New regulatory trends: effects on coal-fired power plants and coal demand

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Preface

This report has been produced by IEA Clean Coal Centre and is based on a survey and analysis of published literature, and on information gathered in discussions with interested organisations and individuals. Their assistance is gratefully acknowledged. It should be understood that the views expressed in this report are our own, and are not necessarily shared by those who supplied the information, nor by our member countries.

IEA Clean Coal Centre is an organisation set up under the auspices of the International Energy Agency (IEA) which was itself founded in 1974 by member countries of the Organisation for Economic Co-operation and Development (OECD). The purpose of the IEA is to explore means by which countries interested in minimising their dependence on imported oil can co-operate. In the field of Research, Development and Demonstration over fifty individual projects have been established in partnership between member countries of the IEA.

IEA Clean Coal Centre began in 1975 and has contracting parties and sponsors from: Australia, Austria, China, the European Commission, Germany, India, Italy, Japan, New Zealand, Poland, Russia, South Africa, Thailand, the UK and the USA. The Service provides information and assessments on all aspects of coal from supply and transport, through markets and end-use technologies, to environmental issues and waste utilisation.

Abstract

This review presents the recent regulatory trends, practices and developments, in major coal producing and consuming countries, which are affecting and may influence future demand for coal and coal-fired power generation. As legislative requirements become more demanding and environmental pressures increase, especially with regard to greenhouse gas emissions (GHGs) and climate change, investment in coal fired power-generating facilities is declining rapidly in most developed countries and to a lesser extent in some developing regions of the world, except Asia where forecasts indicate that demand will increase for some time to come. The report explores the implications of further curbs on GHG emissions from coal-fired plants in the most recent and forthcoming national regulations and international agreements. Policy, legislation and pollution reduction strategies are presented as well as future projections of coal utilisation in major coal consuming economies, including those where forecasts indicate that coal will remain a major player in power generation for the estimable future; such as China and India.

Acronyms and abbreviations

ACER	Agency for the Cooperation of Energy Regulators
ADP	Durban Platform for Enhanced Action
AEO	annual energy outlook (EIA, USA)
APEC	Asia Pacific Economic Cooperation
APERC	Asia Pacific Energy Research Centre
ASEF	Asia Europe Foundation
BAT	best available technology
BAU	business as usual
BOOT	Build-Own-Operate-Transfer
BREF	best available techniques reference document
BSER	best system of emission reduction
CAA	Clean Air Act (USA)
CAGR	compound annual growth rate
CCS	carbon capture and storage
CCUS	carbon capture, utilisation and storage
CDM	Clean Development Mechanism
CER	Clean Energy Regulator (Australia)
CGGC	Center on Globalization, Governance and Competitiveness (USA)
CIL	Coal India Limited
CIS	Commonwealth of Independent States
COAG	Council of Australian Governments (Australia)
COP	Conference of the Parties
CPP	Clean Power Plan (USA)
CSAPR	Cross State Air Pollution Rule (USA)
CSD	Commission on Sustainable Development
CSP	Concentrated solar power
CTF	Coal Task Force
DECC	Department of Energy and Climate Change (UK)
EC	European Commission
ECB	European Central Bank
EDGAR	Emissions Database for Global Atmospheric Research
EFAP	Energy Efficiency Action Plan
EIA	Energy Information Administration (USA)
EIAD	Environmental Impact Assessment Directive
ELV	emission limit value
EOR	enhanced oil recovery
ERF	Emissions Reduction Fund (Australia)
ESCI	Energy Security and Climate Initiative (USA)
ESD	Effort Sharing Decision
ESP	electrostatic precipitation
EU	European Union
FCCC	Frame Convention on Climate Change
FF	fabric filtration
FGD	flue gas desulphurisation
FOB	Free on board or freight on board
GRP	Green Rating Project (India)
ICCTF	Indonesia Climate Change Trust Fund

IEA	International Energy Agency
IEA CCC	IEA Clean Coal Centre
IED	Industrial Emissions Directive
IEEFA	Institute for Energy Economics and Financial Analysis (USA)
IGCC	integrated gasification combined cycle
IMPEL	Implementation and Enforcement of Environmental Law
INDCs	intended nationally determined contributions
IPEEC	International Partnership for Energy Efficiency Cooperation
IPPs	Independent Power Producers
IPPCD	Integrated Pollution Prevention and Control Directive
IRP	Integrated Resources Plan (South Africa)
JI	Joint Implementation
JRC	Joint Research Centre
ktoe	kilo-tonne of oil equivalent
LCPD	Large Combustion Plants Directive
LNG	liquefied natural gas
LRTAP	Long-Range Transboundary Air Pollution
MATS	Mercury and Air Toxics Standards (USA)
MEA	Multilateral environmental agreement
MEP	Ministry of Environmental Protection (China)
NAPCC	National Action Plan on Climate Change (India)
NCC	National Coal Council (NCC)
NDRC	National Development and Reform Commission (China)
NECs	National Emission Ceilings
NEPMs	National Environmental Protection Measures (Australia)
NERP	National Emission Reduction Plan
NGCC	natural gas combined cycle
NHMRC	National Health and Medical Research Council
NMEEE	National Mission on Enhanced Energy Efficiency (India)
NPCA	National Plan for Clean Air (Australia)
NPI	National Pollutants Inventory (Australia)
NRA	Nuclear Regulation Authority (Japan)
OECD	Organisation for Economic Co-operation and Development
PAT	Perform and Achieve Trade scheme (India)
PDP	Power Development Plan (Thailand)
PLF	plant load factor
PLN	Perusahaan Listrik Negara (Indonesia)
PM	particulate matter
PPA	Power Purchase Agreement (India)
ppm	parts per million
PPP	Public Private Partnership (Indonesia)
PRB	Powder River Basin (USA)
RES	Renewable Energy Sources
RGGI	Regional Greenhouse Gas Initiative (USA)
SAPP	Southern African Power Pool
SCR	Selective catalytic reduction
SED	Solvent Emissions Directive
UN	United Nations
UNECE	United Nations Economic Commission for Europe

UNEP	United Nations Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change
US EPA	United States Environmental Protection Agency (USA)
WCA	World Coal Association
WEC	World Energy Council (UK)
WEO	World energy outlook (IEA, France)
WID	Waste Incineration Directive

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1 Introduction

Coal has historically been, and continues to be, a main fuel in the power-generating sector throughout the world. In 2014, coal provided >30% of global primary energy requirements, ~40% of the world's electricity generation and ~68% of steel production. Forecasts and projections indicate that coal will remain a major power generating fuel, albeit to a lesser extent, in the future. In Asia and North America, coal is a key fuel, which reflects the regions coal demand. Asia is the world's largest consumer with a 63% share of total use and North America, mainly the USA, is the world's second largest consumer with a 14% share of total use. The global trade in thermal coal including major exporters and importers is shown in Figure 1.

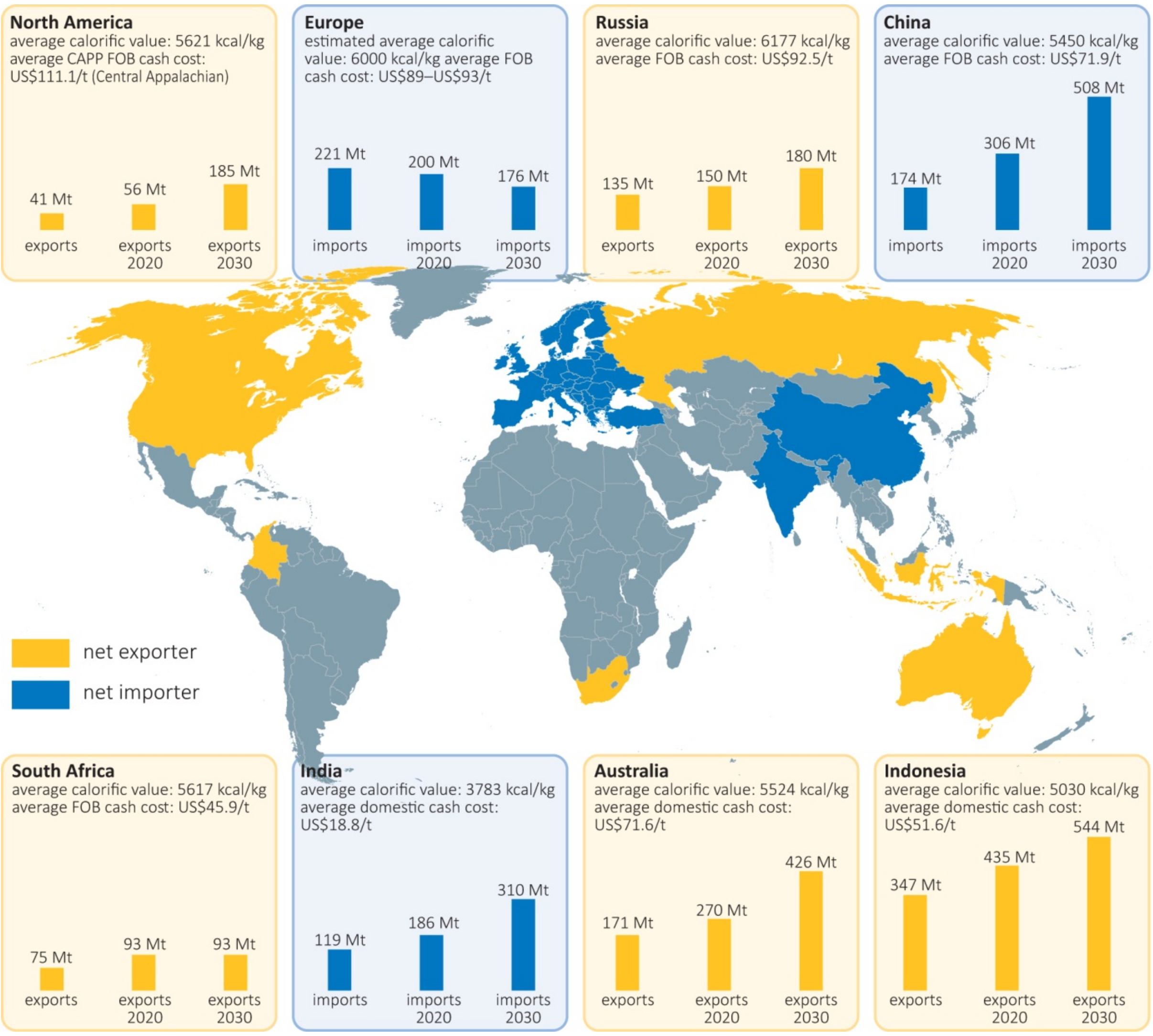

Figure 1 Global trade in thermal coal including major exporters and importers (Accenture, 2013)

In terms of total coal imports, steam and coking, in 2013/14 Asia held the top five positions (China, India, Japan, Korea (Republic) and Chinese Taipei) followed by Germany and the UK, while the main exporters were Indonesia, Australia, Russia, USA, Colombia, South Africa and Canada (*see* Table 1). In Europe, Russia is a main exporter of natural gas, oil and coal into many European countries. The ongoing tension between Russia and Ukraine has raised concerns about security of supply in Europe, especially since the production rate of natural gas in some European countries is declining. As solutions to reduce import dependency, energy efficiency and renewable energy have become main areas of attention as well as a broader import basis. However, the latter focus is on the import of LNG not coal (WEC, 2015).

Table 1 Top Coal exporters and importers (IEA, 2015 and WEC, 2015)

Top coal importers (2013E)	Steam, Mt	Coking, Mt	Total, Mt
1. China	229	63	292
2. India	189	50	239
3. Japan	137	51	188
4. South Korea	97	34	131
5. Chinese Taipei	60	7	67
6. Germany	47	10	57
7. UK	35	6	41
Top coal exporters (2014)			
1. Indonesia	408	2	410
2. Australia	195	180	375
3. Russia	133	22	155
4. USA	31	57	88
5. Colombia	79	1	80
6. South Africa	76	0	76
7. Canada	4	31	35

Population and economic growth are the two main drivers for increasing energy demand. There has been a dramatic growth in population in the last century, especially so in the last 2 decades. The continuing growth in world population today is mainly in developing countries and particularly in Africa, South Asia, Latin America and the Middle East. Among the developed countries, a relatively high rate of growth of population took place in North America in 1800-1900 but the current annual population growth rate in the region is just under 1% (WPR, 2015). Rapid development of electricity production occurred in the last century. Electricity allowed social and economic development throughout the world, particularly in industrialised/more developed countries. More developed countries include all countries in Europe, North America, Australia, New Zealand, and Japan. Less developed countries include all countries in Africa, Asia (excluding Japan), Latin America and the Caribbean, and the regions of Melanesia, Micronesia, and Polynesia. Electricity revolutionised industry, transport, construction and the municipal economy. It also improved the standard of life dramatically in the industrialised world. The continuing high growth of global production of electricity in the last three decades of the 20th century has however been extremely uneven, per capita, in different parts of the world – high in the developed countries and less so in developing countries. It is worth noting that between 1990 and 2010, over 800 million individuals gained access to electricity due to coal-fired power generation. The vast majority of those are in developing countries. Demand for coal-fired power generation is expected to continue, especially in developing countries, with a focus on improving the standard of life rather than environmental protection. However, in most countries, policymakers advocate and promote, and in some cases mandate, the deployment of advanced combustion technologies in new coal-fired electricity-generation plants and, improving the efficiency of existing ones. Trends in regulatory frameworks that aim to limit emissions and/or govern fuel choice in power generation are developing and spreading globally. This review attempts to assess such trends and their effect on coal-fired power generation. Existing and future global/multilateral, bilateral and national regulatory requirements to control/reduce emissions to air, especially of greenhouse gases (GHGs) and their impact on coal demand are the focus of this report.

Water policies and availability for the power sector were the topic of a recent report by IEA Clean Coal Centre (CCC) (*see* Carpenter, 2015). Management of coal combustion waste/residue was the subject of the IEA CCC review by Zhang (2014). IEA CCC has also published numerous reviews on coal-based power generation technology, emissions, legislation and impacts, the latest of which includes Nalbandian (2007) and Sloss (2009). These and many other publications, as well as a dedicated database on 'emission standards for coal-fired power plants', are available from the IEA CCC website www.iea-coal.org. This review discusses only the most recent regulatory trends and their effect on coal-fired power generation and potential coal demand.

2 Coal and environmental regulations and agreements

There are two primary instruments and vehicles through which environmental law is developed, memorialised, and implemented. According to Lamotte (2014), these are the non-binding 'soft law' regimes, which provide a mechanism based on collaboration and voluntary participation. Nonetheless, such soft laws may serve as a harbinger for hard laws. The other instrument is binding mechanisms that may be global, regional, or bilateral, and they may take the form of agreements, frameworks, or protocols to frameworks or agreements. There are many technical differences among various binding mechanisms, discussed in detail by Lamotte (2014).

Legislation is becoming increasingly more stringent to the point where, in some parts of the world; such as the EU, power providers/utilities are *required* to either construct state-of-the-art, advanced power plants or invest in retrofitting pollution control technologies in existing facilities. The investment in pollution control technology is necessary, if not unavoidable, to ensure the continued, reliable supply of electricity with a less detrimental environmental impact. The result has been a reduction in air pollutant emissions (SO_2, NOx and particulate matter) in many regions throughout the world, achieved over the last few decades. However, the combustion of coal results in relatively high GHG emissions compared to other fossil fuels, such as gas, and the technologies to deal with these emissions, remain at demonstration level and are considered prohibitively costly. Visit www.iea-coal.org for detailed reviews on GHG control technologies and carbon capture and storage (CCS) developments and status.

Meanwhile, energy-related CO_2 emissions increased over the last two decades especially in developing countries as they have experienced rapid economic growth. The International Energy Agency (IEA) (Paris, France) has assembled several scenarios and assessed their impact on the energy market (http://www.iea.org/publications/scenariosandprojections/). The 'new policies scenario' involves governments introducing energy efficiency programmes, supporting renewables, reducing fossil fuel subsidies, and in some cases putting a price on carbon emissions. Under this scenario, CO_2 emissions would increase by 20% by 2035 and the world's temperature would rise by 3.6°C. In the 450 parts per million (ppm) CO_2 scenario, governments would implement selected energy efficiency policies, limit the use of inefficient coal-fired power plants, increase the use of renewables and nuclear power, and use CCS technologies to stop the emission of CO_2 from power generating units and industry reaching the atmosphere. If implemented, the IEA estimates that there will be about a 50% chance of meeting a target of 2°C increase in temperature by 2035 (compared with 2009). What is more, under this scenario, the demand for coal should remain around 2014 levels (that is, ~8 Gt per year) until 2020 then decline by 2.5%–3.5% per year to ~5 Gt per year (including coking coal) by 2035. If the 2°C target, maximum increase in temperature is to be achieved, the world's emission of GHGs can only continue at current rates for about 35 years, meaning coal combustion for power generation will need to gradually decrease and eventually disappear in that time or emit less or become almost free of GHG emissions altogether, for example using CCS. The IEA (2015b) WEO special report on energy and climate change reiterated that energy related GHG emissions need to peak by 2020 to achieve the 2°C target. According to Jalesko and others (2014), the former scenario is somewhat challenging, as the new technologies (for example, renewables) will need to support a further increase in demand for electricity (an annual increase of 3.4% in demand for coal in the last five years) as well as replace existing coal-fired power plants. The latter would be possible if wide-scale and fast adoption and uptake/installation of CCS occurred by 2035.

Environment (2009) discusses the numerous multilateral agreements and international organisations dedicated to protecting the environment. In 1972, the United Nations Environment Programme (UNEP) was established. In 1992, the Framework convention on Climate Change (FCCC) was signed and the Commission on Sustainable Development (CSD) was established at the United Nations (UN) conference on environment and development. Today, there are several hundred multilateral environmental agreements (MEAs) as well as other types of agreements relevant to the environment. In 2001, the total number of MEAs reported by UNEP was 502. These were developed on an ad hoc basis, in an uncoordinated manner and without reference to other existing agreements. Each agreement has its own secretariat, technical working groups and regular sessions. In the absence of a coherent strategy, numerous other environmental organisations, bodies and programmes have emerged. The result, according to Environment (2009) is a bewildering system. The ineffectiveness of these agreements is attributed by Environment (2009) partly to a lack of political will and, to institutional shortcomings within the environmental governance systems. Figure 2 gives a general, simplified overview of a ***complex*** international environmental regime.

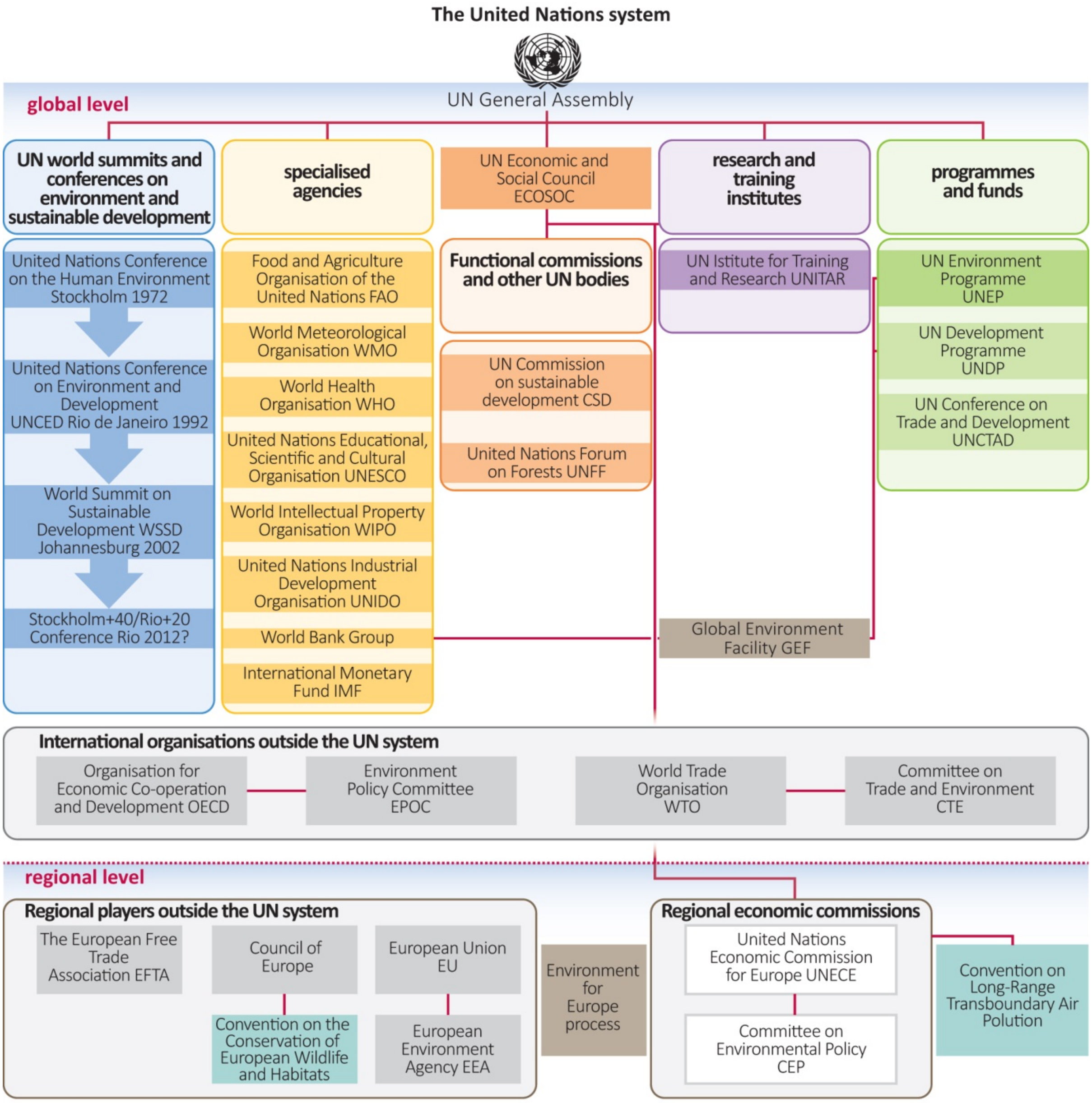

Figure 2 Overview of the international environmental regime (Environment, 2009)

Environment (2009) considers that effective environmental governance requires not only institutions with adequate authority but also clearly defined goals. These goals should also have a set target date. Even if these goals are not achieved within the specified timeframe they would have an impact on policy development and focus global attention on the most pressing problems and, help prioritise and give a coherent orientation to development efforts.

2.1 Global/multilateral agreements

Global/multilateral agreements are purpose-built agreements aimed at particular topics with limited (rather than open-ended) mandates and scopes (Lamotte, 2014). Many such agreements have been negotiated across the spectrum of policy clusters, including the atmosphere and climate change (for example, the United Nations Framework Convention on Climate Change (UNFCCC)). These agreements are legally and institutionally distinct from each other, and each has a limited but substantive mandate. The international environmental field does not have a global institutional architecture that serves as a platform for all related activity. Instead, each agreement, once negotiated and entered into force, establishes its own institutional governance structure and, crucially, its own quasi-regulatory processes. The plenary body for most global/multilateral agreements is known as the Conference of the Parties (COP). COP is an organisation that comprises representatives from each party/country. COP is typically designated as the primary decision making authority for the treaty. As such, the COP is given not only the power to review compliance with and implementation of a treaty, but also the authority to create subsidiary bodies, consider new information, and adopt resolutions that fill the interstices of the agreements through amendments and decisions (Lamotte, 2014).

2.1.1 United Nations Framework Convention on Climate Change (UNFCCC) (COP 21)

Control and reduction of anthropogenic CO_2 emissions are addressed by the annual international conferences of the UNFCCC parties as well as by the Intergovernmental Panel on Climate Change, World Energy Council and the European Union. To date, the measures discussed and adopted, have proven insufficient and the anthropogenic emissions of GHGs, particularly CO_2, continue to increase. Some reduction in CO_2 emissions growth rate occurred in the Organisation for Economic Co-operation and Development (OECD) countries, but the growth rate accelerated in non-OECD countries, particularly in China and India. Nevertheless, in 2011 CO_2 emissions in OECD countries were highest in the USA (5.29 Gt) and Japan (1.19 Gt). In non-OECD countries the highest emitters were China (7.96 Gt), India (1.75 Gt) and the Russian Federation (1.65 Gt). However, the highest CO_2 emissions per capita in OECD countries were in Australia (17.4 t), USA (16.9 t), Canada (15.4 t) and Korea (Republic) (11.8 t). In non-OECD countries, the emissions per capita were highest in Saudi Arabia (16.3 t), the Russian Federation (11.7 t), Taiwan (11.3 t), South Africa (7.3 t) and Iran (7.0 t) (WEC, 2015). According to Olivier and others (2014), global CO_2 emissions from fossil fuel combustion and from industrial processes (cement and metal production) increased in 2013 to 35.3 Gt, which is 0.7 Gt higher than 2012. The relatively moderate increase of 2% in 2013 compared to 2012 is a continuation of a trend in slowing annual CO_2 emissions growth. The Emissions Database for Global Atmospheric Research (EDGAR) provides global past and present day anthropogenic emissions of GHGs and air pollutants by country and on a spatial grid. The current development of EDGAR is a joint project of the European Commission Joint Research Centre (JRC) and the Netherlands Environmental Assessment Agency (http://edgar.jrc.ec.europa.eu/).

The aim of the international, annual conference of the UNFCCC is the reduction of global GHG emissions, particularly CO_2. The main objective is to negotiate an international agreement for the reduction of global CO_2 emissions by at least 50% by the year 2050 from 1990 levels and to limit the global level of GHGs concentration in the earth's atmosphere to 450 ppm of CO_2 equivalent. According to WEC (2015), reaching this objective would require the agreement of all countries to take the necessary actions as well as to invest heavily in the global energy sector and assist developing countries to install CO_2 reducing technologies whilst acknowledging that all these activities would entail increases in energy costs.

The UN negotiations (COP 21), which took place from 30th November to 11th December 2015 in Paris (France), have resulted in a new, currently draft, international climate change agreement that covers most countries in the world. Adoption of the new agreement should be at the Paris climate conference in December 2015 and implementation will be set for 2020 onwards. The UNFCCC COP 21 refers to the 21st session of the Conference of the Parties to the UNFCCC, which took place in November/December 2015 in Paris, France. In preparation, countries have agreed to outline what post-2020 climate actions they intend to take domestically under a new international agreement, known as their intended nationally determined contributions (INDCs). The INDCs are the primary means for governments to communicate, internationally, the steps they plan to take to address climate change in their own countries. The INDCs reflect each country's ambition for reducing emissions, taking into account domestic circumstances and capabilities. Some countries may also address how they will adapt to climate change impacts, and what support they need from, or will provide to, other countries to adopt low-carbon pathways. On 1 October 2015, a total of 147 Parties (75% of all Parties to the UNFCCC) had submitted their INDCs. For details on each country INDCs, visit http://cait.wri.org/indc/, the WRI interactive Paris contributions map for the latest proposed commitments. The UNFCC Secretariat plans to release, by 1 November 2015, all INDCs submitted by 1 October. The report will reflect the aggregate emissions impact of available INDCs ahead of COP 21. The final agreement, following the COP 21 meeting in December in Paris, will be added to this review as an addendum prior to publication (WRI, 2015).

The agreement will take the form of a protocol, another legal instrument or 'an agreed outcome with legal force', and will be applicable to all Parties. The negotiations are through a process known as the Durban Platform for Enhanced Action (ADP) (European Commission, 2015a). The current climate agreements commit developed countries to take climate action, but not developing countries, some of which have become major emitters of GHGs. After the 2009 Copenhagen (Denmark) climate conference failed to adopt a new agreement, the 2011 Durban (South Africa) conference decision was that a new agreement applicable to all countries should conclude in 2015 and enter into force in 2020 (Erbach, 2015; European Parliament, 2015). The climate conferences in Warsaw (Poland) (2013) and Lima (Peru) (2014) agreed that all countries are to put forward their proposed emissions reduction targets for the 2015 agreement as "intended nationally determined contributions" well in advance of the Paris conference. The contributions are prepared at national level by each Party, as the EU has done, and submitted to the UNFCCC. The UNFCCC secretariat will publish these contributions and prepare, by 1 November 2015, a synthesis report to assess whether they put the world on track to keep global warming below 2°C. A negotiating text for the 2015 agreement was agreed in Geneva in February 2015. Before the Paris conference, negotiations continued at inter-sessional UN meetings in June, September and October 2015 in Bonn (Germany) (European Commission, 2015a).

The European Parliament carried out an in-depth analysis of the ongoing negotiations aiming to conclude a new international legally binding agreement on climate change by December 2015. The document, by Erbach (2015), describes the current climate change agreements and summarises the state of negotiations. Furthermore, it analyses the elements of the new proposal and the Parties' negotiating positions, and outlines the many challenges facing EU climate diplomacy. According to Erbach (2015), the Lima (Peru) Conference left a number of important issues unresolved. Firstly, the nature of countries' contributions is not clearly specified, which will make them hard to compare and assess. It is also likely that they will not add up to the emissions reductions required to keep global warming below the internationally agreed limit of 2°C. A process for the periodic assessment and strengthening of national efforts will therefore be an important element of the Agreement. Processes for monitoring, reporting and verification of national contributions will also have to be agreed. Erbach (2015) highlights another unresolved issue, which is the Agreement's legal form. While some negotiators favour a strong, legally binding agreement, others prefer a bottom-up approach based on voluntary contributions. Finally, necessary issues that must be addressed are fairness and equity between countries, acknowledging that developed countries have a greater historical responsibility for climate change and stronger capabilities for taking action. Therefore, they can be expected to make a larger contribution to emissions reductions as well as to provide financial assistance or support for developing countries' climate action, although the size and extent of these contributions are far from being agreed. The outcome of the Lima climate change conference, held in Peru, presented EU climate policy with new challenges as regards shaping the Paris Agreement, and once the Paris Conference (2015) is over, to building collaborations with partners worldwide. Erbach (2015) considers that the probable shift from a legally binding environmental treaty towards a 'soft' agreement based on national contributions presents both risks and opportunities. There is a need for continued engagement with international partners to achieve the transformations of the economies and energy systems required to make sure that the risks of global warming remain manageable (Erbach, 2015; European Parliament, 2015).

Nachmany and others (2015) reviewed climate change legislation in 99 countries (*see* Figure 3). The study covers national laws and policies directly related to climate change mitigation and adaptation, passed before 1 January 2015. Together, the countries in the study produce 93% of world GHG emissions and include 46 of the top 50 emitters.

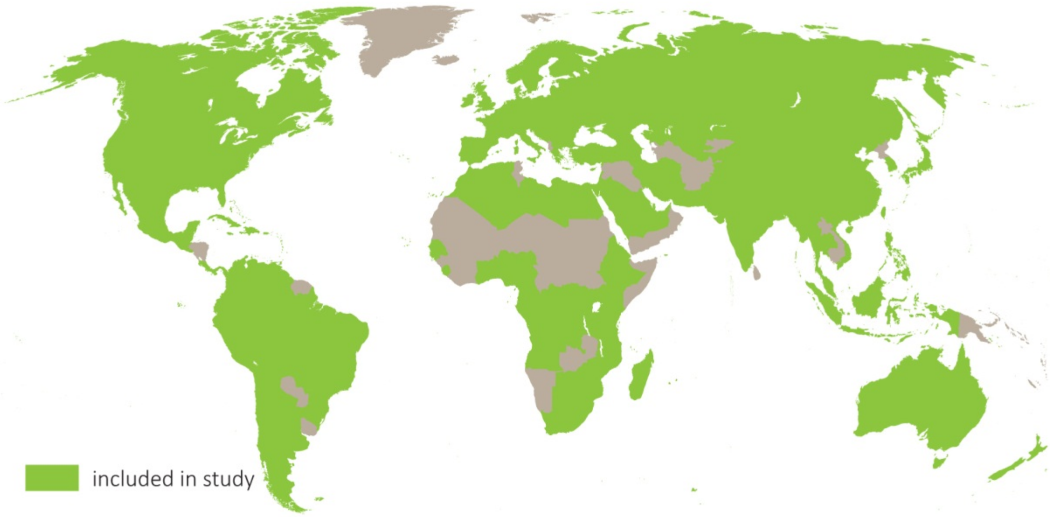

Figure 3 Countries covered in the global climate legislation study (Nachmany and others, 2015)

Since 1997, the number of climate laws and policies has increased dramatically, from 54 to 804 at the end of 2014. Of the countries in the study, 58 have framework laws or policies to address both mitigation and adaptation. Framework legislation is defined as a law or regulation with equivalent status, which serves as a comprehensive, unifying basis for climate change policy, which addresses multiple aspects or areas of climate change mitigation or adaptation (or both) in a holistic, overarching manner. Forty-five countries in the study, (including the EU as a block) have economy wide targets to reduce their emissions. Targets may take various forms; absolute or relative (*see* Table 2). Together, these countries account for >75% of global emissions. Of the 99 countries, 80% have renewable energy targets. The study is of greater significance as countries prepare for the COP 21, UN Conference of the Parties meeting in Paris in December 2015 and work out their intended nationally determined contributions (INDCs) to the new climate agreement (Nachmany and others, 2015). Regardless of the new climate targets, the global coal market is expected to be under stress if oversupply and decreasing prices continue (Banks and others, 2015).

Table 2 Countries with absolute and relative economy-wide emission reduction targets (Nachmany and others, 2015)

Absolute targets		Relative targets
Austria	Kazakhstan	Brazil†
Belgium	Maldives	China‡
Bulgaria	Netherlands	India (excluding agriculture)‡
Cost Rica	New Zealand	Indonesia†
Czech Republic	Norway	Israel†
Denmark	Poland	Malaysia‡
Dominican Republic	Portugal	Mexico†
Ethiopia	Romania	South Africa†
European Union*	Russia	South Korea (Republic)†
Finland	Slovakia	Vietnam‡
France	Spain	Iran†
Germany	Sweden	
Greece	Switzerland	
Hungary	Ukraine	
Ireland	United Kingdom	
Italy	United States of America	
Japan		
Covering 37% of global emissions		**Covering 38% of global emissions**

* Covering the EU 28, including the 19 covered in the study
† Emissions reduction against business as usual (BAU) scenario
‡ Emissions intensity target

The study includes detailed country chapters with a full list of laws for each of the 99 countries, country fact sheets with key indicators, and a complete database of over 800 climate-related laws. The study is available on the website of the Grantham Research Institute on Climate Change and the Environment (UK) (www.lse.ac.uk/GranthamInstitute/Legislation) (Nachmany and others, 2015).

2.1.2 Cooperative agreements

In 2014, as President of the G20, Australia led the development of the G20 Energy Efficiency Action Plan (EEAP). The G20 is an international forum for governments and central bank governors from 20 major economies. The members include 19 countries: Argentina, Australia, Brazil, Canada, China, France, Germany, India, Indonesia, Italy, Japan, Mexico, Russia, Saudi Arabia, South Africa, Korea (Republic), Turkey, UK and the USA. The EU is the 20th member and is represented by the European Commission (EC) and by the European Central Bank (ECB). The G20-EFAP, endorsed by the G20 leaders at the November summit, aims to provide a significant step for improving energy efficiency globally through international cooperation. The G20-EFAP documents six work streams where G20 members and guests work together to improve energy efficiency. Each G20 member and guest nominated which work streams it would participate in from the Action Plan. These work streams are progressed through the International Partnership for Energy Efficiency Cooperation (IPEEC) and other international organisations such as the IEA, throughout 2015. The G20 has also tasked the IPEEC to report on the progress of these activities to the G20 at the end of 2015 (APERC, 2015). The plan is available at www.g20.org/sites/default/files/g20_resources/library/g20_energy_efficiency_action_plan.pdf.

The Asia Pacific Economic Cooperation (APEC) is a 21 member, cooperative body, which is predominantly concerned with trade and economic issues, and members engaging with one another as economic entities. Hence the phrasing: 'APEC economies' to describe APEC members. The APEC economies include Australia, Brunei, Canada, Chile, China, Hong Kong, Indonesia, Japan, Republic of Korea, Malaysia, Mexico, New Zealand, Papua New Guinea, Peru, Philippines, Russia, Singapore, Chinese Taipei, Thailand, USA and Vietnam. In a statement made in November 2011 at the APEC Ministerial Meeting in Honolulu, Hawaii, the APEC Ministers aspired to meet an APEC-wide regional goal of reducing the energy intensity of the APEC economies by at least 45% by 2035, using 2005 as a base year. This came after reviewing data analysed by the APEC Energy Working Group, which indicated that APEC is on the path to exceed, significantly, its previous energy intensity goal. The 45% reduction is an aggregate goal, which recognises that economies' rates of improvement may vary for many reasons (APERC, 2014). However, there are several, significant factors, that may make realising the 45% target unlikely. Achieving economic growth in the Asia Pacific region (and the affordable power this requires) is likely to outweigh other demands (Accenture, 2013).

2.2 Regional regulations/agreements

Regional agreements take a variety of forms. In some cases, regional agreements may be freestanding and independent regimes tailored to the unique environmental circumstances of a given region. According to Lamotte (2014), in other cases, regional environmental agreements cover the same substantive terrain as global environmental agreements, but layer on additional obligations that apply only among the parties to the regional agreement. In still other cases, regional environmental agreements may overlap with, but impose slightly different obligations to, those set out in comparable global agreements. This scenario arises where the regional agreement may have preceded and served as a model for the subsequent global agreement. This is the case, for example, with the Protocol on Persistent Organic Pollutants to the United Nations Economic Commission for Europe (UNECE) Convention on Long-Range Transboundary Air

Pollution (LRTAP) Protocol, which predates a global agreement that was adopted on the same topic, the Stockholm Convention on Persistent Organic Pollutants (Stockholm Convention). Although their basic structure and function is similar, there are subtle distinctions among the obligations in each agreement, as well as in the lists of chemicals that they cover. Where agreements overlap, the determination of which obligations apply is subject to the rules of treaty interpretation, primarily those set out in the Vienna Convention on the Law of Treaties (Lamotte, 2014).

