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Report

Linking Global and Regional Energy Strategies (LinkS)

Final report

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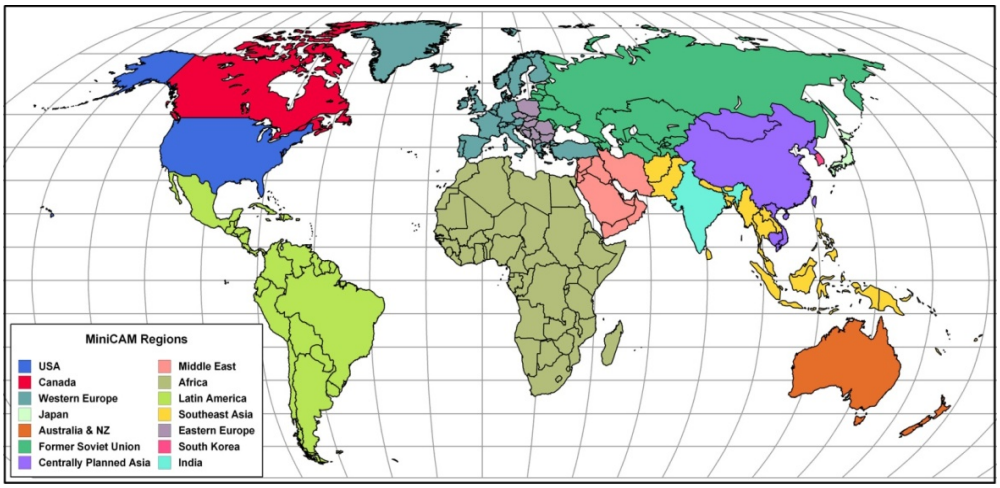

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ABSTRACT
The LinkS project was designed to analyse how global long-term strategies can be used as guidelines for the development of energy supply and technology deployment in regional energy systems. In order to produce recommendations for policy development and regional energy investment strategies, both quantitative and qualitative research were applied. Until an international climate change mitigation agreement with binding targets is established, the states and regions that implement mitigation strategies on their own initiative represent key actors for significant emissions reductions. This report therefore introduces a novel scenario "Global-20-20-20", where a hypothetical protocol based on the EU 20-20-20 policies is extended in time and space to a global scenario where an increasing number of the world's regions gradually adopt the EU approach. This hypothetical protocol illustrates the aggregated potential of "globalizing" individual regional climate policy efforts, and is a major reference for much of the work presented in this report. Furthermore, in-depth studies of the European and Chinese regions under several global policy scenarios are presented.
An Executive Summary is published as a separate Technical Report A7373.

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SINTEF

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1 Overall description of the LinkS project

The main research questions that led to the establishment of the LinkS project were the following: *How can we correlate scenarios for the energy system between a very long-term and global level and a regional level; and what additional insights will such a correlation yield?* There are a number of models that focus on climate changes and long-term effects of different energy system designs on emission of greenhouse gases (GHG). The models that include both social processes (e.g. economic development) and physical processes in nature are called *Integrated Assessment Models* (IAM). See also (Springer, 2003; Nakata, 2004; Weyant, 2009). Although many IAM models offer a rich portfolio of technologies they generally have very low geographical detail. On the other hand, regional energy system optimization models are bottom-up models that have large details in both technological and geographic scope but are limited to a single region and, usually, shorter time frame of the analysis. A large number of energy system scenario studies are made for Europe in the last decade, but all of them either neglect or have to make exogenous assumptions about global developments e.g. for fossil fuel prices, carbon prices and raw materials.

Thus, the project «*Linking global and regional energy Strategies (LinkS)*» was designed to analyse how global long-term strategies can be used as guidelines for the development of energy supply and technology deployment in regional energy systems. Today, regions like the EU have quite ambitious strategies for renewable energy and emission mitigation, while others have no specific strategies yet. If rapidly growing economies like Brazil, Russia, India and China delay their emission reduction efforts, the OECD countries have to do correspondingly more to keep total GHG emissions within necessary limits. We therefore have to find correlated strategies that are efficient and acceptable in several regions at the same time.

In order to produce recommendations for policy development and regional energy investment strategies, both quantitative and qualitative research were applied. As for the quantitative modelling, the partners in LinkS employ several energy system models. Our US partner Joint Global Change Research Institute calculates the long term development of global economy, energy supply, land use and climate with the equilibrium model *Global Change Assessment Model (GCAM)* in a 100 year perspective for 14 regions of the world. Different scenarios are then projected down into different regions by technology specific models: *World Gas Model (WGM)* from the University of Maryland is used for global gas and oil markeds, the *EMPS* model of SINTEF is used for the European power market while *TIMES* from Tsinghua University in Beijing is used in regional energy systems in China. Some new methodologies are developed to integrate these models, in particular the evaluation of which investments to do where and when to ensure development in the desired direction. In addition, a new model *EMPIRE* (European Model for Power system Investment with (high shares of) Renewable Energy) was developed by a PhD at NTNU. Finally, the project assesses suitable regulations and policies to implement the recommended strategies in different regions.

As for the qualitative research, regional knowledge and data on policy instruments were provided by the respective research partners. Different regional policy instruments and in particular the EU-20-20-20 policy package were assessed in order to provide recommendation for further development of regional and thus global GHG emission abatement strategies. Figure 1.1 shows how the different research tasks and corresponding models in LinkS were connected.

*An Executive Summary of the LinkS project is published as a separate Technical Report A7373***.**

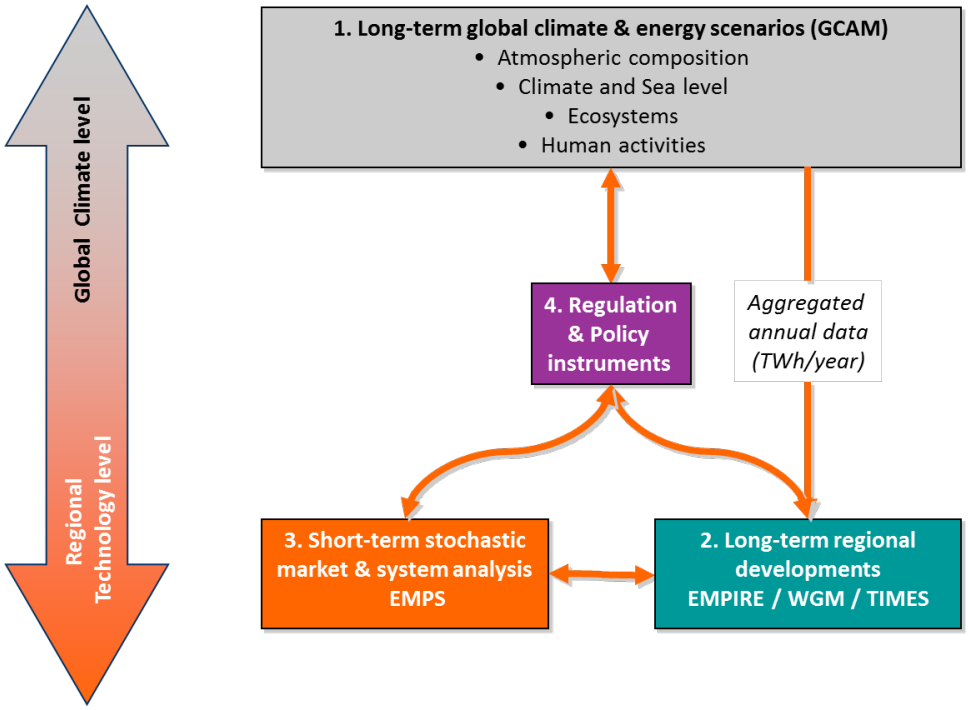


Figure 1.1 Research tasks and models in the LinkS project

This report first provides the reader with an overview of current regional energy and climate policies in Europe, US and China in Chapter 2. In the foundation for future global climate-change policy accords it is crucial to focus on major regional entities like China, the US and the EU, which both demonstrate different approaches to climate policy formulation and implementation, as well as constitute the world's three main emitters of greenhouse gases.

Chapter 3 explains the global scenario analysis and the GCAM model, which was a common reference for all the other models applied in the project. It also importantly introduces a novel scenario *"Global-20-20-20"*, which is a major reference for much of the work presented in this report.

Chapter 4 analyses possible regional policy implications of the Global-20-20-20 scenario, and if it could represent a viable approach to climate-change mitigation. Climate change abatement is a global responsibility, yet no global authority is governing common policy measures. Unless international climate co-operation is made mandatory with binding targets, the states and regions that implement climate change mitigation strategies on their own initiative represent key actors for significant GHG emissions reductions. The potential of "globalizing" individual regional climate policy efforts and possible mechanisms for realization of globalized regional approaches is discussed.

In Chapter 5 we present results from a specific subtask where we test if it is appropriate to utilize a general IAM model such as GCAM to study trade leakage for the aluminium sector.

Chapter 6 presents scenarios for developments of the global gas market with the World Gas Model. CO_2 is the primary greenhouse gas emitted from human activities, and with continuing increase in global natural gas demand (EIA, 2011a), GHG emission control from natural gas is highly relevant to climate change mitigation. Hence, the development of the global gas market with the prospect of increased deployment of

policy instruments like carbon taxes, cap-and-trade programs an emission allowances is analyzed in this chapter. The World Gas Model used CO_2 prices from GCAM as input data.

Chapter 7 presents scenarios for development of the Chinese energy and cement sectors with TIMES. China is one of the three largest GHG emitters in the world, together with the United Sates and the European Union. The demand for primary energy in China reached 31.8 billion tons of coal equivalents in 2011, ranking first in the world. The development of the Chinese energy sector, taking into account the effect of current Chinese national policies, is therefore highly relevant for global climate-change mitigation. Electricity demand from GCAM is used as input data in one of the scenarios.

In Chapter 8 the developments in the European electricity sector is analyzed in detail with the EMPIRE and EMPS models. The European electricity sector is vital in reaching the European Union's climate and energy policy targets for 2020, named the "EU-20-20-20" target, and the continued development towards a decarbonisation of the European Community by 2050 (European Commission, 2011b). Previous studies like the Energy Roadmap 2050 (EC, 2011b) have looked at the development under scenarios specific to the European region. In our study, EMPIRE and EMPS use CO_2 prices, fuel prices, electricity demand, and electricity production from the global scenarios of GCAM as input data for the development of the European electricity system.

Chapter 9 presents some examples of linking between WGM and the regional models TIMES and EMPIRE. As opposed to the "top-down" linking where other models used GCAM outputs as a reference projection that tied the analysis together, this "horizontal" linking proved to be more challenging due to the large differences in spatial, temporal and technology functionality in the models.

Finally, Chapter 10 provides the reader with the final discussion and summary of main findings.

More detailed documentation of the EMPIRE and EMPS models are given in Appendix.

2 Regional policy overview (Europe, US, China)

From November 26th to December 7th, 2012 the eight session of the United Nations Framework Convention on Climate Change (UNFCCC) was held in Doha, Qatar. One of the major outcomes was the Amendment to the Kyoto Protocol, which extended and quantified the emission limitation and reduction commitments for the Annex B parties for the period 2013-2020 (UNFCCC, 2013). As of October 2013, the Kyoto Protocol is the only international climate treaty with specific emission reduction targets.

2.1 The features of climate policy action in the U.S

The United States signed the Kyoto protocol in its first period (1998-2012) and agreed to commit to a 7 percent emission reduction compared to 1990 levels within 2012 (UN, 1998), however the Protocol was never ratified by the U.S. Senate[1]. When Barack Obama took office in 2009, he immediately proposed strengthening of the federal climate policy. A comprehensive and ambitious climate bill was passed in the House of Representatives in June 2009, but was not brought to a vote in the Senate. In the Copenhagen Accord, and in the United Nations Framework Convention on Climate Change (UNFCCC) pre-meeting in Bonn 2011, the US communicated an anticipated GHG emission reduction target of around 17 % below 2005 levels within 2020 (USDS 2010). The final US target would be reported to the UNFCCC, and would be based on the new energy and climate legislation. Yet in the recent Doha Amendment, the US is no longer listed as having a quantified emission limitation.

Presently, there is no legislation at the federal level that ensures that the US achieves its international emissions reduction pledge. However, there are a myriad of regulations at the federal and state level that explicitly or indirectly reduce GHG emissions. Explicit climate policy initiatives are being promulgated under the Environmental Protection Agency (EPA)'s existing authority of the Clean Air Act (CAA) as well as the Regional Greenhouse Gas Initiative (RGGI) in the Northeastern US and the California cap and trade program. This is supplemented by a wide range of federal and state level initiatives with the goal of improving energy security or supply, such as renewable energy standards and energy efficiency measures. These reductions, however, are likely to fall short of the international pledges and may be less economically efficient than a coordinated effort.

Understanding the present state of US climate change policy requires consideration of the roles and responsibilities of the different branches of the US government, the interactions between the federal authorities and the US states, the motivation and incentives of the different players as well as the interactions with the public sentiment on the nature and severity of climate change and other linked issues on energy security.

The progression of comprehensive climate policy at the federal level reflects the election cycles and the relative balance of power between the Democrats and Republicans between the President's Office, the Senate and the Congress. For international treaties, this arises from US Senate's mandate to approve or reject ratification on a treaty. Furthermore, an eventual approval by the Senate needs a 2/3 majority. Additionally, congressional approval is required to pass legislation.

After ratifying the UNFCCC framework in 1992, the Clinton Administration proceeded with several pieces of legislation, namely the Energy Policy Act of 1992 (EPAct 1992) that were designed to comprise the US

[1] To ratify a treaty a thwo-thirds majority, 67 sentators, must vote in favor in a Senate floor vote (Bang, 2011)

response to the UNFCCC. While the UNFCCC contained voluntary targets only, the main goal was to establish binding targets. At the Convention of the Parties (COP) – 3 in Kyoto, targets were discussed. The Senate (S.Res. 98) voted unanimously that the US should not sign any agreement limiting developed countries emissions unless the agreement also included schedules to limit GHGs from developing countries. Nor should this agreement result in serious harm to the economy of the US. Regardless, the Clinton Administration signed the Kyoto protocol in its first period (1998-2012) with a commitment to a 7 % emission reduction compared to 1990 levels by 2012 (UN, 1998); however, it did not submit it to the Senate for ratification.

During the 108th and 109th Congresses, climate change was relatively absent from legislative agenda, whereas by the 110th Congress (2007 – 2009), where the Democrats holding the majorities in both the Senate and House, climate change legislation - such as the America's Climate Security Act of 2007, was developed, albeit failing to pass the Senate.

In 2009, at the COP-15 in Copenhagen, President Obama signaled a change in approach from the Executive Office, pledging a GHG reduction target "in the range of a 17% emission reduction by 2020 compared with 2005 levels". This target was consistent with the level of reduction put forth in climate change legislation that was passed by the US House of Representatives in June 2009 (111th Congress) prior to the COP. While this legislation was not ultimately approved by the US Senate, the State Department has reaffirmed this pledge in international settings.

The 2009 commitments arose from competing emissions trading plans that were proposed in the 111th Congress, namely the American Power Act (Kerry-Lieberman), Clean Energy Jobs and American Power Act (Kerry-Boxer), and the American Clean Energy and Security Act (Waxman – Markey) (ACES). In July 2010, the Senate announced that it would not consider climate change legislation during that session. More recent attempts in 2012, such as the Clean Energy Standard Act (S. 2146), which would have established a standard for clean energy generation in the US through 2035, died in the Senate Committee on Energy and Natural Resources (Govtrack 2012).

While attempts to pass comprehensive legislation have failed, there are a number of measures that have been forwarded through other pieces of legislation that are consistent with GHG emission reductions. The best-known policy has been the production tax credit (PTC) for wind power, first introduced in 1992. Having been continuously extended it has led to substantial expansions in installed wind power capacity in the US.

Importantly, federal level initiatives may also now promulgated by the Environmental Protection Agency (EPA) under the authority of the Clean Air Act (CAA). In 2007, the US Supreme Court ruled that CO_2 and other GHGs are covered by the CAA's definition of air pollutant (Massachusetts v. EPA 2007). The EPA was then tasked with deciding whether GHGs endanger public health or welfare as required for regulatory action under the CAA. In 2009, the EPA issued the endangerment and contribution finding. The US Court of Appeals subsequently upheld the endangerment funding in 2012. The EPA has promulgated regulations for motor vehicles setting standards to cut GHGs and increase fuel economy for cars and light-duty trucks, the GHG Reporting Rule and Carbon Pollution Standard for New Power Plants. These efforts represent a substantial effort to reduce GHG emissions in the US. However, the CAA is an imperfect vehicle for climate-relevant policies as the EPA is limited in its actions that are better suited to conventional air pollutants.

Individual US States have significant amounts of authority to pursue individual and joint initiatives that complement or exceed the federal actions. US States have a long history of serving as laboratories for policies. Presently, 42 of the 50 states have introduced policy efforts addressing climate change, including

initiatives such as renewable portfolio standards (RPS) and other tax credits for energy efficiency measures that may enhance the federal level activities. These actions have the potential to impact global GHG emissions, as individual states constitute seventeen of the world's top fifty emitters of carbon dioxide.

Policies that will reduce GHG emissions in the US are highly decentralized. Congress has not ratified the existing international treaties. Given the existing legislative guidance, any international agreement that entails binding emission reductions without commensurate binding emission reductions from developing countries, namely China, will fail to be ratified. However, the US may pursue the bilateral or multilateral agreements that contain climate change provisions. Domestic initiatives will, however, continue at the federal, regional, state and city scale. States will continue to pursue a number of policies, most notably the California cap-and-trade. Taken as a whole, these policies have the potential to make an important contribution to limiting emissions. However, they are unlikely to attain reductions consistent with the UNFCCC commitments.

2.2 The character of climate policy initiatives in China

China ratified the Kyoto Protocol in 2002 (UNFCC 2013), but has, as a developing country, no quantified emission reduction target under the program. China is a dominant player in the Clean Development Mechanism (CDM), the only market-based mechanism in the Kyoto Protocol involving both developed and developing countries (Maraseni, 2013). China has also contributed actively to the global efforts through mainstreaming mitigation into its energy and environment policy. China's national goals dated year 2010 are: i) CO_2 emissions reduction per unit gross domestic product (GDP) by 40-45% by 2020 from the 2005 level; ii) increased share of non-fossil fuels in primary energy consumption to around 15% by 2020, and iii) increased forest coverage by 40 million hectares and forest stock volume by 1.3 billion cubic meters by 2020 from 2005 levels (DCC 2010). This political statement was partly translated into a legal instrument in year 2011, a mandatory target to reduce carbon intensity by 17% by 2015 in its 12th Five Year Plan (FYP).

Marking a shift in a history where China's national policy on climate change was not transparent (QI et al. 2007), the National Development and Reform Committee (NDRC) published China's National Program on Climate Change in June 2007, representing the first time the Chinese government synthesized its climate strategies at the national level. In October 2008, the government of China published its first annual white paper on climate change, and the latest annual white paper came in 2012.

The 11th FYP (2006-2010) was the first plan to specifically mention "climate change" (QI et al. 2007), and it was also the first time that China established quantitative targets for saving energy, as well as emission reductions at the highest level of national economic and social development overall planning. Moreover, the 11th FYP specified an energy intensity reduction objective of 20% for the period 2006-2010, whereas the current 12th FYP (2011-2015) the target is 16% energy intensity reduction and 17% carbon intensity reduction (Li and Wang, 2012).

The 11th FYP was dominated by legal prescriptions, and a 'command-and-control' policy approach towards emission mitigation (e.g. shutdown of power plants and heavy industries). Since it resulted in increased social and economic unrest (Li and Wang 2011), the 12th FYP set forth to realize energy and carbon intensity abatement targets through "*cost-effective policies to minimize the impacts of climate policy on the stable socio-economic development*" (Li and Wang 2012:520). China's midterm climate ambitions for 2020 were partly reflected in the plans as a five-year target, due to the nature of FYPs with their five years intervals. In previous FYPs, initiatives for emission reductions have mainly been a co-product of measures embedded in energy and transport policies aimed at cutting energy costs and increasing security of supply

(Richerzhagen and Scholz 2007). But the 12th FYP shows a clear trend that climate target has become a mandatory target together with energy intensity target.

The people's Congress passed the 12th FYP in March 2011 and was representative of China's efforts to rebalance its economy. The plan listed the target of reducing carbon dioxide emission per unit of GDP by 17% from 2010 level as a *legally binding mandatory target*. The State Council followed up with an issue in December 2011 of a work plan for GHG emission control during the 12th FYP period.

The work plan identified major targets of combating climate change as follows: 1) Reduce CO_2 emissions per unit of GDP by 17% by 2015 from 2010 level; 2) control GHGs from non-energy activities; 3) improve climate change policy system and mechanisms and systems for GHG statistics; 4) carbon emission trading market establishment; 5) low carbon pilot projects and 6) GHG emissions control.

The work plan emphasized key policy targets both quantitatively and qualitatively, including:

- accelerating the adjustment of industrial structures by increasing the share of value added from service and strategic emerging industries to 47% and 8%, respectively,
- promoting energy conservation continuously,
- developing low carbon technologies by increasing the proportion of non-fossil energy consumption to 11.4%,
- strengthening the carbon sinks towards a target of increasing 12.5 million hectares of forests and 600 million cubic meters of forest stock by volume,
- piloting CCS demonstration projects,
- controlling GHGs from non-energy activities including industrial production processes, agriculture and waste treatment,
- enhancing replacement of emission intensive products such as cement, steel, lime and other emission intensive products.

To achieve those targets, some key carbon oriented policies are also introduced in the work plan which shows a substantive step from previous climate relevant policies package towards a more climate specific policies package. Firstly, the low carbon development pilot programs which initiated low carbon pilot at various levels, at local level 5 provinces and 8 cities are selected as the first bundles of pilot ; the similar pilot are also conducted at industrial park level, communities level and product level (e.g. standards, labeling, verification, low carbon consumption). Secondly, a statistical and accounting system for GHG will be established with the aim to establish comprehensive GHG statistics to be involved in evaluation system of local government performance, developing GHG inventory at local level, key sectors and enterprises. Finally, to gradually establish a voluntary emission trading scheme, a series of emission trading pilot programs in two provinces and five cities with a view to initiate a national ETS starting from 2016, and to develop supporting system for emission trading (e.g. registry, third party, regulation).

Summarized, major current policy initiatives in China are climate-relevant, but a significant shift towards a more climate-specific pattern has been made during the 12th FYP period. However, despite announced ambitions there are few policy efforts directly aimed at *emission reductions per se*. It remains to be seen whether the recent personnel changes at the top level of China's government will imply any further changes in that respect. The Chinese government plays a leading role in the Chinese economy, and administrative measures can be introduced fast and with an obvious effect, as demonstrated with the energy conservation policies during the first three years of the 11th five-year period. An important

institutional feature, adding leverage to the provinces' role and positions, is the importance of regional leaders' fulfillment of national objectives in order to get political promotion.

2.3 The climate policy approach of the EU

In a global climate context, in particular in the UNFCCC, the EU has played an important role. The EU has joined a second commitment period of the Kyoto Protocol (European Commission 2011). The European Union and its member States have pledged to reduce its greenhouse gas emissions by 20 percent compared to the 1990 level by 2020 under the Kyoto Protocol. Furthermore, the share of EU final energy consumption that is produced from renewable resources shall be raised to 20%, and the energy efficiency in the EU shall be improved by 20% (European Commission, 2012). All together, these are called the "20-20-20 targets".

The ambitious targets for 2020 can be seen as an integrated approach to climate and energy policy. These are related to EU's growth strategy towards 2020 which encompass targets on employment, R&D, innovation, poverty and social exclusion (European Commission 2011).

Although unified on a supranational level, the EU legislation does not provide explicit guidelines to implementation at the national level, which is decisive for how the EU decisions are transposed and brought into force (Wallace & Wallace, 2010; Hooghe & Marks, 2001). The result is the Member States as a whole has a variety of policy schemes related to climate change – including renewable energy (see section 4.3, below). The variety in the Member States can be explained by the combined effects of: Differing energy resources; differing market structures related to distribution and infrastructure; differing technology options and considerations; and differing policy and governance structures (Schreurs & Tiberghien 2010, Lafferty and Ruud 2008). The substantive divergences between Member States, and between Member States and a supra-national EU level have represented general obstacles to the establishment of a common EU climate-change policy framework.

One of the major GHG emissions reduction policy instruments across sectors is the EU Emission Trading System (ETS). It is a climate-specific, market-based "cap-and-trade" instrument. The development and implementation of the ETS illustrates the inherent dynamic between the supranational and national levels of decision-making within the EU (c.f. Skjærseth & Wettestad, 2008). The ETS was formally established by the Directive 2003/87/EC[2], and finally adopted in 2003 (OJEU 2003). It covers approximately 45% of the total GHG emissions in the EU (European Commission, 2013), and was introduced to help Member States achieve their Kyoto targets (EEA, 2012). It has been far less controversial than a potential carbon tax which was debated in the early 90's, but which was watered down due to resistance from various Member States, the European industrial lobby, and various parts of the EU Commission (Skjærseth & Wettestad, 2008). The EU ETS has recently entered into its third trading phase (2013-2020). Major changes are; a single, EU-wide cap on emissions instead of the previous 27 national caps, auctioning of allowances as the default method instead of free allocation (with harmonized allocation rules on those allowances still given away from free), and lastly, some more sectors and gases are included (European Commission, 2013). The cap will decrease continuously from 2013 onwards using an annual reduction factor of 1.74% of the average total quantity of allowances issued annually in 2008-2012, while an increasing share of allowances will be auctioned (EEA, 2012)[3]. To avoid carbon leakage the significant exposed production and industries in the EU ETS system are granted a higher share of free allowances (European Commission, 2012b).

[2] A directive issued by EU institutions requires the Member States to fulfill certain objective(s), but the concrete legislative and other means are to be decided at the national level.

[3] In 2013, up to 40% will be auctioned (European Commission, 2013), which is four times more than in the previous phase, where only around 10% of the allowances were auctioned, and the rest was allocated freely.

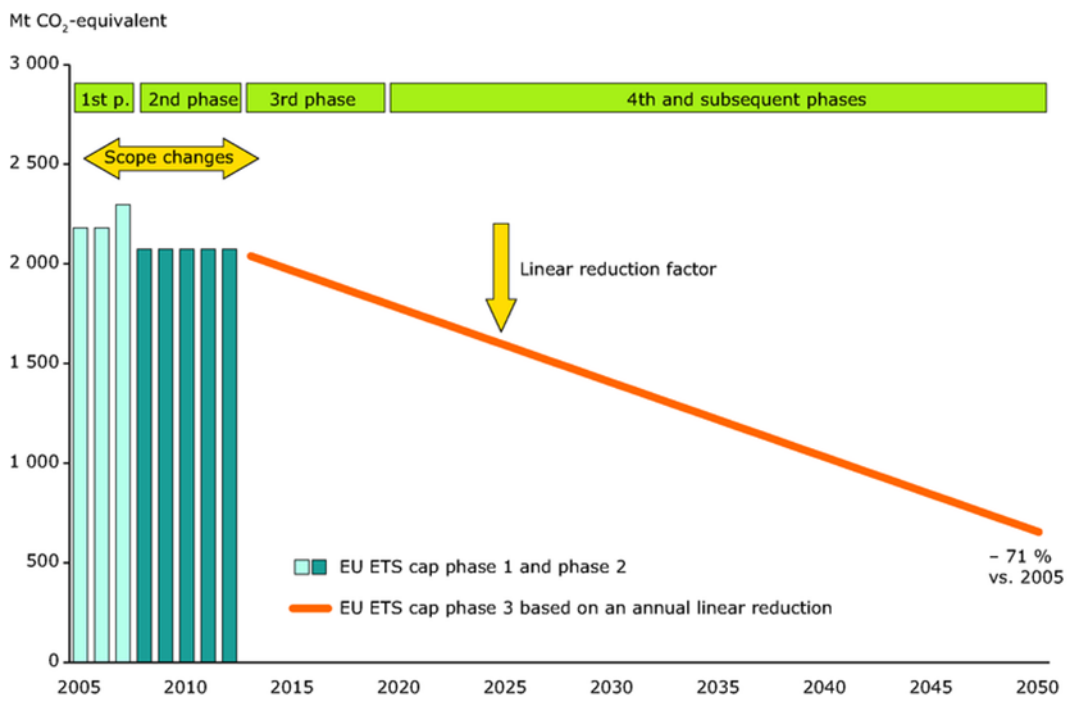


Figure 2.1 Perspective on the EU ETS cap until 2050
(http://www.eea.europa.eu/data-and-maps/figures/perspective-on-eu-ets-cap)

From January 1st, 2012, the EU ETS also aimed at covering CO_2 emissions from commercial flights to, from, and within the EU, regardless of whether the airline or operator is based in the EU region or not. Air carriers from the US and other countries have strongly objected, and the U.S government and other nations have pressed the EU to exclude foreign carriers from the ETS (CRS 2012).

Summarized, the EU has both *climate-specific* policies and policy instruments (20% emission reduction and ETS system). As will be elaborated in section 4.3 there are also *climate-relevant* policy initiatives in place, connected to the EU targets on energy efficiency and renewable energy. A major challenge is to ensure an effective and coherent coordination of these initiatives – across levels of anchorage and sectors.

3 Global scenario analysis with GCAM

The world has become increasingly interconnected and events in any individual region are affected by events throughout the world. Events in China, for example, carry implications for Norway and the rest of Europe both directly and indirectly through effects on the South and the Western Hemisphere. In this part of the project we explore the global implications for human energy, economic and land systems of limiting human climate forcing. We explicitly consider interactions between the world's regions on decade to century time scales, the characteristic time scale for stabilization of the concentration of greenhouse gases in the atmosphere. We do this by first establishing a counterfactual reference baseline evolution of the Earth's energy, economic and land systems as they might develop over the remainder of the 21st century in the absence of new policies whose primary purpose is limiting climate change. Through a set of structured sensitivity exercises we explore the effects of climate policy stringency, technology availability and policy architecture on technology choice, technology deployment timing, and economic cost of limiting human climate forcing. Our experimental design to gain insights in these three domains is as follows.

Policy Stringency: We limit climate forcing to two alternative levels, 450 ppm carbon dioxide equivalent (CO_2-e) and 650 ppm CO_2-e. We assume that all mitigating regions employ a carbon tax that is applied uniformly to all emissions sources and is used to reward all permanent removals of carbon from the atmosphere (e.g. terrestrial sequestration via afforestation). However, we assume regions of the world join an emissions mitigation coalition over time as discussed in Section 3.2. We also assume that a full set of energy technologies including CO_2 capture with geologic storage (CCS) and nuclear power are available for deployment by society. (We relax that assumption when we explore technology availability below.) Against this background, we compare the implications for energy and land system transitions implied by the two alternative levels of climate forcing limits.

Technology Availability: Many technologies are capable of producing energy services with reduced or without climate forcing emissions. However, all technologies are different bundles of characteristics including technology performance, technology cost, ancillary emissions, other environmental and health concerns, labor requirements, and capital intensity. It is possible that any given technology will be, for some reason, unavailable, either because it failed to meet the test of the market or because society consciously chose not to deploy it. To explore the implications of technology availability we chose two technologies that could potentially play a large role in a climate-constrained world, CCS and nuclear power. We begin with the 650 ppm CO_2-e climate forcing scenario described above and compare it with two alternative technology suites one which excludes CCS and the other which excludes both CCS and nuclear power. We report implications for the timing and scale of deployment of other technologies and economic cost implications of these alternative suites.

Policy Architecture: Many emissions mitigation proposals consider a portfolio of policy instruments, e.g. the European Union's "20-20-20" energy policy (Commission of the European Communities, 2007). We consider the implications of broadening international participation and extending the degree of ambition over time of the European Union's 20-20-20 energy and climate policy architecture. We compare the effectiveness of this policy architecture to the conventional carbon tax regime and explore implications for technology deployment, environmental performance and economic cost.

