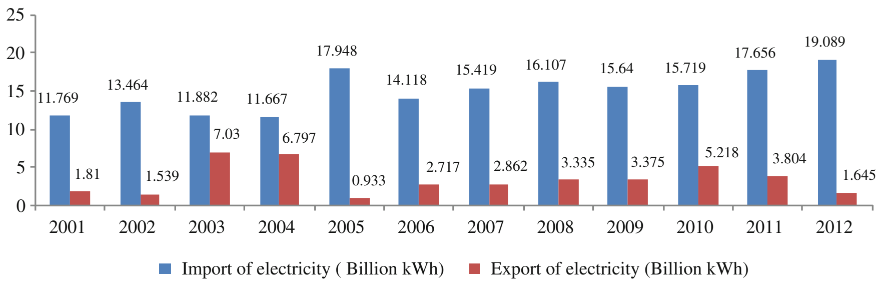

Fig. 2.39 Exports and imports of electricity from Finland during the period 2001–2012. *Source:* EIA

considered was reached in 2003. On the other hand, the imports of electricity from Finland during the period 2001–2012 increased 62.1 %. Finland is an import electricity country, because its generation of electricity does not satisfy the current level of electricity consumption. The peak in the import of electricity during the period considered was reached in 2012. It is expected that the country will continue exporting and importing electricity during the coming years.

2.15 France

France has begun to deregulate its electricity sector, which is the second-largest electricity sector in the EU, behind Germany. The country adopted its first deregulation legislation concerning electricity distribution in February 2000, a full year after the EU's first implementation deadline. In 2004, France allowed competition in the entire non-residential sector, which represents over 70 % of the French market; by 2007, deregulation was spread to the residential sector as well. French law also deregulates electricity generation, but no significant independent generators have yet entered the market. EdF is not required to sell off its own generating capacity, so most newly-entering distributors continue to purchase electricity from EdF. The energy dependency[13] of France in 2011 was 48.86 %, this represents a decrease of 0.6 % respect to 2010.

2.15.1 Crude Oil Reserves

According to public sources, France reported at the beginning of 2007 a total of 122 million barrels of proven crude oil reserves. In January 2010, crude oil reserves were estimated at 101.2 million barrels[14]; this represents a reduction of 17.1 % respect to 2007. According to Index Mundi, France had 91,630,000 barrels of crude oil reserves in 2011; this represents a decreased of 25 % respect to the reserves reported in 2007 and 9.5 % respect to the reserves reported in 2010. In 2013, the proven oil reserves reported by France was 85 million barrels per day, a decrease of 7.3 % respect to 2011. During the period 2007–2013, the crude oil reserves dropped 30.4 %.

[13] Energy dependency shows the extent to which an economy relies upon imports in order to meet its energy needs. The indicator is calculated as net imports divided by the sum of gross inland energy consumption plus bunkers.

[14] France, Germany, and Italy have an oil-sharing agreement to allow each other to purchase their strategic oil reserves in the event of an emergency.

2.15.2 Production and Consumption of Oil

France has the second-largest economy in Europe in terms of nominal gross domestic product (GDP), after Germany, and the fifth largest in the world. With little domestic energy production, the country relies on a diversified set of imports to meet most of its oil and gas consumption. France was the 12th largest oil consumer and the 7th largest net importer of petroleum liquids in 2011. Oil represents approximately one-third of France's total primary energy consumption and that share has been falling since 2001. France has virtually exhausted all of its indigenous oil fields: the Parisian Basin, the Aquitaine region, and Alsace. The production of oil in France during the period 2000–2012 is shown in Fig. 2.40.

The production of oil in France during the period 2000–2012 decreased 22.5 %. The peak in the production of oil, during the period considered, was reached in 2000. The lowest production of oil was reached in 2012. It is expected that the production of oil will continue to decrease during the coming years.

On the other hand, the consumption of oil in France during the past 13 years decreased 13 % (see Fig. 2.41). The peak in the consumption of oil, during the period considered, was reached in 2001. Since that year the consumption of oil has decreased continuously and it is expected that the consumption of oil in France will continue to decrease during the coming years, particularly for the generation of electricity.

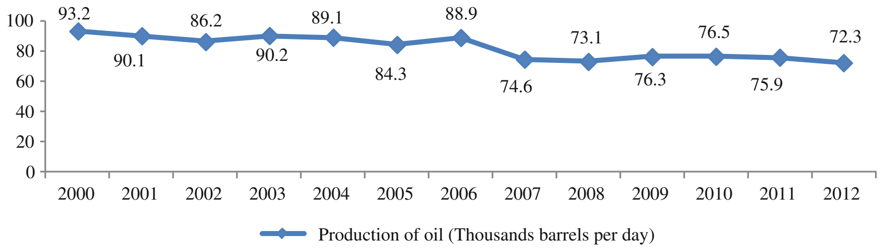

Fig. 2.40 Production of oil in France during the period 2000–2012. *Source:* IEA

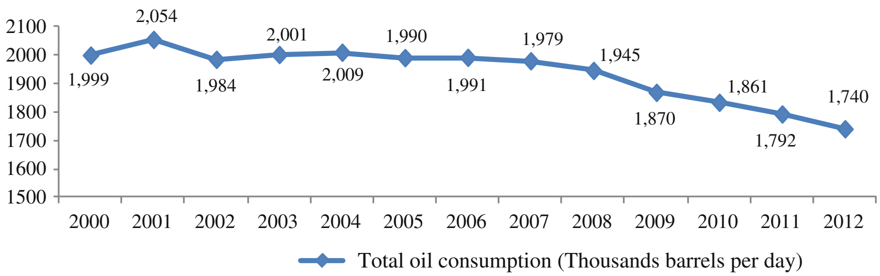

Fig. 2.41 Total oil consumption in France during the period 2000–2012. *Source:* EIA

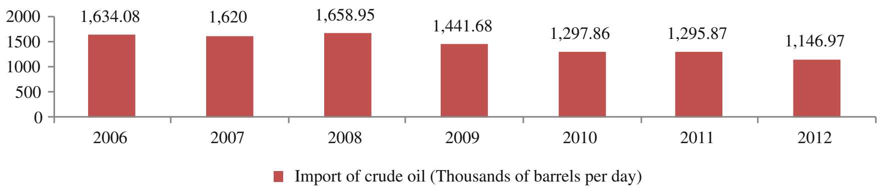

Fig. 2.42 Imports of crude oil from France during the period 2006–2012. *Source:* EIA

2.15.3 Import and Export of Oil

According to the IEA (2012) report, France's net oil imports were approximately 98 % of domestic oil consumption, consisting of crude oil and middle distillates (gas and diesel oil). France has relatively well diversified crude import sources, with a range of OPEC countries (notably Libya and Saudi Arabia) accounting for around 43 % of imports, and countries from the former USSR accounting for a further 32 %. With regard to oil products, nearly 50 % of refined oil product imports came from OECD countries (85 % of those from Europe), with another 30 % from the former USSR.

France imports crude oil through three major sea ports (Marseille, Le Havre, and Saint-Nazaire) and the South European Pipeline System (SPSE) to Germany. After unloading, the crude oil is processed in refineries near these ports or by inland refineries connected to the ports by pipelines, except for some oil which transits France via pipeline to Switzerland and Germany. Finished refined oil products are imported into France through seven seaports, including the three used for crude oil imports. Four of these sea ports are also used to export oil refined product.

The imports of crude oil from France during the period 2006–2012 decreased 29.1 % (see Fig. 2.42). The reason for this decrease is the economic crisis that Europe is facing since 2008, and the reduction of the participation of oil in the country energy mix. The peak in the imports of crude oil during the period considered was reached in 2008 and since that year the imports of crude oil has been decreasing each year. It is expected that the imports of crude oil from France continue this trend at least during the coming years. France did not export crude oil in the period considered.

2.15.4 Electricity Generation and Consumption

The evolution of the generation of electricity in France during the period 2000–2012 is shown in Fig. 2.43. According to that figure, the production of electricity in France increased during the past 12 years in 4.3 %. During the period 2008–2009, a significant reduction in the production of electricity occurred in France due to the economic crisis that started affecting Europe in 2008. However, in 2010 the generation of electricity increased 6.4 % respect to 2009, but decreased 1.6 % from 2010 to 2012. The consumption of electricity in 2011 was 12.6 % lower than the electrify generated in the country in that year, indicating that the country

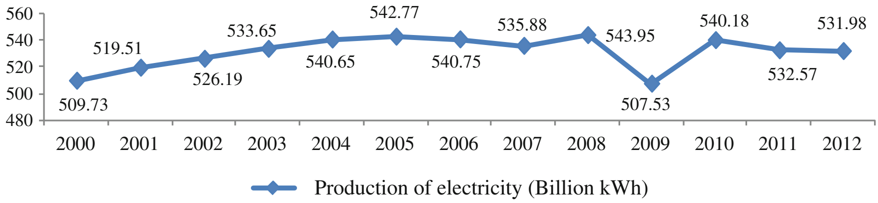

Fig. 2.43 Production of electricity in France during the period 2000–2012. *Source:* EIA

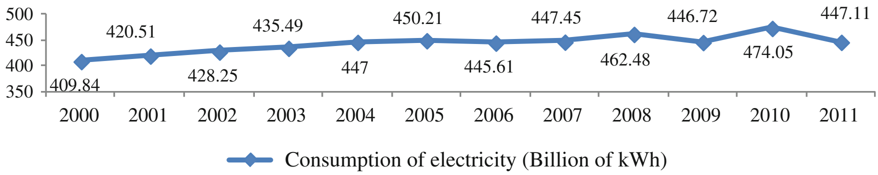

Fig. 2.44 Consumption of electricity in France during the period 2000–2011. *Source:* EIA

has a surplus of generation capacity that can be used with the aim of satisfying the foreseeable increase in the consumption of electricity without the need to construct more power plants at least during the coming decades. The peak in the generation of electricity, during the period considered, was reached in 2005.

In 2008, the electricity production from oil sources in France was reported at 1.03 % of the world level, according to World Bank sources. In 2009, the electricity production from oil sources in France increase to 1.15 % of the world total, and in 2010 the electricity production was 1.12 % of the world total (5,857 billion kWh), a reduction of 0.03 % respect to 2009. In 2011, the electricity generated by oil sources reached 6,163 billion kWh (1 % of the world total); this represents an increase of 5.2 % respect to 2010. The generation of electricity using oil as fuel represents between 1 and 1.15 % of the total electricity generated in the country in the past years. It is expected that this percentage will be even lower in the future (Fig. 2.44).

The consumption of electricity in France in the past 12 years increased 9 %, but is well below the generation of electricity. The peak in the consumption of electricity during the period considered was reached in 2010. It is expected that the consumption of electricity in France continue increasing during the coming years, but in a moderate manner.

2.15.5 Import and Export of Electricity

The imports and exports of electricity from France in the period 2001–2012 are shown in Figs. 2.45 and 2.46. The imports of electricity from France during the period 2001–2012 increased significantly (179 %). The peak in the imports of electricity from France during the period considered was reached in 2010 and the

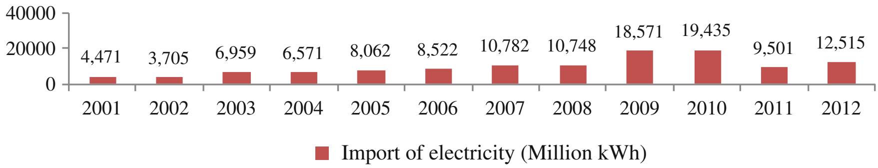

Fig. 2.45 Imports of electricity from France during the period 2001–2012. *Source:* Eurostat and EIA (2011 and 2012)

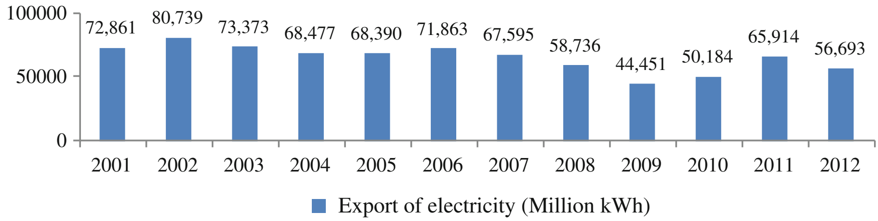

Fig. 2.46 Exports of electricity from France during the period 2001–2012. *Source:* Eurostat and EIA (2011 and 2012)

lowest import of electricity was reached in 2002. It is expected that France will continue importing electricity during the coming years.

According to Fig. 2.46, the exports of electricity from France during the period 2001–2012 decreased 22.2 %. The economic crisis affecting the European region is one of the causes of the decreasing in the exports of electricity from France to other countries. However, it is expected that France will continue exporting electricity to other European countries at least during the coming years.

2.16 Germany

Germany is influenced heavily by EU regulations in the energy field. The EU requires privatization and competition in member countries' energy markets, and Germany has been considered one of Europe's leading market reformers. Following reunification of the country in 1990, the major task of German energy policy was to merge successfully the radically different energy sectors of the Eastern and Western part of the country, particularly for electricity generation. West Germany had a diversified and mainly privately owned energy system supply with a high standard of energy efficiency and a commitment to environmental protection. In contrast, East Germany's energy sector was highly centralized, predominantly State-owned, and mainly dependent on lignite or brown coal as its primary fuel for electricity generation. Lignite, because of its characteristic chemical impurities, results in higher emissions of toxins into the atmosphere than other fuels when burned.

2.16.1 Crude Oil Reserves

According to *Oil and Gas Journal* (*OGJ*), Germany had 367 million barrels of proven crude oil reserves in 2006. Most of these reserves are located in Northern and Northeastern Germany.[15] In 2011, according to Index Mundi, the country's crude oil reserves were calculated at 276 million barrels, a decrease of 25 % respect to 2006. In 2103, the crude oil reserves were calculated by EIA at 254 million barrels; this represents a reduction of 8 % in the level of crude oil reserves respect to 2011.

2.16.2 Production and Consumption of Oil

According to the IEA (2012) report, Germany has very little domestic oil production equivalent to around 2 % of oil consumption—and the government expects that oil production will continue to decline at a rate of around 5 % annually. Due to the level of domestic oil production, Germany relies heavily on imports of crude oil for satisfying its energy needs. It has well diversified and flexible oil supply infrastructure, which consists of crude oil, oil product and gas pipelines, and crude and oil product import terminals. Despite the increase use of renewable and an important participation of nuclear energy in the country energy mix (until 2022, when all nuclear power plants in operation will be closed), oil continues to be the main source of energy in Germany although it has declined markedly since the early 1970s. It now represents approximately 32 % of Germany's total primary energy supply down slightly from 32.6 % in 2009; this represents a decrease of 0.6 %. The production of crude oil in Germany during the period 2008–2012 is shown in Fig. 2.47.

The production of crude oil in Germany during the period 2008–2012 increased 23.2 %. The peak in the production of crude oil during the period considered was reached in 2012. It is expected that the production of crude oil will continue to increase during the coming years, with the aim of satisfying the foreseeable increase in the demand of this energy source in several economic sectors.

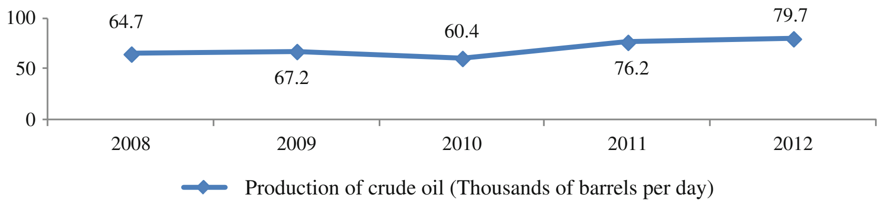

Fig. 2.47 Production of crude oil in Germany during the period 2008–2012. *Source:* EIA

[15] Germany is divided into several prospective areas, which are the foreland of the Alps, but the main centers of oil production and reserves are located in North Germany.

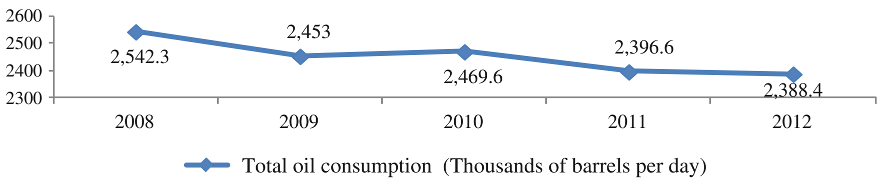

Fig. 2.48 Total oil consumption in Germany during the period 2008–2012. *Source:* EIA

In 2004, Germany was the fifth-last consumer of oil in the world consuming 2.7 million barrels per day of crude oil, with imports supplying over 90 % of these needs. In 2009, the country consumed an estimate of 2.437 million barrels per day, around 263,000 barrels per day less than in 2004. The evolution of the consumption of oil in Germany during the period 2008–2012 is shown in Fig. 2.48. From that figure, the following can be stated: Total oil consumption in Germany dropped during the period 2008–2012 from 2,542,300 barrels per day in 2008 to 2,388,400 barrels per day in 2012, a decrease of 6.1 %. It is expected that the consumption of oil will continue decreasing during the coming years, particularly for the generation of electricity.

2.16.3 Export and Import of Oil

According to the German economic statistics agency, the largest source of German's crude oil imports in 2006 was Russia (34 %), followed by Norway (16 %) and the UK (12 %).[16] Germany also imports large amounts of refined petroleum products. Fossil fuel energy consumption in Germany has shown a systematic decline since 1968. During that year, the level of fossil fuel consumption reached almost 99 %; in 2008 this level was around 81 %; this represents a decrease of 18 % during the past 40 years. It is expected that this trend will follow the same pattern in the coming decades.

According to the IEA (2012) report, Germany's total oil imports were equivalent to approximately 98 % of domestic oil consumption. Imports include crude oil and oil products. Germany also exports around 372,000 barrels per day of crude oil and oil products to other countries. The country relatively well diversified crude import sources, with countries from the former USSR accounting for 50.8 % of imports, another 25 % coming from OECD countries (mostly European), and a further 18.2 % of crude oil imports from a range of OPEC countries (notably Nigeria, Algeria, Angola, and Libya). With regard to oil products, almost 88 % of refined oil product imports come from OECD countries (95 % of those from Europe—notably the Netherlands, Belgium, and the UK), with most of the remainder from countries of the former USSR.

[16] Before the war in Libya in 2011, Germany oil import from this country reached 12 %.

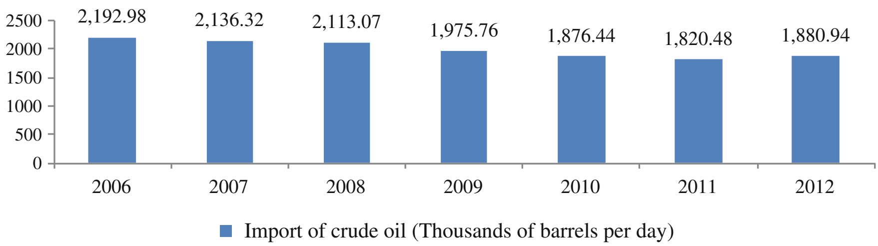

Fig. 2.49 Imports of crude oil from Germany during the period 2006–2012. *Source:* EIA

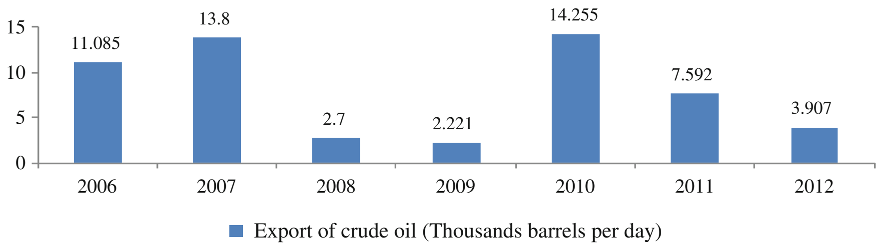

Fig. 2.50 Exports of crude oil from Germany during the period 2006–2012. *Source:* Eurostat

The imports and exports of crude oil from Germany during the period 2006–2012 are shown in Figs. 2.49 and 2.50. The imports of crude oil from Germany during the period 2006–2012 dropped 14.3 %. The decrease in the imports of crude oil since 2008 was the result of the reduction of industrial consumption due to the negative impact of the current economic crisis in many European countries. The peak in the imports of crude oil during the period considered was reached in 2006. It is expected that the imports of crude oil from Germany will continue decreasing at least during the coming years. The shutdown of all nuclear power reactors in 2022 could change that trend.

The exports of crude oil from Germany during the period 2006–2012 decreased 65 %. The peak in the exports of crude oil during the period considered was reached in 2010. It is expected that Germany will continue exporting certain amount of crude oil during the coming years.

The current power plants using hard coal as fuel for the generation of electricity in Germany should be totally changed by 2040 (Fig. 2.51). In the case of gas/oil power plants all of these plants will be changed by 2038. By 2034, all CHP power plants will also be replaced. The replacement of all nuclear power plants and old and ineffective power plants using oil, natural gas, and carbon for electricity generation during the period 2010–2040 will require the investment of billions of euros in the construction of new power plants, particularly using an increase of different renewable energy sources for electricity generation, as well as for the construction of new transmission and distribution lines all over the country.

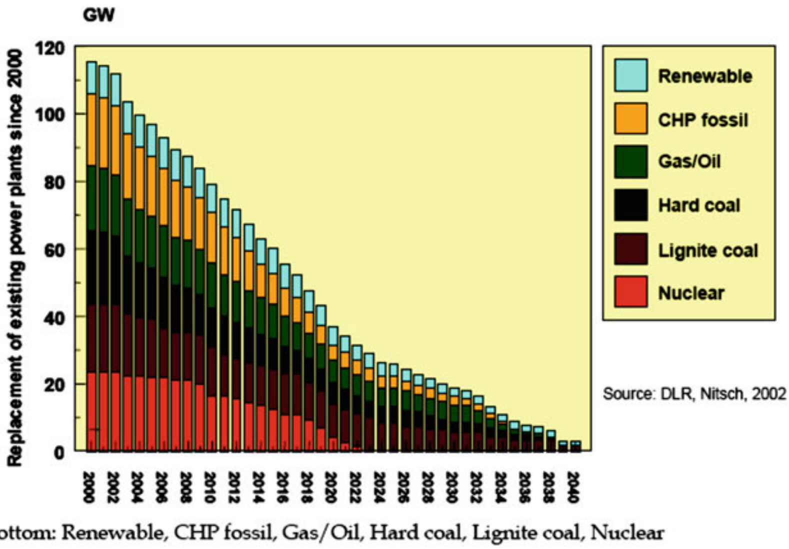

Fig. 2.51 Need for replacement of existing power plants until 2040

2.16.4 Electricity Generation and Consumption

According to EIA sources, Germany has Europe's largest electricity market. In 2001, Germany generated 544.8 billion kWh of electricity, two-thirds of which came from fossil fuels (mostly coal), with around 28 % coming mostly from nuclear power along with small amounts of hydropower and other renewable energy sources (8.5 %), and 7.5 % from natural gas and oil-fired power plants. In 2004, the country produced 566.9 billion kWh, an increase of 4 % respect to 2001 and consumed 524.6 billion kWh of electric power. The largest share of this production (61 %) came from conventional thermal sources, followed by nuclear energy (28 %), and other renewables (7 %). In 2013, the total electricity generated from fossil fuels reached 347.17 billion kWh; this represents a decrease of 34 % respect to 2004. Although Germany produces more electricity than it consumes, the country is a small net electricity importer, because of transmission losses and its proximity to foreign sources of electricity generation.

In 2011, Germany has an installed electrical capacity of 159.507 million kW, which includes considerable excess generation capacity. Recent German estimates predict 14 % growth in electricity consumption between 1999 and 2020. Electricity imports in 2010 (46.274 billion kWh), which also could rise in coming years, come primarily from France, the Czech Republic, Sweden, Denmark, and Austria. Germany also exports small amounts of electricity to France, the Netherlands, Luxemburg, Switzerland, the Czech Republic, Poland, Sweden, Denmark, and Austria.

The evolution of the electricity production and consumption are shown in Figs. 2.52 and 2.53.

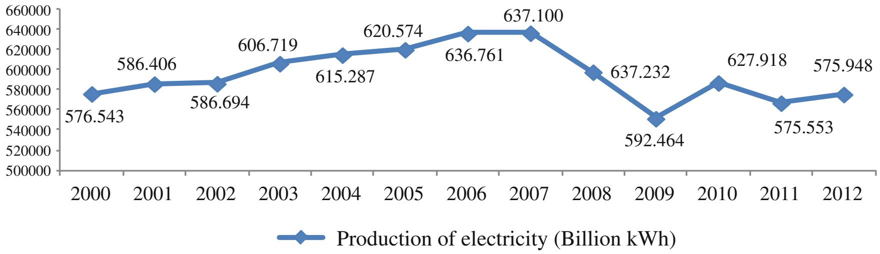

Fig. 2.52 Production of electricity in Germany during the period 2000–2012. *Source:* Eurostat and EIA

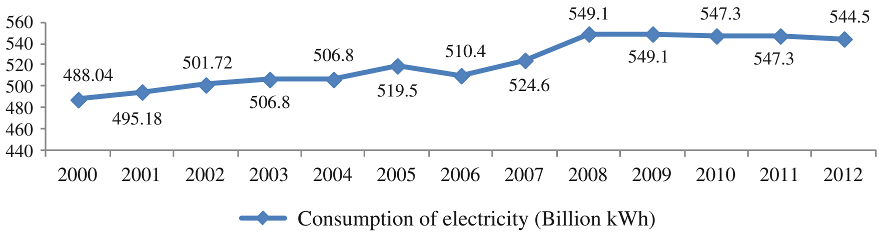

Fig. 2.53 Consumption of electricity in Germany during the period 2000–2012. *Source:* Index Mundi

The production of electricity from Germany during the period 2000–2012 decreased very little (0.2 %). The peak in the production of electricity during the period considered was reached in 2007. From 2007 to 2009, the production of electricity dropped 7.1 % due to the economic crisis that is still affecting Europe, particularly the Euro zone. It is expected that the generation of electricity in Germany will increase once again during the coming years, as a result of the economic measures that the EU is adopting to overcome the current economic situation facing several of its members.

On the other hand, the consumption of electricity in Germany increased 11.5 % during the past 13 years. The peak in the consumption of electricity during the period considered was reached in 2008 and 2009. During the period 2009–2012, the consumption of electricity dropped 1 % due to the economic crisis, which is still affecting Europe. The government expect that the consumption of electricity in Germany will increase, but in a moderate manner, during the coming years, if the economic crisis affecting the whole European region does not force the industry to reduce once again the production of goods.

2.16.5 Export and Import of Electricity

The evolution of the imports and exports of electricity from Germany during the past 12 years is included in Fig. 2.54.

According to Fig. 2.54, the imports of electricity from Germany during the period 2001–2012 increased 1 %. The peak in the imports of electricity, during the period considered, was reached in 2005. On the other hand, the exports of electricity from Germany increased significantly (58.6 %). The peak in the exports of electricity during the same period was reached in 2012. It is expected that Germany will continue to be a net electricity exporter during the coming years and will continue importing electricity from its neighboring countries.

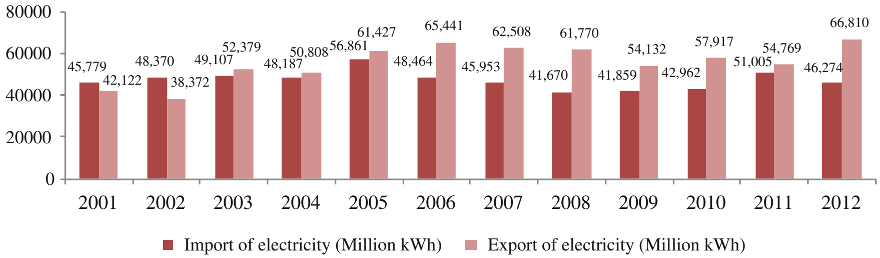

Fig. 2.54 Imports and exports of electricity from Germany during the period 2001–2012. *Source:* Eurostat and EIA (2011 and 2012)

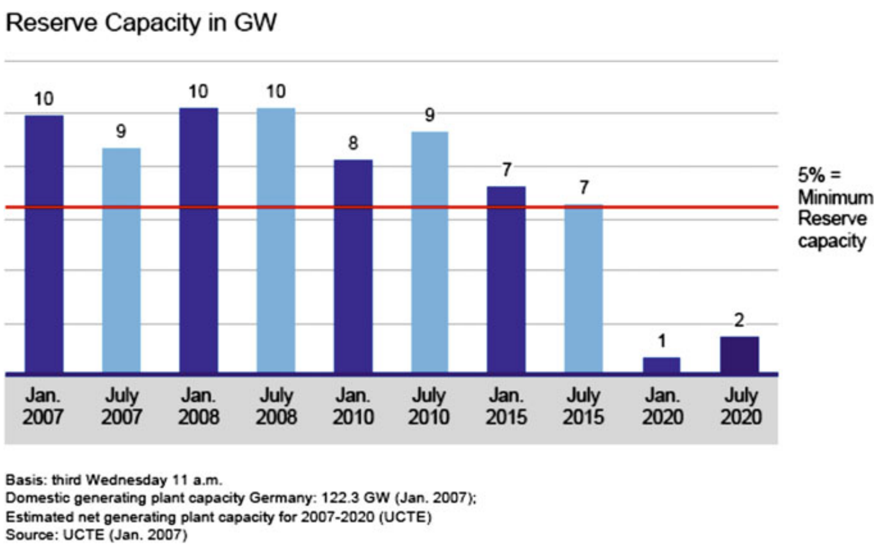

Fig. 2.55 Germany reserves electricity capacity. *Source:* Factbook electricity generation capacity in Europe

It is important to highlight that Germany reserves electricity capacity will decrease from 10 % in 2007 to 7 % in 2015. The minimum reserve electricity capacity adopted by the Germany's government is 5 %. However, this situation could change after 2015. To avoid problems with the supply of electricity after that year, the government is considering additional measures to increase the foreseeable level of electricity reserves that could be available for the period 2015–2020 (see Fig. 2.55). The current projection shows that without the increase in the current level of reserve capacity in the country, this indicator will be very low for 2020 (maximum 2 % in 2020).

2.17 Greece

Oil remains the most important energy source in Greece, although its share in total primary energy supply has gradually declined from 77 % in 1973 to 52 % in 2010; this represents a decrease of 25 % in the past 37 years. Over the years, oil has been substituted first by lignite and more recently by natural gas. Lignite is the second-largest energy source in the country, accounting for 27 % of Total Primary Energy Supply in 2010. It is the most important source for electricity in Greece at this moment. According to the IEA (2011) report, oil has by far the highest share in final energy consumption in Greece, around 65 % in 2009. This share has remained relatively steady until today. In addition to the transport sector, oil is also the dominant fuel in industry and the building sector. Among the IEA Member States, Greece has the highest share of oil in its energy mix, and only Ireland is in a similar situation where oil dominates all consumption sectors.

The adoption of Law 2773/1999 provides the adequate framework for the deregulation of the electrical energy market and as such, domestic production, transmission, and distribution in the energy field is open to private investors, breaking the government monopoly of the energy sector. Greece is continuing stepping up efforts to liberalize it historically state-controlled electricity markets, taking also into consideration the recent obligations under the EU third Internal Energy Market Directives. The new Energy Law 4001/2011 (Official Gazette FEK 179/A/22 August 2011, IEA 2011) strengthens the power of the regulatory authority, provides for consumer protection, and allows for unbundling electricity and gas transmission. The government is also committed to reducing its ownership in the energy sector to clearly below 50 %.

With the goal of further increase in competition, efficiency, and dynamism of the energy sector and the Greek economy in general, in addition to Law 4001/2011, Greece has also already laid down a program for privatizing state-controlled energy companies, as part of the Mid-term Fiscal Plan adopted by the government.

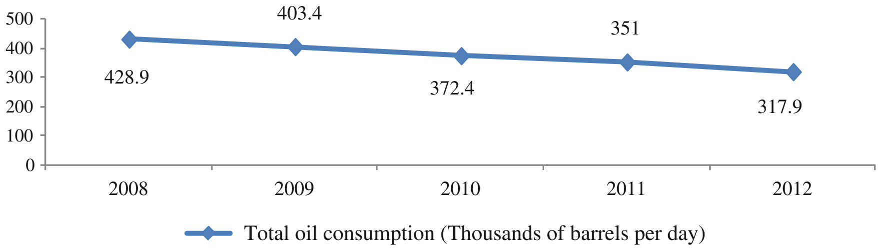

Fig. 2.56 Total oil consumption in Greece during the period 2008–2012. *Source:* EIA

2.17.1 Crude Oil Reserves

Greece does not have significant reserves of crude oil. According to EIA and other sources, the country's crude oil reserves are estimated at 10 million barrels in 2013. This figure has not changed in the past 5 years.

2.17.2 Production and Consumption of Oil

Greece, which produces almost no oil,[17] aims to develop potential hydrocarbon reserves as part of an effort to overhaul its economy and lessen dependence on energy imports, which in 2011 reached 67.6 % of its total energy needs. The evolution of the consumption of crude oil during the period 2008–2012 is shown in Fig. 2.56. The consumption of oil in Greece in the past 5 years decreased 26 % as a consequence to the severe economic crisis that are affecting the country since 2008. The government expects that the consumption of oil will continue decreasing during the coming years.

2.17.3 Export and Import of Oil

Greece imports practically all the oil it needs, while it has ample reserves of lignite and a large potential for renewable energy. In order to avoid crude oil supply problems, Greece has diversified its crude oil import sources, reducing its dependence on OPEC countries by gradually increasing crude oil imports from Russia and OECD members.

According to the IEA sources in Greece, in 2010 the country imported 405,460 barrels per day of crude oil, which consisted of 272,335 barrels per day of crude oil,

[17] Oil is produced from the Prinos offshore oil field in the Kavala Gulf in the Northern Aegean Sea. In 2012, the domestic oil production was 7,500 barrels per day.

and 133,125 barrels per day of oil refined products. The major import sources of crude oil were Russia (33 %), Iran (24 %),[18] Libya (13 %), Saudi Arabia (12 %), and Kazakhstan (7 %). Greece exported 17,022 barrels per day of crude oil in 2010 exclusively to Macedonia. Greece's oil product exports increased by 57 % from 102,000 barrels per day in 2004 to 183,075 barrels per day in 2010. In 2010, the country imported around 66.3 % of its energy needs; in 2011 it was around 67.6 %, an increase of 1.9 % respects to 2010, and this trend is expected to continue during the coming years, but the amount of crude oil to be imported could be much less than the level reached in 2010, due to the current economic and financial crisis that the country is still facing.

With the purpose of reducing the imports of energy, the government is promoting the exploration of the Western part of the country.[19] Greece has received until today eight bids by companies to search for oil in three blocks in the Western part of the country, according to public government sources. The three blocks combined two offshore and one onshore, may contain between 250 and 280 million barrels of oil; these blocks are near the towns of Patras and Katakolo as well as in Epirus, in the country Northwest. Almost 200 fruitless test wells have been bored in various parts of Greece in the past century, the most recent about 12 years ago.[20] Oil and natural gas reserves are estimated to worth €25 billion. Greece now plans to enter negotiations on royalty and taxes with the winning applicants. According to the tender documents, Athens hopes to receive royalties between 2 % and 20 % of the hydrocarbons produced, in kind or in cash. It also wants to impose a 25 % income tax on the winner.

2.17.4 Electricity Generation and Consumption

Greece has a total electricity installed capacity of 15.1 million kW in 2010 (around 2.517 million kW or 16.7 % belong to oil power plants). In 2011, the installed capacity reached 16.3 million kW, an increase of 7.9 % respect to 2010, and is dominated by thermal energy (68 %). In that year, Greece produced 50.4 billion kWh, 58 % of which from lignite, 16 % from gas, 8 % from hydro, and 6 % from wind. Electricity, as the second-largest energy source, provided 23 % of total final consumption in 2009. Its share has gradually increased from 17 % in 1990 and is now slightly above the

[18] As a result of the EU sanctions against Iran the import of crude oil from this country stopped in 2013.

[19] Territorial disputes with neighboring Turkey prevent Athens from looking for oil in the East part of the country.

[20] However, most of the tests were badly managed or carried out at the wrong locations. The country spends between €10 and €12 billion per year on oil imports, about 5 % of its gross domestic product, and this level of expenditure cannot be maintained under the present economic situation.

EU average of 21.7 %. The service sector consumed 41 % of all electricity produced by the country, the residential sector 33 %, and the industry 26 %.

According to World Bank sources, in 2010, the electricity generated by oil power plants was 9,642 MW; this represents 16.8 % of the total electricity produced in the country in 2010. In 2011, the total electricity generated by the oil power plants was 9,990 MW, which represents 15.9 % of the total electricity generated by the country in that year and 3.6 % higher than the electricity generated in 2010. The evolution of the generation of electricity during the period 2000–2011 is shown in Fig. 2.57.

During the period 2000–2011, the production of electricity in Greece decreased 6.4 %. After the severe economic and financial crisis that are still affecting the country, the production of electricity is expected to continue decreasing at least during the next years. The peak in the production of electricity, during the period considered, was reached in 2008.

The electricity consumption per capita in 2010 was 5,627 kWh; in 2011 the consumption per capita was 5,723 kWh, an increase of 1.7 % respect to 2010 (Fig. 2.58). The electric power transmission and distribution losses in Greece were 4,860 kWh in 2010 and 5,053 kWh in 2011, an increase of 4 % between these 2 years.

The consumption of electricity in Greece increased in the past 5 years only 1 % due to the impact of the economic crisis in the economy in the residential sector. The peak in the consumption of electricity, during the period considered, was reached in 2008 the year of the beginning of the crisis. Since that year, the consumption of electricity in the country has decreased and this trend is expected to continue at least during the coming years.

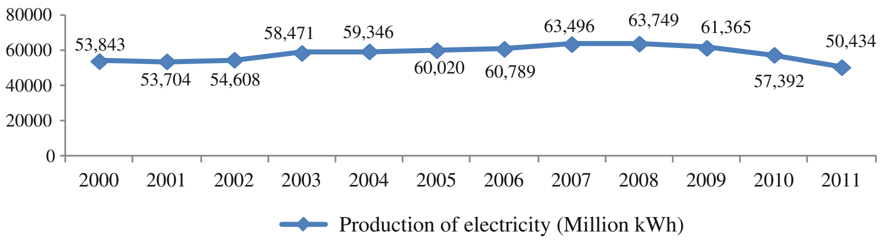

Fig. 2.57 The production of electricity in Greece during the period 2000–2011. *Source:* EIA

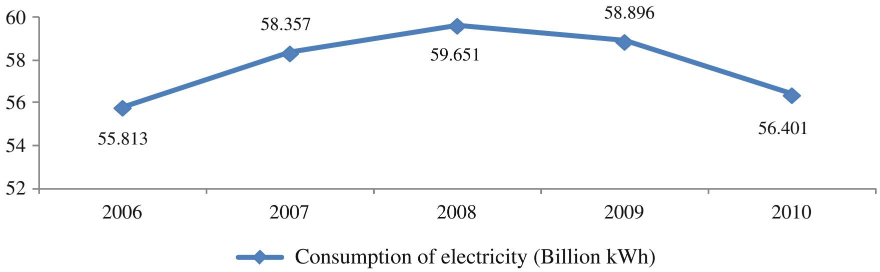

Fig. 2.58 Consumption of electricity in Greece during the period 2006–2010. *Source:* Eurostat

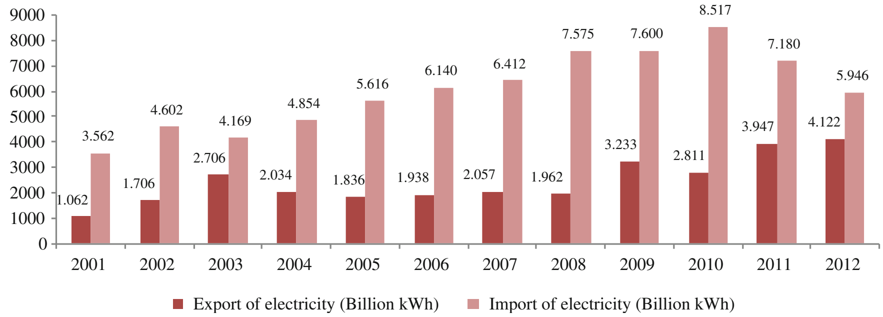

Fig. 2.59 Exports and imports of electricity from Greece during the period 2001–2012. *Source:* EIA

2.17.5 Export and Import of Electricity

The exports and imports of electricity from Greece during the period 2001–2012 is shown in Fig. 2.59.

The imports of electricity from Greece increased in the past 12 years around 66.9 %. However, it is expected that the imports of electricity will continue decreasing during at least the coming years. During the same period, the country increased the exports of electricity in 288 %. The government also expects that the exports of electricity from Greece will continue this trend, at least during the coming years, but perhaps not at the same rate.

The World Bank considers that the country need to invest more than €30 billion in the energy sector until 2020 for the upgrade and building of new power plants, in transmission and distribution, in the use of renewable energy sources for the generation of electricity, in the increase energy efficiency, and in the reduction of the dependency in the use of conventional energy sources for the generation of electricity. This is a big challenge for the government due to the lack of resources available to support such huge investment under the economic and financial crisis that still are affecting the country.

2.18 Hungary

According to Lynch (2003a, b), Hungary's energy policy was oriented toward achieving EU accession and is based on the following:

- Develop diverse energy supplies and eliminate dependency on imports from the former Soviet Union, particularly Russia;

- Improve environmental protection;
- Increase energy efficiency through modernization of supply structures and better management of electricity consumption;
- Attract foreign capital for investment in capital-intensive energy projects;

The 1999 energy plan issued by the government indicates a movement toward cleaner technologies, including emissions controls for coal-fired generation power plants and eventual replacement of some coal-fired power plants by gas turbines. The 2001 Electricity Act brings the Hungarian electricity market into accord with EU Directives in terms of third party access to the electricity grid and removal of subsidies, and defines a market structure that includes electricity generation companies, electricity distributors, power traders, and an electricity grid operator.

The Hungarian energy policy aims at maintaining a balance between security of supply, cost-effectiveness, energy efficiency, and protection of the environment. The EU accession in 2004 has changed the energy outlook in Hungary. The transposition of the Acquis Communautaire and the unification of Hungarian markets to EU markets, including conformity with the relevant EU Directives, are acting as the main drivers for energy policy development.

In February 2008, the National Climate Change Strategy for the period of 2008–2025 was adopted by the Hungarian Parliament.[21] The strategy is emphasizing the need for increasing energy efficiency, energy savings, and the use of renewable energies for the generation of electricity. The aim is of reducing the use of fossil fuels for this specific purpose. It does not mention nuclear energy as part of the concept. In April 2008, a resolution on a new energy policy concept for the period of 2008–2020 was adopted by the Parliament. The main goals are aimed at increasing the security of supply, competitiveness, and sustainability. It also includes the emphasis on increasing energy efficiency and energy saving as well as the use of renewable energy sources for the generation of electricity. It deals with the future of nuclear energy, too. According to the resolution, the government should start working on the preparation of the decision on new nuclear capacity for the replacement of the old plants and the proposal should be submitted to the Parliament in time. The government should create the necessary conditions for the implementation of the programs aimed at the final disposal of radioactive wastes, and should inform the Parliament on the implementation of the energy policy at least in every 2 years and in case of need it should propose the review of the concept.

[21] In the summer of 2008, the EC closed the investigation initiated against Hungary in 2005 in the subject of the potential state aid nature of long-term power purchase agreements (PPA). In the decision closing the investigation, the EC requested the Hungarian authorities to end all these State aids and have the affected power plants obliged to pay back the illegal State aids. These PPAs were concluded in the period from 1995 to 2001, and accounting for more than 60 % of the Hungarian electricity production, hindered competition to evolve. The Parliament passed the Act 70 of 2008 on Certain Issues in Association with Electricity on 10 November 2008, which provide for ending PPAs by the deadline 31 December 2008 and for the method of the determination of State aids to be paid back. In 2009, the government had negotiations with the affected parties and the EC (Hungarian Annual report to the EC 2010).

Hungary has successfully introduced the legislation laying the foundation for market reform in line with the most recent EU Gas and Electricity Market Directives. From 1 July 2007, all electricity and gas customers became fully eligible to freely select their supplier. A new act on electricity (Act LXXXVI of 2007) has been adopted by the Hungarian Parliament. The aim of the new act is a full liberalization of the electricity market in order to enhance economic competitiveness and provide sustainable security of supply. The Act is in harmony with the requirements of the EU. The provisions of the Act came into force, partly from 15 October 2007 and from 1 January 2008. In the beginning of 2008 the electricity market has become fully liberalized. Nevertheless, 2008 is considered a transition period, during which the players on the market have to learn the new rules. Real market competition is expected in 3–4 years.

Hungarian electricity consumers are paying for substantial subsidies to the renewable and CHP (Combined heat and power) sectors through levies on their tariffs.

2.18.1 Crude Oil Reserves

According to EIA sources, Hungary crude oil reserves in 2012 was estimated at 30 million barrels, an increase of 12.9 % respect to the level registered in 2010, and the same level reported in 2011. Crude oil reserves are located mostly in the South-East of the country. According to the Budapest Business Journal (2011), Hungary's crude oil reserves are enough to last 103 days of consumption at current level. In 2013, the crude oil reserves were estimated at 27 million barrels, which is 10 % lower than the level reported in 2012.

2.18.2 Production and Consumption of Oil

Oil represents just over 25 % of the total primary energy supply in Hungary and it is expected to remain at this level until at least 2020. Domestic oil production will continue to decline, further increasing dependence on imports. Oil consumption as a whole dropped incrementally since 2007 and stood at 4,703,000 tons in 2010. The share of oil in total energy consumption as a whole is gradually declining. Oil's share in the country's total primary energy supply has declined progressively since the 1970s, from 39 % in 1973 to only 26 % of total primary energy supply in 2010, a decrease of 13 %.

According to the IEA report on Hungary (2012), domestic crude oil production peaked in 1985 at 64,000 barrels per day. In 2010, domestic production, including crude oil and condensate, amounted 13 % of total oil supply. In 2011, domestic crude oil production increased 10.5 % respect to 2010. The evolution of the production and consumption of crude oil in Hungary during the period 2000–2011 is shown in Fig. 2.60.

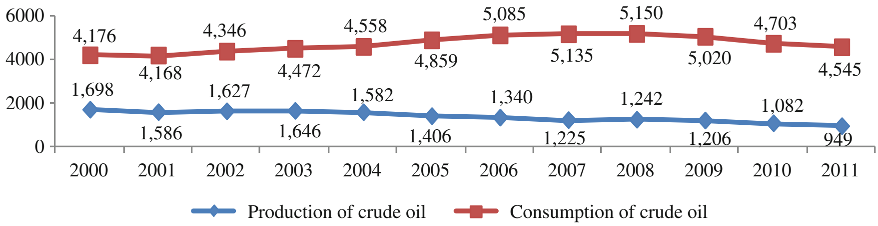

Fig. 2.60 Production and consumption of crude oil in Hungary during the period 2000–2011 (Thousands tons). *Source:* Eurostat

The production of crude oil in Hungary during the period 2000–2011 decreased 44.2 %. The peak in the production of crude oil, during the period considered, was reached in 2000. Undoubtedly, the economic and financial crisis affecting the country has caused a negative economic impact on the level of domestic production of crude oil and this situation has no changed until today. It is expected that this situation will not change significantly, at least during the coming years.

The consumption of crude oil in Hungary during the period 2001–2011 is shown in Fig. 2.60. The consumption of this type of energy source increased 8.8 % during that period. The peak in the consumption of crude oil was reached in 2008. After that year, the consumption of crude oil decreases 8.7 % due to the economic and financial crisis affecting the whole European region, including Hungary.

While total oil demand in 2010 was higher than in 2000, oil use for transport has increased significantly, on average by 4.1 % per year since 1995. In 2009, the transport sector consumed 61 % of total oil supply, and diesel alone accounted for 38 % of oil product demand. Industry accounted for 23 % of the total in 2009, a relatively constant share over the past decade. In contrast, oil use in the other sectors has declined significantly; power generation, residential and commercial services, and the agriculture sectors used 42 % of oil supply in 1995, but only 13 % in 2009, a decrease of 29 %. It is important to highlight that oil use for space heating is minimal in the country. The government expects the demand for oil products to grow by about 2 % per year between 2010 and 2020. The key driver for growth is diesel use, increasing between 3 % and 4 % yearly until 2020.

Approximately 87 % of Hungary's crude oil supply in 2010 is imported, with most of this coming from Russia via the Druzhba pipeline. Because of the declining domestic crude oil production, import dependency is expected to grow further in the coming years.

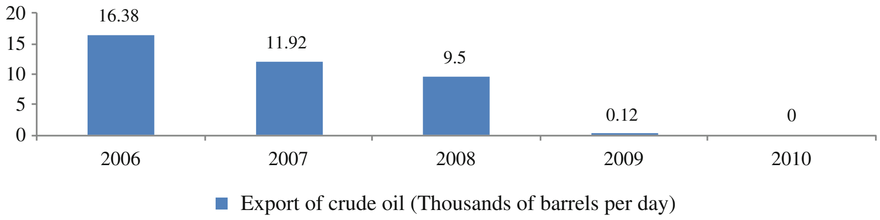

Fig. 2.61 Exports of crude oil in Hungary during the period 2006–2010. *Source:* EIA

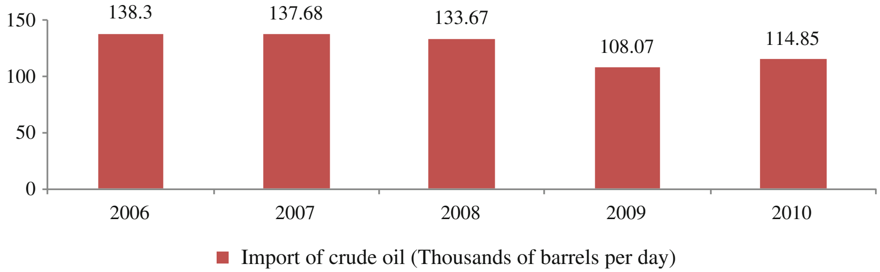

Fig. 2.62 Imports of crude oil from Hungary during the period 2006–2010. *Source:* EIA

2.18.3 Export and Import of Oil

The evolution of the exports and imports of crude oil in Hungary during the period 2006–2010 is shown in Figs. 2.61 and 2.62.

The exports of crude oil from Hungary decreased significantly during the period 2006–2010 from 16,380 barrels per day in 2006 to 0 barrels per day in 2010. It is expected that Hungary will continue not exporting crude oil during the coming years.

The evolution of the imports of crude oil from Hungary during the period 2006–2010 is shown in Fig. 2.62. From that figure the following can be stated: The imports of crude oil from Hungary during the period 2006–2010 decreased 17 %. It is expected, however, that the imports of crude oil will increase again during the coming years with the aim of satisfying the possible increase in the energy demand and to a decrease in the domestic crude oil production.

2.18.4 Electricity Generation and Consumption

Hungary was part of the East European Integrated Power System, which meant that the former Soviet Union was one of Hungary's primary electricity suppliers. However, after the collapse of the Soviet Union, the Eastern European countries almost immediately announced their intent to join the Union for the Co-ordination of Transmission of Electricity (UCTE). In order to demonstrate each country's capability to take its own responsibility and to coordinate action on electricity supply, Poland, Hungary, the Czech and Slovak Federal Republic formed CENTREL, which became the first step in UCTE membership.

The reform of the electricity industry commenced in 1994–1995, when Act No. XLVIII of 1994 on the Production, Transportation and Supply of Electricity was formulated and came into effect. The Hungarian Energy Office was established in 1994. The privatization of the electricity sector began and took place in several phases. At present, the majority of power plants and 100 % of the electricity suppliers (today called network and service provider companies as a result of privatization) are privately owned.

In Hungary the electricity policy is integrated part of the energy policy. The most important document, which based the Hungarian electricity market liberalization is the "Hungarian Energy Policy Principles and the Business Model of the Energy Sector" (Resolution 2199/1999 VIII.6). It was adopted by the Government in 1999.

Hungary became a full member of the EU on 1st May 2004 and it necessitated further harmonizing the Hungarian legal framework of the EU law. An important step of the harmonization was the adoption of a new Act on Electricity LXXXVI (2007), which had been passed by the Parliament on 25 June 2007. The harmonization and the electricity policy objectives have reflected in the Act. The aim of the Act is the effective operation of the competitive electricity market. Access to the electricity grid is guaranteed at regulated prices. Transmission, distribution, and system operation tariffs are set and published by the Minister of Transport, Telecommunication, and Energy. New capacities are established on a commercial basis through an authorization process. The new Act regulates the rules of full market opening effective from 2008.

Although Hungary's installed power generation capacity can theoretically meet its demand, the country has imported around 10 % on average of its electricity needs over the past decade. This highlights the fact that Hungary has few adequate domestic generation capacity reserves. Although the country can meet its peak demand, it is well below the UCTE average of around 22 % or the Central and South Eastern European average that is around 30 %. Capacity reserve security is guaranteed with available cross-border import capacities.

To satisfy the increase demand of electricity the country imported in 2010 an estimated of 9,879 million kWh. In the same year, Hungary exported around 4,703 million kWh of electricity to other countries.

The evolution of the production of electricity in Hungary during the period 2000–2012 is shown in Fig. 2.63.

The peak in the production of electricity was reached in 2010. During the period 2000–2012, the production of electricity increased 6 %. After 2008, the economic and financial crisis affecting the whole European region provoked a slight decrease in the production of electricity of 0.18 billion kWh (0.5 %).

During the period 2000–2012, the consumption of electricity increased 27.2 % (see Fig. 2.64). The peak in the consumption of electricity, during the period

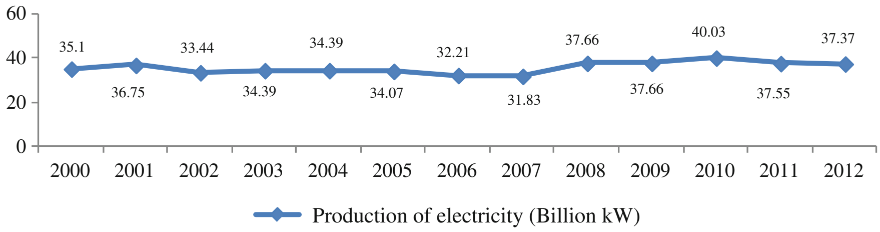

Fig. 2.63 Production of electricity in Hungary during the period 2000–2012. *Source:* Index Mundi

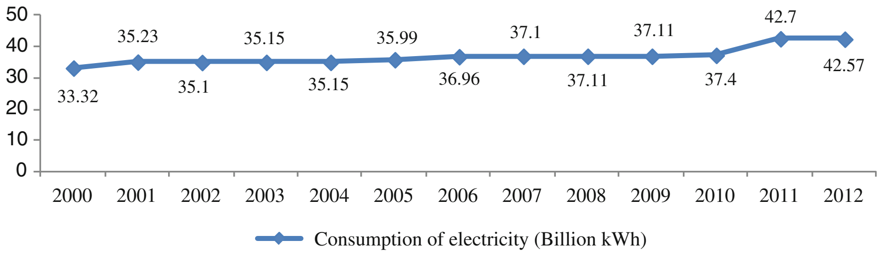

Fig. 2.64 Consumption of electricity in Hungary during the period 2000–2012. *Source:* Index Mundi

considered, was reached in 2011. It is expected that the consumption of electricity will continue to increase slowly during the coming years, particularly after the end of the current economic and financial crisis that still is affecting the country. The increase in the consumption of electricity was 21.2 % higher than the increase in the generation of electricity. It is important to highlight that during the period considered the consumption of electricity was higher than the generation of electricity forcing the country to import electricity from neighboring countries.

2.18.5 Export and Import of Electricity

The exports and imports of electricity from Hungary during the period 2001–2012 are shown in Fig. 2.65.

The peak in the exports of electricity was reached in 2007. Since that year, the exports of electricity decreased 16 %. It is expected that the increase in the export of electricity reported after 2010 will continue the same trend at least during the coming years. The imports of electricity reached its peak during the period considered in 2012. It is expected that the imports of electricity will continue increasing in the future due to an increase in the demand of electricity and a decrease in the generation of electricity.

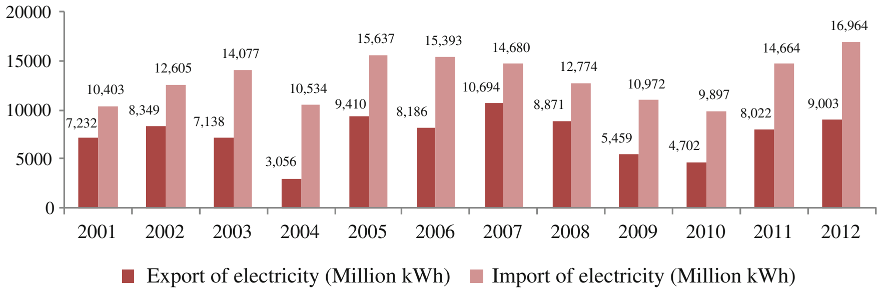

Fig. 2.65 Exports and imports of electricity by Hungary during the period 2001–2012. *Source:* Eurostat and EIA

It is important to highlight that the largest single contributor to Hungary electricity grid comes from the Paks nuclear power plant, which supplies approximately one-third of the country's power supply. Nuclear energy and natural gas are the main energy sources for the production of electricity in the country since the end of 1980s. The participation of oil in the generation of electricity is very small and it is expected to be zero sometime during the 2010s.

2.19 Italy

With limited domestic energy sources, Italy is highly dependent on imports to meet its energy consumption needs. In absolute terms, oil consumption has remained relatively static since 1970, but oil's share of Italy's primary energy mix has decreased significantly, steadily being replaced by natural gas. A pressing issue affecting Italy has been the country's electricity supply. Over the past decade, Italy's installed electricity generation has not been able to keep up with demand, resulting in an increased share of electricity imports as a percent of total consumption.

According to EIA sources, Italy began liberalizing its electricity sector in 1999, following the EU Directives, initially allowing only large customers to choose their own supplier. Liberalization has now spread to the majority of the retail market. As part of the liberalization, the Italian government began to privatize ENEL, the former, State-owned power monopoly that previously controlled all aspects of the electricity sector. In 2000, the Italian government forced ENEL to sell 27 % of its generating capacity, and to that end, ENEL created three new independent companies: ELETTROGEN, EUROGEN, and INTERPOWER. Along with removing ENEL's monopoly on electricity generation, distribution, and transmission, the Italian government began to divest its holdings in the company: as of April 2006, the government held 31 % of the company's shares.

In the summer and early fall of 2003, Italy experienced two significant power blackouts. The first occurred on June 26, 2003, when supply was unable to meet a surge in power demand as the result of increased air conditioning use during an extreme heat wave. On September 2003, all of Italy, except Sardinia, experienced a second blackout, when a tree struck a power transmission pylon in Switzerland. Although it appeared that these blackouts were caused by temporary or incidental factors, many analysts have suggested that the root of the cause lies in under-investment in Italy's power sector, which has resulted in less than sufficient reserve generation capacity and increased dependence on electricity imports. In response to the power crisis, the Italian government eased regulations on building new power plants and sought to encourage greater investment in the electricity sector.

According to government sources, Italy has adopted a National Energy Efficiency Action Plan 2008–2016, which sets an energy savings target of at least 9.6 % between 2008 and 2016. The Law Decree of July 2004 imposes energy saving obligations on energy distributors, and those savings have to be achieved among end users. The obligations are expressed in primary energy and yearly targets have been fixed until 2012 (e.g., 4.3 million tons of oil equivalent in 2010 and 6 million tons of oil equivalent in 2012). Over the period 2005–2008, 3.7 million tons of oil equivalent were saved, compared with the target of 3.3 million tons of oil equivalent; 77 % of the energy saving projects were aimed at the reduction of electricity consumption, 19 % at natural gas and the remaining 4 % at other fuels.

At the same time, Italy intends to double its domestic production of oil by 2020 and boost renewable energy power generation as it moves to cut consumers' energy costs and boost flagging economic growth. A new energy strategy, presented to the cabinet in 2012, has as its main aim to achieve 14 % of its energy needs met by domestic production by 2020 from the current 7 %. According to government sources, this new strategy will help to reduce imports of oil to 67 % of the country's energy needs from 84 % at present, while also slashing €14 billion euros (US$18.23 billion) per year off its €62 billion euro energy import bills. According to the government's new energy strategy, between 36 and 38 % of electricity is expected to be generated from renewable in 2020, from 23 % in 2010—on a par with natural gas. The new energy strategy, which confirmed plans to transform Italy into a gas hub for Europe, expects private energy investments to 2020 to the tune of around €180 billion euros, in part supported by government incentives.

2.19.1 Crude Oil Reserves

In January 2011, the estimated proven crude oil reserves reached 476.5 million barrels; this means a decrease of 145.5 million barrels or 23.6 % respect to the level of crude oil reserves reported in 2006. In 2013, the estimated proven crude oil reserves were 521 million barrels; this represents an increase of 9.3 % respect to the level reported in 2011.

2.19.2 Production and Consumption of Oil

According to the 2010 BP Statistical Energy Survey, Italy primary energy consumption was 163.39 million tons oil equivalent, 1.46 % of the world total. During the period 2000–2011, the evolution of the domestic production of crude oil and other liquids is shown in Fig. 2.66.

In Italy, domestic production of hydrocarbons continues to be below the peak reached in 2007. In fact, in the first 4 months of 2013 about 1.64 million tons of crude oil was extracted from Italian deposits. It was thus 12.8 % less compared to the same period last year. Basilicata Region, which itself covers about 76 % of the total, marked a drop by 15.2 % on an annual basis. The domestic production of crude oil from Italy during the period 2000–2012 increased 9.9 %. It is expected that the production of crude oil and other liquids will continue to increase during the coming years, but in a modest rate.

Oil production falls far short of domestic needs and for this reason, the country should import crude oil and oil products. The evolution of the consumption of oil during the period 2000–2012 is shown in Fig. 2.67.

The consumption of oil in Italy during the past 13 years decreased 21.1 % and the government expect that this trend will continue during the coming years. Developed market energy demand is forecast to reach 40.270 million tons of oil equivalent by 2015, representing a decrease of 17 % respect to 2011. Italy's estimated 2010 oil market share of 4.51 % is set to ease to 4.28 % by 2015; this represents a decrease of 0.23 %.

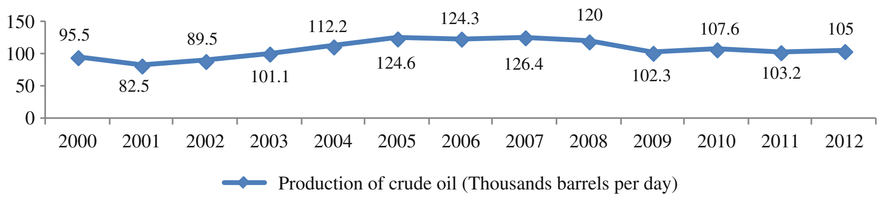

Fig. 2.66 Production of crude oil and other liquids in Italy during the period 2000–2011. *Source:* EIA

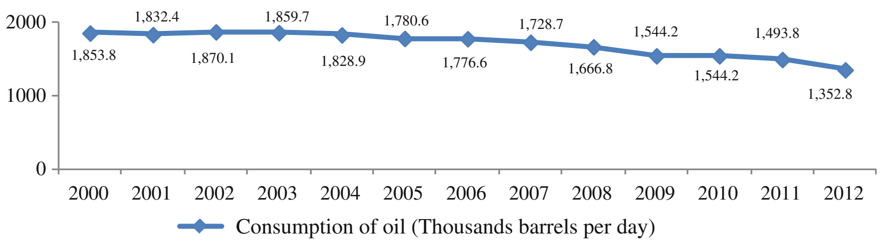

Fig. 2.67 Consumption of oil in Italy during the period 2000–2012. *Source:* EIA

Under an energy plan adopted in October 1981, the government reduced oil's share of the nation's primary energy requirement from 67 % in 1980 to 50 % by 1990; this represents a reduction of 17 %. This goal was reached (and surpassed) in 2000, when oil accounted for less than 50 % of Italy's energy consumption for the first time in more than two decades. This trend continued during 2000s.

From 1970 to 1991, Italy's per capita consumption of energy rose by 70 %. The country's energy consumption by type of energy source in 2010 was: natural gas, 30.5 %; renewables, 4.3 %; coal, 2.7 %; and oil and oil products, 39.8 % (less than 50 % reached in 1990). For Italy, oil is the dominant fuel, accounting for 39.8 % of primary energy demand in 2010, but its share in the energy mix is much lower than in 2000. This trend is expected to continue during the coming years.

It is important to highlight the following: It was expected that with the energy sector liberalization in Italy, the energy bills will decrease. However, this not happened. It is not a problem of competition, but of diversification of the energy sources. Should Italy generate electricity burning oil or natural gas, the most expensive energy sources, whose price have doubled or even tripled in the past few years, when all the other nations are using nuclear energy, some renewable energy sources and coal to generate electricity at a much lower cost? In the opinion of some experts, what Italy really needs is diversification of its energy sources, rather than liberalization of the energy sector, including an increase in the participation of renewable.

It is worthwhile to remember that after the 1973 oil crisis, all the others developed nations, except Italy, have substituted the oil with nuclear or coal for electricity generation and in recent years these countries increases also the use of renewables with this specific purpose. France, for example, reduced the participation of oil in electricity generation from 45 % to 2 % (a reduction of 43 %); Germany from 23 % to 1.5 % (a reduction of 21.5 %); Sweden from 19 % to 3 % (a reduction of 16 %); and Belgium from 78 % to 15 % (a reduction of 63 %), just to mention a few examples. In the case of Italy, it has instead increased the hydrocarbon use in electricity production from 61 % to 71 %; this represents an increase of 10 %. This is the reason why the Italian's energy bills are double than they are in France, three times higher than in Sweden, and 60 % higher than the European average, with a major cost of about €8 billion.

2.19.3 Import and Export of Oil

Italy is a net exporter of refined petroleum products. According to Eurostat, the country imported 1.86 million barrels per day and exported 3.77 million barrels of petroleum products in 2005. In 2009, the country exported an estimated of 529,100 barrels per day. The large amount of oil product imports came from Libya (24 % before the war in this country in 2012), the United States (17 %), and Algeria (10 %), while the largest amount of oil product exports went to Spain (18 %), Belgium (8 %), and the United States (7 %). The country imported an estimated of 1.8 million barrels per day in 2009, almost the same amount than in 2005.

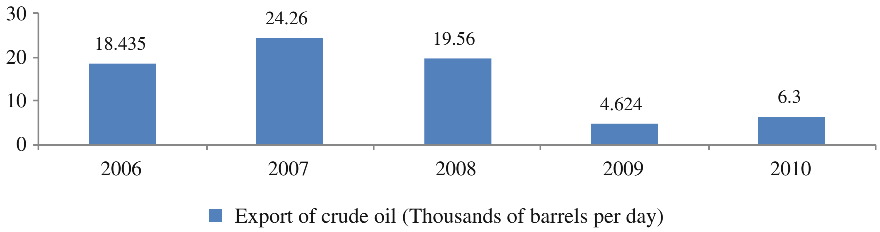

Fig. 2.68 Exports of crude oil from Italy during the period 2006–2010. *Source:* EIA

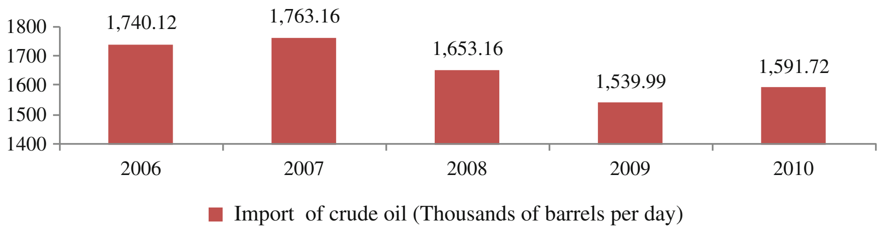

Fig. 2.69 Imports of crude oil from Italy during the period 2006–2010. *Source:* EIA

The evolution of the exports and imports of crude oil from Italy during the period 2001–2010 are shown in Figs. 2.68 and 2.69. From Fig. 2.68, the following can be stated: The exports of crude oil from Italy during the period 2006–2010 decreased from 18,435 barrels per day in 2006 to 6,300 barrels per day in 2012, a decrease of 64 %. Due to the current economic crisis the country is facing, it is expected that the country continue exporting crude oil in a small scale during the coming years.

The imports of crude oil from Italy during the period 2006–2010 decreased 8.6 %. The peak in the imports of crude oil, during the period considered, was reached in 2007. As a result of the current economic crisis the country is facing, it is expected that the imports of crude oil will continue decreasing at least during the coming years.

2.19.4 Electricity Generation and Consumption

Electricity represents 19 % of the current final energy consumption in Italy, with a steadily increasing market share. The electric power industry, nationalized in 1962, underwent a restructuring when the government sold off 32 % of ENEL, the major Italian power company in November 1999 in Europe's largest initial public offering.

Italy's total installed electrical capacity was 68.5 million kW in 2001. Installed capacity at the end of 2007 was 93.5 million kW; this represents an increase of

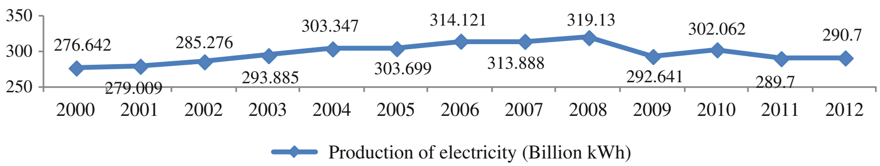

Fig. 2.70 Production of electricity in Italy during the period 2000–2012. *Source:* Eurostat

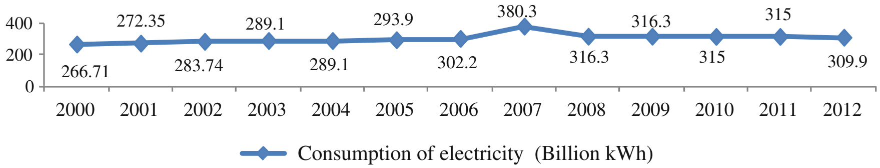

Fig. 2.71 Consumption of electricity in Italy during the period 2000–2012. *Source:* Index Mundi

36.7 % respect to 2001. In 2009, the electricity installed capacity was 101.2 million kW, an increase of 8.2 % respect to 2007. In summary, the electricity installed capacity in Italy increased during the period 2001–2009 in 49.2 % (or 6.23 % per year as average). In 2011, the total installed electricity capacity reached 118.220 million kW. Despite the economic and financial crisis Italy is facing, it is expected that the electricity installed capacity in the country will continue this trend, but in a moderate manner at least during the coming years.

The generation, and consumption of electricity in Italy during the period 2000–2012 are shown in Figs. 2.70 and 2.71.

The production of electricity in Italy during the period 2000–2012 increased 5 %. The peak in the production of electricity during the period considered was reached in 2008. After that year the production of electricity dropped 9 % as a result of the economic and financial crisis that still is affecting the country. It is important to highlight that the production of electricity increased during the period 2000–2008 at 15.3 %.

The consumption of electricity in Italy during the period 2000–2012 increased 16 %. In 2008, Italy entered into an economic and financial crisis and, for this reason, the consumption of electricity during the period 2008–2012 dropped 2.1 %. The peak in the consumption of electricity during the period 2000–2012 was reached in 2007. The country's power consumption is expected to increase 9.8 % during the coming years.

2.19.4.1 Import and Export of Electricity

The evolution of the imports and exports of electricity from Italy during the period 2001–2012 is shown in Figs. 2.72 and 2.73.

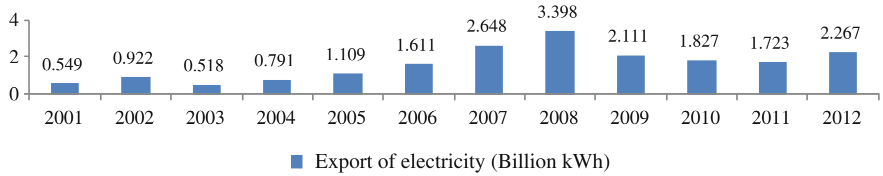

Fig. 2.72 Exports of electricity from Italy during the period 2001–2012. *Source:* Eurostat and EIA

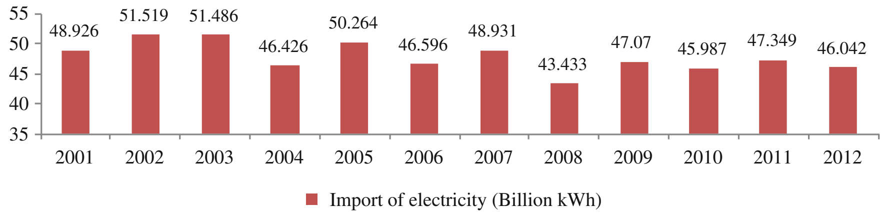

Fig. 2.73 Imports of electricity from Italy during the period 2001–2012. *Source:* Eurostat and Index Mundi

The exports of electricity from Italy during the period 2001–2012 increased 313 %. The peak in the exports of electricity, during the period considered, was reached in 2008. The economic and financial crisis, which is affecting Italy since 2008, forced the government to reduce the exports of electricity by 33.3 % during the period 2008–2012. In 2012, the exports of electricity increased 31.5 % respect to 2011.

On the other hand, the imports of electricity by Italy during the period 2001–2012 dropped 6 %. The peak in the imports of electricity, during the period considered, was reached in 2002. The major decrease in the imports of electricity was reached in 2008 (11.3 % respect to 2007) at the beginning of the economic and financial crisis, which is still affecting Italy.

Italy relies heavily on electricity imports and, for this reason, is the European largest net importer of electricity. The majority of the imported electricity comes from France, Switzerland, Germany, among others.

According to Business Monitoring International's (BMI) sources, Italy's thermal generation in 2010 was estimated at 234 billion kWh. BMI is assuming 1.5 % average annual growth in 2011–2015 power generations, leaving a potential 49 billion kWh supply shortfall after system losses. Between 2011 and 2020, BMI is forecasting an increase in Italian electricity generation by 17.8 %, which is toward the middle of the range of the developed markets. This equates to 11 % during the period 2015–2020, up from 6.1 % in 2011–2015; this represents an increase of 4.9 %. Primary energy demand growth is set to rise from 4.3 % in 2011–2015 to 5.9 % during 2014–2020, representing 10.5 % for the entire forecast period. Thermal power generation is forecast to rise by 17 % between 2011 and 2020.

Per capita electricity consumption in Italy in 2007 was a little over 5,200 kWh and in 2008 was around 6,054 kWh per person, an increase of 16.4 %, which is a little bit lower than the electricity consumed by the EU-15 in that year (the average consumption was 7,409 kWh per person). In 2009, electricity consumption per capita in Italy was also far below the European average (4,900 kWh in 2009 compared with 5,700 kWh for the EU). In 2011, the per capita electricity consumption in Italy reached 5,392.72 kWh, according to the World Bank.

2.20 Norway

Few countries in the European region are more energy directed than Norway. Whereas most EU countries have paid particular attention to the relationship between their economic growth and the consumption of energy, Norway has to a high degree based her industrialization and economic growth on the exploitation of indigenous energy resources. Therefore, establishing principles of developing and using energy resources has been an important political topic in Norway energy policy.

In the past four decades, twenty billion barrels of crude oil have been pumped up from the Norwegian Continental Shelf since production started in June 1971. It all began in the Ekofisk field, which in 2006 was Norway's most productive oil and natural gas field. Today there are fifty one active oil and natural gas fields on the Norwegian Continental Shelf, and even after so many years of production the Norwegian Petroleum Directorate believes that Ekofisk still has the largest reserves in the country. In total, nearly 40 % of the discovered marketable crude oil resources on the Norwegian Continental Shelf have not yet been extracted. In addition, there are probably many undiscovered fields in this area. The Norwegian Petroleum Directorate estimates that the undiscovered resources alone amounts to 7.3 billion barrels of crude oil.

Norway provided 12 % of OECD Europe's crude oil imports in 2010, and is the largest oil producer and exporter in Western Europe.

2.20.1 Crude Oil Reserves

In 2010, *BP Statistical Review of World Energy* estimated Norway crude oil proven reserves at 7.1 billion barrels. According to EIA sources, in 2011 Norway's crude oil proven reserves were estimated at 5.67 billion barrels; this represents 21.2 % less that the level reported in 2010. In 2012, the crude oil reserves were estimated at 5.32 billion barrels, a further reduction of 0.35 billion barrels respects to the 2011 estimated (6.2 % less than in 2011). In 2013, the crude oil proven reserves were estimated at 5.366 billion barrels; this represents an increase of 0.34 billion more than the level reported in 2012.

2.20.2 Production and Consumption of Oil

The production of crude oil in Norway started to decline in 2001 when the country has reached the peak in the crude oil production since the beginning of this activity. In 2011, the production reached 1,752,200 barrels per day, which represents 54.4 % of the production reached in 2001; in other words, the production of crude oil in Norway decreased 45.6 % in the past eleven years (4.14 % per year as average). The production of crude oil dropped further to 1.606 million barrels per day in 2012. It is expected that this trend will continue during the coming years unless new crude oil deposits are found and are economically exploited.

In order to meet the challenges related to mature oil fields, the Norwegian authorities have undertaken several policy changes. The two most important ones are opening the Norwegian Continental Shelf to a wider range of national and foreign companies and making all exploration areas around mature oil fields available through annual licensing rounds.

According to Fig. 2.74, the production of crude oil in Norway started to decline after 2001 reducing the level of production from 3,226,300 barrels per day in that year to 1,606,600 barrels per day in 2012; this represents a reduction of 50.3 % of the production reached in 2001 (see Table 2.9).

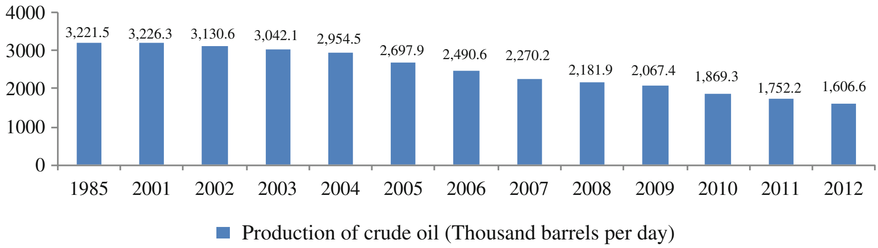

Fig. 2.74 Production of crude oil (including lease condensate) in Norway during the period 1985–2012. *Source:* EIA

Table 2.9 Oil production, consumption and reserves in Norway in 2011 and 2012 (Thousands of barrels per day)

	2011					2012
	Norway	Europe	OECD	World	Rank	Norway
Total oil production	2,007.35	4,273	21,567	86,992	14	1,902.1
Crude oil production	1,752.24	3,418	14,875	74,055	15	1,606.6
Consumption	244.98	15,033	45,877	87,328	49	na
Net export/imports (−)	1,762.37	−10,759	−24,310	–	204	na
Refinery capacity	319	16,787	45,873	88,097	47	319
Proven reserves (billion barrels)	5.67	12	–	–	21	5.32

NA not available
Source: EIA

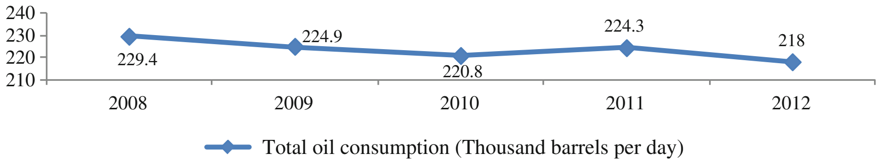

Fig. 2.75 Total oil consumption in Norway during the period 2008–2012. *Source:* EIA

In 2011, the consumption of oil in Norway was 224,300 barrels per day; this represents an increase of 15.9 % respect to 2010. In the past 11 years the consumption of oil in the country remained above 200,000 barrels per day. The evolution of the consumption of oil during the period 2008–2012 is shown in Fig. 2.75.

According to Fig. 2.75, the consumption of oil in Norway during the period 2008–2012 decreased 5 %. It is expected that the consumption of oil in Norway will continue this trend during the coming years.

2.20.2.1 Import and Export of Oil

Norway is the seventh-largest exporter of oil in the world. Taking into account the difference between crude oil production and crude oil consumption, the country can export an important part of this difference, that in 2011 was about 1,601.57 million barrels per day.

From Fig. 2.76, the following can be stated: The imports of crude oil from Norway decreased in the period 2000–2010 from 18,130 barrels per day in 2000 to 11,320 barrels per day in 2010, a decrease of 37.6 %. It is expected that this trend will continue in the future and other energy sources will be used in order to satisfy the country growing necessities of electricity as a result of the decrease in the domestic crude oil production.

The exports of crude oil from Norway during the period 2000–2010 decreased 45 % (4.5 % per day as average) (see Fig. 2.77). It is expected that the exports of crude oil from Norway will continue to decrease during the coming years as a result of the reduction of the production of crude oil reported in the past years.

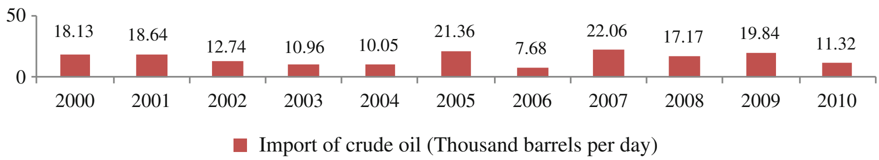

Fig. 2.76 Imports of crude oil from Norway during the period 2000–2010. *Source:* EIA

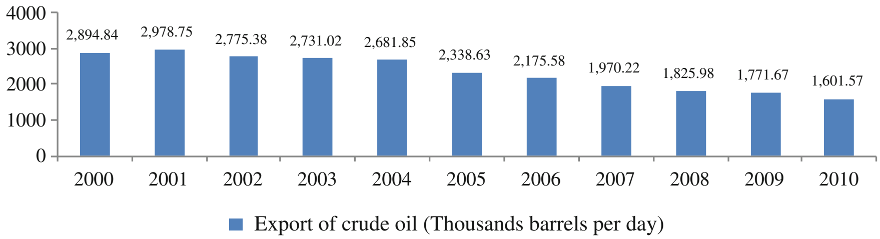

Fig. 2.77 Exports of crude oil from Norway during the period 2000–2010. *Source:* EIA

2.20.3 Electricity Generation and Consumption

Norway has an electricity installed capacity of 30.56 million kW in 2008; in 2011, the declared installed capacity was 31.76 million kW an increase of 3.9 % respect to 2008. In this last year, Norway produced 135 billion kWh of electricity; in 2009, the electricity generated by the country was 128.87 billion kWh, which is 6.7 % lower than the total electricity produced in 2008. In 2012, the generation of electricity reached 129.9 billion kWh, which is 0.8 % higher than in 2009.

The generation of electricity using fossil fuels as fuel reached 42.2 % in 2010, which is 40.6 % higher than the generation achieved in 2009. It is expected that in the future, oil will not be used for the generation of electricity in the country.

The evolution of the generation and consumption of electricity in Norway during the period 2000–2012 is shown in Fig. 2.78.

The production of electricity in Norway decreased 2.3 % during the period 2000–2007. However, the generation of electricity started to increase since 2008. The production of electricity decreased once again during the period 2011–2012 (9 %). In total, the generation of electricity in Norway increased 12.5 % during the period 2000–2012. On the other hand, during the period 2000–2012, the consumption of electricity in the country increased 4.1 %. The production of electricity in 2012 was 12.3 % higher that the consumption.

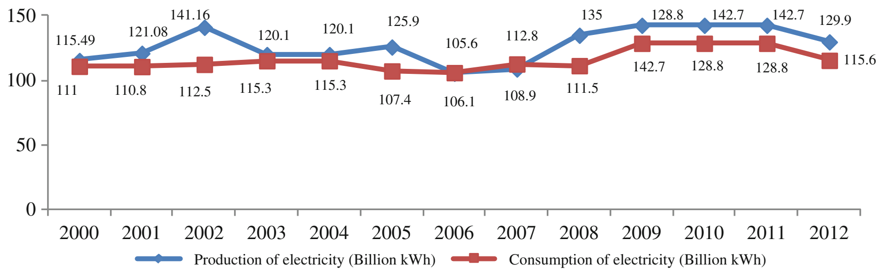

Fig. 2.78 Production and consumption of electricity in Norway during the period 2000–2012. *Source:* Index Mundi

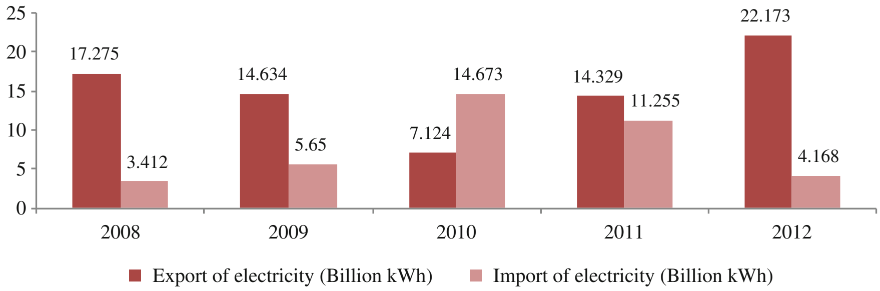

Fig. 2.79 Exports and imports of electricity from Norway during the period 2008–2012. *Source:* EIA

2.20.4 Export and Import of Electricity

In 2012, Norway exported electricity to other countries for 22.173 billion kWh, an increase of 54.7 % respect to 2011. According to Fig. 2.79, the exports of electricity during the whole period increased from 17.275 billion kWh in 2008 to 22.173 billion kWh in 2012, an increase of 28.3 %. The peak in exports of electricity from Norway to other countries was reached in 2012. It is expected that Norway will continue exporting electricity to other countries during the coming years, particularly to other Nordic and Baltic countries.

On the other hand, Norway increased by 22.2 % the imports of electricity during the period 2008–2012. The peak in the imports of electricity was reached in 2010. It is expected that the imports of electricity from Norway will continue decreasing during the coming years.

2.21 Poland

After rising sharply in the early 1970s, domestic crude oil production dropped in the 1980s because no new oil deposits were discovered. Domestic crude oil had never accounted for more than 5 % of total consumption of the country, but even this figure had dropped sharply by 1980. Under these circumstances, the former Soviet Union supplied between 80 % and 100 % of Poland's imported crude oil, with some purchases from the Middle East, when market conditions permitted.

Due to the strong dependency of the country to the supply of crude oil from Russia, the Polish oil sector has to address two essential challenges. One of these challenges is the following: The key factor in energy security policy is to assure permanent availability of crude oil supplies. Disruption of crude oil supplies via the land route is the most immediate challenge, if the Druzhba pipeline is definitively closed. As the Russian side seems to voice more openly its intentions of decreasing the role of the Druzhba pipeline system in the future, there is a serious concern with the possible implications of this action. The policy planning needs to take into account both options: the amount of crude oil transported via this infrastructure being reduced, or the pipeline being permanently shut down. The other challenge is to find a new transit infrastructure, independent of the Russian network. For that very reason, the project of building Odesa-Brody-Plock pipeline has a fundamental significance for the region.[22]

Taking into account the recent statements by the Russian side implying a low importance assigned to the Druzhba pipeline, as well as the occurring disruptions in crude oil supplies to Poland, Ukraine, Belarus, and Lithuania, the planned enlargement of the Russian sea terminal in Primorsk finds a new meaning and should be considered from a proper perspective. It is becoming more evident that the terminal would serve to export Russian export blend crude oil bypassing current transit countries: Poland, Belarus, and Ukraine. Accordingly, it is a reasonable assumption that the Russian side wants to marginalize land-based route, that is the Druzhba pipeline, and even disable it from transporting crude oil in the future. The Belarusian-Polish section of the Druzhba system—with sea terminal in Gdansk—would thus be excluded from Russian transit scenarios. This would give Moscow the option of threatening consumers in Poland with possible shut downs of the system (Naimski 2007).

2.21.1 Energy Policy

According to Lynch (2003b), in September 1996, Poland's Cabinet approved new guidelines for implementing reforms in the energy sector. These guidelines establish an energy regulatory authority and allow third party access to the Polish electricity transmission grid. The objective is to create a competitive energy market through the privatization of the energy industry, and to attract the investment necessary for industrial modernization and environmental protection. While emphasis is placed on the increased use of oil and natural gas, coal is expected to remain the dominant fuel, particularly in the electric power sector during the coming years.

On June 14, 2000, various amendments to the Energy Act went into effect, with the intention of making energy markets work on a more transparent and businesslike basis. These new regulations require that energy supply companies audit their billings and authorize energy suppliers to enter users' premises to measure their readings. They also authorize cut off of users' supplies if electricity, natural gas, or heat are being obtained illegally. The amendments stipulate that owners of apartment buildings are responsible for allocating electricity, natural gas, and heating costs to individual apartments. Rates charged for electricity, natural gas,

[22] Its main goal is to create a new transportation corridor for crude oil from the Caspian Sea region (Kazakhstan and Azerbaijan) to Europe. Caspian crude oil could thus be supplied to Poland and further to other consumer countries via Naftoport in Gdansk.

and heats are subject to approval by the Energy Regulation Authority. The amendments also give the government the power to require energy companies active in distribution to purchase electricity or heat made from renewable or unconventional sources. Energy companies will be required to submit development plans in cooperation with their communities, showing how they intend to supply energy over the next 3 years.

2.21.2 Crude Oil Reserves

According to EIA sources, in 2013 Poland proven crude oil reserves reached 160 million barrels, an increase of 66 % respect to the level reported in 2010.

2.21.3 Production and Consumption of Oil

Poland indigenous crude oil production is very small. In 2009, Poland produced 25,000 barrels per day of crude oil, which covered some 5 % of the country's total crude oil demand. In 2012, the production of crude oil reached 13,400 barrels per day (19,100 barrels per day if includes other products).

The production and consumption of oil in Poland during the period 2000–2012 is shown in Fig. 2.80. The production of oil during that period was small, but shows an increase of 25.1 %. It is expected that the production of oil in Poland will continue to be small during the coming years. At the same time, the consumption of oil increased during the whole period 26.9 %. However, after 2010, the consumption of oil started to decrease as a result of the impact of the economic and financial crisis which still is affecting Europe. It is also expected that the consumption of oil in Poland for electricity generation will continue the same trend during the coming years, particularly if the decision of the government to construct a nuclear power plant will be implemented as planned. Finally, it is important to highlight that the consumption of oil in the country is much higher than the

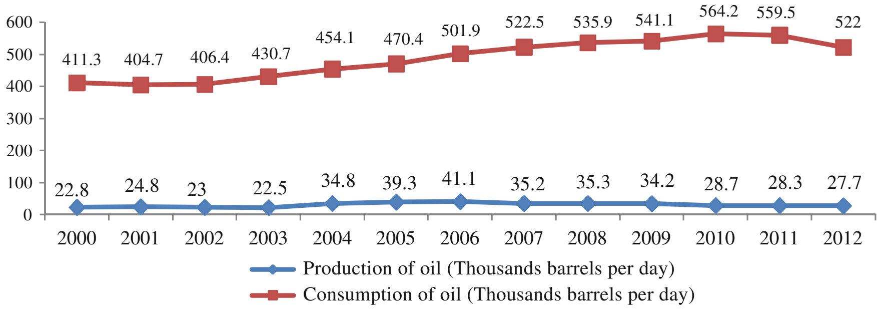

Fig. 2.80 Production and consumption of oil in Poland during the period 2000–2012. *Source:* EIA

production of this type of energy source forcing the country to import a high amount of oil from foreign countries, especially Russia. This situation will not change in the future, but perhaps with a different structure regarding the countries involved in the supply of crude oil.

2.21.4 Import and Export of Oil

Russia is the single largest source of crude oil imports of the country and provided about 94 % of the total needs in 2009. Crude oil imports from Russia are carried out via the Druzhba pipeline. In 2009, the remaining needs of crude oils were imported from Algeria (2.7 % of the total), the UK (1.7 %), Norway (1.5 %) and the rest of Iran.[23] In 2009, roughly 48 % of the refined oil product imports came from Russia (26 %), Lithuania (12 %), and Kazakhstan (10 %), while some 34 % of refined oil products were imported from Germany (26 %) and Slovak Republic (8 %). The evolution of the imports and exports of crude oil from Poland is shown in Fig. 2.81.

The imports of crude from Poland during the period 2008–2012 increased 18.4 % and the trend is to increase the imports of crude oil due to a small production of this type of energy source during the coming years. On the other hand, the exports of crude oil from Poland during the same period decreased 14.9 %. It is expected that Poland will continue importing oil during the coming years, but perhaps a lower level, if the nuclear power plant planned to be constructed in the country is implemented. The exports of oil will continue to be very small during the coming years.

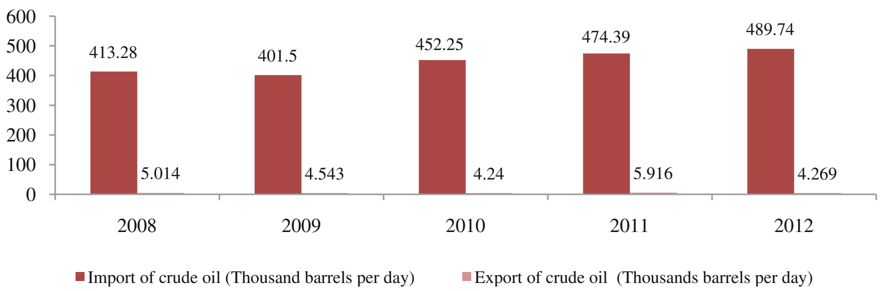

Fig. 2.81 Imports and exports of crude oil from Poland during the period 2008–2012. *Source:* EIA

[23] As result of the EU sanctions against Iran, no EU country could import crude and oil refined products from Iran after 2012.

2.21.5 Electricity Generation and Consumption

According to Index Mundi, Poland has an installed electricity capacity of 33.03 million kW in 2009,[24] an increase of 1 % respect to the level reported in 2006 (32.5 million kW), with 92 % generated in coal power plants. In 2011, the capacity installed was 34.318 million kW, an increase of 3.9 % respect to 2009. The electricity generated in Poland is mainly based on coal as most of the capacity is installed in coal fired power plants (87 % of the total in 2009). Generation capacity construction in Poland has been inconsistent over the past 40 years, resulting in an aging system that is becoming an increasingly serious problem. From 2008 to 2015, investments of 3,758 MW new power plants are planned, and 6,324 MW will be modernized. Currently, 80 % of energy boilers, turbines, and generators installed in Polish power plants are above 20-years old. In order to meet the strict EU environmental requirements (Poland committed to limit CO_2 emissions by 20 % and set 20 % share of renewable sources in Poland's energy production balance in 2020), the modernization of existing installations is indispensable. It will be also important that investments are undertaken in the area of improving energy efficiency in the Polish power generation and transmitting sectors, which is an important area to reduce energy consumption.

Current Polish power plant energy efficiency is calculated at 36 %, with energy losses estimated at 10.638 billion kWh. The Polish power transmission and distribution system generates energy losses of 9.36 %, which is one of the highest in Europe. Existing power generation and network losses constitute about 25 % of total energy production.

The evolution of the generation and consumption of electricity in Poland during the period 2007–2011 is shown in Fig. 2.82. The production and consumption of electricity in Poland are very close each other and the gap between them is being narrowed in 2008, 2009, and 2011. On the other hand, the generation of electricity in Poland increased 2.7 %. The production of electricity in 2011 by power plants using oil as fuel was 2,726 MW (1.8 % of the total). According to the decision

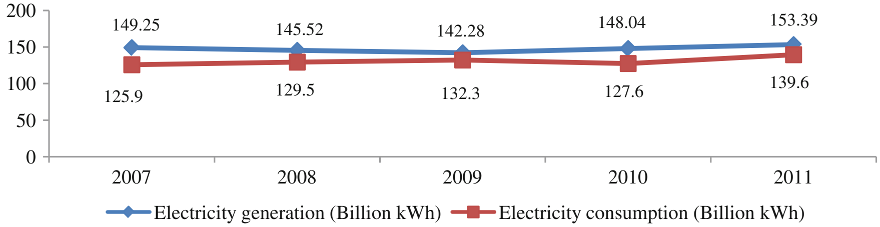

Fig. 2.82 Generation and consumption of electricity in Poland during the period 2007–2011. *Source:* EIA

[24] Out of this installed capacity, 3 % correspond to oil power plants.

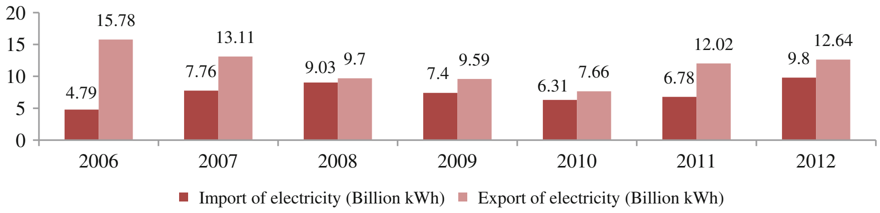

Fig. 2.83 Imports and exports of electricity from Poland during the period 2006–2012. *Source:* EIA

adopted by the government related to the structure of the energy mix of the country during the coming decades, it is expected that oil will not be used for the generation of electricity.

The consumption of electricity in Poland during the same period increased 10.9 %. It is expected that this trend will continue during the coming years.

2.21.6 Import and Export of Electricity

The evolution of the imports and exports of electricity from Poland during the period 2006–2012 are shown in Fig. 2.83.

According to Fig. 2.83, the imports of electricity by Poland during the period 2006–2012 increased 104 %. The peak in the imports of electricity, during the period considered, was reached in 2012. The exports of electricity from Poland during the same period dropped 20 %. The peak in the exports of electricity, during the period considered, was reached in 2006. It is expected that the exports of electricity continues to decrease during the coming years, taking into account the small gap that exist between electricity generation and consumption.

2.22 Portugal

Portugal is highly dependent on imported fossil fuels to meet its energy needs (52 % of its total energy needs). The reason is very simple, Portugal does not have any non-renewable resources worth using. Natural gas and electricity are gaining some ground, but the energy mix is likely to hold without any significant changes over the next few years. The total energy consumption per capita amounts to 1.745 tons of oil equivalent per inhabitant.

According to Portugal Annual Report to the European Commission (2011), there have been a recent reinforcement of the energy sector due to the construction of two combined cycle power plants for the generation of electricity in the central region of the country, with an the increase in power capacity in 838 MW. Additionally, 465 MW of capacity came into operation under a special regime. It is important to highlight that in recent years, there has been a significant growth in the weight of production under a special regime, both in terms of installed power and in terms of national consumption satisfaction, growing from 2.4 billion kWh in 2005 (13 % of consumption) to 5.9 billion kWh at the end of 2010 (34 % of consumption, an increase of 21 %).

