International Energy Agency

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Energy, Climate Change & Environment

2014 Insights

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INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 29 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

- Secure member countries' access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.
- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
- Improve transparency of international markets through collection and analysis of energy data.
- Support global collaboration on energy technology to secure future energy supplies and mitigate their environmental impact, including through improved energy efficiency and development and deployment of low-carbon technologies.
- Find solutions to global energy challenges through engagement and dialogue with non-member countries, industry, international organisations and other stakeholders.

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Foreword

I am pleased to release *Energy, Climate Change and Environment: 2014 Insights.*

The future of the energy sector and that of our planet's climate are inextricably linked. Access to secure, affordable energy is a critical driver of economic growth and social development. However, current approaches to energy supply and consumption are exerting a heavy toll on the global environment: energy sector carbon dioxide emissions account for over 60% of total global greenhouse gas emissions, and there are serious concerns in many regions about the energy sector's impact on air quality, water resources and ecosystems.

The International Energy Agency (IEA) works to ensure reliable, affordable and clean energy for its member countries and beyond. We contribute to fulfilling this mission with various publications, including tracking and reporting of energy and emissions statistics, and modelling work such as the *World Energy Outlook* and *Energy Technology Perspectives*. This new publication, and subsequent editions, will complement this existing body of work. Each year, it will provide a technical analysis of selected policy issues at the energy-climate interface, focusing both on topical issues and on those that we consider are not receiving sufficient attention. This policy analysis is accompanied by an annual update of key energy and emissions statistics.

The topics chosen this year are diverse, indicative of the wide range of challenges the world faces to reconcile energy and climate objectives. Three initial chapters focus on a set of proven policy tools that countries can adapt to their own context when putting together a stronger package of policies for energy sector decarbonisation:

- Policies to accelerate the upgrading or retirement of existing high-emissions infrastructure - what we call "'unlocking" – that can create greater space for clean energy. This is important because keeping climate change within manageable levels will require that "locked-in" existing infrastructure be addressed.
- Emissions trading, which provides a cost-effective framework for emissions mitigation and the flexibility to design systems that fit with national circumstances. This includes co-ordination with other energy policies that are also necessary for the transition to low-carbon growth.
- Alternative energy-specific metrics that can better support efforts to reduce short- to medium-term emissions, as well as support the long-term low-carbon transformation of the energy sector.

The fourth chapter presents the special focus of this year's publication: the linkages between air pollution control and greenhouse gas emissions. This is a highly topical issue globally and one that is playing out in both of the world's largest greenhouse gas emitters, China and the United States, though in very different contexts. The extent to which policies designed to improve air quality may help reduce carbon emissions (and vice versa) is explored, supported by the experience of various countries at different stages of development.

This set of policy topics is complemented by regional energy-related emissions data. We trust this will provide useful insights into emissions trends over the past several years as well as their drivers; not only for international decision makers, but for the wider audience of energy practitioners and policymakers.

As international climate negotiations advance towards a new climate agreement in 2015, it is important to consider how to best track the implementation of countries' pledged contributions, many of which will require the transformation of their energy sector. As an observer organisation in the United Nations Framework Convention on Climate Change negotiations, the IEA can play a role in supporting the international community in this effort through the provision of high-quality data and analysis.

In order to realise a clean energy future, the world will need to significantly "bend the curve" away from current energy and emissions trends. Fortunately, the energy landscape is rich in options to allow a transformation to a more secure, affordable, and sustainable system in an increasingly carbon-constrained world. This publication is designed to help us better understand some of the key challenges and options in getting there.

Energy, Climate Change and Environment: 2014 Insights is published under my authority as Executive Director of the IEA.

Maria van der Hoeven
Executive Director
International Energy Agency

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Table of contents

Foreword . . . 3

Acknowledgements . . . 4

Executive Summary . . . 9

Chapter 1. Policies and actions to "unlock" high-emissions assets: The example of coal-fired power generation . . . 15

Chapter 2. The new landscape of emissions trading systems . . . 27

Chapter 3. Metrics for tracking progress in energy sector decarbonisation . . . 35

Chapter 4. The air pollution-GHG emissions nexus: Implications for the energy sector . . . 45

4.1 GHG co-benefits of air quality controls of large stationary sources . . . 47

4.2 China's air quality constraints: Implications for GHG mitigation in power and key industry sectors . . . 57

4.3 The regulatory approach to climate policy in the United States . . . 68

Chapter 5. Data: Energy and emissions data . . . 83

World . . . 84

OECD Americas . . . 86

OECD Asia Oceania . . . 88

OECD Europe . . . 90

Africa . . . 92

Non-OECD Americas . . . 94

Middle East . . . 96

Non-OECD Europe and Eurasia . . . 98

Asia (excluding China and India) . . . 100

China . . . 102

India . . . 104

Acronyms, abbreviations, and units of measure . . . 107

List of figures

Figure ES.1 Current status of ETSs worldwide . . . 10

Figure ES.2 Examples of Type I (fleet average emissions intensity [lines]) and Type III (new-build emissions intensity [bars]) metrics for power generation in the 6DS, 4DS and 2DS . . . 11

Figure ES.3 Selected indicators of global CO_2 emissions, per capita GDP (GDP / population), carbon intensity of economic activity (CO_2 / GDP), population, and energy sector carbon intensity (ESCII): Change from 1990 . . . 13

Figure 1.1 World installed fossil fuel power generation capacity in the 450 Scenario relative to the New Policies Scenario . . . 16

Figure 1.2 2010 levelised cost of electricity for coal and gas, showing switching prices . . . 17

Figure 1.3 Age of current (2014) capacity of coal-fired power plants in the United States . . . 24

Figure 2.1 Current status of ETSs worldwide . . . 28
Figure 2.2 Global proliferation of ETSs 2005-15 . . . 28
Figure 3.1 ESCII for China . . . 37
Figure 3.2 Actual and achievable emissions intensity of UK power generation . . . 38
Figure 3.3 Fleet average and new-build emissions intensity of power generation in IEA 6DS, 4DS and 2DS . . . 42
Figure 4.1.1 Generation mix in the United States under base case scenario and Transport Rule (TR or CSAPR) scenario in 2012, 2014 and 2020 . . . 50
Figure 4.2.1 Towards China's 2020 targets: GDP, CO_2 emissions, CO_2 intensity . . . 59
Figure 4.2.2 Trends in CO_2 emissions intensities for the top five emitting countries . . . 60
Figure 4.2.3 Life-cycle GHG emissions from natural gas and coal power . . . 61
Figure 4.2.4 Map of Beijing, Tianjin and Hebei low-emissions region . . . 65
Figure 4.3.1 US energy-related GHGs, by economic sector (million tonnes of carbon dioxide equivalent [$MtCO_2e$]) . . 69
Figure 4.3.2 US CO_2 emissions from electricity, by fuel source ($MtCO_2e$) . . . 73
Figure 4.3.3 Projected GHG reductions under the Clean Power Plan and mobile source rules ($MtCO_2e$) . . . 76
Figure 4.3.4 Change in US electricity generation capacity in 2030, by technology, from base case (GW) . . . 78
Figure 4.3.5 Projected monetised benefits and costs under the Clean Power Plan in 2030 (2011 USD billions) . . . 79

List of tables

Table ES.1 Unlocking actions for existing coal plants and the range of policies that can drive them . . . 9
Table 1.1 Unlocking actions for existing coal plants and the range of policies that can drive them . . . 18
Table 1.2 Recent coal lock-in and unlocking potential for Germany and the United States . . . 24
Table 3.1 Selected potential Type II energy sector metrics . . . 39
Table 4.1.1 Emissions from power plants in the United States in the base case (no further controls) and with CSAPR . . . 49
Table 4.1.2 Projected EGU emissions of SO_2, NOx, mercury (Hg), hydrogen chloride (HCl), PM, and CO_2 with the base case and with MATS, 2015 . . . 51
Table 4.1.3 Potential pollutant / atmospheric relationships associated with emission precursor reductions . . . 53
Table 4.2.1 Key national air pollution control regulations . . . 58
Table 4.2.2 Impact to 2020: Coal quality also matters . . . 62
Table 4.2.3 Steps to retrofit existing plants with pollution control by production capacity in 2014 . . . 62
Table 4.2.4 Regional measures: Potential CO_2 emissions impact . . . 64
Table 4.2.5 Municipal measures: Potential CO_2 emissions impact . . . 65
Table 4.2.6 Hebei region: Estimated CO_2 emissions . . . 66
Table 4.3.1 Composition of US electricity generation, by fuel source (%) . . . 77
Table 4.3.2 Projected reductions of CO_2 and air pollutant emissions in 2030 . . . 79

List of boxes

Box 1.1 Lifetime limits, or lifetime extensions? . . . 19
Box 2.1 A simulation of emissions trading in China . . . 29
Box 3.1 How are Type III metrics distinct from Type I or Type II? . . . 37
Box 3.2 How can alternative metrics help re-frame decarbonisation as a positive transformation? . . . 38
Box 3.3 Energy efficiency indicators and GHG reductions . . . 40

Box 3.4 Metrics to help avoid further power sector lock-in . . . 42
Box 4.1 Air pollution control options and associated CO_2 emission reduction co-benefits at the plant level . . . 46
Box 4.1.1 Complex effects of air pollutants on climate forcing . . . 49
Box 4.1.2 An expanding approach: East Asia . . . 51
Box 4.1.3 Retrofitting with end-of-pipe pollutant controls . . . 56
Box 4.2.1 Impact to 2020: Technology choice matters . . . 61
Box 4.2.2 Coal command control: Potential GHG implications . . . 63
Box 4.2.3 Expanding low-emissions alternatives . . . 64
Box 4.2.4 Shanghai: Potential CO_2 emissions impact . . . 66
Box 4.2.5 Dual pollution / GHG metrics . . . 68
Box 4.3.1 How did the United States arrive at Clean Air Act regulation of GHG emissions? . . . 70
Box 4.3.2 How do emissions standards work in the US context? . . . 72
Box 4.3.3 The federal-state process under Clean Air Act Section 111 . . . 74
Box 4.3.4 State compliance options under the Clean Power Plan . . . 75
Box 4.3.5 State implementation choices will affect the impact of the Clean Power Plan on the energy sector . . . 78

Executive Summary

The development of our energy systems has been and will continue to be markedly affected by a variety of environmental concerns, from air quality issues and acid rain, to more recent emphasis on climate change. Investments and other actions to provide for secure, affordable energy are influenced and modified to varying degrees by these diverse environmental considerations. In particular, the potential impact of climate change policies on the energy sector is increasing with the growing concern regarding climate change from greenhouse gas (GHG) emissions, 60% of which are generated by the energy sector. More than ever, the development of the energy sector and our planet's environment and climate are inextricably linked, creating the need for a fuller understanding of the opportunities to promote synergies between energy and environmental and climate policies.

This publication, *Energy, Climate Change and Environment: 2014 Insights* complements IEA modelling work such as the *World Energy Outlook* and *Energy Technology Perspectives* by providing a technical analysis of selected policy issues at the energy-climate interface, as well as providing updated key energy and emissions statistics. A summary of each chapter is provided below.

Policies and actions to "unlock" high-emissions assets

Meeting the challenge of climate change is not only about channelling new investments toward clean energy, but also addressing high-emissions assets that are already in place. Long-lived infrastructure can create path dependence in energy systems and the potential for lock-in. Staying on track to limit temperature rise to below two degrees Celsius requires a transition away from these assets at faster rates than natural infrastructure replacement would dictate (i.e. before the end of their economic lifetimes). Current assets could be seen as "locked in", but they can also be "unlocked" through policy intervention.

High and rising carbon prices could drive changes in infrastructure; however, given the low prices in most current carbon pricing systems today, alternative policy options need to be explored to unlock high-emissions infrastructure. The context of coal plants, one of the largest sources of energy sector GHG emissions, provides useful insights. There are a number of unlocking options available (Table ES.1), many of which are already in use.

In choosing policy options to unlock existing infrastructure, careful attention needs to be paid to not undermining

Table ES.1

Unlocking actions for existing coal plants and the range of policies that can drive them

Unlocking action	Policy options		
	Direct regulation of plants	Regulated change in supply/ demand balances	Influence markets via price
Retirement of coal plant	• ownership decision to shut down • regulated lifetime limits • regulated phase-out	• fleet-wide GHG emissions performance standard • regulated increase in renewable capacity • demand reductions	• fuel price changes • carbon pricing • preferential pricing for renewables
Change dispatch of the existing power generation fleet	• "clean-first" dispatch • priority dispatch of renewables	• fleet-wide GHG emissions performance standard	• fuel price changes • carbon pricing • removal of fossil fuel subsidies
Retrofit of coal plant to increase efficiency	• targets for plant retrofit rates	• fleet-wide GHG emissions performance standard	• carbon pricing • removal of fossil fuel subsidies
Retrofit of coal plant for carbon capture and storage (CCS)	• regulated lifetime limits • CCS retrofit mandates	• CCS trading schemes • fleet-wide GHG emissions performance standard	• carbon pricing • preferential pricing for CCS generation
Biomass co-firing or conversion	• ownership decision to convert	• renewable generation quota • fleet-wide GHG emissions performance standard	• carbon pricing • preferential pricing for renewables

long-term outcomes. For example, it is critical that any early retirements be replaced by clean generation. Equally, policies to drive deployment of clean generation need to be complemented by policies that address fossil fuel emissions, in order to avoid unintended consequences such as the mothballing of gas plants instead of coal in Europe. Moreover, energy security should always be a priority to produce sustainable actions from an energy perspective: early retirements need to be matched with new supply or energy efficiency gains to keep reserve margins at acceptable levels.

The new landscape of emissions trading systems

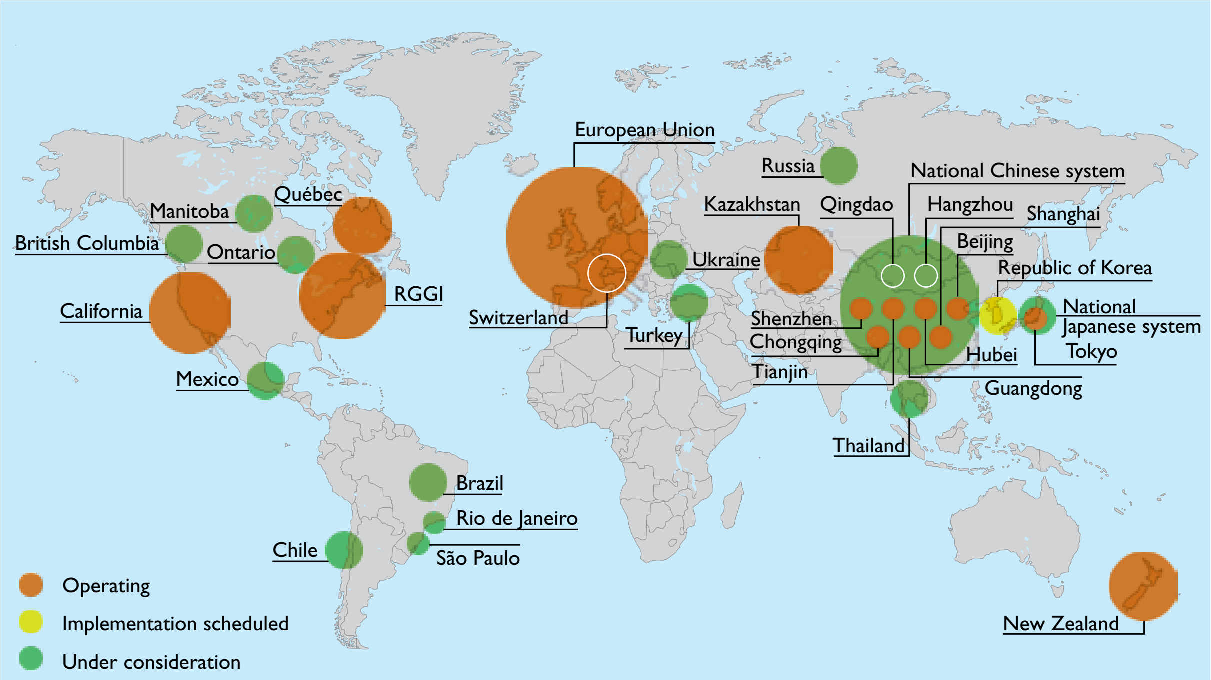
Emissions trading systems (ETSs) are enjoying somewhat of a resurgence around the world. As a form of carbon pricing, ETSs represent effective and low-cost policy responses to climate change. Beginning with the European Union Emissions Trading Scheme in 2005, which remains the largest system, current or planned systems now exist in all corners of the globe. Since 2013 the world has seen a rise in ETS implementation, with new or expanded systems in China, California, Québec, Kazakhstan and Switzerland. The Northeast United States, New Zealand, and Tokyo are other examples, and there are more under preparation: South Korea has passed legislation to begin emissions trading by 2015, and India, Chile, Brazil, Thailand and Mexico are in various stages of consideration and development of ETSs (Figure ES.1). While it is clear that support for carbon pricing and emissions trading is not universal, it is difficult to ignore the trend of expansion.

Key lessons can be drawn from recent ETS experiences:

- Improved integration of ETSs and complementary energy policies can ensure each set of policies meet its respective objectives.
- Measures can be taken to enhance ETS resilience and flexibility within changing economic conditions.
- ETS design must consider changing political contexts and public perceptions given that real as well as perceived impacts determine policy success.
- ETSs may be implemented in highly regulated electricity systems, though additional measures may be needed to ensure propagation of the carbon price signal.

Figure ES.1

Current status of ETSs worldwide



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Note: The size of each circle is approximately proportional to GHG emissions covered.

Source: Adapted from country sources and ICAP (International Carbon Action Partnership) (2014), "ETS Map", https://icapcarbonaction.com/ets-map.

- Compensating those groups affected by rising electricity prices (driven by the carbon price) may achieve better outcomes than preventing the price rise.

Lastly, although the role of ETSs within an international climate change agreement remains uncertain despite their global expansion, the United Nations Framework Convention on Climate Change (UNFCCC) process has important potential functions to play. The UNFCCC process can help balance, on one hand, flexibility for countries to develop their own market-based approaches to GHG reductions with, on the other, the need to establish common international rules and standards to build trust and credibility.

Energy metrics: A useful tool for tracking decarbonisation progress

While GHG emissions reductions goals are an essential component of decarbonisation, specific energy sector metrics can provide deeper insight into the underlying drivers of change, and can track interventions with long-term as well as short-term impacts. Energy sector policies and actions that reduce GHG emissions may be motivated primarily by wider benefits such as energy security, building experience with new technologies, cutting air pollution, or reducing energy bills, with GHG emissions reductions as a secondary benefit.

There is a wide range of metrics that could be used to track energy sector decarbonisation: those expressed in GHG terms (Type I, e.g. the IEA Energy Sector Carbon Intensity Index [ESCII]); those that have an impact on shorter-term GHG emissions levels but are not themselves expressed in terms of GHG emissions (Type II, e.g. energy efficiency or renewable energy goals); and those that track actions with an impact on long-term emissions pathways (Type III) (Figure ES.2).

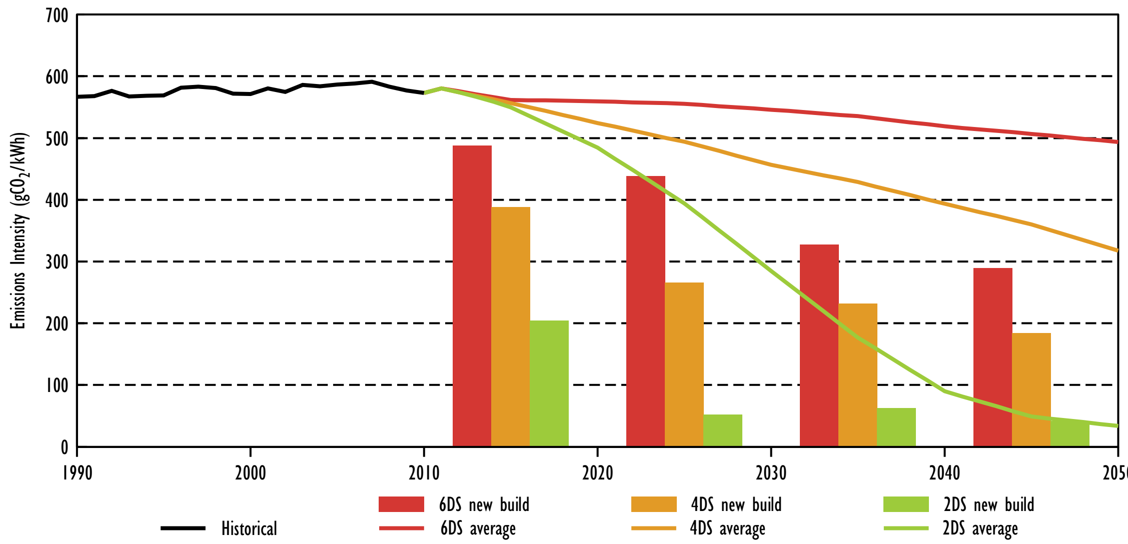
There are many reasons countries may be motivated to use energy sector goals and metrics to support GHG emissions reductions:

- Goals based on energy sector metrics can link more directly to policies under government control (e.g. renewable portfolio standards). They may consequently be easier to adopt, as outcomes are more easily influenced by policy and decision makers can have more confidence in delivery.
- Clean energy policies are implemented for a wide range of reasons and often have multiple benefits, of which emissions reductions are only one; accordingly, energy sector metrics may better reflect these objectives.
- Discussions toward the new 2015 agreement seek to frame climate action as an opportunity to be seized rather than a burden to be shared. Energy metrics can potentially help change the discourse around climate goals.
- Alternative metrics can help to target the long-term transformation that is needed to complement short-term goals (e.g. to prevent lock-in of high-emissions infrastructure or support the development of key clean technologies).

The use of energy sector metrics in addition to GHG goals could be helpful within and outside the UNFCCC process to help drive the energy sector actions needed for decarbonisation. The use of metrics that better reflect the various goals of parties could help them build support for climate policy.

Figure ES.2

Examples of Type I (fleet average emissions intensity [lines]) and Type III (new-build emissions intensity [bars]) metrics for power generation in the 6DS, 4DS and 2DS



Data Source: IEA (2014e), Energy Technology Perspectives 2014, *OECD/IEA, Paris.*

The air pollution-GHG emissions nexus: Implications for the energy sector

The energy sector is the greatest contributor to heat-trapping GHG emissions through the combustion of fossil fuels. Fossil fuel combustion also causes air pollution, which poses increasingly pressing problems around the world as public health and economic damages continue to accrue in countries at all levels of development. This presents critical challenges for the production and use of energy, which is central to economic growth and development.

However, opportunities are available to "co-manage" these challenges at the air pollution-GHG emissions nexus in a variety of contexts. This is especially important since the interplay between air pollution control and GHG emissions abatement may not always be positive. Many countries are recognising the potential to address these dual priorities: China and the United States provide interesting illustrations of how this issue is playing out in very different contexts. With this in mind, a special focus in this year's publication is on the linkages between air pollution control and GHG emissions:

- **GHG co-benefits of air quality controls of large stationary sources.** Many countries have been tightening air quality regulations to force significant emissions reductions of air pollutants such as sulphur dioxide, particulate matter, and mercury. Compliance with these regulations can also produce co-benefits in terms of GHG reductions. These co-benefits and the channels through which they arise are examined, drawing on the experience of the European Union, the United States and Canada, as well as other regions. The results can be quite small or quite large, depending on factors that include the relative economics of coal- and gas-fired power generation and future expectations related to carbon control. The benefits of multi-pollutant strategies that take an integrated approach are underscored.

- **China's air quality constraints: Implications for GHG mitigation in power and key industry sectors.** China's "war on air pollution" agenda can drive ancillary reductions in carbon dioxide (CO_2) emissions and lead to the development of complementary air pollution and low-carbon policies. However, regional variation in pollution control measures and the design of industrial policies and measures in power and key industry sectors may limit GHG benefits (i.e. through geographic dislocation of emissions, methane or CO_2 leaks or increased CO_2 emissions intensity of pollution-reducing technologies). This is especially true if competing lower-carbon technology options do not provide for security of supply, or if air quality measures or monitoring and enforcement do not take a comprehensive accounting of environmental impacts. Overall, air pollution controls can lead to meaningful reductions in GHG emissions, provided they are structured to achieve these dual objectives.

- **The regulatory approach to climate policy in the United States.** To advance its climate change goals, the US government is targeting GHG emissions reductions through a sectoral approach, using a regulatory framework normally reserved for the control of conventional air pollutants. The cornerstone of this approach is the application of federal carbon pollution standards to the electric power sector. Though the use of regulatory standards is a notable expansion of the climate policy toolkit beyond the market mechanisms that dominated much of the previous policy debate, they have been designed with some degree of market flexibility in mind. These GHG-targeted regulations also have important implications for air quality and public health co-benefits.

Trends in energy and emissions data

Global energy-related CO_2 emissions reached their highest levels in 2012 (Figure ES.3). As the global economy recovered from the 2008-09 recession, emissions rose 5.4% in 2010, the highest growth rate in over three and a half decades. However, this rate of growth has since slowed to 2.8% in 2011 and 1.2% in 2012. Closer inspection of individual regions reveals substantial differences in regional trends. For instance, contrasting emissions trends were observed between OECD and non-OECD regions: OECD Europe and OECD Americas experienced declines in 2011 and 2012, while emissions grew in non-OECD regions over the same period, led by China and India.

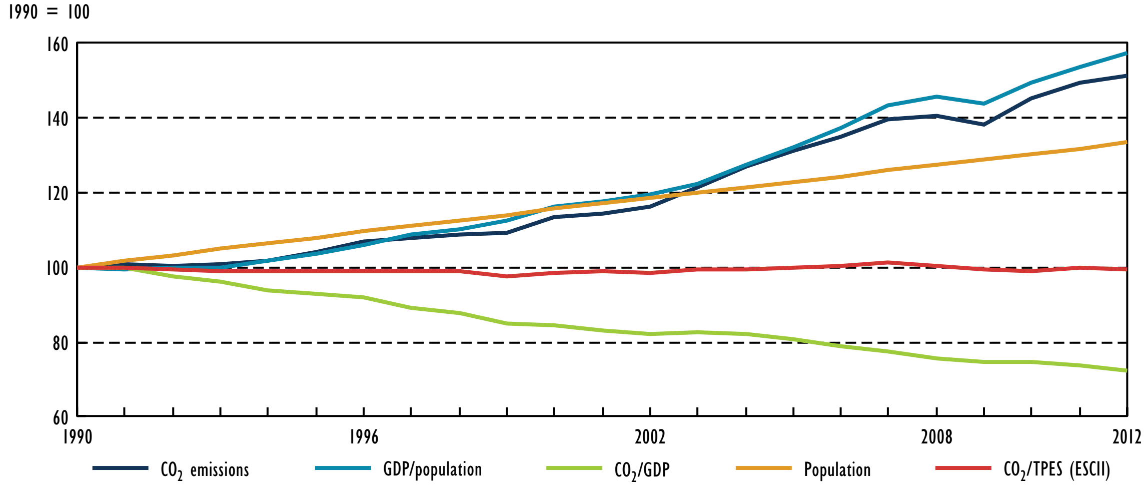
In 2011 and 2012, coal remained the largest contributor to emissions with its greatest shares (43.9% in both years) over the reporting period (1971-2012). Oil had the second largest share (35.3%), followed by gas (20.3%) in 2012. The rising demand for fossil fuels was also driven largely by consumption in fast-growing, non-OECD regions.

Economic growth continued to decouple from emissions growth, with 2012 having the lowest-ever emissions intensity (CO_2/GDP). Despite this, an increasing demand for energy due to rising population and wealth drove overall emissions upwards.

Among all sectors, the electricity and heat generation sector accounted for the greatest share of emissions in 2012 (42.1%), which also represented the largest contribution made by this sector over the reporting period. In 2011 the global electricity sector was the most fossil fuel-dependent it had been, with the share of non-fossil electricity reaching its lowest levels in over two decades (31.6%), driven in part by a decline in nuclear power generation. In other words, fossil fuels comprised over two-thirds (68.4%) of the

Figure ES.3

Selected indicators of global CO_2 emissions, per capita GDP (GDP/population), carbon intensity of economic activity (CO_2/GDP), population, and energy sector carbon intensity (ESCII): Change from 1990



electricity generation mix. In 2012, the share of non-fossil electricity increased slightly (to 31.8%).

Renewable sources of electricity such as wind, biomass and solar enjoyed the greatest rate of growth in 2011 and 2012 among all energy sources (including fossil fuels). In fact, in 2012 their share in the electricity mix rose to a level matching that of oil (to 5.0%) for the first time. This growth was driven by emerging economies, in particular that of China. However, the carbon intensity of energy supply (which measures the overall carbon intensity of the energy sector, namely our global energy mix) remained relatively unchanged, highlighting the very limited decarbonisation that has taken place in the energy sector over the past several decades.

Looking ahead

The world will need to significantly "bend the curve" away from current energy and emissions trends in order to tackle the challenge of global climate change. The analyses contained in *Energy, Climate Change and Environment: 2014 Insights* are intended to inform countries as they explore options to decarbonise their energy sectors. Better policies and data will be needed to support greater ambition and more effective action to reduce energy sector GHG emissions.

Chapter 1 • Policies and actions to "unlock" high-emissions assets: The example of coal-fired power generation

This chapter examines a critical but often overlooked aspect of the transition to low-carbon energy systems: how to manage the phase-out or retrofit of existing high-emissions infrastructure. It illustrates the wide range of tools that policy makers could consider to address "locked-in" plants, which have all been implemented in some form.

Introduction

Meeting the challenge of climate change is not only about channelling new investment towards clean energy, but also addressing high-emissions assets that are already in place. Long-lived infrastructure can create path dependence in energy systems, and the potential for lock-in (Unruh, 2002). Staying on track to limit temperature rise to below 2°C requires a transition away from these assets at faster than natural infrastructure replacement rates (i.e. sooner than their economic lifetimes would suggest). Current assets could be seen as "locked in", but they can also be "unlocked" through policy intervention. This chapter reviews policy options available to accelerate the capital stock transition to "unlock" existing assets, by driving early retirement, fuel switching or retrofitting for carbon capture and storage. It looks at policies already in place and what more could be done. It also considers wider aspects of the unlocking challenge, such as the need to replace retired capacity to maintain energy security. This analysis will focus on the example of unlocking coal-fired power generation, because this is the most significant source of infrastructure lock-in in IEA analysis. Nonetheless, the variety of policy tools explored could also be applicable in other sectors.

Lock-in of coal-fired electricity generating capacity in the IEA scenarios

New coal-fired generation covered nearly half of increased demand for electricity from 2001 to 2011. Of this, 60% (434 gigawatts [GW] of 734 GW) uses lower efficiency subcritical technology. This level of investment in new coal without carbon capture and storage (CCS) is not consistent with the IEA energy sector pathways to keep global temperature rise below 2°C.

Continuing to lock in high-emissions, long-lived infrastructure could seriously impede the feasibility of keeping temperature rise below two degrees. In particular, if current investment trends continue, by 2017 emissions from infrastructure in place would, across its lifetime, generate all emissions allowed under the IEA 2°C Scenario (2DS) (IEA, 2011).

One possible implication of this lock-in is that all new energy sector investment after 2017 (including in vehicles and industry) would need to be zero-emissions to stay on track for two degrees. A more realistic alternative is for some old or high-carbon existing infrastructure to be retired early. While new investment would still need to be predominantly low-carbon, the early retirements would create space for a limited quantity of new, high-efficiency, lower-emitting infrastructure. Indeed, this is the outcome seen in the IEA World Energy Model: to move from the New Policies Scenario (consistent with 3.6 degrees warming) to the 450 Scenario (consistent with 2°C), a significant proportion of existing fossil fuel electricity generation infrastructure must be retired early or idled, in addition to the retrofitting of suitable plants with CCS. Of the 2 300 GW of capacity retired early, idled or retrofitted for CCS, 165 GW would be retired even before making a commercial return on the capital invested (Figure 1.1).

There is also significant potential for further lock-in between 2014 and 2020, if strong policy action is delayed until a new global climate treaty comes into effect after 2020. This delay could significantly increase costs compared to moving onto a low-carbon path immediately: for every USD 1 of investment saved before 2020 through this delay, USD 4.30 will need to be spent after 2020 to get back on track (IEA, 2011).

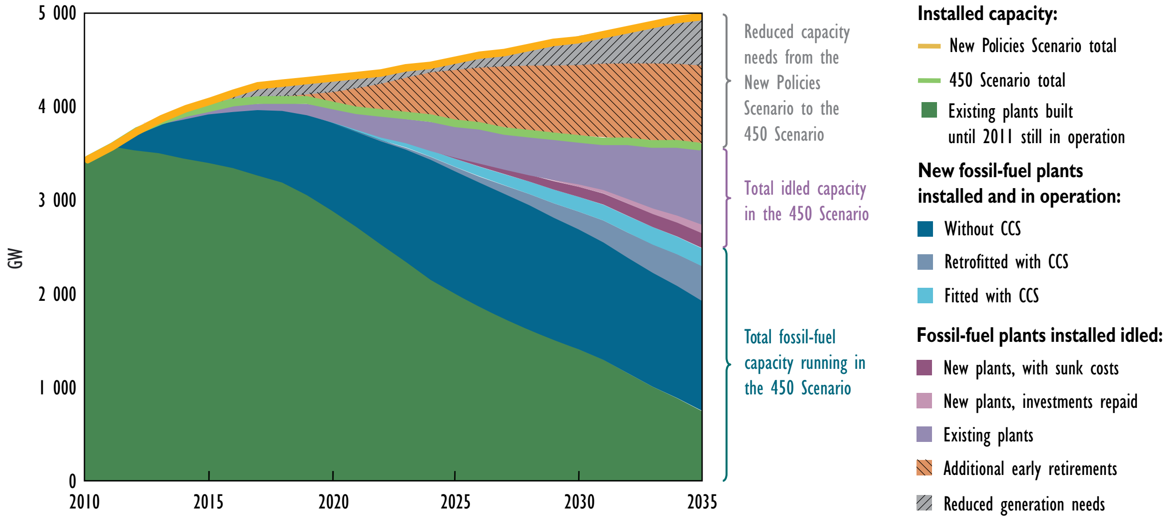
This chapter analyses what policies and actions could be implemented to unlock this locked-in infrastructure, driving the retirement, upgrade or CCS retrofit of inefficient coal plants, and their replacement with cleaner alternatives.

Can we rely on carbon pricing alone to unlock?

In the IEA models, high and rising carbon prices play an important role in the transformation to low-carbon energy systems. For example, in the *Energy Technology Perspectives* (*ETP*) model's 2DS, the marginal costs (highest-cost

Figure 1.1

World installed fossil fuel power generation capacity in the 450 Scenario relative to the New Policies Scenario



Source: IEA (2013a), World Energy Outlook Special Report 2013: Redrawing the Energy-Climate Map, *OECD/IEA, Paris.*

actions required) are USD 30 to USD 50 per tonne of carbon dioxide [tCO_2] in 2020, and USD 80 to USD 100/tCO_2 in 2030 (IEA, 2014a). This gives an indication of the carbon price that would be required to drive these actions. Given concerns about energy affordability and competitiveness, and uncertainties around the future framework for international climate commitments, there has been significant political difficulty in introducing strong domestic carbon pricing policies to date. As a result, while carbon pricing policies are spreading, prices are far from levels consistent with a 2°C pathway.

As one example, it is instructive to consider what magnitude of carbon price could be needed to drive a switch from coal- to gas-fired generation. Over the long term, switching to gas is not enough to limit temperature rise to below 2°C; however, gas can be a short-term option as part of a bridge towards deeper decarbonisation. Understanding the coal-to-gas switching price gives an indication of what level of carbon prices might be needed in the short term. One simple comparison is to look at the levelised cost of electricity, which translates capital, operating, fuel and carbon costs into a per-unit cost of generation.

Three situations are shown schematically in Figure 1.2, exploring coal-gas competition between new and existing plants. The first (intersection A) shows the situation where a new plant of some type is needed to meet electricity demand. In this example, a carbon price of around USD 30/tCO_2 would make a new gas plant more cost-effective than a new coal plant over the lifetime of the plants. The second situation (intersection B) instead relates to competition between plants that have already been built. If the electricity market has surplus capacity, both plants do not need to run and they compete to be dispatched based on their short-run (operating, fuel, carbon) costs.[1] Here a higher carbon price of around USD 60/tCO_2 would lead to the gas plant being dispatched ahead of coal. A plant that cannot be dispatched may be retired or mothballed.

The final situation (intersection C) represents a new gas plant competing to take the place of an existing coal plant, pushing it out of the market. The gas plant investor must be confident of recovering capital and short-run costs, whereas the existing coal plant can run only to cover its short-run costs.[2] This creates a greater cost differential for the carbon price to overcome: in this example a high carbon price around USD 110/tCO_2 is needed.

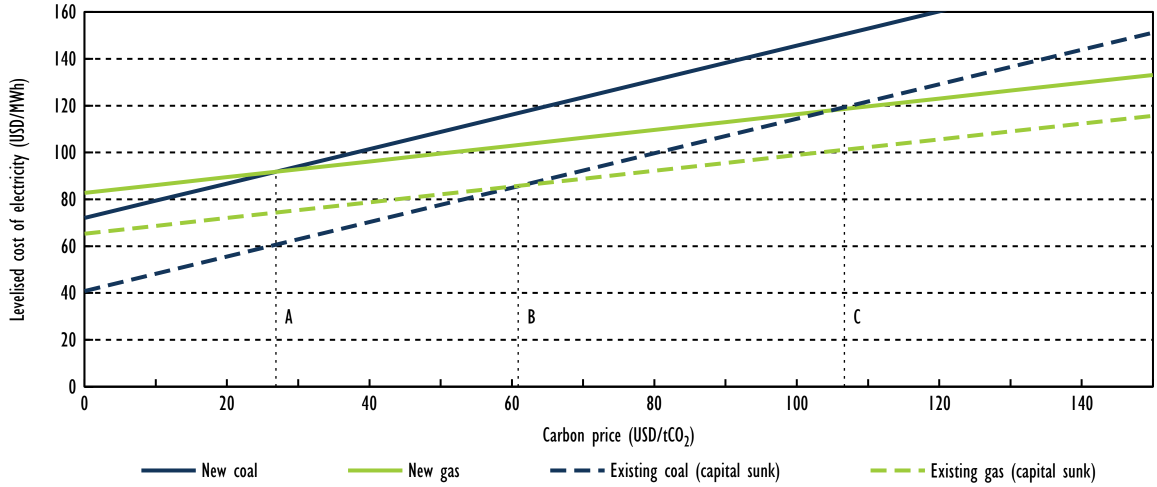
This illustrates why unlocking is so difficult: once capital is invested in a facility (i.e. once capital is "sunk"), it is costly to replace the plant prematurely. A moderate carbon price is needed to guide new investment decisions, but higher prices are needed to unlock existing capacity. Given governments' current plans for carbon pricing policies, price levels that would guide new investments (situation A) may be achievable, but the kinds of prices that would drive unlocking of existing plants (particularly in regions without surplus electricity supply) seem unlikely in the near future. While this example used coal-to-gas fuel switching, the dynamics are similar for other technologies: new investors must factor in recovery of capital costs, while an existing

1. That is, capital cost recovery is not included in the decision to dispatch.

2. This is the case whether the coal plant has repaid its capital or not.

Figure 1.2

2010 levelised cost of electricity for coal and gas, showing switching prices



Notes: Data for Germany Black Coal PCC and Gas combined-cycle gas turbine (CCGT) with 10% discount rate. Fuel prices: hard coal USD 90/tonne, natural gas USD 10.3/million British thermal units (MBtu).

Source: IEA/NEA (2010), Projected Costs of Generating Electricity: 2010 Edition, *OECD/IEA, Paris.*

plant does not. This raises the question as to what else can be found in the unlocking policy toolkit.

Key "unlocking" policies and actions

This section will consider the key actions that can be taken to unlock existing coal-fired generating capacity, and the policies that could drive them. Potential actions include changing dispatch of the existing power fleet; retrofitting to improve plant efficiency; retrofitting with CCS; biomass blending or conversion; and phase-out (retirement) of plants. These actions could be driven by policies ranging from very direct regulation to market-based policies that work via price changes, as outlined in Table 1.1.

Direct phase-out of coal generating plants

The most direct approach to unlocking is to simply mandate the phase-out of certain coal-fired generation units. If assets are held by a publicly owned provider this could be done by ownership decision (as in the case of Ontario); alternatively, there could be government regulation (as in China and Canada). For privately held assets, the government could also consider negotiating contracts for closure (Australia). The climate benefits of retiring a coal plant early depend entirely on what replaces it: if it is replaced by a new fossil fuel plant rather than low-carbon capacity, early retirement could in fact lead to even greater long-term lock-in.

Example: Ontario, Canada

The Canadian province of Ontario completed a phase-out of coal-fired electricity generation in April, 2014, with the last of 19 units in 5 plants ceasing to burn coal. This resulted from a planned full phase-out of coal generation by Ontario's publicly owned utility company, driven by Premier McGuinty who held office from 2003 to 2013. In comparison, coal generation supplied 25% of Ontario's power in 2003. A study for the Ontario government prior to the phase-out found CAD 4.4 billion in expected benefits, including health, financial and environmental costs. The phase-out has resulted in sulphur dioxide and nitrogen oxide pollution falling by 93% and 85% respectively between 2003 and 2011, and GHG emissions from the electricity sector falling from 41.1 million tonnes (Mt) to 5 Mt (Government of Ontario, 2013). This is the single largest GHG emissions-reducing action in Canada to date.

The province of Ontario completed a phase-out of coal-fired electricity generation in 2014. In 2003, coal accounted for 25% of the province's power.

The closure of Ontario's coal units was implemented in a phased manner to ensure sufficient reliable electricity supply at peak times. A key element in the transition plan was aggressive energy efficiency actions. Ontario's electricity demand is now declining, enabling easier retirement of plants. Other elements of the overall transition plan included feed-in tariffs for renewable energy (installed wind capacity has increased from 400 megawatts [MW] in 2007 to 2 000 MW in 2013), building of new gas-fired units, and conversion of the Atikokan and Thunder Bay coal-fired stations to burn sustainable biomass (Marshall and ClimateWire, 2013; Ontario Power Generation, 2014; CBC, 2014). Between 2003 and 2010, Ontario added over 8 GW in cleaner energy capacity. A key factor in the implementation of this plan is that coal-fired electricity generation is owned and controlled by the province, giving

Table 1.1

Unlocking actions for existing coal plants and the range of policies that can drive them

Unlocking action	Policy options		
	Direct regulation of plants	Regulated change in supply/ demand balances	Influence markets via price
Retirement of coal plant	• ownership decision to shut down • regulated lifetime limits • regulated phase-out	• fleet-wide GHG emissions performance standard • regulated increase in renewable capacity • demand reductions	• fuel price changes • carbon pricing • preferential pricing for renewables
Change dispatch of the existing power generation fleet	• "clean-first" dispatch • priority dispatch of renewables	• fleet-wide GHG emissions performance standard	• fuel price changes • carbon pricing • removal of fossil fuel subsidies
Retrofit of coal plant to increase efficiency	• targets for plant retrofit rates	• fleet-wide GHG emissions performance standard	• carbon pricing • removal of fossil fuel subsidies
Retrofit of coal plant for carbon capture and storage (CCS)	• regulated lifetime limits • CCS retrofit mandates	• CCS trading schemes • fleet-wide GHG emissions performance standard	• carbon pricing • preferential pricing for CCS generation
Biomass co-firing or conversion	• ownership decision to convert	• renewable generation quota • fleet-wide GHG emissions performance standard	• carbon pricing • preferential pricing for renewables

it scope to determine the generation mix. The combination of an aging fleet of coal plants and favourable gas prices also enabled the transition.

Example: China

As part of its 11th and 12th Five-Year Plans, China has undertaken significant measures to modernise its coal generation fleet. The 11th Five-Year Plan (2006-10) placed emphasis on efficiency, encouraging new builds of larger high-efficiency units, closing small, inefficient power plants (each <100 MW), and improving the efficiency of its fleet of 200- to 300-MW plants. The plant closures were driven by the "large substitutes small" programme. Under these arrangements, to be allowed to expand generation companies were required to close a quantity of small, inefficient plants (e.g. for 1 000 MW of generation, 600 MW must be closed). This has led to closure of 77 GW of smaller plants, with a further 20 GW of closures planned for the 12th Five-Year Plan period (Burnard et al., 2014). In the 12th Five-Year Plan, coal production is capped at 3.8 gigatonnes (Gt) by 2015, which could prompt further efficiency improvements in the industry.

Example: Canada

The Canadian federal government has introduced regulations that will apply from 1 July 2015, limiting the lifetime of coal-fired electricity generation units. "End of life" coal units must either be shut down, or be retrofitted with CCS to bring emissions below the level of a natural gas plant. All pre-1975 units must close by 2020, and later vintage plants may run for approximately 50 years before shutdown or retrofit (Environment Canada, 2013).[3]

The 50-year lifetime allowed under this regulation is somewhat long,[4] but the regulation is still expected to force closure of five existing plants by 2020. If a shorter lifetime were applied, this type of policy could be used to drive accelerated unlocking of existing plants.

Example: Australia

As part of its 2011 carbon price policy package, the Australian government announced its intention to negotiate the closure of approximately 2 000 MW of high-emissions generating capacity, in particular targeting old brown-coal capacity. This policy was an acknowledgement that the carbon price levels expected in the Australian emissions trading system (ETS) would not necessarily drive retirement of these plants. Negotiations were abandoned in 2012 after the government and plant owners failed to agree on terms. Several factors are said to have influenced the generators' decision to keep plants in the market: the

3. More precisely, 1975-86 vintage plants may run up to 50 years or to 2030, whichever comes earlier; post-1986 vintage plants may run for 50 years.

4. By comparison, for the IEA ETP model, the nominal plant lifetime for coal is 40 years.

Box 1.1

Lifetime limits, or lifetime extensions?

A key consideration in accelerating retirement of coal-fired generation is what will replace the retired capacity. The IEA scenarios show early retirement as a critical component of keeping temperature rise below 2 °C, but these scenarios also assume that replacement capacity is low-carbon (renewable, nuclear, or fitted with CCS).