Numerical Experiments: We explore the three dimensions of climate policy using the Global Change Assessment Model GCAM (Calvin et al, 2011). A brief summary of the chief characteristics of GCAM 3.0 are useful for the reader to appreciate both the capabilities and limitations of the modeling environment we have employed in this chapter.

GCAM 3.0 is a coupled integrated assessment model (IAM) of human and biogeophysical Earth system processes relevant to climate change to conduct our numerical experiments (Calvin, et al., 2011). GCAM tracks emissions, atmospheric disposition, radiative and climate effects of 16 greenhouse gases, aerosols and short-lived species. It is an IPCC-class IAM; that is, it can produce all of the information needed by state-of-the-art climate models for future climate projections. In fact, GCAM and its progenitor models have participated in the development of ALL of the IPCC scenarios (e.g. IPCC, 1989; Leggett, et al., 1992; Nakicenovic and Swart, 2000; and van Vuuren et al., 2011).

GCAM is a dynamic-recursive model, which links a fully-coupled global energy-economy-agriculture-land-use model with a climate model of intermediate complexity and is a direct descendent of the Edmonds-Reilly model (Edmonds and Reilly, 1985). GCAM subdivides the world into fourteen regions and operates from 2005 to 2095 in five-year increments. The agriculture and terrestrial system (Wise and Calvin, 2011 and Kyle, et al., 2011) further subdivides each of the GCAM's fourteen geopolitical regions into as many as eighteen sub-regions, based on the agro-ecological zones described by Monfreda et al. (2009). The GCAM simultaneously determines a consistent set of market-clearing prices for all energy, agricultural and forest products. GCAM computes the supply and demand for primary energy forms (e.g., coal, natural gas, crude oil), secondary energy products (e.g., electricity, hydrogen, refined liquids), several agricultural products (e.g., corn, wheat, rice, beef, poultry, etc.) and three different sources of bioenergy supply (a cellulosic crop, crop residues, and municipal solid-waste) (Luckow et al., 2010). The GCAM model assumes global trade in fossil fuels and agricultural products, and tracks emissions of a full suite of gases and reactive substances from a variety of human activities.

3.1 The Reference scenario

All of the scenarios discussed here are departures from a single counterfactual reference scenario which describes a potential evolution of the global energy, economic and land systems in the absence of new policies to limit anthropogenic climate change. While the reference scenario is clearly unlikely in that it is hard to imagine that no new climate policies to limit human emissions of climate forcing agents would be imposed anywhere through the remainder of the 21st century, it is nonetheless a useful counterfactual scenario. Comparisons to it help illuminate the degree to which a world with climate policy must evolve differently than a world without additional climate mitigation policies.

The reference scenario is shaped by assumptions regarding the human population, scale of economic activity, resource availability and the suite of technologies available to provide energy services. These assumptions define the background against which human society might evolve over decade to century time scales. We use the Global Change Assessment Model (GCAM) version 3.0 to represent the relationship between those assumptions and the energy, economic and land systems.

We have chosen a set of assumptions that correspond to those used in Thomson et al. 2011. The Representative Pathway 4.5 (RCP 4.5) is an important scenario that every climate model was required to examine for the IPCC 5th Assessment Report (AR5). RCP 4.5 is a scenario that stabilized human climate forcing at 4.5 Wm^{-2} by the end of the century without exceeding this limit at any time during the century. 4.5 Wm^{-2} is the same thing as 650 ppm CO_2 equivalent (CO_2-e). Though RCP 4.5 used a version of GCAM 2, GCAM has undergone substantial improvements in many areas, though its most prominent improvement is in its representation of land system processes, important for understanding the role of terrestrial carbon sequestration, bioenergy production and land surface physical climate effects.

Population and labor productivity growth assumptions help shape the scale of human activities. Our assumptions are shared by all scenarios and shown in Figure 3.1. Global population is assumed to grow from its present level, less than 7 billion people, to a peak in excess of 9 billion people, before declining to less than 9 billion people by the end of the century. OECD nations' populations represent an ever decreasing share of the world's population. We assume that population growth in Asia goes through a peak and decline, with African populations having the latest demographic transition.

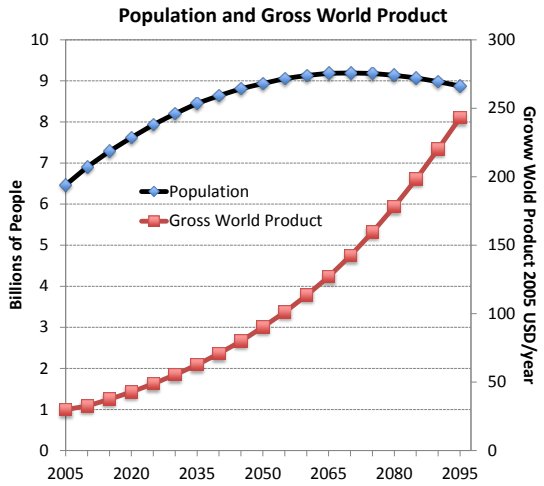


Figure 3.1 Global Population and Gross World Product Assumptions

Gross World Product is assumed to expand steadily throughout the remainder of the 21st century. The role of Asia initially grows most rapidly but eventually economic development in Africa and other developing economies begins to accelerate as well. While a wide range of per capita incomes are assumed to remain at the end of the 21st century, the relative disparity is assumed to diminish.

Technology is assumed to improve throughout the 21st century. Energy and agricultural technology performance assumptions are shown in Table 3.1 and are based on Clarke, et al. (2007). A full suite of technologies are assumed available including, wind power, solar power (thermal, PV, and distributed), geothermal power, nuclear power, and bioenergy (purpose grown, municipal solid waste, and crop residues). Emissions mitigation scenarios in the following sections have access to CO_2 capture and storage (CCS) technology, deployable for use with any large point-source emitter. CCS technology do not deploy outside of the context of a climate policy as it adds costs without a corresponding revenue stream absent a value on carbon or explicit regulatory policy.

Bioenergy is an energy carrier which is treated as a renewable energy form by the energy sector.[4] (In climate policy scenarios it can be used in combination with CCS technology, as bioenergy with CCS (BECCS), to deliver energy and fuels with net negative emissions. We consider a variety of BECCS technology options including power production, fuel refining, and long-lived feedstocks, e.g. plastics).

[4] Note that we track any emissions associated with clearing land for its production in the agriculture and land-use component of GCAM.

Table 3.1 Energy and Agricultural Technology Performance Assumptions

Technology	Assumed Performance
Fossil Fuel Extraction	Extraction costs of coal, oil, and gas resource drop by 0.75% per year
Advanced Grid for Renewable Tech	1:1 backup required when renewables supply 50% of capacity
Solar Tech	Capital and O&M costs decline at a faster rate (double)
Wind Tech	Capital and O&M costs drop at 0.5% per year
Geothermal Tech	Faster improvement in hydrothermal / EGS available with the improvement rate of 0.5% per year or more
Nuclear Power	Lower capital recovery factor with capital and O&M costs declining at 0.3% per year
Carbon Capture & Storage (CCS)	Lower-cost non-tradable regional land-based storage with larger capacity, expensive global-access offshore storage
Building Tech	Faster improvements in end-use efficiencies
Transportation Tech	Faster declines in fuel intensities in all modes
Industry Tech	Faster improvements in end-use efficiencies
Crop Production	Crop yield improvements converging to 0.25% per year by 2050

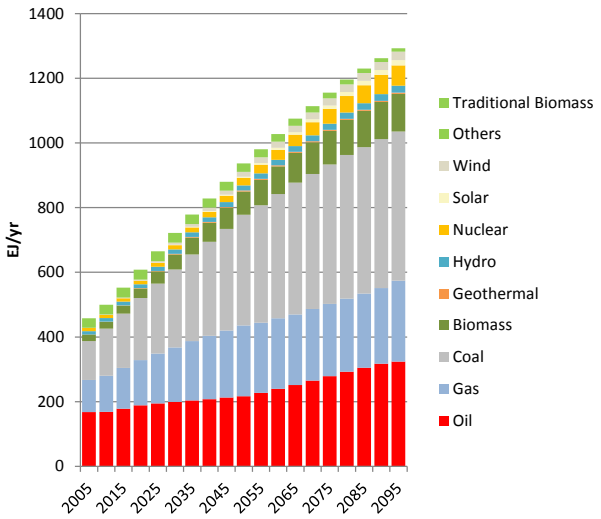


Figure 3.2 Reference Scenario Global Total Primary Energy Production and Consumption

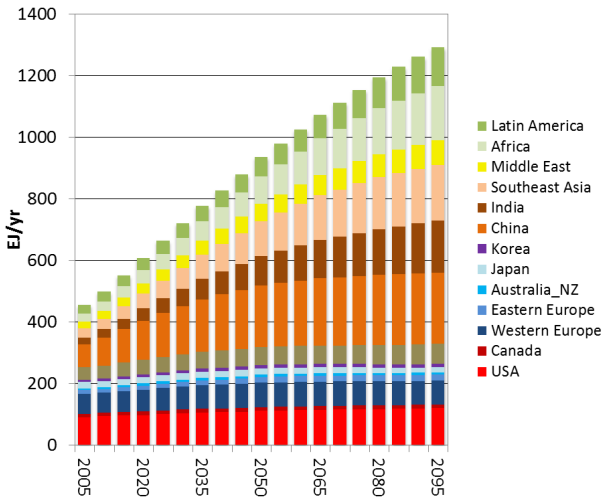


Figure 3.3 Regional Distribution of Reference Scenario Global Primary Energy Consumption

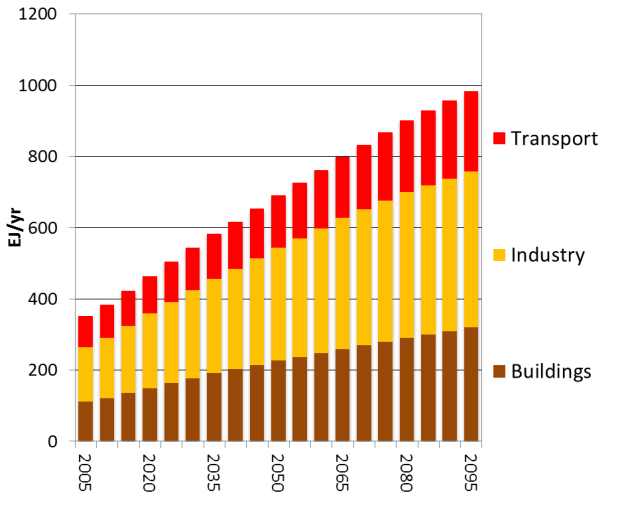


Figure 3.4 Reference Scenario Global End-use Energy Consumptions

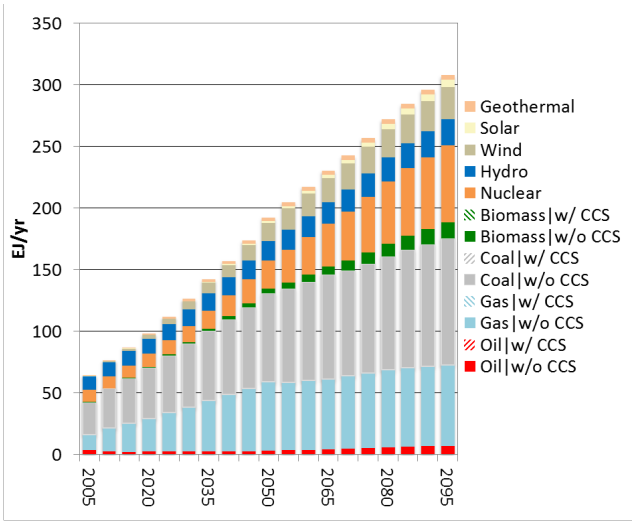


Figure 3.5 Reference Scenario Global Total Electricity Generation by Fuel

3.1.1 The Reference Scenario Global Energy System

The reference scenario global energy system grows by almost a factor of three, from slightly more than 450 EJ/yr in 2005 to almost 1300 EJ/yr in 2095, see Figure 3.2. Growth in global energy consumption is distributed unevenly around the world. Regions such as the United States and Western Europe stabilize energy use near mid-century, while developing economies such as China, India, and Africa experience much more rapid economic and energy system growth, Figure 3.3. All end-use sectors of the global economy expand energy use, by more than a factor of two, Figure 3.4. End-use energy demand grows somewhat less rapidly than energy use in total due to the increasing share of power in the end-use energy mix.

All energy forms experience increased production over the century in our reference scenario. Coal use grows more rapidly than average, driven by growth in the demand for electric power, Figure 3.5, and the relatively abundant and inexpensive supply of coal. Renewable energy forms also grow more rapidly than average driven by increasing demands for electric power and declining costs of supply. Since nuclear power is assumed to be deployed in the reference scenario based solely on its costs of production, its deployment also increases.

3.1.2 Land use

The terrestrial system evolves gradually in the reference scenarios, Figure 3.6. Growth in population and income places increasing demands on the world's lands for food and fuel. Improving crop yields offset increasing demands for land. However, as per capita incomes rise, particularly in developing economies, demands for protein increase, expanding demands for pastureland as well as lands for crops to feed livestock. Land-use change emissions are small, but positive through the first half of the 21st century. Emissions decline in the second half of the century as crop yields eventually catch up with demands for agricultural land and demands for pastureland saturate, Figure 3.7. Land-use change emissions decline and become slightly negative by the end of the century. Fossil fuel and industrial emissions continue to increase throughout the century and represent the dominant source of emissions. Total more than double, reflecting the dominance of fossil fuels in the global energy system.

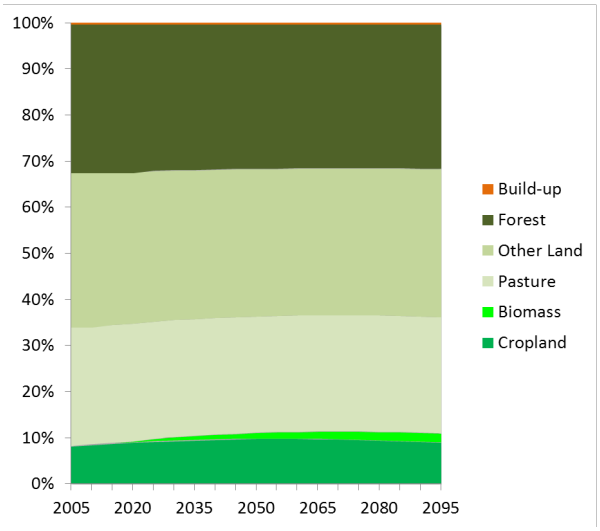


Figure 3.6 Global Land use in the Reference Scenario

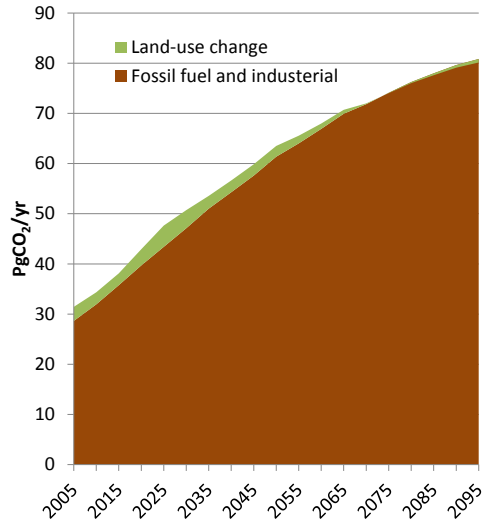


Figure 3.7 Carbon Emissions from Fossil Fuels and Industrial Sources and from Land-use Change

3.1.3 Greenhouse Gas Concentrations and Temperature Change

Greenhouse gas emissions and concentrations rise throughout the 21st century in the reference scenario. This rise is shown in Figure 3.8. CO_2 equivalent concentrations rise from their 2010 level of approximately 394 ppm CO_2-e to more than 980 ppm CO_2-e in 2095. Atmospheric CO_2 concentrations (not including the equivalent additional effects of non-CO_2 greenhouse gases and short-lived species) rise from approximately 389 ppm CO_2 to 811 ppm CO_2. The increasing disparity between CO_2 only concentrations and equivalent concentrations from all human system emissions grows over time. This is due to reductions over time in emissions of sulphur aerosol emissions, which exert a cooling (negative forcing) effect on the Earth's climate.

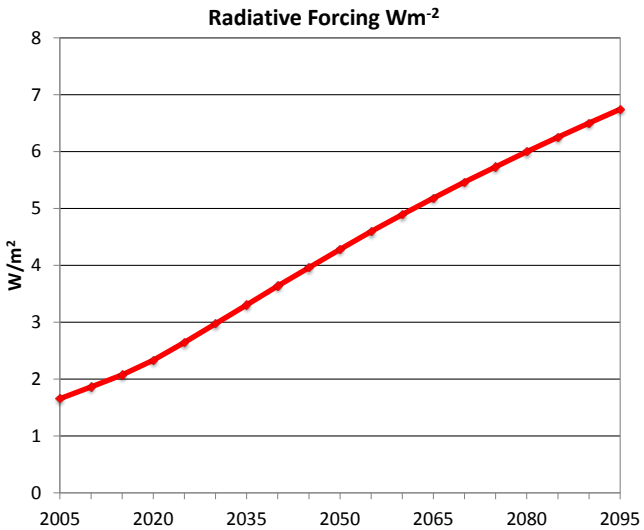


Figure 3.8 Reference Scenario Radiative Forcing From Atmospheric Constituents (Preindustrial Forcing is 0.0)

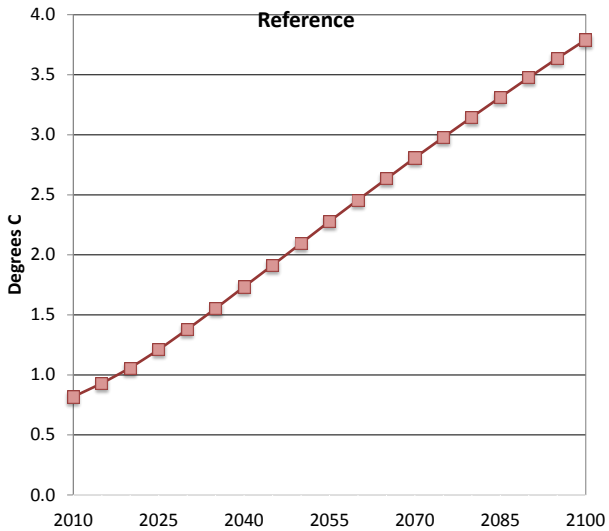


Figure 3.9 Reference Scenario Global Average Surface Temperature Change Relative to Pre-industrial (Climate Sensitivity = 3.0)

The average Earth surface temperature rises over time tracking climate forcing. Assuming a climate sensitivity (the change in the average Earth surface temperature change from each doubling of the concentration of CO_2 in the atmosphere) of 3.0, the deviation from preindustrial average Earth temperature exceeds 3.5 degrees Centigrade by 2095. This change greatly exceeds goals set by the international political process which focus on limiting average Earth surface temperature change relative to pre-industrial levels to two degrees Centigrade or less. In fact, the two-degree level is reached by mid-century.

3.2 Policy Stringency Implications: The 450 ppm and 650 ppm scenarios

To better understand the implications for energy, economic and land system transitions of pursuing alternative long-term policy objectives, we created two contrasting sensitivity experiments. Each limits climate forcing at the end of the 21st century, but one limits it to 450 ppm CO_2-e (2.6 Wm^{-2}) and the other limits it to 650 ppm CO_2-e (4.5 Wm^{-2}). 450 ppm CO_2-e is generally taken to be consistent with limiting global mean surface temperature change to two degrees centigrade with more than 50 per cent likelihood. The scenarios also correspond to the two lower, year-2100 limits (of four) that climate models have explored in the IPCC 5th Assessment Report.

We limit greenhouse gas emissions so as to yield corresponding atmospheric concentrations to levels that are either 450 ppm CO_2-e or 650 ppm CO_2-e at the end of the 21st century. We restrict the 650 ppm CO_2-e scenario never to exceed the target's equivalent CO_2 concentration. However, the 450 ppm CO_2-e limit is sufficiently stringent that we allow equivalent concentrations to exceed the end-of-century limit in earlier years. The difference in the shape of the two different time-paths is shown in Figure 3.11.

We assume that a common carbon-equivalent tax is applied to all emissions of greenhouse gases equally in every region and sector that is engaged in emissions mitigation. At any point in time the carbon-equivalent tax is equal everywhere and in every sector.

An important feature of ALL global LinkS scenarios in which carbon-equivalent taxes are applied is that we bring ALL emissions sources under the control regime. That includes fossil fuel, industrial and land-use change emissions. Greenhouse gases and short-lived species emissions are valued using Global Warming Potential (GWP) coefficients to compare across gasses. Applying the same price to land-use change emissions as other emissions carries with it important implications for land use and the composition of diets as discussed in Wise, et al. (2009). It also means that indirect land-use change emissions are not an issue in this part of the policy regime for those regions that are participating in the regime, since they are directly prices. However, interaction between participating and non-participating regimes through land-use carbon emissions leakage is an issue (Calvin, et al., 2009; Edmonds, et al., 2013).

3.2.1 International Participation in Emissions Mitigation Regimes

While we employ an idealized policy instrument to penalize emissions and reward sequestration and net removal of carbon from the atmosphere, we assume that the world's regions undertake emissions mitigation in a delayed manner. That is we assume that regions join an emissions mitigation coalition in the order used in the EMF22 study, Clarke, et al. (2009) shown in Figure 3.10.

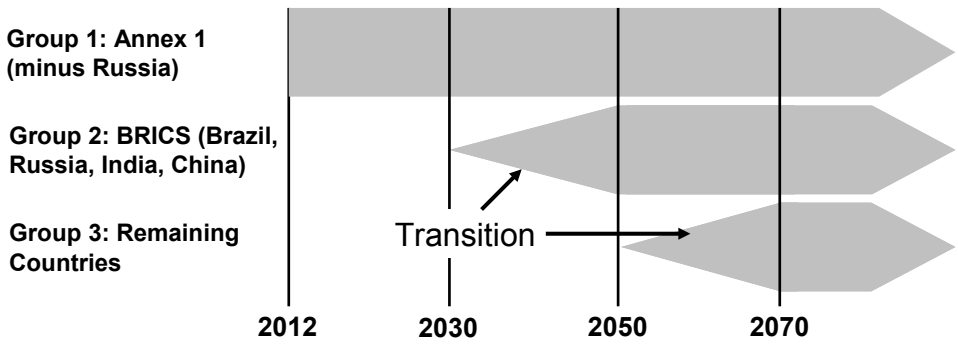


Figure 3.10 EMF22 Accession Regime

3.2.2 Implications of Policy Stringency for Atmosphere and Climate Forcing

Limiting radiative forcing limits climate change. Emissions pathways for the two policy scenarios are shown in Figure 3.12 and Figure 3.13. The peak and decline nature of the CO_2 emissions pathways are evident in both policy scenarios. The relatively stable emissions in the final decades of the century under the 650 ppm CO_2-e scenario reflect the nature of the scenario limit, which achieves a stable CO_2-equivalent concentration shortly after the middle of the century. It is also something of an artifact of interactions with non-CO_2 emissions. Beyond the end of the century, carbon emissions must resume their decline to maintain a stable CO_2 concentration. In the long term, 1000-year time scales, CO_2 emissions must be zero for the CO_2 concentration to be constant.

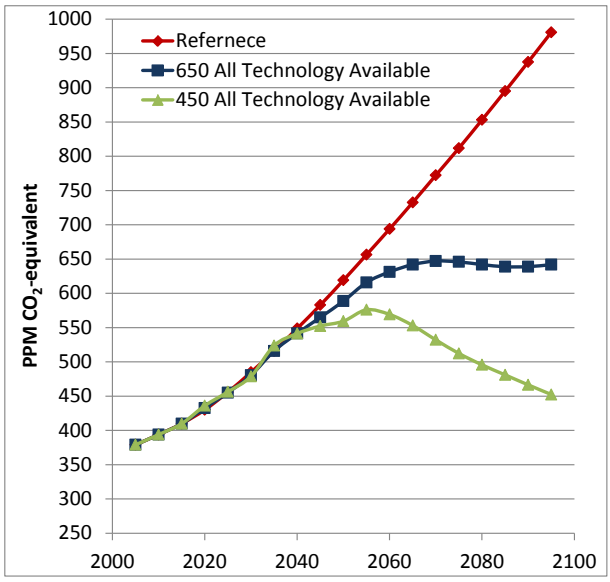


Figure 3.11 Time Path for Climate Forcing for Reference and Two Emissions Control Scenarios with 650 and 450 ppm CO2-e Limits

The 450 ppm CO_2-e policy scenario exhibits substantial negative total emissions beginning in 2060. Negative emissions are needed to draw down atmospheric CO_2 concentrations, which peak at approximately 500 ppm in 2055. By the end of the century CO_2 concentrations have declined to 382 ppm, more than 60 ppm below the equivalent concentration level. Negative emissions are accomplished through the use of bioenergy in combination with CCS.

Terrestrial systems play an important role in limiting climate forcing. Terrestrial systems account for carbon stocks in excess of 7,000 $PgCO_2$-e (2,000 PgC). The application of a carbon value induces significant land-use change. Cumulative emissions are given in Table 3.2 below. Cumulative land-use change emissions are positive in the reference scenario, but negative in the policy scenarios. That is, on balance carbon sequestration is occurring in terrestrial systems.

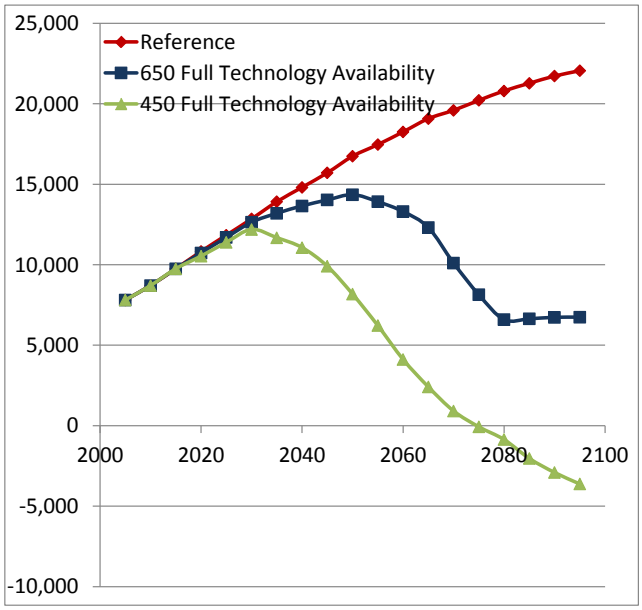


Figure 3.12 Global Fossil Fuel and Industrial Emissions Paths: Reference, 650 ppm CO_2-e and 450 ppm CO_2-e (TgC/yr)

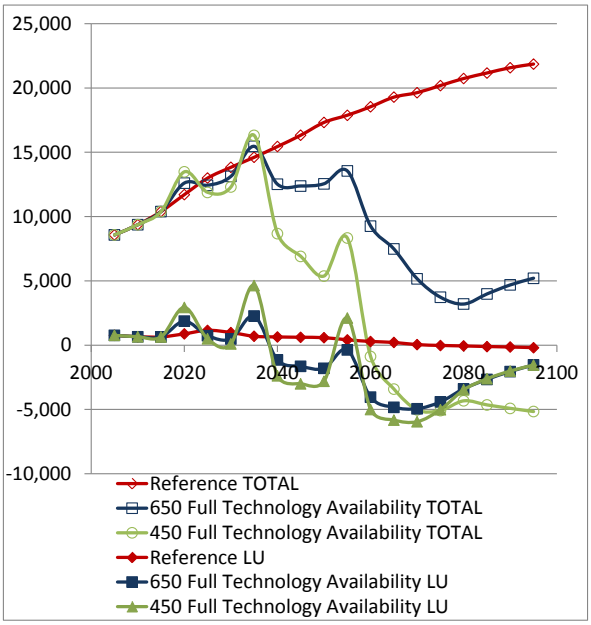


Figure 3.13 Total Human CO_2 Emissions and Land Use Change Emissions Paths: Reference, 650 ppm CO_2-e and 450 ppm CO_2-e (TgC/yr)

Note, however, that the path of net global land-use change emissions is not smooth. It is characterized by peaks and declines, Figure 3.13. Each peak is associated with the expansion of the emissions mitigation coalition and associated land-use emissions leakage as discussed in Calvin, et al. 2009 and Edmonds, et al., 2013. The expansion of the mitigation coalition to new regions means that the new regions immediately value terrestrial carbon in addition to fossil fuel and industrial emissions. The carbon price provides the incentive needed to cease deforestation and expand afforestation (carbon sequestration).

Table 3.2 Cumulative Carbon Emissions 2005 to 2095 (PgC)

Scenario	Fossil fuel & industrial	Land-use Change	Total
Reference	1442	38	1,481
650 ppm CO_2-e (Full Tech)	969	-124	843
450 ppm CO_2-e (Full Tech)	517	-134	382

Since land surface is limited, the expansion of land into sequestration systems raises global food prices and creates an incentive for non-mitigating regions to expand their land under crop cultivation through land clearing engendering the “spike” in land-use change emissions. Sequestration activities in the mitigation coalition immediately begin to draw down land-use change emissions, once again reducing net global land-use change emissions. Hence, we observe the “spiky” behavior of land-use change emissions. Eventually the mitigation coalition expands to include all regions, ending the leakage pattern and insuring that land-use change emissions remain negative for the remainder of the century.

3.2.3 Carbon Prices

Figure 3.14, are used to limit greenhouse gas emissions and encourage sequestration of carbon in the two policy scenarios we consider. The magnitude and time profile of the two price paths differ. In the 650 ppm CO_2-e mitigation scenario the carbon price reaches $100 per ton of CO_2 in 2080 and declines slightly thereafter. That price is reached thirty years earlier in the 450 ppm CO_2-e scenario and continues to rise throughout the century.

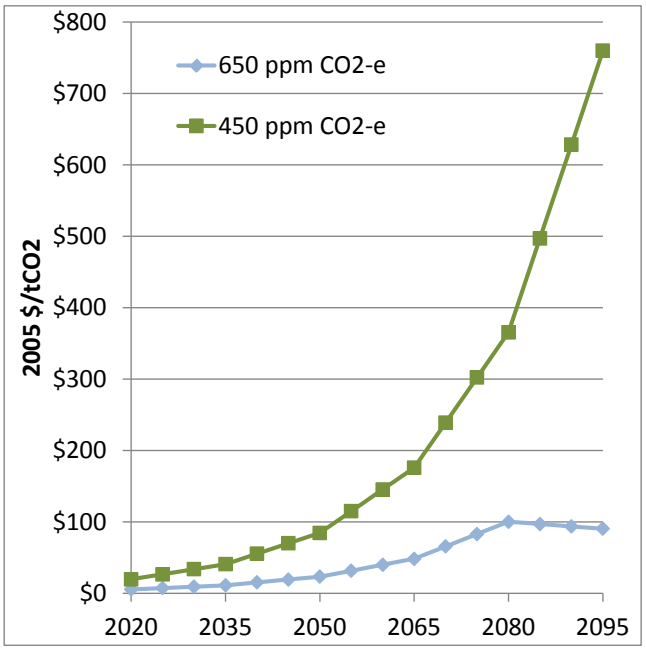


Figure 3.14 Carbon Dioxide Prices Associated with Two Climate Policy Scenarios

3.2.4 Implications of Policy Stringency for the Global Energy System

Global primary energy use changes with the application and stringency of the emissions mitigation policies as shown in Figure 3.15, Figure 3.16, Figure 3.17, and Figure 3.18.