Over the last year, the capacity margin, which is defined as the difference between installed generation capacity and the maximum peak load for the year referred to as installed capacity, grew to 48 % compared with 45 % in 2009 and 40 % in 2008, this represents a total increase of 8 % in the past years.

2.22.1 Crude Oil Reserves

Portugal has no significant proven crude oil reserves reported in 2013. Currently there is no indigenous crude oil production, although some oil exploration activities are still conducted.

2.22.2 Consumption of Oil

Oil demand in Portugal has been relatively stable in the past decade, but the recent trend shows a slow decline from the peak of 343,000 barrels per day reached in 2002. In 2009, total oil demand averaged 274,700 barrels per day, which is 20 % lower than the level reached in 2002. The government projects that total oil consumption will be roughly 313,000 barrels per day by 2020.

The evolution of the consumption of oil in Portugal during the period 2008–2012 is shown in Fig. 2.84. According to this figure, the consumption of oil in Portugal during the period 2008–2012 dropped 19 %. According to government sources, the trend is to reduce the consumption of oil in the country, particularly for the generation of electricity during the coming years. For this reason, the government continue adopting measures to reach that goal. In the case of the generation of electricity, the objective of the government is not to use oil for this purpose in the future.

Portugal's demand restraint measures were legally formalized by the law of 2001, which specifies a set of potential measures, both persuasive and compulsory

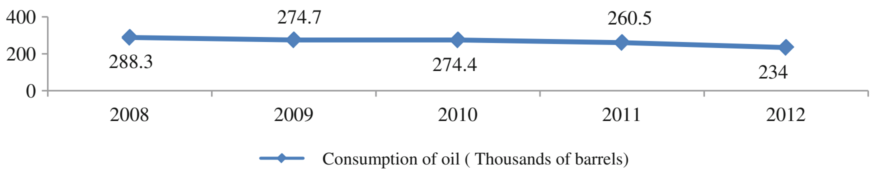

Fig. 2.84 Consumption of oil in Portugal during the period 2008–2012. *Source:* EIA

that can be applied in order to reduce the consumption of oil. Persuasive measures designed to stimulate the population to reduce oil consumption, include media awareness campaigns, publication of leaflets and explanatory guides, display of posters in public locations, and direct action by State or public administration agents. If further action is required, the following compulsory measures are envisaged:

- Restrictions on the use of passenger cars (e.g., driving bans, interdiction of motor sport events, reduction of speed limits or requirements concerning occupancy);
- Restrictions on under-utilized public or commercial transportation;
- Restrictions on the use of energy-consuming equipment (e.g., limiting operating times and lighting levels, reducing use of heating and cooling in public or private buildings);
- Imposition of operating rules for energy-consuming equipment;
- Enforcement of fuel switching.

The law of 2001 also allows for measures that indirectly promote energy saving, such as the introduction of flexible working hours or the increase of energy tariffs and charges.

2.22.3 *Import and Export of Oil*

In 2009, Portugal imported 211,071 barrels per day of crude oil and 99,013 barrels per day of refined oil products. While around two-thirds of crude oil were supplied by eight OPEC members, some 70 % of refined oil products were imported from OECD Europe countries. In the same year, Portugal exported 49,652 barrels per day of refined oil products, including around 19,000 barrels per day of gasoline and 12,000 barrels per day of residual fuel oils.

The evolution of the imports of crude oil from Portugal during the period 2008–2012 is shown in Fig. 2.85. It is important to stress that oil is the main fuel consumed in the country, with 50 % of the total energy consumption in 2010 (down from 65 % in 1990, a decrease of 15 %). No crude oil was exported from Portugal in the past years. The imports of crude oil from Portugal during the period 2008–2012 decreased 17 % as a result of the reduction of the activities in the industrial sectors. The peak in the imports of crude oil during the period considered was reached in 2008. It is expected that the country will continue importing crude oil during the coming years.

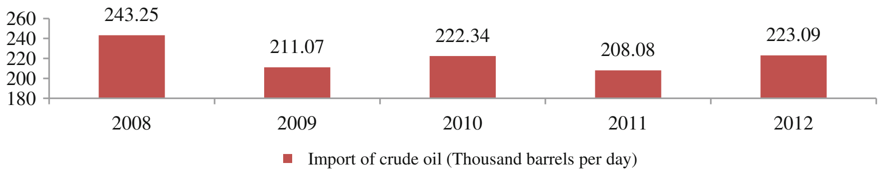

Fig. 2.85 Imports of crude oil from Portugal during the period 2008–2012. *Source:* EIA

2.22.4 Electricity Generation and Consumption

The organization of the Portuguese electricity sector was defined by Decree-Laws 182/95 and 187/95 and changed by Decree-Laws 56/97 and 198/2000. More recently, Decree-Laws 184/2003 and 185/2003 initiated a revision process of the national electricity system, addressing the adaptation of the Portuguese system to the new Iberian market. The model is based on the existence of two sub-systems: the public electricity system and the independent electricity system (Ferreira et al. 2007).

The national law followed the Electricity Directive and established the new legal framework for the Portuguese electricity sector. Decree-Law No. 172/2006, as amended, further developed this legal framework and established rules for activities in the electricity sector. Following implementation of the electricity framework, the binding and non-binding sectors of the national electricity system (SEN) were replaced by a single market system, and the generation and supply of electricity and management of the organized electricity markets are now fully open to competition, subject to obtaining the requisite licenses and approvals. However, the transmission and distribution components of the electricity industry continue to be provided through the award of public concessions.

Under the electricity framework, the SEN is divided into six major functions: generation, transmission, distribution, supply, operation of the electricity market, and the logistical operations that facilitate switching electricity suppliers for consumers. Subject to certain exceptions, each of these functions must be operated independently of other functions, from a legal, organizational, and decision-making standpoint.

The electricity sector activities are required to be developed in accordance with the principles of rationality and efficiency in the use of resources throughout the entire value chain (i.e., from generation to the final consumption of electricity), and in accordance with the principles of competition and environmental sustainability, with the purpose of increasing competition and efficiency in the SEN, without prejudicing public service obligations.

The principle of centralized planning of generation plants has been abandoned in the new electricity framework. Initiatives to construct and operate new power plants lie with market participants, and the Portuguese government will only intervene to supplement private initiatives, cover market failures, or ensure electricity supply.

The evolution of generation and consumption of electricity in Portugal during the period 2000–2012 is shown in Fig. 2.86. According to that figure, the generation of electricity in Portugal increased 15.5 % despite to the impact of the economic crisis affect the country and as a result in the increase in the consumption of electricity in the residential sector. It is expected that the generation of electricity in Portugal continues to increase during the coming years, but perhaps a lower rate. However, despite of the increase in the generation of electricity in the period 2000–2012, Portugal's electricity consumption per capita is still 20 % lower than the EU average, although it almost doubled between 1990 and 2010 (around 4,650 kWh per capita in 2010). It is also important to highlight that the generation and consumption of electricity in Portugal are so close, and this situation could be

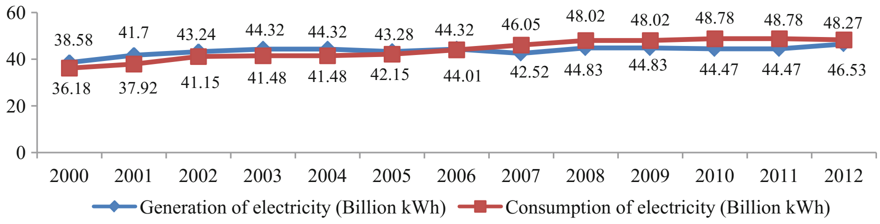

Fig. 2.86 Generation and consumption of electricity in Portugal during the period 2000–2012. *Source:* Index Mundi

critical for the supply of electricity to the Portuguese population in the coming years.

Industrial electricity consumption increased strongly between 1990 and 2000 (over 3 % per year), slowed down until 2007 and declined in 2008 and 2009 as a result of the severe economic and financial crisis affecting the country. In 2010, it rose by 1.8 %, but remained below its 2008 level. The share of the industrial sector in electricity consumption is now 33 %, compared with 51 % in 1990, a decrease of 18 %. That fall is due to the strong increase in the electricity consumption of the households and the services sector (over 5.4 % per year over 1990–2010), which now accounts for 64 % of electricity consumption, compared with 46 % in 1990, an increase of 18 % in the past two decades.

The consumption of electricity increased in Portugal during the period 2000–2012 from 36.18 billion kWh in 2000 to 48.27 billion kWh in 2012, an increase of 34.4 %. Since 2010, there has been no oil used for the generation of electricity by Portugal.

2.22.5 *Import and Export of Electricity*

The evolution of the exports and imports of electricity from Portugal during the period 2000–2012 is shown in Fig. 2.87.

The exports of electricity from Portugal decreased 23.8 % during the past 13 years. It is expected that the exports of electricity will continue this trend, at least during the coming years. On the other hand, it can be stated that the imports of

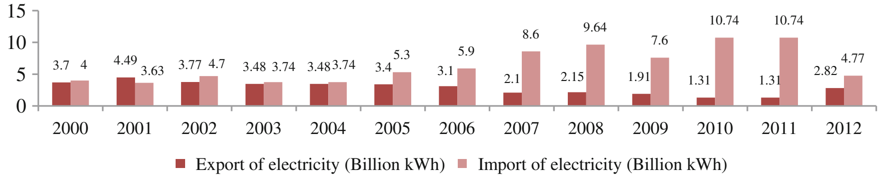

Fig. 2.87 Exports and imports of electricity from Portugal during the period 2000–2012. *Source:* Index Mundi and EIA (2011 and 2012)

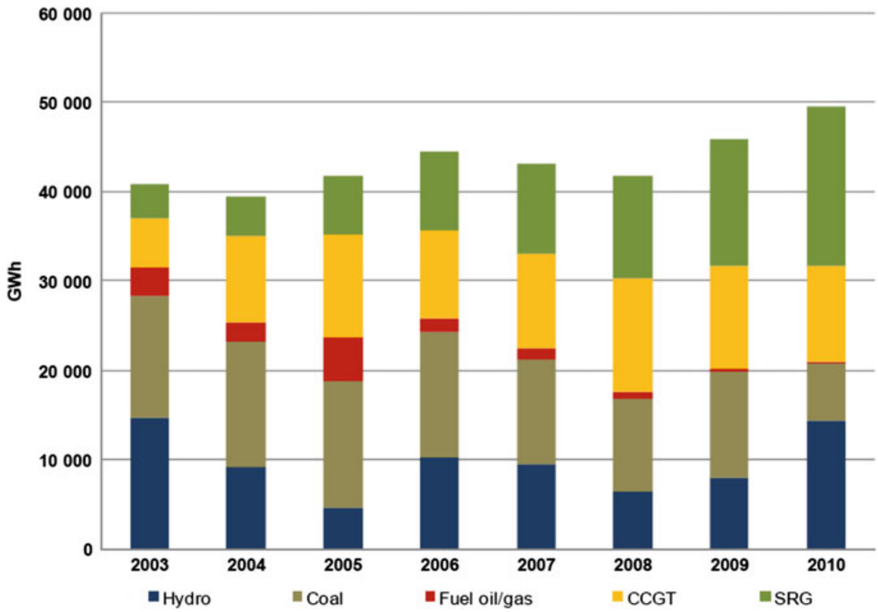

Fig. 2.88 Characterization of the power plant generation system in Portugal by technology and energy produced. *Source:* REN

electricity from Portugal during the same period increased 19.3 %. However, it is important to highlight that during the period 2005–2011 Portugal imported a significant amount of electricity reaching 10.74 billion kWh in 2011. The peak in the imports of electricity during the period considered was reached in 2010 and 2011. After that peak the imports of electricity dropped 55.6 %, and this trend is expected to continue at least during the following years.

The participation of fuel oil/gas power plants in the generation of electricity has been decreasing since 2005 (see Fig. 2.88). In 2006, the participation of fuel oil/gas in the generation of electricity was 3 %; in 2010 was 0 % (Entidade Reguladora dos Serviços Energéticos 2011). It is expected that this situation will remain without change at least during the coming years.

The electricity transmission and distribution losses increased from 3,686 billion kWh in 2006 to 4,281 billion kWh in 2010; this represents an increase of 16 % in 4 years. In 2011, the transmission and distribution losses was lower than in 2010 (4,086 billion kWh). It is expected, however, that the electricity distribution losses will decrease during the coming decades as a result of the different measures adopted by the government to increase the efficiency of the electrical grid.

2.23 Romania

Romania was the first country in the world with an oil production of 275 tones officially registered in 1857 in the international statistics.[25] It was followed by the United States in 1859, Italy in 1860, Canada in 1862, and Russia in 1863. The first commercial oil well in Romania was drilled in 1857, and Bucharest was the world's first city public illuminated with kerosene. Romania is now a mature oil processing country with refining, transportation, and retail infrastructure. A notable change in the oil sector happened in 2004 when the State-owned oil company PETROM was sold by the government to the Austrian Group OMV. That move opened the market to international competition.

The Electric Power Law No.13/2007,[26] adopted by the government in 2007 has as its main aim, the restructuring of the electricity sector. The law has the following objectives:

- Ensures the non-discriminatory and regulated access for all participants on the electric power market and the public electricity network;
- Demands the transparency of the taxes and prices for electric power;
- Promotes using new and renewable energy sources for the generation of electricity;
- Promotes local and global environmental protection;
- Ensures the safety of commercial electric power for the consumer.

In 2007, the Romanian government approved a long-term energy strategy, building up on the Energy Strategy of Romania for 2007–2020. The government's strategy emphasizes:

- Increasing energy efficiency;
- Boosting renewable energy;
- Diversifying import sources and transport routes;
- Modernizing power lines;
- Protecting critical energy infrastructure.

The energy sector in Romania is a critical segment of the economy. Romania has traditionally been a significant European producer of oil, natural gas, and coal and, more recently, of uranium, which has allowed the country to keep its energy import dependence rather low—around 30 %—compared to other countries in the region. However, the domestic production of primary energy resources, especially crude oil

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[25] Others considered that the first production of oil was carried out in Pennsylvania in the United States.

[26] Relevant legislation in Romania is as follows: Energy Law (2007); Law on Electricity (2007); Law on Energy Efficiency (2006); National Strategy for Energy Efficiency 2007–2020 (2007); Government Decision Regarding the Strategy for the Promotion of Renewable Sources of Energy (2003). Government Decision Regarding the Promotion of Electricity Produced from RES (2004); and the South-East European Energy Community Treat (2006).

and natural gas has entered a terminal decline, as the current annual reserve replacement for crude oil and natural gas is no more than 15–20 %.

At present, the energy sector in Romania faces significant challenges on both national and global levels, including improving the security of energy supplies, increasing economic competitiveness and reducing the sector's impact on the environment. Energy infrastructure—power lines, oil and natural gas pipelines—are relatively developed, but aging, as most of the networks have been built in the 1960s and 1970s.

2.23.1 Crude Oil Reserves

According to EIA source, in 2011 Romania's estimated proven crude oil reserves were 600 million barrels, being the third largest in the EU.[27] The current proven crude oil reserves represent around 11 % of total EU crude oil reserves. At present oil consumption, crude oil reserves will be exhausted in less than 20 years (Pociovalisteanu et al. 2010). In 2013, proven crude oil reserves were calculated at the same level that in 2011.

2.23.2 Production and Consumption of Oil

Romania produced an average of 90,300 barrels of crude oil per day in 2012, around 0.11 % of the world total. Romania is the largest oil producer in Central and Eastern Europe. However, its oil production has fallen from 252,000 barrels per day in 1980 to 101,600 barrels per day (90,300 barrels of crude oil) in 2012, a decrease of 60 %. To satisfy its energy needs, the country has to import crude oil from other countries reaching 44,075 barrels per day in 2010.

According to the latest Romania Oil and Gas Report from BMI, the country will account for 3.56 % of Central and Eastern European (CEE) regional oil demand by 2015, while providing just 0.47 % of supply. Oil demand in Romania could potentially grow at 3 % per annum, rising to 247,000 barrels per day by 2015. In spite of greater efforts by PETROM, the report sees domestic crude oil production slipping from an estimated 101,600 barrels per day in 2011 to 71,000 barrels per day by 2015, a reduction of 30.2 %. This implies rising import levels, with volumes is expected to reach 176,000 barrels per day of crude oil by 2015.

There are three important Romanian crude oil exploration sites. The Carpathians, the sixth largest hydrocarbon bearing thrust belt in the world after those found in the Middle East, the Caspian, and Mexico, are a mountain range that cross Central and

[27] The oil reserves dropped from 956 million barrels in 2006 to 600 million in 2011, a decrease of 37.3 %.

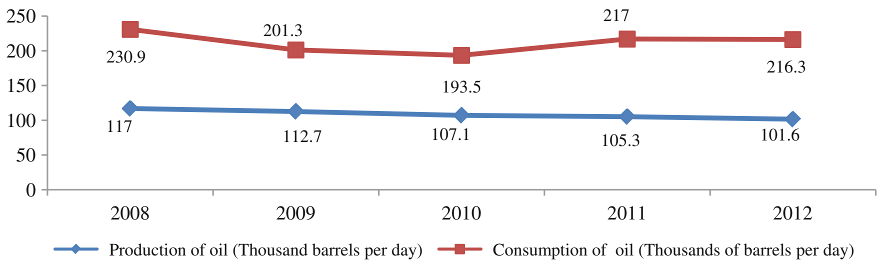

Fig. 2.89 Production and consumption of oil in Romania during the period 2008–2012. *Source:* EIA

Eastern Europe and stretches for approximately 1,609 km. The region has a long history of hydrocarbon production with over 14 billion barrels oil equivalent of reserves discovered over the years with plenty of scope for further discoveries to be made. The Romanian Carpathians region benefits from good infrastructure, including pipelines and refineries, has a strong support service industry and lower drilling costs.

Another interesting area is Bacau. To date exploration in this block has been concentrated in the Northeastern corner of Bacau, close to the Roman natural gas field. Stratigraphic traps in Sarmatian gas sands and possible Badenian structural traps add to the prospectively of this part of the block.

The third interesting block is Brates. A well, Barchiz-1, was drilled in late 2010 and encountered shallow oil-bearing Oligocene sands similar to those found in the Geamana field to the South. Testing resulted in modest quantities of oil being recovered, but a poor cement bond prevented drilling beyond 1,450 m.

The evolution of the production and consumption of oil in Romania during the period 2008–2012 is shown in Fig. 2.89. Oil production in Romania during the period 2008–2012 dropped 13.2 %. It is expected that the production of oil dropped further to 71,000 barrels per day in 2015; this represents a further decrease of 30.2 %. During the period 2000–2012, the peak in oil production was reached in 2001 with 124,000 barrels per day.[28] In the case of oil consumption, it dropped 6.4 %. The government expect that the consumption of oil, particularly for the generation of electricity, will dropped further during the coming years.

In order to stop the decline in oil production, the government is adopting additional measures to redevelop mature oil fields in the country; steam injection will be tried using long horizontal holes, rather than the vertical used to date, in the heavy oil Suplac field in the Western part of the country. Water injection is to be tried in the Oprisenesti field in the East, and polymer injection is being considered for the Videle field in the South. Videle was earlier the site for a successful World Bank funded project that used in situ combustion to try and reverse the declining production of this and the Balaria fields. The treatment was intended to increase ultimate oil recovery from 15 % to 39 %. Oil consumption in Romania during the

[28] The peak oil production was reached in 1976 with 290,000 barrels per day.

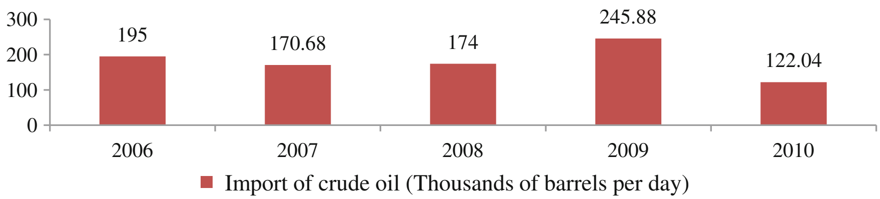

Fig. 2.90 Imports of crude oil from Romania during the period 2006–2010. *Source:* EIA (no data available for 2011 and 2012)

period 2000–2012 was above oil production level in each year of the period considered, forcing the government to import crude oil to satisfy the demand. The situation is not worse because oil consumption dropped from 224,240 barrels per day in 2000 to 216,300 barrels per day in 2012, a decrease of 3.4 %, but with a significant decrease in 2009 and 2010.

2.23.3 *Import and Export of Oil*

The evolution of the imports of crude oil from Romania during the period 2006–2010 is shown in Fig. 2.90.

Imports of crude oil from Romania during the period 2006–2010 decreased 37.5 %. It is expected that this trend will continue during the coming years, but the country will continue importing crude oil in the future. Exports of crude oil from Romania was almost nonexistent during the period 2001–2009. Only one exports of crude oil were reported in 2010 of around 1,604 barrels per day. The decrease in oil production and the high demand of oil during the period 2001–2010 were two main factors that caused a decrease in the exports of crude oil to other countries during that period.

2.23.4 *Electricity Generation and Consumption*

Electricity in Romania is primarily generated from thermal power plants (coal, natural gas, and oil), with the balance of production from hydroelectric facilities and nuclear power. The extent of connection to the electricity network is not 100 %, although it is close. Romania has an extensive interconnected power transmission and distribution network with an overall length of about 600,000 km (Oprescu et al. 2002). Over the period 1998–2000, the vertically integrated State owned monopoly was divided into five separate States owned enterprises: One each for nuclear generation (NUCLEARELECTRICA), hydro generation (HIDROELECTRICA), thermal generation (TERMOELECTRICA), transmission (TRANSELECTRICA), and distribution (ELECTRICA). Since then the distribution function has been further divided into eight regional companies, with four of these privatized to foreign

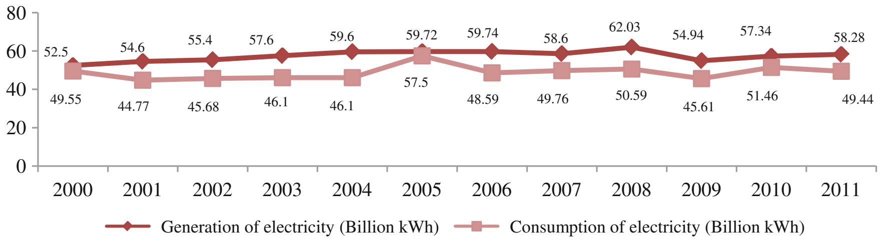

Fig. 2.91 Generation and consumption of electricity in Romania during the period 2000–2011. *Source:* Index Mundi, INS (2006); MEC (2006) and EIA

buyers. TERMOELECTRICA has also been further horizontally unbundled, but the privatization of the generation sector has been delayed.

An independent regulatory body has been established and regulatory reform has advanced significantly. The wholesale market has been operating since 2000, although its design was modified in 2005. Its operator, OPCOM, aims to transform it into a regional energy market. The retail market liberalization is ongoing. Since July 2005, all industrial consumers have been eligible to change their supplier and the market was completely open as of 1 July 2007. The reform of the electricity sector of Romania has been fuelled by the accession negotiations with the EC on the Energy Chapter, which started in March 2002 and was closed in 2004. Negotiations have been focused on the buildup of emergency oil stocks, nuclear safety, and the internal energy market; therefore, Romania's obligation to implement the EU Directives required adequate legislation as well as functioning markets and institutions. From the very beginning, Romania accepted the entire EU Directives in the electricity sector and did not foresee any problems in fully applying it in the future (Diaconu et al. 2007).

The evolution of the generation and consumption of electricity in Romania during the period 2000–2011 is shown in Fig. 2.91.

Generation of electricity in Romania increased 11 % during the period 2000–2011 (an increase of 1 % each year as average). The major decrease in the generation of electricity occurred in 2008–2009, when the production dropped due to the negative impact of the world economic and financial crisis in the country. After 2009, the generation of electricity started a slow recovering process reaching the level of electricity generated in 2007.

According to the BMI report (2012), during the period 2012–2021, Romania's overall power generation is expected to increase by an annual average between 3.8 % and 4.2 %, reaching 83.1 billion kWh in 2021. Driving this growth is an annual 3.7 % gain in gas-fired supply, a 7.8 % rise in nuclear generation and a 16.7 % average increase in renewable-based supply, offsetting a 1 % average annual decline in oil-fired electricity.[29] Thanks largely to the forecast rise in net generation,

[29] It is expected that the participation of oil in the generation of electricity in the energy mix of the country continue diminishing in the coming years.

growth of which outpaces the underlying demand trend Romania's power supply surplus may increase over the next 10 years.

A falling percentage of transmission and distribution losses—from around 11.5 % to 10.8 %—will help protect the export trade. The theoretical net export capability by 2021 is put at 8.2 billion kWh.

Electricity consumption patterns in Romania have showed considerable fluctuations throughout the past two decades. Electricity consumption decreased significantly between 1989 and 2000, largely owing to the downfall of industrial demand after 1989 as a result of the collapse of the socialist European countries and of the former Soviet Union. The situation stabilized in 2000, when electricity consumption rose for the first time in more than a decade, reaching its peak in 2005. Furthermore, Romania is a net exporter of electricity, with an approximate net export total of 2.95 billion kWh in 2010 and 5.16 billion kWh in 2011, an increase of 75 % between these 2 years. Net power consumption looks set to increase to 66 billion kWh by 2021, an increase of 33.5 % respect to 2011. During the period 2012–2021, the average annual growth rate for electricity demand is forecast at 2.8 %.

Over the past 6 years, Romania has decommissioned nearly 3,000 MW of thermal generation capacity. Further decommissioning is expected as many power plants require refurbishments and modernizations to meet EU requirements.

The Romanian generation sector is facing major challenges as a significant percentage of the generation assets are already past their useful technical life, with 30 % being approximately 40 years old. As a result, Romania must replace units with an overall output of 5,544 MW by 2020, namely 28 % of the total installed capacity. By 2035, Romania will need an available installed capacity of more than 20,000 MW with the aim of satisfying its internal energy needs.

2.23.5 Import and Export of Electricity

It is important to highlight that Romania is, at the same time, a net exporter of electricity and, and importer of electricity. Serbia, Ukraine, Bulgaria, and Hungary are the countries from where Romania import electricity. The evolution of the exports and imports of electricity from Romania during the period 2000–2011 is shown in Fig. 2.92.

The exports of electricity in Romania increased significantly during the period 2000–2011; around 9.5 folds. It is expected that this trend will continue during the coming years. The imports of electricity in the same period dropped 37.6 %. It is expected that the imports of electricity continues decreasing at least during the coming years.

Finally, it is important to highlight the need of the adoption of additional measures by the government in order to ensure durable energy development of the country in the future. These measures are, among others, the following:

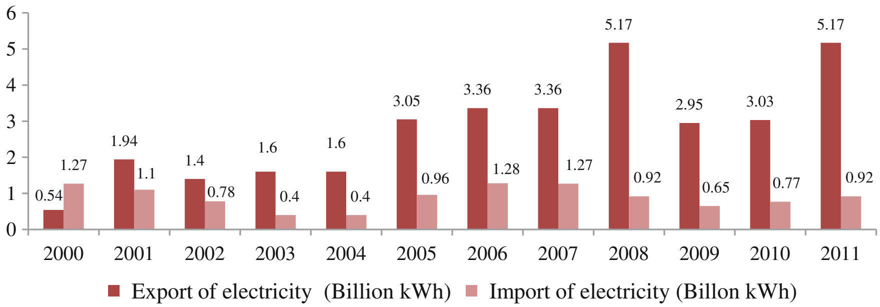

Fig. 2.92 Exports and imports of electricity from Romania during the period 2000–2011. *Source:* Index Mundi and EIA

- Developing a long-term energy strategy correlated directly with the EU's energy policy;
- Improving the institutional, legislative, and regulatory framework for the field of energy, which would allow implementation of national energy efficiency programs, seeking to reduce energy losses;
- Promoting the use of renewable energy sources for the generation of electricity;
- Remote modern heating-systems-efficient centralized economic projects of joint implementation, and trade in carbon credits (green certificates) based on the Kyoto Protocol;
- Promoting the use of nuclear energy for the generation of electricity, with the purpose of reducing CO_2 emissions;
- Creating a framework for attracting investments and privatizing continuously the energy industry;
- Promoting and financing research, development, and innovation activities in the field of energy;
- Presence of ethics in the governance of the energy sector;
- Accountability of institutions and central and local authorities in tracking direction and control measures on energy and sustainable energy development.

2.24 Russian Federation (Russia)

2.24.1 The New Energy Strategy

On November 2009, the new energy strategy[30] of the Russian Federation until 2030 was adopted by the government. The new document was made in accordance with current trends and new systematic changes of energy development. According to

[30] The aim of previous energy policy adopted in 2003 was "to maximize utilization efficiency of natural energy resources and energy sector potential for the growth of economy and population living standards". The new energy policy, in principle, has the same objective.

this document, crude oil production in Russia will develop with positive trends. At the first stage, it is planned to produce between 486 and 495 million tons of crude oil; at the second stage an estimated between 505 and 525 million tons of crude oil; and at the third stage (till 2030) between 530 and 535 million tons of crude oil. The increase of crude oil reserves shall be accordingly 1,854, 5,597, and 5,122 million tons of crude oil (Kozhurbaev et al. 2008).[31]

The project "Strategies of oil industry development in Russia for coming decades" prepared by Russian oil experts, provided analysis of four possible scenarios of crude oil production development in the country. According to this project, the crude oil production in Russia can increase between 582 and 590 million tons of crude oil in 2020. The crude oil production will reach its maximum level in 2021–2025 and will slightly decrease in 2030. In this last year, it could reach 591 million tons (optimistic scenario) (Kozhurbaev et al. 2008). Conditions to such substantial increase of crude oil production shall be the increase of geological works (deep drilling and geophysics) that should be carried out during the coming decades.

Because the historical maximum of crude oil production of 624 million tons reached by the former Soviet Union in 1988 (565 million tons of crude oil was produced by Russia, 90.5 % of this maximum), the prognosis about the production in 2025 looks very optimistic. Other specialists consider that it is possible to produce 540 million tons of crude oil in 2020 and then keep this volume until 2050. This forecast is based on the calculation of crude oil production in different basins and oil fields in the country till 2050.

According to government and other public sources, it is expected that crude oil production in the Volga—Ural Basin—will decrease in the coming years. Crude oil production in the Eastern Siberia and Republic Sakha is expected to increase from 17 % to 30 % of the total country's crude oil production in 2050. West Siberia is expected to keep the leading position and is considered to be the main crude oil producing region for the long-term perspective. West Siberia, Volga—Ural, Timan—Pechora, North Caucasus, East Siberia, and Republic Sakha could produce up to 19.3 billion tons of crude oil till 2050.

The above expectation could be achieved at the expense of already proven crude oil reserves, and also with an increase provable and estimated crude oil reserves. In order to maintain the crude oil production level between 520 and 540 million tons per year, new provable and estimated crude oil reserves shall be involved in production after 2020.

In conclusion, it is worth mentioning that different estimations and prognosis about the Russia's crude oil reserves are based on current geological, economic, technological, and political factors. Calculations are done in accordance with real situation at the first decade of the 21st century. Nowadays, the condition of potential

[31] It is important to stress that the main type of fuel used in Russia for the generation of electricity is natural gas. In 2009, the share of natural gas in the Russian energy equation was 56.2 %. Oil accounted for only 18.3 % of the country's energy consumption, coal for 14.4 %, nuclear energy for 5.3 %, and hydro power for 5.6 %.

reserves of crude oil in Russia means they can afford to maintain production of more than 500 million tons of crude oil annually until the middle of the century. In order to achieve this figure, it is necessary to implement new ways to search and explore new oil fields, improve current technology and technical base, among others. Such measures will require substantial State and private investments, and improvement of the current legislation.

If Russia could successfully achieve the above mentioned goals the country will become of great strategic importance in enhancing the world's energy security. The country still holds substantial crude oil reserves and with a well-considered approach to crude oil production, will keep playing a lead in the crude oil supplying role for decades.

However, it is important to highlight the following: In the mid-2000s, Russia was entangled in disputes with many European States over energy price, which led to oil and natural gas cut off on several occasions. One of these cut offs was the natural gas cut off to Ukraine, which led in turn to a cut off of most of Central Europe's supplies from Russia. In 2006, a break in the Druzhba pipeline to Lithuania occurred after a refinery dispute, and Russia has refused to repair the damaged pipeline. In 2010, Russia also cuts crude oil supplies to Belarus over a pricing dispute, and Moscow had to make up supplies to Europe via shipments by sea.

In order to be prepared to deal with these issues, Russia then created a strategy to begin diversifying its oil transit routes to its biggest customers in Europe without relying so much on the transit States. First, Russia increased crude oil transit to the port of Primorsk via the Baltic pipeline system. Then Russia began building a large second line of the Baltic pipeline system of the Baltic port of Ust-Luga. Baltic pipeline system-2 was completed in November 2011 and is expected to become operational before 2014. Its capacity will be 1.1 million barrels per day, though only 850,000 barrels per day are planned for export via the newly expanded port at Ust-Luga. The rest of the crude oil will go to the Kirishi refinery and will be exported via tanker. This export expansion will enable Moscow to strike direct deals with customers such as Poland and Germany and ship crude oil directly to them without having to rely on troublesome transit States. Moscow can increase its leverage over Kiev now by diverting crude oil that would be transited by Ukraine to the new oil pipeline, depriving Ukraine of oil transit revenue and some of its importance as a transit State.

However, there are two problems with the Baltic pipeline system-2: The first one is the freezing of the Baltic ports for 2 months a year and the second is the price difference of shipping compared to piping the oil. It costs approximately US$3 per barrel to ship the oil out of the Baltic compared to piping it overland via Druzhba, meaning the 850,000 barrels per day to be exported via the Baltic line and then shipped in tankers from Ust-Luga port will add millions to the cost of export. Overall, though, Russia sees these as minor problems compared to what they gain by using the expanded Baltic pipeline system.

Russia's second diversification strategy is to expand its customer base so as not to rely so much on Europe. In 2009, Moscow and Beijing commissioned the Eastern Siberia-Pacific Ocean oil pipeline (ESPO), which runs more than

4,800 km from Russia's central Siberian oil fields to China and the Pacific coast. The first leg of the line has a capacity of 600,000 barrels per day, with 300,000 spurred off to China at Daqing and the other 300,000 barrels per day sent to the Russian port of Kozmino, where it can be bought on the open market. In 2011, customers who bought crude oil from Kozmino included the United States, China, Japan, South Korea, and the Philippines.

The second stage of ESPO will add another 400,000 barrels per day of capacity to the pipeline. The crude oil ultimately will be sent to a massive new refinery at Nakhodka, near Kozmino, but a refinery that large will take years to build and ground was just broken on the project recently. Meanwhile, Russia will sell the crude oil from Kozmino.

For the construction of the ESPO, China agreed to loan US$25 billion to Russian oil companies ROSNEFT and TRANSNEFT on the condition that oil supplies are sent to China with a price break. Though the first line has been built and the second is under construction, the expansion of the line is being disputed as Russia and China disagree over pricing. China wanted to lock in its oil supplies from ESPO in a multi-decade contract with the price per barrel US$3 to US$13 less than prices at Kozmino. But Russia wanted to add an extra transit cost for the oil already being piped via the ESPO spur line to Daqing. On 28 February, the countries struck a deal under which China will receive a discount of $1.50 per barrel for the price at Kozmino for 20 years.

Russia is diversifying its customer base so that if demand in Europe declines—or if Russia and its European customers find themselves in a politically untenable situation—Russia will still have a large market to its East. The current sanctions applied by the EU and the USA to Russia as a result of their actions in Crimea, justify the decision adopted by the Russian government to diversify its customer base expanding the oil market to Asia and the Pacific region. In the past decade, Russia has increased its oil exports to Asia from 3 % to 15 % of total exports, with more increases expected. When ESPO is expanded,[32] Russia theoretically could supply one-fifth of China's imports, or one-third of Japan's imports. However, Russia is not singling out one customer in East Asia yet; it is supplying many customers. Conversely, no East Asian country wants to become too reliant on Russia after seeing Moscow cut off supplies to its customers in the West.

Russia has a goal to double production in Central and Eastern Siberia to supply East Asia by 2015. However, the fields in Eastern Siberia are a year behind in its development. The Kremlin is trying to spur the projects along by giving the projects and their developing companies' tax breaks and cutting export duties. Thus far,

[32] On January 1, 2011 Russia officially launched commercial supply of its ESPO crude oil blend to China via a new offshoot pipeline from the East Siberia-Pacific Ocean. The shipment followed an agreement signed in February 2009 between ROSNEFT, pipeline-operator TRANSNEFT, China National Petroleum Corporation, and China Development Bank. Under the agreement, ROSNEFT agreed to supply 300,000 barrels per day of crude oil over 20 years. In return, China Development Bank agreed to provide ROSNEFT and TRANSNEFT with 20 year loans of US$15 billion and US$10 billion, respectively.

exporting oil to Asia has not led Russia to divert any oil supplies from Europe, since the infrastructure is separate. It does, however, give Russia the security of having multiple markets and more flexibility should problems arise in one area or the other. This gives Russia knowledge that its oil revenues are a little more secure in spite of the market's inherent instability.

2.24.2 Crude Oil Reserves

In 2012, British Petroleum (BP) in its annual report estimated Russian crude oil reserves at 87.2 billion barrels, which represents 5.2 % of the world's crude oil reserves,[33] most of which are located in Western Siberia between the Ural Mountains and the Central Siberian Plateau.[34] In 2013, the proven crude oil reserves were calculated at 80 billion barrels; this represents a decreased of 8.3 % respect to 2012. These reserves allowed the former Soviet Union to become a major world oil producer in the 1980s, reaching production of 12.5 million barrels per day in 1988. Roughly 25 % of Russia's crude oil reserves and 6 % of its natural gas reserves are on Sakhalin Island in the far Eastern region of the country, just North of Japan.[35] According to auditors of the company "DeGolyer & MacNaughton", proven crude oil reserves in Russia could be between 150 and 200 billion barrels. Russia was the third-largest producer of liquid fuels in 2012, following the United States and Saudi Arabia.

In 2012, Russia produced an estimated 10.4 million barrels per day of total liquids (of which 9.9 million barrels per day was crude oil), and it consumed roughly 3.2 million barrels per day. Russia exported over 7 million barrels per day in 2012, including roughly 5 million barrels per day of crude oil and the remainder in oil products.

According to Grama (2012), Russia holds the eighth largest crude oil reserves in the world. That is the reason why Russia plays the leading role in the world's energy supply and also why the development of the world's economy, particularly in the case of several of the European countries, substantially relies on Russia to provide their supply of crude oil and natural gas. The main Russian crude oil reserves are located in the following Basins.

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[33] According to EIA sources, the crude oil reserves were estimated at 60 billion barrels or 3.9 % of the world total.

[34] Initially, the core of the industry was in the Volga-Urals region located in the Southern part of European Russia. As its production peaked during the 1970s, the focus shifted to West Siberia, which has remained the heartland of Russia's crude oil business. However, this region's production has been declining in the past few years, while major Russian oil producers have gradually stepped up their efforts to look for opportunities in new regions of the Russian Federation—East Siberia, the Far East, and the Arctic.

[35] Approximately 14 billion barrels of crude oil exist on Sakhalin Island in the far Eastern region of the country.

2.24.3 Crude Oil Fields

2.24.3.1 The Western Siberia Basin

Recently, almost all of Russia's crude oil production increases have come from the Western Siberia Basin in the Khanty-Mansiysk Okrug region.[36] A total of 75 % of Russia's crude oil production comes from this region, and two-third of Russia's crude oil reserves are located there (Websurveys 2011). The most important oil fields are Samator, Ust-Balyk and Salym (Ivanenko 2007). Pipelines transfer crude oil for export to the Black Sea, Baltic Sea, and the Pacific coast.

2.24.3.2 The Volga—Ural Basin

The basin is located along Yaik (Ural) and Volga Rivers. It is also known as "Second Baku" and has an area of around 70 million km^2. The building of the basin was first started during World War II and from the mid-1950s to mid-1970s; it was the largest crude oil production area in the former USSR. From an exploration viewpoint, the basin is much matured. Since the 1960s, only two new oil fields with reserves of more than a million barrels of recoverable crude oil were found. Before that time there were seven with more than 2 billion barrels each, and the largest—Romashkino field—with stocks of more than 17 billion barrels (Grace 2005). From 1978, the West Siberian Basin took leading position and the crude oil production in Volga-Ural Basin decreased year by year. But still the basin holds 20 % of all crude oil production in Russia. The basin is located in economically developed regions; therefore, crude oil processing and petrochemical industry are also very developed there. There are more than 10 oil refineries with a total processing capacity of 150 million tons of crude oil per year. The developed pipeline infrastructure allows the crude oil to be transported to other regions of Russia and for export (Grace 2005).

2.24.3.3 Timan—Pechora Basin

The basin is located in the Northeast European part of Russia. It is difficult to estimate the total crude oil resources of the above-mentioned basin, because some of the areas are still in the early stages of exploration, but according to the information provided by LUKOIL, the total crude oil reserves in 2000 were estimated at

[36] More specifically from Priobskoye, Prirazlomnoye, Mamontovskoye, Malobalykskoye, and Surgut group of oil fields. The Sakhalin group of oil fields in the Far East is expected to contribute to most of Russia's crude oil production in the near-term. According to EIA sources, in the longer-term, untapped crude oil reserves in Eastern Siberia, the Caspian Sea, and Sakhalin Island are expected to play a larger role in the production of crude oil in Russia in the future.

10.7 billion of crude oil and by 2015, the explored reserves are estimated to be between 20 and 25 billion of crude oil (Fedun 2011).

The Timan-Pechora Basin is considered as the third biggest crude oil producer of Russia, and there is great development potential in the area. According to the information provided by the Science Communications Arctic Center about the reserves of the Timan—Pechora Basin, it can be said that “if the crude oil reserves are compared world-wide, they are equivalent to Norway’s North Sea reserves” (Arctic Center 2011).

There are different evaluations on the Russian crude oil proven reserves and the volumes of reserves that can be commercially extracted differ a lot. Russian companies have gradually started to implement new technologies of crude oil extraction, for example, horizontal boreholes and computerized systems for reservoir management. Thus, the evaluations of extractable crude oil reserves keep changing. Because of new technologies that allow crude oil to be extracted even from depleted oil fields, Russian oil companies managed to increase crude oil extraction by 50 %. According to Martin Viverovsky, senior Vice President of Moscow’s representative office of “DeGolver & MacNaughton”, “the most important is that new technologies started to be implemented in Western Siberia. Results are already very obvious”. According to the company evaluations made in 2012 in Western Siberia, crude oil production can reach 10 million barrels per day. With the development of new technologies the crude oil production in Western Siberia could increase accordingly. Also the volume of proven crude oil reserves will grow together with exploration of new regions such as the Arctic, the Caspian Sea, and mostly Eastern Siberia.

According to the Energy Strategy of Russia for the Period up to 2020, which was first adopted by the Russian government in 2003, trends and basic indexes of oil exploration were the following: “In perspective, the levels of oil exploration in Russia are mainly defined by the following factors: demand for liquid fuel and world’s prices, development of transport infrastructure, tax conditions, technological achievements, and the quality of proven raw materials base. Long-term volumes of crude oil production in Russia will substantially differ in accordance with the socio-economic development of the country. With favorable conditions and under good socio-economic situations, crude oil production in Russia can grow to 520 million tons in 2020, an increase of 15.6 % respect to 2010. With moderate variation of socio-economic development of the country, the predicted level of crude oil production in 2020 will be 450 million tons. With negative economic situation, the growth of crude oil production will increase for only 1 or 2 years, and after that period will decline to 315 million tons in 2020”. Important features of this strategy include:

- Greater emphasis on energy efficiency through economic re-structuring and demand-side management;
- Establishment of market-based energy pricing mechanisms;
- Exploration and development of new oil and gas bearing regions and modernization/expansion of export facilities;

- Diversification of export markets;
- Development and construction of new generation nuclear technologies, particularly closed nuclear fuel cycle;
- Refurbishment of gas-fired power plants with combined-cycle technologies.

Nevertheless, with any dynamics of crude oil production the strategic targets of the industry will be the provision of necessary reserves, gradual increase of production with its stabilization for long-term prospective.

As the development of the real situation has demonstrated, for the 7 years since the Strategy 2020 was implemented, the production of crude oil in Russia has grown in 2009 from 421 to 494 million tons, an increase of 17 %. Even the oil prices were very favorable during this period—such growth cannot be possible without sufficient crude oil reserves.

Finally, it is important to stress the following: Russia does have promising offshore crude oil and natural gas resources. It is estimated that about 90 % of all Russian shelves within the Arctic contain some untapped crude oil and natural gas. The shelves are estimated to cover an area between 5.2 and 6.2 million km^2 and experts estimate that the shelves hold 90 to 100 billion tons of crude oil equivalent, of which natural gas resources account for 80 % of that total.

One of the more promising areas for Russia's energy resources are the offshore basins in the West Arctic's Barents and Kara Seas. The basins cover a total area of 2 million km^2 and they potentially contain at least between 50 and 60 billion tons of conventional fuel. In the Barents Sea, the Prirazlomnoe oil field in the area of Pechora Bay is of special interest. The Prirazlomnoe oil field amounts to more than 200 million tons. Once developed, these areas are sure to lead to significant changed in the world's system of crude oil and natural gas transportation.

2.24.4 Production and Consumption of Oil

According to the Russian energy forecasting agency APBE, Russia's power demand is expected to grow from around 950 billion kWh in 2005 to more than 1,050 billion kWh in 2014; this represents an increase of 5.3 %.

According to 2009 data and on a standalone basis, independent suppliers in Russia have a 29.4 % market share, while regional suppliers have 70.6 %. RUSENERGOSBYT is the biggest independent supplier with 12.1 % of the total, RUSAL, SIBIRENERGO, and other independent suppliers have shares of 5.9 %, 5.8 %, and 76.2 %, respectively.

During the past few years, the region has attracted the interest of several Western oil companies. In 2010, Russia was the world's largest crude oil producer with production of 9.4 million barrels per day, amounting to around 12 % of the world's total crude oil production. The figure was around 2 % higher than in 2009. The evolution of crude oil production in Russia during the period 2000–2012 is shown in Fig. 2.93.

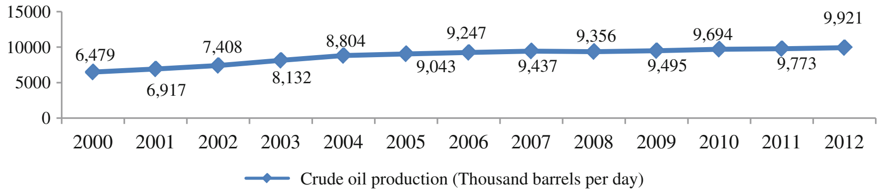

Fig. 2.93 Crude oil production (including lease condensate) in Russia during the period 2000–2012. *Source:* EIA

Crude oil production in Russia during the period 2000–2012 increased 53.1 %. However, it is important to highlight that the production of crude oil in Russia decreased 1 % in 2008 respect to 2007 for the first time since 2000. Russia planned to increase crude oil output from its continental self-five-fold by 2030, according to Prime Minister Dmitry Medvedev. Under the plan, Russia's crude oil production would reach 66.2 million tons. The government was considering a long-term exploration of the shelf's energy resources. The objective is earning US$266 billion after the program is implemented. According to government sources, exploration in the Arctic region was urgent, but admitted it had been hampered by a lack of infrastructure in the region and funding.

Russia is the world's number one crude oil including lease condensate producer in 2013, and looks set to retain this position through the next decade. Crude oil production is around 10 million barrels per day and this level of production should be sustained at current levels, if Russia wishes to incentivize the implementation of more costly projects over the coming decade. According to Russia's President Vladimir Putin, Russia is to maintain its crude oil production at around 10 million barrels per day (505 million tons per year) long-term. "We are to maintain this production level, which covers domestic demand and exports, for a fairly long time." The output level of 505 million tons per year was the highest in the post-Soviet era, and largely due to the start-up of new fields in Eastern Siberia such as Vankor, Verkhnechonsk and Talakan. Putin's comments indicate the government is aiming for the upper level of crude oil production forecast by the national long-term development program for the oil industry until 2020. The evolution of the consumption of oil in Russia during the period 2002–2012 is shown in Fig. 2.94.

Oil consumption in Russia during the period 2002–2012 increased 24 %. The trend is to increase oil consumption during the coming years, despite the decrease that was registered between 2008 and 2009 as a result of the economic and financial crisis affecting the country. Russia's increasing energy consumption is mainly driven by increasing economic activity, boosted in part by high world energy prices. The Russian economy has grown steadily at an average annual rate of 5.1 % since the economic recovery started in 1999 as a result of the re-valuation of the national currency in 1998; later supported by soaring world energy prices starting in 2000, reaching very high price levels in the period 2008–2012.

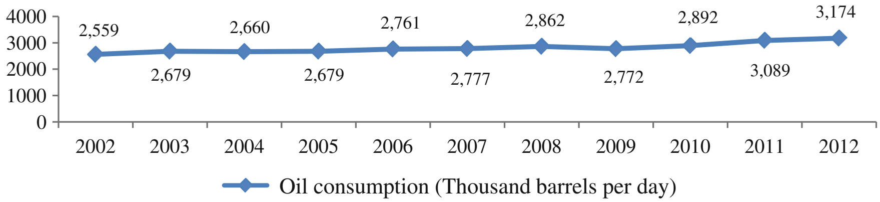

Fig. 2.94 Oil consumption in Russia during the period 2002–2012. *Source:* BP

It is important to highlight that Russia meets all of its energy requirements by domestic production, having the world's largest natural gas reserves, the second largest coal reserves and the eighth largest crude oil reserves. However, with depleting crude oil and natural gas reserves in the economy's traditional oil and gas bearing regions, the economy has been prompted to explore for new land in order to increase the current level of crude oil and natural gas reserves. As a result of Russia's increasing energy consumption over the past decade and the need to reduce the economy's energy intensity while sustaining Russia's export position, the government approved the "Energy Strategy of Russia for the Period up to 2020", in August 2003, outlining the economy's long-term energy policy.

Finally, it is important to highlight that Russia is expected to consume 2.7 million barrels per day in 2035 (IEO 2011).

2.24.5 *Export and Import of Oil*

Russia's exports of crude oil and refined oil products in 2010 totaled about 7.5 million barrels per day, up from 6.7 million barrels per day in 2008, an increase of 11.9 %; 6.5 million barrels per day in 2007. The rise in 2010 is due to an increase in the capacity of Russia's export outlets and increased production of crude oil and lease condensate.

According to the governmental document called "Energy Strategy of Russia for the Period up to 2030", exports of crude oil, lease condensate, and refined petroleum products are expected to rise between 530 and 535 million tons per year. The evolution of the exports of crude oil from Russia during the period 2000–2011 is shown in Fig. 2.95.

Russia's exports of crude oil increased 69.3 % during the period 2000–2011. In 2009, more than 80 % of Russia's crude oil exports has been shipped to the Atlantic market, primarily, to Europe; around 12 % of its export crude oil was shipped to the Pacific market, mainly, to China, while 6 % was exported to North and South America, with the majority of those exports going to the United States (5 % of total exports).

For the time being, the Atlantic market remains the principal destination for Russian crude and oil-product exports. Technologically, deliveries to that market already have reached saturation point and have stopped growing over the past few years. The demand for crude oil in Europe, which accounts for nearly 80 % of

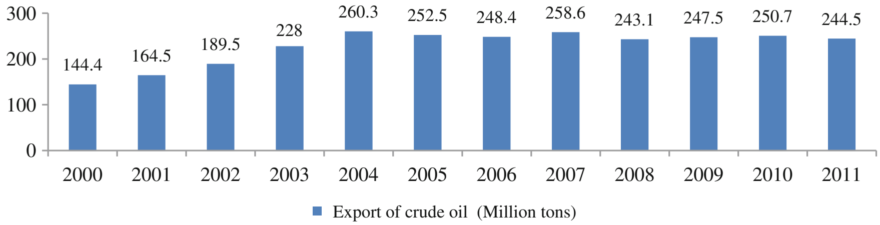

Fig. 2.95 Exports of crude oil from Russia during the period 2000–2011. *Source:* Customs Statistics and Rosstat, Harmonized System, Code 2709. *Note* 2003: Included is crude oil shipped abroad in 2003 customs clearance of which was completed in January, 2004; 2004: Bank of Russia estimate; 2010 and 2011: Included is crude oil exported to the countries, which are members of the Customs Union (Russian Federation, Belarus, and Kazakhstan)

Russia's crude oil exports, has mostly remained stagnant, while at the same time decreasing in a number of countries, primarily, Germany, Great Britain, Italy, France, the Netherlands, and Belgium. Russia faces its toughest competition from the Middle East and North African suppliers shipping to Southern European markets, and from Canadian, West African, and South American suppliers shipping to the US Atlantic Coast. Russia's prospects for its own share of the Atlantic market will mostly be linked to the continued decrease in production in the North Sea, something that should allow Russia to increase its deliveries to Northern and Western Europe, primarily through Rotterdam. Russia will also have to try and maintain its direct pipeline shipments to refineries in Poland, Germany, Belorussia, the Czech Republic, Slovakia, and Hungary, and to continue its hybrid deliveries to Russian-controlled refineries in Ukraine, Romania, Bulgaria, and Serbia.

Over the past several years, against the background of diversification of export routes and development of new oil and gas centers in Eastern Siberia and in the Far East, there has been an increase in the deliveries of crude oil and oil-products to the Asian and the Pacific market, which is today the biggest and fastest growing market for energy products in the world, combining the countries of the Asia-Pacific region and the Pacific Coast of the Americas. Crude oil production in the region is showing a trend toward reduction, while the consumption and imports from other regions have been growing at a fast pace. While Russia's main competitors on the Asian and the Pacific market are, primarily, Middle East countries, the distances over which their own shipments must travel are, on average, two to five times longer than the distances that deliveries must travel from West or East Siberia. Moreover, they involve additional transportation risks (including passing through the Gulf of Aden, the Gulf of Oman, and the Straits of Bab El-Mandeb, Hormuz, and Malacca). The main customers for Russian crude oil and oil-product exports to Asian and the Pacific destinations include China, Republic of Korea, Japan, the United States, Thailand, and Singapore. While China is likely to remain the region's most lucrative market in the coming decades, there are some good prospects for considerably expanding exports to the Republic of Korea, the USA, Philippines, Thailand, and Vietnam, and for starting shipments to Indonesia.

Finally, it is important to highlight the following: In the long-term, it will be more challenging for Russia to meet its Energy Strategy target of 10.7 million barrels per day of crude oil by 2030. Issues that could make it difficult to achieve this target include:

- Maintaining crude oil production is associated with untapped crude oil reserves in the frontier regions of East Siberia, the Far East, and the Yamal-Nenets Basin of West Siberia. Development of technical fields in these regions requires large investment in facilities and infrastructure due to the remoteness of crude oil assets from existing transportation routes. This is reflected in the higher average capital expenditure in these regions;
- Most of Russia's major new crude oil reserves are in poorer-quality reservoirs or difficult high-cost operational conditions. Russian companies have limited experience offshore and with difficult reservoirs, and may seek technical support from international companies. However, many international companies remain wary of doing business in Russia; and large-scale joint ventures have proven difficult to negotiate in the past. The current EU and USA sanctions against the Russian energy sector could make more dificult the cooperation between Western and Russian energy companies in this strategic sector.

2.24.6 Electricity Generation and Consumption

Russia is one of the top electricity generating country in the world, with more than 222 GW of installed generation capacity in 2006; in 2010, the installed capacity reached 229 GW, an increase of around 3 % respect to 2006. In 2011, electric power generation totaled approximately 996 billion kWh, and Russia consumed about 861 billion kWh; this represents 86.3 % of the total electricity generated in the country. Russia is the fourth largest electricity generator after the USA, China, and Japan, producing 5 % of the world's electricity (IEA 2009); in 2009 there were more than 700 generating power plants in Russia with a total installed capacity of more than 222 GW[37]; domestic electricity generation was 1,016 billion kWh and domestic consumption 1,003 billion kWh.[38]

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[37] According to EIA sources, in 2008 the electricity installed capacity was 224.2 million kWh. In 2011, this capacity reached 231.647 million kWh.

[38] According to EIA sources, there are eight separate regional power systems in the Russian electricity sector, seven of which are connected to an integrated power system. These systems are: Northwest, Center, South, Volga, Urals, Western Siberia, Siberia, and Far East. The Far East region is the only one not connected to an integrated power system. Federal Grid Company (FGC), which is more than 70 % owned by the Russian government, controls most of the transmission and distribution in Russia. The grid comprises almost 2 million miles of power lines, 160,600 km of which are high-voltage cables over 220 kV.

According to Federal Statistical Services of Russian Federation (FSS 2010), Russia is a net exporter of electricity (exports account for 2 % of domestic supply, and imports 0.3 % of its total needs); the composition of the installed generating capacity in Russia by type of fuel is: 68 % thermal, 11 % nuclear and 21 % hydropower. Around one third of Russian generation capacity is nuclear and hydro (16 % and 18 %, respectively) and are in State hands, while the other two thirds (66 %) are thermal and partially privatized. Of the thermal share, 69 % are gas fired, 27 % coal fired and 4 % are from other fossil fuels.

As of 2009, Russia accounted for 38.93 % of electricity generated in the Eastern and Central European region. It is expected that by 2014, Russia's share is likely to go down to 29.5 %, a decrease of 9.43 % respect to 2009. In spite of this reduction, Russia will still remain a net exporter of electricity to neighboring States.

Generation of electricity in Russia is accomplished by using different energy sources as natural gas, coal, hydropower, and nuclear energy. The country's thermal generation in 2009 was 659 billion kWh. This figure represents 51.6 % of total production in Central and Eastern Europe. In 2014, it is expected that Russia will be responsible for 49.8 % of thermal energy generated in this region, a reduction of 1.03 % respect to 2009.

The power sector in Russia includes over 440 thermal and hydropower plants. A small number of generating facilities in the Eastern part of the country are not linked to Russia's electricity-delivering network. The power-generation facilities have the ability to produce 216 billion kWh. In 2009, the system generated 984 billion kWh. In the past two decades, the Russian power sector saw significant fluctuations. Between 1992 and 1999, power generation declined by 18 %. The figures rose by the same 18 % from 2000 to 2009.[39]

Russia's factors affecting electricity consumption trends can be identified by reviewing consumption by end consumer groups. Russia's annual consumption constitutes mainly of industrial consumption (roughly a half of total consumption). The share of residential consumption increased while the share of industrial consumption decreased after 1990. However, the share of residential consumption of Russia is still lower than in the Nordic countries.

According to a Business Monitor International forecast, the increase in power generation will be close to 15 % in the coming years. At the same time, the 2.1 % rate of capacity expansion will not be matched by the 1.5 % mean yearly growth of demand. As a consequence, Russia will have surplus capacity available for exports, around 193 billion kWh, much higher than the current 135 billion kWh.

The evolution of the generation and consumption of electricity in Russia during the period 2000–2011 in included in Fig. 2.96. During that period, the generation of electricity in Russia increased from 771.95 billion kWh in 2000 to 925.90 billion kWh in 2011, an increase of 19.9 %.[40] From Fig. 2.96, it can be easily seen that the

[39] During the period 2008–2012, Russia increased its thermal generating capacities in 37.85 million kW.

[40] Russia is one of the top producers and consumers of electric power in the world.

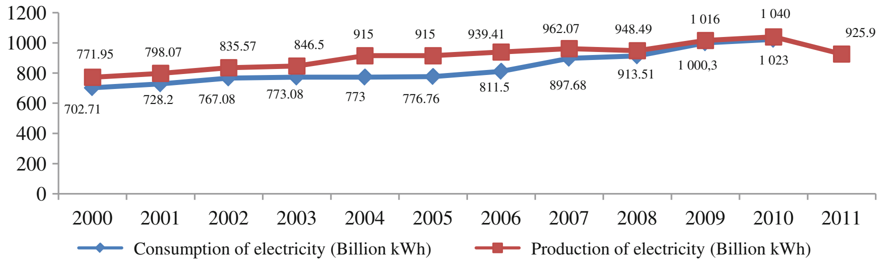

Fig. 2.96 Production and consumption of electricity in Russia during the period 2000–2011. *Source:* Index Mundi, Titi Tudorance, and World Bank

production of electricity increased systematically until 2010, with an important decrease in the period 2010–2011. The peak in the production of electricity, during the period considered, was reached in 2010.

The participation of oil in the generation of electricity of Russia is very low reaching 1.6 % in 2007 and 1.7 % in 2008. This percentage is expected to be almost the same until 2020. In 2030, it is expected that oil will not be used as fuel for the generation of electricity.

The consumption of electricity is closing the gap with the production of electricity, particularly in the past 4 years. The electricity consumption per capita in Russia in 2008 was 6,435.4 kWh. The electric power transmission and distribution losses in Russia in 2008 was 109.240 billion kWh; this represents almost 11 % of the total electricity generated in the country in that year. The evolution of the consumption of electricity in Russia during the period 2000–2011 increased 14.6 %. The electricity consumption increased during the whole period considered and the tendency is to continue increasing during the coming years.

According to APEC Energy Demand and Supply Outlook 2030 (2006), electricity demand in Russia is projected to grow at 1.9 %, requiring the government to increase the installed generation capacity up to 352 GW by 2030,[41] an increase of 66 % respect to 2009. In this projection, oil will be the major fuel for remote on-site electricity generation in isolated areas, particularly for Northern regions and the Russian Far East. However, in general, the participation of oil in the generation of electricity in the future will be much lower than today (it is expected to be 0 % in 2030, according to Fig. 2.97).

Russia exports electricity to other countries. The electricity exported from Russia to other States during the period 2000–2011 is included in Fig. 2.98. From that figure can be easily stated that the level of electricity imported is lower than the

[41] Natural gas would be the main input fuel for electricity generation with a share of 39 %, followed by nuclear (24 %), coal (20 %), and hydro (15 %). Electricity generation from renewables is expected to increase robustly at an average annual growth rate of 7.4 % for the next 28 years; despite this increase the share in electricity generation would remain relatively small at 2 % in 2030.

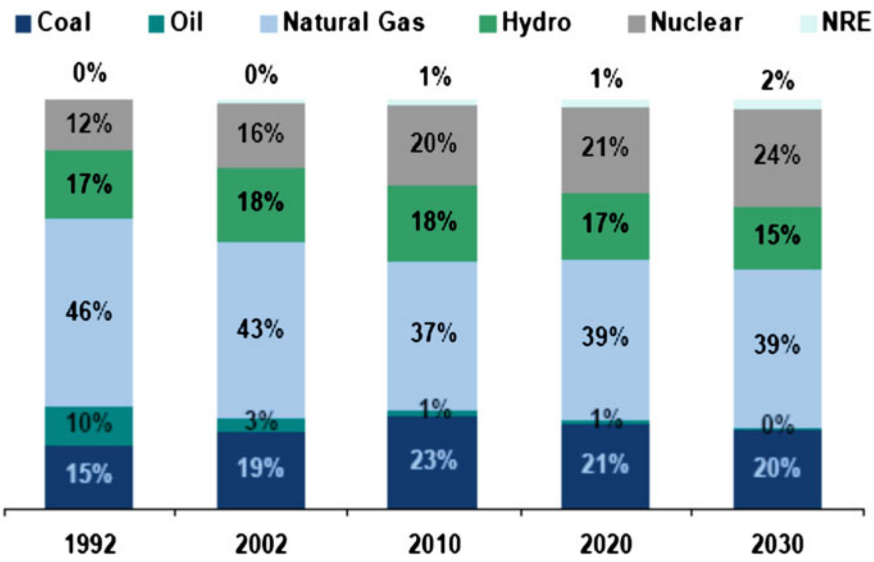

Fig. 2.97 Participation of different energy sources in Russia generation mix until 2030. *Source:* APEC (2006)

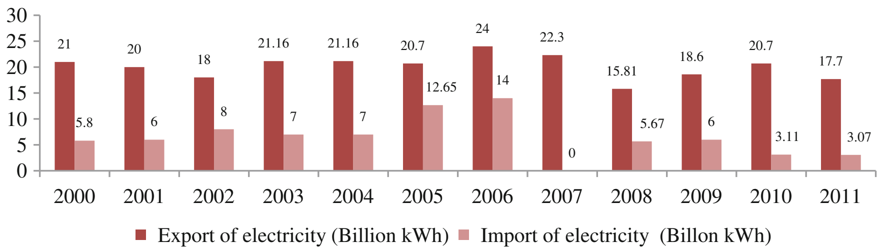

Fig. 2.98 Exports and imports of electricity from Russia during the period 2000–2011. *Source:* Index Mundi

level of exported of electricity during the whole period and it is expected that this situation will not change in the near future (Table 2.10).

Russia imports electricity from Kazakhstan (Northern regions) and Kyrgyzstan (transit) in Central Asia, and from Ukraine and Lithuania. At the same time, Russia exports to Finland/Nord Pool, Belarus, Kazakhstan (Western regions), and Georgia, Armenia, Mongolia, and China.

Finally, in order to meet the growing domestic demand and maintain its position as world energy exporter, Russia has to invest heavily in oil and gas exploration and development in new frontier areas. The total investment required the Russia's energy sector until 2030 is estimated between US$709 and US$923 billion. Of this, expansion of electricity generation capacity and transmission would require

Table 2.10 Indicators of strategic development of the electric energy industry for the period up to 2030

Indicators/directions	2008 (actual)	Phase 1	Phase 2	Phase 3
Electricity production				
The share of non-fuel energy in the electricity production structure (%)	32.5	At least 34	At least 35	At least 38
Fuel supply of thermal power plants				
The share of gas in the fuel supply structure (%)	70.3	70—71	65—66	60—62
The share of coal in the fuel supply structure (%)	26	25—26	29—30	34—36
Energy security and electricity supply reliability				
The probability of the Russian power systems deficit-free operation	0.9960	At least 0.9990	At least 0.9991	At least 0.9997
Efficiency of electric energy industry				
Coal-fired power plants performance index (%)	34	At least 35	At least 38	At least 41
Gas-fired power plants performance index (%)	38	At least 45	At least 50	At least 53
Nuclear power plants performance index (%)	32	At least 32	At least 34	At least 36
Specific fuel consumption for electricity production at thermal power plants, grams of coal equivalent/kWh (in % as compared to 2005)	333 (99)	No more than 315 (94)	No more than 300 (90)	No more than 270 (81)
Losses in power grids (percentage of electric supply to the grid)	13	No more than 12	No more than 10	No more than 8

Source: Energy Strategy of Russia for the period up to 2030

investments between US$405 and US$513 billion, respectively. In addition, between US$295 and US$401 billion will be needed for oil and natural gas exploration, production, and infrastructure development through 2030. At 2005, the IEA estimated the need for investment into Russia's generation capacity to be US $157 billion in the next 25 years with another US$200 billion needed for investment in the network.

According to government sources, due to long years of services (on average power plant's equipment is around 30 years old), around 50 % of the current number of power plants operating in the country should be replaced by new power generating plants in the next 10 years.

2.25 Spain

Although oil continued to be Spain's major source of energy, mostly in the transportation sector, it had diminished in importance significantly since 1973. Oil consumption grew steadily between 1973 and 1979, reaching 50 million tons in that last year, but by 1985 it had declined to 39 million tons; this represents a reduction of 22 %. Crude oil accounted for two-thirds of the country's primary energy requirements throughout the 1970s, but by the middle of the 1980s the figure had dropped to just over half. In 1985 alone, Spanish industry saved US$260 million by replacing oil consumption with coal and natural gas, particularly for the generation of electricity.

Spain possessed a small domestic crude oil production capability that yielded only 1.6 million tons in 1987. Despite a sizable exploration effort, only a few small fields and two medium-sized ones were discovered until today. The Casablanca oil field, discovered in 1983, yielded 90 % of Spain's domestic crude oil production in 1987, but it was not large enough to offset an overall decline in Spanish production. The fall in oil prices in the 1980s further reduced the country's exploration efforts.

The Spanish oil industry imported and refined foreign crude oil; it distributed petrochemical products within Spain and, in the mid-1980s, it exported to other countries about 10 million tons of oil products per year.

As with some other sectors of the Spanish economy, the domestic crude oil industry had been brought under State control. Distribution of petroleum products had been in the hands of the State monopoly, Compañía Arrendataria del Monopolio de Petróleos (CAMPSA) since 1927, and large portions of the shipping and refining system were State owned. To rationalize the oil industry and to make it able to withstand foreign competition, the National Institute for Hydrocarbons (INH) was established in 1981 in order to direct CAMPSA and those parts of the oil, natural gas, and petrochemical industry supervised by INH.

To prepare for Spain's entry into the EU, after which State monopolies were required to be phased out, all of INH's holdings, with the exception of the State gas company, Empresa Nacional del Gas (ENAGAS), was placed under a new holding company in the late 1980s. The company, REPSOL, which had a stock market listing, was gradually to allow a greater role for private capital in the oil industry. By 1988, REPSOL had become Western Europe's seventh largest oil company, and its management planned to continue to control about half of the Spanish market once that market was fully opened to foreign firms in 1992. EU membership rendered CAMPSA's future uncertain, for it would no longer be allowed its distribution monopoly. The Treaty of Accession that brought Spain into the EU stipulated that specific amounts of nine groups of oil products from foreign suppliers would have access to the Spanish market. In 1986, these products were to have a 5 % share of the domestic market, a share that was to increase by 20 % (of this 5 %) each year thereafter.

2.25.1 Crude Oil Reserves

Crude oil reserves in Spain in 2012 were estimated at 150 million barrels.

2.25.2 Production and Consumption of Oil

Spain has very little domestic crude oil and natural gas production and relies heavily on imports, the sources of which are well distributed amongst Africa, the Middle East, countries of the former Soviet Union, and OECD countries. The production of crude oil stood at 2,170 barrels per day in 2011. Spain is thus highly reliant on imports of both crude oil and oil refined products. All oil imports arrive by sea.

Crude oil consumption as a whole has dropped incrementally from its peak in 2007 (1.61 million barrels per day), and stood at 1.47 million barrels per day in 2010, a decrease of 6.7 %.[42] In 2011, this consumption dropped to 1.38 million barrels per day, a further decrease of 6.2 % The share of crude oil in total energy consumption as a whole is gradually declining and it is expected that this trend will continue during the coming years.

It is important to highlight that crude oil and natural gas dominate Spain's primary energy supply, with an aggregate 67 % of the total. The consumption of both sources, but mainly of natural gas, has increased dramatically in recent years (total increase has been 125 % since 1990). The production of crude oil (including lease condensate) in Spain during the period 2008–2012 is shown in Fig. 2.99.

The production of crude oil in Spain increased 11 % during the period 2008–2012, but the level of production is very small. It is expected that the production of crude oil, including lease condensate, will continue to be very small during the coming years.

During the period 2000–2012, the consumption of oil in Spain decreased 10.1 % (see Fig. 2.100). However, during the period 2000–2005, the consumption of oil increases 12.1 %. As a result of the severe economic and financial crisis Spain is suffering, the consumption of oil decreased 20 %. It is expected, due to the economic situation of Spain, a further reduction in the consumption of oil, at least during the coming years, will be registered.

[42] After growing significantly up until 2005, crude oil demand started to decline in a significantly manner and it is expected that this trend will continue during the coming years, particularly for the generation of electricity.

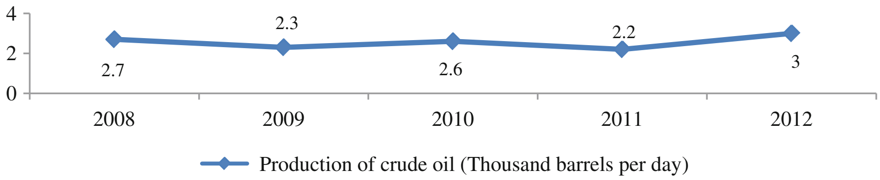

Fig. 2.99 Production of crude oil (including lease condensate) in Spain during the period 2008–2012. *Source:* EIA

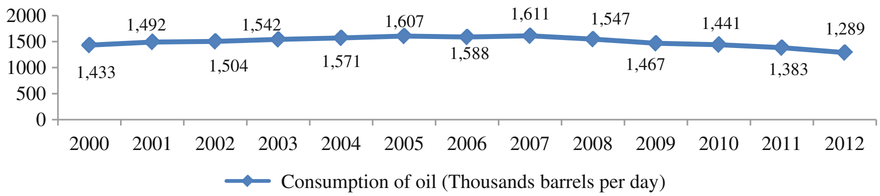

Fig. 2.100 Consumption of oil in Spain during the period 2000–2012. *Source:* Eurostat

2.25.3 Import and Export of Oil

Spain's energy balance depends strongly on energy imports. Import dependency is above the EU-27 average, but one element is important to be aware of, government regulation limits the percent of total oil and gas imports any single country may sell in Spain to ensure diversity of supply. A large percentage of imports consist of crude oil and natural gas, covering an 88 % of total imported energy. Nigeria is a major supplier of crude oil, but significant quantities of crude oil are also imported from Russia and Mexico (Fig. 2.101).

Imports of crude oil during the past 5 years decreased 12.3 %. It is expected that due to the reduction of the activities in the industrial sector as a result of the economic and financial crisis that are still affecting the country, the imports of crude oil from Spain will continue decreasing during the coming years.

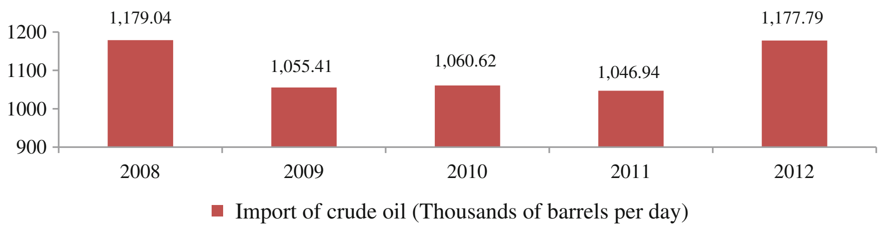

Fig. 2.101 Imports of crude oil from Spain during the period 2008–2012. *Source:* EIA

2.25.4 Electricity Generation and Consumption

Although Spain's mountainous terrain would appear to be well suited to hydroelectric power production, the scarcity of water limited such potential and was the principal reason for Spain's heavy dependence on thermal power. In 1986, only 27.2 % of the country's electricity came from hydroelectric plants, while 50.6 % came from conventional thermal power plants, and 22.2 % came from nuclear power plants. The most important fuel for the production of electricity was coal, which generated about 40 % of the total. In 1987, the production of electricity amounted to 132 million kWh, about six times the amount produced in 1960, and twice the production level of 1970. The total installed capacity of the electrical system was about 106.295 million kW, an amount large enough to meet the country's needs and to allow some exports. In the second half of the 1980s, the growth of the demand for electrical power was less than anticipated, and Spain had a supply adequate to last until the mid-1990s. The Spanish level of per capita electrical power consumption was among the lowest in Western Europe, surpassing only those of Greece and Portugal.

Before the 1980s, Spain's electricity sector was fragmented and dispersed. Later, the development of the economy and the increase demand of electricity generation introduced the concept of power supply as a public service and to consider the electricity sector as a natural monopoly, whether public or private property. However, from the 1980s, several economic, technical, and political elements highlighted the inefficiencies of the monopoly model adopted and prompted the beginning of an energy reform process, with the ultimate aim of introducing competition in the electricity sector. The introduction of competition involves the restructuring of the electricity sector, which must pass from the monopoly model to a free market model (Bilbao et al. 2011).

Liberalization of such an industry involves the creation of a combination of competitive energy and retail markets, and regulated transmission and distribution activities. Successful liberalization requires well organized energy, associated ancillary services and transmission capacity markets to achieve competition with physical balancing and appropriate regulation of monopoly power (Jamasb and Pollitt 2011).

Liberalization requires a suitable market structure within which effective competition can be fostered. Generally, this involves restructuring the sector by unbundling vertically integrated activities and reducing their horizontal concentration. The aim of vertical unbundling is to separate potentially competitive generation and retail supply from the natural monopoly activities of transmission and distribution networks.

The generation and consumption of electricity in Spain during the period 2000–2011 is shown in Fig. 2.102.

The generation of electricity in Spain during the period 2000–2011 increased 33.8 %. However, the production of electricity increased significantly from 2000 to 2008 and then started to decrease until 2011 (4.3 %). The reduction of electricity in

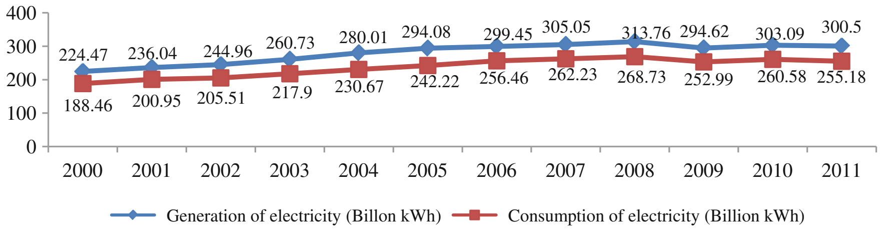

Fig. 2.102 The generation and consumption of electricity in Spain during the period 2000–2011. *Source:* Eurostat and Index Mundi

the past 3 years is due to the slowdown in the industry sector as a result of the severe economic and financial crisis still affecting the country. The total electricity generated in 2008 using oil as fuel represented only 5.8 % of the total electricity generated in that year, and it is expected that this proportion could be reduced even further during the coming years.

Electricity consumption grew rapidly until 2008 (4.7 % year on average between 2000 and 2008). That growth rate stopped in 2009 for the first time since 1985; consumption decreased in 2009 by 5.9 % respect to 2008. This decrease in energy consumption was linked to the effects of the severe economic crisis, since industrial consumption dropped 8 %.

2.25.5 Export and Import of Electricity

During the period 2000–2010, Spain exported electricity to other countries and also imported electricity from other countries as well. The amount of electricity exported and imported from Spain is shown in Fig. 2.103.

During the period 2000–2008, the exports of electricity from Spain grew 141.7 %. Among countries that receive electricity from Spain are France, Portugal, Andorra, and Morocco. However, after 2008, the exports of electricity started to decline and due to the severe economic and financial crisis affecting the country, it is expected that this trend will continue without change at least during the coming years.

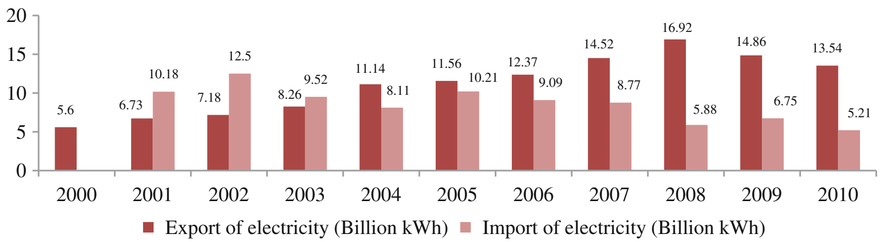

Fig. 2.103 Exports and imports of electricity by Spain during the period 2000–2010. *Source:* Eurostat

During the period 2001–2010, Spain reduced its imports of electricity in almost 51 %. Spain imports electricity from France. The electric power transmission and distribution losses in 2011 in Spain reached 26.793 billion kWh, an increase of 3.8 % respect to 2008.

2.26 Slovenia

Despite the fact that Slovenia is completely dependent on the import of liquid and natural gas fuels (48 % in 2010), the country's energy dependency was 4.9 % point below the EU-27 average and the reason for classifying Slovenia among the EU Member States with energy medium dependency. In 2012, according to Slovenia information, the energy dependency of the country reached 51 %, which is 3 % more than in 2011.

The use of diesel fuel doubled in the past 10 years, which the Statistical Office of the Republic of Slovenia ascribes to an expansion of passenger transport and even more so of cargo road transport.

Slovenia covers 81 % of its needs for hard fuels through domestic production and almost of its needs for energy from renewable sources.

According to Fig. 2.104, petroleum products and solid fuels covered 55.8 % of the total primary energy needs in Slovenia in 2010, followed by nuclear energy by 19.8 %, natural gas by 13.7 %, renewable with 6.5 % and hydro with 4.2 %.

In 2010, in Slovenia the final energy consumption increased 3 % compared to 2009. The increase of total final energy consumption was mainly influenced by higher consumption of renewable energy sources by 10 %, heat by 7 %, and electricity and natural gas by 6 %. It is the second consecutive year that the consumption of liquid fuels decreased, namely by 2 %. It is important to highlight that the consumption of transport diesel remained about the same level as reported

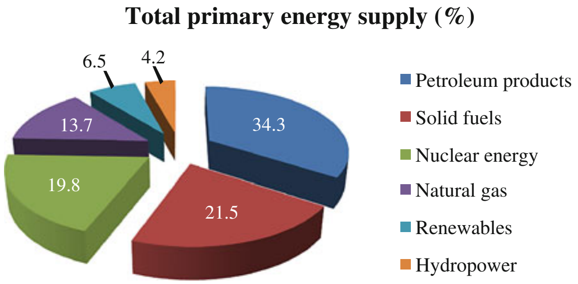

Fig. 2.104 Total primary energy supply in Slovenia in 2010. *Source:* Statistical Office of the Republic of Slovenia, 2012

in 2009, but the consumption of motor gasoline decreased by 5 %. Undoubtedly, the decrease in the consumption of motor gasoline and in other liquid fuels is the result of the decrease in the industrial and other economic sectors due to the severe economic and financial crisis affecting the whole EU, and particularly the country in the past 5 years.

2.26.1 Crude Oil Reserves

Slovenia's small crude oil reserves have all but run out and it must now import nearly all its crude oil that is consumed.[43]

2.26.2 Consumption of Oil

In 2010, Slovenia consumed an estimated 63,000 barrels per day. Crude oil consumption is expected to grow in the coming decade, with some forecasts predicting demand rise to 77,000 barrels per day in 2016, an increase of 22.2 % respect to 2010, before reaching up to 89,000 barrels per day by 2020, a further increase of 15.5 % respect to 2016 and 90,000 barrels per day by 2021, an increase of 1.1 % respect to 2010. It is important to highlight that all of new increases in the consumption of crude oil should be met entirely by imports. The consumption of oil in Slovenia during the period 2000–2012 is shown in Fig. 2.105.

The consumption of oil by Slovenia during the period 2000–2012 increased 10 %. However, the consumption of oil dropped in 2002, 2007, 2009, and 2010 to respect the year before. At the same time, the increase in the consumption of oil during the past 3 years has been very small (0.07 %). It is expected that the consumption of oil will continue the same general current pattern during the coming years.

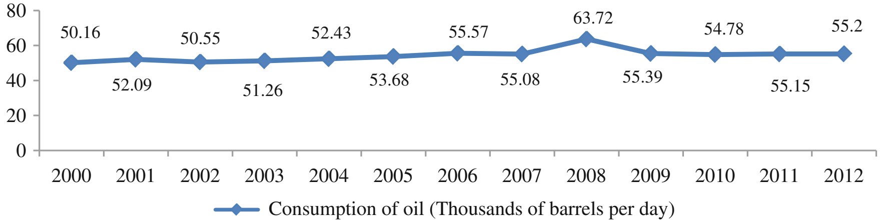

Fig. 2.105 Consumption of oil in Slovenia during the period 2000–2012. *Source:* EIA

[43] Most crude oil imports come from Russia.

2.26.3 Electricity Generation and Consumption

In 1999, Slovenia adopted the new Energy Act, which followed the Electricity Directive (96/92/EC). The Energy Act envisaged the gradual and progressive opening up of the market, which should lead to increase competitiveness in the electricity sector. The electricity market reforms involved the introduction of competition in electricity generation and supply activities, and the design of an organized power market to facilitate electricity trading. On the other hand, transmission and distribution activities, due to their natural monopoly character, remain regulated. Starting at the beginning of 2003, foreign companies were allowed to participate in the market while eligible customers were entitled to import electricity under commercial agreements.

In order to comply with the new Electricity Directive (2003/54/EC), Slovenia adopted the amended Energy Act in 2004. On 1 July 2004 all customers, except households, became eligible customers. This resulted in 75 % opening of the electricity market. Finally, the Slovenian electricity market was fully opened on 1 July 2007, as were other markets in the EU. Although the electricity market has been fully liberalized, the objectives of the reforms have not been fully achieved. Concentration on the generation and retail markets remains relatively high. To some extent, this is the result of the small size of the electricity market in Slovenia, the lack of generation and interconnection capacities with neighboring countries, and the ownership structure of electricity companies. In addition, it seems that it has been more important to the government to protect domestic generators than to enhance competition in the power market (Hrovatin et al. 2007).

With the opening of the electricity market in 2007, electrical energy became a marketable commodity for industrial consumers in Slovenia. Tariff customers are provided with electricity, in accordance with the tariff system by distribution companies in the framework of the public service in the supply of electricity to tariff customers. Electricity users are able to negotiate the price of electricity to several distributors. Different rates of the electricity network fee are applied, depending on the voltage level, season (high-middle-low), and overall consumption of power.

In 2010, the installed electric capacity was 3.4 GW distributed in the following manner: Thermal, 42.2 %; nuclear, 21.5 %; and hydro, 34.5 %. In 2009, electricity consumption per capita was 5,600 kWh, which is close to the EU average, after having been slightly higher since 2001. Since 1990, electricity has covered about 20 % of final energy consumption. Power consumption increased regularly between 1990 and 2008 (1.8 % per year), but fell by 11 % in 2009, since industrial demand for electricity fell strongly as a result of the economic and financial crisis affecting the whole EU, including Slovenia. Industry accounts for 50 % of power consumption in Slovenia, but the share of that sector is declining (65 % in 1990) due to the sharp increase in the electricity consumption of the service sector (from 9 % in 1990 to 24 % in 2009, an increase of 166.6 %).

In 2011, electricity production was 16.060 billion kWh and electricity consumption was 12.602 billion kWh. Electricity production by source was the following:

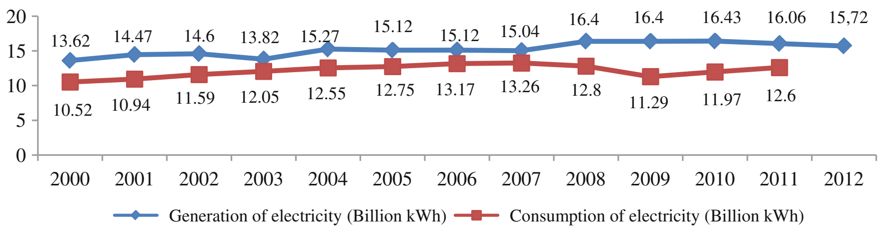

Fig. 2.106 Generation and consumption of electricity in Slovenia during the period 2000–2012. *Source:* Eurostat and government sources

Hydro, 23.7 %, a decrease of 10.8 % respect to 2010; thermal, 34.5 %, a decrease of 7.7 % respect to 2010; and nuclear power, 41.8 %, an increase of 20.3 % respect to 2010. In 2012, the production of electricity was 15.715 billion kWh; this represents an increase of 10.1 %. Most electricity was produced in thermal power plants (38 %, an increase of 3.5 % respect to 2011), followed by production in nuclear power plant (35 %, a decrease of 6.8 % respect to 2011), in hydropower plants (26 %, an increase 2.3 % respect to 2011) and in solar power plants 1 %.

Current investments are allocated to the construction of the new 600 MW block of Šoštanj thermal power plant, which is expected to be finished by 2014.

The generation and consumption of electricity in Slovenia during the period 2000–2012 are shown in Fig. 2.106.

The generation of electricity in Slovenia during the period 2000–2012 increased 15.4 %. However, during the period 2008–2010, the generation of electricity remained stable at 16.4 billion kWh, but started to decline in 2011. In 2009, the generation of electricity using oil as fuel was 28 million kWh, representing only 0.18 % of the total electricity generated by the country in that year, according to IEA sources. It is expected that in the coming years oil will be excluded from the Slovenia generation of electricity energy mix.

On the other hand, during the period 2000–2011, the consumption of electricity in Slovenia increased 19.8 %. From Fig. 2.106, it is easy to conclude that the consumption of electricity increased systematically since 2000–2007, and started to decline in 2008 as a result of the economic and financial crisis affecting the whole EU, including the country itself. After 2009, the consumption of electricity started to increase again (11.6 %). The government expect an increase in the consumption of electricity during the coming years.

In the framework of its National Energy Efficiency Action Plan, Slovenia has set an energy savings target of 4.3 billion kWh in 2016. Financial incentives totalizing €15 million will be allocated by the government to promote efficient electricity use, to replace low-efficiency electric motors and air-compressors, and to install frequency converters, energy-saving pumps, and ventilators. The largest savings are expected to be achieved in the household sector (27 % of total savings), and the rest will be distributed among the other sectors: 19 % in services, 20 % in industry and 17 % in transport. A further 17 % are expected to be achieved through cross-sectorial measures. These measures are focused on the efficient use of fossil fuels,

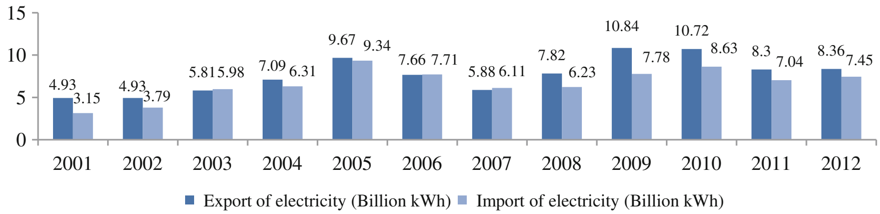

Fig. 2.107 Exports and imports of electricity from Slovenia during the period 2001–2012. *Source:* Eurostat and government sources

electricity and district heating and, to a lesser extent, on the promotion of renewable and cogeneration systems. However, it is expected that the consumption of electricity will increase again in the coming years, but at a lower rate.

The consumption of electricity per capita in 2008 was 6,920 kWh, according to World Bank sources, and the electric power transmission and distribution losses in 2011 was 0.823 billion kWh based on EIA source information. The electricity losses are very small compared to other EU countries.

2.26.4 Export and Import of Electricity

The evolution of the imports and exports of electricity from Slovenia during the period 2001–2012 is shown in Fig. 2.107.

The exports of electricity in Slovenia during the period 2001–2012 increased significantly (69.6 %) and the country will continue exporting electricity to other EU countries during the coming years. The imports of electricity increased during the same period in 137 % and it is expected that Slovenia will continue importing electricity during the coming years.

2.27 Sweden

In September 2005, former Prime Minister Göran Persson made the following announcement: "Sweden will seek to end its dependency on fossil fuels by 2020."[44] To implement this decision a Commission on Oil Independence was established in December 2005, chaired by the Prime Minister, with the aim of drawing up a comprehensive program to reduce Sweden's dependence on oil. The Commission issued on June 2006 a report entitled "Making Sweden an Oil-Free Society." The key proposals included in the report were the following:

[44] In 1970, oil accounted for over 75 % of Swedish energy supply; by 2009, this figure was just 32 %, a decrease of 43 %. The main reason for this significantly decrease is the declining in the use of oil for residential heating.

- Through more efficient use of fuel and new fuels, consumption of oil in road transport shall be reduced between 40 % and 50 %;
- In principle, no oil shall be used for heating residential and commercial buildings;
- Industry shall reduce its consumption of oil between 25 % and 40 %.

Energy consumption within industry in Sweden is dominated by a limited number of sectors. The pulp and paper industry is the sector that uses by far the most energy. They account for 45 % of the energy used within industry, and the steel industry—which is another energy-intensive sector—accounts for 18 %. Together, these sectors are responsible for just under two-thirds of the total energy used within industry during 2011. Biofuel and electricity are the predominant energy bearers within the industry and accounted for 31 % and 32 % respectively of the total amount of energy used within industry. The use of electricity increased while at the same time the use of biofuels decreased somewhat in 2011.

2.27.1 Crude Oil Reserves

According to the government and the EIA sources, there are no crude oil reserves reported in the country in 2013.

2.27.2 Production and Consumption of Oil

Sweden does not produce crude oil. The consumption of oil in Sweden during the period 2001–2012 is shown in Fig. 2.108.

The consumption of oil in Sweden during the period 2001–2004 increased 10.2 %. After that year, the consumption of oil dropped significantly and reached 310,800 barrels per day in 2012; this represents a significant reduction of 14.3 %. It is expected that the consumption of oil in Sweden will continue to decrease, particularly for the generation of electricity, during the coming years as a result of the implementation of different measures adopted by the government in order to increase the participation of renewables in the country's energy mix.

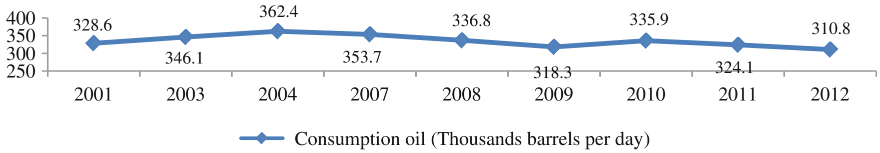

Fig. 2.108 Consumption of oil in Sweden during the period 2001–2012. *Source:* Index Mundi and EIA

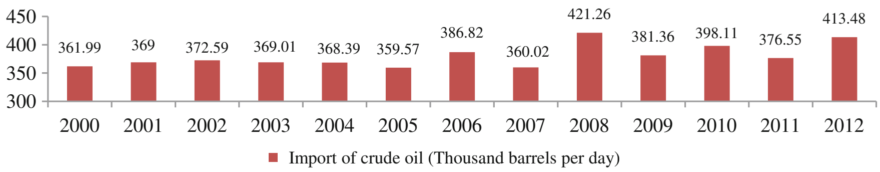

Fig. 2.109 Imports of crude oil, including lease condensate, from Sweden during the period 2000–2012. *Source:* Index Mundi and EIA

2.27.3 Import of Oil

Sweden imports crude oil from Denmark, Norway, UK, Russia, Venezuela, and from other OPEC and Middle East countries. The total amount of crude oil, including lease condensate, imported from Sweden during the period 2000–2012 is shown in Fig. 2.109.

The imports of crude from Sweden increased 14.2 % during the period 2000–2012. It is expected that the imports of crude oil from Sweden continues this trend, at least during the coming years. Sweden does not exported crude oil to other countries during the past 3 years, except 600 barrels per day exported in 2007. In 2012, the exports of oil refined products to other countries reached 278,669 barrels per day. More than 200,000 barrels per day, as average, of oil refined products were exported from Sweden to other countries during the period 2000–2012.

2.27.4 Electricity Generation and Consumption

Use of electricity has increased in Sweden over several decades and is, per capita, remarkably high compared with other industrial countries in the developed world. Sweden consumes a substantial amount of electricity per capita (16,000 kWh per person per year). Only a few countries in the world have higher electricity consumption than Sweden. It is uncertain how consumption of electricity will develop in Sweden in the future when historically low Swedish electricity prices are leveled out to the European level and if the country close all of their nuclear power reactors.

Very little electricity is produced in Sweden using oil or other fossil fuels and, for this reason, the dependence on oil for power generation has gradually decreased. It is expected that this trend will continue during the coming years.

In order to reduce further the consumption of electricity during the coming years, the government and industry should cooperate to achieve the following:

- More efficient use of electricity in industry. It is assessed that non-energy-intensive industry can, in many cases, improve electricity efficiency by 40 % and residential and commercial buildings by 20 %;
- Increased production of domestic renewable electricity;
- Reduced consumption of electricity for heating buildings.

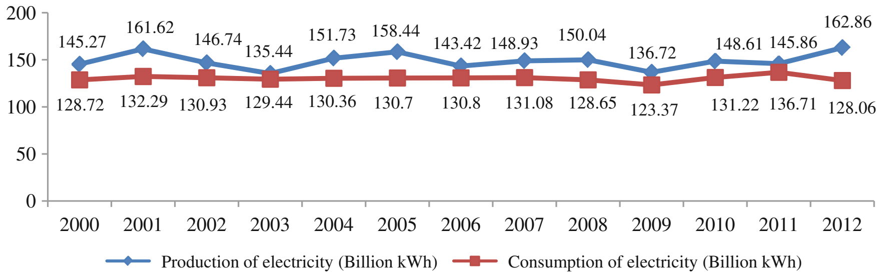

Fig. 2.110 Production and consumption of electricity in Sweden during the period 2000–2012. *Source:* Eurostat and EIA (2011 and 2012)

According to government sources, oil-fired power plants generated 1.559 billion kWh in 2009, which is 0.07 % of the total electricity generated in the country in that year (133.524 billion kWh); this represents a decrease of 360 billion kWh (24 %) respect to 2008 (1.199 billion kWh). The distribution losses in 2009 were 10.7 billion kWh, which is 15 % higher than the distribution losses reached in 2008 (9.3 billion kWh). In 2011, the distribution losses reached 10.569 billion kWh, which is 13.6 % higher than the level reached in 2009.

The production and consumption of electricity in Sweden during the period 2000–2012 is shown in Fig. 2.110.

During the period 2000–2012, the generation of electricity in Sweden increased 12.1 %. The production of electricity fluctuated during the whole period moving up 1 or 2 years and moving down 1 of 2 years after. On the other hand, the consumption of electricity during the same period, decreased only 0.2 %. It is important to highlight that after 2007 the consumption of electricity dropped significantly as a result of the impact of the economic and financial crisis that affected the country during 2008 and 2009. After 2009, the consumption of electricity increased again by 6.3 %, but decreased 6.4 % during the period 2011 and 2012.

2.27.5 *Import and Export of Electricity*

The imports and exports of electricity from Sweden during the period 2001–2012 is shown in Fig. 2.111. During that period, the exports of electricity from Sweden increased 69.4 %. It is expected that the exports of electricity from Sweden will continue in the future. In the same period, the imports of electricity increased 4.6 %. It is expected that Sweden will continue importing electricity during the coming years, particularly after the possible closure of all of their nuclear power plants currently in operation.