Conversely, weak near-term climate policy could lead to short-sighted decisions to invest in new coal capacity in the period from now until 2030. In this case, it could be desirable to extend the use of existing coal plants beyond their 30-year nominal lifetime to prevent the more significant lock-in caused by building new coal plant as replacements. Even replacing existing capacity with high-efficiency coal is not always a good solution if this high-efficiency coal itself must be retired after 2030: this can even increase costs due to the higher capital costs of the high-efficiency coal (Johnson et al.*, 2014). If there is high confidence that CCS will be available and if the replacement high-efficiency plants are built CCS-ready, the ability to retrofit for CCS mitigates the risk of lock-in.*

Policies to "unlock" existing plants must therefore be accompanied by measures to drive investment in low-carbon replacement generation; otherwise, unintended outcomes could arise.

expectation of low future carbon prices due to linking with the European Union ETS (EU ETS); the possible repeal of the carbon pricing policy at the upcoming elections; and the compensation offered to brown-coal generators who continued to operate (Australian Financial Review, 2012). Payments for closure, as for any intervention in market-based decision-making, risks creating a situation of moral hazard, where there is an expectation that any future plant retirements will also receive payment (Riesz, Noone and MacGill, 2013). Terms for any such payment programme should therefore be structured carefully, to ensure that it only rewards actions that genuinely go beyond those that would have been driven by existing market signals or regulation.

Change dispatch of the existing generation fleet

In general, decisions on which power plants to run (dispatch) at any time are based on their short-term running costs. Shifts in fuel or carbon prices can change short-term generating costs, and if there is surplus capacity in the generating fleet this can lead to redistribution of running hours among different plant types. This represents one of the main short-term measures that could be used to reduce CO_2 emissions in electricity generation. Changes to dispatch can be driven by price, or could be mandated by regulation depending on the characteristics of the power system. Priority dispatch for renewable electricity generation is a common form of regulated change in dispatch that has the effect of reducing fossil fuel plant running hours.

Example: United States

Shale gas development has led to a substantially lower gas price in the United States, which has in turn driven a shift in running hours from coal to gas plants. Between 2006 and 2011, electricity generated from coal and petroleum dropped by 292 million megawatt hours (MWh), while previously underutilised natural gas generation increased by 200 million MWh (US EIA, 2012). While not driven by climate policy, this shift illustrates that there can be significant potential to reduce the running hours of existing "locked-in" coal plants in markets with other underutilised capacity. In competitive markets, fuel price changes can reverse, so policy interventions such as energy taxation or carbon prices would be needed for a more long-lasting, price-driven shift in dispatch. The combination of an aging coal fleet and favourable gas prices has underpinned the US experience: this will not necessarily be a template for other regions.

Example: China

Another approach to changing dispatch is through regulation rather than price. Since 2007, the Chinese government has piloted the "Energy Efficient and Environmentally Friendly Power Generation Scheduling" approach, which would prioritise generation according to its pollution and efficiency characteristics. This would be an alternative to the current Chinese dispatch model based on annual mandates on generation time, which leads to economic inefficiencies because it does not provide the least-cost dispatch of generating units.

Retrofit to improve efficiency of existing coal plants

While not a long-term solution to unlocking, coal plants' efficiencies can be improved and, hence, their useful lifetimes slightly extended in a low-carbon scenario through energy efficiency upgrades. Policies to drive efficiency upgrades could include direct regulation (e.g. a schedule to meet certain efficiency standards), GHG regulation of the fleet, or price changes including carbon pricing.

Example: China

There is significant potential for energy efficiency upgrades of older coal-fired power plants in China. While China's average coal plant efficiency of 37% exceeds the global average of 33%, there is still a large fleet of smaller (200 MW to 300 MW) subcritical power stations of low efficiency. In collaboration with China's National Energy Administration (NEA), the IEA approached the China Electricity Council to work to identify possibilities for the upgrading and retrofitting of older coal-fired power plants. The focus of the study was two 300-MW subcritical units, each more than ten years old and producing around 1.5 million tonnes of carbon dioxide per year ($MtCO_2$/yr). The plants' performance was generally good, improvements having been identified in recent years (raising boiler efficiency, improving energy conversion, reducing auxiliary power consumption, e.g. for pumps and motors, and introducing best-practice operating procedures). Plant A had already made 25 000 tonnes of carbon dioxide per year (tCO_2/yr) savings, and had plans for 41 000 more. At Plant B, 73 000 tCO_2/yr had been saved, with potential for a further 46 000 with retrofit for co-generation. Overall, the project estimated a potential 100 000 tCO_2/yr savings for a 300 MW unit producing only electricity, and even more where co-generation could be installed (Burnard et al., 2014).

CCS retrofit

IEA analysis shows that CCS is a critical technology in two-degree pathways. It also significantly reduces the costs of the decarbonisation transition by reducing the number of coal-fired plants that must be retired early. The cost-effective 2DS shows a cumulative 120 gigatonnes (Gt) of emissions captured and stored between 2015 and 2050. CCS provides one-sixth of reductions in 2050, and 14% of cumulative reductions relative to the business-as-usual scenario. A significant share of the globally installed coal generation fleet can be considered appropriate for CCS retrofitting (Finkenrath, Smith and Volk, 2012).[5]

The next seven years will be critical for the development of CCS, and the *Technology Roadmap: Carbon Capture and Storage 2013* (IEA, 2013b) lays out the key actions needed in this period in finance, characterisation of storage sites, requirements for new plants to be CCS-ready, demonstration projects, stakeholder engagement, cost reductions, and planning for CO_2 transport needs. The strategy has the following medium-term goals: by 2020 capture and storage should be demonstrated in at least 30 projects across all sectors, with 50 Mt stored per year. By 2030, CCS should be routinely used to reduce emissions in power and industry, with over 2 000 Mt/yr being stored. Policies to drive retrofitting for CCS could include regulatory requirements, trading schemes, or financial support.

Biomass blending or conversion

Many coal-fired power stations have the technical potential to be converted to run on biomass, either blended with coal (known as co-firing), or as 100% conversion to biomass. Because biomass is more expensive, a relatively high carbon price would be needed to provide a market incentive for this type of fuel switch. Examples to date have instead been driven by renewable energy support policies.

Example: United Kingdom

The 4-GW Drax power station is the largest power station in the United Kingdom, and the last coal-fired power station built, having been constructed in two stages in 1974 and 1986. It produces around 7% of the United Kingdom's electricity.

In July 2012, Drax announced plans to become a predominantly biomass-fuelled generator, by converting three of its six coal generating units to burn biomass (wood pellets). The first two units have been converted, and biomass handling facilities are in place. Drax is also developing wood pellet supply and transport facilities in North America to fuel the plant (Drax Power Limited, 2014). The GHG savings from burning biomass relative to coal at the plant are over 80%. In general, GHG savings are highly dependent on the full life-cycle emissions from biomass production, so rigorous standards and the enforcement of biomass sustainability are critical.

The decision to convert units to 100% biomass followed a series of large-scale co-firing trials, where up to 12.5% biomass was injected directly with the coal. A 400-MW direct injection co-firing facility was commissioned in 2010, together with a capacity of 100 MW by co-milling pellets with coal. These co-firing activities reduced Drax's emissions intensity from 850 grammes of carbon dioxide per kilowatt hour (gCO_2/kWh) to 700 gCO_2/kWh by 2011, and made it the world's largest co-firing facility (Drax Power Limited, 2010). Co-firing received funding from the UK Renewable Obligation, and the more recent conversions to 100% biomass were enabled by a long-term contract with the government.[6]

Example: Ontario, Canada

As part of its planned phase-out of coal-fired generation, the Canadian province of Ontario is converting two coal stations to sustainable biomass. Work to convert the

5. For example, plants younger than 20 years and over 300 MW comprise 40% of the globally installed fleet, while plants younger than ten years and over 300 MW comprise 29%.

6. Contracts for difference against the market electricity price.

Atikokan station is underway; this will be the largest 100% biomass plant in North America with a 200-MW full capacity. Wood pellets were chosen as fuel because of their similar energy content to lignite, which the station was designed for, allowing for easier adaptation of the plant. Work underway involves some plant modifications, and construction of fuel handling facilities. The plant will be run in a flexible mode, providing backup for hydro, solar and wind generation (Ontario Power Generation, 2014). The relatively abundant supply of biomass fuel in Canada facilitated this conversion.

Regulation of greenhouse gas emissions

Instead of directly targeting the retrofit or closure of generating plants themselves, it is also possible to regulate GHG emissions either from individual plants or from the power sector overall, which should provide companies with an incentive to switch dispatch of plants, retrofit, fuel switch or retire the highest-emissions sources. Regulation could take the form of an emissions performance standard for the entire generating fleet (as distinct from a performance standard for new plants only), or a regulated share of low-carbon capacity.

Example: United States regulation of existing power plants

In 2013 the United States Environmental Protection Agency (US EPA) proposed carbon pollution standards that will apply to new fossil fuel power plants. Under this proposal, all new plants must have emissions no greater than a gas-fired plant, and therefore no new coal plant can be built unless it is fitted with CCS. The proposed rule is still to be finalised.

The next step in the regulatory process is the proposed rule for existing sources, published in June 2014. This rule sets fleet-wide GHG emissions performance standards to be met by each state. This regulation is expected to reinforce existing trends for retirement of old coal-fired capacity, which is already being driven out of the market by low gas prices and regulation of air pollutants. The regulation of existing sources is scheduled to be finalised in 2015, and implemented by the states in 2016. These regulations provide an interesting link from regulation to carbon markets: the California and Northeastern Regional Greenhouse Gas Initiative (RGGI) emissions trading systems have argued that these markets should be deemed equivalent and satisfy the US EPA emissions performance regulations.[7]

7. See Chapter 4.3 for more detailed analysis of US EPA greenhouse gas regulation.

Example: United States Clean Energy Standard

A policy tool that was proposed in the United States in 2012 but has not been implemented is a broad "Clean Energy Standard" for the power sector (US Senate, 2012). This would have required an increasing share of generation from clean sources, reaching 80% by 2050. The way that "clean energy" was defined in this proposal was based on GHG emissions, on a scale between conventional coal (0% clean) and renewable energy (100% clean). Gas-fired generation, and coal plants with CCS, were to receive partial credit in proportion to their GHG emissions, and power companies would be able to trade obligations to facilitate cost-effective delivery of the target. Over time, this policy would have provided a clear signal to retire high-emissions generation plants, particularly coal, to meet the standard.

One economic analysis found that a broad clean energy standard for the power sector could be reasonably effective, and cost-effective, in driving decarbonisation (RFF, 2010). This is because it can be designed as a close substitute for a carbon price: because the obligations are framed in terms of GHG emissions and are tradable, the clean energy standard closely approximates a form of emissions trading. For the same target level of emissions reductions, the analysis found the clean energy standard required implementation of measures up to an effective carbon price of USD 14 (compared to USD 8 for a pure carbon pricing policy), and notably did not increase electricity prices above reference levels (compared to carbon pricing instruments which resulted in USD 0.02-0.03 / kWh increases).

Regulation of other pollutants

Unlocking can also result from policies that target other objectives such as air pollution, with GHG emissions reductions a secondary benefit. Section 4.1 finds that, based on case studies from a number of global regions, air pollution controls can potentially lead to GHG reductions provided that they are structured to achieve these dual objectives.

Example: China

China's "war on air pollution" aims to address the dangerous air pollution (particularly particulate matter [PM] 2.5 and PM_{10}) levels seen in urban areas. As part of this, there are targets to reduce the share of coal to below 65% of total power generation by 2017, from 79% in 2011. Construction of new coal-fired power plants will be banned near the key urban areas of Beijing, Shanghai and Guangdong. Regional caps on coal use will also contribute to this reduction. If these short-term actions are accompanied by longer-term structural reforms, there is opportunity for both long-term air quality and GHG reductions. See Chapter 4.2 for further exploration of the GHG implications of China's air quality regulations.

Displacing coal plants with new low(er)-carbon generation

Coal-fired power generation could also be displaced by rapid deployment of alternative technologies such as renewable generation or nuclear, without any particular policies targeted at retirement of the fossil fuel plants. While the alternative low-carbon technologies have high capital costs, once installed they have low running costs so will be dispatched ahead of fossil-fuelled plants. The highest-cost fossil-fuelled plants are then no longer needed to meet a given level of demand, resulting in mothballing or closure of these plants, or their use only as reserve capacity. Policies that support deployment of renewable technologies also bring down their costs over time, reinforcing their unlocking potential.

With current low natural gas prices in the United States, many coal plants are high cost, so policies to deploy renewable energy will add to the pressure on retirement or retrofitting of coal-fired generation. However, in most parts of the world gas-fired generation is more expensive than coal, so if the need for fossil-fuelled supply decreases it could be gas plants' running hours that are reduced. In these jurisdictions, if policy makers wish to specifically target retirement of high-emissions coal plants in the short term, additional policy is needed: either a carbon price that would shift the short-run costs in favour of gas (situation B of Figure 1.2), or regulatory (or ownership) intervention to support gas over coal.

Displacing coal plants by decreasing electricity demand

If electricity demand can be reduced through energy efficiency interventions, the highest-running-cost fossil fuel plants will no longer be required. This mirrors the case of displacing coal-fired generation with new low-carbon capacity. As in that case, policy makers should carefully consider how relative coal and gas prices will influence which plants are mothballed.

Example: European Union

EU power markets have recently seen a significant quantity of combined-cycle gas turbine (CCGT) generation mothballed. One study of ten utility companies found that 20.08 GW of CCGT assets were closed or mothballed in 2012-13, 8.87 GW of which was owned by the companies for less than ten years (Caldecott and McDaniells, 2014). Several key drivers pushed these gas-fired plants out of the market:

- Falling electricity demand, driven both by the financial crisis and strong European energy efficiency targets and policies.
- Strong renewable energy deployment, supported by national policies aimed at delivering Europe's mandatory target for a 20% share of renewable energy in the final energy consumption by 2020.
- Changing relative fuel prices in Europe: coal prices have fallen (in part due to lower demand in the United States, due to shale gas prices), while gas prices have risen.
- A weak carbon price from the EU ETS, which fails to bridge the gap between coal and gas plants' short-run costs. The weak carbon price is itself caused in part by the financial crisis reducing demand for emissions allowances, and in part by renewables deployment supplying a significant share of the reductions required under the system (Gloaguen and Alberola, 2013).

In summary, a combined contraction of demand and increase in renewable energy supply has created oversupply in the market, and the conditions for fossil fuel plant retirement. However, the same factors have also created oversupply in the EU ETS, and therefore low-carbon prices that favour retirement of gas over coal. Although there is currently excess capacity, 100 GW of new thermal capacity will be needed in the European system to 2025. To deliver this investment, reform of the wholesale market is needed (IEA, 2014b).

This is an important lesson for policy makers hoping to decarbonise electricity systems only by promoting investment in low-carbon generation: these policies need to be complemented by others that address the fossil fuel side of the market. Carbon pricing and electricity market design need to be consistent with renewable energy and energy efficiency policies, so that all are aligned in a coherent package and do not to undermine one another.

Removal of fossil fuel subsidies

Electricity prices that do not reflect full costs of supply due to explicit[8] or implicit[9] fossil fuel subsidies encourage excessive energy use and can lead to inefficient investment decisions in generating plants. They create a powerful incentive to build high-emissions plants, and to build greater quantities of generation than would otherwise be required, each contributing to lock-in. In recent years, pressures on government budgets and increases in gas and oil prices have increased interest in fossil fuel subsidy reform, including commitments from G20 and Asia-Pacific Economic Cooperation (APEC) countries to phase out subsidies over time.

8. For example, fossil fuels being sold domestically below market prices.

9. For example, support to the coal mining industry which has the effect of lowering coal prices.

Fifteen percent of global CO_2 emissions receive fossil fuel subsidies equivalent to a negative carbon price of USD 110 per tonne, twice as much as the 8% of emissions that are subject to a positive (though currently low) carbon price (IEA, 2013a). The global cost of fossil fuel subsidies in 2012 reached USD 544 billion, compared to USD 101 billion in support of renewable energy (IEA, 2013c). Partial phase-out of fossil fuel subsidies is one of four key zero-cost actions highlighted by the IEA that can keep GHG emissions close to a two-degree path in the period to 2020 (IEA, 2013a).[10]

Fossil fuel subsidy reform would contribute to unlocking in two ways: it should reduce pressure on electricity demand, creating scope to retire inefficient plants, and it lessens the price differential between fossil fuel and renewable generation sources, making replacing existing generation less of a financial hurdle. It should also reduce the risk of future lock-in.

Managing the medium term with a view to the long term

With plant lifetimes of 30 to 40 years or beyond, power plants under construction today could still be in service in 2050, by which time electricity systems globally need to be nearly decarbonised. In choosing short-term policy options to "unlock" existing infrastructure, careful attention therefore needs to be paid to not undermining long-term outcomes. It is critical that any early retirements be replaced by clean generation; otherwise, the replacement generation could itself need to be retired early in the coming decades.

For example, in the short term, switching from coal- to gas-fired generation may be an attractive option to reduce emissions. However, gas without CCS can only be a short-term bridging fuel. In the IEA 2DS, the global average emissions intensity of power generation drops below that of CCGT plants in 2025. This fall in emissions intensity is driven partly by new investments in power generation being on average of much lower emissions intensity than that of gas, even before 2020 (See Chapter 4 for an analysis of fleet average versus new-build emissions intensity of power generation). While gas still has a role to play in the coming decades, over-reliance on gas to replace coal could create the need to unlock gas assets in the future. From this perspective, unlocking with replacement renewable generation has greater long-term potential, as it avoids lock-in concerns and brings benefits of cost reductions due to learning from technological experience.

One potential indicator of how difficult unlocking may be is the age of the coal-fired power generation fleet. Tracking new power plants aged 15 years or younger, and capacity under construction or under planning, can reveal recently created carbon lock-in.[11] Conversely, data on plants aged 35 years or older highlight the potential for "unlocking" plants that have already recovered their capital costs (Figure 1.3). In the United States, for example, 177 GW of coal-fired power capacity is more than 40 years old (US EIA, 2013). This information could be combined into indicators of lock-in (e.g. recently added coal as a percentage of all generation) and potential for easy unlocking (e.g. older coal plants as a percentage of all generation) (Table 1.2).

Conclusion

If existing high-emissions infrastructure is allowed to continue to run for its design lifetime, the prospect of limiting temperature rise to below 2°C seems remote. On current investment trends, by 2017 existing infrastructure would generate all emissions allowed under a two-degree scenario, meaning that any new investments would need to be zero-emissions.

Fortunately, previous investment decisions are not irreversible: it is possible to "unlock" generation capacity. There are a number of examples, explored in this chapter, of policy tools that are already in use. While these policies were considered in the context of unlocking coal-fired power generation, similar policies could be applied in other sectors. Options considered were: changing dispatch of the existing power fleet; the managed phase-out of plants; regulation of GHG emissions; retrofitting to improve plant efficiency; CCS; biomass blending or conversion; and displacing plants by building cleaner generation or decreasing electricity demand. Carbon pricing can play a role, ensuring the cleanest fossil fuel plants are favoured, even if very high carbon prices that would drive plant retirement directly seem unrealistic in the short term.

Early retirement of existing coal-fired plants clearly creates issues for owners of these assets. Where they are publicly owned (as in the case of Ontario), owners can choose to bear the immediate cost of early retirement in return for wider benefits (in the case of Ontario, they are estimated at CAD 4.4 billion in health, environmental and financial benefits).

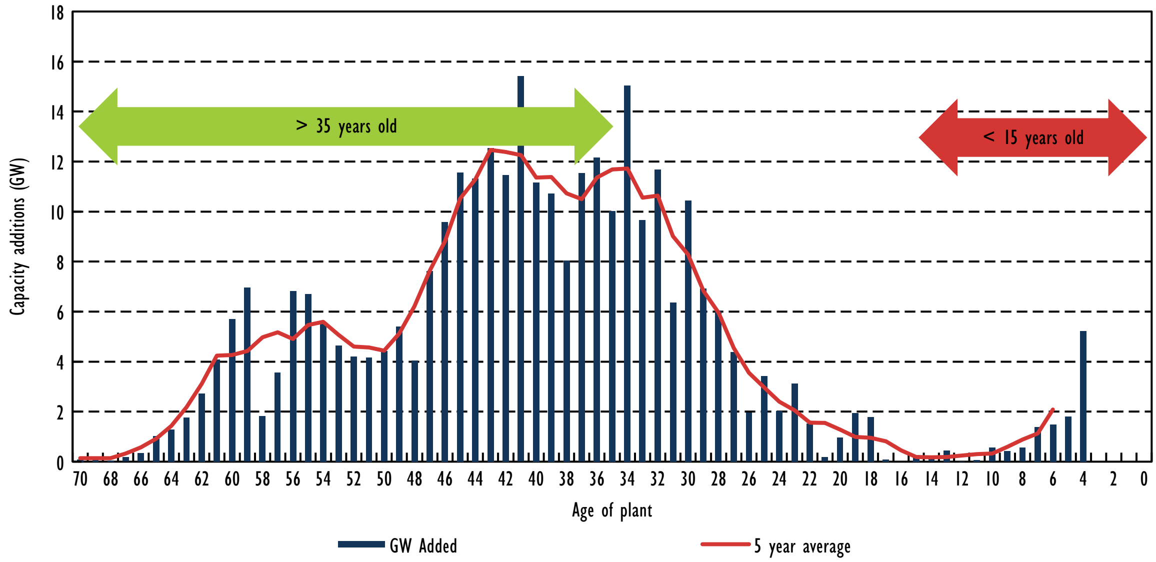
Where assets are privately owned, there may be split incentives between the plant owners (who naturally wish to maximise return on their investments) and wider society. There will naturally be resistance to early closure of plants. If utilities and other power companies are expected to be a major source of investment in new clean generation, then

10. The "4-4-2" scenario assumes full phase-out in fuel importing countries by 2020, and a 25% reduction in subsidy rates by fuel-exporting countries.

11. Capacity data can be combined with projected capacity factors, assumed lifetimes, and CO_2 emission rates to estimate locked-in emissions from these plants.

Figure 1.3

Age of current (2014) capacity of coal-fired power plants in the United States



Note: The red line is the five-year moving average of additions; year zero is 2014.

Source: US EIA (2011), Form EIA-860, Annual Electric Generator Report 2010, *Generator Vintage data, www.eia.gov/todayinenergy/chartdata/generator_vintage.csv.*

Table 1.2

Recent coal lock-in and unlocking potential for Germany and the United States

	Germany	United States
Recent lock-in (Coal plant <15 years as percentage of all generation)	2.5%	1.8%
Unlocking potential (Coal plant >35 years as percentage of all generation)	10.4%	17.0%

Notes: Capacity measured in nameplate capacity of operable, not retired plants. Germany: data available until 2013; United States: data available until 2012.

Sources: German Federal Network Agency (2014), Kraftwerksliste der Bundesnetzagentur – Stand: 02.04.2014, www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie; US EIA (2013), Form EIA-860 Data – Schedule 3, "Generator Data" (Operable Units Only), Electric Power Annual 2012, *www.eia.gov/electricity/data.*

damage to their balance sheets caused by early write-off of coal-fired assets could cause problems for future investment. These issues point to the need to proceed with caution in designing policies to unlock coal-fired generation. For example, policies that drive early retirement could be coupled with support for CCS retrofit or biomass conversion, to provide options to minimise stranding of assets. In addition, it would be helpful for policies to provide companies with flexibility to manage obligations within their portfolios (e.g. for fleet-wide emissions performance standards rather than individual plant regulation).

Policies to accelerate infrastructure turnover through policy intervention require careful thought, or they could lead to security of supply concerns: retirements need to be matched with new supply or energy efficiency gains, to keep reserve margins at acceptable levels. A key in this regard is to provide a stable framework for low-carbon investment alongside any retirement policies. Equally, policies to drive deployment of clean generation need to be complemented by policies that address fossil fuel emissions. If not, there could be unintended consequences, such as the mothballing of gas plants instead of coal in Europe due to low demand, high renewables, and low-carbon prices.

While there are options available for unlocking existing assets, it would, of course, be preferable not to add to the challenge by continuing to lock in generation capacity. The IEA *World Energy Investment Outlook* outlines what investments are consistent with a 2°C scenario in different regions, providing guidance for countries to avoid adding further costly mistakes.

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Chapter 2 • The new landscape of emissions trading systems

This chapter examines the recent rise in implementation of emissions trading systems (ETSs) around the world. A form of carbon pricing, ETSs represent effective and low-cost policy responses to addressing climate change. This chapter draws lessons from key ETS experiences making up today's dynamic policy landscape, to help policy makers in considering the design and implementation of this complex but valuable policy option.

Introduction

The implementation of carbon pricing through greenhouse gas (GHG) ETSs is gaining momentum globally, with the ETS policy landscape more diverse and widespread than it has ever been[1]. This chapter analyses the significance of recent developments in both long-standing and newly implemented ETSs, drawing lessons for policy makers.[2] This discussion focuses on issues emerging from the interaction between ETSs and the energy sector, underscoring the need for ETS policy design to carefully consider implications on the energy sector, and vice versa.

Key issues include the challenges of implementing an ETS in energy systems of a more regulated nature; the need to understand and address the impact of carbon prices on electricity prices; and the importance of incorporating policy flexibility to respond to external influences such as other energy and climate policies.

The global ETS landscape

Beginning with the European Union Emissions Trading Scheme (EU ETS) in 2005, which remains the largest system, current or planned systems now exist in all corners of the globe (Figure 2.1).

Since 2013 the world has seen a rise in ETS implementation, with new or expanded systems in China, California, Québec, Kazakhstan, and Switzerland (Figure 2.2). China has seven municipal and provincial pilot ETS projects running, which is expected to inform development of a national system after 2016. The state of California and province of Québec participate in a linked ETS. The Northeast United States, New Zealand, Kazakhstan and Tokyo are other examples, and there are more under preparation: South Korea has passed legislation to begin emissions trading by 2015, and India, Chile, Brazil, Thailand and Mexico are in various stages of consideration and development of ETSs. While it is clear that support for carbon pricing and emissions trading are not universal, it is difficult to ignore the trend of expansion.

European Union

The flagship EU ETS was the first international ETS to be implemented and remains the world's largest, covering more than 11 000 power plants and industrial installations in 31 countries. The EU ETS has undergone changes over time, from Phase I in 2005 to Phase III which began in January 2013. For example, coverage has expanded from industry and electricity generation at the outset to include regional aviation, as well as including other GHGs beyond carbon dioxide (CO_2).

Phase III has also heralded the start of a concerted phase-out of free allowance allocation. In 2013, 40% of allowances were auctioned (with the electricity sector purchasing the majority of allowances through auction). The intention is to move to 100% auctioning of allowances by 2027 for sectors that do not face competitiveness concerns. Separate national emissions caps have also been aggregated into a single EU-wide cap.

The EU ETS has faced various challenges. In recent years, much attention has focused on the low prices of emissions allowances, essentially reflecting an excess of allowance supply compared to demand. This is the result of two important factors. Firstly, the 2008-09 recession reduced electricity demand and industrial and manufacturing activity. Secondly, complementary policies designed to increase Europe's share of renewable energy to 20% and improve energy efficiency by 20% (by the year 2020) resulted in emissions reductions that were partly unaccounted for in the determination of the EU ETS cap.

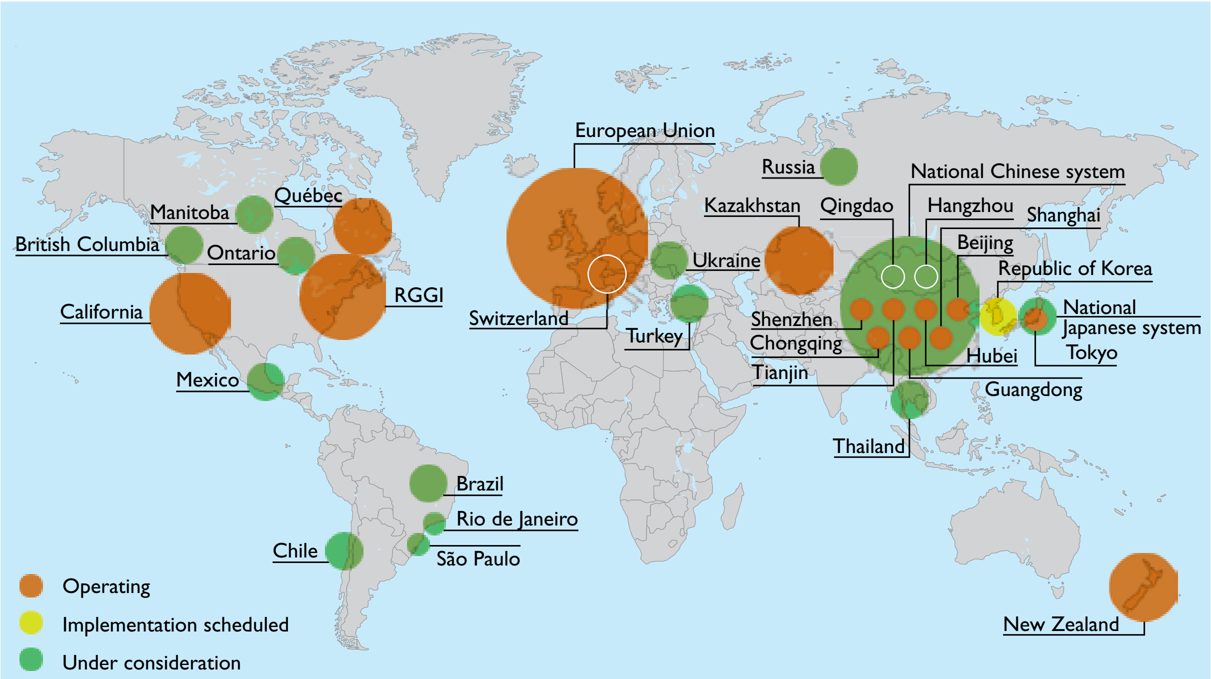
To address the oversupply of allowances in the EU ETS, a measure was approved at the end of 2013 to implement "back-loading", which defers auction of some allowances from the early part of the Phase III trading period until

1. "Greenhouse gases" and "carbon emissions" are used interchangeably in this chapter.

2. This chapter does not discuss crediting systems such as the Kyoto Protocol's Clean Development Mechanism, Japan's Joint Crediting Mechanism, and crediting for avoided deforestation (REDD+) which may also be relevant for the markets beyond 2020. Furthermore, this chapter discusses issues generally more relevant to downstream emissions trading systems (applied at the level of energy users, e.g. a manufacturing facility), rather than upstream systems (applied to energy producers, suppliers and distributors, e.g. a coal mine), as the latter has been the more commonly applied approach.

Figure 2.1

Current status of ETSs worldwide



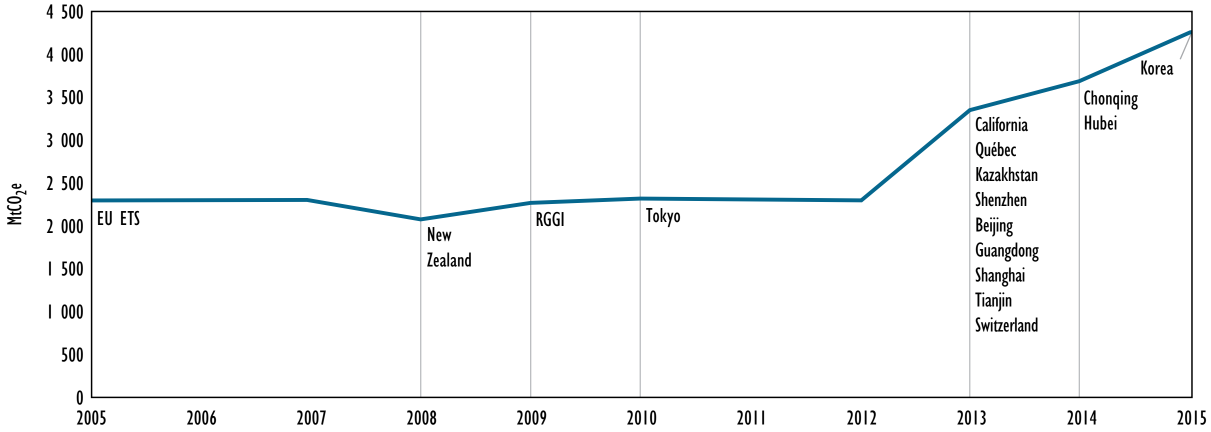
This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Note: The size of each circle is approximately proportional to GHG emissions covered.

Source: Adapted from country sources and ICAP (International Carbon Action Partnership) (2014), "ETS Map", https://icapcarbonaction.com/ets-map.

Figure 2.2

Global proliferation of ETSs 2005-15



Source: IEA analysis based on country sources.

later years. It is expected that allowance prices will rise in the short term as a result. As a longer-term solution, the European Commission has also proposed the establishment of a market stability reserve, which would hold back allowances from auction if oversupply exceeds a certain threshold, and release allowances into the market below another threshold.

China

China implemented its first ETS pilot programme in June 2013, in Shenzhen. Since then, six others have started running: four at the municipal level in Beijing, Shanghai, Chongqing and Tianjin and two at the provincial level: Guangdong and Hubei. Potential schemes in the cities of Hangzhou and Qingdao are also being considered. These pilot systems will inform the potential implementation of a national system during the next Five-Year Plan (2016-20). As a rapidly growing emerging economy, China's use of market mechanisms in the form of ETSs can help steer a path towards "green growth".

An interesting aspect of the Chinese pilots is that they provide a testing ground for how ETSs can be implemented in a highly regulated electricity system. An ETS generates price signals, which are designed to result in market responses. If emitters face a price incentive to reduce emissions but are constrained by regulations on how they can respond to that price, the ETS will function differently and ETS design choices must take this into account.

The seven Chinese pilot systems, by design, allow different ETS design elements to be tested in a range of jurisdictions with varying economic characteristics. The pilot systems cover anywhere from one- to two-thirds of the jurisdiction's CO_2 emissions. Most place caps on emissions intensity as opposed to absolute emissions. Most allocate all emissions allowances for free based on different benchmarks of past emissions, although a small amount of auctioning has taken place in Guangdong, as well as in Hubei, Shanghai and Shenzhen. All pilots cover industrial sectors, with some extending coverage of the commercial sector. Shanghai's also covers some airline transportation. All pilots cover CO_2 emissions exclusively. A snapshot of emissions allowance prices in May 2014 shows that they have been generally comparable to those in other ETS systems (the European Union's, California's, and the Regional Greenhouse Gas Initiative [RGGI]).

Australia

The Australian government repealed its carbon price legislation in July 2014. Still, Australia's ETS contained unique design elements, which can still provide a number of lessons for policy makers considering ETS implementation.

Box 2.1

A simulation of emissions trading in China

To support the design of a national Chinese ETS and supplement the learning process started with the pilots, the IEA, together with the China Electricity Council (CEC), China Beijing Environment Exchange (CBEEX), and the Environmental Defense Fund (EDF), developed and ran an ETS simulation with the Chinese power sector in the summer of 2013. The simulation focused on three issues critical to developing an active market: How would China's generators adapt to a carbon constraint? How would carbon market size and trading flexibility affect trading and operations? How would different participants' starting positions affect trading?

The simulation results strongly suggest that China's generators will be able to adapt to manage both a carbon constraint and their power production mandates. Generators selected a range of strategies when managing their virtual fleets of generating units (new and existing), each with its distinct carbon footprint, cost structure, and allowance requirements.

In the simulation, ETS market design decisions had a direct impact on the manner in which the overall market functioned, how individual companies operated within it, and overall and company-specific efficiencies. Broad, integrated markets with flexible rules to facilitate trading provided the best opportunity to lower the cost of meeting carbon constraints, on both a source-specific and market-wide basis. Generally, the most profitable companies were those who most actively traded in the market. The availability of offsets (which under the simulation were provided by non-participants) gave participants an important additional source of carbon capacity, in particular versus allowances which could only be acquired from trading with other participants (i.e. competitors).

Though limited in scope, the simulation bodes well for a national Chinese ETS covering the power sector. When faced with a simulation that included a fixed carbon cap, an ETS that provided for tradable allowances and offsets, penalties for non-compliance, and an increasing power generation obligation, Chinese power generators were able to meet power generation, carbon and profit mandates. Consistent with expectations, the simulation also showed that ETS market design has a direct impact on company-specific and market-wide efficiencies.

The Australian ETS was established in 2012, beginning with a transitional fixed-price period in which allowances would be sold at AUD 23 per tonne of carbon dioxide (tCO_2).[3] From 2015, the ETS was to have entered its flexible price phase, with allowance prices set by trading of emissions allowances. Discussions had also begun to link the Australian system with the EU ETS. The system covers electricity, industrial and, to an extent, transportation and waste emissions. The design called for most allowances for emissions-intensive and trade-exposed industry to be allocated for free, while the power sector would purchase allowances at auction or from the ETS market.

Two interesting design features of this system are worth highlighting. Firstly, to enable the system to be resilient to unforeseen changes in circumstances, emissions caps were to be set five years in advance on a rolling basis. This was intended to provide a window of certainty for investors, yet also flexibility to policy makers to adjust the system as necessary to maintain an appropriate balance between allowance supply and demand. Second, a package of changes to income tax and social support were put in place to offset the impact of rising electricity prices on consumers. Australia's market-based electricity system allows full pass-through of the carbon price to electricity prices, providing a price incentive for consumers to use electricity more efficiently. Compensating adversely affected groups rather than preventing this cost pass-through promotes efficient functioning of the ETS while also addressing concerns of distributional impacts.

Development of the Australian system has also taken place in a dynamic political context, with five years of intense political debate preceding the eventual implementation of emissions trading in 2012. When an emissions trading proposal was first announced in 2007, both major political blocks supported its introduction. There have since been two changes of government, and there is no longer bipartisan support for carbon pricing. Having repealed the carbon pricing legislation, the present government instead intends to introduce direct incentives for emissions reductions.

California and Québec

The California and Québec ETSs each began trading in 2013 and were officially linked on 1 January 2014. They are based on a common architecture developed under the Western Climate Initiative (WCI),[4] which facilitated linking. Given that sub-national ETSs are increasing in prevalence across the globe, this first example of linking sub-national systems internationally is of particular interest.

This linking has been an important signal for other sub-national governments, including other members of the WCI, of concrete progress in establishing a functional carbon market in North America.

Linking systems improves access to low-cost emissions reduction opportunities. Issues in linking include potentially substantial financial transfers between jurisdictions, ensuring adequate accounting and enforcement in each jurisdiction, and commonality of key design elements such as offset protocols, and price ceilings and floors. Linking can be more successful if jurisdictions are able to co-ordinate ETS design prior to implementation, as was done in this case through the WCI. The WCI framework includes the use of price ceilings and floors to provide greater certainty for investors in the face of unpredictable economic circumstances and overlapping policies.

Key lessons from recent ETS developments

Recent developments in the ETS policy landscape are notable on several fronts. First, ETSs are being implemented in an increasingly complex economic and policy landscape. As focus grows on the necessary transition to low-carbon economies, ETSs are increasingly being implemented where there is already a rich set of other policies that target energy efficiency improvements, deployment of renewable energy, and research and development of low-carbon technologies.

Second, several major ETS jurisdictions are just beginning to recover from the 2008-09 economic recession. The effect of the recession on ETS function reaffirms the notion that an ETS does not operate in a vacuum and that flexibility in ETS design to manage the wider policy and economic context is important.

Third, the global expansion of ETS adoption signals a shift in the role of what have traditionally been considered developing countries, whose participation in carbon markets has previously been as recipients of investment and assistance rather than as purchasers of emissions reductions. One consequence of this shift is that ETSs are being considered and implemented in electricity markets that are subject to greater regulatory control, which raises issues for matching ETS design to existing regulatory structures. Until recently, ETSs had been applied only in jurisdictions with fairly liberalised electricity markets.[5]

Finally, although ETSs are expanding, their implementation is by no means universally accepted or irreversible. The withdrawal of parties from the WCI in the United States and

3. Therefore, this effectively acted as a carbon tax in the transitional period.

4. WCI is a group of US states and Canadian provinces that collectively developed the basic framework of both the California and Québec markets.

5. In general, jurisdictions in industrialised countries (Europe, Australia, and North America) have had the most extensive experience with electricity market liberalisation.

Canada, and the change of direction in Australia, provide indications of how support for ETSs can change over time.

Better integration of ETS and complementary energy policies

The transition to low-carbon energy systems will require action across a broad range of policy areas. Complementary policies can support an ETS by targeting reductions that may not be effectively driven by the carbon price, such as energy efficiency improvements and research and development of low-carbon technologies.[6] On the other hand, if poorly aligned with the ETS, overlapping policies can translate into increased costs and deflated allowance prices. Managing interactions between the ETS and complementary energy policies is therefore critical.

Steps that can contribute to better policy integration are to improve certainty in the delivery of energy policies (so that the ETS market better understands their likely impact), and to ensure that ETS emissions caps are set taking energy policies into account. In-built flexibility in ETS caps would also be helpful to allow adjustment for changes to complementary policies that were not included when the cap was set, just as it would allow for adjustment to changing economic circumstances. The 2030 Climate and Energy Package, which includes energy efficiency and renewable energy objectives for 2020-30, includes provisions to improve co-ordination in the development of national energy plans by member states and to enhance tracking of progress towards policy goals using indicators. The proposed market stability reserve for the EU ETS is also intended to improve integration of policies.

An ETS can interact positively or negatively with complementary policies in the same jurisdiction. Co-ordinating the design of the ETS with interacting climate and energy policies is central to ensuring each delivers its respective objectives.

ETS design for resilience to changing economic conditions

The collapse in prices in the EU ETS has resulted from a combination of economic recession and complementary energy policies that were not fully accounted for when the ETS cap was set (Gloaguen and Alberola, 2013). This has led to the proposal of a market stability reserve, which would allow for adjustment of allowance volumes based on pre-agreed trigger ranges. This would provide certainty that the quantity of allowances on the market at any given time will remain within a certain range. The establishment of pre-defined rules also allows adjustments to be made without undergoing a lengthy approval process.

Allowance prices can also be managed directly through price (instead of quantity) limits in the form of price floors (minimum price levels) and price ceilings (maximum price levels), as is done in the California and Québec markets. These measures can also be accompanied by the establishment of an allowance reserve, which releases allowances at the price ceiling, and withholds allowances if market prices are at the price floor. A third approach to providing greater flexibility is to allow for more frequent revision of the ETS cap instead of using allowance reserves. In the Australian ETS design, caps were to be set five years ahead to provide certainty, but on a rolling basis to enable annual adjustment for changing circumstances.

With these multiple ETS design choices available, vulnerabilities of an ETS to external market circumstances (such as the recent economic recession) are not necessarily a given. System resilience can be improved if policy makers carefully consider their options.

ETS resilience to changing political contexts

The signals sent by an ETS to change operational and investment decisions ultimately rely on a market created by government decisions. As a result, the continuity and predictability of an ETS will depend on continued political support. The experience with several ETS introductions has been that political controversy reduces once the system has been in place and operating for some time and stakeholders gain experience with it. The recent developments in Australia show that this should not be taken for granted: ETSs, like other carbon pricing mechanisms, are not immutable and can be modified or repealed. Uncertainty about future political support for carbon pricing will have implications for the ability of an ETS to drive change in longer-term investment decisions that are central to decarbonisation of the energy sector.

ETS implementation in highly regulated electricity systems

While many electricity markets in Europe, Australia, and North America have undergone market liberalisation over the past two decades, many jurisdictions both within and outside of these regions still closely regulate their electricity prices and electricity production (including in what order individual plants are "dispatched").

Reflecting the cost of carbon emissions through increased prices (of fuels and electricity) is the foundation of a carbon pricing policy such as an ETS. Where electricity prices

6. Carbon pricing addresses one particular market failure: the costs of carbon emissions being external to economic decision-making. However, other market failures may be better addressed by other policies. For example, measures targeting energy efficiency improvements can address lack of information and principal agent issues, while promotion of research and development can address insufficient investment in a public good.

are regulated, the pass-through of carbon prices to end consumers can be prevented, hampering the functionality and effectiveness of the ETS by removing the incentive for consumers to change their electricity use behaviour.

In the Chinese power system, electricity prices are set by the state, and electricity generators are therefore not able to automatically pass on additional carbon costs through a higher electricity price, at least not in the short term.[7] Different power plants are dispatched based on provincial-level plans, which tend to allocate each plant a certain number of operating hours, rather than based on the costs of generation or the environmental attributes of different plants. Inefficiencies result when more expensive or more polluting plants are dispatched while cheaper or cleaner ones remain idle. These factors provide a rationale for the prevalence of free allocation in the Chinese pilot ETS systems, as producers would be unable to recuperate the increased costs of purchasing carbon allowances through higher electricity prices.[8] However, without price pass-through, electricity users do not face an additional financial incentive to adjust their use of energy. While it is most critical that electricity supply become less emissions-intensive, demand-side response is also needed for a full low-carbon transition of the electricity system.

Policy design can be adjusted to account for the lack of price pass-through in regulated electricity systems. As already mentioned, free allocation of allowances can form part of the design. Another option is to require large electricity consumers (e.g. industrial or commercial users) to participate in the ETS market, effectively extending carbon prices to the demand side. This approach is applied in several of the Chinese pilot systems. This remains an imperfect solution, however, as many users such as households are not included under the demand-side cap. A better response would be to pursue a greater degree of market liberalisation, allowing flexibility for electricity prices and dispatch to adjust to carbon prices and other market signals. This could help improve the functioning of both the electricity system and the ETS in a more comprehensive manner, beyond individual policy measures taken to emulate market forces and responses. The question remains as to what extent the application of an ETS in China may catalyse consideration of electricity market reform. Latest discussions about economic reform at the government's Third Plenum signal this as a possibility. In summary, ETSs may be workable within regulated electricity markets, though measures may need to be taken to ensure propagation of the carbon price signal.

7. In regulated electricity systems where electricity rates are based on average costs (marginal and fixed costs), the rise in carbon costs could eventually be reflected in electricity prices during rate adjustment periods. However, the "pass-through" of carbon costs to electricity prices would not be immediate and would be subject to the method of rate determination.