2.2.1 European Union

There are three different types of EU legislation: regulations, directives and decisions. A regulation applies directly to each member state, acts as a law and binds member states and individual citizens. Transposition for incorporation into national legislation is not necessary. A directive is the most frequently used legal act within Europe and is binding for each member state at which it is directed. Although an aim is defined (such as a reduction target), the choice of form and means to achieve that target is left to the internal agencies. A directive must be incorporated into national legislation within a specified period. A decision is aimed at specific target groups such as member states or corporate bodies. It is immediately binding. The EU may also make recommendations, which although not binding, carry political weight. Historically, individual countries within Europe set their own national emission legislation with the stringency of this legislation varying quite significantly from country to country. With the enlargement of the EU, there is now an approach towards alignment of environmental legislation for all member countries. The following sections briefly review the major legislation in the EU, which is relevant to coal-fired power plants. These include the Large Combustion Plants Directive (LCPD) and the Integrated Pollution Prevention and Control Directive (IPPCD), which are discussed in previous reports by Nalbandian (2007) and Sloss (2009).

In November 2005, the EC launched a review of European legislation on industrial emissions. This led to the commission proposing an Industrial Emissions Directive (IED) on 21 December 2007, which was ratified by the European Council on 8 November 2010 and came into force on 6 January 2011. The EU sets limits for emissions of pollutants from large combustion plants. The Act is known as the Directive 2010/75/EU of the European Parliament and of the Council of 24 November 2010 on industrial emissions. Implementation was carried out over several years starting 7 January 2013 with full implementation to be achieved by 1 January 2016. The IED takes an integrated approach to industrial emissions. It brings seven separate directives into one including the LCPD, the IPPCD, the Waste Incineration Directive (WID), the Solvent Emissions Directive (SED) and three existing directives on titanium dioxide. For a breakdown of the implementation timescale and more information on the IED, visit http://www.apis.ac.uk/overview/regulations/industrial-emissions-directive. Its main purpose is to reduce harmful industrial emissions, in particular through better application of Best Available Techniques (BAT), thereby benefiting both citizens' health and the environment. Chapter III of Directive 2010/75/EU contains special provisions for combustion plants. It applies to combustion plants with a total rated thermal input, which is equal to or greater than 50 MW, irrespective of the type of fuel used. Combustion plants excluded from the scope of the directive include plants where the products of combustion are used for heating or drying, post-combustion plants designed to purify the waste gases by combustion (which are not operated as independent combustion plants). Also excluded are facilities for the regeneration of catalytic cracking catalysts; facilities for the conversion of hydrogen sulphide into sulphur, reactors used in the chemical industry and coke battery furnaces (EUR-Lex, 2014).

As stated above, the IED requires better application of BAT. However, a number of changes are expected including slight variations to the requirements of existing directives, new requirements on existing installations, regulation of additional installations and possible deregulation on some installations. For the power generating sectors in the EU, the implementation of the IED in 2015 is expected to result in closure of older, inefficient coal-fired power plants over the next few years (for example, in Germany a total of ~6 GW coal-fired capacity is expected to cease operation between 2013 and 2017). A list of reference documents that have been drawn (or are planned to be drawn), as part of the exchange of information carried out in the framework of the IED, can be viewed at http://eippcb.jrc.ec.europa.eu/reference/. The information provided at the EC website contains the BAT reference documents, the so-called Best Available Techniques Reference Documents (BREFs), as well as a few other reference documents that have been adopted under both the IPPCD and the IED. According to the IED, BAT conclusions (available at the website) shall be the reference for setting the permit conditions to installations covered by the Directive (European Commission, 2015).

In addition, the law includes rules on aggregation. For example, where the waste gases of two or more separate plants are discharged through a common stack, the combination formed by such plants is considered as a single combustion plant and their capacities are added, for the purposes of calculating the total rated thermal input. The new emission limit values (ELV) for large combustion plants are generally more stringent than in previous directives. There is a degree of flexibility (transitional national plan and limited lifetime derogation) for existing installations. The definition of existing installations in the LCPD is based on the age of the plant. Existing plants are those licensed before 1 July 1987. New plants include those licensed after 1 July 1987 but before 27 November 2002 (and operational before 27 November 2003) while 'new' new plants are those licensed after 27 November 2003. According to the LCPD, by 1st January 2008, all large combustion plants (>50 MW) in Europe were required to comply by one of three options. The three options are: meet set ELVs for particulate matter (PM), SO_2 and NOx, sign up to lower SO_2 and NOx 'bubbles' that are equivalent to the ELV reductions and which are part of an National Emission Reduction Plan (NERP), or opt out of ELVs and NERP and commit to shut down by the end of 2015, operating for no more than 20,000 hours over that period. Table 3 shows the implementation timeline for the adoption of the LCPD for existing plants in the EU and Table 4 compares the ELVs for existing plants with those for new plants, highlighting, in the footnotes, requirements for plants which cannot meet the new LCPD limits due to fuel characteristics (Nalbandian, 2007; Sloss, 2009).

Table 3 Implementation timetable of the revised 2001 LCPD for existing plant (Nalbandian, 2007; Sloss, 2009)

Milestone	Commission requirements
By 27 November 2002	Member states shall bring into force the laws, regulations and administrative procedures necessary to comply with the Directive
By 27 November 2003	Member states shall communicate their National Plan to the Commission
Within six months of the communication referred to above	The Commission shall evaluate whether or not the National Plan meets the requirements of Article 4(6) of the Directive. If the Commission considers that this is not the case, it shall inform the Member state and within the subsequent three months the Member state shall communicate any measures it has taken in order to ensure that the requirements are met
By 30 June 2004	If an operator of an existing plant seeks to be exempt from the ELVs or inclusion in a National Plan, the operator must submit a written declaration to the competent authority, not to operate the plant for more than 20,000 operational hours starting from 1 January 2008 and ending no later than 31 December 2015. The operator is also required to submit each year to the competent authority a record of the used and unused time allowed for the plant's remaining operational life
By 1 January 2008	Member states shall comply with the revised LCPD either by ensuring that existing plants comply with the ELVs or that existing plants are subject to a National Plan, except for existing plants that are exempt under the limited operating life derogation
From 1 January 2016	The more stringent NOx ELVs for solid fuel plants >500 MWth apply and the low load factor derogations for SO_2 and NOx emissions from solid fuel plants of 400 MWth and >500 MWth respectively become more stringent
From 1 January 2018	The low volatility solid fuel derogation allowing a less stringent NOx ELV ceases

Table 4 Revised 2001 LCPD emission limit values (ELVs) for existing plants (Nalbandian, 2007; Sloss, 2009)

Pollutant	Fuel type	ELVs[1], mg/m^3			
		50–100 MWth	100–300 MWth	300–500 MWth	>500 MWth
SO_2	Solid[2,3]	2000	2000–400 (sliding scale)	2000–400 (sliding scale)	400
	Liquid	1700	1700	1700–400 (sliding scale)	400
	Gaseous	35 – in general 5 – liquefied gas 800 – low calorific gases from gasification of refinery residues, coke oven gas & blast furnace gas			
NOx	Solid[4,5]	600	600	600	500 200 (from 1 January 2016)
	Liquid	450	450	450	400
	Gaseous	300	300	300	200
PM	Solid	100	100	100	50[6]
	Liquid[7]	50	50	50	50
	Gaseous	5 – as a rule 10 – blast furnace gas 50 – steel industry gases that can be used elsewhere			
SO_2, NOx and PM	Multi-firing units using two or more fuels	Special provisions apply to these units as detailed in Article 8 of Directive 2001/80EC.[8]			

1. The ELVs for existing plant are calendar monthly mean values, *see* Article 14 of Directive 2001/80EC (EUR-Lex, 2014). The reference O_2 content for solid fuels is 6% and 3% for liquid and gaseous fuels
2. Plant ≥400 MWth, which do not operate more than the following number of hours a year (rolling average over a period of five years), shall be subject to an ELV for SO_2 of 800 mg/m^3: until 31 December 2015, 2000 hours; and from 1 January 2016, 1500 hours
3. Where the ELVs cannot be met due to characteristics of the fuel, a rate of desulphurisation of at least 60% shall be achieved in the case of plant with a rated thermal input of 100 MWth, 75% for plant >100 MWth and 300 MWth and 90% for plant >300 MWth. For plant >500 MWth, a desulphurisation rate of at least 94% shall apply or at least of 92% where a contract for the fitting of FGD or lime injection equipment has been entered into and work on its installation has commenced before 1 January 2001
4. Until 31 December 2015 plant >500 MWth which from 2008 do not operate more than 2000 hours per year (rolling average over a period of five years) shall, in the case of plant subject to a National Plan, have their contribution to the National Plan assessed on the basis of an ELV of 600 mg/m^3. From 1 January 2016 such plants, which do not operate more than 1500 hours per year (rolling average over a period of five years), shall be subject to an ELV for NOx of 450 mg/m^3
5. Until 1 January 2018 in the case of plants that in the 12-month period ending on 1 January 2001 operated on, and continue to operate on, solid fuels whose volatile content is <10%, 1200 mg/m^3 shall apply
6. An ELV of 100 mg/m^3 may be applied to existing plant ≥500 MWth burning solid fuels with a heat content of <5800 kJ/kg, a moisture content >45% by weight, a combined moisture and ash content >60% by weight and a calcium oxide content >10%
7. An ELV of 100 mg/m^3 may be applied to plant <500 MWth burning liquid fuel with an ash content >0.06%
8. Special provisions apply to multi-firing units using two or more fuels as detailed in Article 8 of Directive 2001/80EC. Summarised briefly these are:
   I. in the case of plants with multi-firing units involving the simultaneous use of two or more fuels (Article 8(1) of Directive 2001/80EC), ELVs shall be set firstly by taking the ELV of each fuel and pollutant; secondly by determining the fuel-weighted ELVs, obtained by multiplying the individual ELV by the thermal input delivered by each fuel, the product of multiplication being divided by the sum of the thermal inputs delivered by all fuels; and thirdly by aggregating the fuel-weighted ELVs
   II. in multi firing units, using the distillation and conversion residues from crude-oil refining for own consumption, alone or with other fuels, the provisions for the fuel with the highest ELV (the determining fuel) shall apply. Notwithstanding point (i) above, if during the operation of the combustion plant the proportion contributed by that fuel to the sum of the thermal inputs delivered by all fuels is at least 50%. Where the proportion of the determining fuel is <50%, the ELV is determined as described in Article 8(2) of Directive 2001/80EC
   III. as an alternative to point (ii), an average ELV for SO_2 may be applied (irrespective of the fuel combination used) of 1000 mg/m^3, averaged over all existing plants within the refinery (Article 8(3) of Directive 2001/80EC)
   IV. in the case of plants with a multi-firing unit involving the alternative use of two or more fuels (Article 8(4) of Directive 2001/80EC), the ELVs corresponding to each fuel used shall be applied

EU countries must ensure that emissions to air are monitored in accordance with the directive requirements and that the conditions laid down in the installation's permit to operate are fully met. The installation and functioning of the automated monitoring equipment are subject to control and to annual surveillance tests (EUR-Lex, 2014).

With regard to carbon capture technology installation and the geological storage of CO_2, that is **CCS**, operators of all combustion plants with a rated electrical output of 300 MW or more should ensure that: firstly, suitable storage sites are available; secondly, transport facilities are technically and economically feasible; and thirdly, that it is technically and economically feasible to retrofit CO_2 capture equipment. The directive on the geological storage of CO_2, the so-called "CCS Directive", establishes a legal framework for the environmentally safe geological storage of CO_2. It covers all CO_2 storage in geological formations in the EU and the entire lifetime of storage sites. It also contains provisions on the capture and transport components of CCS, though these activities are covered mainly by existing EU environmental legislation, such as the Environmental Impact Assessment Directive (EIAD) or the IED, in conjunction with amendments introduced by the CCS Directive. The CCS Directive has been in place since 2009 and had to be transposed into national law by June 2011. The European Commission was required to review the Directive and present a report to the European Parliament and Council by 31 March 2015. An external evaluation study started in April 2014 and a stakeholder consultation was out between mid-May and mid-July 2014 (European Commission, 2015b).

When the CCS Directive was agreed in 2009, there was an expectation that by 2014/15, up to 12 large-scale CCS plants would be in operation in Europe. However, to date there are only two large-scale CCS plants operating in Europe (both in Norway), and 13 operational facilities in the world, the majority of which are associated with enhanced oil recovery (EOR) operations. The consensus view for this lack of progress is attributed mainly to the low prices of CO_2 emissions achieved within the EU Emissions Trading Scheme (EU ETS), which has made the financial case for CCS unattractive for developers. The lack of progress has made it difficult to evaluate the Directive because there has been virtually no practical testing of its content, apart from one recent permit (the ROAD project in the Netherlands) and two ongoing permit applications in the UK, which have complied with the initial stages of the Directive. This has meant that the evaluation has been limited, relying mainly upon stakeholder's opinions and their limited experience with the Directive, in combination with the lessons that can be learnt from projects and project preparation inside and outside Europe (IMPEL, 2015).

According to IMPEL (2015), the conclusion on the evaluation of the Directive is that the overall need for CCS (and European CCS regulation) to decarbonise power production and heavy industry in Europe (in line with the 2050 emission reduction targets) remains genuine and urgent. However, given the lack of practical experience it would not currently be appropriate, and could be counterproductive, to reopen the Directive for significant changes. The non-regulatory guidance documents would benefit from some revision now and there are a number of issues of potential concern in the Directive that should be examined in the light of greater practical experience in approximately five years' time; that is in 2020.

Nevertheless, there are issues which affect CCS in other Directives (particularly the EU-ETS Directive), that should be considered now.

The EU has set a goal of reducing GHG emissions to 20% below 1990 levels by 2020. The target is divided between sectors covered under the EU ETS, covering about 45%of total GHG emissions, and the Effort Sharing Decision (ESD), which sets targets for the remaining economic sectors. Under the EU ETS Directive there are no country-level targets. The EU ETS puts a cap on CO_2 emissions and creates a market and price for carbon allowances. The 45% of EU emissions include energy intensive sectors and approximately 12,000 installations. The EU ETS applies to all plants with an installed capacity greater than 20 MW. In 2008, countries in the EU entered phase II of the EU ETS. For the most part, reduction targets for the majority of member countries were met by a combination of trading and actions taken to reduce emissions at sources other than coal-fired power plants. According to Lelong and others (2015), the impact of the EU ETS, the first in the world emissions trading scheme which was launched ten years prior, on emissions to date may be debatable. Nevertheless, ETSs as a means to regulate emissions have now spread to America, Asia and Oceania; 27% of global electricity is generated in a market with a carbon price. For information on the state of carbon pricing: around the world in 46 carbon markets see http://www.carbonbrief.org/the-state-of-carbon-pricing-around-the-world-in-46-carbon-markets (World Bank Group: Climate Change and ECOFYS, 2014).

In phase III which commenced in 2013 and runs until 2020, it is expected that the Clean Development Mechanism (CDM) and Joint Implementation (JI) will deliver many of the credits required. This will mean projects will be funded outside the country to which the credits/reduction targets apply and these may include options such as the closure and replacement of less efficient coal-fired power plants, especially in developing countries. The EU ETS, in combination with Kyoto targets and further EU requirements, will require plants beyond 2020 to be ‘carbon capture ready’ and this will affect the design, planning and permitting of future coal-fired plants. The EU ETS, ensures that in case of leakage, operators have to surrender emission allowances for any resulting emissions. Liability for local damage to the environment is dealt with by using the Directive on Environmental Liability. Liability for damage to health and property is left for regulation at Member State level. Furthermore, barriers to CCS in existing waste and water legislation are removed, and the LCPD is amended to require an assessment of capture-readiness for large plants. The revised directive includes CCS explicitly in Annex I. Emissions captured, transported and stored according to this Directive will be considered as not emitted (European Commission, 2015b).

Requirements of phase III of the EU ETS include (Carbon Trust, 2013):

- **Design:** a centralised EU-wide cap on emissions is set.
- **Cap will reduce over time:** the 'cap' will decline by at least 1.74% a year, so that emissions in 2020 will be at least 21% below their level in 2005.

- **More sectors will be covered:** the scheme will include the production of all metals (including aluminium). For some sectors, it will include the emission of other greenhouse gases in addition to CO_2. The scheme is also inclusive of other industries, such as aviation.
- **Opt-out:** May be possible in set cases. For example, the Department of Energy and Climate Change (DECC) (UK) introduced an opt-out provision for small emitters and hospitals in the UK, allowing them to move to a more "light-touch" scheme with lower administrative costs (which affects disproportionately smaller companies). The opt-out will deliver an equivalent carbon reduction.
- **Allowances:** Since 2013, at least 50% of allowances have been auctioned instead of given to installations. Use of CDM allowances will be more tightly restricted during phase III to no more than 50% of the reductions required.

On 19 December 2014, the European Commission, DG Climate Action, launched a consultation on the revision of the EU ETS Directive. The consultation was launched in light of the European Council agreement on the 2030 framework for climate and energy. The aim of the consultation was to gather the views of stakeholders on some elements of the Council agreement, which will be translated into a legislative proposal to revise the EU-ETS for post 2020. The deadline for responding was 16 March 2015.

As for malfunctioning and/or breakdown of abatement equipment, the countries must ensure that the permits issued by their competent authorities contain provisions relating to malfunction or breakdown of abatement equipment. In the case of a breakdown, the operator must reduce or close down operations if a return to normal operation is not achieved within 24 hours, or operate the plant using low-polluting fuels.

The European Commission (2015a) has set out the EU vision for the new global climate change agreement (*see* Section 2.1) that will, through collective commitments based on scientific evidence, put the world on track to reduce global emissions by at least 60% below 2010 levels by 2050. The EU wants Paris to deliver an international agreement that fulfils the following key criteria (European Commission, 2015a):

- create a common legal framework that applies to all countries;
- include clear, fair and ambitious targets for all countries based on evolving global economic and national circumstances;
- regularly review and strengthen countries' targets in light of the below 2°C goal;
- hold all countries accountable – to each other and to the public – for meeting their targets, and
- the EU's contribution to the new agreement will be a binding, economy-wide, domestic greenhouse gas emissions reduction target of at least 40% by 2030.

The energy map within the European region is consistent. The WEC (2015) report lists the same six critical uncertainties and need for action issues throughout the EU States. These are Russia and the situation with the Ukraine, energy prices, climate framework, renewable energies, EU cohesion, and energy subsidies. The issue and potential future of coal utilisation vary substantially in some parts of the EU. This is an effect of coal resources and the strategic meaning of the fuel in some EU countries, both in the energy sector and the economy as a whole. For example, in Poland, where coal is abundant and is the main fuel in power generation.

According to Tomczak (2014), the energy sector in the EU is dominated by discussions around the new Energy and Climate Policy Framework for 2030, as well as new environmental standards proposed as part of the Clean Energy Package. For the coal industry, it is not only climate targets, but also stricter environmental regulations, that are likely to be most testing. New environmental standards for coal-fired power plants and smaller coal-fired boilers could prove challenging for the position of coal in the EU. The three key initiatives to watch are (Tomczak, 2014):

- More-ambitious definitions of BAT for controlling the emissions of various pollutants from large coal-fired plants.
- New environmental standards for medium-sized combustion plants, such as heat-generating boilers.
- Tighter limits on pollutant emissions allowed for each of the EU member states.

The revision of BAT standards for large combustion plants could result in more ambitious technology requirements on all new coal-fired power stations in the EU. A new standard for mercury emissions, which were not included in previous EU rules, is also discussed, but not yet proposed within the current legislation.

The Minamata Convention on Mercury (signed in September 2013) required that UNEP (United Nations Environment Programme) commence work on the guidelines for implementation of the Convention. For coal-fired plants, this means BAT/BEP (best available techniques/best environmental practice) on new plants and an option of BAT/BEP, emission limit values (ELVs), reduction targets or 'suitable alternatives' for existing plants (www.iea-coal.org). The Convention discussions and the LCPD BREF debate on mercury controls noted that emission levels that can be achieved (and have been achieved since 2010 in EU reference plants) are <1 µg/Nm^3 (N: normalised at 6% O_2 concentration) on a yearly average, based on hourly averages. For hard coal <1 µg/Nm^3 mercury emissions are achievable as co-benefits of selective catalytic reduction (SCR) for NOx control and electrostatic precipitation (ESP) and wet scrubber flue gas desulphurisation (FGD) for SO_2 reduction, or SCR and fabric filtrations (FF) and wet scrubber FGD. However, with activated carbon injection/triple action catalyst/boiler bromide addition or other dedicated mercury controls, <1 µg/Nm^3 is attainable with guarantees. The EU has not adopted mercury emission regulation yet, especially as no dedicated mercury controls are in use on large-scale coal-fired plants in Europe although trials are ongoing in Germany. About 80% of all hard coal, large combustion plants in Europe already meet levels of <4 µg/Nm^3 on an annual basis as a co-benefit of installed air pollutant control technologies. As for lignite, as above, levels below 1 µg/Nm^3 may be achievable with dedicated technologies. However, only levels of <3 µg/Nm^3 are achieved currently in some plants in the

EU (for example, in Germany and the Czech Republic) as a co-benefit of ESP and wet scrubber FGD. Currently, the LCPD BREF (not yet adopted) recognises that levels below 1 µg/Nm^3 are attainable with dedicated mercury controls for both types of coal, even if the higher range (7 µg/Nm^3) allows for business as usual (that is, optimisation of traditional pollution controls). However, the levels expected to be 'agreed' for plants >300 MWth are <1–4 µg/Nm^3 (for hard coal) and <1–7 µg/Nm^3 (for lignite), which should be complied with by 2021 at the latest, depending on the publication date of the revised LCPD BREF (EEB, 2015 and Schaible, 2015). For detailed reviews on SCR, ESP, FF and FGD visit www.iea-coal.org.

In March 2007, the EU 27 countries adopted a binding target of 20% final energy consumption from renewable energy by 2020. In January 2008, the EC presented a draft Directive on the promotion of the use of energy from Renewable Energy Sources (RES). After the European Parliament and the Council agreed the RES Directive in December 2008, it entered into force in June 2009. If transposed accurately, within national laws, the RES Directive becomes the most ambitious piece of legislation on renewable energy in the world.

The EU Agency for the Cooperation of Energy Regulators (ACER) was established to further progress the completion of the internal energy market, both for electricity and natural gas. ACER was officially launched in March 2011, and is based in Ljubljana (Slovenia). As an independent European body, which fosters cooperation among European energy regulators, ACER works to ensure that market integration and the harmonisation of regulatory frameworks are achieved within the framework of the EU energy policy objectives. The latter aim to create a more competitive, integrated market, an efficient energy infrastructure that guarantees the free movement of energy across the EU borders and the transportation of new energy sources, thus enhancing security of supply for EU end users, in addition to guaranteeing a monitored and transparent energy market. For more information on ACER visit http://www.acer.europa.eu/The_agency/Pages/default.aspx.

The European Energy Union package, described as "a framework strategy for a resilient energy union with a forward-looking climate change policy", was finalised and published on 25 February 2015. The policy was introduced to ensure that Europe has secure, affordable and climate-friendly energy. The EU Energy Union strategy is made up of 5 components (European Commission, 2015d):

- **Supply security:** diversifying Europe's sources of energy and making better, more efficient use of energy produced within the EU.
- **A fully-integrated internal energy market:** using interconnectors which enable energy to flow freely across the EU - without any technical or regulatory barriers. Energy providers can then freely compete and provide the best energy prices.
- **Energy efficiency:** consuming less energy in order to reduce pollution and preserve domestic energy sources. This will reduce the EU's need for energy imports.

- **Emissions reduction:** renewing the European emissions trading scheme, pushing for a global deal for climate change in Paris in December 2015, and encouraging private investment in new infrastructure and technologies.

- **Research and innovation:** supporting breakthroughs in low-carbon technologies by coordinating research and helping to finance projects in partnership with the private sector.

The EU Energy Union document focusses on renewables and discusses the investment in gas exploration as well as nuclear power but reducing dependence on gas imports. The document considers that in order to reach the Energy Union goal, EU Member States have to move away from an economy driven by fossil fuels. Gas is a fossil fuel and is discussed extensively in the document. Coal, another fossil fuel, is not mentioned in the document despite the fact that, and according to the European Commission website (https://ec.europa.eu/energy/en/topics/oil-gas-and-coal/coal-and-other-solid-fuels), in 2015, "coal accounts for about a quarter of all electricity production in the EU and is also an important fuel for industrial processes like steel production. As a cheaper and more readily available alternative to other fossil fuels such as natural gas and oil, coal forms an integral part of the energy mix of many EU countries. It also helps some EU countries reduce their dependence on imports." However, as the EU is working towards drastically reducing its carbon emissions, including from coal-fired power plants, part of the EU strategy includes the implementation of clean coal technologies such as CCS (European Commission, 2015c). Furthermore, the policy document highlights that latest data (2015) shows that the EU imported 53% of its energy at a cost of around EUR 400 billion, making it the largest energy importer in the world. Six Member States depend on a single external supplier for their entire gas imports and therefore are vulnerable to supply shocks (European Commission, 2015d).

2.3 Bilateral agreements

Bilateral agreements are, in brief, enforceable agreements between two countries/states. An example is limiting transboundary air pollutant sources from one country/state to another. These agreements impose binding obligations on the parties, who in turn may impose obligations on private actors within their jurisdiction through domestic implementing laws. For example, the USA and Canada Air Quality Agreement of 1991, which focused originally on measures to reduce acid rain in the shared atmosphere (Lamotte, 2014). In November 2014, the USA and China, the world's major CO_2 emitters, announced targets to reduce US greenhouse gas emissions 26–28% below 2005 levels by 2025 and China announced targets to peak CO_2 emissions around 2030, with the intention to try to peak earlier, and to increase the non-fossil fuel share of all energy to around 20% by 2030. Together, China (~28%) and the USA (~16%) account for over one third of global greenhouse gas emissions (The White House, 2014). On 14 November 2014, the two countries reaffirmed the importance of strengthening bilateral cooperation on climate change. They announced making a joint effort and with other countries, to adopt a protocol, another legal instrument or an agreed outcome with legal force under the Convention applicable to all Parties at the United Nations Climate Conference in Paris in 2015. According to Buckley (2015), the National

Development and Reform Commission (NDRC) announced, during a press briefing, that China would open a nationwide carbon market in 2016, to help the government reduce emissions by 2030.

2.4 National regulations

Historically, countries in Western Europe (such as Germany and Denmark), Japan and the USA had the most stringent air pollutant emission legislation. However, today, most countries, throughout the world, have introduced or, are in the process of adopting strict emission standards for fossil fuel use, especially in power generation. . For national, country-by-country analysis of emission legislation throughout the world, *see* the emission standards database under the heading databases on the IEA Clean Coal Centre website www.iea-coal.org.The adoption of direct national regulations has been the most effective and widely used pollution control and reduction methodology throughout the world. Regulatory standards have had a major influence on cutting emissions from coal combustion plants. Increasingly stringent rules and requirements have led to the development of efficient and reliable emissions control technologies, the application of which, in some countries, is mandatory or unavoidable in order to meet set targets. In this section, recent developments in national regulations are discussed, mainly for countries that have a major role to play in coal production and consumption.

Australia

Individual states in Australia have the jurisdiction to set their own emission legislation, including targets for greenhouse gas reduction. Over and above this, the National Environmental Protection Measures (NEPMs) can be set based on goals, standards, protocols and/or guidelines. Since 1998, efforts have been made to set air quality and emissions standards as well as monitoring and reporting requirements through the NEPMS agreed by State and Territory governments and the Commonwealth. Implementation of these NEPMs falls to State and Territory governments. According to Environmental Justice Australia (2014), there is no penalty if States and Territories do not comply with NEPMs. In addition, state monitoring and enforcement of air pollution laws is patchy. Currently, although there is a National Pollutants Inventory (NPI) for the quantification of emissions, there are no binding national emission standards for SO_2 or NOx. The National Health and Medical Research Council (NHMRC) (Australia) has issued emission *guidelines* for SO_2 and NOx. However, the set limits are general and can be met relatively easily. Australian coals are generally low in sulphur and therefore, SO_2 emissions are not regarded as a high priority for control and there are, to date, no FGD or similar controls on Australian coal-fired plants. Although NOx limits have been specified in some states, it is thought that these are relatively lenient and have not required the installation of any NOx control technologies. In 2009, the focus of Australian emission legislation was very much on the development of new clean coal technologies and low carbon options. Thus, existing coal-fired plants are not facing any immediate retrofit requirements. Future strategies considered for energy in Australia towards 2050 relate to the reduction of mercury and CO_2 emissions through the use of brown coal in integrated gasification combined cycle (IGCC) technology with and without CCS (Sloss, 2009).

According to Environmental Justice Australia (2014) and based on the NPI 2011/2012, (www.npi.gov.au), coal-fired power stations in Australia are one of the biggest and most harmful sources of air pollution. Electricity generation is the single largest source of both fine particulate matter ($PM_{2.5}$) and SO_2 pollution as well as the second-largest source of NOx. Coal mining together with electricity generation is responsible for about 58% of all $PM_{2.5}$ emissions. Environmental Justice Australia (2014) consider that air pollutants also have an impact on climate change. For example, black carbon, or soot, a type of $PM_{2.5}$, which results from incomplete combustion of fossil fuels, biofuels and biomass is considered by Bond and others (2013) to be a major contributor to climate change as it increases the effects of warming in the atmosphere and, has a much greater (twice the direct) climate impact than previous assessments. According to Bond and others (2013), black carbon ranks "as the second most important individual climate-warming agent after CO_2". Reducing black carbon is predicted to have a significant effect on reducing global warming. Ozone, SO_2 and CO are other contributors to climate change. In Australia, black carbon comes from not only coal combustion but also from other sources, such as vehicle emissions, as well as bushfires and wood burning heaters. Environmental Justice Australia (2014) states that as air pollution has an impact on climate change, climate change will also have an impact on air pollution. As temperatures increase and the impacts of climate change become more severe, the frequency of high ozone days in excess of the national standards is also expected to increase. The South Australian Environmental Protection Agency predicts that as temperatures increase and humidity levels decline, the increased intensity and frequency of dust storms in Australia will add to extreme air pollution events, which will include higher levels of petrochemical smog, and result in higher human exposure to PM pollution and ozone.

The Council of Australian Governments (COAG) promised a National Plan for Clean Air (NPCA) in 2011. The Commonwealth Environment Minister however, recently announced that development of the Plan would be delayed until at least July 2016. Environmental Justice Australia (2014) advocates the single national regulation that clearly articulates pollution standards would ensure a consistent national approach that applies in every community across Australia. The Air Pollution Prevention Act would be a standalone Commonwealth legislation that does not rely on agreement from States and Territories. It could be in place much quicker than a COAG negotiated outcome, as it would remove years of negotiation on appropriate standards between the States and Territories. It would also replace the current air pollution NEPMs. Furthermore, a national Air Pollution Regulator should be established as a Commonwealth government agency with responsibility for implementing, monitoring and enforcing the Air Pollution Prevention Act. The Regulator would be responsible for ensuring States and Territories compliance with the standards, investigating community complaints of breaches, and taking enforcement action against States and Territories, which is currently lacking. Finally, Environment Justice Australia (2014) advocates that the States and Territories would be required to implement the national laws in each jurisdiction and enforce local breaches of the Act. They would be required to report to the Regulator annually on implementation, monitoring and enforcement of the Act.

According to the Asia Pacific Energy Centre (APERC, 2014), in 2011/12, 254 TWh of electricity was generated in Australia, mostly with coal (69%). In 2012-13, coal accounted for 59.2% of Australia's primary energy production in energy content terms, and 64% of the 249 TWh of electricity generated. Given its abundance, coal is expected to remain the most commonly used fuel in electricity generation there. However, a large number of wind energy projects, are planned or underway, and are expected to account for an increasing proportion of total electricity generation over the medium to long term (APERC, 2014). APERC (2015) consider that given Australia's abundant energy resources and geographical proximity to burgeoning markets in the Asia–Pacific region, it is capable of meeting a significant proportion of the world's growing energy demand, as well as its own domestic needs. Meanwhile, in line with APEC's aspirational goal of a 45% energy intensity reduction by 2035 compared to 2005 levels, energy intensity in Australia declined by nearly 3.0% in 2012-13.

According to APERC (2015), the Australian Government is committed to reducing GHG gas emissions by 5.0% below 2000 levels by 2020. The Emissions Reduction Fund (ERF) is the government programme established to meet this target. Legislation for the ERF was passed by parliament on 31 October 2014. The capped ERF fund has three main components: crediting emissions reductions, purchasing emissions reductions, and safeguarding emissions reductions. The ERF enables the Government to 'purchase lowest cost abatement (in the form of Australian carbon credit units) from a wide range of sources'. The Clean Energy Regulator (CER) is to administer the fund. However, the carbon tax was repealed by Parliament with effect from 1 July 2014.

China

China is the world's largest coal user, producer and importer (*see* Section 3.2.3). Motivated by air quality concerns, China has introduced strict emission standards and is making efforts to reduce the use of coal in power generation. However, demand for coal in China remains the highest in the world (4.2 Gt in 2012) according to the EIA (2012). In September 2014, the government prohibited the building of new coal-fired power plants in three populated areas around Beijing, Shanghai, and Guangzhou as part of the country's national action plan (Hope, 2014). The authorities also announced, in 2014, that coal-fired plants in Beijing, with a total capacity of 2.4 GW, were to be replaced with gas-fired units by the end of 2014. The first of these plants ceased operation, in mid-2014, two more facilities were shut down by March 2015 while the mandatory closure of the one remaining plant has been postponed to the end of 2016 (http://www.bkweek.com/a/lanmu/duxin/2015/0330/3471.html). EIA (2014) indicate that overall, China's efforts to shift coal-fired generation to other sources in the long term depends on the country's ability to increase domestic production or import of other sources, such as gas.

China's latest national air pollution standards for thermal power plants went into effect on January 1, 2012, replacing standards, that had been in effect, since 2003 (WRI, 2012). These standards brought Chinese power plant regulation generally in line with the developed world standards for both new and existing facilities. The regulations gave existing power plants a 2.5 years grace period to meet the new standards after which all existing plants became subject to the new standards. There are separate standards for oil and natural gas-fired power plants, with the oil standards being at least as strict as coal and the natural gas standards much stricter. However, since most of China's power generation comes from coal, the coal standards are the most relevant to address the air pollution challenges there. Table 5 compares China's new standards to the USA and EU standards for coal-fired power plants.

Table 5 China, EU and USA coal-fired power plant standards for sulphur dioxide (SO_2), Nitrogen oxides (NOx), particulate matter (PM) and mercury (Hg), mg/m³ (IEA CCC; 2015 and WRI, 2012)

Pollutant	Plant type	China, mg/m³	EU, mg/m³	USA, mg/m³
NOx	**New plant**	100	500 (until 31/12/2015) 200 (from 01/01/2016)	117
	Existing plant (defined in China as built between 01/01/2004-31/12/2011 (defined in the USA as built before 28/02/2005)	200	500 (until 31/12/2015) 200 (from 01/01/2016)	117
	Existing plant (defined in China as built between 01/01/2004 (defined in the USA as built before 28/02/2005)	200	500 (until 31/12/2015) 200 (from 01/01/2016)	640 (built 1978-1996) 160 (built 1997-2005)
SO_2	**New plant**	100	200	160 (built after 2005)
	Existing plant (28 provinces in China) (Provinces with high sulphur coal: Guangxi, Sichuan, Guizhou, Chongqing)	200 400	400	640 (built 1978-1996) 160 (built 1997-2005)
PM	**New and existing plant**	30	50 (with an exception of 100 for low quality coal, ie lignite)	22.5
	New and existing plant (from 1 January 2015)	0.03	0.03 (Germany only. No EU-wide set standard)	**New:** 0.001 (bituminous, gangue) and 0.005 (lignite) **Existing:** 0.002 (bituminous, gangue) and 0.006 (lignite)

Coal-fired power plants consume more than half of China's annual coal production, and emit over 40% of China's SO_2 and NOx air pollutants. The new standards are more stringent for new plants in large regions that have the most serious air pollution problems. In regions designated by China's Ministry of Environmental Protection (MEP) as having severe air pollution problems, the limits are 50 mg/m³ for SO_2, 100 mg/m³ for NOx, and 20 mg/m³ for particulate matter.

These 2012 regulations are a major commitment to environmental investment by China. The Chinese government estimates compliance with the new MEP standards will require power companies to invest about US$ 41 billion (2012) to upgrade pollution abatement equipment, with the annual operating cost for NOx control equipment alone projected at approximately US$ 9.6 billion (2012) (61.2 billion RMB). To pay for the investment, on 1 December 2011, China's National Development and Reform Commission raised electricity prices for industrial users by RMB 0.03 (or 0.47 US cents) per kWh. This increase includes RMB 0.008 for NOx control. The increase supports both the costs of the environmental investments and operating costs, and it raises the price of coal-fired power, increasing the incentives for efficiency and making renewable energy more competitive (WRI, 2012).

During China's 11th Five-Year Plan (2006-2010), installation of SO_2 control technology took place on the vast majority of China's coal-fired power plants. According to WRI (2012), the new pollution abatement equipment, combined with the closure of 76 GW of the most highly polluting old coal-fired power plants, reduced China's total sulphur emissions by over 14%. NOx control was added in March 2011, in the 12th Five-Year Plan (2011-2015). According to the Chinese Electricity Council, by the end of 2010 (before the requirement came into force) 14% of coal-fired power plants (totalling 90 GW) had already installed NOx control technology. During the next five years, this number grew considerably, and additional equipment is being added to control mercury and to meet tighter standards for other pollutants.

A summary, in English, and the full text of the regulations, in Chinese, are available from the MEP online at:
http://english.mep.gov.cn/standards_reports/standards/Air_Environment/Emission_standard1/201201/t20120106_222242.htm. In its World Energy Outlook (WEO) 2014, the IEA expects China to continue to be a major industrial coal consumer. Aside from the power sector, the iron, steel and cement industries rely on coal for heat as well as power. As such, coal is set to continue as China's main energy source up to 2035, and possibly beyond. According to the IEA (2014), China will continue increasing coal production to meet demand.

According to Jalesko and others (2014), China increased its coal demand by 7.5% per year between 2005 and 2013 and, as the world's largest consumer in 2014, accounted for about 45% of global coal consumption. As a result, air pollutant and CO_2 emissions increased dramatically in the country. Furthermore, issues encountered included the availability and consumption of clean water in the coal industry. According to Buckley (2015), with 20% of the world's population and only 7% of available fresh water, dealing with water scarcity in China is a strategic priority. In January 2015, the government announced a 4 trillion yuan (US$ 645 billion) water-infrastructure investment programme that runs until 2020. Water policies and availability for the power sector were the topic of a recent report by IEA Clean Coal Centre (CCC) (*see* Carpenter, 2015).