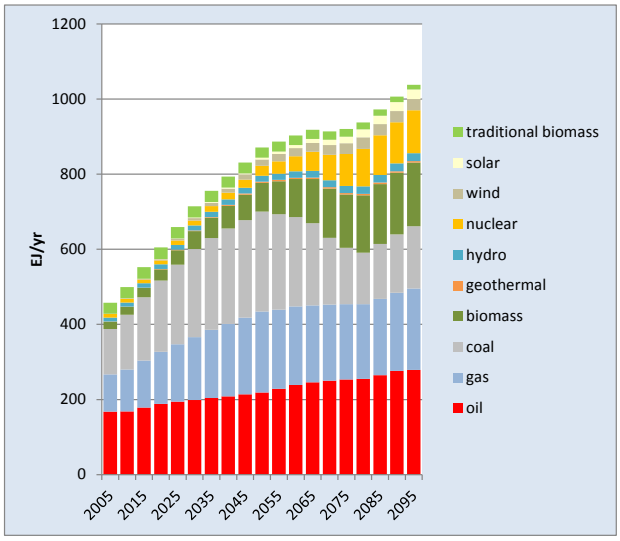


Figure 3.15 Global Primary Energy by Source: 650 ppm CO2-e

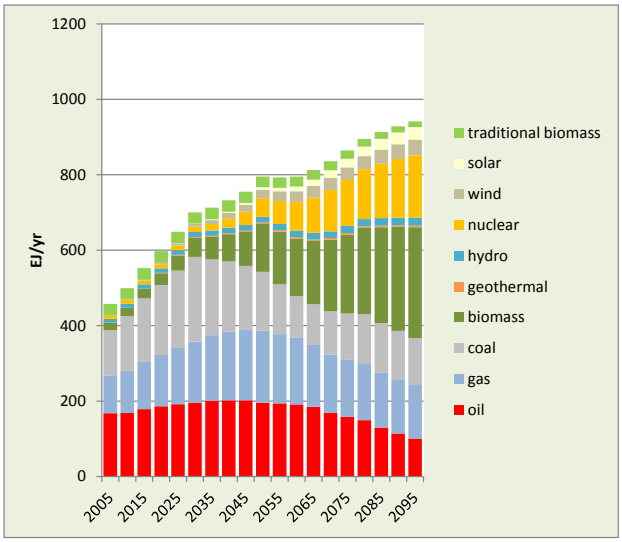


Figure 3.16 Global Primary Energy by Source: 450 ppm CO2-e

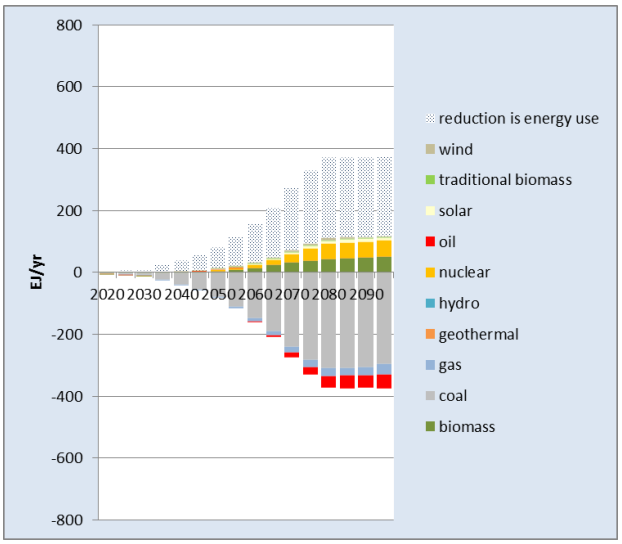


Figure 3.17 Change in Global Primary Energy by Source compared to Reference: 650 ppm CO2-e

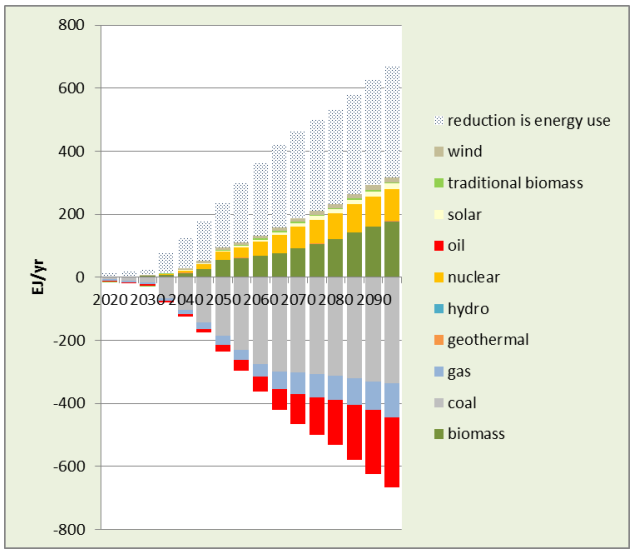


Figure 3.18 Change in Global Primary Energy by Source compared to Reference: 450 ppm CO2-e

Coal use is substantially curtailed by mid-century in both policy scenarios. However, oil use exhibits greater reductions in the second half of the century in the 450 ppm CO_2-e scenario compared to the 650 ppm CO_2-e case. Similarly, less gas is used in both mitigation scenarios with the more stringent scenario utilizing less than the 650 ppm CO_2-e case. The more stringent scenario deploys more nuclear power and bioenergy than the less stringent mitigation case.

Carbon prices induce a substitution in end use sectors toward the use of electric power because the price of electric power rises less rapidly than the price of fossil fuels. As climate policy becomes more stringent, power generation grows, Figure 3.19 and Figure 3.20.

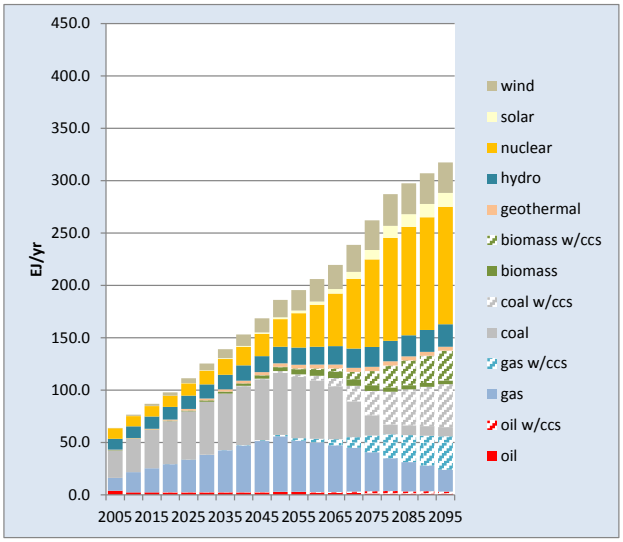


Figure 3.19 Global Electric Power Generation by Source: 650 ppm CO2-e

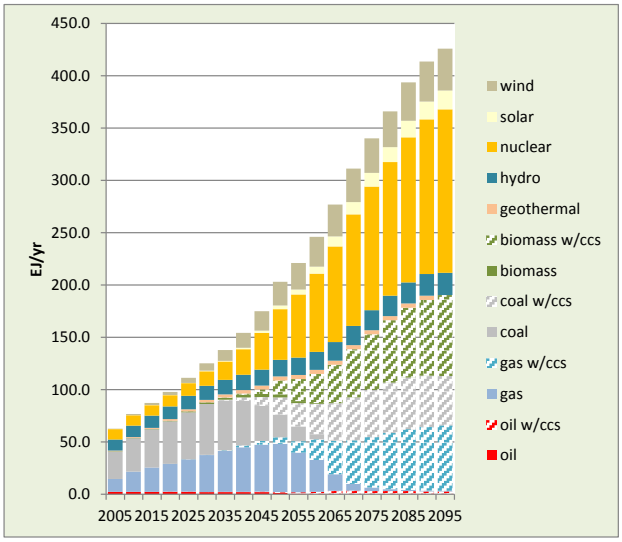


Figure 3.20 Global Electric Power Generation by Source: 450 ppm CO2-e

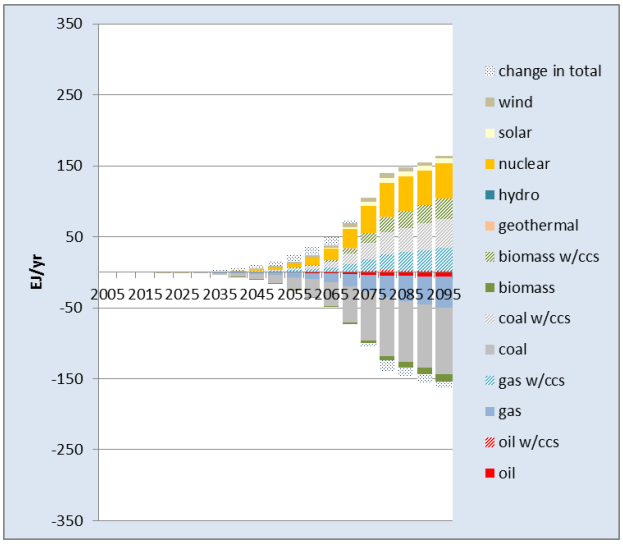


Figure 3.21 Change in Global Power Generation by Source compared to Reference: 650 ppm CO2-e

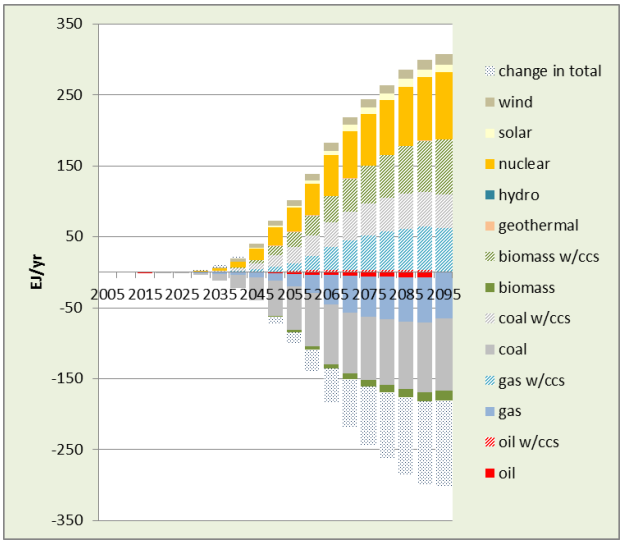


Figure 3.22 Change in Global Power Generation by Source compared to Reference: 450 ppm CO2-e

The composition of the fuels used to generate power also changes, Figure 3.21 and Figure 3.22. In both policy scenarios the use of coal without CCS virtually disappears. Some use of gas without CCS continues throughout the century in the 650 ppm CO_2-e scenario, but CCS dominates gas use after the middle of the century. The more stringent the policy, the more dramatic is the difference with the reference scenario. Bioenergy is deployed in conjunction with CCS increasingly as time passes. While fossil fuels do not dominate power generation as completely as they did in the reference scenario, the availability of CCS technology allows for their continued use.

When all technology options are available, bioenergy plays an important role in limiting emissions and controlling climate forcing. First, it is a renewable feedstock. Hence, it has no direct emissions, though it can have indirect emissions including those associated with cultivation and indirect emissions associated with changes in land use.

Bioenergy use, particularly non-traditional bioenergy use, expands in response to the carbon price. Higher carbon prices induce higher bioenergy production and use Figure 3.23. Whether or not this results in greater land employed for crops whose primary purpose is bioenergy depends on both the bioenergy price and the carbon price, though the joint production of bioenergy with other products, e.g. forest products and biofuels, and dual use products, e.g. corn which can be used either as a biofuel feedstock or crop, complicate the measure of land in use for bioenergy production. Initial increases in the price of carbon induce a rapid change in land use, Figure 3.13. Regions participating in the emissions mitigation protocol expand forest area rapidly. At lower bioenergy prices, the increase in bioenergy comes from increased use of crop residues and waste streams. As the price of bioenergy rises, purpose-grown bioenergy crops become competitive with terrestrial sequestration. The two then begin to expand together, Figure 3.24.

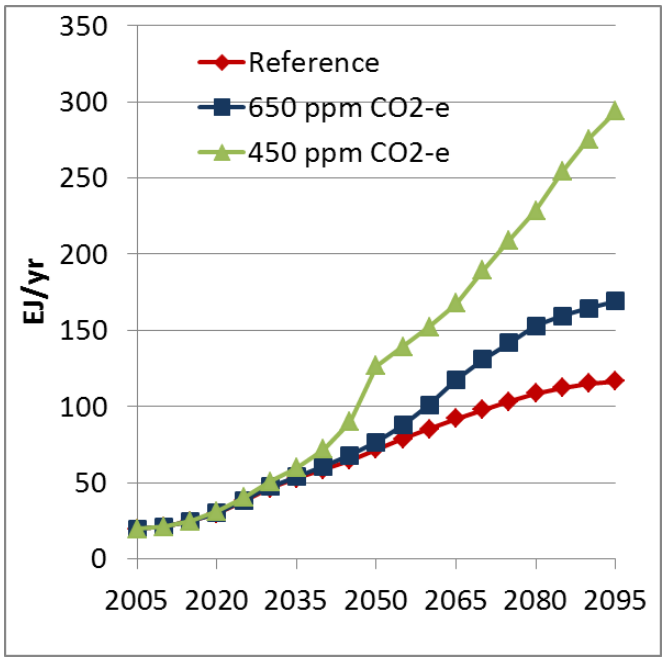


Figure 3.23 Global Non-Traditional Bioenergy Production: Reference, 650 ppm CO_2-e and 450 ppm CO_2-e

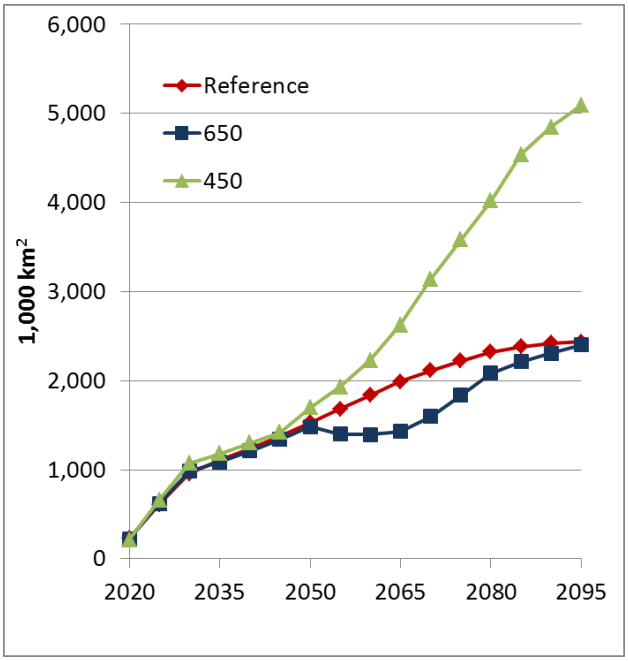


Figure 3.24 Land Area Used to Grow Bioenergy Crops: Reference, 650 ppm CO_2-e and 450 ppm CO_2-e

Many researchers have pointed out that the expansion of bioenergy production can have the consequence of increased deforestation, referred to as indirect land-use change emissions (ILUC). ILUC occurs in the scenarios we have developed whenever a new region joins the mitigation coalition, as discussed above. At the end of the century, when all regions of the world are part of the mitigation coalition, ILUC ceases to be an issue, as all carbon in the world is under the emissions mitigation regime and there is nowhere in the world for it to migrate. Hence, as shown in Figure 3.13 and Table 3.2, terrestrial carbon is actually sequestered net over the course of the scenario. Of course, the problem of land-use leakage during the period in which incomplete participation in the mitigation regime is a problem, Figure 3.13.

The finiteness of land availability also affects the price of food crops. Since the value of carbon is embedded in all land, it is also embedded in the prices of products derived from the land. Crop prices, Figure 3.25, track carbon prices, Figure 3.27. Without the carbon price crop prices actually decline as a result of the assumed rate of crop yield improvement, Table 3.1. While the effects of these price increases are mitigated by the fact that incomes are also rising, that is small comfort to those at the bottom of the income distribution. This finding highlights the inevitable trade-offs that emerge as a consequence of finite resource availability in the face of competing alternative uses.

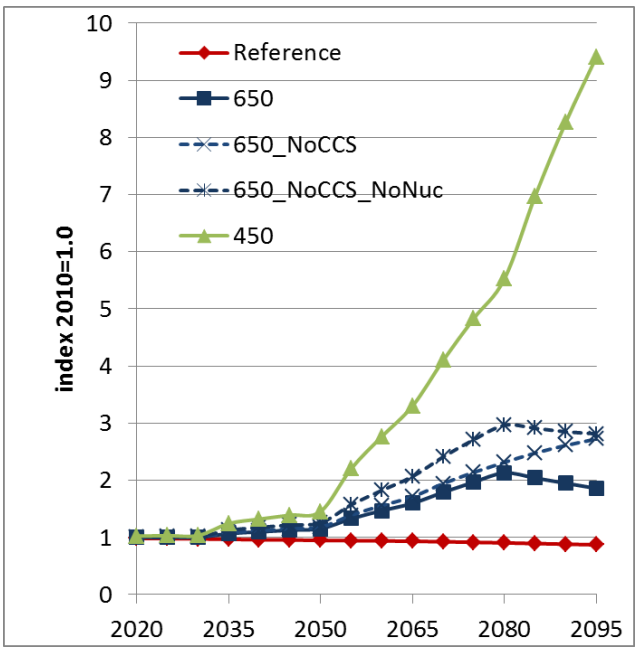


Figure 3.25 World Market Price for Wheat: Reference, 650 ppm CO_2-e and 450 ppm CO_2-e

3.3 Technology Availability Implications

In the previous section of this chapter we observed that when all technology options were available to reduce carbon emissions, both nuclear power and CCS deployed extensively. It is conceivable that for one reason or another these technologies might not be available. In this section we explore the implications of technology availability for the energy system and land use.

We begin by considering the implications of a technology suite without CCS, but with all other technologies available. We next consider the consequence of a technology suite that contains neither CCS nor nuclear power options.

Our approach is to run the scenarios precisely as they were outlined in the previous section. That is we run the scenarios limiting radiative forcing to 650 ppm CO_2-e, with the same accession rules and the same use of the carbon price as the policy instrument. The only difference is that in each scenario we change technology availability and compare the results.

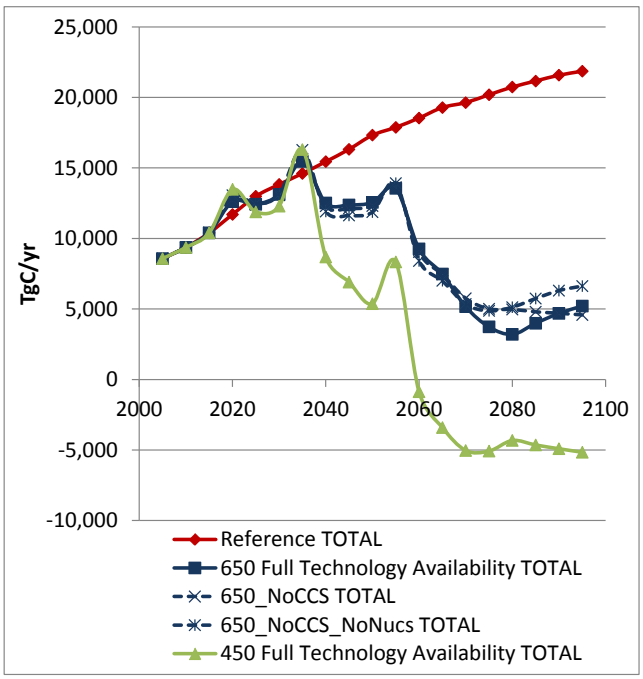


Figure 3.26 Total Carbon Emissions for the Reference Scenario, 450 ppm CO_2-e, and Three Alternative Technology Availability Assumptions

3.3.1 Implications of alternative technology assumptions for emissions and carbon prices

Little effect is observed for the time path of carbon emissions, climate forcing, and global average surface temperature as a consequence of changing the suite of available technologies, Figure 3.26. This is as might be anticipated in that the climate forcing limit itself and the unchanged policy instrument leave little room for difference on aggregate scales for these variables.

On the other hand, the carbon price needed to limit radiative forcing to 650 ppm CO_2-e rises as the technology portfolio becomes increasingly constricted, Figure 3.27. While removing both CCS and new nuclear builds from the technology set roughly doubles the carbon price relative to the full technology availability scenario, the increase is substantially less than observed when the full technology suite is available but the mitigation goal is 450 ppm CO_2-e. The marginal impact on the carbon price before the end of the century, of removing both nuclear and CCS from the technology portfolio over removing CCS alone, is large. This is due largely to the fact that each serves as something of a backstop for the other in power generation. If one is available it tends to take over power generation, while if neither is available power generation expands by utilizing technology options that draw on resources that exhibit increasing costs.

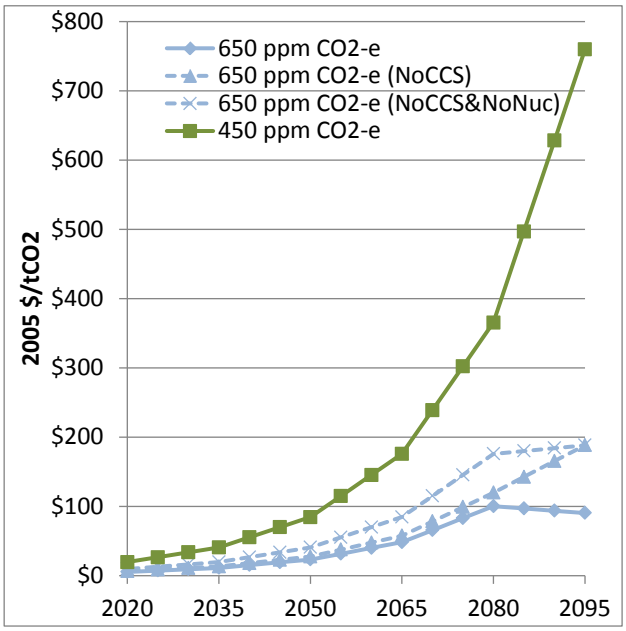


Figure 3.27 Carbon Price in Mitigating Regions: Reference, Three 650 ppm CO_2-e Technology Cases and 450 ppm CO_2-e

3.3.2 The energy and land use implications of alternative technology availability assumptions

The change in the global energy system is affected straight forwardly by the different technology availability assumptions. The change in the global energy system is displayed in Figure 3.28 for the three technology portfolio assumption sets used to examine limiting climate forcing to 650 ppm CO_2-e. Whereas the reference energy scenario produced and consumed more than 1200 EJ/yr in the year 2095, all three 650 ppm CO_2-e scenarios exhibit substantial reductions in total system magnitude. When all technologies are assumed available, the reduction in system scale is approximately 300 EJ/yr in 2095, roughly one fourth. Constraining technology choice reduced system scale by approximately half for both the 650 *NoCCS* and *NoCCS&NoNuc* technology scenarios.

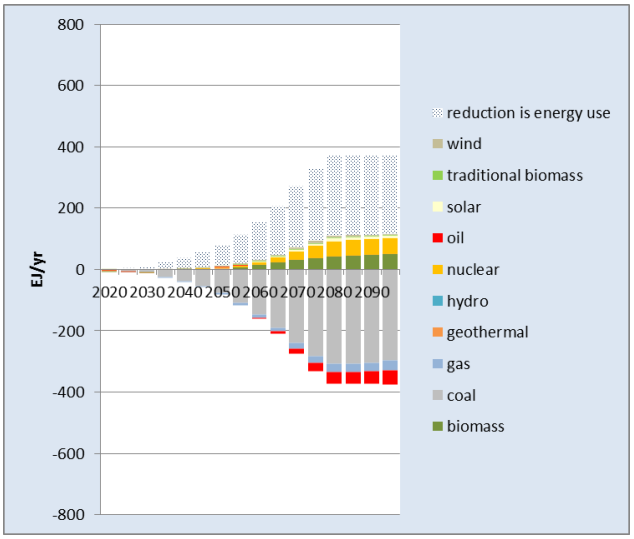
Coal production and use, which accounted for more than one-third of primary energy in the reference scenario in 2095, is cut in half in the 650 stabilization scenario with full technology availability, and is virtually extinguished in the 650 *NoCCS* and *NoCCS&NoNuc* technology scenarios. The role of nuclear power expands in the 650 *NoCCS* technology scenario, while it contracts in the *NoCCS&NoNuc* technology scenario. Renewable energy forms, such as wind, solar, and bioenergy expand their roles in the 650 *NoCCS* technology scenario and expand further in the *NoCCS&NoNuc* technology scenario.

Land use is affected by technology availability both directly through demand for bioenergy and indirectly through changes in the carbon price, which in turn affects terrestrial sequestration. Demands for bioenergy

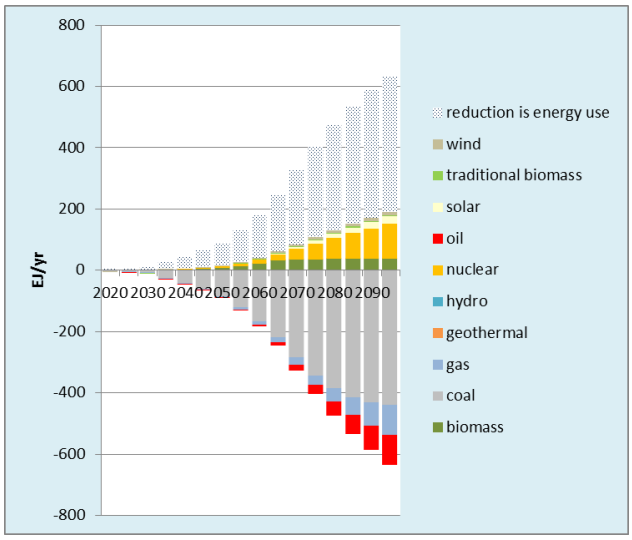
are similar in the three 650 ppm CO2-e scenarios with alternative technology availability assumptions. Demands are somewhat higher for the *NoCCS&NoNuc* technology scenario than for the 650 all technology scenario, but differences are on the order of 20 per cent or less. On the other hand the amount of land for bioenergy is smaller in the technology limited scenarios than in the 650 ppm CO2-e all-technology scenario. As discussed earlier, this is driven by interactions between the carbon and bioenergy prices, which are in a range where somewhat higher carbon prices under technologically constrained scenarios lead to greater terrestrial carbon sequestration, and shift bioenergy production toward increasing use of crop residues and waste streams as bioenergy sources in preference to purpose-grown crops.

3.3.3 Discussion of Technology Availability

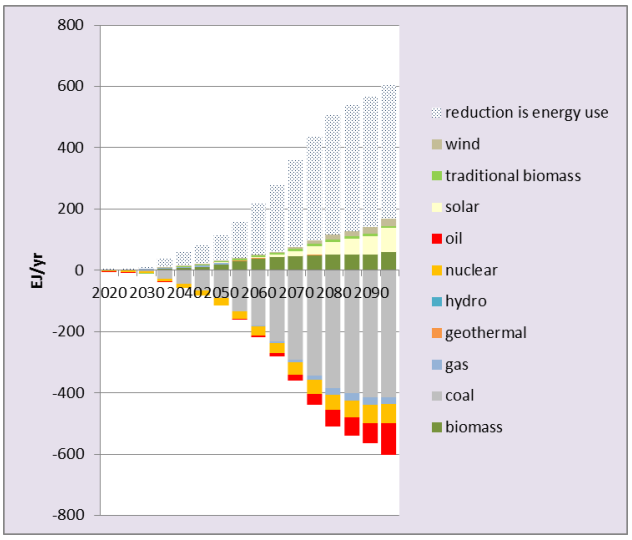
Technology availability clearly affects the global energy, land and economic systems. However differences in total land-use change emissions and global energy system emissions are much greater across the three technology stringency scenarios than across the three technology availability scenarios we explored. This is largely the result of the fact that all pathways to 650 ppm CO_2-e limits are highly constrained. Energy system changes were much more substantial. Changes in the global energy system across technology availability assumptions shown in Figure 3.28 are at least as great as changes between stabilization scenarios. Changes in prices such as those for wheat, Figure 3.25, which is a reflection of the carbon price, Figure 3.27, are less severe across technology availability assumptions than across stabilization levels.



a) 650 ppm Reference



b) 650 ppm NoCCS



c) 650 ppm NoCCS_NoNuclear

Figure 3.28 Comparison of changes to the global energy system over time for three alternative technology portfolio assumption sets stabilizing climate forcing as 650ppm CO_2-e

3.4 Policy Architecture Implications: The Global 20-20-20 scenario

To this point we have assumed that even if regions of the world were delayed in engaging in emissions mitigation, that once they began limiting emissions, they participated in an idealized policy architecture employing a common global carbon-equivalent emissions fee or in the case of sequestration, reward. Real world policy architectures are likely to vary from the ideal. For example, the European Council adopted energy and climate change objectives for 2020 referred to as the "EU 20-20-20" program. The program initiated policies and measures engaging a broad suite of policy instruments designed to reduce greenhouse gas emissions by 20% (potentially rising to 30%), to increase the share of renewable energy in final consumption to 20% and to make a 20% improvement in energy efficiency (Commission of the European Communities, 2007; European Commission, 2010).

The European Council has also set a long-term commitment to reduce carbon emissions by 80-95% by 2050 (European Commission, 2010), assuming that other industrialized nations join. In the EU, the energy sector is expected to contribute about 40% of this reduction by 2050 (European Commission, 2011).

The European Union employs the Emissions Trading System (ETS) as a mechanism for cost-effectively limiting greenhouse gas emissions. The EU 20-20-20 program is supplemented by additional directives, e.g. Commission of the European Union (Directive 2009/28/EC of 23 April 2009 on the promotion of the use of energy from renewable sources), and policies and measures that set standards for motor vehicle efficiency and fuel composition.

The EU energy and climate policy program is a potential model from other nations to follow. As such it represents an opportunity to explore the cost and effectiveness of policies that could be, and in this case have been, deployed in the real world. We have constructed a hypothetical protocol based on the EU program. We have extended the protocol in time and space, examining a program in which an increasing number of the world's regions adopt the EU approach as outlined in Table 3.3. The accession assumptions were worked out within the LinkS project among all of the member groups as a point of coordination. We refer to the hypothetical global policy based on the EU 20-20-20 program as the '*Global 20-20-20*' policy portfolio.

Table 3.3 Timing of Regional Participation and Determination of the Reference Year Emissions Mitigation and Establishment of Standards

First year in which climate mitigation policies and measures are introduced	Region	Reference Year
2020	• Eastern Europe • Western Europe	1990
2035	• Australia & New Zealand • Canada • China • Japan • S. Korea • USA	2005
2050	• Former Soviet Union • India • Latin America	2020
2065	• Africa • Middle East • Southeast Asia	2035

Global 20-20-20 Policies and Measures: We assume that four groups of policies and measures are implemented, beginning in Europe and then extending to other OECD regions and China, and then to the rest of the world. The four categories of policies and measures and associated degrees of stringency are given in Table 3.4. Each protocol stage or "period" is assumed to be 15 years. Standards are linearly tightened between periods.

Global 20-20-20 Policy 1: Greenhouse Gas Emissions Limits (GHG): We prescribe a limit on greenhouse gas emissions, defined in terms of CO_2 equivalent. We then impose a regional carbon-equivalent tax that limits emissions in each region to be no more than the limit prescribed in Table 3.4. It is well known that the carbon tax approach gives an equivalent result in terms of physical flow—energy production, use and land-use—to a "cap-and-trade" regime in which permits are required by emitters for all emissions (Coase, 1960). Activities that remove carbon from the atmosphere (e.g. terrestrial sequestration or bioenergy production) are rewarded at the same rate as activities that emit carbon to the atmosphere (e.g. fossil fuel burning or bioenergy use).