8. If carbon prices could be passed through, free allocation would lead to windfall profits for generators. In essence, industry stands to gain twice: once from the "gift" of free allowances and again from charging higher prices for the goods and services sold.

ETS design and electricity prices

Passing the cost of carbon on through higher electricity prices reflects the fulfilment of an important objective of a carbon pricing system: propagation of a carbon price signal. Specifically, it helps extend the reach of this signal beyond electricity generators to electricity users, who will face an increased incentive to change the way they use electricity to reduce emissions. However, rises in energy price can have an important impact on particularly vulnerable groups, including low-income households (who spend proportionately more of their income on energy and therefore may face a disproportionately greater burden compared to higher income households), and trade-exposed industry and power generators (who may be unable to convert carbon costs into increased product prices due to competition in their export jurisdiction).

In Australia, empirical estimates of the rate of carbon price pass-through into wholesale electricity prices vary. Broadly, findings suggest that the majority of costs were passed through, with a few estimates even exceeding 100% (Nelson, Kelly and Orton, 2012; Frontier Economics, 2009). Despite the majority of costs being translated into higher wholesale prices, the effect of the carbon price is diluted at the retail level. This is because other factors beyond wholesale prices, such as transmission and distribution charges, determine the retail electricity price.[9] In liberalised electricity markets such as Australia's, generators have an incentive to pass through the carbon price, even if allowances are received for free. Though it may appear that receiving a free lump-sum allocation would discourage pass-through (since emitters are not faced with an actual increased cost of generation), they still face higher opportunity costs because they could sell the allowances.[10]

Importantly, compensating affected groups rather than preventing the cost pass-through offers dual benefits for ensuring that end users face incentives to change their electricity use while addressing concerns of distributional impacts. Measures to support and compensate vulnerable groups include:

- Free allowances (or compensation for electricity price rises) for at-risk industry. In the short term, this acts as a financial transfer to provide transitional support to

9. The Australian Energy Market Commission estimates that on average across states and territories, the carbon component represented 9% of overall retail electricity price in Australia (AEMC, 2013).

10. Although this is the case with grandfathering allowances, it is not so with output-based allocation where opportunity costs are not created when tying allocation with production.

industry.[11] However, free allocation can be overly generous and result in windfall profits. This has been the case in early stages of the EU ETS, where, for example, the pulp and paper sector is estimated to have received 20% more allowances than required in Phase I of the EU ETS (Trotignon and Delbosc, 2008). Conditional free allocation of allowances could partially address these concerns. These conditions for receiving free allowances may include commitment to invest in best available technology and energy efficiency, or to implement energy management systems. Allocating allowances based on best-practice benchmarks (which the EU ETS moved to in Phase III) or based on output (as compared to "grandfathering" based on historical emissions) can also reduce the extent of windfall profits.

- Measures to "cushion the blow" for households. These include reducing income and other taxes, distributing lump-sum payments or providing energy bill assistance. Wide-scale investment in energy efficiency may reduce total electricity demand, thereby lowering electricity prices and benefitting consumers of electricity. These measures can serve to benefit industry as well. In Australia, about half of the revenue from the carbon price policy is used to compensate households through tax cuts and household payments.

As an impact with high visibility, rises in electricity prices play an important role in shaping public perceptions of an ETS's overall impact on the economy and, in turn, its acceptability by different groups. There is often a lack of understanding that carbon pricing is the least-cost policy response from the perspective of the economy as a whole: even though energy price rises can have a negative economic effect, carbon pricing policies also raise revenue that can be used to stimulate economic activity. In every jurisdiction where an ETS has been introduced, industry has voiced concerns about high electricity prices leading to losses in growth and competitiveness, while concerns about the rising cost of living for households are also expressed.

In the end, an ETS by nature will increase the price of goods and services: in fact, its core objective is to do just that by better reflecting the societal costs of emitting GHGs. It is important to remember, however, that carbon pricing remains the most cost-effective method of promoting emissions reductions. Policy design should not be concerned with whether costs will be imposed, but rather how they are distributed. The question of who pays has been fundamental in the challenges faced in schemes around the globe. The policy makers' challenging task is to design an ETS that not only fairly distributes costs, but is also perceived to do so.

ETSs in an international climate agreement

While ETSs are expanding worldwide, it remains unclear what role they will play within a post-2020 international climate change agreement under the United Nations Framework Convention on Climate Change (UNFCCC).

The Kyoto Protocol envisaged creation of a harmonised global emissions trading market, allowing for government-to-government trading between countries with emission reduction obligations, including flexibility mechanisms through the Clean Development Mechanism (CDM) and Joint Implementation (JI) programmes. However, international trading at the government level has been minimal, and the evolution of ETSs has instead taken place at the national or sub-national level. How to recognise and encourage linkages across the generally uncoordinated establishment of disjointed ETSs and other carbon pricing instruments will be a challenge for the new climate agreement.

While ETSs are developing from the "bottom up", the UNFCCC can still play an important "top-down" role. This is because, in order for any emissions reductions that are transferred across national borders to count towards national reduction targets, there must be common rules for recognising and accounting for reductions. The transfer of emissions reductions can take place between two markets that face emissions reduction caps (e.g. California and Québec), or between one market that is capped and another which is not, in the form of an emissions offset (e.g. EU ETS purchasing CDM emissions reduction credits from a developing country).[12]

Broadly, the UNFCCC process has important functions to play in three major realms. The first is to establish standards for the quality and environmental integrity of traded emissions reductions. This would provide assurance that domestically produced emissions reductions used for compliance outside of the jurisdiction in which they were produced meet a certain quality standard, increasing confidence and building trust across market participants. Existing international standards such as ISO standards and the CDM Validation and Verification Standard could be built upon. A host of standards being used in voluntary carbon markets could also serve as templates. One interesting possibility is to create risk ratings for units, comparable to those applied in financial markets. This would allow reduction units of varying quality (such as environmental integrity) to be differentiated but ultimately compared (Marcu, 2014).

A second role for the UNFCCC is to ensure accurate tracking of international flows of emissions reduction units. This may also involve developing rules for domestic registries

11. Free allocation based on grandfathering will not address concerns of emissions leakage and competitiveness. However, allocation based on production output ("output-based allocation") can, by lowering the marginal production costs of a trade-exposed firm.

12. Carbon offsets do not necessarily need to cross political borders. The electricity sector covered under an ETS may purchase offsets generated from the forestry sector in the same jurisdiction.

and transaction tracking, such as through the International Transaction Log (ITL) of the Kyoto Protocol. Finally, the UNFCCC will need to develop an accounting framework that clarifies how internationally traded emissions reductions can be counted towards national targets put forward under the new agreement. These three functions could help deliver comparability ("fungibility") of reductions from different systems and facilitate system linking by creating common rules on how reductions from different jurisdictions can be credited, compared and tracked.

Conclusion

Emissions trading is an effective and low-cost policy response to climate change, and is gaining traction in jurisdictions worldwide. From the long-standing EU ETS to recently implemented pilots in China, these experiences provide rich ground from which to extract insights and lessons across a diverse range of economic, political, and social contexts. Implementation of ETSs in real-world energy systems is far more complex than the "text-book" prescriptions would suggest. The complexities of ETS implementation include the need to manage co-ordination with interacting policies, to provide resilience to changing economic conditions, to manage impacts on electricity price, and to determine how ETS design can fit within the existing regulatory structure of a jurisdiction's energy sector.

Complexity is added to the policy maker's task by the need to also address political economy questions, that is, to manage both real impacts of ETS introduction and public perceptions. Energy price rises have been at the forefront of concerns, so policy makers should carefully consider options for a pragmatic, robust outcome. Political context will influence not only the sustainability and certainty of ETS policies, but also the extent to which they can be made ambitious enough to drive deep decarbonisation.

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Chapter 3 • Metrics for tracking progress in energy sector decarbonisation

This chapter explores the range of metrics that could be used to track decarbonisation of the energy sector. While greenhouse gas goals are an essential component of decarbonisation, specific energy sector metrics provide deeper insight into the underlying drivers of change, and can track interventions with long-term as well as short-term impacts.

Introduction

As countries implement actions to decarbonise their energy systems, the choice of metrics used to track progress on these actions matters a great deal. First, understanding and accurately tracking all countries' actions will be critical to a successful international climate regime. Second, the choice of metrics can itself have an influence on what actions countries choose to take, and the ambition of these efforts. This chapter will consider why, in addition to greenhouse gas (GHG) goals, the use of energy sector metrics could be helpful within and outside the United Nations Framework Convention on Climate Change (UNFCCC) process to help drive the energy sector actions needed for decarbonisation, and how energy sector metrics could be tracked.

Energy sector policies and actions that reduce GHG emissions may be motivated primarily by wider benefits such as energy security, building experience with new technologies, cutting air pollution, or reducing energy bills, with GHG emissions reductions coming as a secondary benefit. There are also many actions needed to put our energy systems on track for long-term decarbonisation that do not necessarily produce short-term emissions savings. Setting energy sector transformation goals only in terms of GHG reductions may therefore not be the most effective means of inspiring action, tracking progress, or enabling strategic decisions on the synergies among desired policy outcomes. It can make sense for countries to set goals and track delivery of actions in line with specific energy sector metrics.

A new climate agreement applicable to all countries is being negotiated under the UNFCCC, to be agreed by the end of 2015 and to come into effect from 2020. As part of this process, parties to the UNFCCC have been invited to communicate their intended national mitigation contributions (i.e. commitments or goals) for the new agreement by the first quarter of 2015 (for those parties ready to do so). Because these contributions are to be nationally determined and not externally imposed, a diverse range of potential contribution types is expected, including some framed in non-GHG terms. If countries do propose a wider range of contribution types, this raises the challenge of how to accurately measure and report these actions.

Choosing the right metrics for energy sector decarbonisation

The ultimate objective of climate negotiations under the UNFCCC is the "stabilisation of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system" (UNFCCC, 1992). To date, this has led to a focus on countries' economy-wide GHG emissions as the primary measure of progress. In preliminary discussions of how the new 2015 climate agreement will be structured, however, it is becoming clear that a diverse range of nationally determined mitigation goals, tracked via a diverse range of metrics, could be included in addition to GHG targets. At the domestic level, tracking a more diverse range of metrics would also benefit countries by helping them to better understand their opportunities for action and to drive energy sector transformation in a more targeted manner. There are many reasons why countries may be motivated to use energy sector goals and metrics to support GHG emissions reductions (Prag, Kimmel and Hood, 2013):

- **Energy sector metrics can link more directly to policy influences.** Short-term total annual GHG emissions can change for many reasons, including changing economic conditions, fuel prices, or weather. Targets that are more closely linked to policies under the control of government (for example, a mandated share of renewable electricity generation) may be easier to adopt, as outcomes are more easily influenced or directed by policy and decision makers can have more confidence that targets can be delivered.
- **The primary purpose is often not emissions reductions.** Clean energy policies are implemented for a wide range of reasons and often have multiple benefits, of which emissions reductions are only one. For example, energy efficiency interventions have benefits for health and well-being, industrial productivity and competitiveness, energy providers, energy consumers, public budgets, and for macro-economic outcomes including jobs.
- **Different metrics can re-frame the challenge positively.** The framing of GHG reductions as a burden to be shared among countries sends the message that

while action on climate change is necessary, it will be an economic burden. Discussions towards the new 2015 agreement are instead seeking to frame climate action positively, as an opportunity to be seized. Alternative framing of metrics can help change the communication and perception of climate goals.

- **Alternative metrics can highlight short-term actions that underpin long-term transformation**. To date, most GHG reduction goals have short-term (5-10 year) targets.[1] This logically encourages implementation of the least-cost measures for short-term emissions reductions – not necessarily the same actions that would be optimal from the perspective of long-term transformation. Tracking actions underpinning long-term transformation, such as lock-in of infrastructure and development of key technologies, would complement short–term GHG goals.

Typology of metrics for energy sector decarbonisation

There is a wide range of metrics that could be used to track energy sector decarbonisation progress. To better understand these metrics, they can be separated into three types, based on their targets and time frames (Prag, Kimmel and Hood, 2013). The energy sector implications of these three types of targets will be analysed in the following sections:

- **Type I:** metrics expressed in GHG terms (e.g. total annual GHG emissions, GHG per unit of gross domestic product (GDP) or production, whether economy-wide or for the energy sector)
- **Type II:** metrics expressed in non-GHG terms, but which are nonetheless likely to have an impact on short- to medium-term GHG emissions levels. This category would include many energy sector metrics such as those used to track energy efficiency, renewable energy and other low-carbon energy deployment goals.
- **Type III:** metrics that track actions that will have a significant impact on long-term emissions, but minimal impact on short- to medium-term GHG emissions levels. These would include tracking research and development of key technologies, or infrastructure investment trends that lead to the lock-in of high-emissions infrastructure.

Within Type II and III metrics, a distinction can also be drawn between metrics that track the outcomes of policy (e.g. energy consumption per GDP), and metrics that track the drivers of emissions reductions (e.g. retrofit rate of existing buildings). These play complementary roles: *outcomes* metrics are important to understand overall progress after implementation, while *drivers* metrics give a more direct understanding of the transition pathway required and the consistency of current actions with the desired goals.

GHG (Type I) metrics

Metrics expressed in terms of GHG emissions enable tracking of the overall outcomes of decarbonisation actions. They are critical to estimating upfront, and to checking after policy implementation, that national and aggregate global emissions reductions are on track to meet the global goal of keeping temperature rise to below 2°C. In the new 2015 climate agreement, Type I metrics are expected to be the principal type of national mitigation contribution. These mitigation contributions could take various forms: annual GHG emissions relative to a base year or targeting a fixed level, or referenced to GDP or a business-as-usual baseline.

In the energy sector, Type I metrics that go beyond total GHG emissions can be useful to understand underlying causes of GHG changes and where action is needed. For example, the IEA Energy Sector Carbon Intensity Index (ESCII) tracks carbon dioxide (CO_2) per unit of energy production, referenced to 2010 levels.[2] It shows that at a global level, the emissions intensity of the global energy supply has remained largely unchanged in the last 40 years as increases in clean energy have been matched by increased use of coal. As demand for energy has risen, so have energy sector emissions. Examining the ESCII in the IEA scenarios to 2050 shows the specific challenge ahead for decarbonising the energy supply: in the 2°C Scenario (2DS) which keeps warming below two degrees Celsius, the ESCII must begin to decline by 2020, and be halved by 2040. In this case, tracking the alternative metric shines light on the fact that the clean energy supply has not kept up with the rapid growth of demand, and a much more rapid transition to a low-carbon energy supply is needed. The ESCII can also highlight progress in decarbonisation drivers that is not apparent from headline GHG emissions. For example, Figure 3.1 shows the ESCII for China: following a rapid increase in the late 2000s as China expanded its reliance on coal, a shift to a cleaner energy supply mix has begun to reduce the ESCII since 2008.

In another example, the Committee on Climate Change (CCC) of the government of the United Kingdom developed indicator trajectories for various economic sectors. The CCC tracks the emissions intensity of power generation, but also

1. Long-term carbon budgets, for example those in UK legislation, are the exception rather than the rule.

2. The ESCII measures CO_2 emissions per unit of total primary energy supply, referenced to 2010 levels. This includes all fossil fuel emissions including transport fuels. Because this is a measure of the emissions intensity of supply, it does not capture emissions saved from increasing end-use energy efficiency.

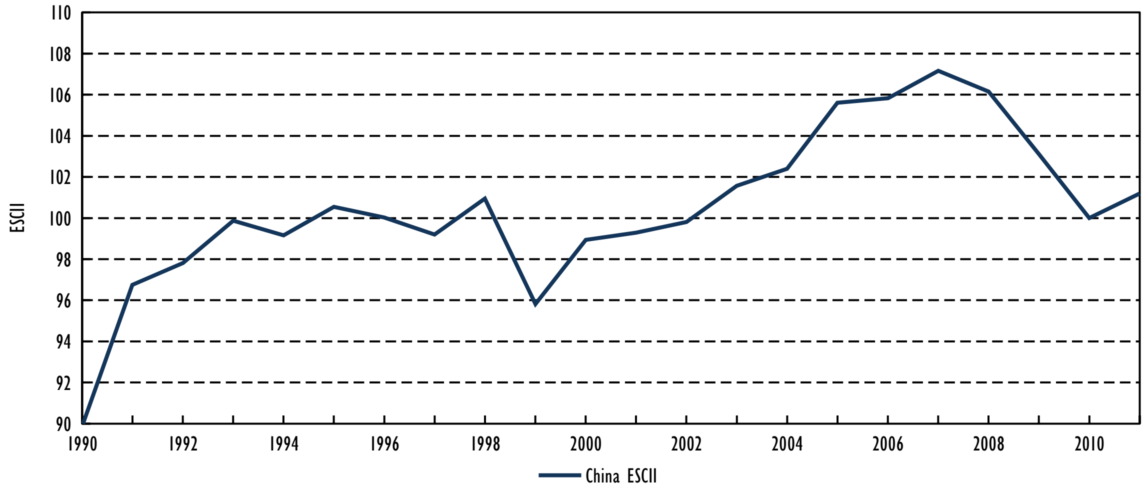
Box 3.1

How are Type III metrics distinct from Type I or Type II?

There will inevitably be some overlap between the short- and longer-term time frames considered by Type I/II and Type III metrics respectively. From the perspective of the UNFCCC negotiations, countries are developing a new climate agreement that would start from 2020 with the first round of targets running to 2025 or 2030. In this context, Type I/II metrics could be those describing actions that will have a sizeable impact on emissions reductions in the period to 2025 (for example, energy efficiency indicators), while Type III metrics relate to actions from which the most significant emissions reductions are expected in the decades after 2025 (for example, indicators of research, development and demonstration [RD&D], or demonstration of CCS or advanced vehicles).

Figure 3.1

ESCII for China



Note: ESCII of 100 equals 2010 value, equal to 2.88 tonnes of carbon dioxide per tonne of oil-equivalent (tCO_2/toe).

a metric of the "achievable" emissions intensity – that is, the minimum emissions intensity of the existing power mix if lowest-emissions plants were dispatched first, given the profile of electricity demand. In 2012, the actual emissions intensity rose due to a fuel price-induced switch from gas- to coal-burning, but the achievable emissions intensity of the fleet continued to decline, showing underlying steady progress with transformation of the power fleet by investment in renewable energy (Figure 3.2). Tracking the divergence of the two indicators in Figure 3.2 shows whether low-carbon capital stock is being optimally utilised from an emissions perspective. Over time, if low-carbon capacity is underutilised, this could undermine incentives to invest.

Non-GHG (Type II) metrics

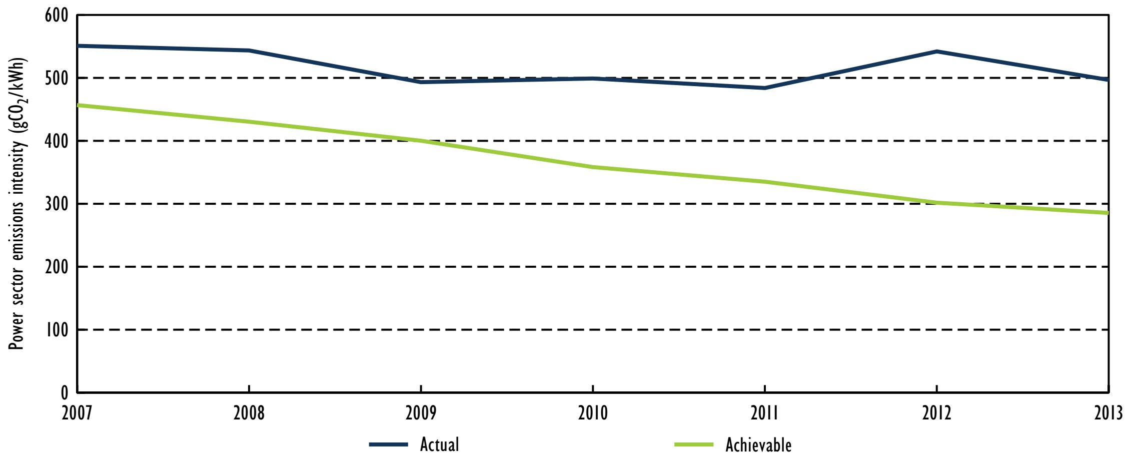
A second set of metrics are not themselves expressed in terms of GHGs, but nonetheless track actions that will have a short-term impact on GHG emissions levels. These include many energy sector metrics across energy production and consumption, such as energy intensity, share of low-carbon electricity generating capacity, or level of fossil fuel subsidies.

Countries often undertake actions to introduce cleaner energy supply or decrease energy demand for reasons other than climate change goals. For example, the deployment of renewable energy could reduce dependence on imported fossil fuels, build a local industry, and improve air quality. An energy efficiency programme could result in savings on energy bills and improved health outcomes. The phase-out of fossil fuel subsidies benefits government budgets and the overall economy, without necessarily harming the poorest section of society. From the energy policy maker's perspective, in many cases GHG emissions reductions are an important co-benefit rather than the primary driver of these actions. Carbon capture and storage (CCS) deployment is the only energy sector action that would be undertaken purely for climate change mitigation purposes, and even this could have local industry-building benefits.

This poses a challenge for climate policy makers: these energy sector actions could result in some of the largest GHG emissions reductions globally, yet goals based on

Figure 3.2

Actual and achievable emissions intensity of UK power generation



Source: CCC (2014), "Meeting carbon budgets: 2014 progress report to parliament", Reproduced under Open Government license v1.0.

Box 3.2

How can alternative metrics help re-frame decarbonisation as a positive transformation?

The framing of GHG goals could influence whether they are perceived as a burden or an opportunity. For example, referencing goals to economic progress (e.g. emissions per unit of GDP rather than total emissions) could help prevent the climate goal being seen as a constraint on economic activity, but rather as a driver of cleaner development. Metrics can also be inverted so that changes relate to increases in a positive value (e.g. maximising GDP for each unit of energy consumed), rather than appearing as constraints (e.g. minimising energy consumption per unit of GDP). Framing can also be changed by expressing goals as changes relative to a base year rather than as absolute values: this places more emphasis on future action than on different relative starting points.

An interesting example that applies both inverting and indexing is the metric proposed for a US "Clean Energy Standard" in 2012 (US Senate, 2012). This proposal would have mandated a steadily increasing share of clean energy in the power supply, reaching 80% clean energy by 2035. In this policy proposal, zero-emissions technologies (renewables, nuclear) would receive one credit, coal-fired power generation would receive zero credits, and gas would receive a partial credit relative to its emissions intensity compared to coal. The clean energy obligation would therefore correspond to the inverse of the emissions intensity of the power sector, also being scaled from 0% to 100%. This reframing of the metric could be seen as changing the story from a reduction in emissions to an increase in clean energy, the latter being popular and more easily understood by the general public.

Type I metrics (and associated climate policies targeting GHGs) may not always be the strongest motivating factor. Setting more direct targets relating to energy supply or consumption may be more relevant to politicians and citizens at the domestic level, as they can reflect the multiple benefits of these actions. It could also be easier for policy makers to have confidence in delivering on goals expressed using Type II energy metrics, as these relate more closely to the policy options that they can choose to implement (Prag, Kimmel and Hood, 2013). Table 3.1 presents a range of Type II metrics that countries could use to track actions in energy demand, renewable energy, carbon capture and storage, and phase-out of fossil fuel subsidies.

A key issue for climate policy makers, including in the UNFCCC process, is to be able to understand the GHG emissions savings associated with goals based on Type II metrics. It is simpler to convert outcome metrics (e.g. energy intensity of industrial sectors) than driver metrics (e.g. a set of appliance energy efficiency standards) to GHG outcomes. This is because outcomes metrics can generally be converted using emissions factors, while for driver metrics additional assumptions are often needed, such as deployment rates. On the other hand, driver metrics may be more relevant to private sector innovation and market strategies, so these could help create expectations for private sector actors.

The specific way in which a Type II contribution is framed can also make it either easier or harder to estimate its likely impact on GHG emissions levels. For example, energy consumption goals could be expressed as a percentage

Table 3.1

Selected potential Type II energy sector metrics

	Possible metrics
Energy consumption	Total primary energy supply (petajoules [PJ], million tonnes of oil-equivalent [Mtoe])
	Final energy consumption (PJ, Mtoe)
	Energy intensity (terawatt hours [TWh] per USD)
	Energy efficiency (accounting for changes in economic structure)
	Energy consumption per unit of production in key energy-intensive sectors
	Technology-specific goals (e.g. vehicle fuel economy or appliance standards, number of energy-efficient light bulbs distributed)
Renewable energy and other low-carbon supply	Annual production of renewables (PJ, Mtoe, kilowatt hours [kWh])
	Share of renewable energy in total energy supply (%)
	Share of renewable energy in total energy demand (%)
	Cumulative installed renewable electricity capacity (megawatts [MW])
	Share of renewable electricity in total generation (%)
	Share of new-build renewable energy in energy investment (%)
	Biofuel production or consumption volume (litres); share (%)
	Share of low-carbon technologies in electricity production (%)
	Emissions intensity of fossil fuel electricity production (CO_2 / megawatt hours [MWh])
Carbon capture and storage	Annual volume of CO_2 captured / stored (cubic metres [m^3])
	Capacity / generation of CCS or CCS-ready plant (MW / MWh)
	Share of CCS in total installed capacity or generation (%)
Fossil fuel subsidy reform	Absolute magnitude of fossil fuel subsidies (USD or other)
	Share of fossil fuel subsidies in total energy subsidies (%)

Source: Adapted from Hood, C., G. Briner and M. Rocha (2014), "GHG or non GHG: Accounting for diverse mitigation contributions in the post-2020 climate framework", paper prepared for the Climate Change Expert Group, OECD / IEA, Paris.

improvement in energy intensity, as a specific quantity of energy savings, or as a final consumption target. Different information for each of these will be required to promote understanding, and to create estimates of expected emissions savings. If Type II metrics are to be used in the UNFCCC negotiations process, guidance on framing each kind of goal (developed under the UNFCCC, or by outside expert bodies) could therefore be useful to enable greater clarity and understanding of the contributions countries propose.

Long-term transformation (Type III) metrics

A third type of metric can track actions that impact longer-term emissions pathways but do not have a large impact on short-term emissions levels. For example, spatial planning and urbanisation trends, material efficiency, the nature of global value chains, and transport modes will have structural long-term impacts on emissions. In addition, tracking RD&D activity could give an indication of whether key low-carbon technologies needed for deep decarbonisation are on track. Tracking characteristics of new investment in long-lived infrastructure in energy supply, energy-intensive industries and key sectors of energy demand could shed light on whether high-emissions infrastructure continues to be locked in. A focus on the long-term consequences of today's actions is particularly relevant for emerging and fast-growing economies: with rapid urbanisation, major parts of their energy infrastructure necessary to meet development needs are still to be built.

Type III metrics would complement the tracking of short-term emissions reductions and would not be measured in isolation of Type I and II metrics. They promote knowledge on how today's decisions impact emissions over time, and what countries can do to avoid further lock-in of carbon-intensive infrastructure. Type III metrics are *driver* metrics. The long-term emissions reductions outcomes of these actions cannot be measured, only estimated.

Box 3.3

Energy efficiency indicators and GHG reductions

Energy efficiency has the unique potential to simultaneously contribute to long-term energy security, economic growth, and even improved health and well-being, as well as being a means to reduce GHG emissions. It is important to develop and maintain well-founded energy efficiency indicators to inform the policy process and help decision makers develop policies that are best suited to meeting domestic and / or international policy objectives.

Energy efficiency is realised in specific sectors and end uses; therefore, energy efficiency indicators should be calculated at the most disaggregated energy end-use level possible. Recent efforts by several countries to collect more detailed end-use data have helped to develop energy efficiency indicators that provide important information for understanding past trends, assessing potential for energy savings and enhancing energy efficiency policies, while taking into account changes in economic structure over time. Gathering high-quality data to inform the full spectrum of detailed indicators takes time. It is important for countries to decide which sectors, or which segments of a sector, will be prioritised, and then build on this experience. The recent IEA publication Energy Efficiency Indicators: Essentials for Policy Making *(IEA, 2014a) and its companion document* Energy Efficiency Indicators: Fundamentals on Statistics *(IEA, 2014b) are intended to provide the necessary tools to initiate and / or further develop in-depth indicators to support the decision-making process on improving energy efficiency.*

Energy efficiency indicators typically reflect ratios or quantities of energy consumption to some activity as variable and, at a sufficiently disaggregated level, can describe the links between energy consumption and human and economic activities. The energy analysis can be extended to examine changes in CO_2 emissions if the fuel mix and CO_2 intensity of energy supply are known. Depending on the level of disaggregation and data availability, individual energy efficiency indicators may be limited in purpose and usefulness if exogenous factors that influence energy demand cannot be disentangled in the analysis. These limitations will also apply to associated CO_2 indicators.

There is very limited experience to date with the use of long-term focused metrics related to GHG emissions trajectories. In one example, the annual IEA publication *Tracking Clean Energy Progress* reports on the research, development, demonstration and deployment (RDD&D) of a set of key clean energy technologies. Progress is assessed relative to the level required in a scenario consistent with average global warming of below 2°C. As such, this methodology translates long-term decarbonisation goals into actions needed in the short term (IEA, 2014c). Other potential Type III climate change metrics that have been proposed include rates of investment in RD&D, the passage of key legislation / regulation, demonstration and deployment of advanced technologies, emissions intensity for new infrastructure (power plants, buildings, industrial plants), implementation of low-carbon urban planning, numbers of green patents, quantity of low-carbon technology exports, or changes to low-carbon investment patterns. (Prag, Kimmel and Hood, 2013; Hood, Briner and Rocha, 2014). Other authors have suggested that the strength of governments' long-term targets and policy frameworks for transformation towards a low-carbon economy could also be tracked (Höhne et al., 2010; Höhne et al., 2011).

A core set of metrics to track actions that underpin long-term energy sector decarbonisation would need to cover all key energy producing and consuming sectors, particularly where long-lived assets are involved. The following examples of indicators may be useful to policy makers:[3]

- **RDD&D of low-carbon energy technologies.** An indicator of low-carbon energy RD&D investment could be public expenditure, in absolute terms or relative to overall energy RD&D. Specific criteria for what can be counted as low-carbon RD&D would improve comparability across economies. The IEA is already collecting data on RD&D budgets from its member countries. This provides detailed, categorised information on budgets for energy efficiency, renewable energy, energy storage, CCS and other technologies relevant to low-carbon energy supply, as well as data on budgets for RD&D on conventional fuel. Deployment rates of key technologies are tracked with a range of metrics in *Tracking Clean Energy Progress 2014.*

- **Age and efficiency of coal-fired power generating fleet.** Reducing the use of high-emissions coal power plants will be a priority in achieving energy supply decarbonisation. Coal-fired generating units typically stay in operation for 30 to 40 years, but many plants operate much longer than this. While options exist to "unlock" locked-in capacity (see Chapter 1), these are expensive. Data on coal power capacity additions from new power plants aged 15 years or younger, and capacity under construction or under planning, can reveal recently

3. This analysis builds on Kimmel (2014).

created carbon lock-in. This information could be used to generate indicators of lock-in (e.g. recently added coal as a percentage of all generation).

• **Presence of decarbonisation goals/passage of key legislation.** Setting a long-term national goal is an important step towards achieving actual long-term reductions in energy-related emissions. While largely ineffective without accompanying policies, targets often trigger the adoption of sustainable energy or energy-related climate change policies, and guide policy makers in the design of these policies. Many countries have adopted goals that either explicitly or implicitly call for long-term energy decarbonisation. Denmark, for instance, aims to consume 100% of final energy from renewable energy by 2050. Metrics could track the presence of a goal, its legal status and progress and the scope of its coverage.

• **Policy implementation.** Policies that incentivise the deployment of low-carbon energy technology, energy efficiency, energy conservation and carbon capture are essential for long-term decarbonisation of the energy supply. Metrics that track the implementation of sustainable energy and emissions reductions policies (for example, actual or effective carbon prices, or simply the presence of policies) could provide insight into whether an energy system is more or less likely to be on track towards long-term targets.

• **Building codes, annual additions, retrofit and turnover rates.** Buildings (residential and commercial) are one of the most long-lived infrastructures that lead to large amounts of CO_2 emissions during their lifetime. In OECD member countries, 60% of the buildings that will be standing in 2050 have already been built today; conversely, in emerging economies the majority of building infrastructure in 2050 is yet to be constructed. Tracking building code requirements for the energy performance of new buildings (and appliance standards for heating and cooling) could focus attention on preventing further lock-in. For OECD member countries, retrofit rates of existing buildings are also a key measure of whether today's actions are consistent with a transition to low-carbon energy systems.

• **Transport emissions.** The IEA tracks new light-duty vehicle fuel economy performance, electric vehicle stock, and new electric vehicle sales as separate indicators in *Tracking Clean Energy Progress 2014*. These data could be further extended to compute an indicator of the share of all low-carbon vehicles among the existing vehicle stock or among all car sales in a year. Key long-term drivers of transport emissions are urban planning decisions, particularly in regions with rapid urbanisation. Developing forward-looking metrics to capture the anticipated emissions impact of urban planning decisions would be challenging.

• **Energy-intensive industries.** As for power generation, to achieve a transition in average emissions intensity of production in key energy-intensive industries (steel, cement, chemicals, refining), new facilities will need to emit significantly less than the existing fleet. A potential metric is the expected lifetime emissions intensity of a new plant, which could be compared to the values modelled to be consistent with below 2°C warming. Alternatively, metrics of the material intensity of the overall economy could drive change in emissions-intensive industry.

• **Electricity system flexibility.** Integration of high levels of wind and solar power will require more system-wide transformations of electricity systems to achieve higher levels of flexibility. This could be achieved through improved grid infrastructure, dispatchable generation, more energy storage capacity, and demand-side management. The IEA flexibility assessment tool (IEA, 2011) is a metric of power system flexibility that could be used to track progress towards more dynamic electricity systems.

While some of these metrics are more comprehensive and refined than others, it is important to underline that no single indicator alone can fully portray a country's progress towards a decarbonised and energy-efficient economy. Rather, an integrated assessment incorporating several of these (and other) indicators is necessary to obtain a well-founded understanding of a country's anticipated long-term, energy-related emissions.

Accounting for energy sector metrics in the UNFCCC process

A key function of the new climate agreement will be to track implementation of countries' pledged contributions, whatever their type. There is existing experience within the UNFCCC of accounting for goals specified in terms of GHG emissions reductions (i.e. using Type I metrics), but there is not yet a framework to account for progress of goals using Type II or III metrics, nor to be able to estimate the GHG emissions reductions expected from these goals. There are a number of issues of accounting for non-GHG contributions as part of the 2015 agreement (Hood, Briner and Rocha, 2014), that could make it easier or harder to integrate energy sector metrics into the UNFCCC process:

• Accounting processes will be different for contributions based on Type II metrics. Demonstrating achievement of the goals would be based on its own metric (e.g. percentage of renewable electricity generation) rather than GHG emissions reductions directly. However, a critical function of the new climate agreement will be to enable understanding of the sum total of countries' GHG reductions, and whether this reduction is consistent with the ultimate objective of the UNFCCC. As such,

Box 3.4

Metrics to help avoid further power sector lock-in

As illustrated by the IEA publication, Tracking Clean Energy Progress 2014, *Type III metrics can translate long-term goals into short-term actions consistent with that goal. To avoid further locking in of high-emissions infrastructure, the challenge is to articulate what investments in the short term are consistent with long-term pathways that limit warming to 2 °C, and to track progress in these investment patterns. For example, the average emissions intensity of new investments could be tracked and compared to what is consistent with a 2 °C pathway.*

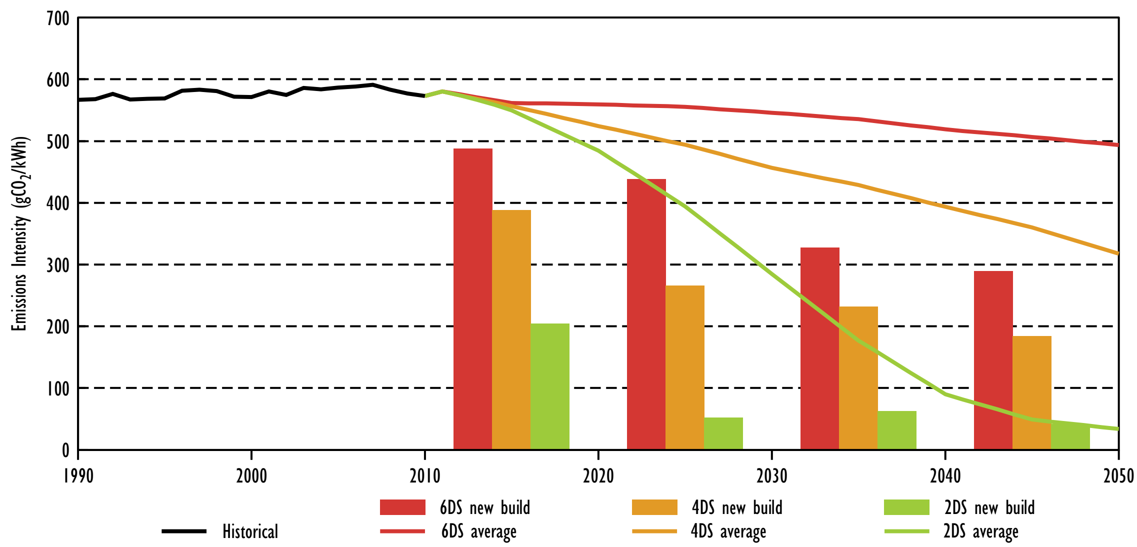
Figure 3.3 shows IEA model results to 2050 in the 6 °C Scenario (6DS), the 4 °C Scenario (4DS) and the 2DS, corresponding to long-term global warming of approximately 6 °C, 4 °C and 2 °C . Two metrics are shown: the lines show the average fleet-wide emissions intensity of power generation, while the bars show the lifetime emissions intensity of new power investment in each decade.[4] It can be seen that to achieve the sharp decline in fleet-wide emissions intensity in the 2DS, shown by the green line, the average global emissions intensity of new generation (the green bars) must be lower than that of natural gas in the period to 2020, and only 10% of today's levels after 2020.

A metric that tracks the expected lifetime emissions intensity of new investment in power generation would therefore be a useful addition to current measures of fleet average parameters. Expected lifetime emissions from new plants could be reported based on emissions intensities, expected running hours and expected plant lifetime. Including plans to retrofit for CCS in these estimates would also focus greater attention on the need for timely development of CCS technologies.

New investment could also be tracked by considering investment, rather than capacity or generation. The IEA calculates that in a 2 °C scenario, in the period from 2020 to 2030 around 85% of global investment in new generating capacity needs to be in non-fossil fuel or CCS-equipped generating plants (IEA, 2014d).

Figure 3.3

Fleet average and new-build emissions intensity of power generation in IEA 6DS, 4DS and 2DS



Data Source: IEA (2014e), Energy Technology Perspectives 2014, *OECD/IEA, Paris.*

translations of contributions based on Type II metrics into expected (prior to 2020) and actual (after 2020) emissions reductions will be important information.

- For goals based on Type II metrics, data quality and availability are variable. There are many ways to present a particular goal (for example, an energy savings target), some of which are easier to translate to GHG impacts than others. Some consistency in the way countries present information on their proposed non-GHG contributions would therefore be helpful for countries to understand

4. The lifetime emissions intensity of a new investment is calculated by dividing the modelled emissions generated by these plants by their total generation in each scenario over the full period to 2050.

each other's proposals. Ideally, guidance for this could be developed before the first quarter of 2015 (when parties are due to communicate their contributions).

- Goals based on Type III metrics address a different challenge (long-term transformation) from those based on Type I metrics (short-term emissions), so it is not appropriate to trade one off against the other: both are necessary. In addition, the difficulty in accurately estimating future emissions outcomes of goals based on Type III metrics would make it problematic to treat them as quantified targets analogous to short-term GHG goals.

- When estimating GHG emissions reductions arising in regions with goals based on Type II metrics, care needs to be taken to account for any emissions sold via market mechanisms (such as the UNFCCC's Clean Development Mechanism, or linked domestic emissions trading systems). If the sold emissions units are used in another country towards meeting a GHG goal, the double coverage of GHG and non-GHG goals could lead to the double counting of emissions reductions.

While goals based on Type II and III metrics may be put forward as part of countries' proposed mitigation contributions, the UNFCCC will remain a treaty focused on GHG reductions, so GHG goals will likely remain the top focus. The challenge for countries as they prepare their national contributions is to strike a balance between a focus on alternative metrics that can help build credibility for energy sector policy interventions and help countries understand each other's actions, and their higher-level GHG targets.

Conclusion

As energy sector decarbonisation is multi-dimensional, multiple levers will be required to measure and drive change. While economy-wide GHG targets are critical to keeping emissions within a budget consistent with global warming of less than 2°C, they alone will not always stimulate maximum action to decarbonise energy systems, nor provide a full understanding of countries' actions. Use of more focused metrics targeting specific energy sector actions could be effective, as they link more closely to the policy levers available to governments, capture wider benefits (and therefore have broader political acceptability), and have the potential to re-frame the climate challenge in a more positive light.

The UNFCCC process has not yet developed guidance on what metrics could be used to capture the full range of necessary energy sector decarbonisation actions, or how national contributions using such metrics should be framed. If non-GHG goals are included in UNFCCC mitigation contributions, guidance on framing each kind of goal would be useful to enable greater clarity and understanding of the contributions countries propose, and to facilitate tracking of progress. The IEA energy efficiency indicators framework provides an example of the type of guidance that would be useful to countries: other indicators could be developed for other key actions such as in renewable energy, low-carbon investment, and clean transport. Guidance could be developed formally within the UNFCCC process, or by outside expert bodies.

However, whether or not goals based on Type II and III metrics are incorporated into countries' mitigation contributions for the new 2015 climate agreement, it would be very useful for countries to begin to track indicators of this type domestically, to better understand whether they are maximising short-term opportunities, and whether current actions are compatible with a long-term transition to low-carbon energy systems. This could help countries minimise further costly lock-in of high-emissions infrastructure that would need to be unlocked through policy intervention later (see Chapter 1 in this volume). Tracking at the global level, for example, as is presented in the IEA *Tracking Clean Energy Progress* report, can complement this providing a high-level picture of whether countries are collectively on track.

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Chapter 4 • The air pollution-GHG emissions nexus: Implications for the energy sector

Introduction

Historically, rapid periods of industrialisation have led to increases in air and other pollutants from the combustion and processing of fossil fuels. Most developed economies have put in place environmental regulations to curb the emissions of "criteria" air pollutants and air toxics. As emerging and developing economies continue on a path to rapid industrialisation based on the increased use of fossil fuels, concerns about air quality are rising in many parts of the world. At the same time, severe air pollution episodes occurring in cities in both emerging and industrialised economies are raising the profile of this issue within the global community.

Political actors are increasingly responding to the risks that air pollution poses to public health, ecosystems, and the economy. An example is the declaration by China's leadership in 2014 of a "war on air pollution," as the central government seeks to head towards a less energy-intensive economic growth model. But these concerns also have applicability in developed countries as they continue to tighten existing air pollution measures associated with power sector, industrial and mobile emissions sources.

Meanwhile, concerns about climate change are ever-salient. The increasingly visible impacts of a changing climate signal the urgent need to drive down greenhouse gas (GHG) emissions. The United States-China Joint Climate Announcement on November 12, 2014 provides evidence for this, with the US targeting a 26-28% reduction of GHG emissions by 2025 and China announcing that it will peak its GHG emissions by around 2030, and increase the share of non-fossil primary energy to 20% by 2030. This announcement has increased political momentum at a critical juncture as the international community negotiates a new agreement by 2015 to address climate change. The joint announcement also illustrates how rising concerns about air quality have the potential to accelerate action on GHG emissions, while efforts to reduce GHG emissions can also lead to local air quality benefits.

Exploring policy synergies

The energy sector is one of the largest sources of air pollutants. Fossil fuel combustion, in particular that of coal, has been the target of government policies and regulations aimed at improving air quality. Many countries have been tightening air quality regulations to force significant emissions reductions of sulphur dioxide (SO_2), nitrogen oxide (NOx), particulate matter (PM), mercury (Hg) and other pollutants.

Fossil fuel combustion is also the primary source of carbon dioxide (CO_2) and other GHG emissions, which drive climate change. As climate change mitigation policies are being developed and strengthened, it is important to analyse potential synergies between air pollution control and GHG emissions abatement. Policies that address multiple air pollutants and provide consistent and long-term signals to industrial emitters can result in cost-effective reductions of both air pollutants and GHGs. Still other policy objectives can be folded into the mix; the emerging literature on integrated scenario analysis indicates that a simultaneous, integrated approach to GHG mitigation, air quality, and energy security objectives shows high cost-effectiveness compared to a piecemeal approach (Clarke et al., 2014).

Many countries recognise the potential to address these dual priorities within the air pollution-GHG emissions nexus. However, the nature and extent of these issues vary across countries, resulting in diverse responses. In China, air pollution resulting from rapid industrialisation over the last few decades poses immediate public health concerns and is a barrier to continued economic development. As the world's largest GHG emitter, China is making substantial efforts to reduce GHG emissions to support a more sustainable development pathway.

On the other hand, the United States has a long history of addressing air pollution through a well-established regulatory system. As the largest GHG emitter among industrialised countries, the United States is a key player in driving international action on GHG emissions reductions. The nascent US approach to climate policy at the federal level is employing a regulatory framework initially designed to tackle conventional air pollutants, but which is being adapted to target reductions in GHG emissions. US GHG regulations for mobile sources and electric power plants are also expected to produce significant reductions in local air pollution, with benefits for public health.

Plant-level compliance options and impacts on GHG emissions

At the plant level, the interplay between air pollution control and GHG emissions abatement is not always positive and it cannot be assumed that addressing one will necessarily benefit the other. For instance, when complying with an air quality requirement, a plant is faced with a number of options for each unit. Depending on the option that an emitter chooses to employ, associated GHG emissions may indeed be reduced significantly, but alternatively may increase. GHG co-benefits at the plant level are directly linked to these compliance choices (Box 4.1).