To counter the adverse effects of coal utilisation, the Chinese government introduced a new policy to deal with climate change by 2020. One recent initiative was to reduce coal consumption as a percentage of total energy consumption to below 65% by 2017 from about 67% in 2012. However, Jalesko and others (2014) consider that the current programmes will not trigger a fundamental change in China's energy profile, and more steps will be needed between 2020 and 2030 to meet the IEA's '450 ppm' scenario (*see* Section 2). In addition, the set targets may change. For example, in 2009 the Chinese government set a target to cut CO_2 per unit of GDP by 40–45% by 2020, compared with 2005 levels. Based on the increase in the consumption of coal in China since 2005, China is already approaching this limit.

As discussed in Section 2.3, China has agreed (with the USA) that its CO_2 emissions will peak around 2030. Hence, China's target to expand total energy consumption coming from zero-emission sources to around

20% by 2030 is notable. This will require China to deploy an additional 800–1000 GW of nuclear, wind, solar and other zero-emission generation capacity by 2030 – equivalent to more than all the existing coal-fired power plants capacity (~850 GW) in operation in China today (The White House, 2015).

In 2014, the Asia Centre published its report following the international energy roundtables meeting organised in partnership with the Asia Europe Foundation (ASEF). The document entitled 'Coal and climate change: "the Chinese way"?' discussed four aspects of the situation in China. The first was climate change issues and the struggle for China to maintain its energy security while preserving its environment and sanitary conditions for its large population, and the current role played by coal in developing economies. The second, aimed at exploring solutions to this dual issue by developing environmental reforms further at first, and then by making a review of technological improvements and solutions that are currently envisaged by the Chinese government. The third area of discussion was the current challenges met by different economic actors in the coal industry, and more precisely in the supply chain. Finally, the debate tackled a more international perspective analysing geopolitical aspects of internationalisation and cooperation (Asia Centre, 2014).

The conclusions of the meeting were that there is greater awareness of environmental issues and structural problems that have occurred due to the historically high share of coal in the country's energy mix but also, that strict reforms have been adopted with strong penalties for those resisting the consolidation of the industry and the sustainable development move in China. However, on occasion, achieving set economic development targets overrides the environmental and social well-being of the population. Asia Centre (2014) consider that as long as coal serves as a benchmark for energy prices in China, the expected switch to other types of inevitably more costly energy sources, will remain a stumbling block. However, the authorities in China have shown commitment and will, where possible, to achieving the strict targets they set. For example, there was a dramatic reduction in energy intensity during the implementation of the 11th Five-Year Plan, with the decrease of coal share within the primary energy mix in 2013. The development of more efficient and less polluting technologies utilised by the country is another sign of commitment to reducing the environmental impacts of coal utilisation in China. Nevertheless, despite expectations of coal utilisation falling throughout the world, due to environmental policies, forecasts continue to predict that coal demand will grow at an average rate of 2.3% per year to 2018, mainly driven by China. Given that China's total energy consumption is still growing along with the economy, albeit at a slower pace, coal production will continue to grow fast. Notwithstanding national policies and targets increasingly favouring natural gas and renewable energy use, as well as recent measures taken against the most polluting and inefficient coal mines and power generators, China cannot possibly consider moving away from coal in the medium-term, and probably not in the long-term either (Asia Centre, 2014).

Wang and others (2014) found that during 2005-2010, emissions of SO_2 and PM in East Asia decreased by 15% and 12%, respectively. The reduction was attributed mainly to the large-scale deployment of FGD and efficient PM removal technology in Chinese coal-fired power plants. During the same period, the emissions of NOx increased by 25%, due to inadequate control strategies. Under current regulations and levels of implementation, NOx and SO_2 emissions in East Asia are projected to increase by about 25% from 2010 levels by 2030, while PM emissions are expected to decrease by 7%. Assuming enforcement of new energy-saving policies, emissions of NOx, SO_2 and PM in East Asia are each expected to decrease by more than 25%. Even greater decreases would be achieved assuming full application of technically feasible, energy-saving policies and end-of-pipe control technologies. In comparison to previous projections, Wang and others (2014) found that their study projects more substantial reductions in NOx and SO_2 emissions when considering the aggressive government plans and standards scheduled to be implemented in the next decade.

Germany

Energy policy in Germany is developed and implemented at the federal and regional levels. Germany is an EU member state and is therefore, bound by the legislation summarised within the European Union section above (*see* Section 2.2.1). As such, German environmental legislation is derived from EU directives and regulations. In brief, the current directives that regulate and influence the emission limit values (ELVs) for coal power plants are: the industrial emission directive for all new facilities and existing installations that 'opt in', the revised LCPD, the national emission ceilings (NECs) for certain atmospheric pollutants directive and the EU ETS. Germany has also transposed the European climate and renewables directives into national law; however, it has delayed implementing the European energy efficiency directive (Bayer, 2015). Germany has adopted an ambitious set of energy policies, commonly referred to as the *Energiewende* (Energy Transition). The *Energiewende* aims to reduce total GHG emissions by 80-95% by 2050. The national goals for the *Energiewende* have been integrated into the *Energy Concept*, a national policy document, which maps the German energy policy to 2050. According to Bayer (2015), the German energy transition, '*Energiewende'* has significant implications for the power sector (*see* Figure 4). For more detail on the *Energiewende, see* Graichen (2015).

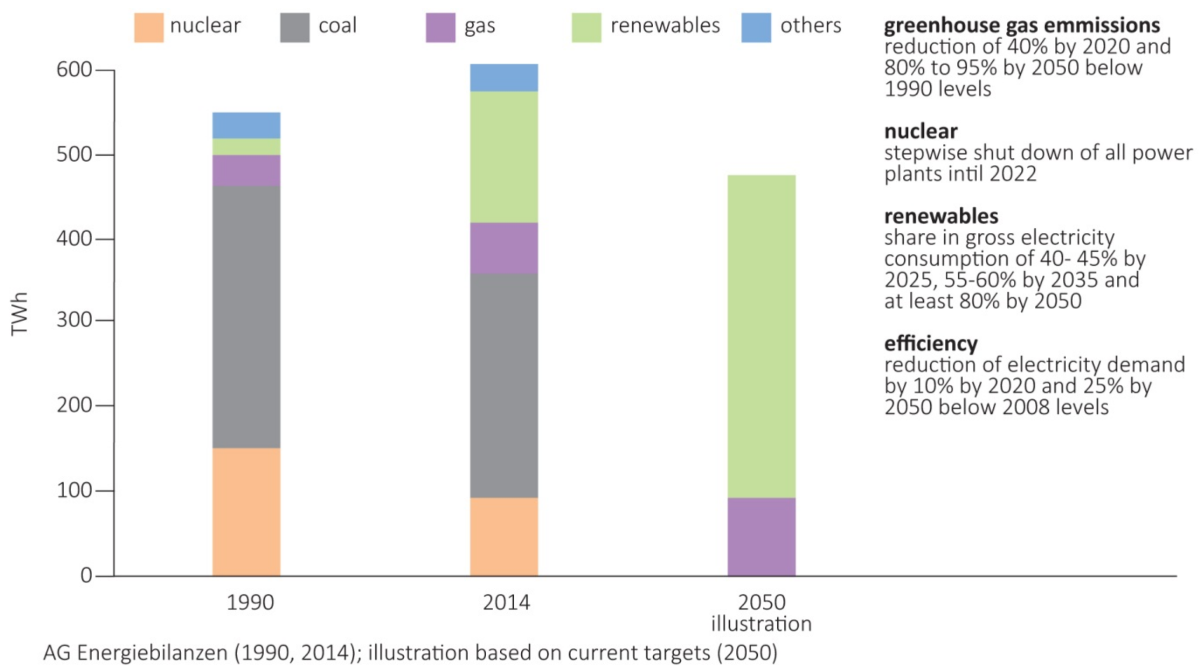

Figure 4 Targets of the German energy transition, '*Energiewende*' (Graichen, 2015)

According to Bayer (2015), the power sector is responsible for ~45% of GHG emissions in Germany. As Figure 4 shows, the *Energiewende* calls for significant improvements in energy efficiency, increasing the share of electricity generated by renewable resources and gradual phasing out of carbon-intensive and nuclear power plants.

Kleiner (2015) listed the following as the most important developments in 2014 in Germany:

- Renewables played a leading role in power in the electricity mix for the first time, displacing lignite and comprising 27.3% of domestic power consumption.
- Demand for power dropped in 2014, by ~4%.
- The share of hard coal and gas in the power mix declined whilst lignite-based power generation continued at high levels.
- GHG emissions fell considerably to their second-lowest level since1990, due largely to the mild winter at the beginning of 2014 and a significant decrease in coal-fired power generation.

Kleiner (2015) also listed the following as the 2015 outlook for the *Energiewende* in the power sector in Germany:

- Power production from nuclear sources to decline by 7-8% due to the closure of the nuclear plant at Grafenrheinfeld in spring 2015.
- Electricity generation from wind power will rise considerably due to the operation of new offshore wind parks with a total capacity of around 2.4 GW. In addition, in 2014 there was a net increase of 3.4 GW of onshore wind power, due to be fully incorporated into the system in 2015.
- Power production from lignite will remain at a high level throughout 2015, while the development of hard coal and gas depends on power demand and the net export balance.
- Electricity prices for households and manufacturing will decline slightly compared to 2014.

According to Schultz and Schwartzkopff (2015), the target to reduce GHG emissions in Germany by 40% by 2020, compared to 1990 levels, is proving difficult to achieve. So, in December 2014, a Climate Action Programme was announced to close the gap of 6-9% shortfall, with the power sector allocated a contribution of 22 Mt of CO_2. The new-proposed *Klimabeitrag* ('climate levy') on the delivery of emissions savings in the power sector would impose financial penalties on the oldest and most inefficient coal plants, especially lignite. Each power station that is older than 20 years would be assigned an emissions allowance (per GW). For any emissions exceeding this allowance a fine would be imposed in the form of carbon allowances at a fixed price, initially envisaged to be €18–20. These additional allowances would then be taken off the market, which would ensure that emissions are not simply allocated to other EU countries. The proposed programme would support the planned EU Market Stability Reserve as part of the reform of the EU ETS. The proposal has met with severe opposition but remains under discussion (Schultz and Schwartzkopff, 2015).

India

Coal is a major energy source for India, accounting for 44% of energy consumption. The country consumed approximately 700 Mt of coal in 2012-13, 70% of which was used in power generation. According to WEC (2015), due to the energy sectors' heavy reliance on coal, supply shortages are one of the main reasons for shortfalls in electricity generation. Other issues include high losses in transmission and distribution and unscheduled, necessary plant outages resulting in widespread blackouts, especially those in 2012. India has the fifth largest coal reserves in the world. However, two government-owned companies run the coal sector, which makes it one of the most centralised sectors in India. In order to provide enough energy to fuel the growing energy demand in the country, there is a need for competition and investment. At the same time there is high uncertainty related to the coal issue. This may be related to potential restrictions on coal use following the climate change negotiations in Paris in December 2015 and increasing international pressure to commit to carbon targets. WEC (2015) consider that these uncertainties may be causing an unfavourable investment environment, potentially undermining the efforts taken to promote the development of the coal infrastructure and supply in India. However, it is important to note that India's INDCs are not about 'reducing' coal use, or, even peaking coal. According to Bhati and Kanchan (2015), it is not clear yet if there is going to be any change in the growth trajectory of coal-based power generation in India.

The Green Rating Project (GRP) (India) is a public-disclosure project in which a non-governmental and non-industry organisation publicly rates the environmental performance of industries. The project started in 1997 and has already rated five major industrial sectors of India: pulp and paper, iron and steel, chlor-alkali, cement and automobiles. In 2015, Bhushan and others studied the coal utilisation sector in India. The study included 47 plants (half of all the plants operating in 2012) spread over 16 States. In general, the sector was found to be polluting and resource-inefficient. This is inevitable, considering that thermal power plants in India commonly use coal that has 40–50% ash content. In addition, the generating fleet is old and mostly based on subcritical technologies. A quarter of the total plant capacity in the study had exceeded its planned operational life. Bhushan and others (2015) note that the problem is compounded by the fact that pollution regulation in India is obsolete and out of tune with new knowledge or technologies. Existing power plants are highly polluting but standards are set only for particulate matter (PM) and not for other pollutants such as SO_2, NOx or heavy metals, for example, mercury. The PM standards are also lax and vary from 50 to 350 mg/m^3, that is, the older the plant the greater the permitted emissions. Furthermore, according to Bhushan and others (2015), most plants routinely flout the set (lax) standards and under the rationale of the need for power, even the most inefficient and polluting plants are permitted to continue operation. However, Bhushan and others (2015) also found plants that utilise state-of-the-art technologies that can meet stringent PM and SO_2 emission requirements, reduce their water consumption and can achieve zero-liquid-discharge to global standards. Bhushan and others (2015) therefore consider that there is ample scope to improve existing plants and achieve similar conditions with future facilities. However, the authors consider that the adoption and enforcement of mandatory and strict regulation is fundamental if the sector, which has refused to date such restrictions, is to achieve better environmental performance.

As stated above, regulation of air pollutants in the power sector in India has been and continues to be inadequate, as India currently has no national regulations for SO_2 or NOx emissions and lenient standards for PM. In addition, an estimated 87% of mercury emissions is attributed to coal-based power plants. There are only a few FGD units currently in operation in the country. However, in April 2015, in a draft notification, the Central Government of India, Ministry of Environment, Forest and Climate Change, proposed, under the Environment (Protection) Act of 1986, the introduction of set emission standards for SO_2, NOx and mercury (Hg) and tightening of the existing standards for PM. The new rules are to be called the Environment (Protection) Amendment Rules, 2015 and they will come into force on the date of their publication in the Official Gazette. This is expected to be 1 January 2017. However, the date set for these standards to be promulgated will be within 2 years from the date of notification. Bhati and Kanchan (2015) consider the proposal's promulgation date quite ambitious especially with the required investment, limited capacity of EPC consultants and manufacturers, and the necessary enforcement of these standards in order to achieve compliance. Table 6 shows the new, proposed emission limits to be adopted by thermal power plants.

Table 6 Proposed emission limits for India's thermal power plants under the Environment (Protection) Amendment Rules, 2015 (Bhati and Kanchan, 2015)

	Pollutant	Standards, mg/m^3
Units installed before Dec 2013*	PM	100
	SO_2	600 (units <500 MW) 200 (units ≥500 MW)
	NOx	600
	Hg	0.03 (units ≥500 MW)
Units installed after 2003 to 31 December 2006*	PM	50
	SO_2	200 (units ≥500 MW)
	NOx	300
	Hg	0.03
Units to be installed from 1 January 2017†	PM	30
	SO_2	100
	NOx	100
	Hg	0.03

* The units to meet the limits within two years from date of the notification
† Includes all the units, which have been accorded environmental clearance and are under construction

With regard to GHGs and climate change, India's CO_2 emissions are reported as the third largest after China and the USA at nearly 6% of global emissions. Bhushan and others (2015) note that 53% of the CO_2 emissions are from fuel combustion for electricity production. The emission intensity of Indian coal-based power plants reportedly ranges between 1.03–1.26 tCO_2/MWh, one of the highest among countries with significant coal-based capacity (*see* Figure 5, note: specific CO_2 emission for India are estimated for the period April 2011-March 2012) (Bhushan and others, 2015 and Hussy and others, 2014). This is mainly due to the outdated and less efficient subcritical combustion technology in use. India's first supercritical unit was commissioned in 2010-11. The 12th Five-Year Plan (2012-17) envisions that 50-60% of new capacity added, during this period, will be based on supercritical technology. Bhushan and others (2015) recognise the limitations of how much efficiency improvement is achievable with older technology and note that deeper cuts in CO_2 emissions would require exploration of options such as implementation of CCS (with high-efficiency units). However, as CCS is costly (both in monetary and power consumption terms) and remains in the demonstration stage, efficiency improvements remain the most cost-effective means to achieve significant cuts in emissions from coal-based power plants in India.

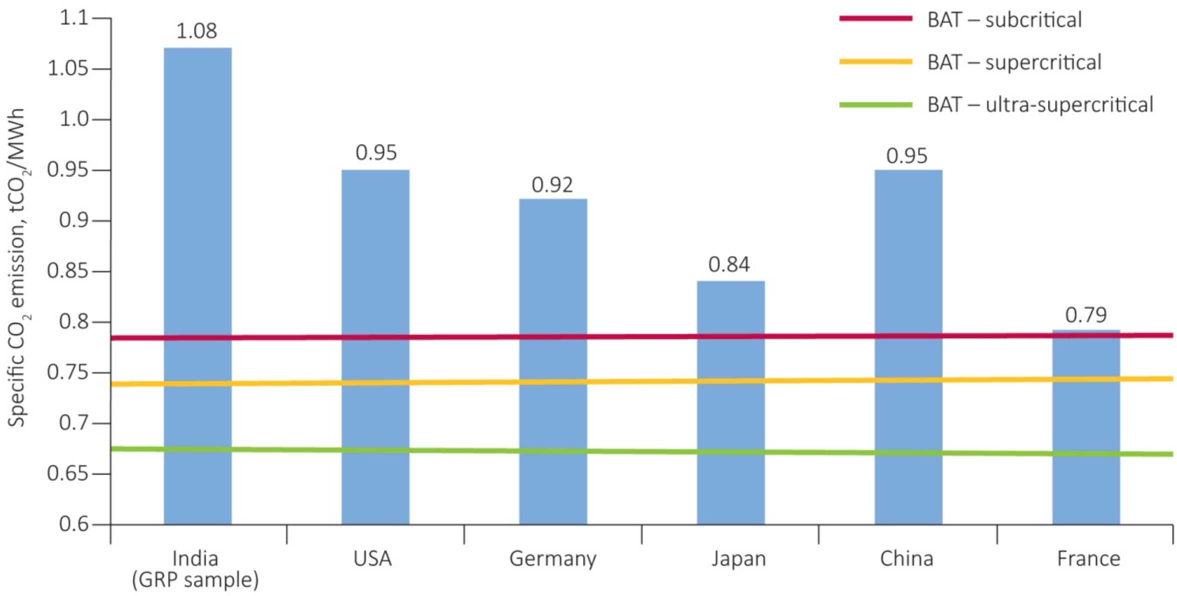

Figure 5 Specific CO_2 emission rates by country (Bhushan and others, 2015; Hussy and others, 2014)

Bhushan and others (2015) consider that the pollution problem in India is further exacerbated by the plant load factor (PLF) of coal-based units, which in 2013-14 was ~65%. Several plants in the study operated at the lower PLF instead of full capacity, due to a lack in demand for electricity. Operating at the lower PLF, according to Bhushan and others (2015) is leading to lower efficiency and higher pollution loads. In addition, as per the 'merit order dispatch', plants producing lowest cost power feed the grid first. Therefore, in general, older plants with no regulatory hindrance, outdated technologies and lower investments in pollution control are able to produce the least costly power. Hence, the tariff structure currently in place leads to increased pollution.

Finally, Indian coal has a high ash content. Fly ash from power plants is the second largest industrial residue stream in the country after mining waste, with 163 Mt generated in 2012-13. The ash handling system involves treatment and disposal of process water and requires land for ash storage. Although there is the option of plants converting to zero discharge units, Bhushan and others (2015) state that Indian plants use water liberally for cooling and ash handling and discharge the excess, which may contain heavy metals and thus cause contamination, into water bodies.

In 2014, Bhattacharya and others published their empirical findings for the economic growth, coal demand and CO_2 emissions in India and made policy suggestions to deal with the environmental impacts of coal utilisation. Their research reaffirmed the co-integrating relationship between economic growth, coal consumption and CO_2 emissions. Following causality testing, Bhattacharya and others (2014) believe that an increase in economic growth will lead to an increase in coal consumption with feedback effects. For policy analysts and forecasters, the findings suggest rising economic growth will lead to an increase in coal demand and therefore, CO_2 emissions. In addition, following a variance decomposition model, the findings show that a 58% variation in GDP by 2030 may be due to the variation in coal consumption, which will cause approximately a 40% variation, that is, an increase, again in CO_2 emissions. Bhattacharya and others (2014) consider that the coal sector in India needs to strengthen policies in reducing supply side constraints and simultaneously implement effective demand management policies to meet the increasing demand for coal.

Fuel subsidies in core industries, an increase in import dependency and inconsistent energy sector reform are some elements behind the widening gap between supply of and demand for coal in India. Moreover, the coal and overall energy sector in general lacks engagement with private and foreign investment. India needs forward-looking policies in the coal sector and in the overall energy market to maintain sustainable growth in future. In conclusion, Bhattacharya and others (2014) recommend several policy aspects to improve efficiency and overall performance of coal utilisation and its primary user electricity sector to help narrow the gap between supply and demand for coal. These include improving efficiency of coal-fired power plants, switching to alternative sources of energy for generating electricity, greater investment in CCT, reducing carbon intensity and CO_2 emissions, implementation of adopted environmental policies, along with freeing different barriers in the coal sector in the long term.

In November 2014, the government outlined plans for the transformation of the electricity system with 100 GW of renewable energy installations by 2019. This involves trebling wind installations to 6–8 GW capacity annually and lifting solar installations capacity tenfold to 10 GW annually. Furthermore, accelerated depreciation tax incentives were set to motivate Indian firms to diversify into renewable energy. In January 2015, India cancelled a tender for two, new, 8 GW, ultra-supercritical coal-fired power plants. This was not on environmental grounds but due to private power companies withdrawing from the tendering process stating that the financial risks associated with this US$ 8 billion of new investment proposals were excessive, including coal fuel supply risks (Buckley, 2015).

Indonesia

At the end of 2012, proven fossil energy reserves in Indonesia consisted of 3.7 billion barrels of oil, 2.9 trillion m^3 of natural gas and 28 Gt of coal. Coal provided 26.2% of total primary energy supply in the country in the same year (APERC, 2015). In 2012, Indonesia produced 226,909 kilo-tonne of oil equivalent (ktoe) of coal, an increase of 9.2% from 207,723 ktoe in 2011. Most of Indonesia's coal production in 2012 (78.8%) was exported while the remainder was used to satisfy domestic demand, mainly for power generation (64.3%), and industry (35.7%). Approximately 57% of Indonesia's total recoverable coal reserve is lignite, 27% is subbituminous coal, 14% is bituminous coal, and <0.5% is anthracite. Heating value of Indonesian coal can range from 5000–7000 kilocalories per kilogram (kcal/kg). The coal in general is of low ash and low sulphur content (typically <1.0%). In 2014, Indonesia was the world's largest thermal coal exporter. As such, this resource plays an important role in the country's economy and energy sector. According to WEC (2015), the country exports approximately 73% of the coal produced. However, with increasing domestic energy demand the government of Indonesia is restructuring the coal sector to ensure it meets its domestic demand too. In 2012, 48% of electricity generation in Indonesia was coal-based (APERC, 2015). Jalesko and others (2014) forecast a sizable production growth in Indonesia (20-30 Mt in 2015 and 2016), even assuming prices of US$ 75 per ton (~83 US$/t).

In August 2007, the Energy Law (Law No. 30/2007) was enacted. The law contains principles regarding the utilisation of energy resources and final energy use, security of supply, energy conservation, protection of the environment with regard to energy use, pricing of energy and international cooperation. It defines the outline of the national energy policy including the roles and responsibilities of the government and regional governments in planning policy and regulation, energy development priorities and energy research and development. Under the Energy Law, the national energy policy addresses the sufficiency of energy to meet the economy's needs, utilisation of indigenous energy resources and energy reserves. The Energy Law mandates the creation of a National Energy Council with the main task of drafting national energy policy. In October 2014, the government issued the new national energy policy, which is intended to create energy security and resilience through an energy management policy for the period of 2014 to 2050.

National emission standards for stationary sources, issued by the Ministry of Environment in 1988, were replaced by new standards that came into force in 1995. The most recent emission standards for stationary sources, including thermal power plants, were issued on 1 December 2008 and replaced the earlier 1995 standards. The new standards set emission limits for particulates (150 mg/m^3), SO_2 (750 mg/m^3) and NOx (850 mg/m^3) applying to new, in development, and existing coal-fired power plants. Old power plants and those in development before the decree was issued must comply with the existing standards issued in 1995. The standards for new power plants are stricter and those in development had to comply with the same standards by 1 January 2015. Fuel types covered by the decree include coal, oil and natural gas. Power plants must meet these emission standards 95% of the time over 3 months. For more detail visit www.iea-coal.org: databases: emission standards). Indonesia is a ratifying signatory to the UNFCCC and hence, as a party to the convention, it is bound by the rights and obligations stipulated in the convention. However, as a non-Annex 1 party to the Kyoto Protocol, Indonesia has no obligation to reduce GHG emissions. Nevertheless, the government of Indonesia has pledged to reduce GHG emissions from forestry and the energy sector by 26% through domestic efforts, and by up to 41% through cooperation with other economies. In order to achieve this, the government has set out a roadmap to integrate climate change issues into development planning. The climate change roadmap integrates mitigation and adaptation into policy instruments, regulations, programmes, projects, funding schemes and capacity building in all development sectors. Two initial phases of the roadmap were the integration of climate change into the Mid-Term Development Plan 2010–2014 and the launching of the Indonesia Climate Change Trust Fund (ICCTF) on 14 September 2009. The ICCTF is a financing mechanism for climate change mitigation and adaptation within Indonesia's policy framework (APERC, 2015).

Japan

Since its indigenous energy resources are modest, Japan imports nearly all of its fossil fuels to sustain economic activity. In 2012, Japan imported about 99.6% of its oil, 99.3% of its coal and 97.2% of its gas. At the end of 2011, proven energy reserves included approximately 44 million barrels of oil, 21 billion m^3 of natural gas and 350 Mt of coal. Coal's contribution to Japan's primary energy supply in 2012 was 25%. The country is the world's largest importer of steam coal for power generation, and pulp, paper and cement production. Japan's main steam coal suppliers are Australia, Indonesia, Russia, China, Canada, the USA, and South Africa (APERC, 2015).

In 2006, Japan launched the National Energy Strategy, which contains a programme of action that extends to 2030 and places considerable emphasis on achieving energy security. The Strategic Energy Plan, an offshoot of the National Energy Strategy, was issued in 2007 but is required to be reviewed at least every three years and to be revised, if necessary. In the 2010 revision, two further principles: energy-based economic growth and reform of the energy industrial structure were added to the three existing principles of energy security, environmental suitability and economic efficiency. The Strategic Energy Plan aims to change the energy supply and demand systems fundamentally by 2030. The plan sets ambitious targets for 2030 including (APERC, 2015):

- doubling the energy self-sufficiency ratio (18% in 2015) and the self-developed fossil fuel supply ratio (26% in 2015) and as a result, raise Japan's energy independence ratio to about 70% (38% in 2015);
- raising the ratio of zero-emission power sources to about 70% (34% in 2015);
- halving CO_2 emissions from the residential sector;
- maintaining and enhancing energy efficiency in the industrial sector to the highest level globally; and
- maintaining, or obtaining, high shares of global markets for energy-related products and systems.

Implementation of the policies in the Strategic Energy Plan, if successful, could result in the economy's total energy-related CO_2 emissions being reduced by 30% or more in 2030 compared to 1990 levels. A 30% emissions reduction means that about a half of the reduction that has to be achieved from the current level to 2050 (80% reduction compared to 1990) will have been realised in 2030.

However, according to ESAI (2014), the fuel mix in Japan's power sector underwent major changes after the incident in 2011 at the Fukushima Daiichi nuclear power plant. In 2012, with much of the nuclear capacity offline, Japanese utilities increased the use of oil, crude and LNG by 80%, 70% and 16%, respectively. In 2013, power plants turned to coal, as the cheaper fuel. Coal use in Japanese utilities rose by 16% in 2013, while the use of oil and crude declined by 23% on average and the use of LNG also decreased by 1%.

Resulting from the nuclear incident, the fourth revision of the plan in April 2014 gave a new direction for the medium to long term (~20 years) for Japanese energy policies, declaring that the period from 2015 to 2018-2020 should be a special stage to reform a variety of energy systems in the country. Principles of the energy policy and viewpoints for reform in the revised 2014 fourth plan include the following (APERC, 2015):

- acceleration of the introduction and uptake of renewables (solar, wind, geothermal, hydro and biomass) as much as possible over the next three years, and maintaining that expansion;
- utilisation of nuclear energy, a technology that is perceived as a reliable and efficient energy source, has low and stable operational cost, and is free from GHG emissions. However, this is based on the premise of ensuring safety;
- in addition, dependency on nuclear power generation to be reduced as much as possible by energy savings and introduction of renewable energy as well as improving the efficiency of thermal power generation; and
- Japan to re-evaluate coal as an important base-load power source in terms of stability and cost effectiveness, but to continue coal utilisation while reducing environmental load (utilisation of efficient thermal power generation technology).

As stated above, at the end of 2014, Japan's power generating sector was entirely nuclear-free, which increased the demand for fossil fuels, especially coal. However, in early September 2014, Japan's Nuclear Regulation Authority (NRA) approved the restart of Kyushu Electric Power Company's Sendai nuclear plant in Kagoshima Prefecture, which has two nuclear reactors with a capacity of 890 MW each. The restart required extensive operational safety checks. Following the pre-operation examination by the NRA, reactor number 1 restarted operation in August 2015 and reactor number 2 began fuel loading in September 2015 (Tsukimori, 2015).

Japan is the second biggest coal importer in the world (*see* Table 1), accounting for about 14.4% of total global coal imports in 2012. In the same year, coal accounted for >25% of the total primary energy supply and, according to the energy strategy, will continue to play an important role in Japan's energy sector, mainly for power generation and for iron, steel, cement, paper and pulp production (APERC, 2015).

Poland

As a Member State of the EU, Poland has adopted the EU regulations and directives for air pollution and controls. The Environmental Protection Act of 27 April 2001 defined the principles of air quality and air protection, and this was followed by decrees on specific areas. Emission standards for air pollutants from combustion plants are set in the 'Decree of the Minister of Environment of 20 Dec 2005 on standards for emissions from installations', effective from 1 January 2006. Poland is a signatory to many international conventions, among others the Geneva Convention and its Protocols (Second Sulphur Protocol, Second Protocol on Emissions of Nitrogen), UN Convention on Climate Change and its Kyoto Protocol. For details on emission standards in Poland and other countries throughout the world, visit www.iea-coal.org, emission standards database.

Polish national energy policy focusses on security of energy supply, with competitive cost structures, minimal environmental impacts and increased energy efficiency. According to the "Energy Policy of Poland to 2030", coal is expected to remain the main fuel for electricity generation, but targets include a general reduction of energy consumption by industry and, a 19% share of renewables by 2020. Electricity consumption in 2030 is expected to increase by 30%, gas consumption by 42% and petroleum products consumption by 7%. More than half of Polish power stations are over 25 years old, whilst about one quarter have been in operation for more than 30 years. The lignite-fired power plants are amongst the newest and they are being retrofitted to meet EU environmental standards. Poland has no nuclear power stations, but has plans to build a nuclear power plant by 2020 (EURACOAL, 2015).

There are currently three main issues in the energy sector in Poland, energy prices, climate framework and coal. According to WEC (2014), these are due to the negotiations of the new European climate and energy targets for 2030. Energy pricing in Poland, as in the other EU States, will depend on the new targets because these will determine the scope and cost of required investment in electricity generation assets. At the same time, climate targets will have an impact on the coal sector because the change in fuel mix may heavily affect the industry as >80% of the installed capacity in Poland uses coal. In exchange for agreeing to an EU-wide 40% cut in emissions by 2030 from 1990 levels, the Polish government negotiated a deal with the EU Commission for Polish utilities to receive free CO_2 allowances after 2020. As discussed above, European power companies have to purchase CO_2 allowances to cover their emissions under the EU ETS. New investments by Polish power companies may also qualify for free CO_2 allowances (Easton, 2014).

Poland has reduced its GHG emissions substantially since 1990. Following the economic collapse of the former Soviet bloc there was a considerable drop in domestic and foreign demand for the country's energy and carbon-intensive products. As a result of the structural shift towards less energy-intensive sectors, the overall GHG emissions fell by around 24% between 1988, the base year (under the UN Climate Change Convention), and 1994. The Polish success in decoupling economic growth from GHG emissions is higher than the European average. GDP grew in Poland by more than 200% between 1988 and 2012 while emissions fell by around 31%. Poland is also on track to meet the EU 2020 target for the sectors not included in the EU-ETS, primarily the residential, transportation and agricultural sectors as well as to meet the 15% RES target. Furthermore, Poland put in place a national development system, with nine integrated development strategies. Two are directly linked to climate change: the 'Strategy for Economic Innovation and Effectiveness' (2012-2020), adopted in 2013, and the 'Strategy for Energy Security and Environment', adopted by the Council of Ministers in 2014. The key strategy document dealing with energy and environment is the: 'Strategy for Energy Security and Environment', adopted in

April 2014, which identifies key priorities for environmental policy by 2020. For more detail on the climate legislative portfolio of Poland as well as 98 other countries, *see* Nachmany and others, 2015.

In August 2014, the Polish Ministry of Economy announced a draft 'energy policy to 2050' that was under consultation until 1 September 2014. The energy policy presents three scenarios: in the base-scenario, coal, and oil to a lesser extent, are expected to continue to remain the dominant energy source despite a slightly lower share in the energy mix as gas consumption should increase, moderately. Renewables should gain momentum as a result of EU obligations (15% of renewables in primary energy consumption), while nuclear units should contribute to lower CO_2 emissions. Two alternative scenarios are presented: in the first one, the nuclear programme would be expanded until reaching a share of 45-60% of power in the electricity generation mix; coal would only contribute 10–15% towards the power mix, a share similar to that of gas and oil, while the renewables share would reach 15%. In the second scenario, gas and renewables would cover 50–55% of the primary energy consumption, followed by coal (30%) and oil (15–20%). According to Williams (2014), renewables could cover at least 20% of the power mix, and nuclear 10%.

However, according to Easton (2014) the events in the Ukraine have led Poland to the conclusion that energy security is a more pressing concern than CO_2 emissions. Poland needs to import Russian natural gas but its energy security is based on its own coal reserves. Nevertheless, Easton (2014) considers that the share of hard coal and lignite-power generation, which currently provide ~90% of electricity, will drop to approximately 50% under the Polish energy policy to 2050.

In brief, according to the WEC (2014), the reality of Poland fulfilling the EU policy objectives on climate change and CO_2 emissions in the relatively short term is doubtful, due to the characteristics of the Polish energy sector (*see* Section 3.2.3). WEC (2014) conclude that, in the energy sector, the most difficult problem for the future is the reduction of CO_2 emissions according to the requirements of the EU as that may cause a substantial rise in electricity prices and thus have negative consequences for the Polish national economy.

South Africa

The South African Atmospheric Pollution Prevention Act came into force on 21 April 1965, providing the basis of policies for air pollution prevention and for the establishment of a National Air Pollution Advisory Committee. The National Environmental Management: Air Quality Act, which came into force on 11 September 2005, mandates the issue of norms, standards, mechanisms, systems and procedures to improve air quality. It establishes the national framework within which these standards will be created. It gives the Minister of Environmental Affairs and Tourism or the members of the Executive Council of a province (MEC) the authority to issue standards, enforce regulations and other measures, and implement penalties for non-compliance and establish 'funding arrangements'. Within the Act, the 'Minimum Emission Standards' was introduced, setting the emission limit values for emissions of air pollutants from combustion plants and industrial processes.

The 'Minimum Emissions Standards' for air pollutants from coal-fired power plants, took effect on 1 April 2010. The standards apply to both permanently operating plants and to experimental (pilot) plants with a design capacity equivalent to those of a listed activity. A 'new plant standard' applies to all plants applying for authorisation after 1 April 2010, while existing plants had until 1 April 2015 to comply with the 'existing plant standard' and have until 1 April 2020 to meet the new plant standards. Table 7 shows the minimum emission standards for combustion installations firing solid fuel. The minimum emission standards for carbonisation and coal gasification (combustion installations) are given in Table 8. Within the standards, existing plants mean any plant or process that has been legally authorised to operate before 1 April 2010, or any plant where an application for authorisation was made before 1 April 2010. New Plant means any plant or process where the application for authorisation was made on or after 1 April 2010 (www.iea-coal.org).

Table 7 Minimum emission standards for combustion installations firing solid fuel (www.iea-coal.org)

Pollutant	Emission limit value (ELV)*, mg/m^3	
	New plant	Existing plant
Particulate matter (PM)	50	100
SO_2	500	3500
NOx (as NO_2)	750	1100

* ELVs apply to all solid fuel, excluding biomass, combustion installations used primarily for steam raising or electricity generation with design capacity equal to or greater than 50 MW heat input per unit, based on the lower calorific value of the fuel used.

Note: Continuous emission monitoring of PM, SO_2 and NOx is required, however, installations < 100 MW heat input per unit must adhere to periodic emission monitoring.

Table 8 Minimum emission standards for carbonisation and coal gasification (combustion installations) (www.iea-coal.org)

Pollutant	Emission limit value (ELV)*, mg/m^3	
	New plant	Existing plant
Particulate matter (PM)	50	100
NOx (as NO_2)	700	2000

* ELVs applicable to all combustion installations not used primarily for steam raising or electricity generation (except test or experimental installations).

Note: Sulphur-containing compounds to be recovered from gases to be used for combustion with a recovery efficiency of not <90% or remaining content of sulphur-containing compounds to be <1000 mg/m^3 measured as hydrogen sulphide, whichever is strictest.

With regard to GHG emissions and climate change, South Africa has almost exclusively dealt with the issue through policies, strategies and regulations rather than legislation. The focus has been in developing market-based mitigation mechanisms and promoting renewable energy and energy efficiency. The only legislation on this issue was a carbon tax introduced in 2012, with expected implementation in 2016. South Africa has pledged to reduce its GHG emissions by 34% by 2020 and by 42% by 2025 compared to a business as usual scenario (Nachmany and others, 2015).