Table 3.4 Policies and measures examined in the Global 20-20-20 scenario

Policies and Measures	Implementation	First Period Commitment	Second Period Commitment	Third Period Commitment	Beyond the Third Period
GHG Emissions Limits	*Emissions reductions are measured relative to those in the 30 years prior to the 1st commitment period. (e.g. 1990 for Europe, 2005 for the USA)*	20%	50%	80%	80%
Renewable Energy Portfolio Standard	*Percentage of final energy that must come from renewable energy sources*	20%	50%	80%	80%
Biofuels Standard	*Percentage of transportation energy from biofuels.*	10%	25%	50%	50%
Energy Efficiency Standard	*Reduction in final energy demand relative to the reference scenario, other things unchanged.*	20%	50%	80%	80%

We denote this policy component as "GHG." By modeling the system as a tax regime, we avoid the problem of prescribing the allocation of permits, which has important implications for income distribution, but not for the national/regional production and consumption of goods and services.

Emissions limits are set relative to observed emissions in a previous, reference year as shown in Table 3.4. The emission limit for the first year in which a region imposes policies and measures is set as the level of emissions 30 years prior to that year, less 20 percent. For the U.S.A., which begins emissions mitigation in the year 2035, the reference year is 2005. For Western and Eastern Europe, which first impose these policies in 2020, the reference year is 1990. Since Africa joins in 2065, its initial emissions limits are prescribed as 80 percent of year 2035 emissions, Table 3.3.

Global 20-20-20 Policy 2: The Renewable Energy Standard (RES): The EU 20-20-20 target requires that there is at least 20% renewable energy in the *final energy demand*. This is implemented in the analysis such that a minimum fraction of final energy must be derived from the production of electricity using renewable energy forms such as wind, solar, geothermal, or bioenergy, or from liquid fuels produced from bioenergy.

Final energy consuming sectors are buildings, industry and transport. This standard differs from a conventional renewable electricity portfolio standard, which sets the fraction of electricity that must be derived from renewable energy forms in that not only must renewable energy be produced, but it must also be consumed. While this standard does not give explicit credit to the direct use of renewable energy in final energy consumption if they are not produced in the form of electricity, a separate standard for bioenergy use is included for the transportation sector as discussed below. Minimum percentages are given in Table 3.4.

Global 20-20-20 Policy 3: Transportation Renewable Energy Standard (TRES): A prescribed fraction of renewable energy is required to be employed in the transportation sector, see Table 3.4. This is implemented in the analysis such that a minimum fraction of transportation energy must be derived from the production of electricity using renewable energy forms such as wind, solar, geothermal, or bioenergy, or from liquid fuels produced from bioenergy.[5]

Global 20-20-20 Policy 4: End-use Energy Efficiency Standard (EE): We require improved performance of end-use energy systems. The required improvement is measured relative to the reference scenario. There are two potential approaches that could be taken to implement such a standard. We could prescribe standards for individual end use technologies and require those. Or, we could take a simpler approach, namely to arbitrarily improve the performance of all technologies as indicated in Table 3.4. We have implemented the EE using the latter method. This approach yields the correct physical system behaviors. However, we have no way to estimate the cost of achieving the improved performance.

3.4.1 Environmental Performance

The Global 20-20-20 hypothetical protocol in conjunction with its assumed pattern of accession to the mitigation coalition limited radiative forcing to a peak of slightly more than 4 Wm^{-2}, which declines for the remainder of the century, Figure 3.29.

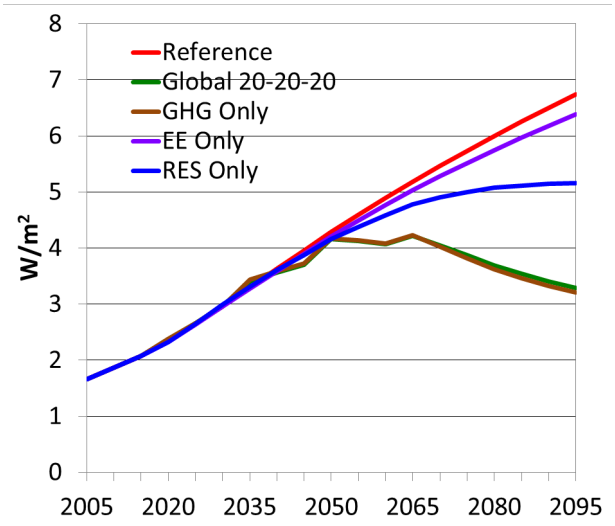


Figure 3.29 Radiative Forcing for the Global 20-20-20 Hypothetical Protocol and Three of Its Component Policies

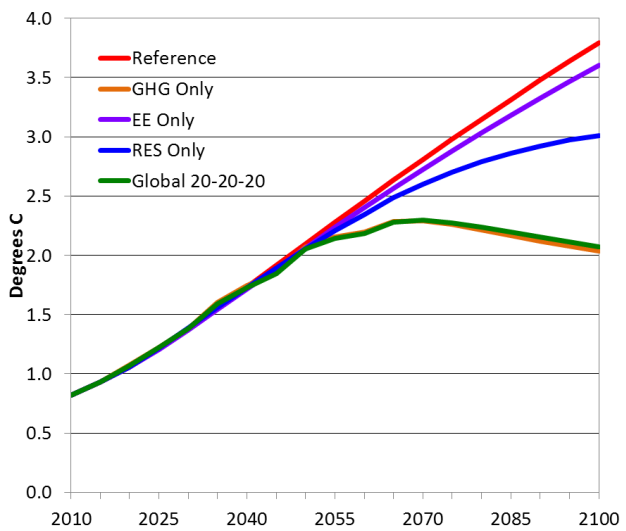


Figure 3.30 Global Average Surface Temperature assuming a Climate Sensitivity of 3.0°C/CO_2-doubling

[5] Note that this constraint is typically non-binding because it overlaps with the RES.

We estimate the implication for global average surface temperature change relative to pre-industrial assuming a climate sensitivity of 3 degrees per doubling of CO_2. We find that average global surface temperature change remains below 2.5°C and declines toward 2°C toward the end of the 21st century, Figure 3.30.

3.4.2 Energy and Land-Use Systems Implications

The global energy system is substantially different under the Global 20-20-20 hypothetical protocol than under the reference scenario. The scale of the global primary energy system is substantially reduced under the Global 20-20-20 protocol relative to the reference scenario. Reductions in primary energy use are on the order of one third, Figure 3.31 compared with Figure 3.32. On the other hand the power sector grows by more than a factor of two by the end of the century, Figure 3.33 compared with Figure 3.34. This is driven by the twin forces of a renewable energy portfolio standard and a carbon price that shifts end-use energy demand away from fossil fuels and toward electricity. The renewable portfolio standard dramatically increases the share of wind and solar power in the mix.

The largest changes in the system are observed after the year 2065 when all regions of the world are part of the emissions mitigation protocol. Substantially more renewable energy is used under the Global 20-20-20 scenario than in the reference scenario. Bioenergy production grows to 286 EJ/yr by 2095 compared with 117 EJ/yr in the reference scenario.

Land use is also substantially changed under the Global 20-20-20 scenario, Figure 3.36 compared to Figure 3.35. Bioenergy production is almost three times greater in the Global 20-20-20 scenario compared with the reference scenario. The land area devoted to purpose-grown bioenergy crops is more than double the reference scenario land allocation. In addition forested areas expand by more than 20 per cent responding to the carbon price incentive to sequester carbon.

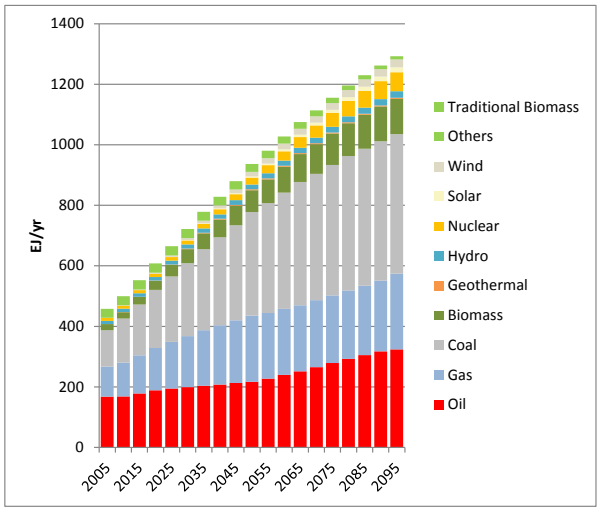


Figure 3.31 Global Primary Energy Consumption by Fuel, Reference Scenario

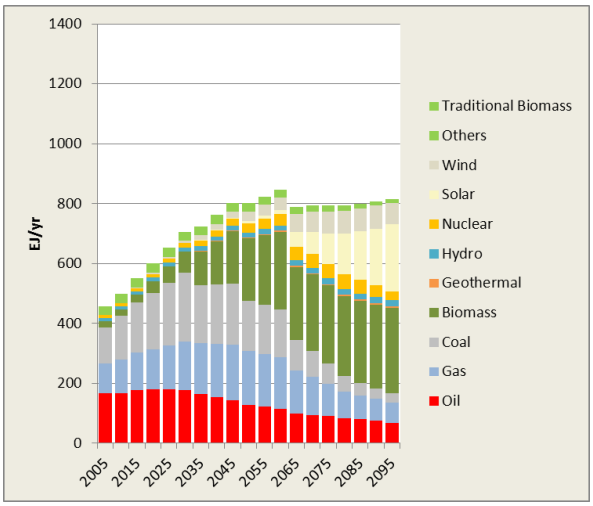


Figure 3.32 Global Primary Energy Consumption by Fuel, Global 20-20-20

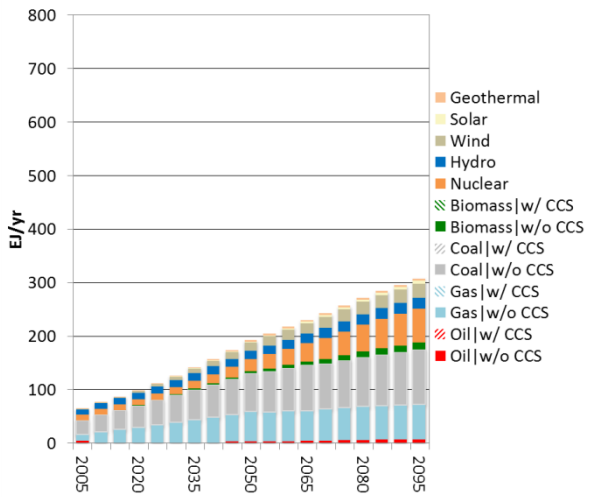


Figure 3.33 Global Electric Power Fuel Consumption by Type, Reference Scenario

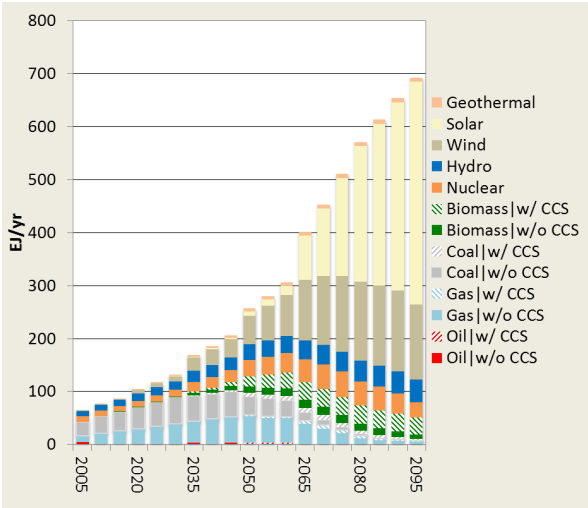


Figure 3.34 Global Electric Power Fuel Consumption by Type, Global 20-20-20

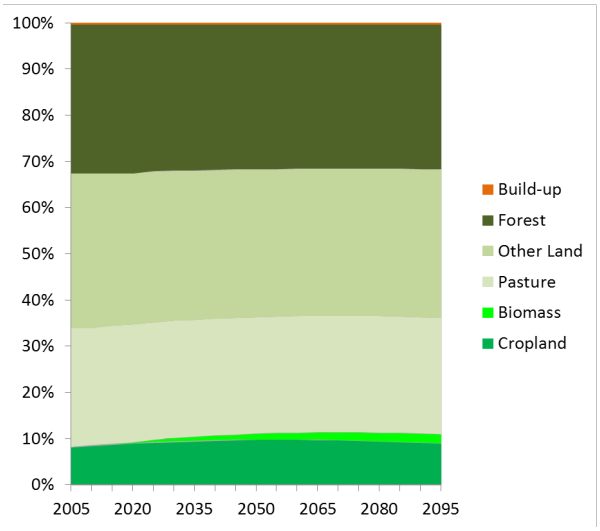


Figure 3.35 Land-use Patters, Reference Scenario

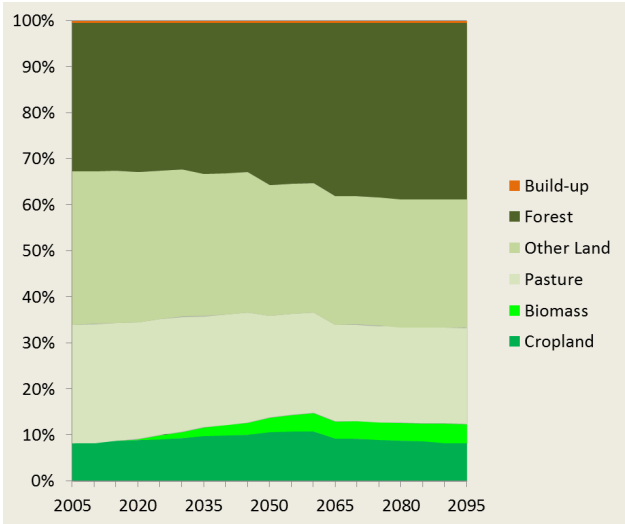


Figure 3.36 Land-use Patters, Global 20-20-20

3.4.3 Individual Policy Components

To better understand the contribution of the components that comprise the Global 20-20-20 scenario, we craft scenarios in which three of the components are run alone:

- Greenhouse gas emissions limits (GHG),
- Renewable energy portfolio standard (RES), and
- Energy efficiency standard (EE).

We then compare these to results from the full Global 20-20-20 scenario and to the other individual components.

Figure 3.37 and Figure 3.38 show CO_2 emissions from fossil fuel and industrial applications and from land-use change. The GHG emissions limit policy closely tracks target emissions of the aggregate Global 20-20-20 portfolio. Other individual policies reduce emissions from fossil fuels, but do not deliver the same level of emissions reduction as the overall emissions limit policy. In other words, the greenhouse emissions limit is needed to meet the overall greenhouse emissions goal. On the other hand, the renewable energy portfolio standard reduced emissions substantially.

Note that CO_2 emissions are driven to zero in both the Global 20-20-20 and the greenhouse emissions limit scenarios, even though the protocol prescribes an 80 per cent reduction in greenhouse emissions. This is because it is cheaper to reduce CO_2 emissions than non-CO_2 emission, whose reductions are less than 80 per cent.

Land use change under the full Global 20-20-20 and emissions limit scenario exhibits the substantial land-use leakage associated with each successive accretion to the mitigation coalition. The increasing share of the world's land area in the emission mitigation coalition nonetheless draws land-use change emissions negative. On the other hand the renewable energy portfolio standard actually increases land-use change emissions because it encourages bioenergy production, which in turn expands land use for crops. The energy efficiency requirement had little effect on land-use emissions, and reduced fossil fuel emissions, but did not cause fossil fuel emissions to decline.

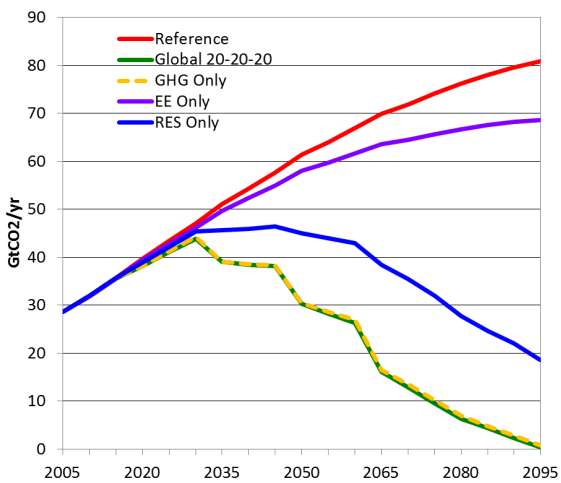


Figure 3.37 Fossil Fuel CO_2 Emissions For Reference and Global 20-20-20 Policy Scenarios

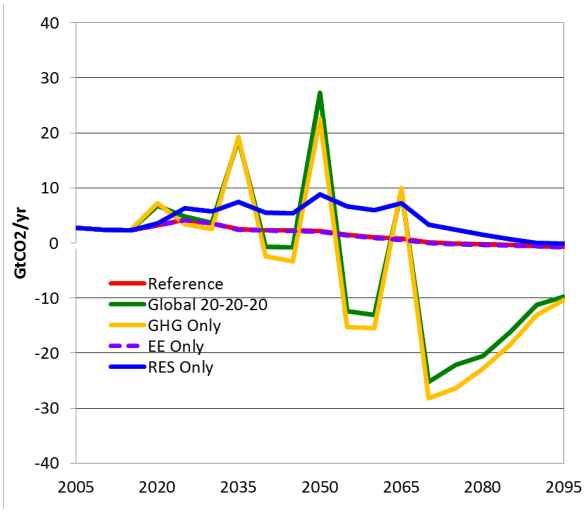


Figure 3.38 Land-use Change CO_2 Emissions For Reference and Global 20-20-20 Policy Scenarios

Figure 3.29 and Figure 3.30show the effects on radiative forcing and average Earth surface temperature of the Global 20-20-20 policy components, which track the emissions patterns.

Figure 3.39 through Figure 3.42 show the effects of individual Global 20-20-20 policy components in contrast to the composite Global 20-20-20 policy package. The large deployment of solar and wind technology in the Global 20-20-20 scenario is mirrored by a similar large deployment of solar and wind in the renewable energy portfolio policy alone, Figure 3.42. Similarly the deployment of CCS technology is mirrored in the greenhouse emissions limit policy, Figure 3.40. Reductions in power sector size, relative to the reference scenario observed in Figure 3.41, are not observed in the composite Global 20-20-20 scenario, Figure 3.39.

Bioenergy production is very different in the Global 20-20-20 and its individual component scenarios, Figure 3.43. The renewable energy portfolio standard engenders the greatest bioenergy production, Figure 3.43, but the lowest afforestation, Figure 3.38. GHG emissions limit generates increased bioenergy production compared with the reference scenario, while the Global 20-20-20 lies somewhere between the two individual scenario elements. Energy efficiency alone has little impact on bioenergy production and use.

The largest effect on crop prices is generated by the GHG emissions limit policy, Figure 3.44. This is the result of pressure from bioenergy production and sequestration as well as the fact that the greenhouse gas emissions limit leads to the incorporation of carbon prices in land rents and therefore crop prices. While the renewable energy portfolio standard leads to the highest use of bioenergy, it increases crop prices much less than the Global 20-20-20 or the emissions limit policy scenarios.

Only the Global 20-20-20 and the GHG emissions policies have explicit carbon prices. The carbon price is significantly lower in the Global 20-20-20 scenario, Figure 3.45. The lower carbon price does not mean that the welfare cost of the policy is lower. It is actually higher since the greenhouse gas emissions limit is the most economically efficient policy instrument, Figure 3.46.

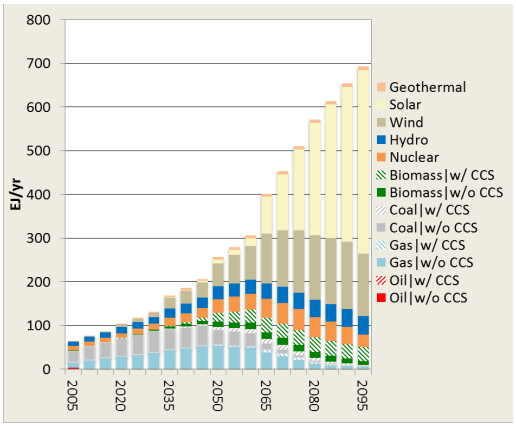


Figure 3.39 Global Electric Power Fuel Consumption by Type, Global 20-20-20

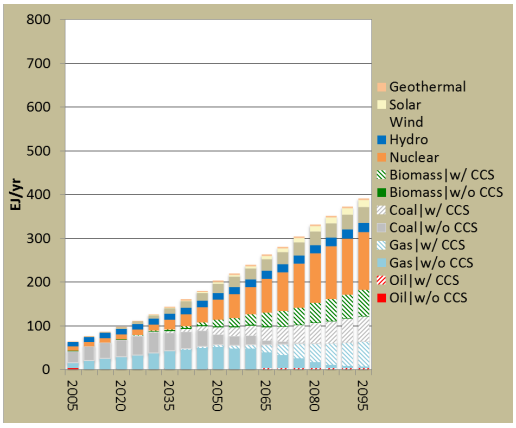


Figure 3.40 Global Electric Power Fuel Consumption by Type, GHG Limit

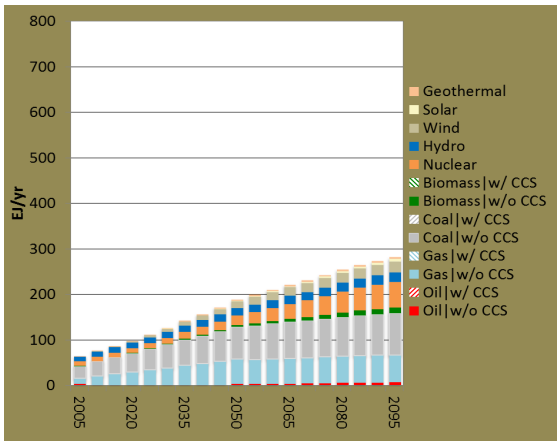


Figure 3.41 Global Electric Power Fuel Consumption Type, Energy Efficiency

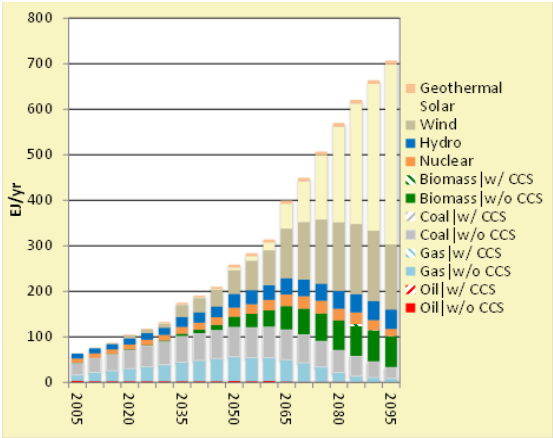


Figure 3.42 Global Electric Power Fuel Consumption by Type, Renewable Energy Standard

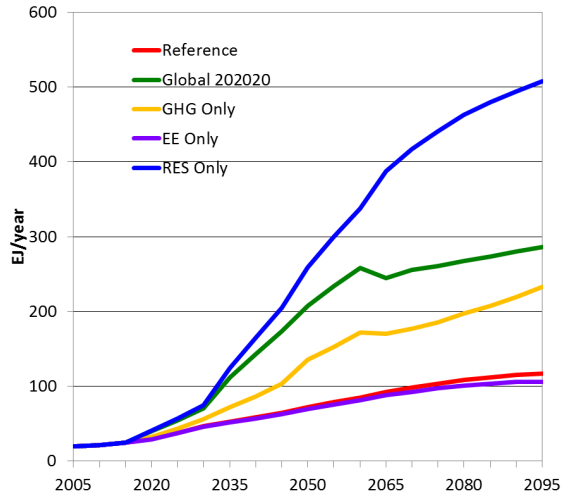


Figure 3.43 Bioenergy Production For Reference and Global 20-20-20 Policy Scenarios

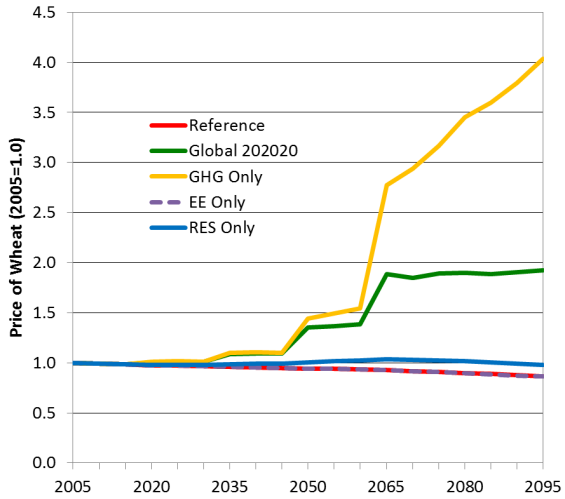


Figure 3.44 Crop Prices For Reference and Global 20-20-20 Policy Scenarios

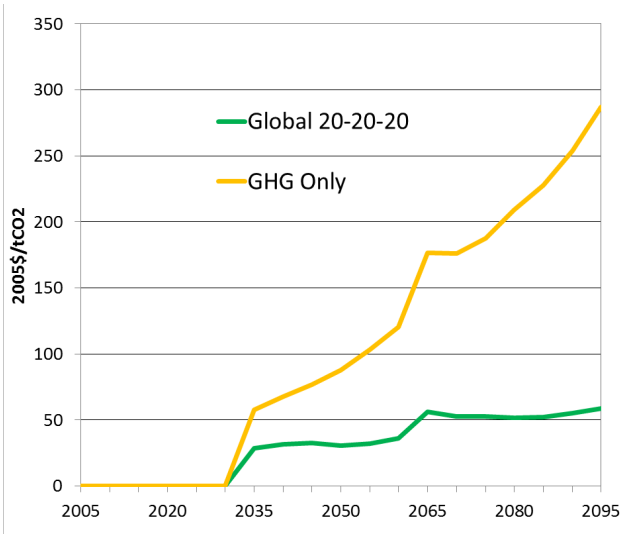


Figure 3.45 Carbon Price for Global 20-20-20 Policy and Greenhouse Emissions Limit Scenarios

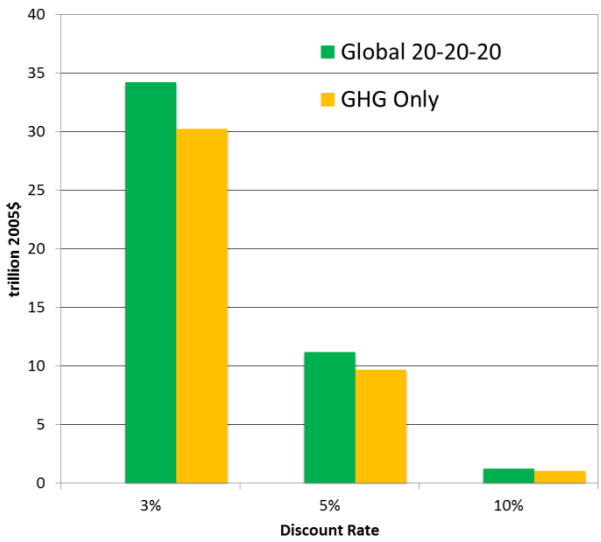


Figure 3.46 Social Cost for Global 20-20-20 Policy and Greenhouse Emissions Limit Scenarios

3.5 Discussion and Comparison

Developing effective regional and local strategies to limit human climate forcing require developing information about the implications for human systems, particularly energy, land and economic systems. We have explored the implications for human systems in three dimensions: Policy Stringency, Technology Availability and Policy Architecture.

Policy Stringency: We construct and compare two alternative limits on CO_2-e concentrations: 450 ppm CO_2-e and 650 ppm CO_2-e. Both scenarios share the same socioeconomic, technology availability and policy

instrument assumptions. We explored the implications for implementing each. We found that both were technically feasible under the common assumptions we employed, but both required immediate departures from the reference pathway. We also found that the more stringent limit implied more rapid deviation from a reference pathway. Both scenarios required greater reliance on renewable energy forms, nuclear power, CCS, and energy efficiency technologies for the global energy system as well as secession of deforestation and initiation of afforestation programs in addition to production of bioenergy and behavioural change toward lower-carbon intensity diets. We also found that the more ambitious climate goal was also more expensive, engaging resources that would otherwise have gone toward other uses.

Technology Availability: Nuclear power and CCS are two technologies, which hold the potential to reduce emissions of CO_2 to the atmosphere while providing energy. We crafted two scenarios to explore the implications of circumstances in which either or both of these technologies were unavailable in the context of a world that is attempting to limit CO_2-e to 650 ppm CO_2-e. We test the ability of human energy, economic and land systems to limit climate forcing to 650 ppm CO_2-e when new deployments of either CCS or CCS and nuclear technologies are unavailable. We find that in general that climate forcing can be held at or below 650 ppm CO_2-e throughout the 21st century regardless of whether or not these two technologies were available. However, we also find that as the non-carbon energy technology set is reduced in scope, pressure to deploy alternative renewable energy forms, energy conservation technologies, and terrestrial carbon sequestration are increased as are economic costs. The carbon price was less sensitive to technology availability than to an increase in policy stringency from 650 ppm CO_2-e to 450 ppm CO_2-e.

Policy Architecture: We explored the implications of broadening international participation and extending the degree of ambition over time of the European Union's 20-20-20 energy and climate policy architecture. We assumed the approach which has four policy elements: a GHG emissions limit, a Renewable Energy Standard, a Biofuel Standard, and an Energy Efficiency Standard. We showed that this policy package was effective in achieving deep reductions in the emission of anthropogenic climate forcing agents. We also found that the economic cost was between 10 and 15 per cent higher than a pure carbon tax policy, but that it deployed substantially more renewable energy and lowered the tax emerging from the carbon market. The Energy Efficiency Standard was not particularly effective in reducing greenhouse gas emissions, but it improved energy efficiency. On the other hand, the Renewable Energy Portfolio caused greenhouse gas emissions to decline and increased electricity use.

Comparison to the 450 and 650 ppm CO_2-e Scenarios: The emissions mitigation strategy used in the Global 20-20-20 scenarios differ fundamentally from the 450 and 650 ppm CO_2-e scenarios in that the latter employ a carbon price alone, which is an ideal economic policy tool whereas the former employs a combination of policy instruments that include regulatory instruments in addition to a cap-and-trade regime. One obvious consequence is that there is a disconnection between the carbon price and total social cost. As we observed in Figure 3.45, the Global 20-20-20 with its regulatory measures in addition to its cap-and-trade measure, leads to a lower carbon price than emerged when only the cap-and-trade policy was in effect. (Recall that greenhouse gas concentrations were the same under the Global 20-20-20 policies and the cap-and-trade only policy).

When only the cap-and-trade regime was in place under the Global 20-20-20 scenario, the carbon price rose to almost $300/tCO2 by the end of the century. This price lies between carbon tax in the 450 and 650 ppm CO_2-e limit cases, as might be expected since *the Global 20-20-20 policy package produces radiative forcing of 3.2 Wm^{-2} in 2095, or approximately 505 ppm CO_2-e*. Note that as the climate constraint tightens, the carbon price increases non-linearly. That is the year 2095 carbon price for the 650 ppm CO_2-e is

approximately \$200/tCO_2, the carbon price for the 505 ppm CO_2-e limit is \$300/tCO_2, and carbon price for +the 450 ppm CO_{2-e} scenario is almost \$800/t CO_2.

Present discounted costs in 2005 USD for the period 2005 to 2095 are given in Table 3.5 along with the fraction of present discounted global GDP that these costs represent.