Finally, it is important to highlight the following: Sweden could, as a result of its energy policy and the political decision to a possible shut down of all nuclear power reactors in the coming years, end up in a difficult situation with respect to electricity generation. As no efficient, economically or politically feasible or environmentally

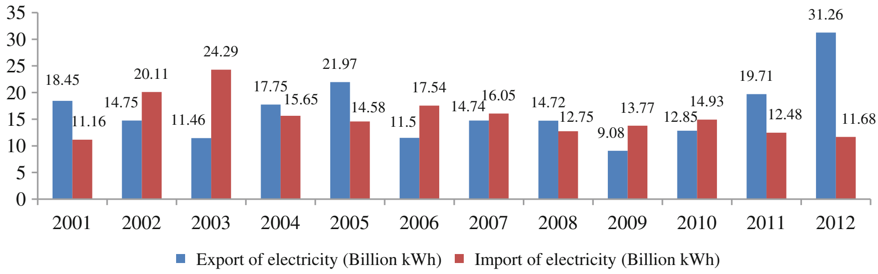

Fig. 2.111 Exports and imports of electricity from Sweden during the period 2000–2012. *Source:* Eurostat

sustainable alternative energy source has emerged, the possible closing down of all nuclear power reactors and the abstention from expanding hydropower could leave Sweden with the only option, at least for the near future, of importing energy. The import option is problematic as the imported energy is often produced in environmentally unsustainable ways, which are not in line with political priorities. Sweden's energy imports of Russian energy can be characterized as highly sensitive and highly dependent, especially concerning crude oil something that should be in the mind of the Swedish politicians when discussing energy options in the future.

2.28 The Netherlands

The first natural crude oil production in the Netherlands was carried out in 1923, near Corle, close to the German border, when 1.5 barrels of crude oil were recovered from Zechstein anhydrites and Carboniferous sandstones (Knaap and Coenen 1987). The second indication of crude oil was found in 1938, during an exhibition in The Hague, where the Bataafsche Petroleum Maatschappij, drilled a demonstration well. At a depth of 460 m, the drillers unexpectedly encountered oil stains.

According to Jager and Geluck (2007), the first commercial crude oil was found 5 years later, in 1943, when the Schoonebeek field was discovered in Lower Cretaceous sandstones at a depth of 800 m in the South-East of the province of Drenthe. With an initial in-place volume of 1 billion barrels, this is the largest onshore oil field of Western Europe. However, the field became uneconomic when 25 % of the viscous oil (25° API) had been produced, and for that reason it was closed since 1996.[45]

[45] Production at Schoonebeek was stopped in 1996, having produced only a quarter of the fields estimated reserves, as the crude oil stream was considered too viscous for production to be economically viable. Enhanced crude oil recovery techniques such as steam injection and horizontal drilling have reversed this, and in January 2011 the field was officially reopened for production. Production from the field is expected to average some 14,000 barrels per day over the coming 25 years, with all amounts to be exported by rail to the refinery in Lingen, Germany.

After World War II, exploration resumed with further oil finds in the West Netherlands Basin (e.g., the Rijswijk, Ijsselmonde, Wassenaar, Ridderkerk, and Rotterdam fields). In the early 1960s, the first careful steps into the offshore were done with the near-coastal well Kijkduin Zee-1. The first crude oil was discovered in 1970 in block F18.

2.28.1 *Energy Policy and Energy Efficiency*

According to government sources, there are three main objectives in the Dutch energy policy. The first objective is that energy supply must be sustainable, reliable, and affordable. The second objective is to cut CO_2 emissions between 80 % and 95 % by 2050 (compared with 1990). The third objective is to increase the use of renewable energy in the energy mix of the country. This is a vital part of the plan, but at the moment it is still relatively expensive. The Dutch government is therefore pursuing an innovation policy to drive down the cost of renewable energy, and encourage large-scale application of renewable in the long term. In addition to this long-term goal, the Netherlands has set the following short-term goals:

- A reduction of 20 % in CO_2 emissions by 2020 (compared with 1990);
- An increase of 14 % in the use of renewable energy sources by 2020 (as a percentage of the overall energy requirement);
- Energy saving of 20 % by 2020.

While the Netherlands aims for sustainable energy management, it is important that energy supply remains as reliable and as inexpensive as possible. The government has, therefore, opted for a balanced, best value-for-money mix of green and gray energy from domestic and foreign sources. Nuclear energy is a necessary part of the energy mix. Nuclear energy also reduces the dependence of the country on other fossil fuel sources, and does not cause CO_2 emissions. However, the nuclear accident at the Fukushima nuclear power plant in Japan in March 2011 could force the government to exclude the use of nuclear energy for electricity production in the future following other EU countries such as Germany, Switzerland, Italy, among others. The government is also promoting energy saving through fiscal measures, stricter energy requirements for buildings and agreements with the private sector, as well as other measures already approved. By 2020, for example, all new buildings must be energy neutral and the houses should produce (almost) as much energy as they consume.

Finally, it is important to highlight that improving energy efficiency is one of the most cost-effective means of becoming less dependent on fossil fuels. Efficient energy use improves the competitiveness of business and leads to lower energy costs for consumers. All scenarios for the move to a low-carbon economy show that saving energy can make a major contribution to reducing greenhouse gases. The government has not set an overall target for energy efficiency, but will make efforts in the coming years to improve efficiency. In the first place, the government is pursuing a generic energy conservation policy. Energy taxes and duties and the emissions trading system offer price incentives to discourage energy consumption. There is also the energy investment allowance (EIA), a generous tax break, which, among other things stimulates investments in energy-efficient assets. The EIA budget for the period 2011 to 2013 inclusive is €151 million per annum. This will generate annual investments of around €1.4 billion. After 2013 the budget will rise further to €161 million per year (Netherland Energy Report 2011).

2.28.2 Crude Oil Reserves

The crude oil reserves of the country are estimated at 287 million barrels in 2012, around 20 million barrels less than in 2011, according to EIA sources. In 2013, the crude oil reserves were estimated at 244 million barrels; this represents a decrease of 15 % respect to 2012.

2.28.3 Production and Consumption of Oil

Oil demand in the Netherlands was around 1 million barrels per day in 2010, with an import dependency of just over 96 %. Domestic crude oil and lease condensate production declined in the Netherlands until 2006, but this tends changed after that year. At the same time, the Netherlands plays a key role as a major crude oil-refining center in Europe, with an extensive supply network of ports, storage facilities, and pipeline connections playing a critical role for crude oil and other oil products supplies to the continent. Likewise for natural gas, the country plays a regional role for supply security.

In the future, the Netherlands will be more dependent for its energy supplies on imports from countries outside the EU. Russia, China, Brazil, and the USA are big players in the energy market. The reason for this dependency is the following: The shore and offshore production of crude oil is projected to continually decline during the coming decades. Total indigenous production in the Netherlands is forecasted to rise to just over 35,000 barrels per day in 2015 and then decline steadily thereafter. Beyond 2035, only a small amount of natural gas liquids production is expected to continue. Import dependency, which equated to just over 96 % in 2010 will, therefore, decline slightly in the period to 2015. For this reason, the government will use energy diplomacy to intensify relations with these countries in order to ensure security of supply of different types of energy sources. The same applies to cooperation with countries around the Arabian Gulf and the Caspian Sea. Active energy diplomacy improves the security of supply and promotes international trade. Dutch businesses can also benefit from these diplomatic initiatives, for example in obtaining access to foreign markets. According to Fig. 2.112, the production of crude oil and lease condensate onshore in the Netherlands during the

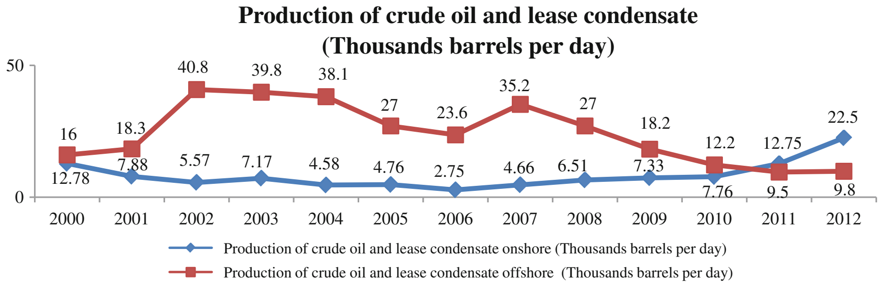

Fig. 2.112 Production of crude oil and lease condensate in the Netherlands (onshore and offshore) during the period 2000–2012. *Source:* EIA

period 2000–2012 increased 76 %. In the case of the production of crude oil and lease condensate offshore the decrease was of 38.8 %. In the mentioned figure, two clear periods in the production of crude oil can be identified. The first period is from 2000 to 2006 where the production of crude oil decrease and the second from 2007 to 2012 where the production increase significantly. In the case of production offshore, the whole period can be divided in three parts. The first part, from 2000 to 2002, the production increased 155 %. The second period from 2002 to 2006, the production decreased 42.2 %. The third period, from 2007 to 2012, the production decreased 72.2.%.

The consumption of oil in the Netherlands during the period 2000–2012 is shown in Fig. 2.113.

According to IEA sources, oil demand in the Netherlands was just over 1 million barrels per day after 2007. Total oil consumption has grown at an annual average rate of 1.7 % since 2000. The industry and transformation sectors, which account for over half of all oil consumed in the Netherlands, have been the primary sectors leading oil demand growth. Oil consumption in these sectors has grown by an average of over 5 % per year since 2000. Rising oil consumption has been primarily in the form of naphtha used by the petrochemical industry in these sectors. Demand for naphtha grew at an annual average rate of 9.5 % from 2000 to 2011. Over the

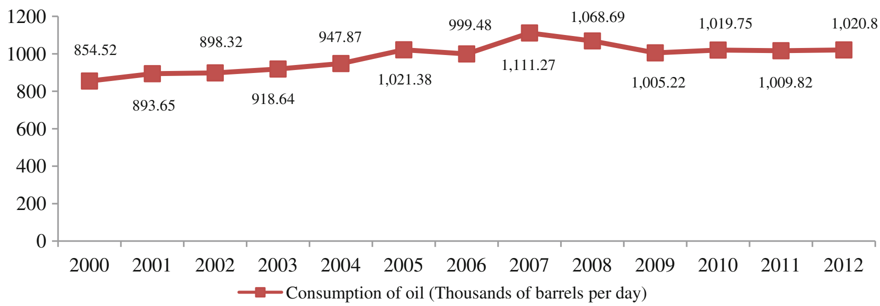

Fig. 2.113 Consumption of oil in the Netherlands during the period 2000–2012. *Source:* EIA

same period, demand for diesel grew by an average of 1.8 % per year. Residual fuel oil was the second largest component of the oil products going to the Dutch market; however, the vast majority of this, 98 %, goes to international marine bunkers, fuelling international sea-going ships.

Total oil demand is expected to continue to grow in the coming years at an annual average rate of just under 1 %. This rate would infer oil demand reaching 1.1 million barrels per day by 2020. The industry sector, which accounted for just over 40 % of oil demand in 2010 and which includes the petrochemical industry, will continue to be the driving force behind oil demand growth. The transport sector, which accounted for 40 % of 2010 demand, is expected to decline due to improved fuel economies and alternative fuel uses such as electricity and bio-fuels.

2.28.4 Import and Export of Oil

During the period 2001–2011, the imports of crude oil by the Netherlands increased from 54,253,000 tons in 2001 to 60,000,000 tons in 2011; this represents an increase of 10.6 %. However, in the long-term, the imports of crude oil by the Netherlands will increase in a systematic manner in order to satisfy a foreseeable increase demand. In 2011, total imports (not including transit volumes) of crude oil and NGLs were nearly 60 million tons or an average of 1.27 million barrels per day. Roughly a quarter of these imports were from the North Sea, a third from Russia and another third from OPEC member countries. Total output of finished oil products from domestic refining was 57.4 million tons, or an average of 1.23 million barrels per day in 2011. The Netherlands also imported 1.8 million barrels per day of oil products in 2011, compared to just over 2 million barrels per day of oil product exports. Net exports of gasoline (109,000 barrels per day in 2011) were primarily to North America while net exports of middle distillates (337,000 barrels per day) were primarily to Germany, Belgium, and France. At the same time, the Netherlands was a net importer of fuel oil, naphtha, and other oil products for the petrochemical sector (207,000 barrels per day in 2011), mostly from Russia (Fig. 2.114).

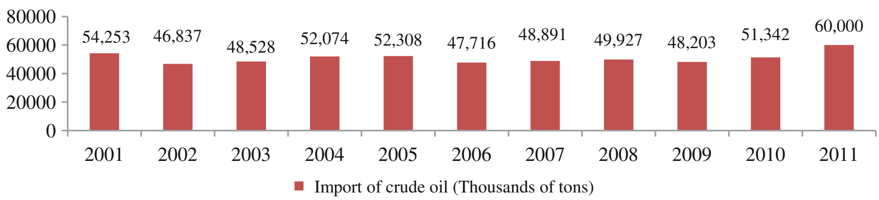

Fig. 2.114 Imports of oil by the Netherlands during the period 2001–2011. *Source:* Eurostat (Data for 2011 is provisional)

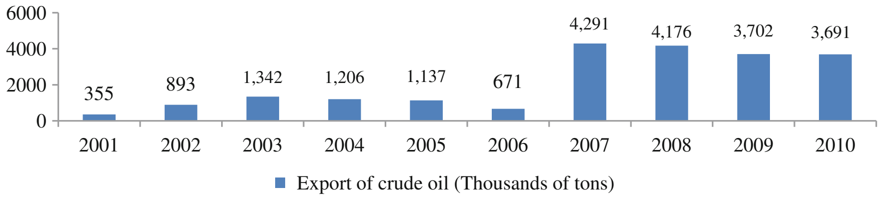

Fig. 2.115 Exports of crude oil from the Netherlands during the period 2001–2010. *Source:* Eurostat

According to Fig. 2.115, the exports of crude oil from the Netherlands during the period 2001–2010 increased 10.3 folds.

With total crude oil refinery output in the country (1.25 million barrels per day) greater than domestic demand, the Netherlands is a net exporter of refined oil products. At the same time, large volumes of crude and oil products enter the country, only to be exported to neighboring countries, as regional suppliers take advantage of available port and storage infrastructure. Thus, the Netherlands is a key link in European oil supply flows, with volumes of oil transiting totaling over four times larger than Dutch oil demand.

2.28.5 Electricity Generation and Consumption

Over the past several years, the Netherlands has become increasingly dependent on energy imports when it comes to electricity requirements. It is important to highlight that a substantial share of the electricity generating power plants in the Netherlands is nearing the end of their technical lifespan. A significant number of these power plants can be extended with substantial investments, but the rest will have to be closed within the foreseeable future. To secure electricity supplies in the future new power plants will have to be built in the country. Moreover, the building of new power plants must commence as soon as possible, if problems around electricity supplies are to be avoided. It is important to know that planning and construction of a new power plant take between 5 and 6 years and, for this reason, a decision to build new power plants should be adopted as soon as possible.[46] The generation and consumption of electricity in the Netherlands during the period 2000–2012 is shown in Fig. 2.116.

During the period 2000–2012, the generation of electricity in the Netherlands increased 8.6 %, but in the past 3 years decreased 17.6 %. It is expected that the generation of electricity will increase during the coming years, with the aim of satisfying the foreseeable increase in the electricity consumption in the country. According to the same figure, the consumption of electricity in the Netherlands during the period 2000–2011 increased 9.8 % and it is close to the level of

[46] The policy to this end is contained in the Dutch government's Energy Report 2005.

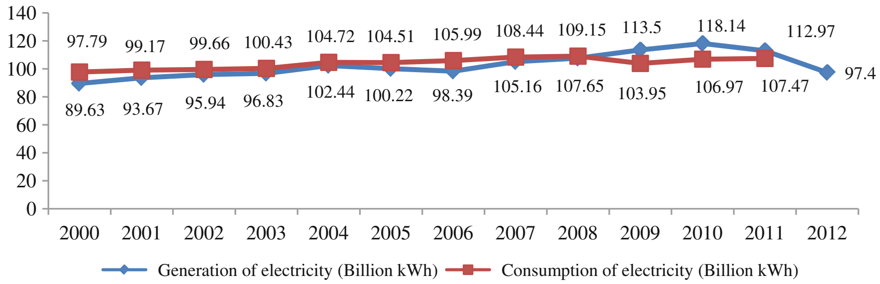

Fig. 2.116 Generation and consumption of electricity in the Netherlands during the period 2000–2012. *Source:* Eurostat and EIA (2012)

generation of electricity.[47] The economic and financial crisis affecting the country provoked the reduction in the consumption of electricity in 4.8 % from 2008 to 2009, but in 2010 and 2011 the consumption increased once again to 106.97 billion kWh and to 107.47 billion kWh, respectively.

2.28.6 Import and Export of Electricity

During the period 2001–2012, the imports of electricity from the Netherlands increased 49.6 %. Electricity imports in 2010 account for 15 % of the total electricity consumed by the country in that year, but could be more than 20 % during the coming years. According to projections by the IEA and the OECD, electricity demand in the Netherlands will grow between 1 % and 2 % per annum up to the year 2020. Strong dependency on imports can endanger secure deliveries in times of shortages.

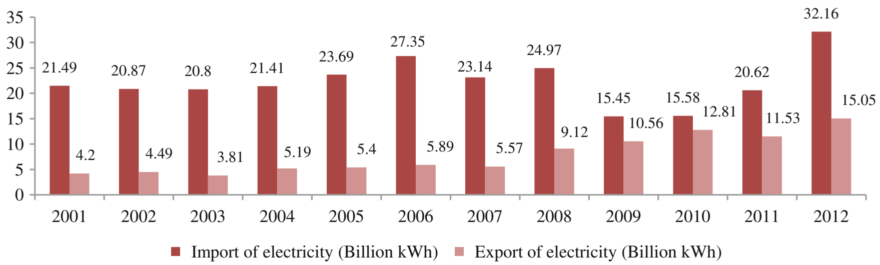

Fig. 2.117 Imports and exports of electricity from the Netherlands during the period 2001–2012. *Source:* Eurostat

[47] Between 2000 and 2008, the consumption of electricity was higher that the generation of electricity forcing the government to import electricity to satisfy the demand. After 2008, this situation changed and the country generated more electricity that it consumed. However, this situation could change once again in the future, if the government does not construct new power plants or increase the import of electricity from other countries.

According to Fig. 2.117, the exports and imports of electricity from the Netherlands during the period 2001–2012 increased significantly (258 %).

2.29 United Kingdom

According to government sources, the UK has experienced strong energy security from a combination of its liberalized energy markets, firm regulation, and extensive North Sea resources. According to different experts' opinion, the outlook for UK energy security remains positive. While the UK's energy system is relatively resilient to energy security challenges, it faces ongoing risks from severe weather, technical failure, and industrial action. These risks can be mitigated, but it is impossible to avoid them entirely.

The UK's energy system also faces a great deal of change as existing infrastructure closes, domestic fossil fuel reserves decline, and the system adapts to meet low-carbon objectives adopted by the government. These changes will create new challenges for UK's energy security in the years ahead.

Some of the actions that the government is adopting in order to make sure the UK's energy system has adequate capacity and is diverse and reliable are the following:

- *Reforming the electricity market:* The UK's program for Electricity Market Reform (EMR) is expected to attract the £110 billion of investment needed to replace and upgrade the UK's electricity infrastructure;
- *Removing barriers to competitive markets:* The government is reforming the planning system for nationally significant infrastructure (like wind farms) to speed up the consent process and include new categories of commercial and business development;
- *Preparing for energy emergencies:* The government is working with the industry and regulators to strengthen the resilience of the UK's energy networks and assets, prepare for all energy emergencies and maintain the capability to lead response and recovery operations across government;
- *Increasing energy efficiency:* The UK Energy Efficiency Strategy sets out how to lowering UK energy security risks through various initiatives to improve the energy efficiency of appliances, businesses, and public sector buildings;
- *Maximizing cost-effective recovery of UK resources:* To provide reliable energy supplies that are not exposed to international energy supply risks, the government will issue licenses for domestic oil and gas exploration and production and support development of the oil and gas industry;
- *Working internationally:* The UK international work aims to promote low-carbon technologies, encourage investment in UK oil and gas production, make sure global energy supply is reliable and enhance price stability. This work includes the EU security of supply regulations and implementation of the third package on electricity and gas markets, which will improve market liberalization;

- *Maintaining reliable networks:* The government is making sure the UK's energy infrastructure can continue to deliver the energy people need and to where they need it. It's also making sure that new energy generation infrastructure is incorporated in a secure, timely, and cost-effective way;
- *Reducing carbon from UK energy supplies:* The government is increasing the use of low-carbon technologies to reduce UK dependence on international oil and gas markets in the long term while maintain diversity in the domestic energy sector.

In response to the challenges affecting energy security in the UK, in December 2012 the Department of Energy and Climate Change published the Energy Security Strategy. The strategy:

- Identifies cross-cutting risks to UK energy security;
- Assesses the main characteristics of energy security;
- Outlines work already happening to maintain the UK's reliable energy supply;
- Sets out all of the actions the government is taking to maintain the UK's energy supply.

2.29.1 Crude Oil Reserves

According to *Oil and Gas Journal*, the UK had 4 billion barrels of proven crude oil reserves in 2006, the highest proven crude oil reserves within the EU at that time. In 2008, the proven crude oil reserves in the country reached more than 4.4 billion barrels, an increase of 10 % respect to 2006. In January 2013, the UK had 3.1 billion barrels of proven crude oil reserves (29.6 % less than in 2008).

The vast majority of UK's reserves are located offshore in the Continental Shelf, and most of the oil production occurs in the Central and Northern sections of the North Sea. Although there is a modest amount of oil produced onshore, in 2012 more than 90 % of total UK production took place offshore. Aging reservoirs and infrastructure have affected UK's oil production over the last few years, with production decline rate increases and widespread outages as a result of technical problems, which were particularly acute in 2012. There are also sizable reserves in the North Sea (North of the Shetland Islands), with smaller amounts in the North Atlantic Sea. Besides these offshore assets, the UK also has the Wytch Farm field, the largest onshore oil field in Europe.

2.29.2 Production and Consumption of Oil

At present, three-quarters of the UK's primary energy demand are met by oil and natural gas. According to *Oil and Gas UK,* by 2020, a total of 70 % of energy consumption in the UK will still come from oil and natural gas, even if the

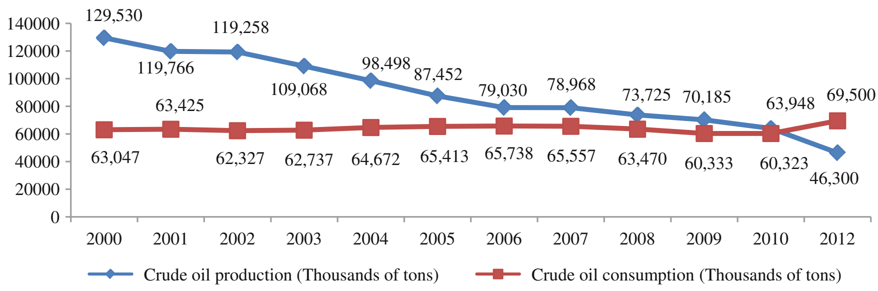

Fig. 2.118 Production and consumption of crude oil in the UK during the period 2000–2012. *Source:* Eurostat

government's target of generating 15 % from renewable sources is achieved. Currently, most of the energy demand can be met from domestic sources. In 2009, crude oil produced on the UK Continental Shelf satisfied almost all domestic consumption, while natural gas from British fields met two thirds of demand.

The evolution of the production and consumption of crude oil[48] in the UK during the period 2000–2012 is shown in Fig. 2.118. As can be easily seen from this figure, the crude oil production in the UK dropped 64.3 % during the period considered. According to the Department of Energy and Climate Change, in 2010 total crude oil production in the country was a little bit more than 63 million tons (1,360,515 barrels per day); this represents a decrease of 7.7 % respect to 2009. The crude oil consumption in that year was 60.323 million tons or 94.3 % of the crude oil produced. In 2012, the UK produced 1.0 million barrels per day (46.3 million tons) of oil and consumed 1.5 million barrels per day (69.5 million tons). In 2012, UK produced about 881,000 barrels per day of crude oil. The 2012 liquid fuel production level was about 14 % lower than the 2011 production level, and it has reached the lowest production level since the 1970s. According to *EIA's Short-Term Energy Outlook* sources, it is expected that the UK oil production continue to decline, remaining below 1 million barrels per day through the end of 2014. Although its proximity to major consuming markets makes UK exploration attractive, recent increases in taxes will continue to affect the attractiveness of the UK fields in the longer term.

The UK government expects that crude oil production in the country to continue declining in the coming years. The main reasons for this decline include:

- The overall maturity of the country's oil fields;
- The application of new crude oil extraction technologies that lead to field exhaustion at a quicker rate;
- Increasing costs as production shifts to more remote and inhospitable regions.

[48] Most of the UK crude oil grades are light and sweet (30–40° API), which generally makes them attractive to foreign buyers.

According to UK Energy in Brief 2010 (2011) report, total production of primary fuels, when expressed in terms of their energy content, fell by 5.7 % in 2009 compared to 2008. Crude oil accounted for 45 % of total energy production, natural gas 36 %, coal 7 %, and nuclear, wind, and natural flow hydro 10 %.

Total oil consumption in the UK was broadly stable, but registered an increase of 25.2 % in 2012 when compared with the level reached in 2010. Over 75 % of oil is consumed in the transport sector. It is expected that the consumption of crude oil in the UK continues to increase slightly, at least during the coming years.

2.29.3 Import and Export of Oil

In the 1970s, the UK was a net importer of energy. Following development of crude oil and natural gas production facilities in the North Sea, the UK became a net exporter of energy in 1981. Output fell back in the late 1980s following the Piper Alpha disaster, but the UK regained a position as a net exporter in the middle of the 1990s. North Sea production peaked in 1999, and the UK returned to being an energy importer in 2004. The UK remains a net exporter of oil products, though the level of net imports of crude oil result in the UK being a net importer of this type of energy source. Latest comparable data from Eurostat for 2007 show that the UK had the second lowest level of import dependency in the EU, behind Denmark, which remains a net exporter (UK Energy Brief 2012). In 2011, a total of 36 % of energy used in the UK was imported, up sharply from the 2010 level as North Sea oil and gas output fell following adverse weather conditions as well as a number of maintenance issues (UK Energy Brief 2012) (see Fig. 2.119).

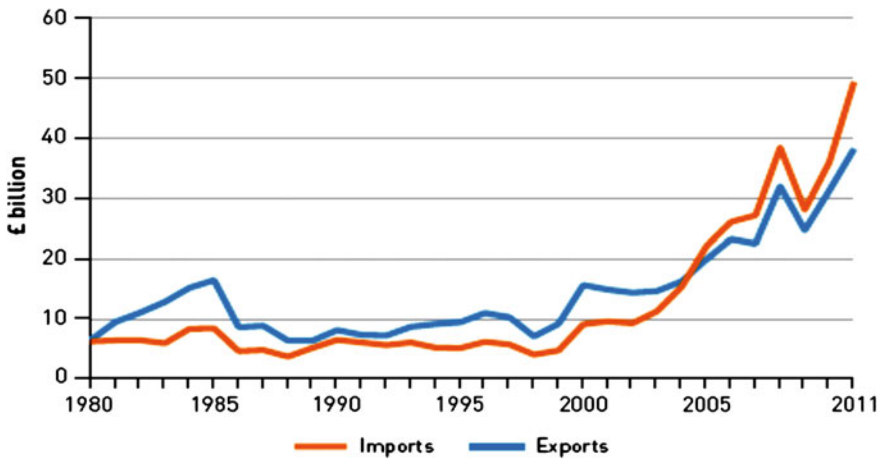

Fig. 2.119 Foreign trade in crude oil and oil products during the period 1980–2011. *Source:* UK Energy in Brief 2012

Table 2.11 Crude oil and oil products (million tons)

	1980	1990	2000	2008	2009	2010	2011
Exports	58.4	80.4	123.9	84.3	77.4	74.5	67
Imports	60.4	69.2	74.8	91.9	83.8	85.8	87.8
Net imports	2	−11.2	−49.1	7.6	6.4	11.3	20.8

Source: UK Energy in Brief 2012 (2013)

The UK remained, during the period 2008–2011, a net importer of crude oil and oil products importing 11.2 million tons in 2010 and 20.8 million tons in 2011, an increase of 85.7 % respect to 2010. During that year, imports of crude oil, NGLs and feedstock increased by 0.5 %, while exports fell by 6.6 %. It is important to note that in 2010, the UK was still a net exporter of oil products exporting 2.1 million tons. Imports of oil products rose by 6 % and exports rose by 0.8 %. About two thirds of UK production of crude oil and NGLs are exported as the UK generally produces a lighter, more valuable crude oil than other areas of the world such as the Middle East or West Africa.

Finally from Table 2.11, the following can be stated: Exports of crude oil and oil products fell from 123.9 million tons in 2000 to 67 million tons in 2011; this represents a reduction of 46 %. In the case of import of crude oil and oil products the situation is the following: The level of crude oil import increased from 60.4 million tons in 1980 to 87.8 million tons in 2011; this represents an increase of 45.3 % for the whole period. The import of crude oil and oil products fell from 84.3 million tons in 2008 to 67 million tons in 2011; this represents a decrease of 20.3 %.

2.29.4 Oil Fields

As UK oil fields mature, the industry has shifted focus from discovering new reserves to increasing the productivity of existing fields and developing smaller, previously avoided ones from the economic point of view. This trend has prompted oil major companies such as BP and SHELL to begin selling their UK assets in order to focus on high growth international opportunities. The result has been the entry into the UK oil sector of many smaller operators.

According to EIA sources, during 2012, a number of new oil field developments took place, mainly by smaller oil field operators. The Apache-operated Bacchus oil field came online in April 2012 and produced an average of 4,000 barrels per day. The Lybster oil field, located in the Central North Sea, came online in May 2012. A number of new oil fields are expected to be developed in 2013, nearly all of which are located in the North Sea. The only exception is the Conwy & Corfe oil field, located offshore in the Morecambe Bay in Northwest England. These projects are likely to yield relatively small volumes of oil, only partly stemming the downward trend in UK's oil production. The two heavy oil projects, Statoil's Bressay and Chevron's Mariner, are expected to come online in 2015 or later (Table 2.12).

Table 2.12 Oil fields

Field name	Development start date	Operator	Total recoverable reserves (million barrels)
Godwin	January	Talisman	5.5
Ptarmigan	January	Premier	3.5
Conwy&Corfe	February	EOG	16.7
Kinnoull	March	BP	48.9
Bentley	September	Xcite Energy	25.6
Enochdhu	September	ConocoPhillips	14.7
Alma&Galia	October	EnQuest	28.9
Crawford Redevelopment	November	EnQuest	26.8

Source: UK's Department of Energy and Climate Change

2.29.5 Investment in the Energy Sector

Since 2004, investment in the energy industries has continued to grow, specifically in electricity. In 2010, of the total amount invested in the energy industry, 40 % were in oil and gas extraction, 44 % in electricity, 14 % in gas with the remaining 2 % in coal extraction and coke, refined petroleum products, and nuclear fuels.

2.29.6 Electricity Generation and Consumption

The 2006 Energy Review attracted considerable press coverage, in particular in relation to the prospect of constructing a new generation of nuclear power plants, in order to prevent the rise in carbon dioxide emissions that would arise, if other conventional power plants were to be built to satisfy the foreseeable increase in the electricity demand during the coming years. However, the nuclear accident at the Fukushima nuclear power plant in Japan in March 2011, forced the government to review plans already adopted for the construction of new nuclear power plants in the country in the near future.[49] This revision could reduce the participation of nuclear energy in the energy mix of the country in the future.

According to a poll conducted by YouGov for Deloitte in 2005, a total of 35 % of the population expects that by 2020 the majority of electricity generation will come from renewable energy sources (more than double the government's target, and far larger than the 5.5 % generated as of 2008). At the same time, a total of 23 % of the population expects that the majority of the electricity will be generated by nuclear power plants, but the percentage could be lower after the nuclear accident at the Fukushima nuclear power plant, and only 18 % consider that the majority of the electricity to be generated in the country should come from fossil fuels. A total of

[49] For more information on this subject see Morales Pedraza (2012).

92 % of the population thought that the government should do more to explore alternative power generation technologies to reduce carbon emissions.

The UK has a privatized electricity sector, where generators and distributors trade electricity on a wholesale market. The largest power producer in the country is British Energy (BE), which controls most of the nuclear power capacity and generates about 20 % of the total electricity supply. Other important generating companies include EON-UK, RWE Power, Scottish and Southern Energy (SSE), and Scottish Power (SP). Twelve regional monopolies control electricity distribution in the UK, most of which are owned by the leading generation companies. National Grid Transmission (NGT) owns and operates the national transmission system in England and Wales, whereas SSE and SP operate the grid in Scotland, and Northern Ireland Electricity (NIE), a subsidiary of the Viridian Group, operates the grid in Northern Ireland.

The UK has slowly integrated the formally-separate electricity markets of its component parts (England, Northern Ireland, Scotland, and Wales). The British government formed the New Electricity Trading Arrangements (NETA) in 2001 to integrate the electricity markets of England and Wales. In 2005, the British government extended NETA to Scotland as the British Energy Transmission and Trading Arrangements (BETTA). There are plans to eventually incorporate Northern Ireland into the BETTA system. In addition, SP and SSE have increased the transmission capacity between England and Scotland to allow them to sell more electricity to English and Welsh customers.

The long-term trend in UK power generation has been a move from coal-fired power plants to combined-cycle gas-fired turbines.

According to Table 2.13, the peak production of electricity using oil as fuel within the period 1980–2011 was reached in 1990 (20 billion kWh). In 2009, the

Table 2.13 Total electricity produced by type of energy source during the period 1980–2011 (Billion kWh)

	1980	1990	2000	2009	2010	2011
Coal	220.8	213.4	114.7	97.8	102.3	103.1
Oil	8.1	20	5.9	5.4	4.3	3.3
Natural gas	–	0.4	144.9	163.5	172.5	144.1
Nuclear	32.3	58.7	78.3	62.8	56.4	62.7
Hydro[a]	3.9	5.2	4.2	4	2.5	4.7
Wind	–	–	0.9	9.3	10.2	15.8
Other fuels	–	–	8.3	12.6	13.2	13.8
Net imports	–	11.9	14.2	2.9	2.7	6.2
Total electricity available for supply	264.9	309.4	371.4	358.3	364.1	353.7

Note: According to Eurostat database the generation of electricity in 2009 was 376.74 Billion kWh
Source: UK Energy in Brief 2012 (2013)
[a] Hydro includes net supply pumped storage

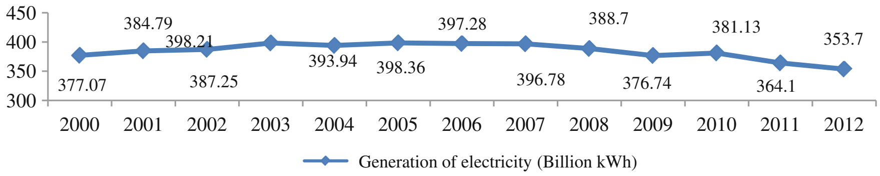

Fig. 2.120 Generation of electricity in the UK during the period 2000–2012. *Source:* Eurostat and UK Energy in Brief 2012

production of electricity using oil as fuel fell to 5.4 billion kWh; this represents a decrease of 73 %. In 2011, the generation of electricity using oil as fuel further decrease to 3.3 billion kWh. In 2013, the generation of electricity using oil as fuel was 0. The evolution of the generation of electricity in the UK during the period 2000–2012 is shown in Fig. 2.120 (Table 2.12).

The generation of electricity in the UK during the period 2000–2012 decreased 6.2 %. The generation of electricity started to decline in 2005 and it has continued this trend during the past 8 years. In 2007, final electricity consumption fell by 0.7 % and fell further 1 % in 2008. In 2009, the consumption of electricity decreased by 34.5 % respect to the level reached in 2008. Electricity consumption in 2010 was divided in the following manner: 31 % for the residential sector; 26.7 % for the industry sector; and 27.2 % in commerce, public administration, transport and agriculture sectors. Fuel industries accounted for a further 7.6 % with the remaining 7.5 % accounted for by transmission and distribution losses. Final consumption of electricity rose by 1 % in 2010 as a whole respect to 2009 and decreased again in 2011 (1.1 %). Domestic use was up 0.4 %, industrial use was up 3.4 % and consumption by other final users (including transport sector use) was down by 0.8 % (Fig. 2.121).

It is important to highlight that total electricity available for supply rose continuously from 1997 to reach a peak in 2005. It has subsequently fallen, due to energy efficiency, economic and weather factors until 2010. After an increase in 2010, in part due to a particularly cold final quarter, supply fell once again in 2011, to its lowest level since 1997, as winter temperatures increased (UK Energy Brief 2012).

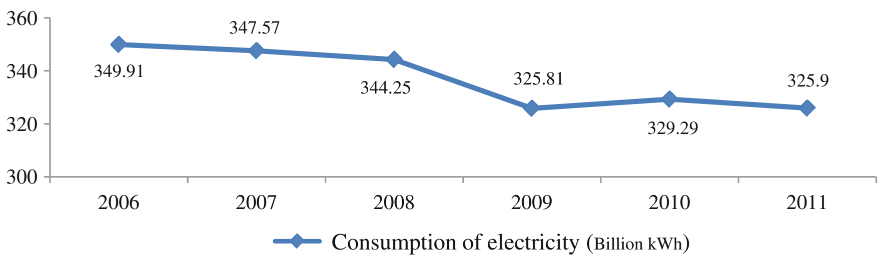

Fig. 2.121 Consumption of electricity in the UK during the period 2000–2011. *Source:* EIA

Finally, since the period 2007–2008, the electricity capacity margin has increased year on year due to both a decrease in peak demand and an increase in capacity. However, during the period 2011–2012, peak demand fell by nearly 4 GW, and capacity fell by nearly 2 GW, largely due to the mothballing of a large CCGT plant. This resulted in an increase in the capacity margin to 43 %. This fall in peak demand was largely due to the mild winter, but improved energy efficiency, the poor economic climate and increased generation from distribution-system connected capacity also helped reduce the demand on the UK transmission networks.

2.29.7 Import and Export of Electricity

From Fig. 2.122, the following can be stated: The imports of electricity from the UK during the period 2001–2012 increased 29.3 %. It is expected that the imports of electricity continue this trend, at least during the coming years.

On the other hand, the exports of electricity from the UK during the period 2001–2012 increased 6.1 folds, despite the fact that the exports of electricity dropped 61.1 % since 2010. It is expected that the UK will continue exporting electricity during the coming years (Fig. 2.123).

Imports and exports of electricity from and to continental Europe are volatile, with suppliers taking advantage of price differentials due to extreme weather, industrial disputes or production difficulties. While net imports reached 12.29 billion kWh in 2008, in 2009 it fell by almost 50 %, as the UK became a net exporter in the fourth

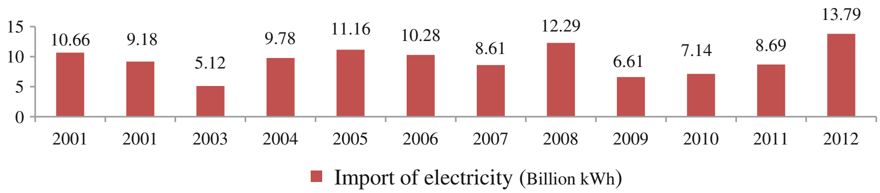

Fig. 2.122 Imports of electricity in the UK during the period 2001–2012. *Source:* EIA

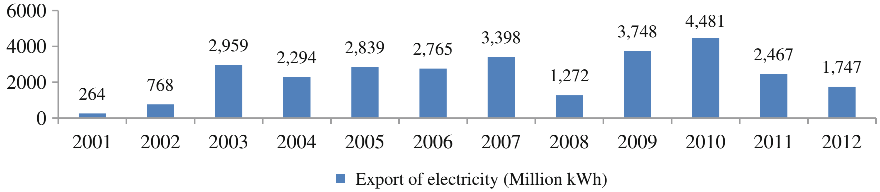

Fig. 2.123 Exports of electricity from the UK during the period 2001–2012. *Source:* Eurostat and EIA

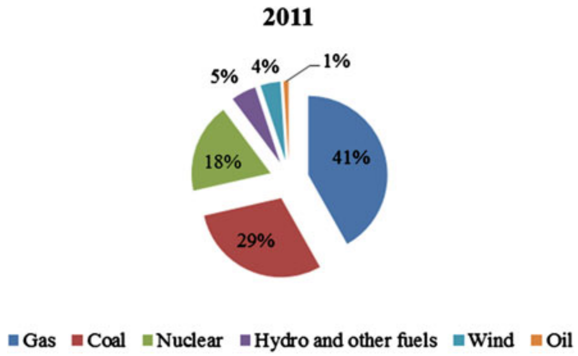

Fig. 2.124 Electricity supplied by fuel type in 2011. *Source:* UK Energy in Brief 2012

quarter of that year, for the first time in six years, continuing into the first quarter of 2010. The UK has since become a net electricity importer again.

From Fig. 2.124, the following can be stated: Oil's share in the production of electricity did not change between 2008 and 2009 (1 %) and it is very small in comparison with other energy sources, but was reduced to 0 in 2013. It is expected that oil will not be part of the energy mix of the country respect to the generation of electricity during the coming years.

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Chapter 3
The Role of Natural Gas in the Regional Electricity Generation

Abstract During the past 40 years, the use of natural gas has grown significantly at world level, particularly for the generation of electricity. Natural gas consumption is projected to nearly double between 2001 and 2025, with the most robust growth in demand expected among the developing countries. Because it is a cleaner fuel than oil or coal and not as controversial as nuclear power, natural gas is expected to be the fuel of choice for the generation of electricity for many countries in the coming decades, including many European countries.

3.1 General Overview

Natural gas[1] is generally considered a conventional fossil fuel. It comes from the decomposition of organic matter, just like oil and coal. Unlike these two energy sources, though, it can come from almost any organic matter, whereas coal comes only from plant matter and oil comes almost exclusively from plankton and

[1] Typically, natural gas is a mixture of lightweight alkanes. Natural gas contains methane (CH_4), ethane (C_2H_6), propane (C_3H_8), n-butane, isobutene (C_4H_{10}), and pentanes (C_5H_{12}). Natural gas consists of over 90 % methane and small amounts of ethane and other hydrocarbons. It may also contain nitrogen, carbon dioxide, and trace amounts of water vapor. Natural gas at ambient temperatures and pressures is a gas. As is typical of gases, it has a very low energy density compared with other fuels. On average, 0.921 m^3 of natural gas has the same energy content as 1.12 liters of gasoline. This makes use of natural gas as a transportation fuel at ambient temperatures and pressures unfeasible. To use natural gas as a transportation fuel, it must be either compressed or liquefied to increase its volumetric energy density. The propane and butanes removed from natural gas are usually liquefied under pressure and sold as LPGs (Demirbas 2002).

J. Morales Pedraza, *Electrical Energy Generation in Europe*,
DOI 10.1007/978-3-319-08401-5_3

microplankton remains, natural gas can come from both of these sources as well. For hundreds of years, natural gas has been known as a very useful substance.[2]

The ancient peoples of Persia, Greece, and India discovered natural gas many centuries ago. About 2,500 years ago, the Chinese discovered that the energy in natural gas could be harnessed, and used to heat water. In the early days of the natural gas industry, natural gas was mainly used to light street lamps, and the occasional house. The Chinese piped the natural gas from shallow wells and burned it under large pans to evaporate seawater to obtain salt. Natural gas was known in England as early as 1659, but it did not replace coal as an important source of energy in the world until after World War II. Natural gas was first used in America in 1816 in gas lamps to illuminate the streets of Baltimore. Soon after, in 1821, William Hart dug the first successful American natural gas well in Fredonia, New York. The Fredonia Gas Light Company opened its doors in 1858 as the nation's first natural gas company. By 1900, natural gas had been discovered in 17 States.

Natural gas-fired power plant is often used as a general designation for all facilities that use natural gas to generate electricity and possibly heat. Several types of natural gas-fired power plants exist in the world. One in which gas turbines generate all the electricity is known as a simple-cycle gas turbine plant. Such facilities can be started up and shut down at short notice, and are therefore suitable for providing peak-load power. Running costs are relatively high.

Electricity generation in gas turbines also produces heat. Combined cycle gas turbine plants (CCGT) and cogeneration plants (Combined heat and power (CHP)) plants exploit this heat, making them considerably more efficient than simple-cycle gas turbine units. In combined cycle power plants, steam turbines are used to generate electricity from the waste heat given off by the gas turbines. When used together, these turbines can give a net efficiency for electricity generation of up to 60 %. Surplus heat from steam turbines or in gas turbine exhaust fumes is carried to a heat distribution system. A cogeneration plant generates less electricity than a CCGT plant for the same level of natural gas consumption. However, it converts a larger proportion, over 80 %, of the energy content of the natural gas to usable energy in the form of both electricity and heat.

In the past 40 years, the use of natural gas has grown significantly at world level. Natural gas consumption is projected to nearly double between 2001 and 2025, with the most robust growth in demand expected among the developing countries. Because it is a cleaner fuel than oil or coal and not as controversial as nuclear

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[2] Decay and millions of years of geological stresses have transformed the complicated organic compounds that once made up living plants or animals into a mixture of alkanes. Natural gas is considered a fossil fuel because most scientists believe that natural gas was formed from the remains of tiny sea animals and plants that died 200–400 million years ago. When these tiny sea animals and plants died, they sank to the bottom of the oceans, where they were buried by layers of sediment that turned into rock. Over the years, the layers of sedimentary rock became thousands of feet thick, subjecting the energy-rich plant and animal remains to enormous pressure. Most scientists believe that the pressure, combined with the heat of the Earth, changed this organic mixture into petroleum and natural gas. Eventually, concentrations of natural gas became trapped in the rock layers like wet sponge traps water (Demirbas 2010).

Table 3.1 Evolution of the consumption of natural gas in OECD Europe and the expected level of consumption during the period 2015–2040

Type of energy	2010	2015	2020	2025	2030	2035	2040	Average annual percent change, 2010–2040
Natural gas	20.4	20.3	21	21.4	22.7	23.9	25.2	0.7

Source: IEO (2013)

power, natural gas is expected to be the fuel of choice for many countries in the future (Demirbas 2010). The natural gas supply chain comprises:

- Exploration and production;
- Delivery to connected transmission pipelines or liquefaction, sea transport, import, gasification, and input to transmission pipelines;
- Transmission, storage, and bulk supply to large consumers directly connected to the transmission system and to the distribution companies;
- Distribution, storage, and retailing of natural gas to industrial, commercial, and residential consumers.

The evolution of the consumption of natural gas in OECD Europe and the expected level of consumption during the coming decades is shown in Table 3.1.

The price of natural gas is normally specific and linked to the supply source and the specific usages of the natural gas at the end-user. Only in the most developed markets exists there a liquid short-term market for natural gas. Traditionally, natural gas is traded on long-term contracts, unlike oil products which are traded on a competitive world market. Due to the structure of the natural gas supply chain, where the means of its transportation are limited to inflexible pipes requiring large investments, natural gas transmission has traditionally been a monopolistic industry. Today, within the EU it is regulated by specific legislation on Third-Party Access and Open Access to the Infrastructure (Bjørnmose et al. 2009).

According to the IEO (2013) report, world natural gas consumption is expected to increase by 64 % from 113 trillion cubic feet (3,990 trillion m^3) in 2010 to 185 trillion cubic feet (6,533 trillion m^3) in 2040. Although the global recession resulted in an estimated decline of 3.6 trillion cubic feet (127.13 trillion m^3) in natural gas use in 2009, robust demand returned in 2010 with an increase of 4 % higher than demand in 2008, before the downturn. Natural gas continues to be the fuel of choice for the electric power and industrial sectors in many of the world's regions, in part because of its lower carbon intensity compared with coal and oil, which makes it an attractive fuel source in countries where governments are implementing policies to reduce greenhouse gas emissions. In addition, it is an attractive alternative fuel for new power generation plants because of relatively low capital costs and the favorable heat rates for natural gas generation. The industrial and electric power sectors together account for 77 % of the total projected world increase in natural gas consumption. The impact of the world economic recession on natural gas use was especially evident in the industrial sector—the end-use sector with the highest level of natural gas consumption—where demand for natural gas declined around 6 % from 2008 to 2009.

According to the IEO (2013) report, electricity generation in the nations of OECD Europe is expected to increase by an average of 1 % per year from 3,496 billion kWh in 2010 to 4,765 billion kWh in 2040; this represents an increase of 36.2 %. Because most of the countries in OECD Europe have relatively stable populations and mature electricity markets, most of the region's growth in electricity demand comes from those nations with more robust population growth (such as Turkey) and from the newest OECD members (including the Czech Republic, Estonia, Hungary, Poland, and Slovenia), whose projected economic growth rates exceed the OECD average.

Natural gas-fired combined-cycle technology is an attractive choice for new power plants because of its fuel efficiency, operating flexibility (it can be brought online in minutes rather than the hours it takes for coal-fired and some other generating capacity), relatively short planning and construction times, relatively low emissions, and relatively low capital costs.

Prospects for natural gas have improved substantially relative to last year's outlook, in large part because of the revised expectations for unconventional sources of natural gas, especially shale gas, both within the United States and globally. The additional resources will allow natural gas supplies outside North America to be used as LNG to supply markets that have few domestic resources. As a result, natural gas markets are expected to remain well supplied and prices relatively low in the mid-term, and many countries, including European countries, are expected to turn to natural gas, rather than more expensive or more carbon-intensive sources of electricity, to supply their future power needs.

From 2020 to 2035, the growth in consumption of natural gas is expected to slow to an average of 0.9 % per year, as prices rise and increasingly expensive natural gas resources are brought to market. By energy source, the projected increase in natural gas consumption during the period 2008–2035 is second only to coal. Other sources expected that the consumption of natural gas worldwide will increase by an average of 2.8 % annually from 2001 to 2025, compared with projected annual growth rates of 1.8 % for oil consumption and 1.5 % for coal consumption. Natural gas consumption in 2025, is expected to be 4.981 trillion m^3, nearly double the 2001 total of 2.547 trillion m^3. The natural gas share of total energy consumption is projected to increase from 23 % in 2001 to 28 % in 2025 (Demirbas 2010). In the case of Europe and other OECD countries, natural gas is expected to be the fastest-growing fuel source, with demand increasing at an annual average rate of 1.4 % from 0.53 trillion m^3 in 2004 to 0.65 trillion m^3 in 2015 and 0.76 trillion m^3 in 2030.

Around the world, natural gas use is increasing for a variety of reasons, including prices, environmental concerns, fuel diversification and/or energy security issues, market deregulation, and overall economic growth, particularly in Asia and the Latin America and the Caribbean regions.

According to the Congressional Research on Europe's Energy Security report (2013), collectively, the EU is the world's largest energy importer, importing about

55 % of their energy supply, and approximately 64 % of their natural gas needs. The EU Member States increasingly rely on natural gas, particularly to reach ambitious targets to reduce carbon dioxide and greenhouse gas emissions in the future. Natural gas comprised 24 % of the EU's primary energy consumption in 2011, a number that is expected to grow to almost 30 % by 2030. The EC forecasts that the EU will import over 80 % of its natural gas needs by 2030.

Analysts note that recent policy decisions, such as a 2011 German announcement that it would phase out the use of its nuclear power plants by 2022 and possible prohibitions on shale gas development by some EU members, could mean a more rapid rise in Europe's dependence on natural gas imports. Russia has long been, and is expected to continue to be, a key supplier of natural gas to Europe. In 2012, Russia accounted for 34 % of European natural gas imports, surpassed by Norway as the lead supplier. Algeria is the third-largest supplier to the EU. Russian and European companies have developed an extensive network of infrastructure to transport Russian natural gas long distances to European markets. Observers expect natural gas to play a significant role in Europe–Russia relations for decades to come. However, the current crisis in Ukraine, the annexation of Crimea by Russia, and the sanctions adopted by the EU and the USA against Russia could change significantly the situation described above.

3.2 Natural Gas Reserves

Almost 73 % of the world's natural gas reserves are located in the Middle East and Eurasia. Russia, Iran, and Qatar combined account for 54.8 % of the world's natural gas reserves as of January 2013.[3] Reserves in the rest of the world are evenly distributed on a regional basis (see Table 3.2 and Fig. 3.1). According to the information included in Fig. 3.1, Europe is the region with the lowest natural gas reserves (146 trillion cubic feet) representing only 2.1 % of the world's total (Table 3.2).[4]

According to the IEO (2013) report, current estimates of natural gas reserve levels indicate a large resource base to support growth in markets through 2040. In the OECD countries, including many where there are relatively high levels of consumption, ratios of reserves to production currently are significantly lower.

[3] The world's largest natural gas field by far is Qatar's offshore North Field, estimated to have 25 trillion m^3, enough to last more than 200 years at optimum production levels. The second-largest natural gas field is the South Pars Gas Field in Iranian waters in the Persian Gulf. It has estimated reserves between 8 and 14 trillion m^3. Since the middle of the 1970s, world natural gas reserves have generally trended upward each year.

[4] The largest increases in reported natural gas reserves in 2010 were for Turkmenistan and Australia. However, it is important to know the following: Europe is particularly promising for unconventional gas and may have some 35 trillion m^3 in place. Most of the potential is located in Bulgaria, France, Germany, Hungary, Poland, Romania, Sweden, and the UK. Development will depend largely on continued technological advances, gas prices, fiscal regimes, and transmission infrastructure.

Table 3.2 World natural gas reserves by country as of January 1, 2013

Country	Reserves (trillion cubic feet)	%
World	6,793	100
Top 20 countries	6,200	91.3
Russia	1,688	24.9
Iran	1,187	17.5
Qatar	890	13.1
Saudi Arabia	288	4.2
United States	273	4.0
Turkmenistan	265	3.9
United Arab Emirates	215	3.2
Venezuela	195	2.9
Nigeria	182	2.7
Algeria	159	2.3
China	124	1.8
Iraq	112	1.6
Indonesia	108	1.6
Kazakhstan	85	1.3
Malaysia	83	1.2
Egypt	77	1.1
Norway	73	1.1
Canada	68	1.0
Uzbekistan	65	1.0
Kuwait	63	0.9
Rest of the world	593	8.7

Source: International Energy Outlook (2013)

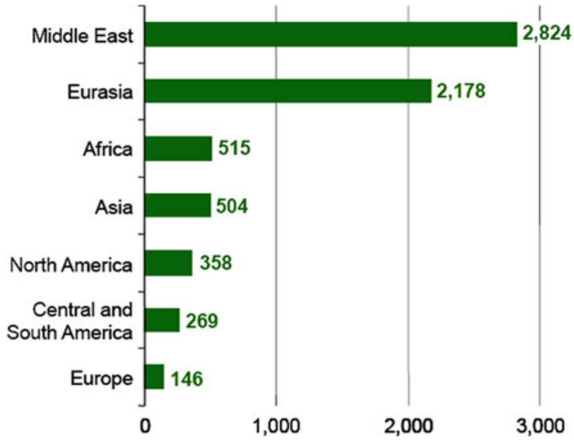


Fig. 3.1 World natural gas reserves by region as of January 1, 2013 (Trillion cubic feet)

Despite high rates of increase in natural gas consumption, particularly over the past decade, most regional reserves-to-production ratios have remained high. Worldwide, the reserves-to-production ratio is estimated at 60.2 years. Central and South America have a reserves-to-production ratio of 51.6 years, Russia 82 years, and Africa 64.7 years. The Middle East's reserves-to-production ratio exceeds 100 years (IEO 2011).

3.3 Natural Gas Network

According to Energy Priority Corridors for Energy Transmission, the European natural gas network has been established gradually during the last 70 years. Generally, the European natural gas infrastructure is quite young and replacement is only considered a major issue in a few EU Member States. Initially, the European natural gas system was developed around four national gas fields in Southern France, Northern Italy, Germany, and Romania. In the 1960s, the largest natural gas field Groningen was found in the Netherlands. Large-scale natural gas import from Norway, Russia, and Algeria took over as the main source of natural gas supply in the 1980s after the two oil crises.

In the 1990s, natural gas was introduced and developed in Greece, Portugal, and Ireland, increasing the number of countries supplying natural gas to the European region. After 2000, there has been a focus on connecting the UK natural gas market to the continent and the Norwegian natural gas fields, connecting new EU Member States to the EU-integrated system, creating new import channels as pipelines from North Africa, the Caspian Sea, and establishing new LNG import facilities. There are four main corridors transporting natural gas to the EU. These are the following:

- *North-Eastern corridor from Russia*. This is the main external source of natural gas supply with 23 % of the EU-27 consumption (115 billion m^3). From the Northern Russian sources, two main supply traces (Northern Lights and Druzhba Gas Pipeline) with pipelines in parallel mainly supplying the EU-27 Northern (via Poland)[5] and South-Eastern region (via Slovakia)[6];

[5] Yamal I (Yamal-Europe) is a 4,196 km pipeline which is runs through Belarus and Poland to Germany. It is Russia's only natural gas export route to Europe that does not cross Ukrainian territory. Even though only about 17 billion m^3 of natural gas are currently exported each year through the Yamal-Europe gas pipeline, the pipelines maximum capacity is about 33 billion m^3. The objective of this route is to meet the market demand of Germany, and eventually of the UK since after planned connection with the Interconnector pipeline is completed; it is the shortest route for Russian gas to the British Isles.

[6] Brotherhood is a 2,750 km long gas pipeline that connects Russia, Ukraine, Slovakia, and Western Europe. Completed in 1967 it has an annual capacity of about 30 billion m^3. Natural gas exports through this pipeline represent about 25 % of the natural gas consumed in Western Europe and about 70 % of Russian gas exports to Western Europe.

- *North-Western corridor from Norway*. Import of natural gas from Norway account for approximately 18 % of the EU-27 consumption (90 billion m^3). From the sources in the North Sea several pipelines connect to the EU. The Langeled, Cats, Seal, Sage, and Pulsmar pipelines connect to the UK for consumption in the UK or transit. Europipe I and II, Norpipe, and Zeepipe are pipelines connected directly to the continental EU import points in Emden and Zeebrügge;
- *Northern Lights* (*Urengoi-Uzhgorod*). It is a 4,500 km long pipeline, completed in 1983, with a capacity of 27.9 billion m^3 of natural gas per annum. It trespasses the territory of Ukraine, where it joins the path of Brotherhood pipeline and heads in the direction of Slovakia, Austria, and Germany. It transports another third of the overall gas destined for Europe;
- *South-Western Corridor from Algeria*. Import of natural gas from Algeria account for approximately 10 % of the EU-27 consumption (50 billion m^3);
- *The GPDF pipeline* via Morocco to Spain and the *Trans-Mediterranean pipeline* to Italy;
- *South-Eastern Corridor from Caucasus/Central Asia/Middle East* (*via Turkey/ the Black Sea*). This import route is seen as a major priority area in the EU-27 security of supply, as this route has considerable future supply potential. Blue Stream is a 1,250 km pipeline that connects Russia to Turkey. It runs from the Izobilnoye natural gas plant in Southern Russia across the Black Sea bed (at record depths of 2,150 m below the sea level) to the Turkish port of Samsun, and onward to Ankara. Online since November 2005, the pipeline was built with an intention to diversify Russian natural gas deliveries to Turkey and, at the same time, avoid third countries, such as Ukraine, Belarus, and Moldova. Blue Stream is expected to operate at full capacity, delivering 16 billion m^3 of natural gas annually. By 2025, Russia plans to export 311 billion m^3 of natural gas to Turkey via this route.

Finally, it is important to highlight the following: Throughout the past four decades, including the politically strenuous years of the Cold War, EU and Russia enjoyed the very stable energy import–export relations. However, since recently Europe is becoming increasingly worried about the stability of crude oil and natural gas exports from Russia. As local production of energy is declining, and the Russian share of total EU bound energy imports is on the rise, Europe is growing concerned about overreliance on one supply country for its energy import needs. Moreover, the overall energy dependency of EU-27 is estimated that could increase up to 64.9 % by 2030. However, if the EU expands once again to include Switzerland, Turkey, and Norway, the EU-30 energy import would decrease to 56.3 % by 2030 due to domestic Norwegian energy production (Borisocheva 2007).

Energy diversification is the main concept behind the aim for greater energy security adopted by the EU. It, in turn, could be separated into three main aspects: (a) Diversification of overall energy sources; (b) Diversification of suppliers; and (c) Diversification of transport routes. In terms of diversification of energy sources, Europe is on the right path of finding a right fuel mix, with sustainability issues in the foreground. In 2004, oil and natural gas accounted, respectively, for 37.2 % and 23.9 % of EU's gross inland consumption, followed by solid fuels and nuclear power, 17.9 % and 14.6 %, respectively. The share of renewable stood at 6.3 %. By 2020, the EU aims to more than triple its share of renewable energy to 20 % and to increase the level of biofuels in transport fuel to at least 10 % by 2020 (Table 3.3 and Fig. 3.2).

Europe is aiming at improving its energy efficiency and developing low carbon technologies. These policies, apart from strengthening of the European energy security position, would also contribute to the EU's strategy for jobs and therefore growth.

With regard to suppliers, EU receives its energy from a variety of sources. However, Russia was and is expected to remain the predominant one during the coming years, but the political crisis in Ukraine could change this projection. The

Table 3.3 Dependency of the EU to natural gas for the period 1990–2030

	1990	2000	2010	2020	2030
EU-25	44.7	47.2	55	63.5	64.9
EU-27	44.6	46.7	54.4	62.9	64.2
EU-30	38.9	36.4	44.4	52.4	56.3

Source: PRIMES

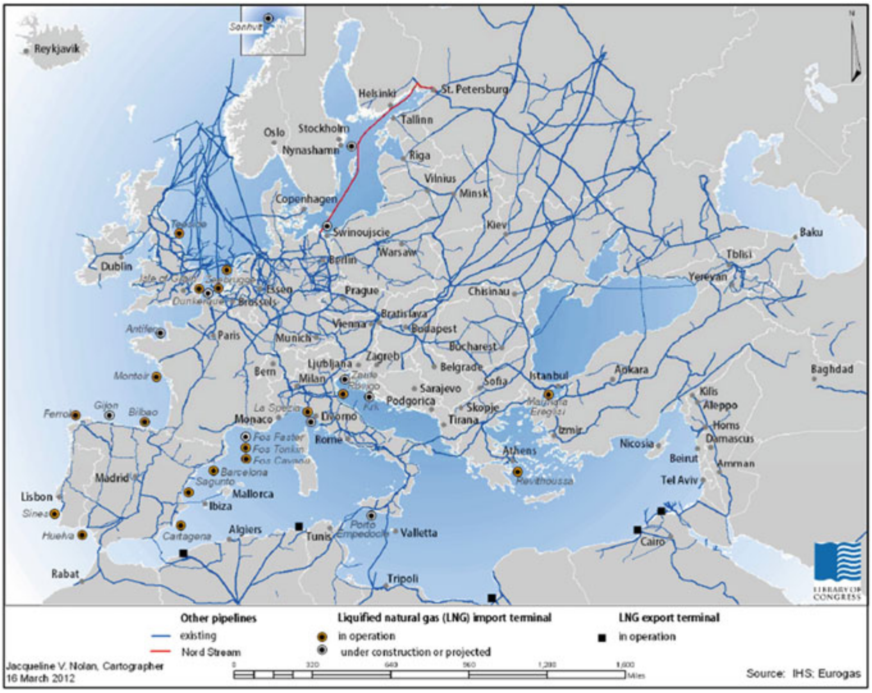


Fig. 3.2 EU natural gas network

supplier States that Europe is currently aiming to expand relations are in Africa (Algeria, Libya, and Nigeria) and in the Caspian Region (Azerbaijan, Kazakhstan, and Turkmenistan). In North Africa, there is a proposal to build a 4,000 km Trans-Saharan gas pipeline, which would transport up to 30 billion m^3 of natural gas to the EU annually scheduled to be operational in 2015. Also, the EU is planning to invest in Libya (a country with extensive crude oil reserves of 39.1 billion barrels, which represents 42 % of all African crude oil reserves) and Algeria (with 4,551 billion m^3 natural gas reserves, which is already providing for about 20 % of EU's natural gas demand, most of it via LNG routes). Thus, in order to intensify contact with such suppliers, some European countries, like Spain and Italy, are currently expanding their LNG port regasification infrastructure.

With regards to Central Asia, getting direct access to the Caspian crude oil and natural gas is vital for European energy security in order to provide an alternative for reducing the dependence on Russian energy resources, due to the regions extensive energy resources and its geographical proximity to Europe. For example, Turkmenistan, is a major natural gas producer, holding 265 trillion cubic feet of proven natural gas reserves, and Azerbaijan, has a large proven natural gas reserves of 35 trillion cubic feet. However, to a great extent the countries of this region are dependent on the existing Russian-controlled energy infrastructure, both legally, as a remnant possession of the Soviet era, and geographically, since they trespass the territory of the Russian Federation, which makes direct cooperation with the EU difficult to say the least. Thus, significant investment in alternative pipeline infrastructure is necessary. However, if Europe is aiming to access the most abundant energy sources of Kazakhstan and Turkmenistan directly, options in this respect are also quite limited. Apart from the currently inconceivable option of building a pipeline through Iran, the only way to get Turkmen natural gas to Europe, and at the same time bypassing Russia, would be across the bottom of the Caspian Sea. However, the unresolved dispute over the ownership of the Caspian Sea between Iran, Kazakhstan, Azerbaijan, Turkmenistan, and Russia greatly undermines this option. Thus, to have access to the Caspian crude oil and natural gas reserves, the EU most overcome these difficulties in an economic manner. This situation is a good example of how diversification of energy suppliers is directly linked to the diversification of transport routes.

A South Caucasus pipeline (SCP) (sometimes called Shah-Deniz pipeline, or Baku-Tbilisi-Erzum pipeline), is a Mediterranean option pipeline connecting Baku (Azerbaijan), Tbilisi (Georgia), and Erzurum (Turkey), from where oil and natural gas is shipped to the European markets. This 692 km pipeline, with the capacity of up to 16 billion m^3 follows the same corridor as the BTC pipeline.[7] From Erzum, the plans are to transport the supplies via the existing Turkey–Greece and the

[7] The Baku–Tbilisi–Ceyhan (BTC) pipeline is a 1,768 km-long crude oil pipeline from the Azeri-Chirag-Guneshli oil field in the Caspian Sea to the Mediterranean Sea. It connects Baku, the capital of Azerbaijan and Ceyhan, a port on the southeastern Mediterranean coast of Turkey, via Tbilisi, the capital of Georgia. It is the second longest oil pipeline in the former Soviet Union, after the Druzhba pipeline.

planned Nabucco and Greece–Italy pipelines. However, these pipelines only manage to reach the resources of Azerbaijan, which in comparison to Kazakhstan and Turkmenistan are quite limited, not even sufficient enough as to fill these pipelines to their capacities and to, thus, make the project economically viable (Borisocheva 2007).

3.3.1 Natural Gas Pipelines Within the EU

From the main import points for natural gas and LNG, natural gas is distributed across the EU-27. The internal transmission grid is especially dense in areas with many import points, e.g., in the Emden and Zeebrügge area and at the Eastern boundaries. Because of the cost of transportation, the natural gas is normally consumed as close as possible to the source. Therefore, only few pipelines internally are dedicated to transmission over large distances. Transgas I and II are examples of a long-distance transmission connecting to the Druzhba pipeline. Each EU Member State transmission system is well integrated in the overall system and TSOs are managing cross-country transmission.

The internal integrated EU-27 natural gas pipeline system is relatively young and well-functioning from an operational point of view. Supply and demand have shown to be balanced in a satisfactory manner, even under extremely cold conditions. Some interconnections, however, have a very high degree of utilization, and due to the security of supply aspects, strengthening of selected interconnections should be considered. The decline in the EU own energy production and increased imports will, however, affect the flow patterns significantly, and may call for infrastructure change projects in the EU-27, especially increased investments in storage capacity, additional capacity at import entry points and interconnections.

3.3.2 New Pipelines and Supply Routes for Natural Gas

As for the construction of new infrastructure, the EC decided on a list of ten natural gas and electricity projects (not oil) of European interest, with the goal that 7 of them would be up and running between 2010 and 2013. The following projects are the ones that have already begun service:

- Green Stream, connecting Libya and Italy, through Sicily;
- Balgzand–Bacton between the Netherlands and the UK;
- The Turkey–Greece section of the Turkey–Greece–Italy pipeline (TGI).

The following projects are under development:

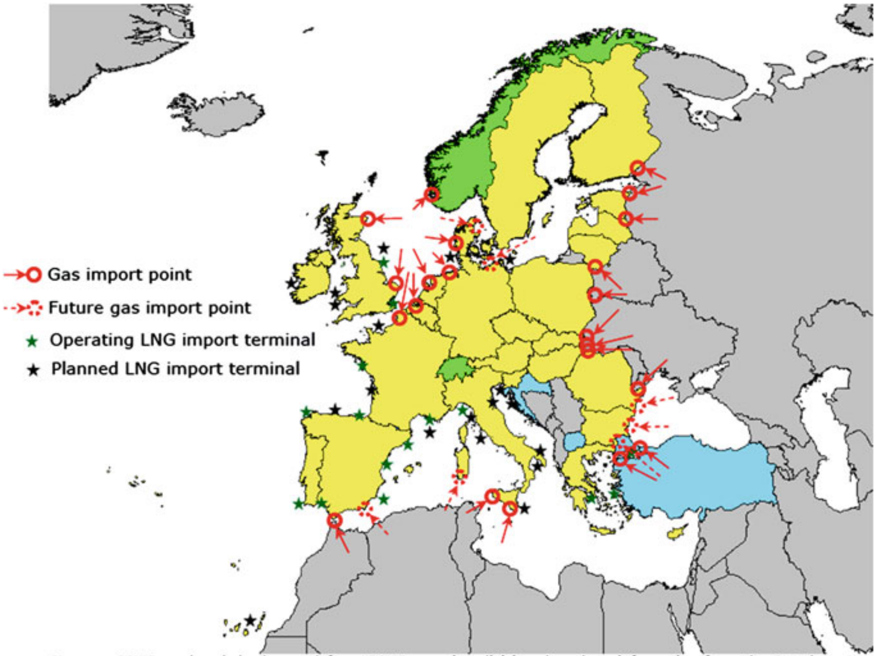
- Transmed II between Algeria, Tunisia, and Italy, through Sicily;
- Medgas connecting Algeria and Spain;

- The Greece–Italy section of the TGI Pipeline;
- Nord Stream between Russia and Germany;
- South Stream between Russia and several EU Member States (Russia–Bulgaria, dividing into Greece–Italy and Serbia/Romania–Hungary–Austria/Slovenia–Italy);
- Galsi connecting Algeria to Italy, via Sardinia, with a branch to France, via Corsica;
- Nabucco 2010 connecting the Caspian region, Middle East, and Egypt, via Turkey, Bulgaria, Romania, Hungary, and Austria and further on with the Central and Western European natural gas markets.

These infrastructures will increase the import capacity between 80 to 90 billion m^3, covering between 16 % and 17 % of the EU natural gas needs.

Finally, it is important to highlight the following: Technical issues for natural gas are more complex and the costs of handling natural gas are higher than those of oil and this should be in the mind of those who will have to take a further decision on the development of the energy sector within the EU. In addition, the following

Fig. 3.3 European gas pipelines. *Source:* www.energy.eu



Source: COWI produced, background from COWI mapping division, based on information from the Petroleum Economist, (2008 edition).

Fig. 3.4 Gas import points, pipelines, and LNG within the EU

elements should be also in the mind of those in charge of the development of the energy sector in the EU.

- While the market for oil transmission services has generally been considered open, efforts have been required to regulate free access to the market for natural gas transmission services;
- The framework ensures fair and nondiscriminating access to natural gas networks and a free flow over national borders that has gradually been established by the EC is in need of improvement. In particular, information requirements should be improved;
- Measures should be taken to ensure efficient transnational allocation of available pipeline capacity;
- The transparency of available pipeline capacity needs to be improved;
- Security of supply concerns, i.e., those related to transit routes crossing unstable countries, which poses a big challenge for the EU to secure its long-term energy needs (Bjørnmose et al. 2009) (Figs. 3.3 and 3.4).

3.4 Increase in the Use of Natural Gas Within the European Region

Natural gas is the second largest source of energy in Western Europe.[8] Most of it is extracted from British, Dutch, Italian, Romanian, German, and Danish fields, with additional natural gas imported mainly from Russia, Norway, and Algeria.

To increase the import capacity and reduce the dependency on suppliers, a number of infrastructure projects supported by the EU have been already mentioned in previous paragraphs. There are, however, still a number of challenges facing the EU natural gas market which need to be resolved. These include, inter alia, reducing the vulnerability to natural gas supply shocks, facilitating the development of an integrated natural gas market, planning for increasing import dependency, and addressing climate change issues. The major feature of the EU internal pipeline is the limited connections between the Western pipeline network and the Eastern infrastructure. There are issues concerning the technical part of natural gas transmission, those related to reverse flow, energy efficiency, and different standards. It is important to highlight that only 20 % of the oil are imported through pipelines, whereas pipelines account for 85 % of the natural gas.

Security of supply is one of the priority objectives of the EU's new energy policy. The EC is concerned that Europe's energy networks are no longer up to the task of providing secure energy supply in the foreseeable future. The physical ruptures of energy transport networks following the crises with transit countries (Ukraine in 2006 and 2008, and Belarus in 2007, just to mention a few examples) have forced the EU to adopt the strategy of diversifying supply routes, which would gradually reduce its dependence on transit countries.

Due to its transnational character involving a diversity of stakeholders, the cross-border pipeline projects require close cooperation between States. As the existing EU natural gas market has a regional character, there is a need for improving energy networks. Regional cooperation is particularly crucial for the development of natural gas infrastructure in order to ensure a timely response in case of energy crises. Energy networks must take a more prominent place in energy policy development and implementation. Transparency should be improved to resolve the issue of consolidation and concentration of national markets, which constitute a barrier to a sufficient expansion upstream (Bjørnmose et al. 2009).

In the absence of a single overarching jurisdiction, the transnational pipeline structure requires balancing of local law and international legal considerations. As

[8] The countries of non-OECD Europe and Eurasia rely on natural gas for more than 50 % of their primary energy needs, a larger share than for any other country grouping, according to IEO (2010) report. In the countries of non-OECD Europe and Eurasia other than Russia, natural gas consumption is expected to grow by 0.6 % annually over the period 2007–2035, from 0.26 trillion m^3 in 2007 to 0.31 trillion m^3 in 2035 (an increase of 19.8 %). Natural gas is the largest component of the countries' primary energy consumption, representing more than 45 % of the total throughout the projection period.

the diversity of players may aggravate a conflict, each cross-border pipeline project requires transparency and alignment of the interests of all stakeholders. Specific problems arise in the case of cross-border pipeline projects or regional projects involving different regulatory regimes. Among these problems are:

- Lack of proper mechanism for conflict resolution;
- Rights and obligations of stakeholders in different States can differ;
- The nature of the natural gas or oil market may differ greatly between countries connected by a pipeline;
- Integration of different legal regimes may increase the transaction costs of constructing and operating a pipeline;
- Security of imports may be hampered by political issues.

To ensure regulatory coherence and enhanced security of supply, cooperation between States is crucial. As set out in the EC's Second Strategic Energy Review and the EC's Green paper "Towards a Secure, Sustainable and Competitive European Energy Network," the EU will be unable to deliver its climate and energy goals without new and improved networks. Energy networks must take a more prominent place in energy policy development and implementation within the EU.

The generation of electricity is an important use of natural gas. However, the electricity generated from natural gas is generally more expensive than that generated using coal because of increased fuel costs. Natural gas can be used to generate electricity in a variety of ways. These include conventional steam generation, similar to coal-fired power plants, in which heating is used to generate steam, which in turns runs a turbine with an efficiency between 30 % and 35 %; a centralized gas turbine, in which hot gases from natural gas combustion are used to turn the turbine; and a combined cycle unit, in which both steam and hot combustion gases are used to turn the turbine with an efficiency between 50 % and 60 % (Demirbas 2010).

3.5 Natural Gas Production

With an output of 681 billion m^3 in 2012 (an increase of 5 % respect to 2011), the USA sits on top of the list of the 10 largest gas producers. Ranked second, Russia slightly decreased its domestic gas output (2 %), but 592 billion m^3 of "blue fuel" produced last year is inaccessible for the pursuers, a more than threefold outpacing Iran, which holds the third place. Seven out of 10 countries increased their natural gas output while only three—Russia, Canada, and Algeria—fell. Iran is the most prosperous country by reserve–production gas ratio, with 209 remaining years to exhaustion of its proven reserves of "blue fuel." Being a leader in the reserve–production oil indicator, Canada ranks last in the top ten by reserve–production gas ratio.

Natural gas demand has grown rapidly across Europe over the past 30 years and power generation—shaped by environmental and commercial advantages enjoyed by natural gas—is the key to continued growth over the next several decades. Imports of natural gas will be needed increasingly as Europe's indigenous supply declines and, for this reason, it is expected that Russia will increase its role as a source of energy and its contribution particularly in terms of natural gas and oil supplies. However, the political crisis in Ukraine could have a negative impact in the role of Russia as an important supplier of natural gas and oil to the EU in the future.

In contrast to the anticipated substantial increases in natural gas demand over the next 30 years, European natural gas production is forecast to decline substantially over the coming years. According to the European energy and transport trends of 2030, the EU-27 natural gas production is expected to decrease from the level of around 200 billion m^3 today to approximately 100 billion m^3 in 2020; this represents a decrease of 50 % for the next 8 years. For example, the UK is projected to be importing between 50 % and 80 % of its gas needs by 2020. By that year, Dutch supplies are also likely to be in decline. While Norwegian natural gas exports are continuing to increase, they will reach a plateau between 95 billion m^3 and 100 billion m^3 in the late 2000s, and additional exports beyond this level will require new discoveries.

Finally, it is important to highlight the following: According to Eurostat sources, EU-27 natural gas production fell by 5.5 % in comparison with 2011. Of the main EU producers, the UK registered a drop in production of 14.4 %, with decreases of 12.5 % in Germany, 10.2 % in France, 9.2 % in Denmark, 0.4 % in the Netherlands and 0.3 % in Romania. In contrast, there was an increase of 30.4 % in natural gas production in Slovakia and 13.9 % in Spain.

Norway, the Netherlands, and the UK are by far the three largest producers of natural gas in OECD Europe, accounting for 85 % of total regional natural gas production in 2010. From 2000 to 2010, production in the Netherlands was fairly flat, as was production by the three largest producers combined, and in OECD Europe as a whole. Stability of total production volumes has been supported by significant growth in Norway's production, which has balanced declines in the UK's production. That balance will be broken in the mid-term, however, as production declines in the UK and much of the rest of Europe overwhelm any additional growth in Norway's production. The OECD Europe's natural gas production is expected to decline in the mid-term and then begins to grow again in the later part of the projection, as production from tight gas, shale gas, and coalbed methane resources becomes more significant. Overall, natural gas production in OECD Europe in 2040 is about the same as in 2010 (IEO 2013).

Summing up the following can be stated: There is an increasing gap between the EU-27 natural gas consumption and own production, which will change future supply patterns both internally and from outside the EU-27. Strengthening of existing supply corridors and establishment of new ones will be important. The internal EU-27 natural gas pipeline system has shown to be flexible and well-functioning even under cold conditions, but with very high capacity usage at some interconnections.

3.6 Natural Gas Consumption

According to different sources, natural gas consumption increased steadily in Europe over the period 1990–2008. It grew at an annual average rate of 4.2 % in the 1990s, but slowed to 2 % from 2000 to 2008. For the first time in 20 years, data on natural gas consumption for 2009 showed plunging natural gas demand in the face of the world economic contraction (but also because of the Russia–Ukraine dispute in January 2009), demand in OECD Europe fell by 5.6 %, losing about 26 billion m^3 and falling back to 2003 levels.[9] Natural gas demand data show that consumption in winter 2008–2009 fell back to winter 2003–2004 levels, according to IEA Natural Gas Information 2010. The picture was not identical across the region, with the major fall registered in Greece, Hungary, and Spain.

Natural gas consumption is expected to return to 2008 levels around the beginning of 2010s, but with major differences between the national markets, sectors of consumption, and period of recovery. Indigenous production and annual contracted quantity levels of imported natural gas can cover demand up until at least 2012, but all contracted natural gas, including LNG,[10] is expected to be below demand after 2014 (or later if demand does not pick up as anticipated), which means that, despite a catastrophic 2009 year for natural gas demand, Europe will need to secure additional natural gas supply probably as soon as 2015 to cover its still growing consumption.[11] The present utilization of below 50 % of LNG facilities is a good possibility to increase the LNG imports, thus diversifying even more. In the long term, focus will shift to ensure the availability of natural gas by filling the import pipelines and LNG import facilities.

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[9] The global market for natural gas is much smaller than for oil because natural gas transport is difficult and costly, owing to the relatively low energy content in relation to volume. Currently, only about 16 % of global natural gas production is traded internationally, with less than 4 % of the trade accounted for LNG. In spite of the high cost of natural gas transportation and the remote location of some future supply regions, increasing international trade in natural gas is expected to occur in the coming years (Bjørnmose et al. 2009).

[10] Natural gas that is mainly methane cannot be compressed to liquid state at normal ambient temperature. Except for special uses such as compressed natural gas (CNG), the only practical solution to long distance gas transportation when a pipeline is not available or economical is to produce LNG at −162 °C. This requires one or more cooling stages. Cooling work consumes between 6 % and 10 % of the energy to be transported. Special insulated tank LNG carriers are required for transportation, and at the receiving end, a regasification terminal heats the LNG to vaporization for pipeline distribution.

[11] The gap between natural gas consumption and the EU-27 own production of 300 billion m^3 is today covered by imports from Russia of 115 billion m^3, from Norway of 90 billion m^3, and from Algeria of 50 billion m^3, in all three cases by means of pipelines, and 45 billion m^3 further imports were LNG. Closing the future gap due to a decline in natural gas own production is foreseen to be covered by increased exports from the Norwegian area, by an increase in LNG imports and the remaining part to be covered by projects under construction, e.g., Nord Stream (50 billion m^3), Medgaz (8 billion m^3) and Nabucco (31 billion m^3). Together with other possible import projects and interconnections this will create a flexible, diverse, and robust natural gas import capacity system.

According to the IEO (2013) report, natural gas is the world's fastest-growing fossil fuel, with consumption increasing from 113 trillion cubic feet (3,990.6 trillion m^3) in 2010 to 185 trillion cubic feet (6,533.28 trillion m^3) in 2040; this represents an increase of 63.7 %. Growth in consumption occurs in every IEO region and is most concentrated in non-OECD countries, where demand increases more than twice as fast as in OECD countries. Natural gas continues to be favored as an environmentally attractive fuel compared with other hydrocarbon fuels. It is the fuel of choice for the electric power and industrial sectors in many of the world's regions, in part because of its lower carbon intensity compared with coal and oil, which makes it an attractive fuel source in countries where governments are implementing policies to reduce greenhouse gas emissions. In addition, it is an attractive alternative fuel for new power generation plants because of relatively low capital costs and the favorable heat rates for natural gas generation. It is expected that the total world consumption of natural gas for industrial uses increases by an average of 1.5 % per year through 2040, and consumption in the electric power sector grows by 2.0 % per year. The industrial and electric power sectors together account for 77 % of the total projected increase in natural gas consumption, and together they account for 74 % of total natural gas consumption in 2040, up slightly from 73 % in 2010.

Natural gas consumption in OECD Europe grows by 0.7 % per year on average, from 19.8 trillion cubic feet (699.24 trillion m^3) in 2010 to 24.5 trillion cubic feet (865.22 trillion m^3) in 2040, the lowest growth rate over the period, both in the OECD region and in the world. In comparison, OECD Europe's renewable energy consumption increases by an average of 2 % per year, and its consumption of both liquid fuels and coal declines through 2040. The decline in demand for energy from coal and liquids results in an increase in the natural gas share of OECD Europe's total energy consumption, from about 25 % in 2010 to 27 % in 2040. More than half of OECD Europe's 4.7 trillion cubic feet (165.98 trillion m^3) of growth in total natural gas consumption from 2010 to 2040 comes from the electric power sector, at 2.7 trillion cubic feet (95.35 trillion m^3). Although the amount of natural gas consumed for electric power production is expected to increase by an average of only 0.4 % per year from 2010 to 2020, it expected to increase by 1.7 % per year from 2020 to 2040, as economies recover from the global recession that began in 2008 (IEO 2013).

Many governments in OECD Europe have made commitments to reduce greenhouse gas emissions and promote the development of clean energy. Natural gas potentially has two roles to play in reducing carbon emissions. One role as a replacement for more carbon-intensive coal-fired power generation and second as backup for intermittent power generation from renewable energy sources. Natural gas is second only to renewable as Europe's most rapidly growing sources of energy for electricity generation, as its share of total power generation is expected to grow from 20 % in 2008 to 22 % in 2035, an increase of 2 % in the next 27 years. In addition, recent actions by some European governments to reduce their reliance on nuclear power in the wake of Japan's Fukushima Daiichi nuclear disaster are likely to provide a further boost to natural gas use in electricity generation in the region (IEO 2011).

However, it is important to highlight the following: The growth of Europe's natural gas markets has been hampered somewhat by a lack of progress in reforms that would make natural gas markets more responsive to or supportive of, electric power markets. The EU has been attempting to implement legislation that would ease third-party access to Europe's natural gas transmission pipelines and thus allows independent operators access to existing infrastructure. The EC ratified its Third Energy Package in 2009, and its stipulations were required to be passed into local law by March 2011. The regulatory changes should increase spot trading and make natural gas markets more flexible by making it easier for market participants to purchase and transmit gas supplies.

Growth in natural gas use for world's electricity generation is projected to account for the majority of total incremental natural gas use to 2030. Natural gas-fired power generation is less carbon-intensive than oil or coal-fired power generation and is expected to remain more cost-competitive than renewable energy during the coming years, making natural gas the fuel of choice for new generating capacity in OCED Europe during the coming decades. In the specific case of OECD Europe, natural gas consumption for electricity generation is expected to grow by 0.5 % per year on average, from 0.544 trillion m^3 in 2007 to 0.62 trillion m^3 in 2035, an increase of 14 % for the whole period, primarily as a result of increasing demand in the electric power sector. Natural gas accounts for about 25 % of the region's total energy consumption over the projection period, with the coal and liquid shares declining from their earlier levels.

From Table 3.4, the following can be stated: The major natural gas consumers in Europe were the UK followed by Germany, Italy, France, Netherlands, and Spain. The major producers of natural gas are the Netherlands, UK, Romania, and Germany. The major importers of natural gas are Germany, Italy, UK, France, Spain, and Belgium.

According to Fig. 3.5, during the period 1960–2009, one of the major increases in the demand of natural gas occurred in the power sector and this trend is expected to continue during the coming years. The consumption of natural gas in the industrial sector is expected do not change during the coming years.

Finally, it is important to highlight the following: The power sector holds the key to substantially increase natural gas demand in Europe over the next three decades. All projections of European natural gas demand see the power sector accounting for between 65 % and 80 % of the increase in natural gas demand over that period. The reasons for this increase in the use of natural gas for electricity generation are straightforward:

- At most likely natural gas prices, electricity generated by natural gas will have a cost advantage over that generated by coal;
- In several European countries, nuclear power plants are either politically unacceptable or commercially too risky to be built by private companies and some countries are going to close all of their nuclear power plants currently in operation in the coming years as consequences of the nuclear accident at the Fukushima nuclear power plant, and the strong public opposition to the use of nuclear energy for the generation of electricity;

Table 3.4 Natural gas gross consumption, production and imports in the European major markets (Billion cubic feet per year)

Country	Natural gas consumption	Natural gas production	Natural gas imports
Austria	318	64	268
Belgium	597	0	1,084
Croatia	95	14	95
Czech Republic	290	5	353
Denmark	138	226	0
Estonia	20	0	22
Finland	109	0	109
France	1,501	22	1,600
Germany	2,656	318	3,065
Greece	148	0	102
Hungary	343	109	208
Ireland	159	7	187
Italy	2,426	275	2,359
Latvia	51	0	55
Lithuania	117	0	192
Luxembourg	39	0	34
Netherlands	1,285	2,257	512
Poland	586	148	385
Portugal	166	0	73
Romania	477	385	115
Slovakia	212	4	145
Slovenia	31	0	26
Spain	1,109	6	1,225
Sweden	39	0	39
United Kingdom	2,765	1,448	1,374
Total	15,776	5,402	14,038

Source: BP Statistical Review of World Energy 2013 and Eurogas

- The use of renewable energy sources for the generation of electricity are currently more expensive than power generated from fossil fuels and, for this reason, are not expected to satisfy more than 20–30 % of electricity demand in the majority of countries over the next 30 years.

This picture suggests that natural gas can be regarded as the fossil fuel bridge to a sustainable electricity future and—as long as the differential between natural gas and coal prices does not widen too greatly—will be the most commercially attractive fuel for power generation in many EU countries. Undoubtedly, natural gas will continue to be the fuel of choice in many regions of the world in the electric power and industrial sectors, in part because of its lower carbon intensity compared with coal and oil, which makes it an attractive fuel source in countries where

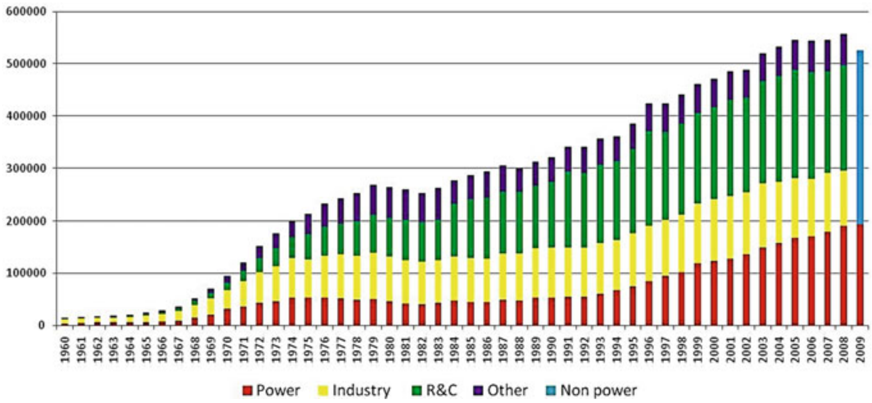


Fig. 3.5 Natural gas demand in OECD Europe during the period 1960–2009 (Million m^3)

governments are implementing policies to reduce greenhouse gas emissions, and because of its significant price discount relative to oil in many regions of the world. In addition, it is an attractive alternative fuel for new power generation plants because of low capital costs and favorable thermal efficiencies.

3.6.1 Natural Gas Demand in the Industrial Sector

Natural gas has innumerable uses in industry, and new applications are being developed every day. It is used to provide the base ingredients for such varied products as plastics, fertilizers, antifreeze, and fabrics. In fact, industry is the largest consumer of natural gas, accounting for 43 % of this type of energy source used across all sectors. Natural gas is the second most used energy source in industry, trailing only electricity. Industrial applications for natural gas also include the same uses as found in residential[12] and commercial settings—heating, cooling, and cooking. Natural gas is also used for waste treatment and incineration, preheating of metals (particularly for iron and steel), drying and dehumidification, glass melting, food processing, and fueling industrial boilers. Natural gas may also be used as a feedstock for the manufacturing of a number of chemicals and other products.

[12] Natural gas appliances are also rising in popularity owing to their efficiency and cost-effectiveness. Some examples of other natural gas appliances include space heaters, clothes dryers, pool heaters, fireplaces, barbecues, garage heaters, and outdoor lights. Natural gas fuel cells and micro turbines both offer residential consumers the possibility to disconnect from their local electricity distributor, and generate just enough electricity to meet their needs. Although this technology is still in its infancy, it is very promising in being able to offer independent, reliable, efficient, and environmentally friendly electricity for residential needs.

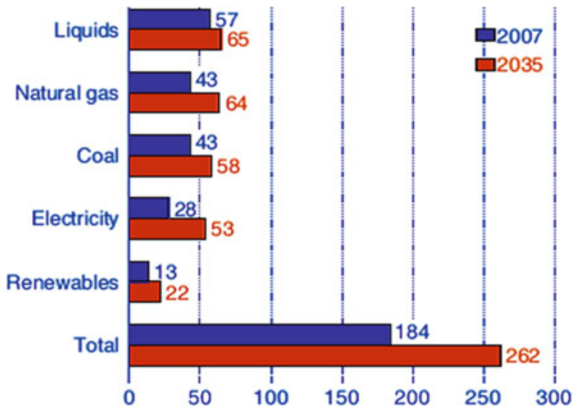


Fig. 3.6 World industrial sector energy consumption by fuel in 2007 and in 2035 (Quadrillion Btu). *Source:* IEO (2010)

Gases such as butane, ethane, and propane may be extracted from natural gas to be used as a feedstock for fertilizers and pharmaceutical products.

It is important to note that natural gas demand in the industrial sector started to slow down before 2008, when the current world's financial and economic crisis began, due to maturity of the sector in the major markets, relocations of industry, this means industry moving out of the area to countries with lower workforce salaries, and efficiency measures that were adopted.

However, natural gas remains a key energy source for industrial uses and for electricity generation throughout the coming decades. The industrial sector accounted for 44 % of total world's natural gas and it maintains that share through 2035 (43 %).[13] Because natural gas produces less carbon dioxide when it is burned than does either coal or oil, governments implementing national or regional policies to reduce greenhouse gas emissions are encouraging its use to displace other fossil fuels in electricity generation. In the electric power sector, for example, natural gas is often an attractive choice for new power generating plants because of its relative fuel efficiency, low emissions, quick construction timelines, and low capital costs, among others. For this reason, electricity generation is expected to become an increasingly important part of the world's natural gas consumption, and will account for 36 % of the world total in 2035, up from 33 % in 2007; this means an increase of 3 % (IEO 2010).

From Fig. 3.6, the following can be stated: Natural gas consumption in the industry sector will increase from 43 quadrillion Btu in 2007 to 64 quadrillion Btu in 2035; this represents an increase of 48.8 % for the whole period or an average annual increase of 1.74 %. The consumption of electricity in the industrial sector will be almost double in the period considered.

[13] Industrial use of natural gas is projected to increase at an average annual rate of 1.74 % from 2007 to 2035 (IEO 2011), as compared with an average increase of 1.1 % per year for liquids consumption in the industrial sector (IEO 2007).

With world oil prices expected to remain high relative to historical levels throughout the projection period, natural gas is projected to displace liquids in the industrial sector to some extent or at least will reach the same level of the liquids.

At the European level, industrial output was down by 13.7 % in 2009. All countries saw their industrial production decline abruptly as a result of the economic and financial crisis affecting the European region, but some countries were more severely hit by the crisis, such as Finland, Luxembourg, Hungary, Italy, Sweden, Germany, Czech Republic, and Spain. The other major natural gas markets (France, the UK, and the Netherlands) also faced severe reductions in industrial output.

During the major part of 2010, data show that industrial production was growing again in all countries except for Greece and Denmark. It was bouncing back particularly rapidly in Slovakia, Luxembourg, and more importantly, Germany, and Poland. Among other major natural gas markets, Netherlands was doing better, followed by France and Italy; the UK and Spain were much slower. It is worth noting that despite encouraging growth in 2010 no countries, with the exception of Slovakia and Poland, had returned to 2008 levels. In the major natural gas markets most were still very far from 2008 levels, particularly Spain, Italy, Germany, France, the UK, and the Netherlands.

Strict EU environmental regulations will force EU Member States to replace high-emission fossil fuels for electricity generation, such as coal, with cleaner burning energy sources, such as natural gas and renewables, and in some cases nuclear energy. This change will reduce significantly the emission of CO_2 in the coming years, and should facilitate that the EU could accomplish their commitment to the Kyoto Protocol.

3.7 Natural Gas Trade

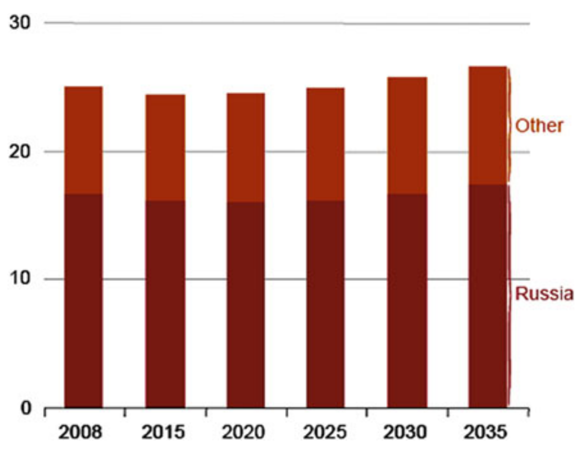
According to IEO (2013), in OECD Europe total natural gas imports is expected to continue to grow over the course of the projection, by an average of 1.6 % per year from 2010 to 2040 as local production sources decline, especially in the UK. Pipeline imports of natural gas to OECD Europe peaked in 2007 and 2008, when they accounted for 37 % of OECD Europe's total supply. Since the onset of the financial crisis in late 2008, which resulted in lower natural gas demand and excess supplies worldwide, buyers generally have preferred to buy larger volumes of LNG or other uncontracted natural gas on spot markets rather than opting for supplies tied to more expensive contracts linked to world oil prices. In 2009 and 2010, the pipeline share of OECD Europe's total natural gas supply declined to 34 %, while the LNG share grew to 13 % in 2010. The pipeline share of OECD Europe's natural gas imports grows to between 40 % and 50 % of total natural gas supply. LNG imports grow to around 20 % of supply and maintain that share through 2040. The recent increase in LNG supplies to OECD Europe, and particularly to the UK, has added complexity to natural gas pricing in the region. In comparison to long-term contracts with prices linked to oil and petroleum product prices, LNG supplies have improved the prospects for spot market trading. Continental Europe's long-term contracts with suppliers of pipeline gas, which include Russia, Algeria, and Norway, among others, have some flexibility in terms of volumes, but the prices generally are linked to lagged prices for oil products. Although some suppliers, such as Norway, switched as much as 30 % of their contracted volumes to spot market pricing, other countries, such as Algeria, altered their pricing far less or not at all (PFC Energy 2011). The subsequent loss of market share by pipeline suppliers to OECD Europe with less flexibility in pricing since 2008 may indicate eventual changes in the pricing of pipeline imports from a variety of countries—including Russia, which is by far the largest exporter to Europe. However, the extent of such changes over the long term remains to be seen.

Natural gas trade involving OECD Europe has recently experienced some major shifts. In 2009, natural gas demand was down approximately 8 % from 2008 as a result of the global economic recession affecting almost all countries in the region. At the same time, imports of LNG were up 27 % (Chan 2010) and imports of Russian pipeline natural gas were down almost 25 % (Gazprom 2010). Continental Europe's long-term natural gas contracts have some flexibility in terms of volumes, but the prices generally are linked to lag prices for oil products. Thus, despite the drop in demand following the global economic recession, most natural gas prices remained high, with the extremely high oil prices from 2008 continuing to figure into contract natural gas prices during the coming years.

Russian natural gas imports account for 26 % of EU consumption, representing 40 % of the imported natural gas consumed by households and businesses. In Central and Eastern Europe, Russian natural gas accounts for 87 % of total imports and 60 % of consumption.