Box 4.1

Air pollution control options and associated CO_2 emission reduction co-benefits at the plant level

An existing power plant, such as a coal-fired generating facility, usually has the following options to comply with tightening air quality regulations. Each of these options has different impacts on a plant's CO_2 emissions. If these strategies are not optimised to achieve reductions in CO_2 emissions in addition to meeting air pollution objectives, plant operators may choose actions that are cost-effective for air pollution control but do not reduce, and may even increase, CO_2 emissions.

1) Retrofitting: Additional pollution control installations

This option results in increased GHG emissions. This is largely a consequence of the requirement for additional energy to operate the flue gas cleaning equipment for targeted pollutants. This energy is typically provided by the fossil fuel that the plant already uses, entailing corresponding emissions. The increased demand for power by the plant itself results in a decrease in overall plant efficiency and a concomitant increase in emissions.

2) Retrofitting: Improved operation of existing controls and improved efficiency

This option addresses all emissions, including those of CO_2. Increased energy efficiency means less fuel is required to produce the same amount of energy – and less fuel translates into reduced emissions of everything from particulates to CO_2. As the plant ages and becomes less efficient, the relative amount of CO_2 emitted increases. Rehabilitation of the plant to improve performance will reduce the CO_2 emissions rate, especially if the rehabilitation process significantly improves the energy efficiency of the plant.

3) Fuel switching: Switching from coal to gas, blending of coal, co-firing with biomass

In general, gas-fired power plants produce about half the CO_2 emissions of coal-fired power plants per megawatt hour (MWh). Precise CO_2 emissions reductions would, however, depend on the type of plant replacing the old coal-fired one: its size as well as its efficiency. If fuel switching occurs at the existing plant, from an old coal boiler to an old gas boiler, CO_2 emissions reductions from fuel switching will not be optimal if plant efficiency is low. Sometimes a percentage of original fuel (coal) can be replaced by biomass. This will lead to reductions of CO_2 emissions from this coal power plant, and the scale of reductions depends on the rate of co-firing.

4) Closure of old plants as part of a shift towards more efficient units and lower-emitting generation technologies (e.g. coal-fired generation replaced with increased generation from renewables)

The move to alternative energy sources such as renewable, nuclear and natural gas will result in reduced CO_2 emissions from the power sector, as CO_2 and air pollutant intensity is much lower for these plants compared to that of a coal plant. Fuel switching from coal- to gas-fired power generation is presently attractive as gas produces less CO_2 (370 kilogrammes [kg] / MWh) than coal (820 kg / MWh). However, gas is not a zero-carbon fuel and CO_2 emissions, while substantially reduced, will remain. The larger the shift to lower and zero-carbon fuels, the greater the GHG emissions reduction. For example, a large positive co-benefit could be expected from China's Air Pollution Prevention and Control Action Plan, released in 2013, that aims to reduce the share of coal to below 65% of total power generation by 2017 (from 79% in 2011). This could mean an annual coal consumption cap of below three billion tonnes by 2020, potentially resulting in cumulative CO_2 emissions reductions in the order of 7.2 gigatonnes (Gt).

It is important to distinguish between outcomes at the plant level and those that might be expected if system- or economy-wide effects were considered. For example, retrofitting for pollution control equipment may cause an initial increase in plant-level emissions due to the plant's increased use of power to run the equipment. However, retrofitting will also raise production costs and can be expected to result in lower output at the plant due to demand effects among electricity end users. This will result in offsetting the increases in the plant's GHG emissions. Similarly, improvements in operating efficiency at the plant level will initially reduce its emissions, but these improvements will also lower its cost of production and raise its competitiveness compared to other plants. As a result, its output could increase and this "rebound effect" would put upward pressure on its emissions.

Overall, policy approaches that deal with air pollutants and GHGs separately may forego important benefits of a more co-ordinated strategy. Designing policy packages that address multiple pollutants simultaneously, including GHGs, could lead to more cost-effective outcomes by helping to rationalise long-term investment decisions and creating synergies among reduction efforts.

Outline of Chapter 4

Examining approaches taken by different countries at the air pollution-GHG nexus provides insight into the various ways efforts to address air pollution and GHGs can interact. This chapter examines these issues in some detail, based on experiences, achievements and innovative policy approaches of several major emitters, namely China, the United States, Canada and the European Union. The China and United States cases are highlighted, illustrating two different approaches to reducing GHGs through air quality regulations, which reflect each country's national circumstances and drivers for addressing air pollution-GHG issues.

These issues are addressed in the following three sections:

- **Section 4.1** provides an overview of the potential GHG co-benefits of air quality controls on large stationary sources. Drawing from experiences of the European Union, the United States and Canada, this section outlines the compliance options at the plant level for meeting air quality regulations, and describes how these choices can have varying impacts on GHG reductions.

- **Section 4.2** is an analysis of the Chinese case: addressing air quality challenges and the implications for GHG mitigation. With the country's national and regional efforts to combat air pollution, initial indications point to potential GHG impacts and co-benefits. This section identifies those strategies and discusses approaches that facilitate synergies between air quality improvements and GHG emissions reductions.

- **Section 4.3** is an analysis of the United States case: addressing climate change using a regulatory framework designed for combating conventional air pollutants. The United States is adapting tools designed within an air quality regulatory framework with the explicit objective of reducing GHG emissions. This section examines the extent to which US GHG regulations, particularly those for the power sector, may yield reductions of both GHGs and conventional air pollutants.

4.1 GHG co-benefits of air quality controls of large stationary sources

This section examines the effects of air quality policies on the decarbonisation of the energy sector. It illustrates how stringent air quality policies can bring about GHG emission reduction co-benefits, and indicates the scale of power-sector decarbonisation that can be expected from stringent air quality regulations. This section draws on worldwide experience, notably from the European Union, the United States and Canada.

Introduction

Fossil fuel combustion is directly related to CO_2 emissions, but also to emissions of other pollutants, such as SO_2, NOx, PM, Hg and other air toxics that have negative impacts on human health and the environment[1]. There is a long history of regulating emissions of SO_2, NOx and PM in order to improve air quality and hence reduce exposure to harmful air pollutants. These regulations consist of both direct emission limits placed on combustion plants (either as emission concentration limit values, or capped annual mass releases), and indirect limits (such as national mass emission caps under the UNECE Gothenburg Protocol and ambient air quality standards) aimed at driving national policies to reduce emissions from the major contributing sources. In the last 10 years air toxics, and in particular mercury, received special attention due to their harmful impacts on human health. In recent years mercury became a subject of stringent regulation in the United States and Canada; in addition, many other countries have developed state-based mercury action plans that also include pollution reduction elements.

These air quality and toxics regulations will be analysed in terms of their capacity to deliver GHG emission reductions. This section aims to answer the following questions:

- Could air quality regulations for large stationary sources, especially the most stringent ones, indirectly lead to some degree of decarbonisation of the power sector?

- How much decarbonisation can be expected from the implementation of stringent air quality regulations?

These questions are important to those policy makers who are looking for cost-effective solutions to multi-pollutant problems, as well as to those who are simultaneously developing both air quality and climate change regulations.

This section reviews how increased tightening of air quality and emissions regulation has been affecting fossil fuel power production and, indirectly, CO_2 emissions from power plants. It summarises some lessons from these experiences and draws recommendations for a multi-pollutant approach that includes air quality and climate policies. Any CO_2 emission reduction achieved as a co-benefit of air pollution control (that does not target CO_2) comes at no extra cost.

1. Emissions from combustion-based sources (e.g. electricity generation) include directly emitted criteria pollutants (e.g. carbon monoxide [CO], primary fine particles and SO_2), air toxics (e.g. benzene, lead, some volatile organic compounds [VOCs] and trace metals including mercury), precursor emissions (e.g. NOx, SO_2, some VOCs, and ammonia [NH_3]), and greenhouse gases (e.g. carbon dioxide [CO_2]).

Thus, all CO_2 co-benefits identified in this section could be considered costless in markets with no carbon price, or value-generating in markets with a carbon price, if the air quality control is taken as a given. However, a multi-pollutant approach, which optimises simultaneously for different pollutants, may lead to alternative control measures with different costs but also possibly different magnitudes of emission reductions, including those of CO_2.

The focus of the section is on changes in CO_2 emissions, because the effects of CO_2 on climate forcing[2] are generally well understood, while the effects of other pollutants can be more complex (Box 4.1.1).

Strong air quality regulations and their co-benefits for CO_2 emissions reductions

Large power plants are subject to air quality-driven emissions regulations in many countries. Air quality standards have been gradually tightening over recent decades to reflect the growing recognition of the risks that air pollution poses to human health and the environment, as well as to take advantage of technological achievements that allow significant emissions reductions.

Large combustion plant regulation in the European Union and indirect CO_2 emissions reductions

Air pollution mitigation policies in the European Union introduced by the Large Combustion Plant (LCP) Directive (and also by the Integrated Pollution Prevention and Control (IPPC) Directive 96/61/EC) played a role in reducing GHG emissions between 1990 and 2008. Primarily aimed at limiting the pollution of large industrial installations, these policies targeted emissions of acidifying substances, ozone precursors and particles in the air. Most of this legislation resulted in bolt-on, end-of-pipe controls that meant reduced plant output (lowering plant efficiency).[3] For instance, NOx burners may have lowered combustion efficiency. Some of the legislation may have led to fuel switching; at some plants, this could mean a lowering of combustion efficiency as mills and heat transfer surfaces adapt to cope with fuels for which the plant was not originally designed. However, according to an analysis by the European Environment Agency (EEA, 2011), the legislation also led to the closure of older plants that were not worth the investment in retrofit flue gas control, ensuring overall efficiency gains for the sector.

Thus, placing emission limits on those pollutants in *some* cases may have resulted in GHG reductions from the sector as a whole and provided further incentives to shift fuel sources, thereby indirectly reducing GHG emissions. CO_2 emissions from public electricity and heat production decreased by 9% between 1990 and 2008 in the EU-15 as a result of the combination of European Commission (EC) pollution regulation, fuel prices that favoured a shift from coal to gas, and modernisation of the power sector entailing the closure of old coal plants. This overall reduction was achieved despite an increased demand for electricity in the European Union during the whole period.

Air quality regulation and multi-pollutant objectives in Canada

Canada created emission limits for PM, SO_2 and NOx in the early 1990s. In 2003 Environment Canada released the New Source Emissions Guidelines for Thermal Electricity Generation that provide limits for emissions for SO_2, NOx and PM from new sources. These guidelines recognise that opportunities to reduce emissions may arise during major alterations to an existing unit. The guidelines therefore recommend that an assessment of the feasibility of emission reduction measures be completed prior to commencing such alterations (Government of Canada, 2003). This assessment should be undertaken by the owner of the unit in close consultation with the appropriate regulatory authority, and improved emission control measures should be implemented wherever feasible. The guidelines are part of continuing efforts to diminish air-polluting discharges to the atmosphere by restricting such discharges from future additions to electricity generation system capacity. Therefore, when a plant is shut down in Canada for refurbishment to control or reduce emissions of one pollutant, this is seen as an opportunity to upgrade the plant in whatever way possible to reduce as many other emissions as possible, and this may include measures that reduce GHG emissions.

Air quality regulations in the United States and indirect CO_2 emissions reductions

Since the early 1970s, the US Environmental Protection Agency (US EPA) has been regulating emissions of six principal pollutants, called "criteria" pollutants: carbon monoxide (CO), lead, nitrogen dioxide (NO_2), ozone, particulates and sulphur dioxide (SO_2) through the National Ambient Air Quality Standards (NAAQS).[4] In 2011, the US

2. The climate is affected by a number of factors, natural and human-made. These factors are called "forcings" because they drive or "force" the climate system to change. The most important forcings include: changes in the output of energy from the sun volcanic eruptions; and changes in the concentration of GHGs in the atmosphere. The size of these forcings is expressed in terms of watts (a flux of energy) per square metre of the Earth's surface. Positive forcing warms the climate, while negative forcing cools it.

3. See Box 4.1.

4. The US NAAQS for SO_2, PM, NO_2 and CO were first promulgated in April 1971. The earliest US EPA emission limits for new large coal-fired boilers (NSPS Subpart D) applied to units built after August 1971. Both NAAQS and NSPS have been revised several times since then.

Box 4.1.1

Complex effects of air pollutants on climate forcing

Air pollutants, such as SO_2, PM, NOx and others may have complex effects on climate forcing responsible for either warming or cooling of the climate. For example, sulphates in the atmosphere, some of which arise from coal combustion, have been shown to have a cooling effect. On the other hand, black carbon is associated with net warming effects on climate. Black carbon (a component of a fine particulate) contributes to global warming by absorbing heat in the atmosphere and by reducing albedo, the ability of a surface to reflect sunlight, when deposited on snow and ice. Black carbon stays in the atmosphere for only several days to weeks. Recent work by the World Health Organisation suggests that black carbon is a better indicator of the health effects of particulate matter than particulate mass alone. The potential dual benefits of black carbon emissions reductions for health and climate have led to specific requirements in both the UNECE Gothenburg Protocol and the draft revised EU National Emissions Ceilings Directive to focus particulate matter emissions reductions on sources of black carbon.

However, these pollutants are generally short-lived in the atmosphere, so it is likely that any change in emissions of pollutants such as sulphates and black carbon will affect climate forcing less than any changes in CO_2 emissions over the long term. Conversely, their short atmospheric lifetime means that emission reductions can deliver a much quicker response in terms of climate warming or cooling, particularly on a regional scale, which potentially makes them an attractive target for climate policy. It is likely that improved understanding of the dual health and climate effects of air pollutants will become increasingly important in future emissions legislation.

Table 4.1.1

Emissions from power plants in the United States in the base case (no further controls) and with CSAPR

Nationwide emissions – with base case	2012	2015
SO_2 (million tonnes)	7.9	7.2
NOx (million tonnes)	2.1	2.1
CO_2 (million metric tonnes)	2217	2252
Nationwide emissions – with CSAPR	**2012**	**2015**
SO_2 (million tonnes)	3.9	3.4
NOx (million tonnes)	2.0	1.9
CO_2 (million metric tonnes)	2206	2226

Source: US EPA (2011), "IPM analyses of the Cross-State Air Pollution Rule (CSAPR)", US EPA, www.epa.gov/airmarkets.

EPA finalised a new environmental regulation aimed at curbing air pollution from the electricity sector. The Cross-State Air Pollution Rule (CSAPR) or "Transport Rule" aims to reduce SO_2 and NO*x* emissions that are crossing state lines and contributing to pollution problems downwind.[5]

To analyse potential impacts of this regulation on the electricity sector, the US EPA has performed a Regulatory Impact Analysis (RIA) on the implementation of the CSAPR (US EPA, 2011). It is important to note that this analysis was completed before the recent surge in shale gas supplies, and assumes relatively high natural gas prices. With high natural gas prices, often the most economical means of reducing emissions is to retrofit coal plants with control technologies. However, as natural gas prices come down, fuel switching and shutdowns become more competitive.

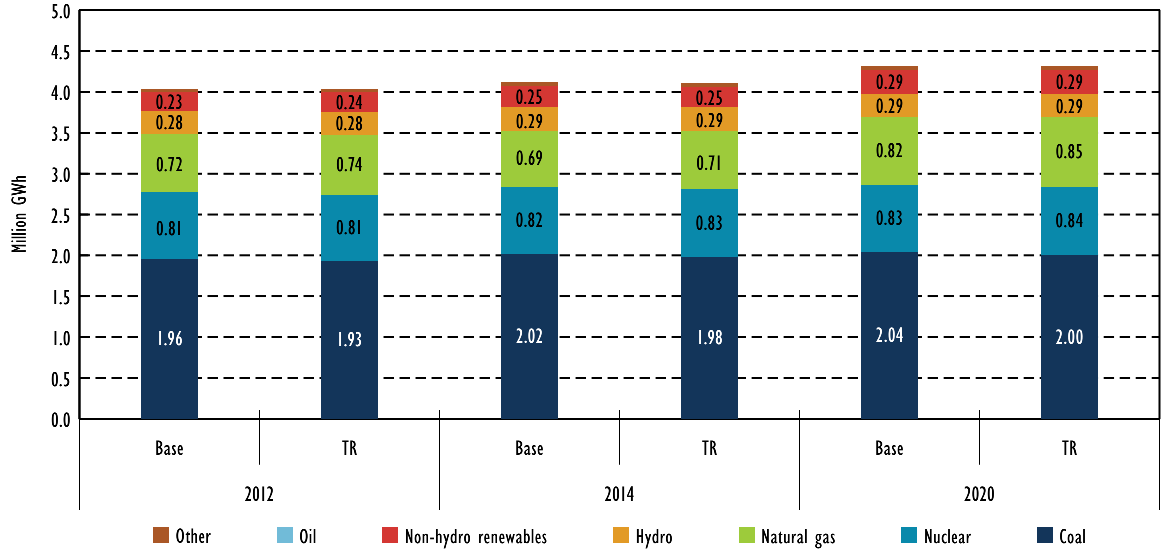
Coal use to 2020 will increase under both scenarios, but less under the CSAPR. The predicted move to alternative energy sources, such as nuclear and natural gas, will result in reduced CO_2 emissions from the power sector. Figure 4.1.1 below shows the potential change in fuel use under baseline conditions and with the implementation of the CSAPR.

The anticipated CO_2 benefit is not significant: the estimates suggest that 26 million tonnes of CO_2 (or about 1% of today's total CO_2 emissions from electricity and heat production in the United States) will be avoided annually.

5. The CSAPR rule remains US law; however, the implementation timeline will change due to intervening court activity. In April 2014, the Supreme Court reversed an August 2012 DC Circuit opinion that had vacated the rule. In the meantime, sources were required to comply with the less stringent Clean Air Interstate Rule.

Figure 4.1.1

Generation mix in the United States under base case scenario and Transport Rule (TR or CSAPR) scenario in 2012, 2014 and 2020



Source: US EPA (2011), "IPM analyses of the Cross-State Air Pollution Rule (CSAPR)", US EPA, www.epa.gov/airmarkets.

However, these savings roughly equal annual CO_2 emissions of the entire electricity and heat sectors of Finland or Brazil. Furthermore, they come at no extra cost.

Expanding air quality regulations within Asia

Numerous countries in Asia have also adopted policies and practices to address air pollutants from power plants. These include Japan, South Korea and China (Box 4.1.2). Many of these countries are moving to highly efficient coal technology which will help address the pollutants issue (see discussion in Box 4.1), although these plants will emit significant CO_2 without carbon capture and storage technology.

Mercury regulations and co-benefits for CO_2 emissions reductions

There is a growing recognition of the importance of controlling mercury emissions. Actions to control mercury emissions from coal-fired power plants may have indirect impacts on CO_2 emissions from these plants.

Coal-fired power plants represent the second largest source of mercury emissions to the atmosphere from human activities (after small scale and artisanal goal mining) (UNEP, 2013). Mercury legislation is currently in place in Canada and in the United States. There is also a mercury strategy in the European Union and an international Minamata Convention to protect health and the environment from mercury contamination. This section examines experiences with mercury control in Canada and the United States, and impacts on CO_2 emissions that have been observed or are expected as co-benefits from complying with these regulations. Canada already has legislation on mercury emissions from coal-fired utilities. The United States finalised the Mercury and Air Toxics Standards (MATS) in 2011 that will enter into force in 2015, though the US EPA has indicated it will allow states to grant compliance extensions through 2016, and possibly even later if reliability is an issue (Beasley et al., 2013).

The United States mercury rule and CO_2 emissions reduction co-benefits

The final US EPA MATS rule addresses emissions from new and existing coal- and oil-fired electricity generating units (EGUs). This rule will reduce emissions of hazardous air pollutants (HAPs), including mercury, from the electric power industry. As a co-benefit, the emissions of $PM_{2.5}$ and SO_2 will also decline.

Under the MATS, the US EPA projects annual mercury emissions reductions of 75% in 2015, and PM2.5 emissions reductions of 19% in 2015 from coal-fired EGUs greater than 25 megawatts (MW) (Table 4.1.2). These data were obtained under a study similar to that performed to estimate the effects of the CSAPR, discussed above. In addition, the US EPA projects SO_2 emission reductions of 42%, and annual CO_2 reductions of 1.2% (or 23 million tonnes of CO_2 per year) from coal-fired EGUs greater than 25 MW by 2015, relative to the base case.

Box 4.1.2

An expanding approach: East Asia

Many countries in Asia are also responding to challenging emissions legislation. Japan has some of the cleanest and most efficient coal plants in the world, and most are installed with flue gas technologies for SO_2 and NOx. South Korea and China are gradually moving towards a more efficient power fleet by upgrading and replacing the existing plants with the new and more efficient ones. China currently has the fastest installation rate of flue gas desulphurisation (FGD) and selective catalytic reduction (SCR) in the world. China has put considerable emphasis on increasing average energy efficiency through the introduction of new higher efficiency units and the closure of 72 GW of small, inefficient plants during the 11th Five-Year Plan (Minchener, 2012). In the current 12th Five-Year Plan (ending 2015) the target is a 16% reduction in energy intensity (energy used per unit of GDP). The trend in China (see Section 4.2) is therefore similar to that in the European Union: a decision must be made at each of the existing older plants to determine whether they merit the investment in flue gas controls for NOx and SO_2. Only the more efficient plants will receive investment for flue gas technology retrofits and the older, less efficient plants will close, resulting in an overall increase in average plant efficiency.

Table 4.1.2

Projected EGU emissions of SO_2, NOx, mercury (Hg), hydrogen chloride (HCl), PM, and CO_2 with the base case and with MATS, 2015

		SO_2	NOx	Hg	HCl	$PM_{2.5}$	CO_2
		Million tonnes		Tonnes	Thousand tonnes		Million metric tonnes
Base	All EGUs	3.4	1.9	28.7	48.7	277	2 230
	Covered EGUs	3.3	1.7	26.6	45.3	270	1 906
MATS	All EGUs	2.1	1.9	8.8	9.0	227	2 215
	Covered EGUs	1.9	1.7	6.6	5.5	218	1 883

Note: With the exception of CO_2, all units are in short tonnes.

Source: US EPA (2011), "IPM analyses of the Cross-State Air Pollution Rule (CSAPR)", US EPA, www.epa.gov/airmarkets/progsregs/epa-ipm/transport.html.

Fossil fuel-fired EGUs are projected to reduce emissions of HAPs emission through a combination of compliance options:

- improved operation of existing controls
- additional pollution control installations
- coal switching (including blending of coals and co-firing with biomass)
- generation shifts towards more efficient units and lower-emitting generation technologies (e.g. some reduction of coal-fired generation with an increase of generation from natural gas).

In addition, there will be some affected sources that find it uneconomical to invest in new pollution control equipment and will be removed from service. These facilities are generally among the oldest and least efficient power plants, and typically run infrequently.

The largest share of emissions reductions occurs from coal-fired units installing new pollution control devices, such as FGD or dry sorbent injection (DSI) for acid gas removal, and activated carbon injection (ACI) if necessary for mercury removal.

CO_2 benefits will depend on the actual retirement of the coal-fired capacity resulting from the rule. The US EPA projects that the MATS will result in an incremental five gigawatts (GW) of coal-fired capacity retiring by 2015, relative to the baseline that also includes the CSAPR.[6]

An analysis of the US EPA MATS rule by NERA Economic Consulting brought different results regarding retirement of coal-fired generation as a result of the MATS' stringent requirements for mercury control (Smith et al., 2012). The NERA study estimates a greater impact on coal power production

6. The US electricity sector must not only comply with the MATS rule, but also with CSAPR, which will be implemented but with some delays caused by legal disputes that were resolved in April 2014. Given the investments that will need to be made to comply with CSAPR as utilities also work towards complying with MATS, it will be useful to also compare the costs of compliance with the MATS rule and with CSAPR, relative to a baseline that includes the Clean Air Interstate Rule (CAIR), which specifies the current SO_2 and NOx limits that generators must meet.

from the MATS rule than that assumed by the US EPA. It finds that retirements by 2015 increase by 19 GW compared to under the CSAPR alone, or by 23 GW from the baseline. Note that the baseline alone includes 15 GW of coal retirements, resulting in overall coal retirements of 38 GW. According to NERA's study, some of the retired capacity is replaced by new natural gas-fired combined cycle units. Nationally, by 2015 there is an incremental build of 1 GW of natural gas combined cycle units and an incremental build of 1.5 GW of combustion turbines driven by the MATS and CSAPR rules combined.

The difference in assessments indicates that the reality may be somewhere in the middle. Thus, the CO_2 benefits may also be larger than initially anticipated by the US EPA. A recent study by Resources for the Future (RFF) evaluated a range of models and scenarios to assess the impacts of MATS and other regulations on coal capacity and CO_2 emissions, and found significant variations (Beasley et al., 2013). According to this study, CO_2 emissions in the United States could drop by between 13 megatonnes per year (Mt/yr) and 123 Mt/yr by 2020 depending on how MATS is implemented. Model estimates of the coal capacity that is predicted to retire range from 3.2 GW to 85 GW, and the range becomes even broader when future CO_2 prices are considered. This range is defined by different assumptions of control measures and combinations of regulations that need to be complied with; the baseline assumptions also vary. Examined models assume a coal capacity retirement of between 5 GW and 40 GW under the baseline scenario. Thus, the resulting reduction in CO_2 emissions from the baseline also varies by scenario.

Phasing-out of coal power generation in Ontario, Canada, as a result of mercury regulation and multi-pollutant objectives combined

In Canada there are caps on mercury emissions for each province, which apply to existing plants and require a total reduction of 60-70% from a baseline. Best available technology (BAT) is required on new plants. Individual provinces must decide the most appropriate means of meeting the required reduction targets; the approaches vary from enhanced pollutant co-benefit controls to ACI and even complete plant closure. The target of zero mercury emissions for the province of Ontario was not decided as a result of mercury reduction requirements alone. Prior to the establishment of the mercury caps, Ontario was already increasingly in favour of a move away from coal because of the potential health benefits associated with the reduction of all types of emissions.

In this situation, therefore, it is difficult to determine the extent to which the requirements for mercury reduction influenced the decision to phase out coal. After the first coal plant shut down in 2005, the remaining four plants in Ontario have ceased to combust coal as of 2014. Two of these plants have/are converting to biomass combustion, and the other two plants have closed with two of the plants' units being preserved for future conversion to alternative fuels, if required (see also Chapter 1). It is clear that for coal power plants, switching to alternative fuels or plant closure will result in relative CO_2 emission reductions. The actual size of these reductions depends on the type of replacement fuel and the capacity of the replacement plant. Biomass is considered a zero-CO_2 fuel compared to coal, which typically has a CO_2 emissions intensity of 820 kg/MWh when combusted; gas produces 370 kg/MWh (Finkenrath, 2011).

Compliance choices available to power plant operators and their effects on CO_2 emissions

Power plant operators have a variety of ways to comply with air pollution regulations: (a) retrofitting plants with air pollution control technologies, (b) improving plant efficiency, (c) fuel switching and (d) plant closure (which may be deferred pursuant to grandfathering provisions). These options, and some of the related drivers, are described in more detail in the Annex to this section. As air quality regulations tighten, plant managers are forced to decide whether their existing plant merits retrofitting with control technologies for flue gas cleaning, or needs to shift to another fuel, or simply close.

The CO_2 co-benefits at the plant level are directly linked to the options a plant operator chooses to follow: they can range from negative (e.g. when retrofit equipment requires additional energy for operation), to small and large on the positive side (as a result of efficiency improvement or fuel switching). One of the greatest impacts of air pollution legislation is a move away from coal, the most emissions-intensive fuel, to other fuels such as gas, and/or the move to more efficient coal-based generation. Retrofitting power generation plants with control technologies for flue gas cleaning may actually increase GHG emissions, at least initially, as fossil fuels are required to power these control technologies.

Multi-pollutant strategies: Addressing air quality and low-carbon development simultaneously

Emissions reduction programmes may have multiple effects on a wide spectrum of pollutants. For example, reducing NOx emissions can result in significant decreases in fine particles, ozone, nitrates, acid deposition and watershed eutrophication, and improvements in visibility. However, reducing NOx emissions can increase mercury deposition. NOx emission reductions can also cause ground- level ozone in certain places to increase due to the NOx titration effect on ozone in VOC-limited areas. These and other multiple effects have to be better understood and analysed to achieve an optimal benefits through effective regulations. Table 4.1.3 illustrates potential pollutant / atmospheric relationships associated with emission precursors in the United States. Including climate forcing of various pollutants in such an analysis would be beneficial in helping policy makers decide on the composition and appropriate concentrations of a multi-pollutant regulation.

Environmental policies can be designed to enable this cross-fertilisation and ultimately create stronger and more effective regimes. By setting goals for a broad range of pollutants over a similar time frame, these approaches encourage power plants to develop long-term financial and environmental plans to optimise investment in, and configuration of, pollution control equipment. This is a primary objective of multi-pollutant strategies. Providing a high degree of legislative / regulatory certainty would also reduce investment risks for companies. Overall, a multi-pollutant, long-term regulatory approach offers better planning, greater certainty, lower costs, and more environmental benefits per dollar invested.

An analysis of control measures and their impacts on multiple pollutants, including GHGs, would help policy makers to decide on the most appropriate pollution control, taking all other factors discussed in this section into account. It is important to analyse potential synergies between air pollution control and GHG emissions abatement, especially since the interplay between the two may not always positive. For example, many pollution control options typically result, at least initially, in increased GHG emissions because the additional energy required to operate the flue gas cleaning equipment is provided by the same fossil fuel that the plant uses, and thereby entails corresponding emissions. In contrast, closing coal or other high-emitting plants in favour of alternative lower-emitting energy sources such as renewables, nuclear and, in the case of coal, natural gas, will reduce CO_2 emissions from the power sector while also helping to address air quality issues.

The majority of this section has focused on retrofitting and upgrading existing plants to comply with current and impending legislation. However, most of the legislation seen in Europe, the United States and elsewhere (such as the Industrial Emissions Directive, CSAPR and MATS) specify tighter, more challenging emission limits or reduction requirements for new-build plants. This puts increasing pressure on power companies to invest in cleaner, more efficient units. Rather than having to bolt on separate controls for each of the relevant pollutants, as has happened for existing plants, new plants have the luxury of being able to consider all the pollutants simultaneously. This will lead to the construction of plants that have a more co-ordinated, multi-pollutant approach. Subject to available financing, this means an optimal choice of fuel, higher-efficiency combustion systems and end-of-pipe multi-pollutant technologies. These could include options such as advanced particulate control systems with sorbent injection or high-performance scrubbing systems combined with oxidation technologies.

The surge in legislation to reduce emissions in recent decades has led to a concomitant surge in research and development in new multi-pollutant control systems which are emerging into the marketplace. By controlling several pollutants with one system, not only is the cost reduced, but the energy drain to the plant to operate the system

Table 4.1.3

Potential pollutant / atmospheric relationships associated with emission precursor reductions

Reduction in pollutant emissions	Ozone	Sulphate	$PM_{2.5}$	Acid deposition	Mercury	CO_2 / global warming
SO_2	⇩	⬇	⬇	⬇	⇩	⇧
NOx	⬇	⇩⇧	⬇	⬇	⇧	⇧
Primary PM – black carbon			⬇			⬇
CO	⇩	⇩	⇩	⇩		
Hg		⇩	⇩		⬇	⇩
CO_2	⇩	⇩	⇩	⇩	⇩	⬇

Notes: Arrow direction denotes relative increase ↑ or decrease ↓ of pollutant resulting from a decrease in associated emissions. ⬇ indicates either a well-established relationship and / or substantial magnitude of effect. ⇩ indicates a possible response that is either not yet well understood or likely to be of minimal magnitude. This analysis indicates the impact of only direct, technology-driven responses at a plant and does not take into account possible energy system-wide interactions, such as demand-side responses that could feed back and influence plant-level production decisions.

Source: Adapted from NARSTO (2004), Air Quality Management in the United States, *National Research Council, National Academies Press, Washington, D.C.*

is also reduced. The result is a more efficient and cleaner plant.

In regions such as the European Union and the United States, new plants are facing challenging requirements in terms of allowable minimum efficiency and maximum CO_2 emissions rates. This will increase the move away from coal unless carbon capture and storage (CCS) technologies are applied.

Conclusion

The climate mitigation co-benefits obtained from the implementation of policies such as the LCP Directive, the IPPC Directive, and Canadian mercury controls, or those anticipated from the implementation of the US EPA CSAPR regulation and US EPA MATS rule, constitute important examples of how CO_2 co-benefits can be harvested across different sectors through the implementation of integrated policies.

The analysis on GHG co-benefits from air quality and mercury regulations in the European Union, the United States and Canada demonstrates that some emission reductions of CO_2 could be achieved as a co-benefit. The results can be quite small or quite large, depending on the relative economics of coal- and gas-fired power generation, and also depending on future expectations related to carbon control. However, it is clear that though air pollution control could generate GHG emissions reductions, the climate change problem cannot be resolved solely through air pollution control.

Those countries that are considering climate policies while concurrently putting in place air pollution policies will benefit from taking an integrated approach and estimating costs and benefits of all emission reductions (air pollution, toxics and GHGs) that can be achieved by proposed policies and requirements. Multi-pollutant strategies with long-term perspectives will allow companies to comply at the optimal cost and will allow governments to move towards cleaner air as well as a low-carbon economy.

Annex to Section 4.1

Compliance choices available to power plants and related CO_2 co-benefits

As air quality legislation becomes more stringent, operators of existing fossil fuel power plants must decide among several main options:

i. fuel switching

ii. retrofitting end-of-pipe pollution control technologies

iii. grandfathering options (i.e. running for a pre-defined number of hours before final closure to allow time for replacement power to be sourced and to keep emissions within the required cap)

iv. plant closure.

Depending on the option that a power plant chooses, associated CO_2 emissions may range from increasing (e.g. due to the additional energy required to run end-of-pipe pollution control) to significantly decreasing (e.g. if an old plant is closed and replaced by low- or zero-carbon technology). Each of these options and their potential impact on CO_2 emissions is discussed in more detail below.

Fuel switching

Fuel switching away from coal can significantly reduce GHG emissions. The actual scale of emissions reductions depends on the replacement fuel. Two switches merit particular attention: coal to gas, and coal to renewables.

- Gas-fired power plants produce about half the CO_2 emissions of coal-fired power plants per unit of electricity produced at the plant level. In addition to reducing relative GHG emissions, the switch from coal to gas or other fuels can result in a net decrease in emissions by eliminating the release of methane from the mining of deeper coals.

- CO_2 emissions reductions also depend on the type of replacement plant: its size as well as its efficiency. If a higher-output plant is constructed to meet growing demand, the total GHG emissions may be as high as from the old plant even though the carbon intensity of the plant is lower. If fuel switching occurs at the existing plant, from an old coal boiler to an old gas boiler, CO_2 emissions reductions could be impaired if plant efficiency is low.

- A number of coal stations now burn a significant proportion of biomass along with their primary coal fuel, referred to as biomass co-firing or partial fuel switching. As well as being CO_2 neutral, the displacement of coal by biomass results in reduced emissions of a range of pollutants including sulphur dioxide and metals.

- Renewable energy plants have zero carbon emissions. However, in spite of increased reliance on variable renewable energy for power generation, some fossil fuel capacity will be needed to provide a base-load power supply through the grid when solar or wind activity is low. Sources such as coal-fired power plants may be required to switch on or ramp up or down their output at very short notice. This leads to coal-fired plants being run in a manner for which they are not designed, resulting in lower efficiency. Further, increased periods of start-up and shut-down, when uncontrolled emissions are generally at their highest, will result in a relative increase in emissions from these plants.

Retrofitting: Pollutant controls

Retrofitting requires substantial investment; the price for installing and operating the necessary pollution control equipment, and the remaining lifespan of a plant, are critical factors in deciding whether to pursue a retrofit. In addition, since it is likely that legislation will become more stringent, operators also must try to predict future plant requirements when deciding on the appropriate retrofit strategy (e.g. to address needs incrementally, or to attempt to future-proof the performance level of any abatement action).

Because energy sources emit more than one pollutant, control technologies or other approaches to reduce emissions (e.g. reduced demand) can affect multiple pollutants simultaneously. Below are examples of pollutant controls available at power plants:

- Particulate controls: the two main types of PM controls are the electrostatic precipitator (ESP) and the fabric filter (FF).
- Selective catalytic reduction (SCR): used for oxidising NOx from the flue gas.
- Wet scrubbers: flue gas desulphurisation (FGD) occurs as flue gas comes into contact with limestone or lime slurry in the scrubber. It is used to control SO_2 and mercury.

There may be some negative cross-effects among pollutants in these systems; for example, high mercury concentrations can reduce the lifespan of some NOx catalysts. For the most part, however, the systems are mutually beneficial. The one common negative effect is an increase in GHG emissions. This is largely a consequence of the additional energy required to operate the flue gas cleaning equipment for targeted pollutants. This increased demand for power by the plant itself results in a decrease in overall plant efficiency and a concomitant increase in emissions. On average, NOx and SO_2 controls can reduce power plant efficiency by 2% (Graus and Worrell, 2007).

In some cases, retrofitting a plant will include modifications to improve plant efficiency. Increased efficiency means the same amount of energy from less fuel – and less fuel, in turn, means reduced emissions of everything from particulates to CO_2 (Sloss, 2009). As the plant ages and becomes less efficient, the amount of CO_2 emitted per unit of electricity produced increases. Rehabilitation of the plant to improve performance will reduce its CO_2 emissions rate, especially if the energy efficiency of the plant is significantly improved.

Any investment in improving a plant to meet air quality requirements anticipates that the plant will operate long enough for this investment to be cost-effective. These improvements, which may extend the lifetime of a plant which otherwise may have closed in a shorter time frame, could be seen as "extending" the GHG emissions rate for this fraction of power generation for longer than may otherwise have been the case.

The cost of upgrading may be substantial: an FGD or SCR system for a coal-based power plant costs EUR 100-150 per kilowatt (kW) each, and EUR 250 / kW combined (at 2004 values). In fact, as has been seen in the North American market, these prices could be far higher depending on the scope of work required for a successful retrofit. At the prices quoted, a plant would need to increase its revenue by EUR 37.5 per kW to recover the additional investment cost alone (over the average plant lifetime), which translates into an all-in cost of EUR 5.0 per MWh for a base-load coal-fired unit (Sloss, 2009). These cost estimates will influence the type of upgrading that a company decides to implement. Co-benefits of any upgrading work will be determined by the types of upgrades: if upgrades are also optimised for a GHG benefit, they may lead to a greater co-benefit for GHGs than upgrades without such an optimisation.

Plant closure

As mentioned above, plant operators faced with tightening emissions legislation must decide whether to invest in upgrading their plant (retrofitting or fuel switching, etc.) or to close it. Obviously, the closure of a coal plant removes a significant amount of GHG from the emissions budget. However, the actual benefit must be evaluated based on the type of replacement plant: is it a more efficient coal plant, a gas plant or a renewable energy plant? Even if the new plant is another coal plant, it is likely to be of a higher efficiency and some reduction in GHG emissions can be assumed. In addition, while emission rate improvements could be significant, the absolute improvement resulting from a plant closure may not be dramatic if the plant was operating at a low capacity factor.

Grandfathering

Grandfathering allows a plant to continue production for a limited number of hours prior to final closure without being in compliance with new concentration-based emission limits for SO_2 and / or NOx. Grandfathering typically involves a reduction in the operating hours of an old coal power plant and will probably reduce overall emissions if the needed operating capacity is then fulfilled by a cleaner and more efficient plant.

However, in some cases grandfathering could lead to an increase in emissions per kWh until these grandfathered plants are taken out of service, depending on how these plants are dispatched. If these plants mete out their remaining allowable hours when they are most needed, such as during peak demand when the plant is switched on and off repeatedly, higher emissions will be produced

Box 4.1.3

Retrofitting with end-of-pipe pollutant controls

Particulate controls: the two main types of PM controls are the electrostatic precipitator (ESP) and the fabric filter (FF). ESPs use an electrical discharge to capture fly ash particles in the flue gas. Due to their association with PM, ESPs can also help reduce emissions of heavy metals such as lead, cadmium, arsenic and nickel, as well as sulphates and black carbon. In FF systems, the flue gas passes through tightly woven fabric, resulting in the collection of particles including heavy metals. Although ESPs and FFs are both effective in controlling PM >99.99%, FFs are becoming increasingly popular as they are more suitable for use in conjunction with sorbents, which can be used to polish fine particulates, SO_2, NOx and mercury from the flue gas to very low levels.

SCR is used for oxidising NOx from the flue gas. SCR systems may have an oxidation effect on mercury, which will enhance its capture in control systems downstream.

Wet scrubbers: FGD occurs as flue gas comes into contact with limestone or lime slurry in the scrubber. SO_2 reacts to form calcium sulphate / calcium sulphite salts, which are removed along with acid gases such as hydrochloric acid (HCl), hydrofluoric acid (HF), and sulphuric acid / sulphur trioxide (SO_3); this process also captures soluble, or ionic, mercury and a proportion of particulate matter and the associated metals. However, carbon dioxide is a direct product of the chemical reaction in the FGD process, resulting in a small additional-process CO_2 emission.

Although these systems are all designed primarily for the control of a single target pollutant, they have some co-benefit effects on other pollutants. New multi-pollutant systems are now being developed which combine these systems to control numerous pollutants simultaneously.

during inefficient start-up and shut-down periods. This would lead to a relative increase in CO_2 emissions per kWh from these grandfathered units.

Factors affecting choices of compliance with air quality regulations

Power plants have several options for compliance with new air quality regulations. Whether to retrofit a plant to achieve compliance or to close the plant will depend on several factors, including the levelised cost of electricity, its net present value, internal rate of return, payback period, current condition of the plants, and impending legislation and regulation. Uncertainty over future market conditions and regulations in competitive markets can result in increased costs for new facilities relative to the cost of increasing production from existing units, particularly if sub-optimal investment decisions are made based on incomplete information or on information that becomes outdated during construction. All these factors may delay the efforts of existing plants to comply with environmental regulations.

The role of a regulatory authority is to create sufficient incentives (or strict enforcement mechanisms) so that the development of the existing power capacity moves in the right direction while balancing environmental concerns, security of supply and creation of opportunities for new investments. Consistency of environmental requirements in neighbouring states and countries also plays a role. Differences in environmental regulations between states or countries may create incentives for utilities to import energy from areas with lower emission controls, resulting in increased emissions in those areas. In Asia, the European Union, and even within the United States, power can be imported from other areas with different legislation. For example, countries that do not support domestic nuclear plants may buy power from France, which still has a large share of nuclear generation. Some regions or states may aim to be “clean”, but in times of need, power is supplied by “dirtier” states next door.

The overall state of the economy, rate of economic growth and availability of spare capacity are important considerations when upgrades must be made. Upgrading plants can be a problem especially in rapidly growing economies where there is already an energy deficit or in economies where there has been a lack of investment in new, modern capacity due to excess old capacity and limited attention to environmental impacts. The option of removing a plant for upgrading is not attractive to most operators, particularly when the final cost and time-out period is uncertain. In order to minimise risk and surprises, the shut-down period must be planned well in advance and all eventualities considered.

4.2 China's air quality constraints: Implications for GHG mitigation in power and key industry sectors

This section examines China's recent policies to combat air pollution, implemented at both the national and municipal levels, as a case study in terms of potential GHG co-benefits. An understanding of the interplay and co-ordination of these policies is necessary to meet the dual objectives of air quality improvement and GHG mitigation. This case highlighting measures taken in China may be helpful for other countries that are embarking on a CO_2 intensive, heavily industrialised growth pathway.

Introduction

China's air quality constraints pose both opportunities and challenges for global climate change mitigation. This section examines China's new air quality improvement measures and their potential impacts on GHG emissions, and will demonstrate how policy choices help determine ancillary reductions in CO_2 emissions. This chapter also presents lessons for emerging and industrialised economies on how to effectively address the challenge of improving air quality in an environment of CO_2 emissions-intense industrialisation. With a focus on key policies targeting the power sector and stationary sources of GHG emissions, this chapter provides a qualitative analysis of the interplay of these policies. The analysis considers case studies at various levels of government implementation and concludes with a discussion of questions and recommendations critical to the implementation and monitoring of these programmes. The focus of this section is on emissions from stationary sources in the energy sector and heavy industrial emissions, but the impact of policies on private vehicles, public fleets and heavy vehicles and other air pollution sources is also crucial to China's regional air quality.

China: Engaging a war on air pollution

China's heavily industrialised growth model has prompted regular campaigns addressing air quality concerns in major urban areas amid increasing frequency of dangerous air pollution levels. These campaigns, such as the one in the run-up to the 2008 Beijing Olympics, led to the closure and relocation of heavy industrial and coal-fired power plants within the Beijing municipality. Similar short-term measures were taken in preparation for the Shanghai World Expo in 2010.

More recently, emissions of fine particulate matter known as $PM_{2.5}$ and PM_{10} (particulate matter smaller than 2.5 and 10 micrometres) and other air pollutants, have culminated in persistently high levels of smog, most notably in Beijing in January 2013, when 25 days of the month were categorised as unhealthy, very unhealthy or hazardous according to World Health Organisation (WHO) Air Quality Guidelines. This event, among others, spurred major policy shifts, including an announcement by Chinese Premier Li Keqiang in March 2014 to immediately tackle $PM_{2.5}$ and PM_{10} levels with a "war on air pollution."

China has begun to increase and implement mandates to address local pollution. For instance, in 2013 China issued an Air Pollution Prevention and Control Action Plan, which includes coal cap policies and aims to reduce the share of coal to below 65% of total power generation by 2017 (from 79% in 2011). In September 2013, China announced that it will ban construction of new coal-fired power plants in the Beijing, Shanghai and Guangdong regions. Decommissioning old plants continues in China, with close to 100 gigawatts (GW) of inefficient plants taken offline since 2006, and additional forced retirements have been announced as part of the Air Pollution Prevention and Control Action Plan.

These "war on pollution" policies offer the opportunity and route towards long-term GHG emissions reductions if short-term actions are complemented with long-term structural reforms that may have overlapping, but perhaps distinct, objectives. As these measures are implemented and expanded, China's air quality constraints will likely drive ancillary reductions in CO_2 emissions and lead to the development of complementary air pollution and low-carbon policies. However, regional variation in pollution control measures and the design of industrial policies and measures may limit impact (i.e. geographic dislocation of emissions; GHG leakage through methane or CO_2 emissions leaked in the production and processing of fossil fuels; or increased CO_2 emissions intensity of alternative pollution-reducing technologies) if competitiveness of alternative options does not provide for security of supply, or if measures and monitoring do not take a comprehensive accounting of environmental constraints.