Table 3.5: Present Discounted Social Cost of Emissions Mitigation Policies

Scenario	Total PD Cost	% PD GCP
650 Stabilization	\$ 1.71	0.11%
650 Stabilization (NoCCS)	\$ 2.00	0.13%
650 Stabilization (NoCCS,NoNuc)	\$ 3.05	0.20%
450 Stabilization	\$ 10.42	0.70%
Global 202020	\$ 10.83	0.73%

(Trillions of Present Discounted 2005 USD, discount rate = 5%)

There is a substantial increase in cost moving from stabilization of CO_2-e concentrations at 650 ppm CO_2-e to stabilization at 450 ppm CO_2-e.

The difference in social cost between 650 ppm CO_2-e with all of the technologies, and without either CCS or nuclear power as mitigation options is roughly a factor of two.

By comparison, the Global 20-20-20 policy package is somewhat more expensive than the 450 ppm CO_2-e, but yields a somewhat lower environmental benefit. Since the Global 20-20-20 includes a cap-and-trade component, it suggests that costs could be lowered by de-emphasizing the non- cap-and-trade policy elements as the program expands its participation and deepens its commitments. It also allows some latitude for a tightening the mitigation while still managing the cost.

3.6 Linking GCAM to other Models

The LinkS project analyses how global strategies can be used as long term guidelines for development of energy supply and technologies in regional energy systems. The partners in LinkS employ several energy system models since each model considers different spatial, temporal and technology perspectives and has different strong points. To rebuild all cumulative experience and functionality into one single model is not feasible given the huge amount of resources such a process would require. Thus, our approach has been to establish a numerically based “soft link” between models, where the output of one model became the input for another.

Because GCAM provides an integrated, long-term representation of global energy, economic and land-use systems, its outputs were used by other models as a reference projection that tied the analysis together. In this section, we briefly describe how these models were linked together. Each of these analyses is described in more detail in the following chapters of this report.

3.6.1 WGM

The World Gas Model used CO_2 prices from GCAM as input data (see Chapter 5). The coupling focused on the 650 ppm and Global 20-20-20 scenarios between now and 2050. While WGM used CO_2 price data directly, the production, consumption, and price of natural gas were not used as input data, and may vary significantly between models. Differences in model structure prevented further calibration and data exchange between the two frameworks.

3.6.2 TIMES

The Chinese TIMES model used electricity demand from GCAM 650 ppm scenario as input to one of their scenarios (see Chapter 7). The coupling focused on development of the Chinese electricity sector only to 2020 since this is the timeframe in the current 5-year plan in China. The Chinese TIMES model has significant detail on industry for a variety of sectors and technologies, while GCAM aggregates this information to a single sector and a limited number of technologies. This information could be used in the future to improve GCAM's representation of Chinese industry sector.

3.6.3 EMPIRE and EMPS

EMPIRE and EMPS used CO_2 prices, fuel prices, electricity demand, and electricity production from the GCAM as input data for the European electricity system (see Chapter 8). The coupling focused on the evolution of the European electricity sector in the 450 ppm, 650 ppm and Global 20-20-20 scenarios between now and 2060. EMPIRE and EMPS ensure that regional electricity demand and production by fuel matches GCAM. Future linkages could include feedback that informed GCAM's electricity generation with bottom-up data from EMPIRE or EMPS. For example, the more detailed analysis of the European electricity system conducted with EMPS could be used to adjust GCAM's renewable potential in the future.

4 Regional policy implications: EU, US, China,

4.1 Background for a regional focus on climate policy

Mitigating climate-change is a global responsibility. However, as previously debated in chapter 2, there is currently no sovereign global political body to institute needed regulatory efforts, as the pledging and efforts connected to the United Nations Framework Convention on Climate Change (UNFCCC), including the Kyoto Protocol, are voluntary, and the implementation is in the hands of national governments.

This implies that unless international climate co-operation is made mandatory with binding targets, the states and regions that implement progressive climate mitigation strategies on their own initiative represent key actors for substantial reduction of greenhouse gas (GHG) emissions. Successful action will require cooperation by the major global actors (Wiener, 2007).

Regional efforts could also be more strongly integrated into a global policy framework. This article explores how future global policy agreements can build on regional initiatives, and still significantly contribute to global climate mitigation regime.

Governance structures in the selected regions have different designs, as do their climate strategies and policies, both related to differences in constitutional-political basis and framework; not least the dynamics between the federal/supra-national/national and the state/national/provincial levels, as well as different economic and industrial structures. These divergent patterns influence both the ability to promote various policy measures relevant for climate-change mitigation, as well as the modalities and strengths thereof.

What measures and processes could be viable in realizing a more prominent role for the regions in global climate-change mitigation? Given the different character and composition of regional policies, our assessment is based on the political-institutional framework for policy formulation and implementation, understood as: (1) the level of governance for decision-making for climate policies (2) the level of the follow-up of climate-policy decisions. Furthermore, major climate policy measures are based on, or aim at changes within specific policy sectors, not least the energy sector. The linkage between climate and energy policy measures is therefore a major reference here.

No single regulatory instrument or policy is "best" for all purposes. Each instrument has its best policy terrain; pragmatic choice depends on context (Wiener, 1999; Bemelmans-Videc, Rist, & Vedung, 1998). A main assumption is that mitigation measures particularly need to be perceived as beneficial at several levels of governance, as well as across economic sectors, and strategic, societal interests – in order to ensure successful implementation. One example is the concept of "double dividend" – the idea that imposing an environmental tax can both improve economic performance and the environment – which arose in the US in the 1980s as a response to an increased climate change concern on one hand, and the US federal budget deficit on the other hand (Babiker, Metcalf, & Reilly, 2003). The German "Energiewende" ("Energy Turn-around") is an example of energy policy efforts aiming at transition towards a 'renewable society', but benefitting economic development and employment. Given the current economic situation, energy policies with climate relevance benefitting socioeconomic development represent win-win strategies.

One prominent example of a regional climate-relevant policy package is the '20-20-20 strategy' established in 2008 by the EU (Commission of the European Communities, 2007; European Commission, 2010). The main targets of this strategy are: (1) 20% reduction in GHG emissions – with policy efforts directly aimed at

GHG-mitigation – in particular the Emission Trading System (ETS); (2) 20% share of renewable energy in the EU's final energy consumption; and (3) a 20% improvement in energy efficiency.

The potential and feasibility of transferring the EU policy strategy towards the US and China will here be assessed, both as a package and by decomposing individual measures. Based on this approach, this section discusses whether and how a more regionalized approach could complement a global climate-change mitigation regime. Our research questions were:

(1) Can the '20-20-20 strategy' of the EU be applicable as a policy reference in other regions, given different political contexts?

(2) Would climate policy strategies and measures anchored within the respective regions constitute a feasible alternative to a global approach to climate-change mitigation?

(3) Through which means could such a regional approach be realized?

4.2 Analytical approaches to the qualitative assessment

A major insight from relevant policy case studies from regions like the EU is the importance of horizontal and vertical policy dynamics in climate and energy policy matters (Lafferty and Ruud, 2008). 'Multi-level governance' is a concept pointing to the interaction of different levels of governance in complex political-institutional settings (Knill & Liefferink, 2007; Pierre & Peters, 2005). This applies very well with the political contexts of the US and China, which is highlighted in Chapter 2. Based on this, two relevant and major concepts in our assessment are 'policy anchoring'; and 'issue-linkage'.

'Policy anchorage' refers to the level of governance from which climate policy strategies and measures are formulated and implemented, and represent the more specific context for the promotion of policy measures. There are two main dimensions of anchorage:

- Policy efforts stemming from a *superior level of governance* (e.g. federal, supranational or national level), which aim at shaping further measures at inferior levels of governance (e.g. regional, local)

  vs.

- Policy efforts stemming from *sub-national and local levels*. Such initiatives could eventually lead to a broader range of alternative measures and outcomes when aggregated at a superior level, albeit potentially also induce innovation and stronger local involvement.

These two dimensions can be seen as complementary, as well as in conflict. Sometimes overall strategies formulated at a superior level must be further specified and implemented at inferior levels, but further specification of overall guidelines do not always aggregate well at the superior level; they can even be counter-productive towards the superior target. However, efforts of reducing divergence at lower political levels may increase the risk that innovation and local knowledge provided by sub-levels are not properly taken into account (Osofsky, 2011).

Climate policy anchoring might influence a country's degree of internal policy co-ordination, which again is a country's basis for their participation in international negotiations. This anchoring, within highly different political and societal contexts and structures, will substantially impact upon different countries' approaches both to regional strategies and to international negotiations.

'Policy anchorage' may be linked to 'Issue-linkage', in order to assess the potential for broader, sector-encompassing climate policy strategies. As illustrated by the case of the EU 20-20-20 program, there is good reason to include energy policy measures as part of a climate-change mitigation strategy. The actual societal and political potential to initiate and develop such linkages is of importance in this regard.

'Climate policy capacity' may with this reference be divided into two core notions: (1) *climate-specific* capacity, specifically devoted to climate change issues; and (2) *climate-relevant* capacity, which supports policy efforts that may also help mitigation or adaptation to climate change (Willems & Baumert, 2003). The distinction between specific and relevant policies provides a basis for assessing whether climate change is a political priority, and the notion of 'climate-relevance' accentuates the importance of considering relevant, sectoral policy measures even in regions without explicit climate-specific policy targets.

The political and institutional framework within which climate-policy measures are formulated and implemented, constitute an important context for a country's 'climate capacity'. This is also related to the ability of individuals, groups, organizations, and institutions to address climate issues as efforts of achieving sustainable development (Sagar, 2000).

4.3 Climate policy anchorage in the EU, China and the US

Stemming from a global level, the international climate change regime has affected the targets set at the federal/national/supra-national levels in all our selected regions. Of the three the EU is the only case where a binding commitment from the global level has led directly to a binding target, committing also its Member States.

Within all the three regional settings the primary basis for approaching the global climate accord is found at the top political level. Still, as indicated in Figure 4.1, this does not necessarily imply that the top level represents a driving force in the actual policy development and implementation.

Within the US context, certain states stand out as the pro-active agents for actual climate action. Although there is federal legislation affecting GHG emissions, explicit CO2-mitigating regulations have yet to pass the US Congress. Although relevant legislation passed at the state level cannot be seen entirely de-coupled from the federal legal authority, the states' climate policy efforts are more or less de-coupled from the political agenda set at the federal level. Hence, as illustrated by the figure above, it could be claimed that there is a rather loosely coupled two-way interaction between federal and state levels in the case of the US.

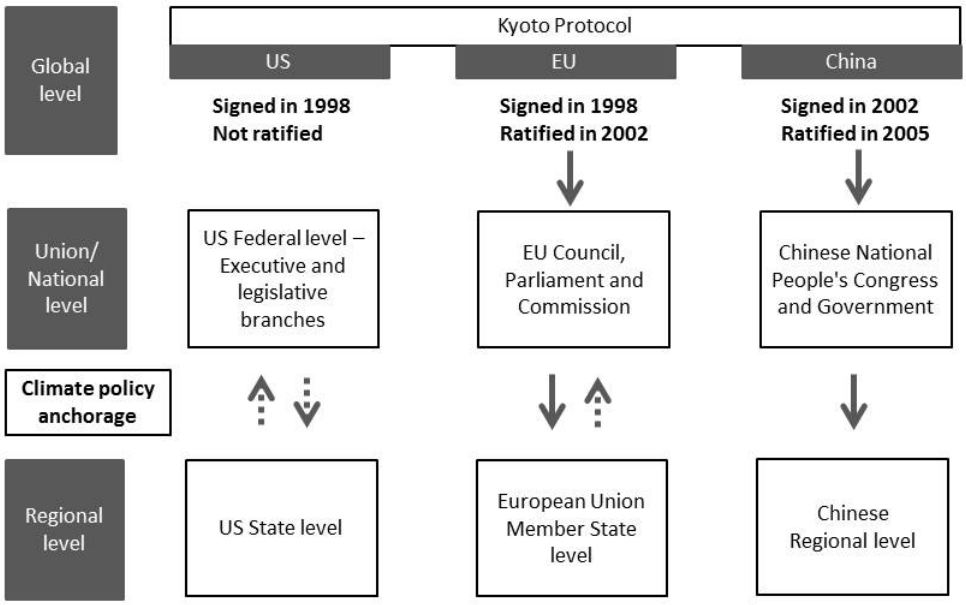


Figure 4.1 Governance system in China, the EU and the U.S: anchoring of climate strategies and instruments (Dalen et al., 2013)

The EU represents a case of two-way dynamics, in parallel to the US case. Central policy efforts are proposed by the EU Commission and often approved by the Union Council and European Parliament. However, the EU legislation does not provide explicit guidelines to implementation at the national level, which is decisive for how the EU decisions are transposed and brought into force (Wallace & Wallace, 2010; Hooghe & Marks, 2001). The result is that the EU Member States as a whole has a variety of policy schemes related to climate change, which can be explained by a number of combined factors (Schreurs & Tiberghien 2010, Lafferty and Ruud 2008). Substantive divergences between Member States, and between Member States and a supra-national EU level have represented general barriers to a common EU framework. Nevertheless, the EU 20-20-20 targets have been set on a supra-national EU level, representing a decisive climate policy driver, as stipulated by Figure 4.1.

China can be seen as an example of a more clear-cut top-down approach, where climate related policy processes are defined and specified from the top political level. Traditional command and control schemes have hitherto been chosen as policy instruments. Yet China is still open for different regional and even local solutions, and new patterns of two-way interaction between national and provincial levels in China may be seen as well. One example is the decomposition of energy-saving goals by regions by the State Council (2006) which takes the decrease of unit GDP energy consumption as the economic and social development indicators and puts it into the region comprehensive evaluation and annual examination system (Dalen et al., 2013).

4.4 The potential of 'transferring' the EU climate package and its measures

Taking the EU 20-20-20 strategy as a point of departure, this section analyses on a preliminary macro-level how and to what extent the main components of the EU strategy could be transferred to a US and Chinese context.

The major measures in EU 20-20-20 are decomposed, but rather than focusing on the concrete, quantified target in specific percentages, the character of the various measures are stressed:

- ***Measure 1:*** X% reduction of GHG emissions: In the EU the ETS is the main policy instrument, representing a *climate-specific* policy measure. ETS encompasses all EU Member States and different industrial and energy producing sectors, being a market-based "cap-and-trade" instrument. To avoid carbon leakage and relocation out of the EU area, exposed industries with large emissions are granted a higher share of free allowances (European Commission, 2012c).
- ***Measure 2:*** X% share of final energy usage must be produced from renewable energy sources (RES). This is an EU wide target, yet constituted by differentiated national targets, building on the particular situation of each Member State. Each Member State must formulate its own policy instruments to fulfill the targets.
- ***Measure 3:*** X% increase in energy efficiency. This target is supported by a range of EU policy instruments; e.g. the EU Directives on energy efficiency, energy performance of buildings, and eco-labeling of products.

Two dimensions pertaining to the potential transfer of an EU 20-20-20 strategy towards the political contexts of China and the US are identified:

a) The potential of transferring specific, singular measures of the EU 20-20-20 towards China and the US, and the possible implementation context.
b) The potential of the transfer of the 'package' as a whole towards China and the US.

4.4.1 The potential of transferring individual policy measures

Measure 1; 'ETS':

A federal ETS could hypothetically be introduced in the US since the region is already market oriented. Besides, there are already experiences with ETS-like schemes at the state level, such as in California and the New England states. This can be further developed without political or legal coordination from the federal level. Federal Cap-and-trade programs or carbon tax has been politically debated, yet this has been deemed politically unviable due to the perception that industry will face high costs and thus weaken competitiveness (Johnson, 2007). In light of this political situation, climate-specific policy measures can still be considered to be more likely at the state level. An US approach to a 'federal ETS' would therefore more likely be composed of state-based schemes and systems being linked together.

An ETS-like policy measure would be more difficult in China since there is currently less experience with similar market mechanisms for climate-change mitigation. Although carbon emission market establishment is listed as one of the major targets in the work plan for GHG emission control during the 12th Five Year Plan period, a direct cap would probably be more appropriate since Chinese authorities have a tradition for command and control measures to reduce emissions (Han et al., 2012). At the same time, given China's increasingly strong market orientation in other domains, it is not unlikely that a nationwide Chinese ETS could develop. Currently there are seven pilot emission markets, where some major cities and provinces are exploring the viability of ETS-like scheme (Han et al., 2012).

Measure 2; Increased share of renewables (RES):

A reinforced priority of RES could be politically viable in a US context, even from a federal perspective. As long as RES-policy initiatives are linked to other concerns than climate-change mitigation, not least security of supply, these will be accepted by a broader range of political forces (Bang, 2010). A number of states

have already employed specific RES-targets and policy measures, such as 'renewable portfolio standards' (RPS) (Bowen et al., 2011). Hence, a federal target where each state is allowed to find its own means of fulfilling the target could be feasible. The state level targets could also be adapted according to the state's structure, economy and industry, like in the EU. On the other hand, given the existing variety of policy approaches to RES in the states, there is also reason to believe that such a common standardization/coordination at the federal level could evoke conflicts of interest (Rabe, 2008).

For China, a more direct target set by the government directly for each province (but again adapted to that province's structure as discussed by (Yang, Teng & Wang, 2013) in parallel with the EU approach. In the 12th FYP, China has set a national target of 11.4 % non-fossil share in primary energy by 2015 compared to 2010 (Hong, Zhou, Fridley & Raczkowski, 2013).

Measure 3; Increased energy efficiency:
Targets for energy efficiency are already a main instrument in China and should be a feasible way to continue.

In the US, however, it seems less likely that federal requirements for energy efficiency will be set for mainly state level activities and industry. At the same time, the US federal government has a tradition of setting targets for energy efficiency in federal operations (such as buildings and vehicle fleet). Targets for energy efficiency related to cars have also been set by the US Congress (Bowen et al., 2011).

4.4.2 The potential of transferring the 20-20-20 package as a whole

Learning from the previous decades of political struggling around climate policies in the US, the potential of federal climate-specific efforts is the very limited. A federal ETS or cap-and-trade scheme is not very likely to prevail in the US Congress. On the other hand, climate-relevant policy measures for the energy sector can be more likely, given historic experiences – and the potential of relying on mutual benefits for security of supply, business development, and employment – in addition to the environmental benefits. This political approach also mirrors the three overriding concerns for the EU's energy strategy; climate-change mitigation, competitiveness, and security of supply.

Given the US experience with difficulties of identifying common political ground on climate-specific policies, it is important to explore the possibilities within climate-relevant areas. Maintaining the competitiveness of domestic industry is traditionally a major concern. When looking at the US climate policy as a whole, the benefit of issue linkage has not induced a more progressive federal climate-specific policy, which is not moving substantially forward. It has even been stated that issue linkage has led to more complexity and higher obstacles in the US (Skjærseth et al., 2013). On the other hand, climate policy improvement, both at the federal and state level, may be created by recent initiatives such as promoting green businesses, combined with efforts of managing environmental pollutants such as regulations for motor vehicles setting standards to cut GHGs and increase fuel economy for cars and light-duty trucks. Further the GHG Reporting Rule and Carbon Pollution standard for New Power Plants also indicate a significant potential of connecting singular policy measures into efforts that more effectively mitigate GHG emissions.

China has ratified the Kyoto protocol, but as a developing country it has no quantified target under the protocol, and a quantified target could be an obstacle for ratification. Chinese policy development and implementation is centered around its Five Year Plan system (FYP) (Li & Wang, 2012). It is a format that naturally supports policy packages, as all matters of national social and economic priority are fitted into

these sequential plans. The top-down system allows for high degree of target co-ordination; hence, one could claim that there is a 'package-approach' already in place in China.

Summarized, policies with 'issue-linkage' and 'policy packages' already are formulated and followed up as a viable path in both China and the US. Instances of issue-linkage related to energy as a means for reducing GHG emissions can be found in all three regions. However, the composition and structure of eventual policy packages, not least the role of *climate-specific* measures, would differ significantly between the regions. The policy anchorage will also display significant variation.

4.5 The potential of 'globalizing' regional climate policy efforts

This chapter discusses whether climate-specific and -relevant policies anchored within the respective regions could constitute a feasible alternative to a 'top-down' global approach. The discussion starts with to what extent a regional approach can be in line with current trends within the global policy framework. Within the UNFCC framework a more sector-based approach to climate-change mitigation has already been discussed. The Bali Action Plan (2006) recognized the concept of "sectoral approaches" as a possible way forward for international climate-change cooperation. On this basis one could also explore the potential for linking the various regional approaches together. In this latter case, the global climate-mitigation regime becomes a possible facilitator.

Although the EU has pursued a 20-20-20 strategy domestically, what role quantified targets could and should play in a potential 'Global 20-20-20' is not straightforward. The 20-20-20 initiative was formulated prior to the financial crisis that hit Europe severely. Consequently, it is not obvious that the EU would bind itself to future, more stringent global commitments. However, a key measure for ensuring acceptance of climate-mitigation policy package has also been the inclusion of policy measures beneficial for the broader economy, including an important policy sector like energy.

In the case of China, the 12th FYP does not emphasize the link between energy and climate, but rather between energy *and the general economy*. This is demonstrated by the substantial focus on energy conservation as a way of employing scarce resources more effectively. China's focus on energy efficiency improvement also yields significant reductions in GHG emissions. As environmental concerns are becoming more manifest – particularly through local pollutants, this can also influence climate policy efforts as emissions reductions in general are pursued.

However, following the logic of the current political approach, one can assume that such efforts will be closely considered in relation to the economic growth strategy. For example, a recent study found that energy saving technologies in the Chinese cement industry will create significant co-benefits at the national level (Yang et al., 2013). This justifies the enactment of more stringent climate policies in the wealthier regions in China. Although this implies a broader sectoral strategy than 'only' energy, it also indicates the importance of issue-linkage benefitting other economic activities as well.

As previously indicated, there are clear challenges for a possible implementation of climate-specific measures in the US. Hence, a stronger emphasis on sectoral, climate-relevant efforts within the global climate-change mitigation regime could potentially reinforce the probability of a more active US participation in committing, global efforts.

In sum, there is a potential of reinforcing a sectoral and, thereby, regional approach in global climate-change mitigation efforts. This could also resonate well with ongoing trends within the global framework, as well as better suit the prevalent policy approaches in the cases of the EU, US and China.

4.5.1 Possible mechanisms for the realization of globalized regional approaches

Based on the overall exploration of possible foundations for more regionalized, sector-oriented global climate cooperation, the analysis points to three categories of mechanisms that could contribute to and facilitate such an approach. One mechanism is the interdependencies represented by economic and industrial activities, not least in the energy sector. A second mechanism could be agreements of inter-regional linkages, such as linking different regional 'ETS'-schemes. Thirdly, the importance of institutional mechanisms for mutual diffusion of policy concepts and policy learning is discussed.

As far as economic interdependence is concerned, a major assumption is that economic structures and patterns of transnational- and regional exchange can induce stronger issue-linkages, both within and between the selected regions (Keohane & Nye, 2011). An example is the interaction between Norway and neighboring Sweden as to energy production and distribution. The two countries are mutually dependent on each other due to high percentage of intermittent renewables in their energy mix, and have a common green certificate market to support new renewable energy projects.

Further acknowledgement and reinforcement of interdependencies might stimulate further development of an international energy market (Sagar & Banuri, 1999). On the other hand, as long as such measures are not politically governed or coordinated, they very much depend on the economic trends and the market situation, and the industry's perception of self- vs. common interests.

When it comes to the second major mechanism – agreements for inter-regional linkages of policy measures, an important case is the growing interest for linking regionally based carbon markets. There has been an ongoing discussion for some years how the EU ETS can be coupled with the California cap-and-trade scheme, as well as Australia. However, this linkage is still not in place, and will probably have to wait to the future structure of the EU ETS is clarified. This also illustrates the inherent challenge with carbon markets, not least getting an effective carbon price within the EU ETS. In this perspective, the prospect for an interlinked, inter-regional ETS model seems limited.

In the domains of renewable energy and energy efficiency there is so far no clear discussion of inter-regional linkages. The EU itself struggles with the idea of formulating a common promotional scheme, such as a common feed-in tariff or renewable certificate system. There are, however, no sign of such a common EU system. Also when it comes to energy efficiency there are few signs of measures which could eventually be part of an inter-regional arrangement.

However, there is a generally reinforced focus on technologies for smarter energy production and usage, not least through the development of distributed energy solutions, smart grid and low-energy buildings. Transnational cooperation in research and technology development is already well developed both within and between the regions – not least the EU and the US.

Both of the above mechanisms seem to represent challenging paths given the current situation. However, one should not under-estimate the force of role-models and the transfer of good examples; both within the

climate-change negotiation context – as well as through various market and non-public, international arenas (Jörgens, 2004; Busch & Jörgens, 2012).

A major finding in this analysis is the importance of policy anchorage; that is, the political mandates for assuming climate-change mitigation policy responsibilities. The three regions are characterized by different, but multiple patterns – manifest and latent – of interaction between the levels of governance. However, as indicated by the policy processes in the US, such mandates can also be initiated and supported by industrial stakeholders – as demonstrated in the energy policy field. This finding implies that stimulating the establishment of arenas where sector- and industry-based actors can exchange ideas on climate-change mitigation measures could be fruitful for the further formulation of climate-change mitigation policies. Additionally, regionally anchored, bottom-up approaches seem to have its strength by representing more limited needs for global coordination.

In order to actually induce and maintain effective arenas for inter-regional policy linkages and exchanges, it would be a clear advantage with agreements on cooperation, coordination, as well as an institutional framework. An appropriate institutional framework could facilitate exchange of policy ideas, and provide a ground for mutual learning and diffusion of ideas and experiences.

4.5.2 Is a Global 20-20-20 approach viable?

A 'Global 20-20-20' approach, based on the EU's current climate-change mitigation strategy, seems to have certain strengths and weaknesses very much depending on the specific context within which it is developed. Nonetheless, by decomposing the individual sub-strategies and main policy measures, elements that may be transferred to other political contexts like the US and China are found.

By taking these regions' specific political and other contextual factors into consideration, it seems feasible that particularly the policy measures for renewable energy and energy efficiency could be anchored at a national/federal level, whereas climate-specific policies – like the EU ETS, seem to be less transferable as a standardized, 'federal' scheme. Both China and US have nascent, less extensive ETS-like schemes based on the state- and provincial levels.

Hence, a transfer of the EU's 'package approach' seems less feasible given current political features in the three regions.

Nevertheless, taken together current processes demonstrate the potential for revitalizing the global climate-change mitigation regime with a stronger regional anchoring, and regionally differentiated measures – not least related to the energy sector. Moreover, this is in line with current thinking within the UNFCC framework. Furthermore, a stronger regional anchoring of global mitigation efforts could induce stronger regional engagement and eventually less requirements for overall, global coordination. However, a caveat is needed: In order to get a 'regional model' to work it is important to further explore and define formalized framework for inter-regional cooperation, building on current regional political and industrial initiatives.

5 Using GCAM to quantify possible carbon leakage in the aluminium industry

A specific subtask performed in the LinkS project examined whether or not it is appropriate to utilize a general IAM model such as GCAM to study trade leakage for the aluminium sector. The research question raised by the industrial partner in LinkS, Hydro, was the following: *Will a relatively ambitious policy for combating CO_2 emissions in one part of the world lead to trade leakage for aluminium production, and possibly increase emissions globally?*

Carbon leakage is a term employed to describe an increase in CO_2 emissions outside of a region caused by the establishment of a carbon taxation scheme or emission cap within the region (IEA, 2008). The main idea is that the resulting increase in energy costs faced by the commercial and industrial sectors could lead to a distorted pattern of investment and international trade. For energy intensive industries this effect is expected to be most pronounced, and the question is whether regional «green» taxation paradoxically could lead to higher global emissions for selected energy-intensive industries such as the aluminium, cement and steel industries.

In 2011, Hydro was the 5th largest producer of primary aluminium in the world with a production of about 1.7 million metric tonnes. Most of the produced aluminium is re-used after its first use, and the total aluminium consumption in the world was over 61 M tonnes in 2011. Aluminium production is energy intensive. Using today's technology, about 14 MWh electricity is needed per metric tonne primary aluminium produced. Using 14 MWh/tonne, 1.7 M tonne primary aluminium corresponds to an annual energy requirement of 23.8 TWh electricity.

GCAM is not a formal system optimization model. The model finds an equilibrium by iterating prices and quantities between different markets and regions. Figure 5.1 is a graphical representation of one area within the energy module in GCAM (Note: the illustration shows SINTEF's interpretation of the energy module).

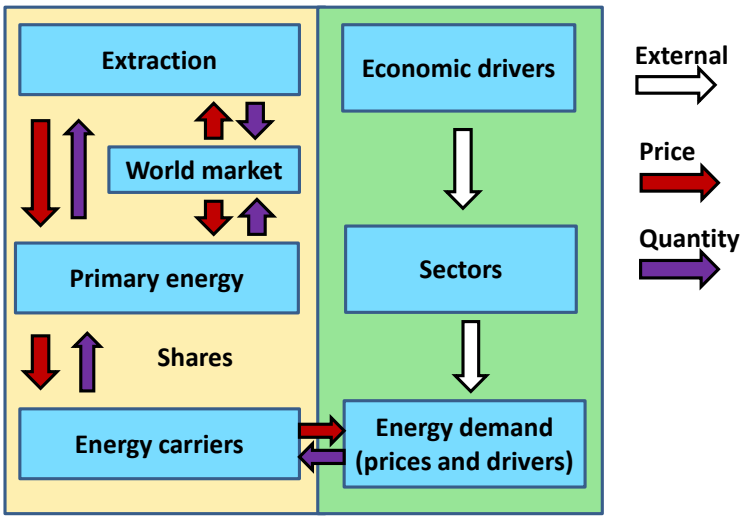


Figure 5.1 Simplified representation of a region within the energy module of GCAM

Some of the main characteristics of the energy module need to be kept in mind in the following study:

a) Within each region the energy demand functions are determined by macroeconomic variables and by calibration, while the actual energy demand also is affected by prices.

b) There is a world market for some primary energy types. Emissions can be treated as a primary energy source. For other commodities (other energy carriers, other inputs to production and all final products), there is no international trade.

c) The least-cost technology does not take the whole market. The shares for different technologies are explicitly represented in the model. They are partly calibrated by statistics, partly determined by costs and partly specified directly by the user.

d) The model is solved in an iterative procedure where prices and quantities are adjusted until the system converges.

5.1 Studying carbon leakage for aluminium

5.1.1 Simulation of global trade of aluminium in GCAM

SINTEF designed a study for how we could utilize GCAM to study carbon leakage for aluminium. To do this, we had to handle two important challenges. Firstly, aluminium is not explicitly represented in GCAM. This sector is included in the aggregated Industry Sector. Secondly, trade for industry products between regions is not represented in GCAM. We dealt with these challenges in 3 steps (Flasnes, 2012):

Step 1

First we sliced out the aluminium sector from the larger "industry" sector in the model, cf. Figure 5.2. This was mostly a challenge of structuring the inputs to the model, and to make it calibrate properly with the new sector-division. After this modification, the cost of producing aluminium in different areas is a new output from the model.