According to Fig. 3.7, the supply of natural gas from Russia to non-OECD Europe and Eurasia during the period 2008–2035 will continue to be above 15 trillion cubic feet or 529.725 trillion m^3, and will be the main supplier of natural gas for these two regions.

Fig. 3.7 Natural gas consumption in non-OECD Europe and Eurasia expected to occur during the 2008–2035 (Trillion cubic feet). *Source:* IEO (2011)



3.7.1 Import and Export of Natural Gas

On the other hand, increasing imports from some of the natural gas supplier countries would be a costly endeavor requiring massive investments to develop the necessary extraction, production, and transportation infrastructure. Piping natural gas from Algeria would require undersea pipelines, which are far more costly than overland pipelines. For this reason, the EU is looking to tap other sources of natural gas, such as the Caspian Basin and Central Asia, but these two regions, like the Middle East, are characterized by high levels of political instability and are thus less reliable as suppliers. As for LNG imports, it is important to stress that they are economically viable only over large distances (Table 3.5).

According to Eurostat sources, the total EU-27 imports of natural gas increased by 1.8 %. Russia is the country of origin for 31.9 % of natural gas imports (Intra-EU trade excluded), Norway supplies 29.4 %, Algeria 13.8 %, Qatar 8.7 % and Nigeria 3.4 % (Table 3.6).

The EU is the single largest trade partner of Russia and accounts for more than 50 % of its foreign trade, 45 % of its imports and 55 % of its exports (see Table 3.7). Today the EU receives 88 % of Russia's total oil exports, 70 % of its natural gas and 50 % of its coal. In total, 75 % of cumulative foreign investments in Russia are from the EU. During 2013, seven European countries relied on Russia for more than 80 % of their natural gas consumption and 11 for more than 50 % of their natural gas consumption. By 2020, Russia's gas export capacity in Europe is expected to increase to 250 billion m^3 per year and 300 billion m^3 per year by 2030. However, until 2013, Russia only has contracts for 158 billion m^3 per year to Europe. The supply of oil, natural gas, and coal could be lower than expected due to the political crisis in Ukraine and the sanctions applied against Russia by the EU and the USA.

From Fig. 3.8, the following can be stated: During the period 2015–2040, the use of natural gas will increase in the electricity sector, but will remain flat in buildings and in the industrial sectors as a result of several measures adopted by different EU countries in order to increase energy efficiency.

Table 3.5 The first ten importers countries of natural gas in the world in 2012 (Million m^3)

1	United States	105,800
2	Germany	99,630
3	Japan	98,010
4	Italy	70,200
5	United Kingdom	53,630
6	France	46,200
7	Korea, South	42,380
8	Russia	38,200
9	Turkey	38,040
10	Spain	36,710

Source: World oil and gas review 2012

Table 3.6 The first ten exporter countries of natural gas in the world

Position	Country	Thousands m^3	Per capita m^3	Year
1	Russia	196,000,000	1,375.4	2013 est.
2	Qatar	113,700,000	134,077.7	2011 est.
3	Norway	107,300,000	22,794.5	2012 est.
4	Canada	88,290,000	2,574.0	2012 est.
5	Netherlands	74,060,000	4,426.6	2012 est.
6	Algeria	52,020,000	1,486.5	2011 est.
7	United States of America	45,840,000	146.1	2012 est.
8	Slovakia	45,430,000	8,285.5	2012 est.
9	Turkmenistan	41,100,000	8,130.8	2012 est.
10	Bolivia	40,280,000	3,914.5	2012 est.

Source: http://world.bymap.org/NaturalGasExports.html

Table 3.7 Major European recipients of Russian natural gas exports in 2013

	Primary energy (%)	Natural gas (%)
Austria	12.8	52.2
Belgium	10.9	43.2
Bulgaria	13.6	100
Croatia	9.4	37.1
Czech Republic	14.2	80.5
Estonia	10	100
Finland	10.6	100
France	2.7	17.2
Germany	8.7	39.9
Greece	7.2	54.8
Hungary	19.7	49.5
Italy	7.5	19.8
Latvia	31	100
Lithuania	50	100
Luxembourg	6.1	29.7
Netherlands	2.1	5.8
Poland	8.3	54.2
Romania	8.8	24.2
Slovakia	20.3	63.3
Slovenia	6.3	57.4
Sweden	1.9	100

Source: Gas data from Eurogas, BP statistical review of world energy 2013, and EIA

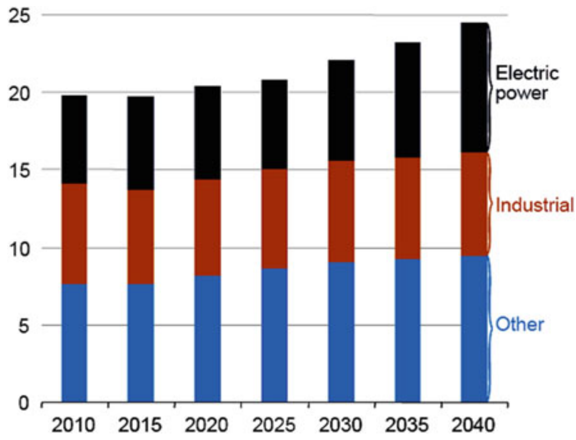


Fig. 3.8 Natural gas consumption in OECD Europe by end-use sector during the period 2007–2035 (Trillion cubic feet). *Source:* IEO (2013)

3.8 Natural Gas Prices in Europe

According to the IEO (2011) report, as natural gas markets have changed over the past several decades, the pricing of natural gas in Europe has evolved. Until the 1980s, when the UK began liberalizing its natural gas market, European markets consisted largely of national or regional monopolies, which held exclusive control over all aspects of natural gas within their territories. Over time, as regulations have been enacted to encourage free markets, and as new infrastructure has made European markets more interconnected, pricing has begun to change. Although long-term contract pricing has not been abandoned, the influence of spot market pricing is growing. Natural gas prices in Europe are likely to become more competitive in the future as infrastructure expands and as new potential supply sources—such as unconventional natural gas—become commercial.

Continental Europe did not begin liberalizing its natural gas markets until the 1990s, when the EU officially abolished national and regional gas monopolies. In the early 2000s, through the EU's Second Gas Directive and other measures, continental gas markets were further liberalized, with elimination of destination clauses in all new import contracts and some existing contracts; requirements for third-party access to natural gas transmission, distribution, and LNG infrastructure; requirements for legal and functional unbundling of transmission operators from competitive businesses; creation of national natural gas regulators; and the establishment of policies allowing consumers to choose their natural gas providers (beginning in 2004 for commercial consumers and in 2007 for retail consumers).

In some respects, the EU's Second Gas Directive stopped short of full liberalization. For example, it did not require third-party access to storage, nor did it mandate full ownership unbundling of transmission assets. However, its biggest weakness was that it failed to directly address market concentration in individual nations, leaving intact companies that were still effectively national gas monopolies. As a result, competition across the value chain was limited by supply and import contracts that encompassed most of the available natural gas. For this reason, the EU's Second Gas Directive initially had little impact on natural gas prices. In 2004, the volume-weighted average duration of downstream contracts was 15 years in Germany, around 6 years in the Netherlands and Poland, around 4 years in France, and less than 2 years in Italy. Since the implementation of the EU's Second Gas Directive, additional measures have been taken in Europe to encourage market development. Europe's natural gas markets have become physically more connected to each other and to the rest of the world. Pipelines have been expanded to link the UK's liquid gas market to the rest of Europe through Belgium and the Netherlands, and additional pipeline connections currently are planned or under construction to better interconnect nations on the European continent.

The EU's Third Gas Directive was adopted in 2009, requiring implementation by March 2011. It seeks to improve EU-wide coordination of transmission regulations and strengthen third-party access requirements and transmission unbundling requirements. It still does not require full unbundling of the ownership of transmission assets, nor does it deal directly with the market concentration of incumbent national gas companies. Although the EU's Gas Directives did not directly challenge the dominance of national incumbents, the 2008–2009 economic downturns did. Natural gas demand in Europe declined sharply after the economic downturn in late 2008, while at the same time the supply of free natural gas (natural gas not controlled by incumbent gas companies, mainly in the form of LNG) was increasing. The EU has voiced interest in expanding its share in LNG over the next 10 years and diversifying its imports away from Russia, particularly after the Ukraine political crisis. The EC is not only concerned about is gas supply security, but increasingly by the rising gas price difference between the US and EU. Between 2005 and 2012, gas prices in the US industrial sector decreased, mainly due to the shale gas revolution, but they rose by 35 % during the same period in the EU. A dispute over natural gas prices has forced Gazprom to cut them by an average of 12 % in 2012. But only 20 % of Gazprom's gas exports to Europe in 2012 were spot market deals, and the remainder was fixed formulae.

The increase in available natural gas supply caused spot prices for natural gas in European markets to fall. However, long-term contract prices, because of their lagged linkage to oil prices, did not fall as far or as fast after the economic downturn. The significant difference that opened up between natural gas prices in spot markets and the prices under oil-linked contracts incentivized many European customers to abandon the incumbents with their oil-linked contracts and instead buy natural gas from the developing spot markets, causing a take-or-pay crisis that left incumbent natural gas companies in continental Europe committed to buying too much natural gas at too high a price and with too few customers wanting too little gas.

The pressures on Europe's incumbent gas companies as a result of their take-or-pay commitments have so far been managed through price review clauses in the contracts and through quantity flexibilities beyond the amounts normally allowed by the contracts. Neither long-term contracts nor contract prices linked to oil were entirely abandoned as a result of the take-or-pay crisis. In continental Europe, contract price reviews have resulted in some incorporation of hub natural gas prices into formulas that previously linked contract gas prices to oil prices, but the extent to which hub prices have been adopted varies. Norway was the most willing to incorporate hub prices; Algeria was not at all willing to do so. Russia in small measure incorporated hub prices into some contracts to North European customers, where relatively liquid gas hubs exist, but refused to incorporate them into Southern European contracts, citing the limited liquidity at natural gas hubs in the region. The additional quantity flexibility comes at a high price. Companies that have been unable to take their minimum quantities still have had to pay for them, but they will be allowed to take them at a later point, sometime in the next few years.

Natural gas volumes paid for but not delivered under take-or-pay provisions grew in 2009 and 2010 as LNG imports into Europe, and especially the UK continued to increase, and imports from Russia continued to decline. It is still unclear whether take-or-pay volumes will continue to increase in 2011 and beyond, or whether companies will instead be able to take delivery of some accrued volumes in addition to their minimum volumes for 2011 and beyond. Several factors have helped lessen the pressures on European long-term contracts. Demand for natural gas in Europe and for LNG in Asia recovered in 2010, helping to keep global LNG markets and European spot markets from loosening further, even as LNG production increased by almost 20 % from 2009. With the little additional growth in global liquefaction capacity expected until after 2015, LNG markets are likely to tighten somewhat in response to the additional demand. European spot markets for natural gas are likely to continue to grow steadily as a result of continued improvement of physical and regulatory infrastructures. Progress could be slowed, however, by regulation that is relatively weak in comparison with still-powerful national incumbents that often are championed by their home governments. Other factors could push markets to develop more quickly.

Significant additional LNG liquefaction capacity is under construction or proposed for 2015 and beyond, and while most of it is in the Pacific Basin, it could still indirectly affect Europe, by pushing more flexible LNG back into the Atlantic Basin and into European markets. Further, a significant amount of new LNG export capacity has been proposed for the US Gulf coast; and while most of the new Pacific liquefaction capacity is likely to be tied up in relatively inflexible long-term oil-linked contracts, adding little short-term liquidity to Pacific markets, the same cannot be said for any potential US exports.

Finally, European spot markets could develop more rapidly than expected if natural gas production from shale gas formations comes online more quickly or in greater quantities than European incumbents are expecting, as happened in North America. And, with physical and regulatory barriers continuing to lessen over time, the next time such a boom in free market-oriented natural gas occurs, the consumer shift from incumbent wholesalers with oil-linked purchase obligations to spot purchases at gas hub prices could be much greater than was seen in 2009 and 2010.

3.9 Natural Gas Security

According to McGowan (2010), a large part of the EU's effort to address energy security has been framed by concerns over natural gas, as borne out by the calls from some Central and Eastern EU Members States for the creation of an "Energy NATO" and, more successfully, for the inclusion of a solidarity clause in the EU's Lisbon Treaty. While concerns over energy security have never been far from the energy policy agenda of the EU (whether collectively or in individual States), they have become particularly important over the past 5 years, with natural gas increasingly seen as the source of vulnerability.

Natural gas dependency in EU-27 is 65.6 % in 2012, slightly less than 67.3 % in 2011. In EU-15 Member States, energy dependency is higher than 90 %.

3.10 Unconventional Gas

Unconventional gas are deposits of natural gas found in relatively impermeable rock formations—tight sands, shale, and coalbeds. To get the gas out of the ground, artificial pathways (fractures) have to be created and specific technologies have to be used. Key technologies are horizontal drilling and modern fracturing techniques.

In February 2011, the European Council stated that: "In order to further enhance its security of supply, Europe's potential for sustainable extraction and use of conventional and unconventional (shale gas and oil shale) fossil fuel resources should be assessed." There are three main types of unconventional natural gas produced today. These are:

- *Tight gas*. This is natural gas trapped in relatively impermeable hard rock, limestone or sandstone;
- *Coal-bed methane* (CBM). This is natural gas trapped in coal seams, adsorbed in the solid matrix of the coal;
- *Shale gas*. This is natural gas trapped in fine-grained sedimentary rock called "shale" that has a characteristic 'flaky' quality.

3.10.1 Shale Gas

Shale gas is a natural gas produced from shale. It belongs to unconventional sources of gas extracted from the rock formations that act as both the source and the reservoir for the natural gas itself. Shale gas is located in a large territorial area, by contrast to conventional gas, which is available in a more concentrated fashion. Numerous wells need to be drilled and analyzed in order to sufficiently determine the potential of a shale formation. The extraction process of shale gas involves stimulating the reservoir to create additional permeability in order for the shale gas to be extracted. Shale gas exploration and development counts five main stages:

- Identification of the gas resource site;
- Early evaluation of the site for drilling;
- Pilot project drilling;
- Pilot production testing of the potential production of the site;
- Commercial development of the site.

Hydraulic fracturing involves the high-pressure injunction of fluids usually mixed with chemical products, into a shale rock formation (90 % of water, 9.5 % of sand or other components like ceramics and 0.5 % other chemicals such as acids, chlorides, salts, isopropanol, among others. Horizontal drilling involves drilling a vertical well to the desired depth and then drilling laterally through the targeted shale formation. Hydraulic fracturing and horizontal drilling are two techniques well known in the industry. What can be considered as new with shale gas activities with respect to these techniques is the combination of technologies used, and especially the large-scale use one must make of these for exploiting shale gas.

In 2009, the IEA estimated that world's shale gas resources totaled 456 trillion m^3, with 109 trillion m^3 in North America (23.9 % of the total), 174 trillion m^3 in Asia (38.2 % of the total), 72 trillion m^3 in the Middle East and North Africa (15.8 % of the total), and 16 trillion m^3 in Europe (3.5 % of the total). In other areas, the level of shale gas in 2009 was 85 trillion m^3 (18.6 % of the total). From these figures the following can be stated: Europe is not one of the best endowed regions of shale gas potential. However, according to McGowan (2010), there has been considerable activity in obtaining concessions and starting the exploration of shale gas in specific areas of the region such as South and Central regions of Sweden, the Northwest and South East of England, Lower Saxony in Germany, as well as in Austria and France. Particular attention has focused on the prospects for shale gas development in Poland, with 58 concessions granted over the past 3 years. For Poland, becoming a major producer of shale gas would transform the country's energy balance and security. However, whether shale gas can play a direct role in enhancing the country's energy security will have to wait and evaluate the impact in all economic sectors. According to the Polish Ministry of Environment, "there is unlikely to be much production of shale gas before the next decade". Indeed, most analyses of a direct contribution to European energy balances indicate that at least one decade is needed for the development of shale gas in the region.

There is also skepticism among many involved in the gas industry as to the likely contribution of shale gas even in the medium term. The most obvious source of such doubts stems from concerns that European geological conditions will not prove as rich in shale gas as those in Asia or North America. Some exploratory efforts have shown disappointing results, for example in Hungary. European shale gas deposits are expected to be found in greater depth, rendering exploration and production more expensive than in North America.

In addition, in terms of infrastructure, Europe is less well geared up for onshore gas exploration and production. But perhaps the most difficult problem to overcome will be that of the acceptability of shale gas. The environmental problems that have become a feature of the USA debate are likely to prove just as hard if not harder to overcome in Europe. With a greater population density in many of the likely plays and tougher planning and environmental standards, the combination of local opposition and stricter controls may mitigate against the sort of dynamic expansion of the production of shale gas in the region seen in the USA.

On the other hand, a recent analysis from the industry association EUROGAS suggests that in the medium-term unconventional gas production, primarily shale gas, but possibly other sources such as coal bed methane, could reach levels of 20–25 million tons of oil equivalent within the EU-27 in the coming years. This level is very small compared with the existing natural gas production of just over 150 million tons oil equivalent and total natural gas consumption of around 400 million tons oil equivalent in 2009. With an EU conventional production forecast to fall to around 100 million tons oil equivalent and consumption forecast to rise close to 500 million tons oil equivalent by 2020, such a contribution from shale gas is not going to transform the EU gas market in the way it has done in the USA. Other estimates are more optimistic, suggesting production levels twice as high and a more modest level of overall consumption, boosting the relative importance of the resource considerably. Even then, the relative impact of shale gas in Europe will be more limited than in the USA, given that the region will remain largely dependent on imports for most of its gas requirements. However, such a contribution could ease the decline in primary energy production within the EU in the coming years.

Finally, it is important to highlight the following: The EC is of the view that shale gas will have little effect on European energy markets or energy policy in the near future. The "stock taking" document on energy strategy released in the spring paid almost no attention to this new type of gas resources. Subsequent comments from EU Commissioner for Energy have also tended to play down the role that shale gas might play in European markets in the near future.

Summing up the following can be highlighted:

- Shale gas does have the potential to extend impact global gas markets, but only under strongly optimistic assumptions about its production costs and reserves;
- In a scenario favorable to shale gas development, natural gas as a whole has the potential to capture 30 % of the world's total primary energy supply by 2025, rising further to 35 % by 2040. This would make it surpass oil as the world's foremost source of energy;
- Relative to a scenario that is not carbon constrained, strict CO_2 emissions targets to reduce the production of natural gas, including shale gas. However, the strict CO_2 emissions targets modeled do not preclude a significant absolute growth in natural gas use. Therefore, support the potential role of natural gas as a bridge fuel;
- Shale gas is relatively evenly dispersed around the world and the majority of regions will likely witness at least some level of production in the future. The USA and China are well placed to become the top producers of shale gas, although significant production also takes place in most of the other regions. The scenario analysis suggests that shale gas will tend to be used within the

regions where it is produced. No single region is expected to produce enough shale gas so as to move from being a net importer to a net exporter;

- The global trade in natural gas, driven by conventional gas, will increase in any scenario. Shale gas development, however, has the potential to moderate the degree of growth, particularly for interregional LNG flows. Low LNG costs would mitigate the reduction in trade resulting from widespread shale gas development;
- The significant shale gas production has the potential to lower natural gas prices, although the extent of this reduction strongly depends on the way natural gas will be priced in the future. In particular, oil indexation has the potential to reduce the fall in natural gas prices resulting from shale gas development;
- The degree of penetration of natural gas in transport strongly depends on the oil–gas price link. A weaker link implies greater potential for shale gas to induce a significant growth of natural gas use in transportation;
- The impact on demand in an optimistic shale gas scenario is not equal across all regions. Much depends on the relative competitiveness of fuels and technologies in each region. This is particularly apparent for electricity generation. While shale gas can induce a dramatic change in the USA's electricity generation mix, its impact on China's mix is more limited;
- Shale gas production will not make Europe self-sufficient in natural gas. The best case scenario for shale gas development in Europe is one in which declining conventional production can be replaced and import dependence maintained at a level around 60 %. Regarding trade flows, the structure of EU gas imports is very sensitive to the LNG cost assumptions (Pearson et al. 2012).

The unique characteristics of each shale site mean that it can take a number of years for a producer to find the best way to exploit an area, resulting in only small volumes of gas being drilled at the start of the project before it can start the production of a larger scale.

3.10.2 Tight Gas

Tight gas development is, from a variety of viewpoints, an underappreciated component of the unconventional oil and gas industry. Like shale, this unconventional resource will enjoy double-digit percentage point growth in capital expenditure over the next 5 years. However, large-scale production is limited to North America and China, a situation that is expected to change by 2023.

On the other hand, Europe, as one of the bigger net energy importers in the world, is trying to find different sources of energy to meet its demand, particularly conventional and unconventional gas. Stimulated by concerns surrounding the depletion of North Sea assets and the monopoly held by Gazprom, several European countries led by Ukraine, Hungary, Slovenia, and Poland have begun studying the possible role that tight gas could have in the energy mix of these countries during the coming decades.

While tight gas is likely found in equal amounts both onshore and offshore, onshore exploration predominates, thanks to better seismic knowledge of the formations in which it is located.

The main problem to be overcome in the case of tight gas is that without secondary production methods, gas from a tight formation would flow at very slow rates, generally making production uneconomical. Until today, major production of tight gas is concentrated in the USA. Recent exploration in Europe has also been successful revealing rich deposits of unconventional gas resources in several European countries. Extraction of these resources has mainly begun in Hungary, Ukraine, and Poland. In addition to these countries, tight gas developments have also been seen in Ireland, the Netherlands, and Sweden. With continued success in the exploration, development, and production of unconventional resources, Europe will not only be able to meet its own growing energy demand, but it can also emerge as a significant producer in the future if public opinion can be pursed that the extraction of tight gas will not have a negative effect in the environment and the population. Expert's calculations determined that the value of capital expenditure on tight gas exploration and production efforts reached US$8,718.9 million in 2013.

3.10.3 Coalbed Methane

Coalbed methane (CBM) is formed by the decomposition of organic material found in coal that is too deep or too poor quality for commercial mining. Although occasionally found at shallow depths, CBM is often buried between 1,000 and 2,000 m underground. At these depths, the underground water pressure pushes the methane to the surface of the coal, where it can then be extracted. It is most often produced using vertical wells and much smaller fracks than what are typically seen in shale gas production, although horizontal drilling is becoming increasingly common in some areas. To remove the gas, the water must first be removed by depressurizing the coal bed. As the pressure drops, water production decreases and the gas is released into the wellbore. The time needed to dewater the reserve varies from source to source and can range from a few months to a few years, meaning that not all CBM reservoirs are commercially viable. Once the water has been removed, it is either reinjected into the extraction process or pumped into evaporation ponds. The water is not potable, but it can often be used for land irrigation. The IEA has estimated CBM to be the source of 10 % of the United States' 2008 total gas production, 8 % in Australia, and 4 % in Canada. CBM pilot projects are currently underway in France and the UK.

3.11 Liquefied Natural Gas

Although natural gas can be piped in a gaseous state,[14] it needs to be liquefied so that it can be economically transported by ship. A full LNG chain consists of a liquefaction plant, low-temperature, pressurized, transport ships, and a regasification terminal. World LNG trade is currently about 60 million metric tons per year, some 65 % of which is imported from Japan. Other importers include France, Spain, Korea, Belgium, Taiwan, and Italy. Indonesia accounts for 39 % of LNG exports, with Algeria in second place with 24 %. Other exporters include Malaysia, Brunei, Australia, Abu Dhabi, and Libya. The USA imports and exports about one million metric tons of LNG per year. No grassroots LNG project has been commissioned since 1989 owing to intense competition with other fuels, notably oil (Demirbas 2010).

LNG accounts for a growing share of world natural gas trade according to the IEO (2011) report. World natural gas liquefaction capacity is expected to increase 2.4 fold, from about 0.1904 trillion m^3 in 2008 to 0.4522 trillion m^3 in 2035. Most of the increase in natural gas liquefaction capacity will occur in the Middle East and Australia, where a multitude of new natural gas liquefaction projects is expected to be developed in the coming years, many of which will become operational within the next decade. Utilization of natural gas liquefaction capacity is expected to remain high during the entire projection period. Despite the growing importance of LNG, long-distance pipelines remain an important component of world natural gas trade. As indigenous natural gas production in OECD Europe declines, its import demand increases, driving much of the global growth in pipeline traded gas.

The recession and long-expected increases in global supplies of LNG combined to push European spot prices for natural gas well below those of long-term oil-linked prices, spurring those consumers who could access LNG on the spot market to increase their LNG purchases. In Europe, in 2009 oil-linked prices were, at times, twice as high as LNG spot prices (Gazprom 2009). Volume flexibility in long-term contracts was inadequate to deal with the drop in demand and the increased LNG supplies. As a result, European consumers accepted less natural gas than contractual minimums and may have failed to take as much as US$2.8 billion worth of natural gas under take-or-pay contracts (Gazprom 2010).

In Europe and Asia, LNG from North America would represent a major alternative to imports from traditional suppliers such as Russia, Norway, Qatar (with increasing frequency of late) and in future also many other countries in Africa. In continental Europe, the markets for natural gas are already in upheaval. Long-term contracts, for example with Russia, which also used to appear to be particularly interesting commercially, are now regarded as being far less appealing. The very

[14] LNG is a product of natural gas, which consists primarily of methane. Its properties are those of liquid methane, slightly modified by minor constituents. In its liquid state, LNG is not explosive and cannot burn. For LNG to burn, it must first vaporize, then mix with air in the proper proportions (the flammable range is between 5 % and 15 %), and then be ignited.

inexpensively priced open supply of gas has in the meantime had an effect that appeared to be utopian just a few years ago. Following protracted negotiations—some of which lasted several years—even Russia has recently shown that it is prepared to make concessions on the conditions of its long-term contracts (with E. ON and RWE, for example). Currently, the particularly important gas suppliers to continental Europe from Norway and Russia are now accepting spot price components in their gas contracts. Norway already is much further ahead in the open gas market.

Contributing to abundant European supplies in 2009 were additional LNG imports from Qatar, which brought three new natural gas liquefaction trains online, and new regasification facilities in the UK and Italy.

Continued growth is expected for natural gas imports, as global LNG supplies continue to expand rapidly over the next few years and as the Medgaz pipeline from Algeria begins exporting natural gas to Spain in the 2010s (Smedley and Junnola 2010). Furthermore, the Nord Stream pipeline from Russia and the Galsi pipeline from Algeria could push additional natural gas supplies into OECD Europe as soon as 2012–2013 and 2014, respectively, according to planned start dates.

Finally, increasing imports of LNG, could also be considered as an alternative to the currently predominantly imported natural gas in gaseous form, since it transportation is realized though different means, mainly though shipping. The benefits of increasing LNG imports are the lower cost of transportation relative to pipeline costs. Europe is currently accounting for only approximately 8 % of the total world LNG consumption (with Asia consuming 92 %). In case of disruption of supply of mainstream energy sources, LNG could play a very important role in filling the gap, mainly because its supply does not require the crossing of countries, which could undermine the process. Thus, Europe's regasification capacity of LNG will become an important aspect, with countries like Italy and Spain leading the way. Currently, Algeria is Europe's main LNG supplier, but Libya and Egypt are now entering the market as well (Borisocheva 2007).

Summing up the following can be stated: In the EU, as well as in other countries and regions, natural gas remains a fuel of choice, particularly for the electricity generation, given its high efficiency and its effects in the environment.

3.12 Investment in the Natural Gas Sector

According to Fraser (2003), the current market preference for gas-fired power generation for base load generation in many OECD countries can be explained mainly by the perceived lower cost of gas-fired power generation. The characteristics of the combined cycle gas turbine (CCGT), its low capital cost, and its flexibility has also added to its attractiveness. The importance of CCGT means that natural gas markets assume a greater importance than ever for power generation development. For governments, this means moving forward on liberalization, and monitoring investment in both natural gas and electric infrastructure.

The preference for gas-fired power generation does expose investors to increased fuel price risk.[15] The creation or development of electricity and natural gas markets has led to a system where, in the absence of hedging possibilities, price risks cannot be managed, but must be assessed by probabilistic approaches.

The absence of liquidity in financial markets for electricity and for natural gas, particularly for long-term products, means that investors must seek other means of hedging their electricity price and fuel price risks. Long-term contracts for electricity between producers and retailers help both manage price volatility. There has also been increased merger activity between generators and retailers in several markets. Mergers between electricity and natural gas producers are partially motivated by increased opportunities for arbitrage.

Power generating companies are also growing in size, in part to be able to finance more of their investment on their own balance sheets. These mergers are increasing concerns about the potential impacts on competition in electricity markets and can be expected to continue to attract close regulatory attention.

The IEA forecasts show that Europe could be up to 65 % dependent on natural gas imports by 2030. They also show that natural gas demand may rise from some 500 billion m^3 per year to over 600 billion m^3. Worldwide, natural gas demand is expected to rise more dramatically. Meanwhile, Europe's supply regions—both indigenous and external—are exposed to natural decline. The IEA estimates that if new investments are not made, this natural decline could halve supply by 2030. In other words, there is a pressing need to develop an additional production capacity of 250 billion m^3 within the next 20 years in order to sustain natural gas consumption in Europe at current levels. This highlights the importance of encouraging timely investment in new and enhanced European natural gas production while simultaneously securing investment in diverse sources from beyond Europe. To avoid any shortfalls in energy supply, that work must begin immediately.

In order to increase the participation of natural gas in the energy mix of Europe in the future,[16] the EU needs an investment of €150 billion in the construction of new gas-fired power plants and an additional €220 billion on natural gas infrastructure. Cumulative investment in the natural gas supply chain over the period 2001–2030 has been estimated to be US$3.1 trillion, more than half of it in exploration and development. Annual spending increased from an average of less than US$80 billion in the 1990s to US$95 billion during the current decade, and

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[15] The cost of fuel can be a significant additional risk to profits, particularly for technologies where fuel costs are a high proportion of total generating costs. Natural gas technologies are particularly sensitive to fuel prices and price volatility, as fuel costs tend to constitute the majority of generating costs (Fraser 2003).

[16] Over the next 20 years, the role of natural gas in global energy consumption is expected to increase substantially. The speed of the transition to natural gas will be driven by environmental constraints, increased demand, and new technologies. A potential source of natural gas lies in the enormous worldwide natural gas hydrate reserves. It was estimated that the size of this resource ranges up to 20,000 trillion m^3 (Kvenvolden 1993).

close to US$120 billion in the third decade of the projection period.[17] Upstream investment will be needed mainly to compensate for the natural decline in production capacity, as well as to meet a near-doubling of natural gas demand over the projection period. On average, an additional 300 billion m^3 of new natural gas production capacity will be required each year—the equivalent of the total current natural gas production capacity of OECD Europe.

Global investment in transmission and distribution networks, underground storage and LNG liquefaction plants, ships and regasification terminals will amount to US$1.4 trillion. A tripling of the physical interregional natural gas trade by 2030 will call for rapid growth in cross-border supply infrastructure. LNG investments will be higher than in the past, because a sixfold increase in LNG trade will more than offset further reductions in unit costs (Birol 2003).

3.13 Use of Natural Gas for Electricity Generation

Natural gas is one of the most widely used forms of energy today. The generation of electricity is one of the main uses of natural gas.[18] Natural gas power plants generate more than a couple of hundred megawatts using the same technology as coal-fired power plants. It is important to highlight that producing electricity from natural gas is in some countries more expensive than using other energy sources because of increased fuel costs. The majority of natural gas-fired electricity production is from electricity-only plant (74 % of the total). However, the share of natural gas-based electricity production from CHP plants is important in some countries. For instance, in Denmark, Poland, the Slovak Republic, Sweden, Switzerland, and Russia, IEA statistics record all natural gas-fired electricity production as coming from CHP plants. Higher than average shares for CHP plants are also found in France, Finland, the Czech Republic, the Netherlands, Hungary, Germany, Austria, Canada, and Italy.

The widespread introduction of successively more efficient CCGT plants in OECD countries has been the main driver behind the increase in both the use of natural gas for electricity production and the average generation efficiency. The latest CCGTs can have efficiencies of about 60 %.

In the electric power sector, natural gas is an attractive choice for new generating power plants because of its relative fuel efficiency and low carbon dioxide

[17] It is important to highlight the following: The private sector will have to provide a growing share of investment needs because State companies will not be able to raise adequate public finance in order to provide the resources needed, particularly during the current economic crisis that are still affecting most of the countries in the EU. The lifting of restrictions on foreign investment and the design of fiscal policies will be crucial to capital flows and production prospects, especially in the Middle East, Africa, and Russia, where much of the increase in global natural gas production and exports is expected to occur in the coming years.

[18] Natural gas is one of the cheapest forms of energy available to the residential sector.

emissions. Electricity generation will account for 35 % of the world's total natural gas consumption in 2030 (Demirbas 2006).

In Europe, indigenous electricity generation was down by 4.9 % in 2009. The sector was less impacted than industrial output, which may be explained by lower elasticity in the electricity sector and cold temperatures in both winters (2008–2009 and 2009–2010). Improved industrial production increased the need for power generation in the second half of 2009. The total electricity production using natural gas amounted to between 15.7 and 28 GW, according to the sources considered. This represents a major increase in comparison with 2009, but it also shows the road to a carbon-free power generation mix is still a long way off. Over the period 2007–2035, natural-gas-fired electricity generation is expected to increase 2.1 % per year.[19] Generation of natural gas worldwide is expected to increase from 3.9 trillion kWh in 2007 to 6.8 trillion kWh in 2035, an increase of 74 %, but the total amount of electricity generated from natural gas continues to be less than one-half the total for coal, even in 2035.

According to the IEO (2011), natural gas is second only to renewable as Europe's most rapidly growing sources of energy for electricity generation, as its share of total power generation is expected to grow from 20 % in 2008 to 22 % in 2035; this represents an increase of 2 %. The increase in the natural gas installed capacity expected to be 1 % as average annual percent change. Although not considered in the IEO projections, recent actions by some European governments to reduce their reliance on nuclear power in the wake of Japan's Fukushima Daiichi nuclear disaster are likely to provide a further boost to natural gas use in electricity generation.

From Table 3.8, the following can be stated: The country with the major electricity production in 2008 using indigenous source was Germany with 613.2 GWh (17.8 % of the total), followed by France with 549 GWh (15.94 %), UK with 372.9 GWh (10.82 %), Italy with 304.4 GWh (8.83 %), Spain with 287.4 GWh (8.34 %), and Turkey with 190.1 GWh (5.52 %). Except in Luxembourg, Belgium, Portugal, the Netherlands, Austria, and other countries, the rest suffered a decrease in electricity generation between 2008 and 2009 as a result of the negative impact of the economic crisis affecting the EU. A little recovering occurred between 2009 and 2010 (Table 3.8).

The fall in industrial output and electricity generation lead to believe that the industrial sector and to a lesser extent, the power sector was particularly hard hit by the current economic and financial crisis affecting the EU. Statistical data for the end of 2009 and the first quarter of 2010 showed some signs of recovery in some EU countries, although this was largely due to colder temperatures than average and

[19] According to the IEO (2013) report, electricity generation in the nations of OECD Europe is expected to increase by an average of 1 % per year from 3,496 billion kWh in 2010 to 4,765 billion kWh in 2040. Because most of the countries in OECD Europe have relatively stable populations and mature electricity markets, most of the region's growth in electricity demand comes from those nations with more robust population growth (such as Turkey) and from the newest OECD members (including the Czech Republic, Estonia, Hungary, Poland, and Slovenia), whose projected economic growth rates exceed the OECD average.

Table 3.8 Indigenous electricity generation changes in the European region during the period 2008–2010

Electricity production in 2008 (Billion kWh)		Share of European production in 2008 (%)	AGRY (%) 2008–2009	January–September 2008–2009–2010 (%)		
			2010 versus 2008	2009–2008	2009–2008	2009–2008
OECD Europe	3,461.37	100	−4.9	−4.6	−2.9	1.8
Austria	61.7	1.79	4.4	1.3	3.4	2.1
Belgium	80.9	2.35	7.8	12.6	18	4.7
Czech Republic	77.1	2.24	−1.4	−4.3	1.3	5.8
Denmark	34.6	1.01	−0.1	3.9	10.1	6
Finland	74.5	2.16	−7.9	−8.7	1.6	11.4
France	549	15.94	−5.7	−4.9	1.1	4
Germany	613.2	17.8	−8.6	−5.8	−5	0.9
Greece	57.4	1.67	−9.2	−3.7	−12.1	−8.7
Hungary	37	1.07	−9.4	−12.4	−6.8	6.8
Ireland	29.2	0.85	−8.1	−6.4	−6.8	−0.4
Italy	304.4	8.83	−8.4	−10.3	−10.6	−0.3
Luxembourg	3.5	0.1	8.8	14.9	31.6	14.5
Netherlands	102.7	2.98	4.9	5.4	4.4	−0.9
Norway	143	4.15	−7.7	−13.1	−18	−5.6
Poland	141.2	4.1	−2	−2.6	1.6	4.3
Portugal	45.2	1.31	7.2	7.7	7.8	0.1
Slovakia	27.2	0.79	−11.3	−12.4	−7.9	5.1
Spain	287.4	8.34	−1.4	−8.8	−3.2	6.1
Sweden	146	4.24	−10.5	−10.8	−5.4	6
Switzerland	66.9	1.94	−0.6	1	−3.5	−4.5
Turkey	190.1	5.52	−2.2	−4.9	4	9.3
UK	372.9	10.82	−4.8	2.4	−3.5	−5.7

Source: IEA electricity statistics, regional and country tables the previous winter. This kept demand in the residential and commercial sectors high.[20] The demand in the winter 2009–2010 was about 9.5 billion m^3 higher than in an average winter.

Changes in natural gas demand showed strong variations between the European markets. In 2009, natural gas demand declined in 15 countries. It plummeted in Greece, Hungary, and Spain. The decline was more focused on the industrial sector in Spain, but although electricity generation did not plummet, natural gas used for power generation registered a sharper fall. However, bad their situation, it was not worse than in some other markets such as Ireland and even in the UK. Demand fell also sharply in Finland, in line with its poor economic situation. Six out of seven of the major natural gas markets registered a loss in consumption: Spain, UK, Italy, Germany, Turkey, and France, while demand in the Netherlands was mostly flat thanks to low natural gas spot prices, which boosted natural gas for power generation. The amazing increase in the use of natural gas in Sweden can be explained by two factors: (a) The opening of a gas-fired power plant; and (b) The size of the market (about one billion m^3), which means that only one natural gas-fired power plant can have such a major impact on total natural gas demand. While most of the markets registered a decline, natural gas consumption seems to have increased in several European countries, included Norway, Portugal, Austria, Luxembourg, and Poland in addition to Sweden.

European natural gas industry was not immune to the effects of the international economic and financial crisis and, for this reason, demand declined by an unprecedented 5.3 % in 2009.[21] The severity of the recession was confirmed with a decline of 1 % of the world GDP in 2009 and 4.1 % in the Eurozone according to the OECD Economic Outlook published in November 2010. In 2011, the crisis increased in the Euro-zone affecting several countries such as Greece, Italy, Spain, Portugal, and Ireland. The fall was expected to have been concentrated in two sectors, industry and power.[22] In the first three quarters of 2010, natural gas demand seemed to have picked up quickly (an increase of 7.3 %), leading to expectations of a faster and stronger recovery than previously foreseen. However, this recovery did not occur in 2011 neither in 2012.

Which are the main factors that are limiting the increase in the use of natural gas for electricity generation within the EU? One of these factors is the high levels of concentration and consequent concerns about wholesale market manipulation in many national natural gas markets. Both natural gas and electricity markets are susceptible to concentration due to the existence of preliberalization monopolies and their natural characteristics. In particular, electricity is a product with low elasticity of demand, so that even with relatively high prices, customers do not reduce their consumption very significantly. That, the effects of congestion, and the need for

[20] From EUROGAS data of natural gas demand by sector, the economic recession affecting the EU had major impacts on the industrial and power sectors, but the residential and commercial sectors managed to grow by 0.7 %.

[21] For additional information see IEA Monthly Gas Survey (IEA 2009).

[22] For additional information see IEA (2010) Medium-Term Oil and Gas Markets 2010.

continual balance of supply and demand, increase the scope for market dominance. For natural gas, competition difficulties also have their roots in the structure of the natural gas industry outside the EU, as well as national production in Member States. These problems are made worse due to the national scope of markets and the lack of integration. In addition, over time and provided there is fair access to networks, new investment will contribute to eroding concentration. This would be particularly encouraged if a list of suitable electricity generation or natural gas storage sites, and adopt mechanisms for releasing such sites for new investors is published. In the short term, market participants have identified a range of other possible measures that would also assist the process of moving to more competitive and contestable electricity and natural gas markets. These measures are: (a) Transparency; (b) Contract structures; and (c) Gas storage (COM 2006).

3.14 Transparency

One of the measures that were identified by market participants is transparency. The problem of concentration is made worse where dominant companies are not required to reveal information to other market participants. For example, wholesale price movements are often caused by variations in production or the use of import capacity by the largest electricity and natural gas companies. If smaller market participants are unable to track the underlying causes of changes in market price, they will be at a disadvantage. A higher degree of transparency would also allow for improved market surveillance (COM 2006). The EC intends to improve the transparency through either the adoption of new legislation or by modifying existing Regulation (EC) No. 1228/2003 or through using Regulation (EC) No. 1775/2005.

3.15 Long-Term Gas Transmission and Downstream Contracts

The EC has "repeatedly acknowledged the role of long-term contracts between external producers (i.e., upstream) and companies supplying customers in the EU. These long-term contracts reflect the need for upfront investments to be undertaken and have an important role to play as regards access to cost-effective energy inputs."

It is important to highlight that the natural gas regulation already "imposes a strict use-it-or-lose-it conditions regarding transmission contracts. This includes contracts which were concluded under Directive 91/296/EEC on the transit of natural gas through the grids. These requirements, when combined with additional investment in natural gas networks, may help overcome the current blockages to meaningful competition. Further development of use-it-or-lose-it guidelines would also help competition develop more rapidly (COM 2006)."

3.16 Access to Gas Storage Facilities

Another factor, which affects competition in the natural gas sector, "is the limited availability of storage, which is often in the hands of the incumbent companies. Although storage is not a natural monopoly, facilities in certain locations may have a large impact on the functioning of the internal market. Voluntary guidelines for best practice for storage system operators were agreed in 2004, but the findings of monitoring the implementation of these guidelines showed a rather disappointing picture in terms of compliance. The EC therefore "intends to examine measures, which would best balance the need for effective access with maintaining incentives for new storage developments (COM 2006)."

3.17 Environmental Impact

Natural gas is the cleanest-burning alternative fuel for electricity generation, and could be considered the most environmentally friendly fossil fuel used for this specific purpose, because it has the lowest carbon dioxide emissions per unit of energy, and because it is suitable for use in high-efficiency combined-cycle power plants.

In the past years, environmental concerns such as global warming have resulted in calls for increased use of natural gas, particularly for the generation of electricity. This is because when natural gas is burned, it gives off only 50 % as much carbon dioxide per unit of energy produced as does coal, and 25 % less than oil, virtually no sulfur dioxide, and only small amounts of nitrous oxides. Carbon dioxide is a greenhouse gas, whereas sulfur dioxide and nitrous oxides produced by oil and coal combustion produce acid rain (Demirbas 2010).

Concerns about acid rain and global warming will no doubt result in increased use of natural gas for electricity generation in the future. Two areas that could see expanded use of natural gas are fuel cells and transportation. Fuel cells are used to generate electricity, and operate something like a battery. The difference is that the energy for fuel cells comes from hydrogen, which can be made from natural gas. Fuel cells eliminate the need for turbines and generators, and can operate at efficiencies as high as 60 %. Fuel cells also operate at low temperatures, thus reducing emissions of acid rain causing nitrous oxides, which are formed during high-temperature combustion of any fuel.

3.18 Future Trends

Despite of progress in the EU infrastructure priority projects, there are still major future challenges facing the EU natural gas market. These challenges are, among others, the following:

- To reduce the vulnerability to natural gas supply shocks;
- To plan for increasing import dependency and the uncertainty about the availability of natural gas reserves;
- To facilitate the development of an integrated natural gas market, due to the EU enlargement;
- To handle the climate challenge where natural gas will be both a bridging and a future energy source;
- To prepare the coming investments for climate change impacts on the pipeline routing and other infrastructure in order to integrate increasing climate risks into investment planning.[23]

As part of the EC's Five-point Energy Security and Solidarity Action Plan, the development of a Baltic interconnection plan will improve the integration of the missing continental members. Development of a Southern Gas Corridor for Caspian supply source and future Middle-East sources will improve the security of supply. An LNG action plan for all EU Member States will improve the diversity and security of supply, especially for countries relying on sole suppliers. Completion of the Mediterranean ring with connections to Italy–Greece, Algeria-Sardinia and internal Italy-strengthening projects, will improve the security of supply and diversity.

Development of a North–South natural gas interconnector in the Central/South-Eastern Europe (e.g., Poland–Slovakia–Hungary) will strengthen the supply of the countries in the region while reducing their dependency on Russian supplies. The European Parliament sets out the following priority objectives that will require special attention in the near future:

- Diversification of sources and routes of supply, particularly the development of a Southern natural gas corridor, including the Nabucco, the TGI, and South Stream projects;
- It is of great importance that supplies from other countries in the region, such as Uzbekistan, in the long-term represent a further significant source of supply for the EU;
- The development of natural gas and electricity interconnections through Central and South-Eastern Europe along a North–South axis is of great importance for EU countries;
- The networks in the Baltic Sea region should be developed and integrated into the Western European network;
- Relations and partnerships with key energy suppliers, transit, and consumer countries are important and must be deepened;

[23] This issue is further addressed in the Acclimatise (2009): Building Business Resilience to Inevitable Climate Change—the Adaptation Challenge. Carbon Disclosure Project Report 2008, Global Oil and Gas, Oxford, 13 Second Strategic Energy Review—Securing our Energy Future.

- Sufficient LNG capacity consisting of liquefaction facilities in the producing countries and LNG terminals and ship-based regasification in the EU should be available to all Member States, either directly or through other States on the basis of a solidarity mechanism.

A summary of the natural gas situation and on the future role to be played by this type of energy source for the generation of electricity during the coming years in a selected group of European countries, is included in the following paragraphs.

3.19 Austria

Commercial use of natural gas in Austria reaches back more than 50 years. Approximately, 20 % of the natural gas used in Austria is produced in the country; the remaining 80 % are imported from the Russian Federation (approximately 50 % of the total amount imported and/or produced in 2010),[24] Norway, and Germany. From the large deposits located in West Siberia, the natural gas flows through thousands of kilometers of underground pipelines to reach Austria.

According to Nachtmann (2007), natural gas domestic production comes from two mature oil and natural gas provinces: the Vienna Basin and the Molasse Basin. Exploration work in the Styrian Basin was terminated in the middle of the 1990s as no economic hydrocarbons have been found there (Fig. 3.9).

In both classical exploration and production areas, the Molasse and the Vienna Basins, continuous exploration is still conducted. The most significant discoveries during the past 10 years are the Haidach natural gas field in the Oligocene of the Molasse (depth: 1,600 m; ultimate recovery approximately 4 billion m^3 (0.112 billion cubic feet)) converted to an underground natural gas storage with a turnover volume of 2.4 billion m^3 (0.0672 billion cubic feet) and the Strasshof sour natural gas field with two reservoirs in the Calcareous Alps underneath the Vienna Basin (depths: approximately 3,200 and 4,300 m; not yet on stream expected ultimate recovery more than 4 billion m^3 or 0.112 billion cubic feet).

It is important to single that Austria is vulnerable in the energy sector, particularly in the case of natural gas. A recent study carried out by the Vienna Institute for International Economic Studies identified which countries, among the EU-15 are most vulnerable to possible natural gas shocks. The study also includes fuel intensity indicators linking energy intensity to depend on imports and the degree of diversification (by source country). The indicators show that the most vulnerable countries in respect to natural gas are Finland, Austria, and Italy.

Austria has a natural gas supply per capita of 0.979 tons (2010 estimate). With a relatively small rate of domestic production, Austria imports the vast majority of its

[24] In 2011, a total of 69.5 % of the total energy used in Austria came from foreign countries; the EU average 2010 is 52.7 %.

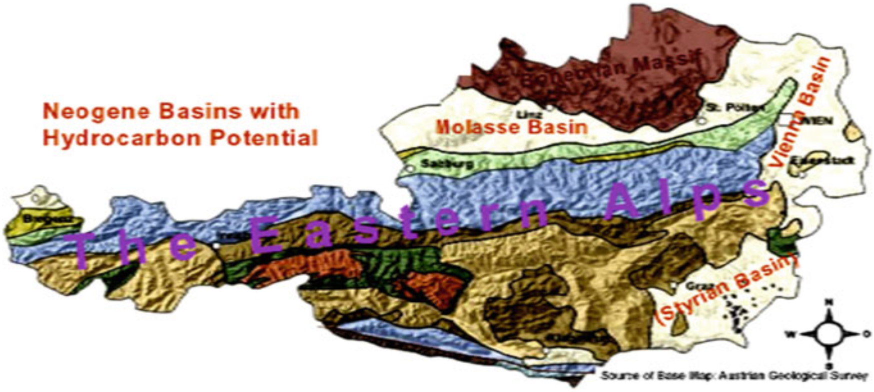

Fig. 3.9 Schematic geology of Austria

Table 3.9 Austria basic natural gas facts

Basic gas facts	2007	2008	2009	2010	2011	2012
Gas reserves (trillion m^3)	20	19	17	16	20	13.49
Gas production (billion m^3)	1,950	1,616	1,759	1,810	1,776	2,366
Gas consumption (billion m^3)	8,866	9,368	9,143	10,007	9,475	11,265
Gas imports (billion m^3)	10,013	10,192	11,634	12,417	14,631	14,408
Gas exports (billion m^3)	2,778	1,995	3,799	4,968	4,852	4,661

Sources: Natural gas information OECD/IEA (2012), EIA (2012)

natural gas volumes its needs. Due to its high dependency on natural gas imports, Austria has built a total storage capacity of 4,639 million m^3 (Table 3.9).

3.19.1 Natural Gas Reserves

According to IEA sources, Austrian natural gas reserves in 2013 were estimated at 13.49 trillion m^3 (0.382 trillion cubic feet); this represents a decrease of 33 % respect to 2011.

3.19.2 Production and Consumption of Natural Gas

The evolution of the production and consumption of natural gas in Austria during the period 2000–2012 is shown in Fig. 3.10.

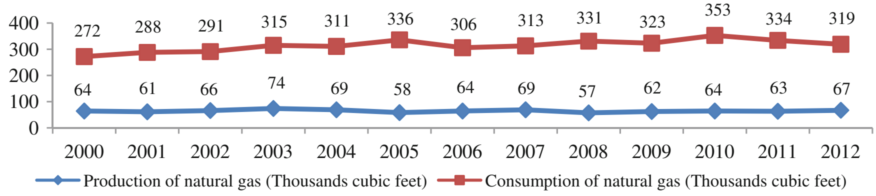

Fig. 3.10 Production and consumption of natural gas in Austria during the period 2000–2012. *Source:* Eurostat

According to Fig. 3.10, the production of natural gas in Austria during the period 2000–2012 increased 4 %. In 2010, natural gas consumption showed an increase of 9.2 % respect to 2009, but in 2011 and 2012, natural gas consumption went down by 5.4 % and 9.7 % respect to 2010. In the Vienna Basin, natural gas production fell by 10.2 %; in the Northern foothill of the Alps, natural gas production rose by 7.9 %. Consumption of natural gas represented 24 % of the total primary energy consumption of the country in 2010. The consumption of natural gas in Austria during the period 2000–2012 increased 17.2 %. It is expected that the consumption of natural gas in Austria will continue to increase during the coming years, particularly for the production of electricity.

3.19.3 Import and Export of Natural Gas

The evolution of the imports and exports of natural gas from Austria during the period 2007–2012 is shown in Figs. 3.11 and 3.12. The imports of natural gas from Austria from the major suppliers is shown in Table 3.9.

It is important to highlight that natural gas imports account for 124 % of the total volume of consuming natural gas, showing that Austria is functioning as a transit country for its neighbors. All of Austria's natural gas imports entered the country via pipeline. Most of the natural gas imports came from Russia and Norway. The estimated share of Russia and Norway in Austria's natural gas imports in 2010 is 48.41 % and 11.97 %, respectively.

According to Fig. 3.11, the imports of natural gas from Austria during the period 2008–2012 increased 13.3 %. The peak in the imports of natural gas during the

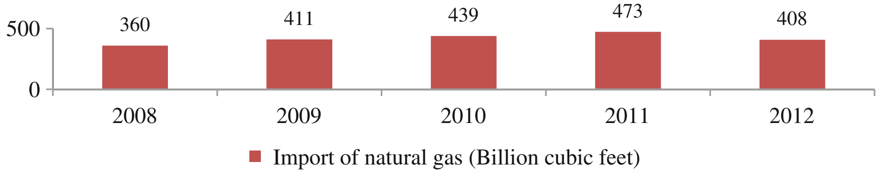

Fig. 3.11 Imports of natural gas from Austria during the period 2008–2012. *Source:* EIA

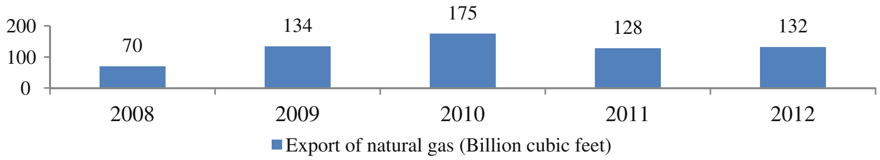

Fig. 3.12 Exports of natural gas from Austria during the period 2008–2012. *Source:* EIA

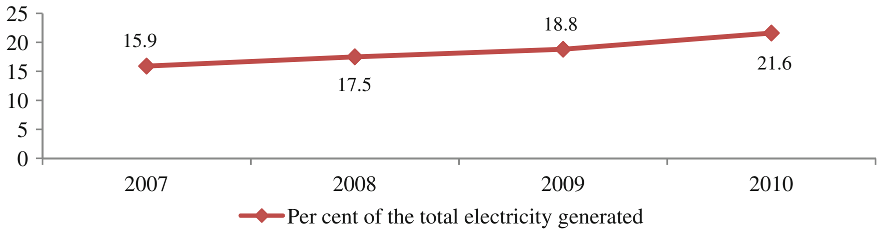

Fig. 3.13 Percent of the total electricity generated by Austria during the period 2007–2010 using natural gas as fuel. *Source:* The World Bank

period considered was reached in 2011. It is expected that the imports of natural gas continues to increase during the coming years due to its major use for the generation of electricity in substitution of oil.

From Fig. 3.12, the following can be stated: The exports of natural gas from Austria during the period 2008–2012 increased 88.5 %. It is expected that the exports of natural gas will continue increasing during the coming years.

3.19.4 Electricity Generation and Consumption

The electricity generated in the country using natural gas as fuel during the period 2007–2010 is shown in Fig. 3.13. According to Fig. 3.13, the participation of natural gas in the electricity generation of Austria during the period 2007–2010 increased from 15.9 % in 2007 to 21.6 % in 2010, an increase of 5.7 %. It is expected that this trend will continue during the coming years.

3.20 Belgium

As Belgium does not have any natural gas sources, the country is completely dependent on imports from producing countries around the world. Natural gas can, therefore, travel thousands of kilometers before reaching the Belgian border. The natural gas is transported to Belgium from the producing countries by pipeline or by LNG vessel.[25] Dutch, Russian, and some Norwegian natural gas have moved to the Belgian border via underground pipelines. British natural gas—and some Norwegian natural gas—reach Belgium through subsea pipes. For the transmission of natural gas through Belgium, only underground pipelines are used. These underground pipelines move natural gas to power plants, large industrial customers, and distribution system operators. They are responsible for further distribution of natural gas to residential end-users and small businesses.

3.20.1 Natural Gas Reserves

Belgium has no proven natural gas reserves reported in 2013.

3.20.2 Production and Consumption of Natural Gas

The evolution of the consumption of natural gas during the period 2000–2012 is shown in Fig. 3.14. According to that figure, the consumption of natural gas increased 14.2 % during the period considered. However, the consumption of natural gas has been very irregular since 2002 increasing in one year and decreasing in the next. The peak in the consumption of natural gas within the period considered was reached in 2010. It is expected that the consumption of natural gas in Belgium will continue increasing during the coming years, but in a moderate rate. Belgium did not produce natural gas in the period considered.

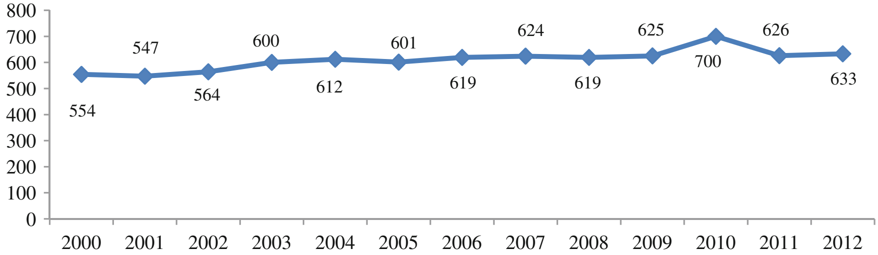

Fig. 3.14 Consumption of natural gas in Belgium during the period 2000–2012. *Source:* EIA

[25] There are underground pipelines and subsea pipelines.

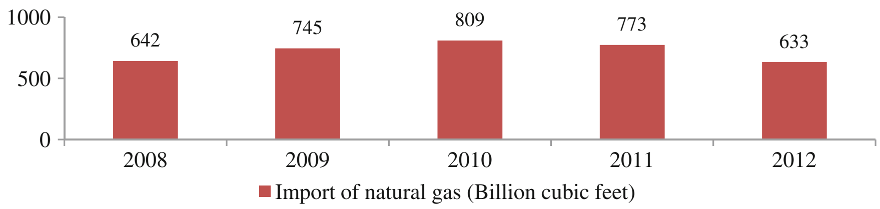

Fig. 3.15 Imports of natural gas from Belgium during the period 2008–2012. *Source:* EIA

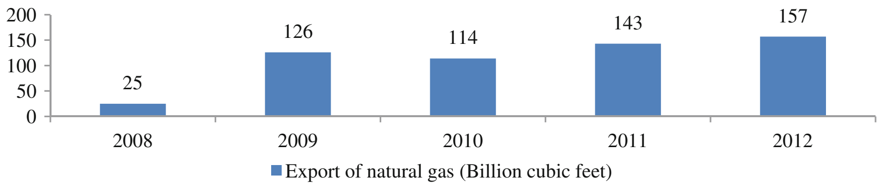

Fig. 3.16 Exports of natural gas from Belgium during the period 2008–2012. *Source:* EIA

3.20.3 Import and Export of Natural Gas

The evolution of the import of natural gas from Belgium during the period 2008–2012 is shown in Fig. 3.15.

Belgium does not have natural gas reserves and, for this reason, all natural gas used in the generation of electricity has to be imported. The imports of natural gas from Belgium decreased 1.5 % during the period 2008–2012.

The evolution of natural gas imports is particularly worrying in the context of the latest concerns about the natural gas supply in the EU: 21 % between 2005 and 2020. The most significant part of the increase will take place in the power generation sector where the share of electricity generated from natural gas-fired power plants is expected to jump from 25 % in 2005 to 37 % in 2020, an increase of 12 % (Devogelaer and Gusbin 2009).

The exports of natural from Belgium during the period 2008–2012 increased 6.28 folds (see Fig. 3.16). The peak in the export of natural gas during the period considered was reached in 2012. It is expected that Belgium continues to be an exporter of natural gas during the coming years.

3.20.4 Electricity Generation

The liberalization process for electricity and natural gas in Belgium must be continued in line with the European common energy market concept. Industry has to be enabled to fully participate in the European wholesale energy market, by co-investing in generation assets, by long-term contracts and by establishing a liquid

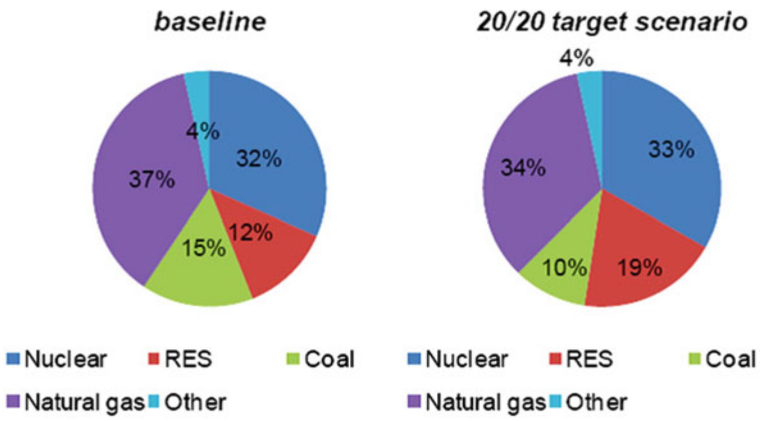

Fig. 3.17 Evolution of the electricity generation mix in Belgium between 2008 and 2020. *Sources:* PRIMES. Other stands for oil and derived gases

wholesale market, supported by sufficient transnational transmission capacity. Sufficient retail market access should develop over time to reach a good mix of suppliers in Belgium.

Net electricity generation is expected to increase from 82 billion kWh in 2005 to 107 TWh in 2020, an increase of 30 %. The evolution of the electricity generation mix between 2008 and 2020 is shown in Fig. 3.17.

A significant change in shares can be noticed in Fig. 3.17. More natural gas and renewable energy resources are expected to be used in 2020 in comparison to 2005; the share of coal will increase somewhat; while nuclear energy declines further to the 2003 phase-out law; the demand for natural gas is projected to be 6 % lower in 2020 than in the 2005. This is the result of opposite trends. An increased demand in industry of almost 9 % and a lower consumption in the residential and tertiary sectors of about 13 % in 2020 compared to the level in 2005. The twin target leads also to electricity savings. On the other hand, the demand for electricity goes up in transport (17 % in 2020 compared to 2005), but the additional consumption is tiny; it represents no more than 0.3 % of total electricity demand in 2020.

Electricity production from natural gas sources in Belgium was last reported at 31.105 billion kWh in 2010, according to a World Bank report released in 2011. The evolution of the electricity production from natural gas sources in Belgium during the period 2007–2010 is shown in Fig. 3.18.

Electricity generated by natural gas increased from 25.386 billion kWh in 2007 to 31.105 billion kWh in 2010; this represents an increase of 22.5 %. It is expected an increase in the use of natural gas for the generation of electricity in the country during the coming years, particularly after the shut down of the nuclear power reactors operating in the country.

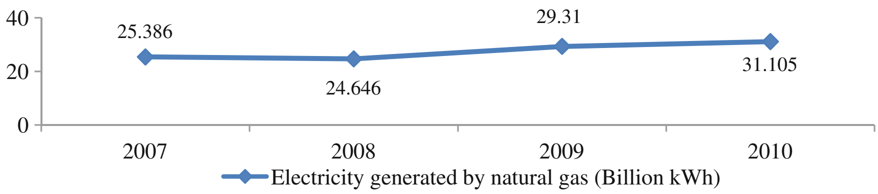

Fig. 3.18 Electricity generated in Belgium using natural gas as fuel during the period 2007–2010. *Source:* World Bank

3.21 Croatia

The first significant natural gas quantities in Croatia were discovered in 1917 in Bujavica, near Lipik, at the depth of 315 m. This deposit started to be commercially utilized in 1926 when 500,000 m^3 were produced. In 1931, an outstanding 6.3 million m^3 of natural gas were produced. In 1930, in Gojlo a new natural gas deposit was found. As a result, in 1937 a new soot factory was built in Kutina, and a year after that, a lime factory, both under the joint name METAN, was constructed. The gasification of Kutina started the same year. However, due to relatively small natural gas quantities, there was no interest in its exploration until the discovery of greater field Janja Lipa in 1942, oil field Šumećani–Križ in 1948, and oil and natural gas field Kloštar in 1951.

The discovery and production start-up of the natural gas field Okoli in 1963 was a turning point in the technology of natural gas production, preparation, and transmission. The natural gas transmission system was upgraded from an operating pressure of 25 bar up to 50 bar. The high energy level provided the increase of the system capacity and supply security, creating the preconditions to increase natural gas production and higher quality of its economic and energy evaluation. In the same year, the natural gas facility Ivanić-Grad was established, a predecessor of today's PLINACRO Ltd. From that year on, the natural gas transmission activity was developed within NAFTAPLIN.

The domestic production of natural gas dropped from 68 % in 1996 to 59 % in 1999 and increase to 62.5 % in 2001. If the share of individual energy forms within the energy sector own use are analyzed in detail, then it can be concluded that by far the largest share is taken by natural gas. In final energy demand, the biggest share decrease was realized in the consumption of natural gas, so that with the 15.3 % present the lowest level recorded. Better situation was in final energy demand in an industry where natural gas was participating with 25.4 %. In the final energy demand, in sectors like households, services, agriculture, and construction, natural gas participates with 19.8 %, right after electricity and liquid fuels. Unfortunately, in the transport sector natural gas does not have an important role. The share of LPG remained on the lowest value of 0.7 %.

Because of its limited energy resources, Croatia is heavily dependent on imported oil and natural gas. The participation of natural gas in the energy mix of the country reached only 10.1 % of the total during the 2000s.

Security of natural gas supply is nowadays one of the cornerstones of the energy policy and the economic and national security strategy in Croatia. Domestic coverage of total primary energy needs in Croatia amounted to 65 % in 1988, dropped to 50 % in 2000, and increased to 52 % in 2008. Based on this information, it is anticipated that by 2030 the domestic share of total primary energy supply is estimated to be between 21 % and 23 %. In view of such forecasts, Croatia will be dependent on the imports of energy sources in order to satisfy its foreseeable energy needs during the coming years (Katarina et al. 2010).

3.21.1 Natural Gas Reserves

The reserves of natural gas in Croatia, like those for crude oil, are located mainly in three sites in the country: Southeast of Zagreb, along the Hungarian border, and along the Adriatic Sea. EIA[26] has reported in 2010 proven natural gas reserves of 38.1402 trillion m^3 (1.08 trillion cubic feet) of natural gas. In January 2011, the natural gas reserves of the country were estimated at 31.077 trillion m^3 [27] (0.88 trillion cubic feet), a decrease of 18.6 % respect to the latest level of natural gas reserves reported. In 2013, the proven natural gas reserves reported by Croatia reached 31.077 trillion m^3 (0.88 trillion cubic feet); this represents the same level of reserves reports in 2011.

3.21.2 Production and Consumption of Natural Gas

Natural gas is produced from 17 gas fields, which covers about 60 % of total consumption. The largest quantities of natural gas come from the Molve, Kalinovac, and Stari Gradec gas fields, where the natural gas power plants for processing and transportation Molve I, II, and III were built. The evolution of the export of

[26] The natural gas sector in Croatia is unbundled and the market open by law as of August 2008, meaning that all customers are deemed eligible and can freely choose a supplier and negotiate a price, though in practice, as with electricity, one entity dominates the market. Croatia has one natural gas producer, INA, the mother company of the PRIRODNI PLIN, which is the wholesale and retail supplier, and also natural gas importer; one TSO, PLINACRO, which was ownership unbundled in 2002 and is 100 % State owned; 38 Distribution System Operators, 13 of which are legally unbundled and 25 to which the 100,000 or fewer customer exemption applies; and 39 suppliers, one of which is also a wholesale supplier. The Distribution System Operators are either privately or municipally owned. Gas storage was ownership unbundled in 2008.

[27] Other sources estimated that the natural gas reserves are 30.564 billion m^3, more than 5 billon m^3 more that the amount included in Table 3.11.

Table 3.10 Imports of natural gas by Austria during the period 2006–2010

By country of origin (in million m^3)	2006	2007	2008	2009	2010	2010 (%)
Russia	5,851	5,411	6,058	5,339	7,843	63.1
Norway	1,272	1,417	1,341	1,321	1,737	15.97
Others	3,121	2,663	2,262	4,368	2,837	20.92
Total	10,244	9,491	9,661	11,028	12,417	100
Total consumption (%)	118.10	116.91	111.16	132.78	124.07	–

Source: Natural Gas Information OECD/IEA (2011 and 2013)

natural gas from Croatia during the period 2007–2010 is shown in Table 3.10. According to that table, in 2012 Croatia imported 1,659 billion m^3 of natural gas, representing 40.8 % of its domestic natural gas consumption in that year. In 2012, the total consumption of natural gas was 4,061 billion m^3; this represents an increase of 13.8 % respect to 2011.

3.21.3 Import and Export of Natural Gas

All of Croatia's natural gas imports are being accomplished via pipeline. In 2010, a total of 96 % of Croatia's natural gas imports originated from Russia, while the remaining 4 % of imported natural gas originated from various countries. So far there are no LNG imports (Table 3.11).

The exports of natural gas from Croatia during the period 2007–2012 decreased from 11 billion cubic feet (3,919.965 billion m^3) in 2007 to 0 billion cubic feet (0 billion m^3) in 2012. It is expected Croatia will not export natural gas during the coming years. On the other hand, the imports of natural gas from Croatia during the period 2007–2012 increased 14.6 %. It is expected that Croatia will continue importing natural gas in order to satisfy its future energy needs during the coming years (Fig. 3.19).

It is important to stress that the dependence on the imports of energy and energy resources by Croatia poses a risk in terms of meeting its total energy needs, due to market factors (instability and high world market prices), as well as money-market

Table 3.11 Natural gas data

Basic gas facts	2009	2010	2011	2012	2013
Natural gas reserves (trillion m^3)	38,140	38,140	31,077	31,077	31,077
Natural gas production (billion m^3)	2,472	2,366	2,260.2	2,401	–
Natural gas consumption (billion m^3)	3,354.9	3,531.5	3,566.8	4,061	–
Natural gas imports (billion m^3)	1,306.7	1,412.6	1,518.5	1,659	–
Natural gas export (billion m^3)	423.8	210.9	–	–	–

Sources: EIA

Note: Other sources estimated the natural gas reserves in 30.564 billion m^3

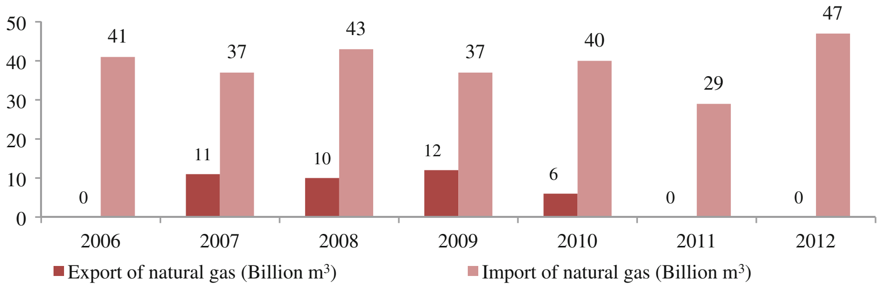

Fig. 3.19 Exports and imports of natural gas from Croatia during the period 2006–2012. *Source:* EIA

factors, such as changes in global geopolitical balance, natural disasters, risks of war conflicts, terrorist attacks, and political instability, among others.

The global financial and economic crisis affecting the whole European region caused a protracted recession in Croatia, which continued through 2011 and 2012. Investment continued to fall at a double-digit rate (−11.3 %) while the decline in private consumption diminished markedly (by −0.9 %). Public consumption also declined (−0.8 %) in contrast to a small increase in 2009 (0.2 %). In the context of the economic recovery in the EU and in other export markets, energy export volumes increased by 6 % in 2010 following the sharp contraction in the preceding year (−17.3 %). The decline in energy import volumes, however, continued, albeit at a much slower speed (−1.3 % in 2010 against −20.4 % in 2009). The mild decline in economic activity continued throughout the winter of 2010/11 and output was 0.8 % lower, year on year, in the first quarter of 2011. In the future, a gradual reducing of the fossil fuels production and an increase in energy generation from renewable energy sources is expected to occur (Katarina et al. 2010).

3.21.4 Electricity Generation

The electricity production from natural gas sources in Croatia was 2,555 MWh in 2010, according to a World Bank report published in 2010; this represents an increase of 3.9 % respect to 2008 (2,459 MWh). The evolution of the generation of electricity using natural gas as fuel during the period 2007–2010 is shown in Fig. 3.20.

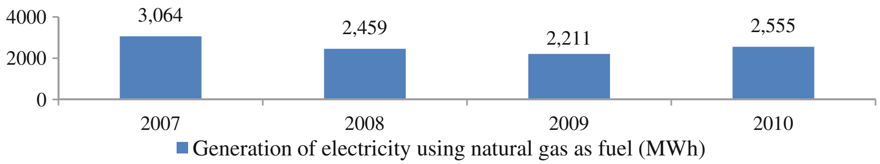

Fig. 3.20 Generation of electricity in Croatia using natural gas as fuel during the period 2007–2010. *Source:* World Bank and Index Mundi

During the period 2007–2010, the generation of electricity in Croatia using natural gas as fuel dropped 16.7 %. In 2010, the participation of natural gas in the generation of electricity reached 22.3 % of the total. However, it is expected that the use of natural gas for the generation of electricity in Croatia will increase in the future.

3.22 Czech Republic

The energy policy framework of the Czech Republic is set by the State Energy Policy adopted in 2004 and revised in 2010. The basic priorities are to strive for independence from foreign energy sources; this means the maximum use of domestic energy resources focusing mainly on energy security, maximize the safety of energy sources, including nuclear energy, and promote sustainable development. The Czech government faces several challenges in fulfilling its energy policy objectives, one of them the implementation of energy efficiency policies and measures and another clarification of its role as an electricity exporter in the future.

The new State Energy Concept presented by the government within its revised energy policy includes a scenario of the Czech energy market in 2050 with shorter term objectives and policy recommendations. The concept concentrates on the need for security of energy supply[28] and the maintenance of the Czech Republic as a net electricity exporter, achieved through a diversified energy mix and maximizing the use of indigenous energy resources, comprising coal, uranium, and renewable energy (mainly biomass and waste). Future expansion of nuclear power capacity has been presented as one of the major pillars of the updated revised energy concept.

Encouragingly, according to the current version of the revised energy policy, nuclear energy is projected to account for about 47 % of the power generation mix in 2050 up from 32 % currently (an increase of 15 %), which will support the Czech government's efforts to achieve climate change objectives. Coal is projected to fall from 60 % to about 12 % of the generation mix in 2050, less than the projected share of renewable energy sources, which will rise to about 30 %. Natural gas will continue to play a complementary role in the generation of electricity (about 11 %)[29] during the coming decades. The new energy concept outlines indicative

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[28] Concerning natural gas security, it is important to stress that the country benefits from having a relatively high capacity of underground commercial natural gas storage. However, it does not have strategic reserves or fuel switching potential for responding to a natural gas supply crisis. Following the January 2009 natural gas supply crisis in Europe, the Czech government put in place over a short period of time and ahead of the 2009/2010 winter season a response plan for dealing with a reduction in natural gas supplies. This plan relies on coordination with industry in order to optimize natural gas storage use and regulate demand side measures in a crisis (Oil and Gas Security in the Czech Republic 2010).

[29] Natural gas represented 16 % of the Czech Republic's total primary energy supply in 2008 a little bit higher than in 2007 and will be responsible for 11 % of the total generation of electricity in 2050. Over the next two decades, the country aims to reduce reliance on coal, while at the same time maintain its status of electricity net exporter through increased use of nuclear and renewable

targets for domestic energy resources, including nuclear fuel, with 90 % and 80 % shares in overall electricity and district heating, respectively. This would be a substantial transformation of the Czech electricity sector.

The Czech Republic plans substantial increases in the development of interconnections with neighboring countries and a further extension of its natural gas transmission grid to provide for larger volumes of reverse flow. Emergency measures have also been identified in order to be better prepared for any significant reduction in natural gas imports, particularly from Russia. The Czech Republic's long-term strategy for the electricity sector has also been affected by the perception of risks related to the natural gas security of supply. The Czech Government should consider potential future developments in the regional natural gas market and the positive role that natural gas plays in addressing climate change and, if feasible also economical, consider expanding the role of natural gas in a long-term strategy to reduce emissions. Natural gas fired power plants are the second fastest types of plants to build after wind farms.

3.22.1 Natural Gas Reserves

According to EIA sources, proven natural gas reserves in the Czech Republic was estimated to be 4.9441 trillion m^3 (0.14 trillion cubic feet) in 2013.

Natural gas deposits are in reservoirs that contain crude oil. The deposits are mostly located in South Moravian part of the Vienna Basin. Northern part of the basin contains rather crude oil deposits. The Carpathian region is considered as a promising area for the occurrence of natural gas. The composition of local natural gas deposits varies considerably. The Dolní Dunajovice deposit is characteristic of high content of methane (98 %) whereas the deposit Kostelany-West contains only 70 % methane and is high in helium and argon, which can be extracted on an industrial scale.

In Northern Moravia, specifically between Příbor and Český Těšín, the natural gas deposits are mostly confined to the weathered and tectonically affected Carboniferous paleorelief. The origin of these natural gas deposits being developed close to the top of the Carboniferous morphological elevations has not been deciphered yet. Ideas about the natural gas to have originated during coalification of the local coal seams have little support and its origin is considered to be connected with the neoid movements, which led to the origin of natural hydrocarbons. This applies particularly to the natural gas deposits of Žukov, Bruzovice, and Příbor. Part of the Příbor natural gas deposit is used as underground gas storage. Natural gas of obviously Carboniferous origin and age is extracted during so-called "degasification of coal" seams of the Czech part of the Upper Silesian coal basin. Its quality varies considerably

(Footnote 29 continued)
energy. Nevertheless, natural gas will have a growing role in the country's future supply mix, and unlike oil, demand for natural gas will continue to rise in the coming years (Oil and Gas Security in the Czech Republic 2010).

depending on the method of extraction and technical limitations related to degasification.

3.22.2 Production and Consumption of Natural Gas

The evolution of the production of natural gas during the period 2008–2012 in the Czech Republic is shown in Fig. 3.21.

The production of natural gas in the Czech Republic during the period 2008–2012 changed from one year to another to the same values ranges from 6 to 7 billion cubic feet (between 211.89 and 247.21 billion m^3). It is expected that the national production of natural gas continues with similar trend during the coming years, unless new deposits can be found and can be exploited economically.

Indigenous natural gas resources, which are used by the producers in the Czech Republic, account for less than 1 % of the country's total demand. These resources mainly include natural gas production in Southern Moravia and the so-called "drained gas" from hard coal mines in Northern Moravia. To meet domestic demand, the remaining natural gas needs to be imported.

The growth in the consumption of natural gas in the past years is attributable to several major factors. One of them was the cold weather. Another factor that influenced natural gas consumption was the environmental tax on all types of fuel with natural gas enjoying a tax break, and the continuously developing competitive environment in the natural gas market. According to the trading companies, the total volume of imported natural gas in 2012 was 10.7 % lower than in 2011. Supplies from the EU and Russia were used more than in the previous years, at the expense of a reduction of imports from Norway. It is to be noted that not all of the imported natural gas was consumed in the Czech Republic; a certain part of this imported natural gas was intended for foreign customers.

Industry is the primary user of natural gas in the country, representing 36 % of total consumption. Residential users make up the second largest group, representing 29 % of natural gas use, primarily for heating. The transformation sector accounted for 13 % of natural gas use, where natural gas-fired generation is mainly used for meeting peak electricity demand.

The evolution of the consumption of natural gas in the Czech Republic during the period 2008–2012 is shown in Fig. 3.22.

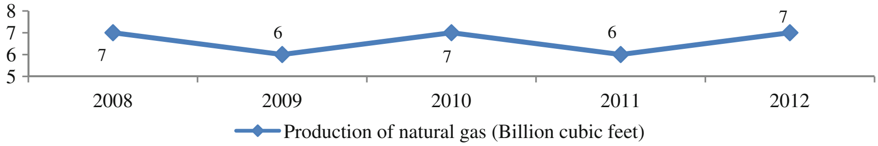

Fig. 3.21 Production of natural gas in the Czech Republic during the period 2008–2012. *Source:* EIA

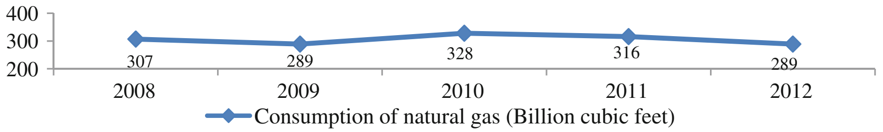

Fig. 3.22 Consumption of natural gas in the Czech Republic during the period 2008–2012. *Source:* EIA

The consumption of natural gas in the Czech Republic dropped 5.9 % during the period considered. However, it is expected that the consumption of natural gas will increase during the coming years in view of the expected recovery in the industrial sector.

Finally, it is important to highlight the following: According to the Czech Republic's National Report on Electricity and Gas Industries 2010, natural gas consumption in the Czech Republic was stagnant from as early as 1997, and it has been slightly declining since 2004, with the exception of the period 2009–2010. Natural gas consumption only increased again in 2010 around 13.5 % respect to 2009, primarily because of the cold winter season. The chief cause of the decline of natural gas consumption from 2010 to 2012 was probably the rising average annual temperature, and customers' efforts to save energy, to cut costs, focusing mainly on better and more modern boiler installations, thermal insulation of buildings, and energy savings achieved with the help of energy audits; further, the connection of municipalities to natural gas supplies has almost been completed.

Projections for 2011 to 2020 expect slight annual increases. If the natural gas-fired power plants currently being considered are actually built, between 2013 and 2015 consumption can be expected to grow by about 800 million m^3 and in 2016 by an additional 900 million m^3. Generating capacities are also expected to be developed in the subsequent years, and natural gas consumption may therefore rise by as much as 30 % between 2013 and 2020.

3.22.3 Import and Export of Natural Gas

The evolution of the imports of natural gas from by the Czech Republic during the period 2008–2012 is shown in Fig. 3.23. The imports of natural gas during the

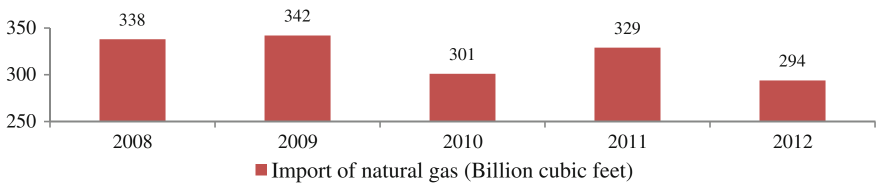

Fig. 3.23 Imports of natural gas from the Czech Republic during the period 2008-2012. *Source:* EIA

Table 3.12 The imports of natural gas from the Czech Republic by country

By country of origin (in million m^3)	% total 2010	% total 2012
Russia	88	66
Norway	12	34
Total	100	100

Source: OECD/IEA (2011) and BP 2012

period 2008–2012 decreased 13.1 %. The lowest level of imports of natural gas during the period considered was reached in 2012. Nevertheless, it is expected that the country will continue to import natural gas for the generation of electricity during the coming years. The imports of natural gas from the Czech Republic by country is shown in Table 3.12.

Historically, an important level of natural gas imports came from Russia. Following efforts in the late 1990s to diversify supply, the government began importing natural gas from Norway. The share of Norwegian gas in Czech Republic natural gas imports decreased significantly from 25.7 % in 2006 to only 12 % in 2010, but increased once again in 2012 (34 %). During the period 2010–2012, the share of the Russian natural gas decreased from 88 % in 2010 to 66 % in 2012; this represents a decrease of 22 %. It is expected that this trend will continue in the future, particularly after the Crimea crisis. Since Czech Republic is a landlocked country, it has no option to import LNG.

As Czech natural gas consumption may not increase by more than 15 % on the peak demand day over the next decade, this existing import capacity from the West will still be more than sufficient to meet import requirements, if supply from the East is disrupted.

In line with the liberalization of the natural gas market under the European Directive 2003/55/EC, each of the vertically integrated companies has been unbundled. RWE TRANSGAS, the dominant importer of natural gas into the Czech Republic, has been split into a TSO, RWE TRANSGAS Net, a natural gas storage operator, RWE Gas Storage, and the remaining part in carrying on the business of natural gas wholesales. In 2008, the share held by RWE TRANSGAS in natural gas imports dropped to about 85 % of the Czech Republic's imports and 69 % of sales to final customers. Regional natural gas suppliers have also been split into trading parts and eight individual distribution system operators. Most of it comes from Russia, through GAZPROM export Ltd., while a lesser part comes from Norway from a consortium of local producers.

The evolution of the export of natural gas from the Czech Republic during the period 2008–2011 is shown in Fig. 3.24. Czech Republic's only significant natural gas export goes to Germany, for which it forms a transit country. Some transit to France also takes place. In Fig. 3.24, the amount of natural gas exported to other countries during the period 2008–2011 are included. The exports of natural gas to other countries represents only a minor percentage of the total production of natural gas.

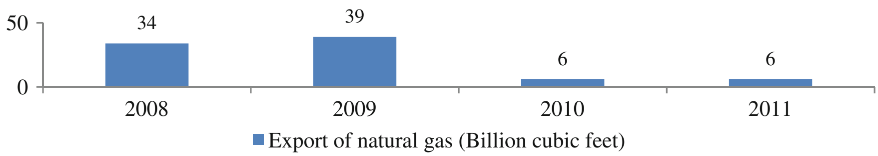

Fig. 3.24 Exports of natural gas from the Czech Republic during the period 2008–2011. *Source:* EIA

3.22.4 Electricity Generation

The Czech Republic is the third largest net electricity exporter in the EU, after France and Germany. Electricity generation is largely composed of domestic coal (60 %) and nuclear (32 %), whereas natural gas (4 %) is mainly used as a complementary fuel in multi-fired power plants and for peaking purposes. CHP constitutes one third of electricity generation and over 40 % of overall heat production, making the country the third largest in CHP use after Denmark and Finland.

The step-by-step opening of the Czech electricity market started in 2002. Since January 1, 2006, when household customers became eligible and acquired the right to choose their supplier, the market has been fully liberalized (1.5 years earlier than required by Directive 2003/54/EC). The market sectors in which competition is feasible are not subject to regulation include electricity generation, imports, and trade.

The electricity industry is dominated by three vertically integrated private run enterprises: C Z Group, E.ON ENERGIE a.s., and Praská Energetika a.s. As suppliers, the three groups have a joint market share of more than 95 % of final customers' total consumption,[30] with a clear dominance of C Z Group. As for small household customers, their share is more than 99 %. There are also about ten independent suppliers actively operating in the retail market. To date, they have been offering electricity, bought from smaller generators or imported from other countries, mainly to large industrial customers.

It is important to highlight that electricity generation and imports and commercial activities related to electricity supply to final customers are not controlled, and are fully subject to market mechanisms. As a consequence the regulatory framework above-described, the electricity price to all end-users, including households, is made up of regulated and unregulated items (Table 3.13).

According to the Czech Republic's National Report on Electricity and Gas Industries 2010, total installed capacity of power plants increased by 1,608 MW in 2010. By this, the installed capacity of thermal power plants, including cogeneration, increased by 49 MW and the installed capacity of natural gas-fired and combined cycle power plants increased by 89 MW, both on a year-on-year basis.

[30] It is noteworthy to mention that, per capita, the Czech Republic is consistently the largest net exporter of electricity in the world (only Norway can export more electricity during a rainy year).

Table 3.13 Capacity installed

Type of power plant	Capacity (MW)	Percentage (%)
Thermal power plants	10,769	54
Nuclear power plants	3,900	19.6
Hydroelectric power plants, including pumped storage	2,203	11.1
Gas-fired and combined cycle power plants	1,024	5.1
Renewables	2,038	10.2

Source: Czech Republic's national report on electricity and gas industries

Thermal power plants have the majority percentage of installed capacity (54 %) followed by nuclear power plants (19.6 %). This proportion will remain without significant change during the coming years.

The use of natural gas for the generation of electricity is very small and the current participation of this type of energy source in the energy mix of the country will not change significantly during the coming years.

3.23 Denmark

The Danish economy has grown by 78 % since 1980. However, over the same period its total energy use has remained almost unchanged, attesting to the administration's policy to promote energy savings and attain a high level of energy efficiency. The main trends and developments in Denmark's natural gas sector are the following:

- The government expects natural gas reserves to progressively decline throughout the forecast period. The government estimates that natural gas reserves will be approximately 40 billion m^3 in 2017, from their current level of 52 billion m^3; this represents a decrease of 23.1 %. Over the long-term, the government forecast reserves to decline to 38 billion m^3 by 2022; this means a further reduction of 5 % respect to 2017;
- In the period 2013–2015, the government project Danish natural gas production to continue its decline. Similar to oil production, however, the government forecast a temporary increase in natural gas production from 2016 to 2018, where production will rise from 5.1 billion m^3 in 2015, to reach 6.5 billion m^3 in 2018. After 2018, the government expects Denmark's natural gas production to once again decline. The significant Svane gas discovery is unlikely to be developed, and is therefore not taken into account in the forecast;
- The government forecast that natural gas production and consumption will both converge toward 4.9 billion m^3 and 4.8 billion m^3, respectively, by 2022, indicating that the country's modest exports are likely to come to a halt not long after the end of the forecast period;

- DONG ENERGY and BAYERNGAS have decided to jointly undertake the development of the Hejre field in the Danish North Sea at a cost of DKK 12.1 billion. Dong E&P expects production to reach 2.13 million m^3 of natural gas per day (0.78 billion m^3 per annum). Commercial operations are expected to start by the end of 2015;
- Denmark's dependence on energy prices and its declining production offer a rather bleak picture for its hydrocarbon export revenues. Oil export revenues will, in 2017, remain around the estimated US$1.50 billion forecast by BMI for 2013, with US$0.9 billion of net imports expected by 2022. Gas revenues are estimated at US$1.1 billion in 2013, falling to US$1 billion in 2017.

3.23.1 Natural Gas Reserves

The Danish Energy Agency (DEA) makes an assessment of Danish natural gas reserves annually. In 2011, the proven natural gas reserves were estimated by EIA in 72.502 trillion m^3 (2.053 trillion cubic feet), which is 5.2 % lower than the level registered in 2011. In 2013, the natural gas reserves were calculated at 53.608 trillion m^3 (1.518 trillion cubic feet), a reduction of 26.1 % respect to 2011.

It is expected that at the current level of consumption, natural gas reserves of Denmark will be virtually depleted in the coming years, if new natural gas deposited cannot be found. For this reason, the import dependence of the country of natural gas is, moreover, likely to rise sharply during the period 2015–2018 and beyond from almost 0 % (Christie 2007), and this dependence will be higher during the period 2020–2022 according to DEA and other sources.

3.23.2 Shale Gas

In about a decade, shale gas may increase its participation in the energy mix of the country. France TOTAL E&P Denmark and the Danish State-owned NORDSØFONDEN have decided to use about €27 million in 2012 to search for shale gas in the Northern part of the Jutland Peninsula. The companies hold two exploration licenses and have committed themselves to a test drilling in this license area, which is the most mature of the two licenses. According to TOTAL E&P Denmark sources, there might be about five times as much shale gas onshore as the country has recovered from the North Sea so far. There is an estimation of the chances of finding commercially interesting quantities to about 20 %, and in case of success production might start in 2020. The project has gathered little public interest so far, although the hydraulic fracturing connected with shale gas has caused environmental problems in other parts of the world. The gas has been located in the Alun Shale around 3–4 km below the surface. This is well below the Danish groundwater, which is used for drinking without any cleansing and is traditionally well guarded by the political parties that constitute the new government, and it is expected that the government will take all necessary precautions in order to protect any groundwater resources.

3.23.3 Production and Consumption of Natural Gas

In 1984, Denmark began producing natural gas from the North Sea and has been a net exporter of this type of energy source since then. Natural gas production comes primarily from the Tyra, Halfdan, Dan, and Tyra fields, which account for 75 % of total Danish natural gas production. Approximately 10 % of total natural gas production is used in the field as fuel, for injection, or is flared. The proportion of natural gas used as lift gas in wells with increasing water production could grow significantly during the coming years as oil extraction becomes increasingly difficult from aging fields.

Natural gas production peaked in 2005, with a total of 10.4 billion m^3 (9,383,000 tons) produced. Total production has declined steeply since and was some 8.2 billion m^3 (7,344 thousands of tons) in 2010; this represents a decrease of 21.2 %. The offshore production of natural gas totaled 6.5 billion m^3 in 2011, of which 5.6 billion m^3 of natural gas was exported ashore as sales gas, a 21 % decline respect to 2010.[31] The remainder of the natural gas produced was either re-injected into selected fields to improve recovery or used as fuel on the platforms. A small volume of unutilized natural gas is flared for technical and safety reasons.

While Danish natural gas production is expected to continue to decline sharply in the immediate short-term, it is expected that it could increase in 2016 and 2018 due to the development of new fields and an increase in the production of existing fields as a result of the use of new extraction techniques. Based on the DEA's expected production profile, Denmark is expected to remain a net exporter of natural gas up to 2020–2022.

The production of natural gas in Denmark during the period 2000–2005 increased 29 %. Since 2005, the production of natural gas declined, with the exception of the year 2008, to reach 227 billion cubic feet (8,016.505 billion m^3) in 2012, which is lower than the production level reached in 2000. Considering the whole period the production of natural gas dropped 21.5 % (Fig. 3.25).

On the other hand, during almost the whole period 2000–2012, the consumption of natural gas dropped 24.2 %. However, during 2009–2010, the consumption of natural gas increased 12.8 %. During the period 2010–2012, the consumption of natural gas decreased again in 6.8 %.

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[31] Six new production wells and one new water□injection well were drilled and completed in Danish fields in 2011. The level of development drilling in 2011 was, therefore, slightly higher than in 2010. Based on previously approved development plans, this level is expected to increase further in 2012. The wells drilled and additional development activities represented total investments of DKK 4.3 billion, which is at the same level as for 2010.

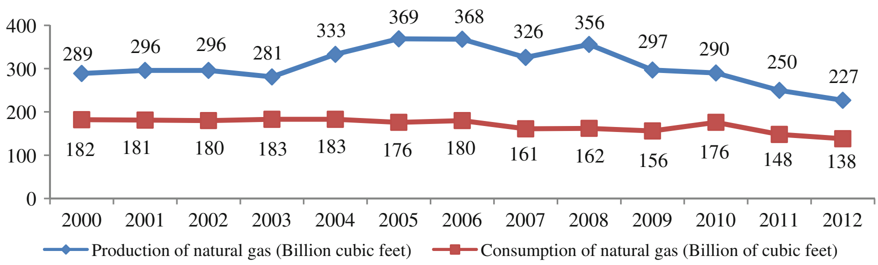

Fig. 3.25 Production and consumption of natural gas in Denmark during the period 2000–2012. *Source:* Eurostat

Future Danish natural gas consumption is expected to decrease as average by 1.3 % per year from 2010 to 2030. The reason for the forecasted decline is greater energy efficiency, a decrease in natural gas use at power plants, a decrease in natural gas consumption at decentralized CHP as a consequence of wind power development, and a shift toward biogas. However, the use of natural gas in connection with the upstream oil production could potentially grow as oil extraction becomes harder from aging fields, thus countering reductions in natural gas use further downstream.

3.23.4 Export and Import of Natural Gas

Denmark is a net exporter of natural gas. Domestic natural gas is exported to Sweden, Germany, and the Netherlands. However, it is important to be aware of the following: While Denmark is expected to remain a net exporter of natural gas, at least until 2020–2022, there could be a need for Denmark to import natural gas much sooner than forecasts for selfsufficiency suggest. In particular, the outlook for Danish production of natural gas indicates that in 2013 imports will be required to meet the combined natural gas demand of both Denmark and Sweden.

During three decades, Denmark has produced more than 210 billion m^3 of gas in the North Sea (72.4 % of the total production in that year), and while this production will be declining over the next few decades, an opportunity for shale gas is emerging onshore in Northern parts of the country. The country has supplied itself with natural gas from the North Sea since the early 1980s, but production peaked in the past decade, and the country will have to rely on imports from somewhere between 2021 and 2030.

The evolution of the exports and imports of natural gas from Denmark during the period 2008–2012 are shown in Figs. 3.26 and 3.27. According to Fig. 3.26, the exports of natural gas from Denmark during the period 2008–2012 decreased 46.2 %. It is expected that the exports of natural gas from Denmark will continue decreasing

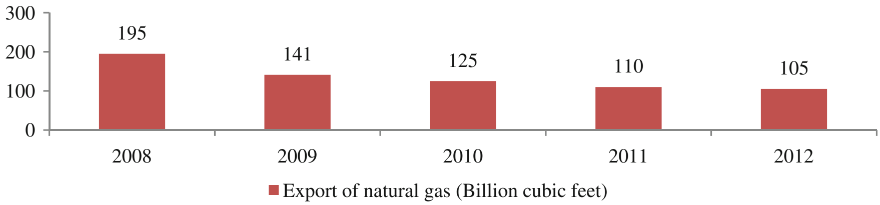

Fig. 3.26 Exports of natural gas from Denmark during the period 2008–2012. *Source:* EIA

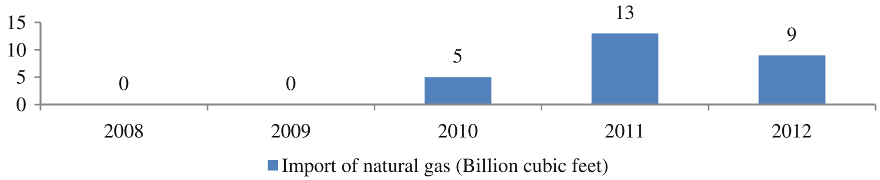

Fig. 3.27 Imports of natural gas from Denmark during the period 2008–2012. *Source:* EIA

during the coming years due to an increase in the use of this type of energy for the generation of electricity and heating in the country. However, it is important to highlight that according to the energy policy adopted by the government, Denmark will continue to be a net exporter of natural gas and can be expected to remain so at least until end of of 2020–2022.

Denmark has started to import natural since 2010. During 2010–2012, Denmark increased the import of natural gas from 5 billion cubic feet (176.58 billion m^3) in 2010 to 9 billion cubic feet (317.835 billion m^3) in 2012, an increase of 80 %. The peak in the imports of natural gas during the period considered was reached in 2011. It is expected that the imports of natural gas from Denmark will increase during the coming years, if the production of this type of energy source does not increase.

3.23.5 Electricity Generation

In 2010, the bulk of natural gas consumption, 44 %, was used for power generation in the transformation sector. The industry made up the second largest group, representing 17 % of natural gas use, while the energy sector, where natural gas is used for oil extraction, represented another 16 %.