Advancing pollution measures with a GHG emissions backdrop: Impact to 2020

China's efforts to reduce air pollution take place at various governmental levels: national, sub-regional, provincial and municipal. In addition, the actions target air pollutants in a diverse manner, through regulation of pollutants as well as through 'blunter' instruments that limit certain energy sources or set targets for technology or fuel choice.

A diverse policy mix bridging China's Five-Year Plans

Looking towards 2020, measures promulgated by China's State Council and relevant ministries include a mix of command and control, industrial and environmental policy regulation and market reforms. These measures seek to address multiple priorities including air pollution, in conjunction with low-carbon development, within an energy infrastructure heavily dependent on coal. China's leadership has emphasised a focus on meeting carbon intensity targets. At the UN Climate Summit in September 2014, State Council Vice-Minister Zhang Gaoli announced that China had reduced its carbon intensity in 2013 by 28.5% from 2005 levels, and continues to increase the share of non-fossil fuels and increase forest stock as it seeks a CO_2 emissions peak.

Since the 11th Five-Year Plan (2005-2010), key pollution policies have been framed in energy and action plans to address environmental protection and climate change, setting specific energy intensity targets. For example, the 12th Five-Year Plan (2010-15) set overall economic targets and reductions of 16% energy intensity and 17% carbon intensity. In addition, economic instruments like emissions trading systems (ETSs), energy and industrial planning, and market transformation encourage the consideration of environmental concerns when planning infrastructure and industrial policy. These concerns relate to air quality, but also to impacts on soil, water and human health.

China's "war on pollution" and current air quality efforts target key criteria pollutants ($PM_{2.5}$, PM_{10}, SOx, NOx and dust) and are underpinned by the new Air Pollution Prevention and Control Action Plan (2013–17), that bridges China's 12th and impending 13th (2016-20) Five-Year Plan objectives, providing guidance for the 13th Five-Year planning process. These measures seek to initiate market-oriented fiscal, price and taxation reform; improve the regulatory and enforcement system; make environmental data more transparent; and ensure strict implementation of the law. An important part of these actions is fostering greater inter-regional co-operation mechanisms for air pollution prevention and control, a key focus of this section.

In the action plan, the central government acknowledges the key challenges in addressing air pollution and cross-regional air quality impacts. The plan seeks to address these issues by building environmental monitoring, early warning and emergency response systems, and formulating and improving an emergency plan to properly address periods of seriously polluted weather and air quality conditions in a co-ordinated regional response. Key policy provisions and relevant frameworks associated with the action plan are highlighted in Table 4.2.1.

Table 4.2.1

Key national air pollution control regulations

Regulation and date	Agency	Policy action
12th Five-Year Plan for Air Pollution Prevention and Control in Key Regions (5 December 2012)	Ministry of Environmental Protection, National Development and Reform Commission, Ministry of Finance	Regional mandate covers three key regions (Beijing-Tianjin-Hebei, Yangtze River Delta, and Pearl River Delta) and ten city clusters, involving 19 provincial-level jurisdictions and 117 cities.
Draft Technical Policy for the Prevention and Control of Ambient Fine Particulates (6 February 2013)	Ministry of Environmental Protection	Identifies sources of fine air particulate, provides technical recommendations, monitoring and emergency counter-measures for those industrial, mobile and residential pollution sources.
Air Pollution Prevention and Control of Action Plan (12 September 2013)	State Council	Provides measures to reduce air pollutants (including PM, NOx and SOx), to gradually eliminate severe air pollution and to substantially improve national air quality over the next five years.
Revised Draft of Atmospheric Pollution Prevention Law (9 September 2014)	State Council (Legislative Affairs Office)	Clarifies government accountability for environmental protection and related enforcement. Improves air pollutant emissions control and forecast systems and strengthens emissions permits and designated low-emissions regions.

Sources: MEP, NDRC and Ministry of Finance (2012), "12th Five-Year Plan on Air Pollution Prevention and Control in Key Regions", 5 December, Government of People's Republic of China; MEP (2013), "The State Council issues action plan on prevention and control of air pollution introducing ten measures to improve air quality", MEP, Beijing, http://english.mep.gov.cn. *State Council (2014) "Revised Draft of Air Pollution and Prevention law," Beijing,* www.chinalaw.gov.cn.

These efforts seek to enhance and build on existing measures and strengthen enforcement. For instance, in the 11th Five-Year Plan there were two national targets dealing with air quality in China, with a focus on controlling sulphur. The first involved the widespread deployment of scrubbers for desulphurisation, and the second, retirement of inefficient highly polluting plants. Province-wide pilot SO_2 markets deployed during this period 2006-10 contributed to a fall in emissions in key pilot provinces, raising the share of coal-fired capacity with FGD to 80% by 2010 (Wang and Hao, 2012). In this period, a combined 59 GW of small, inefficient power plants were closed and replaced by newer, larger and cleaner power generation assets (Cao et al., 2013).

Measuring air quality impact to 2020: GHG implications

China's recent pollution-focused actions since 2012, unprecedented in scope, may lead to significant GHG emissions reductions in major cities. Based on a recent report, these measures (see Table 4.2.1) could lead to an estimated reduction in CO_2 emissions in "low-emissions zones" of about 700 megatonnes of carbon dioxide ($MtCO_2$) in 2017 and 1 300 Mt in 2020 (Greenpeace, 2014). In March 2014, Premier Li Keqiang announced that implementation of these measures will include reducing outdated steel production capacity by 27 Mt in 2014, and cement production by 42 Mt (Reuters, 2014). This translates into potential reductions of 48.6 $MtCO_2$ from steel and 23 $MtCO_2$ from cement production. From a GHG perspective, the targets announced by Premier Li Keqiang may offer significant initial steps, but amount to less than roughly 2% of China's three Gt of annual industrial CO_2 emissions, if that production is not replaced.

But these air pollution measures only reflect part of China's domestic low-carbon priorities. While the 12th Five-Year Plan focused on intensity targets for energy (16%) and carbon (17%) to drive greater energy and resource efficiency in the period to 2015, China's domestic climate Action Plan aims to meet a 40-45% reduction in carbon intensity by 2020 compared to 2005 levels (Figure 4.2.1). China came close to achieving its 20% energy intensity target during the 11th Five-Year-Plan period (2006-10), attaining 19% by official account. However, future gains will be increasingly challenging as China moves towards its 2020 targets. In 2012, China's CO_2 emissions grew by the smallest amounts in a decade (300 Mt), as electricity generation growth was supplied by expansion of renewables, including hydropower.

These policies follow the central government's interest in developing an economic growth model less dependent on heavy industry and energy-intensive consumption; the shift is towards domestic consumption and growth of the service and other less intensive sectors. However, rising income and consumption may continue to increase per capita energy demand even as energy intensity levels decline (Figure 4.2.2). Based on the New Policies Scenario (IEA, 2013), this increased demand is likely to be met by heavily coal-based power generation over the medium term,

Figure 4.2.1

Towards China's 2020 targets: GDP, CO_2 emissions, CO_2 intensity

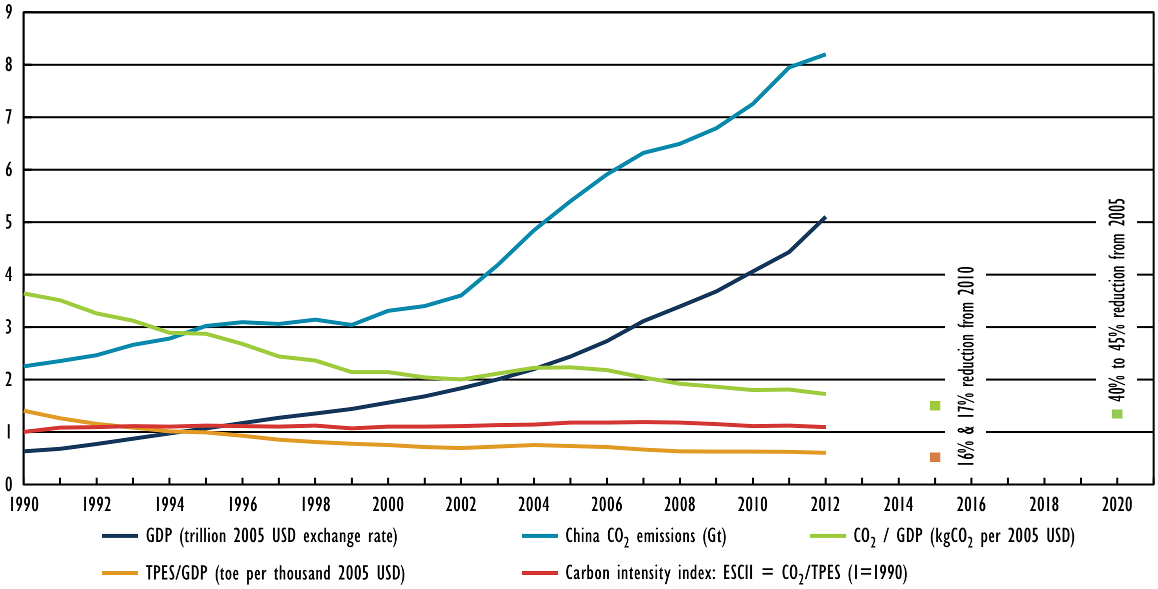
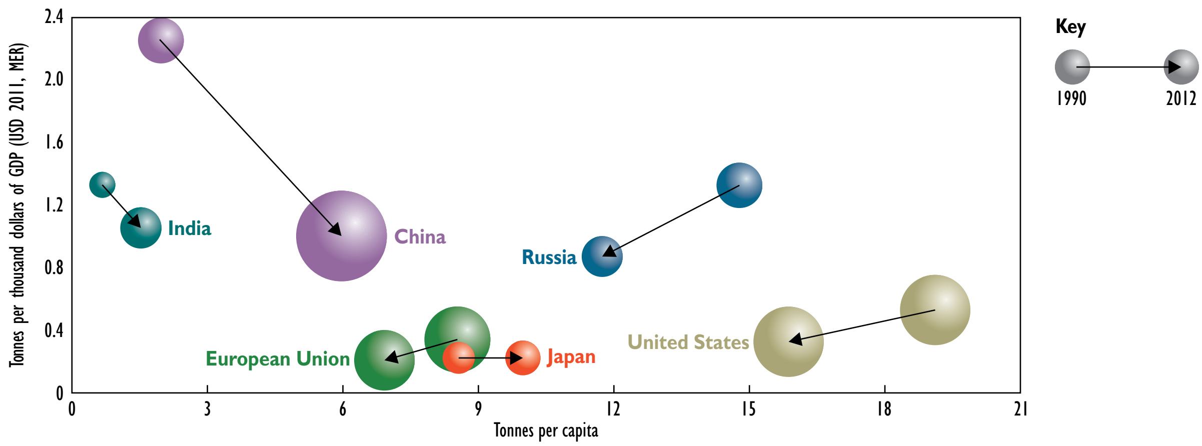


Figure 4.2.2

Trends in CO_2 emissions intensities for the top five emitting countries[7]



Notes: Bubble area indicates total annual energy-related CO_2 emissions in that region. MER = market exchange rate.

Source: IEA (2013a), Redrawing the Energy-Climate Map, *World Energy Outlook Special Report, OECD/IEA, Paris.*

with studies expecting China's coal demand to peak sometime between 2020 and 2030. China's broad targets and policies are reinforced by new dedicated air quality measures, increasingly enforced by a stronger Ministry of Environmental Protection (MEP).

Notwithstanding national priorities and direct efforts to curtail emissions from outdated or low-efficiency power and industrial plants, significant investment and development are taking place in coal technology and across the coal value-chain infrastructure (Liu, 2014).

This investment and development includes higher-efficiency coal combustion technologies, and integrated gasification combined cycle (IGCC) and coal gasification technologies with the aim to reduce particulates from coal combustion in the long term. By the end of 2013, China's National Development and Reform Commission (NDRC) had approved 15 large-scale coal conversion plants and were considering approval of up to 20 more that included coal to synthetic natural gas, methanol, olefins and diesel (Platts, 2014). Though these conversion plants may reduce local air pollutants, the processes are very carbon-intensive (as reflected in Box 4.2.1) and require significant water resources.

7. Emissions per GDP can be useful measures of efforts over time for one country, but are less useful when comparing countries. The ratio is very dependent on the base year used for the GDP purchasing power parity (PPP). In this figure, the GDP and GDP PPP series, and all associated ratios, have been readjusted from USD 2000 to USD 2005 values. As a result, the CO_2/GDP PPP ratio of China expressed in USD 2005 is twice as high as that of the United States; when the ratios were expressed in USD 2000, China's was only about 20% higher.

In most cases, these plants are planned to be large and integrated into mega-industrial clusters that benefit from economies of scale, centralised transmission and distribution infrastructure. This removes the generation or industrial facilities from densely populated urban centres, with an aim to significantly improve air quality in China's cities by 2020, when many of these facilities are slated to come online.

However, electricity generation from coal has nearly doubled since 2006, including continued construction of subcritical plants. For long-term impact, a coal cap, industrial energy efficiency and production policies and market reforms introduced at the national level should be designed to effectively complement municipal programmes aiming to shut down sub-optimal plants in urban and population-dense regions. Regulating air particulate pollution only in urban areas may prove to have a limited impact on GHG emissions, and may even lead to increases if particular technologies or energy policies prevail and lead to geographic dislocation of emissions, GHG leakage and life-cycle CO_2 intensity increases of alternative fuels or technologies (Figure 4.2.3).

Coal command control, a multilayer air pollution response: Impact to 2020

A nationwide coal cap policy

With announced plant retirements, China is experimenting with national coal cap policies by setting targets at municipal and provincial levels. The national government is establishing a mid and long-term coal consumption

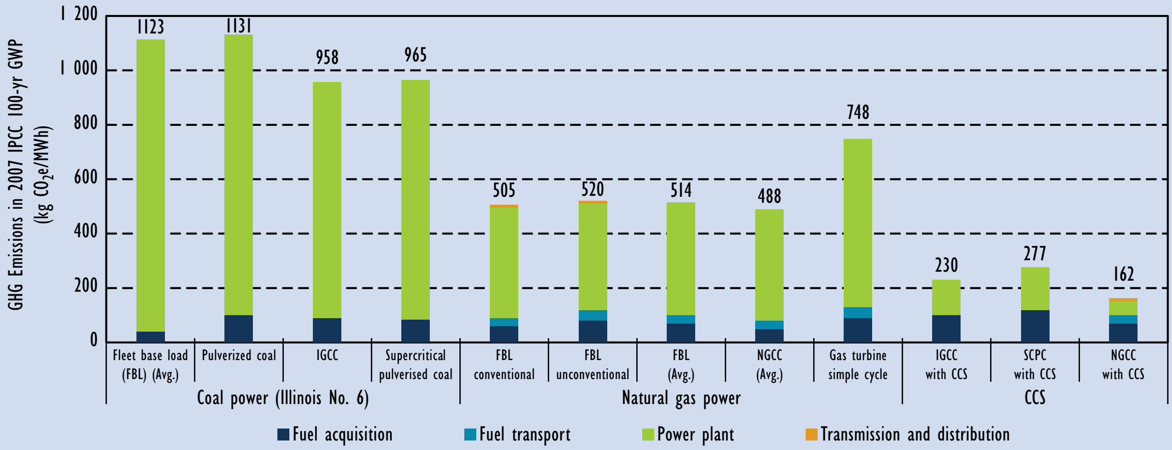
Box 4.2.1

Impact to 2020: Technology choice matters

As China's provinces announce air pollution targets for main particulate emissions irrespective of GHG targets, air quality measures may prove to have limited impact on GHG emissions if specific technologies, resources or economic policies prevail. For instance, life-cycle emissions from unconventional gas may impact GHG emissions as provinces switch from coal to gas, if methane leakage and associated impacts are not fully accounted for. The development of cleaner (in terms of local air pollutants), but still carbon-intensive coal technologies such as IGCC, coal-to-chemicals, synthetic gas and coal-to-liquids may lead to local air quality improvements, but may also drastically increase GHG emissions by 2020 and beyond. This could lead to large-scale, long-term and locked-in CO_2 emissions, unless the early application of carbon capture and storage (CCS) is successfully integrated into each plant. The figure below also emphasises the life cycle of alternative choices and the relative GHG impact of select coal and gas technologies, with and without the application of CCS. The coal technologies do not include GHG emissions of coal conversion or coal-to-liquids technologies which would have considerably higher GHG emissions than the most GHG-intensive technologies shown below.

Figure 4.2.3

Life-cycle GHG emissions from natural gas and coal power



Source: IEA adapted from NETL (2012), Role of Alternative Energy Sources: Natural Gas Power Technology Assessment, Department of Energy, Washington.

cap to progressively reduce the proportion of coal in primary energy consumption among other efficiency and air pollution measures. To enforce China's Air Pollution Prevention and Control Action Plan (September 2013), three key air pollution control regions are putting coal cap pilot programmes in place. These zones include the Beijing-Tianjin-Hebei region, the Yangtze River Delta region around Shanghai and the Pearl River Delta region in Guangdong province. These regions and others are beginning to institute both coal consumption caps and negative coal consumption growth targets on a voluntary basis.

China's coal consumption has shown signs of slowing since 2012, driven in part by China's efforts to exert greater control and downward pressure on GDP growth targets, shifts in urbanisation and industrial capacity, market reforms and broad economic structural policies, along with increased attention to environmental constraints. The NDRC, China's central planning authority, has set the target of keeping coal use below 65% of total primary energy supply (TPES) by 2017, which will be implemented through efforts by provincial and local authorities as they develop targets to meet national guidance. At a local level, in Beijing for instance, the same 65% target must be obtained by 2015.

China's National Energy Administration is also considering coal policies banning high-ash (greater than 25%) and high-sulphur (greater than 1%) coals, while encouraging imports of higher-quality coals and limiting lignite and coals with calorific values of less than 4 540 kilocalories per kilogramme (Bloomberg, 2014). In China, where newly built supercritical plants commissioned in 2013 are using low calorific value gangue coal (or waste coal), a coal cap and related policies may push higher-efficiency plants towards higher-quality coals. Additionally, in September 2014, China

Table 4.2.2

Impact to 2020: Coal quality also matters

Plant and coal type	Subcritical (hard coal)	Super critical (hard coal)	Ultra-super critical (USC) (hard coal)	IGCC (hard coal)	USC (sub-bituminous low-sulphur)
Coal (kg/kWh)	0.32	0.3	0.28	0.32	0.45
CO_2 (kg/kWh)	0.84	0.79	0.72	0.81	0.80
CO_2/Coal	2.6	2.6	2.6	2.5	1.8

Source: IEA analysis and IEA Coal Information (2014 Edition), OECD/IEA, Paris

announced a ban on the import and local sale of coal with high ash and sulphur content starting from 2015 in a bid to tackle air pollution.

With 65% coal cap policies set to 2017 at the national level and similar municipal cap policies in cities like Beijing, the Development Research Center of the State Council has stated that total coal consumption could peak by 2020, with annual coal consumption capped below 3 billion tonnes (Bt) and oil limited to below 550 Mt by 2020 and capped at 650 Mt by 2030.

China's multilayer response also includes integrated governance measures to strengthen co-ordination and enforcement of emissions of pollutants through a 2014 State Council "22 policies" plan (Zhao, 2014). This plan will build from the previous Air Pollution Action Plan which includes a series of early retirements and expanded retrofits (Table 4.2.3) for China's most polluting plants, with a focus on major municipalities including Beijing and Shanghai, and "naming and shaming" campaigns that list China's Best and Worst Cities by air quality and pollution measures. Coal resource policies also include efforts to expand dedicated pollution abatement technology (FGD/other) and retrofits to improve criteria emissions performance.

This multilayer response also reflects experience with market-based approaches (SO_2 markets) in lieu of direct command and control measures (e.g. Beijing Olympics, municipal efforts, and the Hebei case as described below) will be important in considering policy approaches in China's dedicated low-emissions zones, regions surrounding Beijing, Shanghai and Guangdong Province. The design of Chinese emissions trading scheme (ETS) pilot programmes will need to consider transforming polluting infrastructure, establishing carbon pricing and additional incentives that may affect capacity markets, and technology mix, as the ETS interacts with stand-alone local air pollution policies.

China's pilot carbon market systems: Impact to 2020

China's seven planned pilot carbon markets have been launched in seven cities and provinces, and are providing a testing bed for a national market that may be developed by 2020, with a national guidance framework in place as early as 2016. In the interim, the pilots provide opportunities for China to scale towards regional schemes and linkages; for instance, the northern cities of Beijing and Tianjin are now operating separate carbon markets. As policies develop to respond to low-emissions zones and deal with leakage effects, the province of Hebei, which surrounds both municipalities, could also be added to the market. Other regional markets may be linked around the Yangtze River Delta, and Jiangsu and Zhejiang provincial manufacturing hubs may join Shanghai's CO_2 market.

Southern regions could link to the Guangdong emissions trading scheme gradually, developing three or four major regional ETS networks that overlap with dedicated low-emissions zones and dense coastal urban centres. Due to air quality measures, these regions with the largest GHG emissions have already been banned by the central

Table 4.2.3

Steps to retrofit existing plants with pollution control by production capacity in 2014

Production capacity type	Policy action
Small coal-fired furnaces (50 000 units)	Shutdown
15 GW	Desulphurisation
130 GW	Denitrification
180 GW	Dust removal

Source: Ministry of Foreign Affairs of the People's Republic of China (2014), "News from China", 26(3), March, http://www.fmprc.gov.cn/ce/cein/chn/xwfw/zgxw/P020140401485442197813.pdf.

Box 4.2.2

Coal command control: Potential GHG implications

With a 65% coal cap policy set to 2017 at the national level, the Development Research Center of the State Council has stated that total coal consumption could peak by 2020 with annual coal consumption capped below 3 Bt. This reflects a trajectory roughly consistent with the IEA New Policies Scenario and would lead to potential annual CO_2 emissions for coal consumption in the order of 7.2 Gt in 2020.

government from building new coal-fired power plants. The announcement of a draft plan for a national emissions market is expected in late 2014 and could possibly underpin and drive national commitments to 2020.

The announcement of a draft plan for a national emissions market is expected in late 2014 and could possibly underpin and drive national commitments to 2020.

Alternative energy: A complement to air pollution measures

China's coal cap and key air pollution control policies are also supported by the expansion of alternative energy technologies and fuel sources. In this context, fuel switching, energy efficiency and renewable energy provide important complements as further explained in Box 4.2.3.

Regional measures: A focus on local actions and low-emissions zones

The central government has announced bans on construction of new industrial plants like steel smelters, cement factories and oil refineries in three major low-emissions regions: Beijing-Hebei-Tianjin, the Yangtze River Delta region surrounding Shanghai and the Pearl River Delta region in southern Guangdong province. This emphasises the increasing need to combat air quality challenges through a comprehensive / holistic approach.

As a showcase for the country, Beijing has made significant efforts to reduce energy consumption and pollutant emissions within the municipality; historically, however, industrial development within the surrounding regions, specifically in the city of Tianjin and surrounding Hebei province, has outpaced these efforts. As a result, overall energy consumption and pollutant emissions in the region of Beijing and Hebei have increased in recent years. In response, Beijing, Tianjin and Hebei are currently regarded as a combined low-emissions area for co-ordinated pollution control measures.

According to China's Ministry of Environment, key regions covering 8% of China's total area, including Beijing and Hebei, account for 55% of national steel production, 40% of total cement output and 52% of gasoline and diesel production. These statistics demonstrate that in densely populated regions, air quality measures must go beyond any single location or province, and should be co-ordinated. Most of this region's economic activity has been driven by energy-intensive industrial development, prompting the national government in 2013 to move towards a less energy-intensive growth model.

Table 4.2.4 provides indicative CO_2 emissions levels for the key polluting industries in this region. Resulting air quality regulations will impact the upper limit of CO_2 emissions in this region.

Beijing: A showcase for national air quality measures

Beijing's coal reduction target of 2.6 million metric tonnes and plans to upgrade 300 polluting enterprises in 2014 follows a series of measures to deal with air quality concerns over the past decade. Major efforts were initiated in the run-up to Beijing's hosting of the Olympic Games. Relocation of energy-intensive and polluting industries was heavily promoted ahead of the 2008 Summer Olympics, when nearly 200 chemical, coking and steel works moved out of the capital. Much of this production was relocated to surrounding provinces, such as Hebei.

The current plan to cut air pollution in Beijing will require a significant shift from coal to gas, boosting demand for cleaner fuels equivalent to 10% of China's total natural gas imports or 5.4 bcm of natural gas annually by 2018 (Reuters, 2014b). By 2017, Beijing aims to cap coal consumption at just 10 Mt, a 13-Mt reduction, in a bid to cut air pollution by a quarter. To achieve this target, the municipality will cut one-third of power capacity and ban construction of new oil refining, steel, cement and thermal power plants.

The cement sector has been an early target for decommissioning: production in the region will be cut by half, amounting to emissions reductions of 20 $MtCO_2$. However, these measures are driven in part by cement sector overcapacity. Beijing has already levied fines on 266 coal-fired boilers from November 2013 to March 2014 as the Environment Protection Regulations have been given more enforcement authority (Zheng, 2014).

Box 4.2.3

Expanding low-emissions alternatives

Fuel switching, renewable energy and energy efficiency

In China, energy efficiency improvements, natural gas switching and renewable energy deployment are currently being imposed to offset coal cap policies and assist in meeting air quality targets. China is increasing its gas procurement contracts and pipeline construction, clean energy technology research and development (R&D), energy efficiency initiatives including combined heat and power (CHP), all of which should help to 'substitute' for reductions in coal production. The Chinese government anticipates boosting the share of natural gas as part of total energy consumption to around 8% by the end of 2015, and to 10% by 2020 to alleviate high pollution resulting from the country's heavy coal use (US EIA, 2014a).

The power, industrial and transport sectors will likley drive overall Chinese gas demand to an estimated 315 billion cubic metres (bcm) in 2019, an increase of 90% from 2014. While China remains a significant importer, half of its new gas demand will be met by domestic resources, most of them unconventional as Chinese production is set to grow by 65%, from 117 bcm in 2013 to 193 bcm in 2019 (IEA, 2014a).

This switching can have significant GHG emissions reduction potential if natural gas is introduced as a substitute for coal, as NOx, SO_2 and other emissions are reduced as well. However, questions remain regarding China's domestic gas production, gas imports and reliance on trade, lack of infrastructure, technical capabilities, and scale of economically recoverable reserves. Methane leakage in the case of gas and unconventional gas development, and other environmental costs, will also need to be considered in the context of overall GHG net impact. Coal gasification technologies promising to reduce local pollutants, while addressing energy security concerns, should be evaluated by their GHG profile and increase in other pollutants (i.e. mercury). However, benefits should be compared in aggregate, taking into account objectives and measures of China's Air Pollution Prevention and Control.

The expansion of non-fossil fuel power generating capacity (including renewable energy, nuclear and hydro) is set to reach 30% of total energy generation capacity in China, in line with the 12th Five-Year Plan 2015 target, and energy efficiency and fuel switching (to gas) are also key tools to benefit air quality while also directly limiting GHG emissions. Additionally, China, as well as other countries, may see an opportunity in expansion of bioenergy and residential, industrial and agricultural waste-based power generation, as this sector grows annually at a global average rate of 10%. Electricity generation from bioenergy and co-firing may increase over the near term, especially in combination with agricultural residues, renewable municipal and industrial waste. Such measures have specific application to co-generation, i.e. the combined generation of electricity and heat (or cooling). This potential will depend on local heat demand and requirements in buildings or industry sectors, and availability, transport and sustainability of feedstock.

Table 4.2.4

Regional measures: Potential CO_2 emissions impact

	Key 8% region production by sector	Total production (China)	Estimated coal use in key region	CO_2 emissions
Steel	55%	779 Mt	363 Mt	653 Mt
Cement	40%	2 300 Mt	202 Mt	511 Mt

Sources: IEA analysis based on World Steel Association (2014), "World crude steel output increases by 3.5% in 2013", www.worldsteel.org / media-centre / press-releases / 2014 / World-crude-steel-output-increases-by-3-5–in-2013.html; USGS (US Geological Survey) (2014), Mineral Program Cement Report, *USGS, Reston, Virginia; World Coal Association statistics.*

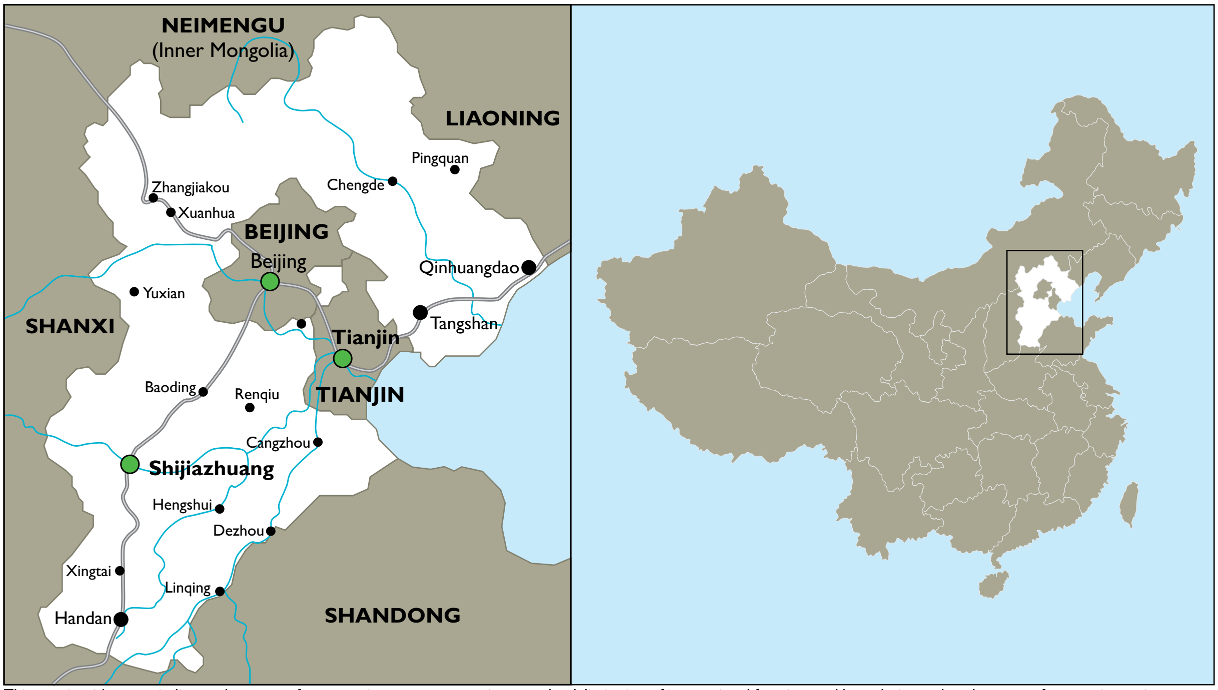
Hebei provincial measures: Addressing leakage through monitoring and enforcement

According to the MEP, the province of Hebei is home to seven of the country's ten most polluted cities, and as it surrounds the municipality of Beijing it is a major contributor to air pollution in northern China.

In 2013, Hebei Province consumed 280 Mt of coal and, including Tianjin, produced more than 200 Mt of crude steel (SCMP, 2014). Four industries, including power, steel, cement and glass, produce the majority of air pollutants in Hebei, emitting 60% of the province's sulphur dioxide, nitrogen oxide and dust, and accounted for 53% of total

Figure 4.2.4

Map of Beijing, Tianjin and Hebei low-emissions region



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Table 4.2.5

Municipal measures: Potential CO_2 emissions impact

Measure	Estimated CO_2 emissions
Beijing's annual coal reduction target of 2.6 Mt	<6.76 Mt CO_2>
Beijing's annual gas demand to 2018 (5.4 bcm)	23 Mt CO_2/a
13 Mt reduction of coal by 2017	<33.8 Mt CO_2>
50% reduction in Beijing cement production	<20 Mt CO_2>

Source: IEA analysis based on Reuters (2014b), "Beijing's clean air plan to boost gas demand," Thomson Reuters.

provincial coal use (167 million metric tonnes) in 2012. The province's current coal consumption reduction target aims to cut 40 Mt of coal by 2017, based on 2012 data. Hebei has pledged to cut steel and cement production capacities by 60 Mt per sector by 2017, setting new air pollution limits and developing a real-time monitoring system by 2014 (Zheng, 2013). In 2014, direct measures include the shutdown of 94 obsolete iron and steel plants, retirement of 60 Mt of cement production capacity, desulphurisation retrofitting in 43 cement plants and 94 glass-making operations, and 49 coal-fired power plant retrofits to reduce dust.

However, these plant closures may not be driven solely by air quality objectives, as northern China has idle capacity approaching 100 Mt and closure targets may be driven more by economics, hence may not translate into actual emissions benefits, but rather reflect the shift towards less energy-intensive economic growth.

The monitoring and enforcement system includes oversight of 521 companies and will report company emissions which have been assigned quotas for a tradable emissions-permit market; otherwise, those companies will be fined (Zheng, 2013). One approach to enforce compliance is the implementation of a naming and shaming programme; names of the ten companies that emit the most pollutants are to be publicly released every quarter in 2014, placing impetus on both industry and official overseers to take corrective actions.

Table 4.2.6

Hebei region: Estimated CO_2 emissions

Measure	Estimated coal use (Mt)	Estimated CO_2 emissions (Mt)
Hebei coal consumption 2013	280	728
Hebei steel production cut by 2017 (60 Mt)	<46.2>	<83>
Hebei cement production cut by 2017 (60 Mt)	<13.3>	<34.6>

Notes: These are indicative CO_2 emissions for key polluting industries; resulting air quality regulations may impact the upper limit of CO_2 emissions. The emissions factor is 2.6 tonnes of carbon dioxide per tonne of coal equivalent (tCO_2/tce).

Source: IEA analysis adapted from Zheng (2013), "Hebei to limit air pollutants, shut down obsolete plants", China Daily USA, *Vol. 11, No. 28, p. 5.*

Shanghai: A look at a municipal-level climate action plan

Shanghai's energy savings and climate plan for 2014 will reduce the energy intensity of its economy by 3% this year through shifts from coal to natural gas, limiting the growth of carbon dioxide emissions to 8.5 Mt and curbing growth in year-on-year energy consumption to 4 Mt of standard coal equivalent (Reuters News, 2014c). Shanghai's 2015 target is to cut energy intensity to 18% below 2010 levels and to limit total coal consumption to 35 Mt. The 2014 plan seeks to increase electricity imports and natural gas power generation, while encouraging expansion of distributed gas and renewable energy development such as wind, solar and biomass. New manufacturing facilities for iron and steel, building materials and non-ferrous metals would be banned in 2014.

Under Shanghai's plan, carbon dioxide emissions from "new energy sources" would rise by 8.5 Mt in 2014, but changes in emissions from existing sources are not estimated. As one of seven regions chosen by the central government to pilot carbon trading, last November Shanghai launched an ETS capping CO_2 emissions from nearly 200 facilities in power generation, manufacturing, petro-chemicals, aviation and ports. As these and other measures are implemented, monitoring and enforcement measures are critical to bring industry practice and effective oversight in line with policies. Specific challenges and impacts are further highlighted in Box 4.2.4.

Air quality in eastern cities: Driving GHG emissions in a journey to the west?

While strong efforts to reduce emissions levels are being made in China's low-emissions zones in the urbanised east, additional efforts to develop so-called "coal bases" in China's western regions are under development. Sixteen coal base sites are currently being built, with some plants already operational. The clustered facilities use coal to make liquid fuels, chemicals, power and synthetic gas, with the fuels and electricity, pipelined and distributed to eastern cities. Similar to natural gas, syngas is much cleaner at the burner tip than coal, and has benefits in terms of transport. As of June 2014, China's NDRC had approved nine syngas plants with planned annual capacity totalling 37.1 billion m^3, located across western China, in Inner Mongolia, Xinjiang, Shanxi and one in Liaoning Province.

A large base in Ningxia, at Shenhua's Ningdong Energy and Chemical Industry west of Beijing, started construction in 2008. The cluster consists of coal mines, coal chemicals, power plants, power lines, pipelines, roads, rail lines and chemical processing plants. The facility is to produce

Box 4.2.4

Shanghai: Potential CO_2 emissions impact

Measures to reduce air and industrial pollutants, and reduce industrial capacity in these municipalities through fuel switching, CHP and alternative sources for power generation, have the potential to significantly impact dual air pollution and GHG emissions objectives. However, tracking the GHG impact of Shanghai's air-quality and low-emissions policies would be more comprehensive if increased emissions in zones outside the low-emissions zone – resulting from industry relocation and increased electricity imports to Shanghai – were considered. Efficiency improvements on existing plants and high-efficiency coal generation may also provide important benefits to both local pollutant and low-carbon goals; however, the retrofits of FGD and scrubbers will require a more systematic and balanced approach. The challenge will be in balancing these existing "command and control" regulations with market reforms and policies to limit the future lock-in of carbon-intense generation and industrial capacity. For instance, the decision to retrofit a subcritical coal-fired power plant with FGD may conflict with an option to retire the plant and switch to a lower emissions plant, in the case of CO_2 pricing policy.

30 000 MW of power, a range of fuels and chemicals consuming coal at a rate of 100 Mt a year, by 2020.

As transmission lines and pipelines spanning hundreds of miles relocate coal-fired power production and gas development to remote areas in western and north-western China, the effect may lead to significantly cleaner air in China's coastal cities. However, syngas and some coal-to-chemicals and coal-to-liquids processes are significantly more energy- and carbon-intensive than equivalent conventional power plants (Yang and Jackson, 2013). In comparison, increased total lifecycle greenhouse gas emissions range from 32-86% for gasification, and for some coal conversion processes, as much as 100%.

Over 40 additional syngas projects have been announced throughout China. If all are completed, they will release 110 Gt of carbon dioxide into the atmosphere over 40 years (Yang and Jackson, 2013). However, a 2014 announcement from China's National Energy Commission, a high-level committee chaired by Premier Li Keqiang, indicates that the central government is concerned about the potential deployment of these GHG-intense technologies. However, in cases such as the production of methanol, in spite of the de-emphasis of methanol nationally, methanol-based industries continue to expand in China through local or provincial supports.

A key question related to coal base development is the availability of water resources in arid regions and the potential for deploying CCS technologies at scale and cost, to reduce the GHG impact of these large industrial clusters. The impact of massive coal base development with various coal conversion technologies, if CCS is not deployed, will negate existing or future benefit of successful large-scale energy efficiency measures, and renewable and nuclear deployment, to minimise GHGs.

For instance, in 2013, China's wind capacity of 92 GW reached 30% of the world total (Chadha, 2014). However, China's 92 GW of wind capacity saves the equivalent emissions associated with just two of China's approved coal-to-gas plants if calculated over a 40-year lifespan. In a low-emissions scheme, therefore, CCS will need to be deployed if coal base development is to proceed at the current scale.

Some strategic considerations to reduce GHG while making air quality improvements

Measures to improve air quality should consider the complex structural challenges to addressing both air quality and the carbon intensity of China's economy in the long term.

Air pollution controls can also lead to significant reductions in GHG emissions, provided that they are structured to achieve these dual objectives. In meeting these dual objectives, policy makers will need to consider that (a) pollution controls do not necessarily reduce GHG impacts (and to a minor extent, scrubbers might increase emissions by an additional nominal parasitic load; see Box 4.1.2); and (b) from a national perspective, emissions from heavy industrial production are likely to shift to unregulated or remote regions. In China in particular, with varying levels of regional development, and divergent regional markets, grid design and enforcement and oversight, this capacity relocation may be more likely to occur.

At a national level, policy makers should consider short-term pollution measures to 2020, and their long-term impact, engaging institutional stakeholders in options that provide air quality benefits consistent with GHG reductions. Achieving dual emissions objectives with a balanced approach that does not increase GHG emissions or technical and infrastructure lock-in in the short term, or that maximises ancillary benefits at least cost, will likely require a systems-planning approach. Such an approach should be driven by an expansive economic assessment of social and external costs and involve key industry and government stakeholders by clearly defining their responsibility and encouraging public participation.

The continued improvement of air quality statistics, accounting, and enforcement measures will be needed to reflect accurate impacts and assist in co-ordination of policy measures at the municipal, provincial and national levels. China's air quality measures in 2013 and 2014 have set an ambitious pace, with objectives that may lead to significant GHG emissions reductions in major cities and low-emissions zones if monitoring and enforcement follow.

The development of metrics that measure combined pollution and GHG emissions reductions could support policy makers in designing and monitoring related dual-objective policies. For evaluating the impact and performance of a set of air quality policies, multiple-criteria, geographically explicit metrics could be considered to provide locally specific measurements, in comparison to national measures and performance. Such a metric may reference (1) an air quality indicator such as the Air Quality Index (AQI) averaged over a given period (i.e. monthly, yearly) in comparison with (2) an Energy Sector Carbon Intensity Index (ESCII) (tCO_2/toe), a measure of carbon intensity of the energy sector (Box 4.2.5).

Energy systems, social costs and emissions intensities of alternative technology and fuel choices should determine long-term air quality measures. Technology R&D for short-term energy policies should consider the impacts of long-term GHG emissions lock-in on both air quality and economic and social costs. For example, ambitious syngas developments may provide air quality improvements, but without CCS will significantly constrain reductions in

Box 4.2.5

Dual pollution / GHG metrics

Combining air pollution control and GHG emissions reduction-related metrics into a single metric can enhance monitoring and oversight. For example, such a metric might reference (1) an air quality indicator such as the AQI averaged over a given period (i.e. daily, monthly, yearly), in comparison with (2) a carbon intensity indicator, such as the ESCII (in tCO_2 / toe), a measure of carbon intensity of the energy sector. Such a comprehensive metric for evaluation by policy makers may more accurately reflect GHG emissions impacts alongside those of air quality, with the aim of clarifying options to achieve low-carbon objectives at least cost. Over time, such standard measures may provide an indication of the relative impact of both GHG emissions and pollution control measures at national and regional levels.

Balancing air quality and GHG emissions: Measurement with impact

Region	Measurement	Impact
Municipal (M_1)	(AQI);carbon intensity (i.e. ESCII)	M_1 / N_1
Provincial / low-emissions zone (P_1)	(AQI);carbon intensity (i.e. ESCII)	P_1 / N_1
National (N_1)	(AQI);carbon intensity (i.e. ESCII)	N_2 / N_1

**N_1 / N_2 Indicates year-on-year change.*

GHG emissions post-2020. Hence, further analysis and research should clarify the full costs of pollution abatement technologies and their performance relative to plants built with CCS.

The effectiveness of command-control measures and performance standards can be enhanced by market price signals. Clear market or pricing signals that fully account for the relative costs of air pollution and energy value-chain impacts can help to generate more efficient outcomes than command-control measures alone. Responsive measures for both air quality and GHG emissions could take into account the impacts to competitiveness if a nationwide carbon price were implemented, in addition to pricing reforms and the removal of fossil fuel subsidies. Experiences with existing markets for SO_2, and the CO_2 market pilots already implemented, will be important to provide experience in achieving regional and nationwide emissions objectives, with regional linking an important option.

Conclusion

China's approach to controlling air quality will affect its long-term GHG emissions trajectory. The nature and extent of that impact requires further analysis across a range of options. However, initial steps in China's air pollution regulations provides potentially important positive results for the reduction of GHG emissions, and also provides some interesting examples and aspects for other countries seeking to address the dual objectives of cleaner air quality and reduced GHG emissions. The challenge in implementing policies with either air quality or GHG emissions reduction objectives raises critical questions regarding intraregional co-ordination, institutional dynamics and the key roles of monitoring, evaluation and enforcement. The interplay of policy measures and actions can also provide an important complementary avenue towards GHG emissions abatement, which other countries might consider in the context of current climate negotiations and long-term energy planning.

4.3 The regulatory approach to climate policy in the United States

To advance its climate change goals, the United States government is targeting GHG reductions through a regulatory framework normally reserved for the control of conventional air pollutants. The principal vehicle for these GHG regulations is the US Clean Air Act, which the US government is adapting in order to tackle GHG emissions reductions in the electricity, industrial, and transportation sectors. This section surveys the suite of US federal regulations applicable to GHG emissions from energy-related sources and assesses some of their impacts.

Introduction

The federal government of the United States has been regulating conventional air pollution on a nationwide basis for over 40 years, but has only recently begun to mandate reductions in GHG emissions on a national level. Interestingly, it is targeting GHG reductions through a regulatory framework that was designed in a different era for a different set of pollutants, including "criteria" pollutants and air toxics.[8] The use of regulatory standards represents a notable expansion of the climate policy toolkit and may come as a surprise to policy observers who expected a comprehensive, market-based approach to take form in the United States instead. The principal vehicle for these regulations is the US Clean Air Act, the nation's venerable environmental law that has been effectively used to reduce levels of conventional air pollution since the 1970s. Though the Act was not designed with GHG emissions in mind, the US government is adapting existing Clean Air Act programmes for the purposes of GHG emissions mitigation.