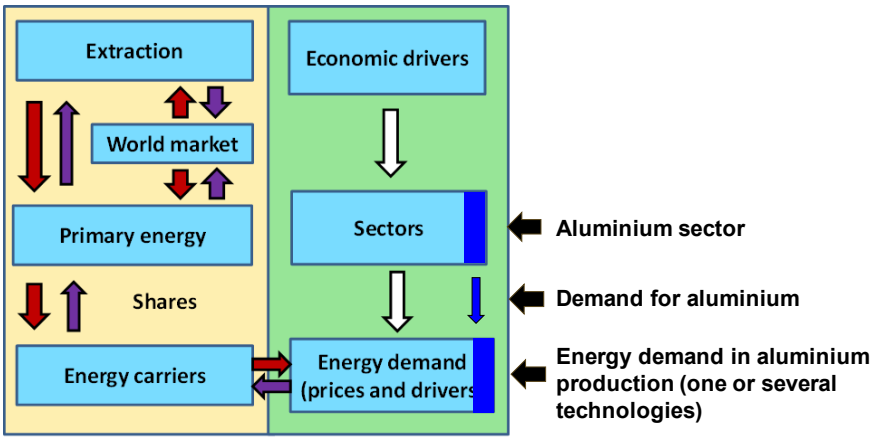


Figure 5.2 Step 1: Slicing out the aluminium sector in a GCAM region

Step 2

The next challenge was to utilize the calculated production costs for aluminium in each area to simulate world-market trade for this product. In GCAM there is no explicit trade between regions for other goods than primary energy, which basically means that demand equals supply for all other products inside each region. Secondly, since energy prices and technology efficiencies vary between regions in GCAM, cost of energy per unit of aluminium produced will depend on the region and there is no endogenously global market price for aluminium.

In addition to the specific energy cost, however, there are regional *Non-energy costs* per ton of aluminium representing regional cost of capital, labour costs, overhead, and other costs. The Non-energy cost can be manipulated such that all regions have total production costs per unit of aluminium equal to the global market price before the GHG-policy is included. The cost of aluminium is then to be understood as the sum of the following components:

$$Price_{rt}^{aluminium} = Cost_{rt}^{aluminium} = P_{rt}^{electricity} * e_{rt} + NonEnergyCost_{rt} \quad (5.1)$$

where $NonEnergyCost_{rt} = h_{rt}^{1} + h_{rt}^{2}$, with h_{rt}^{1} is to be seen as the *actual* non energy costs associated with aluminium production in region r at time t, and h_{rt}^{2} is the artificial component of the exogenously determined $NonEnergyCost$ which is set to model an international market with a global aluminium price assumed to be 550 USD/tonne in 2020. The resulting energy and non-energy costs are shown in Figure 5.3 and Figure 5.4.

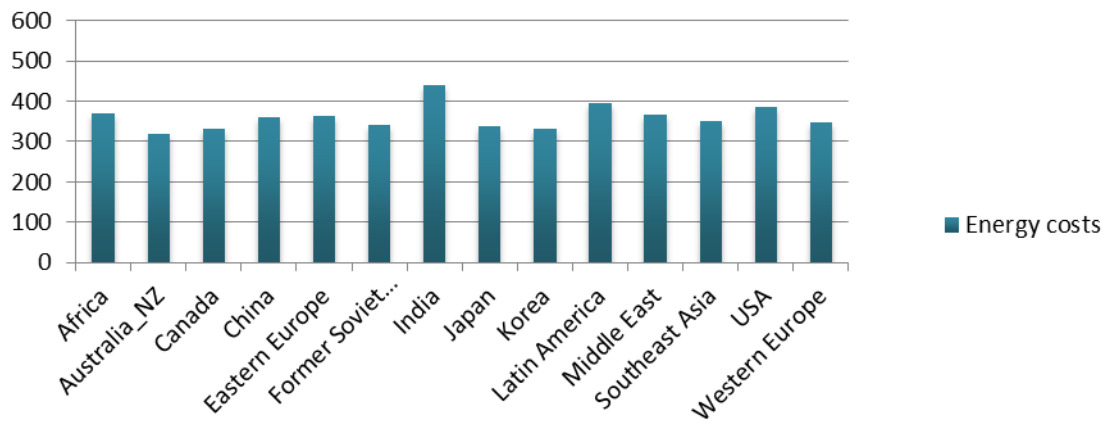


Figure 5.3 Calculated energy costs (based on energy prices from initial GCAM solution) [USD/tonne]

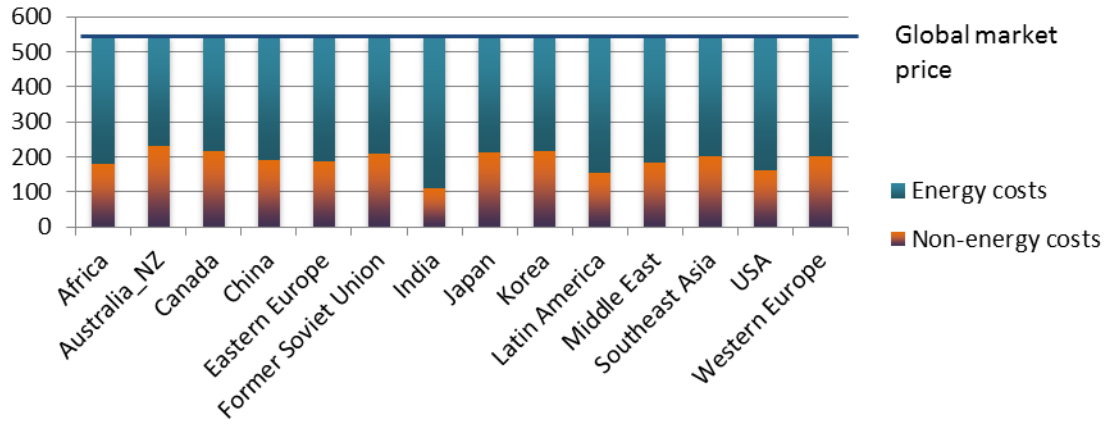


Figure 5.4 Calibrated non-energy costs [USD/tonne]

Step 3

In order to examine possible carbon leakage for the aluminium sector, which will be a response to a given change in incentives such as emission taxes, we need to compare the outcome for the world-market equilibrium for two different sets of policies. In this approach we would have to calculate the initial world market equilibrium with initial or no carbon policies, then redo the calculation for a new set of policies and compare the results.

In this step, an increased CO_2 quota price was assumed for Europe (Eastern and Western) from 2020, see Figure 5.5. In an initial test, half of the aluminium production in these two countries was manually allocated to the largest production regions outside Europe, see Figure 5.6. This resulted in only very small changes in production costs, in the order of 0.2%, as shown in Figure 5.7.

An algorithm for endogenous reallocation of aluminium production as function of production cost in GCAM was suggested in (Flasnes, 2012) but not implemented due to time and resource restriction.

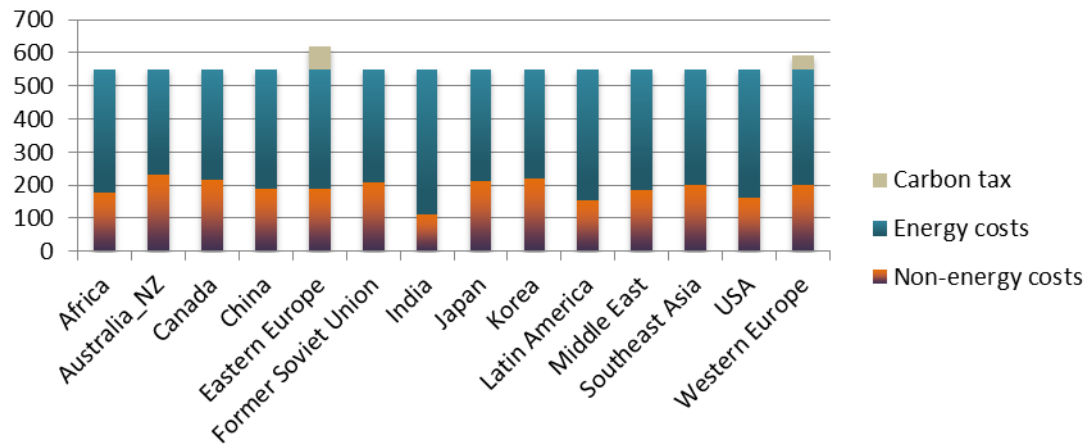


Figure 5.5 Price effect of the carbon tax on regional aluminium prices [USD/tonne]

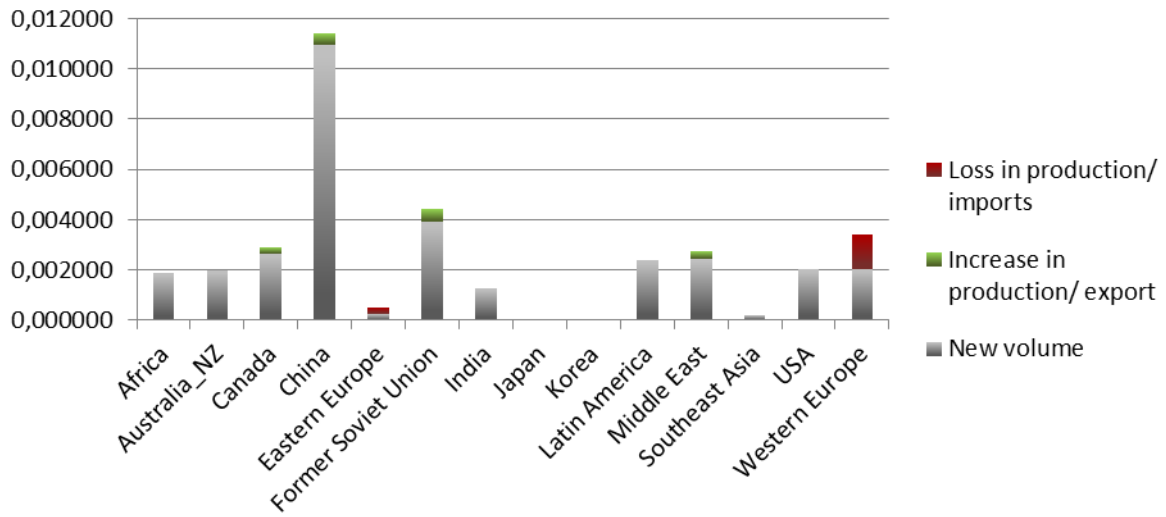


Figure 5.6 Changes in production volume as a result of 50% carbon leakage from Europe [Mill. Tonne]

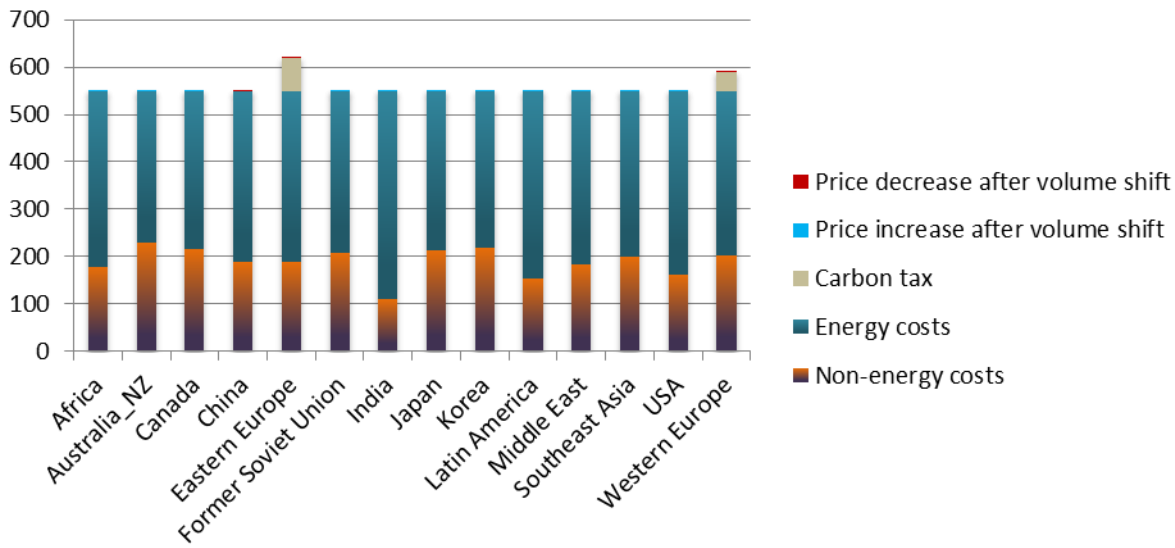


Figure 5.7 Regional aluminium prices after 50% carbon leakage from Europe [USD/tonne]

5.1.2 CO_2 effect of displacement of production volumes

A first attempt at transferring a production volume of 1000 tonnes from Western Europe to different regions in GCAM was performed in (Flasnes, 2012). Volumes have been displaced in 2020 by altering regional income elasticities, and only the effect in 2020 is considered. Figure 5.8 shows the changes in global carbon emissions when 1000 tonnes of aluminium production is reallocated from Western Europe to different regions on the world. The output from GCAM gives a strong indication of a significant increase in emissions when aluminium production is transferred from Western Europe to China, while a slightly less conclusive effect is observed for transfer to The Former Soviet Union, the Middle East or Canada.

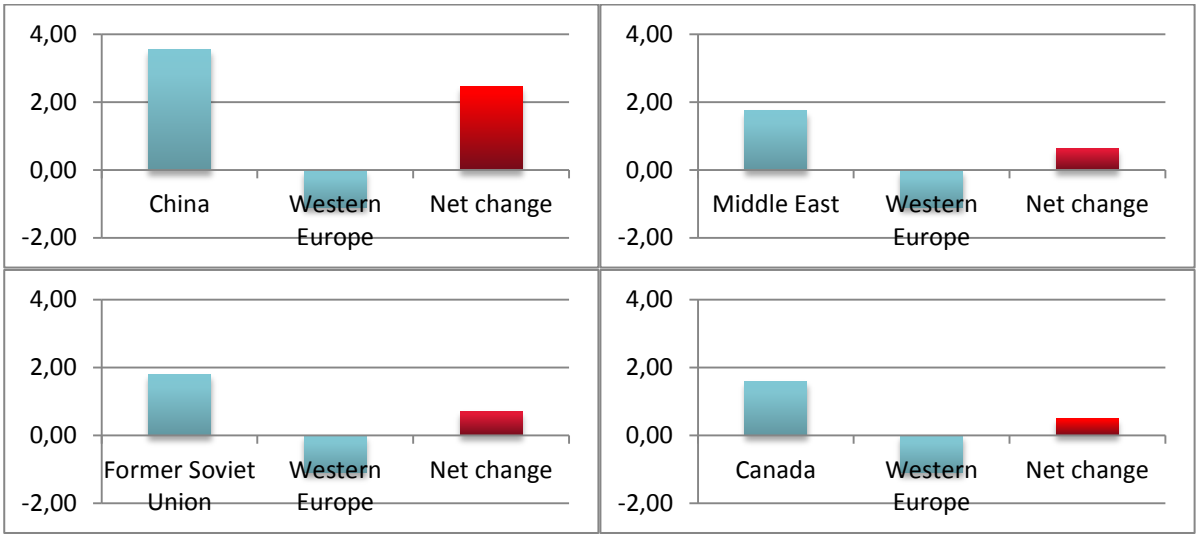


Figure 5.8 Changes in global emissions when 1000 tonnes of Al production is reallocated from Western Europe in 2020 [Mtonne C]

The aluminium industry is modelled with the same technology, and thus efficiency, in all regions and the changes in emissions are therefore related to the difference in regional electricity generation mix alone. Regional differences in technological advancement and energy efficiency will in reality add to the difference in emissions. If the work with GCAM is continued and better accuracy in production volume modelling is achieved, this analysis should be redone to investigate the effect of marginal displacement over a longer time horizon.

5.1.3 Cost advantage from energy price difference

Energy costs are affected by the underlying development of the energy systems in different regions. This includes future changes in primary energy supply, assumptions concerning the development of demographic and economic parameters affecting end-sector energy demand, and the assumed future evolution of regional energy technologies. Without any regulatory intervention and carbon emission regulations, the cost of energy in aluminium production is expected to decline over the next century in most regions, according to GCAM modelling.

However, according to the Global 20-20-20 policy scenario as formulated for GCAM in Section 3.4, the effect of the European Emissions Trading Scheme (ETS) on European electricity prices and consequently on the cost of producing aluminium, is significant and results in a permanent average increase of energy costs for European aluminium producers in the order of 17 % compared to a scenario where no such carbon taxation was in place. This is illustrated in Figure 5.9.

The Global 20-20-20 scenario gives rise to shifts in these regional cost curves at different points in time corresponding to the different regional implementation start dates, see Figure 5.10. Note that GCAM interpolates values between each 15-year time step, so the effect of the policies are noticeable before the policy is actually implemented (in Europe, the 2020 implementation date actually causes an increase in costs already in 2010 because of this interpolation). Again, these results assumes a constant energy efficiency in the aluminium industry across regions and time steps of 14MWh per tonne of aluminium, so regional advantages related to advancements in technology, skill and knowledge etc affecting energy use, are not included in this comparison.

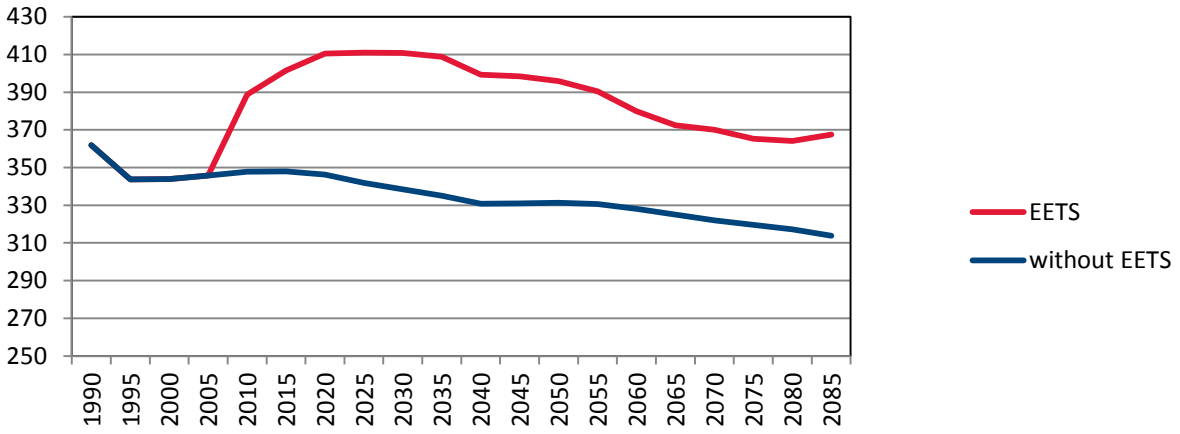


Figure 5.9 Energy cost aluminium production in Western Europe with and without the impact of the carbon tax through the European ETS as modelled in GCAM for the Global 20-20-20 policy scenario [USD/tonne]

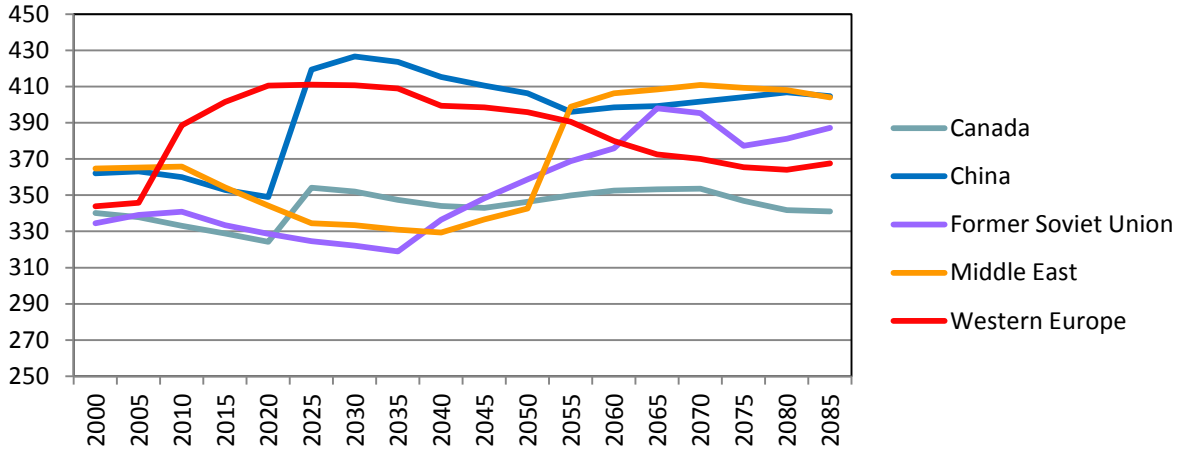


Figure 5.10 Energy cost including carbon taxation from the Global 20-20-20 scenario in a selection of other significant aluminium producing regions [USD/tonne]

Since all regions in the world are assumed to eventually introduce a carbon tax similar to the EU, the relative cost advantage to reallocating production from Europe will only last for a limited window of time under the Global 20-20-20 scenario. As an illustration, a very rough analysis of the energy cost advantage obtained per tonne produced in China or the Middle East instead of in Western Europe in the time period 2010-2025 and -2035 respectively, is given in Figure 5.11.

In order to get annual cost savings between the five year interpolated time steps, the cumulative annual growth rate has been used to fill in the gaps. For the energy savings from moving one tonne of aluminium from Western Europe to China in the years 2021-2024, a linear decline was been assumed.

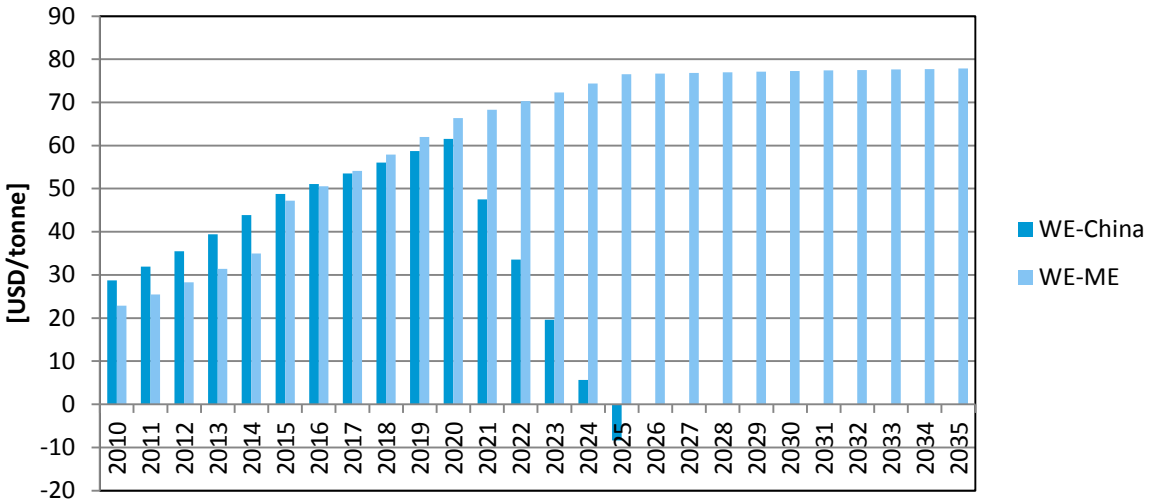


Figure 5.11 Relative cost advantage of moving Al production from Western Europe to China or Middle East during 2010-2035 [USD/tonne]

5.2 The need for a general energy model

An important advantage of general models like CGE and IAM models is that spill-over effects between different markets can be studied. In our case, we need to consider two types of spill-over effects:

- Effect of policy on aluminium market through energy markets
- Aluminium market's influence on energy prices

Since aluminium production is energy intensive, production costs are heavily affected by energy prices. Moreover, energy prices are affected by policies for instance for combating GHG emissions and support for renewable energy. Therefore, a general model is needed to allow for a systematic evaluation of how a given policy change affects energy prices and thereby also energy related production costs for aluminium. By contrast, in a partial model for the aluminium market, one would have to make some ad-hoc assumptions of how policy change affects energy prices, or forecasts/estimates from other sources have to be utilized. In any case, the effect of policy through energy prices is needed to study trade leakage for the aluminium sector in an economic model.

If changes in the aluminium market have considerable influence on energy prices, this will typically dampen the initial trade-leakage effect of any given policy. For instance, an increased CO_2-tax may give higher production costs for aluminium through higher power prices. However, if higher electricity price give reduced electricity demand from the aluminium sector, this will give a downward push on prices that partly crowd out the initial price increase. The strength of this crowding out effect is among other things affected by the aluminium sector's share in total electricity consumption. Table 5.1 shows the annual production of electricity and primary aluminium production for some major areas, as well as the estimated electricity consumption for the aluminium sector using 14 MWh/tonne.

Table 5.1: Production of aluminium and electricity

Area	Electricity production (TWh)	Primary aluminium production (M tonnes)	Estimated electricity use*) (TWh)	Share of total electricity demand
China	3695	17,7	247,8	6,7 %
USA	4337	4,9	68,6	1,5 %
Europe	4168 (EU 27 + Russia)	8,5	119	2,8 %

*) 14 MWh / tonne

As the table clearly indicates, the estimated consumption of electric energy used for primary aluminium production in USA and Europe is relatively low when measured as a share of total electricity production. The share is larger for China, which by far is the largest aluminium producer in the world. Suppose now that an ambitious environmental policy in Europe leads to a trade-leakage of ½ of the existing aluminium production because of higher power prices. This will then lead approximately to a 1.4 % reduction in total electricity consumption annually in Europe. This is not a large change, and prices probably will not be very much affected. This is broadly consistent with the findings above, where production costs change by only about 0.2 % if 50% of the aluminium production in Europe were re-allocated to the other major producer areas.

It is likely that the aluminium sector has a relatively small impact on energy prices, even though there may be regional variations. Therefore, the intended world-market simulation will typically lead to corner solutions where all production is located to one area, and still production costs for aluminium will be lowest for this area. This can of course be an explanation for China's high share of total production. In practice, however, all production is not allocated to the least-cost area immediately. Also, by including transport costs and risks e.g. for future policies, a more diversified allocation of production is likely.

5.3 Conclusions

SINTEF Energy Research does not have a partial model for aluminium, and we did not have enough resources to make a credible partial model for the global aluminium market as a case study for Hydro in the LinkS project. GCAM is the only tool currently available in the LinkS toolbox that in principle can be used to study that market. Through the referred study it has been demonstrated how a policy change affects energy prices, and thus production costs for aluminium. A mechanism for international trade with aluminium has been implemented and applied, but there are still unsolved consistency issues.

Statistics indicates that aluminium production's share of total electricity consumption in Europe and USA is relatively low. It is therefore not likely that electricity prices will be much affected because of trade leakage for aluminium e.g. from Europe to China. This was also demonstrated by the referred study. Consequently, if our primary interest is in the market for aluminium, it is probably unnecessary to use a general model such as GCAM to consistently handle spillover effects from the aluminium market to energy markets.

On the other hand, a partial model for the aluminium market cannot be used to quantitatively estimate how a given policy change (e.g. a reduced ceiling in the European cap and trade system for CO_2) will affect the location of the aluminium industry. Somehow, a link must be created from policy changes to energy costs. GCAM can be applied to systematically evaluate how a policy change affects energy markets and energy related costs for aluminium.

Regarding the implemented world market for aluminium, further work is needed to provide consistent results. Also, other mechanisms such as transport costs and risk-considerations should be added to improve the methodology.

An important final question is whether or not GCAM is an adequate tool for future analysis of the aluminium market. One promising approach could be to utilize GCAM to calculate energy prices in the different areas under different policies. After a GCAM simulation has been carried out, production costs for aluminium (for different areas and technological solutions) can be calculated. Possibly these results can be provide valuable inputs either to strategic considerations, or to a detailed partial model for the aluminium market.

6 World Gas Model scenarios for development of the global gas market

6.1 Overview of recent events in global gas markets

6.1.1 Reserves

The U.S. Energy Information Administration (EIA, 2011a) estimates global proved natural gas reserves to be around 190,800 billion cubic meters (bcm) compared with 187,959 bcm in 2010. Most of these reserves are located in the Middle East and Eurasia with 137,352 bcm, or 71 percent of the world total. In terms of shale gas reserves, EIA (2011b) approximates those technically recoverable resources for select basins in 32 countries totaling 187,535 bcm. China has the largest share with 36,079 bcm followed by the United States at 24,411 bcm and Argentina third at 21,919 bcm. However, in June, 2012, the EIA has recently revised down their 2011 estimate for U.S. shale gas reserves by 40% due to more drilling data, i.e., from 24,411 bcm to 13,650 bcm.

Supply

Global gas supply increased by 3.1% in 2011 compared to 2010, reaching 3,375 bcm. The 99 bcm increase was almost entirely from two regions, North America and the Middle East (BP Statistical Review, 2012). From the Middle East, Qatar ramped up its production 25% more (32 bcm) compared to 2010 while the U.S. shale gas production climbed up by 46% to 240.7 bcm compared to shale production in the previous year (EIA, 2011d). However, European domestic production declined by approximately 10% from 2010 to 2011. Given advanced drilling techniques, EIA predicts that by 2035 shale gas production is estimated to account for 46% of the total U.S. gas production (EIA, 2011c). Many countries attempt to follow the U.S. shale gas development path. For example, China has recently begun to focus on shale gas as a potential new source of gas supply to meet growing demand. The government also announced its national shale gas policy and is targeting shale gas production of 6.5 bcm by 2015 and 60 bcm by 2020. The Ukraine is attempting to reduce dependence on Russia by exploring its own shale gas resources and signed a drilling deal with Shell in early 2013. For Europe, the shale exploration in Poland is slowing down after disappointing early attempts at extraction. Although Europe has large unconventional gas reserves, France, Bulgaria, and the Netherlands passed laws banning hydraulic fracturing (hydrofracking) procedures for environmental reasons (Scott, 2013).

Demand

The U.S. Energy Information Administration (EIA, 2011a) reports that global natural gas demand increased to 3,368.8 bcm in 2011 higher than the 4.9% increase recorded in 2010. Natural gas consumption increased in most regions except for Europe. Asia's consumption increased 6.8%, but European consumption declined by about 7.2% from 2010 to 2011. China's gas demand increased approximately 18.5%, reaching 130 bcm. Higher demand in China was driven by economic growth, particularly the industrial and transportation sectors while additional demand from Japan originated in gas-fired power generation used to compensate for a decrease in nuclear power due to the nuclear disaster in 2010.

Natural Gas Prices

During the middle of 2012, Henry Hub gas prices dropped to $2 per million British thermal units (MMBtu)[6] – the lowest prices in a decade, while the average import prices in Japan reached $17 per MMBtu. German

[6] All dollars in this section of the report are USD unless stated otherwise.

import and UK prices were between $8-10 per MMBTU (BP Statistical Review, 2012). The North American gas market is expected to remain isolated from other regional markets. This phenomenon is recognized by the gap between Japanese liquefied natural gas (LNG) prices and Henry Hub gas prices which rose from around about $7 per MMBtu in January, 2011 to over $14 per MMBtu in March, 2012. In Section 4.5, using the World Gas Model we found that U.S. LNG exports will be competitive in the global gas market due to their substantially lower prices compared to other markets (Moryadee et. al, 2013).

Global LNG Trade

In 2011, compared to 2010, global LNG trade rose by 68.14 bcm which amounted to an increase of 9.4%. In 2011, there were 4110 LNG trips where a "trip is defined as a completed loaded voyage from an export terminal to an import terminal". Of this total number, 1,438 trips or 34% involved shipping LNG to Japan while 1,109 trips or 27% went to Europe.

In terms of LNG exports, in 2011, Qatar was the largest exporter with 31.3% of global LNG trade or 103.4 bcm followed by Malaysia at 10.3% of global supplies and Indonesia third at 9.1% (GIIGNL2012). On the import side, in 2011, the total market share of Asian LNG buyers grew to 63.6%, while Europe and the Americas respectively recorded a 2.6% and 1.6% loss in market share of consumption (GIU, 2011). LNG consumption demand in Asia is strong with growth of 14.8% between 2010 and 2011 because of the increase of Japanese LNG consumption to compensate for diminished nuclear power generation from the 2010 disaster. These circumstances made Japan the world's largest LNG consumer in 2011 with 109.11 bcm, compared to 97.8 bcm in 2010. South America LNG demand grew on average of 13.8% in 2011 as compared to 2010. Likewise, European LNG imports increased 0.4% compared to 2010 with additional amount from Qatar to the United Kingdom. However, North American LNG import has continued to decrease due to the rise of its domestic unconventional production.