According to IEA sources, the percentage of generation of electricity using natural gas as fuel during the period 2007–2010 is shown in Fig. 3.28. From that figure, the following can be stated: The percentage in the generation of electricity using natural gas as fuel in Denmark during the period 2007–2010 increased from

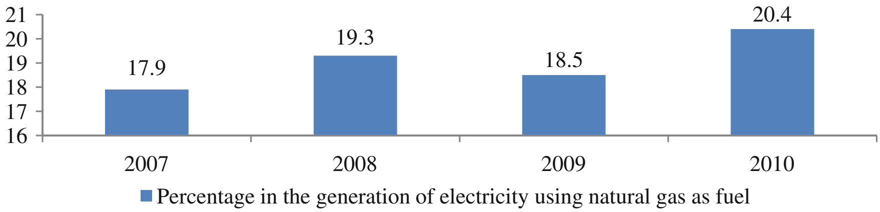

Fig. 3.28 Percentage in the generation of electricity using natural gas as fuel in Denmark during the period 2007–2010. *Source:* IEA

17.9 % in 2007 to 20.4 % in 2010; this represents an increase of 2.5 %. It is expected that the percentage of the use of natural gas for the generation of electricity in Denmark will continue to be around 20 % during the coming years.

3.24 Finland

Finland is highly dependent on imported fossil fuels—namely oil, natural gas, and coal—and will remain so in the long term. This poses a significant challenge in terms of energy security. The government has taken significant steps to address this concern and has sought to bolster its emergency response capabilities by building significant strategic reserves. According to the 1992 Act on Safeguarding Security of Supply, the National Emergency Supply Agency (NESA), must ensure that the country holds alternative fuels for oil and natural gas disruptions that match at least 5 months of consumption. Notably, this stock holding requirement is above the IEA oil stock requirement of 90 days of net imports of all member countries.

A second measure adopted is diversification. Finland has succeeded in developing a particularly well-diversified national electricity production mix, with roughly three equal thirds of its production coming from renewable, nuclear, and hydrocarbon energies, respectively. Its energy resilience has been further consolidated through deepened integration in the wider Nordic electricity market that notably includes its hydroendowed Scandinavian neighbors. In 2012, the entire Nordic area had one common electricity price during 31 % of the time, up from 25 % in 2011 and 18 % in 2010.

Another way to avoid dependence on energy imports is to reduce domestic demand, and Finland has been resourceful in initiating and implementing significant energy efficiency programs. Finland's 2008 Climate and Energy Strategy set as an overarching goal to reverse growth in final energy consumption, and an additional ambitious target to save approximately 11 % of total final consumption by 2020 compared to the business-as-usual scenario. Given Finland's climate, building codes have been revised and subsidies enhance the efficiency of existing building stock have been introduced. Efforts are also planned in the transport sector, with the introduction of a new private vehicle technology and speeding up the renewal of the existing car stock by 2020. Yet its transport sector remains highly oil dependent. Developing further efficiency innovations in the transport sector would enable Finland to reduce its exposure to imported hydrocarbons. The Finland's commitment to energy efficiency is to reach 20 % in 2010.

An inevitable characteristic of Finland's energy consumption structure is the high share of energy-intensive industry, as well as a long lighting and heating season. Yet the country has turned these vulnerabilities into strengths by developing one of the world's most extensive and efficient CHP industries and district heating networks. CHP accounts for over a third of total electricity production, well above the EU average of 10 %, and district heating provides almost half of the country's space heating.

Finally, Finland has sought to maintain what alternative indigenous forms of hydrocarbon energy it possesses. It is one of only three IEA member countries with peat in its energy supply, and its use is a topic of much public debate because of its high-carbon intensity and negative environmental impact. Nonetheless, peat use accounts for 6 % of total energy consumption, and about one million Finns have their homes and offices heated partly by peat-fired district heating systems. While subsidies have been abolished and the tax regime is increasingly burdensome for its long-term use, peat nevertheless continues to benefit from a comparative preferential tax regime because of its unique technical qualities in CHP co-firing with biomass, security supply benefits, widespread availability, price stability, and its contribution to regional economic development. Nevertheless, because of its high emissions profile, the outlook for peat in Finland's future energy mix remains undecided and is a source of uncertainty.

While each of these elements contributes to ensuring the country's energy security, the government's principal long-term goal in terms of energy security is clearly intertwined with another key pillar of its energy policy—the "decarbonization" of its economy, notably by developing cleaner means of energy production and consumption

3.24.1 Natural Gas Reserves

According to EIA sources, Finland has no natural gas reserves reported in 2013.

3.24.2 Production and Consumption of Natural Gas

Finland produces no natural gas. The evolution of the consumption of natural gas during the period 2000–2012 is shown in Fig. 3.29.

The consumption of natural gas in Finland during the period 2000–2012 decreased 12.2 %. The peak in the consumption of natural gas in the country during the period considered was reached in 2004. The consumption of natural gas

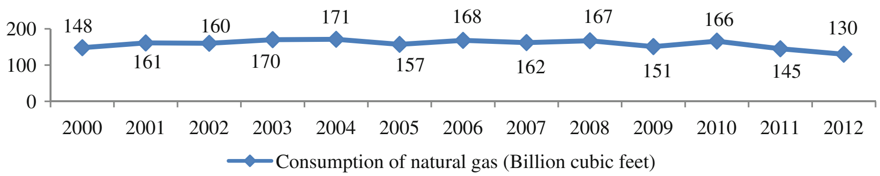

Fig. 3.29 Consumption of natural gas in Finland during the period 2000–2012. *Source:* EIA

dropped 21.7 % during the period 2010–2012. Natural gas (including shale gas) continues to be an important component of the energy mix of the country, but not as critical to the national energy system as renewables and nuclear power.

3.24.3 Import of Natural Gas

The evolution of the imports of natural gas in Finland during the period 2008–2012 is shown in Fig. 3.30. According to that figure, during the whole period 2008–2012, the imports of natural gas from Finland dropped 22.8 %. The peak in the imports of natural gas during the period considered was reached in 2008. It is expected that the imports of natural gas from Finland will continue decreasing at least during the coming years.

3.24.4 Electricity Generation

The evolution of the percentage of electricity generation in Finland using natural gas as fuel during the period 2007–2011 is shown in Fig. 3.31.

The generation of electricity in Finland using natural gas as fuel increased slightly from 13 % in 2007 to 13.9 % in 2010; an increase of only 0.9 %. However, during the period 2010–2011, the generation of electricity generated by natural gas dropped from 13.9 % to 13 %, the same level reached in 2007. It is expected that the participation of natural gas in the energy mix of the country will not change significantly during the coming years.

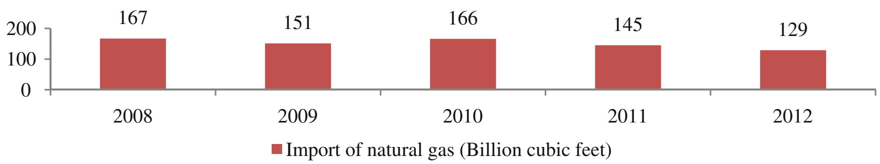

Fig. 3.30 Imports of natural gas from Finland during the period 2008–2012. *Source:* IEA

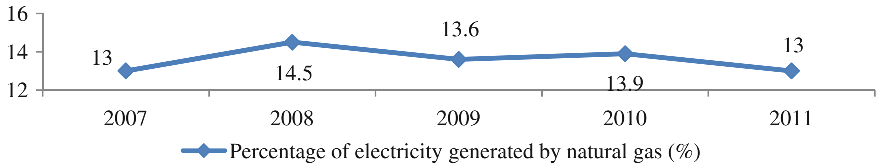

Fig. 3.31 Percentage of electricity generated in Finland during the period 2007–2011 using natural gas as fuel. *Source:* IEA and Finnish energy industry (2011)

Lastly, it is important to highlight the following: Finland has a very high energy consumption per capita, in fact the biggest user of electricity per capita in the EU (16,000 kWh per capita) and a high share of combined heat and power production. Around 30 % of the total electricity is generated by CHP. Electricity production in Finland in 2011 was 70.6 billion kWh and the consumption was 84.4 billion kWh forcing the country to import electricity from neighbor countries in order to satisfy the demand.

3.25 France

Gaz de France (GdF) dominates all natural gas activities in the country. Prior to recent energy reforms, GdF had a legal monopoly on the production, distribution, transportation, and importation of natural gas in the country. However, in recent years, EU Directives forced the government to open the French natural gas sectors to foreign investors. At the same time, GdF has taken advantage of this openness to enter the domestic natural gas markets of other EU countries as well. As a result, almost one-third of GdF's 15 million customers are outside France. Natural gas in France represents only 0.5 % of the total primary energy production of the country in 2010 and this situation has not changed in 2012.

3.25.1 Natural Gas Reserves

According to EIA sources, in 2013 France reported a proven natural gas reserve of 0.378 trillion cubic feet (13.349 trillion m^3).

3.25.2 Shale Gas

In France, three exploration authorizations of shale gas were granted in March 2010. Schuepbach Energy LLC, in association with GdF Suez, was granted the

Villeneuve-de-Berg and the Nant exploration authorizations. Total Gas Shale Europe (TGSE) and Total Exploration and Production France (TEPF) were granted, jointly and severally, the Montélimar exploration authorization. Devon Energie Montélimar SAS contemplated obtaining such an authorization for the same site, but withdrew eventually.

However, it is important to highlight that oil drilling has been suspended since February 2011 for all projects. It was decided that the Conseil Général de l'Industrie, de l'Energie et des Technologies (CGIET), and the Conseil Général de l'Environnment et du Développement Durable (CGEDD) would investigate the economic, social, and environmental impact of shale gas activities. In the meantime, Act n° 2011-835 was enacted on the prohibition of exploration and exploitation of liquid hydrocarbon mines by means of hydraulic fracturing and on the cancellation of exploration permits granted for projects using this technique (the Prohibition Act). However, recently all three exploration authorizations in the field of shale gas approved by the government have been abrogated, as a consequence of this Prohibition Act.

3.25.3 *Production and Consumption of Natural Gas*

France has very little domestic natural gas production. In 2003, the country consumed 52.973 trillion m^3 (1.48 trillion cubic feet), with less than 5 % of that demand met from domestic sources. The most important suppliers of France's natural gas are Norway, Russia, and Algeria. The evolution of the production and consumption of natural gas in France during the period 2000–2012 are shown in Figs. 3.32 and 3.33.

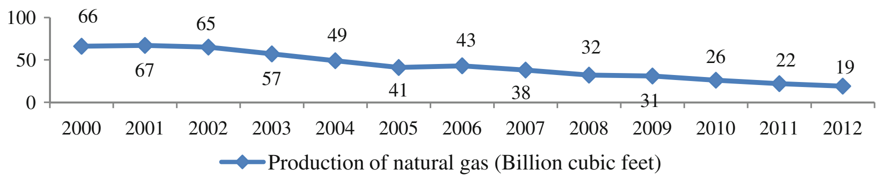

Fig. 3.32 Production of natural gas in France during the period 2000–2012. *Source:* EIA

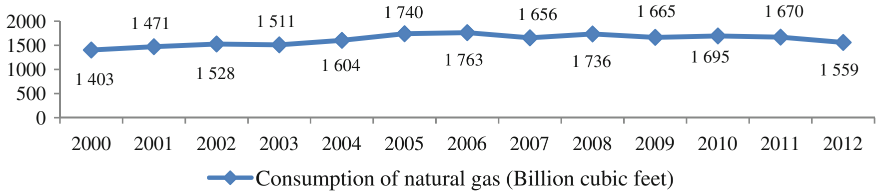

Fig. 3.33 Consumption of natural gas in France during the period 2000–2012. *Source:* EIA

The production of natural gas in France during the period 2000–2012 dropped significantly (71.3 %). The peak in the production of natural gas during the period considered was reached in 2001 and since that year it has significantly declined until 2012, except in 2006 when the production of natural gas increased 4.8 %. It is expected that the domestic production of natural gas will continue declining during the coming years, unless new natural gas reserves are found.

According to Fig. 3.33, the consumption of natural gas in France during the period 2000–2012 increased 11.1 %. The peak in the consumption of natural gas during the period considered was reached in 2006. France imported a high percentage of the natural gas that the country consumed each year. The production of natural gas in 2011 only covered around 1.2 % of the total demand and, for this reason, France should increase the import of natural gas in order to satisfy any possible foreseeable increase in the use of this type of energy source for the generation of electricity in the future.

3.25.4 Import and Export of Natural Gas

The evolution of the imports and exports of natural gas from France during the period 2008–2012 are shown in Figs. 3.34 and 3.35.

According to Fig. 3.34, the exports of natural gas from France during the period 2008–2012 increased 151 %. The peak in the exports of natural gas during the period considered was reached in 2012. It is expected that France will continue exporting natural gas to neighboring countries during the coming years, but perhaps in a lower level.

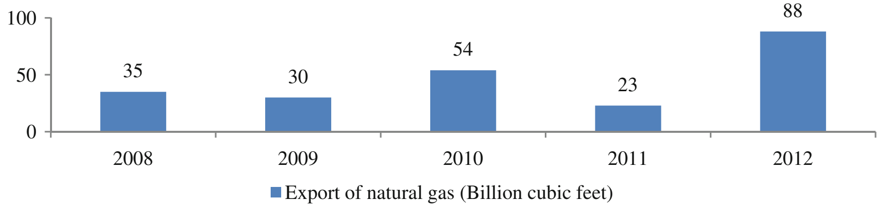

Fig. 3.34 Exports of natural gas from France during the period 2008–2012. *Source:* EIA

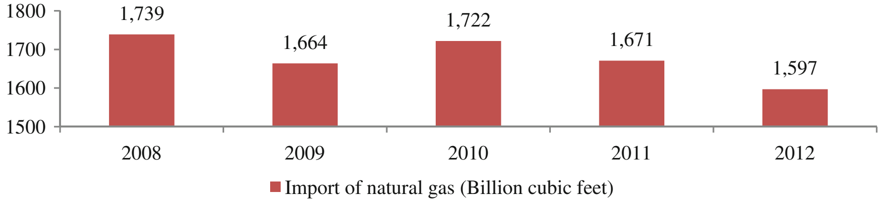

Fig. 3.35 Imports of natural gas from France during the period 2008–2012. *Source:* EIA

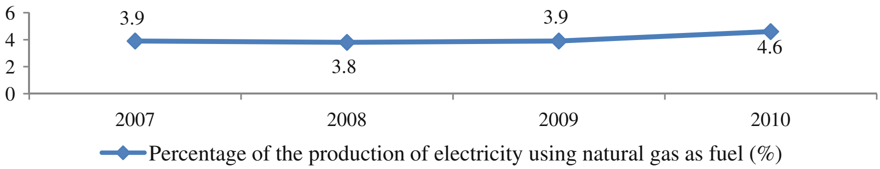

Fig. 3.36 Percentage of the production of electricity in France using natural gas as fuel during the period 2007–2010. *Source:* Eurostat

The imports of natural gas from France during the period 2008–2012 decreased 8.2 %. The peak in the imports of natural gas during the period considered was reached in 2008. It is expected that the imports of natural gas from France will increase during in the coming years, particularly if the decision to reduce the current level of the participation of nuclear energy in the energy mix of the country is implemented as was approved by the government.

3.25.5 Electricity Generation

Lower electricity generated from nuclear power plants in 2009 accounted for more electricity using natural gas as fuel. However, nuclear power is back on track in 2010 and the use of natural gas in the electricity production has, therefore, been limited despite 1.3 GW of additional natural gas power plants that entered in operation in 2010. The evolution of the percentage of the production of electricity as natural as using fuel in France is shown in Fig. 3.36.

According to Fig. 3.36, the percentage of the production of electricity in France using natural gas as fuel is very low and during the period 2007–2010 increased from 3.9 % in 2007 to 4.6 % in 2010; this represents an increase of only 0.7 %. The peak in the level of production of electricity using natural gas as fuel during the period considered was reached in 2010. The consumption of natural gas for the generation of electricity is expected to increase during the coming decades, particularly if the intention of reducing the participation of nuclear energy in the energy mix of the country is implemented as was approved by the government.

3.26 Germany

Germany began to liberalize its natural gas sector in the late 1990s in order to comply with EU Directives. Unlike other EU countries, though, Germany did not establish a national regulator for the liberalized natural gas sector. Rather, it relied upon negotiated access between suppliers, distributors, and transmission companies.

Germany has very little domestic oil and natural gas production and relies heavily on imports. It has well diversified and flexible oil and natural gas supply infrastructure, which consists of crude, product and gas pipelines, and crude and oil product import terminals. Natural gas imports into Germany exclusively by cross-border pipeline. The country has no LNG infrastructure, although some German companies have booked capacities in overseas LNG terminals.

3.26.1 Natural Gas Reserves

According to EIA sources, Germany has 4.414 trillion m^3 of proven natural gas reserves in 2013. Almost all of Germany's natural gas reserves are located and the production occurs in the Northwestern State of Niedersachsen, between the Wesser and Elbe Rivers. Germany's sector of the North Sea also contains sizable natural gas reserves, currently supporting the A6-B4 production project. The prospective areas for natural gas are nearly the same as for oil, e.g., the foreland of the Alps, the Thuringian Basin, the North German Basin, and the Oberrheingraben. However, environmental regulations have curtailed the complete exploration of the area where the bulk of the natural reserves is located.

3.26.2 Shale Gas

In Germany, shale gas exploration projects are in different stages of planning or exploitation. Several projects exist within the States of North Rhin Westphalia, Lower Saxony, Saxony-Anhalt, Thuringia, and Baden-Wuerttemberg. In North Rhine Westphalia, one commercial project of EXXONMOBIL Production Deutschland GmbH (EPMG) aiming at the exploration of shale gas received an authorization from the government. Nine requests for granting an exploration authorization are pending of government approval. In Lower Saxony nine exploration authorizations were granted to EMPG. Two exploration authorizations are granted in Baden-Wuerttemberg (Three Leg Resources) and Thuringia (BNK Petroleum), respectively. Saxony-Anhalt issued one exploration authorization to BNK Petroleum.

In Lower Saxony, EPMG has drilled five shale gas exploration wells plus an additional one in North Rhine Westphalia, which results are currently being examined by experts of the company. EPMG has committed itself not to conduct any further shale gas fracturing activities until it receives a "go-ahead" from an installed independent expert group. In the other Länder test drillings are currently at a planning stage.

It is important to highlight that the issue of shale gas production is politically controversial in Germany—particularly with regard to drinking water and environmental protection—so public opinion is a major factor that need to be included in any further decision that the government should take related to the exploitation of shale gas for the generation of electricity or for any other purposes in the coming years.

3.26.3 Production and Consumption of Natural Gas

Natural gas production in Germany has remained roughly stable in recent years, while consumption has grown markedly. Germany's only offshore natural gas field is located in the German North Sea, about 304 km offshore. The field began production in September 2000. Known as the *Deutsches Nordseekonsortium* (German North Sea Consortium), the field is operated by a consortium of Wintershall (operator), BEB ERDGAS and ERDOEL, BASF, and RWE-DEA.

According to EIA sources, Germany is the EU's second largest consumer of natural gas, after the UK. Germany produces insufficient natural gas to satisfy domestic consumption and should meet most of its demands through imports. On the other hand, natural gas consumption in Germany has declined 10 % since 2006. The evolution of the production and consumption of natural gas during the period 2008–2012 is shown in Fig. 3.37.

According to government commissioned analysis, the total consumption of natural gas in Germany is expected to continue to decline over the long-term. The share of natural gas in Germany's energy mix is currently around 22 %. However, it is expected that this share to rise in the medium-term to 24 % by 2025; an increase of 2 % respect to 2010. On the other hand, electricity generated from natural gas seems to be on the rise again, thanks to 1.8 GW of additional natural gas power plants that entered operation in 2010.

The production of natural gas in Germany during the period 2008–2012 dropped 25.6 %. The peak in the production of natural gas during the period considered was reached in 2008. Since that year the production of natural gas in the country has been declining and it is expected that this trend will continue decreasing during the coming years.

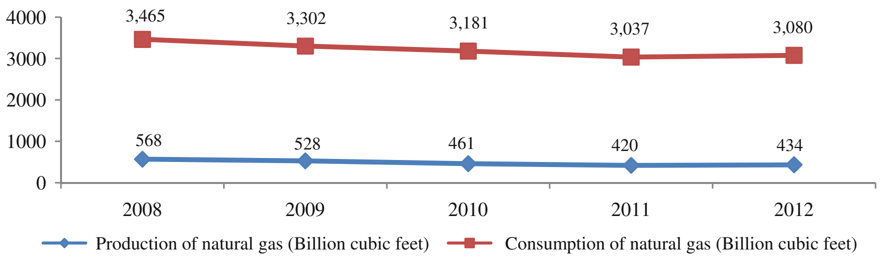

Fig. 3.37 Production and consumption of natural gas in Germany during the period 2008–2012. *Source:* EIA

On the other hand, the consumption of natural gas in Germany during the period 2008–2012 dropped 11.2 %. It is important to highlight that during almost the whole period considered, the consumption of natural gas decreased, except the period 2011–2012, during which the consumption increased 1.4 %. The peak in the consumption of natural gas during the period considered was reached in 2008. It is expected that the consumption of natural gas in Germany will increase during the coming years, as a result to the decision of the government to shut down all nuclear power reactors in operation before 2022.

3.26.4 Import and Export of Natural Gas

German natural gas imports are geographically relatively well diversified. In 2010, the biggest import source was Russia, which supplied 39 % of natural gas imports; next was Norway on 35 % and the Netherlands on 22 %. Germany has no LNG infrastructure, so all of the country's natural gas imports are supplied via a number of cross-border pipelines.[32] However, some German companies have booked capacities in overseas LNG terminals, e.g., E. ON Ruhrgas has contracted 3 billion m^3 a year in Rotterdam, Netherlands. The government expects that LNG will become an increasingly important source of natural gas for Europe in the future, so it considers access to LNG terminals to be important. For this reason, are encouraged German companies to purchase regasification capacities in LNG terminals in neighboring countries, and LNG volumes from new suppliers. E.ON Ruhrgas had plans to build an LNG terminal in Germany, but there was insufficient long-term interest for it to be viable commercially. Nevertheless, there is a permitted site for an LNG terminal in Germany so it remains a future possibility.

Germany might be forced to import even more natural gas from Russia and other countries during the next decade, if all nuclear power reactors in operation in the country are shut down before 2022, at a time when Russia itself is facing an emerging natural gas crisis domestically, despite the fact that it has the largest natural gas reserves in the world, and the adoption of a set of sanctions by the EU and the USA for the military occupation of Crimea in 2014.

The evolution of the imports and exports of natural gas from Germany during the period 2008–2012 is shown in Figs. 3.38 and 3.39.

The imports of natural gas from Germany during the period 2008–2012 decreased 5.3 %. It is expected that the imports of natural gas from Germany will increase in the coming years due to the closure of all nuclear power reactors

[32] The volume of trade at the two German trading posts, VP NCG and VP GASPOOL, has increased significantly. According to government sources, a total of 102 billion m^3 of natural gas was traded in 2011—47 % more than 2010. This means that Germany's cross-border natural gas pipeline network needs to be seen in a broader European context as well as its domestic German context.

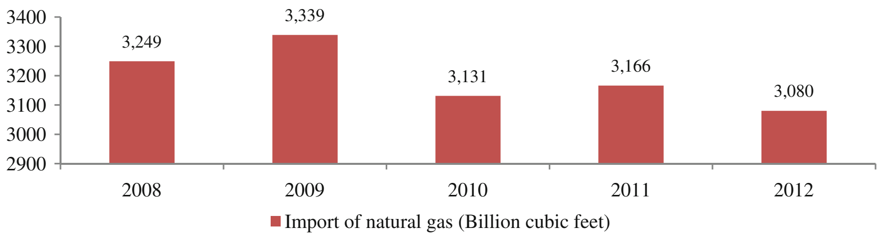

Fig. 3.38 Imports of natural gas from Germany during the period 2008–2012. *Source:* EIA

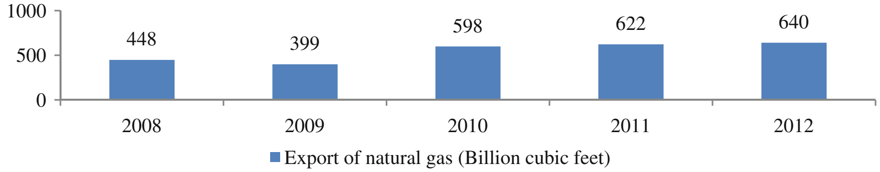

Fig. 3.39 Exports of natural gas from Germany during the period 2008–2012. *Source:* EIA

currently in operation, and due to the closure of a number of old coal power plants now used for the generation of electricity in the country.

The exports of natural gas from Germany during the period 2008–2012 increased 42.8 %. It is expected that Germany will continue to be an exporter of natural gas at least until 2022, when all nuclear power reactors will be shut down and the government expect an increase in the use of natural gas and renewables for the generation of electricity.

3.26.5 Electricity Generation

The evolution of the percentage in the production of electricity in Germany using natural gas as fuel during the period 2007–2010 is shown in Fig. 3.40.

The production of electricity using natural gas as fuel in Germany during the period 2007–2010 represents no more than 15 % of the total. During that period, the peak in the generation of electricity using natural gas as fuel was reached in 2008. If

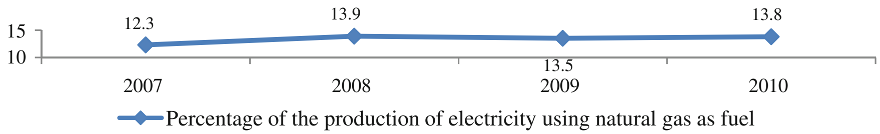

Fig. 3.40 Percentage of the production of electricity in Germany using natural gas as fuel during the period 2007–2010. *Source:* IEA

the whole period is considered, the generation of electricity using natural gas as fuel increased from 12.3 % in 2007 to 13.8 % in 2010, an increase of 1.5 %. With the shut down of all nuclear power reactors operating in the country before 2022, it is expected an increase in the use of natural gas as fuel for the generation of electricity during the coming years.

Lastly, it is important to highlight that German importers have contracted around 922 billion m^3 worth of natural gas for delivery via Germany's cross-border pipeline network up to 2025—and some existing contracts also extend beyond that year. It is assumed by the government and the importing companies that existing contracts will be extended and new ones concluded over time, if needed.

3.27 Greece

Natural gas was introduced to Greece in 1988 when the Public Gas Corporation (DEPA) was established. DEPA is 35 % owned by Hellenic Petroleum and 65 % by the Greek State. Today, the deregulated energy market in Greece provides for companies to participate in the transmission and distribution of natural gas. This type of energy source has become an important component of Greece's energy policy as the country diversifies to include cleaner and more competitively priced energy.

The energy policy of Greece favors major private sector investment. It is estimated by the World Bank that investment of more than €30 billion will be required by 2020 in the upgrade and building of new power plants, in transmission and distribution, and in renewable energy sources.

Greece's comprehensive energy policy to establish sustainable, competitive, and secure sources of energy, has established an encompassing regulatory and market framework for the energy sector. This, in combination with Greece's wide-ranging investment regulatory framework, provides for exceptional opportunities for investment in a number of economic sectors. Legislation (Law 2773/1999) provides for the deregulation of the electrical energy market and as such, domestic production, transmission, and distribution in the energy field is open to private investors. This sweeping change has transformed the electricity and energy market in Greece into one of the most exciting sectors of growth and opportunity in Europe before the beginning of the current economic and financial crisis that is affecting the country in a severe manner. While previously all electricity production, transmission, and distribution were under a monopoly regime, today companies from around the world are taking advantage of this tremendous market opportunity and the weakness of the country to overcome alone the current economic and financial crisis.

Greece's strategic geoeconomic location, between energy producers in the Middle East, North Africa, and the Caspian Sea region, as well as on the vital transport routes of the Aegean Sea and the Eastern Mediterranean, mark it as the expanding hub between East and West. For this reason, Greece has initiated crucial major ventures in oil, natural gas, and alternative sources that literally put the country at the heart of the Southeast European energy axis.

3.27.1 Natural Gas Reserves

According to EIA sources, there are 0.035 trillion cubic feet (1.236 trillion m^3) of proven natural gas reserves reported by the government in 2013.

3.27.2 Production and Consumption of Natural Gas

There is practically no natural gas production reported by the government since 2005. The evolution of the consumption of natural gas in Greece during the period 2008–2012 is shown in Fig. 3.41. According to Fig. 3.41, the consumption of natural gas in Greece increased slightly during the period 2008–2012 (3.3 %). Based on government sources, it is expected that the consumption of natural gas will continue increasing during the coming years.

3.27.3 Import of Natural Gas

Greece does not export natural gas during the period 2008–2013. The evolution of the imports of natural gas from Greece during the period 2008–2012 is shown in Fig. 3.42.

During the past 5 years, the imports of natural gas from Greece increased 6.7 %. The peak in the imports of natural gas during the period considered was reached in 2011. It is expected that the imports of natural gas from Greece will continue increasing in the coming years, particularly when the current economic and financial crisis affecting the country is overcome.

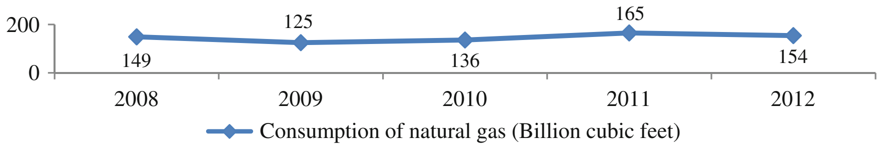

Fig. 3.41 Consumption of natural gas in Greece during the period 2008–2012. *Source:* EIA

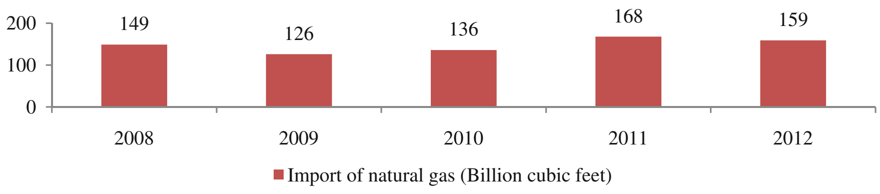

Fig. 3.42 Imports of natural gas from Greece during the period 2008–2012. *Source:* EIA

3.27.4 Electricity Generation

Electricity demand in Greece is expected to grow at 3.5 % annually from 2010 to 2020, but this projection could change significantly depending how far the current economic and financial crisis could affect the economy of the country during the coming years. According to Greece's Energy Regulatory Authority (RAE), 6,000 MW of additional capacity will be needed by 2015 in order to satisfy the foreseeable energy demand in the near future.

One of the most important uses of natural gas in the country is for the operation of cogeneration plants for electricity production. The dominant fuel used today in this type of power plants, both for environmental and economic reasons, is natural gas. The efficiency of a cogeneration plant may exceed 90 % and cogeneration offers energy savings of between 15 % and 40 % compared with energy derived from more conventional means. Cogeneration produces approximately 4 % of total electricity in Greece, a percentage that is expected to increase significantly in the near future. The following are key factors for the expanding role of cogeneration in Greece:

- The deregulation of electricity generation has attracted many project proposals, most of which are natural gas-fueled;
- Electricity demand in Greece is expected to grow at 3.5 % annually from 2010 to 2020. According to Greece's Energy Regulatory Authority (RAE), 6,000 MW of additional capacity will be needed by 2015;
- Four important changes in the Greek natural gas system occurred;
- Major structural natural gas projects are being carried out to connect Greece and Italy with the Caspian region (supply);
- The deregulation of the natural gas market with new tariffs;
- The government is promoting the use of natural gas for electricity production and for heating, complying with supply policy and environmental commitments;
- European policy and support schemes toward the creation of a single electricity and gas market in Europe.

Since 1990, Greece has converted a number of power plants to cogeneration mode. In addition, the conditions for the development of CHP are improving both in legal certainty and fuel supply after the adoption of Law 3486 on the electricity liberalization directive and the developments of natural gas infrastructure. The Hellenic Association for the Cogeneration of Heat and Power estimates that the total potential for CHP is more than 700 MW in the industrial sector, and between 100 MW and 300 MW in the services sector under current CHP policies.

Finally, it is important to highlight the following: The market prospects for cogeneration in Greece are increasing, a result of the wider use of natural gas and the financial support for the cogeneration plants provided through EU funds, and through the attractive investment incentives of the Greek government.

Finally, it is important to highlight that the percentage of the production of electricity in Greece during the period 2007–2010 increased 5.2 %. The major percentage in the production of electricity was reached in 2010. During the period

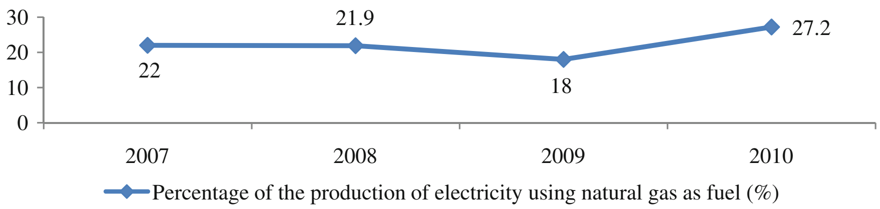

Fig. 3.43 Percentage of the production of electricity in Greece using natural gas as fuel during the period 2007–2010. *Source:* IEA

considered Greece was under severe economic and financial crisis, particularly in the energy sector, and despite all measures adopted by the government the current crisis is far from over. However, and despite of this situation, it is expected that the use of natural gas in the generation of electricity in the country will continue to increase during the coming years. Natural gas is the second within the country energy mix after coal (Fig. 3.43).

3.28 Hungary

Hungary has little domestic oil and natural gas production and relies heavily on energy imports. Russia is the dominant supplier for both oil and natural gas. Natural gas demand has declined since its peak in 2005, but remains the fuel with the largest share of Hungary's energy primary supply, standing at almost 40 % in 2010.[33] It is important to highlight that natural gas demands dropped by some 6.1 % owing to the economic and financial crisis that is affecting the whole EU, but partially recovered in 2010 and the process still continue.

The government adopted a new energy policy in order to improve the current conditions of the energy sector. It has the following main objectives:

- Develop diverse energy supplies with the aim of eliminating dependency on energy imports from Russia;
- Improve environmental protection;
- Increase energy efficiency through modernization of supply structures and better management of electricity consumption;
- Attract foreign capital for investment in capital-intensive energy projects.

In 1999, the government issued an Energy Plan indicating a movement toward cleaner technologies, including emissions controls for coal-fired generation and

[33] Natural gas has the highest share in the energy primary supply of Hungary, standing at 40 % in 2010, well above the 2009 IEA average of 24 %. Natural gas consumption has more than doubled in volumetric terms between 1973 and 2010. Its share is expected to decline somewhat, as the country seeks to diversify its energy primary supply (IEA 2012).

eventual replacement of some coal-fired power plants by gas turbines power plans. The 2001 Electricity Act brings the Hungarian electricity market into accord with EU Directives in terms of third-party access to the electricity grid and removal of subsidies, and defines a market structure that includes electricity generation companies, electricity distributors, power traders, and an electricity grid operator.

It is important to highlight that natural gas and crude oil dominate primary energy supply in Hungary. However, the share of oil, as well as the share of solid fuels, has declined significantly since 1990 as these fuels have been gradually replaced by natural gas. For this reason, natural gas supply has increased by 31 % over the period 1990–2004.

Preliminary plans under preparation call for a major changeover from coal power plants to gas turbine power plants. Under these plans, there would eventually be only one coal power plant left for the production of electricity in the whole country, the Matra power plant located in the North of Hungary. This is a lignite mine-mouth power plant that currently produces 13 % of Hungary's electricity. It is estimated that changing a 200 MWe power plant from coal to gas turbines takes 2 years and costs between US$60 and US$80 million. Under Hungary's policies, the cost of rehabilitating the land previously used for coal mining for a natural gas power plant will be included in the price of electricity. Integration of steam coal-producing mines to power companies, mostly took place prior to the first wave of privatization in 1995.

3.28.1 Natural Gas Reserves

According to EIA sources, in 2013 the country's natural gas reserves were estimated at 0.286 trillion cubic feet (10.10 trillion m^3), the same level reported in 2012.

3.28.2 Tight Gas

Hungary has unconventional gas resources—tight gas[34]—but this potential remains very uncertain. Several companies, including MOL, EXXON-MOBIL, and

[34] According to Wikipedia, **tight gas** is natural gas produced from reservoir rocks with such low permeability that massive hydraulic fracturing is necessary to produce the well at economic rates. Tight gas reservoirs are generally defined as having less than 0.1 millidarcy (mD) matrix permeability and less than ten percent matrix porosity. Although shales have low permeability and low effective porosity, shale gas is usually considered separate from tight gas, which is contained most commonly in sandstone, but sometimes in limestone. Tight gas is considered an unconventional source of natural gas.

FALCON, are involved in unconventional gas exploration, for example in the Makó Trough and the Békés Basin. However, most activities are in the preliminary stages and it is too early to estimate if and when unconventional gas could reverse the declining production trend. The government is encouraging unconventional gas production with lower royalty rates (12 %) than conventional gas production (up to 30 %). However, the terms of new gas exploration contracts are determined on a case-by-case basis by the government (IEA 2012).

3.28.3 Production and Consumption of Natural Gas

Natural gas production comes mostly from mature fields, but the government believes that production can be maintained at close to these volumes until around 2020. Thereafter, however, production is expected to decline considerably if no new resources are developed.

The evolution of the production and consumption of natural gas during the period 2000–2012 is shown in Fig. 3.44.

From Fig. 3.44, the following can be stated: The peak in the production of natural gas within the period 2000–2012 was reached in 2001. During the whole period the production of natural gas dropped 30.1 %. It is expected that this trend will continue during the coming years unless new gas reserves are discovered. The peak in the consumption of natural gas was reached in 2005. Considering the whole period, the consumption of natural gas dropped 15.1 %.[35] It is expected that the consumption of natural gas will increase up to 10–16 billion m^3 by 2020.

In October 2011, the parliament approved a new energy strategy up to 2030, thereby revising the previous 2008 strategy through to 2020. One of the key changes is that the 2008 strategy foresaw a slight increase of total natural gas demand up to 16 billion m^3 by 2020, while one scenario in the new energy strategy foresees a stabilization of natural gas demand at around 10 billion m^3 in the longer term. However, future natural gas demand in Hungary faces considerable uncertainty. The residential and commercial sectors have high potential for energy savings, with energy efficiency measures expected to save estimated between 1.5 and 2 billion m^3 per year by 2030. However, consumption in power generation is expected to grow further within the same timeframe (by another 3.5–4 billion m^3

[35] According to the IEA (2012) report, the residential sector is the largest consumer of natural gas in Hungary, standing at some 35 % of total natural gas demand in 2009. As such, the supplies of natural gas are of paramount importance in the cold winter months, as many homes depend on natural gas for residential use and heating. Equally important, the transformation sector accounted for around 30 % of natural gas demand. The commercial sector accounted for 17 % of natural gas demand, and industry accounted for another 13 %. It is worth noting that the industrial sector and power producers were particularly affected by the recession in 2009 that still is affecting several EU countries. Natural gas consumption in the power sector fell by 4 % in 2008 and by 28 % in 2009, and natural gas consumption by industry underwent a 26 % decline, all due to the economic recession affecting the country.

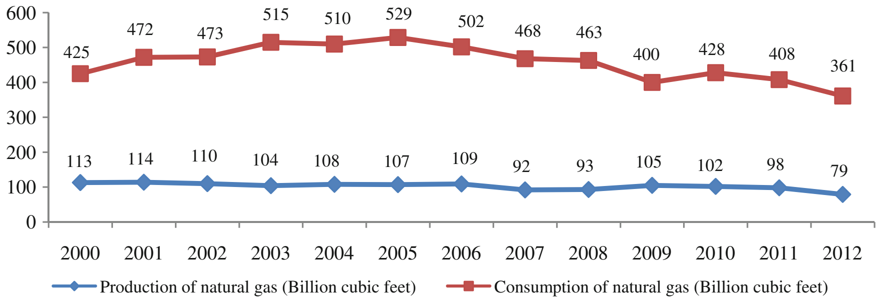

Fig. 3.44 Production and consumption of natural gas in Hungary during the period 2000–2012. *Source:* Eurostat

per year), as many new "midmerit" and "peaking" gas-fired power plants are under construction or are planned (IEA 2012).

3.28.4 Import and Export of Natural Gas

Hungary imports approximately 75 % of its natural gas demand. More than 80 % of imports come from Russia, with small amounts also coming from other former Soviet Union countries, France, and Germany. Imports from Western Europe have increased incrementally since 2008, as traders have taken the opportunity of cheaper spot natural gas from this region. Yet despite the Russia-Ukraine crisis in early 2009, Russian and Russian-transiting Turkmen gas still account for most of the supplies, and have actually increased as a share of total imports to Hungary.

The imports and exports of natural gas from Hungary during the period 2008–2012 are shown in Figs. 3.45 and 3.46.

The imports of natural gas by Hungary during the period 2008–2012 decreased 28.3 %. The peak in the imports of natural gas during the period considered was reached in 2008 and since that year the imports of natural gas declined each year until 2011. It is expected that the imports of natural gas will increase once again after 2012, at least during the coming years, as a result of the overcome of the economic crisis that still is affecting the country.

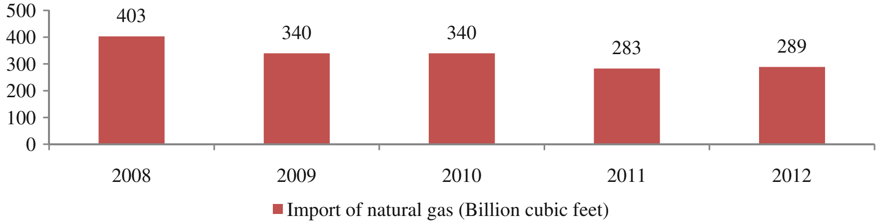

Fig. 3.45 Imports of natural gas from Hungary during the period 2008–2012. *Source:* EIA

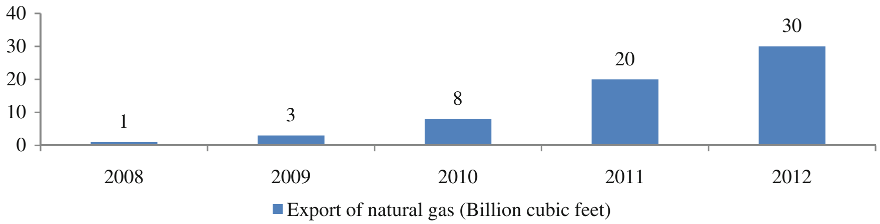

Fig. 3.46 Exports of natural gas from Hungary during the period 2008–2012. *Source:* EIA

According to Fig. 3.46, the exports of natural gas from Hungary during the period 2008–2012, increased significantly 30 folds. The level of export of natural from Hungary will depend on the level of production and consumption that could be reached during the coming years as well as on the discovering of new natural gas deposit that could be exploited economically.

3.28.5 Electricity Generation

Hungary's power sector is heavily dependent on natural gas. Despite the reduction in the dependency on natural gas for the generation in the past 4 years (7.1 %), a little more than a third of Hungary's electricity was produced from natural gas in 2010. The percentage in the production of electricity using natural gas as a fuel is shown in Fig. 3.47.

The percentage in the production of electricity using natural gas as fuel in Hungary during the period 2007–2010 dropped from 38.1 % in 2007 to 31 % in 2010, a decrease of 7.1 %. It is expected that the use of natural gas for the generation of electricity will increase once again during the coming years, particularly after the country start it recovering process at the end of the current crisis, which is not only affecting Hungary, but also the EU as a whole.

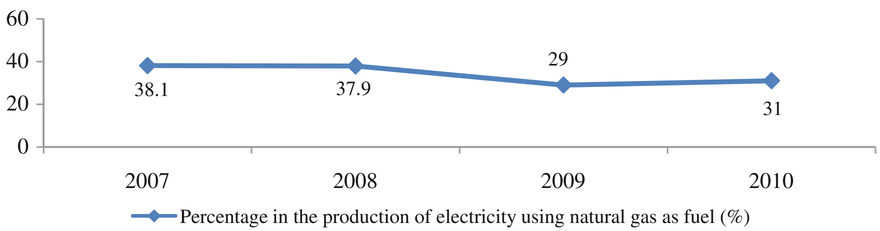

Fig. 3.47 Percentage in the production of electricity using natural gas as fuel in Hungary during the period 2007–2010. *Source:* Eurostat

3.29 Italy

Natural gas has become the most important fuel for electricity generation in Italy, gradually displacing the use of oil for this specific purpose whose share has reduced in recent years. Generation from renewable energy sources exhibits some variability, with a contribution of nearly 20 % in the country electricity mix the past years. The share of solid fuels has also increased, contributing to a fairly diverse electricity mix. Total electricity generation in Italy has increased noticeably in recent years.

Italy has mostly brought its natural gas sector into compliance with EU regulations concerning liberalization. These areas include the opening of the sector to new entrants; the unbundling of production, distribution, and transmission activities, and the freeing of natural gas prices from State control. Natural gas liberalization has slowly eroded ENI's dominant position in the energy sector, with ENI's share of total natural gas delivered to the national grid declining from almost 100 % prior to liberalization to 68 % in 2003 and 34.8 % in 2012, almost 50 % lower than in 2003.

3.29.1 Natural Gas Reserves

According to EIA sources, in 2013 the proven natural gas reserves of Italy were estimated at 2.202 trillion cubic feet (77.764 trillion m^3), a decrease of 34 % respect to 2009.

3.29.2 Production and Consumption of Natural Gas

Natural gas production, which increased from 15 million m^3 in 1937 to 15,273 million m^3 in 1974, stood at 17,500 million m^3 in 1999. Produced primarily in the Po River Valley, the natural gas is piped to the large cities of the North. ENI[36] controls the majority of the production and distribution of natural gas and oil in the country. Partial privatization of ENI took place between 1995 and 1998.

The evolution of the production and consumption of natural gas in Italy during the period 2000–2012 are included in Fig. 3.48.

According to Fig. 3.48, the production of natural gas in Italy during the period 2000–2012 decreased 51.8 %. However, it is expected that the production of natural gas in Italy continue the increase registered during the past 3 years after the significantly decrease registered during the period 2000–2009. On the other hand, the consumption of natural gas during the same period increased 5.9 %. The peak in the consumption of natural gas was reached in 2005. It is expected that the

[36] ENI was the sixth-largest publicly traded oil company in the world in the 2000s.

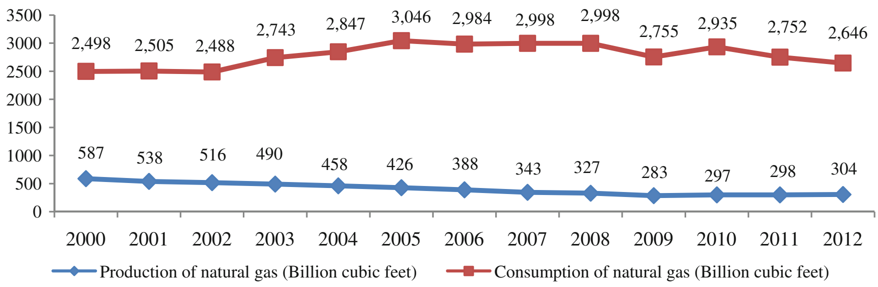

Fig. 3.48 Production and consumption of natural gas in Italy during the period 2000–2012. *Source:* Eurostat

consumption of natural gas in Italy will increase once again during the coming years, particularly after that the country overcome the current economic crisis that is affecting Italy.

3.29.3 Liquefied Natural Gas

According to Clough (2008), imports of Liquefied Natural Gas (LNG) constitute a very small portion of Italy's total natural gas imports. The country has a single LNG receiving terminal at Panigaglia, located on the country's Western coast near La Spezia. Natural gas companies are planning to construct several LNG receiving terminals in Italy in order to meet estimated future demand of natural gas. British Gas (BG) plans to construct an LNG receiving terminal in Brindisi, along Italy's Southeast coast. In late 2004, it awarded a contract for construction of the facility to Italy's TECNIMONT, with an initial output capacity of 27,192.55 million m^3 (770 million cubic feet) per day. In March 2006, the federal government overturned a ban on the construction of the project by local authorities who had opposed the terminal on environmental grounds. BG has already secured a supply of LNG for the terminal from its own integrated production–gasification project in Egypt. EXXON-MOBIL and Qatar Petroleum each hold 45 % stakes in the North Adriatic LNG project, an effort led by Italy's EDISON to build an LNG receiving terminal on Italy's Northern Adriatic coast. In May 2005, the consortium awarded a contract for construction of the main LNG receiving terminal to Norway's Aker Kvaerner.

The Italian city of Livorno, on Italy's central West coast, has been considered as a site for two LNG proposals. In May 2004, the offshore LNG Terminal OLT consortium received environmental approval for its proposed LNG receiving terminal near Livorno; OLT, composed of GOLAR LNG and Italy's CROSSGAS, plans to permanently moor a standard LNG tanker offshore, convert it into a floating storage and regasification unit, then connect it to the coast via a subsea pipeline. The Livorno offshore facility will have an initial capacity of 13,772.85

million m^3 (390 million cubic feet) per day. In 2006, ENDESA purchased a 25 % stake in the project.

A consortium of BP, EDISON, and chemical company SOLVAY plans to construct a 290 million cubic feet per day LNG terminal on the site of a former Solvay chemical plant near Livorno. In January 2005, Italy's environmental ministry approved plans for the construction of the project. However, local government leaders have expressed opposition to the project, which could delay its planned initial production date.

In March 2005, Spain's Gas Natural (GN) presented plans to local officials for the construction of two LNG receiving terminals in Italy, located in the Northern city of Trieste and the Southern port of Taranto. Under its proposal, GN would build facilities at each location with production capacities of 27,192.55 million m^3 (770 million cubic feet) per day each, in order to fuel its plans to expand its presence in the Italian natural gas market. In the case of the Trieste site, ENDESA would join with GN in the project, offloading much of the plant's output for its nearby power plant.

SHELL signed an agreement in August 2005 with Italy's ERG to build an LNG receiving terminal next to ERG's oil refinery at Priolo Gargallo, Sicily. SHELL began construction of the US$510 million facility in 2007.

It is unclear if all of the proposed LNG projects will actually proceed to completion. It is unlikely that Italy's domestic market could absorb this large new natural gas supply, especially considering the expansion of piped natural gas imports from North Africa. However, there has been some talk of using Italy as a natural gas hub, landing LNG there for re-export to the rest of Europe.

3.29.4 Import and Export of Natural Gas

Three large-sized gas pipelines connect ENI's national networks in the areas of production of natural gas: Algeria, Russia, Holland, and Norway are the main entry of natural gas to Italy.

Italy aim is to reduce their dependence on North African natural gas imports, posing potential trouble for countries including Algeria, the one oil- and gas-rich country in the region so far spared from major social unrest. Italy imports around a third of their natural gas needs from Algeria and over 10 % from Libya and Egypt combined. Violent uprisings that have toppled governments have already reduced supplies from Libya and Egypt, while an attack on Algeria's In Amenas gas facility run by BP and Statoil in January 2013 has highlighted the risk there. The election of a new President in Algeria in 2014 has increased the political instability of the country and the energy internal market.

Italy is trying to diversify away with the likes of LNG and the TAP pipeline. Italy's National Energy Plan (NEP), approved earlier this year, aims to seek new gas sources, mainly through new pipelines and more capacity to import LNG, and cites the need to ensure security of supply. If the Trans Adriatic Pipeline gets built

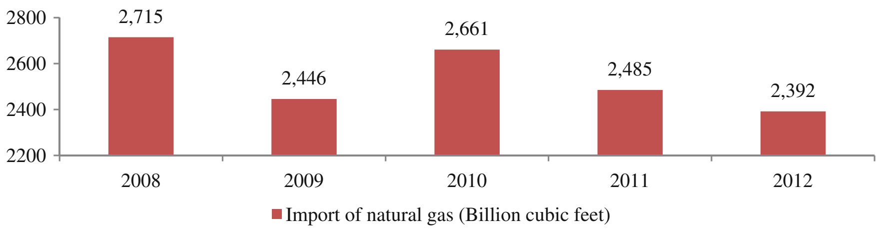

Fig. 3.49 Imports of natural gas from Italy during the period 2008–2012. *Source:* EIA

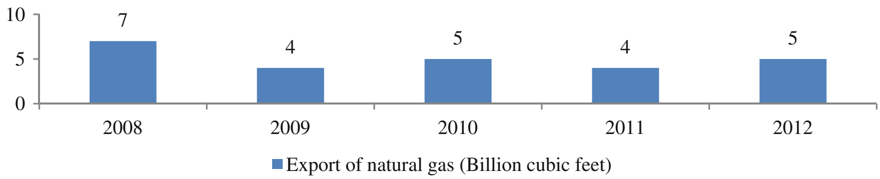

Fig. 3.50 Exports of natural gas from Italy during the period 2008–2012. *Source:* EIA

later this decade, Italy would serve as the landing point in Europe for 10 billion m^3 of gas per year from Azerbaijan. The new pipeline volumes that may come are not enough. So the government thinks LNG is the most important means to address diversity of supply.

The evolution of the imports and exports of natural gas from Italy during the past 5 years is shown in Figs. 3.49 and 3.50. The imports of natural gas from Italy during the period 2008–2012 decreased 11.9 %. The peak in the imports of natural during the period considered was reached in 2008. Since 2010, the imports of natural has been decreasing, and the total decrease reached 10.1 %. It is expected that the imports of natural gas from Italy will increase once again during the coming years, particularly the import of LNG, as a result of the overcome of the current economic crisis that is still affecting the country.

According to Fig. 3.50, the exports of natural gas from Italy during the period 2008–2012 decreased 28.6 %. It is expected that Italy will continue exporting natural gas, included LNG, during the coming years.

3.29.5 Electricity Generation

According to Clough (2008), Italy began liberalizing its electricity sector in 1999, initially allowing only large customers to choose their own supplier. Liberalization has now spread to the majority of the retail market. As part of the liberalization, the Italian government began to privatize ENEL, the former State-owned power monopoly that previously controlled all aspects of the electricity sector. In 2000, the Italian government forced ENEL to sell 27 % of its generating capacity, and to that

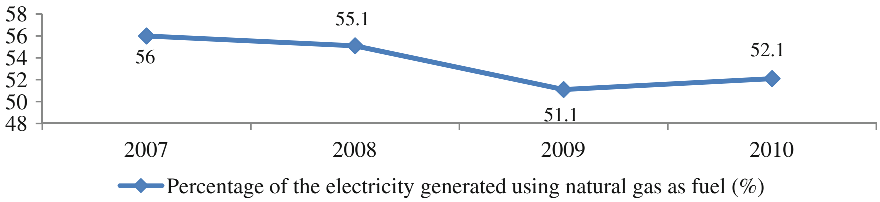

Fig. 3.51 Percentage of the electricity generated in Italy using natural gas as fuel (%) during the period 2007–2010. *Source:* Eurostat

end, ENEL created three new independent companies: ELETTROGEN, EUROGEN, and INTERPOWER. Along with removing ENEL's monopoly on electricity generation, distribution, and transmission, the Italian government began to divest its holdings in the company.

TERNA owns the electricity transmission grid in Italy. The company was previously a wholly owned subsidiary of ENEL, but the company has reduced its holdings in order to satisfy Italy's energy liberalization goals: in 2005, ENEL only held 5 % of the shares of TERNA. While ENEL remains the dominant generator and distributor of electricity in Italy, other companies have emerged as significant players in the sector. Many of these companies have extended their market share by purchasing the former assets of ENEL.

There have been frequent disputes between Italy and France concerning the liberalization of their respective electricity sectors. Italy has implemented most EU requirements relatively quickly, whereas France has been one of the slowest countries to adopt these changes. The dispute surrounding the Electricite de France's purchase of a stake in Italy's EDISON was only resolved after the French government agreed to allow ENEL to invest in the French electricity sector.

The percentage of electricity generated in Italy using natural gas as a fuel during the period 2007–2010 is shown in Fig. 3.51. From Fig. 3.51, it can be stated that the participation of natural gas in the generation of electricity in the country is very high. During the period 2007–2010, it reached a level above 50 %. However, the participation of natural gas in the generation of electricity during the period 2007–2010 as a whole dropped from 56 % in 2007 to 52.1 % in 2010, a decrease of 3.9 %. Despite the reduction of natural gas in the generation of electricity in the country in the past years, it is expected that the use of natural gas will continue to be an important element of the energy matrix of the country during the coming decades.

3.30 Norway

A number of plans currently exist for building natural gas-fired power plants in Norway, and five projects have so far been licensed. NATURKRAFT AS has received licenses for two natural gas-fired power facilities, INDUSTRIKRAFT MIDT-NORGE AS has received one license and STATOIL has received one license in accordance with the Energy Act for an integrated natural gas-fired power plant at its Snøhvit gas liquefaction plant in Northern Norway, and a natural gas-fired power plant at Tjeldbergodden. The natural gas-fired power plant at Kårstø is planned to have an installed capacity of about 420 MW, corresponding to an annual output of about 3.5 billion kWh. An application has also been submitted for a natural gas-fired power plant at Mongstad and one in Hammerfest. The government has in addition received an advanced notification of two natural gas-fired power projects in Grenland and Elnesvågen.

Energy requirements for the Snøhvit gas liquefaction project are to be met by an integrated natural gas-fired power plant providing 215 MW of electricity and 167 MW of heat, which was licensed in 2003. An annual output of about 1.5 billion kWh is also been planned. The natural gas-fired power plant is due to be completed before the Snøhvit gas liquefaction plant comes on stream, and is specially adapted to the energy requirements of the Snøhvit facility.

In accordance with the new government decision, compulsory quotas will be applied to natural gas-fired power plants. Small quantities of electricity are generated by natural gas turbines at petroleum plants along the Norwegian coast. Some sites also produce small amounts of electricity using gas turbines and gas engines. Natural gas from the Grønmo landfill in Oslo is used to generate electricity.

3.30.1 Natural Gas Reserves

In 2013, the proven natural gas reserves in Norway were estimated at 2,581.53 trillion m^3 (73.1 trillion cubic feet), according to EIA sources.

3.30.2 Production and Consumption of Natural Gas

The production and consumption of natural gas in Norway are shown in Figs. 3.52 and 3.53. The production of natural gas in Norway during the period 2008–2012 increased 18.6 %. The peak in the production of natural gas during the period considered was reached in 2012. It is expected that the current trend will continue during the coming years. Undoubtedly, natural gas will increase their role in the

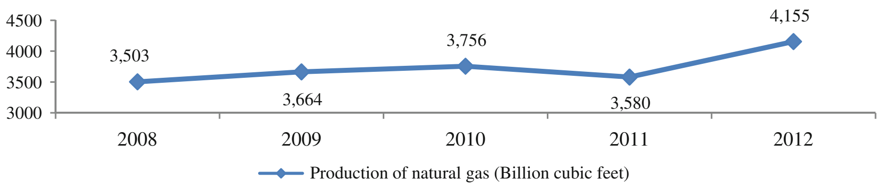

Fig. 3.52 Production of natural gas in Norway during the period 2008–2012. *Source:* EIA

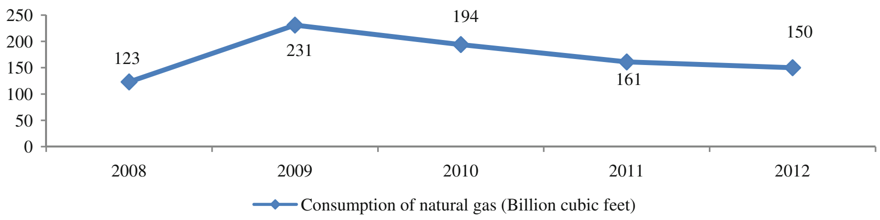

Fig. 3.53 Consumption of natural gas in Norway during the period 2008–2012. *Source:* Eurostat

country energy mix in the years to come. According to the level of natural gas production, Norway ranks seven at world level.

According to Fig. 3.53, the consumption of natural gas in Norway during the period 2008–2012 increased 21.9 %. The peak in the consumption of natural gas during the period considered was reached in 2009. Since that year the consumption of natural gas has been decreasing and it is expected that this trend will continue at least during the coming years as a result of the adoption of additional efficiency measures in order to reduce the use of different energy sources, particularly for the generation of electricity.

3.30.3 Export and Import of Natural Gas

The country exported 137,779 billion m^3 of natural gas in 2012. During that year, Norway was the world's third largest exporter of natural gas after Russia and Qatar. However, Norway, Europe's second-largest natural gas supplier after Russia, is nearing the limits of its exports capacity as its pipelines are almost fully utilized and no major new fields are coming online soon; this situation could limit its export capacity of the country in the future.

Figure 3.54 shows the European countries importing natural gas from Norway during the period 2000–2010.

The UK is the country with the highest trend in the import of natural gas from Norway increasing from less than 5 billion m^3 in 2001 to 25 billion m^3 in 2010; this represents an increase of 5 folds. In 2010, the country was second, according to the level of import of natural gas from eleven European countries included in Fig. 3.54 (Germany imported 30 billion m^3 in 2010).[37] Around 95 % of Norwegian natural gas sales are delivered by pipelines and the balance by LNG.

Norwegian gas is important for the energy supply in Europe, and it is exported to all of the major consumer countries in Western Europe. The country first started to export natural gas some 30 years ago (as a by-product of its oil production). In

[37] Growth in Norwegian natural gas sales post-2005 has primarily been to the UK, and during 2010, Norway supplied approximately 28 % of all natural gas consumed in this country.

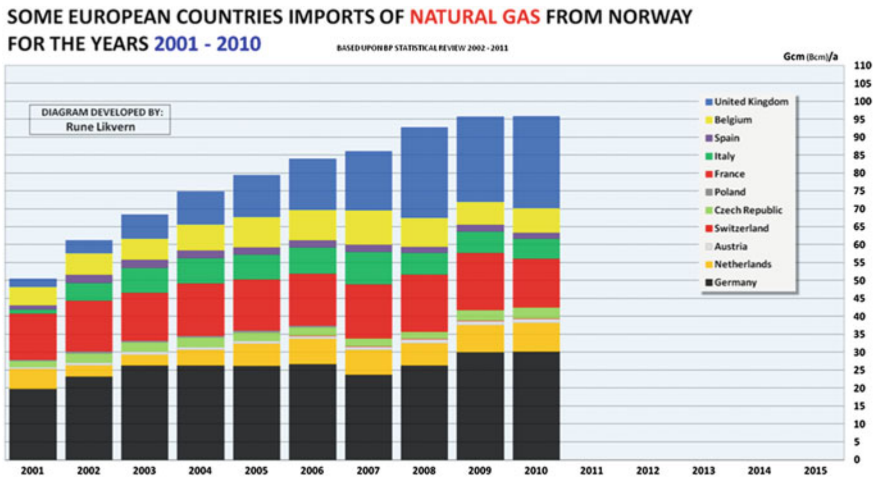

Fig. 3.54 European countries that are importing natural gas from Norway during the period 2001–2010. *Source:* Rune Likvern

terms of energy content, gas exports in 2012 were more than eight times larger than the average Norwegian production of electricity. Norwegian gas exports supply approximately 15 % of the European gas consumption. Most Norwegian exports go to UK, Germany, Belgium, France, and the Netherlands. Producers on the Norwegian continental shelf have entered into sales agreements with buyers in Germany, France, the UK, Belgium, the Netherlands, Italy, Spain, the Czech Republic, Austria, and Denmark. From the Snøhvit field, Norway also supplies LNG to the USA, Spain, and other customers.

The capacity in the Norwegian pipeline system is about 120 billion m^3 (3.396 billion cubic feet) per year. There are four receiving terminals for Norwegian gas on the Continent: two in Germany, one in Belgium, and one in France. There are also two terminals in the UK. The Norwegian gas transport system consists of a network of more than 7,800 km of pipelines. Achieving the highest possible value for Norwegian petroleum resources is a paramount goal for the government and the industry. Most of the fields on the Norwegian continental shelf contain both oil and gas, and achieving the optimum balance between oil and gas production is vital. The gas management system must facilitate efficiency in all stages of the gas chain—exploration, development, and transport.

The evolution of the exports of natural gas from Norway during the period 2008–2012 in shown in Fig. 3.55.

According to Fig. 3.55, the exports of natural gas from Norway increased 15.5 % during the period 2008–2012. It is important to highlight that in 2012 Norway became the world's third-largest exporter of natural gas, but that does not mean that the EU is guaranteed an increase in supplies from Norway—at least not in the immediate future—and any increase that there might be would not fill the gap left if other supply routes fail. The Norwegian Petroleum Directorate has confirmed that it

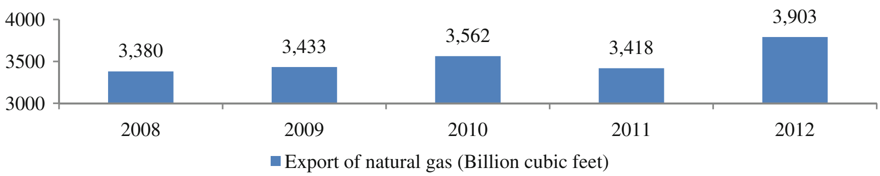

Fig. 3.55 Exports of natural gas from Norway during the period 2008–2012. *Source:* EIA

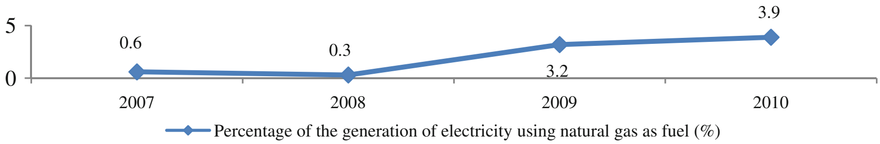

Fig. 3.56 Percentage of the generation of electricity in Norway using natural gas as fuel during the period 2007–2010. *Source:* CEDIGAZ and OPEC

would be possible to increase the amount of gas transported to the European mainland and to the UK by 10–15 billion m^3 more (totaling between 2.8 and 3.22 billion m^3 each year), but anything above that would not be feasible as the main pipelines are already running at full capacity.

3.30.4 Electricity Generation

Norway uses less natural gas domestically in electricity generation (around 3.9 % of annual production for electricity generation in 2010). It is used for power generation at the production facilities, increased oil recovery (Grane), feed for the methanol plant at Tjeldbergodden, and for power plants and supplies to households and industries in Haugesund and Stavanger. The percentage of the generation of electricity using natural gas as fuel during the period 2007–2010 is shown in Fig. 3.56. From that figure, the following can be stated: The percentage in the generation of electricity using natural gas as fuel in Norway increased 3.3 % during the period 2007–2010. This percentage is still very low compared to other European countries. The government expects that the percentage of the generation of electricity using natural gas as fuel will increase during the coming years, as a result of an increase in the demand in the industrial and residential sectors.

3.31 The Netherlands

The Netherlands became a significant producer and exporter of natural gas following the discovery in 1959 of a gas field near the village of Slochteren in the Northern province of Groningen. Offshore production in the Dutch sector of the North Sea began in the 1970s. As of the end of 2012, the Netherlands had produced a cumulative total of more than 3.2 trillion m^3 of natural gas, while remaining gas resources were estimated in 2013 at 43.436 trillion cubic feet (1,533.942 trillion m^3). Of these remaining resources, the Groningen field accounted for 980 billion m^3, with 160 billion m^3 to be found in other smaller onshore fields and 164 billion m^3 in offshore formations (IEA Netherlands 2012).

The Dutch energy policy is partially based on EU energy policy, which in turn aims at reducing dependence on natural gas for electricity supplies, and increase the participation in renewable for this purpose. A recent study by the IEA suggests that the EU has become strongly dependent on natural gas for energy supplies, but the natural gas stocks are limited and the majority of them are located outside the region and in very unstable areas from the political point of view. They largely come from politically volatile countries, particularly located in the Middle East. Prices are unstable too. With this in mind, the IEA calls for more variety in the sources—naming coal and renewable as alternatives for the generation of electricity.

3.31.1 Natural Gas Reserves

According to EIA sources, in 2013 the natural gas reserves of the country were estimated at 43.436 trillion cubic feet (1,533.942 trillion m^3). The Netherlands holds the second largest natural gas reserve in Western Europe after Norway. It hosts approximately 0.7 % of the world's total natural gas reserves. The confirmed natural gas reserves are for example sufficient at current levels of production to meet demand for 58 years, while the unconfirmed reserves are likely to be enough for the next 250 years.

3.31.2 Shale Gas

The Dutch government postponed a decision to allow shale gas drilling until a study of the potential effects of hydraulic fracturing on the environment is carried out by competent experts. There are negative reactions from local governments, such as those in Flevoland—including the cities of Noordoostpolder, Boxtel, and Luttelgeest, which have vociferously opposed fracking after being identified as promising shale gas areas. A recent report prepared by the consulting consortium of Witteveen and Bos, Arcadis, and Fugro concluded that risks stemming from shale gas in the Netherlands are very small, but admitted accumulated risks are slightly larger than conventional oil explorations due to the greater number of wells required. It claimed there would be very little seepage of methane into vulnerable aquifers as in the United States, because Dutch shale formations are deeper than the American ones. The study proposed by the government will be carried out in one and half year.

3.31.3 Production and Consumption of Natural Gas

The country's natural gas production peaked in 1979 and has been decreasing ever since. The evolution of the production of natural gas in the Netherlands during the period 2008–2012 is shown in Fig. 3.57. In 2012, the production of natural gas was 1,624 billion cubic feet (57,351.56 billion m^3), a decrease of 5.3 % respect to 2008. The peak in the production of natural gas during the period considered was reached in 2010.

The evolution of the consumption of natural gas in the Netherlands during the period 2008–2012 is shown also in Fig. 3.57. According to this figure, the consumption of natural gas in the Netherlands decreased 3.7 % during the period 2008–2012. The peak in the consumption of natural gas during the period considered was reached also in 2010. It is expected that the reduction in the consumption of natural gas during the past 3 years could change in the future and an increase in the use of natural gas for the generation of electricity will be reported by the government and the industry during the coming years.

The European and Dutch dependence on energy imports is expected to increase during the coming decades. The EU has limited oil and gas reserves, and the Dutch gas reserves are also dwindling. Current data suggest that Dutch gas production could remain at its present level until approximately 2030, after which it will decline. In the Netherlands, the production sector of the natural gas industry is private while the wholesale segment is partly private and partly publicly owned. There are 11 parties engaged in the production of natural gas with the dominant player being Nederlandse Aardolie Maatschappij B.V. (NAM), who is 50 % owned by SHELL and 50 % by ESSO and is accounting for about 75 % of the market.

Most production consists of low-calorific gas. Approximately half of the total production is exported. The Groningen-field (Slochteren) accounts for 50 % of the national production and 70 % of Netherlands's reserves. The low-calorific gas market is largely dominated by GASGEBOUW. The company GASTERRA (owned 50 % by the State, SHELL with 25 % and ESSO with also 25 %) acts as the single buyer for all NAM fields, selling the natural gas to downstream companies.

Concerning the security of natural gas, the Dutch gas production and infrastructure capacities provide a significant level of security for domestic supply.

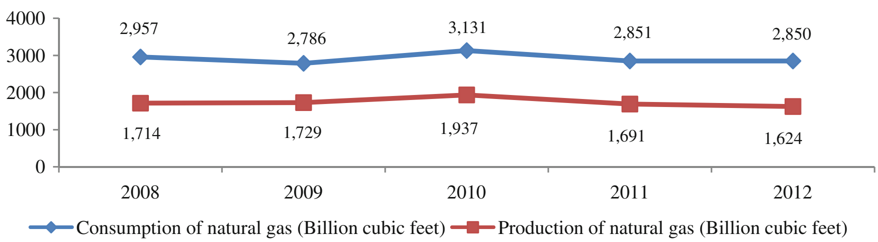

Fig. 3.57 Production and consumption of natural gas in the Netherlands during the period 2008–2012. *Source:* EIA

However, as domestic production declines (the Netherlands is expected to become a net importer of gas after 2030), well timed investments in storage capacities and LNG installations will be necessary to maintain supply flexibility.

3.31.4 Import and Export of Natural Gas

In the past years, natural gas imports represented around 52.5 % of the total volume of consumed natural gas, but the transit volumes being a significant part of this. All of the country's natural gas imports are being accomplished via pipeline; so far there are no significant LNG imports. Most of the natural gas pipeline imports originate mainly from Norway and Russia. The share of Norway in the country's natural gas imports increased in 2009 to 52.3 %, while the share of Russian natural gas imports contracted to 14.1 %; almost 5.4 % less than 2008. The UK supplied in 2009 around 22.7 % of the total natural gas imported by the country. In 2012, the Netherlands imported 921 billion cubic feet (32,525.12 billion m^3).

In 2012, the Netherlands exported a total of 2,133 billion cubic feet (75,326.9 billion m^3) of natural gas, 8.1 % more than the previous year. The country is the second largest natural gas exporter in Western Europe after Norway. Approximately 38.5 % of the exported volumes went in 2009 to Germany, while most of the rest went to Belgium (18.2 %) and Italy (15.4 %). It is expected that the country continues to be a net natural gas exporter during the coming years. The exports of natural gas from the Netherlands decreased during the period 2008–2012 in 2.2 %.

The evolution of the imports and exports of natural gas from the Netherlands during the period 2008–2012 is shown in Fig. 3.58.

According to Fig. 3.58, the imports of natural gas from the Netherlands dropped 9.7 % during the period 2008–2012. It is expected that the country will continue importing natural gas during the coming years, particularly for the generation of electricity due to an stable production of natural gas until 2030.

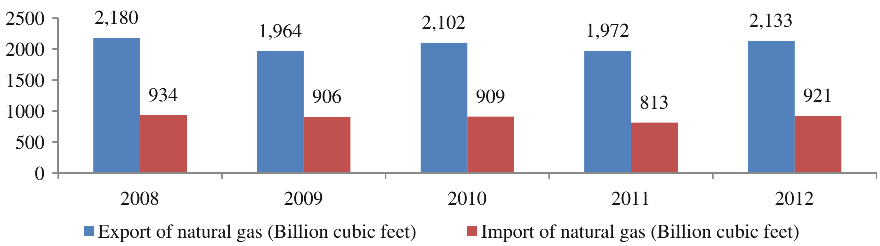

Fig. 3.58 Exports and imports of natural gas from the Netherlands during the period 2008–2012. *Source:* EIA

3.31.5 Gas Pipelines, LNG, and Other Storage Facilities

Pipeline Gasunie is the first independent natural gas transportation provider with a cross-border network in Europe. The company offers transportation services in the Netherlands through its subsidiary Gas Transport Services B.V. (GTS) and in Germany via GASUNIE Deutschland. The Dutch TSO operates a grid of around 11,500 km. GASUNIE's numerous installations include an LNG facility (peak shaver) and around 1,100 custody transfer. The State, represented by the Ministry of Finance, is the sole shareholder of GASUNIE.

There are no operational LNG terminals in the Netherlands, except GASUNIE's peak shaver. Nevertheless, there are 12 billion m^3 regasification terminals under construction in Rotterdam with the aim of becoming operational before 2015. In addition, another terminal is proposed at Eemshaven in the North of the Netherlands. It is expected that this terminal will enter into operation in 2015.

Until today, there are four operational storage facilities in the Netherlands with a combined technical storage capacity of 5,078 million m^3. There are two nondepleted gas fields; one depleted gas field and one LNG peak shaver with an aggregated 177 million m^3 per day withdraw capacity and a 39.85 million m^3 per day injection capacity. In addition to the existing storage capacity, there are two projected storage facilities in the Netherlands with a combined technical storage capacity of 4,400 million m^3, a withdrawal capacity of 58.6 million m^3 per day, and an injection capacity of 42.8 million m^3 per day. There is one depleted natural gas field and one salt cavity.

3.31.6 Electricity Generation

The evolution of the percentage of the electricity generated in the Netherlands during the period 2007–2010 using natural gas as a fuel is shown in Fig. 3.59.

The use of natural gas for the generation of electricity in the Netherlands is very high respect to other European countries. During the period 2007–2010, the percentage of the electricity generated in the country using natural gas as fuel increased from 58 % in 2007 to 62.2 % in 2010, an increase of 4.2 %. Electricity generated

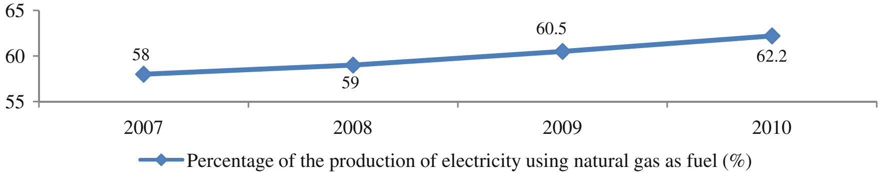

Fig. 3.59 Percentage of the electricity generated in the Netherlands during the period 2007–2010 using natural gas as fuel. *Source:* Eurostat

from natural gas has been on the rise since the second half of 2009 due to additional capacity of new natural gas power plants. It is expected that this tendency will continue during the coming years.

3.32 The Russian Federation (Russia)

The objective of the energy policy of Russia is to maximize the effective use of natural energy resources and the potential of the energy sector to sustain economic growth, improve the quality of life of the population, and promote strengthening of foreign economic positions of the country.

The following main elements of the long-term development of the fuel and energy complex are specified in the Energy Strategy of Russia for the period up to 2030:

- Transition to the path of innovative and energy-efficient development;
- Change in the structure and scale of energy production;
- Development of competitive market environment;
- Integration into the world energy system.

The strategic objectives of the gas industry development are the following:

- Stable, uninterrupted, and economically efficient satisfaction of domestic and external demand for natural gas;
- Development of the unified system of natural gas supply and its expansion to the East of Russia, enhancement of interregional integration on this basis;
- Improvement of the organizational structure of the natural gas industry aimed at increase in its economic efficiency, development of the liberalized gas market;
- Provision of stable revenues for the Russia's consolidated budget corresponding to the energy sector significance in generation of the gross domestic product and export at the given phase of the State energy policy implementation.

Nevertheless, the qualitative results projected for the first phase of the Energy Strategy of Russia implementation have not been fully achieved, namely the setting up a base for stable and progressive development of the energy sector, including:

- Establishing a coherent framework, creating highly competitive energy markets with fair trade principles;
- Completing the conversion of the related sectors of the economy to a new level of energy efficiency;
- Transition from the leading role of the fuel and energy complex in the economy of the country to the function of an effective and stable supplier of energy resources for the needs of the country's economy and population.

According to government sources, to overcome some of these difficulties in the period 2010–2019, overall investments in the Russian energy sector should reach US$280 billion in order to modernize and expand this sector. Of that total, upstream natural gas, generation, transmission, and distribution account, respectively, for US $70 billion (25 % of the total), US$80 billion (28.6 % of the total), US$30 billion (10.7 % of the total), and US$100 billion (35.7 % of the total).

While considering the prospects of natural gas industry development the following trends need to be taken into account:

- Depletion of main gas deposits in the Nadym-Pur-Taz district of the Tyumen Region and, consequently, the necessity of developing new gas-producing centers on the Yamal Peninsula and Continental Shelf of the Arctic and Far Eastern seas, in the Eastern Siberia and Far East;
- Increase in the share of hard-to-recover reserves (low-pressure gas) in the structure of the natural gas industry mineral resource base;
- Increase in costs of natural gas production and transportation;
- Development of technologies for production and transportation of LNG.

Finally, it is important to highlight the following principal goals that must be realized to achieve the strategic objectives of the gas industry development:

- Compensation of the decline in natural gas output volumes of old deposits in the Nadym-Pur-Taz district of the Tyumen Region (Yamburgskoye, Urengoiskoye, Medvezhye deposits) by means of putting into operation new deposits in remote regions with complicated natural, climatic, and geological conditions;
- Appropriate gas transport infrastructure construction aimed at provision of natural gas deliveries onto the domestic market and diversification of export destinations;
- Promotion of geological exploration works aimed at provision of expanded reproduction of mineral resource base in major gas-producing regions and on the Continental Shelf of the Russian Federation, as well as at development of natural gas deposits of regional and local importance;
- In-time renovation of equipment and pipes of gas transportation system, excluding reduction in its capacity;
- Further development of regional trunk and distribution pipeline infrastructure;
- Development of production and export of LNG;
- The development of gas-processing and gas-chemical industries aimed at the rational utilization of valuable fractions of hydrocarbons and associated petroleum gas;
- Gas market demonopolization, creation of competitive environment, and establishment of nondiscriminatory access to gas industry infrastructure for all business entities (Energy Strategy of Russia for the period up to 2030).

3.32.1 Energy Savings

According to the Energy Strategy of Russia for the period up to 2030, energy saving in the gas industry will be performed in the following main areas:

- *Gas production*. Reduction in natural gas consumption for technological needs, optimization of technological facilities working regime, improvement of control over, and accounting of natural gas, as well as increase in the recovery rate of gas formations;
- *Gas transportation*. Reconstruction of gas transportation facilities and system organization of technological working regimes of trunk gas pipelines, reduction in gas losses, introduction of automated management systems and telemetry, improvement of engineering condition of gas-transfer facilities, introduction of highly efficient gas-turbine drives for gas-transfer facilities with high performance index, as well as expansion of gas-transfer facilities with controlled electric drive use;
- *Gas processing*. Increase in the rate of workflow heat utilization, increase in the performance index of gas-fired heat generating units, as well as optimization and automation of process flows;
- *Underground gas storage*. Optimization of buffer gas volume, reduction in formation gas losses, use of noncommercial gases (nitrogen, fumes, etc.) as buffer gas volumes.

3.32.2 Natural Gas Reserves

In 2013, the proven natural gas reserves in Russia were reported at 59,611.72 trillion m^3 (1,688 trillion cubic feet), according to EIA sources; this represents an increase of 0.04 % respect to 2010. The majority of these natural gas reserves are located in Siberia, with the Yamburg, Urengoy, and Medvezh'ye fields alone accounting for about 45 % of Russia's total natural gas reserves. Significant natural gas reserves are also located in Northern Russia.

3.32.3 Production and Consumption of Natural Gas

According to Russia Country Analysis Brief (2010), in 2012 Russia was the world's second-largest natural gas producer, second only to the USA (see Table 1.4). However, in that year Russia was the world's largest exporter of natural gas. In 2013, the situation has not change and Russia produced 19.1 % of the world's total natural gas and exported 185 billion m^3.

The largest concentration of natural gas production is located in Siberia, where about 95 % of Russia's natural gas is produced. Some of the most prolific fields in this area include Yamburg, Urengoy, and Medvezh'ye, all of which are licensed to GAZPROM, Russia's State-run natural gas exploration and production company. However, these three fields have seen output declines in recent years. In response, the company launched the Yamal megaproject in late 2008 with the purpose of increasing natural gas production. Additionally, the Zapolyarnoye field, is expected to offset some of the declines of GAZPROM's big three fields.

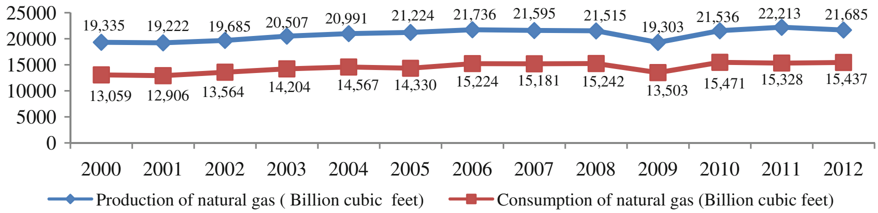

Fig. 3.60 Production and consumption of natural gas in Russia during the period 2000–2012. *Source:* EIA

The prospective regional structure of natural gas production by 2030 will be as follows:

- Gas production in the European part of Russia is planned to be increased up to 131–137 billion m^3 (against 46 billion m^3 in 2005) at the expense of development of the Timano-Pechorskaya oil and gas producing area and shelf deposits (first of all, Stockman deposit);
- Gas production in the Western Siberia is expected at the level of 608–637 billion m^3 at the expense of development of the deposits on the Yamal Peninsula and the waters of the Gulfs of Ob and Taz intended to compensate the decreasing output of old gas deposits (Urengoiskoye, Medvezhye, Vyngapurovskoye, and Yamburgskoye);
- Gas production in the Eastern Siberia and Far East will increase up to 132–152 billion m^3.

The evolution of the production and consumption of natural gas in Russia during the period 2000–2012 is shown in Fig. 3.60. The production of natural gas in Russia increased 12.1 % during the period considered. The peak in the level of natural gas production was reached in 2011. On the other hand, the consumption of natural gas in Russia increased 18.2 %. It is expected that the production and consumption of natural gas will continue this trend during the coming years. The peak in the consumption of natural gas during the period considered was reached in 2010.

Russia exports significant amounts of natural gas to customers in the Commonwealth of Independent States. In addition, GAZPROM (through its subsidiary GAZEXPORT) has shifted much of its natural gas exports to serve the rising demand in the countries of the EU, as well as Turkey, Japan, and other Asian countries. It is expected that in the future Russia will increase the exports of natural gas to the Asia and the Pacific region.

3.32.4 *Gas Fields, Pipelines, and LNG Facilities*

Two-thirds of the overall Russian natural gas exports are destined for the European markets, with largest EU importers being Germany, Italy, France, and Hungary.

However, in terms of consumption, Central and Eastern European countries are even more dependent on Russian energy imports. In this subregion, Russian natural gas accounts for an average of 87 % of total imports and 60 % of consumption. However, this situation could change in the future due to the political situation in Crimea and the increase tension between the EU and Russia as a result of the role of Russia in this crisis.

Due to a variety of factors such as rigorous EU regulations regarding the environment, with special emphasis on the replacement of high-carbon-emission fossil fuels, such as coal, social resistance to nuclear power, and the steadily depleting intra-EU energy resources, the natural gas import figure is predicted to climb to a 60 % mark by 2030, with most experts agreeing that natural gas would soon replace oil as the EU's dominant energy source. Since Russia provides for the more readily available supplies, with other natural gas exporting countries such as Algeria lacking necessary quantities or transportation links, the importance of Russia's natural gas exports would continue to grow in the near to medium-term future.[38] However, if Russia intends to increase the export of natural gas, extensive measures toward the development of new export pipeline infrastructure is necessary. Such infrastructural projects currently underway or under discussion are plentiful. They include the enhancement and improvement of links with Western EU Member States, the Central Asian region, Eastern Balkan States, as well as with Asia and North America.

According to Borisocheva (2007), the current energy infrastructure of the Central Asia region is a legacy of the Soviet era, when all of Central Asian oil and natural gas was exported throughout the Russian territory. This inheritance has made Russia a dominant player in the region's external energy policy, as most current Central Asian energy export routes. Due to its own need for diversification, Russia is has been jealously guarded and even expanding its control of the region in recent years. More recent developments include a purchasing agreement for all the Turkmen natural gas that the country can produce for the next 25 years, allegedly paying double the price for Turkmen natural gas as compared to market value. These extra quantities will be used to supply Russian own internal demand for natural gas, which is quickly rising, with the rest adding to the export supplies to Europe. At the same time, the presidents of Russia, Turkmenistan, Kazakhstan, and Uzbekistan, announced an agreement to refurbish the entire Soviet built pipeline network that carries Central Asian natural gas to outside markets throughout the Russian territory, which would be capable of carrying 90 billion m^3 of natural gas annually once completed.

Another major development that represents a Russian stronghold of the Caspian region is the newly signed Pre-Caspian natural gas pipeline deal that aims to transport Turkmen natural gas via Kazakhstan to Russia and then via Russian pipeline system onwards to Europe, with a capacity of up to 30 billion m^3 in the

[38] The occupation of Crimea by Russia could change this situation.

2010s. This project was perceived as a major blow to the European efforts of securing the Trans-Caspian natural gas pipeline proposal.

In addition to increasing its export capacity, Russia is also aiming to cut its dependence on the transit countries of Ukraine and Belarus, particularly in the case of Ukraine. These transits flow, during the past years have been under threat of Ukrainian high jacking, exemplified by illegal siphoning-off, transit-fee regulation instability, and general quasi-violent political insecurity in the country. The 2006 Russia-Ukraine and the 2007 Russia-Belarus stalemates, which arose due to disagreements in energy transit fees across the country, resulted in temporary supply decreases to Western Europe, and have prompted a number of pipeline projects that would diminish Russian dependence on ex-Soviet transit countries, including the Baltic States. Some of these projects include the Nord Stream natural gas pipeline across the Baltic Sea; Burgas-Alexandroupolis natural gas pipeline, connecting Bulgaria to Greece; the extension of Blue Stream; and a South Stream natural gas pipeline. All these projects aim primarily at increasing the level of supplies to Europe directly by eliminating Russian reliance on transit States. This strategy should, as a result, reduce GAZPROM's dependence on those countries, eliminate transit fees, and, thus, offer Europe lower energy costs and protecting from a possibility of an unpredictable supply disruption arising due to the problematic relationship with producer and transit States. The political situation in Ukraine has reinforced the decision of Russia to reduce to the minimum the amount of natural gas exported to Europe using Ukraine as a transit country.

Finally, within Europe, Russia is expanding its presence in the following countries: UK, Belgium, Netherlands, and Scandinavia. During the past years, GAZPROM sold the first shipments of 140,000 m^3 of LNG in the UK; bought a 10 % share of the West European natural gas pipeline Interconnector; acquired, through a subsidiary, a natural gas retail business, Pennine Natural Gas Limited, in the UK; signed a preliminary contract with Belgium for natural gas supplies and a construction of the underground natural gas storage facility; and arranged for a distribution access to European customers through Gaz de France and ENI. Similar contracts were signed with Austria, Czech Republic, and Bulgaria.

This constitutes a new step in the direction of diversification of markets, since it actually involves an expansion into the European supply lines with an aim of getting direct access to the local distribution channels, thus making further profits from sales along the entire supply chain, from production to consumption. However, this strategy is in clear conflict with the interest of the EU. European leadership is concerned that the entry of the Russian natural gas monopoly, GAZPROM, into local markets would undermine local control of vital assets, and further intensifies the overall dependence on one supply source. In order to halt this expansion, the European Parliament has amended the EU Gas Directive to include provisions for unbundling and third country aspects, (sometimes referred to as the "GAZPROM clause") which requires effective unbundling of TSOs, supply and production activities not only at national level, but also throughout the EU. This means that no supply or production company active anywhere in the EU can own or operate a transmission system in any EU Member State. This legislation is a direct attempt to prevent Russian penetration into the European energy market in a great scale.

On the other hand, Russia and Bulgaria signed a long-awaited agreement to formalize the planned South Stream natural gas pipeline that will bring Russian natural gas across the Black Sea to the European markets. The South Stream natural gas pipeline project means a lot for the diversification of Russian natural gas supplies to European consumers and energy security, strengthening the position of Bulgaria as a key center of natural gas transit in Europe. The South Stream natural gas pipeline, developed by GAZPROM and ENI, will carry up to 63 billion m^3 per year of Russian natural gas across the Black Sea to Bulgaria, where it will split into two lines to be built by GAZPROM jointly with local partners. One line will run Southwest of Greece and into Southern Italy. The other line will run Northwest to Northern Italy, with an offshoot to Austria, via Bulgaria, Serbia, Hungary, and Slovenia.

Russia and Kazakhstan agreed to jointly develop the Imashevskoye gas condensate field located on the border of the two countries, Russia's Ministry of Natural Resources said in a statement on July 2010. The agreement came during a meeting between experts from gas giant GAZPROM, the Ministry of Natural Resources and Ministry of Foreign Affairs on the Russian side and KAZMUNAIGAZ and the Ministry of Oil and Gas on the Kazakh side. In 2005, the two countries drafted a proposal for a 50:50 joint venture for the field, which are possible reserves reports of 128.7 billion m^3 of natural gas and 20.7 million metric tons of gas condensate, but the governments not moving the project forward until now. The agreement was signed during a meeting between former President Dmitry Medvedev and President Nursultan Nazarbayev. "This field will be the first developed object that is located on the territory of two States," said an official from Russia's Ministry of Natural Resources. Imashevskoye is located in Russia's Astrakhan region and Kazakhstan's Atyrau region.

Separately, Russia's Ministry of Natural Resources approved a list of blocks to be offered for exploration this year, with biggest natural gas resources situated in the West Siberian Yamal-Nenets region. For natural gas listed are the Tambeisky license, with 116.4 billion m^3 of natural in the Yamal-Nenets Autonomous district, and the Kutopiyegansky and Yamalsky licenses, each holding 85 billion m^3 of natural gas in the same region.

Summing up the following can be stated: There are currently nine major pipelines in Russia, seven of which are pipelines for exporting natural gas. The Yamal-Europe I, Northern Lights, Soyuz, and Bratrstvo pipelines all carry Russian natural gas to Eastern and Western European markets via Ukraine and/or Belarus. These four pipelines have a combined capacity of 141.26 trillion m^3 (4 trillion cubic feet). Three other pipelines, Blue Stream, North Caucasus, and Mozdok- Gazi-Magomed connect Russia's production areas to consumers in Turkey and other republics in the East. The following are the proposed natural gas pipelines:

- *Yamal-Europe II*. The Yamal-Europe I pipeline (35.315 trillion m^3 or 1 trillion cubic feet), which carries natural gas from Russia to Poland and Germany via Belarus, would be expanded another 35.315 trillion m^3 under this proposal. GAZPROM and Poland currently disagree on the exact route of the second branch as it travels through Poland. GAZPROM is seeking a route via South-eastern Poland to Slovakia and on to Central Europe, while Poland wants the branch to travel through its own country and then on to Germany;
- *South Stream*. The first component of the South Stream project plans to send natural gas from the same starting point as the Blue Stream pipeline at Beregovaya for 896 km under the Black Sea, achieving a maximum water depth of over 1,981.2 m. The second, onshore component will cross Bulgaria with two alternatives: One directed toward the Northwest, crossing Serbia and Hungary and linking with existing natural gas pipelines from Russia; and the other directed to the Southwest through Greece and Albania, linking directly to the Italian network. As a result of the Russia-Ukraine disputes, the pipeline will be constructed through Turkey's waters, avoiding Ukraine's territory altogether. GAZPROM expects the pipeline to be completed by 2015;
- *Nord Stream Pipeline*. A Northern pipeline extending over 3,200 km from Russia to Germany via the Baltic Sea, was initially approved in 2005. Once completed, the pipeline will be the longest subsea pipeline, with a capacity to transport 67.1 trillion m^3 (1.9 trillion cubic feet) of natural gas. Environmental concerns have resulted in delays, and the expected completion date has been moved 2013–2014 from its original start-up date of 2010.

3.32.5 Import and Export of Natural Gas

Russia is the world largest export of natural gas, The imports of natural gas during the period 2000–2012 is shown in Fig. 3.61.

According to Fig. 3.61, the imports of natural gas from Russia during the period 2000–2012 increased 258 %. However, during the period 2000–2008, the imports of natural gas from Russia show a systematic increase, but during the period 2009–2012 shows a decrease in the imports of natural gas. The peak in the imports of natural gas during the period considered was reached in 2008. It is expected that

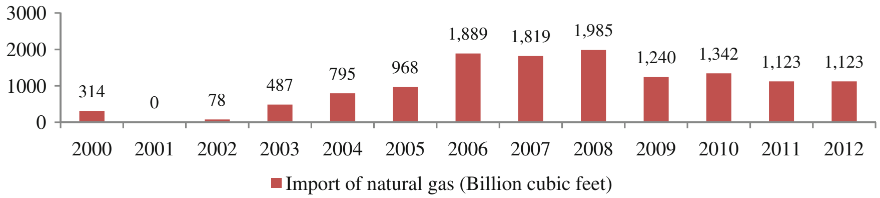

Fig. 3.61 Imports of natural gas from Russia during the period 2000–2012. *Source:* EIA

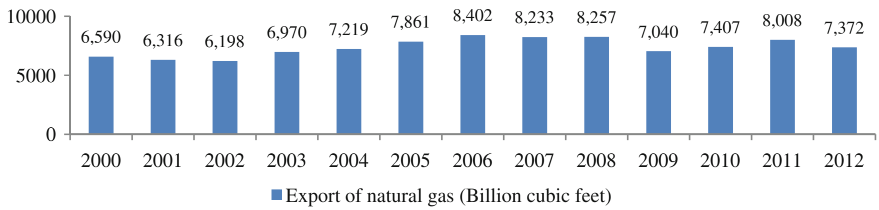

Fig. 3.62 Exports of natural gas from Russia during the period 2000–2012. *Source:* EIA

Russia will continue importing natural gas from some Asian countries during the coming years.

Exports of natural gas from Russia during the period 2000–2012 increased 11.9 % (see Fig 3.62). It is expected that the exports of natural gas from Russia will increase during the coming years, particularly to the Asian and the Pacific region.

Finally, it is important to highlight the following: Recent increases in natural gas reserve estimates and advances in shale gas technology make natural gas a fuel with good prospects to serve a bridge to a low-carbon world. Russia is an important energy supplier as it holds the world largest natural gas reserves, and it is the world's largest exporter of natural gas.

The role of natural gas in the energy mix should be considered in the context of several policy assumptions: with no greenhouse gas mitigation policy and scenarios of emissions targets in developed countries. Scenarios where Europe takes on an even more restrictive target of 80 % reduction of greenhouse gas emissions relative to 2005 by 2050 and reduces its nuclear based generation should be also considered. Asian markets become increasingly important for natural gas exports and several scenarios about their potential development should be also considered, particularly after the political situation in Crimea and the sanctions adopted by the EU and the USA against Russia.

Undoubtedly, over the next 20–40 years natural gas can still play a substantial role in Russian exports and there are substantial reserves to support a development of the gas-oriented energy system both in Russia and in its current and potential gas importers. It is expected that exports of natural gas grow up to 10–12 trillion cubic feet (353.15–423.78 trillion m^3) in 2030 and 15–18 trillion cubic feet (529.725–635.67 trillion m^3) in 2050. Alternative scenarios provide a wider range of projections, with a share of Russian gas exports shipped to Asian and the Pacific markets, rising to 30 % by 2030 and to more than 50 % in 2050. The patterns of the international gas trade show increased flows in the Asian and the Pacific region from the Middle East, Central Asia, Australia, and Russia. Despite the increase on LNG imports from Europe, the region will still maintains sizable imports from Russia, at least during the coming years.

On the other hand, Russia has increasingly become dependent on natural gas imports from Central Asia and the Caspian Region (60–80 billion m^3 per year) in order to satisfy domestic natural gas consumption and to maintain high priced exports to Europe. At present, one third of all European natural gas imports from Russia are supposed to come de facto from Central Asia.

Under these circumstances, in a Russia plagued with chronic underinvestment and delays of commissioning in new natural gas fields at home, declining production and fast-growing internal consumption, it has also become doubtful whether Russia will be able to fill both the Nord Stream and the South Stream pipeline projects in the coming decades. These pipelines are officially declared to be pursued "more or less" simultaneously. They are also seen to be complimentary to one another. These planned pipelines are in addition to Russia's contracted natural gas export obligations via the Yamal pipeline, the Ukrainian pipeline system, and via the Blue Stream pipeline in the Black Sea. Both pipelines, the Nord Stream and South Stream pipelines, are to be commissioned no later than 2014; neither Russia nor Central Asia (including Turkmenistan) has currently the 31 billion m^3 of natural gas a year required to fill the South Stream pipeline.