USA

The Clean Air Act (CAA), adopted in 1963 and amended in 1970, forms the basis of for air-pollutant control legislation in the USA. The Act is a comprehensive federal law that regulates air emissions from stationary and mobile sources. The CAA gives the US Environmental Protection Agency (EPA) authority to establish National Ambient Air Quality Standards (NAAQS) for SO_2 and five other pollutants considered harmful to public health and the environment (the other pollutants are ozone, particulate matter, NOx, carbon monoxide and lead). The law also requires the US EPA to periodically review the standards to ensure that they provide adequate health and environmental protection, and to update those standards as necessary. Since the adoption of the CAA, and numerous subsequent acts, the US power-generating sector has made significant progress in terms of reducing its particulate matter, NOx and SO_2 emissions over the past several decades. On March 20, 2012, the US EPA took final action to retain the existing secondary NAAQS for NOx and SOx. According to Van Atten and others (2015), in 2013, power plant NOx and SO_2 emissions were 80% and 74% lower, respectively, than they were in 1990 when Congress passed major amendments to the CAA. Large reductions in mercury emissions have also been realised, with emissions in 2013 50% below those of the year 2000. Less progress has been made in terms of reducing CO_2 emissions. In 2013, power plant CO_2 emissions were 14% higher than 1990 levels. In more recent terms, CO_2 emissions from power plants have declined, with 2013 emissions 12% lower than emissions in 2008 (Van Atten and others, 2015). For more information on the CAA and subsequent acts visit www.iea-coal.org.

In June 2014, the US EPA proposed the Clean Power Plan (CPP) as a nationwide regulation (to be implemented by the states) to regulate CO_2 emissions from existing fossil fuel power plants under Section 111(d) of the Clean Air Act (CAA). The proposed CPP had two main parts: (1) calculation of the emission rate targets, and (2) direction for states to implement plans to meet those targets. The US EPA used building blocks to calculate emission rate targets, but the CPP did not propose to require or limit states to using those building blocks for implementation. The CPP presented two sets of CO_2 emission rate targets for comment. The CO_2 reductions projected by the US EPA to be achieved from each set of targets, calculated using 2005 emission levels as a baseline are as follows (Navigant, 2014):

- Option 1 interim reduction of 26–27% from 2020 to 2029
    - 30% reduction by 2030 (this has changed to 32% reduction by 2030)
- Option 2 interim reduction of 23% from 2020 to 2024
    - 23–24% reduction by 2025.

On 3 August 2015, and following millions of comments on the proposed CPP, the US EPA announced the finalised CPP as a historic and important step in reducing carbon pollution from power plants to take action on climate change. In summary, the final rule of the CPP is that "under CAA section 111(d), US states must establish standards of performance that reflect the degree of emission limitation achievable through the application of the "best system of emission reduction" (BSER). Taking into account the cost of achieving such reduction and any non-air quality health and environmental impacts and energy requirements, the Administrator determines which has been adequately demonstrated. The US EPA has determined that the BSER is the combination of emission rate improvements and limitations on overall emissions at affected electric generating units that can be accomplished through any combination of one or more measures from the following three sets of measures or building blocks" (US EPA, 2015a,b,c,d):

1. Improving heat rate at affected coal-fired steam electric generating units.

2. Substituting increased generation from lower-emitting existing natural gas combined cycle units for reduced generation from higher-emitting affected steam generating units.

3. Substituting increased generation from new zero-emitting generating capacity for reduced generation from affected fossil fuel-fired generating units.

Specifically, the US EPA is establishing CO_2 emission performance rates for two subcategories of existing fossil fuel-fired electric generating units, fossil fuel-fired electric steam generating units and stationary combustion turbines. The rates are intended to represent CO_2 emission rates achievable by 2030 after a 2022-2029 interim period on an output-weighted-average basis collectively by all affected electric generating units. The interim and final emission performance rates are presented in Table 9:

Table 9 Emission performance rates (adjusted output-weighted-average pounds of CO_2 per net MWh from all affected fossil fuel-fired electric generating units) (US EPA, 2015a)

Subcategory	Interim rate lb CO_2/MWh (kg CO_2/MWh)	Final rate lb CO_2/MWh (kg CO_2/MWh)
Fossil Fuel-Fired Electric Steam Generating Units	1534 (~696)	1305 (~592)
Stationary Combustion Turbines	832 (~377)	771 (~350)

In addition, states with one or more affected electric generating units will be required to develop and implement plans that set emission standards for the affected units. These emission standards may incorporate the subcategory-specific CO_2 emission performance rates set by the US EPA. Alternatively, standards may be set at levels that ensure that the affected electric generating units in the state, individually, in aggregate, or in combination with other measures undertaken by the state, achieve the equivalent of the interim and final CO_2 emission performance rates between 2022 and 2029, and by 2030, respectively. The CPP final rule also establishes an 8-year interim compliance period that begins in 2022 with a sliding or glide path for meeting interim CO_2 emission performance rates separated into three steps: 2022-2024, 2025-2027, and 2028-2029. The US EPA is also establishing mass-based CO_2 emission performance goals for each state. These and other details of the final CPP rule are discussed in the US EPA (2015) documents. *See* US EPA (2015b) for a detailed regulatory impact analysis for the CPP final rule. For greater detail on the methodology that translates CO_2 emission performance rates to mass-based CO_2 performance, please refer to www.epa.gov (US EPA, 2015a, b and c). For a technical summary of the CPP prepared for the States see US EPA (2015d). http://www3.epa.gov/airquality/cpptoolbox/technical-summary-for-states.pdf.

On 25 June 2013, the Climate Action Plan for tackling climate change was announced. The plan consists of a wide variety of actions and has three key components as follows (APERC, 2015):

- **Cut carbon pollution in the USA:** In 2012, carbon emissions in the USA fell to the lowest level in two decades. In order to build on the progress, the US EPA put in place new, more demanding rules to cut carbon pollution.
- **Prepare the USA for the impacts of climate change:** taking new steps to reduce carbon pollution, the plan also includes preparation for the impacts of the changing climate. The US EPA will help state and local governments strengthen roads, bridges and shorelines to protect homes, businesses and way of life from the impacts of climate change.
- **Lead international efforts to combat global climate change and prepare for its impacts:** As no country is immune from the impacts of climate change and no country can meet this challenge alone, it is imperative for the USA to couple its action with leadership, internationally. The USA must help forge a global solution to the global challenge of climate change by galvanising international action to reduce emissions significantly (particularly among the major emitting countries), prepare for climate impacts, and drive progress through international negotiations.

Carter (2014) discussed, in detail, the regulatory and other challenges to coal use in the USA. Coal utilisation in the USA is primarily for the generation of electricity. A number of environmental protection regulations target each media: air, water and solid residues resulting from such coal utilisation. More recently, according to Jalesko and others (2014), the discovery of large deposits of shale gas in early 2010 triggered a sharp decline in prices from US$ 7/MBtu (~US¢ 2.4/kWh) in 2009 to US$ 1.9/MBtu (US¢ 0.65/kWh) in 2012. Gas, as a lower cost and lower carbon energy source, has created incentives in the USA to increase gas-fired power generating capacity and reduce coal utilisation in the power generating sector. In 2012, regulations and market forces combined resulted in the retirement of 10 GW of coal-based power plants. In 2014, both government and private sector studies projected that the number would exceed 60 GW (about 20% of US coal-based electric generation capacity) by 2020. These estimates did not reflect the more recent additional regulations developed to reduce CO_2 emissions from the electric power sector. Analysis by the USDOE/EIA concluded that additional coal retirements due to CO_2 regulation of the power sector could reduce coal-based power generation by 35–98% in 2040, compared to 2011, depending on the stringency of the requirements. The impetus for retirement of these facilities is mainly due to age but also due to lower output and revenue. Most coal-fired capacity in the USA was established in the 1970s and 1980s. Approximately, 19% of existing coal-fired capacity (~63 GW) is at least 50 years old and about 62% of the capacity (~212 GW) is between 30 to 50 years old. As such, power generators are retiring inefficient older facilities. This is enabled by power market fundamentals such as lower natural gas prices and lower electricity demand.

The second largest market for US coal production in 2014 was exports. In 2012, ~13% of US coal was exported, and this is projected to grow. A relatively untapped source of exports is subbituminous coal in western USA. In contrast to the current exports that originate primarily in eastern mines, the growth is expected from the interior and/or western mines. However, the coal is mainly on Federal lands, for which a lease to mine is mandatory, and would require new export terminals on the west coast. Environmentalists oppose both the leasing and construction of terminals on the West Coast. Carter (2014) considers it unclear how the economic and environmental interests associated with these coal resources will be reconciled. The controversy over US coal exports was the subject of an article by Darmstadter (2013) in which he considers the prospect of US coal exports meeting foreign demand could help the US coal industry survive but then only modestly.

According to Carter (2014), the future of coal production and utilisation in the USA is largely dependent on future policies of the Federal Government. There are serious uncertainties regarding regulations and policies still under development. The most significant uncertainties are the stringency of future regulations that impact coal use by electric power plants, the potential for federally funded research to reduce the cost of CO_2 mitigation technologies such as CCS, future regulation and export policy regarding natural gas, and federal policies related to coal exports and coal production from federal lands.

In their discussion on the structural changes in the USA coal market, Jalesko and others (2014) found that since 2010, the demand for coal dropped by 125 Mt. In addition, US EPA regulations, recent and new, are likely to result in the retirement of more than 60 GW of coal-fired capacity by 2016 and ~90 GW by 2020. However, coal will continue to play an important, albeit declining, role. This is because a complete replacement of coal with shale gas is unrealistic over the short- to medium term. In the long term, Jalesko and others (2014) assume that ongoing gas prices between US$ 4.5/MBtu (~US$ 4.75/GJ) and US$ 4.25/MBtu (~US$ 4.48/GJ) would result in replacing about 200 Mt of coal. The impact however, is not expected to be cross-border; while coal from the Powder River basin is expected to continue to be competitive, it would be uneconomic for many utilities to burn Central Appalachian coal. In October 2014, NERA Economic Consulting discussed, in detail, the potential energy impacts of the US EPA proposed CPP to reduce CO_2 emissions from existing power plants.

At the end of July 2015, it was still not yet clear what the final CPP would look like and how individual states or multi-state programmes would choose to implement it and, as with past environmental regulation of the US power sector, there is uncertainty around the longevity of the plan when considering litigation and future elections. The targets set in the CPP were planned to come into effect by 2020. However, in the announcement on the 3 of August 2015, finalising the CPP, the standards were set to reduce CO_2 emissions by 32% from 2005 levels by 2030. Nevertheless, since the changes required to meet the proposed targets will take time to implement, it is expected that utilities and other major bodies in the electric sector will begin to review their supply and demand side strategy and adjust their near-term and long-term planning to meet the known, broad parameters of the rule prior to 2030. The process of retiring plants and replacing them with new generation sources takes time, and varies by state and region. State renewable and energy efficiency policies and programmes can also take years to develop and implement.

According to Navigant (2014), the immediate impact of the then proposed CPP and the final regulation planned for release in June of 2015 (released on 3 August 2015) would be to spur changes in utility strategy, planning, and programmes to prepare for compliance with the interim targets. Despite the fact that final emission rate targets and their state implementation plans are not yet fully-known, utilities and other entities are likely to be already starting to plan their compliance strategies. Planning will need to be flexible so that utilities can adjust as the final targets are released in 2015 and as implementation plans are established, starting as early as 2016 or as late as 2018. Navigant modelled the US EPA Option 2 in order to explore the potential impacts of the CPP. The assumption in the modelling is that states band together to form regional implementation plans and that those regions can trade together, leading to a national carbon price. Under these assumptions, Navigant (2014) estimated that over 45 GW of coal capacity would be at risk for retirement by 2025 due to the CPP. This represents approximately 40% of all expected coal retirements by 2025. The EIA (2014) projected that 60 GW of coal-fired capacity will be retired by 2020. Navigant (2014) projections of the implementation of the CPP show that all four of the US EPA building blocks will be applied in varying degrees for compliance across the country. States will likely leverage the flexibility offered in the CPP, but coal plants are likely to close as they become uneconomic to operate. In addition, compliance will most likely involve improvements in plant efficiencies, lowering of the capacity factors of remaining coal-fired power plants, as well as replacing coal generation with existing or new natural gas, renewables, and/or nuclear generation. While the lower capacity factors will make some coal units uneconomic, leading to plant retirements, most coal retirements will be driven by a combination of the MATS standards, which was planned to come into effect in 2015, and continuing favourable economics for natural gas generation driven by shale gas production. Other drivers of coal retirements include age, economics, and other environmental regulations (Navigant, 2014).

In brief, the 2015 CPP establishes state-by-state targets for CO_2 emission reductions and offers a flexible framework for the states to meet these targets. The final rule, announced in August 2015, is expected to reduce the US power generating sector emissions by an estimated 32% compared to 2005 levels by 2030. The plan provides a number of options to reduce CO_2 emissions and determines individual state emissions reduction targets by estimating the extent to which each state can take advantage of each option. Options for cutting emissions include energy efficiency, increased but limited natural gas utilisation, investment in renewable energy, nuclear power and reducing reliance on coal-fired power generation. Targets differ between states due to a varying mix of electricity-generation resources, technological application feasibility, costs and emissions reduction potentials. States are free to combine any of the options set by the US EPA in a flexible manner to meet their targets. States can also join, together, in multi-state or regional arrangements to find the lowest cost options for reducing their carbon emissions, including the use of emissions trading programmes. States must submit a final plan, or an initial plan with a request for an extension, by 6 September 2016. Up to two-year extensions (until 6 September 2018) may be granted by the US EPA (US EPA, 2015a, b, c and d).

With regard to the Mercury and Air Toxics Standards (MATS) rules, states argued that cost should be considered when regulating hazardous air pollutants. However, the arguments were not successful (April 2014), the rule was passed and compliance became mandatory from April 2015, unless they had received an extension. However, early in 2015, petitioners (including 23 States) sought review of the US EPA rule in the District of Columbia (DC) Circuit, which upheld the US EPA refusal to consider costs in its decision to regulate. As stated above, the CAA directs the US EPA to regulate emissions of hazardous air pollutants from power plants but only if it concludes that "regulation is appropriate and necessary" after studying hazards to public health posed by power-plant emissions. The US EPA considered power-plant regulation "appropriate" because the plants' emissions pose risks to public health and the environment and because controls capable of reducing these emissions were available. It found regulation "necessary" because the imposition of other CAA requirements did not eliminate those risks. The Agency refused to consider cost when making its decision. It estimated, however, that the cost of its regulations to power plants would be US$ 9.6 billion/y, but the quantifiable benefits from the resulting reduction in hazardous-air-pollutant emissions were estimated at US$ 4-6 million/y. On 29 June 2015, the US Supreme Court made the decision that the US EPA interpretation was unreasonable when it deemed cost irrelevant to the decision to regulate power plants. The US Supreme Court ordered the reversal of the judgment of the Court of Appeals for the DC Circuit and remanded the cases for further proceedings consistent with this opinion (http://www.supremecourt.gov/opinions/14pdf/14-46_bqmc.pdf) (US Supreme Court, 2015). However, Weeks (2015) considers that the MATS Rule itself remains in place, and that the US EPA are in the process of fixing the 'appropriate and necessary' determination. To date approximately 62 GW of coal-fired electric generating capacity in the USA has already been retired or converted to other fuel sources in an effort to comply with the MATS regulation. Larson (2015) considers it unlikely that the Supreme Court decision will have any effect on the majority of the closed facilities.

Patel (2015) discusses experts' opinion on the potential impact of the CPP's legal uncertainty. Details of the debate, which took place in March 2015 on power and energy at the US House of Representatives: Energy and Commerce Committee is available on http://energycommerce.house.gov/hearing/epa%E2%80%99s-proposed-111d-rule-existing-power-plants-legal-and-cost-issues. Although the US EPA released the finalised CPP regulation in August 2015, along with a proposed federal implementation, which would be imposed on the states that do not develop their own plans, the legality and cost of the CPP is an issue, which continues to be debated.

3 Coal-fired power generation and coal demand

In 2014, coal provided >30% of global primary energy requirements, ~40% of the world's electricity generation and 68% of steel production (Jalesko and others, 2014; WCA, 2014). Overall coal consumption by region and the share of coal within the total primary energy sources, globally, is shown in Figure 6. Imports and exports by country of destination/origin are shown in Figure 7 (Accenture, 2013). Table 10 provides a listing of top hard coal producer, exporter and importer countries (WEC, 2014).

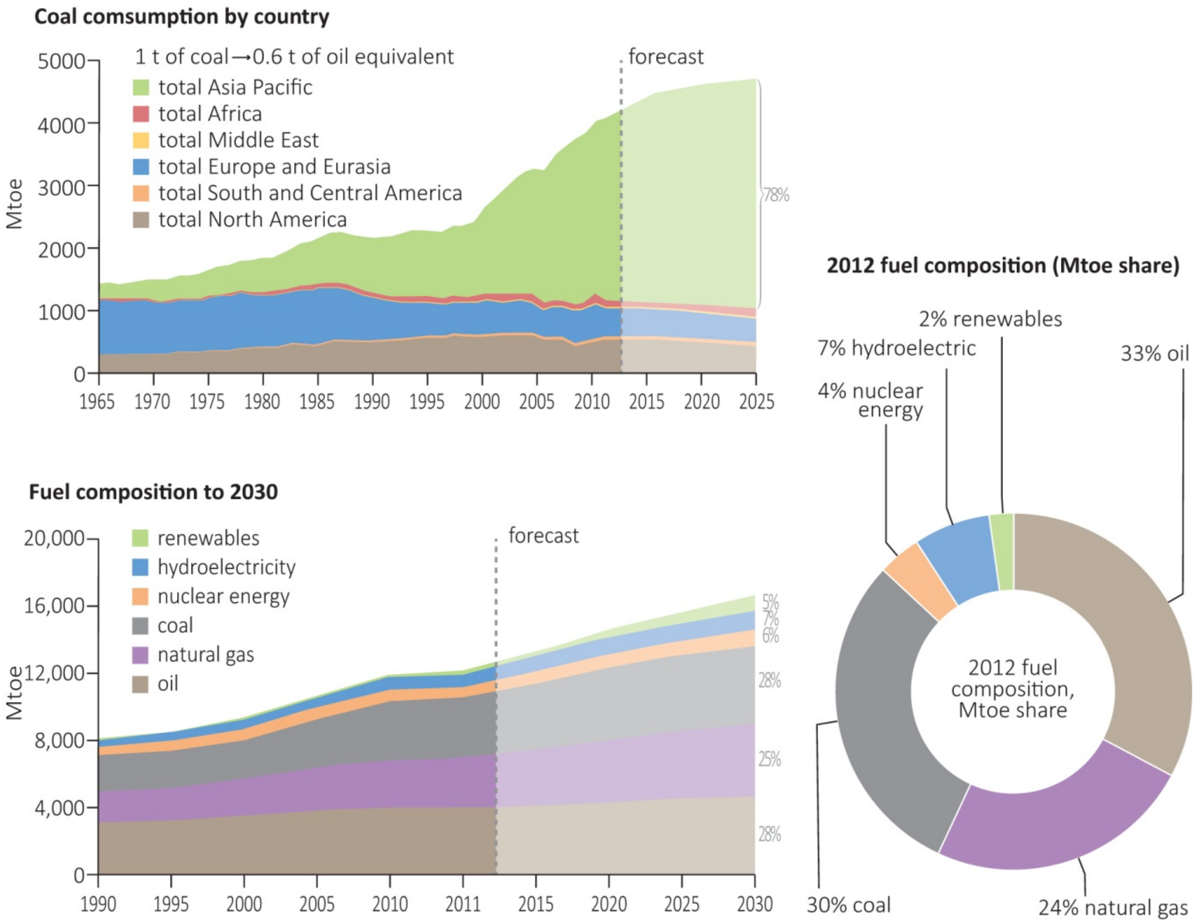

Figure 6 Overall coal consumption by region and the share of coal within the total primary energy sources (Accenture, 2013)

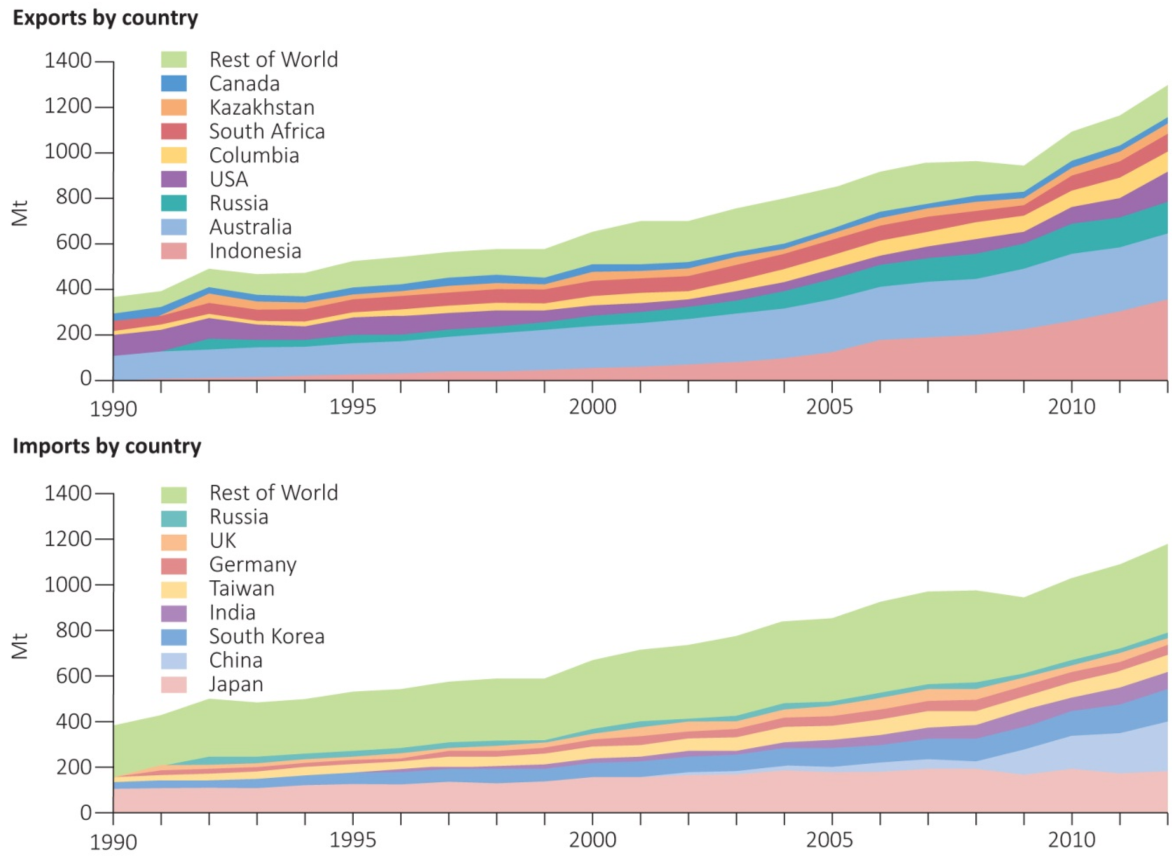

Figure 7 Coal imports and exports by country of destination/origin (Accenture, 2013)

Table 10 Main producers, exporters and importers of hard coal in 2013 (WEC, 2014)

Producers		**Exporters**		**Importers**	
Country	**Mt**	**Country**	**Mt**	**Country**	**Mt**
China	3561	Indonesia	426	China	327
USA	834	Australia	336	Japan	196
India	568	Russian Federation	141	India	180
Indonesia	489	USA	107	Korea (Republic)	127
Australia	396	Colombia	74	Taiwan	68
Russian Federation	274	South Africa	72	Germany	50
South Africa	256	Canada	37	UK	49
Kazakhstan	115	Kazakhstan	33	Turkey	28
Colombia	85	Mongolia	22	Italy	20
Poland	77	Vietnam	18	France	17
Rest of the world	328	Other countries	67	Other countries	271
World	**6983**		**1333**		**1333**

In a report published in Oct 2014, Bryce (2014), summarised that between 1990 and 2010, about 830 million people, the vast majority of those in developing countries, gained access to electricity due to coal-fired power generation. Bryce (2014) considers that roughly twice as many people gained access to electricity due to coal as due to natural gas; and for every person who obtained access to electricity over that period from non-hydro renewable sources, such as wind and solar, about 13 gained access due to coal. *For electricity production, no other energy source can currently match coal when considering cost,* *scale, availability and reliability.* In all, >500 GW of new coal-fired capacity is forecast to be built worldwide by 2040. Given the pivotal role of coal in providing electricity to poor and rich countries alike, Bryce (2014) concluded that it is highly unlikely that global CO_2 emissions will fall in the near future.

The main advantages of coal are availability and proven efficient heat-rate conversion for power generation. The relatively low cost of coal, compared to alternative generation fuels is another advantage. On the other hand, coal has a large carbon footprint compared with other energy sources. According to BP (2014), global coal reserves are about 890 Bt, enough to last more than 110 years at current production levels. Of that, 50–60% consists of low quality, subbituminous and lignite coals. Main producers of lignite are Germany, the Russian Federation, USA, Poland, Turkey, Australia and Greece. Predominantly, lignite is used domestically in the producer countries, mainly for electricity generation. Hard coal (~40–50% of reserves), which is largely used for power generation domestically, is traded internationally. In a carbon-constrained environment, most of those assets will turn into stranded assets. The term 'stranded asset' refers to the unexpected devaluation or write-down of an asset. For coal, this could happen because of a physical barrier, such as getting the coal out of the ground and transporting it to the market, or a reduction in the demand for the coal that makes the cost of extraction unviable (McLean, 2014). According to AURIZON (2014), recent predictions regarding the form and timing of climate change interventions have introduced the question of 'stranded assets' to the wider fossil fuels sector.

There is suggestion that an eventual strengthening in international emissions reduction legislation will impose absolute regulatory or economic barriers to fossil fuel demand that will undermine the value of thermal coal based investments. In the coal sector, stranded assets discussions have focussed on thermal coal (coal used in power generation) because metallurgical coal, which is used in oxygen-based steelmaking currently has no available substitute. Table 11 shows the top ten coal/lignite consuming countries in 2014. Table 12 highlights the top twelve countries where the percentage share of coal-based power generation is highest throughout the world (AURIZON, 2014).

Table 11 Domestic coal consumption in 2014 (Enerdata, 2015)

Country	Mt
China	3473
India	924
USA	835
Germany	236
Russia	211
South Africa	197
Japan	184
Korea (Republic)	134
Poland	130
Australia	122

Table 12 Percentage share of coal, in descending order, in the top 12 countries utilising coal for power generation throughout the world (WCA, 2014)

Country	%
Mongolia	95
South Africa	93
Poland	83
China	81
India	71
Australia	69
Israel	61
Indonesia	48
Germany	44
UK	39
USA	38
Japan	21

Policy makers have options to shift the fuel mix from coal for power generation towards less carbon intensive energy sources, such as renewables or natural gas. For example, command and control regulations on particulate matter, NO_x and SO_2 and other emissions have already necessitated either the installation of pollution control technologies (such as SCR for NOx control and FGD for SO_2 reduction) or the closure of coal-fired power plants around the world. Other options, already adopted in some countries, include using carbon pricing (such as the EU ETS, *see* Section 2.2.1) and regulations requiring the use of emission performance standards that require new coal-fired plants to limit the amount of CO_2 they emit per unit of electricity generated. Installation and utilisation of CCS would allow coal-fired plants to operate while adhering to strict regulatory requirements. However, CCS is not commercially viable yet, not only due to the technologies' parasitic power requirements but also cost. Finally, policy makers can also provide direct support to alternative energy sources, for example via subsidies to solar and wind power (Lelong and others, 2015).

3.1 International view

Jalesko and others (2014) discussed carbon constraints casting a shadow over the future of the coal industry. Key facts on coal according to Jalesko and others (2014) include:

- Coal consumption rose by 3.9% per year between 2000 and 2013, with an increase of about 3% in 2013, reaching 8 billion tons (7.3 Gt). According to the International Energy Agency (IEA, 2014b)), coal will become the world's top source of energy, before oil, in the coming years.
- China produces and consumes about 45% of coal, with more than half used for electricity generation.

- The top 10 coal producers in 2012 included China (~3.2 Gt), the USA (0.9 Gt), India (~0.54 Gt), Australia, Indonesia and Russia (~0.36 Gt, each), South Africa (~0.27 Gt); Germany (~0.18 Gt) and, Kazakhstan and Poland (~0.09 Gt, each).
- Most thermal coal, used for power generation, is consumed domestically. The seaborne market (that is, exports to other countries) makes up just 14% of global demand (*see* Figure 1).
- There are about 1200 coal-fired power plants around the world, with more than 450 in India and 360 in China. The average life of these plants is 40 years.
- Thermal coal accounts for the lion's share of coal demand (87% or close to ~6.35 Gt), while consumption of coking coal, a key raw material in the steel industry, was about 0.91 Mt) in 2013.

In an in depth analysis of thermal coal production, marketing and trading, Accenture (2013) found the following:

- Asia: coal demand is expected to more than double in India and Southeast Asian countries with combined demand by 2035 exceeding that of the OECD as a whole.
- North America: as domestic demand in the USA falls with natural gas substituting coal as feedstock, there is an expectation to increase exports and hence, slow down the decline of the coal production industry. However, opposition to exports is currently halting development of terminals on the west coast to transport the coal to other continents, for example, Asia.
- South America: more than US$12.2 billion (2013) is expected to be invested in the next 10 years in the Colombian coal industry. This is forecast to add an additional 20 Mt to Colombian coal production, mostly available for exports.
- Africa: South African throughput growth is expected to be limited due to high production and logistics costs. However, neighbouring countries have an untapped export potential. For example, in Mozambique, if the expected investment is carried out, capacity is forecast to increase from 10 Mt/y, at present, to more than 50 Mt/y by the early part of the next decade.
- Australia: although costs along the supply chain are expected to rise in the coming years, IEA projections suggest a 25% growth in production by 2020, driven mostly by growth in Chinese imports. However, estimates may be revised (down) as current capacity rationalisation and reduction in capital expenditure impact longer-term projections.
- Europe: Europe's position as a relatively large coal importer is decreasing due to a focus on cleaner energy sources. Few new coal-fired plants have come online in recent years while a number are being decommissioned. However, biomass cofiring, coal upgrading and CCS offer opportunities to limit reduction in coal-fired capacity and comply with the increasingly more stringent environmental regulations.

- The Commonwealth of Independent States (CIS): production is expected to increase somewhat to 2020, thereafter slowing down slightly with a 2010-2035 compound annual growth rate (CAGR) of -0.1%. Most mines in CIS face low production cost efficiencies and have lacked investment over the past 20 years to remain competitive and grow throughput.

The Asia Pacific Energy Centre (APERC), a department of APEC, publishes an annual overview of APEC energy. The primary objective of the APERC is to conduct studies to foster understanding among APEC members of regional energy outlooks, market developments and policy issues. In 2014-2015, the APERC published edition 6 of the APEC energy demand and supply outlook, with a 28 year view (2012-2040) (APERC, 2015). The study presented data on the development outlook for the coal industry and included an economy-by-economy projection of APEC's energy demand and supply for the years 2012 to 2040. The project was undertaken assuming business-as-usual, as well as alternative scenarios and the role of coal in the total energy balance. 'Business-as-usual' meant no major changes in policy except for changes required by existing law. The Study focused on the economics and the prospects of clean coal technology and more efficient coal production in the APEC region (Sokolov, 2015).

APERC used modelling to project energy demand and supply for each member and for APEC as a whole. The modelling process included assembling a database of key assumptions for each economy, including a historical database of the coal industry. Four sub-models (transport demand model, industrial demand model, electricity supply model and other sector demand model) were used to estimate energy demand in key sectors. In 2012, coal was the largest energy resource in the energy balance of APEC economies, accounting for approximately 36% of total primary energy supply, up from nearly 27.9% in 1990, which equates to a growth rate of 3.2% per year. The share of coal in the energy mix continues to increase and is expected to reach 38% in 2040 while the share of gas is forecast to reach 19%. Hence, coal is and will remain the main energy source in APEC economies for the near future. Advances in coal combustion technology will allow the coal base generation to experience significant growth: from 6094 TWh in 2011 to 12477 TWh in 2040. Growth in Chinese electricity output from coal is forecast to account for most of the growth (4632 TWh), while coal generation in the USA is projected to decrease (APERC, 2015; Sokolov, 2015).

Sokolov (2015) considers that under business-as-usual assumptions, coal production in the APEC region will continue to grow by about 1% per year during the outlook period. It will amount to 4466 Mt of oil equivalent (Mtoe) in 2040 or about 46% more than in 2011. All 15 existing coal producing APEC economies will continue to produce coal and Papua New Guinea may also start some minor production. China will continue to be the major coal producing economy in APEC economies and worldwide. Production in China is forecast to be 2234 Mtoe in 2040 or about 50% of the APEC region production compared to 58% in 2012. By 2040, the forecast indicates that there will be 13 APEC economies that are net importers of coal and 7 net coal-exporting economies. Brunei is projected to have no production, consumption, imports, or exports of coal during the outlook period.

In 2015, coal accounts for more than half of the CO_2 emissions from fossil fuel combustion in the APEC region, and within the business-as-usual scenario projections are that that these CO_2 emissions from coal will grow by more than 45% between 2012 and 2040. However, it is expected that APEC economies will continue their policies of accelerating the deployment of advanced coal combustion technologies, coal beneficiation technologies and coalmine methane recovery and utilisation technologies. The APERC note that improving the economics of coal liquefaction technologies and IGCC for power generation should receive special attention as they could moderate the impact of the coal industry on climate change. In addition, the APEC economies need to further the development of CCS and evolve an economic evaluation for an integrated CO_2 transport, utilisation and storage infrastructure in the region (APERC, 2015 and Sokolov, 2015).

3.2 Regional view

By the end of this decade, the IEA projects that global coal demand will reach 9 Bt/y. It also states that total new coal generation capacity commissioned in the world in 2010-14 was 200 MW/d (IEA, 2014a) (www.iea.org). Furthermore, the IEA notes that despite China's efforts to moderate its coal consumption, it will still account for three-fifths of demand growth during the outlook period. Moreover, India, ASEAN countries and other countries in Asia will join China as the main engines of growth in coal consumption, offsetting the decline in Europe and North America. The following sections discuss the historical, current and projected utilisation of and demand for coal in power-generation by region as well as the influence of environmental regulations. The regions covered are those where coal plays a major role in power generation including Australia, Africa, Asia, Europe and North America.

3.2.1 Australia

Australia accounts for around 2.4% of world energy production and is the second largest exporter of coal. The country has >105 Mt economically demonstrated recoverable resources of black and brown coal. Australian coals are high in energy content and are relatively low in sulphur, ash and other contaminants. Its significant energy resources combined with its geographical proximity to the Asia–Pacific region means that Australia is capable of meeting a significant proportion of the developing world energy demand, as well as its own domestic needs. Coal is Australia's second largest commodity export and an important component of domestic energy supply, accounting for approximately 64% (>249 GWh) of total electricity generation in 2012-13. A number of wind energy projects, planned or underway, are expected to account for an increasing proportion of total electricity generation over the medium to long term. However, given its abundance, coal is expected to remain the most commonly used fuel in electricity generation (APERC, 2015).

Ker (2015) considers that despite the current depressed prices for coal, mining companies continue to prepare new coal assets (*see* Figure 8). This is due to the current and forecast potential future demand for coal in the Asia Pacific region.

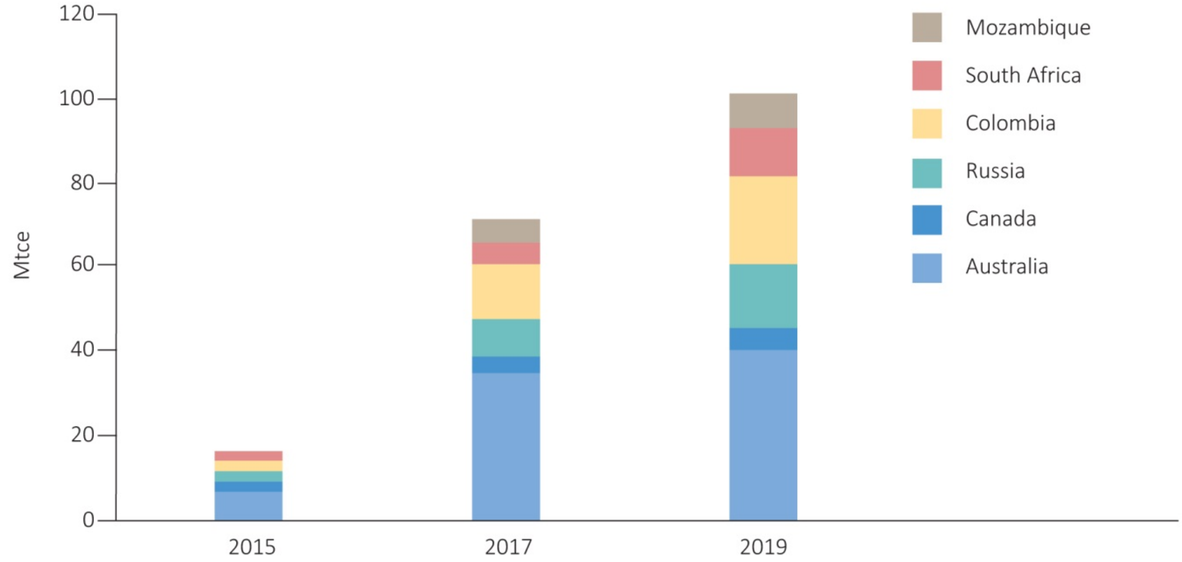

Figure 8 Cumulative projected expansion of hard coal export mining capacity, 2015-2019 (Ker, 2015)

3.2.2 Africa

Coal plays a major role in industry in **South Africa**. Proven coal in the country's reserves were estimated at 33 billion ton (~30 Gt) at the end of 2013, accounting for 95% of total African coal reserves and 3% of total world reserves. According to the EIA (2015), South Africa has the largest recoverable coal reserve and coal production base in Africa. According to BP (2015), South Africa produced 3.8% of the world total of 8.16 Gt of coal in 2014. In 2013, the country was 5th in the list of top coal producing countries in the world and it remains so in 2015, producing an average of 224 Mt of marketable coal annually. In 2013, the country was 6th in the top 10 coal exporting countries (3rd in 2014) and 2nd in the list of countries heavily dependent on coal for power generation at 93% of total capacity (WCA, 2014). In 2014, South Africa exported 78 Mt of coal, over 50% of which went to Asia. The main destination was India, which accounted for 40% of the exports. Europe is the second largest regional importer of South African coal, followed by Africa, the Middle East, and the Americas (*see* Figure 9).