Natural Gas Facilities

Pipelines: Pipeline&Gas Journal (2011) reports worldwide pipeline construction in 2011 as follows: North America – 28,099 miles ; South/Central America – 9,869 miles; Africa – 7,759 miles; Asia Pacific Region – 41,525 miles; Former Soviet Union and Eastern Europe – 18,896 miles; Middle East – 9,345 miles; and Western Europe and European Union - 4,445 miles.

LNG facilities: Global liquefaction capacity of 384.45 bcm at the end of 2011 can be broken down in this way; Middle East– 138.3 bcm, Pacific–138.7 bcm, and Atlantic-Mediterranean –107.3 bcm. With 115.8 bcm of liquefaction capacity under construction, global capacity is expected to increase to 461.9 bcm by 2016 (GIU, 2011).

Global Regasification capacity reached about 882.8 bcm with 89 LNG regasification terminals at the end of 2010, More than 50% of the world's regasification capacity are located in Asia. The utilization rate in the U.S. reduces 5%, but the rest of the world remain stable (GIIGNL 2011).

6.2 The World Gas Model (WGM)

To analyze global gas markets, the World Gas Model (WGM) was used (Moryadee et. al, 2013). The WGM, developed at the University of Maryland with cooperation from DIW Berlin, is a large-scale complementarity model of the global gas markets where agents include natural gas producers, traders, storage operators, an integrated pipeline and system operator, and marketers. The role of each market agent in WGM is summarized as follows:

- Producers supply natural gas to their dedicated traders and the producers are modeled as optimizing their profits subject to engineering bounds on daily and time-horizon production levels;
- Traders also are modeled as maximizing their profits and buy gas from either producers or storage operators during high-demand seasons and selling it to the local market or exporting it internationally via high-pressure pipelines and/or LNG vessels;
- Storage operators optimizing their profits by buying gas in low-demand seasons and selling it back to traders during high-demand seasons taking into account various engineering constraints on storage reservoirs;
- An integrated pipeline and system operator assigns the pipeline capacity to traders and makes decisions regarding the expansion of the pipeline capacity in order to maximize its profit;
- Marketers distribute gas to end users represented by an inverse demand curve.

The WGM characterizes three types of producers: conventional gas, shale gas, and non-shale unconventional gas in each region of the U.S. The production capacity is calibrated based on data from the U.S. Department of Energy's Annual Energy Outlook (2010). The U.S. contains a total of 24 natural gas producers, of which seven are shale gas and seven are conventional. The rest of the U.S. producers are conventional producers. In term of market behaviors, traders have a weighted combination of both price-taking and price-making behavior. On one extreme, they can be price-takers with no market power consistent with perfect competition. Conversely, they can also be Nash-Cournot players who can manipulate market prices along with other traders or some weighted combination of these two extremes. The particular weight is determined by the node (country) in question and calibration with historical values.

In the current version the WGM takes into consideration environmental aspects. The WGM incorporates CO2e emissions for each major player on the supply side of the market. In addition, we can impose regional CO2 prices ($/ton of CO2e) as a cost on market participants. This new feature is a benefit for conducting CO2 reduction policy analysis as described in later sections. Lastly, the model operates with five-year periods from 2005-2050 as well as two seasons (low and high demand). Three versions of WGM used in several case studies for the LinkS project are summarized in Table 6.1.

Table 6.1 The versions of WGM used in LinkS

Version	Descriptions
WGM2012	The World Gas Model outcome is calibrated to match global natural gas market trends in 2010 and incorporates natural gas market projections from multiple sources, such as the EC European Energy and Transport: Trends to 2030 (European Commission, 2008) and Natural Gas Information (IEA, 2007). Moreover, because of concerns regarding the dramatic growth in unconventional gas production in North America, the unconventional production reference from the forecast presented in the Annual Energy Outlook (AEO, 2009) is used. We use WGM2012 in Sections 6.5 (U.S. LNG Export) and 6.6 (European Pipeline Study). *In these two studies we use WGM2012 without calibration with GCAM because the consumption and price output from this version is closer to global natural gas trends in 2010 than GCAM reference due to the development of unconventional gas, LNG trades, and restriction of the policy. However, CO_2 prices from GCAM Global 20-20-20 scenario are used as input to WGM in one of the cases in Section 6.5.*

WGM2012CO_2	This version is based on the calibration from WGM2012, but modified to allocate CO_2 costs between consumers and producers used in Sections 6.3 and 6.4. CO_2 prices from GCAM 650 ppm scenario are used as input to WGM in Section 6.4, but model results are not calibrated.
WGM650ppm	We use WGM650ppm for the LinkS model calibration in Chapter 9. In the first iterative process, the WGM natural gas consumption is calibrated to match the GCAM 650 scenario with CO_2 costs. In the second iterative process, natural gas demand for European power generation is recalibrated to output from the EMPIRE model. Furthermore, China's natural gas consumption in WGM is specifically calibrated according to output from TIMES model.

6.3 Allocation of CO_2 cost in the supply chain

6.3.1 The Problem

Policy makers apply carbon taxes, cap-and-trade programs and emission allowances to limit or reduce the amount of GHG emissions. In most cases, these policies can be expressed in terms of a monetary value per unit of emissions and act as incentives or disincentives for both producers and large energy consumers inducing a switch to cleaner energy sources or improved technologies. Under non-perfect competition the carbon pricing can have a significant negative impact on the price and consequently as shown in case studies on some market players. Therefore, there was a need to develop a model that could support proportional assignment of carbon costs, and, hence, allow the development of more desirable carbon policies (either from the consumers' or suppliers' perspective). The existing decision-support models do not provide analysis options for assessing the effectiveness of carbon pricing on the natural gas industry. However, in the new version of WGM modified and expanded for LinkS project we allocate carbon emissions to players based on their shares in the total supply. This modified version of WGM that considers carbon costs and proportional allocation in the market was used for our analysis. Specifically, 27% of 0.37 metric tons per thousand cubic meters of natural gas emissions were allocated to production, 12% to processing, 28% to transmission, 24% to distribution, and 9% to storage related pollution of the supply chain players. The emissions from the final consumption of 2.39 metric tons per thousand cubic meters of natural gas were also applied to producers, storage operators and traders as part of the gas supply chain that delivers natural gas to its users through the marketer (EIA, 1998; INGAA, 2000).

This modification of the standard WGM as discussed above allows for inclusion of carbon costs per ton corresponding to the desired carbon policy. The approach implemented in this project is different from existing techniques by means of assigning carbon costs simultaneously to the suppliers and the consumers in varying proportions depending on the modeler's choice. In contrast to perfectly competitive markets, consideration of the WGM structure as a Nash-Cournot game provides non-intuitive outcomes depending on the given parameters per policy scenario and the equilibrium point.

6.3.2 The Formulation

The formulation of a sample player in WGM is presented below. Overall, the same approach is applied for each player's problem in the WGM.

Notation

For consistency with the original formulation of the WGM, the terms for carbon emissions and carbon costs used in the extension follow the same structure. For instance, market player indices are the first letters of

their full names. For example, $SALES^X$ are the total sales of a market agent of type X. Also, $SALES^{X \to Y}$ are the sales of an agent of type X to an agent of type Y and $PURCH^{Y \to X}$ are the purchases of an agent of type Y from agents of type X. Country nodes are denoted by indices from the set N, and subsets of nodes where a player X is present, by $N(x)$; to denote individual nodes in this set, we write $n(x)$. To denote the subset of agents X present at node n, a $X(n)$ is used; for individual set elements, $x(n)$ was used. Units used in the model are provided in more detail in (Gabriel et al., 2012).

In general, the following terms are used: Market prices π, Inverse demand function $\Pi(\cdot)$. Shadow prices of constraints are given in lower case Greek symbols, with superscripts representing the relevant player type (describing the player in the supply side of the market, such as producers, traders, transmission system operators, storage operators and marketers), and subscripts representing the players, nodes, seasons and years (e.g., α^P_{pdm}, the dual of the producer $(\cdot^P)$ capacity constraint for producer p in year m and season d).

The following are the sets used in the original model formulation (Gabriel et al., 2012):

$a \in A$	Gas transportation arcs, e.g., {NNED_GER, LNOR_FRA, RGER_GER}[7]
$d \in D$	Demand seasons, e.g., {low, high}
$p \in P$	Producers, e.g., {P_NOR, P_RUW, P_RUE}[8]
$m \in M$	Years, e.g., {2005, 2010, 2015, 2020}
$n \in N$	Model nodes[9], e.g., {N_NOR, N_RUW}

The complete list of notation is provided in (Gabriel et al., 2012).

Producer's Problem

The first player in the natural gas supply chain is the producer that extracts the gas (either onshore or off-shore) and after processing makes it available to the trader (i.e., the producer's marketing arm dedicated only to a particular producer). It is assumed that all the production costs are included in the model by the given production function. This is a simplification of reality in which the actual costs may be fairly complicated to compute and may not have desirable mathematical properties such as convexity or differentiability with respect to quantities produced.

The formulation presents a discounted profit maximization problem for the producer p, where profits are represented as the difference between sales $SALES^P_{pdm}$ and production and investment costs. Cash flows in year m are discounted by a factor of γ_m. Since sale rates are per day and may differ by season, those are multiplied by the number of days in the season d. Also, $days_d$. cc^{ton}_{pm} denotes the carbon cost per ton of CO_2e for the producer p in year m. The factor CE^P is the carbon emissions factor associated with the production process per unit of natural gas. The superscript of this factor changes for other players in the supply chain (i.e. for traders or storage operators).

[7] The first letter indicates the type of arc; combinations of three letters denote the region or country name. NNED_GER represents a pipeline from the Netherlands to Germany; LNOR_FRA is an LNG shipping arc from the Norwegian liquefaction node to the regasification node of France and RGER_GER the arc from the German regasification node to the German country node. NNIG_LNG denotes the arc from the country node Nigeria to the Nigerian liquefaction node.

[8] Indicating the producers in Norway, Russia West and East and in other countries

[9] Model nodes represent geographical regions in the world (see Gabriel et al., 2012). They can be defined flexibly in the model data set. Due to the limited relevance and impact of countries that only produce and consume small amounts, several countries have been grouped with neighboring ones and are represented in the model data set on an aggregate level. For some countries the opposite is true: their consumption or production is so high, and the geographical distances so large, that a division of the countries in several regions is warranted.

To account for the proportional application of carbon costs along the supply chain, the term Ω is included as the weight per node. Here Ωis a value in [0, 1].

The objective function of the producer's problem, with carbon costs applied to both the supply side and the consumer side is:

$$\max_{SALES^P_{pdm}} \sum_{m\in M} \gamma_m \left\{ \sum_{d\in D} days_d \left[\left(\pi^P_{n(p)dm} + \Omega_{pm} \cdot cc^{ton}_{pm} \cdot CE^P\right) SALES^P_{pdm} - c^P_{pm}\left(SALES^P_{pdm}\right) - \left(1-\Omega_{pm}\right) cc^{ton}_{pm} \cdot SALES^P_{pdm} \cdot CE^P \right] \right\} \quad (4.1)$$

In this function, the price $\pi^P_{n(p)dm}$is multiplied by the $SALES^P_{pdm}$ and summed up over days. Similarly, the costs $c^P_{pm}\left(SALES^P_{pdm}\right)$ are deducted from revenues, where the difference is the profit that is being maximized. The new added terms for carbon costs are $\Omega_{pm} \cdot cc^{ton}_{pm} \cdot CE^P$ which represents the proportion of carbon cost being assigned to the consumer. Here the term cc^{ton}_{pm} is multiplied by CE^P the carbon emissions factor CE^P. When these terms are multiplied by the amount of sales, we get the cost of carbon corresponding to the traded amount of gas. When the carbon cost is transferred to the producer and deducted from its revenues, the term $(1-\Omega_{pm})$ is used together with $cc^{ton}_{pm} \cdot SALES^P_{pdm} \cdot CE^P$ and then is subtracted from the revenues. Finally, we find the total discounted profits by multiplying all terms by the number of days per high and low seasons, and sum over time periods.

Before the modification, the objective function for the producer's problem without consideration of carbon costs in WGM was given as:

$$\max_{SALES^P_{pdm}} \sum_{m\in M} \gamma_m \left\{ \sum_{d\in D} days_d \left[\left(\pi^P_{n(p)dm}\right) SALES^P_{pdm} - c^P_{pm}\left(SALES^P_{pdm}\right) \right] \right\} \quad (4.2)$$

The producers' and other players'constraints were not modified, but are shown for completeness.

The sales are restricted to the maximum production capacity $\overline{PR}^P_{pm}$, which can vary over time:

$$s.t. \quad SALES^P_{pdm} \le \overline{PR}^P_{pm} \quad \forall d, m \quad \left(\alpha^{PR}_{pdm}\right) \quad (4.3)$$

Due to reserve limitations and regulatory requirements, the total production of natural gas in a considered time period is limited to the production ceiling $\overline{PH}_p$.

$$\sum_{m\in M} \sum_{d\in D} days_d SALES^P_{pdm} \le \overline{PH}_p \quad \forall m \quad \left(\alpha^{PH}_p\right) \quad (4.4)$$

Lastly, sales must be non-negative:

$$SALES^{P}_{pdm} \geq 0 \quad \forall d, m \tag{4.5}$$

6.4 The 650 scenario in WGM

6.4.1 650ppm Case[10]

In this section, we describe output from the World Gas Model (WGM) considering the 650 ppm Case which has the highest share of natural gas of the six GCAM scenarios. The 650 ppm Case differs from the Base Case (renamed as "650ppm-0CO_2") due to the inclusion of carbon policy requirements. These requirements limit pollution levels in the atmosphere to 650 parts per million by 2095, which is a relaxed restriction compared to more aggressive policies such as the European 20-20-20 Case. The corresponding carbon costs for this case are obtained from resulting GCAM runs (Table 6.2) and used as input data to the World Gas Model.

The data in Table 6.2 are comparably lower than carbon costs proposed for the stricter 20-20-20 Case. Nevertheless the costs in Table 6.2 come online earlier than the 20-20-20 Case and hence provide interesting economic insights described in the numerical results and analyses section. Also, it should be noted that the carbon prices for the last time periods (from 2050 to 2060 (Table 6.2)) under the 650 ppm Case become more consistent over the different regions in the world.

Table 6.2 Costs of Carbon Dioxide Equivalents per metric ton in 2005 U.S. Dollars for 650ppm Case

Region	Considered Time Periods											
	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
Africa	-	-	-	-	-	-	-	-	-	14.1	35.7	64.7
Australia/NZ	-	-	7.54	10.2	12.9	15.6	21.2	26.8	32.4	44.1	55.7	67.4
Canada	-	-	7.54	10.2	12.9	15.6	21.2	26.8	32.4	44.1	55.7	67.4
China	-	-	-	-	-	10.7	16.9	24.1	32.4	44.1	55.7	67.4
Eastern Europe	-	-	7.54	10.2	12.9	15.6	21.2	26.8	32.4	44.1	55.7	67.4
FSU	-	-	-	-	-	10.7	16.9	24.1	32.4	44.1	55.7	67.4
India	-	-	-	-	-	10.7	16.9	24.1	32.4	44.1	55.7	67.4
Japan	-	-	7.54	10.2	12.9	15.6	21.2	26.8	32.4	44.1	55.7	67.4
Korea	-	-	-	-	-	-	-	-	-	14.1	35.7	64.7
Latin America	-	-	-	-	-	10.76	16.97	24.15	32.4	44.1	55.7	67.4
Middle East	-	-	-	-	-	-	-	-	-	14.12	35.70	64.75
Southeast Asia	-	-	-	-	-	-	-	-	-	14.12	35.70	64.75
USA	-	-	7.54	10.22	12.91	15.60	21.22	26.84	32.46	44.12	55.79	67.45
Western Europe	-	-	7.54	10.22	12.91	15.60	21.22	26.84	32.46	44.12	55.79	67.45

[10] Note that only the carbon costs from GCAM are incorporated in WGM in this analysis. The reason for this was to match other outputs to more specific industry references.

6.4.2 Overview

One major conclusion from the 650ppm case is that there may be significantly different market results depending on where the carbon policy is applied in the natural gas supply chain. In particular, where the carbon costs are assigned– upstream or downstream or a mixture—can have dramatically different results. To gauge the effects of proportional assignment of these carbon costs along the natural gas supply chain, three representative countries were picked: the U.S., Germany and Russia. These three countries were picked to cover three major regions of the world (North America, Europe, Asia) as well as three different market structures (perfect competition and self-sufficient supply, oligopoly with strong dependence on imports , strategic producer, respectively). Some non-intuitive changes also occur in regions where the carbon policy was not adopted by the time considered for comparison. In fact, it is found that the early adopters of carbon policies may not be the most adversely affected regions.

To measure the effect of the impact from carbon policies on the natural gas market the following metrics are used: the consumer and producer surpluses and average wholesale prices. Before presenting the specifics for the U.S. it is important to realize the global impact of carbon policy implementation on the natural gas markets. As such the average wholesale price changes in 2015 and 2050 for all regions for 650ppm Case scenarios are presented in Figure 6.1.

In Figure 6.1 and throughout this section, the following notation is used. First, the Omega symbol Ω represents the fractional assignment of the carbon costs along the natural gas supply chain from the downstream perspective. Thus, $\Omega = 0$ (%) is when the carbon costs are subtracted only from the suppliers' revenues directly (0% applied to the consumers). When Ω= 100 (%), the consumer faces the direct addition of the tax to the total price. When Ω= 50 (%), the producers and consumers share 50-50 carbon costs. Lastly, Ω=_0CO2 indicates a no carbon cost case used as a reference.[11] As opposed to a perfectly competitive market where supply side costs would be passed on to the consumers, given that the WGM and global gas markets have strategic, somewhat oligopolistic producers, the results are not immediately predictable from economic theory. Moreover, given the various pipeline, LNG and other constraints that can bind, and the mixture of perfect competition and imperfect competition aspects, the prediction of what might happen under the various cases considered can really only be tested using a model like the WGM with key countries highlighted (as mentioned above).

From Figure 6.1, several global results are clear. First, by 2050 when all regions will have adopted some carbon costs, the average regional wholesale prices are higher than if no carbon costs had been applied (blue, left-most bar). These price increases can be dramatic (e.g., for China, Europe) or less so (e.g., Africa). The particular results depend on the timing of the carbon costs implementation, the pipeline and LNG import-export picture, local production costs, etc. and are thus a mixture of many market and policy effects. Another global finding for 2050 is that for most of the regions considered, the Ω=0% case when only the producers face these carbon costs as an adder to their production costs results in the highest average prices. This is certainly true for example for Europe and North America but not universally true (e.g., the Mideast). The lowest average regional prices are not necessarily when the consumers bear 100% of these carbon costs (Ω=100%) as shown in this figure for China and the Former Soviet Union as two examples. For these two important regions, the lowest average prices occur when the carbon costs are allocated equally (Ω=50%) between the producers and the consumers. Conversely, from an average price

[11] The calibration for the Base Case is the original calibration of WGM that matches the reference databases not the 650 ppm scenario from GCAM.

perspective, this figure shows that taxing the consumers 100% (Ω=100%) produces the lower prices for regions such as North and South America. Thus, it can be seen that the results are not always consistent geographically since there are many market and other factors that can be influential.

From Table 6.2 it is seen that only few regions adopt the proposed 650ppm carbon policy by 2015. Moreover, by 2015 the cost for regions adopting the policy is relatively low. In contrast, by 2050 all regions have this policy adopted and therefore the impact of carbon costs is much more noticeable compared to 2015.

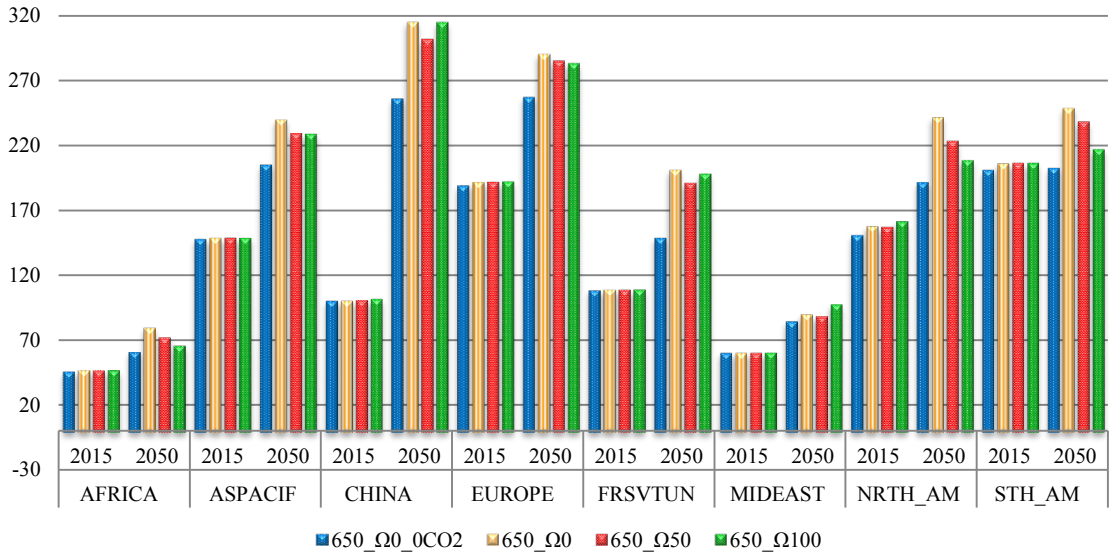


Figure 6.1 Average Regional Wholesale Prices in 2015 and 2050 $/ thousand cubic meters (KCM) ($2005) (650ppm Case)[12]

The next set of analyses consider country-specific results for the U.S., Germany, and Russia. As described above, these case study countries were selected for representative reasons both geographically as well as due to their different market structures and import-export profiles.

6.4.3 Analysis for the United States

More specific details for market change comparisons for all cases are presented below for the U.S. Figure 6.2 shows the average wholesale price and production levels in the U.S. from 2015 (as a first year of carbon policy adoption in at least one region) to 2050 (the time horizon for which the results of the model are reported). Numerical results of these cases are presented in Table 6.3.

[12] It should be noted that the impact of such carbon cost applications may vary from region to region and from case to case due to non-perfect competition and the elasticity of inverse demand functions.

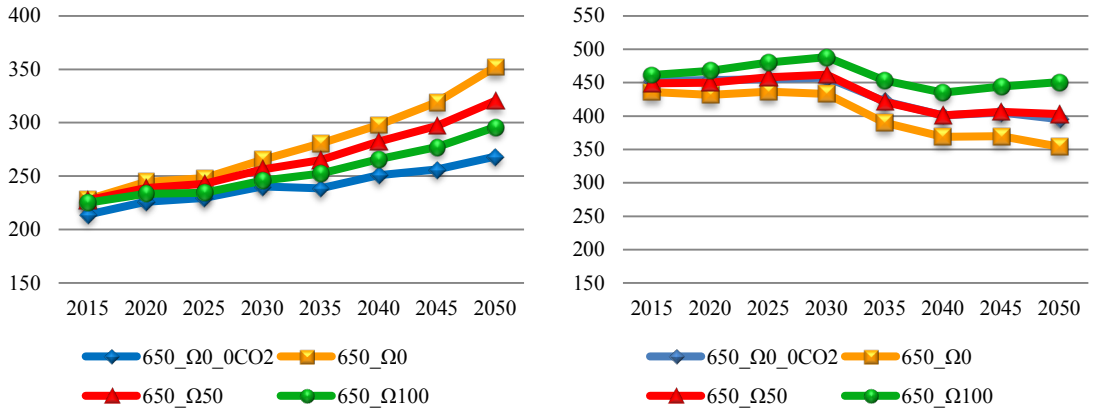


Figure 6.2 Average Wholesale Prices $/KCM (2005 dollars) (left) and Production in bcm/Y in the U.S. (650ppm Case) (right[13])

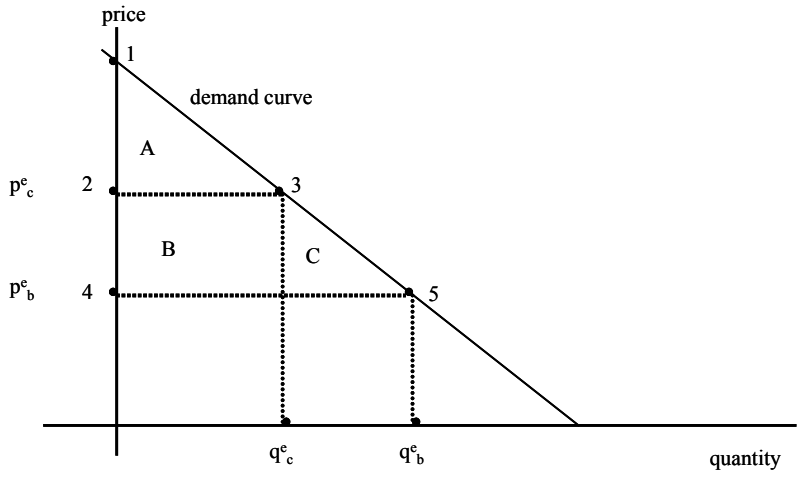
From the results we notice that in 2030 the U.S. production levels drop and then start increasing again. This is because prices for carbon are not unilaterally added to all regions simultaneously. For the average wholesale prices we notice a steady increase which is due a stepwise increase for the carbon cost from one time interval to another. We can see that for the U.S., having the carbon costs 100% paid by the consumers, results in the lowest gas prices for each of the years indicated for the three non-base cases (650_Ω0,650_Ω50,650_Ω100) but still higher than the Base Case (650_Ω0_0CO2). In addition, when the costs are 100% paid by the consumers, as one would expect, the production levels are the highest of the three non-base case since the producers don't need to endogenize these costs. The production levels are also higher than the Base Case. What is interesting is that this same case (650_Ω100) represents the smallest loss in consumer surplus so in effect the consumers benefit the most when they are responsible for the carbon costs (see Figure 6.3 and Table 6.4 for consumer surplus aspects). [14]

Table 6.3 Average Wholesale Prices and Production Volumes in the U.S. (650ppm Case)

Year	$/KCM ($2005) 650ppm Case Scenarios				Production in bcm/Y 650ppm Case Scenario			
	650_Ω0_0CO2	650_Ω0	650_Ω50	650_Ω100	650_Ω0_0CO2	650_Ω0	650_Ω50	650_Ω100
2015	214.12	228.22	227.43	225.12	453.40	435.83	448.79	461.33
2020	225.99	244.47	238.89	233.63	453.67	431.59	449.75	467.48
2025	229.72	248.20	242.75	234.39	455.38	436.56	458.05	480.01
2030	240.29	265.26	256.33	245.79	457.45	433.19	461.67	488.07
2035	238.60	280.51	264.94	252.34	421.90	390.05	421.31	453.20
2040	250.86	297.94	282.20	265.74	401.06	368.86	401.09	435.00
2045	256.36	319.26	296.94	277.14	405.31	369.74	406.38	444.32
2050	268.21	351.98	320.51	295.88	395.11	354.00	402.77	450.63

[13] Note that the Base Case almost entirely matches the 50% shared carbon tax case, thus it is hidden from the graph. Furthermore, the Base Case is not tuned to the three 650 ppm cases and has a different price/volume characteristic that the other three.

[14] To compute the loss of consumer surplus one can take the equilibrium price and quantity differences between scenarios and find the difference of the consumer surpluses (same as the sum of area B plus C).



$$B + C = \frac{1}{2}\left(p^e_c - p^e_b\right)\left(q^e_c + q^e_b\right)$$

Figure 6.3 Consumer Surplus as the area of B+C.

Table 6.4 Loss of Consumer Surplus in the U.S. from the carbon cost allocation

Year	Billion $ ($2005) 650ppm Case Scenarios								
	No Carbon Cost (Ω0_0CO2) vs. 650ppm 0% to consumers (Ω0)			No Carbon Cost (Ω0_0CO2) vs. 650ppm 50% to consumers (Ω50)			No Carbon Cost (Ω0_0CO2) vs 650 ppm 100% to consumers (Ω100)		
	Consumer surplus	Producer surplus	Total	Consumer surplus	Producer surplus	Total	Consumer surplus	Producer surplus	Total
2015	6.27	3.35	9.62	6.00	1.78	7.78	5.03	0.18	5.21
2020	8.18	4.57	12.75	5.83	2.30	8.13	3.52	0.01	3.53
2025	8.24	5.78	14.02	5.95	2.93	8.88	2.18	0.03	2.21
2030	11.12	7.89	19.01	7.37	3.47	10.84	2.60	1.06	3.66
2035	17.01	9.45	26.46	11.11	4.09	15.20	6.01	1.28	7.29
2040	18.12	10.55	28.67	12.57	4.91	17.48	6.22	0.78	7.00
2045	24.38	12.53	36.91	16.47	6.08	22.55	8.83	0.70	9.53
2050	31.38	17.95	49.33	20.86	8.42	29.28	11.7	1.63	13.33

One might ask it is preferable from policy perspective to apply the carbon cost to the consumers? This happens because of the oligopolistic structure of the market where the rival firms operate in the elastic region of the demand curve and therefore the impact from the tax might be higher (see the analysis for Germany for a short discussion of the role of this elasticity). Table 6.5 presents the total production costs in each time period considered. Conversely, as shown in Table 6.4 the producers do worse, but only at smaller amount if 100% of the tax is applied to the consumers. Lastly, the loss of the total surplus is minimized using the same approach to carbon tax allocation, namely when the consumers pick up 100% of the carbon costs (650_Ω100).

Table 6.5 Total Production Costs in the U.S (Billion $) (650ppm Case)

Year	Billion$ ($2005) 650ppm Case Scenarios			
	650_Ω0_0CO2	650_Ω0	650_Ω50	650_Ω100
2015	48.18	49.59	49.46	49.20
2020	49.27	51.33	51.14	50.76
2025	53.25	56.71	56.50	56.16
2030	57.74	62.35	61.76	60.51
2035	56.00	60.85	60.01	58.83
2040	56.67	62.24	61.59	60.66
2045	60.44	67.09	66.68	65.52
2050	62.81	73.25	72.53	69.90

The results of Table 6.4 indicate for the U.S. in 650ppm Case the worst option of policy implementation would be if the tax was applied to the suppliers. The best case would be if the tax is imposed on consumers. This dynamics in market behavior is because actors in the oligopolistic market operate in the elastic region of the inverse demand curve (similar to a monopolistic market).

The market structure in the U.S is modeled as a perfect competition although within the model the market also interacts with other players from other regions. As an example of a region that exerts market power on the natural gas market the impact of carbon policy adoption in Europe is considered next.

6.4.4 Analysis for Germany

Germany is selected for analysis due to its geographic location and market structure. Specifically, it does not have much natural gas, and is highly dependent on Russian supplies as opposed to the U.S. which is more self-sufficient. First we present the difference in average wholesale prices and the production levels for Germany in Figure 6.4 and Table 6.6.

Similar to the U.S. case, the loss of consumer surplus is computed and is given in Table 6.7. The loss in consumer surplus is equal to the total surface given by B plus C in Table 6.4.