3.32.6 Electricity Generation

According to the Energy Strategy of Russia for the period up to 2030, the priorities in the electric energy industry are:

- Developing gas turbines with a capacity of 300–350 MW and highly efficient condensation combined cycle gas turbine units with a capacity of 500–1,000 MW and a performance index exceeding 60 %;
- Designing standard modular combined cycle cogeneration units with a capacity of 100 MW and 170 MW and a performance index amounting between 53 % and 55 % of heat and power plants;
- Introducing technological energy complexes working on gas and solid fuel for combined production of electricity and synthetic liquid fuel;
- Developing highly integrated intelligent transmission and distribution networks (Smart Grid) in Russia's Unified Energy System;
- Developing power electronics, especially various types of network control devices (flexible alternating current transmission systems), automated electricity demand control systems, and hydroelectric equipment for tidal power plants.

The total electricity capacity installed in Russia in 2013 reached 223.1 million kW. The percentage of the production of electricity in Russia using natural gas as fuel during the period 2007–2009 is shown in Fig. 3.63.

From Fig. 3.63, the following can be stated: During the period 2007–2009, the participation of natural gas in the generation of electricity in Russia decreased from 48 % in 2007 to 47.4 % in 2009; this represents a decrease of only 0.6 %. According to the different measures adopted by the government in the electricity generation sector, it is expected that the use of natural gas for the generation of electricity will increase and will continue to play an important role in the country's energy mix during the coming years.

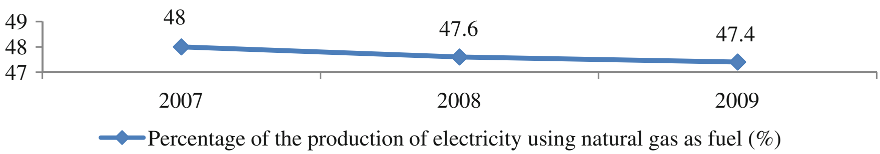

Fig. 3.63 Percentage of the production of electricity in Russia using natural gas as fuel during the period 2007–2009. *Source:* IEA and OGPSS

3.33 Poland

In September 1996, Poland's Cabinet approved specific guidelines for implementing reforms in the energy sector. These guidelines establish an energy regulatory authority and allow third-party access to the Polish electricity transmission grid. The objective is to create a competitive energy market through the privatization of the energy industry, and to attract the investment necessary for industrial modernization and environmental protection. While emphasis is placed on the increased use of oil and natural gas, coal is expected to remain the dominant fuel, particularly in the electric power sector during the coming years.

Poland's new energy law entered into force in December 1997. Under the new law, large electricity users can negotiate directly with generators of power. The Polish power grid company—Polskie Sieci Elektroenergetyczne (PSE)—is obliged to provide transmission to the buyer and seller, if it is technically feasible. It is estimated that 30 % of Poland's electric energy is now sold competitively. The rest is sold under agreements that PSE signed with 35 power plants.

The Polish Energy Regulatory Authority has indicated its intention to put more emphasis on the spot market for short-term contracts for electricity and less emphasis on long-term contracts. This would constitute a major change, since approximately 70 % of the electricity currently supplied to the grid is presently under long-term contracts. If the balance shifts to short-term contracts, this might tend to favor new generation sources, municipal combined heat and power, and green power sources that have a legally privileged status.

On June 14, 2000, various amendments to the Energy Act went into effect, with the intent to make energy markets work on a more transparent and businesslike basis. These new regulations require that energy supply companies audit their billings and authorize energy suppliers to enter users' premises to measure their readings. They also authorize cut off of users' supplies if electricity, natural gas, or heat are being obtained illegally. The amendments stipulate that owners of apartment buildings are responsible for allocating electricity, gas, and heating costs to individual apartments. Rates charged for electricity, gas, and heats are subject to approval by the Energy Regulation Authority. The amendments also give the government the power to require energy companies active in distribution to purchase electricity or heat made from renewable or unconventional sources. Energy companies will be required to submit development plans in cooperation with their communities, showing how they intend to supply energy over the next 3 years.

Diversification of supply sources and routes, development of natural gas infrastructures for such diversification, expansion of underground storage capacity, and increase of domestic natural gas production are the key elements of Poland's natural gas security policy. Energy enterprises running a business of international natural gas trading and importers are obliged to maintain 20 days of compulsory natural gas stocks in Poland in 2011. Compulsory stock levels will increase to 30 days from October 2012.

Finally, it is important to highlight the following: According to government sources, the country, in compliance with the European Directive on energy efficiency, adopted in 2006 its National Energy Efficiency Action Plan, which lays down a final energy savings target of at least 9 % between 2008 and 2016.

3.33.1 Natural Gas Reserves

According to EIA sources, in 2013 the government estimated the natural gas proven reserves of the country at 3.249 trillion cubic feet (114.738 trillion m^3).

3.33.2 Production and Consumption of Natural Gas

The evolution of the production and consumption of natural gas in Poland during the period 2000–2012 is shown in Fig. 3.64.

The production of natural gas in Poland during the period 2000–2012 increased 19 %. The peak in the production of natural gas in the period considered was reached in 2012, but the trend is to continue to increase during the coming years. On the other hand, the consumption of natural gas in Poland during the period 2000–2012 increased 35.3 %. However, only a very small of the natural gas consumed in the country was used for the generation of electricity, and it is expected that this situation will not change significantly at least during the coming years.

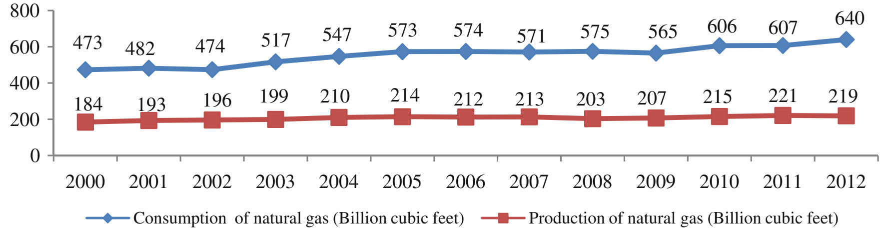

Fig. 3.64 Production and consumption of natural gas in Poland during the period 2000–2012. *Source:* Eurostat

In the document entitled “Energy Policy of Poland until 2030”, natural gas demand is forecast to increase by 18 % in 2020 and by 43 % in 2030, respectively, compared to the level reached in 2010.

3.33.3 Shale and Tight Gas

According to a 2012 report of the Polish Geological Institute and the National Research Institute (PGI), shale gas recoverable resources of the onshore and offshore Baltic–Podlasie–Lublin Basin are estimated in 1,920 billion m^3. Taking into account constraints on key parameters of the calculations the higher probability range of recoverable shale gas resources is between 346 and 768 billion m^3.These resources are therefore 2.5–5.5 times higher than documented conventional gas fields in Poland.

With the level of current natural gas consumption in Poland the shale gas resources together with conventional fields are an equivalent of 35–65 years of cumulative gas consumption on Polish market, or 110–200 years of gas production in Poland at its current level if no changes in current proportion between domestic production and import are produced.

According to information provided by Poland’s State-controlled natural gas company PGNiG on July 2010 the company had started to work on its first shale gas test well in its Pionki-Kazimierz concession near Pulawy in Southeast Poland. PGNiG’s Markowola-1 test well is searching for shale gas in Devonian and Carboniferous shale that are a secondary target compared to the country’s main shale gas potential. EXXON-MOBIL and other companies are prospecting gas in the country’s Silurian and Ordovician shale areas. Halliburton is carrying out the hydraulic fracturing or fracking of the Markowola-1 well, the country’s first large-scale tight gas fracturing. If the Markowola-1 prospect is confirmed, then gas production could start in 3 or 4 years.

PGNiG invested around US$210 million in domestic gas exploration in 2010, of which several million were spent on unconventional gas exploration. PGNiG started to work on another unconventional prospect, the Lubocino-1 test well in its Wejherowo concession in Pomorze, North Poland, in November 2010. PGNiG has 13 shale gas exploration concessions in Northern, Central and Eastern Poland, and six tight gas exploration concessions, primarily near Poznan in Western Poland.

3.33.4 Natural Gas Fields and LNG Facilities

As the Carpathian deposits have been largely used up and many of them are being closed down, now most of the country’s natural gas comes from the Polish Lowland. The significance of this region grew even more in 1996 with the finding of the Barnowko-Mostno-Buszewo deposit near Gorzow Wielkopolski. This is Poland’s biggest deposit, estimated at some 4.5 billion m^3 of high-methane gas. The Polish Lowland natural gas is found mainly in Permian and Carboniferous rocks and has a high content of nitrogen. The gas from the Carpathians and Carpathian Foreland, found in Jurrasic, Cretaceous and Tertiary rocks, is of better quality, high on methane and low on sulfur.

Of the 242 documented deposits of natural gas in Poland, the biggest are: Przemysl in the Carpathian Foreland (nearly 21 billion m^3); Koscian (South-East of Poznan; 10.4 billion m^3), exploited only since 1999; and Barnowko-Mostno-Buszewo. The biggest oil deposits are Barnowko-Mostno-Buszewo and Cychry, also in the Polish Lowland.

In 2000, a very promising deposit was discovered at Miedzychod in the Notec Forest. It is almost certain to be as big as Barnowko-Mostno-Buszewo, if not bigger. Other interesting exploration sites are located in the Carpathian Foreland, between Rzeszow, Przemysl, Lubaczow, and Tarnogrod.

Poland is a key transit country for Russian natural gas to Western Europe through the Yamal pipeline. The Polish natural gas system is connected with the European natural gas network system, but mostly along the East-West direction. There are four key entry points through which natural gas is imported into the transportation system of Poland; they are Lasów (from Germany), Drozdowicze (from Ukraine), Wysokoje (from Belarus) and Kondratki (from Belarus, Yamal pipeline). The Polish natural gas transmission system currently includes 9,768 km of pipelines, fourteen compressor stations and 854 gas stations.

Third-party access to the Yamal pipeline is not offered, which has been subject of EC objections. The new transit deal signed in October 2010 made OGP Gaz-System the operator of the Yamal pipeline in Poland. The EC approved this agreement, but highlighted the need to ensure that the gas-system provides access to the Yamal pipeline on a nondiscriminatory basis. The flow of natural gas through this pipeline is possible only in the East–West direction.

Poland's first LNG terminal is planned to be constructed at Świnoujście. Polskie LNG S.A., a 100 % subsidiary of the OGP Gaz-System S.A., is responsible for the construction, ownership, and operation of the LNG terminal. In the first stage of operation, the LNG terminal will enable the regasification of 5 billion m^3 (13.7 million m^3 per day) of natural gas annually. In the next stage, it will be possible to increase the dispatch capacity up to 7.5 billion m^3 per year (20.5 million m^3 per day), depending on gas demand. In 2009, QATARGAS and PGNiG signed a sales and purchase agreement for LNG supply from Qatar. Under the agreement, QATARGAS will supply 1.5 billion m^3 per year of LNG to PGNiG under a 20 year long-term agreement, starting from 2014.

Poland's natural gas transmission system operator Gaz-System had signed a contract on July 2012 for the supply of pipeline that will allow it to expand the capacity of the country's interconnector with Germany.

3.33.5 Import and Export of Natural Gas

It is important to highlight that virtually all imported natural gas is supplied through pipelines, except for very small quantities of LNG transported by road in tanks. Russia has been the principal source of natural gas imports for Poland. The share of Russian gas in the total gas imports stood at 82 % in 2009, while natural gas imports from Germany accounted for 11 %. According to government sources, GAZPROM increased natural gas supply to Poland to 10.5 billion m^3 in 2011 and 11 billion m^3 from 2012 and beyond; this represents an increase of 4.7 % respect to 2011. The supply contract will end in 2022. According to the new contract signed, the country could re-export of Russian natural gas received in other countries.

According to Fig. 3.65, the imports of natural gas from Poland during the period 2008–2012 increased 9 %. According to the different measures adopted by the government and the power energy, it is expected that the imports of natural gas for the generation of electricity will continue to increase during the coming years.

Poland is not an important exporter of natural gas (see Fig. 3.66). During the period 2008–2011, the maximum export of natural gas was reported in 2010 at 2 billion cubic feet (70.63 billion m^3). However, this situation could change during the coming years due to the discovering of unconventional gas in some parts of the country and the new contract signed with Russia, allowing the re-export of natural gas imported from this last country to other countries.

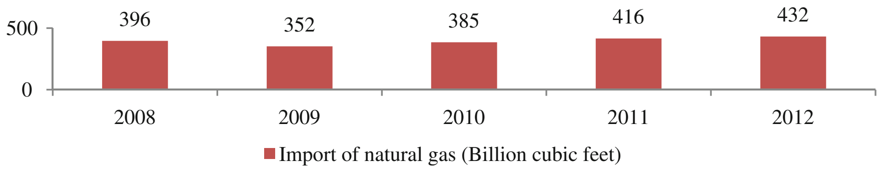

Fig. 3.65 Imports of natural gas from Poland during the period 2008–2012. *Source:* EIA

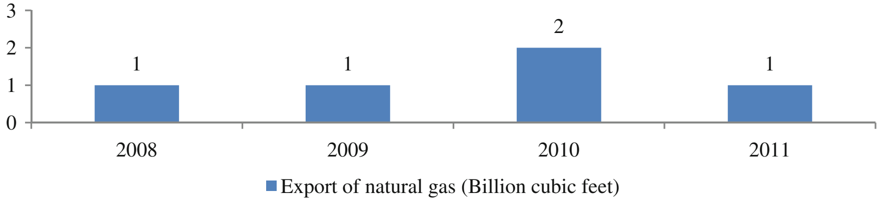

Fig. 3.66 Exports of natural gas from Poland during the period 2008–2011. *Source:* EIA

3.34 Electricity Generation

According to EIA sources, Poland has an installed electricity capacity of 34,318 million kWh in 2011, with more than 90 % of coal power plants (Fig. 3.67).

The electricity installed capacity in Poland increased from 32.257 million kW in 2005 to 34.318 million kW in 2011; this represents an increase of 6.3 %. However, it is important to highlight that the generation capacity construction in Poland has been inconsistent over the past 40 years, resulting in an aging system that is becoming an increasingly serious problem. To improve this situation, the government has decided to carry out new investment in the energy sector. From 2008 to 2015, investments of 3,758 MW new power blocks are planned, and 6,324 MW will be modernized. Currently, 80 % of energy boilers, turbines, and generators installed in Polish power plants are above 20 years old. In order to meet the strict EU environmental requirements the modernization of existing installations is necessary. It will also be important that investments are undertaken in the area of improving energy efficiency in the Polish power generation and transmitting sectors. Current Polish power plant energy efficiency is calculated at 36 %, with energy loss by power plants estimated at 10.638 billion kWh annually, very high in comparison to EU standards. Existing power generation and network losses constitute about 25 % of total energy production.

The participation of natural gas in the Poland's electricity generation during the period 2007–2010 is shown in Fig. 3.68.

According to Fig. 3.68, the use of natural gas for the generation of electricity in Poland during the period 2007–2010 was very small.[39] In the past 4 years the use of natural gas for the generation of electricity went from 2.8 % in 2007 to 3.1 % in 2010, an increase of only 0.3 %. Poland's electricity consumption per capita is 40 % below the EU average.

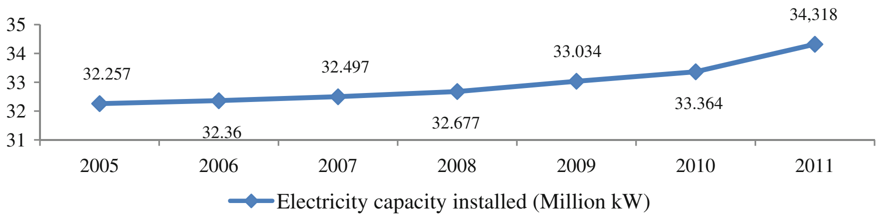

Fig. 3.67 Evolution of the electricity capacity installed in Poland during the period 2005–2011. *Source:* EIA

[39] However, it is important to single out that gas-fired power generation has increased steadily since 1990 over 18.6 % per year, but still the participation of natural gas in the generation of electricity is very small.

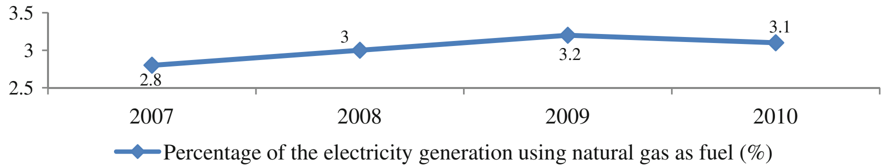

Fig. 3.68 Percentage of the electricity generated in Poland using natural gas as fuel during the period 2007–2010. *Source:* EIA

The share of electricity in final energy consumption is increasing slowly. In 2009, it was about 16 % (13 % in 1990). Electricity consumption was stable until 2000 and grew by 2 % per year until 2008. In 2009, it declined by 3 %. That decrease in consumption of natural gas for electricity generation was linked to the effects of the global economic crisis affecting the whole European region, since industrial consumption (43 % of power consumption in 2008) dropped by 3 %.

The efficiency of the electricity sector improved between 1990 and 2000, rising from 24 % to 33 %, an increase of 9 %. Maintenance investments were kept at a minimum during the 1970s and 1980s, leading to a very low efficiency level in 1990s. The introduction of gas-fired capacity for the generation of electricity has been limited, reaching 850 MW in 2009; CCGT plants account for just 3.2 % of the thermal electricity generation capacity installed in the country.

It is expected that during the coming years the use of coal for the generation of electricity will continue to be very high and the use of natural gas for the same purpose very low. The use of shale and tight gas for the generation of electricity could change the role of gas in the energy mix of the country in the future, but this depends of the government decision to approved the extraction of shale and tight gas and if this extraction is economically possible.

3.35 Portugal

Following EU Directives, the natural gas sector in Portugal became fully liberalized on the 1st of January 2010, resulting in the coexistence of a regulated market with a liberalized market in all segments, reinforcing the need to implement measures that would ensure the efficient and sustained operation of both markets. In addition to this scenario, Decree Law No. 66/2010 of the 11th of June, established the extinction of the regulated natural gas tariffs for end-users with annual consumption of over 10,000 m^3.

The timetable for market liberalization as defined by law, through the decision taken by the Council of Ministers on the 22 of June 2006, establishes that the following parties can freely choose their supplier:

- All producers of electricity operating under the standard regime, as of the 1st of January 2007;
- All customers whose annual consumption is over 1 million m^3, as of the 1st of January 2008;
- All customers whose consumption is over 10,000 m^3, as of the 1st of January 2009;
- All other customers, as of the 1st of January 2010.

Thus, 2010 marks the first year of the complete liberalization of the Portuguese natural gas market, with all customers being able to choose their supplier freely. For the purpose of selecting a supplier, the following types of natural gas contract may be entered into:

- A natural gas supply contract with suppliers in the liberalized market;
- A natural gas supply contract with last resort suppliers;
- A natural gas contract on the organized markets or via bilateral contracts, in the case of customers who have the status of market agents.

According to Entidade Reguladora dos Serviços Energéticos, the composition of the Portuguese power plant generation system has experienced two major changes in the past few years:

- A strong growth in the installed capacity in generation in special regime, a fact which translates into the increase in the share from approximately 13 % of installed capacity in special regime in 2003 to approximately 33 % in 2010, an increase of 20 %;
- In the standard regime segment (thermal and large hydro power) the make-up also underwent change, although not as marked, with the natural gas unit (CCGT) representing, in 2010, approximately 33 % of the standard regime when, in 2003, it represented only 15 %[40]; this signifies an increase of 18 %. Regarding this, 2010 is marked by the entry of another natural gas combined cycle power plant belonging to the company ENDESA, with two groups totaling an installed capacity of 830 MW.

In spite of an increase in the value of the annual maximum peak load, the value of the quotient between the maximum peak verified and the installed capacity in the power plant generation system fell from 83 % to 79 % due to the entry of the new capacity based on natural gas combined cycle (Pego plant).

According to Fig. 3.69, the participation of natural gas and fuel oil in the energy mix of the country suffered no significant change during the period 2003–2010. It is expected that the level of participation of natural gas in the country energy mix will continue without significant changes at least during the next years.

[40] The CCGT capacity tripled between 2000 and 2009 (3.4 million kWh in 2010), and now accounts for 35 % of the thermal capacity (18 % of Portugal's total installed capacity).

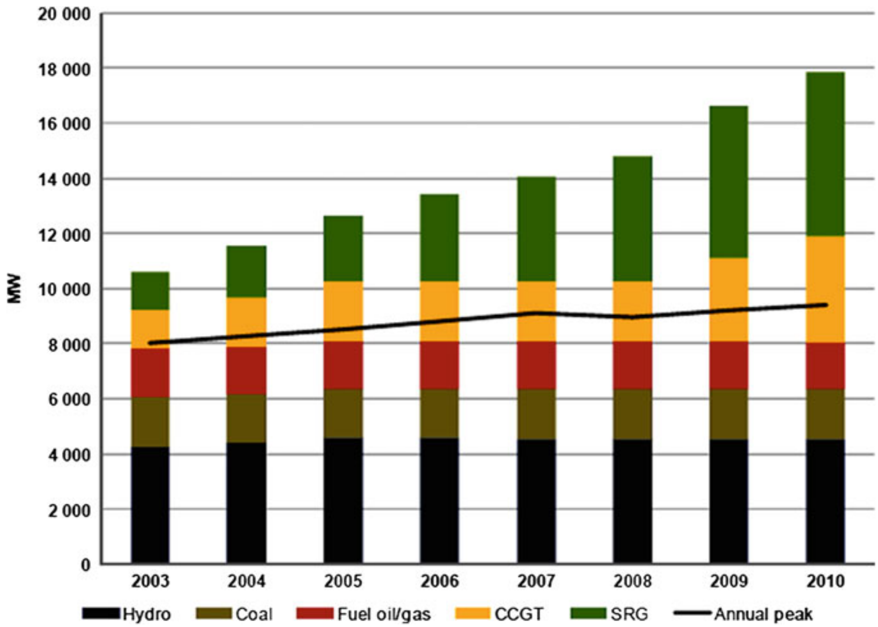

Fig. 3.69 Characterization of the power plant generation system in Portugal by technology and energy produced. *Source:* REN

3.35.1 Integration of Natural Gas Market

The integration of the natural gas market has been achieved through two initiatives, the Iberian Natural Gas Market (MIBGAS) and South GRI (Gas Regional Initiative, Portugal, Spain, and France). The proposed organizational model and operating principles for MIBGAS, presented to the Portuguese and Spanish governments in 2008, describes the plan of action for the creation and future development of this market. This plan contains the following actions:

- Harmonization of licenses for supplying natural gas in Iberia;
- Convergence in the access tariff structure;
- Joint planning of the Iberian natural gas system.

In light of the positive outcome of the public consultation, which ended on the 15th of April 2009, a proposal for the mutual recognition of licenses to supply natural gas under MIBGAS to interested governments was presented. The proposal included a joint analysis of the comments received.

In relation to the harmonization of the access tariffs, a preliminary study was initiated in an effort to characterize the current situation and possible tariff obstacles to the transmission of natural gas in the Iberian Peninsula. This joint study carried out on this specific subject will serve as starting point for the public discussion about tariff harmonization. The study was completed in 2011.

In relation to South GRI, the five priorities common to the three regions of the natural gas regional initiative defined in 2010 where investments in new interconnections, access to the capacity of the natural gas pipelines, transparency, interoperability, and security of supply. In this context, in 2010, there were developed regarding transparency in the Southern region as a new obligation was imposed on the TSOs requiring the publication of regular updates about the interconnection capacity.

In 2010, and according to the Entidade Reguladora dos Serviços Energéticos, South GRI also focused its efforts on coordinated Open Seasons (OS), which are being used to promote investment and increase the interconnection capacity in the South region. In this region, two OS are leading to a significant increase in the interconnection capacity between France and Spain through the reinforcement of existing interconnections (in Larrau and Biriatou), and the creation of a new natural gas line in the Eastern Pyrenees.

3.35.2 Natural Gas Reserves

Portugal has no proven reserves of natural gas reported in 2013. There is no indigenous natural gas production, and therefore the country relies on imports to meet all of its domestic natural gas requirements.

3.35.3 Consumption of Natural Gas

Natural gas began to be supplied to the Portuguese market in 1997. Since then, natural gas demand has steadily increased, reaching 163 billion cubic feet (5,756.345 billion m^3) in 2012. Natural gas demand is expected to continue to grow in the medium-term, mainly in industry, services, and residential sectors. In spite of the new National Renewable Action Plan, it is expected that the consumption of natural gas in electricity generation sector will consistently rise over the next decades.

According to IEA (2011), the seasonality of natural gas consumption in Portugal is not as evident as the one observed in most European countries. The reason for this is the fact that Portugal has a mild climate and that natural gas is not much used in the housing sector for heating.

During the past years, some 59 % of natural gas was imported in the form of LNG, mainly from Nigeria and the rest were supplied from Algeria, through the Mahgreb-Europe natural gas pipeline under a long-term take-or-pay contract.[41]

[41] Portuguese total natural gas imports came in the form of LNG from Nigeria, Trinidad and Tobago, and from others countries, while the remaining imports were supplied by Algeria through the Euro Maghreb pipeline system.

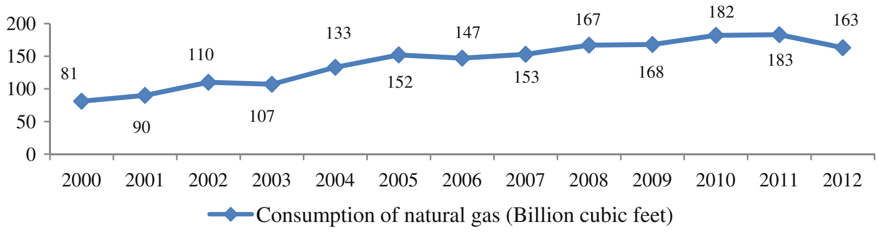

Fig. 3.70 Consumption of natural gas in Portugal during the period 2000–2012. *Source:* EIA

In 2004, the first LNG terminal in Sines initiated operations and it has been supplied since then mainly with natural gas from Nigeria. The development of the natural gas network was made feasible by the contracts with the new combined cycle electric generators that have been consuming about half of the imported natural gas. There are six regional distribution networks for natural gas, almost all controlled by Gas de Portugal (GdP). The consumption of natural gas in Portugal during the period 2000–2012 is shown in Fig. 3.70.

The consumption of natural gas in Portugal increased 101 % during the period 2000–2012. The peak in the consumption of natural gas was reached in 2011 and declined 11 % during the period 2011–2012. It is expected that the consumption of natural gas in Portugal will continue to increase during the coming years, particularly when the economic and financial crisis affecting the country is over.

It is important to highlight that natural gas is increasingly consumed in the industrial sector (over 54 % between 2000 and 2010) and its share in industrial energy consumption is now 19 %.

3.35.4 Import and Export of Natural Gas

The evolution of the imports of natural gas from Portugal during the period 2000–2012 is shown in Fig. 3.71.

According to Fig. 3.71, the imports of natural gas by Portugal during the period 2000–2012 increased 100 %. It is expected that the imports of natural gas will

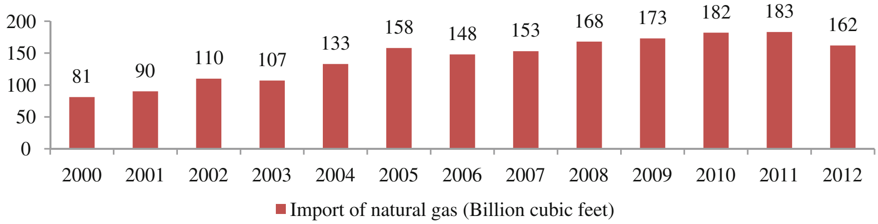

Fig. 3.71 Imports of natural gas from Portugal during the period 2000–2012. *Source:* EIA

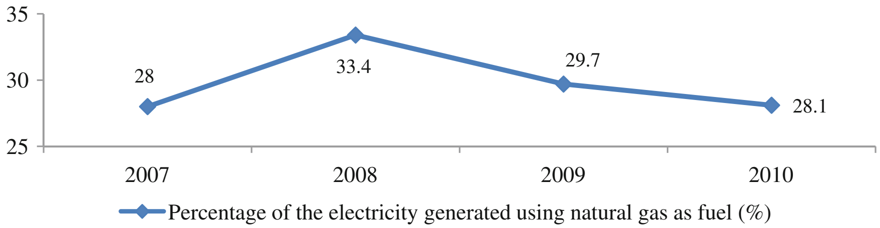

Fig. 3.72 Percentage of the electricity generated in Portugal using natural gas as fuel during the period 2007–2010. *Source:* World Bank

continue to increase during the coming years, particularly after the end of the severe economic and financial crisis that the country is still facing. The country did not export natural gas during the period considered.

3.35.5 Electricity Generation

The percentage of the electricity generated in Portugal using natural gas as fuel during the period 2007–2010 is shown in Fig. 3.72.

According to Fig. 3.72, the use of natural gas for electricity generation in Portugal during the period 2007–2010 dropped 5.3 %. This decrease is due to the severe economic and financial crisis that is affecting the country since 2009. The use of natural gas for electricity generation in 2010 was almost the same than the level reached in 2007. However, it is expected that the participation of natural gas in the electricity generation balance in Portugal will increase once again in the coming years changing the tendency shown in Fig. 3.72.

The rate of transmission and distribution losses in Portugal decreased steadily by 2.4 % per year between 1990 and 2010 and is now around 7.2 %, which is slightly above the EU average.

3.36 Slovak Republic (Slovakia)

In 2011, Slovakia's natural gas industry celebrated its 155 anniversary. Considering the size of the country, Slovakia has a highly developed natural gas infrastructure. Despite 155 years of tradition, a real boom of the Slovak natural gas industry came to a construction of an international transit natural gas pipeline in 1971 for the supply of natural gas from the former Soviet Union to the Western Europe.[42]

[42] However, it is important to highlight that already in the 1960s, there was the international pipeline called "Bratstvo" going through the Slovak territory. Bratstvo pipeline was used to deliver natural gas from the former Soviet Union to Czechoslovakia and after 1968 also to Austria.

It is important to highlight that energy policy is a part of the Slovak national economic strategy, since ensuring maximum economic growth while retaining its sustainable development is conditioned by the reliability of the energy supplies at optimum cost and adequate environmental protection. However, the implementation of the energy policy is conditioned by the fact that the only substantial domestic energy source is lignite (brown coal) and that domestic natural gas production is insignificant. For this reason, the energy imported dependency of the country is 98 %; in the particular case of natural gas, the country depends 98 % of the natural gas imported from Russia.

Slovakia, though a very small producer of natural gas, is important as a transit country for the EU. About 25 % of the natural gas consumed in Western Europe pass through Slovakia, which represents about 70 % of total Russian natural gas exported to the region.

Some of the main problems that Slovakia has to face regarding the future use of natural gas for the generation of electricity and on the security of energy supply are:

- Insufficient diversification of the natural gas resources;
- Absence of a mature natural gas market;
- State interventions and infringements upon regulatory office's rights;
- Absence of the North-South interconnection;
- Increasing dependency on natural gas for the generation of electricity;
- The high consumption per capita of natural gas (more than 80 % of Slovak households are connected to the natural gas network;
- Threats of Russian natural gas supplier GAZPROM to reduce or cut off natural gas supply;
- Increasing natural gas consumption in other countries of the EU;
- Construction of new competitive transport natural gas pipelines in the region outside of the country.

3.36.1 Natural Gas Reserves

According to EIA sources, in 2013 the natural gas proven reserves in Slovakia was estimated at 17.6575 trillion m^3 (0.5 trillion cubic feet). The level of natural gas proven reserves has suffered no change since 2007.

3.36.2 Production and Consumption of Natural Gas

The production of natural gas in Slovakia is very limited. The production of natural gas during the period 2000–2012 is shown in Fig. 3.73.

The production of natural gas in Slovakia during the period 2000–2012 suffered almost no change moving in a range between 4 and 7 billion cubic feet (141.26 and

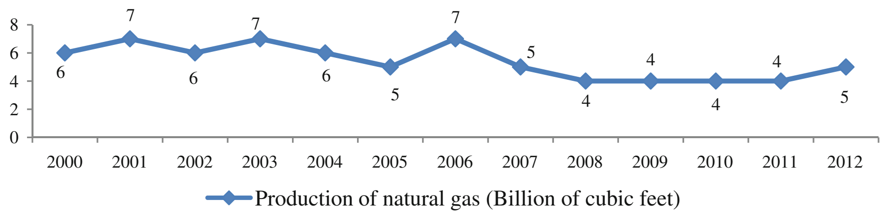

Fig. 3.73 Production of natural gas in Slovakia during the period 2008–2012. *Source:* EIA

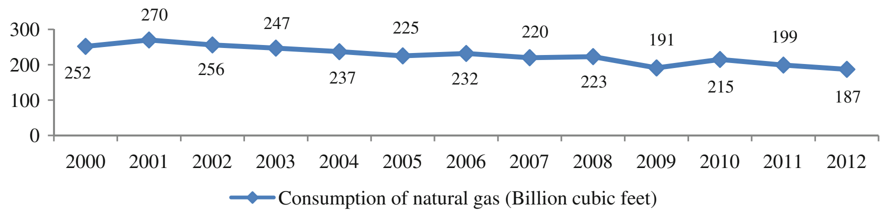

Fig. 3.74 Consumption of natural gas in Slovakia during the period 2000–2012. *Source:* EIA

247.21 billion m^3). It is expected, however, that the production of natural gas in Portugal will decline during the next 2 years, reaching roughly one third of current production by 2014.

On the other hand, the evolution of the consumption of natural gas from Portugal during the period 2000–2012, is shown in Fig. 3.74. From that figure it is easy to see that the consumption of natural gas has been much higher that the level of the domestic production.

Natural gas consumption in Slovakia during the period 2000–2012 decreased 25.8 %. The peak in the consumption of natural gas during the period considered was reached in 2001. Since that year the consumption of natural gas has been decreasing as trend, except in 2006, 2008, and 2010. The reason for the increase in the consumption of natural gas in 2010 respect to 2009 was due to a strong growth in industrial output in that year. Total natural gas demand is expected to rise between 7 and 7.1 billion m^3 between 2020 and 2030.

It is important to highlight that the electricity generated from natural gas has been lagging behind due to high nuclear and hydropower generation. Expected development of the natural gas consumption by 2030 is shown in Fig. 3.75.

According to various analyses carried by energy experts, it can expect that in a long-term perspective (up to 2030) the key role in satisfying the electricity consumption in Slovakia will be played by higher utilization of nuclear power, natural gas, and renewable energy sources. This trend is based on the assumption that due to stricter emission limits, coal consumption will be gradually decreasing, particularly for the generation of electricity. The consumption of natural gas is expected to increase from 6.9 billion m^3 in 2010 to 7.1 billion m^3 in 2030; this represents an increase of only 2.8 % in 25 years.

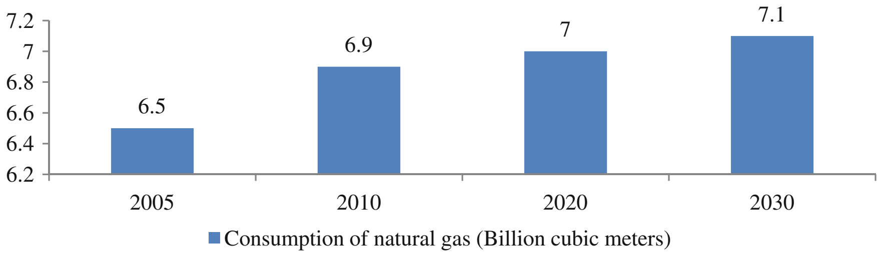

Fig. 3.75 Expected consumption of natural gas in Slovakia for the period 2020–2030. *Source:* Ministry of Economy of Slovakia

3.36.3 Import and Export of Natural Gas

The evolution of the imports of natural gas in Slovakia during the period 2000–2012 is shown in Fig. 3.76.

According to Fig. 3.76, the imports of natural gas from Slovakia during the period 2000–2012 decreased 31.5 %. The major decrease in the imports of natural gas occurred during the period 2011–2012 (28.7 %). On the other hand, the exports of natural gas from Slovakia during the period 2005–2012 was in general very small with the exception of the year 2006 when the country exported 20 billion cubic feet (706.3 billion m^3). Before 2005, Slovakia registered no export of natural gas (Fig. 3.77).

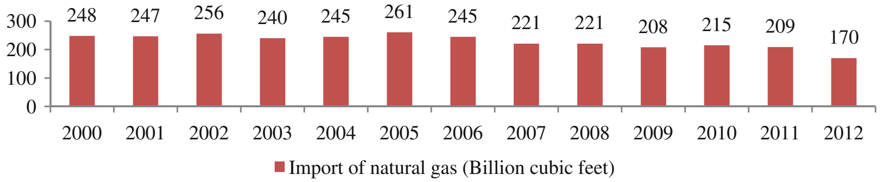

Fig. 3.76 Imports of natural gas from Slovakia during the period 2000–2012. *Source:* EIA

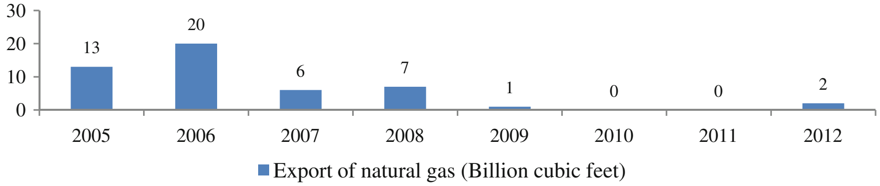

Fig. 3.77 Exports of natural gas from Slovakia during the period 2005–2012. *Source:* EIA

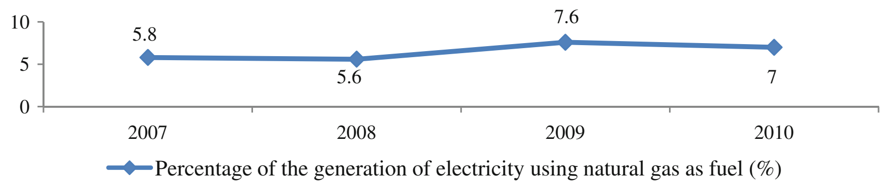

Fig. 3.78 Percentage of the electricity generated in Slovakia using natural gas as fuel during the period 2007–2010. *Source:* World Bank

3.36.4 Electricity Generation

The electricity generated using natural gas as fuel is very limited in Slovakia. The generation of electricity using natural gas as fuel during the period 2007–2010 is shown in Fig. 3.78.

According to Fig. 3.78, the percentage of electricity generated by Slovakia using natural gas as fuel during the period 2007–2010 increased from 5.8 % in 2007 to 7 % in 2010; this represents an increase of only 1.2 %. The peak in the use of natural gas for the generation of electricity during the period 2007–2010 was reached in 2009. The total electricity installed capacity in Slovakia in 2009 was 7.076 million kW. The installed capacity reached 7.855 million kW in 2013.

Finally, it is important to highlight some of the actions that the Slovakian government should adopt in order to solve some of the problems limiting the use of natural gas for the generation of electricity in the future. The first action is the construction of the North–South interconnection pipelines. In the case of Slovakia, the construction of the North-South interconnecting pipelines with Poland would enable the country to be connected to the Yamal gas pipeline and later to the LNG terminal at the Baltic Sea. Interconnector with Hungary would enable the country to be connected to the Hungarian natural gas industry network and later to the LNG terminal at the Adriatic Sea. The second action is to build new underground natural gas storage for foreign commercial use, but also to reserve part of it as strategic natural gas stocks held by the Slovak government.

3.37 Spain

In order to reduce Spain's dependence on imported oil, the government approved certain measures to encourage natural gas consumption.[43] Efforts to redirect the use

[43] The increase in the use of natural gas for electricity generation will help Spain to achieve the target for reduction of all greenhouse gases under EU agreements that amounts to an increase in the emission of the basket of greenhouse gases of 15 % over 1990 levels during the period 2008–2012. However, it is important to highlight the following: The government has developed its national climate change strategy. As part of that the development, the National Climate Change

of fossil fuels were successful, and in the 1980s the consumption of natural gas increased faster than that of any other fuel.

Domestic production of natural gas began in 1984 with the development of the Serrablo field; two years later the Gaviota field went into operation. In 1987, domestic production supplied about 16.7 % of Spain's natural gas consumption. Domestic production shortfalls were taken up by imports from Algeria and Libya under long-term contracts. In 1988, it was agreed that Spain's gradually expanding natural gas pipeline network would be connected to the European network, and Norwegian natural gas started to arrive in Spain in 1992.

Spain holds massive natural gas reserves, including shale gas, which could spawn a multi-billion dollar industry in the country. Natural gas prospecting could open up a €44 billion industry, helping the Iberian nation boost its economy.

As much as 80 % of Spain's natural gas reserves are housed within shale rock. Most exploration projects are located in the Basque-Cantabrian Basin in northern Spain, in Alava, Burgos, and Cantabria. Exploration could also help Spain to become more energy-independent. Spain imports nearly 99 % of its oil and gas.

There are six LNG regasification terminals operating in Spain with an aggregate nominal capacity of 60.1 billon m^3 per year. In addition there are expansions of the current LNG terminals and three new LNG regasification facilities are under construction or have been concluded.

3.37.1 Natural Gas Reserves

According to EIA sources, Spain natural gas proven reserves reported at 0.09 trillion cubic feet (3.18 trillion m^3).

3.37.2 Production and Consumption of Natural Gas

The evolution of the production of natural gas in Spain during the period 2008–2012 is shown in Fig. 3.79.

From Fig. 3.79, the following can be stated: The production of natural gas in Spain is very low and did no increase during the period 2010–2012. It is expected that the production of natural gas will continue this trend, at least during the coming years.

(Footnote 43 continued)
Council, a government advisory body, has identified a number of policy options for combating climate change that would affect the power sector. These options include increased energy efficiency, substitution of natural gas for coal or oil in power generation, and greater use of nuclear power and renewable electricity generation.

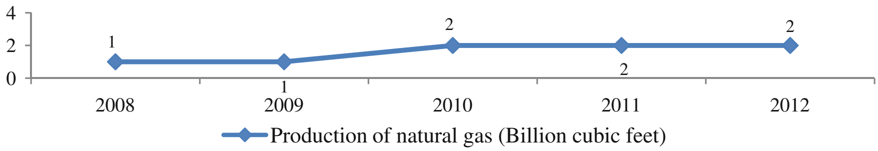

Fig. 3.79 Production of natural gas in Spain during the period 2008–2012. *Source:* EIA

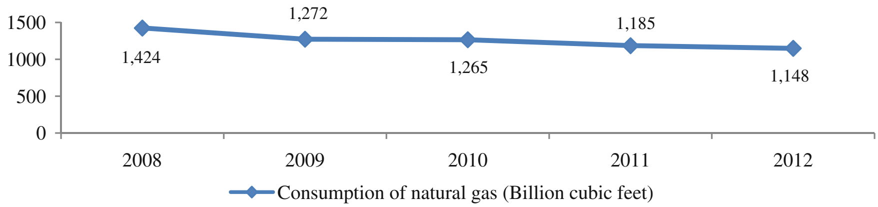

Fig. 3.80 Consumption of natural gas in Spain during the period 2008–2012. *Source:* EIA

The consumption of natural gas in Spain during the period 2008–2012 is shown in Fig. 3.80.

The consumption of natural gas in Spain during the period 2008–2012 decreased 19.4 %. The peak in the consumption of natural gas in Spain during the period considered was reached in 2008.

Natural gas demand dropped by an estimated 11 % in 2009 respect to 2008, due to weather conditions, the increase in renewable electricity supplies and the drop in economic activity. Since that year, the consumption of natural gas in the country has been decreasing and this trend is expected to continue at least during the coming years due to the negative impact that the current economic crisis has in almost all economic sectors of the country. However, the natural gas consumption for electricity generation is still high, accounting for 52 % of total consumption. The industrial sector is the second largest consumer of natural gas with 28 % of demand, followed by the residential sector with 10 %.

From the data included in Figs. 3.79 and 3.80, the following can be stated: Spanish production of natural gas is negligible and for this reason the country is highly reliant on natural gas imports to meet its domestic needs. Algeria is the main supplier of natural gas to Spain, supplying an estimated of some 33–35 % of total supplies, followed by Qatar, Egypt, Trinidad and Tobago, Nigeria and Norway (between 10 % and 12 % each). Algerian supplies are expected to increase further, following the completion of the 8 billion m^3 MedGaz underwater natural gas pipeline directly from Algeria to Almeria in 2010. It is important to note that Royal Decree 1766/2007 obliges direct suppliers and consumers carrying supplies for more than 7 % of national consumption, to diversify their portfolio so that their supplies from the main supplying country stands below 50 %.

Spanish gas supply is well diversified with a large number of suppliers and a large proportion of LNG supplies. Around 76 % of Spain's gas imports were LNG deliveries (from a diversified portfolio of sources), with the remaining 26 % being pipeline supplies.

3.37.3 Import and Export of Natural Gas

The evolution of the imports and exports of natural gas from Spain during the period 2008–2012 are shown in Figs. 3.81 and 3.82.

Imports of natural gas from Spain during the period 2008–2012 dropped 14 % due to a severe reduction of economic activities in the country. It is expected that after the economic crisis that still is affecting the country, the imports of natural gas will start to increase, although the country is trying to reduce the imports of natural gas from Algeria. The share of Qatar and Nigeria in Spain's gas imports increased to 15.9 % and 20.3 % respectively in 2010, while the share of Algerian gas in Spain's imports decreased to 32.7 %.

According to Fig. 3.82, the exports of natural gas from Spain increased 44.5 folds. It is expected that the exports of natural gas from Spain continue increasing during the coming years. Spain export around 54.98 % of the natural gas export to France. As domestic production is quite low in Spain, part of the imported natural gas is transported to other countries.

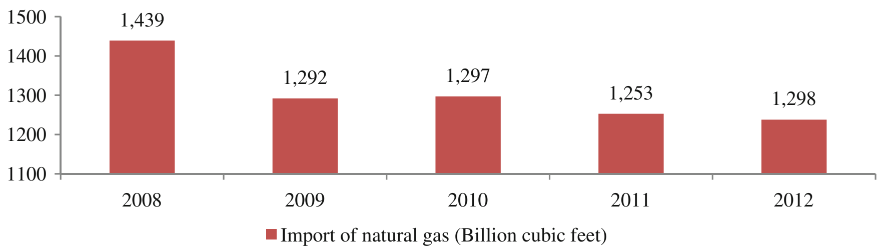

Fig. 3.81 Imports of natural gas from Spain during the period 2008–2012. *Source:* EIA

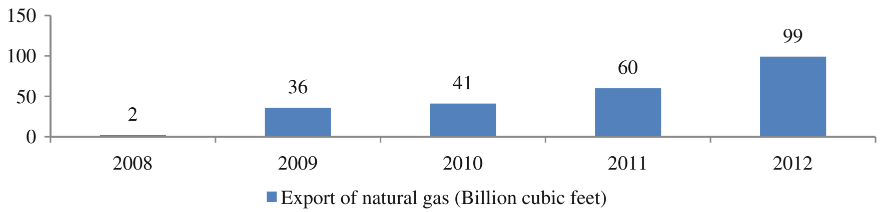

Fig. 3.82 Exports of natural gas from Spain during the period 2008–2012. *Source:* EIA

3.37.4 Electricity Generation

According to government sources, the main elements of the Spanish electricity reforms are the following:

- Competition in the generation of electricity through an electricity market and contracts between customers and suppliers;
- Nondiscriminatory access to transmission and distribution networks;
- Free entry into the generation of electricity;
- Legal separation of network businesses (transmission and distribution) into distinct operational separate companies from commercial businesses of generation and retail supply;
- Regulation of the network and end-user tariffs by the government.

Since the second half of 2000s, natural gas has been the main source of energy used for the production of electricity in Spain. It is important to highlight that the contribution of natural gas for the generation of electricity is growing rapidly taking into account that they accounted for just 10 % in 2000.

The installed electricity capacity in 2009 using natural gas as fuel is the following: In CCGT, 22,243 MW; in fuel plus gas (conventional) 3,927 MW for a total of 26,170 MW. In 2011, installed power capacity grew by 1,879 MW, meaning that the total generation capacity at year end was 100,576 MW (1.9 % up on the previous year). The large majority of this increase in power (93 %) comes from the new renewable facilities, mainly wind power (997 MW) and solar power (674 MW). In 2013, the installed capacity reached 101,714 MW, an increase of 1.1 % respect to 2011. The total electricity production in Spain was reported at 295,299 MW in 2010, according to a World Bank report released in 2011; this represents an increase of 10 % respect to 2009. The total electricity generated in the country using natural gas as fuel is shown in Fig. 3.83. In 2010, the total electricity generated using natural gas as fuel reached 31.6 %.

From Fig. 3.83, the following can be stated: The generation of electricity using natural gas as fuel in Spain during the period 2000–2010 increased 21.6 %. However, the increase in the use of natural gas for the generation of electricity

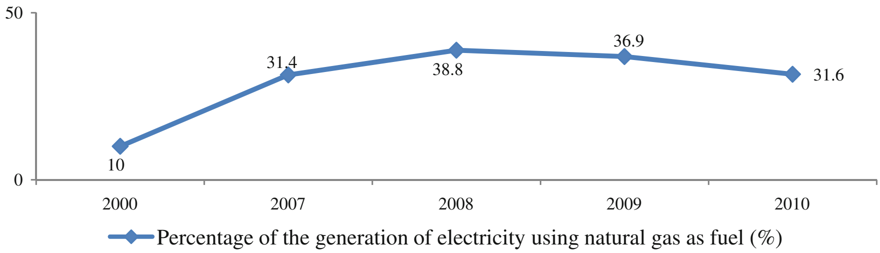

Fig. 3.83 Percentage of the generation of electricity in Spain using natural gas as fuel during the period 2007–2010. *Source:* World Bank

during the period 2007–2010 was only 0.2 %. It is expected that the generation of electricity using natural gas as fuel will continue the current trends at least until the economic crisis still affecting the country is over.

3.38 Sweden

The natural gas market in Sweden is rather limited, only 3.5 % of the total Swedish energy needs are covered by natural gas. However, in those areas in Sweden, where natural gas is established it covers approximately 20 % of the energy needs. In Sweden, approximately 30 municipalities, mainly situated in the West-Coast area and the Southern part of the country, have access to natural gas. However, despite the fact that the number of end-users on the Swedish natural gas market has decreased in the past years, there has been a tendency of rising volumes of sold natural gas on the Swedish wholesale market. The increase in natural gas consumption was mainly due to the start of a large gas-fired CHP plant in 2009 and cold weather during 2010. In 2011, the volume was down to 1,230 million m^3 mainly due to warm weather. Another contributing factor has been the increased use of LNG in urbanized areas like for example Stockholm, where natural gas was not a traditional energy source before.

3.38.1 Natural Gas Reserves

There are no natural gas reserves reported by Sweden in 2013.

3.38.2 Shale Gas

In Sweden, only minor shale gas projects are ongoing. They all have been initiated by Gripen Gas recently. In the course of 2010 and 2011, Gripen Gas AB has received twelve exploration authorizations for exploring the Östergötland and Kalmar Counties covering a surface of 420 km^2. Also Tekniska verken I Linköping AB have received an exploration authorization for the Östergötland County. Shell Exploration and Production AB has won exploration authorization for the Skåne County. Two other exploration authorizations for Shell AB are expired. All of the projects are at a survey stage. An exploitation concession for a small-scale operation in the area of Tornby K N°1 has been granted in 2008. However, according to the Mining Inspectorate, this has not been followed by any activity until today.

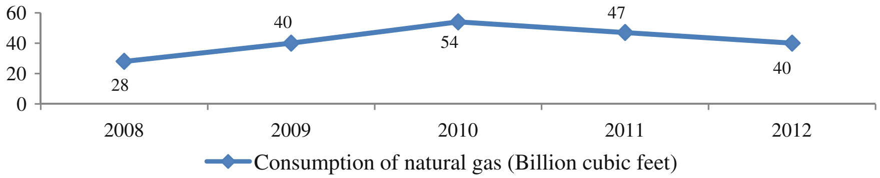

Fig. 3.84 Consumption of natural gas in Sweden during the period 2008–2012. *Source:* Eurostat

3.38.3 Production and Consumption of Natural Gas

There is no production of natural gas reported from Sweden in 2013. Concerning natural gas, consumption in Sweden in 2012 totaled 40 billion cubic feet (15,538 billion m^3), all of which was supplied via a single interconnector with Denmark. While natural gas plays only a minor role in Sweden's energy mix, its role in the energy supply of Southern and Western Sweden is much more substantial, accounting for around 20 % of the area's total energy use. Around 30 large consumers, including CHP plants, account for roughly 80 % of total gas demand in the country, while households and other small consumers, numbering over 33,000, account for 2 % of the total. In 2011, 53 % of total natural gas used was consumed in the transformation sector and 33 % in the industry sector, which includes non-energy use. The residential and commercial sectors, each accounted for another 6 %, while the remainder of natural gas used was in the transport sector (2 %). The consumption of natural gas in Sweden during the period 2008–2012 is shown in Fig. 3.84.

Natural gas consumption in Sweden grew 42.8 % during the period 2008–2012. Industrial output is on the rise in 2010, but the increase is not as impressive as natural gas used for electricity generation following the addition of 460 MW of natural gas fired power capacity in 2009.

In 2012, Sweden imported 1,412.6 billion m^3 (40 billion cubic feet) of natural gas to satisfy the power demand in that year.

3.38.4 Import and Export of Natural Gas

The evolution of the imports of natural gas in Sweden during the period 2008–2012 is shown in Fig. 3.85.

According to Fig. 3.85, the imports of natural gas from Sweden during the period 2008–2012 increased 25 %. The peak in the imports of electricity during the period considered was reached in 2010. Since that year the consumption of natural gas decreased 31.1 %. It is expected that the imports of natural could increase during the coming years, particularly after the closure of some of the nuclear power reactors in operation in the country during the coming years. The country did not export natural gas during the period considered.

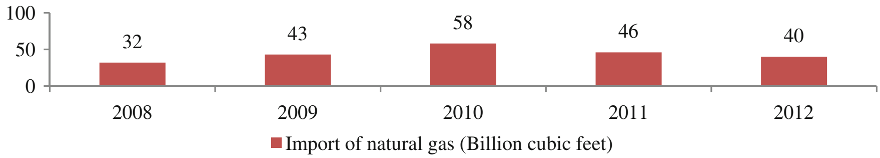

Fig. 3.85 Imports of natural gas from Sweden during the period 2008–2012. *Source:* EIA

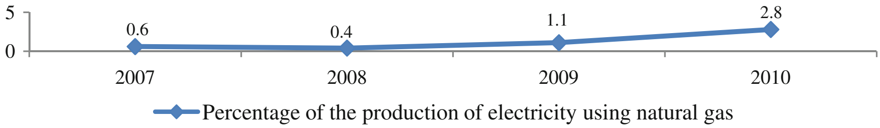

Fig. 3.86 Percentage of the production of electricity in Sweden using natural gas as fuel during the period 2007–2010. *Source:* Eurostat

3.38.5 Electricity Generation

The electricity generated in Sweden using natural gas as fuel during the period 2007–2010 is shown in Fig. 3.86.

The production of electricity using natural gas in Sweden is very small. It increased from 0.6 % in 2007 to 2.8 % in 2010; this represents an increase of only 2.2 %. However, this percentage could change in the future as a result of the decision of the government to shut down some of the nuclear power reactors currently in operation in the country during the coming years.

The total electricity generated in the country increased from 157,635 million kWh in 2001 to 162,437 million kWh in 2012; this represents an increase of 3 %.

3.39 United Kingdom

During the 1980s and early 1990s, there was a massive expansion in gas-fired generation capacity, known as the "Dash for Gas", in the UK. The construction of gas-fired power plants compared to coal-fired or nuclear power plants were especially attractive due to the high interest rates of the period. Natural gas looks very promising in providing future UK energy needs. However, in recent years domestic production from the North Sea gas fields has been decreasing and this trend is expected to continue during the coming years.[44] Despite investment to enhance pipelines and storage of imported natural gas (mostly from Norway) adopted by the

[44] It is expected that for the year 2021, North Sea oil and natural gas production is predicted to slip 75 % from 2005 levels.

UK government and the private energy sector, there is a reluctance to allow too great reliance on Russia and its natural gas exports for energy needs.

Since 2004, investment in the energy industries has continued to grow, specifically in electricity. In 2010, of the total amount invested in the energy industry, 40 % were in oil and gas extraction, 44 % in electricity, 14 % in gas with the remaining 2 % in coal extraction and coke, refined petroleum products and nuclear fuels (UK Energy in Brief 2012).

3.39.1 Natural Gas Reserves

According to EIA sources, the UK held an estimated of 8.687 trillion cubic feet (306.781 trillion m^3) of proven natural gas reserves in 2013. Most of these reserves are located in the following three areas:

- Associated fields in the UK Continental Shelf;
- Nonassociated fields in the Southern Gas Basin, located adjacent to the Dutch sector of the North Sea;
- Nonassociated fields in the Irish Sea.

3.39.2 Shale Gas

A new study from the British Geological Survey estimated that 1.3 quadrillion cubic feet of natural gas (45.41 quadrillion m^3) lie trapped in shale rock beneath northern England. Combined with other measures to support the use of renewable and nuclear energy sources for the generation of electricity during the coming years, the shale gas resources will help the UK to satisfy the energy needs in the future. The UK is promoting the development of its shale gas reserves in the hope that it can replicate the success achieved in the USA where prices of gas have tumbled amid a boom in production. Britain also needs to offset a rapid decline in output from its existing natural gas fields. Gas production fell 15 % from a year earlier, continuing a long slide as the aging North Sea became increasingly depleted.

According to the British Geological Survey they do not have enough information to predict how much shale gas could be commercially produced from the Bowland shale formation in Northwest England, but has made an estimated that about 45,909.5 trillion m^3 (1,300 trillion cubic feet) of shale gas is held in the Bowland Basin, which covers 11 counties in the North of England. The UK Department of Energy and Climate Change said in a report last year that typically around 10 % of shale gas resources have proven to be recoverable in the USA where the industry is more advanced. Based on current information, the consumption of natural gas recoverable shale gas would be equivalent to more than 40 years of natural gas consumption.

The UK government is planning an assessment of reserves in the Southeast of the country, which will please supporters of the technology who regard shale gas as a secure energy source that offers lower emissions than coal, and could help to bring down energy prices. However, experts acknowledge that while a shale gas boom has dramatically lowered energy prices in the USA, the same result is unlikely on this side of the Atlantic, because of higher drilling costs and greater population densities. Drilling is still in its early stages in the UK, but the Department of Energy and Climate Change said there are already 176 licenses currently issued for onshore oil and gas exploration, and it expects considerable interest from developers when it launches the 14th onshore licensing round next year.

The government hopes that shale gas will reduce dependence on foreign energy. However, it is important to highlight that the UK's shale gas industry is still at an early stage, with no commercial production. Of the handful of exploration wells that have been drilled, only one has been hydraulically fractured the process used to extract shale gas. Most industry experts say the UK is years away from commercial production on any great scale in the production of shale gas.

On the other hand, shale gas exploitation in the UK has also faced significant opposition from environmental groups. These groups say that hydraulic fracturing, which involves blasting shale rock with sand, water, and chemicals to release the gas, could contaminate groundwater. In 2011, the UK's only fracking operation, run by Cuadrilla Resources in Lancashire, was halted after it caused earth tremors. The company was granted permission to resume fracking in that area and expects to do so next year. Last week the company had to delay drilling an exploratory well in West Sussex, in Southern England, after the Friends of the Earth environmental organization complained to the Environment Agency that the company lacked the necessary permits.

The French oil giant TOTAL is another company that will explore for natural gas and oil in shale rock in Britain during the coming years. Under the deal, which was announced in January 2013, TOTAL would commit about US$50 million for a roughly 40 % stake in licenses held by a group of companies in Lincolnshire in the East Midlands, according public available information. TOTAL's participation would be a vote of confidence in the government of Prime Minister David Cameron, which has been trying to promote shale gas as an alternative to declining production of oil and gas in the North Sea, despite opposition from local communities and environmental groups. Surging production of oil and gas from shale rock has sharply lowered energy prices in the USA and helped make its industry more competitive, though it has also brought criticism from environmental advocates. Britain, however, is one of the few countries in Western Europe that has encouraged the exploration of shale gas.

Analysts say that if shale gas production is successful in Britain, countries like France and Germany, which are thought to have considerable shale gas potential, might reassess their thinking. So far, shale gas exploration in Britain has been led by a handful of small companies. Other large European oil companies, including BP and Royal Dutch SHELL, have taken a cautious approach to British shale gas. SHELL's chief financial officer, Simon Henry, has said that "the company was wary of attracting the protests and news media attention that accompanied some onshore drilling efforts in Britain." TOTAL is already attracting some of that attention, even before an official announcement.

But too few wells have been drilled and tested to know whether the resources can be exploited commercially. John Browne, a former chief executive of BP who is the chairman of Cuadrilla Resources, said in late November that the industry needed to drill 10,000–12,000 wells to determine whether British shale gas was viable. However, Dr. Mark Broomfield, Specialist Consultant, Ricardo-AEA has said at the Unconventional Gas Aberdeen 2014 conference that is very unlikely—more likely there will be between 600 and 3,000 wells by 2035. He said his organization had recently completed the study of the likely industry development of the unconventional hydrocarbon industry in the UK, looking at both shale gas and coal bed methane. In terms of production, the consultancy estimates between 1 and 10 billion cubic meters per year by 2030, this could represent between 1 % and 10 % of UK consumption. Dr. Broomfield contrasted this estimate with that of an Institute of Directors' report from 2013 whose mid-range forecast was 30 billion m^3 per year. The intention is to produce around 10–13 billion m^3 in 15 years' time.

In the case of the production of coal bed methane, the number of well to be drilled range between 200 and 1,000 wells by 2035.

The Gainsborough Trough, the geological formation where TOTAL plans to explore, has not been investigated for shale gas and oil, but Igas Energy, a British company, has conventional oil and gas production in the vicinity.

3.39.3 Production and Consumption of Natural Gas

The UK is the fourth-largest producer of natural gas in the world, behind Russia, the United States, and Canada. The UK produced 0.1 trillion m^3 of natural gas in 2003, about the same as the previous year, but a decrease from the peak of 0.11 trillion m^3 in 2000. Since that year the production of natural gas has been declined to a little more than 60 billion m^3 reached at 2010. According to the Department of Energy and Climate Change, natural gas production in 2010 was 4.3 % lower than in 2009. As with oil, UK natural gas production is also declining as UK Continental Shelf reserves deplete. Gas production in 2011 was 21 % lower than in 2010 and 58 % lower than the record level seen in 2000. In 2012, the production of natural gas reached 1,323 billion cubic feet (46,721.7 billion m^3).

In order to take advantage of its domestic natural gas reserves, the UK's government has encouraged the use of natural gas, including its substitution for coal and oil in industrial consumption and electricity production.

According to the Department of Energy and Climate Change, natural gas demand in 2010 was 8.3 % higher than in 2009, while electricity consumption was 1 % higher in 2010 than in 2009. In 2012, the consumption of natural gas reached 2,641 billion cubic feet (93,266.9 billion m^3), which is 7.4 % lower than the level reported in 2011.

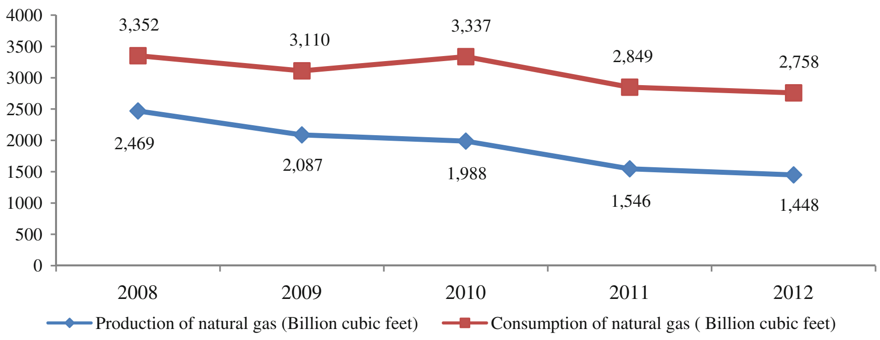

Fig. 3.87 Production and consumption of natural gas in the UK during the period 2008–2012. *Source:* Eurostat

In the opinion of the UK's experts, the future for energy in the next 30 years in the country is natural gas. It is cheap, widely available quickly, and least polluting of fossil fuels in terms of greenhouse gases. While UK is currently involved in almost all types of power generation, the participation of natural gas in the energy matrix is likely to become stronger, simply because a natural gas plant can be built in 2 years, whereas it takes 10 years to complete a nuclear power facility, not to mention the delays for environmental permitting and approvals.

The production and consumption of natural gas in the UK during the period 2008–2012 is shown in Fig. 3.87.

The production of natural gas in the UK during the period 2008–2012 decreased 41.4 %. It is expected that this trend will continue during the coming years unless the production of shale gas start in the next years, something that could be difficult to happen. On the other hand, the consumption of natural gas in the UK during the same period decreased 18 %. However, it is expected that the consumption of natural gas in the country will increase its participation in the generation of electricity during the coming years, as a result of the reduction of the participation of nuclear energy in the production of electricity in the future.

3.39.4 Natural Gas Fields

The largest concentration of natural gas production in the UK is the Shearwater-Elgin area of the Southern Gas Basin. The area contains five natural gas fields, Elgin, Franklin, Halley, Scoter, and Shearwater. Most of the leading oil companies in the UK are also the leading natural gas producers, including BP, SHELL, and TOTAL.

3.39.5 Import and Export of Natural Gas and LNG

In 2004, the UK was a net importer of natural gas for the first time since 1996. In 2010, net imports of natural gas were equivalent to about 40 % of UK final consumption and LNG accounted for 35 % of gas imports.[45] The evolution of the imports and exports of natural gas from the UK during the period 2008–2012 are shown in Figs. 3.88 and 3.89.

From Fig. 3.88, the following can be stated: The imports of natural gas from UK during the period 2008–2012 increased 34.4 %. The peak in the imports of natural gas during the period considered was reached in 2010 and since then the imports of natural gas started to decrease (8.8 %).

According to Fig. 3.89, the exports of natural gas from the UK during the period 2008–2012 increased 4.2 %. It is expected that, in general term, this trend will continue in the future.

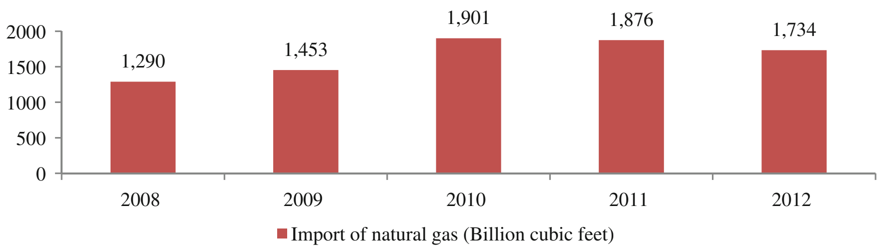

Fig. 3.88 Imports of natural gas from UK during the period 2008–2012. *Source:* EIA

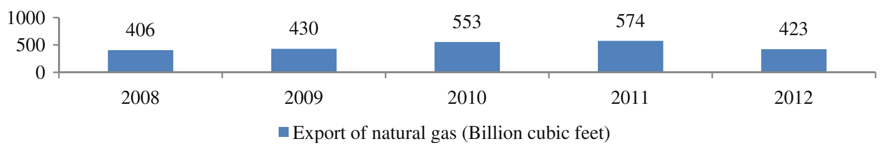

Fig. 3.89 Exports of natural gas from the UK during the period 2008–2012. *Source:* EIA

[45] LNG was imported from Algeria, Egypt, Nigeria, Norway, Qatar, Trinidad and Tobago, and Yemen. About three quarters of these LNG imports came from Qatar. Just under half of the UK's total gas imports were sourced from the Norwegian Continental Shelf. Supplies were also delivered to the UK from the European mainland via the Balgzand (Netherlands)-Bacton and Bacton-Zeebrugge (Belgium) interconnectors.

3.39.6 LNG Facilities

Currently, the UK has a single LNG import terminal, the NGT's Grain LNG on the Isle of Grain. The facility has a send out capacity of 11.89 million m^3 per day, which NGT plans to expand to 0.04 billion m^3 per day. Algeria's SONATRACH and BP are the principal importers using the terminal.

EXXON-MOBIL and Qatar Petroleum have received regulatory approval for the South Hook LNG receiving terminal in Milton Haven, in Wales. The terminal will receive its LNG from the QATARGAS II liquefaction project in Ras Laffin, Qatar, which is also a joint project between the two companies. In 2010, LNG accounted for just over a third of total gas imports and was nearly double what they were in 2009. The South Hook LNG project increased its initial capacity of 0.028 billion m^3 per day to a maximum capacity of 0.059 billion m^3 per day.

Finally, BG has collaborated with Netherlands-based PETROPLUs and PETRONAS to also build an LNG receiving terminal in Milton Haven, on the site of an existing natural gas storage facility owned by PETROPLUS. The project started with an initial send out capacity of 16.42 million m^3 per day.

3.39.7 Electricity Generation

Much of the change in the use of natural gas for electricity generation in recent years is the result of changes in the relative prices of natural gas and coal. The downturn in 2005 resulted from generators preferring coal when natural gas prices reached very high levels at the end of the year. By the end of 2006, however, natural gas use had risen back to the levels of 2003 and 2004, as prices fell back. This increase continued through to 2007 and 2008. However, in 2009, natural gas use for electricity generation decreased, mainly as a result of less use during the first quarter of 2009 compared to the same period in previous years, when natural gas use for generation generally tends to be higher. This decline was short-lived as natural gas-fired generation increased once again in 2010, particularly during the first quarter of 2010 where levels (101,724 million kWh) were on par with those seen during the first quarter of 2008 (101,728 million kWh), the record high recorded.

At the moment, electricity generation, transport, and heating each account for roughly one-third of the UK's energy consumption. Around 40 % of electricity supply is currently produced by gas-fueled power plants. This proportion has been gradually rising since 1990 and is likely to increase faster over the next 15 years. This is because it has been forecast that, in order to meet demand, the UK must replace approximately one third of its electricity generating capacity by 2025. In 2010, natural gas accounted for 47.5 % of the total electricity produced in the country; this represents a further increase of 17.25 %. It is important to highlight that electricity generated from natural gas seemed to be on the rise in 2010, which could be explained by lower nuclear power and about 2.2 GW of additional gas-fired

Table 3.14 Consumption of electricity during the period 1980–2011 (Billion kWh)

	1980	1990	2000	2007	2008	2009	2011
Electricity generators	4	6.5	324.6	355.9	376.8	356.2	306.7
Energy industries	19.1	39.2	102.1	98.9	96.9	93.8	84.9
Industry	177.5	164.6	198.5	144.3	148.7	123.9	132.4
Domestic	246.8	300.4	369.9	352.9	359.6	334.8	293
Services	60.4	86.4	110.5	94.8	95.6	83.1	82.4
Total	507.8	597	1,105.5	1,046.8	1,077.7	991.8	899.4

Source: UK Energy in Brief 2010 and 2012 (2011)

power plant's capacity installed since the end of 2009. Natural gas used for electricity generation increased by 4.3 % in 2010 respect the 2009 level. The gas's share rose by 1.8 % points to 47.3 % (Table 3.14).

In the early 1970s, following the advent of UK production of natural gas, the consumption grew rapidly. Industrial consumption peaked in 2000, but has fallen since then by around 38 %, magnified by the economic recession affecting the country and the whole EU, which saw a fall of 17 % between 2008 and 2009. There was steady growth in all other sectors until around 2004. Consumption then declined until 2007, mostly as a result of higher prices, energy efficiency and, to a lesser extent, of warmer than average temperatures, before rising in some sectors in 2008, and then falling off in 2009. After falling to an 8 year low in 2006, natural gas consumption by electricity generators rose by 14 % in 2007 and by a further 6 % to a record high level in 2008, before returning to around 2007s level in 2009 (UK Energy in Brief 2010).

UK gas production peaked in 2000 and has since been in general decline. With declining production in the UK has become increasingly reliant on gas imports to meet demand. Since 2000 net imports have been steadily increasing year on year, with the exception of 2011 which saw a 3 % decrease on last year's level. This decrease in imports can be attributed to the reduced gas demand for domestic use and generation. Despite this small fall in imports, LNG's share of total gas imports rose once again from 35 % in 2010 to 46 % in 2011, an increase of 11 %, via two new LNG terminals at Milford Haven (South Hook and Dragon) and the expansion of the Isle of Grain LNG terminal. The growth in LNG has also contributed to the UK's record gas export levels, which stand at 183.7 TWh, 4 % higher than in 2010 and 26 % above the level in 2000 (UK Energy in Brief 2012).

On the other hand, the participation of natural gas in the production of electricity in the UK during the period 2007–2011 decreased from 42.2 % in 2007 to 40.7 % in 2011; this represents a decrease of 1.5 % (Fig. 3.90).

Finally, it is important to highlight the following: The mix of fuels used to generate electricity continues to evolve. Since 1990, the decline of coal and oil and the rise of natural gas and, in more recent years, renewable, have been the most marked features, but none of these fuels have followed a smooth path. Natural gas rose most markedly over this period from 0.4 billion kWh in 1990 to a peak of

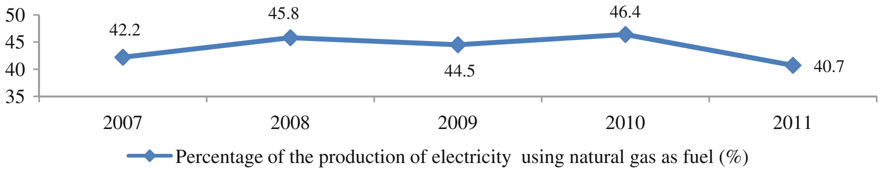

Fig. 3.90 Percentage of the production of electricity in the UK during the period 2007–2011 using natural as fuel. *Source:* IEA and UK Energy in Brief (2012)

173.0 billion kWh in 2008. After falling in 2009, as overall demand fell, natural gas rose again in 2010 and fell again in 2011 to its lowest level since 2006 due to poor market conditions (UK Energy in Brief 2012).

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Chapter 4
The Role of Coal in the Regional Electricity Generation

Abstract Coal was the main energy source not only in Europe, but also worldwide until the 1960s. Owing to advances in oil extraction, conversion, and application technologies, coal began to lose market share to oil. The entry of natural gas and nuclear power into the energy market at the beginning of the 1970s put further pressure on the use of coal for the generation of electricity in many countries. All these new energy sources were cleaner to use and in some cases even cheaper. Gradually, coal started to be perceived as a "dirty and old-fashioned fuel for use in poorer countries" for electricity generation. As a result, despite the rising energy demand, gross coal consumption in the EU-15 has been declining since 1970, while the share of coal in gross inland energy consumption has more than halved, from more than 30 % to approximately 15 %. In contrast, coal retained a 25 % share in gross inland energy consumption globally over the period 1970–2000.

4.1 General Overview

According to the IEO (2013), world coal consumption is expected to rise at an average rate of 1.3 % per year, from 147 quadrillion Btu in 2010 to 180 quadrillion Btu in 2020 and 220 quadrillion Btu in 2040. The near-term expansion of coal consumption reflects significant increases in China, India, and other non-OECD countries. In the longer term, growth of coal consumption decelerates as policies and regulations encourage the use of cleaner energy sources, natural gas becomes more economically competitive as a result of shale gas development, and growth of industrial use of coal slows, largely as a result of China's industrial activities. Coal consumption is dominated by China (47 %), the United States (14 %), and India (9 %), with those three countries together accounting for 70 % of total world coal consumption in 2010. Their share of world coal use is expected to increase to 75 % in 2040. However, the growth rates by region will be uneven, with total coal consumption in OECD countries remaining near 2008 levels and coal consumption in non-OECD countries increasing at a pace of 2.1 % per year. As a result, increased use

J. Morales Pedraza, *Electrical Energy Generation in Europe*,
DOI 10.1007/978-3-319-08401-5_4

of coal in non-OECD countries accounts for nearly all the growth in world coal consumption over the period (IEO 2011).

Consumption of all other energy sources (except liquids) grows faster than coal use, particularly in the power sector. For example, the coal-fired share of world electricity generation is expected to decline from 40 % in 2010 to 36 % in 2040, while the renewable share is expected to increase from 21 % to 25 %, the natural gas share from 22 % to 24 %, and the nuclear share from 13 % to 14 %.

In 2008, coal accounted for 28 % of world energy consumption. Of the coal produced worldwide in 2008, 60 % was shipped to electricity producers and 36 % for industrial consumers, with most of the remainder going to consumers in the residential and commercial sectors. According to the IEO (2011), coal's share of total world energy consumption is expected to remain relatively fat throughout the period 2010–2035, declining slightly from a peak of 29 % in 2010 to 27 % in 2015, where it remains through 2035.

Sustained high prices for oil and natural gas make coal-fired generation more attractive economically, particularly in nations that are rich in coal resources. However, it is important to highlight that the outlook for coal-fired generation could be altered substantially by national policies or international agreements to reduce greenhouse gas emissions. The electric power sector offers some of the most cost-effective opportunities for reducing carbon dioxide emissions in many countries. Coal is both the world's most widely used source of energy for electricity generation and also the most carbon-intensive energy source. If a cost, either implicit or explicit, were applied to carbon dioxide emissions, there are several alternatives for low emission technologies that currently are commercially proven or under development, which could be used to replace some coal-fired power generation plants. Implementing these new technologies would not require expensive large-scale changes in the power distribution infrastructure or in electricity-using equipment.

The security and diversity of energy supply are causing growing concern in the EU. A renaissance in coal use, the major energy source 40–50 years ago, but currently with a modest and continuously declining contribution to the EU's energy supply, could potentially improve the energy balance of the EU. However, the recent trends in coal markets make the long-term supply prospects for coal uncertain. The sharp increase in oil prices in recent years, and the temporary cut-back in natural gas supplies from Russia due to payment problems with Belarus and Ukraine, and recently with the Crisis in Crimea, have boosted concerns about the security, diversity, reliability, and affordability of energy supplies in the EU[1] (Kavalov and Peteves 2007).

Coal was the main energy source not only in Europe, but also worldwide until the 1960s. Owing to advances in oil extraction, conversion, and application

[1] In 2007 and 2008, the oil price increases significantly reaching more than US$140 per barrel. In the first quarter of 2012, the oil prices reached US$120 per barrel. In the first two months of 2013, the price of oil is over US$100 per barrel. At the end of 2013, the oil price was above US$100 per barrel.

technologies, coal began to lose market share to oil. The entry of natural gas and nuclear power into the energy market at the beginning of the 1970s put further pressure on the use of coal for the generation of electricity. All these new energy sources were cleaner to use and in some cases even cheaper. Gradually, coal started to be perceived as a "dirty and old-fashioned fuel for use in poorer countries" for electricity generation. As a result, despite the rising energy demand, gross coal consumption in the EU-15 has been declining since 1970, while the share of coal in gross inland energy consumption has more than halved, from more than 30 % to approximately 15 %. In contrast, coal retained a 25 % share in gross inland energy consumption globally over the period 1970–2000 (Kavalov and Peteves 2007).

However, in recent years there is a renewed interest in the use of coal in the EU, as well as in other countries within and outside the European region, for different purposes based on a wide perception that coal is an abundant, widely available, cheap, affordable, and reliable energy source. According to Morales Pedraza (2008), the main reasons for this renewed interest are the following:

- There is more coal than oil and natural gas worldwide, particularly in Europe. With current consumption trends, the reserves-to-production ratio of world proven coal reserves are higher than that of world proven oil and natural gas reserves—minimum 109 years versus 40 and 65 years, respectively. World coal reserves are also more evenly distributed around the globe compared to oil and natural gas reserves. The geopolitical distribution of world coal reserves differs also from that of oil and natural gas;
- Historically, coal prices have been lowered and more stable than oil and natural gas prices, owing to more evenly spread of coal reserves and hence the smaller room for price manipulation. The EU has large reserves of coal than oil or natural gas, even though it does not hold a large share of the world's coal reserves (only 4.3 % of the total world coal recoverable reserves). Consequently, import dependence on fossil fuels (i.e., mainly coal) is lower than the dependence on natural gas and oil. A more complete and efficient exploitation of indigenous coal reserves would reduce the EU's overall energy import dependence.

4.2 World Coal Reserves

The confirmed world coal reserves are 860,938 million tons in 2012 (a decrease of 5.4 % respect to 2010), which would be enough to cover the demand of all countries at the current consumption rhythms for not less than 109, 46 years more than in 2010. World proven reserves of coal in 2012 were sufficient to meet 109 years of global production, by far the largest reserves-to-production ratio for any fossil fuel. Asia and Europe hold the largest regional coal reserves while North America has the highest reserves-to-production ratio. The USA holds the largest individual reserves, followed by Russia and China.

Table 4.1 World recoverable coal reserves as of January 1, 2010 (Billions of tons)

Region/Country	Hard coal	Sub-bituminous	Lignite	Total
World total	452.9	291.4	165.1	909.4
United States	119.6	108.7	33.3	261.6
Russia	54.1	107.4	11.5	173.1
China	68.6	37.1	20.5	126.2
India	59.5	–	5.1	64.6
Other Non-OECD Europe and Eurasia	49.1	19	27.3	95.3
Australia and New Zealand	40.6	2.5	41.5	84.6
Africa	35.1	0.2	–	35.3
OECD Europe	9.3	3.4	19	31.7
Other Non-OECD Asia	2.5	2.8	4.5	9.8
Brazil	–	7.8	–	7.8
Other Central and South America	7.7	1.1	–	8.8
Canada	3.8	1.0	2.5	7.3
Other	3	0.3	0.1	3.4

Source: IEO (2010)

Historically, estimates of world recoverable coal reserves, although relatively stable, have declined gradually from 1,145 billion tons in 1991 to 1,083 billion tons in 2000, 909 billion tons in 2010 and 860.9 billion in 2012, a decrease of 25 % in the past 20 years. Although the decline in estimated reserves is sizable, the large reserves-to-production ratio for world coal indicates that sufficient coal will be available to meet demand well into the future. Further, because recoverable coal reserves are a subset of total coal resources, recoverable coal reserve estimates for a number of regions with large coal resource bases—notably China and the United States—could increase substantially as coal-mining technology improves (IEO 2010) (Table 4.1).

Although coal deposits are widely distributed, 68.7 % of the world coal recoverable reserves are located in four countries: the United States (28.7 % of the total), Russia (19 %), China (13.9 %), and India (7.1 %).

In 2011, the coal deposits are widely distributed in the following manner: the United States (27 %, 1.8 % less than in 2010), Russia (18 %, 1 % less than in 2010), China (13 %, 0.9 % less than in 2010), non-OECD Europe and Eurasia outside of Russia (11 %), Australia/New Zealand (9 %), and India (7.1 %, the same than in 2010). The world consumes much more hard coal than brown coal and the gap is growing continuously.[2] In addition, the preference is naturally for hard coal that is

[2] Most of people have heard about anthracite coal, bituminous coal, and lignite, but not everybody knows the exact difference. Anthracite is also called “hard coal,” bituminous coal “soft coal,” and lignite “brown coal.” These names are a good help in distinguishing coal, but we will here give a short table, which gives the scientific classification in general use (Table 4.2).

Table 4.2 Types of coal

	Class A anthracite coal		Class B bituminous			Class C coal	Class D Sub-bitum's coal brown coal lignite	
Composition	1 %	2 %	1 %	2 %	3 %	Long…. Smoking Flame 30–40 % volatile matter. Very porous coke	1 %	2 %
Carbon	93–95	90–93	83–90	75–90	70–80		60–75	45–65
Hydrogen	2–4	4–4.5	4.5–5	4.5–5.5	4.5–6		6–6.5	6–6.8
Oxygen and Nitrogen	3-5	3–5.5	5.5–12	6–15	18–20		20–30	30–45
Calorific value	8,000–8,330 calories	8,330–8,600 calories	8,400–8,900 calories	7,700–8,800 calories	6,600–7,800 calories		5,500–7,200 calories	4,000–6,000 calories

Source: http://www.workerseducation.org/coal/coal_1-4.html easier (and cheaper) to recover. Without a corresponding increase in hard coal reserves, which will most likely be more difficult and more expensive to exploit than hard coal deposits in the past, the world is going to run out of high-quality coal much earlier than it will of lower quality coal.

4.3 Low Coal Technologies

The EU is leading the world in responding to climate change by adopting targets and putting a price on coal through the Emissions Trading Scheme, as well as creating a truly internal energy market. The EU must act with equal determination and ambition on a policy for the use of low coal technologies for the generation of electricity. These are the conditions to catalyze a new industrial revolution. In a coal-constrained world, the mastery of technology will increasingly determine prosperity and competitiveness. If the EU falls behind in the intensifying global race to win low coal technology markets, the EU may need to rely on imported technologies to meet established targets, missing huge commercial opportunities for EU businesses (COM 2007).

The transition to a low coal economy will take decades and touch every sector of the economy, but the EU cannot afford to delay action in this important field. Decisions taken over the next 10–15 years will have profound consequences for energy security, for climate change and for growth and jobs in Europe, among others. The cost of action may be higher, but the price of inactivity will be much higher.[3] As an illustration of the scale of the problem, the Stern Review on the Economics of Climate Change report (UK HM Treasury) estimates that "the cost of action could be limited to around 1 % of global gross domestic product per year, while inaction could result in losing between 5 % and 20 % of global gross domestic product annually."

The vision is of a Europe with a thriving and sustainable economy, with world leadership in a diverse portfolio of clean, efficient, and low coal technologies as a motor for prosperity and a key contributor to growth and jobs, despite the current economic crisis the EU is facing since 2007, particularly in countries such as Greece, Italy, Spain, and Portugal. Low coal technologies in general remain expensive and face market penetration obstacles. Energy efficient technologies tend to have high upfront costs, which deter market take-up. A twin-track approach is therefore needed: (a) Reinforced research to lower costs and improve performance; and (b) Proactive support measures to create business opportunities, stimulate market

[3] Power plants with carbon capture will be more expensive to build and operate than power plants that do not capture CO_2, but will have lower CO_2 emission than other types of coal-fired power plants.

development, and address the non-technological barriers that discourage innovation and the market deployment of efficient and low coal technologies (COM 2007).

To achieve the 2050 vision and targets toward complete decarbonization in the energy balance, the EU needs to develop a new generation of low coal technologies through major breakthroughs. Even if some of these technologies will have little impact in the coming years, the EU should continue supporting these activities in order to ensure that they will be available as early as possible.

EU Member States have to deliver their contributions to the 20 % in CO_2 reduction targets agreed in 2020, and put their energy systems on a pathway toward decarbonization by 2050. A dedicated and substantial effort on energy technology can help achieve the targets in a way that maximizes the benefits for EU Member States and limits the costs. The actions of the EU Member States should aim at increasing investment and provide clear market signals to reduce the risks and stimulate industry to develop more sustainable technologies. In a world in which energy demand is still increasing and Europe's share of greenhouse emissions is set to fall from 15 % to 10 % by 2030, a global effort and cooperation are needed to address the global challenges. The EU needs to take international cooperation on energy technology to a new level, in the same way as the Emissions Trade Scheme is being used to catalyze the development of a global cap and trade system for carbon. If the EU is unable to create a global market appetite for low coal technologies and ensure their widespread take-up, then achieving the EU's ambitious goals could result in much wasted effort and resources—a high cost strategy for business and society (COM 2007).

What the EU could do to foster international cooperation in the use of low coal technologies in the future? The following are some of the actions that should be promoted:

- Low coal technology research;
- Setting international standards to stimulate the global development, commercialization, deployment, and access to low coal technologies;
- Networking energy technology centers;
- Setting up large-scale demonstration projects on low coal technologies with the highest potential in those countries with the possibilities to implement them;
- Increasing the use of innovative financing mechanisms, such as the Global Energy Efficiency and Renewable Energy Fund;
- Reinforcing the use of the Kyoto Protocol mechanisms, notably the Clean Development Mechanism for investments in emissions reduction projects, if the post-2012 international agreement on further CO_2 reductions is reached (Morales Pedraza 2008).

4.4 Coal Production

At present, the prospects for European coal production are quite clear. Indigenous hard coal production in the EU will continue to decline for several reasons. Hard coal has been intensively mined in Europe for more than a century and the easier accessible deposits of good quality of hard coal have already been exploited. As hard coal in Europe can be recovered mainly from underground deposits,[4] European coal miners are forced to go for deeper and more difficult to recover reserves of the poor quality of hard coal, which increases costs. For this reason, European indigenous hard coal production is two to three times more expensive than imported hard coal, forcing some EU countries to cease national hard coal production. In countries where hard coal production still exists (mainly for socio-economic reasons), it is heavily subsidized,[5] but the subsidies are gradually being phased out, following EC instructions. The expiry of the European Coal and Steel Community in 2002 has accelerated this process (Kavalov and Peteves 2007).

The case of lignite is different. The EU has greater reserves of lignite than of hard coal and reserves are available and exploited in a larger number of countries. Lignite in Europe is typically mined open-cut, which keeps extraction costs low. European lignite production is generally cost competitive with imports of hard coal without subsidies. Consequently, lignite recovery in the EU will most likely survive, unlike hard coal production, in the coming decades. Lignite represents an important energy source for the EU, as it helps to reduce its energy import dependence. Nevertheless, the reserves–production ratios (under current economic and regulatory conditions) in the major EU lignite producers are rather low, e.g., Germany—33 years and Greece—54 years (Kavalov and Peteves 2007).

Three largest countries in the former Soviet Union (Russia, Kazakhstan, and Ukraine) hold almost 20 % of the world hard coal reserves and 30 % of brown coal reserves in the 2000s. Even so, they are not major players in the world coal market. After the substantial economic changes in the 1990s, Ukraine has become a net importer of coal, Russia has restarted exports just recently and only Kazakhstan has managed to keep a noticeable presence on the world coal market, but with a gradually declining volume and share (Table 4.3).

The European region produced in 2012 a total of 773.6 million short tons of coal. China by far is the major coal producers with 4,025.4 million short tons, followed by the USA with 1,016.5 million short tons and by India with 649.6 million short tons.

[4] With the exception of the UK, where hard coal is recovered via surface mining.

[5] With the exception of the UK, whose indigenous hard coal production is generally competitive to imported hard coal.

Table 4.3 Production of coal by country and year (Million tons)

Country	2005	2006	2007	2008	2009	2010	2011	Share (%)	Reserve life (years)
China	2,349.5	2,528.6	2,691.6	2,802.0	2,973.0	3,235.0	3,520.0	49.5	35
United States	1,026.5	1,054.8	1,040.2	1,063.0	975.2	983.7	992.8	14.1	239
India	428.4	449.2	478.4	515.9	556.0	573.8	588.5	5.6	103
Australia	375.4	382.2	392.7	399.2	413.2	424.0	415.5	5.8	184
Russia	298.3	309.9	313.5	328.6	301.3	321.6	333.5	4.0	471
Indonesia	152.7	193.8	216.9	240.2	256.2	275.2	324.9	5.1	17
South Africa	244.4	244.8	247.7	252.6	250.6	254.3	255.1	3.6	118
Germany	202.8	197.1	201.9	192.4	183.7	182.3	188.6	1.1	216
Poland	159.5	156.1	145.9	144.0	135.2	133.2	139.2	1.4	41
Kazakhstan	86.6	96.2	97.8	111.1	100.9	110.9	115.9	1.5	290

Source: Wikipedia

4.5 Increase in the Consumption of Coal

The development of novel and more environmentally-friendly coal technologies (the so-called "Clean Coal Technologies"), have changed somehow the perception that coal is a "dirty and the old-fashioned fuel for use in poorer countries" for electricity generation. Designed to enhance both the efficiency and the environmental acceptability of coal extraction, preparation, and use, these technologies are believed capable of bringing coal back into fashion. This is because the environmental concerns with coal are associated with the ways in which coal is used rather than with coal itself. Although some clean coal technologies are still at the research and development stage, they are enjoying growing interest worldwide, particularly in the EU.

With the use of new coal technologies, the world consumption of coal is expected to increase from 25 % to 28 % in 2030, an increase of 3 % in the next 17 years. However, and according to IEO (2010), coal consumption within OECD countries will decline almost 10 % in the next 15 years, decreasing from 47.9 quadrillion Btu in 2007 to 43.1 quadrillion Btu in 2010, and it is expected to remain virtually flat after 2025. After that year, OECD coal consumption is expected to increase to 48.3 quadrillion Btu in 2035 (an increase of 12 % with respect 2010), largely because of an increase in natural gas prices that allows coal—in the absence of policies or regulations to limit its use—to compete economically. Almost all of the OECD increase in coal consumption after 2025 is attributable to North America.

In the case of OECD Europe, according to the IEO (2013) report, total coal consumption in the countries is expected to decline from 12.2 quadrillion Btu in 2010 (27 % of the OECD total) to 10.7 quadrillion Btu in 2040 (25 % of the worldwide total). Although all nations in the region consume coal, 65 % of OECD Europe's 2010 total coal consumption was concentrated in Germany, Poland, Turkey, and the UK, with Germany alone consuming 26 % of the regional total. The electric power sector accounted for 67 % of the region's total coal consumption in 2010, and most of the rest was consumed in the industrial sector. Electric power demand for coal is expected to decline steadily in the region and will drive the downward trend in the region's overall coal consumption.

The Industrial Emissions Directive (IED), agreed to by the European Council of Ministers and the European Parliament in 2010, as well as regional climate change policy goals, will drive the decline. The implementation of the IED requires the use of best available technology for reduction of sulfur dioxide and nitrogen oxides, among other pollutants, and is likely to trigger retirements of some coal-fired power plants, especially in the four leading coal-consuming countries after 2016. Undoubtedly, the scale of the retirements outweighs the scale of new coal-fired capacity additions in Germany, Turkey, Poland, the Netherlands, and Italy, where new coal-fired capacity is needed to fill the supply gaps produced as a result of the shutdown of all nuclear power plants in Germany in 2022, to replace less competitive power plants, such as oil-to-coal conversions and replacements in Italy, and to supply more power to meet demand growth especially in Turkey (World Resource Institute 2012).

Total installed coal-fired generating capacity in OECD Europe is expected to decline from 204 GW in 2010 to 169 GW in 2040 (a reduction of 17.2 %), and coal's share of total electricity generation is expected to decline from 24 % in 2010 to 15 % in 2040; this represents a reduction of 9 %. Coal consumption in the OECD Europe industrial sector is expected to remain largely flat. The effects of energy efficiency measures in OECD European countries, such as moving away from less efficient processes like open-hearth steelmaking, are more than offset by the effect of the increase in industrial output.

It is important to highlight that over the period 2007–2035, slight increases in coal consumption in North America and OECD Asia[6] are, to a large extent, offset by declines in OECD Europe. In this last region, the use of coal will concentrate in the future mainly in the electricity generation, but this increase is expected to be, however, more slowly than the natural gas and oil.

[6] This increase will take place mainly in areas where the extraction costs of coal are smaller, like in Australia, China, India, Indonesia, North America, and Latin America.

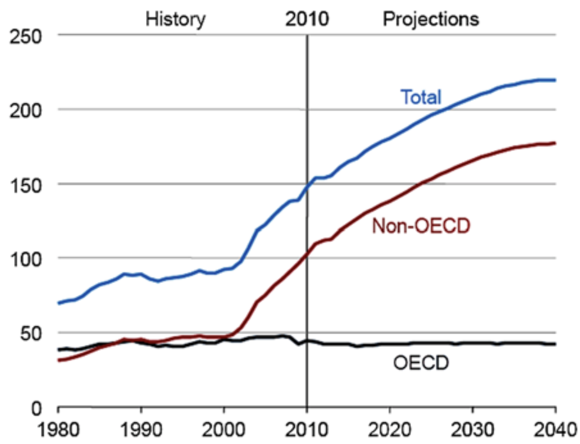


Fig. 4.1 World coal consumption by region during the period 1980–2040 (Quadrillion Btu). *Source:* IEO (2013)

The worldwide coal consumption increased by 35 % between 2002 and 2007, largely because of the growth in the use of coal in China. Between 2007 and 2009, however, coal consumption declined by 3 %. Coal use was strongly affected by the global recession, and consumption contracted strongly in 2009, in large part because coal is widely used in the production of heavy commodities (such as steel and pig iron), which were particularly hard hit in the recession that are affecting several countries in different regions, mainly in the EU and the USA (Fig. 4.1).

According to the IEO (2011), in the absence of national policies and/or binding international agreements that would limit or reduce greenhouse gas emissions, world coal consumption is expected to increase from 139 quadrillion Btu to 209 quadrillion Btu in 2008 and 2035, respectively at an average annual rate of 1.5 %. Regional growth rates are uneven, with little growth in coal consumption in OECD nations, but robust growth in non-OECD countries, particularly among the Asian economies. Strong economic growth and large domestic coal reserves in China and India lead to a substantial increase in their coal use for electric power and industrial processes. Installed coal-fired generating capacity in China is expected to nearly double from 2008 to 2035, and coal use in China's industrial sector is expected to grow by 67 %.

Some European countries import more coal to compensate for their own dwindling coal production, by setting some of the projected decline in coal imports to other European nations. For example, Germany's planned closure of its remaining hard coal mines by 2018 (which, as a result of the recent government announcement concerning the closure of the country's remaining nuclear power plants, might not occur) results in an increase in imports of coal for electricity generation. Germany's coal imports level of overtime, because no incremental coal-fired capacity is expected to be built. For Turkey, growth of electricity demand and steel industry output offsets some of the decline in Europe's coal uses through 2035. Turkey has

Table 4.4 Consumption of coal by country and year (Million short tons)

Country	2008	2009	2010	2011	Share (%)
China	2,966	3,188	3,695	4,053	50.7
United States	1,121	997	1,048	1,003	12.5
India	641	705	722	788	9.9
Russia	250	204	256	262	3.3
Germany	268	248	256	256	3.3
South Africa	215	204	206	210	2.6
Japan	204	181	206	202	2.5
Poland	149	151	149	162	2.0
World Total	7,327	7,318	7,994	N/A	100

Source: Wikipedia

accounted for most of the growth in steam coal trade to the region over the past decade, with Russia is supplying the bulk of the coal. Italy's conversion of power plants from oil to coal, including the recently commissioned Torrevaldaliga North plant, also offsets some of the decline in Europe's coal demand, according to IEO (2011). The Torrevaldaliga North plant alone could raise Italy's steam coal imports by 9 million tons per year in 2015.