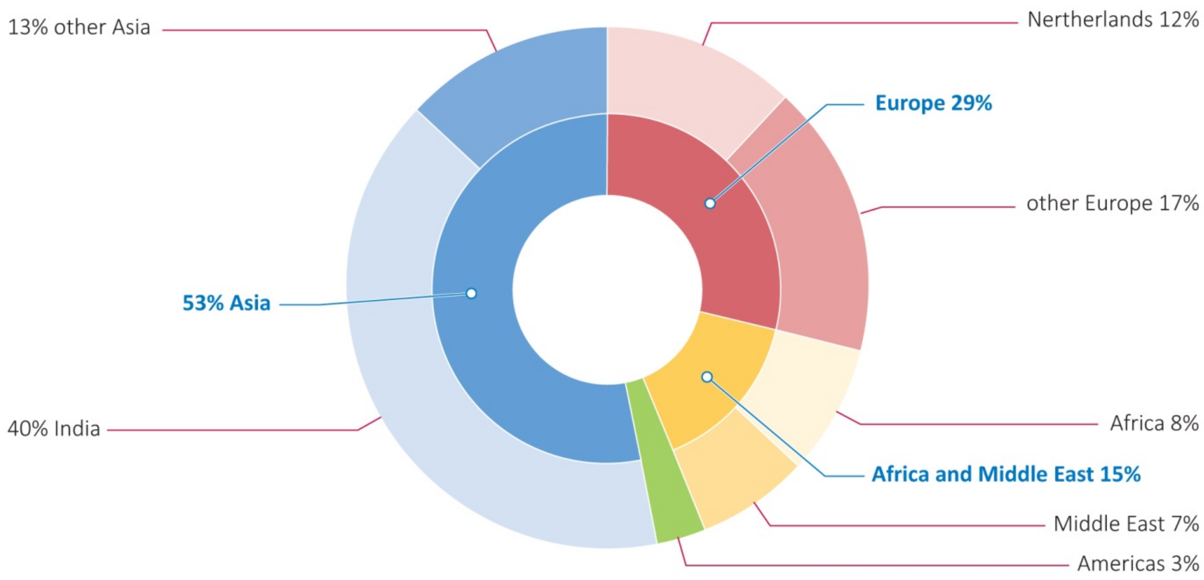

Figure 9 South African 2014 coal exports, by destination (EIA, 2015a)

Coal dominates the energy sector, despite a growing interest in oil and gas, as well as the introduction of renewable energy sources. State-owned Eskom (www.eskom.co.za) generates, transmits and distributes ~95% of the electricity used in South Africa. Eskom, which operates 13 coal-fired power stations, is the largest consumer of coal in the country. It utilises about 50% of domestic coal. However, estimates indicate that Eskom could face a 40–60 Mt/y coal supply shortfall after 2018, owing to increased demand and underinvestment in new mining projects. Although most of the energy matrix in South Africa is coal-based, the government has invested heavily since early 2000 in the promotion of not only renewable energy but also energy efficiency (Nachmany and others, 2015). In 2013, 72% of total primary energy consumption in South Africa came from coal (77% in 2015), followed by oil (22%), natural gas (3%), nuclear (3%), and renewables (<1%, primarily from hydropower). South Africa is the leading CO_2 emitter in Africa (accounting for 40% of emissions) and the 13th largest CO_2 emitter in the world (EIA, 2015a).

Electricity capacity in South Africa is currently ~46 GW (gross). As stated above, Eskom supplies roughly 95% of South Africa's electricity, the remainder coming from independent power producers (IPPs) and imports. Eskom buys and sells electricity with countries in the region. South Africa is a member of the Southern African Power Pool (SAPP), which began in 1996 as the first formal international power pool in Africa with a mission to provide reliable and economical electricity supply to consumers in SAPP member countries. Eskom exports electricity to Lesotho, Namibia, Botswana, Zimbabwe, Mozambique, Swaziland, and Zambia, and it imports electricity from Namibia, Lesotho, and Mozambique (EIA, 2015a).

In 2014, plant reliability declined mainly due to increased unplanned outages. Matona (2014) discussed the decrease in plant availability from 85% to 75% over the previous five years. The decrease is attributed to several factors including the delaying of critical maintenance and continuing to operate the facilities in an effort to maintain electricity provision to the nation. Other factors include the deterioration of maintenance quality (64% of current, Eskom-installed, base-load capacity plants are past their midlife, requiring longer outages and more extended restoration time than planned); declining coal quality, which impacts plant performance, resulting in necessary additional maintenance; weather conditions, such as extreme heat or prolonged heavy rains; and disruption of fuel supply to power stations. In the latter few months of 2014, there was a significant increase in unplanned plant maintenance/breakdown (5–9 GW), which had a compounding negative effect on power system reliability. Matona (2014) noted that, as the electricity reserve margin in the country is low, there is not enough capacity to meet demand, necessitating the need for planned, controlled and rotational load shedding, to protect the power system from a total country-wide blackout. Matona (2014) detailed the process of load shedding, which took place in 2014 in order to maintain supply of electricity. The author outlined a six-point plan towards sustainability including:

- additional capacity (by bringing new base load and peaking power station units on line, on time);
- maintenance (by effectively executing maintenance plans to return plant to the desired performance levels);
- plant incident control (by safely and rapidly returning a plant to service);
- demand side management and energy efficiency (a need to reintroduce the demand side management programme to lower demand for energy in the country);
- load shedding schedule improvements (by bridging the gap with municipalities to ensure alignment and thereby predictability); and
- energy conservation programme (critical that the country revisits the option of introducing a national energy conservation programme).

An outline of electricity requirements in South Africa is given in the Integrated Resources Plan (IRP), which, as an electricity plan, defines the long-term electricity needs of the country and identifies the generating capacity, technologies and costs associated with meeting that demand. The current version of the IRP, known as the policy-adjusted IRP or IRP 2010 and promulgated in 2011, covers 2010 to 2030. It has evolved since its initial draft to bring forward the introduction of renewable energy and accelerate planned new coal builds. In addition to all existing and committed power plants, including 10 GW of new coal capacity approved before the IRP 2010, the final plan includes an extra 6.3 GW of new coal-fired capacity, 9.6 GW of nuclear, 17.8 GW of renewable energy and 8.9 GW of other sources. By 2030, South Africa is projected to have an installed capacity of 89.5 GW, of which 45.9% will be from coal, 12.7% from nuclear, 21% from renewable energy and the balance from other sources such as gas, pumped storage and hydropower. The IRP was reviewed in 2013, with demand assumptions identified as one of the main issues, and the South African Department of Energy published an updated version of the IRP 2010. The document materially lowers the projected demand outlook over the 20-year horizon. The update anticipates that 6.6 GW less capacity will be required by 2030 (Nachmany and others, 2015). A summary of the adjusted IRP plans for the generation mix in South Africa is shown in Figure 10 (Modise and Mahotas, 2010).

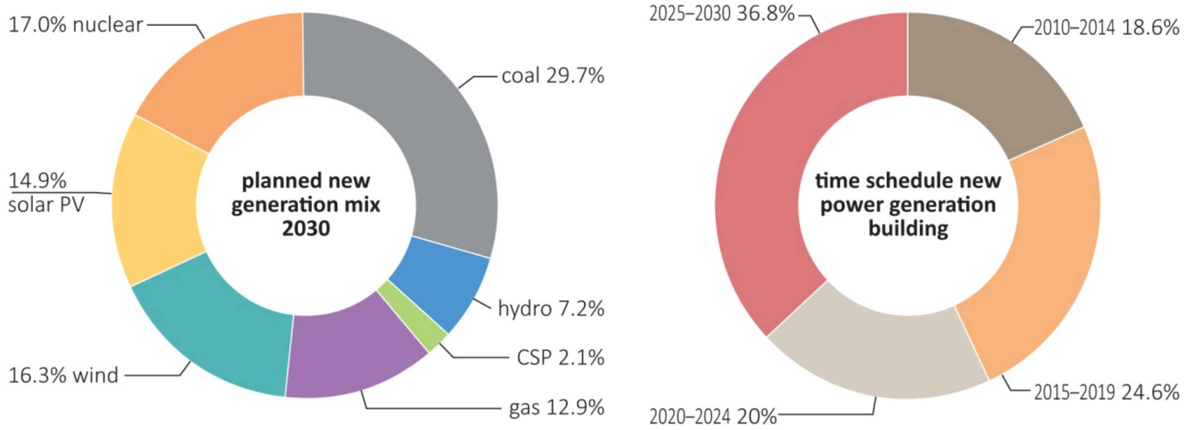

Figure 10 Summary of the policy adjusted IRP plans for electricity generation mix in South Africa (Modise and Mahotas, 2010)

According to the EIA (2015), environmental groups continue to target the coal industry with reference to air, land, and water pollution from extraction to end use. Nonetheless, coal use is expected to increase as Eskom plans to expand coal-fired electricity generating capacity to meet growing demand by bringing online the coal-fired Medupi power station (4764 MW) and the coal-fired Kusile plant (4800 MW) in stages over the next few years. However, cost overruns, construction delays, and labour strikes are causing project delays, exacerbating South Africa's power problems.

3.2.3 Asia

APERC (2014 and 2015) publishes an annual review of the energy overview and outlook in the APEC countries. In this section, countries discussed are those where coal plays a major role, and forecasts indicate that this trend will continue in the economy and/or power generation, in the form of exports or imports.

China is the world's largest coal user, producer and importer. Figure 11 gives a comparison between global and Chinese coal consumption in 2012.

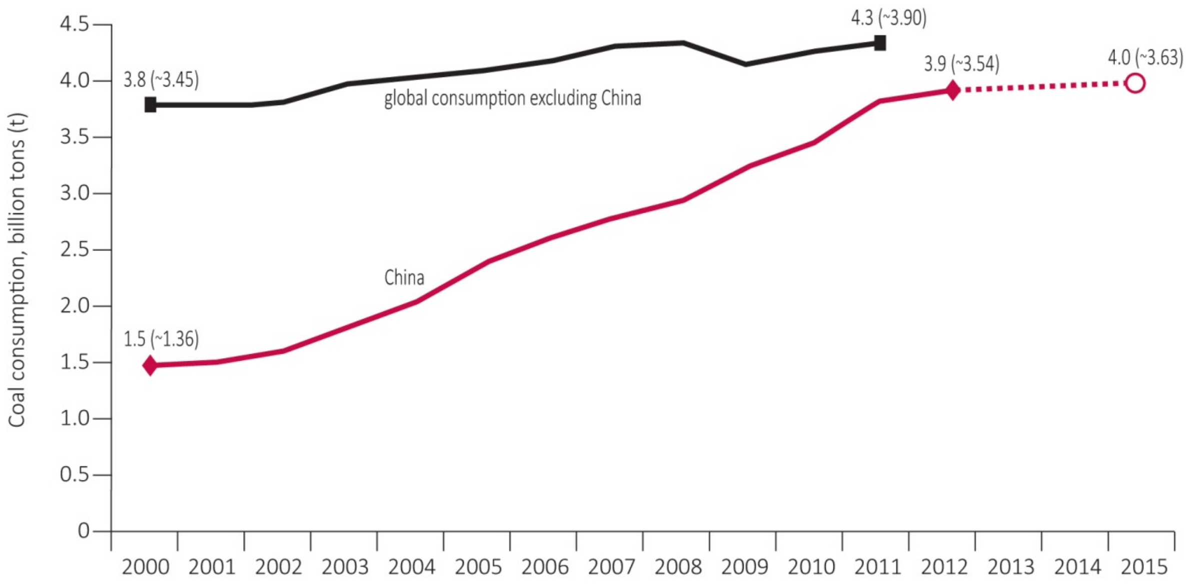

Figure 11 Global vs Chinese coal consumption, billion tons (t) (EIA, 2014)

Bernstein Research (2013) analysed the future of coal in Asia, mainly China and India. They estimated that China will cease to import coal in 2015 and will see a decline in coal consumption in absolute terms in 2016 as hydro, nuclear, renewables and gas-fired power generation take greater market shares in the power sector. However, although imports have declined, China continues to import coal. Bernstein Research (2013) expected that China would start decommissioning coal-fired power stations and replacing them with nuclear or renewables by the second half of the decade. Buckley (2015) summarised the Institute for Energy Economics and Financial Analysis (IEEFA) (USA) view on recent global electricity market trends that show the beginning of a structural decline in seaborne thermal coal markets, including in China. According to Buckley (2015), coal demand in China grew 10% annually over the decade to 2011, after which the rate of growth halved to 4–6% in 2012 and 2013. In 2014, coal demand in China declined by 2.1% year-on-year. Buckley (2015) considers that coal demand in China will permanently peak by 2016 (if not earlier), and gradually decline thereafter.

According to EIA (2015), total coal imports in China rose to 360 million short tons (~327 Mt) in 2013, approximately 14% higher than 2012 levels. Indonesia and Australia being the largest coal exporters to China, supplying 65% of China's imports in 2013. However, the government imposed restrictions on coal imports with high ash and sulphur content starting January 2015 and reinstated the import tariff at 3% to 6% to protect the market share of domestic producers and pare back the recent excess coal supply. Coal imports declined in 2014 as a result of slower economic and electricity consumption growth as well as excess domestic supply. China imported about 320 million short tons (~290 Mt) in 2014, an 11% drop from 2013 levels. EIA (2014) projects that total net generation in China will increase to 7,295 TWh by 2020 and 11,595 TWh by 2040, nearly three times the generation level in 2010. Although China plans to rely more on electricity generation from nuclear, other renewable sources, and natural gas to replace some coal to reduce carbon emissions and air pollution in urban areas, coal will continue to play the major role in the energy mix (*see* Figure 12).

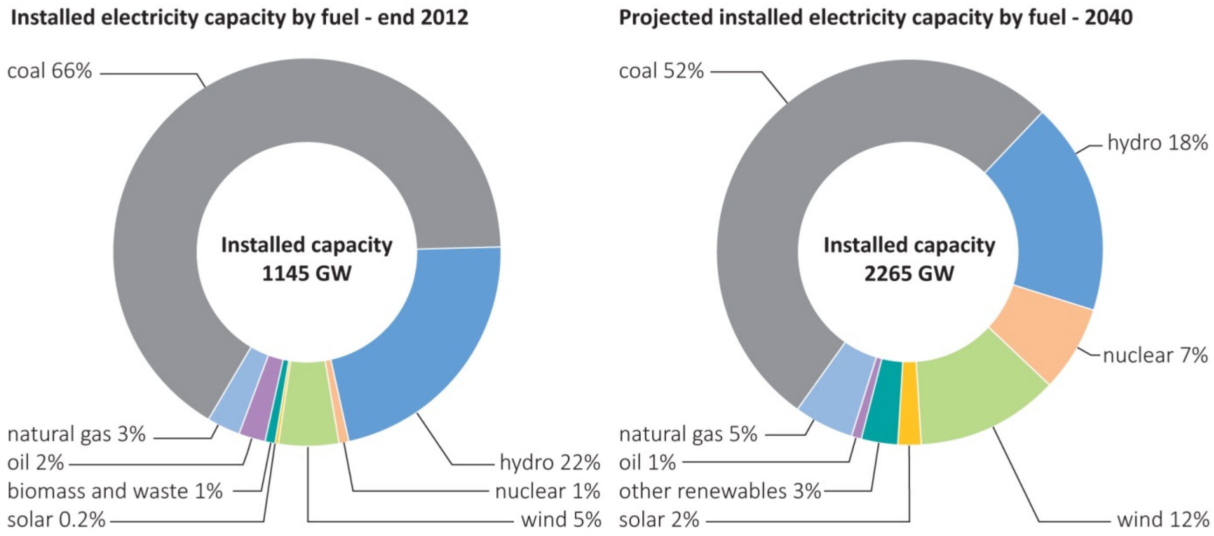

Figure 12 China's, to end 2012, and projected (2012-2040) installed capacity by fuel (EIA, 2014)

Furthermore, according to the IEA (2014b), global coal demand will grow by 15% to 2040, but almost two-thirds of the increase will be in the next decade. Chinese coal demand is expected to plateau at just over 50% of global consumption, before reducing *after* 2030. Demand is forecast to decline in the OECD, including the USA. India is forecast to become the world's second-biggest coal consumer before 2020, and surpass China soon after 2020, as the largest importer. The IEA (2014) considers that current low coal prices have put pressure on producers worldwide to cut costs, but the shedding of high-cost capacity and demand growth are expected to support an increase in price, sufficient to attract new investment. China, India, Indonesia and Australia alone are expected to account for over 70% of global coal output by 2040 (EIA 2014; Nalbandian, 2015).

Meanwhile, the IEA (2014b) considers that although coal utilisation in China could decrease, the country is forecast to remain a major user of coal for many years in the future. The IEA (2014b) project that coal demand grows annually at 2.6%, more than 100 Mt per year in the mid-term. China is expected to demand more coal than any other country for some time, but the historical growth in all of the coal indicators, such as production, consumption and imports will not continue at the same rate. Moreover, despite the general increasing trend, temporary fluctuations in coal demand for power generation may occur, for example due to extreme weather conditions. Imports could also decrease at any time, depending upon prices and/or policy changes. The IEA (2014a,b) consider that slower economic growth and a lower energy intensive economy combined with greater energy portfolio diversification will gradually curtail coal demand growth in China in the coming years. However, although the share of coal in the energy mix will reduce, total electricity output with coal is forecast to increase.

In 2013, total coal demand in China was 3.6 billion tons (~3.3 Bt), compared with domestic production of about 3.7 billion tons (~3.4 Bt). Meanwhile, total imported coal from overseas was about 330 Mt, leading to an oversupply of more than 420 Mt. This resulted in domestic coal producers having to cut prices to face both an economic slowdown and lower seaborne prices. According to BP (2014), China has ~113 Bt of coal reserves (about half of which is lower quality, subbituminous and lignite coal), meaning that China's reserves are less than 30 years at current consumption levels. Jalesko and others (2014) conclude that the life and quality of the reserves, in addition to more stringent regulatory requirements and climate change issues, will push the Chinese government toward other energy sources.

Chinese coal demand is expected to peak between 2015 and 2020. The China Development and Reform Commission suggests peak coal demand in China will be reached by 2015. Others, such as the Chinese Coal Industry Association, see the consumption of coal reaching 4.8 billion tons (~4.35 Bt) by 2020, well above the level projected by the IEA. Jalesko and others (2014) assume that, with a GDP increase of 7.4% and 7.2% in 2014 and 2015, respectively, coal demand growth in China will decelerate before reaching a plateau by 2020. This is due to the slow shift of the economy toward consumption from capital investments, lower GDP growth and the Chinese government increasing focus on tightening emission standards and moving to more renewable energy sources. Other tangible factors include the low level of fresh water and lack of long-term quality coal resources. On the other hand, coal is still the cheapest energy source and the application of new policies in China can take time (Jalesko and others, 2014).

In the past, China has offset the gap between domestic coal production and domestic demand with imports. Due to China's need to meet higher demand for quality coal, imports are expected to continue and to increase in the mid-term. However, without the development of gas in China, as well as renewables, it is unlikely that there will be a reduction in coal utilisation. For example, according to EIA (2014), China's technically recoverable (unconventional) shale gas resources are about 1100 trillion cubic feet (~31 trillion m^3). However, in 2013, the country produced only 0.5 billion m^3 of shale gas. The Chinese government aims to produce between 60 billion m^3 and 100 billion m^3 of shale gas by 2020 (equivalent to 150–250 Mt of coal). However, even these targets, which are modest compared to the overall demand for energy in China, could be difficult to achieve given the geological challenges, lack of infrastructure and local bureaucracy. As for (conventional) natural gas, China recently signed a natural gas deal with Russia to secure an annual supply of 38 billion m^3 for 30 years. Pipeline construction will take between four and six years. The transaction is part of an objective to more than double the consumption of natural gas to about 400 billion m^3 by 2020. In order to meet this objective, the country will need to build more liquefied natural gas (LNG) facilities and bring more piped gas to the country (Jalesko and others, 2014).

In **India**, most power companies source their coal from Coal India Limited (CIL), a public-sector mining company that mines about 80% of the coal needs of the country. The Ministry of Coal, in an April 2014 report, estimated proven reserves in India of around 125 Gt. However, the WCA estimates recoverable reserves in India in the range of 60–80 Gt. Historically, India imported small amounts of coal. In 1990, India's coal imports were 3% of total coal used. In 2012-13, India imported 145 Mt of coal at ~**US$ 15 billion compared to US$ 416 million** in 1990. During the 11th Five-Year Plan, coal demand increased at a CAGR of 8.5% while domestic production (CIL) capacity increased at a CAGR of only 4.4%. Coal-fired power plants in India, which depend primarily on indigenous mines, 116 of 153 GW installed capacity, require about 48 Mt of coal per month. CIL has a target of producing about 36–37 Mt coal/month. In 2013, India imported 63 Mt of coal for the power sector. India's coal import sources in 2013 are shown in Figure 13.

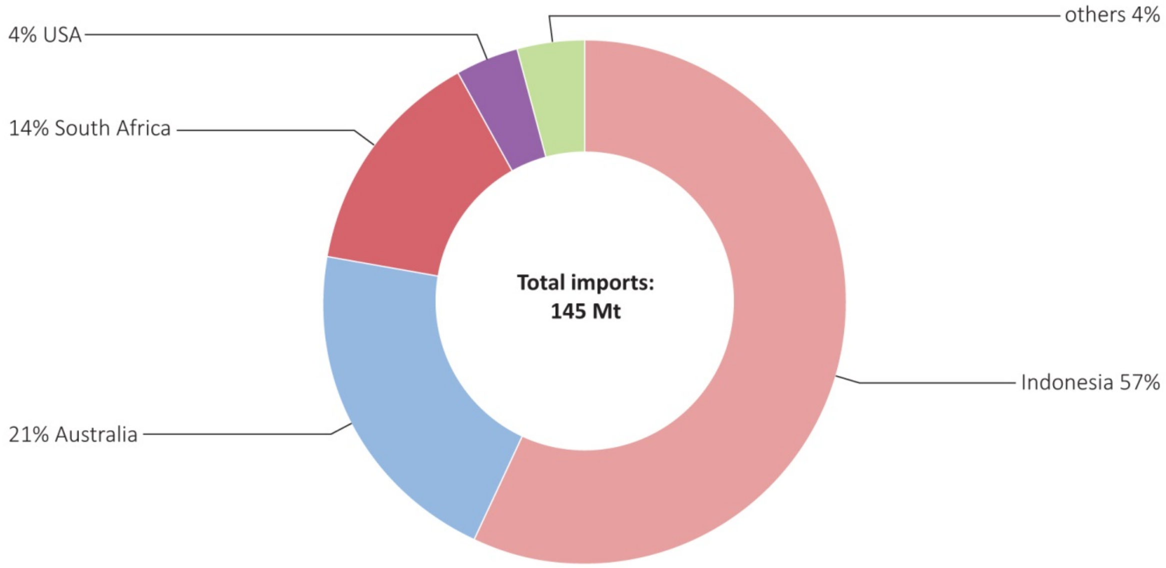

Figure 13 India's coal imports (2013) (Bhushan and others, 2015)

As domestic production has been unable to meet the growth in demand for coal in recent years, projections by the Planning Commission estimate that coal imports will keep rising from 145 Mt in 2013 to a projected 235 Mt in 2022, despite a doubling of domestic production in the next eight years (*see* Figure 14).

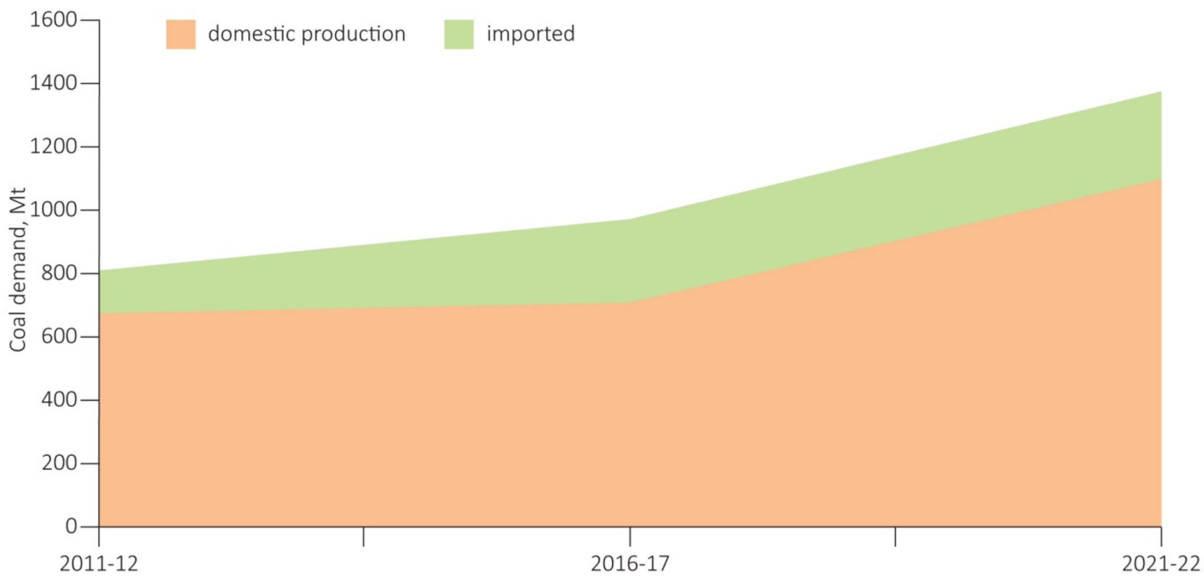

Figure 14 Coal demand, domestic production and imports (Bhushan and others, 2015)

Coal demand is driven primarily by the power sector, which consumes over 70% of the total coal used in India. According to the Planning Commission, the power sector will remain the dominant consumer of coal (*see* Figure 15).

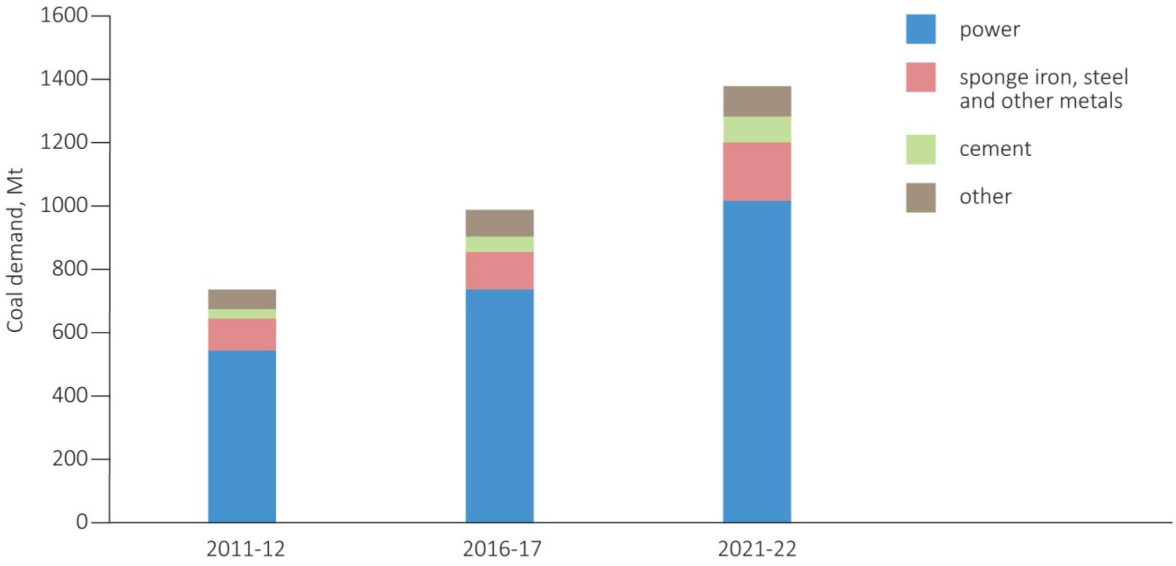

Figure 15 Percentage demand for coal in varying sectors (Bhushan and others, 2015)

Bhushan and others (2015) also note that coal drives the power sector in India as 60% of the current installed power capacity (254 GW) in the country is coal-based, which contributed over 72% of the total electricity generation in 2013-14. The Planning Commission projects that by the end of the 13th Year Plan in 2021-22 approximately 81% of the power will be generated with hard coal-, lignite- and gas-based power plants.

In 2012, only 1% of total coal-fired capacity in India utilised supercritical technology, 28% exceeded their lifespan expectancy, efficiency of older plants on average was, and remains, ~32% and even supercritical units only achieved ~38% efficiency. The Perform and Achieve Trade (PAT) scheme was announced under the National Mission on Enhanced Energy Efficiency (NMEEE), which was one of eight missions announced in the National Action Plan on Climate Change (NAPCC) in 2008. The scheme was the first attempt to introduce the concept of energy efficiency in thermal power plants in India. It identified nine energy intensive sectors and set targets for reduction in energy intensity for each of the sectors. Out of the total 144 thermal power plants covered under the PAT scheme, 97 are lignite-fired units. However, Bhushan and others (2015) consider the target for reduction modest in terms of percent reduction at only 3% from power generating plants. Bhushan and others (2015) discuss the PAT scheme and its effects and shortcomings in detail.

Indonesia was the world's number 1 coal exporting country in 2014. At the end of November 2012, 4.52 GW of new generation capacity was in operation under phase I of the accelerated power development programme. In 2010, the government mandated the state-owned utility, Perusahaan Listrik Negara (PLN) (Indonesia), to implement Phase II of the programme. In this phase, PLN is required to add 11.1 GW of capacity, 68% based on coal, 19% geothermal, 10% on combined cycle gas and 3% hydropower. The two-phase accelerated power development programme aims to increase generating capacity quickly, encourage renewable energy utilisation, and at the same time eliminate oil-based power generation, except in regions where there are no other competitive alternative energy sources. In 2014, the Ministry of Energy and Mineral Resources established a final energy mix for the 10 GW Phase II, with a total Phase I and II capacity of ~17.5 GW, 60% of which will fire coal. The scheduled completion date for the 10 GW Phase II is 2022 (APERC, 2015).

In late 2011, the Central Java ultra-supercritical coal power plant 2x1000 MW project was approved under the Public Private Partnership (PPP) programme. The terms of the PPP include government investments and guarantees on PLN power purchases through a private guarantor. According to APERC (2015), government guarantees for the PPP Central Java power plant project are an advanced step in infrastructure development in Indonesia, as it is considered more transparent and accountable. The PPP scheme to be used for the Central Java power plant project is the Build-Own-Operate-Transfer (BOOT) scheme, which has a concession period of 25 years. Commercial operation is expected to commence at the end of 2016.

The **Republic of Korea** has few indigenous energy resources including 326 Mt of recoverable coal reserves and 3 billion m^3 of natural gas. To sustain its high level of economic growth the Republic of Korea imported about 90% of its primary energy supply in 2012. It was the second-largest importer in the world of both coal and LNG. In 2012, coal, 98% of which was imported, provided 29% of the total primary energy supply in the country. Most of it was imported from Australia; Canada; China; Indonesia; Russia and the USA. The basic plan of electricity demand and supply for 2008–22, finalised in December 2008, projected that electricity demand would grow by 2.1% per year from 2008 to 2022 and an additional capacity of 33.6 GW would be required by 2022. When including decommissioning in the account, this translated to about 101 GW of total generation capacity for that period. As well as nuclear and gas-fired facilities, seven coal-fired power plants are planned for construction, thus continuing the demand for coal in the Republic of Korea (APERC, 2015).

Malaysia is endowed with rich energy resources, both conventional (oil, gas and coal) and renewable energy. Coal reserves are assessed at 1,938 Mt and provide 20.6% of the country's total primary energy supply. The coal is mostly of bituminous and subbituminous quality. Although the coal resources are substantial, domestic coal production is moderate as most of the coal deposits are deep inland with no adequate infrastructure in place, which makes extraction costly. In addition, the declaration of some areas as protected, prohibits coal mining activities. In 2012, domestic coal consumption decreased slightly by 0.85% from 1759 ktoe in 2011 to 1,744 ktoe; 90% was consumed by the power generating sector. Malaysia imports coal to meet its growing requirements from Australia, Indonesia and South Africa. In 2012, total installed power generating capacity was ~29 GW. Thermal generation, mostly from natural gas and some from coal accounted for 93% of the total electricity generated. There are plans to expand the generating capacity of coal-fired power plants in Peninsular Malaysia and Sarawak using supercritical and/or ultra-supercritical technology to achieve greater efficiency and less CO_2 emissions (APERC, 2015).

The Russian Federation has vast natural resources that include major deposits of coal, natural gas, oil and other minerals. However, formidable obstacles such as climate, terrain and distance (due to the size of the Federation) hinders full exploitation of these resources. Nonetheless, proven reserves of coal amount to >157 Gt or 17.6% of global reserves. At current rates of coal consumption in the economy, these reserves are reported as sufficient for 800 years. The Federation is responsible for approximately 10% of world coal trading (142.9 Mt of coal exported in 2013) while domestically, coal contributed 17.8% of the total primary energy supply in the Federation in 2012. More than 90% of the Russian Federation total energy exports were to Europe and the CIS. More recently, the Russian Federation has been diversifying its export routes, including for coal, towards regional markets in the Asia–Pacific region (China, Japan and the Republic of Korea). In 2014, about 44% of Russian coal exports went to Asia (*see* Figure 16). Total Russian coal exports have almost tripled over the past decade and they are expected to continue to grow in the future. The coal-exporting ports are geographically located to serve either European or Asian markets. In addition, China and some East European countries receive imports from Russia directly by rail (EIA, 2015b).

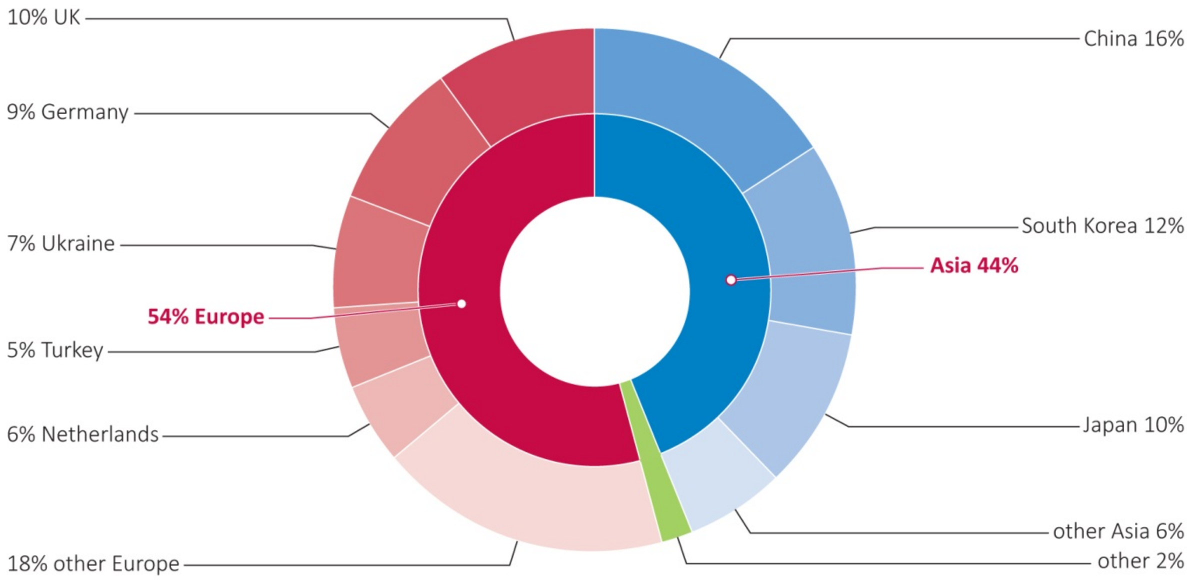

Figure 16 Russian coal export by destination in 2014, % (EIA, 2015b)

In January 2012, the Government Presidium of the Russian Federation approved a long-term programme for developing the coal industry to 2030. The programme specifies the basic provisions of the energy strategy to 2030 relating to the coal industry. The Russian strategy for developing the coal sector to 2030 foresees transferring the centre of the coal production to Russia's eastern regions to supply Asian markets, which now, according to APERC (2015), total approximately 80% of world consumption.

Chinese Taipei is one of the most densely populated areas in the world. It has very limited domestic energy resources and relies on imports for most of its energy requirements. There are no coal reserves in the country. The lack of domestic energy and mineral resources results in Chinese Taipei importing nearly all of its energy requirements, with imports accounting for 97.8% of its primary energy supply in 2012. Coal's contribution to the total primary energy supply in 2012 stood at 33.5%. Australia and Indonesia are the major suppliers, accounting for 81.6% of the total coal imports. In 2012, Chinese Taipei imported 64.6 Mt of coal, most of which (72.8%) was used for power generation. Electricity generation in the same year reached >250 GWh. Coal's share of the total electricity production was 27% (APERC, 2015).

In **Thailand**, coal provided 8% of the total primary energy supply in 2012. Most of the proven coal reserves in the country (1,239 Mt) are lignite with lower calorific values. Hence, higher quality feedstock is imported to meet energy demand for both electricity generation and the industry sector. The Thai Government plans to diversify the economy's energy sources. Under the Third Revision of Thailand Power Development Plan (PDP 2010), approved in 2010, coal (with clean coal technology) will be one of the main sources of energy diversification by 2030. In 2015, the Ministry of Energy is preparing a new version of the PDP, which provides a more diversified energy mix by increasing the share of coal. In 2012, total electricity generation was ~171 GWh. Thermal generation, mostly with natural gas and coal, accounted for 85% of the power generated. With regard to climate change, the Thai government is in the process of setting relevant standards and promoting CDM projects to reduce social and environmental impact as well as greenhouse gas emissions. Thailand aims to reduce CO_2 emissions by at least 1 Mt a year (APERC, 2015).

3.2.4 Europe

Coal accounts for about 25% of all electricity production in Europe and is an important fuel for industrial processes such as steel production. As a cheaper and more readily available alternative to other fossil fuels such as natural gas and oil, coal forms an integral part of the energy mix of many European countries. It also helps some of the countries reduce their dependence on oil and gas imports. However, by continuously tightening environmental regulations, most of Europe is working towards reducing its carbon emissions drastically, including from coal-fired power plants. Part of this strategy will necessarily involve the implementation of clean coal technologies such as CCS if coal is to continue playing an important role in the fuel mix.