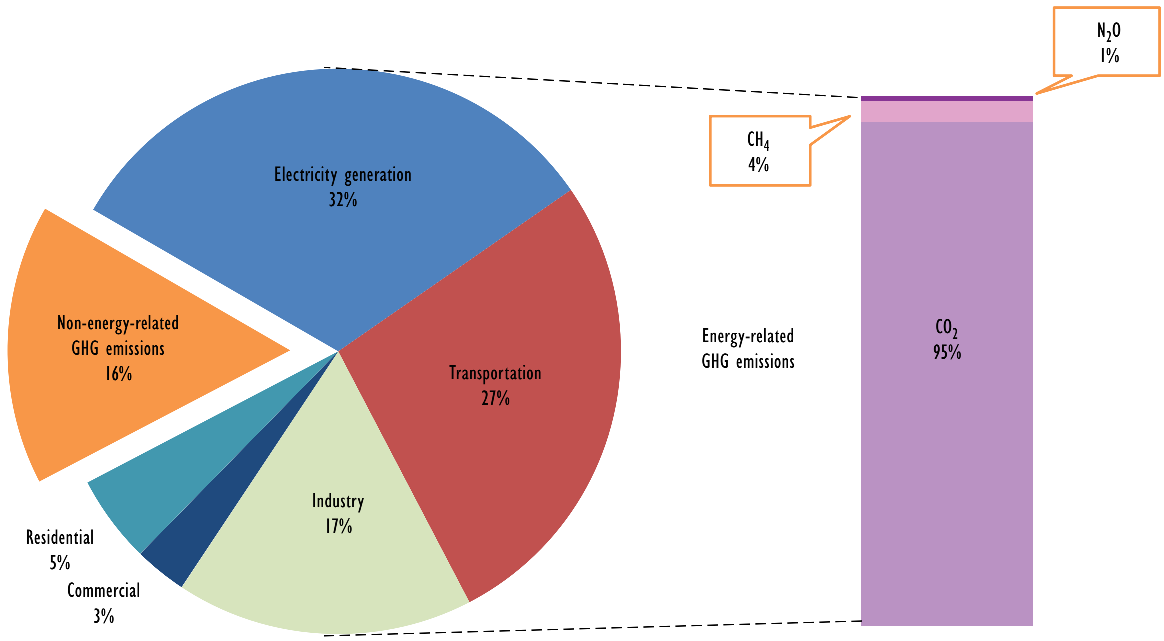
This section surveys the suite of US federal regulations applicable to GHG emissions from energy-related sources in the electricity, industrial and transportation sectors.[9] The proposed GHG emissions standards for the electricity sector are an important component of these regulations. While employing traditional regulatory mandates, the rule for existing power plants has been designed flexibly to allow for market-based approaches, including the emissions trading systems that several states are already participating in. With the caveat that this particular rule was only very recently released, some projected impacts of these regulations are examined, including the extent to which they are expected to achieve GHG emissions reductions, enable transformation in the electricity sector, and produce public health co-benefits from improved air quality. The section concludes with some implications for US climate commitments in the near- and longer-term.

The US emissions context

The challenge to reducing GHG emissions in the United States is largely an energy challenge, as energy-related sources account for over 84% of total nationwide GHG emissions (Figure 4.3.1). The largest sources of emissions

Figure 4.3.1

US energy-related GHGs, by economic sector (million tonnes of carbon dioxide equivalent [$MtCO_2e$])



Notes: "Non-energy-related GHG emissions" includes emissions from agriculture (8%), industrial processes (5%), waste (2%), land use, land use change and forestry (1%), and solvent and other product use (0.1%). Energy-related GHG emissions from "US Territories," a separate category amounting to 1% of the total, were allocated to the energy-related emissions of the other sectors in proportion to their relative shares.

Source: US EPA (2014a), Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2012, *US EPA, Washington, D.C.*

8. Criteria pollutants are commonly found air pollutants that include particulate matter, ground-level ozone, carbon monoxide, sulphur oxides, nitrogen oxides and lead.

9. See also IEA 2014, Energy Policies of IEA Countries: United States of America 2014, OECD/IEA, Paris.

come from the use of energy in electricity generation (32% of total GHGs), in transportation (27% of total GHGs) and in industry (17% of total GHGs). Residential and commercial uses of energy, mainly for heating and cooking, account for about 8% combined. The vast majority of energy-related GHGs are emitted as CO_2, primarily from the combustion of fossil fuels. Smaller shares are associated with methane (CH_4), primarily from fugitive emissions from oil and gas systems and coal mines, and nitrous oxide (N_2O), mainly from electricity generation.

The emerging contours of the US regulatory approach

Regulating GHG emissions under the Clean Air Act

To date, the US regulatory approach to GHG emissions mitigation at the federal level is based largely around the application of existing Clean Air Act programmes to energy-related emissions in the electricity, industrial and transportation sectors. Passed by Congress in 1970 and amended in 1977 and 1990, the Clean Air Act is the major US environmental law addressing air quality problems caused by a variety of conventional air pollutants. Though the law does not target GHGs explicitly, existing Clean Air Act programmes are being adapted for the purposes of GHG emissions mitigation, as political constraints have stalled efforts to pass comprehensive climate change legislation at the federal level (Box 4.3.1). Regulation of energy-related GHGs under the Clean Air Act has proceeded in a manner that is reflective of the structure of the statute, the basic division being between stationary sources (in the electric power and industrial sectors) and mobile sources (in the transportation sector).

Transportation emissions were addressed first with a series of combined fuel economy and GHG emissions standards for **new mobile sources** starting in 2011. GHG regulations for **new stationary sources** affecting electric power and industrial sources followed: GHG permitting requirements for large stationary sources in 2011 and proposed GHG emissions standards for new electric power plants in 2012. As for **existing stationary sources**, GHG emissions standards have recently been proposed for the existing fleet of electric power plants, the single largest category of stationary source emissions.

GHG standards could also be proposed for emissions from stationary industrial sources, most of which are energy-

Box 4.3.1

How did the United States arrive at Clean Air Act regulation of GHG emissions?

Until 2010, two separate tracks were in motion to establish a framework that would govern US climate policy at the federal level. One track sought new legislative authority from the US Congress mandating nationwide reductions in GHG emissions through a federal carbon pricing mechanism. Under an alternative track, proponents argued that an existing law, the Clean Air Act, already conferred regulatory powers on the US EPA to control GHG emissions, much in the same way that it authorises the US EPA to identify conventional air pollutants like SO_2 and lead and put in place regulations to limit their emissions.

After several unsuccessful attempts to push through comprehensive climate legislation, the legislative track led to narrow passage of the American Clean Energy and Security Act (H.R. 2454) by the US House of Representatives in 2009. Built around an emissions trading programme ("cap-and-trade"), it was designed to comprehensively address all US GHG emissions from multiple sectors. Notably, it would have pre-empted most of the US EPA's regulatory authorities over GHG emissions. However, the US Senate failed to pass companion legislation in 2010, and thus President Obama, who supported the House's proposal, was unable to sign it into law. A shift in control of the US House later that year made further proposals politically impossible, and the legislative track has stalled ever since.

Meanwhile, under the regulatory track, a group of states, cities, and non-governmental organisations had sued the US EPA to force it to exercise its existing Clean Air Act authorities and impose limits on GHG emissions from new motor vehicles.[10] After a protracted legal battle, the US Supreme Court ruled in 2007 that GHGs were indeed "air pollutants" that cause "air pollution" as defined under the law and affirmed the US EPA's statutory authority to regulate them.[11] The ruling also required the US EPA to make a scientific determination as to whether GHGs posed a risk to public health and welfare. Following the change in administration in 2009, the US EPA moved quickly to issue such an "endangerment finding,"[12] setting the stage for regulation of GHG emissions from mobile sources and also triggering legal obligations under the Act to regulate certain large stationary sources as well.

related, but some of which are non-energy process emissions. GHG standards for petroleum refineries have been promised (US EPA, 2010a), while standards could conceivably cover other industrial sources, including iron and steel, cement, chemicals, and other manufacturing sectors. With the boom in US shale gas production, concerns have intensified about fugitive methane leaks from natural gas systems, and GHG emissions standards for petroleum and natural gas systems have also recently come under consideration (White House, 2014).

Other federal regulations

Beyond the Clean Air Act, there are other federal regulations that have implications for energy-related GHG emissions, though they do not target GHG emissions reductions specifically. For example, since 2009, 24 new or updated energy efficiency standards for new appliances and equipment have been issued (US DOE, 2014). These standards reduce energy usage from the commercial, residential, and industrial sectors and are consequently expected to reduce GHG emissions.

State-level action

US states, it should be noted, have their own regulatory authority within the federal system and had been exercising it with respect to GHG emissions long before the US federal government started issuing GHG regulations. States have done this by regulating GHG emissions on their own, through state-level and regional emissions trading programmes, and by implementing other policies that have indirect effects on GHG emissions (such as energy efficiency resource standards, renewable portfolio standards, building codes and urban planning measures). States can also pressure the federal government to take action, through indirect means by creating patchworks of inconsistent regulations across states, through direct influence by filing lawsuits against federal agencies, or through express authority in statute, such as California's unique authority to regulate air pollution from vehicles under the Clean Air Act. However, state actions, while important, are not the focus of this section.

10. GHG emissions from new motor vehicles were the target of a 1999 petition, the US EPA's 2003 denial of which sparked the lawsuit.

11. Specifically, Massachusetts v. Environmental Protection Agency *authorised the US EPA to regulate GHGs under the mobile source portion of the act.*

12. More precisely, the US EPA also made a "cause and contribute" finding indicating that emissions from new motor vehicles and engines contribute to GHG pollution which threatens public health and welfare.

Regulating GHG emissions from stationary sources

GHG permitting requirements

The first GHG regulations implemented for stationary sources were pre-construction permitting requirements. Under the Clean Air Act programme known as New Source Review (NSR), new sources (and existing sources making major modifications) that already require an NSR permit for other pollutants will also be subject to GHG emissions limitations prior to commencing construction. An NSR permit ensures that new sources will employ what the US EPA determines is the "best available control technology" (BACT), among other requirements.13 The BACT for GHGs will be determined on a case-by-case basis, as it is for other pollutants.

GHG emissions standards

Several Clean Air Act programmes could have been used to design GHG emissions standards for stationary sources. These include National Ambient Air Quality Standards (NAAQS), which are employed for the control of conventional air pollutants such as particulate matter and SO_2, or National Emissions Standards for Hazardous Air Pollutants (NESHAP), which are used for the control of toxic pollutants such as mercury (see Section 4.1). There are a number of reasons why these Clean Air Act programmes are considered a poor fit for the regulation of GHGs from stationary sources (Richardson, Fraas and Burtraw, 2010). Instead, the US EPA opted to use emissions performance standards (Box 4.3.2) under Section 111 of the Act.

Clean Air Act Section 111 requires that an emissions performance standard be based on the "best system of emission reduction" (BSER) that the US EPA administrator deems has been "adequately demonstrated" – meaning that the standard is benchmarked to the performance of a particular technology (i.e. to its emissions rate).[14] However, the use of that technology is not mandated specifically; what is required is that an emitting source meet the emissions rate standard. The US EPA has a great deal of flexibility in setting these standards and is permitted to take costs, health, and environmental impacts and energy requirements into account.[15] The agency must also periodically update these standards to reflect improvements in control technologies.

13. Emitters must also obtain operating permits under Title V of the Clean Air Act, which do not impose additional requirements but consolidate all compliance obligations, including those for GHGs, into one permit.

14. This has been the traditional interpretation, but "system" need not mean a specific technology (see Box 4.3.4).

15. This is in contrast to NAAQS and NESHAP, which the US EPA is required to set on a purely scientific basis in order to protect public health or welfare, not being permitted to take compliance costs into consideration.

Box 4.3.2

How do emissions standards work in the US context?

For conventional air pollutants like SO_2 or PM, the United States has historically used a traditional regulatory approach (also known as "command and control") in the context of a federalist system that divides power between the central government and the states. Under this system, the federal government sets uniform air quality standards on a national basis and designates the individual US states to define and enforce emissions standards for source emitters within their state borders.

Emissions standards can take the form of a technology standard, *which mandates the use of a particular kind of pollution control technology (e.g. a smokestack scrubber) or controls the use of particular inputs to production (e.g. by requiring the use of low-sulphur coal). Alternatively, a* performance standard *limits the amount of pollution allowed for a given volume of air or water (e.g. an air quality standard that specifies pollutants in microgrammes per cubic metre of air (mg / m^3) or parts per million (ppm), averaged over some time interval or imposed as "not-to-exceed" limits). A performance standard can also target pollution directly at individual source emitters, imposing a limit on the rate of emissions per unit of time, output or input (e.g. pounds of sulphur dioxide per million British thermal units (lbs SO_2 / MBtu) of fuel input).*

Over time, the policy trend has been towards greater integration of market-based mechanisms into this regulatory framework at the state level, as they are considered to have many positive attributes including greater cost-effectiveness. Flexible tools such as trading and price mechanisms are in place for NOx and SO_2 emissions.

Regulating GHGs from electric power plants

The overwhelming majority (98%) of GHG emissions from electricity is CO_2 from the combustion of fossil fuels. Historical CO_2 emissions from US electricity generation from 1990 to 2013, and projected emissions for 2014 to 2040, are shown in Figure 4.3.2. Historically, coal-fired generation has accounted for the bulk of electricity-related CO_2 emissions and "business-as-usual" projections foresee coal-related CO_2 emissions continuing to dominate into the foreseeable future. However, the gradual historical decline in the share of coal-related emissions is projected to continue, due to continued increases in the use of gas, which is expected to overtake coal as the principal fuel for electricity generation in 2035 (US EIA, 2014c). However, since the burning of coal produces about twice as much CO_2 per MWh as gas, the relative contribution of coal to total GHG emissions from electricity would remain much higher.

After a decades-long march upwards, CO_2 emissions from electricity have fluctuated dramatically in recent years due to the economic downturn, significant changes in the relative fuel prices of coal and gas, weather conditions, and other factors. Electricity emissions peaked in 2007 at 2 426 $MtCO_2$ and declined about 15% through 2013, even without any federal GHG regulations. Going forward, CO_2 emissions from electricity are expected to grow 11% between 2013 and 2040. Virtually all of the emissions from coal-fired generation in 2040 will be from power plants in operation today, since very little new coal-fired capacity is expected to come on line. Thus, regulations that target GHGs from existing electric power plants, particularly coal-fired generators, have the potential to tap into a large source of current and future emissions.

GHG emissions standards for new power plants

GHG emissions standards were proposed for new power plants in 2012 (and revised in 2013) under Section 111(b) of the Clean Air Act (emissions standards for existing power plants were proposed separately in 2014 and are discussed below). For new power plants, the rule proposes separate standards for coal-fired electric generating units (EGUs) and natural gas-fired EGUs.[16]

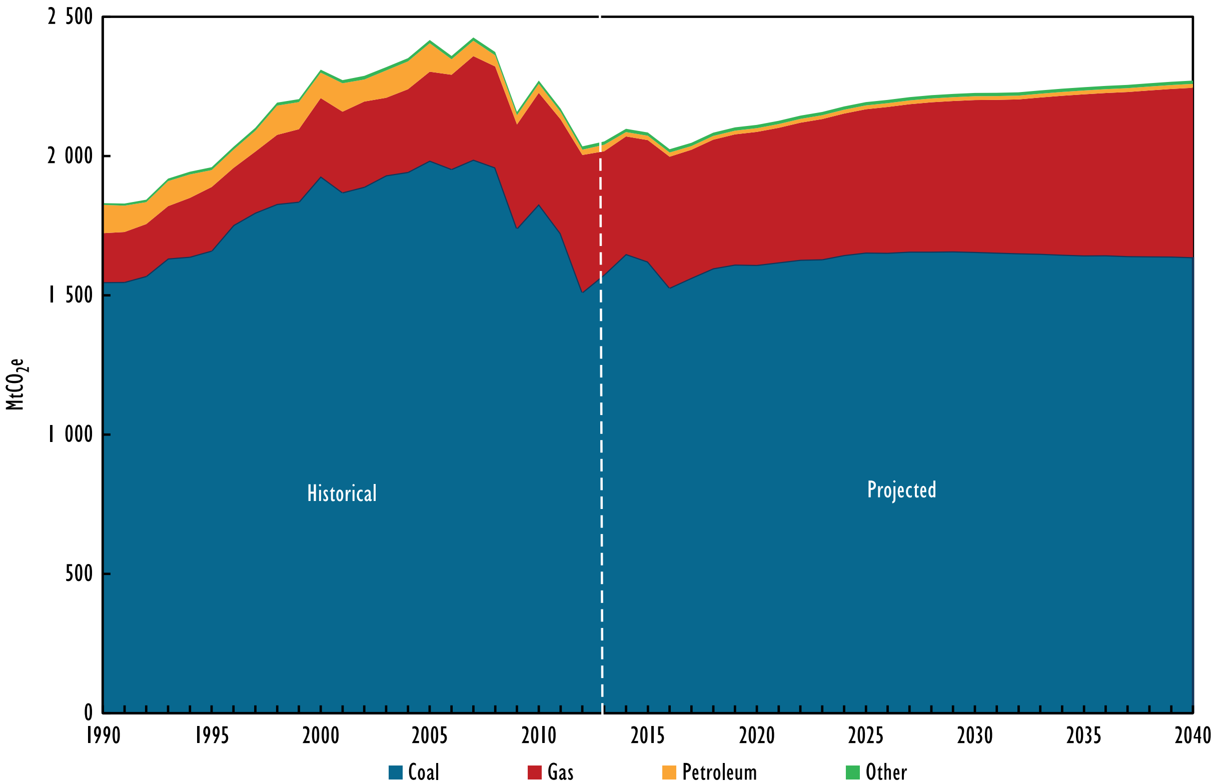
New coal units would be able to choose from two options, both of which would require application of CCS technology. The first option would require coal-fired EGUs to meet a 12-month average emissions rate of 1 100 lbs CO_2 / MWh (499 g CO_2 / kWh), requiring immediate application of CCS. The second option would allow delays in the application of CCS, but would require a more stringent, seven-year average emissions rate between 1 000 and 1 050 lbs CO_2 / MWh (454 and 476 g CO_2 / kWh).[17] New gas units would be required to meet a standard of 1 000 to 1 100 lbs CO_2 / MWh (454 to 499 g CO_2 / kWh), depending on their size, which is already possible using existing natural gas combined cycle (NGCC) technology.

16. These standards for new EGUs are referred to as New Source Performance Standards (NSPS).

17. The US EPA has invited comment on the final standard within that range.

Figure 4.3.2

US CO_2 emissions from electricity, by fuel source ($MtCO_2e$)



Sources: Historical emissions: US EIA (2014b), "Monthly Energy Review, May 2014", US EIA, Washington, D.C.; projected emissions: US EIA (2014c), Annual Energy Outlook 2014, *US EIA, Washington, D.C. (reference case).*

The standards have thus benchmarked CCS as the BSER for new coal plants and NGCC as the BSER for new gas plants.[18] New coal plants equipped with even the most advanced coal generation technologies would need to implement partial CCS to comply. These include supercritical pulverised coal, which emits about 1 700 lbs of CO_2/MWh (771 g CO_2/kWh), or IGCC, which emits about 1 450 lbs CO_2/MWh (658 g CO_2/kWh). However, CCS technology is still nascent. The world's first two commercial-scale coal-fired power plants equipped with CCS are under construction and expected to be operational in 2014,[19] but progress in this sector is slow and plants take many years to construct (Global CCS Institute, 2013). Even in the absence of the rule, regulators have concluded that no conventional coal-fired plants (other than CCS demonstration projects) are likely to be built through 2030. Since NGCC meets the proposed standard already, and nearly all fossil fuel-fired EGUs being built currently in the United States use NGCC, no units would be required to use CCS before the standard must be reviewed in 2022 (US EPA, 2013).

Thus, because of projected market conditions that favour natural gas-fired and renewable generation over coal-fired generation (including include slow growth in electricity demand, excess gas-fired capacity, and the effects of other environmental regulations), the proposed rule is expected to result in negligible CO_2 emission changes, quantified benefits and costs. It could, however, serve as a backstop in the event that inaccurate market projections make non-CCS coal competitive once again (McCarthy, 2013), and also as a regulatory stimulus to the development of CCS. The real importance of these standards, however, lies in their implications for the existing fleet of fossil fuel-fired power plants. This is because once the US EPA issues performance standards for new sources within a source category, the Clean Air Act obligates it to issue standards for existing sources (or more precisely, obligates it to issue "guidelines" for states to set standards).

18. The US EPA concluded that due to insufficient information, the technical feasibility of CCS for new NGCC units could not be determined and thus did not benchmark it as the BSER for this sub-category (US EPA, 2014b).

19. These are Southern Company's Kemper County facility in Mississippi, United States, and the Boundary Dam Power Station in Saskatchewan, Canada.

GHG emissions standards for existing power plants

In June 2014, GHG emissions guidelines were proposed for existing EGUs, also known as the "Clean Power Plan." They were issued under Section 111(d) of the Clean Air Act, which has been rarely used in the past. The US government projects the rule will achieve an overall reduction in GHG emissions from the US power sector of 30% in 2030 relative to 2005 levels, and an average interim reduction of 20% from 2020 to 2029. Unlike emissions standards for new power plants, there is no requirement that this be a uniform national standard (Box 4.3.3). Instead, each of the 50 US states has been assigned a final goal for 2030 specifying the maximum carbon intensity of electricity generation in that state (in lbs CO_2/MWh) and an interim intensity goal for the 10-year "glide path" beginning in 2020. Importantly, the overall 30% reduction goal is not a binding target; the state carbon intensity goals are. Actual emissions reductions in 2030 could be higher or lower, depending on state implementation choices, market conditions, population growth, and other factors. The proposed final goals range from 215 lbs CO_2/MWh (97.5 g CO_2/kWh) for Washington State to 1 783 lbs CO_2/MWh (809 g CO_2/kWh) for North Dakota, reflecting differences in their fuel mixes and carbon abatement opportunities.

Under the proposal, a state's carbon intensity goal applies to the state's electricity generation portfolio, broadly defined.[20] One allowable compliance option would be for a state to rigidly apply this uniform intensity standard to each power plant, or even each EGU, operating within its state borders, potentially prohibiting carbon-intensive generation technologies. Alternatively, and more cost-effectively, states will be allowed to achieve their state intensity goals on a *system-wide* basis. This will allow for crediting of emissions reductions "inside the fence line" of the plant, such as from improvements in operating efficiency, but also "outside the fence line," such as those achieved through re-dispatch from coal-fired to gas-fired generators, coal plant retirements, increases in low- and zero-carbon generation capacity, and demand-side energy reductions (Box 4.3.4). Importantly, states will be allowed to use market-based mechanisms and potentially collaborate with other states to meet collective regional goals, further increasing the scope for cost-effective compliance strategies.

The US EPA is currently scheduled to finalise its guidelines in June 2015. States must submit their implementation plans by June 2016 (with potential extensions of one year for single-state plans and two years for co-operative, multi-state plans). The proposed rule, if implemented, will mark the first time that the US federal government has mandated reductions in GHG emissions from existing stationary source emitters. About 1 000 fossil fuel-fired power plants (with 3 000 units) nationwide will be covered under the rule. Given that the existing fossil fuel fleet accounts for about one-third of total US GHG emissions, these standards will be the single most important element of President Obama's Climate Action Plan (White House, 2013) from a mitigation perspective. They are expected to come under myriad legal challenges on numerous fronts and could face an uncertain political future depending on upcoming election outcomes. Nevertheless, the rule sends a powerful signal to the US electric power industry that it will, in all likelihood, face a carbon-constrained future (Burtraw, 2014).

Box 4.3.3

The federal-state process under Clean Air Act Section 111

Like other Clean Air Act programmes that address air pollution, the Clean Power Plan sets up a federal-state process by which the US EPA sets emissions "guidelines" – which are in fact legally binding federal mandates – and states are given the responsibility for devising plans to implement and enforce them, subject to US EPA approval. Emissions standards for existing sources under Section 111(d), such as those for existing power plants under the Clean Power Plan, can be quite different from those for new sources under Section 111(b). Under Section 111(b), the US EPA is required to impose a uniform national standard on a plant-by-plant basis, and states have no say in setting, implementing, or enforcing the standards. Under Section 111(d), in contrast, states are, in principle, afforded considerably more flexibility in drafting their plans, akin to the NAAQS programme that governs air quality regulations (Monast et al., 2012). Under the proposed Clean Power Plan, based on its interpretation of 111(d), the US EPA decided to give maximum deference to the states regarding their ability to design the structure and scope of the programme.

20. The US EPA's carbon intensity formula is complex and does not include all generation sources (for example, most existing nuclear sources are excluded). Thus, each state's carbon intensity goal is an artificial measure that does not represent the emissions intensity of the state's entire power sector.

Box 4.3.4

State compliance options under the Clean Power Plan

For the purpose of setting state carbon intensity goals, the US EPA assumed that state compliance actions would fall under four "building blocks" of carbon abatement strategies. The US EPA has determined that the application of these building blocks constitutes the BSER, as required in Section 111(d) of the Clean Air Act.[21] *The percentage of overall GHG abatement accomplished by each of these measures is listed in parentheses.*

1) *Heat rate improvements at coal-fired power plants (12%)*
   - *operating efficiency improvements of 6% assumed to be available nationwide*
2) *Re-dispatch base-load power from coal plants to NGCC plants (31%)*
   - *through increased utilisation of idle or under-used existing gas plants to 70% capacity,*[22] *and accounting for new gas capacity already under construction*
3) *Increased use of zero- and low-emitting power sources*
   - *through preservation of "at risk" nuclear capacity, construction of new nuclear (7%)*
   - *in all states, incremental increases in renewable energy supply (33%)*
4) *Demand-side energy efficiency measures (18%)*
   - *each state is assumed capable of reducing its energy consumption by 1.5% each year through a variety of end-use efficiency measures*

Importantly, states will be allowed to use market mechanisms such as emissions trading to achieve their goals. They will also be allowed to convert their rate-based goal into a mass-based goal (i.e. a state-wide carbon budget), in order to facilitate cap-and-trade approaches, potentially joining existing programmes such as the Regional Greenhouse Gas Initiative (RGGI) or forming new ones.

Regulating GHGs from mobile sources

Mobile source regulation of GHGs started in 2009 and has proceeded for two classes of motor vehicles: cars and light trucks (collectively known as "light-duty vehicles" or LDVs) and medium- and heavy-duty vehicles (MHDVs). These vehicle categories together account for about 24% of total US GHG emissions. Two sets of regulations were issued for LDVs, which include cars, sport utility vehicles, minivans and other light trucks, for model years 2012-16 and 2017-25. Regulations for MHDVs cover model years 2014-18 and will be proposed for model years 2019 and beyond by 2015 and finalised the following year.

These mobile source regulations, which become more stringent over time, are designed to reduce both GHG emissions and oil consumption. They are two-pronged standards that integrate GHG emissions standards with corporate average fuel economy (CAFE) standards for new vehicles.[23] For LDVs, they mandate fleet-wide averages of 35.5 miles per gallon (mpg) by 2016 and 54.5 mpg by 2025, representing an average annual increase of 5%.[24] LDVs must meet an estimated combined average emissions level of 250 g CO_2 / mile in model year 2016, and 163 g CO_2 / mile in model year 2025. The rule also includes standards of 0.010 g / mile and 0.030 g / mile for N_2O and CH_4. The rules for MHDVs resemble those for LDVs but are more complex.

The US government may be compelled to regulate some other mobile source categories in the future (McCarthy and Yacobucci, 2014). Aircraft is the most significant of these, at 2.3% to 3.2% of total US GHG emissions, depending on whether international air travel originating in the United States

21. Abatement measures that the US EPA assumed would not be employed by coal-fired boilers to comply with the rule, based on cost considerations, were coal-to-gas fuel switching, co-firing with a lower-carbon fuel (gas or biomass), and retrofit for partial CCS. While these measures might be viable compliance options for individual EGUs, and are not precluded, the US EPA did not believe that they would be cost-effective on a national basis and thus could not serve as the BSER for the purposes of determining state carbon intensity goals.

22. The NGCC fleet (1 800 units surveyed) was found to have an average capacity factor between 44% and 46% in 2012, which was assumed could be reasonably increased to 70% in each state (US EPA, 2014d).

23. The standards were issued jointly by the US EPA and the National Highway Traffic Safety Administration (NHTSA).

24. Average fuel economy of LDVs was 25 mpg when the first set of standards was announced in 2009, the level at which it had remained for over two decades during a period of federal inaction.

is included. All other transportation and non-transportation sources are less significant individually, accounting for less than 1% each. Though it has made no move to do so, the US government also has the authority to regulate the GHG content of fuels directly, which would enable it to target more immediate emissions reductions from the existing vehicle fleet.

Assessing the impacts of federal GHG regulations

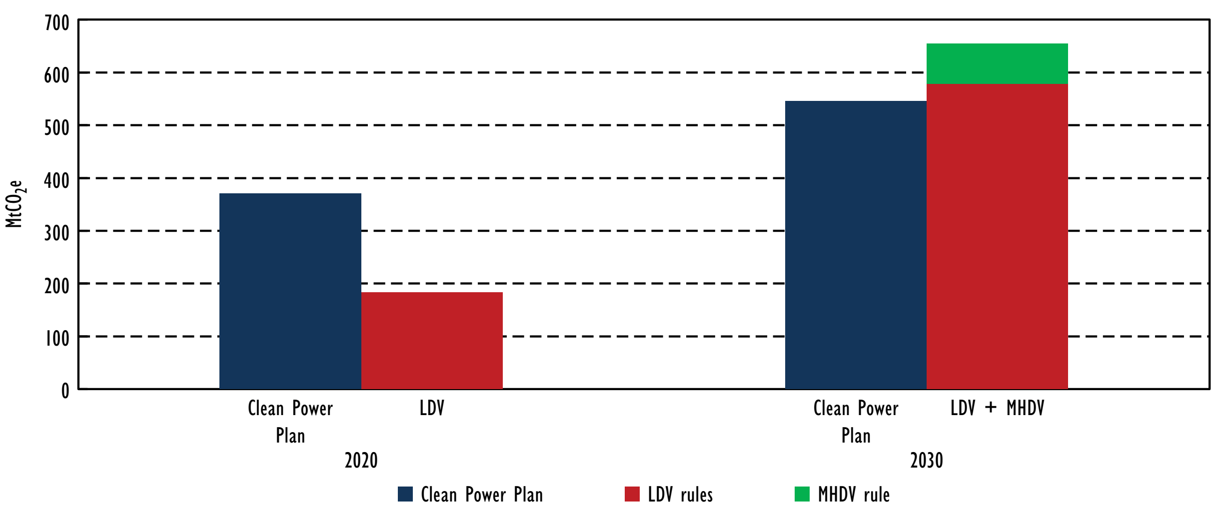
Expected impacts from federal GHG regulations would arise principally from the mobile source regulations already implemented and the proposed GHG emissions standards for existing power plants (Clean Power Plan), since the proposed rule for new power plants is expected to have little overall impact and GHG emissions standards for other stationary sources have yet to be proposed (with the exception of landfills). As for the Clean Power Plan, it was only very recently proposed and there are many uncertainties regarding individual state implementation of the rule. Given the timing of this publication, it is premature to give a full assessment of its impacts, as detailed independent analyses are only just beginning to emerge (Box 4.3.5).[25] However, some initial insights can be gleaned from the modelling analysis released by the US EPA at the time rule was proposed in June 2014.

Impacts on GHG emissions

Figure 4.3.3 provides an indication of the extent to which GHG emissions might be reduced under federal GHG regulations covering existing power plants and mobile sources. A direct comparison of cumulative GHG reductions cannot be made, for a variety of reasons; however, "snapshots" of particular years can be compared.[26] Projected annual reductions in GHGs under the Clean Power Plan (covering existing power plants) and under the LDV rules (covering cars and light trucks) are shown for 2020 and 2030, compared to projected base case emission levels. In 2020, projected reductions under the Clean Power Plan are larger than those from mobile source regulations (371 versus 183 $MtCO_2e$). By 2030, however, emissions reductions from mobile sources (578 $MtCO_2e$, or 654 $MtCO_2e$ if adding the impact of the rule for MHDVs) will be greater than those from power plants (545 $MtCO_2e$). This reflects the gradual turnover of the existing vehicle fleet, as it takes time for new vehicles subject to more

Figure 4.3.3

Projected GHG reductions under the Clean Power Plan and mobile source rules ($MtCO_2e$)



Note: The LDV rules and MHDV rule cover model years 2012-25 and 2014-18, respectively, and include impacts from both fuel efficiency and GHG standards; MHDV rule impacts were not made available for 2020.

Sources: Based on: US EPA (2014c), Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants, *US EPA, Washington, D.C. ("Option 1, Regional" scenario); US EPA (2010b),* Final Rulemaking to Establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards: Regulatory Impact Analysis, *US EPA, Washington, D.C.; US EPA (2012),* Regulatory Impact Analysis: Final Rulemaking for 2017-2025 Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards, *US EPA, Washington, D.C.; US EPA and US DOT (2011),* Final Rulemaking to Establish Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles: Regulatory Impact Analysis, *US EPA and US DOT, Washington, D.C.*

25. The US EPA extended the public comment period on the proposed rule through 1 December 2014.

26. Cumulative or year-by-year estimates of emissions reductions were not always provided in the underlying modelling analyses. Also, as the analyses were conducted at different times, they make counterfactual projections from different reference cases and are thus not strictly comparable.

stringent fuel efficiency and GHG emissions standards to replace older vehicles.[27]

Electricity sector transformation

CO_2 emissions from electricity generation in 2020, the year the proposed Clean Power Plan would take effect, are projected to have already fallen 13% below their 2005 level (Figure 4.3.2). Thus, the power sector rule is in effect proposing to reduce emissions an additional 17% over the following decade. Under the rule, fossil fuels are still expected to dominate power generation in 2030 (Table 4.3.1). Coal would still produce a significant share of generation at 31%, down from 39% currently, whereas the dominant share would be produced by gas, rising to 33% from 27%. The share of nuclear would rise slightly (1%) and hydro would be unchanged compared to current levels, while renewables would increase to 9% from 6%. A comparison of columns 1 and 2 underscores that projected market conditions (including other energy and environmental policies) would have for the most part moved the US power sector in these same directions.

In fact, a comparison across all three columns indicates that the proposed rule, if implemented, could be anticipated to reinforce and accelerate current trends – in terms of shifting generation from coal to gas and, to a lesser extent, from fossil fuels to non-hydro renewables – as opposed to bringing about a wholesale transformation of US electricity generation. Overall, it is estimated that the Clean Power Plan will reduce the CO_2 intensity of US electricity generation from its 2012 fleet-wide rate of 1 100 lbs/MWh (499 g/kWh) to 890 lbs/MWh (404 g/kWh) in 2030, a 19% reduction that would lower the average fleet-wide rate to about that of a typical NGCC plant (Brattle Group, 2014).[28] Currently, the United States is ranked eighth-highest with regards to the carbon intensity of its power generation sector among IEA members (IEA, 2013b).

Projected changes in electricity generation capacity under the rule are also instructive (Figure 4.3.4). Under the Clean Power Plan, overall capacity in 2030 is 994 gigawatts (GW) (far right column), down 9% compared to the base case at 1 095 GW (far left column). Forty-five GW of this decline comes from incremental retirements of existing coal-fired power plants, representing a 19% reduction in coal-fired capacity compared to the base case, and 10 GW comes from retirements of existing natural gas plants (3 GW of NGCC and 7 GW of combustion turbines). Thirty-five GW comes from a relative reduction in new builds of NGCC (in other words, NGCC capacity still expands under the rule, but is about 43% smaller than what it would have been, due largely to demand-side reductions). Reductions in oil/gas steam capacity contribute another 17 GW. Overall, fossil fuel generation capacity falls by 110 GW and is 14% smaller, relative to the base case. At the same time, there are only modest impacts on zero-carbon generation capacity: nuclear and hydro are basically unchanged, and renewables expand by 10 GW (or 9%).

Climate benefits and air quality co-benefits

The link between air pollution policies and GHG co-benefits, discussed in Sections 4.1 and 4.2, can also go in the other direction: policies to reduce GHG emissions can have ancillary benefits for air quality (Table 4.1.3).

Table 4.3.1

Composition of US electricity generation, by fuel source (%)

Source	2013	2030	
		Base case	Proposed rule
Coal	39%	37%	31%
Gas	27%	31%	33%
Oil	1%	1%	0%
Nuclear	19%	17%	20%
Hydro	7%	6%	7%
Non-hydro renewables	6%	8%	9%
Other	1%	0%	0%

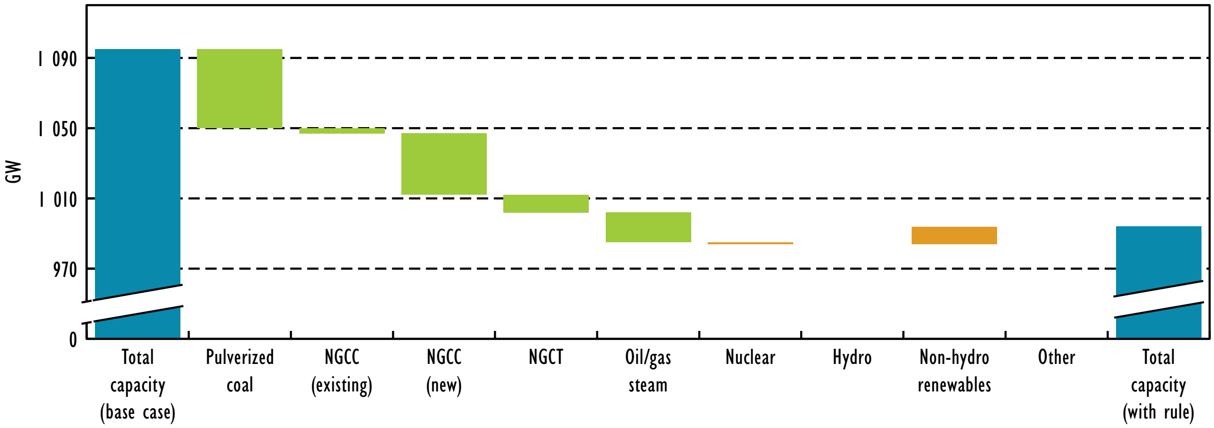
Sources: For 2013: US EIA (2014b), "Monthly energy review, May 2014", US EIA, Washington, D.C.; for 2030: US EPA (2014c), Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants, *US EPA, Washington, D.C. ("Option 1, Regional" scenario).*

27. The median survival rate for 1990 cars, for example, was 16.9 years, and that for light trucks was 15.5 years (McCarthy and Yacobucci, 2014).

28. This is the emissions rate of the entire generation fleet (emissions divided by all power generation regardless of source fuel).

Figure 4.3.4

Change in US electricity generation capacity in 2030, by technology, from base case (GW)



Source: US EPA (2014c), Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants, *US EPA, Washington, D.C. ("Option 1, Regional" scenario).*

Box 4.3.5

State implementation choices will affect the impact of the Clean Power Plan on the energy sector

One independent modelling analysis of the Clean Power Plan was released publicly after this section was written (Larsen et al. 2014). It reports large impacts on the composition of electricity generation by 2030 in terms of fuel switching from coal to natural gas, with the share of natural gas rising to 41% and the share of coal falling to 23%.[29] The analysis explores the impact of expanded multi-state co-operation and inclusion of energy efficiency crediting, finding that both lead to reduced power sector abatement (and lower electricity and energy costs). The more states can cooperate and pool their compliance burdens (i.e. trade compliance credits), the less fuel switching is required to meet the Clean Power Plan targets. Energy efficiency crediting also supplants fuel switching to a certain degree and can crowd out modest increases in nuclear and renewable generation. Unlike the US EPA analysis, upstream coal and natural gas production were also modelled. Some regions are projected to benefit under the rule because positive changes in net coal and natural gas production revenue outweigh negative changes in electricity and other energy costs experienced by households and businesses.

Table 4.3.2 shows estimated reductions in conventional air pollutants that would occur along with reductions in CO_2 emissions in 2030 as a result of the Clean Power Plan. In addition to a 24% decline in CO_2 emissions relative to the base case, reductions of between 20% and 28% are expected for Hg, NOx, $PM_{2.5}$ and SO_2.[30,31]

Monetary values have been estimated for these multi-pollutant reductions. Climate benefits are associated with the reductions in CO_2 emissions (representing the value of avoided climate damages). Ancillary health benefits are associated with reductions in ambient $PM_{2.5}$ (i.e. fine particles) and ozone (i.e. smog).[32] The health benefits attributed to decreases in fine particles and smog are overwhelmingly reductions in premature mortality (accounting for over 90% of ancillary health benefits), but also fewer non-fatal heart attacks, asthma attacks in children, hospital admissions, and missed school and work days.

Projected combined benefits for 2030 range from USD 54 to USD 89 billion (Figure 4.3.5). The wide range of health benefits mainly reflects the varying degrees of human sensitivity to pollution levels (i.e. concentration-response functions) that were assumed, as climate benefits are

29. This scenario assumes national cooperation (i.e. a maximum degree of coordination among states that is unlikely to emerge in practice, but serves as a bounding case) and no crediting of demand-side energy efficiency.

30. These emission reductions are incremental to those that would occur under previous US EPA rules, including MATS and CAIR (see Section 4.1).

31. The analysis also found reductions in net upstream methane emissions from natural gas systems and coal mines, and CO_2 from the flaring of methane, but these are small relative to the changes in direct emissions from power plants.

32. SO_2, NOx and direct emissions of $PM_{2.5}$ are precursor pollutants for the formation of ambient $PM_{2.5}$, as is NOx for the formation of ozone.

Table 4.3.2

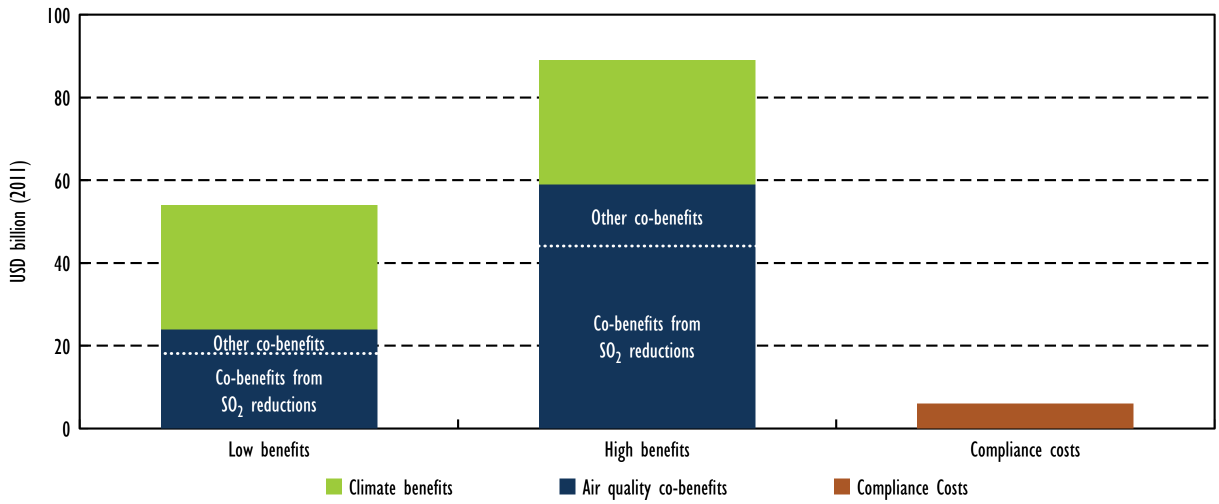
Projected reductions of CO_2 and air pollutant emissions in 2030

Pollutant	Emissions			% Change in emissions
	Base case	Proposed rule	Change	
CO_2 (million metric tonnes)	2 256	1 711	-545	-24%
SO_2 (thousand tonnes)	1 530	1 106	-424	-28%
NOx (thousand tonnes)	1 537	1 131	-406	-26%
$PM_{2.5}$ (thousand tonnes)	198	144	-54	-27%
Hg (tonnes)	8.8	7.0	-1.8	-20%

Source: US EPA (2014c), Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants, *US EPA, Washington, D.C. ("Option 1, Regional" scenario).*

Figure 4.3.5

Projected monetised benefits and costs under the Clean Power Plan in 2030 (2011 USD billions)



Source: US EPA (2014c), Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants, *US EPA, Washington, D.C. ("Option 1, Regional" scenario).*

constant at USD 30 billion in this range.[33] With greater assumed sensitivity, the value of air quality co-benefits is higher, as are total combined benefits. The breakdown of total benefits into climate benefits and air quality co-benefits is also presented. Most of the air quality co-benefits are attributed to reductions in SO_2.[34] Also shown are estimates of total compliance costs. It is worth noting that these cost estimates are greatly exceeded by even low-end projections of public health co-benefits, ignoring climate benefits altogether.

Implications for current US climate commitments

Under the 2009 Copenhagen Accord, the United States pledged to reduce its GHG emissions by 17%, 42%, and 83% below 2005 levels by 2020, 2030, and 2050, respectively.[35] One independent analysis (Burtraw and

33. Climate benefits presented in this range are discounted at 3%. In the analysis, they range from USD 7.5 to USD 76 billion depending on the discount rate employed, and are based on the US government's social cost of carbon estimates. They represent global climate benefits, whereas air quality health co-benefits are computed for the United States only.

34. This is not because SO_2 is considered more harmful than the other pollutants. Reductions in direct emissions of $PM_{2.5}$ are associated with much higher benefit-per-tonne estimates than SO_2, but the projected absolute reduction in SO_2 is much greater in sheer tonnage.

35. The upper end of the U.S. target announced in a joint agreement with China in November 2014 (a 26-28% reduction in emissions from 2005 levels by 2025) is consistent with this emissions reduction pathway.

Woerman, 2012) projected that federal regulations of CO_2 from stationary and mobile sources have the potential to reduce US GHG emissions 10.5% below 2005 levels by 2020. State and regional policies would reduce another 2.5% and "secular trends," including changes in relative fuel prices and greater energy efficiency, would reduce them by another 3.3%, bringing the total reduction to 16.3%.[36] Thus, under a federal regulatory approach to GHG emissions, this analysis concluded that the United States would at least be within striking distance of meeting its near-term climate commitment.

A more recent analysis, conducted after the Clean Power Plan was proposed, considered "low abatement" and "high abatement" scenarios in which the United States achieves economy-wide GHG reductions of, respectively, 12.4% and 18.1% by 2020 relative to 2005 (Larsen, Larsen and Ketchum, 2014).[37] It finds that implementation of the Clean Power Plan, which contributes close to 60% of needed abatement in the high abatement scenario, is a necessary, but not sufficient, condition for the United States to fulfil its 2020 climate commitment.[38] Meaningful action on hydrofluorocarbons (HFCs), methane and other energy CO_2 will also be needed, involving an ambitious mix of federal regulations, programs and R&D and public-private partnerships. The high abatement scenario is also contingent on optimistic land use and forest outcomes in 2020, which are largely beyond the federal government's control.