The use of coal worldwide increased in the period 1971–2030 and generated from less than 5,000 billion kWh in 1971 to around 15,000 billion kWh in 2010; this means an increase of around 200 %. During the period 2010–2030, it is expected that coal generated from 15,000 billion kWh to around 20,000 billion kWh; this means a further increase of around 33 %. In 2030, coal is expected to continue to be the main type of fuel used worldwide for the generation of electricity followed by natural gas.

From Table 4.4, the following can be stated: The major consumers of coal in 2011 were China with 4,053 million short tons (50.7 % of the world total), followed by the USA with 1,003 million short tons (12.5 %), India with 788 million short tons (9.9 %), and Russia with 262 million short tons (3.3 %).

4.6 Import of Coal

According to the IEO (2013) report, coal becomes a less significant component of the region's fuel mix for electricity generation, with most European countries placing greater emphasis on renewable energy and natural gas for electricity generation. Other factors affecting the outlook for coal imports to Europe include environmental initiatives that further reduce emissions of sulfur dioxide, nitrogen oxide, and particulates, leading to some significant retirements of coal-fired generating capacity; the phase out of domestic hard coal production in Germany by 2018; and Turkey's plans to increase its coal-fired generating capacity substantially (Hitchin 2010). Restrictions on carbon dioxide emissions, primarily based on the EU's Emissions Trading System, are another potential issue for European coal consumption and imports. Thus far, however, carbon dioxide emission prices have been relatively low and have not significantly affected Europe's coal demand (Economist 2013).

Germany, the United Kingdom, Turkey, Italy, and Spain accounted for more than 60 % of Europe's total seaborne coal imports in 2011. New coal-fired generating capacity is expected to contribute to rising imports through 2015, especially in Turkey and Germany. Turkey has plans to add substantial amounts of new coal-fired generating capacity, much of which will burn domestic lignite coal; however, approximately 10 GW of post-2010 additions, including both planned and under construction, is likely to be fuelled by imports (IHS CERA 2012). Germany is also adding new coal-fired generating capacity, with 8 GW to be fuelled by imported coal and 3 GW by domestic lignite (2.1 GW of new lignite capacity became operational in 2012) (RWE AG 2013). The new coal-import-based capacity additions, combined with the phasing out of its hard coal production by 2018, are factors that support increasing coal imports in Germany through 2020. Other coal-import-based capacity additions are either planned or under construction in Italy, the Netherlands, and Morocco.

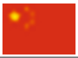
In the longer term, the impact of new capacity on coal imports is diminished by the retirement of existing electric generating units. The emission reduction requirements for coal-fired generating capacity established by the EU's Large Combustion Plant Directive (LCPD) lead to some planned retirements of coal-fired capacity, particularly in the UK, where approximately 8 GW of capacity will be shuttered.

According to the IEO (2010), total coal imports by the European region in 2035 are expected to be about the same as in 2008. Europe's demand for lower sulfur coal (from South America and Eurasia) will be tempered over time by the gradual addition of flue gas desulfurization equipment at existing coal-fired power plants.

According to the Energy Markets in the EU, the list of the top six countries which exported to the EU hard coal in 2011 were Indonesia, South Africa, USA, Australia, Colombia, and Russia, although long-term developments have shown a changing picture. Since 1990, imports from Colombia, the second largest exporter of hard coal to the EU, have been increasing.

From Table 4.5, the following can be stated: The major importers of coal in 2010 were Japan with 206.7 million of short tons (17.5 % of the world total), followed by

Table 4.5 Imports of coal by country and year (Million short tons)

Country	2006	2007	2008	2009	2010	Share (%)	2011
 Japan	199.7	209.0	206.0	182.1	206.7	17.5	194.1
 China	42.0	56.2	44.5	151.9	195.1	16.6	192.5
 Republic of Korea	84.1	94.1	107.1	109.9	125.8	10.7	138.2
 India	52.7	29.6	70.9	76.7	101.6	8.6	86.8
 Taiwan (China)	69.1	72.5	70.9	64.6	71.1	6.0	73.5
 Germany	50.6	56.2	55.7	45.9	55.1	4.7	49.3
 Turkey	22.9	25.8	21.7	22.7	30.0	2.5	26.4
 United Kingdom	56.8	48.9	49.2	42.2	29.3	2.5	35.9
 Italy	27.9	28.0	27.9	20.9	23.7	1.9	25.7
 Netherlands	25.7	29.3	23.5	22.1	22.8	1.9	27.2
 Russia	28.8	26.3	34.6	26.8	21.8	1.9	27.3
 France	24.1	22.1	24.9	18.3	20.8	1.8	17.3
 United States	40.3	38.8	37.8	23.1	20.6	1.8	14.5
Total	991.8	1,056.5	1,063.2	1,039.8	1,178.1	100	–

Source: Wikipedia and EIA (2011)

China with 195.1 million short tons (16.6 %), the Republic of Korea with 125.8 million short tons (10.7 %) and India with 101.6 million short tons (8.6 %). Seven European countries are included in the above table as main importers of coal.

4.7 Export of Coal

The major exporters of coal in 2010 were Australia with 328.1 million short tons (27.1 % of world total), followed by Indonesia with 316.2 million short tons (26.1 %), Russia with 122.1 million short tons (10.1 %) and the USA in 83.2 million short tons (6.9 %) (see Table 4.6).

Table 4.6 Exports of coal by country and year (Million short tons)

Country	2005	2006	2007	2008	2009	2010	Share (%)	2011
Australia	255.0	255.0	268.5	278.0	288.5	328.1	27.1	319.6
Indonesia	142.0	192.2	221.9	228.2	261.4	316.2	26.1	341.1
Russia	98.6	103.4	112.2	115.4	130.9	122.1	10.1	138.6
United States	51.7	51.2	60.6	83.5	60.4	83.2	6.9	108.2
South Africa	78.8	75.8	72.6	68.2	73.8	76.7	6.3	79
Colombia	59.2	68.3	74.5	74.7	75.7	76.4	6.3	89
Canada	31.2	31.2	33.4	36.5	31.9	36.9	3.0	37.6
Kazakhstan	28.3	30.5	32.8	47.6	33.0	36.3	3.0	37.6
Vietnam	19.8	23.5	35.1	21.3	28.2	24.7	2.0	26.9
China	93.1	85.6	75.4	68.8	25.2	22.7	1.9	18.2
Mongolia	2.3	2.5	3.4	4.4	7.7	18.3	1.5	24.4
Poland	26.5	25.4	20.1	16.1	14.6	18.1	1.5	14.8
Total	936.0	1,000.6	1,073.4	1,087.3	1,090.8	1,212.8	100	2,208.8

Source: Wikipedia and EIA (2011)

4.8 The CO_2 Emissions

An important element that should keep in mind by energy authorities during the process of defining the structure of the energy balance of any country in the future, is the negative effect that the use of coal has for man and the environment. This is particularly true, if more countries have to use worse coal quality in the energy sector in the coming years, particularly for electricity generation. While more and big coalfield are exploiting the content of ashes and humidity will increase. The increment of ashes because of the burning of coal reduces the efficiency of the generating units, causes premature deterioration of some of the equipment used in the industry, increasing the maintenance costs of such equipment, and has negative ecological and socioeconomic effects.

The CO_2 emissions, as well as other harmful substances associated with the burning of coal, will not be able to be eliminated totally, even with the use of new technologies developed to reduce the mentioned negative effects. This situation could represent an important limitation in the participation of coal in the European and world energy balance in the coming decades.

In only one century, countries have discharged to the atmosphere as much CO_2 as other gases of the greenhouse effect that its concentration exceeds any previous level since the conquered of fire by the human being half millions of years ago. All the available models predict that if countries do not curb drastically greenhouse gas emissions to the atmosphere, a catastrophe could occur.

A study made by French specialist's points out that in Europe the growths in the consumption of coal will be above 40 % for the coming years, and this increase would add, in an important manner, the CO_2 emission to the atmosphere. However, to avoid that this could happen the European governments are taking measures to reduce the CO_2 emission in other activities. This foreseeable situation should be in the mind of politicians and executives when deciding the position to be given to coal in the world energy balance in the coming decades, particularly in the case of the European region.

It has been demonstrated that the main factor that contributes to the heating of the atmosphere is the CO_2 emission. Only the burn of fossil fuels that takes place every year launched into the atmosphere around 20,000 million tons of this gas. An increment, as foresee in the use of coal in Europe and in other developed countries as an energy primary source as well, would increase significantly the quantity of CO_2 that would be emitted toward the atmosphere, even with the use of new technologies more efficient and less polluting. The emission of CO_2 can reach 9,000 million of tons annually, mainly due to electricity generation. Also, the coal-fired powers plants produced acid rain, smog, breathing illnesses, mercury contamination, and contribute in a great extend to the emissions of gas with the greenhouse effect.

In general, the CO_2 emissions in the European countries and other countries of the OECD that signed the Kyoto Protocol could reach 12,500 million of tons in the 2010s, that is to say about 2,800 million (29 %) above fixed objective. It is important to highlight that Russia and other countries of Central and Eastern Europe are in a different situation, since their CO_2 emissions are below of the assumed commitments.

The results of an expert study on low-carbon coal-fired power generation in Europe illustrated what can be achieved when additional measures are applied to Europe's coal-fired power plants. The adoption of these measures has the potential to reduce its CO_2 emissions in 2020 by almost 13 %, if these measures are fully implemented. This corresponds to a total reduction potential of 104 million tons of CO_2. The main conclusions regarding these measures are as follows:

- Carbon capture and storage has a great potential for reducing CO_2 emissions, but at a considerable cost (the highest cost of all the measures considered);
- Biomass cofiring is expensive and cannot be recommended as a structural solution for the sector. However, it may be an option if sources of inexpensive (waste) biofuel are available and it is aided by subsidy mechanisms (e.g., green certificates) and specific market instruments (e.g., carbon credits);
- Combined heat and power is interesting when applicable, and can be achieved at negative cost for all segments;

- Local heat demand has to be seriously considered when investigating suitable locations for new power plant constructions;
- A shift from subcritical to supercritical units has the largest abatement potential and can be achieved at negative cost for all segments.

Finally, it is important to consider the human health factor in the use of coal for the generation of electricity. Coal-fired power plants cost the EU up to €42.8 billion a year in health costs associated with coal-fired power plants, according to a recent study entitled “The Unpaid Health Bill: How coal power plants make us sick”, published by the Health and Environment Alliance (HEAL). The study includes the figures for mortality increase to 23,300 premature deaths, or 250,600 life years lost, while the total costs are up to €54.7 billion annually when emissions from coal power plants in Croatia, Serbia, and Turkey are included.

The use of coal in power generation in Europe is on the rise again and that there are about 50 new coal power plants currently in the pipeline. “But the continued reliance on coal comes with a price that decision makers are hardly aware of: the unpaid health bill,” the report notes. “This health bill is paid by individuals, national health care budgets, and by the economy at large due to productivity losses.” The study added that coal power generation is also a major contributor to climate change. “Coal is the most carbon-intensive energy source in the EU, contributing approximately 20 % of total greenhouse gas emissions.” Building new coal power plants would work against efforts to tackle chronic disease, the study said, while creating substantial costs for public health and locking in hazardous emissions for decades.

The external costs to health from coal power generation have been missing from the debate on the future of Europe’s energy mix. These costs should be taken into consideration in all future energy investment decisions.

4.9 Participation of Coal in Electricity Generation

One of the main uses of coal as an energy primary source is for electricity generation. Coal is projected to provide an important share of the total energy used for electricity generation worldwide in 2030. The coal’s energy’s share, it is expected to increase, at world level, up to 43 % in 2035, a very modest increase from the level reached in 2010s.

From Fig. 4.2, the following can be stated: The consumption of coal in OECD Europe is expected to decrease from a little less than 20 quadrillion BTU in 1980 to a little more than 11 quadrillion Btu in 2040; this represents a reduction of approximately 45 % for the whole period.

In absolute terms, coal-fired electricity production is higher in the USA (2,129 billion kWh) and China (1,957 billion kWh). These two countries accounted for 58 % of global coal-based electricity production. Other countries with significant coal-fired electricity production include India, Germany, Japan, South Africa, Australia, Russia, Poland, the Republic of Korea, the UK, and Canada. It is important

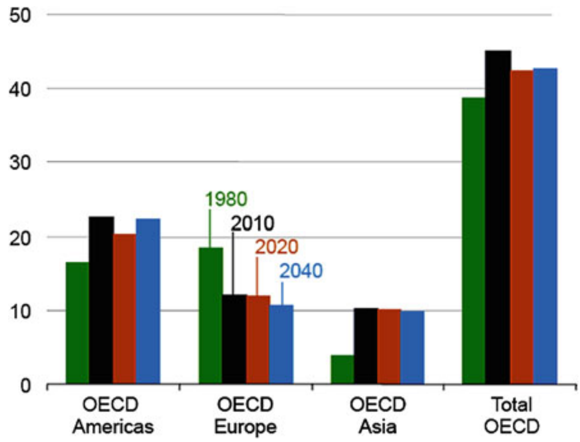


Fig. 4.2 OECD coal consumption by region in 1980, 2010, 2020, and 2040 (Quadrillion Btu). *Source:* IEO (2013)

to highlight that in most countries, the vast majority of coal-fired electricity production is in electricity only plants. However, in Russia, Denmark, Norway, Poland, and Sweden, all electricity production from coal is coming from combined heat and power plants. The Slovak Republic and Finland also have more than half of coal-fired electricity generation from CHP plants (Taylor et al. 2008).

From Table 4.7, the following can be stated: The use of coal for electricity generation at world level produced in 2010 a total of 8.1 trillion of kWh, which represent 40 % of the total electricity generated in that year. In 2015, it is expected that coal will produce, at world level, around 9.2 trillion kWh of electricity, an increase of 13.5 % respect to 2010; in 2020, the use of coal for generation of electricity, at world level, is expected to produce a total of 10.1 trillion kWh, an increase of 9.8 % respect to 2015; in 2025, a total of 11.3 trillion kWh will be produced using coal as fuel, an increase of 11.9 % respect to 2020; in 2030, a total of 12.3 trillion kWh will be produced using coal as fuel, an increase of 8.8 % respect to 2025; in 2035, a total of 13.2 trillion kWh will be produced, an increase of 7.3 % respect to 2030; and in 2040, a total of 13.9 trillion kWh will be produced, an increase of 5.3 % respect to 2035. In average annual percent change for the whole period 2010–2040 will be 1.8 %, the fourth larger increase. Considering only OECD countries, the average annual percent change for the whole period 2010–2040 will be −0.2 %, one of the lowest foreseeable increases for the whole period, and in non-OECD countries 2.9 %, one of the lowest increases for the whole period.

Several hundreds of coal-fired power plants have been built in the EU, but several of them need to be replaced or refurnish in the coming years, if coal is going to continue to be used for the generation of electricity in the future. Plans to replace or refurbish existing coal-fired capacity in a number of countries in OECD Europe are a clear indication that coal will continue to play an important role in the region’s overall energy mix during the coming years.

The worldwide mix of primary fuels used to generate electricity has changed a great deal over the past four decades. Coal continues to be the fuel most widely used in electricity generation, although generation from nuclear power increased

Table 4.7 OECD and non-OECD net electricity generation by energy source during the period 2008–2035 (Trillion kWh)

Region	2010	2015	2020	2025	2030	2035	2040	Average annual percent change, 2010–2040
OECD								
Liquids	0.3	0.3	0.2	0.2	0.2	0.2	0.2	−1.1
Natural gas	2.4	2.7	2.9	3.1	3.5	3.9	4.3	2.0
Coal	3.5	3.3	3.3	3.3	3.3	3.3	3.3	−0.2
Nuclear	2.2	2.1	2.4	2.6	2.7	2.7	2.7	0.7
Renewables	1.9	2.4	2.8	3.0	3.2	3.4	3.7	2.2
Total OECD	10.3	10.8	11.5	12.2	12.9	13.5	14.2	1.1
Non-OECD								
Liquids	0.6	0.6	0.6	0.6	0.5	0.5	0.5	−0.9
Natural gas	2.1	2.3	2.6	3.1	3.7	4.4	5.0	3.0
Coal	4.6	5.9	6.9	8.0	9.0	9.9	10.6	2.9
Nuclear	0.4	0.8	1.3	1.7	2.1	2.5	2.8	6.3
Renewables	2.2	2.9	3.7	4.2	4.7	5.3	5.9	3.3
Total non-OECD	9.9	12.5	15.1	17.6	20.1	22.6	24.8	3.1
World								
Liquids	0.9	0.9	0.8	0.8	0.7	0.7	0.7	−1.0
Natural gas	4.5	5.0	5.5	6.2	7.2	8.3	9.4	2.5
Coal	8.1	9.2	10.1	11.3	12.3	13.2	13.9	1.8
Nuclear	2.6	2.9	3.6	4.3	4.8	5.1	5.5	2.5
Renewables	4.2	5.3	6.5	7.2	7.9	8.8	9.6	2.8
Total World	20.2	23.3	26.6	29.8	33.0	36.2	39.0	2.2

Source: IEO (2013)

rapidly from the 1970s through the 1980s, and natural gas-fired generation grew rapidly in the 1980, 1990, and 2000s. The use of oil for electricity generation has declined since the late 1970s, when oil prices rose sharply (IEA 2012). Coal accounted for 24 % of OECD Europe's net electricity generation in 2010, but concerns about the contribution of carbon dioxide emissions to climate change is expected to reduce that share during the period 2010–2014. The coal share of OECD Europe's electricity generation declines to 15 % in 2040, and the region's total coal-fired generation in 2040 is nearly 14 % percent lower than in 2010. In the IEO (2013) report, electricity generation from coal in OECD Europe is expected to decline by 0.5 % per year from 2010 to 2040.

Although total installed coal-fired electricity generating capacity in OECD Europe is expected to decline from 200 GW in 2007 to 177 GW in 2035, according to IEO (2010), coal will remain an important component of Europe's power generation. Plans to retire aging and inefficient generating capacity will, to some extent, be offset by new coal-fired capacity to be built. Currently, between 15 GW and 20 GW of new coal-fired generating capacity is under construction in OECD Europe, with projects in Germany representing more than one-half of the new construction (PiE's New Plant Tracker 2010). There are also plans to refurbish some existing coal-fired capacity to make it more efficient.

In addition to some recent new coal-fired capacity built in Turkey, electricity producers in Germany, Spain, France, Italy, Poland, the Czech Republic, and Slovakia have revealed plans to upgrade or replace existing coal-fired generating facilities over the next two decades. Power producers in Germany plan to build nearly 11 GWe of new coal-fired generating capacity by 2012–2013, primarily to replace existing and less efficient coal-fired capacity. A key incentive for the new coal-fired generating capacity builds in Germany is a provision guaranteeing carbon dioxide emission rights for the new capacity during the first 14 years of its operation (IEO 2007) and the closure of all nuclear power plants by 2022 decided by the government after the Fukushima nuclear accident occurred in March 2011 in Japan.

All the above facts suggest that coal could have a future in the European energy mix, but in a smaller scale than before, particularly in electricity generation, undergoing a real renaissance and becoming once again one of the fossil fuel options at least during the coming years, but using new low coal technologies.

The recent growth in coal consumption has not been matched by a corresponding development of the supply base, unlike with oil and natural gas. Consequently, the coal radio-production ratio, which had remained constant above 200 years for several decades, plunged from 227 years in 2000 to only 155 years in 2005 and to 109 years in 2010. However, the use of coal in Europe in the near future should take into account that “coal is the fossil fuel with the highest carbon intensity, having a carbon content between 50 % and 98 %. Other coal components are hydrogen (between 3 % and 13 %), oxygen, and small amounts of nitrogen, sulfur and other elements. Coal also contains different proportions of water and inorganic matter that remains as residue (ash) upon burning. These large variations in coal composition determine the type of coal available for different applications” (see Fig. 4.3) (Kavalov and Peteves 2007).

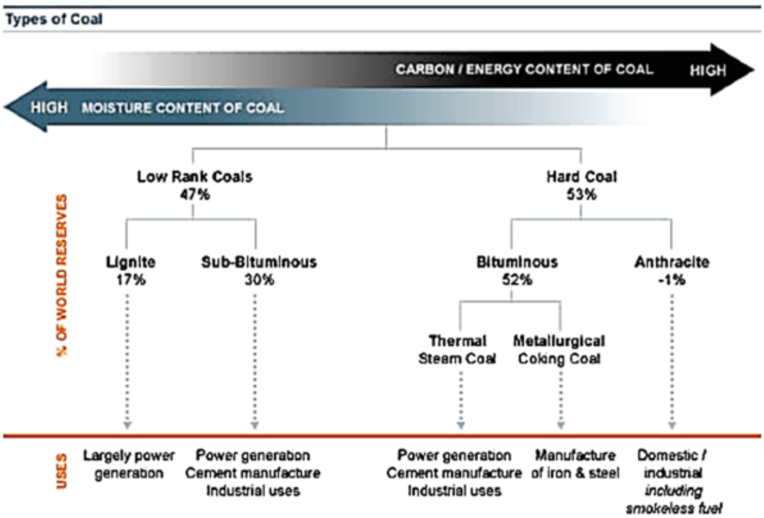


Fig. 4.3 Types of coal depending on carbon/energy and moisture content, with their shares in total coal reserves and typical applications. *Source:* Kavalov and Peteves (2007)

The electricity generation sector is the main consumer of coal worldwide. This is not surprising as electricity and heat generation account for more than half of global coal demand. The metallurgical sector comes next, mainly for the production of pig iron and to a lesser extent steel. The top ten countries using coal/peat for electricity generation are included in Table 4.3.

4.10 Investment in the Coal Sector

Total investment in the coal supply chain over the next three decades will be much less than in previous periods, at around US$400 billion, or US$13 billion per year, despite the fact that coal is expected to account for 24 % of the world's primary energy supply in 2030. This reflects the higher labor intensity of the coal sector, the much lower cost of extracting coal compared with oil and natural gas and the expectation that increasing market competition and consolidation in the main producing countries will result in lower unit capital costs. Mining will account for the bulk of investment requirements (88 %) in the coal sector in the coming years. China alone will absorb 34 % of world coal investment, followed by the OECD countries—notably the USA and Australia. The key uncertainty facing coal investment over the coming years remains developments in market conditions, notably environmental policies. Global investment in the electricity sector is expected to be US$9.8 trillion, 60 % of which will be outside OECD countries.

Market liberalization has created new challenges and uncertainties in OECD countries. Concerns exist about the investment adequacy as markets are adapting to the new conditions after the economic crisis affected the EU. Policy makers will need to address these concerns by setting up appropriate market frameworks that send the right market signals to investors so that they provide adequate investment when and where it is needed. Uncertainty about future environmental legislation requiring power plants to reduce their emissions poses additional risks to investors.

4.11 Energy Efficiency

The efficiencies of coal-fired power plants depend on a range of factors, including the technology employed, the type and quality of coal used and the operating conditions and practices. Denmark has some of the most efficient coal-fired power plants in the world, including a new generation of pulverized coal supercritical plants that were introduced in the 1990s (IEA 2007). Other countries in the EU have been replacing old coal-fired generation plants during the past few years in order to reduce the CO_2 emissions.

Improvements continue to be made in conventional coal power plant design and new combustion technologies are being developed. These allow more electricity to be produced from less coal known as improving the thermal efficiency of the power plant. Efficiency gains in electricity generation from coal-fired power plants will play a crucial part in reducing CO_2 emissions at a global level. Efficiency improvements include the most cost-effective and shortest lead time actions for reducing emissions from coal-fired power generation. Not only do higher efficiency coal-fired power plants emit less carbon dioxide per megawatt produced, they are also more suited to retrofitting with CO_2 capture systems.

Improving the efficiency of pulverized coal-fired power plants has been the focus of considerable efforts by the coal industry. There is huge scope for achieving significant efficiency improvements as the existing fleet of power plants are replaced over the next 10–20 years with new, higher efficiency supercritical and ultra-supercritical plants and through the wider use of Integrated Gasification Combined Cycle (IGCC) systems for power generation. A one percentage point improvement in the efficiency of a conventional pulverized coal combustion plant results in a 2–3 % reduction in CO_2 emissions.

Undoubtedly, increase in energy efficiency is one of the priorities of the EU energy sector in the coming years.

4.11.1 Energy Efficiency Measures Adopted in the South East Subregion

According to Hooper and Medvedev (2008), there are three sources of energy efficiency that were adopted within the European region. These are the following: First, more advanced emerging economies has experienced substantial improvements in energy efficiency (EBRD 2006), partly as higher prices have driven substitution and investment toward less energy-intensive processes and partly from increased awareness of the opportunities and the implementation of energy efficiency measures introduced through regulatory and policy reform.

Second, the development and implementation of robust collection mechanisms at the supply level is expected to reduce nontechnical losses from relatively high current levels measured on a regional basis. Investment in transmission and distribution networks and interconnector capacity is expected to reduce technical losses. The most efficient countries in the region in terms of distribution losses of electricity are Greece and Slovenia with 8 % and 4 % of distribution losses respectively. In a sharp contrast to these two countries, Albania is losing more than 30 % of its domestically supplied electricity due to inefficient transmission and distribution networks. For the remainder of the region the percentage of electrical losses lies in the interval between 10 % and 20 %.

Third, all countries in the region have experienced an increase in the use of electricity per capita. This factor is considered to be a good alternative to the economic development of a country, since it captures a disposable volume of electricity for all types of economic activity. Turkey and Albania are characterized by a very low domestic supply of electricity per capita, and while per capita consumption of electricity in these two countries is almost three times lower than in the most economically developed countries in the region (Greece and Slovenia), they are net importers of electricity. Thus, the anticipated economic development in Turkey and Albania will increase the demand for electricity and, absent significant investment in generation and transmission capacity, their dependence on imported electricity must also rise, and is expected to converge to the regional and European average. Bosnia and Romania are in a slightly different situation. While domestic supply per capita is also low, they are currently net exporters of electricity. However, it is important to highlight that without the expansion of generation facilities, the export potential of Bosnia and Romania will decrease over time, and at some point they could become net importers of electricity as Slovenia did in 2003.

Summing up, the following can be stated: The subregion as a whole and most countries within it are net importers of electricity, including the biggest producer, Turkey. The largest exporter, are Bulgaria, Bosnia and Romania. Slovenia was a net exporter of electricity for all years except in 2003. It is interesting to note that three of the four net exporters in the region are also nuclear energy producers. Cross-border flows in the subregion and with Central Europe have improved since 2004 as a result of the reconnection of the two UCTE zones.

Finally, it is important to highlight the following: in order to maintain an economic growth in South East European countries, there is an urgent need to increase electricity generation, improve efficiency, and find reliable partners to supply deficient electricity amounts through import. As a result of these considerations, the prime concern of the countries in the subregion is to create the conditions such that domestic and foreign investors are willing to build new generation facilities and rehabilitate the existing ones in order to satisfy the foresee increase in the electricity demand in the coming years.

4.12 Perspective on the Use of Coal for Electricity Generation

However, regarding the perspective in the use of coal for electricity generation within the EU, it is important to highlight the following: The EU approved a proposal to close uncompetitive hard coal mines in the EU that rely on subsidies by 15 October 2014. The coal mines that rely on operating subsidies are located mostly in the Ruhr region in Germany, in Northwest Spain and in the Jiu Valley in Romania. More than 40 % of electricity in Germany is produced from coal, roughly half of which is hard coal. In Romania, coal-produced electricity is also around 40 %, most of which is hard coal. In Spain, the share is around 25 %, also mostly hard coal. Under the approved rules, interim operating aid would only be allowed for coal mines with a closure plan in place, otherwise State aid will not be allowed to continue in the future, as is the case now. “The new rules aim to ensure the orderly closure of coal mines so we have no mines operating solely on the basis of receiving State support," EC spokesman Jonathan Todd told a press briefing in Brussels. "Companies need to be viable without subsidies. This is a question of fairness vis-a-vis competitors that operate without State aid. The subsidies should go increasingly toward supporting the social and environmental costs of doing so," said Joaquin Almunia, the EC's head of competition policy.

Under the EC's proposal, operating subsidies would be reduced over time, with a reduction of at least 33 % every 15 months. If the loss-making mine is not closed by October 15, 2014, the State should be paid back. "Any closure aid would be conditional on the presentation by the national government of a plan of appropriate measures, for example, in the field of energy efficiency, renewable energy or carbon capture and storage, to mitigate the negative environmental impact of aid to coal," Todd said. It was well received by green lobbyists who called for the Council to support the EC's proposal.

According to EC sources, total aid to the hard coal sector has been halved to €2.9 billion in 2008 from €6.4 billion in 2003; this represents a decrease of 45.3 % in 5 years. The amount of aid going toward production has fallen by 62 % to €1,288 billion in the same period. Hard coal production in the EU was 772.275 million short tons in 2011 or 9.1 % of world production. However, the proposal adopted by the EC is not going to be easily approved by EU Member States. Poland representative in the EU parliament has indicated that will block the proposal approved by the EC dealing with the closure of uncompetitive hard coal mines in the EU by 2014, Konrad Szymanski said. "A blocking group of countries should be formed against the proposal," said Szymanski, who is a member of the Committee of the Industry, Research and Energy in the EU parliament within the European Conservatives and Reformists group. According to Szymanski, the UK, Germany, Spain, and Romania are also against the proposal.

Which is the world's current situation in the use of coal for the generation of electricity? From Table 4.8, the following can be stated: Among the 12 world top countries that generate electricity using coal as fuel, four countries are members of the EU. Poland is the EU country with the highest percentage in the use of coal for the generation of electricity.

Finally, it is important to highlight, if you look at trends over the past 5 years, that most of the countries showing the strongest percentage decreases in coal consumption are located in the European region. These countries include Denmark (47.6 % decrease), Finland (34.3 % decrease), Austria (33.8 % decrease), and Sweden (33.2 % decrease). It is expected that this trend will continue in the future considering the whole European region.

Table 4.8 Coal in electricity generation

South Africa: 93 %	Poland: 87 %	PR China: 79 %
Australia: 78 %	Kazakhstan: 75 %	India: 68 %
Israel: 58 %	Czech Rep: 51 %	Morocco: 51 %
Greece: 54 %	USA: 45 %	Germany: 41 %

Source: IEA (2012)

In the following paragraphs, the current situation and perspectives in the production, consumption, reserves, imports, exports and use of natural gas for electricity generation in a selected group of European countries are briefly described.

4.13 Austria

According to the EC Energy Service Directive (Directive 2006/32/EC 2006), Austria is obliged to improve its energy efficiency by 9 % by 2016 compared to the period 2001–2005. In order to implement the requirements of the above mentioned EC Directive, voluntary agreements to support energy savings with energy suppliers, distributors and trading associations, and an agreement between the Federal State and the provincial governments concerning issues on energy efficiency competence were negotiated in 2009. One of the goals of this strategy is to limit Austria's final energy consumption for the year 2020 to the 2005 level.

4.13.1 Production, Consumption and Reserves of Coal

In Austria, fossil fuels are the main energy source: oil is the number one (41 %), followed by natural gas (21 %) and coal (11 %). There are six coal-fired power plants operating in the country with a capacity installed of 7,749 MW. In 2010, the use of coal for the generation of electricity dropped to 6 % and this trend is expected to continue in the coming years.

Austria does not produce coal and lignite since 2005 and has no coal reserves reported. In 2010, Austria's total primary energy consumption amounted to an estimated 33.06 million tons oil equivalent, a 4.5 % increase compared to 2009. Coal accounted for 3.16 million tons oil equivalent or 9.5 % of the total. The consumption of coal during the period 2000–2012 is shown in Fig. 4.4.

According to Fig. 4.4, the consumption of coal in Austria during the period 2000–2012 dropped by 28.6 %. The reduction of the consumption of coal from 2011 to 2012 was 23.1 %. The production of electricity using coal as fuel represents, in 2012, only 0.1 % of the total. It is expected that the participation of coal in the energy mix of the country will continue to decrease during the coming years.

According to the Austrian Energy Agency report (2009), the reduction in the use of coal for electricity generation was due to the obligation to add more biofuels to fossil fuels and the increased generation of district heating from biomass. This obligation, which will be in force during the coming years, has resulted in a record high use of renewable energy sources in Austria during the period considered. Renewable energy sources account for 25 %, with biomass being the most important renewable energy source (59 %), followed by hydropower (36 %). Other

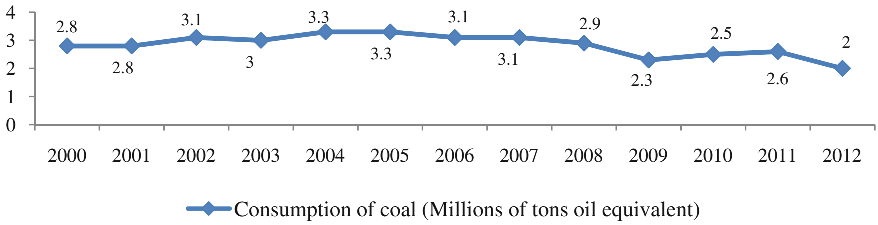


Fig. 4.4 Consumption of coal in Austria during the period 2000–2012. *Source:* BP Statistics

renewable energy sources include solar, wind and geothermal energies with a share of 5 %. Austria has adopted a policy that rules out the use of nuclear energy in its energy mix.

4.13.2 Import and Export of Coal

Austria has limited primary energy resources and is dependent on energy imports for two-thirds of its primary energy supply.[7] Although no longer exploited, lignite resources total 333 million tons, mainly lying in Western Styria near Graz. After the World War II, hard coal and lignite mining in Austria was expanded to replace the production lost elsewhere; lignite output peaked at over 6 million tons in 1963 when hard coal output was 100 thousand tons. However, with the reopening of borders and the resumption of trade, as well as the general trend toward greater oil and natural gas use and the development of hydropower, Austria's underground hard coal mines became less competitive. Beginning in the 1960s, Austria started the gradual closure of its underground hard coal mines, followed eventually by the closure of the last opencast lignite mine in 2005. By 1991, lignite production had fallen to 2 million tons, this being a rather small component of energy supply. After more than two centuries of mining activity, Austrian coal production definitively ended in 2006 with the recultivation of Oberdorf lignite mine. Although large lignite resources remain, their extraction would not be economic. Since that year. Austria has to import all of its coal needs.

In Austria, the largest consumers of imported coal are the steel industry and the power industry, each requiring around 2 million tons per year. The hard coal imported from Austria comes mainly from Poland, the Czech Republic, and Russia. The clean CO_2 capture in the industry is sold to the industrial gas industry for further use.

The evolution of the imports and exports of coal in Austria is shown in Figs. 4.5 and 4.6.

[7] In the case of coal, Austria has to imported 100 % of its currents needs.

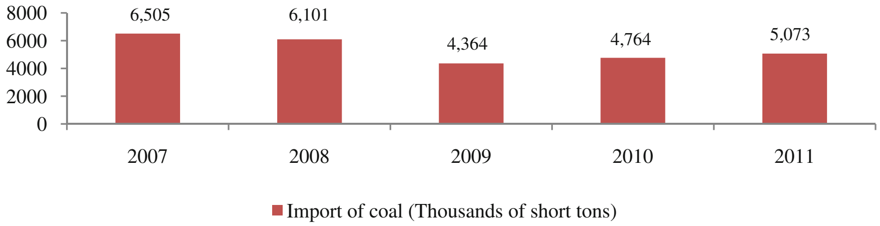


Fig. 4.5 Imports of coal from Austria during the period 2007–2011. *Source:* EIA

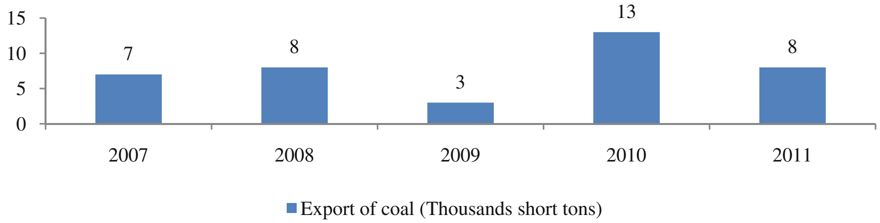


Fig. 4.6 Exports of coal from Austria during the period 2007–2011. *Source:* EIA

According to Fig. 4.5, the imports of coal from Austria during the period 2007–2011 dropped by 22.1 %. The lowest level of import of coal during the period considered was reached in 2009, one year after the economic crisis started to affect the whole EU. After that year the imports of coal started to increase once again, and it is expected that this trend will continue at least during the coming years due to an increase in the activities in the industry sector.

According to Fig. 4.6, the exports of coal from Austria during the period 2007–2011 increased by 14.2 %. The peak in the exports of coal by Austria during the period considered was reached in 2010. It is expected that Austria will continue exporting coal during the coming years in an amount similar to the level reached in 2007, 2008, and 2011.

4.13.3 Electricity Generation

Austria's total electricity capacity has increased on an annual compound basis by 1.39 % over the past 20 years reaching 22,797 MW in 2008. During that year, the total installed capacity base increased by 1,358 MW (over 6.99 %) with the largest source of new capacity being biomass and waste (over 820 MW). In 2010, the installed electricity capacity in the country reached 21,114 MW, an increase of 1.5 % respect to 2009. In 2011, the installed capacity reached 22,364 MW; this represents a further increase of 5.9 % respect to 2010.

The total production of electricity in 2011 in Austria from all sources reached 54.474 billion kWh; the total consumption was 63.801 billion kWh (2010). The per capita production of electricity in 2010 was 7,797 kWh.

The electricity production from coal sources in Austria represents 10.8 % of the total electricity generated in the country in 2010. It is expected that the participation of coal in the generation of electricity in the country will decrease during the coming years, if new natural gas power plants are constructed.

4.14 Belgium

According to IEA sources, in its 2005 review of energy policy in Belgium, coal provided approximately 11 % of the electricity generated in the country by all energy sources. The country has domestic coal resources, but the government decided to close all coal mine due to high costs of production. The last coal mine was closed in 1993.

In terms of energy supply apart from the introduction and growth of nuclear power, the most significant trend has been a reduction in the use of coal for the generation of electricity in the past few years. Over the last 30 years, coal consumption has dropped by nearly 70 %, from 5.7 million tons of oil equivalent to 1.8 million tons of oil equivalent.

It is important to highlight that in the decade from 1994 to 2004 there was a dramatic growth in gas-fired power generation at the expense of coal-fired generation. For this reason, electricity generated from coal in that period has fallen by 16 % dropped from providing 27 % of total generation in 1994 to just 11 % in 2005. As of beginning 2005, there were seven operating coal-fired power plants in the country. These plants are the following: Amercoeur with a capacity of 127 MW, Les Awirs with a capacity of 126 MW, Langerlo with a capacity of 470 MW, Mol with a capacity of 255 MW, of which 124 MW in conservation, Monceau with a capacity of 92 MW, Rodenhuize with a capacity of 268 MW, and Ruien with a capacity of 444 MW, all of which were operated by Electrabel. In 2005, the Les Awirs coal power plant was converted to run on 100 % biomass, but still is being able to run on coal as well. For economic reasons, the government closed three of the seven coal power plants that were operating in the country in 2005. These plants are Monceau in 2007, Amercoeur in 2009, and Mol in 2010. As of end 2010, Rodenhuize is being converted to run on 100 % biomass, such that Ruien and Langerlo are now the only remaining coal-fired power plants operating in Belgium.

On the other hand, EON is building a coal-fired power plant in the harbor area of Antwerp. The new plant will cost approximately €1.5 billion, and is expected to come on line in 2014. With its planned capacity of 1,100 MW, it would be able to satisfy 8 % of total Belgian power consumption. The planned combined heat and power plant will have a fuel efficiency of 46 % high above the usual figure for coal-fired plants. At the same time, CO_2 emissions are planned to be 25 % lower, compared with the average of existing coal-fired power plants in Belgium. The harbor area of Antwerp was chosen because of its deep-water facilities at the port and, for this reason, coal can be delivered easily to the plant. It is also close to large energy consumers, e.g., chemical factories. The plant will also deliver steam and heat to industrial and household consumers. The EON spokesman said the company did not expect any problems, as far as planning procedures were concerned, because the plant will be built on an industrial site.

Belgium has negligible economically recoverable resources of fossil energy and relies heavily on imported energy. Coal was once the main indigenous energy source, but there has been no domestic production of coal since the last mine closed in 1993. Primary energy supply is relatively diversified, with oil meeting 42 % of the country's needs in 2010, natural gas 28 % and coal 5 %. Nuclear power accounts for a fifth of energy supply and about half of total electricity generation. Renewables and imported electricity and heat account for the remaining 5 % of primary energy supply. In aggregate, imports meet more than three-quarters of the country's energy needs (treating nuclear power as indigenous production).

The principal goals of Belgian energy policy are the security of supply through the diversification of geographical sources of supply and fuels; energy efficiency; transparent and competitive energy pricing; and environmental protection. The three regions—Wallonia, Brussels-Capital, and the Flemish region—have also adopted energy policies covering their areas of competence, prioritizing energy efficiency and renewable.

4.14.1 Coal Reserves

There are no coal reserves reported by the government in 2013.

4.14.2 Production and Consumption of Coal

Belgium is not a coal producer since 1993.[8] According to Fig. 4.7, the consumption of coal by Belgium during the period 2008–2012 decreased by 55 %. It is expected that this trend will continue during the coming years, particularly the use of coal for the generation of electricity.

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[8] The peak in the production of coal in Belgium was reached in 1957 and since that year the production declined until the closure of the last coal mine in 1993.

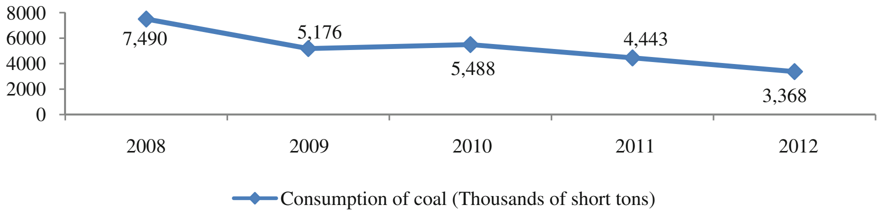

Fig. 4.7 The consumption of coal by Belgium during the period 2008–2012. *Source:* EIA

4.14.3 Export and Import of Coal

The evolution of the exports and imports of coal from Belgium during the period 2008–2012 are shown in Figs. 4.8 and 4.9. Belgium is not a coal producer, but it is exporting some amount of coal to other countries. The exports of coal from Belgium during the period 2008–2012 decreased by 49 %. Taking into account that Belgium is not a coal producer, it is expected that this trend will continue during the coming years.

On the other hand, the imports of coal from Belgium during the period 2007–2011 decreased by 39 %. It is expected that with the decision of the government to reduce the participation of coal in the energy mix of the country, this tendency will continue at least during the coming years.

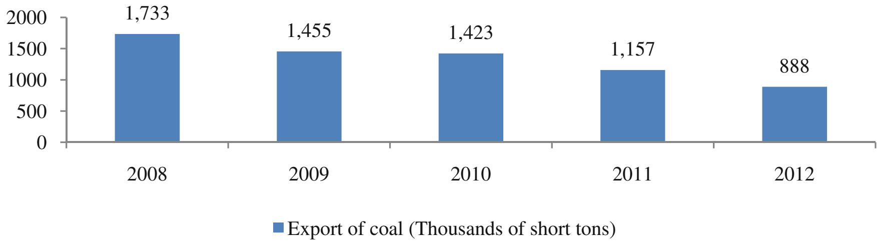

Fig. 4.8 Exports of coal from Belgium during the period 2008–2012. *Source:* EIA

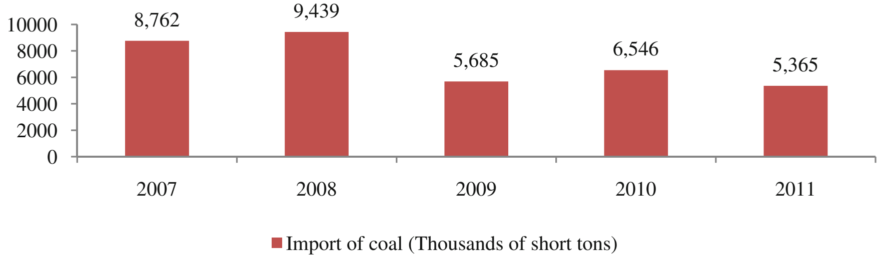

Fig. 4.9 Imports of coal from Belgium during the period 2007–2011. *Source:* EIA

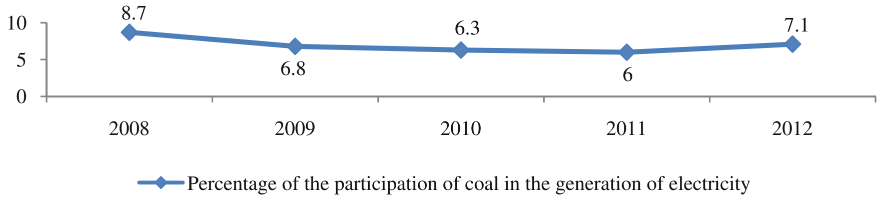

Fig. 4.10 Percentage of the participation of coal in the generation of electricity in Belgium during the period 2008–2012. *Source:* The World Bank

4.14.4 Electricity Generation

Electricity consumption per capita is about 7,400 kWh, which is 30 % higher than the average consumption in other European countries. Electricity accounts for 17 % of final energy consumption, up slightly since 1990 when it stood at 15 %. Belgian electricity consumption increased at the regular pace of 2 % per year between 1990 and 2008. In 2009, it dropped by 7 % due to the economic and financial crisis, which is still affecting the EU. The industrial sector accounts for a large share of overall electricity consumption, with around 50 % of the total. That share has decreased slightly since 1990.

The participation of coal in the generation of electricity in Belgium during the period 2008–2012 is shown in Fig. 4.10. According to this figure, the participation of coal in the generation of electricity in Belgium during the period 2008–2012 decreased from 8.7 % in 2008 to 7.1 % in 2012, a reduction of 1.6 %.

4.15 Croatia

The Croatia's government provides for the reconstructions on the existing facilities in terms of modernization and capacity increase, with the minimum capacity of 350 MW for each power plant. The government also expresses the need for the construction of new thermal power plants of total capacity not less than 2,400 MW in the coming years.

Croatia has no operating coal mines and has only one coal-fired power plant in operation. The coal for the Plomin power plant is imported through Plomin Port.[9] The plant, with 330 MW power capacity, has two generating units. The first generating unit, referred to as Plomin 1, is a 110 MW unit, which was commissioned in 1969. The second generating unit, referred to as Plomin 2, is a 220 MW unit, which was commissioned in 2000.

[9] The Plomin power plant originally sourced coal from mines in and near the nearby town of Lubin.

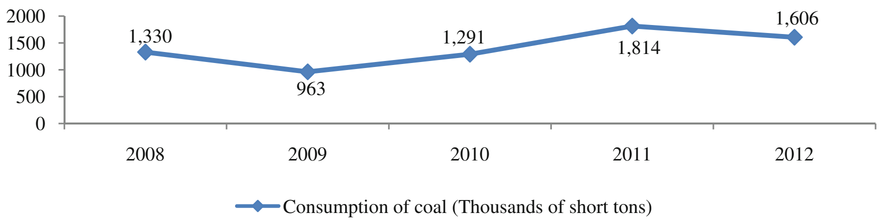

Fig. 4.11 Consumption of coal by Croatia during the period 2008–2012. *Source:* EIA

4.15.1 Coal Reserves

Croatia has no coal reserves reported in 2013.

4.15.2 Production, Consumption, Export and Import of Coal

Croatia does not produce coal. The evolution of the consumption of coal by Croatia during the period 2008–2012 is shown in Fig. 4.11. The consumption of coal by Croatia during the period 2008–2012 increased by 20.8 %. It is expected that the consumption of coal by Croatia will increase at least in the coming years, despite the EU policy to reduce the emission of CO_2 and to increase the use of cleaner technology for the generation of electricity. Croatia did not export coal during the period 2009–2012.

Finally, it is important to notice that the imports of coal from Croatia increased by 37.6 % during the period 2007–2011, and it is expected that the country will continue importing coal during the coming years.

4.15.3 Electricity Generation

In 2010, coal met 12 % of electricity demand in Croatia. With the generation of the new coal power plant to be connected to the grid in 2016, it is expected that the share of coal-fired thermal power plants in Croatia in that year will be about 22 %. The electricity distribution losses in 2010 was 2.022 billion kWh one of the largest since 2008. In 2011, the distribution losses were reduced to 1.831 billion kWh.

4.16 Czech Republic

Since nineteenth century, mining, processing, and utilization of coal in Bohemia and Moravia represent an important industry sector. In fact, coal is the only significant indigenous energy resource in the country.

The new State Energy Concept provides a scenario of the Czech energy market in 2050 with shorter term objectives and policy recommendations. The Concept concentrates on the need for security of energy supply and the maintenance of the Czech Republic as a net electricity exporter, achieved through a diversified energy mix and maximizing the use of indigenous resources, comprising coal, uranium, and renewable energy, mainly biomass and waste.

Key priorities and objectives in the new policy include:

- *Focus on domestic energy sources:* The policy gives preference to using all available domestic energy sources and states the necessity of keeping dependence on energy imports to a sustainable level. By 2040, a total of 80 % of all energy consumed is expected to be from domestic sources;
- *The balanced mix of energy resources:* The policy envisages that, by 2040, between 50 % and 60 % of net electricity consumption will derive from nuclear power, between 18 % and 25 % from renewable and secondary energy sources, between 5 % and 15 % from natural gas, and between 15 % and 25 % from brown and black coal;
- *Strengthening the role of nuclear energy:* The policy envisages that, at the Temelin nuclear power plant, the third and fourth nuclear units will be completed, and, at the Dukovany nuclear power plant, the life of the existing four units will be prolonged and a fifth unit built;
- *Elimination of renewable energy support:* The policy anticipates that renewable energy sources will become more economically viable and that state support will be gradually eliminated;
- *Decreasing use of coal in electricity production:* The policy envisages that new coal-fuelled energy sources would only be permitted to produce combined heat and power;
- *Use of waste:* The policy encourages the use of waste in energy production with the goal of utilizing up to 80 % of its combustible part;
- *Development of distribution system:* The policy anticipates developing and strengthening the distribution system to allow connection of new electricity production capacities, as well as the implementation of a smart energy network system;
- *Gas storage:* The policy envisages increasing gas storage reservoir capacity to allow storage of up to 40 % of the Czech Republic annual gas consumption;
- *Supporting off-grid systems:* The policy advocates supporting local off-grid systems to ensure continuity of energy supplies in case of natural disasters, terrorist attacks or other energy blackouts;
- *Energy savings:* The policy encourages increasing the number of passive energy buildings and only allowing new construction of this type of buildings after 2020.

Future expansion of nuclear capacity has been presented as one of the major pillars of the updated of the new energy policy. Nuclear energy is projected to account for about 47 % of the power generation mix in 2050 up from 32 % currently, which will support the Czech government's efforts to achieve climate change objectives. Coal is projected to fall from 60 % to about 12 % of the generation mix in 2050, less than the projected share of renewable energy sources, which will rise to about 30 %. Natural gas will continue to play a complementary role (about 11 %). The Concept outlines indicative targets for domestic resources, including nuclear fuel, with 90 % and 80 % shares in overall electricity and district heating, respectively. This would be a substantial transformation of the Czech electricity sector.

The North Bohemian Brown Coal Basin is the most important brown coal deposit in the Czech Republic. In the past, it produced almost 80 % of this domestic energy-producing raw material and became the foundation for the fast development of electric power engineering in the Czech lands after World War II. It is capable of sustaining further development of brown coal mining for the next almost 50 years and eventually up to 120 years.

Current Czech Republic's dependence on energy is minimal. It was reported in 2012 that 27 % of energy demand is met by imports. However, the country's dependence on energy imports is expected to grow to almost 50 % by 2020; an increase of 23 % respect to 2012. It is reported that imports are to increase in Czech Republic from Ukraine and Russia during the coming years. The Center for Eastern Studies reported that "dependence of Czech metallurgy on hard coal and the heating industry's dependence on brown coal are making the Czech government more inclined to keep production at domestic coal mines at a high level."

4.16.1 Coal Reserves

According to government and EIA sources, coal reserves in the Czech Republic are estimated to be in 2013 approximately 1,213 million short tons. The structure of stock as follows:

- Hard coal: 37 %;
- Brown coal: 60 %;
- Lignite coal: 3 %.

4.16.2 Production and Consumption of Coal

Possibilities to exploit new coal resources are currently limited by past decisions taken on environmental grounds and the concerns of local populations. Taking into account the importance of the coal industry and its long-term contribution to the country's security of supply, there is increasing pressure to revoke the original decision of the government to limit exploitation of brown coal reserves. Since domestic production is decreasing, more coal should be imported first of all from Poland, and also from Ukraine and Russia. Brown coal production is expected to go down in the next few years due to local ecological limits. It is estimated that brown coal deposits will reach 850 million tons in the protected areas, which have made the legitimacy of the limits the subject of a heated political debate for years in the Czech Republic. The government measures already adopted does not resolve this issue and envisages a gradual decrease in coal exports to Slovak power plants and an increase in imports from German coal mines. The declining domestic production and the risk of coal price fluctuations will encourage Czech firms to buy shares in deposits and production companies. Judging from their acquisition activity so far, they are likely to search for such opportunities above all in Poland and Germany, and also in Ukraine and the Balkans.

In July, the Czech Government approved a law to stop subsidies for new renewable projects at the end of 2013.

The evolution of the production and consumption of coal in the Czech Republic during the period 2008–2012 is shown in Figs. 4.12 and 4.13.

The production of coal by the Czech Republic during the period 2008–2012 dropped by 14.3 %. It is expected that the production of coal in the Czech Republic continues to decrease during the coming years as well as its participation in the energy mix of the country at least until 2050.

On the other hand, the consumption of coal in the Czech Republic during the period 2008–2012 also dropped by 15.9 %. It is also expected that the consumption of coal in the Czech Republic continues to decrease, particularly for the generation of electricity, during the coming years.

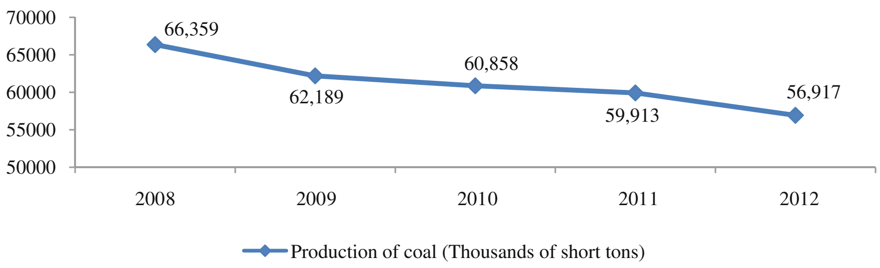

Fig. 4.12 Production of coal in the Czech Republic during the period 2008–2012. *Source:* EIA

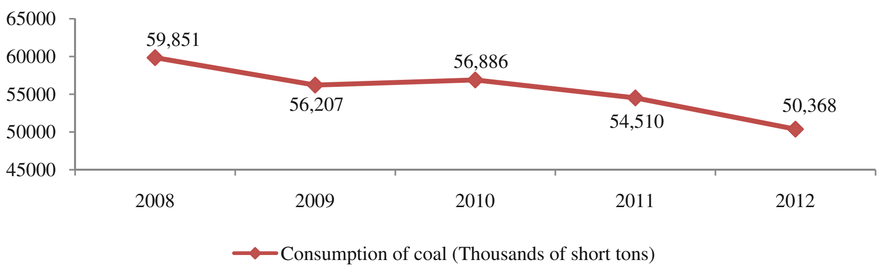

Fig. 4.13 Consumption of coal in the Czech Republic during the period 2008–2012. *Source:* EIA

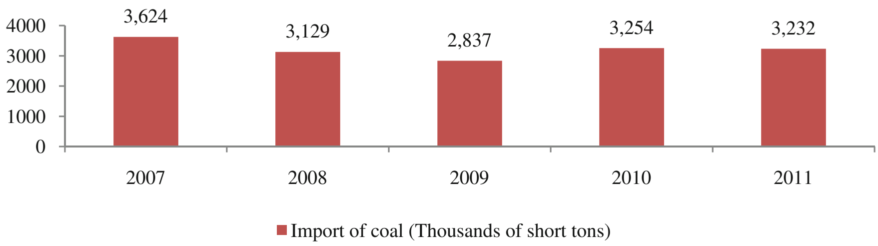

Fig. 4.14 Imports of coal from the Czech Republic during the period 2007–2011. *Source:* EIA

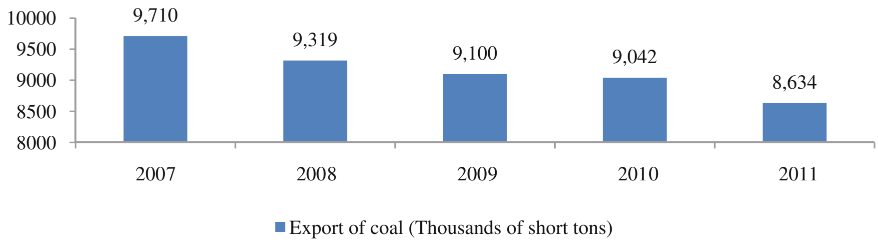

Fig. 4.15 Exports of coal from the Czech Republic during the period 2007–2011. *Source:* EIA

4.16.3 Import and Export of Coal

For the time being, the Czech Republic's hard coal exports are approximately three times the size of its imports. Since domestic production is decreasing, more coal should be imported from Poland, Ukraine, and Russia.

The evolution of the imports and exports of coal in the Czech Republic during the period 2007–2011 is shown in Figs. 4.14 and 4.15.

The imports of coal from the Czech Republic during the period 2007–2011 decreased by 10.9 %. It is expected that coal will continue to be one of the energy sources to be used for the generation of electricity in the Czech Republic during the coming years, but an increase in the use of nuclear energy and renewable for the same purpose could reduce the participation of coal in the energy mix of the country until 2050.

The exports of coal by the Czech Republic decrease 11.1. % during the period 2007–2011. It is expected that the exports of coal by the Czech Republic will continue to decrease during the coming years, due to a reduction in the use of coal for the generation of electricity in several countries within the EU.

4.16.4 Electricity Generation

According to the Czech Republic's National Report on the Electricity and Gas Industries in 2010, on 31 December 2010, the total installed capacity in the Czech electricity grid was 19.033 million kW. In 2011, the total capacity installed in the country reached 19.976 million kW, according to EIA sources. The country's total electricity consumption, including network losses, increased to almost 61 billion kWh (61.031 billion kWh) in 2010. In 2011, the total consumption of electricity decreased to 60.247 billion kWh; this represents a reduction of 15.1 %. The Czech Republic is the third largest net electricity exporter in the EU after France and Germany.

Investments in the electricity grid, in particular the transmission system, are occasioned by the needs of the electricity market's development and the need to respond to the markedly changing conditions in the system, in particular changes in the ring and parallel electricity flows. These changes are mainly attributable to the operation of wind farms in the north and west of Germany; they have a negative impact on cross-border electricity exchanges and do not contribute to the security of supply for customers in the Czech Republic. They also deteriorate the grid throughput and have a negative impact on electricity transmission and transit in the north–south direction. It is important to highlight that the Czech Republic's transmission system could allow electricity exchange options with all its neighboring countries. The net transfer capacity of the existing interconnections of 17 cross-border lines is over 30 % of Czech installed capacity. Further extension of the infrastructure through the construction of new lines and modernization of existing lines is planned for the period to 2026. These developments are consistent with the export oriented strategies of the Czech Republic.

EuroCoal claims that coal is the only significant indigenous energy resource in the country. Also, according to EuroCoal, in 2010, approximately 57 % of the total gross electricity production (85.9 billion kWh) in the Czech Republic was generated from coal, 33 % was generated from nuclear energy and 7 % from renewable sources.

4.17 Denmark

In February 2011, the government launched its Energy Strategy 2050, which outlined proposals for the early phases of the process toward meeting the long-term goal of achieving national independence from coal, oil, and gas. This far-reaching and visionary strategy sets out the energy policy tools needed to deliver Denmark's long-term energy goals and identifies clear medium-term actions of the government. The strategy outlines a number of new short- to medium-term policy initiatives which, if implemented, are projected to reduce the consumption of fossil fuels in the energy sector (excluding transport and activities related to North Sea exploitation) in 2020 by 33 %, compared with 2009 levels, while over the same period, increasing renewable energy's contribution to gross energy consumption to 33 %. New initiatives to boost energy efficiency are projected to bring the reduction of energy consumption to 6 % in 2020, below the 2006 level.

According to the new strategy, the transition to a fossil fuel-free economy must meet the following principles:

- *Cost effectiveness:* The transition must be cost-effective, with a focus on initiatives that provide maximum security of supply and the greatest reduction in fossil fuel use;
- *Minimal impact on public finances:* The distribution of costs and benefits must not create a burden on public finances. Energy consumers will finance the transition;
- *Retaining competitiveness:* The competitiveness of Danish business will have to be taken into account; therefore, energy costs should not increase significantly;
- *Full utilization of international frameworks:* The transition must make full use of global opportunities and take advantage of participation in international markets.

Care must also be taken to ensure that the environment remains protected and is not negatively impacted by, for example, infrastructure developments. Sustainable use of biomass will also be required.

Security of supply is an equally important element of Danish energy policy. Translating this into fossil fuel independence is an extreme interpretation of energy security. Many countries realize security of supply through a diverse energy mix in terms of fuel supply, supply sources, and supply routes. The geographical position of Denmark near the North Sea and the Baltic Sea, and with access to the European natural gas pipeline system, the European electricity system, as well as a well-developed gas storage infrastructure, reduce the risk of a long-term gas supply emergency, even when Denmark becomes a net-importer of energy.

Finally, it is important to highlight that in Denmark the final energy mix has remained relatively stable over the last two decades with oil remaining the largest energy source, at 44 % of total final consumption of energy, followed by electricity (19 %), heat (17 %), and natural gas (11 %).

4.17.1 Coal Reserves

There are no coal reserves reported by Denmark in 2013.

4.17.2 Production and Consumption of Coal

Denmark does not produce coal. The evolution of the consumption of coal in Denmark during the period 2008–2012 is shown in Fig. 4.16.

According to Fig. 4.16, the consumption of coal in Denmark dropped significantly during the period 2008–2012 (37 %). According to the energy policy adopted by the Danish government, it is expected that consumption of coal, particularly for the generation of electricity, will continue to decrease during the coming years.

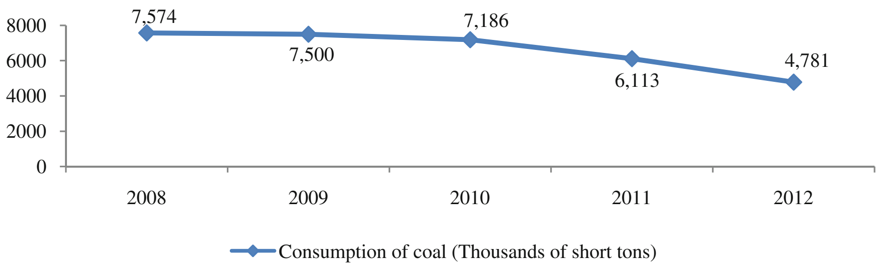

Fig. 4.16 Consumption of coal in Denmark during the period 2008–2012. *Source:* EIA

4.17.3 Import and Export of Coal

The evolution of the imports and exports of coal from Denmark during the period 2007–2011 is shown in Figs. 4.17 and 4.18.

The imports of coal from Denmark during the period 2007–2011 decreased by 24.6 %. According to the energy policy adopted by the Danish government, the imports of coal will continue decreasing during the coming years. The majority of the coal consumed by Denmark (27 % of the total) came from Colombia.

On the other hand, the exports of coal from Denmark during the period 2007–2011 dropped significantly from 209,000 short tons in 2007 to 0 short tons in 2011. It is expected that in the future Denmark will continue not exporting coal to other countries.

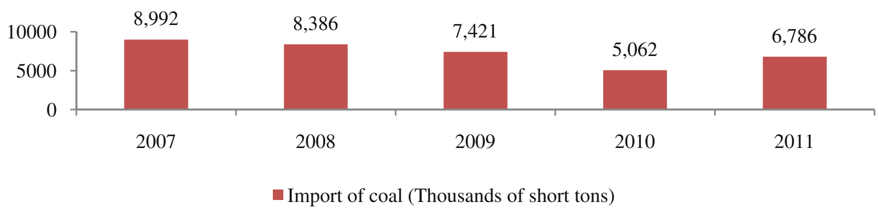

Fig. 4.17 Imports of coal from Denmark during the period 2007–2011. *Source:* EIA

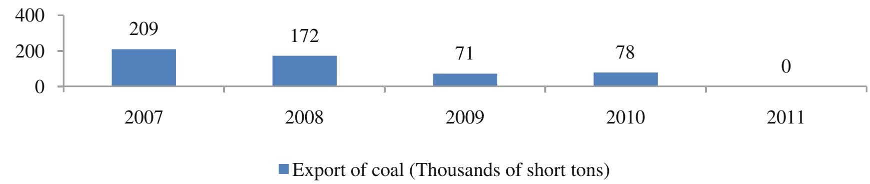

Fig. 4.18 Exports of coal from Denmark during the period 2007–2011. *Source:* EIA

4.17.4 Electricity Generation

Denmark generated 38.6 billion kWh of electricity in 2010, largely from coal (44 %), natural gas (20 %), and wind power (20 %). In 2010, Denmark imported 10.6 billion kWh of electricity, mostly from Norway and Sweden, and exported 11.7 billion kWh mostly to Germany. In 2012, the country generated 29.847 billion kWh. The evolution of the generation of electricity using coal as fuel in Denmark during the period 2006–2010 is shown in Fig. 4.19.

According to Fig. 4.19, the generation of electricity in Denmark using coal as fuel during the period 2006–2010 decreased by 9.93 %. The adoption of different energy efficiency measures and the decision of the government to eliminate the use of fossil fuels in the generation of electricity, particularly coal, will reduce the participation of this type of energy source in the energy mix of the country during the coming years.

4.18 Finland

Total energy consumption in Finland was 34.1 Mtoe[10] and end use was 27.0 Mtoe in 2010. Total energy consumption and end use increased quite steadily until 2003. The data for 2005 reflect the lengthy industrial dispute in the forestry industry. During the period 2006–2009, total energy consumption and end use clearly felt. Energy consumption in 2008 and 2009 shows the impact of the international economic and financial crisis, which affected production in energy-intensive sectors in particular. In 2008, consumption also felt owing to an exceptionally mild winter. However, in 2010, total energy consumption rose by 9 % compared to the previous year. The main reasons for this growth were the growth in industrial production that accompanied the economic recovery, and a very cold winter. Although there are clear reasons for lower than normal level of total energy consumption in

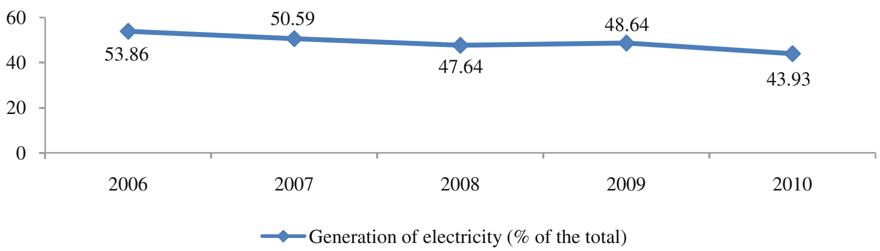

Fig. 4.19 Consumption of coal from Finland during the period 2008–2012. *Source:* EIA

[10] Million tons equivalent.

2003–2010, it may be noted when examining the whole 1990–2010 period that the growth that has continued for a long time is at the very least being curtailed.

Energy supply in Finland is diversified with no single fuel dominating the fuel mix. Oil accounts for 24 % of total energy consumption, wood fuels 21 %, nuclear energy 17 %, coal 13 %, natural gas 10 %, and other energy sources and net imports of electricity a total of 15 %.

4.18.1 Coal Reserves

Finland has no coal reserves reported in 2013.

4.18.2 Production and Consumption of Coal

Finland does not produce coal and all of the coal used for the generation of electricity and for other purposes is imported.

The consumption of coal from Finland during the period 2008–2012 dropped by 10 % (Fig. 4.20). The peak in the consumption of coal during the period considered was reached in 2010. Since that year the consumption of coal decreases 33.5 %. It is expected that the consumption of coal for the generation of electricity in Finland will continue to decrease during the coming years, but is expected to increase in other sectors.

4.18.3 Import and Export of Coal

The evolution of imports and exports of coal from Finland during the period 2007–2011 is shown in Figs. 4.21 and 4.22.

According to Fig. 4.21, the imports of coal from Finland during the period 2007–2011 increased by 2.4 %. It is expected that the imports of coal will continue this trend, at least during the next few years, but perhaps its participation in the

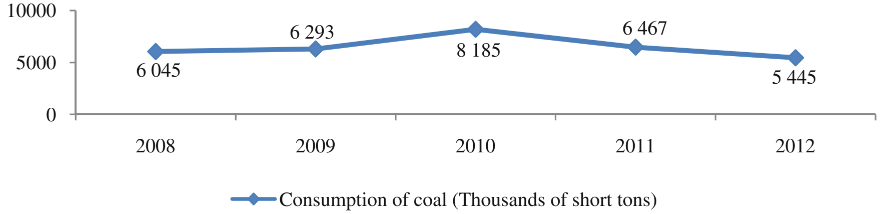

Fig. 4.20 Consumption of coal from Finland during the period 2008–2012. *Source* EIA

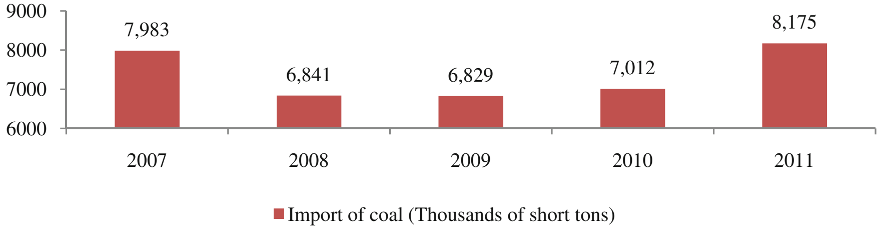

Fig. 4.21 Imports of coal from Finland during the period 2007–2011. *Source:* EIA

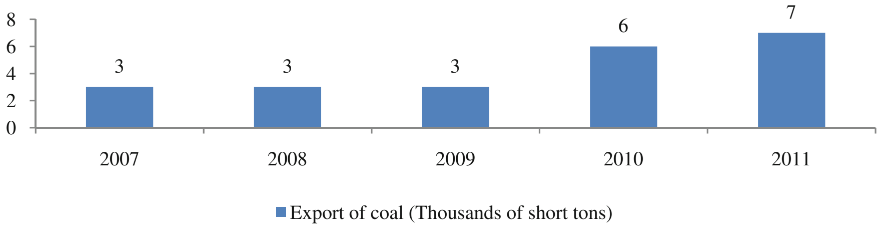

Fig. 4.22 Exports of coal from Finland during the period 2007–2011. *Source:* EIA

energy mix of the country will be lower in the future compare to the role is playing today, particularly for the generation of electricity.

According to Fig. 4.22, the exports of coal from Finland during the period 2007–2011 increased by 133.3 %, but the total amount exported is very small. Finland is not a producer of coal and has no coal reserves and for this reason exports only a small amount of coal to other countries. It is expected that this situation will not change during the coming years.

4.18.4 Electricity Generation

In 2012, production of electricity in Finland amounted to 67.688 billion kWh and is the biggest consumption per capita of electricity in the EU. Total electricity consumption in 2011 diminished by 4.8 % respect to 2010 and amounted to 81.055 billion kWh. Of the total electricity consumption, 84 % was covered by domestic production and 16 % by net imports of electricity from Russia, the Nordic countries and Estonia. Net imports of electricity increased by 32 % in the past few years due to the improved water situation in the Nordic countries.

Altogether, 33 % of electricity generated in Finland was produced with renewable energy sources. Around one-half of this was produced by hydropower and almost all of the remainder with wood. A total of 32 % of the production of electricity was covered with nuclear power, 27 % with fossil fuels and 7 % with peat. The amounts of electricity produced with fossil fuels and peat decreased respect to 2010. The biggest decrease was seen in electricity produced with coal, in 2011 a total of 13 % of the electricity generated in the country was using coal as fuel,[11] a decrease of 2.4 % respect to 2009, and this trend is expected to continue during the coming years.

4.19 France

France no longer has any operating coal mines after the closure of the La Houve Mine in 2004, and all coal used in the country are imported. According to the EIA sources, approximately half of the coal is used for power generation and the remainder by the steel industry. Coal-powered generators produce a mere 4 % of the country's electricity, and, for the moment, fracking is not authorized. In northern France, in the Nord-Pas de Calais region, once the heart of the country's coal-mining industry, there is, however, some interest in extracting coalbed methane as a replacement for conventional natural gas, despite local protests that the reserves are too small and the price of drilling too high. In this region, one of the poorest of France, where unemployment is around 14 %, mayors would like to see the money invested to improve housing and attract clean industries. They also fear that methane extraction could very well be a first step toward the legalization of fracking, and consider the nonconventional drilling of coalbed methane a threat to local water supplies because of the waste water it produces. The steady decline in the country's coal sector over the past several decades is attributable to cheaper coal imports replacing the domestic sources, its shift to nuclear power, and its concern for the environment.

According to government sources, half of the current coal power plants will be closed by 2015. However, there are plans prepared by foreign companies to resume coal production in France. The British company, ATH, through its French subsidiary SRMMC, has six coal concessions in south-central France covers an area of 36 km^2, with an estimated resource of approximately 4.5 million tons of recoverable coal.

4.19.1 Coal Reserves

France has relatively small coal reserves of 40 million short tons reported in 2006, and there is no new level of coal reserves reported by the government since then.

[11] In 2009, the participation of coal in the country's generation of electricity was 15.4 %.

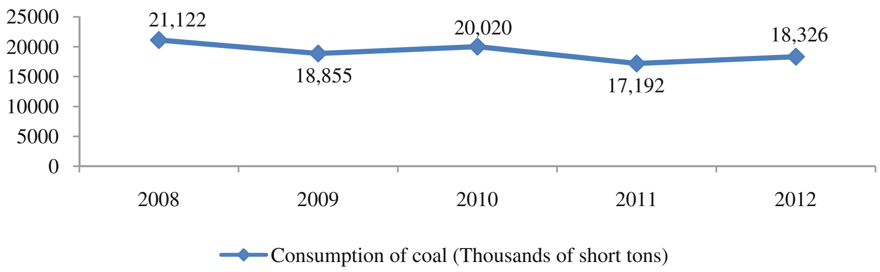

Fig. 4.23 Consumption of coal from France during the period 2008–2012. *Source:* EIA

4.19.2 Production and Consumption of Coal

France has no production of coal reported since 2004. The evolution of the consumption of coal by France during the period 2008–2012 is shown in Fig. 4.23. According to this figure, the consumption of coal by France during the period 2008–2012 dropped by 13.3 %. It is expected that the use of coal for the generation of electricity will continue to decrease until 2015, when the government expects that no coal will be used for this specific purpose.

4.19.3 Import and Export of Coal

France exports coal during the past 5 years. The evolution of the exports of coal from France during the period 2007–2011 is shown in Fig. 4.24.

According to Fig. 4.24, the exports of coal from France during the period 2007–2011 dropped by 85.5 %. It is expected that the exports of coal to other countries will continue decreasing during the coming years. In the case of the imports of coal, the evolution is shown in Fig. 4.25.

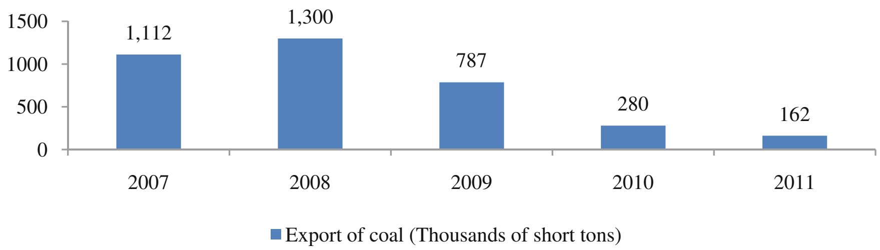

Fig. 4.24 Exports of coal from France during the period 2007–2011. *Source:* EIA

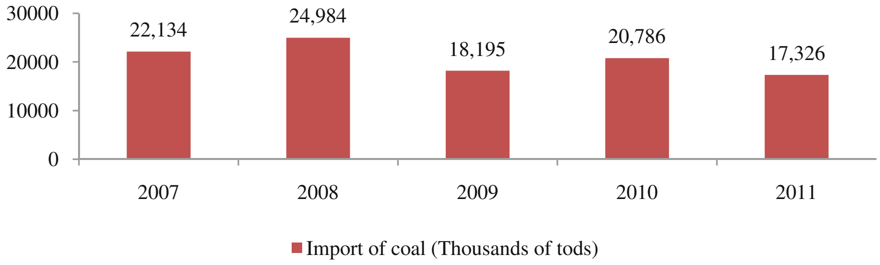

Fig. 4.25 Imports of coal from France during the period 2007–2011. *Source:* EIA

The imports of coal from France during the period 2007–2011 dropped by 21.8 %. It is expected that the imports of coal from France continue decreasing during the coming years, particularly after 2015 when half of the current coal-powered plants will be closed.

4.19.4 Electricity Generation

French national electricity demand in 2012 was 2.1 % higher for a total of 489.5 billion kWh than in 2011, due to the colder temperatures observed during the year. The increase in demand was driven by the residential and professional sectors (+2.4 %), whilst electricity consumption by the industrial sector (−4.0 % for the heavy industry) and small/medium businesses (−1 %) declined under the influence of the economic and financial crisis, which is still affecting Europe.[12] In general, French annual electricity demand is stabilizing at a value of approximately 480 billion kWh per year (disregarding variations specific to the energy sector). The demand peak reached 102 100 MW in February 2012. The spread between the peak and the lowest level of demand, at off-peak times on summer nights, has never been greater.

French electricity generation was down slightly in 2012 (−0.3 %), with a significant drop in the electricity generation in thermal facilities (−7 %). The participation of coal in the electricity generation in France dropped from 5 % in 2009 to 4.6 % in 2010, according to the World Bank. It is expected that this trend will continue until 2015, when the government expect that no coal will be used for this specific purpose.

[12] The country's electricity consumption per capita is significantly higher than the European average due to the high penetration of electric heating (7,250 kWh in 2009, compared with 5,650 kWh in the EU). The share of electricity in final energy consumption is increasing steadily and reached 23 % in 2009 (compared with 18 % in 1990); this represents an increase of 5 % in the past 20 years. The country's electricity demand has been increasing relatively rapidly: almost 2 % per year on average since 1990 and over 1 % per year since 2000. It dropped by 2 % in 2009, with a significant reduction of power consumption in the industrial sector as result of the economic and financial crisis affecting the whole EU.

France continues to be a net exporter of electricity to neighboring countries, and remained the biggest energy exporter in Western Europe in 2012, despite a reduction in net export volumes. France exported in 2012 a total of 44 billion kWh, although this figure was down by 21 % in 2011.

The government continues with its program of investment with a budget of €1,440 million in 2013, up from €1,361 million in 2012, to offset major regional energy disparities and optimize exchanges between European countries.

Conventional thermal generation was down by 7 %. Electricity generation by coal-fired power plants increased, whilst output from combined cycle gas turbines felt. This explains the drop in the coal price on the global markets, along with the very low CO_2 cost.

During the period 2011–2021, French overall power generation is expected to increase by an annual average of 1.01 %, reaching 601.90 billion kWh in 2021. Coal-fired generation looks set to fall steadily during the forecast period, reflecting moves toward a greener and cleaner supply slate.

4.20 Germany

Germany produces two types of coal: Anthracite, also known as hard coal, and lignite or brown coal. Hard coal production, which is located primarily in the Ruhr and Saar regions, is expensive in Germany relative to other major coal producers, because German coal is located deep underground and therefore more expensive to extract. Hard coal production has remained a viable industry only through heavy subsidization, which is being reduced in the past few years, but should be ended in the coming years in order to apply EC Directive on this issue.

Lignite or brown coal production, however, is inexpensive in Germany. Germany is the world's largest lignite producer, with about one-fifth of global output. Currently, over one-half of Germany's lignite production occurs in the Rhineland region in the Western part of the country. Lignite was the most important fuel in the former East Germany, producing about three times as much lignite as West Germany in the years prior to reunification. Since reunification, wasteful and environmentally damaging mining methods practiced in the former East Germany have been reformed and lignite output has fallen by about 40 %.

4.20.1 Production, Consumption and Reserves of Coal

According to EIA sources, Germany is by far Europe's largest coal producer and consumer.[13] Both production and consumption fell sharply between 1991 and 2001

[13] Germany is the seventh largest coal producer in the world.

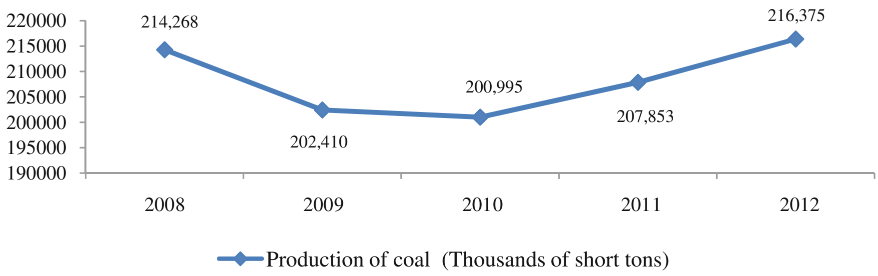

Fig. 4.26 Production of coal in Germany during the period 2008–2012. *Source:* EIA

as the country was restructured during integration, and many of the former East Germany's inefficiently run lignite mines were abandoned. After reunification, Germany has made efforts to diversify its fuel mix. Over 75 % of German coal production is used for electricity generation.

As of 2003, Germany had 7.4 billion short tons of recoverable coal reserves. Over 97 % of these coal reserves are lignite with the remainder composed of bituminous and anthracite. Brown coal is Germany's most important domestic energy source. According to Statistik der Kohlenwirtschaft, a German coal industry association, the brown coal production represents over 40 % of Germany's total domestic energy production. The latest report on the country's coal reserves was in 2008 and reached 44,863 million short tons, according to EIA sources.

The production of coal in Germany during the period 2008–2012 increased by 0.9 % (see Fig. 4.26). It is expected that this trend will continue during the coming years.

4.20.2 Coal Mines

The country operates ten coal mines. However, German coal production has declined rapidly since reunification in 1989–1990. The closure of older and inefficient coal mines in the former East Germany has been the principle cause of this decline, in addition to the EC Directives on the subsidies for the production of coal within the EU.

Most of Germany's hard coal deposits are deep below ground and difficult to access, making their extraction problematic and expensive. As a result, the government must provide large subsidies to the industry to maintain production. The German government gave the coal industry US$3.6 billion in subsidies in 2005, down from US$3.7 billion in 2004. In 2012, the level of government subsidies reached US$2.3 billion; this represents a reduction of 36.2 % respect to 2005. Germany use coal for the generation of 55 % of its total electricity.

4.20.3 Import and Export of Coal

As domestic coal production declines, Germany is emerging as a significant coal importer. Gross imports of hard coal, coke, and briquettes have more than doubled since unification, and in 2001 for the first time ever, the consumption of imported coal exceeded the consumption of domestic coal. Germany's largest suppliers are Australia, Canada, Poland, South Africa, and Colombia. The Federation of German Coal Importers expects German hard coal imports to increase over the next 20 years, as nuclear power is phased out in 2022 and domestic production declines.

Coal is Germany's only major domestic fuel source and the government considers maintaining hard coal production capacity critical to the country's energy security as much as possible. For this reason, Germany subsidizes the production of hard coal in order to maintain a cadre of working coal professionals. The coal industry is also a major employer in Germany. Germany's State assistance to coal producers was addressed by the EU in 2000 and 2001, resulting in temporary agreements authorizing coal subsidies in EU Member States. In July 2002, upon expiry of the 1952 European Coal and Steel Community Treaty, the Energy Ministers of the EU Member States agreed to phase out subsidies to domestic coal producers and stipulated that beginning in 2003, subsidies will be reduced to below their 2001 levels. The phase out subsidies to domestic producer has been postponed to 2018. Other EU Member States, which provide assistance to their coal industries are France, Spain, and the UK, but Germany's assistance is by far the largest.

The evolution of the imports and exports of coal from Germany during the period 2007–2011 is shown in Figs. 4.27 and 4.28.

According to Fig. 4.27, the imports of coal from Germany during the period 2007–2011 decreased by 12.4 %. The peak in the imports of coal within the period considered was reached in 2007. It is expected that the imports of coal from Germany will increase during the coming years due to a reduction in the domestic coal production.

On the other hand, the exports of coal from Germany during the period 2007–2011 dropped by 11 %. Since 2008, the exports of coal from Germany has been decreasing each year. However, it is expected that Germany will continue exporting coal during the coming years.

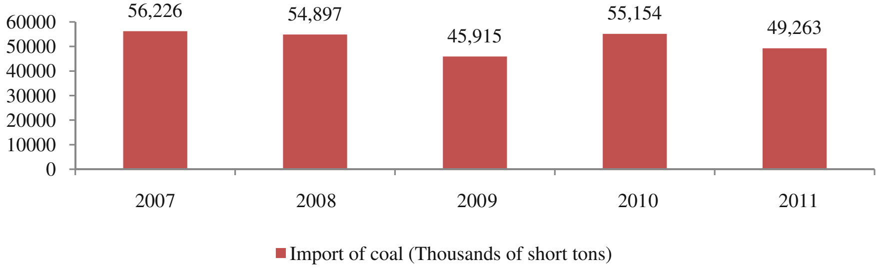

Fig. 4.27 Imports of coal from Germany during the period 2007–2011. *Source:* EIA

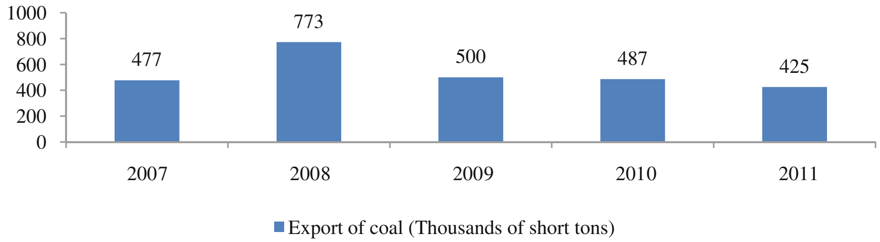

Fig. 4.28 Exports of coal from Germany during the period 2007–2011. *Source:* EIA

4.20.4 Electricity Generation

In 2011, the gross electric power generation in Germany totaled 613.1 billion kWh. A major proportion of the electricity supply is based on lignite (24.9 %), hard coal (18.6 %), and nuclear energy (17.6 %) (see Fig. 4.29). In 2012, according to EIA sources, the total electricity generated by the country reached 575.948 billion kWh; this represents a decrease of 6.1 % respect to 2011.

The evolution of the generation of electricity in Germany during the period 2010–2012 is shown in Table 4.9.

The majority of Germany's electricity is generated through fossil fuel combustion (hard coal, lignite, natural gas, and oil), nuclear energy, and renewable energy. Coal accounted for over 40 % of Germany's generation in 2010, 2011 and 2012; nuclear energy for over 15 %, and gas for over 12 %. In 2013, the generation of electricity using lignite as fuel rose to 162 billion kWh, the highest level since

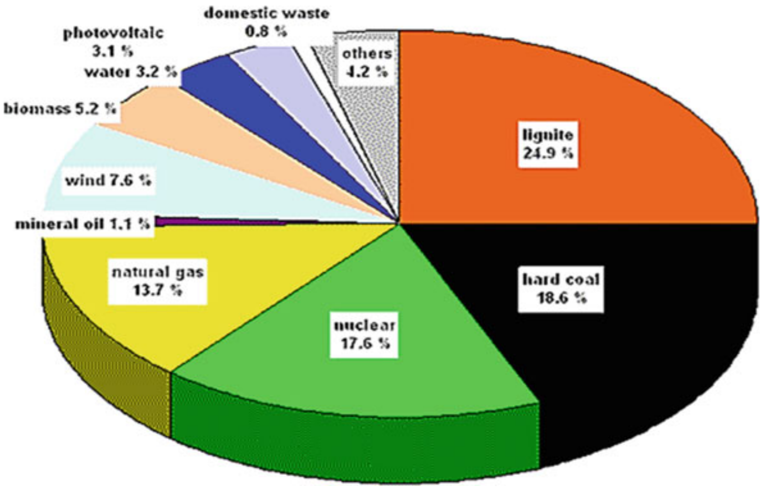

Fig. 4.29 The participation of coal and other energy sources in the generation of electricity in Germany in 2011. *Source:* European Nuclear Society

Table 4.9 Gross electricity production in Germany from 2010 to 2012

Gross electricity production in Germany from 2010 to 2012						
Energy sources	2010		2011		2012[a]	
	Billion kWh	%	Billion kWh	%	Billion kWh	%
Gross electricity production, total	633.0	100	613.1	100	628.7	100
Lignite	145.9	23.0	150.1	24.5	161.1	25.7
Nuclear energy	140.6	22.2	108.0	17.6	99.5	15.8
Hard coal	117.0	18.5	112.4	18.3	116.1	18.5
Natural gas	89.3	14.1	86.1	14.0	75.7	12.0
Mineral oil products	8.7	1.3	7.2	1.2	8.0	1.3
Renewable energy sources	104.8	16.6	123.8	20.2	142.4	22.6
Wind power	37.8	6.0	48.9	8.0	50.7	8.1
Water power[b]	21.0	3.3	17.7	2.9	21.8	3.5
Biomass energy	29.6	4.7	32.8	5.3	38.7	6.2
Photovoltaic energy	11.7	1.8	19.6	3.2	26.4	4.2
Household waste[c]	4.7	0.7	4.8	0.8	4.9	0.8
Other energy sources	26.7	4.2	25.6	4.2	25.9	4.1

[a] Provisional data
[b] Production in run-of-river power plants and storage power plants as well as production from natural inflow in pumped storage power plants
[c] Only production from biogenic share of household waste (about 50 %)
Source: Arbeitsgruppe Energiebilanzen (AGEB)

reunification in 1990, according to preliminary figures from AGEB, a collection of industry associations and research institutes. Electricity output from brown coal plants rose 0.8 % in 2013, according to the German Institute for Economic Research. As a result, Germany's CO_2 output is expected to have risen in 2013, even as power from renewable sources has reached 25 % of the energy mix in that year. It is expected that coal will continue to be the main source of energy for the generation of electricity during the coming years, and undoubtedly, this situation will have a negative impact in the intention of the German government to reduce the emission of CO_2.

Germany's electricity transmission system is connected to neighboring countries, and the country participates in some cross-border electricity trade. Germany is a small net importer and exporter of electricity. The main import sources were France, Switzerland, the Czech Republic and Denmark, while the main export destinations were the Netherlands, Austria, and France.

It is important to highlight that the increase in coal-generated power also led to a new record in German electricity exports to around 33 billion kWh. In 2013, Germany exported more power than it imported on 8 out of 10 days. Most of it was generated by from brown coal and anthracite power plants, according to Agora Energiewende.

4.21 Greece

While Greece produces no hard coal, it is the second largest European producer of lignite after Germany. The largest domestic coal producer is the government-owned Public Power Corporation (PPC), which controls approximately 63 % of the known coal reserves. In addition, hard coal consumed in the country is imported from South Africa, Russia, Venezuela, and Colombia.

Since 2001, the monopoly of PPC on power generation has been reduced and the market opened up to private power generators. Since PPC lost its legal monopoly, the Greek government has issued licenses for over 2,750 MW of private thermal generating plants. However, most private producers have been unable to finance new power plants. New coal-fired power plants are planned for Evia and Viotia, located between Athens and Larisa in Central Greece, and for Aitoloakarnania in the Western part, near Messolongi. Two larger 1,600 MW coal power plants are also projected in the northern Nea Karvali, near the town of Kavala and Central Almyros, in Thessaly. Finally, it is important to highlight that the government proposed that coal be imported from Ukraine, China, and South Africa, because Greek coal is being considered more expensive.

4.21.1 Production, Consumption and Reserves of Coal

In 2008, coal reserves in Greece were calculated, according to EIA sources, at 3,329 million short tons. There is no report on the level of coal reserves since that year.

If coal is to satisfy roughly 70 % of the foreseeable electricity needs for the coming years, then a total of 2,384 million short tons must be produced. For coal to continue to play a role in safeguarding Greece's energy independence after the year 2024, further exploration should continue unimpeded, new and improved mining methods must be applied, beneficiation methods must be implemented immediately in order to use deposits where calorific values are marginal owing to high ash content, and underground mining must be initiated. Finally, coprocessing of lignite encountered in small deposits, with organic wastes, such as by-products from agricultural industries must be promoted.

The evolution of the production of coal in Greece during the period 2008–2012 is shown in Fig. 4.30.

The production of coal in Greece during the period 2008–2012 decreased by 2.9 %. The lowest production of coal was reached in 2010. It is expected that the

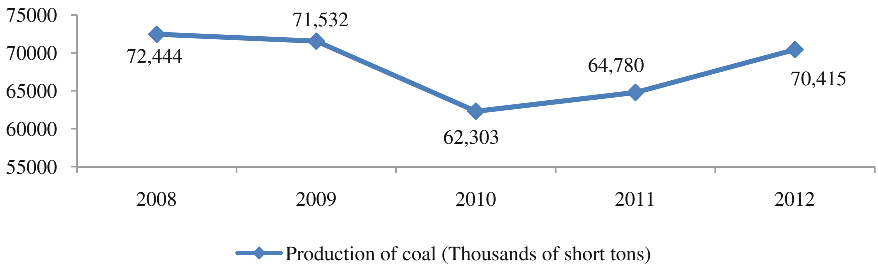

Fig. 4.30 Production of coal in Greece during the period 2008–2012. *Source:* EIA

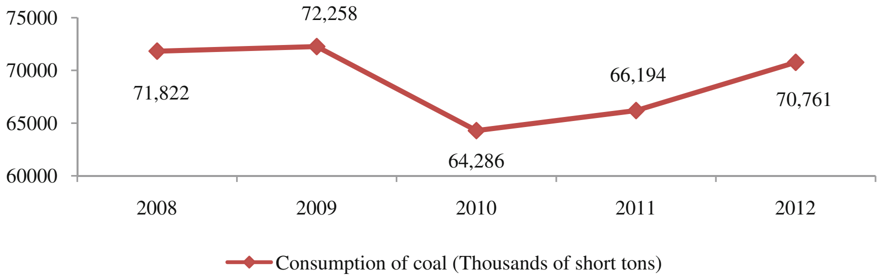

Fig. 4.31 Consumption of coal in Greece during the period 2008–2012. *Source:* EIA

production of coal in Greece continues to increase during the coming years as well as the participation of this type of energy source in the energy mix of the country (70 % of the total electricity generated by the country in 2024 and beyond is expected to use coal as fuel).

According to Fig. 4.31, the consumption of coal in Greece during the period 2008–2012 dropped by 1.5 %. The lowest consumption of coal was reached in 2010 and after that day the consumption of coal started to increase again. It is expected that the consumption of coal will continue increasing during the coming years.

4.21.2 Import and Export of Coal

Greece has not exported coal in the past few years. The imports of coal from Greece during the period 2007–2011 is shown in Fig. 4.32.

According to Fig. 4.32, the imports of coal from Greece during the period 2007–2011 decreased by 12 %. The lowest level in the imports of coal was reached in 2009. It is expected that Greece will continue importing coal for the generation of electricity during the coming years.

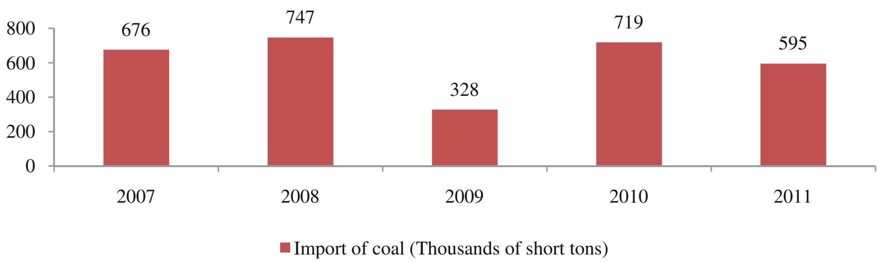

Fig. 4.32 Imports of coal from Greece during the period 2007–2011. *Source:* EIA

4.21.3 *Electricity Generation*

Approximately 75 % of the country's electricity generation comes from thermal power plants, predominantly coal. According to the U.S. Geological Survey, lignite accounted for approximately 65 % of the fuel for the country's power generation. Greece's electricity generation capacity has grown by 50 % in the last decade and projections are for an additional 6,000 MW being required by 2015. The bulk of additional capacity is expected to come from natural gas-fired power plants.

It is important to highlight that an increase of 3 % in electricity demands is expected over the next 30 years. In order to satisfy this foreseeable increase in the electricity demand has been estimated that 83,320 MWh installed capacity will be required by the year 2024. In 2011, Greece has an electricity capacity of 16.534 million kW. The consumption of electricity in 2011 reached 56.372 billion kW.

4.22 Hungary

Hungary is not in a position to abandon fossil energy for the generation of electricity at least during the near future; in particular, natural gas purchased at fair prices will continue playing a major role, while domestic coal and lignite stocks represent the strategic reserves of Hungary's energy industry.

Coal mining was once a booming industry in Hungary, ensuring the livelihood of many, mostly in underdeveloped areas. But after 1990, all that changed; mines were privatized and soon after, many closed down due to their uneconomical operation and the lower the prices of other energy sources. There were eight coal mine companies in Hungary in 1990, but only a few are left in operation. Twenty years ago, the mining industry employed 81,000 people (of which 52,000 worked in coal mines); today, the few existing mines give jobs to about 2,000 people only, and the number of employees in the entire industry has dropped to 22,500.

But in spite of the decline of the mining industry, Hungary is still rich in fossil fuel resources: its coal reserves have been estimated at 10.6 billion tons from which lignite counts for 60 %, sub-bituminous coal for 25 % and bituminous coal for 15 %. According to industry professionals, 3.3 billion tons of these could be exploited economically (31 % of the total coal reserves). The annual output of coal mining is 9–10 million tons. With the current coal level of production, such reserves could be enough for a few more centuries, and could reduce Hungary's dependence on imports. But for the time being, exploration is uneconomical and raises several environmental issues. In addition, the industry faces today is that there is no adequate training for miners. As a result of all these factors, mining development has come to a near standstill.