Around 30% of the power generated in the EU-28 is coal-based. Steel producers and other energy-intensive industries also require large quantities of energy. Therefore, as coal is an important, abundant and reliable source of energy, it will remain a vital component of the EU energy supply. The share of coal (including peat) in electricity production for EU member states, 2012 is shown in Figure 17. Furthermore, 88% of the EU's energy reserves are in the form of hard coal and lignite (2012 data) (*see* Figure 18) (EURACOAL, 2015; 2014).

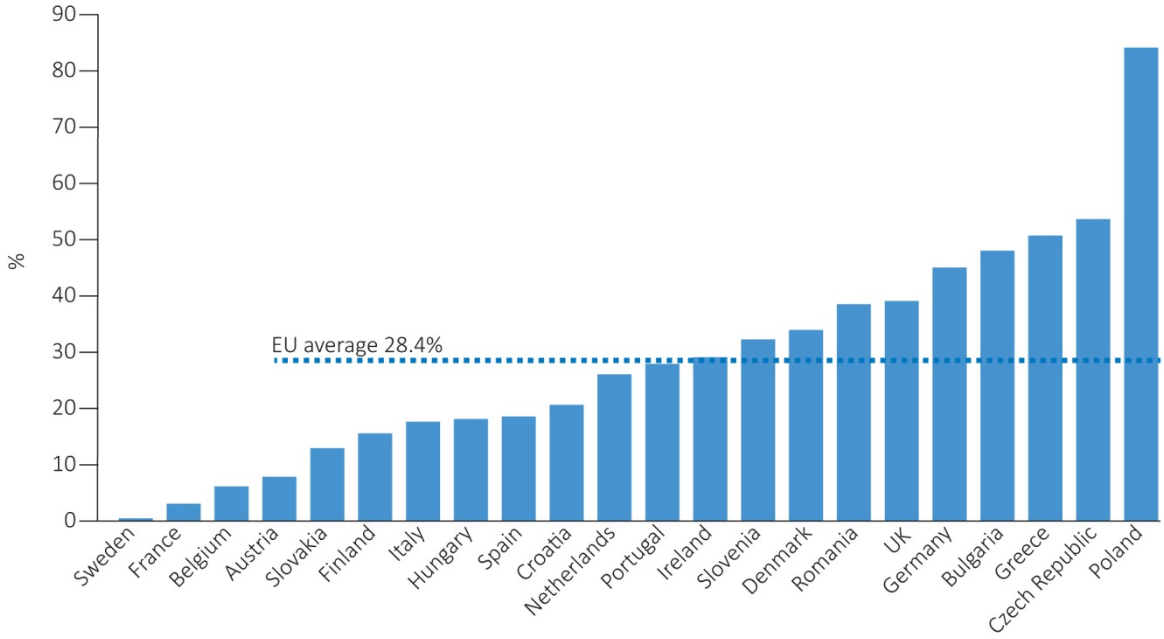

Figure 17 Share of coal in electricity production for EU member states, 2012 (EURACOAL, 2014)

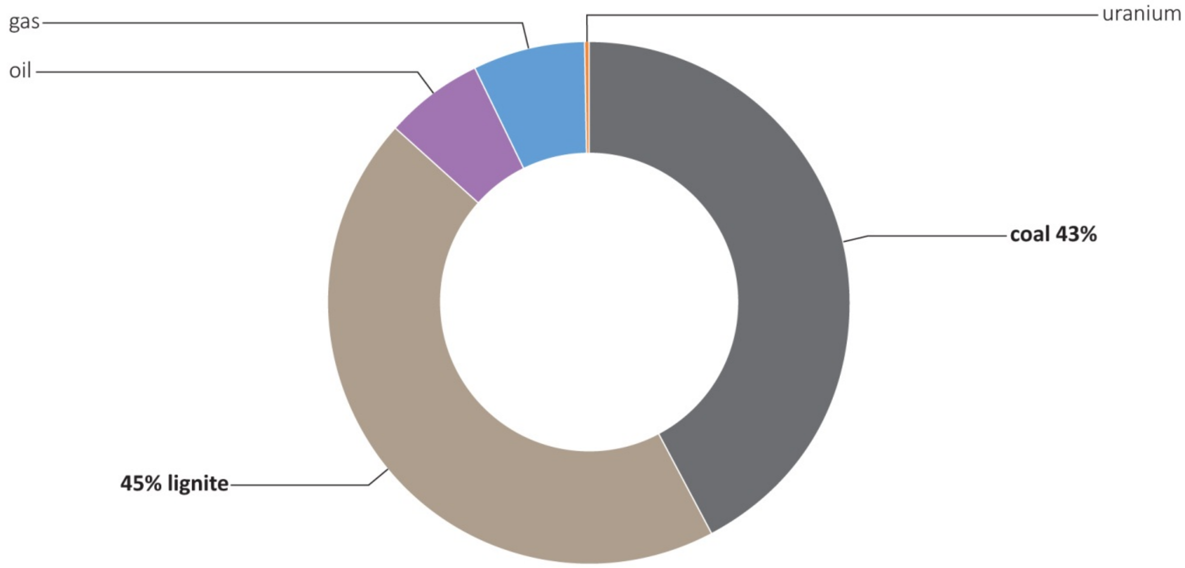

Figure 18 EU energy reserves in the form of hard coal and lignite (2012 data) (EURACOAL, 2014)

Between 2000 and 2012, EU electricity generation increased by 9%. Output from nuclear and coal plants shrank, but grew from gas plants and renewable energy sources. Nevertheless, overall, fossil fuels continue to underpin about 50% of generation, with coal, in particular, viewed as competitive especially at base load (*see* Figure 19) EURACOAL (2014).

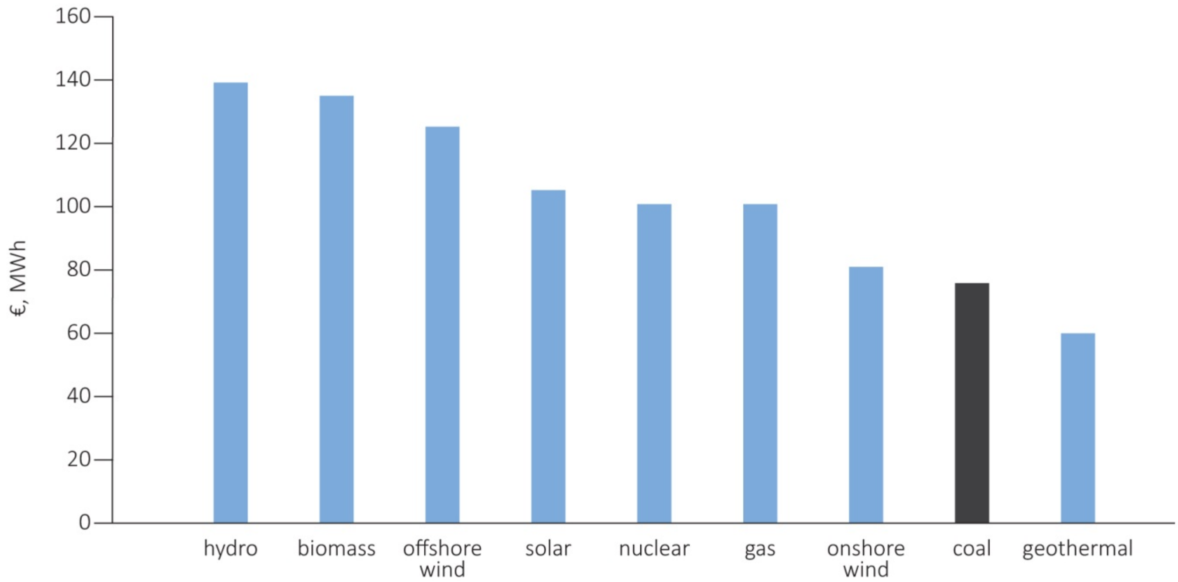

Figure 19 Levelised cost of electricity generation in the EU, 2012 (EURACOAL, 2014)

In 2013, total EU net electricity generation was 3.10 million GWh, which was slightly less (-0.9%) than the year before. This was the third consecutive fall in output, following on from a 0.1% fall in 2012 and a reduction of 2.2% in 2011. As such, the level of net electricity generation in 2012 remained 3.6% below its peak level of 2008 (3.22 million GWh). EURACOAL (2014) considers that, in contrast to the changes in output increasing in the early- to mid-2000 and declining somewhat in more recent years, generation capacity increased by 41% over the 2000/2012 period. Well over 200 gas-fired power plants were constructed, totalling over 100 GW and renewables capacity grew by 190 GW. Given the relatively higher costs of renewable energy and the intermittency of wind and solar power, coal, gas and nuclear power will be necessary for many years to come. According to EURACOAL (2014), instead of building a new renewable power system to replace the existing system, Europe is in fact building a second system that relies on conventional plants on still nights and at many other times. Whereas nuclear plants produce around 80% of their maximum possible output and fossil plants can run with similar reliability, wind turbines produce barely more than 20% and solar photovoltaic panels generate not much more than 10% of their rated full-load output. The percentages are compared with full-load operation. For example, the average wind turbine in Europe produces an output equivalent to the same turbine running at full output for 1,936 hours. Given that there are 8,760 hours in a year, this is a 22% load factor. In practice, wind is highly variable, so the turbine rarely runs at full output and has periods when it is stationary, but the load factor gives a precise indication of how much power the machine produces each year. Despite the growth in wind and solar photovoltaic capacity, the power supplied from these renewable sources remains relatively small and not well-aligned with periods of high electricity demand (*see* Figure 20).

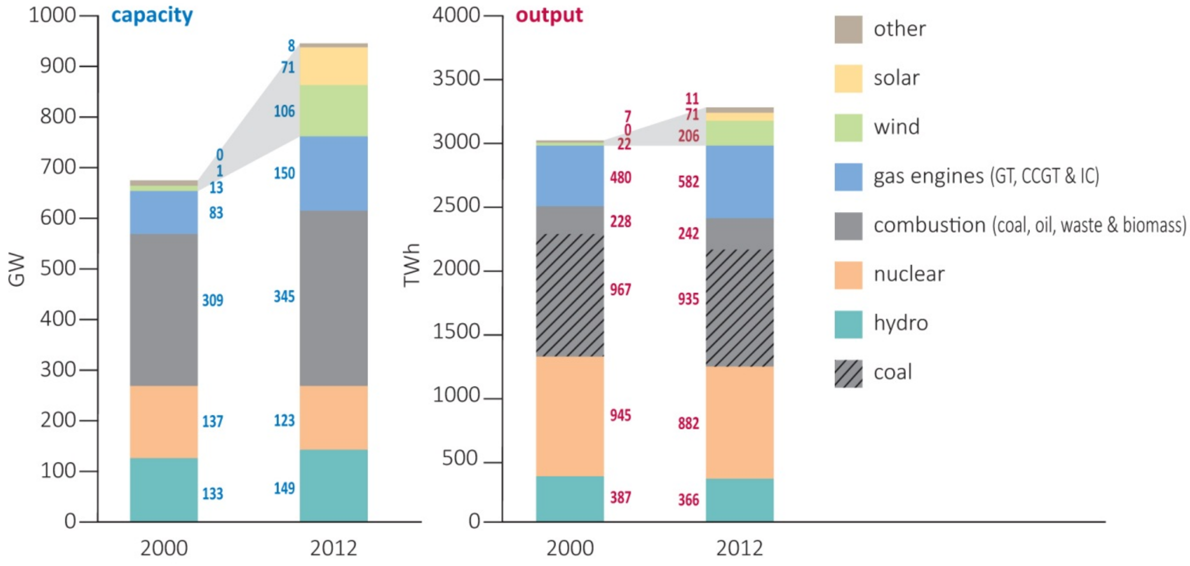

Figure 20 EU power plant capacity and output growth from 2000 to 2012 (building a second system) (EURACOAL, 2014)

Nies and others (2013) reported the power statistics and trends in 2013 on behalf of the European Union of Electricity Industry (EURELECTRIC). The key messages from the publication were:

- In the energy policy context, member states opted for diverging policies. At the end of 2013, the period was characterised by regulatory uncertainty and increased national intervention, leading to a slowdown (if not setback) of energy market integration in Europe.
- Demand trends showed stagnation. Demand in 2012 stagnated at the 2011 level, after a significant 2% decrease from 2010 to 2011. According to Nies and others (2013), the overall picture of stabilisation concealed widely varying developments across the region, with some countries experiencing a growth in demand, others experiencing a decline, while others reported stagnating electricity demand.
- In generation trends, the EU appeared to have shifted from the trend of 'RES plus gas' to 'RES plus coal'. From 2011 to 2012, generation from renewable resources increased by 7% and coal-fired generation grew by 13%, accompanied by a significant 23% drop in gas-fired generation. Nuclear generation also declined by 2.8%.
- Installed capacity trends showed that RES capacities continued to increase in 2012, albeit at a slower year-on-year rate of 11%, compared to 15% in 2011. A common characteristic of added RES capacities throughout the whole period is that they are subsidy driven. The overall slowdown of RES growth is expected to continue as national RES support policies continue to change.
- Power prices in Europe increased, pushing affordability and industrial competitiveness concerns to the forefront of the energy policy debate. Policy costs imposed through taxes and levies weigh considerably on retail prices, which grew three times faster than other price components.

- Last, but not least, environmental trends indicated that although electricity consumption stagnated and low-carbon intensive generation increased in 2012, the increase in coal-fired generation resulted in no reduction in CO_2 emissions.

However, according to Olivier and others (2014), 2013 saw a continuation (since 2006) of decreasing CO_2 emissions in the EU by 1.4%, compared to 2012, even though GDP recovered somewhat since the global economy collapse in 2008, with a 0.1% increase in 2013 (compared to 0.3% decline in 2012). The main reasons for falling CO_2 emissions are attributed to the decreases in primary energy consumption from coal (2.7%), oil (2.2%) and gas (1.4%) and the emissions from the sectors under the EU ETS, which saw a 3% decline. Investments in renewable energy continued in 2013; the electricity demand in the EU-28 was met by 8% supply through wind power, and the installed capacity for solar energy increased slightly to 81.5 GW in total, in 2013.

In 2015, Blok and others studied the impact of efficiency in energy productivity on growth throughout the world, in general, and more closely in Europe, France, Germany, Netherlands, Poland, Spain and the UK (country case studies and roadmaps). Their findings indicate that to achieve a high-energy productivity growth scenario, coal utilisation would decline throughout the case study countries (Blok and others, 2015).

The three largest consumer countries of coal in Europe are Germany, Poland and the UK. In **Germany**, mainly domestic and some international coal is used predominantly for power generation, but also for iron and steel production. In 2013, electricity generation accounted for 86% of German coal consumption, while iron and steel production accounted for 7.5%. Coal combustion in total is responsible for over a third of Germany's GHG emissions. Lignite production has roughly halved over 1990-2013 while hard coal production slumped by almost 90%. Although after 2018 there will be no hard coal mining in Germany, the country remains the largest producer of coal in the EU, with its mining output accounting for 37% of all EU coal production. Globally, Germany ranks 7th amongst the top coal producing countries, and is the world's top producer of lignite (Schulz and Schwartzkopff, 2015).

Resulting from the decline in hard coal production, Germany has had to import significant and increasing amounts to supply its fleet of hard-coal power stations (*see* Figure 21). Hard coal imports have increased from ~20 Mt in 1990 to >50 Mt in 2013, constituting 76% of its hard coal consumption. Germany imports hard coal from Russia (28%), the USA (19%), South Africa (14%), Colombia (13%), Australia (13%), Poland (9%), Canada (3%) and others (1%). Hard coal exports, on the other hand, only amounted to ~250,000 t in 2013. Lignite exports were negligible (Schulz and Schwartzkopff, 2015).

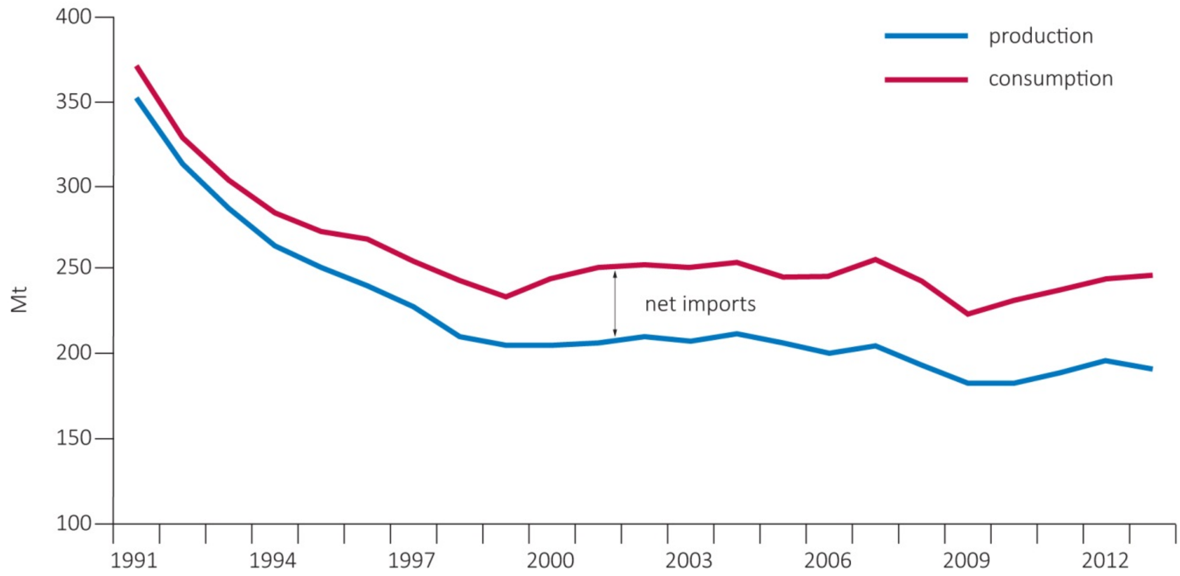

Figure 21 German coal consumption and production 1991-2012 (Schultz and Schwartzkopff, 2015)

Coal utilisation in the electricity sector in Germany, in 2014/15, is listed below (note that coal capacity figures in the list below include planned additions and retirements in 2015) (Shultz and Schwartzkopff, 2015).

Total installed capacity (2014)	192 GW
Installed lignite capacity (2015)	20.5 GW (10.9% of total capacity)
Installed hard coal capacity (2015)	28.3 GW (13.8% of total capacity)
Peak electricity demand (2014)	83.1 GW (43% of total capacity)
Electricity generation, lignite (2014)	156 TWh (26% of total electricity generation)
Electricity generation, hard coal (2014)	109.9 TWh (18% of total electricity generation)
Average retirement age of coal plant (2014)	52 years
CO_2 emissions from coal power generation (2014)	258.8 Mt CO_2 (28.4% of total CO_2 emissions)

Coal has historically played a major role in the German electricity mix, with annual electricity production of ~300 TWh since 1990. However, in relative terms, and in the same timescale, coal-fired power generation has declined by 15%, due to the increase in electricity production from other resources. The share of coal in the electricity mix therefore declined from 56.7% in 1990 to 43.2% in 2015. Most of the reduction is due to the decrease in hard coal production, which has declined consistently since 2007, mirroring the drop in domestic production. Power generation with lignite has in contrast, remained relatively stable with a share of 26.2%. The combination of lignite and hard coal have and continue to dominate the German electricity fuel mix.

Over 2007-2014, electricity demand declined by 0.5% annually. Energy efficiency and the continued investment in renewables reduced the market share of coal in electricity generation (*see* Figure 22) (Buckley, 2015).

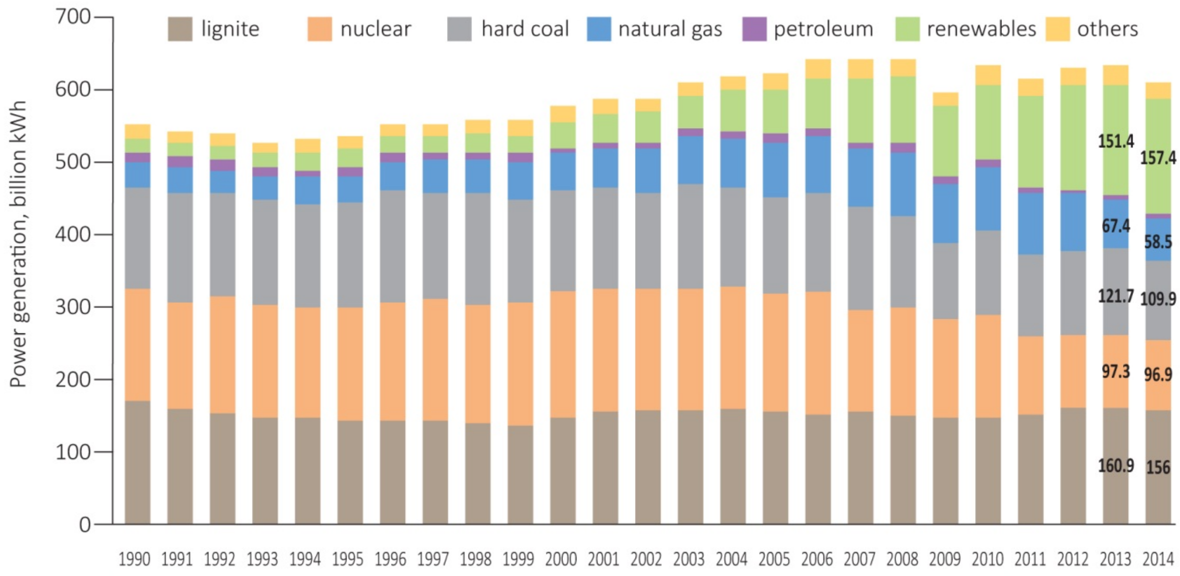

Figure 22 Gross power generation by fuel in Germany, TWh (1990-2014) (Buckley, 2015)

In 2015, Bayer (2015) reported on the German power system, the largest in Europe. In terms of installed capacity, Germany has the highest share of renewable power in Europe (83 GW) and is third in the order of countries with most installed renewable capacity (excluding hydro), worldwide (*see* Figure 23). In 2014, renewable energy contributed >25% of electricity produced in the country. At the same time, hard coal and lignite combined, contributed 44% to electricity production while nuclear energy accounted for about 16% (*see* Figure 24).

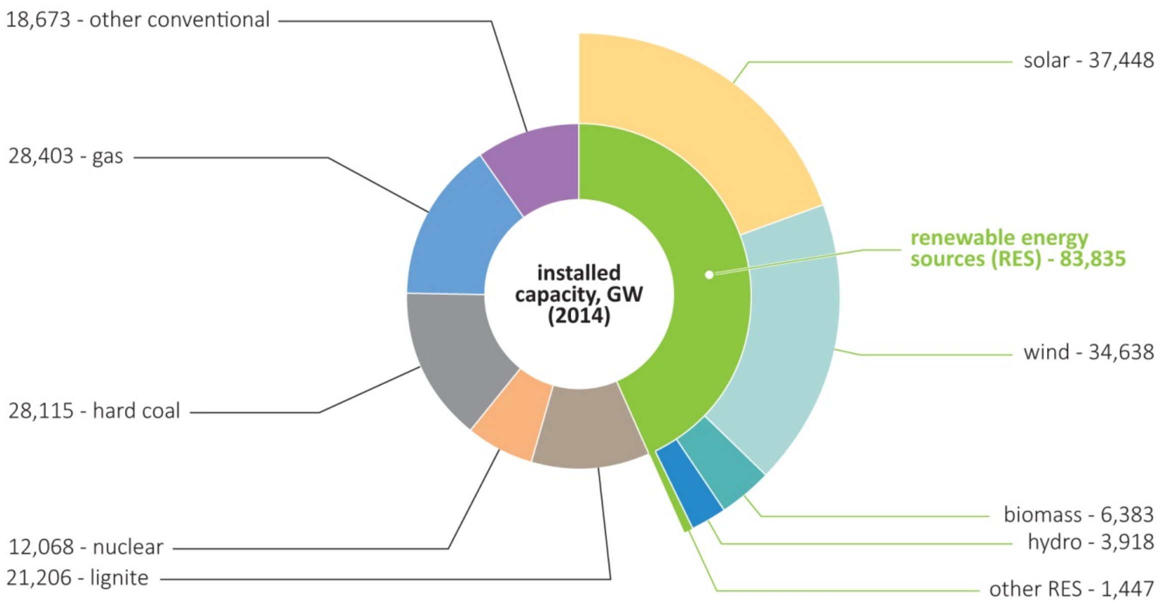

Figure 23 German power generating installed capacity, GW (2014) (Bayer, 2015)

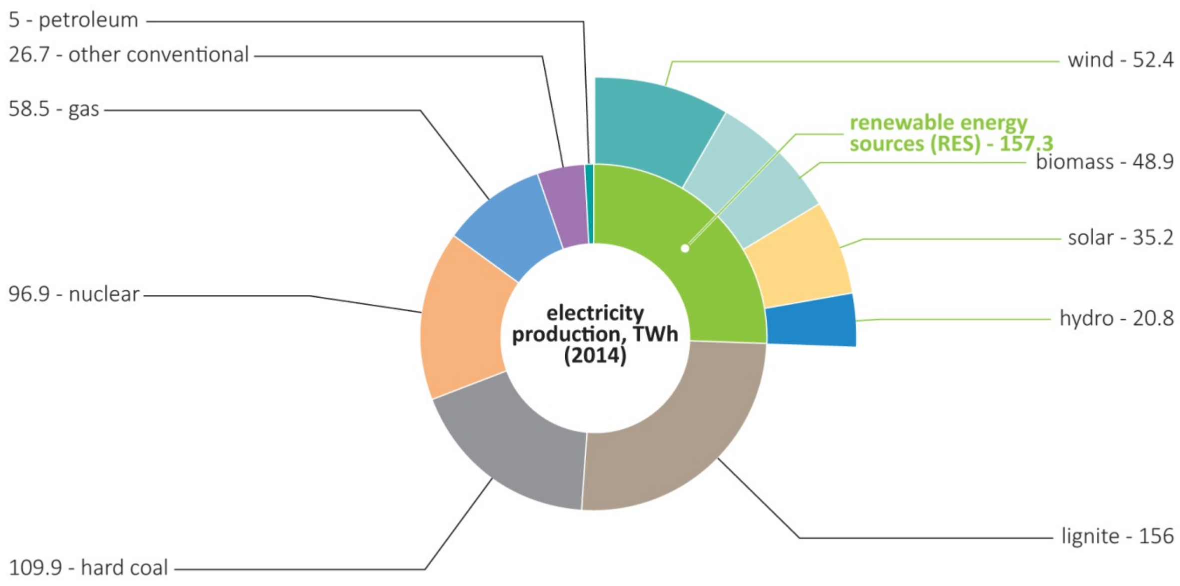

Figure 24 German electricity production, TWh (2014) (Bayer, 2015)

As of July 2014, 6,558 MW of thermal power generation was under construction, with completion scheduled by 2016, while 11,251 MW of capacity are planned to cease operation by 2018. Bayer (2015) considers that, against a background of constriction in the transmission grid between the North and South, Southern Germany is experiencing some inadequacy in resources, in part due to the decommissioning of 5 GW of nuclear capacity in 2011 and, also, due to planned closures of an additional 3,869 MW. A potential negative power balance of up to 5,717 MW by 2018 may thus occur. It should be noted that, if a system instability is envisaged, the government is able to reject applications for plant closure (Bayer, 2015).

Meanwhile, Schultz and Schwartzkopff (2015) note that close to 7 GW of new coal capacity has been constructed since 2011 and >3 GW is currently under construction. In tandem with power plants closures, Germany saw a 2.2 GW net addition of coal capacity between 2011 and 2015. The investment decisions for these plants were taken in 2007-09. Since 2010, there have not been any prospects for new investment in coal-fired plants in Germany (*see* Figure 25).

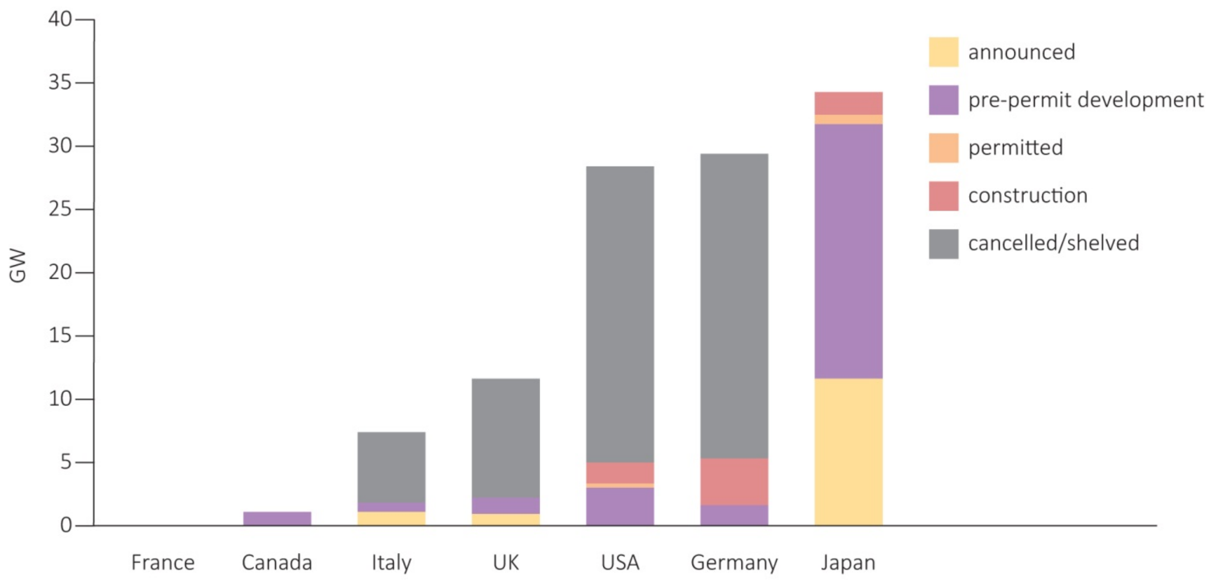

Figure 25 G7 coal expansion plans since 2010 (Schultz and Schwartzkopff, 2015)

Schultz and Schwartzkopff (2015) note that despite the progress with the deployment of renewables, hard coal and lignite power plants have continued to operate at high load factors, reducing the use of lower-carbon gas plants and exporting electricity to neighbouring countries. The plan is that by the end of 2022, the German power sector will be nuclear free and by 2035, the aim is for 55–60% of electricity to be generated from renewable sources. However, given the current market structures, in particular the 'merit order effect', and in the absence of new policy instruments, the production of electricity from coal will likely remain cheaper than using gas.

According to Jungjohann and Morris (2014), there is strong resistance to CCS in Germany and the government does not envisage political acceptance within Germany to move the technology forward. The CCS demonstration plant in Jaenschwalde in Eastern Brandenburg halted in December 2011 and the smaller CCS pilot installation at Schwarze Pumpe, near Berlin, shut down in July 2014. In their study on the 'German coal conundrum', Jungjohann and Morris (2014) concluded that without a strengthening of the EU-ETS or other policy changes, natural gas is unlikely to offset coal in the German power generating sector until the early 2020s. However, with growing renewables utilisation and mine closures after 2018, the share of hard coal in the mix will decline. Many hard coal plants will operate at low capacity levels. Lignite, on the other hand, is likely to retain its position in the German power generating mix while nuclear plants are phased out. Finally, a coal phase-out in Germany, in the long term, currently under discussion and driven by renewables' growth, will not begin until after 2023 and the nuclear phase out Jungjohann and Morris (2014).

Poland is the second largest coal producer in Europe, after Germany. At the end of 2014, according to BP (2015), the country had 5,465 Mt of proven coal reserves (70% anthracite and bituminous). Hard coal production in Poland decreased from 76.5 Mt in 2013 to 72.5 Mt in 2014. Poland produces small quantities of crude oil and natural gas and it is a net oil and natural gas importer. In 2012, Poland's total primary energy consumption was ~101 Mtoe. Coal constituted 55% of consumption, with the remainder represented by oil (26%), natural gas (15%), and renewable energy sources (4%). According to BP (2015), Poland produced 158 million tons (~143.3 Mt) of coal in 2012, which typically accounts for around 20% of total coal production in Europe. Poland consumes almost all of the coal it produces (hard coal and lignite), while exporting a small amount. The electricity sector is heavily reliant on coal, as coal-fired power plants represented >85% of installed capacity in 2010. More recently, the government announced a goal of sourcing 15.5% of domestic energy supply from renewable energy sources. However, the strength of the coal industry, the local abundance of coal, and relative price of coal has contributed to opposition by Poland to some environmental measures proposed by the EU (WEC, 2014 and EIA, 2013).

Existing installed capacity of the Polish grid is ~38 GW. However, according to the WEC (2014), at least 10 GW of that capacity is decapitalised units, which exceed 40 and in some cases 50 years of operation. The WEC (2014) considers that these units should not constitute a real reserve of power, but older ones be liquidated and newer facilities, modernised. The situation, according to the WEC (2014) also indicates the necessity of rapid construction of new capacity in the Polish power system and particularly an increase in peak capacities through the construction of gas-fired units, construction of efficient, supercritical coal-fired units, construction of nuclear plants, and construction of renewable electric capacities. The Polish, state-controlled utilities are currently investing 25.1 billion zlotys (~€ 5.9 billion) construction of 4698 MW of mainly hard coal-fired power plants. These more efficient coal plants, to replace older facilities, are expected to reduce emissions by approximately 25% (Easton, 2014).

Indigenous hard coal and lignite are strategic fuels for power generation in Poland. Their contribution to total power generation is dominant in 2015, at ~90% share and is expected to continue so in the medium term but to a lesser extent by 2050, at ~50%, with the shortfall to be covered by renewables and nuclear power (EURACOAL, 2013; Easton, 2014).

In brief, the characteristics of the Polish energy sector, which can affect the future of coal-based power generation, are as follows (WEC, 2014).

- Domestic hard coal and lignite are the main fuels for electricity generation (about 90% in 2015); domestic reserves of natural gas are low and more than 70% of natural gas consumed in Poland is imported.
- Poland has no nuclear plants. A share of nuclear electricity production may be achieved in the time horizon of 3-4 decades under the condition that the construction of the first nuclear plant would begin in a few years.
- Poland does not have considerable hydro or renewable energy resources; therefore despite the ongoing development of wind-based power and biomass fired generation these source may cover no more than ~12% of electricity demand.

- Transformation of the Polish power sector into a low emission source of electricity and the application of CCS in coal-fired power plants requires time and construction of lower emission gas fired plants, and nuclear power stations, all considered prohibitively costly.

In its review, the WEC (2014) consider that currently, Poland is not a major emitter of CO_2 in absolute terms. However, Poland appears to have high CO_2 emission because of the relatively high consumption of coal in comparison with the most developed countries in Europe. Therefore, the energy policy of Poland should comprise the activities that aim to reduce GHG emissions substantially. However, the process should be given a long time and should take into account the realities of the Polish economy.

In the **UK**, energy trends from the Department of Energy and Climate Change (DECC) show coal-fired power generation down by 11.5 TWh in the 3rd quarter of 2014 over the same quarter in 2013, a reduction of 43%, while gas-based generation increased by 8.0 TWh and renewables by 2.6 TWh. In addition, with ~50% of the UK remaining coal-fired power plants planned to cease operation due to the revised LCPD requirements over the next 2–3 years, coal demand in the UK will decline. Furthermore, the UK has set legally binding targets for carbon emissions and implemented various policies and guidelines for new coal-fired power plants, most notably the policy of no new coal-based power generation without CCS. As the commercial application of CCS in the near future remains unlikely, this means no coal-fired power plants in the UK for the foreseeable future.

3.2.5 North America

Canada has large coal reserves with 8,700 Mt of proven resources. Of that amount, 6600 Mt are deemed recoverable using existing technology under current and expected local economic conditions. Annual coal production has remained relatively steady since 1990. In 2012, Canada produced 33.5 Mtoe of coal. Thermal coal production was 53.3% and the remainder, 46.7% was metallurgical coal. Coal exports account for 52% of production; approximately 20.8 Mtoe of coal was exported in 2012. While Canada is a moderate coal producer, it is a significant exporter of metallurgical coal, which accounts for about 90% of Canada's coal exports. Canada exports coal to a variety of countries. However, Asia is Canada's primary export market, accounting for 81% of exports. Canada also exports coal to a number of European countries, the USA, Mexico and some Latin American countries. Canada generated 616 TWh of electricity in 2012, a decrease of approximately 0.3% from 2011 (618 TWh). This decrease is largely driven by the rapid decline in thermal power generation of 6.8% from 2011, an ongoing trend since 2000 at an annual average decline of 2.3%. In 2012, hydropower plants were the largest contributor to Canadian electricity at 61.2%, followed by thermal generation (coal, natural gas and petroleum) at 21.0% and nuclear at 14.5%. In comparison, the share of renewables, other than hydro, of total electricity generation, is relatively small at 3.3%, but is growing steadily. Regulations limiting the use of coal, low natural gas prices, and the decreasing cost of renewable energy are reported as improving the environment in Canada (APERC, 2015).

Furthermore, a new regulation came into force in July 2015 that requires a set, restrictive performance standard for new coal-fired electricity generation. This is expected to further reduce coal consumption in

Canada, but not necessarily the production of coal. The Regulation, adopted under the Canadian Environmental Protection Act 1999, is a performance standard that sets an emissions intensity level comparable to that of NGCC technology, fixed at 420 t/GWh. It also contains a caveat to encourage new technology for GHG reductions, where units that incorporate CCS technology can apply to receive a temporary exemption from the performance standard until 31 December 2024 (APERC, 2015).