Over the longer term, whether the Clean Air Act, in conjunction with other actions, can be employed to achieve deeper and broader decarbonisation objectives is an unsettled question. One independent assessment that has looked at potential emissions reductions across the entire economy concludes that reductions of 10% to 40% below 2005 levels could be achieved by 2035 through federal regulations alone, depending on the level of ambition (Bianco et al., 2013). However, the study projects that, even at the more ambitious end, reductions are insufficient to put US emissions on a trajectory consistent with a 2°C pathway through 2050, even when complemented by a similarly stringent level of state actions. It concludes that new legislation from the US Congress would eventually be needed for deep, longer-term reductions.

Conclusion

The US federal government has embarked on a regulatory approach to climate policy, contrary to earlier expectations that it would use a top-down, comprehensive, market-based approach. The current suite of federal GHG regulations, if enacted, is expected to help the United States "close the gap" between current emissions levels and its 2020 climate commitment. An important component of this regulatory approach is the GHG emissions standards for existing power plants, which have only recently been proposed. It is still too early, at the time of this publication, to judge their full impact, as detailed independent analyses focused on the actual rule have only just begun to emerge. Taken together, the suite of US federal GHG emissions regulations for mobile and stationary sources, implemented and proposed in recent years, has the potential to influence the collective level of ambition in the build-up to a new global agreement in Paris in 2015 and beyond. This will depend to what extent they are perceived by the international climate community as sufficiently ambitious, robust, measurable, and enforceable. As such, they warrant further and careful study.

36. Interestingly, the analysis points out that this 16.3% reduction, all of which would be achieved domestically, exceeds the 8.2% permanent domestic reduction that would have occurred in 2020 under the cap-and-trade legislation passed by the US House in 2009 (Box 4.3.1). This is because 44% of the total projected emissions reduction for 2020 under this legislation, adjusted for banking, would have come from international offsets.

37. The reference case in this analysis includes all current US policies and regulations through 30 September 2014, including the mobile source rules depicted in Figure 4.3.3. Thus, the impacts of these policies on reducing emissions have already been accounted for.

38. Implementation of the Clean Power Plan in this scenario assumes nationwide compliance cooperation among states and only allows generation options to contribute to compliance, i.e. no crediting of demand-side energy efficiency.

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Energy data presented in Chapter 5 are collected by the Energy Data Centre (EDC) of the IEA. Estimates of CO_2 emissions from fuel combustion are calculated using the IEA energy balances and the default methods and emission factors from the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*. Six graphs illustrate CO_2 emissions data for 2011 and 2012 for each of ten global regions and the aggregate world region.

- CO_2 emissions are depicted on all graphs except that of Figure 5.

- Figure 1 shows the CO_2 emissions contributions of each of four fossil fuels: coal / peat; oil; gas; and other fossil fuels which include industrial waste and non-renewable municipal waste.

- Figure 2 shows the CO_2 emissions contributions of the six primary economic sectors, as well as a comparison of 1990 and 2012 sector contributions. Other includes emissions from commercial / public services, agriculture / forestry and fishing. Emissions from unallocated autoproducers (entities generating electricity and / or heat wholly or partially for their own use as an activity which supports their primary activity) are included in the electricity and heat sector. "Manuf. ind. and construction" denotes manufacturing industries and construction.

- Figure 3 shows key indicators: carbon intensity of the economy (CO_2 / GDP) (where a decline would reflect "decoupling" of economic growth from CO_2 emissions), CO_2 emissions per capita, and economic growth (GDP), all indexed to 1990 levels.

- Figure 4 shows the Kaya identity, which decomposes changes in CO_2 emissions into four main factors: population, per capita GDP, energy intensity of economic activity (total primary energy supply per unit of gross domestic product [TPES / GDP]), and carbon intensity of the energy mix, referred to as the Energy Sector Carbon Intensity Index (ESCII) calculated as carbon dioxide per unit of total primary energy supply (CO_2 / TPES). The Kaya decomposition is indexed to 1990 levels.

- Figure 5 represents the carbon intensity of energy supply (as per the ESCII) and CO_2 both indexed to 2010 levels (left axis), along with the TPES in absolute terms (right axis).

- Figure 6 focuses on the electricity sector, showing the share of each fuel in the electricity mix (left axis) as well as the percentage share of non-fossil fuel electricity (right axis). Coal includes peat and oilshale. Other includes geothermal, solar, wind, biofuels and waste. Electricity generation includes both main activity producer and autoproducer electricity. CHP heat constitutes heat generated through combined heat and power (CHP) processes.

- The "reporting period" refers to 1971-2012 in Figures 1 and 2, to 1990-2012 in Figures 3, 4 and 6, and to 2005-12 in Figure 5.

Table 5.1 at the end of the chapter summarises the aggregation of countries within each of the ten world regions.

Methodology

GDP: The gross domestic product (GDP) purchasing power parity (PPP) data have been compiled for countries at market prices in local currency and annual rates. These data have been scaled up / down to the price levels of 2005 and then converted to USD using the yearly average 2005 PPPs.

TPES: Total primary energy supply (TPES) is used to indicate the energy inputs into an economy. It includes energy imports and excludes exports and should be differentiated from primary energy (domestic) production. TPES is made up of production + imports - exports - international marine bunkers - international aviation bunkers ± stock changes. Note: exports, bunkers and stock changes incorporate the algebraic sign directly in the number.

World

Figure 1

CO_2 emissions by fuel

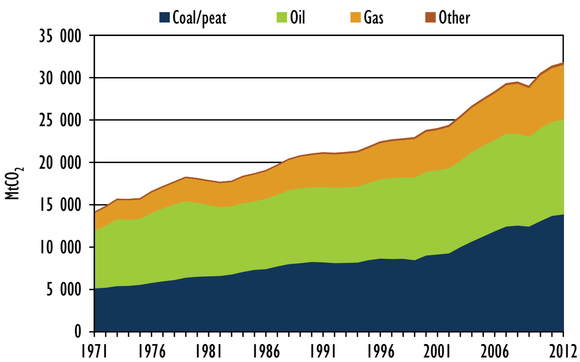


Figure 2

CO_2 emissions by sector

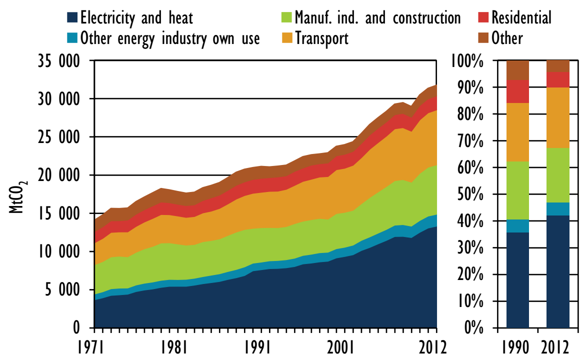


Figure 3

Selected CO_2 and GDP indicators (change from 1990)

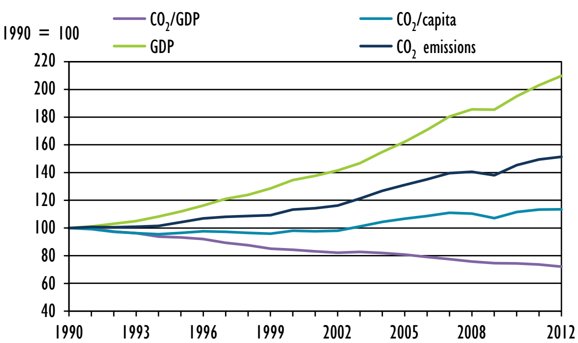


Figure 4

Kaya decomposition: Drivers of CO_2 emissions (change from 1990)

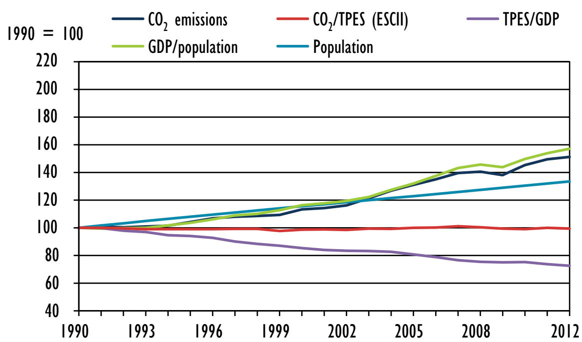


Figure 5

Carbon intensity (ESCII) and related CO_2 emissions

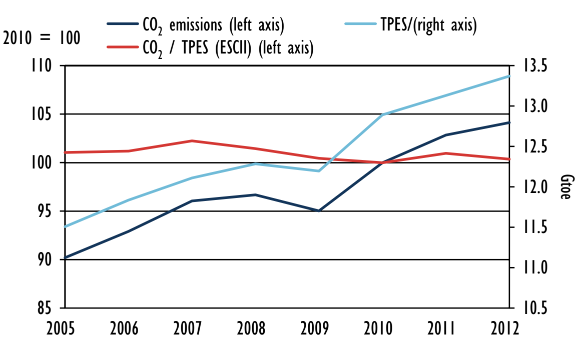
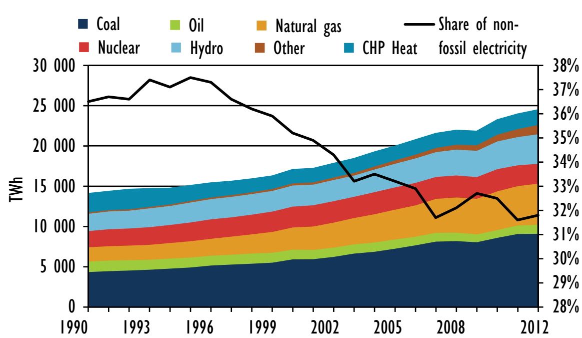


Figure 6

Electricity generation mix



Key features in electricity and CO_2: World

• Global CO_2 emissions continued to rise in 2011 and 2012, reaching their highest-ever levels in 2012 (51.3% greater than those in 1990). As the global economy recovered from the 2008-09 recession, emissions rose 5.2% in 2010, the highest growth rate in almost 40 years. However, this rate of growth since slowed, to 2.8% in 2011 and 1.2% in 2012. Emissions increased at an average of 2.0% per year over the entire reporting period (1971-2012).

• Contrasting emissions trends were observed between OECD and non-OECD regions. OECD Europe and OECD Americas rejected the trend of rising emissions in 2011 and 2012, experiencing declines in emissions levels. For both regions, this was the largest two-year decrease in emissions outside times of economic recession in the past three decades. Meanwhile, emissions grew substantially in non-OECD regions over the same period, led by China and India whose emissions grew approximately three times faster than the global average.

• In 2011 and 2012, coal remained the largest contributor to emissions with its greatest shares ever in these two years (43.9%) (Figure 1). Oil's shares were 35.4% and 35.3% in 2011 and 2012, respectively. The rising demand for fossil fuels was driven largely by consumption in fast-growing, non-OECD regions.

• The electricity and heat generation sector accounted for the largest share of emissions in 2012 (42.1%), which also represented the greatest contribution made by this sector over the reporting period (Figure 2).

• Economic growth continued to decouple from emissions growth (CO_2/GDP declined), with 2012 having the lowest-ever emissions intensity (CO_2/GDP) of the reporting period (Figure 3). Despite this, increasing population and wealth resulting in an increased demand for energy (TPES) drove overall emissions upwards (Figure 4 and Figure 5).

• Meanwhile, the carbon intensity of energy supply (ESCII) remained relatively unchanged, highlighting the very limited decarbonisation that has taken place in the energy sector over the past several decades (Figure 5).

• In 2011 the global electricity sector was the most fossil fuel-dependent over the reporting period, with the share of non-fossil electricity reaching its lowest-ever levels (31.6%). In other words, fossil fuels comprised over two-thirds (68.4%) of the electricity generation mix. In 2012, the share of non-fossil electricity increased slightly (to 31.8%). This dip in 2011 was driven by a decline in nuclear power generation (Figure 6).

• Despite this, non-hydro renewable power sources such as wind, biomass and solar enjoyed the greatest rate of growth in 2011 and 2012 among all fossil fuel and renewable energy sources (39.0% over the two-year period) (Figure 6). In fact, in 2012, the share of non-hydro and non-nuclear renewable sources rose to match that of oil (5.0%) for the first time in the reporting period, with generation in absolute terms growing 6.6 times between 1990 and 2012. This growth was driven by emerging economies, in particular that of China. Overall, hydropower remained the most important source of renewable electricity within the generation mix (16.2% in 2012).

• The 2008-09 economic recession played a key role in characterising global emissions trends in the last five years, particularly those of OECD regions, with 2011 and 2012 trends reflecting gradual economic recovery. Closer inspection of individual regions, however, reveals substantial differences in regional trends, which will be discussed in the sections that follow.

OECD Americas

Figure 1
CO_2 emissions by fuel

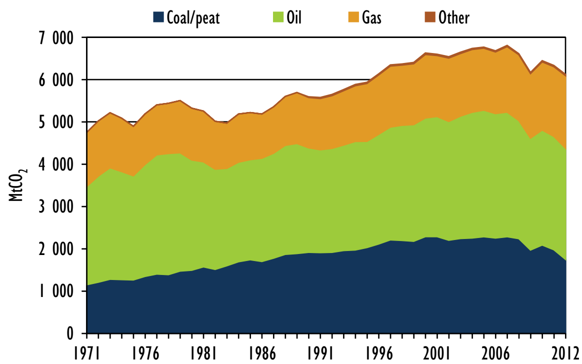


Figure 2
CO_2 emissions by sector

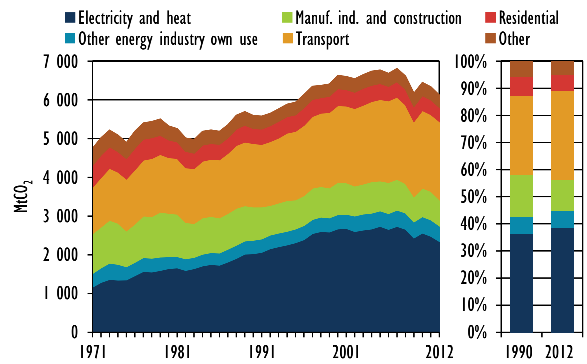


Figure 3
Selected CO_2 and GDP indicators
(change from 1990)

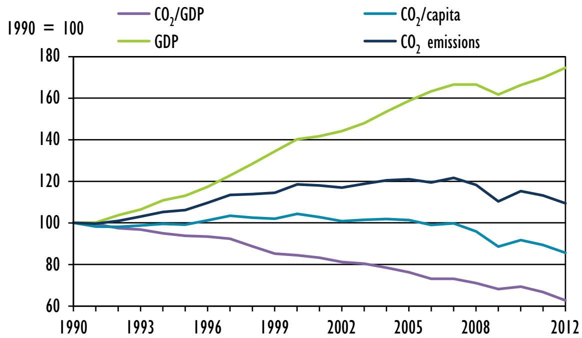


Figure 4
Kaya decomposition: Drivers of CO_2 emissions
(change from 1990)

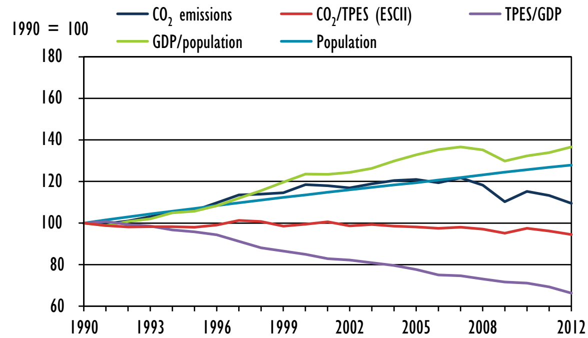


Figure 5
Carbon intensity (ESCII) and related CO_2 emissions

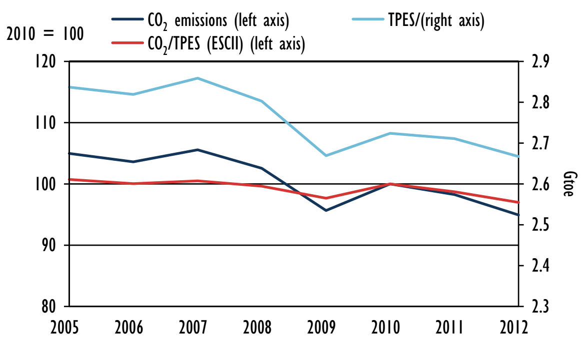
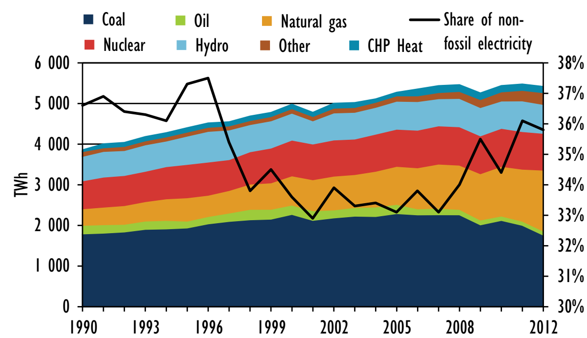


Figure 6
Electricity generation mix



Key features in energy and CO_2: OECD Americas

- In 2011 and 2012, CO_2 emissions in the OECD Americas experienced the greatest percentage decline of all regions. This was the largest decline over a two-year period (1.7% in 2011 and a further 3.4% in 2012) in the region since 1975, outside times of recession. In 2012 specifically, emissions declined by the greatest percentage since 1975, in any year when the economy grew.

- Nonetheless, this region still had the highest per capita emissions in 2012, almost three times higher than the global average. Overall, 2012 emissions were 9.4% above 1990 levels (Figure 3).

- The 2011-12 emissions decline was driven primarily by a drop in the energy intensity of the economy (TPES/GDP) (Figure 4). In 2012, TPES/GDP dropped the most of any year in the reporting period (4.4%), 2.4 times faster than the average annual rate of decline since 1990 (Figure 4). An important driver of this trend was a decline in energy consumption in the United States, as a result of reductions in heating demand due to warmer weather, reductions in industrial output and transportation demand, as well as improved vehicle efficiency (US EIA, 2013).

- The carbon intensity of energy supply (ESCII) of this region also played an important role in reducing emissions, declining the most of all regions over 2011 and 2012 (3.0%). In fact, this is the region's largest-ever decrease in ESCII over the reporting period, which largely reflects the shift from coal to natural gas, particularly in the power sector (Figure 5).

- In 2012, oil remained the largest proportional source of CO_2 emissions (42.9%). Meanwhile, the share of gas came closest to overtaking coal as the next greatest contributor of CO_2 emissions since the start of the reporting period (coal: 28.6%; gas: 28.0%) (Figure 1). This reflects the continued shift from coal to natural gas in power generation, primarily in the United States.

- The electricity and heat generation sector remained the greatest contributor of CO_2 emissions since reporting began (38.4%),[3] though its share began declining after 1998. The transportation sector contributed the second largest share (32.9%) in 2012 (Figure 2). The relative contributions of these sectors had not been this close since 1988, reflecting a declining share from electricity and heat (from a peak in 1998 of 40.9%) and an increasing share from transportation (from its lowest point of 25.3% in 1971, the start of reporting) (Figure 2).

- Indicators show positive trends in economic decarbonisation since 1990, particularly since 2010, with the simultaneous increase in GDP (and population) and decline in CO_2 emissions. In fact, CO_2/GDP declined the most in 2012 of any year in the reporting period (6.0%), hinting at a promising trend of economic decoupling from CO_2 emissions growth (Figures 3 and 4).

- In terms of electricity generation, total output reached a high in 2011 and declined in 2012. Coal remained the most significant generation source (33.5%). Nonetheless, its share declined consistently from the 1990s, peaking in 1997 at 47.3% of electricity output and reaching its lowest share over the reporting period in 2012 (Figure 6).

- From 1990 to 2012, the share of non-hydro renewable electricity sources increased the most of all fossil and non-fossil sources. However, they still only accounted for 5.2% of the total generation mix in 2012. Meanwhile, nuclear accounted for 17.2% and hydro 13.5% (Figure 6).

3. Except for 1971, when transportation (25.3%) contributed more than electricity and heat (24.6%).

OECD Asia Oceania

Figure 1
CO_2 emissions by fuel

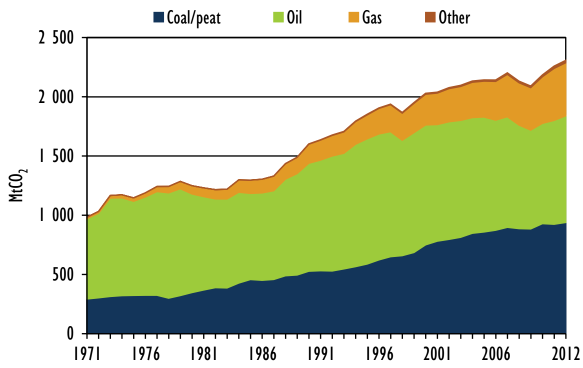


Figure 2
CO_2 emissions by sector

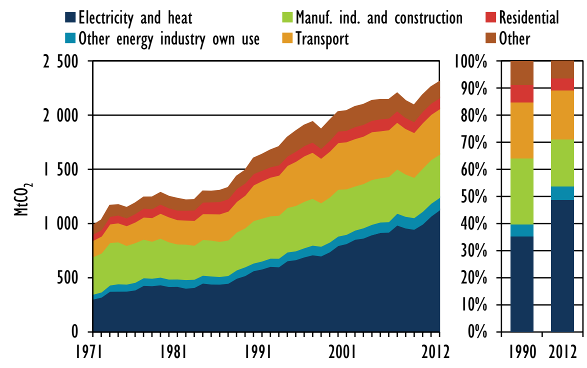


Figure 3
Selected CO_2 and GDP indicators
(change from 1990)

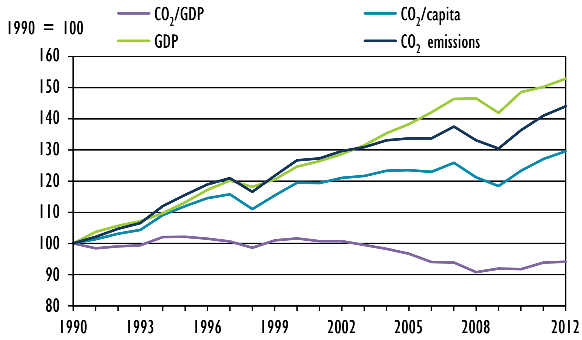


Figure 4
Kaya decomposition: Drivers of CO_2 emissions
(change from 1990)

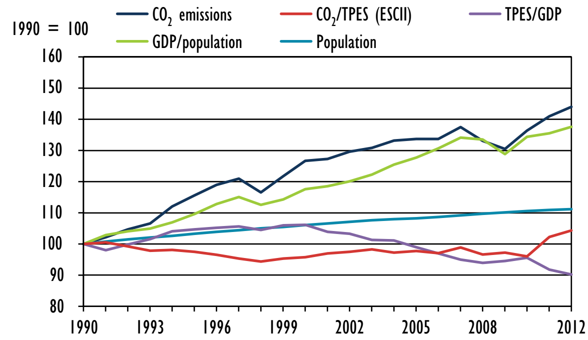


Figure 5
Carbon intensity (ESCII) and related CO_2 emissions

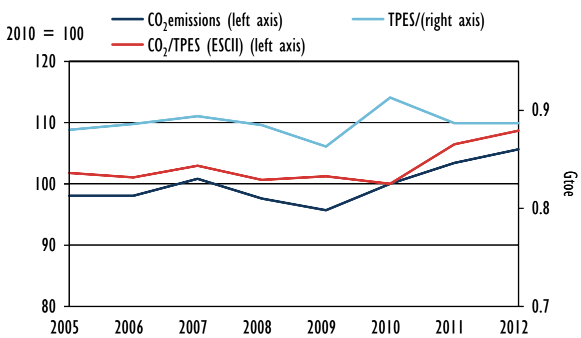
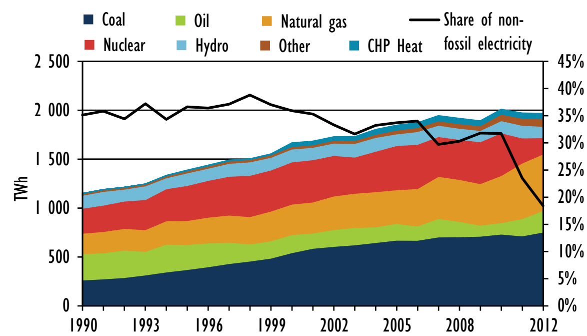


Figure 6
Electricity generation mix



Key features in energy and CO_2: OECD Asia Oceania

- Unique among the three OECD regions, CO_2 emissions rose in 2011 and 2012 (3.4% in 2011 and 2.2% in 2012) since their dip in 2009 due to the economic recession.

- An important component of this emissions rise is the marked increase in carbon intensity of energy supply (ESCII); ESCII values increased far more in this region (8.5%) in comparison to the global average (0.2%) in 2011 and 2012. Notably, ESCII rose particularly quickly in 2011, surpassing 1990 levels for the first time in two decades (Figure 4).

- The increase in ESCII was driven by changes in the electricity sector: by 2012, nuclear power had dropped its share in the electricity mix to less than 40% of its 2010 levels (Figure 6). The primary driver of this was the directed reduction in nuclear generation in Japan following the Fukushima nuclear accident. At the beginning of 2014, all of Japan's nuclear power plants were offline, but were expected to return to service at an undetermined date. Japan produced about half of the emissions of the region.

- Oil and natural gas, and to a smaller extent coal, filled the supply gaps (Figure 1). Oil in particular nearly doubled its share in the electricity mix, from 6.0% in 2010 to 11.5% in 2012, reversing a trend of declining oil shares since the mid-1990s (Figure 6).

- However, signs indicate that this suspension in nuclear power generation may be temporary. Japan released an energy plan in April 2014, placing emphasis on both coal and hydropower and affirming a role (albeit diminished) for nuclear power in the electricity generation mix.

- Although the trend of decoupling of economic growth from CO_2 emissions (CO_2/GDP) began in the early 2000s, CO_2/GDP reached a low in 2008 and began to rise again. This is also unique among OECD regions, which experienced consistent declines in CO_2/GDP to 2012 (Figure 3). This rise in carbon intensity was primarily due to the increased emissions-intensiveness of the energy supply outpacing GDP growth, rather than to increases in energy supply (TPES) itself (Figure 5).

- The Kaya decomposition provides particular insight, showing a decline in energy supplied per unit of economic growth (TPES/GDP) in 2011 and 2012 (5.7%), accompanied by an increase in the ESCII during the same period. This underscores the influence of a more carbon-intensive energy supply in driving the rise in CO_2 emissions (Figure 4 and Figure 5).

- The rise in ESCII is also reflected in Figure 6, where the share of non-fossil electricity dropped significantly in 2011 and 2012 (from 31.7% in 2010 to 23.5% in 2011 and 18.4% in 2012). While the greatest share of this decline is attributed to the drop in nuclear power generation, a decline in the share of hydropower also played a role. Meanwhile, as in other world regions, the share of non-hydro renewable electricity sources such as wind, solar and biomass increased steadily, reaching its greatest share in the generation mix in 2012 (3.7%) (Figure 6).

- The electricity and heat generation sector contributed the most to emissions, reaching its greatest share in 2012 over the reporting period (48.8%). Meanwhile, the manufacturing industries and construction sector (17.3%) and residential sector (4.4%) contributed their lowest-ever shares to emissions in 2012 (Figure 2).

OECD Europe

Figure 1
CO_2 emissions by fuel

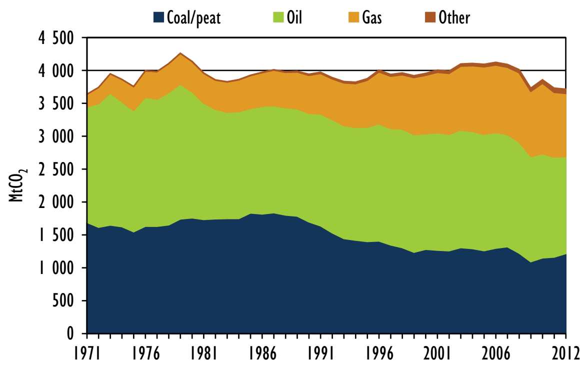


Figure 2
CO_2 emissions by sector

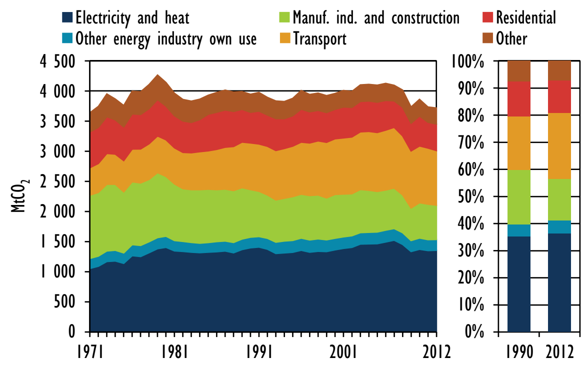


Figure 3
Selected CO_2 and GDP indicators
(change from 1990)

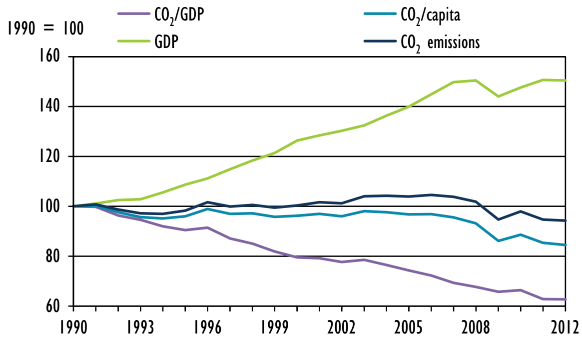


Figure 4
Kaya decomposition: Drivers of CO_2 emissions
(change from 1990)

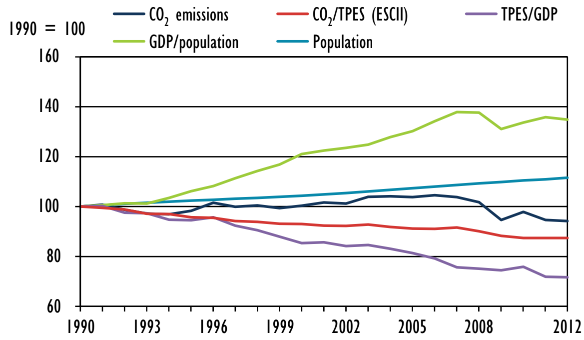


Figure 5
Carbon intensity (ESCII) and related CO_2 emissions

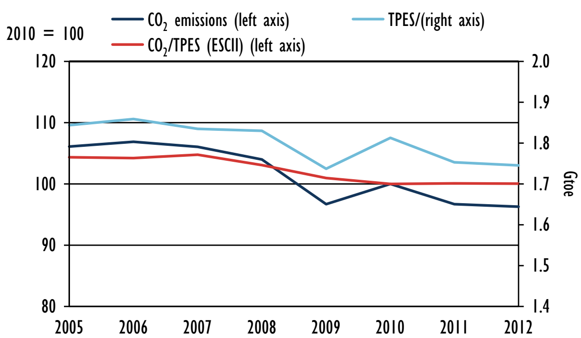
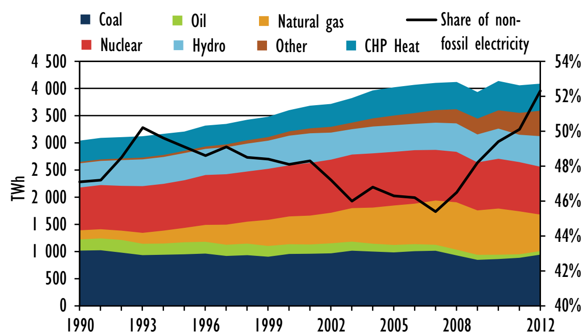


Figure 6
Electricity generation mix



Key features in energy and CO_2: OECD Europe

- CO_2 emissions decreased 3.3% in 2011 and more modestly, 0.4%, in 2012. In 2012, emissions were 5.8% lower than 1990 levels. This region had the lowest-emissions intensity (the lowest level of CO_2 emissions per unit of GDP) of all regions in 2012.

- Although oil was the greatest contributor to emissions, as has been the case for the last two decades, the 2012 share (39.7%) was the smallest since reporting began. The past four decades saw a gradual increase in the share of gas along with a decreasing share of coal. However, these trends reversed in 2011-12: coal increased 2.9% while gas decreased 2.0% (Figure 1).

- These 2011-2012 changes were driven by higher prices for natural gas relative to coal as a generation fuel. Reasons for this price differential include the low price of natural gas in the United States favouring coal exports (to Europe) and low-carbon prices under the European Union Emissions Trading Scheme (EU ETS).

- Of all sectors, electricity and heat generation contributed the greatest share to emissions in 2012, with its second highest share ever (36.4% as compared to 37.2% in 2007). This reflects a greater reliance on high-emitting electricity sources, along with declining emission shares from the transportation, manufacturing industries and construction, and residential sectors (Figure 2).

- Over the past several years, emissions declined both in sectors that are covered under the EU ETS such as electricity and heat, and manufacturing, industry and construction, as well as those outside the scheme, such as transport (Figure 2). These declines can be attributed to policy responses (the EU ETS and the 20/20/20 climate and energy package targeting renewable energy and energy efficiency improvements), as well as to relatively flat economic activity (Figure 3).

- Overall, the decline in 2011-12 emissions was thanks primarily to a decline in total primary energy supplied (TPES) (Figure 5) as well as to a decline in energy intensity of economic growth (TPES/GDP) (Figure 4), rather than to a cleaner energy supply (ESCII).

- The carbon intensity of the energy supply (ESCII) remained essentially flat in 2011 and 2012. This was the first time since 1990 that the ESCII did not decline in two consecutive years, reflecting the shift to coal from gas (Figure 4 and Figure 5). Nonetheless, between 1990 and 2012 ESCII declined by 12.6%, the most of any region. This is notable given that at the global level, ESCII remained essentially unchanged during the same period.

- Figure 6 shows that, despite increasing emissions from the electricity generation sector, the share of non-fossil sources rose. Interestingly, non-fossil generation reached an all-time high in 2012 (52.3%), the highest of all OECD regions and the second highest of all world regions after non-OECD Americas. The rise in electricity sector emissions can therefore be attributed to an increased emissions intensity of the fossil fuel sources employed, a further indication of the shift towards more carbon-intensive coal and away from less carbon-intensive natural gas.

- Other sources of renewable power (namely solar, wind, and biomass) grew more than any other energy source, rising 41.7% over 2011-12 (Figure 6). This may be attributed to policies to increase the share of renewable power under the 2009 Renewable Energy Sources (RES) Directive, which aims to meet 20% of energy demand through renewable sources by 2020.

Africa

Figure 1
CO_2 emissions by fuel

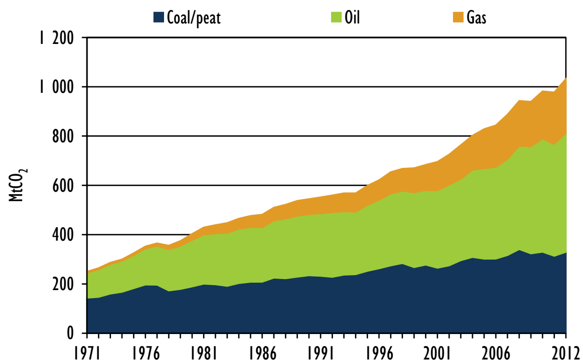


Figure 2
CO_2 emissions by sector

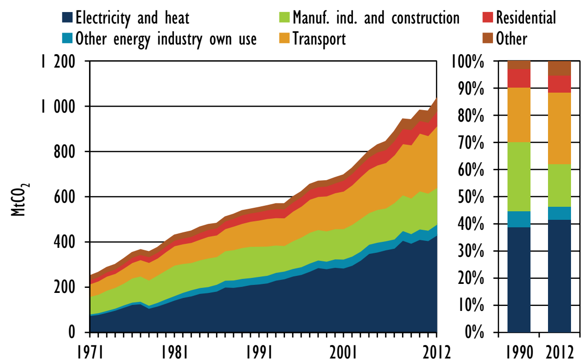


Figure 3
Selected CO_2 and GDP indicators
(change from 1990)

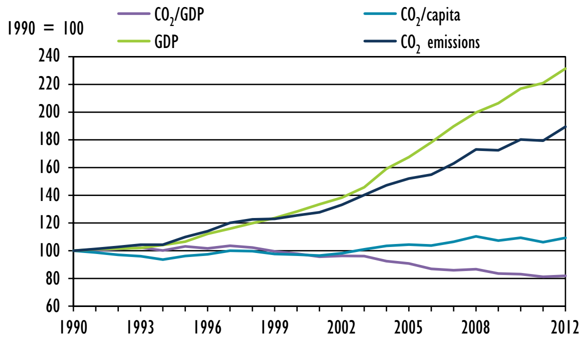


Figure 4
Kaya decomposition: Drivers of CO_2 emissions
(change from 1990)

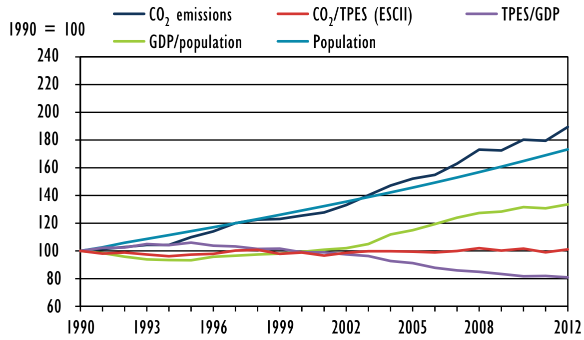


Figure 5
Carbon intensity (ESCII) and related CO_2 emissions

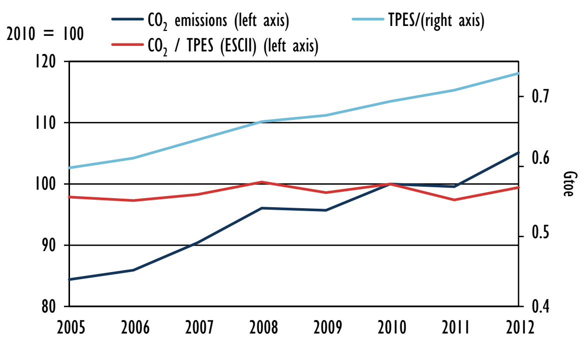
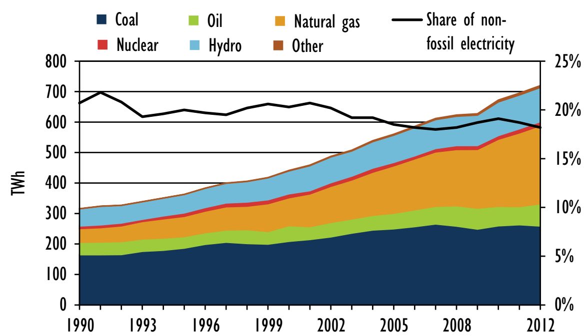


Figure 6
Electricity generation mix



Key features in energy and CO_2: Africa

- CO_2 emissions declined modestly in 2011 (0.4%), then rose substantially in 2012 (5.6%). In 2012, emissions were 89.4% higher than 1990 levels.

- In absolute terms, this region produced the lowest CO_2 emissions per person of all regions. Africa has also experienced high population growth: over 2011 and 2012, the population grew the most of any region (5.1%). Between 1990 and 2012, Africa had the highest percentage population growth of all regions (73.3%), more than double the global average growth rate (Figure 4).

- The declining share of coal's contributions to emissions over the past four decades (31.9% in 2012 compared to 57.2% in 1971) was accompanied by a proportional increase in the share of natural gas (21.3% in 2012 compared to 2.1% in 1971). In 2012 coal achieved its lowest share and gas its second highest share over the reporting period, though oil remained the largest relative contributor to emissions (46.8%) (Figure 1).

- Both absolute and proportional emissions from oil decreased in 2011 from 2010 levels. A major factor in this decline was the civil war in Libya, one of the region's major oil-producing countries, which significantly curtailed oil production and resulted in increased oil prices. In 2012, over 85% of the region's oil production was concentrated within five countries: Nigeria, Libya, Algeria, Angola and Egypt (Figure 1).

- Of all sectors, electricity generation and heat contributed the greatest share to emissions in 2012 (41.7%) (Figure 2). Meanwhile, access to electricity remained a major concern in this region. In 2011, 57% of the population lacked electricity access, the greatest share of the population of any region. Electricity generation is highly geographically concentrated, with South Africa and Egypt accounting for close to 60% of generation in 2011.

- The 2012 increase in emissions was due primarily to a rise in economic growth (Figure 3) and in TPES (Figure 5) especially from fossil fuels. However, while GDP growth outpaced emissions growth in 2011-12, the rate of GDP increase was the lowest among non-OECD regions (average annual increase of 3.3%).

- The late 1990s marked the beginning of a trend of more rapid decoupling of emissions growth from economic growth. CO_2/GDP continued to decline in 2011 (dropping 2.3%) but rose modestly in 2012 (0.8%) (Figure 3). The carbon intensity of energy supply (ESCII), however, remained relatively flat from 1990 to 2012 (Figure 4).

- Within the electricity sector, coal has been the dominant fuel in the generation mix since 1990, although its share declined over time while that of natural gas rose. In 2012, the proportional contributions of coal and gas in the generation mix converged (coal: 36.0%; natural gas: 35.6%).

- In contrast to other regions, the share of non-fossil electricity sources decreased in 2011 and 2012 (Figure 6), due partly to a decline in the share of hydropower. Nonetheless, this region has substantial untapped hydropower potential. Nuclear power accounted for a small share of electricity generation (1.8%), with two reactors in South Africa comprising all (commercial) nuclear power capacity in the region.

- Since 1990, however, non-hydro renewable sources experienced the greatest proportional increases among all electricity sources. This may be thanks to new policies and measures implemented by some countries to expand renewable energy production, such as the Morocco Energy Strategy, the South African renewable energy target, and Egypt's renewable energy strategy. Nonetheless, these sources remained a very small percentage of the region's overall generation mix (0.8% in 2012).

Non-OECD Americas

Figure 1
CO_2 emissions by fuel

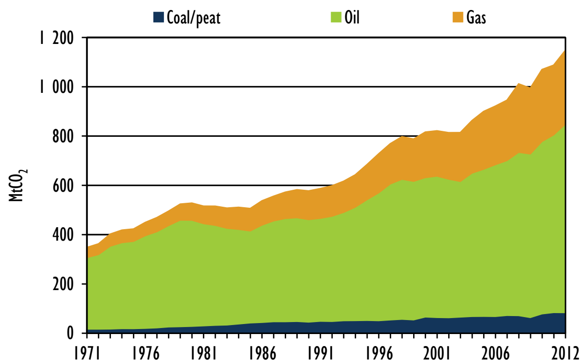


Figure 2
CO_2 emissions by sector

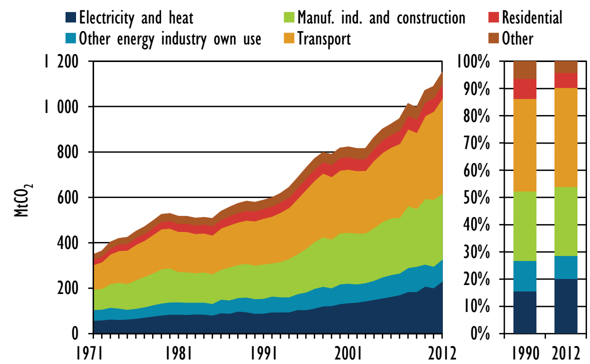


Figure 3
Selected CO_2 and GDP indicators
(change from 1990)

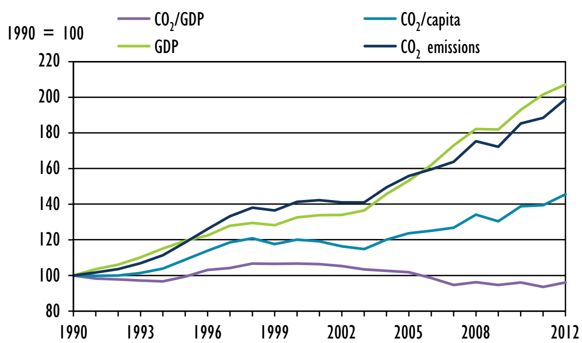


Figure 4
Kaya decomposition: Drivers of CO_2 emissions
(change from 1990)

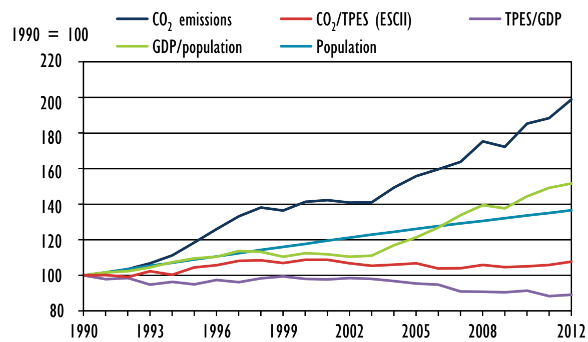


Figure 5
Carbon intensity (ESCII) and related CO_2 emissions

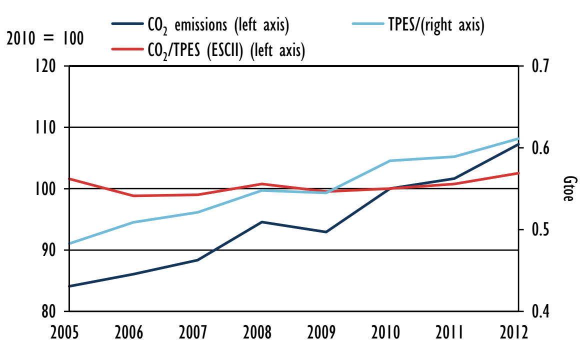
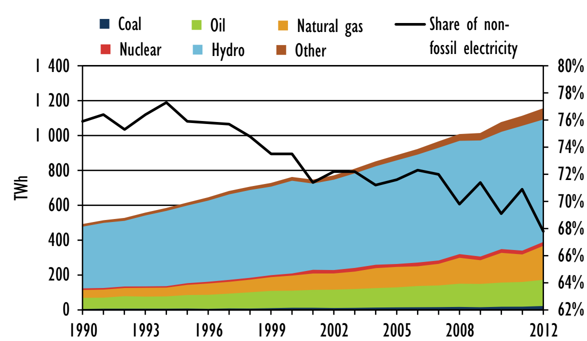


Figure 6
Electricity generation mix



Key features in energy and CO_2: Non-OECD Americas

- This region includes key emerging economies, such as Brazil and Mexico. CO_2 emissions rose 1.6% in 2011 and a further 5.5% in 2012, reaching levels 98.8% higher than in 1990.