Coal does not play significant role in the country's energy production—coal-fired power plants produce only 15 % of the energy—and the country are constantly reducing coal production; before 1990, the country produced up to 29 million tons of coal, while now it extracts only 9–10 million tons. Currently, 100 % of coal production is presented with lignite and sub-bituminous coal, while Hungary closed its last bituminous coal mine in 2003. There are two operable open-pit mines and one underground mine—all producing lignite and sub-bituminous coal. Hungary exports 400,000 tons of lignite and sub-bituminous coal to neighboring countries, and imports 2.7–3 million of tons of anthracite and bituminous coal (including coking coal for its coke-chemical facilities).

In spite of such hurdles, there are some signs of the revival of Hungary's coal-mining industry. With the upgrading of coal, the Mecsek coal Basin, located in the South Transdanubia region, has come into the limelight. After several years of preparation, Hungarian engineering company Calamites Kft has just started trialing operations in its open-pit in Nagymányok, where there is more than 2 million tons of black coal buried underground. Although preliminary plans include selling the coal to power plants, such options are rather limited in Hungary at the moment. Therefore, the mine currently sells coal to local residents.

4.22.1 Coal Reserves

In 2010, the coal reserves in the country were estimated at 8.5 billion tons, a decrease of 2.1 billion of tons from the last report made in 2008. Lignite and brown coal accounts for about 80 % of the country's total coal reserves, making this type of energy source the most important indigenous sources of energy.

4.22.2 Production and Consumption of Coal

The evolution of the production and consumption of coal in Hungary during the period 2008–2012 is shown in Fig. 4.33.

The production of coal decreased by 1.3 % in Hungary during the period 2008–2012. The peak in the production of coal during the period considered was

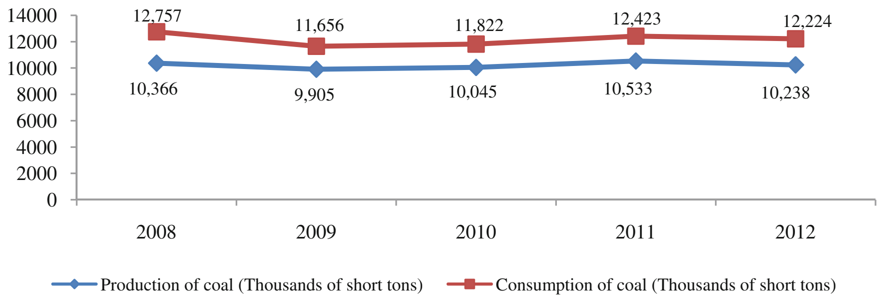

Fig. 4.33 The production and consumption of coal in Hungary during the period 2008–2012. *Source:* EIA

reached in 2011. The major coal consumption peaked at 16 million short tons around the middle to late seventies. The amount of coal consumed by power plants slowly decreased until 2003, and then, as old coal-fuelled units were shut down (or switched to biomass), there was a more rapid fall. Consumption now seems to have stabilized at 9–10 million of short tons per annum. The composition of the consumption has changed significantly: while the quantity of brown coal decreased to a quarter of that consumed in the 1970s, the share of lignite doubled (from 39 % to 79 %) (Perger 2009).

It is expected that Hungary will continue the production of coal during the coming years, but its participation in the generation of electricity could be less than today in order to reduce the emission of CO_2. The consumption of coal during the period considered decreased also in 4.2 %. The lowest consumption of coal during the period 2008–2012 was reached in 2009. It is expected that Hungary will continue more or less with the same level of consumption of coal in the future, but perhaps its future participation in the energy mix, particularly for the generation of electricity, could be lower than today.

During the whole period considered, the consumption of coal was higher that the production, forcing the country to import coal in order to satisfy the demand of this type of energy source.

4.22.3 *Import and Export of Coal*

The evolution of the imports of coal from Hungary during the period 2007–2011 is shown in Fig. 4.34.

According to Fig. 4.34, the imports of coal from Hungary during the period 2007–2011 dropped by 30.5 %. It is expected that this trend will continue in the future, and the participation of coal in the energy mix will continue decreasing, particularly for the generation of electricity. The peak in the imports of coal during the period considered was reached in 2008.

On the other hand, the evolution of the exports of coal during the period 2007–2011 is shown in Fig. 4.35. The exports of coal from Hungary during the period 2007–2011 dropped by 53.2 %. It is expected that the country will continue exporting coal to other countries during the coming years.

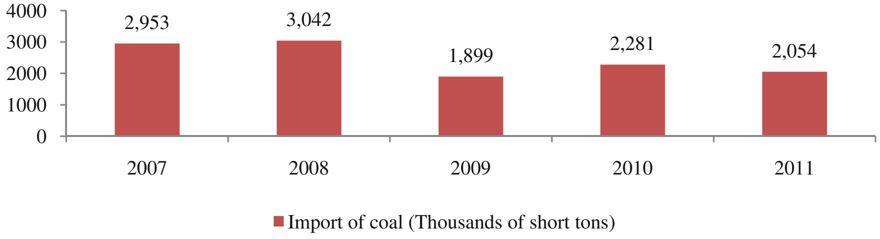

Fig. 4.34 Imports of coal from Hungary during the period 2007–2011. *Source:* EIA

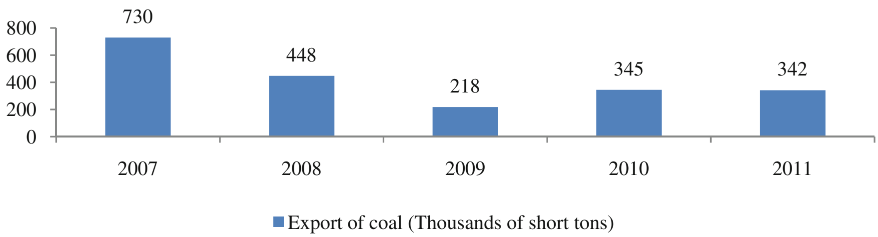

Fig. 4.35 Exports of coal from Hungary during the period 2007–2011. *Source:* EIA

4.22.4 Electricity Generation

With the lack of significant improvement to the power plants currently in operation, electricity generation followed a similar course to coal consumption. In 2007, a total of 82 % of the electricity generated was based on lignite, while the share of brown coal decreased from 58 % in 1975 to 10 % in that year. Presently, five power plants are fuelled by coal. The capacity of the 27 units in operation is between 10 MW and 225 MW. The average efficiency of the units was 31.35 %, ranging between 11 % and 36 %. Since practically all of the units were commissioned in the 1950 and 1960s, this low level of efficiency is not surprising. Several small units were shut down over the last decade, or their fuel was switched to natural gas or to biomass, specifically firewood. Further decommissioning is expected between 2011 and 2015.

National gross electricity generation in Hungary in 2010 amounted to 33,889 billion kWh, from a total installed capacity of 9.531 million kWh. Some 5.2 billion kWh was imported. The electricity produced from coal had a share of 17 % of national gross electricity generation.[14] Most of the coal-based electricity was generated by MÁTRAI ERÖMÜ ZRT (MÁTRA).[15]

[14] In the field of electricity generation, taking into account primary energy content, coal's significance has rapidly reduced: while it had an over 50 % share in 1980, this decreased to 30 % by the mid-nineties, and then to 20 % in 2007 and to 17 % in 2010; this represents a decrease of 33 % in the last 30 years. The decline is basically due to the fall in the use of brown coal, while in the case of lignite, a slight, but continuous increase is observable over the last three decades (Perger 2009).

[15] MÁTRA's 1,000 km^2 lignite field, which has proven mineral reserves of approximately 800 million short tons, is located 90 km to the East of Budapest. Extraction here is concentrated at the two opencast mines of Bükkábrány and Visonta. In 2010, MÁTRA produced approximately 8.2 million short tons of lignite after removing some 67 million m^3 of overburden. The MÁTRA power plant is located at Visonta and has a total capacity of 935 MW (comprising 2 × 100 MW units, 1 × 212 MW, 2 × 232 MW and two gas turbines of 2 × 30 MW). The lignite mined at Bükkábrány, some 60 km away from Visonta, is transported to the power plant by rail. In order to reach a further productivity improvement in MÁTRA's opencast mines, a project to build a new compact excavator was carried out between 2007 and 2009. This machine is a prototype of the world's biggest compact excavator. It started operation in the Bükkábrány opencast mine in mid-2009, with an annual output of some 12 million m^3.

4.23 Italy

The Italian coal mine production industry had a total revenue of US$7.6 million in 2010, representing a compound annual growth rate of 63.9 % for the period spanning 2006–2010. Industry production volumes increased by a compound annual growth rate of 49.7 % between 2006 and 2010, to reach a total of 116,400 short tons in 2010. The performance of the industry is forecast to decelerate, with an anticipated compound annual growth rate of 21.9 % for the five-year period 2010–2015, which is expected to drive the industry to a value of US$20.4 million by the end of 2015.

The only coal source in Italy is located in Sulcis Iglesiente Basin, in the southwest of Sardinia. In 1972, coal-mining activities in this basin were suspended, but since 1997 the basin has been studied by several researchers in order to evaluate new solutions to use in an environmentally-friendly way the coal of Sulcis. At present, the production is about one million tons yearly. Italian operators have in pipeline projects for the conversion of coal of a big part of their production and for the deployment of existing plants never used for coal combustion. Today in Italy there are 13 coal power plants in operation.

4.23.1 Production, Consumption and Reserves of Coal

Presently, coal supplies between 14 % and 15 % of the power produced in Italy. ENEL, the former State utility now partially privatized, is planning to convert several old large oil-fired power plants to coal, in order to have a better energy mix. The first of these already under construction is a 2,000 MW power plant in Civitavecchia, near Rome, which is expected to come on line before 2014. A second 2,000 MW power plant is planned in Porto Tolle, in the River Po delta, which is expected to be online in 2016. These two power plants will emit an additional 20 million tons of CO_2 per year.

It is important to stress that investing in coal-fired power plants could undermine Italy meeting its targets for reducing greenhouse gas emissions to help protect the climate. For this reason, instead of continuing to invest in low coal quality, the country should invest in its renewable energy potential and improve energy efficiency.

According to Fig. 4.36, the primary production of coal in Italy during the period 2008–2011 decreased by 22 %. However, it is expected that Italy will continue to produce coal for their use in the generation of electricity during the coming years. The consumption of coal by Italy during the period 2008–2012 is shown in Fig. 4.37.

According to Fig. 4.37, the consumption of coal by Italy during the period 2008–2012 decreased by 6.3 %. However, it is important to highlight that since 2009, the consumption of coal in Italy has increased each year from 21,057,000 short tons in 2009 to 24,492,000 short tons in 2012, an increase of 16.3 %. It is expected that the consumption of coal by Italy, will continue increasing during the coming years.

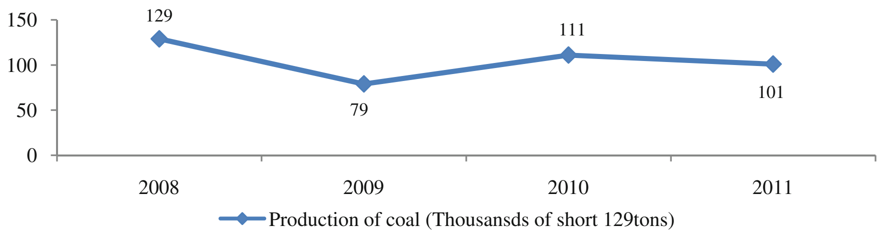

Fig. 4.36 Production of coal in Italy during the period 2008–2011. *Source:* EIA

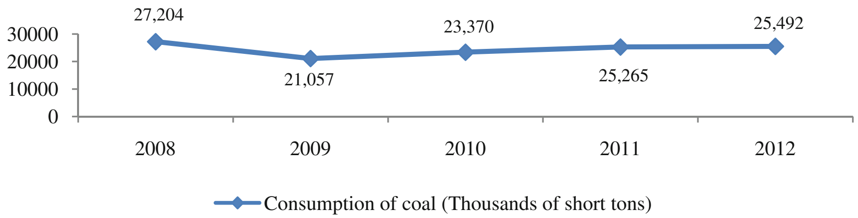

Fig. 4.37 Consumption of coal by Italy during the period 2008–2012. *Source:* EIA

4.23.2 Import and Export of Coal

Italy imports via sea about 90 % of its coal demand. Importing countries are the USA, South Africa, Australia, Indonesia, Colombia, Canada, China, Russia, and Venezuela. The imports and exports of coal from Italy during the period 2007–2011 are shown in Figs. 4.38 and 4.39.

According to Fig. 4.38, the imports of coal from Italy during the period 2007–2011 decreased by 8 %. The lowest level of imports of coal was reached in 2009, due to the economic and financial crisis, which is still affecting Italy. However, it is expected that the imports of coal will continue increasing during the coming years. During the period 2009–2012, the imports of coal increased by 23.4 %.

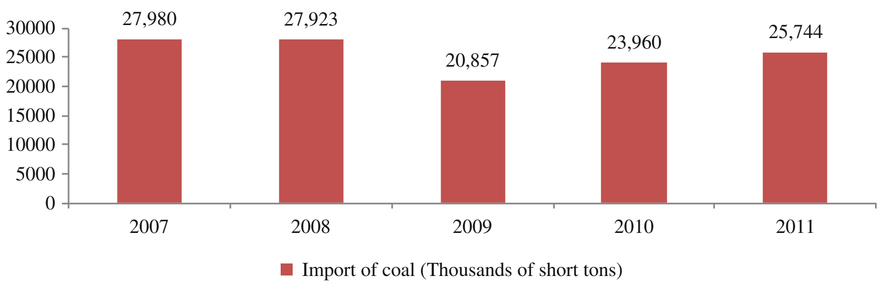

Fig. 4.38 Imports of coal from Italy during the period 2007–2011. *Source:* EIA

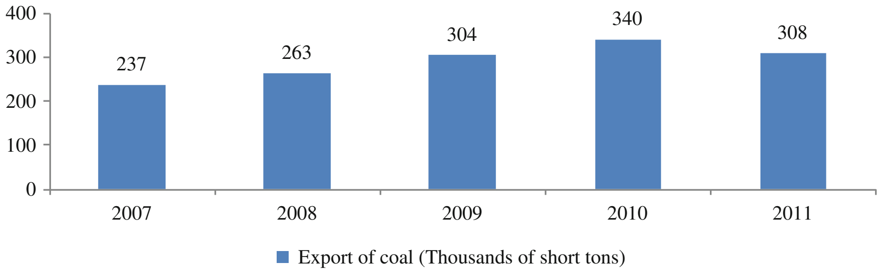

Fig. 4.39 Exports of coal from Italy during the period 2007–2011. *Source:* EIA

From Fig. 4.39, the following can be stated: The exports of coal from Italy during the period 2007–2011 increased by 29.9 %. It is expected that the exports of coal from Italy will continue increasing during the coming years.

4.23.3 Electricity Generation

The electricity production from coal sources in Italy was reported at 41,602 billion kWh in 2010, according to a World Bank report published in 2012; This production, in 2012, represents 14.7 % of the total electricity generated in the country (283,189 billion kWh). It is expected that the participation of coal in the energy mix of the country will continue to play an important role during the coming years.

4.24 Poland

Poland has the fastest-growing economy in the EU, but the power that drives it comes from the dirtiest of fossil fuels, coal. Coal produces around 93 % of Poland's electricity, and it is a cheap way to produce energy, but it provides an enormous headache for any government trying to meet ever-stricter EU greenhouse gas emission targets. Around one-fifth of the country's electricity is produced from just one plant, Elektrownia Belchatow, in central Poland. It is Europe's largest thermal power plant and its biggest polluter, emitting the equivalent of close to 39 million tons of CO_2 in 2011, a rise of 31 % from 2010. The power plant burns lignite (brown coal), the cheapest fossil fuel, which produces energy at half the cost of hard coal and a quarter the cost of natural gas.

Poland's 2009 Energy Policy until 2030, states that 74 % of the country's energy will still come from fossil fuels by 2030, and it is expected that the share of renewable energies will reach at least 15 % of energy total production by 2020, and increase by 1 % until 2030, while nuclear will be 10 %.

4.24.1 Production, Consumption and Reserves of Coal

The production of primary energy in Poland is based mainly on fossil fuels. The first place belongs, and will most likely belong for a long time to harden coal and lignite, which cover 56 % of the demand. Based on these facts, it is expected that Poland will continue using coal for the generation of electricity during the coming years, and for this reason will continue investing in the coal mining industry. The government has indicated that Poland's economy will continue to be based on coal, but in a more modern way, and will reduce CO_2 emissions in line with EU targets with the aid of new technology.

On the other hand, and in order to reduce the CO_2 emissions, the country has recently invested in exploring its shale gas potential. A nuclear power plant has also been in the pipeline, partly as a means of lowering Poland's dependence on Russian natural gas. While the future of nuclear power plant is unclear, coal and shale gas are top of the government power agenda. According to government sources, the future of Polish energy is in brown and black coal, as well as shale gas. It is clear that energy independence requires not only the diversification of energy resources, but also the maximum use of one's own resources, and for this reason, coal will continue to play an important component of the energy mix of the country during the coming years.

According to EURACOAL, Poland has hard coal reserves totaling 16.9 billion tons, mainly located in Upper Silesia and in the Lublin Basin. Mineable lignite reserves amount to almost 15 billion tons.

The production and consumption of coal by Poland during the period 2008–2012 are shown in Figs. 4.40 and 4.41. According to Fig. 4.40, the production of coal dropped by 7.5 % as a result of the severe economic and financial crisis that is still affecting the whole EU. However, since 2010, the production of coal has started to increase once again from 146,257,000 short tons in that year to 158,428,000 short tons in 2012; this represents an increase of 8.3 %. The lowest coal production during the period considered was reached in 2010. It is expected that the production of coal in Poland will continue increasing during the coming years.

The consumption of coal during the period 2008–2012 decreased from 3.3 %. The peak in the consumption of coal during the period considered was reached in 2011. It is expected that the consumption of coal will continue to increase even

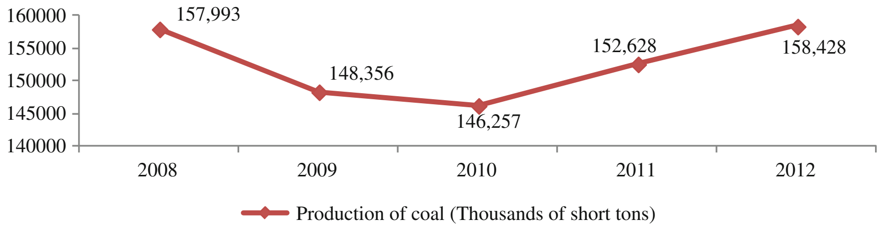

Fig. 4.40 Production of coal from Poland during the period 2008–2012. *Source:* EIA

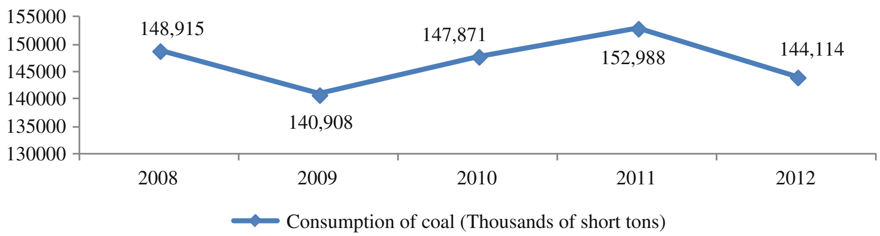

Fig. 4.41 Consumption of coal from Poland during the period 2008–2012. *Source:* EIA

further during the coming years, if the proposed nuclear power plant is not constructed and the participation of renewable energy sources for the generation of electricity did not reach the projected level.

4.24.2 Import and Export of Coal

The evolution of the imports and exports of coal from Poland during the period 2007–2011 are shown in Figs. 4.42 and 4.43. According to Fig. 4.42, the imports of coal from Poland during the period 2007–2011 increased by 145 %. Taking into account the current and foreseeable participation of coal in the energy mix of the country, it is expected that the imports of coal from Poland will continue increasing during the coming years.

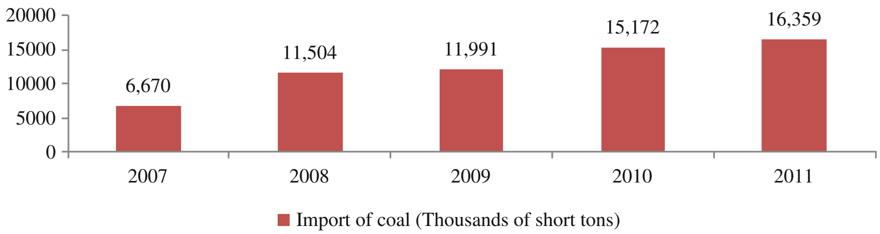

Fig. 4.42 Imports of coal from Poland during the period 2007–2011. *Source:* EIA

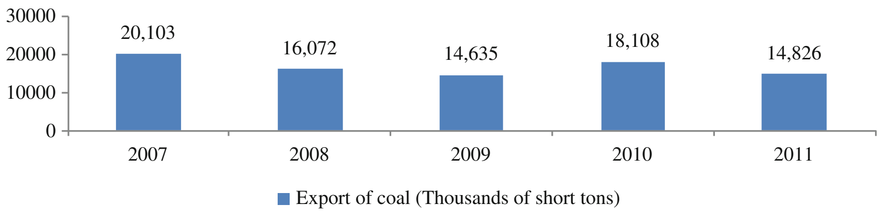

Fig. 4.43 Exports of coal from Poland during the period 2007–2011. *Source:* EIA

Poland is now a net exporter of coal and is expected that it will continue to be an exporter country during the coming years. The evolution of the exports of coal during the period 2007–2011 is shown in Fig. 4.43.

From Fig. 4.43, the following can be stated: The exports of coal from Poland during the period 2007–2011 decreased by 26.3 %. The lowest level of exports of coal was reached in 2009 as a result of the beginning of the economic and financial crisis that are still affecting Poland and the whole EU.

4.24.3 Investment in the Energy Sector

In the near future, the Polish energy sector will require substantial investments. Development opportunities for the sector result from dynamic growth of the Polish economy, which despite the current crisis that is affecting a number of countries within the EU, the country grows fast. Also, it is a natural consequence of aging of the existing power plants and industrial installations. Modernization is also motivated by EU requirements, especially as regards lowering dust, nitrogen oxide, and carbon dioxide emissions. The fact that emission requirements will have to be met might result in a necessary retirement of many power plants using coal as fuel that are producing high emissions when stringent emission standards become effective.

The sector will require significant investments, as confirmed among others by the average age of existing power plants. Almost 40 % of power plants now operating in Poland are over 40 years old and 15 % of them are over 50 years old and qualify for immediate retirement. According to government sources, over 70 % of power plants currently operating in the country are more than 30 years old.

It is important to highlight that only within the next few years, necessary investments will include the replacement of units of a few thousand megawatts of capacity. Total funds necessary for modernizing the Polish energy sector, including investments in power plants and transmission grid, are estimated at PLN 150–200 billion in the next 15 years. The investment includes the modernization and extension of the high and moderate voltage transmission grid, the construction of a nuclear power plant, and the modernization and replacement of existing power plants (Energy Sector in Poland 2013).

4.24.4 Electricity Generation

According to the Energy Sector in Poland (2013); the gross national electricity production volume in 2011 was 163.2 billion kWh (4 % growth compared to 2010). The domestic consumption of electricity was 157.9 billion kWh. The difference between production and consumption was exported. The foreseeable gross demand for 2015, 2020, 2025, and 2030 is shown in Table 4.10.

Table 4.10 Foreseeable gross electricity demand for 2015, 2020, 2025 and 2030

	2015	2020	2025	2030
Final energy	115.2	130.8	152.7	171.6
Energy sector	11.6	12.1	12.7	13.3
Transmission and distribution losses	13.2	13.2	15	16.8
Net demand	140	156.1	180.4	201.7
Own needs	12.8	13.2	14.2	15.7
Gross demand	152.8	169.3	194.6	217.4

Sources: Forecast on demand for fuels and energy by 2030, Ministry of Economy 2009

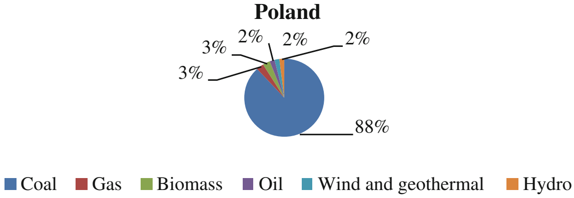

Fig. 4.44 Participation of different energy sources in the generation of electricity in Poland. *Source:* Poland Energy Report Enerdata, July 2012

From Table 4.10, the following can be stated: The demand for electricity for the following decades is expected to increase from 163.2 billion kWh generated in 2011 to 217.4 billion kWh in 2030; this represents an increase of 33.2 %.

In 2011, installed capacity of the National Electricity System grew compared to preceding years and was 37.4 GW. The capacity increased by more than 1,600 MW compared to 2010. The electricity generated in Poland by source is shown in Fig. 4.44. From that figure, the following can be stated: in 2012, a total of 88 % of the electricity generated in the country used coal as a fuel. It is expected that the current level of participation of coal in the energy mix of Poland will continue to be very high during the coming years, but this participation could be lower due to an increase in the use of other energy sources for electricity generation and the implementation of the strict EC Directives.

4.25 Russian Federation (Russia)

The future of Russia's ability to remain a global energy supplier remains unclear. After a decade of robust energy exports and revenues, Russia is cutting natural gas prices in Europe, while revenue projections for its energy behemoth, Gazprom, are declining starting in 2013. The energy sector is far more than a commercial asset for Moscow; it has been one of the pillars of Russia's stabilization and increasing strength for more than a century. The government of Russia has designated energy security as the primary issue for Russia's national security, especially since recent changes in global and domestic trends have cast doubts on the energy sector's continuing strength.

Currently, energy revenues make up half of the government's budget. This capital influx was and continues to be instrumental in helping Russia build the industrial basis needed to maintain its status as a regional and global power. However, as the Russian governments became dependent on energy, the revenues also became a large vulnerability. Beyond export revenues, the energy sector has contributed to the creation of a domestically stable and industrialized state. Russia's domestic energy consumption is very high due to extremely cold weather for most of the year, but despite inefficiencies within the energy sector and the cost of producing energy, the country's domestic reserves have enabled Moscow to provide its citizens and the industries that employ them with low energy prices.

The energy sector also contributes to Russia's ability to expand its influence to its immediate neighbors. Moscow's use of energy as leverage in the buffer states differs from country to country and ranges from controlling regional energy production (as it previously did in the Azerbaijani and Kazakh oil fields) to subsidizing cheap energy supplies to the countries and controlling the energy transport infrastructure. Russia has used similar strategies to shape relationships beyond the former Soviet states. For instance, Russia is one of Europe's two main energy suppliers and is the only European supplier with large reserves of oil and natural gas and historically cheap prices. Russia's physical connectivity to Europe and ability to undercut any competitor has served as the basis of many of Moscow's relationships in Europe.

According to the new Energy Strategy of Russia for the Period up to 2030, the objective of the energy policy of Russia is to maximize the effective use of natural energy resources and the potential of the energy sector to sustain economic growth, improve the quality of life of the population, and promote strengthening of foreign economic positions of the country.

The new strategy determines the objectives and goals of the Russian energy sector long-term development in the upcoming period, its priorities and guidelines, as well as mechanisms of the State energy policy at the implementation phases of the strategy ensuring realization of the stated objectives. While implementing the Energy Strategy of Russia for the Period up to 2020, the validity of most of its key provisions was confirmed by the actual development of the country's energy sector, even under conditions of abrupt changes of foreign and domestic factors determining the main operating parameters of the Russian fuel and energy complex. The strategy extends the time period up to 2030 with new goals and priorities for the country development.

The strategy sets new guidelines for the development of the energy sector in the transition of the Russian economy to the innovative path of development specified in the Conception of Long-Term Socioeconomic Development of the Russian Federation up to 2020 approved by Decree N° 1662-r of the Government of the Russian Federation dated November 17, 2008.

The new strategy is based on the experience derived from the implementation of the Energy Strategy of Russia for the Period up to 2020 and on an analysis of the current trends and the new system challenges to energy developer. The new strategy takes into account possible fluctuations in foreign and domestic conditions of economic development in Russia. Nevertheless, the key objectives and long-term quality guidelines for the transition of the country's economy to the innovative path of development are specified as invariables despite the possible consequences of the global economic crisis that started in 2008. The very same requirements are imposed on the key objectives and long-term quality guidelines of the new strategy. This includes:

- Current results of the Energy Strategy of Russia for the Period up to 2020 implementation and the purpose of the new strategy;
- Main trends and forecasts of the socioeconomic development of the country, and of the interaction between economy and energy;
- Prospects of demand for Russia's energy;
- Main provisions of the State energy policy and its most important elements;
- Development prospects of the Russian fuel and energy complex;
- Expected results and implementation system of the new strategy.

The long-term State energy policy aims to protect the rights and legal interests of the Russian citizens and business entities, ensure State defense and security, effectively manage State property, and achieve a new qualitative state of the energy sector. The policy is implemented taking into account the following unalterable principles:

- Consistency of the State measures in implementing key strategic guidelines for development of the energy sector;
- Interest in setting up strong and stably developing energy companies representing Russia on foreign markets with dignity and contributing to the successful functioning of competitive domestic energy markets;
- Relevance and predictability of State regulations aimed at private initiative stimulation in implementing State energy policy, including investments.

The main strategic guidelines of the long-term State energy policy are as follows:

- Energy security;
- Energy efficiency of the economy;
- Budget efficiency of the energy sector;
- Environmental safety of the energy sector.

The main components of the State energy policy are as follows:

- Subsoil use and management of the State subsoil fund;
- Development of domestic energy markets;
- Promotion of a rational energy balance;
- Regional energy policy;

- Innovative and scientific and technical policy in the energy sector;
- Social policy in the energy sector;
- Foreign energy policy (Energy Strategy of Russia for the Period up to 2030).

Among the priorities of scientific and technological progress in the coal energy sector, including in the new Energy Strategy of Russia for the Period up to 2030 are the following:

- Improving the quality of exploration works, including the introduction of the latest methods of three-dimensional modeling;
- Increasing the level of development of the material, technical and scientific research base in the area of work safety, accident prevention and liquidation (including automation of industrial processes in coal extraction, developing new technologies and equipment for effective coalbed degasification, developing equipment and protection means from methane, and coal dust explosion);
- Developing and introducing the system of measures aimed at improving the quality of coal production (including widespread use of techniques and technologies, providing for improvement in the quality of coal produced, developing and applying efficient coal preparation technologies, designing equipment to produce, transport, and store standardized coal fuel);
- Radical technical renewal of coal production (including equipping open-pit mines with highly productive mining, transport techniques of continuous and cyclical action, including for coalbed selective mining; developing underground coal-mining technologies with prior utilization of scouring mechanized complexes and excavating equipment of new technical level, as well as short bottom-hole technology with continuous miners and self-propelled means of transportation for coal);
- Developing production of liquid and natural gas products from high coal processing, integrated use of related resources, and coal conversion waste;
- Improving efficiency of scientific research on the safety of coal mining, as well as scientific research on geo-mechanical phenomena in management of coalbeds prone to sudden methane outbursts and mine dumps, developing measures to prevent them.

The new strategic objectives of the coal industry development are the following:

- Reliable and efficient satisfaction of domestic and external demand for top grade solid fuel and products of its processing;
- Provision of marketability of coal products under the conditions of domestic and foreign market saturation with alternative energy resources;
- Increase in the level of operational safety of coal mining and reduction in its harmful impact onto the environment. The restructuring of the coal industry, providing its transformation from a planned unprofitable industry into an efficiently operating one has been generally completed.

New highly efficient coal production facilities are under construction, which leads to reduction in coal production costs, growth of labor productivity, and reduction in industrial injury rate. State subsidizing of the coal industry has ceased. Development of the coal industry is performed mainly at the expense of internal funds of business entities and borrowed financial resources (about one third of the total volume of investments). Commissioning of new coal-mining facilities, mainly in the Kuznetsk Basin, resumed after a lengthy pause.

4.25.1 The New Coal Strategy

One of the objectives to be achieved by Russia in the implementation of the new Energy Strategy is the reduction of the CO_2 emission by the development of the coal industry on the basis of the use of new clean coal technologies for the generation of electricity. To achieve the strategic objective set for promoting a rational fuel and energy balance, the following goals must be realized: decrease in the share of gas in the domestic energy consumption along with the corresponding increase in the share of coal and nonfuel energy.

In order to achieve the strategic objectives of the coal industry development, the following main goals must to be realized:

- The program of unprofitable and unpromising coal mines closure completion;
- Provision of sustainable and rational reproduction of the mineral resource base of the coal industry;
- Rationalization of the structure and regional allocation of production facilities for coal mining and beneficiation providing efficient use of the resource potential of the industry;
- Transport and port infrastructure development aimed at the transportation of the coal cargo according to economically justified tariffs and diversification of destinations of their deliveries;
- Increase in efficiency of State regulation processes and processes of corporate management in the coal industry, providing sustainability of coal enterprise development and promoting growth of their competitiveness;
- Enhancement of efficiency of coal mining, beneficiation, and processing by improving technologies and equipment used, as well as introducing advanced organizational solutions;
- Production of high-quality end products (synthetic liquid fuel, ethanol and other products of coal chemistry with high added value), complex use of coal and associated resources, including coalbed methane.

The increase in the share of coal in the fuel and energy balance, contemplated in the context of the policy of the rational fuel and energy balance promotion, will require, alongside with creation of conditions for efficient interfuel competition, the optimization of coal production costs with simultaneous improvement of taxation system in the industry and application of flexible tariff regulation in railroad coal transportation.

Finally, it is important to highlight the following: At the first phase of the new strategy implementation, the following measures are planned to be fulfilled in the coal industry:

- Realization of a complex of program measures aimed at stabilization of the situation in the coal industry under the conditions of reduction in coal production;
- Completion of the coal industry restructuring;
- Technical re-equipment and intensification of coal production;
- Augmentation of coal beneficiation;
- Reduction in accident and injury rates at coal-mining facilities;
- Further development of the coal export potential of the industry.

The second phase of the new strategy implementation pertaining to the coal industry development contemplates formation of new coal-producing centers at new coal deposits with favorable mining and geological conditions; equipment of the coal industry enterprises with highly productive machinery and technologies meeting world environmental standards; elimination of system restrictions at coal products transportation to domestic and foreign markets; development of the outsourcing system; achievement of thermal hard coal maximum processing taking into consideration domestic market requirements; implementation of pilot projects on the basis of Russian technologies of high-level coal processing and coalbed methane production.

The third phase of the new strategy implementation pertaining to the coal industry development contemplates ultimate increase in labor productivity with meeting the world standards in the sphere of industrial safety, labor protection and environmental safety in the course of coal mining and beneficiation; commercial output of high-level processing coal products (synthetic liquid fuel, ethanol, etc.) and associated resources (methane, underground waters, and construction materials).

4.25.2 Production, Consumption and Reserves of Coal

According to the Energy Strategy of Russia for the Period up to 2030, Russia holds the second place in terms of coal reserves in the world (19 % of the world reserves), the fifth place in terms of annual production (5 % of the world production) and also accounts for approximately 12 % of the world thermal coal trade. Russia possesses substantial coal resources estimated by the EIA at 173,074 million short tons in 2008.

By the year 2030, Russia is going to boost its annual coal production to 430 million short tons. The target coal consumption figure at Russian thermal power plants projected for 2030, as per the Coal Industry Development Program up to 2030, is lower than the same in the Energy Strategy up to 2030: 102 and 158 million short tons, respectively. The forecast for coal consumption in the Russian energy generation sector, as laid out in the Coal Industry Development Program up to 2030, factors in the generating companies' actual plans with regard to the expected launch of new coal-based capacities and modernization of existing ones. Combined, these capacities are in total 26.1 million kWh by 2030. Plans for the period between 2012 and 2020 also include implementation of pilot projects for introducing modern coal combustion technologies at thermal power plants—initiatives seen as necessary for further scale-up to commercial application. The generating companies and coal enterprises are recommended to coordinate their development programs with government ministries and agencies so that the modernization efforts at coal-fired power plants would conform to the goal of using cleaned—or processed—coal as the primary fuel.

According to the Coal Industry Development Program up to 2030, State budget funding to be allocated for the implementation of the program is less than 9 % of its total funding (RUR 251.8 billion out of the total of RUR 3.7 trillion); the program envisages a new level of public–private partnership in the industry. The program also projects that by 2030, national coal production will grow to 430 million short tons, with coal mined at 82 opencast mines and 64 subsurface mines, and that labor productivity (output per one worker employed) will be five times as high as the same in 2010. Before the program is completed, plans also include launching 505 million short tons in new and modernized coal production capacities, while retiring 375 million short tons in unviable and loss-making capacities and reducing the level of wear and tear of fixed assets from 70–75 % to 20 %, a reduction of 50–55 %.

On the whole, according to the program, and in line with the adopted rate of establishing new major coal-mining areas, coal-mining activities are to be gradually shifted eastward. The contribution of mining operations in Eastern Siberia to total national coal production is expected to increase from 25.8 % to 32 %; this represents an increase of 6.2 % and the share of coal production in the Far East is expected to grow from 9.7 % to 15.2 %; this represents an increase of 6.5 %.

Russia is the largest coal consumer within the non-OECD Europe and Eurasia, consuming 4.3 quadrillion Btu in 2007 or 49 % of the total for this region. In Russia, the coal share of total primary energy supply is expected to decline from 16 % in 2010 to 14 % in 2040; a reduction of 2 %. The power and the industrial sectors are responsible for 89 % of the country's coal consumption, which was split almost evenly between the two sectors in 2010. Coal demand in the power and industrial sectors is expected to grow on average by 0.9 % per year and 0.5 % per year, respectively, from 2010 to 2040. Coal use in the residential and commercial sectors, primarily for space heating and water heating, accounted for the remaining 11 % of Russia's coal consumption in 2010—more than in any other country (IEO 2013).

That share is expected to decline to 6 % of total coal consumption in 2040, as the sector transitions to cleaner and more efficient energy sources for heating, such as electricity and natural gas.

Coal plays a relatively minor role in Russia's electric power sector, providing only 16 % of total electricity generation in 2010, compared with 50 % for natural gas. In January 2012, the government adopted a coal strategy that calls for a total of

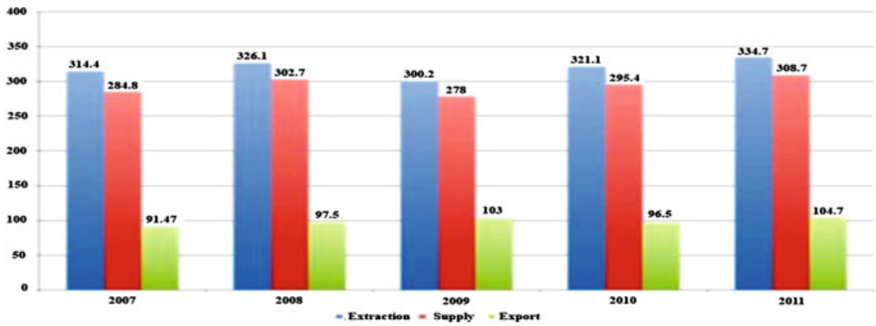

Fig. 4.45 Production, supply and exports of coal in Russia during the period 2007–2011. *Source:* Rosinformugol, Ministry of Energy of the Russian Federation, Russian Federal State Statistics Service

US$120 billion of private and public investment in the coal industry and includes plans to expand coal use in the electric power sector (Bryanski 2012).

Another main goal of the strategy is to increase exports, especially to Asia. The success of the strategy will depend on the future cost of long-haul inland transportation. In any event, the diversification-oriented policy is likely to spur some expansion of Russia's coal-fired generating capacity and encourage higher rates of growth in coal consumption compared with the rest of the non-OECD Europe and Eurasia region, where coal fuelled 34 % of total electricity generation in 2010. However, with natural gas supplies in the other countries of the region both abundant and less expensive than coal, their total use of coal for electricity generation is expected to grow by only 0.4 % per year on average from 2010 to 2040.

The evolution of the production, supply and exports of coal in Russia during the period 2008–2012 is shown in Fig. 4.45.

According to Fig. 4.45, the production of coal in Russia during the period 2007–2011 increased by 6.4 %. It is expected that the production of coal in Russia will continue increasing during the coming years. Although Russia possesses the world's second largest coal reserves, coal production is limited by both economic and logistical challenges. Because Russia is a major natural gas producer, with abundant supply available at relatively low subsidized rates from the State-owned natural gas company, its electric power sector has favored the use of natural gas. In contrast, the privatized coal sector saw its direct subsidies eliminated during industry restructuring in the 1990s. Depletion of coal reserves in European (Western) Russia, rising mining costs, and the high cost of transporting Siberian coal reserves over long inland distances further challenge the economics of Russian coal (IEO 2013).

The individual shares of the major coal-mining areas in national coal production are as follows: Kuznetsk Basin: 52 %; Kansk-Achinsk Basin: 12 %; Pechora Basin: 5 %; East Donets Basin: 3 %; and South Yakutsk Basin: 3 % (Slivyak and Podosenova 2013).

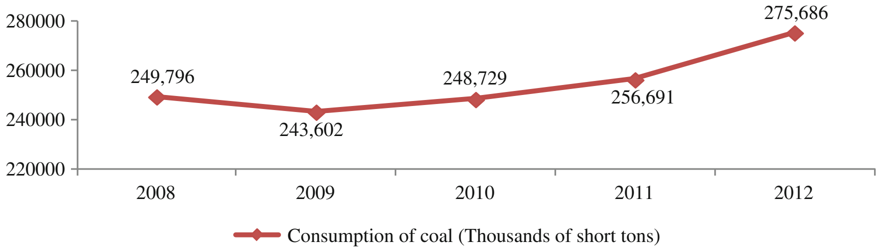

Fig. 4.46 Consumption of coal in Russia during the period 2008–2012. *Source:* EIA

The evolution of the consumption of coal in Russia during the period 2008–2012 is shown in Fig. 4.46.

The consumption of coal in Russia during the period 2008–2012 increased by 10.3 %, The lowest consumption of coal during the period considered was reached in 2009 due to the impact of the economic and financial crisis that still is affecting the whole European region. After that year, the consumption of coal started to increase once again.

4.25.3 Import and Export of Coal

Although Russia is one of the world's top coal-exporting countries, long inland transport distances from major coal-producing areas to export terminals add substantially to the cost of its coal exports at the ports. For example, rail shipping distances from the country's top-producing Kuzbass region in Western Siberia to ports in Northwest Russia, such as Ust-Luga, are approximately 2,600 miles, and rail shipping distances from Kuzbass to far Eastern ports, such as Vostochniy, are in excess of 3,600 miles, translating into shipping costs in excess of US$40 per ton (IEA Clean Coal Center 2013). On the other hand, Russia's relatively low coal production costs counterbalance the high inland transportation costs, keeping its exports competitive in world markets. According to the IEO (2010), rail bottlenecks from coal basins to port facilities appear to be Russia's primary limitation in its efforts to expand coal exports. Nevertheless, Russia has managed to triple its seaborne coal exports from 2000 levels for a total of 76 million short tons of coal in 2008. Russia's coal exports to Asia will be facilitated by capacity expansion at the new Pacific port of Muchka, where SUEK[16] has built about 13 million short tons an annual export capacity, and MECHEL has plans for about 28 million short tons of export capacity at the new Muchka Bay Terminal 2. As in 2008, Eurasia (primarily Russia) is expected to supply 8 % of the coal traded internationally in 2035.

[16] Siberia's coal energy company.

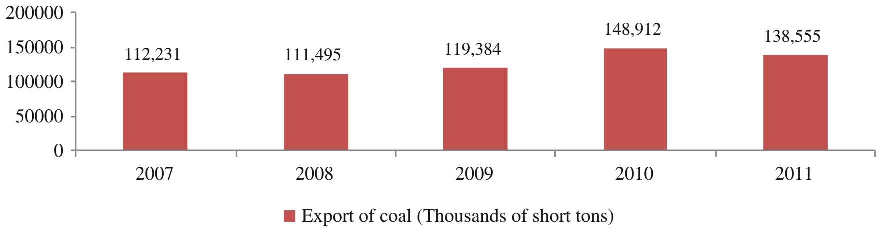

Fig. 4.47 Exports of coal from Russia during the period 2007–2011. *Source:* EIA

The evolution of the exports of coal from Russia during the period 2007–2011 is shown in Fig. 4.47. According to that figure, the evolution of the exports of coal from Russia during the period 2007–2011 increased by 23 %. It is expected that the exports of coal from Russia will continue increasing during the coming years, if the government allocated sufficient resources to improve the infrastructure of the coal sector.

According to Slivyak and Podosenova (2013), the reason that Russia has seen a rise in its export of coal is by no means because there is an excess of coal on the domestic market, nor because of a rising demand for Russian coal on the markets abroad. This is a move borne of necessity—the result of technical limitations of boiler equipment in use at the thermal power plants operating in Russia. These plans have no need for high-rank coal as they are designed to burn fuel supplied from the specific coalfields. Of the total annual volume of coal burnt at Russia's thermal power plants today, 90 % is coal of lower ranks, and high-quality coal is shipped for export.

Export has become the largest consuming sector for Russian thermal coals, while the share of supplies to the country's own power plants has declined from 39.8 % to 31.4 %; this represents a decrease of 8.4 %. The internal consumption sector offers hardly any margin for growth, while foreign markets are becoming ever more competitive. In global coal exports, as well as in the global coal pricing trends, the market is shaped by five heavyweights that together account for between 70 % and 80 % of all export shipments of coal: Australia, Indonesia, Russia, China, and South Africa. As for demand for coal, this is determined by developing countries—first and foremost, by the fast-growing economies of China and India. The primary consumers of coal products are Japan, China (including Taiwan), and South Korea. Japan, South Korea, India, and Taiwan are also the largest importers of coal on the Asian market, with Germany and Great Britain is the principal importers in Europe.

Russia supplies coal to over thirty countries. The list of the world's largest consumers of Russian coal included Cyprus, Ukraine, Japan, Poland, Turkey, Finland, Bulgaria, Belgium, the Netherlands, Slovakia, Spain, South Korea, Great Britain, Switzerland, Romania, Italy, Germany, Kazakhstan, Hungary, and Lithuania, accounting for over a third of all export shipments. In early 2012, speaking at a meeting discussing the development of the country's coal industry, Russian Minister of Energy projected that Russia's coal exports to the countries of the Asia–Pacific region 85 million short tons by 2030.

However, it is important to know that the future of coal exports from Russia remains uncertain, but they will most likely play a minor role in the world coal market of around 8 % of the total. The reasons are the following:

- Except for the coalfields currently in operation in the Kuzbass region (Western Siberia), the great majority of Russia's other coal reserves is located in the Central and Eastern parts of the country, away from both the main consuming centers in the Western (European) part of the country and the seaports in the Far East. Bringing that coal to either destination involves expensive rail transport. Rail transport is also required for the currently operated Kuzbass coal mines. Consequently, Russia is a relatively expensive producer of coal and can be competitive on the world market only when international coal prices are high;
- Russia's railway system is generally not in a good state. There is a particular dearth of railway infrastructure in the low-populated Siberian regions, where the major coalfields are located. The seaport infrastructure is not any better either. Significant investment is needed to overcome these shortcomings, but the funds have not been secured;
- Coal production and exports suffer from a generally low level of mechanization and productivity, as well as poor mine safety (Kavalov and Peteves 2007).

There are a few options that could be considered by the Russian government to increase coal exports in the coming decades, but all of them need important investment. The most feasible option, which, however, would not boost coal exports, would be to use the coal from remote fields for internal energy needs. This could be done either by building coal-fired power plants near the remote deposits and then transmitting or exporting the electricity or via gasification of the coal reserves with subsequent transshipment of the coal-derived gas. In both cases, significant investment is needed to improve and/or construct new transmission networks and/or pipelines. This option might be attractive for Russia from a strategic point of view, since it would release additional natural gas for export, maybe the country's most strategic export commodity (Kavalov and Peteves 2007).

Russia imports some amount of coal. The evolution of the imports of coal from Russia during the period 2007–2011 is shown in Fig. 4.48.

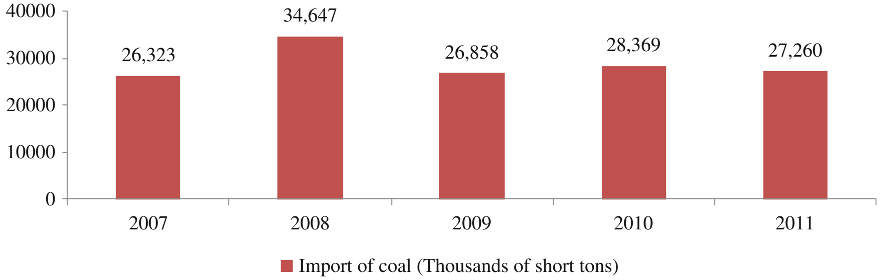

Fig. 4.48 Imports of coal from Russia during the period 2007–2011. *Source:* EIA

According to Fig. 4.48, the imports of coal from Russia during the period 2007–2011 increased by 3.5 %. The peak in the imports of coal during the period considered was reached in 2008. It is expected that Russia will continue importing coal during the coming years.

4.25.4 Electricity Generation

Although natural gas is the leading source of electricity generation in Russia, and continues to hold that position throughout the coming decades, increased electricity generation from nuclear and coal-fired power plants, taken together, will account for 68 % of the country's generation growth. Over 140 thermal power plants in Russia run on coal; the number of boiler houses using coal as fuel is unknown, but may be assumed to add up to tens of thousands. Paying due attention to the ecological consequences of burning coal for power generation is important because in plans developed through 2020, it is thermal power plants that are projected to remain the country's primary energy-producing sources, and the proportion of coal-fired plants in the national fuel mix may increase from 25 % to 36–37 %, with the share of natural gas decreasing from 70 % to 58 %. If this happens and government programs are implemented according to plan, then CO_2 emissions may in 10 years rise by 1 million tons.

Coal-fired power generating units operating in Russia are equipped with technologies that do not allow for efficient capture, transportation, storage, and management of coal ash and boiler slag. They are also characterized by relatively high levels of atmospheric pollution. Emissions of fine suspended particles and sulfur dioxide from many coal-fired generating units in Russia are about 10 times higher than at coal-fired power plants in the EU. Fine particulate matter is especially hazardous to human health, and the additional mortality associated with the impacts

Table 4.11 Operating and economic characteristics of standard 1,000 MW power plant, with breakdown by fossil fuel type

	Modern Russian coal-fired plants	Coal-fired plants in developed countries	Modern Russian natural gas plants
Capital costs (U.S. dollars per kilowatt installed capacity)	1,400–1,700	1,400–1,700	800–1,000
Capacity factor (%)	35–36	40	45–55
Sulfur dioxide emissions (tons per year)	11,0000	5,500	20
CO_2 emissions (tons per year)	2,000	1,051	600
Nitrogen oxides emissions (tons per year)	27,000	600–1,600	200–1,700
Ar ea of land condemned for power plant construction (hectares)	24,.000	15,000	

Source: Slivyak and Podosenova (2013)

of atmospheric pollution is primarily attributed to the health effects of fine particles in the air (Slivyak and Podosenova 2013) (see Table 4.11).

The total investment that is needed in the electricity sector during the period 2008–2013 will be between US$572 billion and US$888 billion. An important part of this investment is for improving the electrical grid.

4.26 The United Kingdom

Starting in 1993, and continuing throughout the 1990s, a combination of factors led to a so-called "Dash for Gas", during which the use of coal was scaled back in favor of gas-fuelled generation. This was sparked by the privatization of the National Coal Board, British Gas, the Central Electricity Generating Board, the introduction of laws facilitating competition within the energy markets, and the availability of cheap natural gas from the North Sea.

4.26.1 Production, Consumption and Reserves of Coal

The country produced 30.6 million short tons in 2003, the fifth most in the EU. Coal production in the UK has declined steadily and dramatically over the past several decades. Decreasing domestic consumption and a surge of low-cost imports have been the principle causes of the production decline. According to the Department of Energy and Climate Change, coal production in 2010 was 18.2 million short tons, which is 1.6 % higher than in 2009, but 41 % lower than the production reached in 2003. Deep mined production was down 1.7 %, while surface mine production was up 4.7 %.[17] Generators' demand for coal was higher by 5 % in comparison to 2009. In 2012, the total coal production in the UK reached 18.145 million short tons, which is 0.4 % lower than in 2010.

The proportion of coal consumed by power plants increased steadily since the 1970s to reach 86 % in 2006 before falling back to 83 % in 2008, a decline of 3 %. The decline in coal consumption at power plants reached a low of 41.8 million short tons in 1999 before climbing to 57.9 million short tons in 2006. Since then it has declined and in 2009 it stood at 40 million short tons, the lowest levels during the period 1980–2009 (see Table 4.12). Coal consumption as a whole declined sharply during the 1990s, at an average annual rate of 6 % compared with just a 1 % annual decline over the previous 20 years. Between 1999 and 2006, coal consumption grew by nearly 3 % per year on average, but in 2007 and 2008 it fell back by around 7 % per year and by a further 16 % in 2009 because of lower coal demand in power plants. By 2004, coal use in power plants had fallen by 43.6 % (50.5 million short

[17] Coal production was 1 % lower in 2009 than in 2008; deep mined production fell by 7 %, while opencast production increased by 4 %.

Table 4.12 Coal consumption (Million short tons)

	1980	1999	2000	2007	2008	2009
Power plants	89.6	84	46,8	53	48.3	40.1
Domestic	8.9	4.2	1.9	0.6	0.7	0.7
Industry	7.9	6.3	1.9	1.9	1.9	1.8
Services	1.8	1.2	0.1	<0.1	<0.1	<0.1
Other energy industries	15.3	12.5	9.2	7.4	7.4	6.1
Total consumption	123.5	108.3	59.9	63	58.4	48.8

Source: UK Energy in Brief (2010)

tons, representing 82.4 % of all coal used in 2004) compared to 1980 levels, though up slightly from its low in 1999.

It is important to note that in the early years of the 2000s, concerns grew over the prospect of an energy gap in UK generating capacity, because it was expected that a number of coal-fired power plants will close due to being unable to meet the clean air requirements of the European Large Combustion Plant Directive (Directive 2001/80/EC 2001).

On the other hand, the Low Carbon Transition Plan launched by the British government in July 2009 aims at 30 % of renewable and of 40 % of low CO_2 content fuels in electricity generation by 2020. Government policy plays a key role in the issues of limiting greenhouse gas emissions and of meeting demand. Shifting availabilities of resources and development of technologies also change the country's energy mix through changes in costs.

In order to meet its obligations under the Kyoto Protocol, the UK likely will continue to phase out coal consumption and production, particularly for the generation of electricity. In June 2003, the UK's government launched the Coal Investment Aid program, with a budget of up to US$111 million. The goal of the project is to create or safeguard jobs in the UK's coal industry by encouraging coal producers to enter into investment projects that maintain access to reserves.

In 2008, the country's coal reserves were estimated at 251 million short tons, according to EIA sources.

4.26.2 Import and Export of Coal

Imports, initially of coal types in short supply in the UK, started in 1970 and then grew steadily to reach around 20 million short tons a year by the late 1990s. The very rapid expansion of imports of coal in 2001 meant that imports exceeded the level of the UK's production for the first time. Since 2002, imports of coal have risen by 15 % a year on average and in 2006 imports were at a record 50 million short tons to meet strong demand from generators and the steel industry. However, since the end of 2008, levels have started to decrease and in 2009 UK imports 42.268 million short tons of coal; this represents a reduction of 14.1 % respect to 2008. Despite this fall, UK imports of coal still accounts for more than two-thirds of UK's supply. Imports of coal in 2010 fell to 29.381 million short tons, 29.331 million short tons below the record high in 2006; this means 41.3 % lower than in 2009. According to DTI, the UK now imports more coal than it produces domestically, with South Africa and Australia representing the principle source of these imports.

The evolution of the imports and exports of coal in the UK during the period 2007–2011 are shown in Figs. 4.49, 4.50 and 4.51. According to Fig. 4.50, the imports of coal from the UK during the period 2007–2011 decreased by 27 %. The lowest level in the imports of coal during the period 2007–2011 was reached in 2010. The peak in the imports of coal was reached in 2008. Since that year, the imports of coal in the UK has dropped in 2009 and 2010 and started to increase once again in 2011.

It is expected that the UK will continue to import coal during the coming years.

From Fig. 4.51, the following can be stated: the exports of coal increased by 19.5 % in the UK during the period 2007–2011. The peak in the export of coal during the period considered was reached in 2010. It is expected that the UK will continue exporting coal during the coming years.

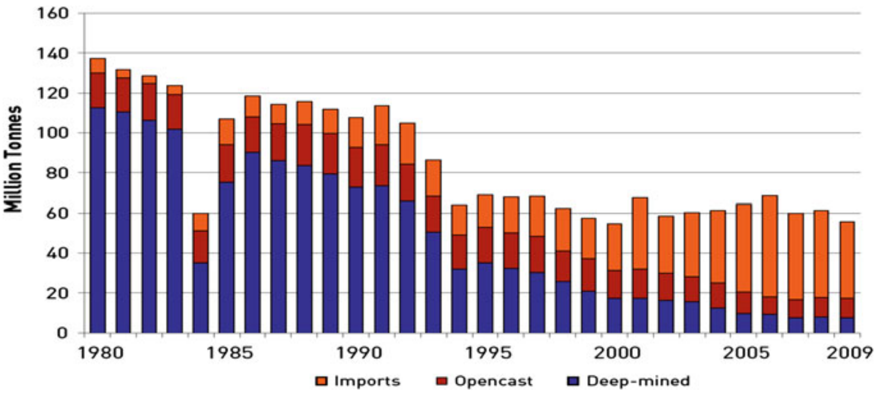

Fig. 4.49 Coal imports from the UK during the period 1980–2009. *Source:* UK Energy in Brief (2010)

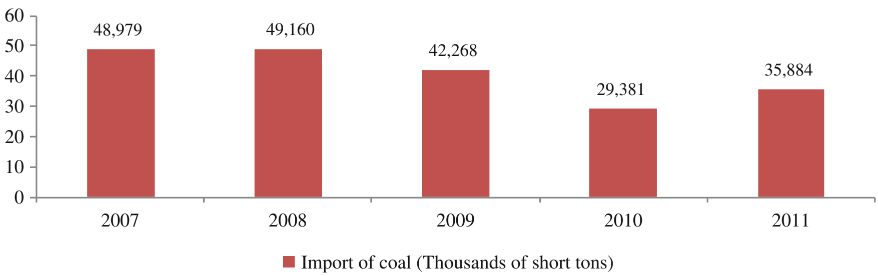

Fig. 4.50 Imports of coal from the UK during the period 2007–2011. *Source:* EIA

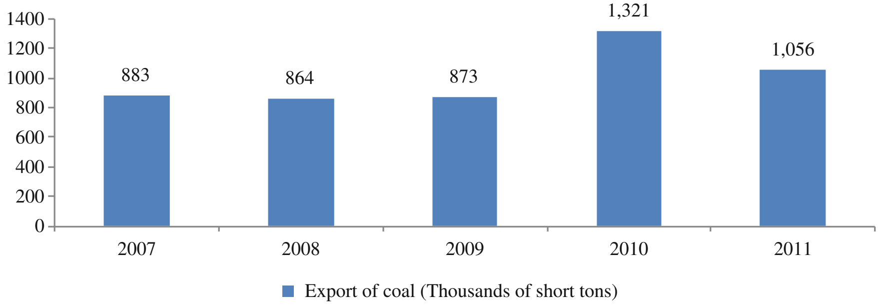

Fig. 4.51 Exports of coal from the UK during the period 2007–2011. *Source:* EIA

4.26.3 Electricity Generation

According to the Department of Energy and Climate Change, total demand for coal in 2010 as a whole, reached 51.3 million short tons; this means 5.2 % higher than in 2009, with consumption by electricity generators up by 5 %. Electricity generators accounted for around 81.2 % of total coal use in 2010, broadly similar to that recorded in 2009. Coal produced 28.5 % of the total electricity generated in the country in 2010. Final consumption decreased by 0.8 % (less than 0.1 million short tons) in 2010 compared with 2009.

Overall, coal use by electricity generators has been generally declining since the first quarter of 2006, when demand peaked at 19 million short tons. This decline is partly due to higher coal prices, making natural gas more competitive for electricity generation. Generators use of coal was at its lowest level since records began in the third quarter of 2009 (6.4 million short tons), but has more than doubled since then to 13.7 million short tons in the fourth quarter of 2010. This was partly due to the exceptionally cold weather conditions during December 2010. In 2010, coal's share of electricity supplied rose by 0.7 to reach 28.4 %. In the third quarter of 2013, coal-fired generation fell by 9.5 % from 28.8 billion kWh in the third quarter of 2012 to 26 billion kWh in 2013. In the same period, coal's share decreased from 35.3 % to 33.3 % (a decrease of 2 %), and it is expected that this trend will continue during the coming years.

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Chapter 5
Conclusion

Undoubtedly, energy production and, particularly, the generation of electricity and their sustained growth, constitute indispensable elements for the economic and social progress of any country. Energy constitutes the motive force of civilization and it determines the level of economic and social development of any country. To ensure adequate economic and social growth in any country, it is indispensable that all available energy sources be used in the most effective and economical manner, particularly for the generation of electricity.

Therefore, the growing price of energy resources and expensive infrastructure is becoming the key issue while solving questions of economic development and integration; and this factor may turn into the one that influences the speed of economic growth of the country the most. The attention of the society to the energy sector development is related to the need for welfare, growth as well as the aspiration to have safe and ecologically harmonized environment. For this reason, the main task of the energy sector today is a reliable generation of safe, ecologically clean, effective and economically perspective energy. This objective may be implemented by forming the energy sector management policy, by changing and defining management and operational costs, and by assessing the impact of energy infrastructure on ecology. Therefore, the need emerges to estimate various aspects of electricity production, transmission and distribution activity by more exhaustive methods, applying environmental assessment, developing and establishing ways that may become helpful in the decision making process (Šliogerien and Krutinis 2008).

According to different expert's opinions in the field of energy, the use of energy at world level will continue increasing gradually until 2030. According to studies made by the French Association of Oil Professionals, "it is expected that for 2030, the world energy demand will be double and it is probably that could be triple for 2050". Until 2030, the primary energy demand at world level is expected to increase annually at 1.7 %, which is somehow smaller than the world growth of 2.1 % registered during the past three decades. It is also expected that 90 % of the increase in the world energy demand in the coming decades will be satisfied with fossil fuels, particularly with natural gas and in a minor scale by coal. If this forecast is true, then around 112,500 million of barrels of oil will be consumed at world

J. Morales Pedraza, *Electrical Energy Generation in Europe*,
DOI 10.1007/978-3-319-08401-5_5

level in 2030 and the production of electricity will account for 32 % of the total global fossil fuel consumed. For this reason, improving the efficiency with which electricity is produced is one of the most important ways of reducing the world's dependence on fossil fuels, particularly oil and coal, thus helping both to combat climate change and improve energy security.

The mix of primary fuels used to generate electricity has changed a great deal over the past four decades on a worldwide basis. Coal continues to be the fossil fuel most widely used for electricity generation in almost all regions (except in the Latin America and the Caribbean region). However, electricity generation using natural-gas-fired power generation plants grew also rapidly in the 1980s and 1990s, and it is expected to continue to grow in the next two decades.

The use of oil for electricity generation has been declining since the mid-1970s, when oil prices rose sharply. High fossil fuel prices recorded between 2003 and 2012, combined with concerns about the environmental consequences of greenhouse gas emissions, have renewed interest in the development of alternatives to liquid fuel, specifically different renewable energy sources, including nuclear energy in some countries, for electricity generation.

In the specific case of OECD Europe, electricity generation is expected to increase by an average of 1 % per year, from 3,496 billion kWh in 2010 to 4,765 billion kWh in 2040. Because most of the countries in OECD Europe have relatively stable populations and mature electricity markets, most of the region's growth in electricity demand comes from those nations with more robust population growth (such as Turkey) and from the newest OECD members (including the Czech Republic, Estonia, Hungary, Poland, and Slovenia), whose projected economic growth rates exceed the OECD average.

The net growth in the past 11 years of natural gas power (118.2 GW), wind power (75.2 GW) and solar photovoltaic (26.4 GW) was at the expense of fuel oil (down 13.2 GW), coal (down 9.5 GW) and nuclear energy (down 7.6 GW). In the specific case of the EU power sector, countries continue to replace ageing fuel oil, coal and nuclear power plants with modern technology, whilst at the same time increasing its total installed capacity to meet increasing energy demand in the coming years (EWEA 2011).

5.1 Liquid Fuels

According to the IEO (2013), the use of all energy sources increases over the time horizon. Given expectations that world oil prices will remain at levels that are high relative to historical experience throughout the projection, petroleum and other liquid fuels are the world's slowest-growing source of energy. Liquids consumption is expected to increase at an average annual rate of 0.9 % from 2010 to 2040, whereas total energy demand increases by 1.5 % or 1.7 % per year. Nuclear power and renewables are the fastest-growing sources of world energy, both increasing at an average annual rate of 2.5 %. Concerns about energy security, the impact of fossil fuel emissions on the environment, and sustained high world oil prices support expanded use of nuclear power and renewable energy over the projection. Government policies and incentives improve the prospects for non-fossil forms of energy in many countries around the world in the outlook.

The liquid fuels share of world marketed energy consumption is expected to fall from 35 % in 2007 to 30 % in 2035; this means a decrease of 5 %. The current high world oil prices lead many energy users to switch away from liquid fuels for electricity generation, when feasible, and replace them with different types of renewable energy sources (IEO 2010).

Europe's power mix changed dramatically over the past 40 years. Four decades ago, almost half of Europe's power came from coal, and a quarter from fuel oil. Back then natural gas was at the level that wind energy is today; less than 3 % of the Europe's power came from nuclear energy. Today Europe generates about one quarter of its electricity from natural gas, just 3 % of fuel oil and in 2009 about 20 % of renewable energy sources (EWEA 2011).

During the past decades, the use of liquid fuels grows modestly or declines in all end-use sectors except transportation, where in the absence of significant technological advances liquid fuels continue to provide much of the energy consumed.

On the other hand, electricity generation from petroleum and other liquid fuels is expected to decline during the next three decades, continuing a two-decade long trend. Worldwide, electricity generation derived from liquids is expected to fall from 5 % of total production in 2010 to 2 % in 2040. Nations respond to high, sustained oil prices by reducing or eliminating their use of oil for generation—opting instead for alternative sources of electricity, including natural gas and nuclear. Even in the petroleum-rich Middle East, there is an effort to reduce the use of liquids for generation in favor of natural gas and other resources, in order to maximize revenues from oil exports. The liquids share of total generation in the Middle East region is expected to decline from 34 % in 2010 to 14 % in 2040. It is also expected that the generation of electricity from liquid fuels decreases from 0.9 trillion kWh in 2007 to 0.8 trillion kWh in 2035; this represents a decrease of 11.2 %.

5.1.1 Crude Oil

Despite the different levels of world's crude oil reserves predicted by different experts, one thing is true world's crude oil reserves are declining and will continue this trend during the next decades (Morales Pedraza 2008). For this reason, many European countries are reducing the participation of oil in their energy mix, and some of them are expecting that this participation reaches 0 before 2050. Every region of the world outside Europe saw its oil reserves increase between 1991 and 2011. Those of South America (19.7 % of the total), Africa (8 %) and the Community of Independent States (7.7 %) rose most significantly, the first having quadrupled (as a result of the decision of Venezuela to report its huge extra heavy oil resources), whilst the other two doubled over the period. The trend for other regions varied from

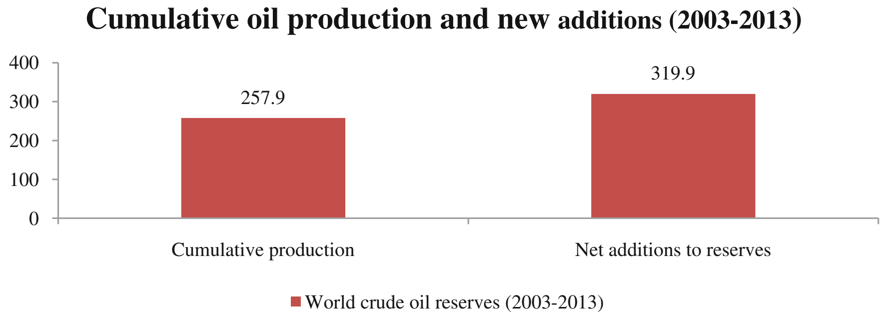

Fig. 5.1 The cumulate global crude oil production during the period 2003–2013. *Source:* OPEC

+77 % for North America (13.2 % of total as a result of the Canada effect) to 20 % for the Middle East (48.1 % of the total) and 12 % for Asia (2.5 % of the total). Europe (0.9 %) was the only region to see a decline of 21 % (World Energy Council 2013).

According to International Association of Oil and Gas Producers, in more than 150 years of intensifying use, the world has consumed about 1 trillion barrels of crude oil. Thanks to growing investment in exploration, production, and innovative technology, crude oil proven reserves have been increasing steadily since the 1980s. However, according to different expert's calculations, the world newly-increased reserves had reached the summit in the 1960s and started to decrease in the past 40–50 years. The prediction model stated that the global ultimate recoverable crude oil reserves are about 400 billion tons. And between the year 2008 and 2035, the world newly-increased crude oil reserves were supposed to be about 410 billion tons. The cumulate global crude oil production during the period 2003–2013 is shown in Fig. 5.1.

At the same time, annual global consumption was approximately 31 billion barrels. Therefore, at that rate of consumption, the world has enough oil to satisfy the demand for some 40 years.

The situation of world crude oil exploitation has been worsening in recent years. Presently, there are sixty super-giant oil fields with reserves more than 5 billion barrels per field in the world. Meanwhile, the production from sixteen of top forty has continually decreased and another six oil fields, including Ghawar just struggle to maintain the stable production. Among 48 major crude oil producing countries, 20 of them have overall declined production. Along with the decline of crude oil production in more and more countries after 2015, it is a tough challenge for increasing the total global capacity of crude oil production. According to the Hubbert Model, the world crude oil production will meet the comprehensive decline from 2025 to 2030. The possibility of remarkably increase of world crude oil production in the future will be quite dim.

The global total crude oil consumption in 2012 was 88,868 thousands of barrels according to OPEC sources. The OECD crude oil demand increase ended in 2000 after consecutive increase for 14 years. From 2001 to 2008, the year-to-year rate of crude oil demand from OECD countries averagely decreased by 0.08 %. And this number was down 3.2 % in 2008. It is predicted that the crude oil consumption demand will keep dropping in the future, according to the national energy policy of OECD and new energy development trend. The prediction shows that the consumption of OECD will decrease between 1.78 and 1.97 billion tons in 2020 from 2.18 billion tons of 2008 with average year-to-year dropping of almost 1.2 %.

After so many years of discriminatory crude oil consumption in the world, now this type of fuel faces a serious problem that can limit, in a future not very distant, the possibilities of economic growth of several countries, particularly those without significant reserves of this and other types of energy sources. In addition, the availability of crude oil for electricity generation and for other uses is more limited now than in the past due to the following reasons:

- A decrease of the world's crude oil reserves;
- The current high level of crude oil consumption;
- The ongoing high world crude oil price;
- The negative impact on the environment caused by the burn of oil for the generation of electricity.

Summing up, it can be stated the following: According to BP Statistical Review of World Energy 2011, after falling for two consecutive years, global crude oil consumption grew by 2.7 million barrels per day or 3.1 %, to reach a record level of 87.4 million barrels per day. This was the largest percentage increase since 2004, but still the weakest global growth rate among fossil fuels. OECD consumption grew by 0.9 % (480,000 barrels per day), the first increase since 2005. Outside the OECD, consumption growth was a record 2.2 million barrels per day or 5.5 %. Global crude oil production increased by 1.8 million barrels per day or 2.2 %, but did not match the rapid growth in consumption. The gains in production were shared between OPEC and non-OPEC producers. Crude oil production outside OPEC grew by 860,000 barrels per day or 1.8 %, the largest increase since 2002. Growth was led by China—which recorded its largest production increase ever—the US, and Russia. Continued declines in Norway—which saw the world's largest decline—and the UK partly offset growth elsewhere.

Non-OPEC countries accounted for 55.5 % of global crude oil production in 2012. Global crude oil runs increased by 1.8 million barrels per day or 2.4 %. Non-OECD countries accounted for 85 % of the increase, and for the first time accounted for a majority of global throughput. Chinese throughput grew by 1 million barrels per day or 13.4 %.

Global refinery capacity utilization rose to 81.5 %. Refining capacity increased by 908,000 barrels per day in 2012 or 1 % respect to 2011. Capacity additions were concentrated in the non-OECD countries, with growth in China (200,000 barrels per day) accounting for almost 22 % of the global total in that year.

After two consecutive declines, global oil trade grew by 2.2 % or 1.2 million barrels per day, with net Asia Pacific imports accounting for nearly 90 % of the growth. Net imports grew robustly in China (over 14.6 %, 680,000 barrels per day) and Japan (over 7.1 %, 280,000 barrels per day). Net export growth was largely from the former Soviet Union (over 7.2 %, 570,000 barrels per day) and the Middle

East (over 2.6 %, 470,000 barrels per day). The growth in global trade was roughly split between crude and refined oil products, though crude oil still accounts for 70 % of global oil trade.

The only country in the European region included within the ten top crude oil producer is Russia. The other main European crude oil exporter outside the top ten is Norway. The main European crude oil importers are Germany, followed by Italy, France, Spain and the Netherlands.

5.2 Natural Gas

In the case of natural gas, there are enough reserves to satisfy the demand during the coming decades. According to EIA sources, global natural gas demand is expected to grow over 9.7 billion m^3 per day (0.2716 billion cubic feet average per day) by the year 2015, and is expecting a further growth in demand around 11.2 billion m^3 per day (0.3136 billion cubic feet average per day) by 2025.

Natural gas is the second-largest source of energy in Western Europe. Most of it is extracted from British, Dutch, Italian, Romanian, German, and Danish fields, with additional natural gas imported from Russia, Norway, and Algeria. According to IEA Natural Gas Information 2010, there are seven major natural gas markets in OECD Europe. These markets are: UK (18 % of the total demand), Germany (18 %), Italy (15 %), Netherlands (9 %), France (8 %), Spain (7 %) and Turkey (7 %) (Fig. 5.2).

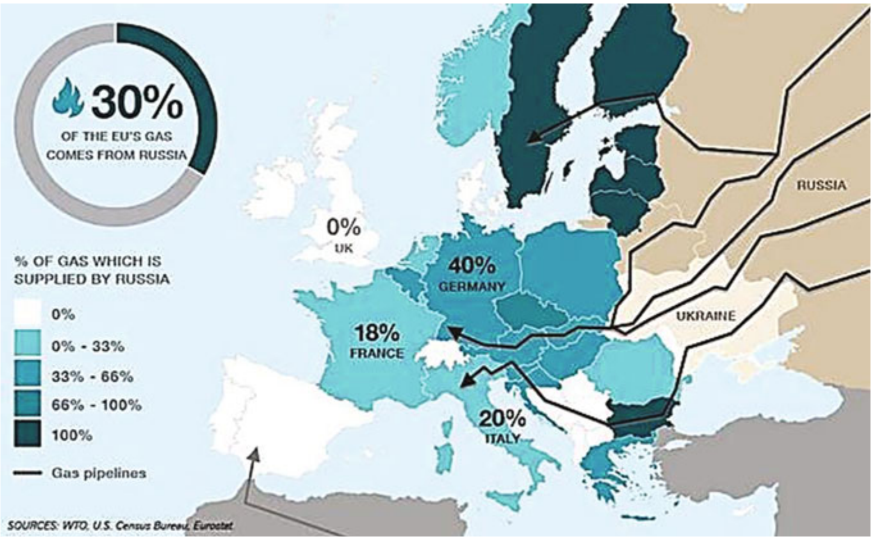

Fig. 5.2 The import of natural gas from Russia. *Sources:* WTO, US Census Bureau, Eurostat

To increase the import capacity and reduce the dependency on suppliers, a number of infrastructure projects supported by the EU have recently been initiated. There are, however, still a number of challenges facing the EU gas market which need to be resolved. These include inter alia reducing the vulnerability to gas supply shocks, facilitating the development of an integrated gas market, planning for increasing import dependency and addressing climate change issues.

Security of supply is one of the priority objectives of the EU's new energy policy. The EC is concerned that Europe's energy networks are no longer up to the task of providing secure energy supply in the foreseeable future. The physical ruptures of energy transportation networks following the crises with transit countries (Ukraine in 2006 and 2008 and Belarus in 2007, just to mention only a few examples) have forced the EU to adopt the strategy of diversifying supply routes, which would gradually reduce its dependence on transit countries.

Due to its transnational character involving a diversity of stakeholders, the cross-border pipeline projects require close cooperation between States. As the existing EU natural gas market has a regional character, there is a need for improving energy networks. Regional cooperation is particularly crucial for natural gas infrastructure to ensure a timely response in case of crises. Energy networks must take a more prominent place in energy policy development and implementation. Transparency should be improved to resolve the issue of consolidation and concentration of national markets, which constitute a barrier to a sufficient expansion upstream (Bjørnmose et al. 2009).

To ensure regulatory coherence and enhanced security of supply, cooperation between States is crucial. As set out in the EC's Second Strategic Energy Review and the EC's Green Paper "Towards a Secure, Sustainable and Competitive European Energy Network", the EU will be unable to deliver its climate and energy goals without new and improved networks.

The generation of electricity is an important user of natural gas and its participation in the energy mix of the European countries could be higher in the coming decades. However, the electricity generated from natural gas is generally more expensive than that generated using coal, because of increased fuel costs. Natural gas can be used to generate electricity in a variety of ways. These include conventional steam generation, similar to coal-fired power plants, in which heating is used to generate steam, which in turns runs a turbine with an efficiency between 30 % and 35 %; a centralized gas turbine, in which hot gases from natural gas combustion are used to turn the turbine; and a combined cycle unit, in which both steam and hot combustion gases are used to turn the turbine with an efficiency between 50 % and 60 % (Demirbas 2010).

Gas demand has grown rapidly across Europe over the past 30 years and power generation—shaped by environmental and commercial advantages enjoyed by natural gas—is the key to continued growth over the next several decades. Imports of natural gas will be needed increasingly as Europe's indigenous supply declines, and for this reason Russia is expected to increase its role as a source of energy and its contribution, particularly in terms of natural gas and oil supplies. Increase the role to be played by Russia in the supply of natural gas is a great concern of the EU, which has increased after the Crimea crisis.

In contrast to the anticipated substantial increases in natural gas demand over the next 30 years, European natural gas production is forecast to decline substantially over the coming years. According to the European energy and transport trends to 2030, the EU-27 natural gas production is expected to decrease from the level of around 200 billion m^3 today to approximately 100 billion m^3 in 2020; this represents a decrease of around 50 % for the next 8 years. For example, the UK is projected to be importing around half of its natural gas supplies during this decade and between 50 % and 80 % by 2020. By that year, Dutch supplies are also likely to be in decline. While Norwegian natural gas exports are continuing to increase, they reached a plateau of 95–100 billion m^3 in the past decade, and additional exports beyond this level will require new discoveries.

According to different sources, natural gas consumption increased steadily in Europe over the period 1990–2008. It grew at an annual average rate of 4.2 % in the 1990s, but slowed to 2 % from 2000 to 2008. For the first time in 20 years, data on natural gas consumption for 2009 showed plunging natural gas demand in the face of the world economic contraction (but also because of the Russia–Ukraine dispute in January 2009), demand in OECD Europe fell by 5.6 %, losing about 26 billion m^3 and falling back to 2003 levels.

Natural gas consumption is expected to return to 2008 levels around before 2014, but with major differences between the national markets, sectors of consumption, and the period of recovery. Indigenous production and annual contracted quantity levels of imported natural gas can cover demand up until at least 2012, but all contracted natural gas, including LNG, is expected to be below demand post 2014 (or later if demand does not pick up as anticipated), which means that, despite a catastrophic 2009 year for natural gas demand, Europe will need to secure additional natural gas supply probably as soon as 2015 to cover its still growing consumption. The present utilization of below 50 % of LNG facilities is a good possibility to increase the LNG imports, thus diversifying even more. In the long-term, focus will shift to ensure the availability of natural gas by filling the import pipelines and LNG import facilities. The largest reserves within pipeline distance and with LNG capacity are found in the Russian Federation, Iran, and Qatar. Russia alone would be able to supply the EU-27 consumption of 500 billion m^3 for 90 years.

Growth in natural gas use for electricity generation is projected to account for the majority of total incremental natural gas use to 2030. Natural-gas-fired power generation is less carbon-intensive than oil or coal-fired power generation, and is expected to remain more cost-competitive than renewable energy, making natural gas the fuel of choice for new generating capacity in OCED Europe in the coming decades. In the specific case of OECD Europe, natural gas consumption is expected to grow by 0.5 % per year on average, primarily as a result of increasing demand in the electric power sector. Natural gas accounts for about one-fourth of the region's total energy consumption over the next two decades, with the coal and liquid shares declining from their earlier levels.

Finally, it is important to highlight the following: The power sector holds the key to substantially increased natural gas demand in Europe over the next three decades. All projections of European natural gas demand see the power sector accounting between 65 % and 80 % of the increase in natural gas demand over this period. According to IEA sources, this equates to an increase in OECD European natural gas demand for power from around 115 billion m^3 in 2000 to more than 400 billion m^3 in 2030; an increase of 248 %. The reasons for this very high share of natural gas are straightforward:

- At most likely natural gas prices, electricity generated by natural gas will have a cost advantage over that generated by coal;
- In most European countries, nuclear power plants are either politically unacceptable or commercially too risky to be built by private companies and some countries are closing all of their nuclear power currently in operation in the coming years, such as Germany, Switzerland, among others;
- Renewable energy sources of electricity are currently more expensive than power generated from fossil fuels and are not expected to account for more than 20 % of electricity demand in the majority of countries over the next 30 years.[1]

This picture suggests that natural gas can be regarded as the fossil fuel bridge to a sustainable electricity future and—as long as the differential between natural gas and coal prices does not widen too greatly—will be the most commercially attractive fuel for power generation during the coming years.

Many governments in OECD Europe have made commitments to reduce greenhouse gas emissions and promote the development of clean energy for electricity generation. Because natural gas is less carbon-intensive than either coal or oil, it is a more environmentally attractive option for electricity generation, and thus is likely to remain an important fuel for Europe's electric power sector development in the long-term.

Russia is the world's second-largest consumer of natural gas after the United States, with demand, totaling 589.76 trillion m^3 (16.7 trillion cubic feet) in 2007, representing 55 % of Russia's total energy consumption. It is expected that Russia's natural gas consumption will grow at a modest average rate of 0.2 % per year from 2007 to 2035. It is important to highlight that natural gas is the largest component of the country's primary energy consumption, representing more than 45 % of the total throughout the coming decades.

The industrial sector remains the region's largest consumer of natural gas, with a share of approximately 40 % of total natural gas consumption throughout the period 2007–2035. However, in the long-term, rising prices for both domestically produced and imported natural gas are likely to moderate the region's growth in natural gas demand.

[1] The EU will review the participation of renewables in the energy mix of the countries for the coming years in order to increase its share from 20 to 27 %.

The main European natural gas producers are Russia, followed by Norway and the Netherlands. The main European natural gas exporters are Russia, followed by Norway and the Netherlands. The main European natural gas importers are Germany, followed by Italy, France, Ukraine, Turkey, Spain, and the UK.

5.3 Coal

According to the IEO (2013), in OECD Europe, falling domestic demand and rising competition from imports cause indigenous coal production to decline from 620 million short tons in 2010 to 504 million short tons in 2040. Germany, Poland, and Turkey are the leading producers in the region, accounting for 69 % of total production in 2010. In 2007, coal-fired generation accounted for 42 % of world electricity supply; in 2035, its share should increase slightly to 43 %. Sustained high prices for oil and natural gas make coal-fired generation more attractive economically, particularly in nations that are rich in coal resources and without limitations for the use of this type of energy sources for electricity generation due to its negative impact on the environment and the climate. World net coal-fired generation is expected to double from 7.9 trillion kWh in 2007 to 15 trillion kWh in 2035; this means an increase of 89.8 %.

However, it is important to highlight that the outlook for coal-fired generation could be altered substantially by national policies or international agreements to reduce greenhouse gas emissions. The electric power sector offers some of the most cost-effective opportunities for reducing carbon dioxide emissions in many countries. Coal is both the world's most widely used source of energy for electricity generation and also the most carbon-intensive energy source. If a cost, either implicit or explicit, were applied to carbon dioxide emissions, there are several alternatives for low-emission technologies that currently are commercially proven or under development, which could be used to replace some coal-fired power generation plants. Implementing these new technologies would not require expensive large-scale changes in the power distribution infrastructure or in electricity-using equipment.

The security and diversity of energy supply are causing growing concern in the EU. A renaissance in coal use, the major energy source 45 years ago, but currently with a modest and continuously declining contribution to the EU's energy supply, could potentially improve the energy balance of the EU. However, the recent trends in coal markets make the long-term supply prospects for coal uncertain. The sharp increase in oil prices in recent years, and the temporary cutback in natural gas supplies from Russia due to payment problems with Belarus and Ukraine as transit countries, and the recent crisis on Crimea, have boosted concerns about the security, diversity, reliability, and affordability of energy supplies in the EU (Kavalov and Peteves 2007).

Coal was the main energy source not only in Europe, but also worldwide until the 1960s. Owing to advances in oil extraction, conversion and application technologies, coal, then began to lose market share to oil. The entry of natural gas and nuclear power into the energy market at the beginning of the 1970s put further pressure on the use of coal for the generation of electricity. All these new energy sources were cleaner to use and in some cases even cheaper. Gradually, coal started to be perceived as a "dirty and old-fashioned fuel for use in poorer countries" for electricity generation. As a result, despite the rising energy demand, gross coal consumption in the EU-15 has been declining since 1970, while the share of coal in gross inland energy consumption has more than halved, from more than 30 % to approximately 15 %. In contrast, coal retained a 25 % share in gross inland energy consumption globally over the period 1970–2000 (Kavalov and Peteves 2007).

However, in recent years there is a renewed interest in the use of coal in the EU, as well as in other countries within and outside the European region, for different purposes based on a wide perception that coal is an abundant, widely available, cheap, affordable and reliable energy source. According to Morales Pedraza (2008), the main reasons for this renewed interest are the following:

- There is more coal than oil and natural gas worldwide, particularly in Europe. With current consumption trends, the reserves-to-production ratio of world proven coal reserves are higher than that of world proven crude oil and natural gas reserves—minimum 155 years versus 40 and 65 years respectively;
- World coal reserves are also more evenly distributed around the globe compared to crude oil and natural gas reserves. The geopolitical distribution of the world's coal reserves differs also from that of oil and natural gas;
- Historically, coal prices have been lower and more stable than oil and natural gas prices, owing to more evenly spread of coal reserves and hence the smaller room for price manipulation. The EU has large reserves of coal than of crude oil or natural gas, even though it does not hold a large share of world coal reserves. Consequently, import dependence on fossil fuels (i.e., mainly coal) is lower than the dependence on natural gas and oil. A more complete and efficient exploitation of indigenous coal reserves would reduce the EU's overall energy import dependence.

The confirmed world coal reserves are 979.8 billion short tons in 2011, which would be enough to cover the demand of all countries at the current consumption rhythms for no less than 155 years. Historically, estimates of world recoverable coal reserves, although relatively stable, have declined gradually from 1,145 billion short tons in 1991 to 1,083 billion short tons in 2000 and 979.8 billion short tons in 2011, a decrease of 14.5 % since 1991. Although the decline in estimated reserves is substantial, the large reserves-to-production ratio for world coal indicates that sufficient coal will be available to meet demand well into the future. Further, because recoverable coal reserves are a subset of total coal resources, recoverable coal reserve estimates for a number of regions with large coal resource bases—notably China and the United States—could increase substantially as coal mining technology improves (IEO 2010).

Although coal deposits are widely distributed, it is important to highlight that 68.7 % of the world coal recoverable reserves are located in four countries: United States (28.7 % of the total), Russia (19 %), China (13.9 %), and India (7.1 %).

The world consumes much more hard coal than brown coal and the gap is growing continuously. In addition, the preference is naturally for hard coal that is easier (and cheaper) to recover. Without a corresponding increase in hard coal reserves, which will most likely be more difficult and more expensive to exploit than hard coal deposits in the past, the world is going to run out of high-quality coal much earlier than it will of lower-quality coal.

At present, the prospects for European coal production are quite clear. Indigenous hard coal production in the EU will continue to decline for several reasons. Hard coal has been intensively mined in Europe for more than a century and the easier accessible deposits of good quality of hard coal have already been exploited. As hard coal in Europe can be recovered mainly from underground deposits, European coal miners are forced to go for deeper and more difficult to recover reserves of the poor quality of hard coal, which increases costs. For this reason, European indigenous hard coal production is two to three times more expensive than imported hard coal, forcing some EU countries to cease hard coal production. In countries where hard coal production still exists (mainly for socioeconomic reasons), it is heavily subsidized, but the subsidies are gradually being phased out, following EC instructions.

The case of lignite is different. The EU has greater reserves of lignite than of hard coal and reserves are available and exploited in a larger number of countries. Lignite in Europe is typically mined open-cut, which keeps extraction costs low. European lignite production is generally cost-competitive with imports of hard coal without subsidies. Consequently, lignite recovery in the EU will most likely survive, unlike hard coal production, in the coming decades. Lignite represents an important energy source for the EU, as it helps to reduce its energy import dependence. Nevertheless, the reserves-production ratios (under current economic and regulatory conditions) in the major EU lignite producers are rather low, e.g., Germany—33 years and Greece—54 years (Kavalov and Peteves 2007).

Three largest countries in the former Soviet Union (Russia, Kazakhstan and Ukraine) hold almost 20 % of the world's hard coal reserves and 30 % of brown coal reserves in the 2000s. Even so, they are not major players in the world coal market. After the substantial economic changes in the 1990s, Ukraine has become a net importer of coal, Russia has re-started exports just recently and only Kazakhstan has managed to keep a noticeable presence on the world coal market, but with a gradually declining volume and share.

The development of novel and more environmentally friendly coal technologies (the so-called "Clean Coal Technologies"), the world consumption of coal is expected to increase from 25 % to 28 % in 2030, an increase of 3 %. However, and according to the IEO (2010), coal consumption within OECD countries will decline almost 10 % in the next 15 years, decreasing from 47.9 quadrillion Btu in 2007 to 43.1 quadrillion Btu in 2010, and it is expected to remain virtually flat after 2025. After that year, OECD coal consumption is expected to increase to 48.3 quadrillion Btu in 2035 (an increase of 12 % respect to 2010), largely because of an increase in natural gas prices that allows coal—in the absence of policies or regulations to limit its use—to compete economically.

It is important to know that over the period 2007–2035, slight increases in coal consumption in North America and OECD-Asia are, to a large extent, offset by declines in OECD-Europe. In this last region, the use of coal will concentrate in the future mainly in the electricity generation, but this increase will be, however, more slowly than the natural gas.

In the absence of national policies and/or binding international agreements that would limit or reduce greenhouse gas emissions, world coal consumption in OECD countries is expected to diminish. OECD coal consumption is expected to decline from 45 quadrillion Btu in 2010 to 41 quadrillion Btu in 2016, recovers to 42 quadrillion Btu in 2020, and remains slightly above that level through 2040. OECD Europe and the United States, which together consume almost three-quarters of the OECD total, lead the trend toward lower consumption. The decline in OECD coal consumption—at an average rate of 0.2 % per year—causes the coal share of the region's total primary energy consumption to fall from 19 % in 2010 to 15 % in 2040 (IEO 2013).

Much of the foreseeable increase in coal use is expected to occur in non-OECD-Asia, which accounts for 95 % of the total net increase in world coal use from 2007 to 2035. Increasing demand for energy to fuel electricity generation and industrial production in the region is expected to be met in large part by coal.

Worldwide coal consumption increased by 35 % between 2002 and 2007, largely because of the growth in China's coal use. Between 2007 and 2009, however, coal consumption declined by 3 %. Coal use was strongly affected by the global recession, and consumption contracted strongly in 2009, in large part because coal is widely used in the production of heavy commodities (such as, steel and pig iron), which were particularly hard hit in the recession affecting several countries in different regions, mainly in the EU and the USA.

According to the IEO (2013), total coal consumption in the countries of the OECD-Europe is expected to decline from 12.2 quadrillion Btu in 2010 (27 % of the OECD total) to 10.7 quadrillion Btu in 2040 (25 % of the worldwide total). Although all nations in the region consume coal, 65 % of OECD Europe's 2010 total coal consumption was concentrated in Germany, Poland, Turkey, and the United Kingdom, with Germany alone consuming 26 % of the regional total. The electric power sector accounted for 67 % of the region's total coal consumption in 2010, and most of the rest was consumed in the industrial sector.

The major coal-consuming countries of the region, all with consumption of 0.7 quadrillion Btu or more, include Germany, Poland, the UK, Spain, Turkey, and the Czech Republic. However, most of the countries in South East Europe rely heavily on coal-based (lignite and brown coal) electricity generation. Macedonia produced 78 % of its electricity using coal, while the figures for Serbia and Greece are 66 % and 61 %, respectively. The dependency on coal for generation in other countries is as follows: Bosnia 52 %, Bulgaria 45 %, Romania 38 %, Slovenia 34 %, Turkey 23 % and Croatia 16 %. Most of the coal burned in thermal power plants is domestically supplied, however, high costs of production caused by low productivity and lack of investment in equipment and technology render many mining companies (which are typically State owned) unprofitable. Nevertheless, some European governments are forced to continue to subsidize the coal mining sector in order to prevent numerous layoffs and the consequential social problems. Albania is the only country in the region that does not burn a significant amount of coal for electricity generation.

According to the IEO (2013), total coal imports mainly to Europe increase from 246 million tons in 2011 to a peak of 297 million tons in 2015, then decline to 274 million tons in 2040. Coal becomes a less significant component of the region's fuel mix for electricity generation, with most European countries placing greater emphasis on renewable energy and natural gas for electricity generation. The countries of OECD Europe account for more than 90 % of total seaborne coal imports to the Europe, both in 2011 and in the future. Although there are significant amounts of overland coal trade between several countries in the non-OECD Europe and Eurasia region, only seaborne shipments of coal for Europe and Asia are included in the IEO report, primarily because of data availability issues and the increased complexity associated with modeling non-seaborne coal trade.

Europe's demand for lower sulfur coal (from South America and Eurasia, for example) will be tempered over time by the gradual addition of flue gas desulfurization equipment at existing coal-fired power plants. Some European countries will import more coal to compensate for their own dwindling coal production, which will offset some of the decline expected for coal imports by other European nations. For example, Germany's planned closure of its remaining hard coal mines by 2018 results in increasing imports of coal for electricity generation. In Turkey, electricity demand and steel industry growth also are projected to offset some of the decline in Europe's coal use. Italy's conversion of power plants from oil to coal also offsets some of the decline in Europe's coal demand.

Most of the world's coal trade is in the form of steam coal, at nearly 15 quadrillion Btu (about 70 % of total coal exports) in 2008. The top five exporters of steam coal are Indonesia, Australia, South America (primarily Colombia), Russia, and Southern Africa (primarily South Africa). Poland is expected to lower their coking coal exports in the long-term, largely because of geological difficulties.

The main European hard coal producers are Russia, followed by Poland. The main European brown coal producers are also Russia, followed by Poland. The main European hard coal exporters are Russia, followed by the Czech Republic. The main European hard coal importers are Germany, followed by the UK, Turkey, Italy and Spain.

However, sustained high prices for oil and natural gas could make coal-fired power generation more attractive economically, particularly in nations that are rich in coal resources and without limitations on the use of this type of energy sources due to its impact in the environment and the climate.

World net coal-fired power generation nearly doubles over the decades from 7.9 trillion kWh in 2007 to 15 trillion kWh in 2035. In 2020, the participation of coal in electricity generation is expected to be 40 %; this represents 2 % lower than the level reached in 2007. In 2035, the participation of coal in electricity generation is expected to be 43 %; this means 3 % higher than the level reached in 2020, and 1 % higher than the level reached in 2007. In general, the use of coal in the European region (OECD countries) will drop from around 19 quadrillion Btu in 1980 to a little bit higher of 10 quadrillion Btu in 2035; this represents a reduction of 9 quadrillion Btu or 47.4 %.

Finally, it is important to highlight the following: According to the IEO (2013), coal-fired power plants will supply the second biggest amount of electricity after renewable sources by 2040 and it is expected to be the second fastest growing sources of energy for electricity generation in the projection period, except for the Latin American and the Caribbean region. This projection could be altered substantially by any future national policies or international agreements that aim to reduce or limit the growth of greenhouse gas emissions.

Coal accounted for nearly 30 % of OECD Europe's net electricity generation in 2007, but concerns about the contribution of CO_2 emissions to climate change could reduce that share in the future. According to the IEO (2010), electricity from coal slowly loses its prominence in OECD Europe, decreasing by 0.3 % per year from 2007 to 2035 and ultimately falling behind renewables, natural gas, and nuclear energy as a source of electricity.

It is also important to consider the following reality during any consideration of the future energy balance in the European region. Europe is running out of indigenous energy resources in the form of fossil fuels at a time when a paradigm shift in energy prices is occurring. In 2012, the oil price was close to US$100–US$ 110 per barrel and it is expected that the oil price will be higher in the coming years. The price of coal and natural gas is also expected to grow in the near future. Most observers agree that the era of cheap fossil fuels is over and signs are emerging that competition for ownership of oil and natural gas is becoming fiercer and will intensify heavily in the coming years. The era of energy uncertainty has come.

Coal is, and it is expected to continue to be, the fuel with the highest participation in electricity generation until at least 2035, followed by the use of different renewable energy sources (after 2015), natural gas, nuclear energy and liquid fuels. In the European region, switching towards natural gas (against coal) was apparent in the first half of 2010, particularly in some large markets in the Northwest of the region such as the Netherlands, the UK, France and even Germany, while the picture was relatively different in Southern Europe where the electricity produced from natural gas was at 2009 levels in Italy and even lower in Spain due to increase hydro and wind electricity generation.

A strong shift to the use of natural gas for electricity generation within the EU could have a significant negative consequences for the security of energy supply, due to the amount of natural gas that need to be imported to satisfy future electricity demand, something that cannot be ignored by politicians, government officials, and the energy industry during the consideration of the best energy mix for the European region in the coming decades.

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