The **USA** is the 2nd largest producer and consumer of energy in the world. It is also rich in energy resources. In 2012, the USA proven coal reserves were 237 Gt. In 2012, coal contributed 20% of the total primary energy supply in the country. Coal production however declined in 2012 by 11.2%, compared to 2011. The decline in production and consumption (in power generation) continues with the increasing production of unconventional gas (Nalbandian, 2015). In 2012, the USA was the fourth largest coal exporter in the world, after Indonesia, Australia and Russia. Coal exports were 126.7 million tons (114.94 Mt), an increase of over 17% from 2011. Coal imports have steadily declined from 38.8 million tons (35.2 Mt) in 2007 to 10.3 million tons (9.34 Mt) in 2012. Europe was the largest importer of coal from the USA, accounting for around 50% of net exports. In 2013, the USA produced 4.1 million GWh of electricity; of that total, 67.5% came from fossil fuel plants. Until recently, coal-fired power plants provided just under half of electricity in the USA. However, this has declined since the wide-scale production of shale gas and also due to environmental regulations. As a domestically abundant resource, coal provides energy security benefits. However, high CO_2 emissions from coal combustion present a challenge for climate policy in the USA.

As discussed in Section 2.4, briefly, the US EPA has finalised in August 2015 the CPP to limit CO_2 emissions from the power-generating sector. The emission regulation aims to limit climate change by enforcing the use of modern and more efficient fossil fuel generation technologies. The carbon restriction will essentially require new coal plants to operate using the latest high efficiency technology, employ biomass co-firing fuels or utilise CCS. With regard to mercury regulation (the MATS rule), on 29 June 2015, the US Supreme Court made the decision that: the US EPA interpretation was 'unreasonable' when it deemed cost irrelevant to the decision to regulate mercury emissions from power plants. This decision is expected to influence the development and adoption of the CPP, which targets CO_2 emissions and climate change. Nevertheless, due to the impact of the multitude of regulations introduced recently in the USA and the age of the US coal-fleet, many coal-fired plants have ceased operation and more are expected to shut down over the next few years (Nalbandian, 2015).

According to Ahmed and others (2013), Table 13 shows the top five electric power-generating companies in the USA and the breakdown of their coal and natural gas fired capacities. These power generators have large installed capital, a long-term investment horizon (30–50 years) and geographic markets that are defined by transmission capacity. The level of regulatory and environmental risks to companies depends on the role of coal in their power generation portfolio. Ongoing technology upgrades are costly and difficult because of the high upfront capital costs and the long lifetime of power generating units. In 2012, the companies slowed their rate of growth as well as new investments because of sluggish demand. They are increasingly meeting marginal demand in electricity by outsourcing power generation. The increasing deregulation of the utilities market makes cost competitiveness a priority for power generators (*see* Figure 26).

Table 13 Top five electric-power generating companies in the USA (Ahmed and others, 2013)

Company	Generation Assets*	Portfolio mix, %	2010 generation sources
Duke Energy Corporation†	60 GW Regulated: 97% Unregulated: 3% Additional generating capacity in six Latin American countries: 4 GW	Coal: 38 Natural gas: 35 Nuclear: 14 Hydro: 6 Wind: 2 Other: 5	Total 165 TWh Internal: 89% Purchased: 11%
American Electric Power	38 GW Regulated: 95% Unregulated: 5%	Coal: 67 Natural gas: 24 Nuclear: 6 Hydro: 2 Wind: 1	Total: 254 TWh Internal: 66% Purchased: 34%
Southern Company	45 GW Regulated: 80% Unregulated: 20%	Coal: 46 Natural gas: 37 Nuclear: 8 Hydro: 6 Other: 3	Total: 207 TWh Internal: 86% Purchased: 14%
Exelon Corporation†	38.6 GW Regulated: 0% Unregulated: 100% Additional generating capacity in Canada: ~90 MW	Coal: 9 Natural gas: 24 Nuclear: 50 Hydro: 5 Wind: 3 Other: 9%	Total: 151 TWh Internal: N/A Purchased: N/A
NextEra Energy Inc	43 GW Regulated: 64% Unregulated: 36% Additional generating capacity in Canada: ~300 MW	Coal: 2 Natural gas: 45 Nuclear: 14 Hydro: 1 Wind: 21 Other: 17	Total: 115 TWh Internal: 87% Purchased: 13%

* Nameplate capacity

† Generation assets and portfolio mix reflects 2012 merger: (Duke Energy Corp. & Progress Energy, Inc; Exelon Corp & Constellation Energy, Inc)

Source: Center on Globalization, Governance and Competitiveness (CGGC) (USA) based on data from proprietary databases and respective company websites & reports (www.cggc.duke.edu).

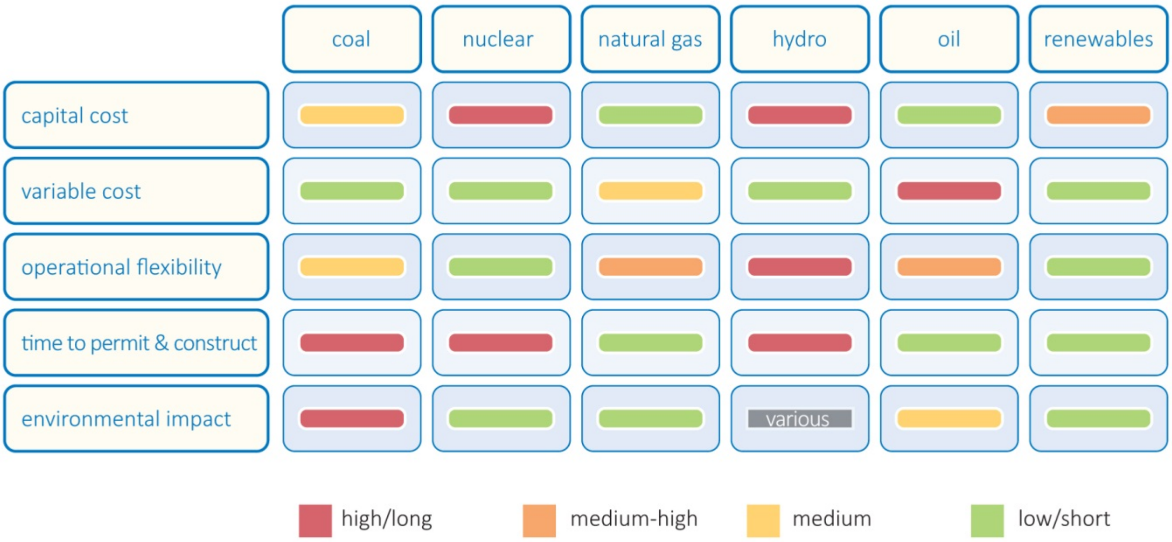

Figure 26 Characteristics of electric generation technologies (Accenture, 2013)

Ahmed and others (2013) outline the strategies of lead power generators that shape their abilities to meet electricity demand effectively, while reducing investment risk and operating cost. The approaches (*see* Figure 27) revolve around growth in natural gas power generation and significant reduction in advanced coal technology investments.

Retire old and inefficient coal-fired units
- different scenarios estimated 35-65 GW of coal retirement by 2020, representing 10%-20% of total US coal fleet
- top five lead firms announced 11 GW of coal retirement by 2016, representing 15% of their coal portfolio

Expand natrural gas-fired capacity in portfolio mix
- US electric power sector added 237 GW of natural gas-fired capacity in 2000-2010, representing nearly 80% of total over the period
- over the same period, the top five firms added 49 GW of natural gas capacity, which is about 83% of their capacity additions

Coal-to-gas fuel substitution and unit dispatch
- In April 2012, coal-fired power generation was 32% down from 44% in April 2010, while natural gas-fired power
- generation increased from 22% to 32%

Reduce investment in coal technology development
- firms continue to reduce R&D investments
- investment commitments are only where regulatory cost recovery is guaranteed
- demonstration projects are postponed or cancelled

Outsource power generation to complement internal generation in meeting demand
- expanding capacity by outsourcing to save on operating cost

Figure 27 US electric power producer strategies and implications for coal (Ahmed and others, 2013)

Ahmed and others (2013) consider that in order for coal to remain part of a diversified US energy portfolio in the future, advanced coal technology must be developed and commercialised. However, federal support for such technology is constrained. Therefore, collaboration in developing technologies that improve efficiency, reduce emissions, and contribute towards a more diverse and secure energy future is necessary. Existing partnerships are limited and inadequate for long-term sustainable coal use. Coal companies will need to expand beyond traditional strategies and become dynamic and proactive in utilising advanced coal technology. Furthermore, expanding and building partnerships with other industries such as the chemical, oil and gas sectors is also necessary to expand coal use beyond electric power (Nalbandian, 2014). These activities can eventually lead to the successful commercialisation of advanced coal technology and a more diversified coal market.

Dodge (2015) also carried out an in depth analysis of the US power generating industry shifting from coal to natural gas. Dodge (2015) considers that there are several pending rules that will have an impact on coal-based power generation, albeit much smaller in comparison to the MATS rule. For example, the Regional Haze Program, which is intended to improve visibility and has similar technical requirements to MATS, and the Cooling Water Intakes Structures regulation, which concerns the use of screens to filter water used for cooling systems. There are also new rules covering disposal of coal ash/residues. Financial impacts of these rules are minor compared to MATS and are not expected to lead to additional plant retirements beyond those resulting from MATS compliance. Nevertheless, these rules could also affect the future of coal utilisation. Moreover, the CPP is expected to lead to additional closures. However, according to Dodge (2015), the CO_2 rules under the CPP, although finalised by the US EPA in August 2015 are bound to face legal challenges, but could result in a further 50 GW of plant closings by 2020.

More than 70 GW of coal-fired electricity generating capacity have already been retired with even more set to retire within the next decade due to recent US EPA regulations. The regulations causing these closures include the MATS rule, the proposed Cross State Air Pollution Rule (CSAPR) rule, and the most recently finalised regulation of CO_2 emissions from coal-fired power plants, the CPP. According to the EIA (2015c), analysis of the CPP shows that natural gas-fired generation increases substantially in the early 2020s, while a large capacity of coal-fired power plants are retired, as an initial compliance strategy. Later, renewable generation, particularly wind and solar photovoltaic generators, are added. In the 'Base Policy' case with the proposed rule, 283 GW of cumulative additions of renewable electricity generation capacity are added to 2040, compared to only 109 GW of renewable generating capacity additions projected in the baseline, that is, the EIA (2015b) (AEO2015) reference case (*see* Figure 28).

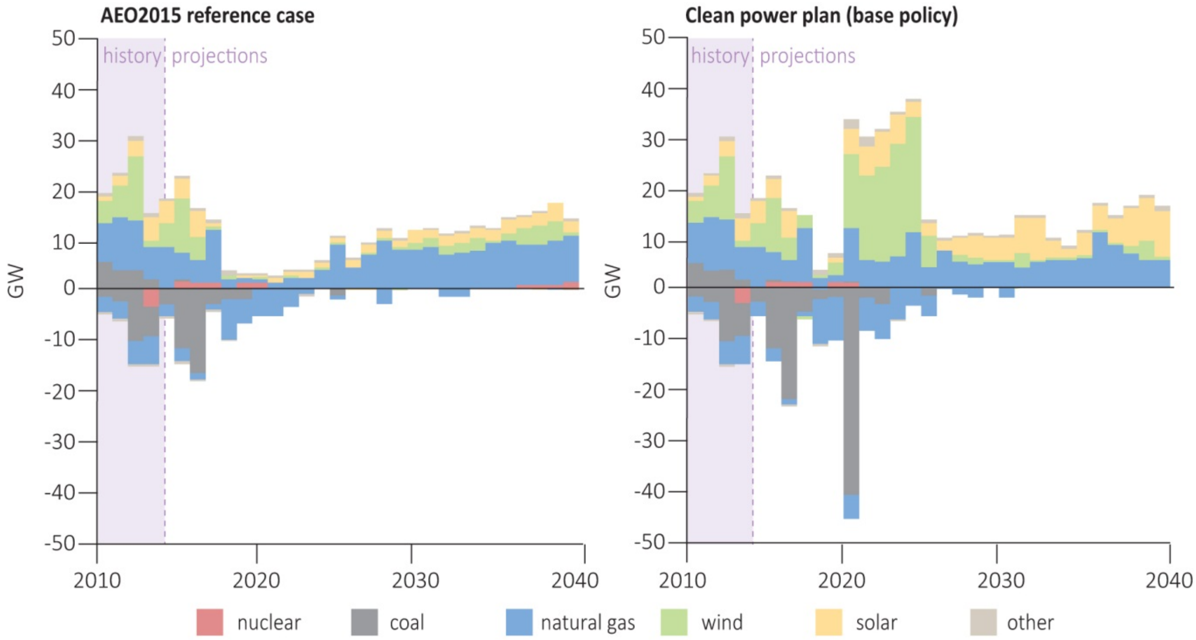

Figure 28 Projected US electric capacity additions and retirements (GW) for two cases, the EIA (AEO2015) reference case and the CPP Base Policy case (EIA, 2015b,c)

The EIA (2015c) notes that even in the absence of the CPP rule, 40 GW of existing coal-fired capacity and 46 GW of existing natural gas/oil-fired capacity are expected to retire to 2040 in the reference case. In the base policy case, 90 GW of coal-fired capacity and 62 GW of natural gas/oil-fired capacity retire by 2040. Further cases that implement the CPP rule accelerate and amplify these retirements, especially for coal. For a breakdown of eight further scenarios/cases, *see* EIA (2015c).

However, in a report published by the Institute for Energy Research (USA), Bezdek and Clemente (2014) consider that 'policy makers, regulators and electric utilities in the USA should institute an immediate moratorium on the premature closure of coal power plants and should reverse planned closures where possible'. According to Bezdek and Clemente (2014), US government policies that drive over-dependence on natural gas to replace base load, reliable, affordable and abundant coal-based power generation not only put the electricity supply at risk but also divert the gas from households and industries and subsequently make it more expensive, thus impacting economic growth.

4 The future of coal

The two main driving forces of growth in energy demand according to the WEC (2015) are population growth and economic growth. Figure 29 shows the dramatic growth in population in the last century, and especially so in the last two decades.

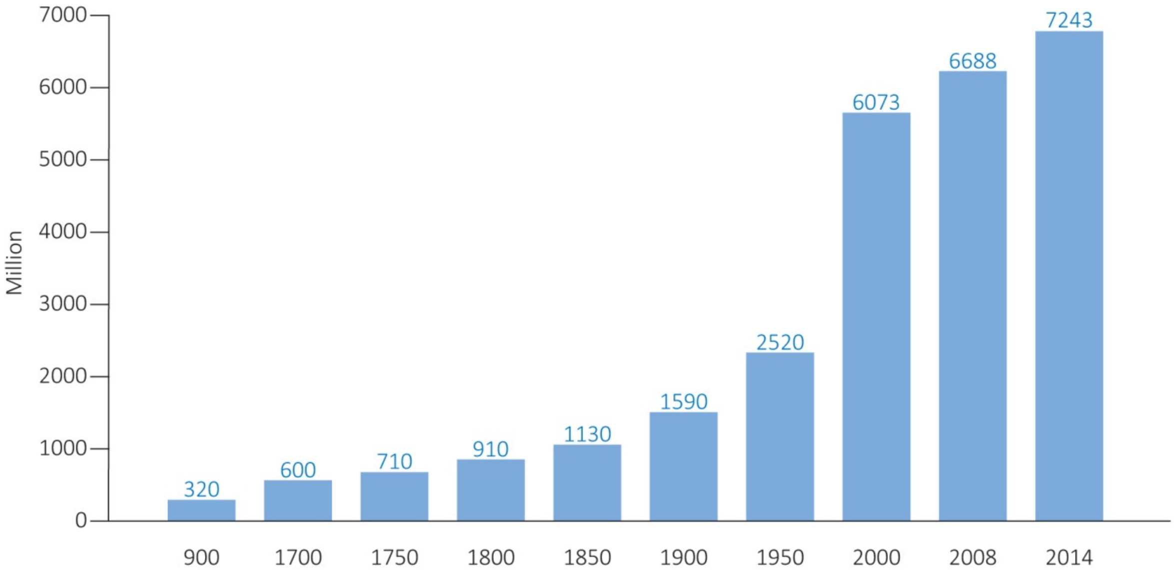

Figure 29 World population from the year 900 to 2014, millions (WEC, 2015)

The continuing, dynamic growth in world population is mainly in developing countries and particularly in Africa, South Asia, Latin America and the Middle East. Among the developed countries, a relatively high rate of population growth took place in North America between 1800 and 1900 (*see* Figure 30).

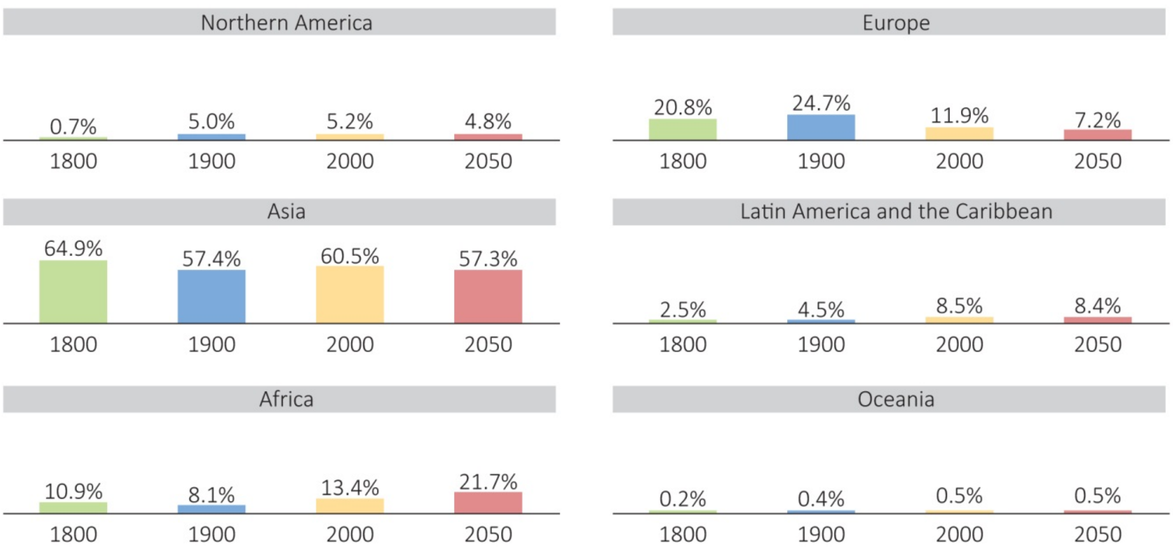

Figure 30 World population distribution by region (1800-2050) (PRB, 2015)

In the first decades of the 20th century global production of electricity amounted to ~500 TWh (before the Second World War in 1939). Rapid development of electricity production took place after the war. In

1950, global production of electricity amounted to 959 TWh. By 1970, it had grown to 4908 TWh. Electricity allowed fast social and economic development throughout the world, particularly in industrialised/more developed countries. It revolutionised industry, transport, construction and the municipal economy. It also improved the standard of life dramatically in the industrialised world. The continuing high growth of global production of electricity in the last three decades of the 20th century was however extremely uneven in the different regions of the world – high, per capital, in the industrialised regions of Europe, North America, the Far East and the Pacific, but immensely lower, per capita, in most countries in Africa, South Asia and Latin America. This trend continues today especially in Africa and South Asia (WEC, 2015).

Throughout the development in power generation, coal retained its high share (>40% in 2012) in globally generated electricity mainly due to the continuing growth in coal-fired power generation in China and India. Changes in the structure of fuels used for global electricity generation in 1971 and 2012 are presented in Table 14 (WEC, 2015). Despite the recent decline in coal-fired power generation in the USA and the slowing down of the coal-fired power plant construction programme in China, coal retained >36% share of power generation globally in 2014.

Table 14 Fuel structure of global electricity generation, 1971-2012 (WEC, 2015)

Fuel/Technology	**Share, %**	
	1971	**2012**
Coal	40.1	40.3
Oil	20.9	5.0
Natural gas	13.3	22.4
Nuclear	2.1	10.8
Hydro	23.0	16.5
Other renewable sources	0.6	5.0
Total	**100**	**100**

Coal demand *growth* however has faltered since 2012. According to BP (2015), global coal consumption grew by 0.4% in 2014, well below the 10-year average annual growth of 2.9%. In the developed world markets, energy feedstock switching, in response to environmental regulation governing emissions and greater emphasis on the utilisation of renewables, has seen coal power plant closures. For example in the USA and more recently the UK, where plans were announced in November 2015 to shut down all coal-fired facilities by 2025 and restrict their use by 2023 (DECC, 2015), despite the relative low-cost advantage of coal compared to other energy sources. Nevertheless, coal-based power producers continue to benefit from the cost competitiveness of coal by finding new means to comply with the more stringent regulations through, for example, co-firing coal with biomass. One such power generator responsible for meeting 7–8% of the UK electricity demand is Drax, the largest coal and biomass-fired power plant (6 x 660 MW) in Europe (Accenture, 2013).

BP (2015) forecasts a sharp change in growth of coal utilisation. Projections are that coal changes from being the fastest growing fossil fuel since 2000 (3.8%/y), to the slowest growing fuel from 2013 to 2035 (0.8%/y). This reflects the slowing of coal-based industrialisation in Asia, compounded by the effects of environmental regulations and low gas prices in key markets, such as the USA. Natural gas is forecast to be the fastest growing fossil fuel (1.9%/y), with oil (0.8%/y) marginally ahead of coal. In the BP (2015) energy outlook review (2013-2035), BP forecasts that fossil fuels have and will, continue to provide most of the world's energy (*see* Figure 31). However, the outcome by 2035 is a more balanced and diversified portfolio of fuels for power generation. Coal *remains* the dominant fuel, accounting for more than a third of the inputs to power generation, but that share is down from 44% today. The prediction is that the gap between the shares of coal and of other fuels will narrow, significantly.

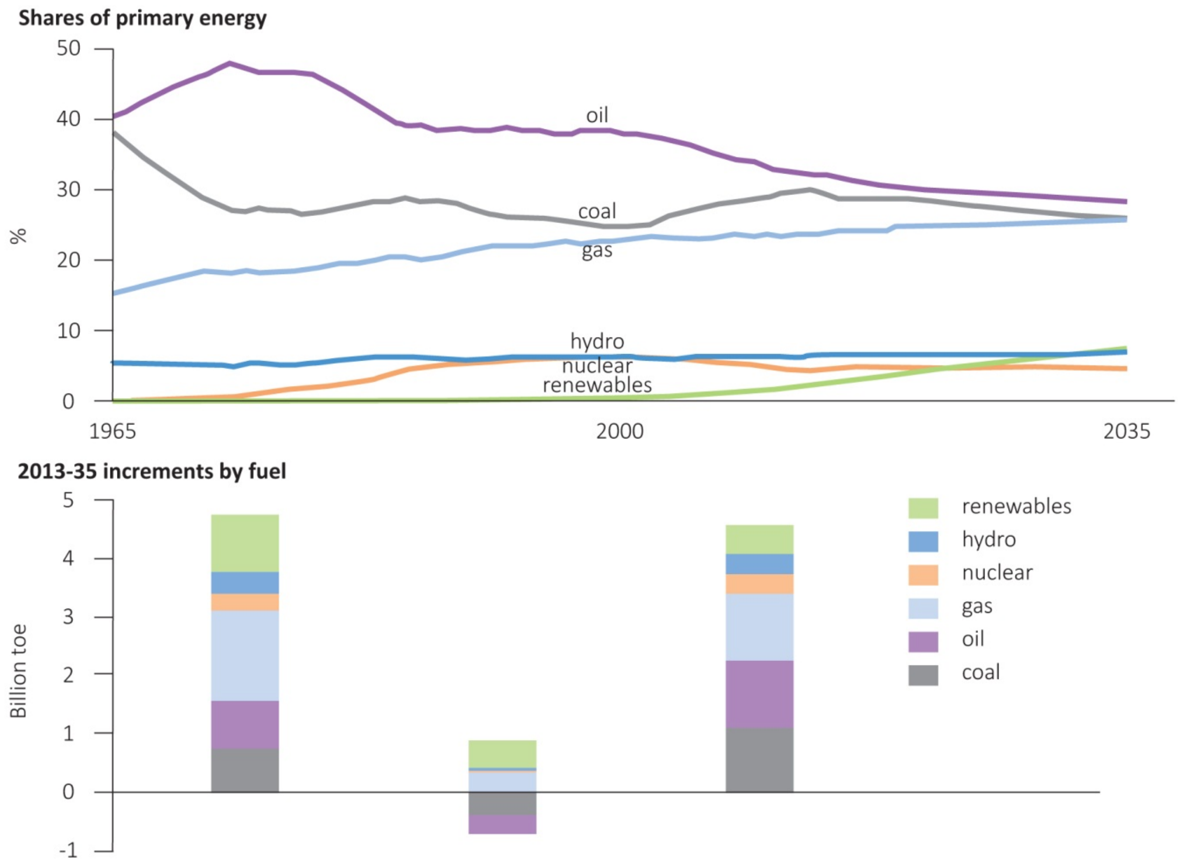

Figure 31 Fossil fuels past, present and future share of primary energy, also by region (BP, 2015)

The BP energy outlook 2015 forecasts that non-OECD consumption will increase by 1.1 Gtoe. The increase will be partially offset by a decline in OECD consumption of -0.4 Gtoe. China continues to lead the growth in consumption (390 Mtoe) even though projections show a decline in growth rate from 8.3%/y during 2000-2013 to 0.8%/y in 2013-2035. Chinese coal consumption is expected to peak in 2025 and then decline slightly in the final decade of the Outlook, that is 2025-2035. The forecast shows coal consumption in India increasing by 360 Mtoe by 2035, making it the second largest growth market in the world. Increases in power sector demand will account for almost 70% of India's consumption growth. The decline in OECD consumption is led by the USA (-220 Mtoe) and the EU (-150 Mtoe). This reduction will be concentrated in the power sector, where environmental policies and available supplies of gas encourage the displacement of coal with gas (BP, 2015).

According to IEA (2015a) energy use worldwide is set to grow by one-third to 2040 in the IEA central scenario (New Policies Scenario), driven primarily by India, China, Africa, the Middle East and Southeast Asia. Non-OECD countries are forecast to account together for all the increase in global energy use, as demographic and structural economic trends, together with greater efficiency, reduce collective consumption in OECD countries from the peak reached in 2007. Declines are projected to be led by the European Union (-15% over the period to 2040), Japan (-12%) and the USA (-3%). The pledges made at the COP21 meeting (Paris – 30 Nov/11 Dec 2015) aim to lower-carbon-intensive fuel utilisation and application of clean technologies in many countries, bringing the share of non-fossil fuels up from 19% of the global mix today to 25% in 2040. Among the fossil fuels, natural gas is the only fuel that sees its share rise, a consumption increase of almost 50% makes it the fastest-growing of the fossil fuels (IEA, 2015). However, fugitive methane emissions must be taken into consideration as they reduce the net climate benefits of using lower-carbon natural gas, especially in the near term (Nalbandian, 2015).

However, WEC (2014) consider that "*calling for divestment from coal does not recognise the reality of growing energy demand, the continuing role of coal and the importance of technology in enabling coal use to be compatible with global efforts to reduce emissions*". Coal accounted for nearly half of the increase in world energy use over the past decade with a global contribution this century that is comparable to the contribution of nuclear, renewables, oil and natural gas combined (*see* Figure 32). In 2013, the share of coal in global primary energy consumption reached 30.1% (the highest since 1970). Coal was also the fastest growing fossil fuel, with coal consumption growing by 3%/y (WEC, 2014).

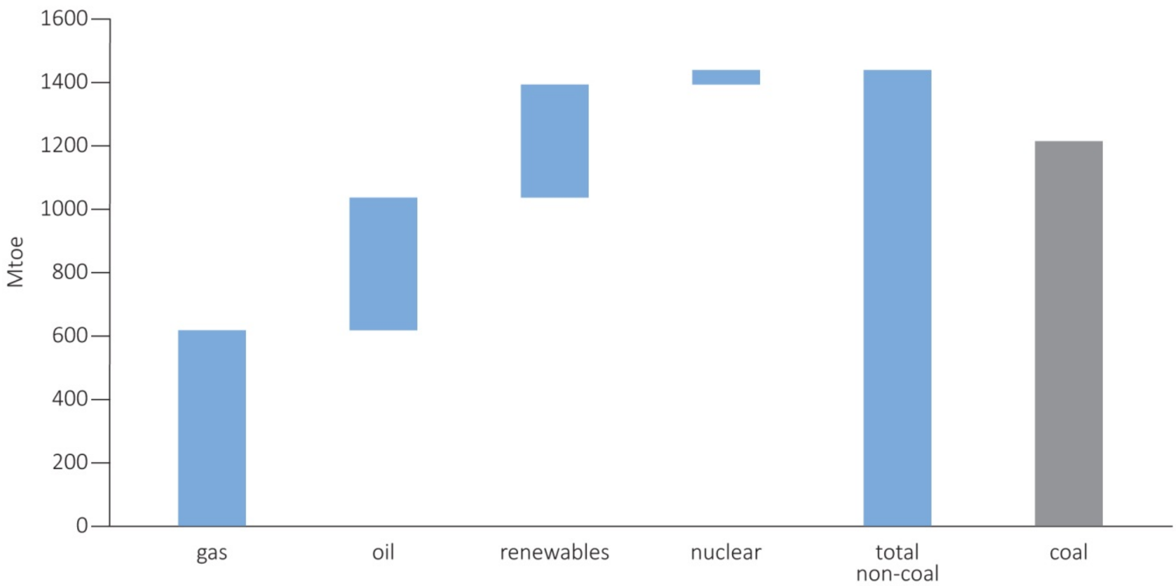

Figure 32 Incremental world primary energy demand by fuel, 2000-2010 (WEC, 2014)

In Europe, in 2011, only Poland and the Czech Republic were not net importers of coal. For the whole EU-28, the average dependency on coal imports was 62%. The dependency of the EU-28 on other fuel sources, such as oil imports reached 85%. All countries, except Denmark, were net importers of crude oil, some almost 100% dependent on oil imports, for example, Poland. The degree of natural gas dependency of the EU-28 was also high and amounted to 67%. All countries, except Denmark and the Netherlands, were, to different extents, net importers of natural gas. For example, dependency of Poland on natural gas imports was 75%. In short, Europe's dependency on fuel imports is greater for oil as well as gas than coal, thus raising the question of fuel and therefore energy mix and security of supply.

In 2014, 1.3 billion of the world population had no access to electricity and 2.6 billion relied on traditional fuels (such as dung and wood) for cooking. The IEA (2011) estimated that more than half of the on-grid electricity needed to meet the 'energy for all' scenario would need to come from coal. The IEA defines 'energy for all' as up to five hours of electricity a day excluding electricity for businesses, industry, hospitals, schools and public buildings for example. According to a WRI report by Yang and Cui (2012), 1199 coal-fired plants (representing ~1400 GW) were proposed globally, across 59 countries to meet the 'energy for all' target. China and India accounted for 76% of the total capacity. The proposals included new coal-fired plants in 10 developing countries: Cambodia, Dominican Republic, Guatemala, Laos, Morocco, Namibia, Oman, Senegal, Sri Lanka, and Uzbekistan. Currently, there is limited or no capacity for domestic coal production in any of these countries. Coal is the chosen fuel, as it is abundant, affordable, accessible, and a reliable source of power (Yang and Cui, 2012).

According to Jalesko and others (2014), seaborne coal totalled ~1 Gt in 2013 (that is, 14% of world demand), a quarter of which was taken by China. Indonesia, Australia, South Africa, and Colombia are among the main seaborne coal exporting countries (*see* Table 1). The seaborne market increased after 2007 when China became a net importer to meet its electricity demand. However, seaborne imports only equal 5–6% of China's coal demand. In 2013, the seaborne market remained in oversupply, despite disruptions such as industrial unrest in Colombia. This has kept prices low and discouraged investment. In 2014, prices for thermal coal dropped to, US$ 75 per ton (US$ 82.5/t) from US$ 105 per ton (US$ 115.5/t) on average in 2012. Jalesko and others (2014) estimated that the US$ 75 per ton (US$ 82.5/t) price is below the breakeven point for about 30% of seaborne volumes (mainly coal from the USA and Russia), while coal from countries such as Indonesia, Australia, Columbia, and South Africa remained competitive.

Jalesko and others (2014) also observed three trends affecting seaborne coal prices in the short term. Firstly, there is limited growth in capital expenditure. Based on data from major coal companies, little seaborne supply was noted coming to the market between 2014 and 2017. Most of any additional capacity is expected to come from Indonesia (approximately 60–80 Mt) and Australia (about 20 Mt). Secondly, Chinese imports **may** increase to satisfy the existing and planned coal-based capacity and replace lower quality coal. Thirdly, Jalesko and others (2014) envisage additional coal export infrastructure, which the US coal mining industry continues to attempt expanding despite environmental opposition. In 2013, the USA exported over 100 Mt of coal, compared with approximately 45 Mt in 2006. However, at the 2014 price level, exports from the USA remained largely unprofitable.

Jalesko and others (2014) forecast that coal prices could rebound from the 2014 depressed levels over coming years, although not to the level of previous years, for example, US$ 100 per ton (US$ 110/t) and higher in 2012. Supporting this forecasted increase will be some industry curtailment and higher demand for seaborne coal (between 2011 and 2013, the seaborne market grew by about 200 Mt, equivalent to the additional export of coal from the USA and new capacity coming from Australia and Indonesia combined). However, Saunders (2015) considers that the outlook for coal prices depends on a number of factors, including the response of Asian demand (for example, China) to various policy measures aimed at reducing the role of coal in the energy mix and protecting the domestic coal industry. Overall, thermal coal prices are expected to remain at relatively low levels over the next few years, owing to the high level of thermal coal supply and a continued shift towards cleaner energy sources in some countries (Saunders, 2015).

Under the IEA 'world energy outlook' scenarios (*see* IEA, 2011), the demand for coal in the future and its price will rely on numerous factors and their timing. According to Jalesko and others (2014), some of the most crucial elements include:

- a change in China's energy profile and that of other countries, such as India, with a potential move to shale gas,
- technological breakthroughs, including reduced manufacturing costs, and the introduction of more efficient methods to generate electricity and capture carbon emissions,
- carbon pricing through either taxation or cap and trade emission reduction schemes,
- new governmental regulations, such as the announcement by the USA of a reduction in CO_2 emissions by 30% by 2030 (compared with 2005) (*see* Section 2.4), and
- global economic growth and urbanisation.

New initiatives, such as those made recently by the USA and China (*see* Section 2.3), may halt the growth in coal demand over the coming years. However, it is uncertain whether such initiatives will lead to a decline in coal use over time to meet the IEA 450 ppm scenario (*see* Section 2). Jalesko and others (2014) consider that any decline in coal utilisation would depend on the availability of viable alternatives, such as large-scale gas developments in China and renewables. It is worth noting that, according to Olivier and others (2014), in its primary energy supply in 2013, China had a larger amount of renewable energy (hydropower) than, at the time, in the USA and the EU-28 combined. This is despite renewable energy in the EU-28 over the past decade, increasing by 87%.

Approximately 190 GW of additional generating capacity is expected by 2030 in the Asia Pacific region, alongside an accelerating shift towards coal (35 GW of committed coal-fired plants are planned and being developed in ASEAN countries alone). Accenture (2013) consider that this is largely the result of increased urbanisation across China, India and Indonesia that translates into higher electrification and energy consumption per capita. Rising levels of GDP and population will also play their part to drive demand, with growth for the region reaching 5.7% in 2013 and 6% in 2014. Meanwhile, forecasts indicate that the population in the region by 2040 will reach 4.6 billion, up from 3.8 billion in 2010. Although there is global pressure to move to cleaner energy sources, there is an expectation that these will not make a substantial, material difference in the Asia Pacific region over the next few years, as governments focus on achieving higher living standards at an affordable cost (Accenture, 2013).

In an in-depth study on what role could coal play in the energy future in the USA, Ahmed and others (2013) summarised their key findings as follows:

- The rapid, recent expansion in US shale gas production is resulting in reduced coal consumption in electric power generation. With natural gas prices low and increasingly more constraining regulations for coal firing, US demand for coal continues to fall as utilities and energy companies switch to the less costly, available alternative, gas. Evidence of this national trend include: an increasing reliance on gas-fired power stations; reluctance to make new investments in existing and new coal fired power plants; and for the first time in over 40 years, in April 2012, coal and natural gas had equal shares in power generation in the USA at ~32%. However, according to the EIA (2015) (https://www.eia.gov/tools/faqs/faq.cfm?id=427&t=3), in 2014, the USA generated about 4,093 billion kWh of electricity. About 66% of the electricity generated was from fossil fuels (coal, 39% and natural gas, 27%).

- Cost of coal mining is increasing while production is declining in the Appalachian region and shifting to the Powder River Basin (PRB). Factors such as geology and the rising costs of complying with a variety of new regulations, transportation and wages are making coal mining, in general, more costly.

- Growing demand in the Asia Pacific region and India for both thermal and metallurgical coal is driving US companies to consider coal export. Falling US domestic consumption is encouraging coal producers to invest in exporting coal to emerging markets where demand growth remains strong. However, opposition on the grounds of environmental impacts and consequences are hindering such export plans. Nevertheless, Ahmed and others (2013) consider that leading US coal companies will continue to invest in Asia and exports rather than unconventional investments in clean-coal technologies within the USA. Despite the growth, exports in 2012 accounted for only ~9% of US annual coal production.

- Increasing deregulation of the USA power market escalates competition among power generators. The deregulation of the power market, which began in the mid-1990s, introduced shorter-term transactions, industry consolidation and energy price fluctuation. The industry spread its generation, transmission and distribution functions from an integrated structure, and focussed on increasing profits and reducing operating expenses, which makes low-cost natural gas attractive. In other words, the industry focused on short-term profitability as opposed to taking long-term riskier positions by building new capital intensive generation.

- Coal-fired power plants are being retired in growing numbers. Retirement announcements are part of a long-term trend for both existing coal-fired plants and proposals to build new facilities. The introduction of increasingly more stringent regulations, the sharp decline in natural gas prices and reduced demand for electricity are contributing factors in the decisions to retire the older, i.e. ageing, less efficient coal-fired generating units.

- Successful commercialisation of advanced coal combustion technology will require incorporating CCS. Coal gasification and liquefaction technologies as well as IGCC power plants are carbon intensive and their commercialisation may not occur unless equipped with CCS. Carbon capture, utilisation and storage (CCUS), which often includes enhanced oil recovery (EOR), is considered a positive utilisation of CO_2 emissions from coal combustion that offsets the cost of carbon capture. Projections indicate that EOR in the USA may have considerable economic impacts but requires collaboration with the oil and gas firms and identifying a reasonable price for carbon.