- Oil contributed two-thirds of all emissions in 2012, having been the largest contributor to emissions since the start of reporting. Meanwhile, the share of emissions from gas increased steadily over the past several decades though it declined slightly in 2011 and 2012 (reaching 26.0% in 2012).

- In 2012 this region had the second largest proven oil reserves after the Middle East region, rising almost two-fold in 2011 primarily due to an increase in the estimated size of reserves in Venezuela. However, it remains to be seen how this rise in proven oil reserves will impact oil production in the medium term.

- Of all sectors, transportation contributed the most to emissions, recording its highest share (36.5%) since reporting began in 2012. Its share grew the most of all sectors, rising 2.5% over 2011 and 2012 (Figure 2). This was due to absolute increases in transportation sector emissions as well as to declining relative contributions of other sectors. Nonetheless, the transportation sector of this region had a relatively low-carbon intensity in 2012, given its relatively high use of biofuels. In 2012, this region accounted for 22% of global biofuel use in road transportation.

- Perhaps paradoxically, the emissions share from the transportation sector was the highest of all regions. An important reason for this high share, however, is the low-carbon intensity of the electricity and heat sector, commonly the greatest contributor to emissions in other regions. In 2012, electricity and heat generation contributed a relatively small share to overall emissions (20.2%), less than half of the global average (42.1%) (Figure 2).

- In 2012 this region had the least emissions-intensive electricity sector among all regions, thanks to its dependence on hydropower (0.201 kg CO_2/kWh compared to the global average of 0.511 kg CO_2/kWh). Hydropower contributed 60.9% to the electricity generation mix in 2012.

- Due to its reliance on hydropower, the electricity generation mix of this region has consistently had the highest share of non-fossil sources. However, this share has been declining steadily for the past two decades. In 2012, 67.8% of electricity was generated from non-fossil fuel sources, the lowest share seen over the reporting period. This resulted from a decline in hydropower production in 2012 despite a rise in non-hydro renewable power, such as biofuels (Figure 6).

- Droughts in recent years and concerns of supply shortages drove investment in electricity sources beyond hydropower, including natural gas and non-hydro renewable sources, such as biofuels, resulting in greater diversity in the electricity generation mix. Both coal (2.3%) and natural gas (16.9%) reached their highest shares in the electricity mix in 2012, and the region was a key producer of biofuel.

- Emissions growth in 2011 and 2012 was driven primarily by economic growth and, to a lesser extent, by a rising population and increasing carbon intensity of energy supply (ESCII) (Figure 3 and Figure 4). The rising ESCII resulted from an increased dependence on fossil fuel imports (particularly gas) to meet rapidly growing demand in the absence of domestic refining capacity and reduced hydropower production (Figure 6).

- Figure 5 highlights the influence of a growing energy supplied to the economy (TPES) in driving rising emissions. In 2011 and 2012 the carbon intensity of energy supply (ESCII) increased 2.5%, the greatest two-year rise in over a decade. The largest rise in 2012 (1.7%) again reflects the increased dependence on fossil fuels for electricity generation.

Middle East

Figure 1

CO_2 emissions by fuel

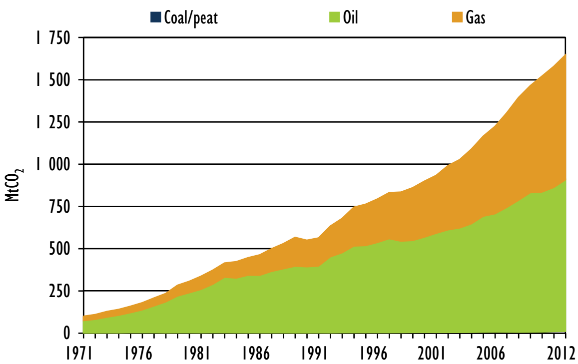


Figure 2

CO_2 emissions by sector

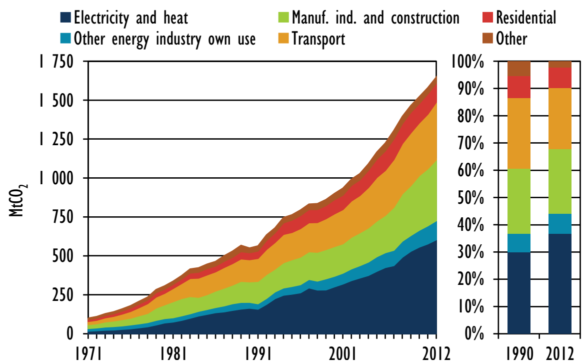


Figure 3

Selected CO_2 and GDP indicators
(change from 1990)

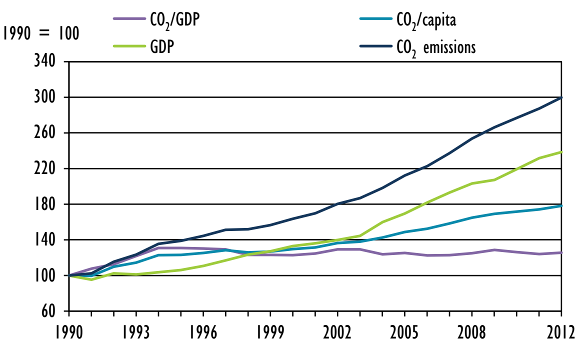


Figure 4

Kaya decomposition: Drivers of CO_2 emissions
(change from 1990)

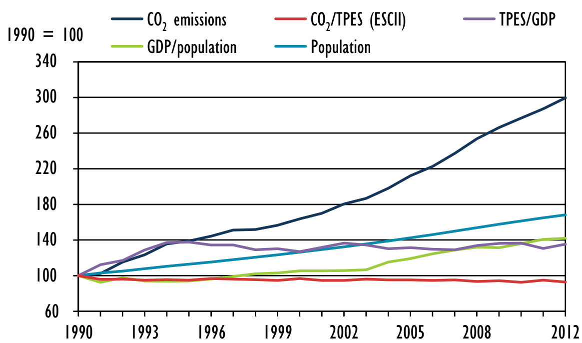


Figure 5

Carbon intensity (ESCII) and related CO_2 emissions

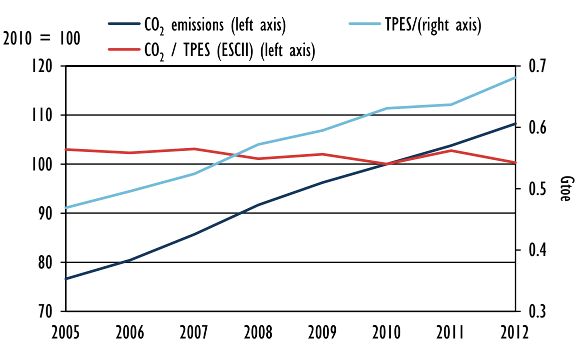
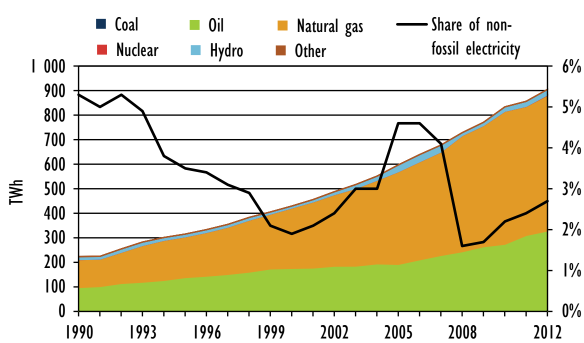


Figure 6

Electricity generation mix



Key features in energy and CO_2: Middle East

- In both 2011 and 2012 this region maintained its growing emissions trend, increasing 4.0% in each year. In 2012, this represented a tripling of emissions since 1990, the third highest rate of emissions increase after China and India. Since 1971, however, the Middle East had the highest rate of emissions increase of all regions (increasing 16.5-fold).

- This region had an emissions level per capita 1.7 times higher than the world average in 2012, second only to that of OECD Americas. Between 1990 and 2012, this region experienced the second highest percentage increase in population (68.2%) after Africa (73.3%).

- In 2012, oil remained the main contributor to emissions. However, as in other regions, its share decreased over time (reaching 54.5%) as the share of gas rose (to 44.9%). Coal contributed by far the smallest share to emissions of any region (0.7%) (Figure 2).

- Despite the rapid rise in shale oil and gas production in North America, this region retained its leading role as an oil and gas producer, containing approximately half of the world's oil and gas reserves and the lowest production costs.

- The continued dominance of both oil and gas reflects the continuing impacts of heavily subsidised domestic oil and gas prices.

- The increase in emissions experienced in 2011 and 2012 was driven by rising GDP and population, leading to increased demand for energy (Figure 3 and Figure 4).

- In contrast to the global trend of declining energy intensity (CO_2/GDP), the energy intensity of this region was 26% higher in 2012 than in 1990 as the economy and energy mix became increasingly dependent on oil and gas. This also underlines the effects of fossil fuel subsidies in supporting oil and gas production (Figure 4).

- After having dropped in 2011 (by 4.4%), the energy intensity of economic growth (TPES/GDP) experienced an increase of 3.8% in 2012 (Figure 4). Meanwhile, the carbon intensity of energy supply (ESCII) experienced a substantial decline in 2012 (2.3%). This was the largest decrease in the region since 1990 (Figure 4 and Figure 5).

- This region has traditionally relied heavily on fossil fuels for electricity generation. In 2012, oil and gas comprised 97.3% of the generation mix, representing the lowest share of non-fossil electricity (2.7%) of all regions. This share of non-fossil electricity, however, had been increasing consistently from a low of 1.6% in 2008. This reflects an interest within the region to diversify the electricity generation mix for reasons of energy security and reliability.

- 2011 marked the first year of nuclear generation within the region, with the completion of a nuclear power plant in Iran. With several other countries in the region actively pursuing nuclear power generation, the share of nuclear energy within the generation mix may rise in the future (Figure 6).

- After a substantial increase in hydropower production in 2010 with new capacity additions in Iran, hydropower production continued to grow in 2011 (14.4%) and 2012 (9.0%). However, it still comprised the smallest share of the electricity mix (2.5% in 2012) among all regions (Figure 6).

- In 2012, the electricity and heat sector was the main contributor to emissions (36.7% in 2012), with its greatest share over the reporting period. Meanwhile, the residential sector had its lowest share of emissions over the reporting period (7.4%) (Figure 2).

Non-OECD Europe and Eurasia

Figure 1
CO_2 emissions by fuel

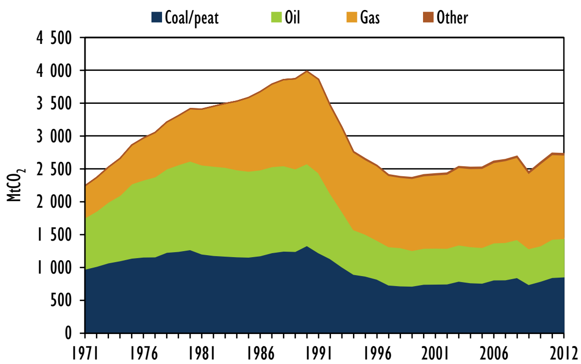


Figure 2
CO_2 emissions by sector

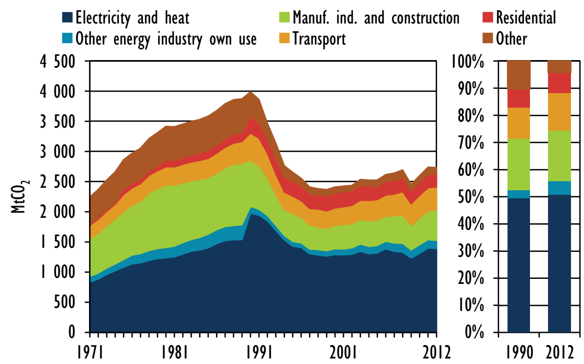


Figure 3
Selected CO_2 and GDP indicators
(change from 1990)

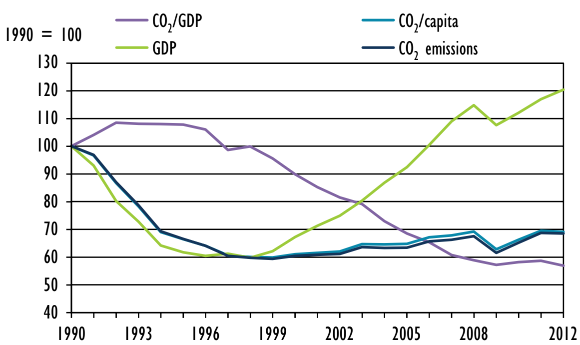


Figure 4
Kaya decomposition: Drivers of CO_2 emissions
(change from 1990)

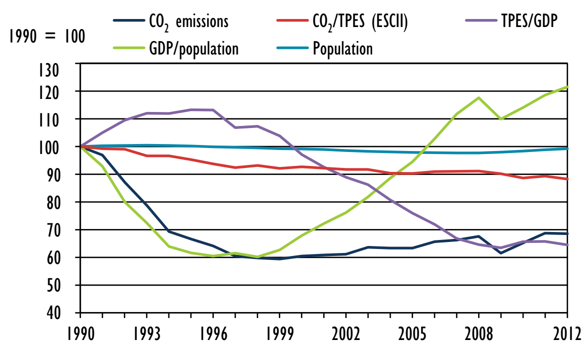


Figure 5
Carbon intensity (ESCII) and related CO_2 emissions

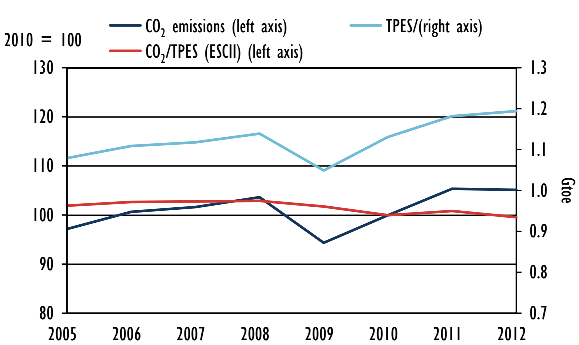
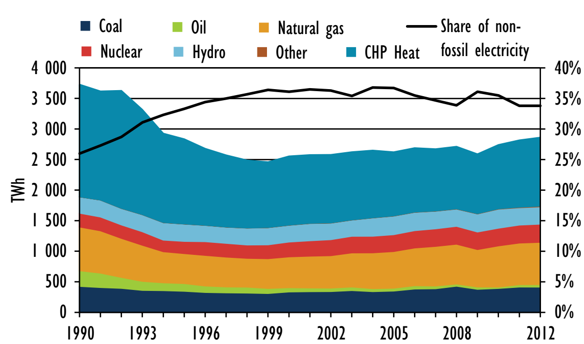


Figure 6
Electricity generation mix



Key features in energy and CO_2: Non-OECD Europe and Eurasia

- After a marked increase in emissions during the recovery period from the economic recession in 2010, emissions continued to rise in 2011 (5.4%), then stabilised in 2012 (declining 0.2%). The emissions increases in 2010 and 2011 were the largest experienced in over three decades.

- In 2012, Russia, Ukraine and Kazahkstan contributed close to 80% of the region's emissions, with Russia's emissions alone comprising 60% of the total.

- In 2012, emissions were 31.5% below 1990 levels, making this the only non-OECD region where emissions were lower than in 1990. De-industrialisation during the break-up of the former Soviet Union began the large decline in emissions in the early 1990s, reaching their lowest levels in 1999. Since then, emissions rose at a modest rate of 1.2% annually, less than half the world average over the same time period.

- Natural gas contributed almost half of all emissions (46.5%) in 2012, though this share dropped slightly from its peak in 2010 (48.0%). Coal contributed about one-third of all emissions (31.4%) in 2012, a share that remained fairly stable over the last two to three decades. Oil's contribution to emissions reached an all-time low in 2012 (21.3%) (Figure 1).

- Due to its rich gas reserves, particularly in Russia, this region was the second largest producer and consumer of natural gas in 2012 after OECD Americas. Russia has the world's largest proven natural gas reserves.

- The electricity and heat sector contributed over half of emissions (50.9%) in 2012, with the manufacturing, industrial and construction sector the next largest contributor (18.8%). The transportation sector contributed a relatively small share (13.7%) in comparison to the world average (22.6%) (Figure 2).

- In 2012 this region had a relatively high emissions intensity and energy intensity of economic growth, with both CO_2/GDP and TPES/GDP 1.8 times higher than the world average. Though the values for these indicators had been declining, this trend was interrupted in 2010. 2012 figures, however, indicate that energy and emissions intensity may continue their decline (Figure 3 and Figure 4).

- This region was particularly impacted by the recent economic recession, as international prices declined for oil and gas, major exports from the region. This region experienced the greatest decline in GDP in 2009 (6.3%) of all regions (global average: 0.1% decline) (Figure 3).

- The rise in CO_2 emissions in 2011 and 2012 is attributed primarily to an increase in energy demand, and to a much smaller extent to an increase in the emissions intensity of energy supply (ESCII) in 2011 (Figure 5). The increased ESCII reflects an increase in coal and oil supply accompanied by a decline in natural gas supply. This is illustrated in the electricity generation sector: in 2011 the shares of coal and oil rose 1%, while that of hydropower dropped nearly 2% (Figure 6).

- Although coal production had historically been modest relative to the large coal reserves in the region, the Russian government has been making an effort over the past decade to restructure the coal industry and increase coal production.

- Within the electricity sector, however, natural gas comprised the greatest share of the electricity generation mix (39.8%) in 2012, while coal comprised just less than a quarter of the mix (24.0%). Oil contributed a minor share (2.3%). The carbon intensity of the region's electricity sector was lower than the global average, thanks to its dependence on lower-emitting fossil fuels (natural gas) and non-fossil sources such as hydro and nuclear power (Figure 6).

- CHP was widely applied in the region, with CHP heat output comprising 64% of total electricity generation in 2012.

Asia (excluding China and India)

Figure 1
CO_2 emissions by fuel

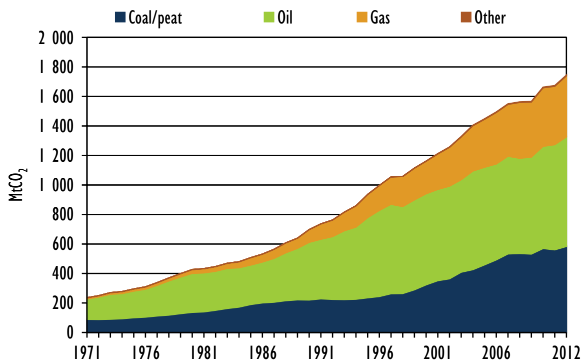


Figure 2
CO_2 emissions by sector

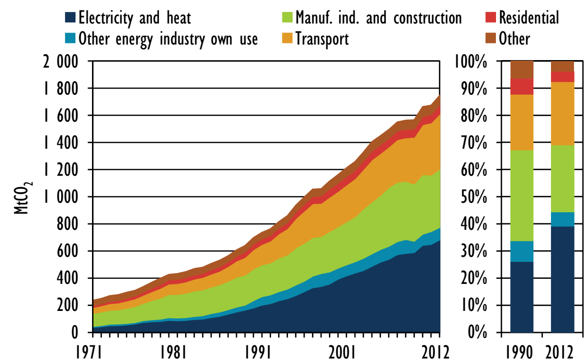


Figure 3
Selected CO_2 and GDP indicators
(change from 1990)

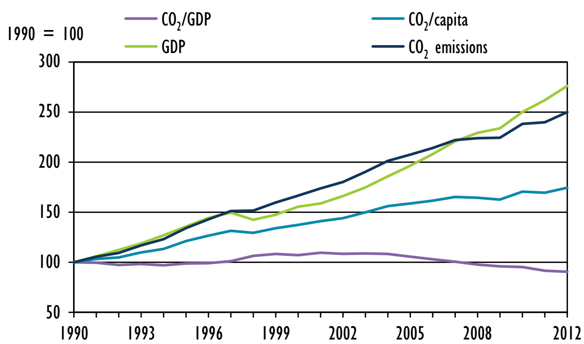


Figure 4
Kaya decomposition: Drivers of CO_2 emissions
(change from 1990)

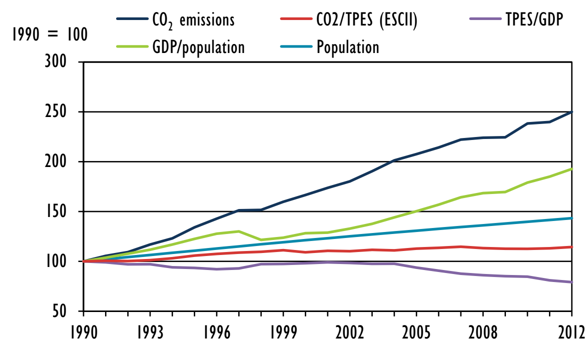


Figure 5
Carbon intensity (ESCII) and related CO_2 emissions

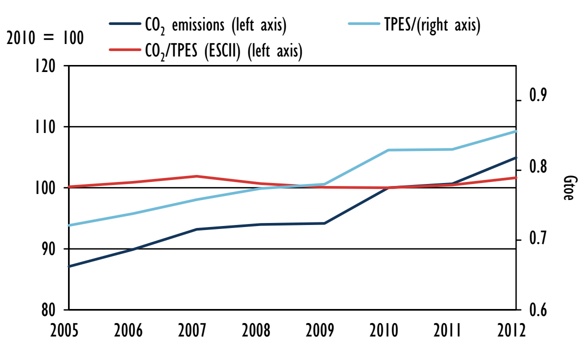
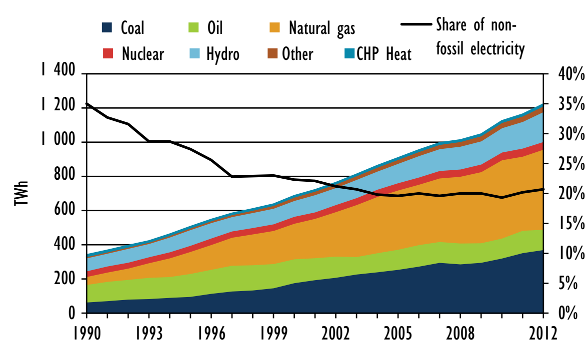


Figure 6
Electricity generation mix



Key features in energy and CO_2: Asia (excluding China and India)

- Following a marked rise in 2010 emissions during the period of economic recovery, emissions rose slightly in 2011 (0.6%) and more substantially in 2012 (4.2%), reaching levels 2.5 times higher than in 1990.

- This region is particularly diverse in terms of energy resource endowment and economic development. It has widely varying rates of electricity access across countries, which in 2011 ranged from universal access in some (such as Singapore, Brunei and Malaysia) to less than 50% in others (such as the Democratic People's Republic of Korea, Cambodia and Myanmar).

- Indonesia is the region's largest economy, and in 2012 produced one-quarter of the region's emissions. In 2011 Indonesia overtook Australia as the world's largest coal exporter by tonnage. Nonetheless, across the entire region, oil remained the greatest contributor to emissions in 2012 (42.6%), as has been the case for the entire reporting period. This was followed by coal (33.5%) and gas (23.7%) (Figure 1).

- Emissions grew at an average of 5.0% annually since 1971 with CO_2 emissions per capita reaching its highest-ever levels in 2012. However, per capita emissions remained just over one-third of the global average. Furthermore, this region experienced its lowest-ever level of energy intensity (CO_2/GDP) in 2012, at 36% lower than the global average (Figure 3).

- The electricity and heat generation sector, the largest contributor to emissions, contributed its largest-ever share in 2012 (39.1%), reflecting the growing demand for energy within this region. In absolute terms, electricity production increased 3.7 times between 1990 and 2012 (Figure 2).

- Reflecting a rapidly growing transportation sector, transportation emissions also registered their highest share in 2012 (23.3%). Meanwhile, the manufacturing industries and construction sector had its lowest share (24.6%).

- The rise in CO_2 emissions in 2012 was driven primarily by high rates of economic growth, and to a lesser extent by a growing population. This region experienced the third highest increase in GDP over 2011 and 2012 (10.2%), after China and India. Furthermore, percentage population growth since 1990 (43.3%) exceeded that of China and India (Figure 4).

- Overall, the increase in demand for energy drove the rise in emissions. The carbon intensity of energy supply (ESCII) played a smaller role, having risen 1.6% between 2010 and 2012 (Figure 4 and Figure 5).

- In 2012 the region's electricity sector was relatively dependent on fossil fuels, primarily natural gas (38.6% of the generation mix) and coal (30.7%). The share of non-fossil sources in electricity generation was 20.7%, about one-third lower than the global average. Nonetheless, while this share reached a low in 2010, it rose gradually to 2012. This was due to increases in nuclear, hydro and other renewable generation in both years (Figure 6).

- The exception to this is nuclear power generation, which rose in 2011 then declined in 2012 to its lowest share over the reporting period (3.7%) due to the shutdown of plants for repair. Chinese Taipei and Pakistan housed the only nuclear plants in this region (Figure 6).

- In 2011 and 2012, absolute hydropower production increased 21.3% and was the greatest contributor to non-fossil electricity generation (14.4% of the total electricity generation mix) (Figure 6).

China

Figure 1
CO_2 emissions by fuel

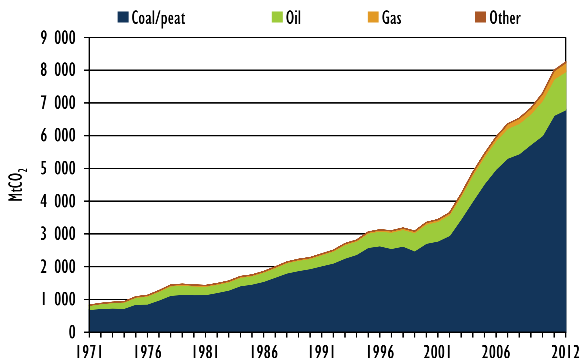


Figure 2
CO_2 emissions by sector

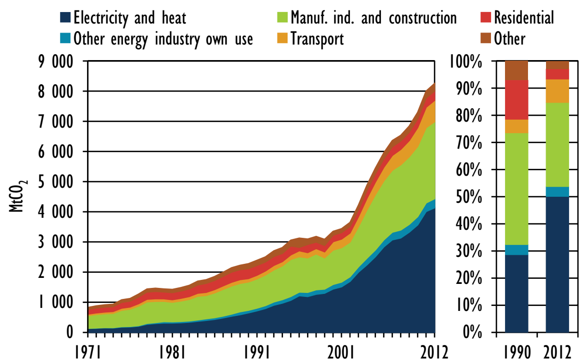


Figure 3
Selected CO_2 and GDP indicators
(change from 1990)

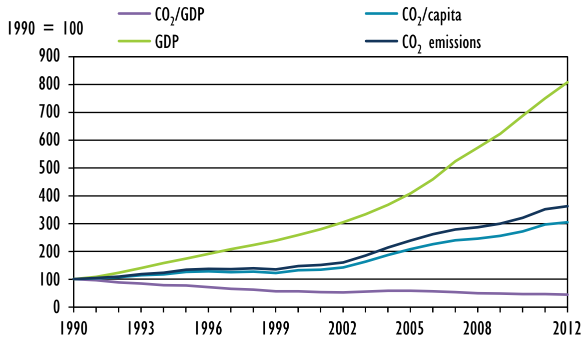


Figure 4
Kaya decomposition: Drivers of CO_2 emissions
(change from 1990)

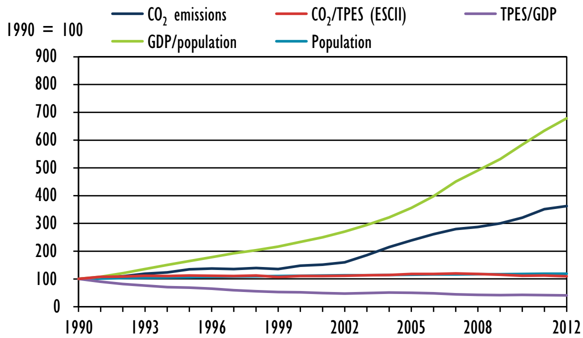


Figure 5
Carbon intensity (ESCII) and related CO_2 emissions

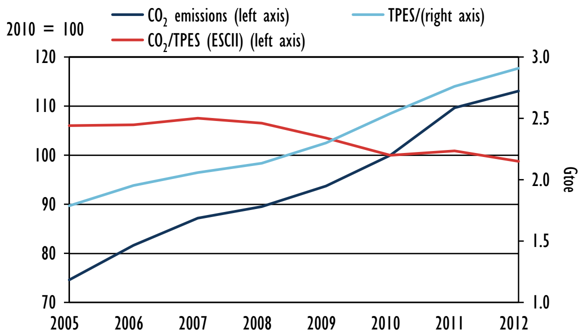
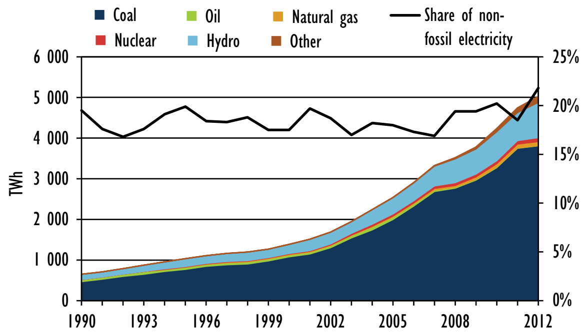


Figure 6
Electricity generation mix



Key features in energy and CO_2: China

- China has experienced unprecedented economic and emissions growth, with both GDP and CO_2 emissions growing at the highest rates of all regions since 1990. Emissions increased at notable rates in 2011 (9.7%), with further growth of 3.1% in 2012 reaching levels 262.2% higher than in 1990.

- This recent growth, however, is modest compared to historical rates, especially those seen from 2003 to 2005. In 2012 the emissions growth rate decreased markedly from previous years: in fact, it was the lowest growth rate experienced over the past decade (3.1%), except during the economic recession in 2008.

- China's rising demand for energy played a dominant role in defining global trends. In 2012, China alone was responsible for 165 Mt of the 170 Mt rise in global coal demand. In natural gas, China's demand comprised 40% of additional consumption among non-OECD regions.

- In 2012 China was the world's leading coal producer, consumer and importer, with coal contributing by far the largest share to emissions (82.3%). Gas increased its contribution to reach its highest share in 2012, though it was responsible for only 3.3% of all emissions (Figure 1).

- As in other regions, the electricity and heat sector was the greatest contributor to emissions, surpassing 50% in 2011 and retaining this share in 2012 (50.1%). Meanwhile, other sectors declined their relative contributions to emissions in 2012, including the manufacturing, industrial and construction sector (to 31.0%) and the residential sector (to 3.8%), both experiencing their lowest-ever shares within the reporting period. These declines, despite rising energy demand in these sectors, may have been due to China's aggressive energy efficiency policies and programmes. Meanwhile, the transportation sector contributed its largest share to emissions in 2012 (8.6%) (Figure 2).

- While CO_2 emissions continued rising over the two-year period of 2011-12 (12.8%), economic growth increased even more rapidly (16.8%). As a result, GDP continued to decouple from emissions growth, as CO_2 / GDP reached its lowest levels in 2012 (Figure 3). Energy use also decoupled from economic growth, as TPES / GDP also experienced its lowest levels in 2012 (Figure 4).

- The energy intensity of energy supply (ESCII) had been declining since 2007, with an exception in 2011 when ESCII rose 0.9%. An important factor in this rise was the increase in coal consumption, reflected in the increase of both domestic production and imports, with China becoming the largest coal importer in 2011 (US EIA, 2014).

- Emissions growth was driven primarily by increased GDP. The population increased relatively little in 2011 and 2012 (0.5% / year), while declining energy intensity of economic growth (TPES / GDP) and carbon intensity of energy supply (ESCII) acted as moderating factors to emissions growth (Figure 3 and Figure 4).

- ESCII declined 2.1% in 2012, the most of any region, owing in part to the reduction in carbon intensity of the electricity sector (Figure 5). This ESCII decline played an important role in moderating emissions growth in 2012. Despite this declining trend, however, ESCII remained 9.5% higher in 2012 than in 1990 (Figure 4).

- China's electricity sector was the most coal-dependent among all regions, with coal comprising 75.9% of the generation mix. However, the individual shares of each fossil fuel source (coal, oil and gas) declined in 2012 while the shares of each non-fossil source (hydro, nuclear, and other renewable sources including wind and solar) all rose from 2011 (Figure 6).

- Strong investment in wind and solar power generation, as well as the completion of the Three Gorges hydroelectric dam in 2012 contributed to the increased share of non-fossil sources within the electricity generation mix, which reached its highest-ever share of 21.8% in 2012 (Figure 6).

India

Figure 1

CO_2 emissions by fuel

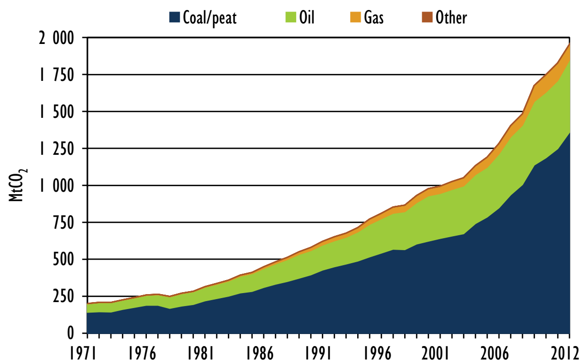


Figure 2

CO_2 emissions by sector

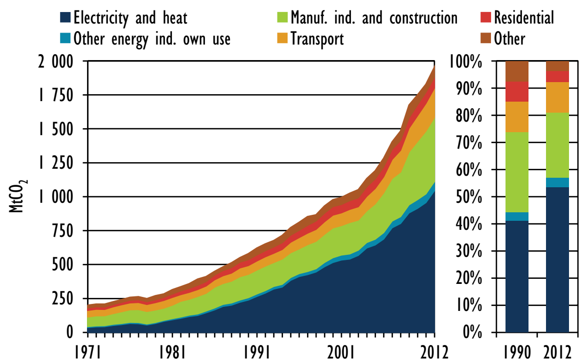


Figure 3

Selected CO_2 and GDP indicators (change from 1990)

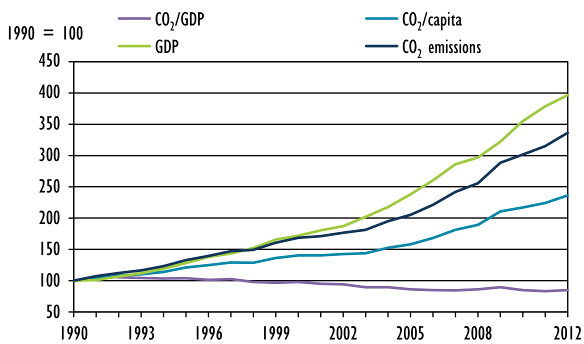


Figure 4

Kaya decomposition: Drivers of CO_2 emissions (change from 1990)

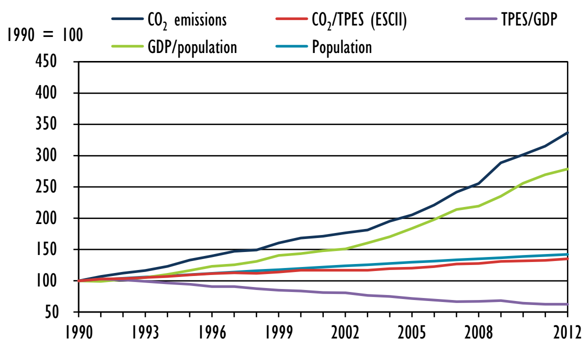


Figure 5

Carbon intensity (ESCII) and related CO_2 emissions

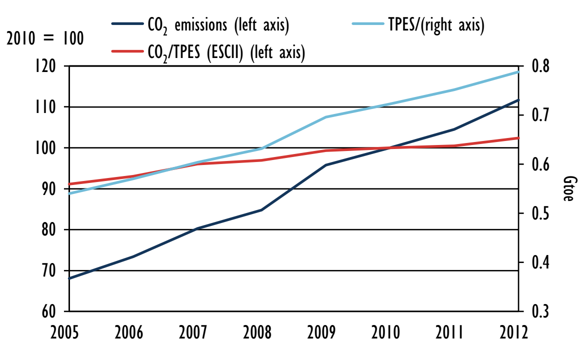
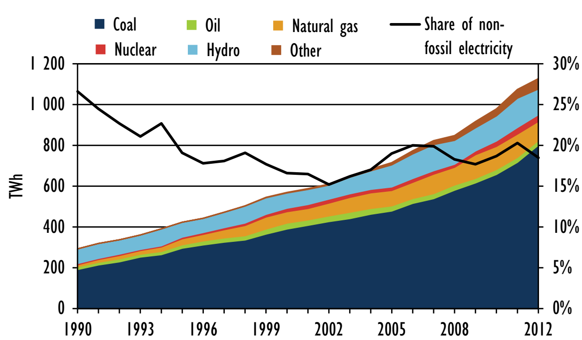


Figure 6

Electricity generation mix



Key features in energy and CO_2: India

- Having had the lowest per capita CO_2 emissions of all regions at the start of the reporting period (1971), absolute and per capita emissions increased markedly over the past three decades. By 2012, emissions had reached levels 237% higher than in 1990, the second highest growth rate in emissions since both 1971 and 1990, behind that of China. Nonetheless, in 2012 per capita emissions remained the second lowest among all regions, after those of the Africa region. India was the world's second most populous country, after China, in 2012.

- In contrast to the global trend of more modest emissions increases in 2012 than in 2011, India's emissions grew at a faster rate in 2012 (6.8%) compared to 2011 (4.5%).

- A rise in energy supply (TPES) (due to rising economic growth and population) was the primary driver of increasing emissions in 2011 and 2012. However, an increasing carbon intensity of energy supply (ESCII) played a much larger role in driving emissions increase in comparison to other regions. Since 1990, the ESCII increased by the greatest percentage of any region (35.1% by 2012), compared to the world average, which remained essentially unchanged during the same period (Figure 4 and Figure 5).

- Although the contribution of coal to emissions hovered around a 70% share over the last four decades, it increased in both 2011 (to 68.3%) and 2012 (to 69.6%). Meanwhile, in 2012, the contribution of oil was at its lowest point across the reporting period, at 25.0% (Figure 1).

- India's electricity generation sector was the second most coal-dependent after that of China. In absolute terms, the use of coal to produce electricity increased by the fastest rate in over a decade and a half (11.7% in 2012). Coal reached its highest share in the electricity generation mix over the reporting period (71.1%) (Figure 6).

- In the electricity sector, the use of coal increased as the lowest shares of hydropower in the generation mix in a decade occurred in 2012. A late monsoon season led to less available water, reducing hydropower production. At the same time, natural gas supply issues resulted in marked declines in gas production since 2010. The share of gas declined from its peak of 12.7% in 2009 to 10.6% in 2011 and 8.3% in 2012 (Figure 6).

- The electricity generation and heat sector almost tripled its contribution to emissions since 1971, though in 2011 and 2012 its share remained fairly consistent at just over 50%. In 2012 the share of emissions from the residential sector was the lowest over the reporting period (4.1%) (Figure 2).

- Following two years of declining emissions intensity of economic growth (CO_2/GDP), CO_2/GDP increased by 2.0% in 2012. Also in 2012, GDP grew at a lower than average rate (4.7% compared to 6.5% average annual increases since 1990) (Figure 3). Moderated GDP, growth coupled with a higher than average emissions growth in 2012, resulted in a rise in emissions intensity of the economy.

- Through concerted efforts to increase renewable power generation, shares of non-hydro renewable sources increased the most of all fuel sources in the generation mix. By the start of 2012, wind power comprised around 70% of total non-hydro renewable power capacity. Overall, electricity generation from these "other" renewable sources increased by a notable 47.7% over 2011 and 2012. Despite this, their contribution remained small, equalling 4.5% of the generation mix in 2012 (Figure 6).

- Electricity shortages remained a primary concern in India as a result of insufficient fuel supply, in particular coal, to match growing demand. In 2011, 25% of the population was without electricity access, the largest population lacking access to electricity of any country.

Table 5.1

Regional aggregation

Region	Countries
OECD Americas	Canada, Chile, Mexico and the United States
OECD Asia Oceania	Australia, Israel,[1] Japan, Korea and New Zealand
OECD Europe	Austria, Belgium, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, the Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey and the United Kingdom
Africa	Algeria, Angola, Benin, Botswana, Burkina Faso, Burundi, Cameroon, Cape Verde, Central African Republic, Chad, Comoros, Congo, Democratic Republic of Congo, Côte d'Ivoire, Djibouti, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Gabon, Gambia, Ghana, Guinea, Guinea-Bissau, Kenya, Lesotho, Liberia, Libyan Arab Jamahiriya, Madagascar, Malawi, Mali, Mauritania, Mauritius, Morocco, Mozambique, Namibia, Niger, Nigeria, Reunion, Rwanda, Sao Tome and Principe, Senegal, Seychelles, Sierra Leone, Somalia, South Africa, Sudan, Swaziland, United Republic of Tanzania, Togo, Tunisia, Uganda, Western Sahara (from 1990), Zambia and Zimbabwe
Non-OECD Americas	Antigua and Barbuda, Argentina, Aruba, Bahamas, Barbados, Belize, Bermuda, Bolivia, Brazil, British Virgin Islands, Cayman Islands, Colombia, Costa Rica, Cuba, Dominica, Dominican Republic, Ecuador, El Salvador, Falkland Island, French Guyana, Grenada, Guadeloupe, Guatemala, Guyana, Haiti, Honduras, Jamaica, Martinique, Montserrat, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Puerto Rico (for natural gas and electricity), St. Kitts and Nevis, Saint Lucia, Saint Pierre et Miquelon, St. Vincent and the Grenadines, Suriname, Trinidad and Tobago, Turks and Caicos Islands, Uruguay and Venezuela
Middle East	Bahrain, Islamic Republic of Iran, Iraq, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syrian Arab Republic, United Arab Emirates and Yemen
Non-OECD Europe and Eurasia	Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus,[2] Georgia, Gibraltar, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Former Yugoslav Republic of Macedonia (FYROM), Malta, Republic of Moldova, Romania, Russian Federation, Serbia, Tajikistan, Turkmenistan, Ukraine, Uzbekistan, Former Soviet Union (prior to 1990) and Former Yugoslavia (prior to 1990)
Asia (excluding China and India)	Afghanistan, Bangladesh, Bhutan, Brunei Darussalam, Cambodia, Chinese Taipei, Cook Islands, East Timor, Fiji, French Polynesia, Indonesia, Kiribati, DPR of Korea, Laos, Macau (China), Malaysia, Maldives, Mongolia, Myanmar, Nepal, New Caledonia, Pakistan, Palau (from 1994), Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Thailand, Tonga, Vanuatu and Viet Nam
China	People's Republic of China and Hong Kong (China)
India	India

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US EIA (2014), "China", US Department of Energy, Washington, D.C., www.eia.gov/countries.

1. The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

2. 1) Note by Turkey: The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of the United Nations, Turkey shall preserve its position concerning the "Cyprus issue". 2) Note by all the European Union Member States of the OECD and the European Union: The Republic of Cyprus is recognised by all members of the United Nations with the exception of Turkey. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

Acronyms, abbreviations and units of measure

Acronyms and abbreviations

AQI	Air Quality Index
BAT	best available technology
DRC	Development Research Center of China's State Council
CO	carbon monoxide
CO_2	carbon dioxide
CCS	carbon capture and storage
CSAPR	Cross-State Air Pollution Rule
CHP	combined heat and power
ESP	electrostatic precipitator
ESCII	energy sector carbon intensity index
ETS	emissions trading system
EU ETS	European Union Emissions Trading Scheme
FF	fabric filter
FGD	flue gas desulphurisation
FYP	Five-Year Plan
GHG	greenhouse gas
GDP	gross domestic product
Gtoe	gigatonnes of oil equivalent
HCI	hydrochloric acid
HF	hydrofluoric acid
Hg	mercury
IGCC	integrated gasification combined cycle
LCP	large combustion plant
MATS	Mercury and Air Toxics Standard
MEP	Ministry of Environmental Protection
MER	market exchange rate
MoF	Ministry of Finance
NDRC	National Development and Reform Commission
NERA	NERA Economic Consulting
NGCC	natural gas combined cycle
NOx	nitrogen oxide
NPS	New Policies Scenario
PPP	purchasing power parity
PC	pulverised coal
$PM_{2.5}$	particulate matter smaller than 2.5 micrometres
PM_{10}	particulate matter smaller than 10 micrometres
SCPC	supercritical pulverised coal
SCR	selective catalytic reduction
SOx	sulphur oxides
SO_2	sulphur dioxide
SO_3	sulphuric acid/sulphur trioxide
TPES	total primary energy supply
USC	ultra-super critical
UNECE	United Nations Economic Commission for Europe
UNFCCC	United Nations Framework Convention on Climate Change
US EPA	United States Environmental Protection Agency
VOC	volatile organic compound
WHO	World Health Organisation
WEO	World Energy Outlook

Units of measure

Gt	gigatonne
GW	gigawatt
kWh	kilowatt hours
MW	megawatt
MWh	megawatt hours
TWh	terawatt hours
Mt	million tonnes
kg	kilogramme
bcm	billion cubic metres

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Energy, Climate Change & Environment

2014 Insights

Policies that respond to climate change and other environmental issues will increasingly impact the development of the global energy sector. The transition to low-carbon economies will need to be carefully managed, as the provision of secure, affordable energy is critical for economic growth and social development. More than ever, there is a need for a fuller understanding of the opportunities to promote synergies between energy, environmental and climate policies. *Energy, Climate Change, and Environment: 2014 Insights* helps address this need with in-depth analysis of selected policy questions at the energy-climate interface, including:

- How can we accelerate the transition from (i.e., "unlock") existing high-emissions infrastructure?
- What are the best ways to design cost-effective emissions trading systems that fit with national circumstances?
- What are some alternative energy-specific metrics that support near-term emissions reductions and long-term decarbonisation of the energy sector?
- And, in the special focus of this report, can curbing local air pollution help reconcile energy priorities with environmental sustainability, including greenhouse gas mitigation?

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