- Finally, Ahmed and others (2013) consider that technology is key in creating alternative markets for US coal, which in recent history have relied on the electric power market as the single most important customer. Companies in South Africa and recently in China have demonstrated economic viability of commercial scale coal gasification and liquefaction. These technologies (and others) are important to the future of coal in the USA market (*see* Nalbandian, 2014). However, there is a need for technology stewardship and broader collaboration in order to drive investments, commercialisation of the technologies and development of a higher-value market for coal.

According to AURIZON (2014), whilst projections for energy demand growth across OECD countries vary, both the IEA and US EIA predictions show continued and significant growth in global energy demand. This is forecast to be spurred principally by non-OECD countries as depicted below (*see* Figure 33), where significant social and economic drivers remain, to provide access to electricity as shown in Figure 34, especially in India where it is estimated that 25% of the 1.27 billion population (2014) do not have access to electricity. Aspirations for improved living and health standards in these emerging economies are the focus of government and economic policy settings. The delivery of low-cost, base-load electricity is considered critical to achieving these aspirations. This, in turn, will continue to drive demand for low-cost, proven energy sources such as coal. At the time of the assessment, despite the significant economic and energy infrastructure development over the past decade throughout the world, according to the AURIZON (2014) and IEA (2013a), and as stated above, over 1.3 billion people (18% of the world's population) continue to lack access to electricity. The IEA (2013a) world energy outlook predicted that 'developing Asia' will see the number of people without access to electricity almost halve between 2011 and 2030 (AURIZON, 2014).

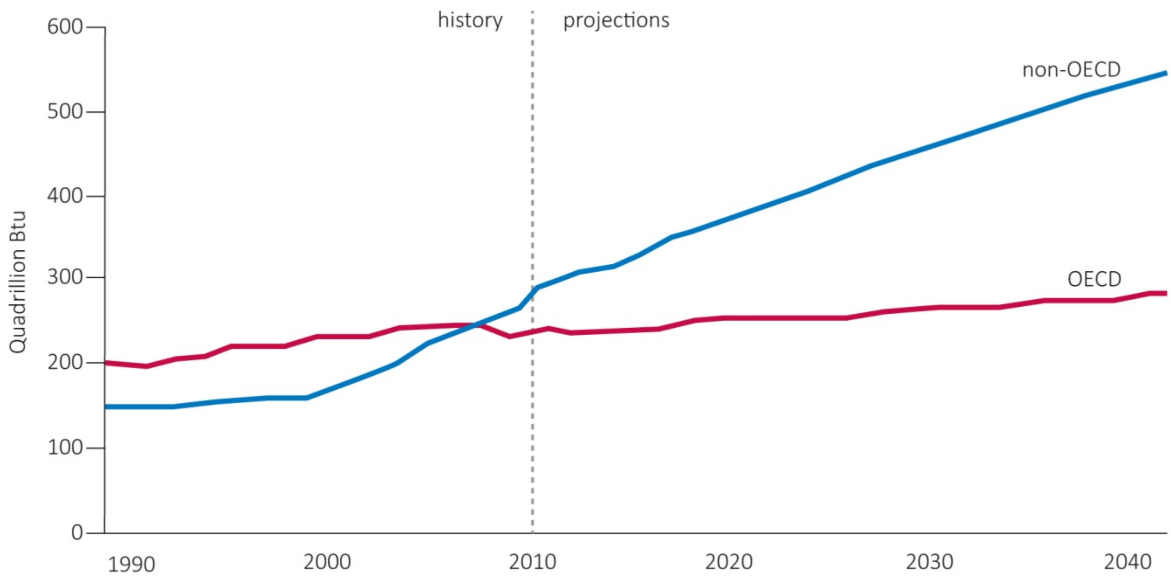

Figure 33 World energy consumption 1990-2040 (AURIZON, 2014; EIA, 2013)

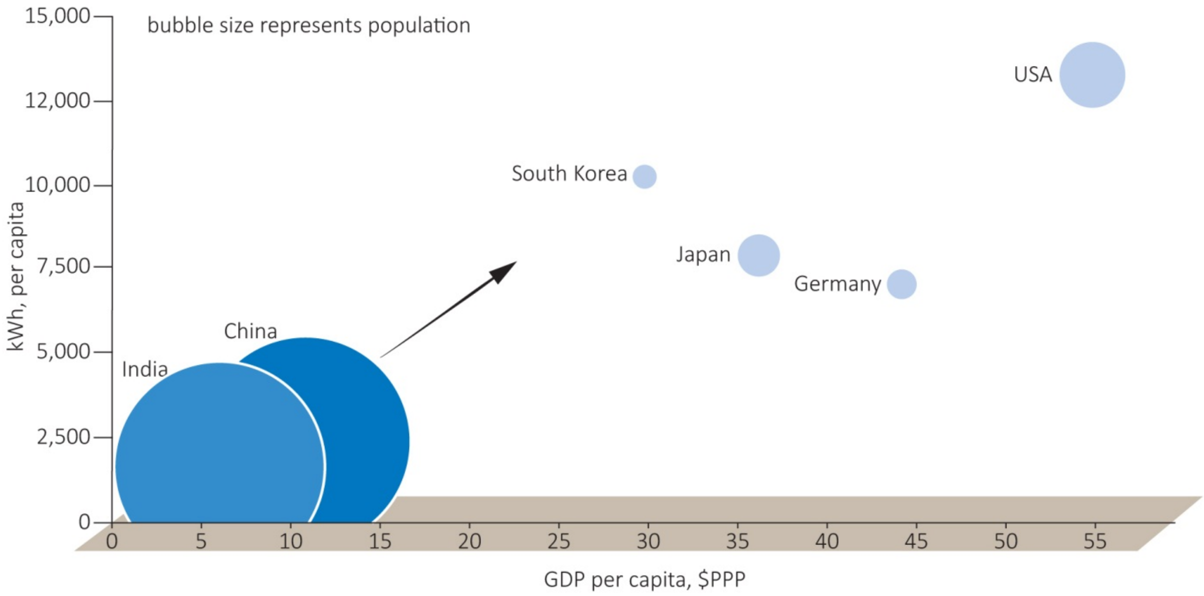

Figure 34 Per capita electricity consumption versus per capita income by key countries (AURIZON, 2014)

AURIZON (2014) consider the ongoing role that thermal coal will play in servicing this sustained increase in global energy needs. According to most forecasts, coal will be a smaller contributor to global electricity generation than currently, but only as an overall percentage of the total mix and in the context of a greater demand for energy. As such, and according to AURIZON (2014), IEA (2013a) and BP (2014), the total amount of thermal coal demand is still expected to increase over the short-, medium- and long-term (*see* Figure 35). When data are focussed on non-OECD countries, the role for thermal coal in satisfying the increase in energy demand is illustrated in Figure 36. AURIZON (2014) consider that, ultimately, the cost, reliability and availability of seaborne thermal coal will underpin its ongoing role as a critical player in the global energy mix.

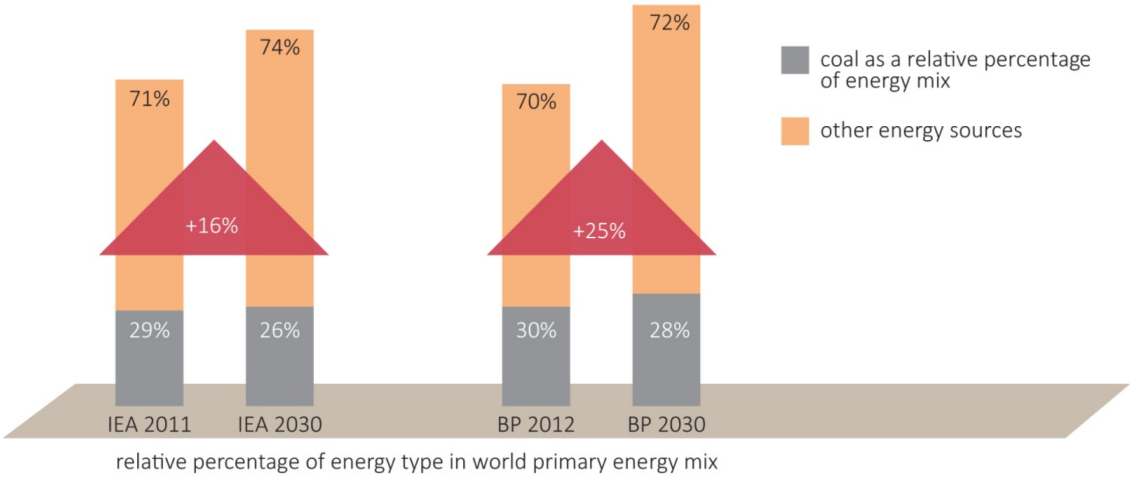

Figure 35 Current and future demand for coal in the global primary energy mix (AURIZON, 2014; BP, 2014; IEA, 2013a)

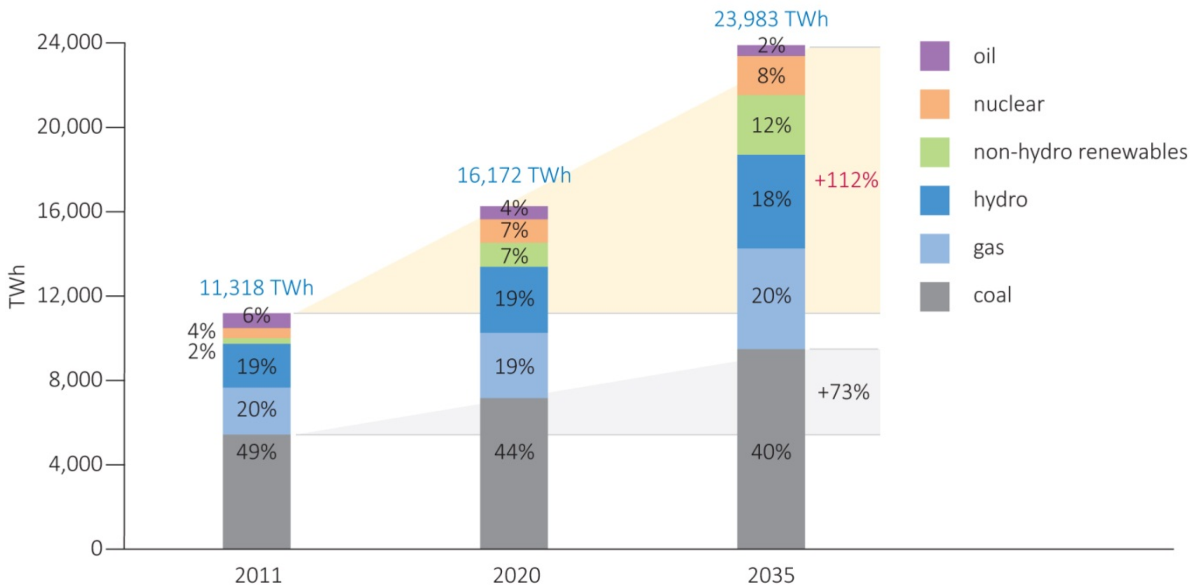

Figure 36 Non-OECD electricity generation by source (TWh, share) (AURIZON, 2014; IEA, 2013a)

According to the BP 2015 energy outlook, growth in Chinese coal consumption is led by demand in the power sector (1.4%/y) followed by industry (0.4%/y). These two sectors will account for 97% of China's coal consumption by 2035. Growth is forecast to slow considerably in all sectors, from the highs during 2000-2013 when power sector consumption grew by 10%/y and industrial consumption by 7%/y. Forecasts indicate that the share of coal as a source of energy will decline across all sectors in China. In power generation, the largest coal-consuming sector, the share of coal is projected to decline from 77% in 2013 to 58% by 2035, as renewables and nuclear power gain greater shares. The loss of market share in industry is expected to be more modest, falling from 59% to 46%. As a result, China is expected to record the steepest decline in the share of coal in primary energy between 2013 and 2035. Nevertheless, in 2035, China will continue to have the highest coal share in primary energy at 51%. The share of coal by sector and inputs to power in China are shown in Figure 37 (BP, 2015).

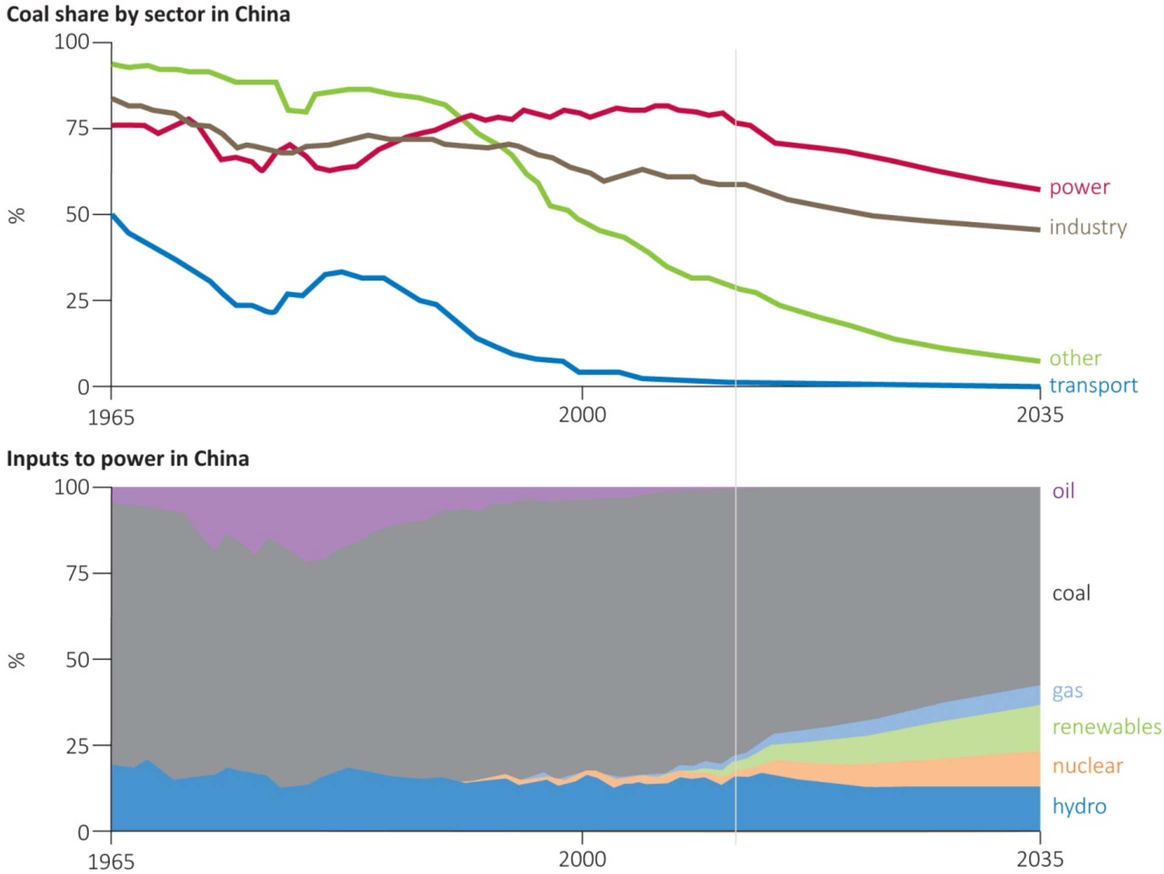

Figure 37 Coal's share by sector and inputs to power in China (BP, 2015)

The Energy Security and Climate Initiative (ESCI) at Brookings (USA) launched a major research project in 2015 on *Coal in the 21st Century*. The projects aims to assist policymakers in understanding the complexities of current and future coal utilisation internationally as well as in the USA. As part of the research methodology, ESCI formed a Coal Task Force (CTF) comprising government officials, the private sector, academia, international organisations, financial institutions, and others, to meet periodically to gain insight on important issues surrounding coal. Banks and others (2015) summarise the key issues raised during the first Task Force meeting in February 2015 dealing with global trends as well as the US market.

According to Banks and others (2015), Asia will lead global coal production and pricing trends in the next 25 years, where coal is going to be more competitive than gas for some time. Forecasts indicate that China, India, Indonesia, and Australia will account for 70% of global coal production by 2040. To illustrate the competitiveness of coal, Banks and others (2015) give the example of Malaysia. A country rich in gas and without coal resources and yet, most incremental energy demand will be met by coal, reflecting that it is more profitable to export the gas and import coal. China has indicated that coal use will peak in 2030, leaving considerable time for the continued utilisation of coal. Projections are that India will double or even treble its power generating capacity (currently ~150 GW) to meet demand for energy, and plans to utilise mainly domestic coal and in some cases (for supercritical applications) blended coal. However, this entails the advent of commercial mining in India, as mining is currently almost a monopoly of the State

Ministry of Coal (Bhati, 2015). According to Banks and others (2015), coal has been and will remain vital to the country's energy infrastructure and economic development. India is the third largest coal producer in the world, and coal accounts for ~68% of the country's electricity generation. India's Planning Commission projects coal utilisation in power generation will have to expand to 2 Gt by 2031-2032 in order to meet growing electricity needs.

Banks and others (2015), note that virtually all the growth in global coal demand will occur in emerging markets, driven by a combination of factors illustrated most dramatically by the figures 90-90-70. To clarify: it is estimated that 90% of global population growth, 90% of total energy demand increase, and 70% of economic output will occur in developing countries by 2030.

In the USA, Banks and others (2015) consider that following the unconventional (shale) gas production boom and the subsequent reduction in coal-based electricity generation (*see* Nalbandian, 2015), there has been a steady increase in US steam and metallurgical coal exports since 2005. Most of this coal (~50%) is exported to Europe. Despite a decline in exports in 2013, volumes are forecast to increase from record annual exports of nearly 126 million tons (~114 Mt) in 2012 to 161 million tons (~146 Mt) in 2040. However, export terminals are primarily located in the Gulf of Mexico and along the East Coast of the country, but there are proposals for several terminals along the West Coast in Oregon and Washington to enable increased export to Asia. Despite interest in these expansion projects, as discussed above, there is considerable environmental opposition especially with regard to coal dust from rail transport (locally), climate change implications, and international transboundary air pollution. Europe is expected to become a less attractive coal export destination due to increased competition from renewables and stricter environmental regulations. The future of US coal exports to Asian markets was the subject of an in depth study by Cornot-Gandolphe (2015).

In 2009, the IEA produced its technology roadmap for CCS as part of modelling a pathway to meet the 2°C target (IEA, 2009). The roadmap projected 100 large-scale CCS projects to be in operation by 2020. In 2013, the roadmap revised that number to 30 (IEA, 2013b). The projects include CCS for both power and industrial sectors, as well as for coal and other fuels. Thirty large-scale projects is equivalent to the capture and storage of approximately 50 Mt of CO_2 (IEA, 2009 and IEA, 2013b). Banks and others (2015) note that there are several emerging key factors in making CCS work from an economic perspective. These include the use of cheap, stranded coal, a plant working at full load and a strong business case, for example, carbon capture and use in EOR (CCUS). However, these factors are localised and not present everywhere. Banks and others (2015) quote the IEA costing of CCS as 90% carbon capture increases capital costs between 45% and 75% and reduces plant efficiency 20-25%. Without a strong and driving policy, in particular, the adoption of a carbon price, and as long as natural gas is competitive with coal, CCS in the USA, will remain an uncompetitive option.

The National Coal Council (NCC, USA) published a report on revitalising CCS and bringing scale and speed to CCS deployment (Krutka and others, 2015). Some of the key findings of the study were (Krutka and others, 2015):

- CCS is the only technology that can mitigate CO_2 emissions from fossil fuel utilisation for electricity generation and key industrial sectors including cement, iron and steel, oil refining, and chemicals.
- Not including CCS as a key mitigation technology is projected to increase the overall cost of meeting CO_2 emission goals by between 70% and 138%.
- US CO_2 emissions are <16% of world emissions. Thus, global and wide scale implementation of CCS is necessary to meet CO_2 emission goals

According to Krutka and others (2015), due to an increasing global population and expanded energy access, total world energy consumption is projected to grow by 56% by 2040, with fossil fuels providing nearly 80% of demand. The effect of these trends on future CO_2 emissions could be substantial. Mitigating potential impacts, while enabling emerging economies to benefit from a reliable energy supply, will require commercially available and cost competitive CCS technology. However, the international community has yet to form a consensus on how to balance development efforts and climate change objectives. The study includes a discussion on pathways for CO_2 utilisation but these are not discussed in this review.

Banks and others (2015) summarise that there will be improvements in efficiency, globally, not only in existing facilities, but also new power stations. For example, many new coal-fired plants coming online in the near future are supercritical and, after 2020, projections indicate that more IGCC and ultra-supercritical technology will be deployed throughout the world. In other words, coal will continue to play a major role in the world energy mix (and especially so in Asia) in the short-, medium- and long-term future. Globally, coal use overall and especially for power generation is projected to increase, but have a decreasing share in the total energy mix.

5 Conclusions

Legislation, for the coal-fired power generating sectors throughout the world is becoming increasingly more stringent to the point where power providers/utilities are *expected and even required* (in some parts of the worlds), either to construct state-of-the-art, advanced coal-fired power plants or to invest heavily in retrofitting existing facilities with dedicated pollution control technologies. The investment in new technologies is made necessary, if not unavoidable, to ensure the continued and reliable supply of electricity while meeting the set regulatory requirements. The result has been a reduction in air pollutant emissions (SO_2, NOx and particulate matter) in most regions, achieved over the last few decades. However, the combustion of coal results in relatively high GHG emissions, compared to other fossil fuels, such as gas, and the technologies to deal with these emissions remain at demonstration scale and are considered prohibitively costly (in monetary terms and parasitic power requirements).

Global CO_2 emissions from fossil fuel combustion and industrial processes (cement and metal production) increased in 2013 to 35.3 Gt, which is 0.7 Gt higher than 2012. The relatively moderate increase of 2% in 2013 compared to 2012 is a continuation of a slowing trend in world annual CO_2 emissions growth. In 2013, the top three CO_2 emitting countries/regions, together accounting for more than half (~55%) of total global CO_2 emissions, were China (10.3 Gt CO_2 or 29%), the USA (5.3 Gt CO_2 or 15%) and the EU-28 (3.7 Gt CO_2 or 11%). Although CO_2 policies are being adopted, negotiated, and/or discussed in many countries they are not expected to have a significant effect on coal mining for export, in Indonesia, Vietnam, and Australia, in order to satisfy global demand in the short term. However, if the internationally agreed 2°C target increase in global temperature is to be achieved, the world emissions of greenhouse gases can only continue at current rates for about 35 years. This means that coal utilisation will have to cease at the end of that period (2050), or greatly reduce GHG emissions (80-90%) by deploying CCS at all facilities. The scenario is challenging, as CCS will need to be commercialised rapidly on a wide scale, or new technologies developed and installed to support a further increase in demand for electricity (an annual increase of 3.4% in demand for coal in the last five years) as well as replace all existing coal fired power plants.

In 2014, coal provided >30% of global primary energy requirements, ~40% of the world's electricity generation and 68% of steel production. Forecasts show that the share of coal in global primary energy will decline to 24% in 2040. However, projections indicate that global coal demand will increase 15% by 2040. The utilisation of coal will differ dramatically by region. Coal demand is forecast to decline in all OECD regions, particularly in the USA where a significant reduction (~ one third) in coal-fired power generation is expected to occur in the next decade. This will be due, not only to increased regulation but also competition from other fuels, especially unconventional (shale) gas and renewables. The forecast for coal demand in developing countries, on the other hand, is an increase by about one third by 2040, with significant growth in Southeast Asia, India, Africa, and Brazil. Coal demand in China is expected to peak in 2030. The largest producers of hard coal in the recent years include China, USA, India, Indonesia, Australia, the Russian Federation and South Africa. Leading exporters of coal are Indonesia, Australia, the

Russian Federation, USA, South Africa and Colombia, and the largest importers are China, Japan, India, the Republic of Korea, Taiwan, Germany and the UK. Today, China is the main producer of electricity, followed by the USA, India, the Russian Federation and Japan. World prices of coal, which generally follow oil prices, saw high growth of both steam and coking coal in 2008. After a period of relative stability, prices of coal fell significantly in the years 2013-2014. There is an expectation that this trend could continue due to environmental pressures and increasingly stringent regulatory demands for coal-based power generation. Other factors also include current high levels of supply and the response of Asian demand (for example, China) to various policy measures aimed at reducing the role of coal in the energy mix and protecting the domestic coal industry.

Advantages of coal include its abundance, with large reserves dispersed globally. Coal, compared with other sources of electricity generation, is a relatively cheap fuel source in many regions across the world. It has and continues to play a role in enhancing energy security and providing a domestic source of energy. In many developing countries, coal is a fuel critical to meet growing electricity demand, support economic growth and broaden access to electricity. However, coal-fired electricity generation is a source of greenhouse gases (GHG) including carbon dioxide (CO_2). However, use of advanced coal combustion processes, carbon capture and storage (CCS) or, carbon capture, utilisation and storage (CCUS) (where possible), offer technological paths for more efficient and environmentally friendly use of coal. Coal combustion also results in sulphur oxides (SOx), nitrogen oxides (NOx), and particulate matter (PM), together comprising major components of acid rain, smog, and soot, respectively. However, emissions of these air pollutants have been reduced dramatically in the last few decades and that trend continues today. There are numerous, efficient technologies, applied throughout the world, that reduce air pollutant emissions from coal-fired power plants. Coal combustion emits other hazardous air pollutants such as lead, chromium, arsenic, and mercury, and produces solid residues such as fly ash, bottom ash, and scrubber by-product. Trace element emissions (such as mercury) are monitored and controlled in some countries but are not adopted yet throughout the world. If and where regulations are introduced to reduce these emissions as well, the costs can make investment in new coal-fired capacity less attractive.

Global demand for coal continues to grow. However, the global coal market is becoming increasingly centred on the Asia Pacific region, where China alone accounts for more than 50% of total production and consumption while the remaining countries in the Asia Pacific region are expected to represent 80% of the global coal market by 2030. Even if the authorities cap coal consumption in China, there are large energy deficits in key countries in Asia (for example, India, Vietnam and Indonesia), where pollution, although an issue, is not top of the agenda as such (in the near-term), and electricity growth through firing coal will continue to encourage growth. New regulations in those countries could reduce output to the seaborne market, leading companies to sell their output domestically. However, with the application of more advanced coal combustion technologies, imports of quality coals to fire in these facilities is forecast to increase.

Coal is and will remain the main energy source in the Asia Pacific Economic Cooperation (APEC) economies for the near- as well as the mid- and even long-term future. Uptake of advanced coal combustion technology will allow coal based generation to experience significant growth from 6094TWh in 2011 to 12,477 TWh in 2040. Growth in Chinese electricity output from coal is forecast to account for most of the growth (4632 TWh).

Europe is dependent on imports of fossil fuels. In 2011, only Poland and the Czech Republic were not net importers of coal. For the whole EU-28, the average dependency on coal imports was 62%. The dependency of the EU-28 on oil imports reached 85% in 2011. The degree of dependence on imported natural gas in the EU-28 was also high and amounted to 67%. Despite the increase in renewable energy utilisation driven by EU policy and environmental pressures, the dependency in Europe on imported coal, oil and gas is forecast to continue, albeit to a lesser extent. Security of supply, especially for power generation, becomes an issue when considering the greater dependency in Europe on imported oil and gas. Furthermore, the price of coal in Europe is relatively low, compared to gas, prices of which increased continuously between 2011 and 2014. This, combined with an ineffective EU Emissions Trading Scheme (ETS) (due to a structural oversupply of emissions allowances and thus a failure to provide a strong enough carbon price to make gas more competitive than coal) means that coal will and should continue to play a significant role in the electricity generation mix in Europe.

After the nuclear accident in Fukushima in 2011, Germany, *the largest producer and consumer of coal in Europe*, made the decision to phase out nuclear power. Germany has introduced an energy transition concept, the '*Energiewende'* aiming to decarbonise the economy as well as phase out nuclear energy by 2022. The recently adopted '*Energy Concept'*, a national policy document, which formulates the German energy policy to 2050, integrates the *Energiewende*, which has been under development for over two decades. This will affect the coal-fired power sector in Germany and reduce demand for coal and increase utilisation of renewables.

China's thermal coal demand growth reached 7.4% per year over the last decade, but that dropped to 1.8% in 2012. The significant drop in demand is attributed to regulations to limit emissions, increasing natural gas and nuclear capacity and lowering the target for GDP. However, thermal coal demand in China, albeit slower, is expected to continue to increase with the existing and planned increase in capacity in the short- to medium-term. In brief, if China wishes its CO_2 emissions to peak around 2030 (as agreed with the USA in 2014) and achieve a target of expanding total energy consumption coming from zero-emission sources to around 20% by 2030, it would have to deploy an additional 800-1000 GW of nuclear, wind, solar and other zero-emission generation capacity by 2030! This equates to more than all the coal-fired power plants that exist in China today, a monumental task.

In India, the high cost differential between domestic and imported sources is the greatest limiting factor for demand. In addition, poor incentives for power generators to pass-through import costs to power prices also inhibit the development of new generation capacity. However, a recent focus on stimulating Independent Power Producer investments, is likely to lead to changes in Power Purchase Agreement price structures, and further stimulate coal power investments across India. Forecasts indicate that coal demand will increase in India over the next decades.

In Indonesia, growing domestic demand is driven by the government's identification of thermal coal as a strategic power source, and the demand for Independent Power Producers to supply the state-owned utility Perusahaan Listrik Negara (PLN). Indonesia is currently constructing and planning to add ~17.5 GW capacity to its existing fleet, 60% of which will fire coal, to be completed by 2022.

The demand for coal in Australia is expected to decline somewhat in line with emissions targets set by government, the introduction of carbon tax as well as the development of natural gas supply from conventional and coal-seam-gas sources that is exerting downward pressure on prices. However, given its abundance and quality, coal is expected to remain the most commonly used fuel in electricity generation.

The coal industry in the USA is facing unprecedented challenges. Coal dominated the US power industry for decades because it was a cheap and abundant domestic fuel. However, since the development of advanced drilling techniques and the increasing production of unconventional (shale) gas in recent years, the peak in coal utilisation and production has passed. Domestic demand for coal is declining, and companies are increasing coal export (where possible, faced with opposition to coal exports on environmental grounds), to Asian markets, cutting back production and closing mines to adjust. In addition, the adoption of increasingly more-stringent environmental regulations, such as the Clean Power Plan, is causing an on-going decline in coal production and utilisation. In brief, due to the impact of the multitude of regulations introduced recently in the USA and the age of the US coal-fleet, many coal-fired power plants have been retired and more are expected to shut down over the next few years. Nevertheless, coal continues to provide ~30% of electricity in the USA.

The long-term future of coal as a major energy source is portrayed as being in jeopardy due to a variety of reasons including regulations, market forces and environmental arguments. However, despite these pressures, ***there are currently no viable, immediate, substitutes to match the relatively low-cost, availability, reliability and scale of electricity production provided by coal-fired power plants, globally.*** Forecasts, short-term, 2020, mid-term, 2035 and 2040, and long-term, indicate that coal consumption will increase but the share of coal-based power generation will decline somewhat in the global generation mix but very gradually. The consensus seems to be that coal will remain an essential fuel, especially when addressing the current lack of access in many regions, throughout the world, to energy services such as electricity and subsequently, a better standard of life. Over 800 million individuals gained access to electricity due to coal-fired power generation between 1990 and 2010. The vast majority of these are in developing countries. As the demand for coal-fired power generation continues, especially in countries, such as China and India, where the focus is on improving standard of life, policymakers ***are*** advocating and promoting, and in some cases mandating, the deployment of modern, advanced combustion technologies in new coal-fired electricity-generation plants and, improving the efficiency of existing ones. Applying such policies will result in achieving higher plant efficiencies and accordingly reduce all emissions including air pollutants and GHGs. However, enforcement of these regulations remains questionable in some regions of the world. Without continuous emissions monitoring and enforcement of standards, these legislative requirements have no impact and therefore may be ineffectual.

In summary, in the short- to medium- term, demand for thermal coal will continue to grow. The pace of growth will moderate gradually until demand eventually peaks and then plateaus. If CCS, for coal-fired power plants, becomes available at competitive cost, the outlook could change in favour of coal. This is due to the abundance of coal and the proven history, availability, reliability and advancements in coal-fired power generation technology. However, without CCS, the current long-term outlook for coal-fired power generation is less certain. This is mainly due to environmental pressures (especially climate change) and greater competition from renewables and natural gas. However, coal will continue to play a major role in providing electricity throughout the world but its share in the total energy mix will be to a lesser extent than in the past. Although international negotiations on climate change have been slow, regional approaches somewhat lenient (such as the EU ETS) and GHG standards for coal-fired power generation a recent and limited development, these represent regulatory barriers, especially for new coal-fired power plants and, if and when adopted, these regulatory requirements will reduce future demand for coal for power generation.

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7 Addendum (UNFCCC, 2015)

COP 21 – the 21st Conference of Parties, that is, the annual meeting of countries that wish to take action on climate change on a global political level was held in Le Bourget, France, from 30 November to 11/12 December 2015 (http://www.cop21.gouv.fr/en/).

Leaders of 150 nations, along with ~40,000 delegates from 195 countries, attended the COP21 conference. The conference mission was*: to agree a legally binding document for reductions in greenhouse gas emissions meant to hold global average temperatures at ~2*°C *increase over pre-industrial global temperatures*.

On Saturday, 5 December 2015, after one week of negotiations, the negotiators from the 195 countries signed off with a draft climate agreement. However, the document left many questions unanswered. Tackling these and other questions started on Monday 7 December 2015. The negotiating teams turned their draft over to the French Foreign Minister, whose task was to guide senior ministers from each country in an effort to seal a final deal before the talks were scheduled to end on Friday the 11 December 2015.

Among the many issues discussed, four were considered the most problematic at the end of the first week of negotiations, including:

- ***Finances*** **-** small countries, particularly island states in danger of being swamped by rising seas, consider that developed nations should contribute financially to compensate them for "loss and damage" caused by global warming. The argument is that the countries likely to suffer the most are the least responsible for carbon emissions—and the least able to rebound from the damage. Wealthy, developed countries have agreed to create a US $100 billion fund by 2020 to help poorer countries. However, questions remain whether nations, primarily the USA, should also be legally bound to compensate other nations for damages. Some smaller countries also consider that an international tribunal should be set up in order to deal with countries that do not meet their obligations.

- ***Effectiveness/compliance*** **-** The plans proposed by more than 180 countries to cut or to reduce growth of CO_2 emissions are voluntary. Only France and China advocated a legally binding document. Some countries are more focussed on the financial compensation sections (see above). The current US administration wants the document to include strict language requiring countries to verify their emissions, but given opposition by many in the current opposition party in the USA, it is considered unlikely that the USA will support a legally binding treaty.

- ***Temperature rises*** **-** Some experts have said that allowing global temperatures to rise to 2°C is too dangerous—especially given how little researchers understand about potential feedback loops. As a result, at least 106 countries are now asking to limit global warming to

1.5°C, while others are "willing to try" for something "well below 2°C". The draft document contains both options. However, all of the current pledges by countries, when combined, do not reach either goal.

- ***Re-visitation*** – As the current plans would not keep global warming below 2°C, China, France, and many scientists urged countries to commit to ratcheting down their pledges even more after five years. It is envisaged that by then, there are likely to be new technological advances, developed and/or demonstrated, and the growing market will continue for renewable energy that will lower the price of solar, wind, and other clean-power options. A minority of countries, such as Saudi Arabia, whose economy relies significantly on oil, want the current proposals to stand until 2025 or 2030.

Following the *end of the COP 21 meeting* and on Saturday 12 December 2015, the Paris Agreement on Climate Change, in which 195 Nations agreed to set a path (based on their historic, current and future responsibilities) to keep the global temperature rise well below 2°C, was adopted. The full document of the agreement is available @ http://www.cop21.gouv.fr/wp-content/uploads/2015/12/l09r01.pdf.

The ambitious, binding and universal agreement sets the way to reach the goals of keeping the global temperature rise this century well below 2°C, to drive efforts to limit the temperature increase even further to 1.5°C above pre-industrial levels and, strengthen the ability to deal with the impacts of climate change. In order to achieve these goals, it was agreed that appropriate financial flows will be put in place that make it possible for the developing countries (and the most vulnerable), to take stronger action, in line with their own national objectives.

The adopted Agreement and the outcome of the COP21 meeting cover the following areas, which were identified as essential for a conclusion:

- Mitigation – rapid reduction of emissions to achieve the temperature goal
- A transparent system and global stock-taking – accounting for climate action
- Adaptation – strengthening the ability of countries to deal with climate impacts
- Loss and damage – strengthening the ability of countries to recover from climate impacts
- Support – including financial, for nations to build a clean and resilient future. The recent and new climate funding announcements are available @ http://newsroom.unfccc.int/financial-flows/list-of-recent-climate-funding-announcements/

As well as setting a long-term direction, countries have agreed to peak their emissions as soon as possible and continue to submit national climate action plans every five years (as nationally determined contributions (NDCs)) that detail their future objectives and plans to address climate change. In addition, Governments agreed to define a clear roadmap on ratcheting up climate finance to US$ 100 billion by 2020 while also setting, before 2025, a new goal on the provision of finance from the US$ 100 billion floor.

Furthermore, international cooperation on technologies and building capacity in the developing world, to address climate change, are also addressed under the new Agreement.

Details of the Agreement also include:

- All countries to submit adaptation communications, in which they may detail their adaptation priorities, support needs and plans. Developing countries will receive increased support for adaptation actions and the adequacy of this support will be assessed.
- The existing Warsaw International Mechanism on Loss and Damage will be significantly strengthened.
- The Agreement includes a robust transparency framework for both action and support. The framework will provide clarity on countries' mitigation and adaptation actions, as well as the provision of support. At the same time, it recognises that Least Developed Countries and Small Island Developing States have special circumstances.
- The Agreement includes a global stocktake starting in 2023, revisited every five years, to assess the collective progress towards the goals of the agreement.
- The Agreement includes a compliance mechanism, overseen by a committee of experts that will operate in a non-punitive way.

Following the adoption of the Paris Agreement by the COP, it will be deposited at the UN in New York (USA) on 22 April 2016 and remain open for signature for one year.

The Agreement will enter into force once 55 countries that account for at least 55% of global emissions have deposited their instruments of ratification.

For more details on the COP21 meeting and Agreement, and the work of the UNFCCC visit http://unfccc.int/2860.php.