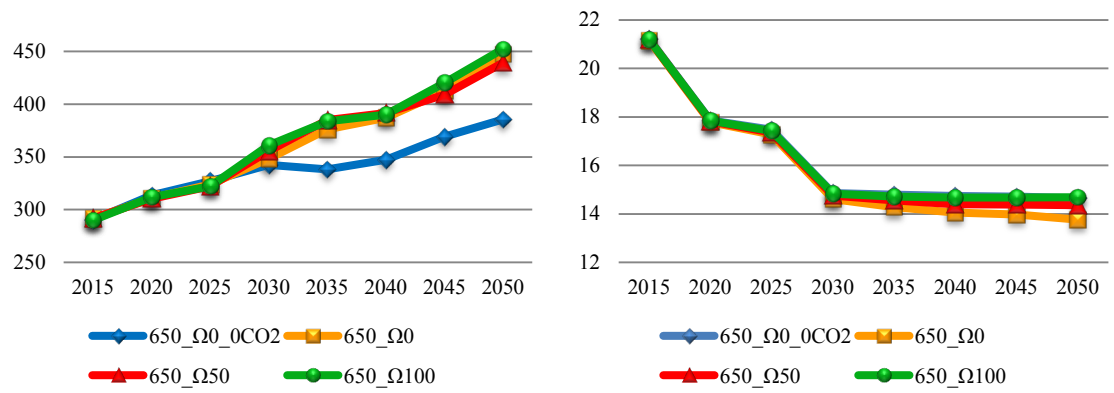


Figure 6.4 Average Wholesale Prices $2005/KCM (left) and Production in bcm/Y in Germany (650ppm Case) (right[15])

[15]No carbon cost scenario overlapped with 50% shared carbon cost scenario.

Table 6.6 Average Wholesale Prices and Production Volumes in Germany (650ppm Case)

Year	$/KCM ($2005) 650ppm Case Scenarios				Production in bcm/Y 650ppm Case Scenario			
	650_Ω0_0CO2	650_Ω0	650_Ω50	650_Ω100	650_Ω0_0CO2	650_Ω0	650_Ω50	650_Ω100
2015	290.28	291.53	291.83	289.93	21.21	21.16	21.18	21.19
2020	313.50	311.02	310.29	311.71	17.86	17.78	17.82	17.84
2025	327.04	323.90	322.06	322.11	17.48	17.27	17.35	17.42
2030	342.46	348.37	355.61	361.01	14.86	14.61	14.76	14.83
2035	338.18	376.10	384.95	383.83	14.80	14.28	14.55	14.72
2040	347.34	387.04	391.62	390.18	14.74	14.06	14.40	14.67
2045	369.18	412.38	408.89	420.31	14.72	13.97	14.39	14.67
2050	385.69	447.66	439.25	452.28	14.65	13.76	14.36	14.69

Table 6.7 Loss of Surplus in Germany

Year	Billion $2005 650ppm Case Scenarios								
	No Carbon Cost (Ω0_0CO2) vs. 650ppm 0% to consumers (Ω0)			No Carbon Cost (Ω0_0CO2) vs. 650ppm 50% to consumers (Ω50)			No Carbon Cost (Ω0_0CO2) vs 650ppm 100% to consumers (Ω100)		
	Consumer surplus	Producer surplus	Total	Consumer surplus	Producer surplus	Total	Consumer surplus	Producer surplus	Total
2015	0.03	0.145	0.175	0.03	0.073	0.103	-0.01	0	-0.01
2020	-0.04	0.163	0.123	-0.06	0.08	0.02	-0.03	0.001	-0.029
2025	-0.05	0.192	0.142	-0.09	0.094	0.004	-0.09	0.006	-0.084
2030	0.09	0.193	0.283	0.19	0.094	0.284	0.28	0.008	0.288
2035	0.55	0.25	0.8	0.69	0.122	0.812	0.67	0.009	0.679
2040	0.57	0.315	0.885	0.65	0.159	0.809	0.63	0.006	0.636
2045	0.62	0.385	1.005	0.58	0.198	0.778	0.75	0.004	0.754
2050	0.88	0.055	0.935	0.78	0.02	0.8	0.98	0.008	0.988

*(-) means gains in the surplus.

The production costs of producers in Germany are given in Table 6.8.

Table 6.8 Total Production Costs in Germany (Billion US$) 650ppm Case)

Year	Billion $ (2005) 650ppm Case Scenarios			
	650_Ω0_0CO2	650_Ω0	650_Ω50	650_Ω100
2015	3.01	3.15	3.08	3.01
2020	2.73	2.88	2.80	2.73
2025	2.88	3.03	2.95	2.86
2030	2.64	2.78	2.71	2.62
2035	2.82	2.97	2.89	2.80
2040	3.02	3.19	3.11	3.00
2045	3.24	3.45	3.37	3.23
2050	3.47	3.77	3.67	3.49

These results indicate that for Germany in the 650ppm Case, the best option for carbon policy adoption would be if the tax is dynamically adjusted between consumers and producers from one time period to another. As an example it might be better to apply the entire tax to consumers in 2015 then on suppliers in 2030. Due to such strategy the total loss of surplus can be lessened. One reason for this dynamic result might be the combination of the elastic range of inverse demand curve where the rival firms operate and get to equilibrium. From an oligopolistic market perspective, a firm can maximize its revenues up to the point where the unit elasticity on the inverse demand curve is (- 1) (Figure 6.5). This means that when rival firms are in the market for profit maximization and they have no incentive to deviate from equilibrium price and quantity the equilibrium is reached. The equilibrium can be reached by adjusting the quantity and prices in the elastic region (from negative infinity to - 1) and the impact of taxation can be even higher than the tax itself. By allocating the tax on the supplier and considering the flexibility of each firm for its production levels the impact on price may not be predicted *apriori*.

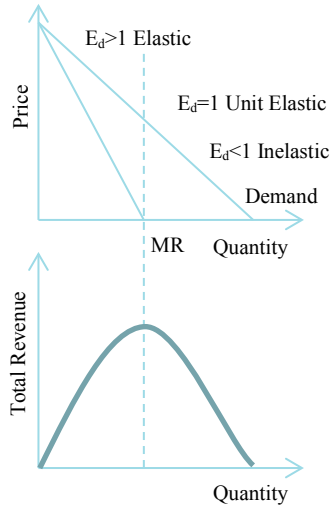


Figure 6.5 The inverse demand curve for a firm in an oligopolistic market

Results for Germany are also affected due to the mixed structure of the market where some part is subject to the market power from suppliers (e.g., Russia and Norway) and some not. The consideration of a mixed structure creates additional difficulty in understanding the exact cause of the change but in this case some firms are price-takers, while others set the price from an oligopolistic perspective. The decisions made by rival firms that also set the price consequently affect the supply decisions of price-taker firms.

For Germany, actual gains in consumer surplus versus the no carbon policy scenario occurred in 2020 and 2025 contrary to the U.S. This can be explained since the German suppliers are not affected by the carbon policy adoption as indicated in Table 6.7. The weight Ω influences somewhat the loss in consumer surplus. Once all nations have adopted the carbon policy by 2050 the impact on consumer surplus is minimized by allocation of carbon cost when Ω is 50% as shown in Figure 6.4. From the consumers' perspective the best carbon tax allocation is for a 50% weight until after 2030 then it is best apply the tax to the supplier. From Figure 6.4 we observe that when the 650ppm carbon policy is adopted in Germany a difference in loss in consumer surplus is already noticeable from the start. In fact the policy impact is in favor of consumers in years 2020 and 2025 where the loss in consumer surplus is negative meaning that the consumer surplus is larger. In 2030 when the German consumers bear 100 percent of the tax they lose more in surplus versus

when they share the tax equally with producers. In fact for 2030 the best for consumer surplus is to have producers to pay 100 percent of the tax.

Why does this happen? For 2030 for Germany the following logic likely prevails. First, due in part to producers paying 100 percent of the tax with resulting higher production costs the production for German producers is lowest among carbon policy scenarios (see Figure 6.4). Also, at the same time producers (via their traders) from other countries ramp up to compensate (Figure 6.6). Some of these producers presumably have lower production costs due to non-adoption of carbon policies resulting in the lowest average wholesale prices for all the carbon cost allocation scenarios. Lower prices leads to higher consumer surplus. Other years are different such as 2050.

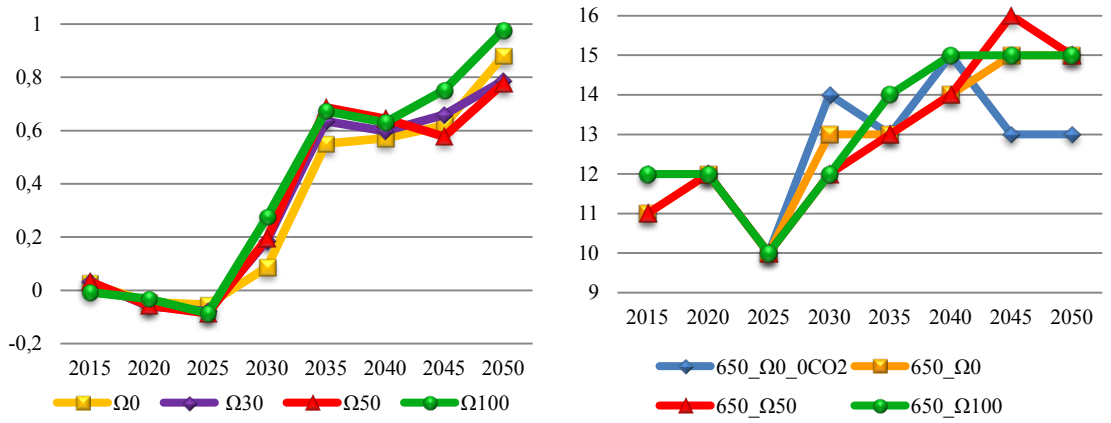


Figure 6.6 Loss of consumer surplus from carbon cost allocation through Ω along the supply chain (left) and daily sales by traders in Germany million cubic meters per day (right)

6.4.5 Analysis for Russia

Next we analyze the market dynamics for Russia. Average wholesale prices and production volumes in Russia are presented in Figure 6.7. From this figure an interesting insight can be gained since from the average wholesale prices we notice that the carbon policy if applied to Russia would have dramatic impacts. It can be observed that when the consumers are responsible for the carbon price in some time periods, prices and production are higher.

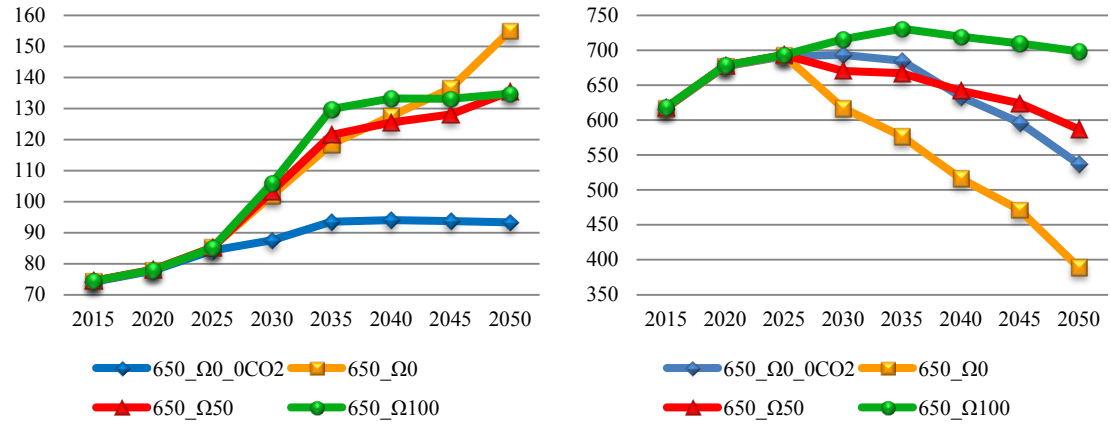


Figure 6.7 Average Wholesale Prices $/KCM ($2005) (left) and Production in bcm/Y in Russia (650ppm Case) (right)

Table 6.9 Average Wholesale Prices and Production Volumes in Russia (650ppm Case)

Year	$/KCM ($2005) 650ppm Case Scenarios				Production in bcm/Y 650ppm Case Scenario			
	650_Ω0_0CO2	650_Ω0	650_Ω50	650_Ω100	650_Ω0_0CO2	650_Ω0	650_Ω50	650_Ω100
2015	74.15	74.40	74.43	74.44	616.79	616.96	617.58	618.20
2020	77.69	78.09	78.03	77.91	676.94	677.58	677.93	678.02
2025	84.28	85.25	85.19	85.01	691.40	692.92	693.06	693.14
2030	87.54	102.02	103.29	105.87	693.25	617.41	670.40	715.69
2035	93.46	118.44	121.49	129.78	685.02	576.86	666.91	730.74
2040	94.03	127.50	125.48	133.24	633.55	516.29	642.10	719.42
2045	93.69	136.44	128.03	133.11	596.73	471.24	624.12	709.82
2050	93.32	154.98	135.40	134.71	536.99	388.77	586.92	698.25

The loss of consumer and producer surplus is computed for the Russian region in Table 6.10. In Russia the loss of consumer surplus increases dramatically starting in 2030 which is when the carbon policy is adopted. From the loss of consumer surplus perspective the policy should be adjusted almost in every time period similar to the case of Germany (Figure 6.6). The production costs in Russia are given in Table 6.11.

Table 6.10 indicates that for Russia to lessen the loss of total surplus, the producers should bear the brunt of the carbon tax starting in 2030 corresponding to the time period when Russia adopts the carbon policy. However, in 2045 the total surplus is higher when both consumers and suppliers equally share the tax. One possible explanation for this dynamic carbon policy is the simultaneous adjustment of the marginal cost curve and the inverse demand curve where the change in slopes may result in a smaller deadweight loss.

Table 6.10 Loss of Surplus in Russia

Year	Billion$ ($2005) 650ppm Case Scenarios								
	No Carbon Cost (Ω0_0CO2) vs. 650ppm 0% to consumers (Ω0)			No Carbon Cost (Ω0_0CO2) vs. 650ppm 50% to consumers (Ω50)			No Carbon Cost (Ω0_0CO2) vs. 650ppm 100% to consumers (Ω100)		
	Consumer surplus	Producer surplus	Total	Consumer surplus	Producer surplus	Total	Consumer surplus	Producer surplus	Total
2015	0.15	0.06	0.21	0.17	0.105	0.275	0.18	0.076	0.256
2020	0.27	0.051	0.321	0.23	0.073	0.303	0.15	0.027	0.177
2025	0.67	0.058	0.728	0.63	0.089	0.719	0.51	0.009	0.519
2030	9.49	7.121	16.611	10.74	3.811	14.551	12.91	0.847	13.757
2035	15.76	14.258	30.018	18.95	6.217	25.167	25.71	0.401	26.111
2040	19.24	20.093	39.333	20.06	8.041	28.101	26.52	3.183	29.703
2045	22.83	25.281	48.111	20.96	9.2	30.16	25.75	5.373	31.123
2050	28.54	35.155	63.695	23.65	12.348	35.998	25.56	9.649	35.209

Table 6.11 Total Production Costs in Russia (Billion US$) (650ppm Case)

Year	Billion US$ (2005) 650ppm Case Scenarios			
	650_Ω0_0CO2	650_Ω0	650_Ω50	650_Ω100
2015	31.32	31.39	31.47	31.32
2020	37.46	37.55	37.59	37.49
2025	41.67	41.82	41.86	41.79
2030	45.18	46.95	47.44	45.78
2035	48.34	53.74	53.20	51.15
2040	47.48	56.74	56.22	50.53
2045	47.34	59.69	58.92	50.47
2050	44.86	62.00	61.92	47.42

6.5 Case: U.S. LNG Exports

The import of natural gas in the United States began to decline after 2007 (EIA, 2010) because of the development of unconventional domestic gas, particularly shale gas, of which the United States has abundant resources. According to the U.S. Energy Information Agency (EIA, 2011b). 24,411 billion cubic meters of technically recoverable shale gas resources—or approximately 40 times the annual U.S. consumption in 2010—are distributed throughout the contiguous 48 U.S. states. With advanced drilling technologies, shale gas production has increased fivefold from 2006 to 2010 and accounted for 23% of the total U.S. natural gas production in 2010 (EIA, 2011a). Shale gas production in the U.S. is projected to reach 339.84 bcm/y by 2030, constituting 46% of the annual total U.S. production (EIA, 2011a). The evolution of shale gas in the U.S. creates export opportunities for natural gas producers as the anticipated domestic production exceeds the domestic consumption requirement (EIA, 2012). With domestic oversupply in natural gas, natural gas prices in the U.S. are substantially lower than in other natural gas markets. The prices at Henry Hub were between $3-4 per million British thermal units (MMBtu) in 2010, which is relatively low compared with Asian prices ($13-17/MMBtu) and European prices ($8-10/MMBtu). The price difference creates an arbitrage opportunity for natural gas producers.

There have been increasing debates regarding whether the United States should export liquefied natural gas (LNG) to the global market. Using the World Gas Model, this section investigates the potential effects of U.S. LNG exports on the domestic and global markets. We analyze U.S. LNG export scenarios related to volume of LNG exports and special circumstances such as quick declining production and a Global 20/20/20 policy scenario[16] used by GCAM.

6.5.1 Description of Cases

This section describes the cases that might influence U.S. LNG exports and global markets. In the Base Case[17], the U.S. has export contracts of 21.9 bcm to Europe and Asia starting from 2015 to 2040. We define two alternative U.S. LNG export contract levels, 99.7 bcm (Medium Exports Case) and 123 bcm (High Exports Case), to examine the effect of increased U.S. LNG exports on domestic and global markets.

[16] The CO_2 costs under the 20/20/20 scenario from GCAM are incorperated in WGM.
[17] Note that the output in this section is from a WGM version not calibrated to GCAM volumes. Only the carbon costs from GCAM are incorporated. The reason for this was to match other industry references.

Moreover, the Medium Export case is combined with two additional scenarios with alternative assumptions: first, under Medium Export/Renewable Policy Case, Medium Exports with renewable policies gauges how CO_2 prices might affect natural gas markets. Second, Medium Exports with low U.S. production focuses on how a ten percent reduction in U.S. production may affect the markets analyzed under Medium Exports/ Low U.S. Prod Case. Table 6.12 summarizes the Cases that we consider in this study.

Table 6.12 Cases and description

Cases Name	Abbreviation	Description
Base	Base	Reference Case: U.S. exports 21.9 bcm/y from the Sabine Pass terminal to Asia and Europe
Medium Exports	Medium Exports	U.S. exports 99.7 bcm/y to Asia and Europe
High Exports	High Exports	U.S. exports 123 bcm/y to Asia and Europe
Medium Exports with Renewable Policy	Medium Exports/Renewable Policy	U.S. exports 99.7 bcm/y with a Global 20/20/20 policy
Medium Exports with Low U.S. Production	Medium Exports/ Low U.S. Prod	U.S. exports 99.7 bcm/y with a 10% decline in production beginning in 2035

6.5.2 Results

WGM Results on the Domestic effects of U.S. LNG exports

Figure 6.8 shows the comparison of average U.S. prices from 2020 to 2040. The increased level of U.S. LNG exports will cause average U.S. price increases of $0.70-$1 MMBtu in the Medium Exports and $1.03-$1.53 MMBtu in the High Exports. Stated another way, the average price increase will be 8.4% under the Medium Exports Case and 10.9% under the High Exports Case. An explanation is that the U.S. is committed to exporting gas to Europe and Asia; thus, the total quantity produced becomes the domestic consumption plus the quantity exported and leads to increased domestic production levels. Thus, less gas is available for domestic markets without higher prices. In terms of U.S. natural gas production, commitment to LNG exports results in increased production in the U.S., especially in shale gas, because of the anticipation of domestic consumption and long-term contract requirements. In addition, Figure 6.8 shows that the total U.S. production increases considerably, 4.5% under the Medium Exports Case and 7.3% under the High Exports Case in 2040.

The introduction of U.S. LNG exports will lead to reduced domestic consumption, presumably because of higher natural gas prices under two increased export scenarios. In 2040, U.S. consumption declines by 5.5% under the Medium Exports Case and by 7.9% under the High Exports Case relative to the Base Case, as indicated in Figure 6.8.

Global influence of U.S. LNG exports

This section analyzes the global effects of U.S. LNG exports from the WGM runs. Table 6.13 Regional Production for 2020 and 2040 (bcm/y) depicts the WGM results for production of natural gas around the world by region for 2020 and 2040.

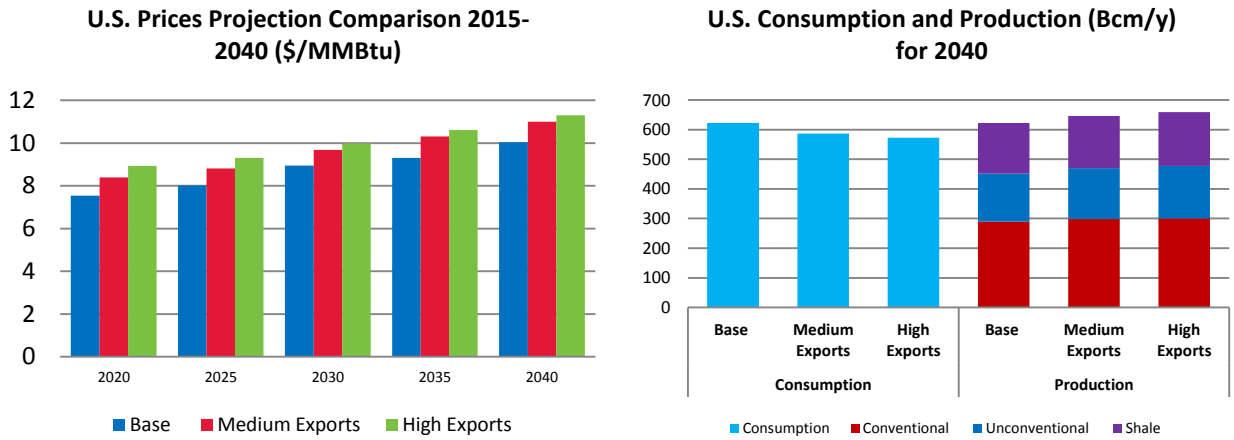


Figure 6.8 U.S. Prices Projection Comparison ($/MMBtu) and U.S. Consumption and Production (bcm)

Table 6.13 Regional Production for 2020 and 2040 (bcm/y)

Regions	Year					
	2020			2040		
	Base	Medium Exports	High Exports	Base	Medium Exports	High Exports
Africa	319.0	314.7	312.7	432.5	427.2	426.3
Asia-Pacific	297.0	295.0	292.3	312.7	311.4	310.9
China	146.7	146.7	146.7	176.4	176.4	176.4
Europe	258.4	255.4	251.8	224.4	223.8	222.2
F. Soviet U.	973.2	962.2	955.2	1121.6	1117.2	1114
Mid-East	491.7	486.0	483.6	737.4	727.5	723.5
N. America	686.1	711.9	724.7	754.3	780.5	795.1
S. America	221.7	222.1	222.1	315.0	314.8	315.3

It is important to note that North America's production increases considerably under the export scenarios (especially, the High Exports) compared with the Base Case. The difference between the Base Case and High Exports Case for North American production will be approximately 38.6 bcm in 2020 and 40.8 bcm in 2040 as a result of the dramatic increase in U.S. LNG exports. Additionally, the production for the rest of the world is slightly affected by the increasing U.S. export volume. Due to an introduction of U.S. LNG, producing regions, such as Africa, the Middle East, and the Former Soviet Union, exhibit decreases in production of approximately 1.9%, 1.6%, and 1.8%, respectively, in 2020. In 2040, the production trends are similar to those for 2020, with little change relative to the Base Case. A significantly smaller effect on production is observed in 2040 relative to that in 2020. For example, the Former Soviet Union will reduce production by approximately 18 bcm in 2020 but only by 7.6 bcm in 2040 under High Exports Case.

In addition, Table 6.14 shows that the presence of increased U.S. LNG exports will lead to lower prices relative to the Base Case, particularly in Asia-Pacific and Europe. In 2020, Asia-Pacific wholesale prices are expected to be $0.32 and $0.61 less expensive under the Medium Exports and High Exports Cases, respectively.

Table 6.14 Regional Prices for 2020 and 2040 ($/MMBtu)

Regions	Year					
	2020			2040		
	Base	Medium Exports	High Exports	Base	Medium Exports	High Exports
Africa	$2.67	$2.56	$2.53	$3.56	$3.48	$3.47
Asia-Pacific	$7.31	$6.99	$6.70	$10.03	$9.72	$9.60
China	$8.47	$8.41	$8.37	$10.89	$10.77	$10.73
Europe	$8.92	$8.68	$8.46	$11.88	$11.66	$11.48
F. Soviet U.	$3.42	$3.36	$3.33	$5.36	$5.27	$5.22
Mid-East	$3.10	$3.05	$3.03	$4.28	$4.20	$4.17
N. America	$7.13	$8.03	$8.84	$9.39	$10.57	$11.10
S. America	$7.39	$7.64	$7.68	$8.81	$8.82	$8.88

Likewise, using the same comparison, European wholesale prices are $0.24 and $0.46 lower than the Base Case. This effect will be less pronounced in 2040. The smaller price gap in later years reflects the elasticity of the supply in the long term. We notice this phenomenon because under the High Exports Case Asia-Pacific prices as compared with the Base Case decrease by 8.3 % in 2020, but only by 4.2 % in 2040. Because Asia-Pacific requires more supply in order to meet growing domestic consumption, production is adjusted by increasing production capacity in later years to form a new equilibrium. Nevertheless, the prices increase greatly for North America. Table 6.14 shows higher prices relative to the Base Case for North America in 2020 (12.7% higher in the Medium Exports and 23% under the High Exports), and the same situation will repeat in 2040.

6.5.3 Other Cases

In this section, we assess the sensitivity of the U.S. LNG exports to climate policy (e.g., Global 20/20/20 scenario by GCAM) and the uncertainty surrounding unconventional gas production. In the Medium Exports/Low U.S. Prod Case, we assume a decline in U.S. production to a level 10% lower than the Base Case in 2035 and 2040. This decreasing production is characterized by a higher rate of decline in shale gas production and possibly limited resources for other natural gas types by future regulations and energy policies. In particular, extraction from shale gas resources is depicted as decreasing rapidly in the long term as stated in (Cohen, 2009). Hence, the U.S. may confront shortfalls in maintaining the production that is necessary to meet growing domestic demands and LNG export commitments. Figure 6.9 indicates that with declining U.S. production in 2040, prices increase $2.16 for North America. Moreover, prices in Europe and Asia remain lower than the prices in the Base Case. Africa gains benefits from decreased U.S. production by increasing production (see Figure 6.10) and LNG trading in 2040. Moreover, Figure 6.10 suggests that North America will reduce LNG trading by approximately 28% as a result of lower production. Thus, we may conclude that even a ten percent decrease in production can significantly affect exports, particularly in terms of prices and LNG trading.

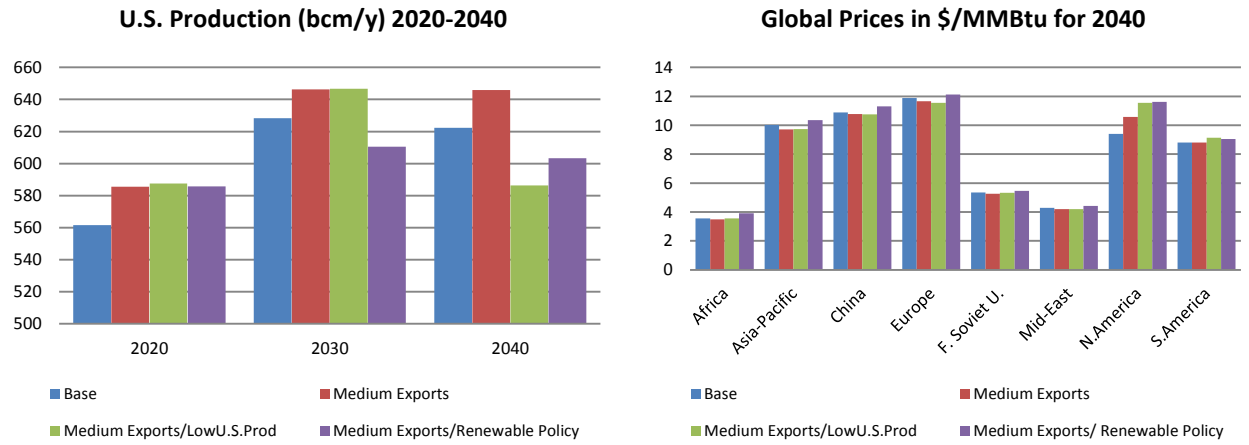


Figure 6.9 U.S. Natural Gas Production (bcm/y) and Global Natural Gas Prices($/MMbtu)

In the Policy Scenario, market players are responsible for regional CO_2 costs due to efforts to reduce CO_2 emissions. Under the policy scenario abbreviated Medium Exports/ Renewable Policy the average prices are the most expensive relative to the other scenarios, particularly in North America. Two reasons for this price disparity are the CO_2 prices, which represent an additional cost to the producers of $45.33 per ton of CO_2e[18] in 2040, and the effect of exports. The prices in N. America are $2.21 higher than in the Base Case, see Figure 6.9. Also, Figure 6.9 indicates that prices in rapidly developing and developed regions, namely, Europe, Asia-Pacific, and China, exhibit an increase of $0.25-$0.55 because of increased CO_2 prices. However, prices in the least developed regions, i.e., Africa and the Middle East, continue to increase for a different reason. Because no renewable policy has been implemented in Africa or the Middle East, producers in these regions increase production output and export to a greater extent to compensate for reduced production in rapidly developing and developed regions, as shown in Figure 6.10.

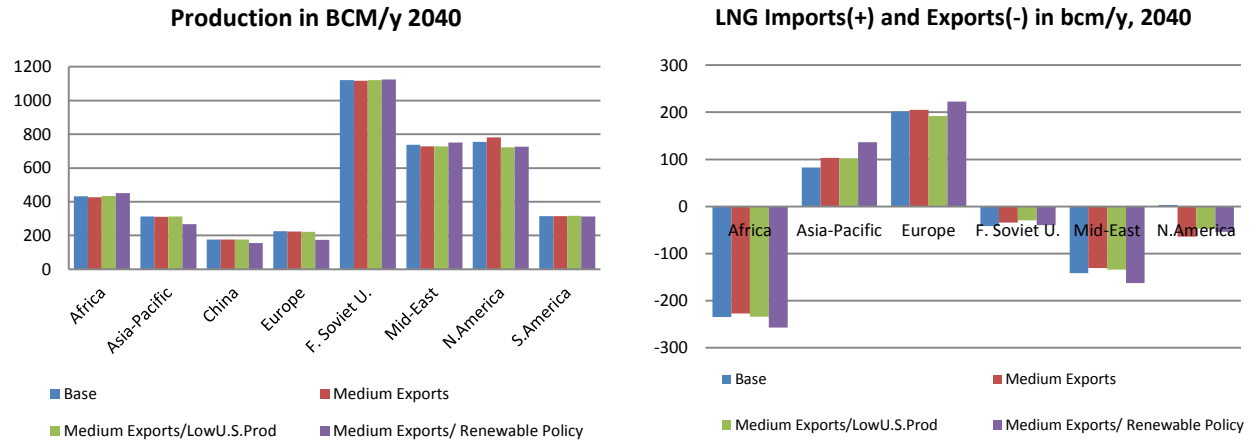


Figure 6.10 Global Production (bcm/y) and LNG Imports/Export (bcm/y)

[18] There are three CO2 allocation schemes. In this case, costs are for the supply sides only. It is Ω=0 as discussed in the previous section.

More interestingly, LNG imports by Europe and Asia increase dramatically, presumably because of reductions in domestic production. Similarly, in 2040, LNG exports from Africa and the Middle East also increase significantly by 22.42 bcm and 21.22 bcm, respectively (see Figure 6.10). LNG trading plays an important role in balancing demand in the renewable policy scenario. Production shifts to regions that have not implemented policies. This type of phenomenon demonstrates that when a policy is not applied globally, some participants will benefit from not being under the policy. Because global trading is allowed, this condition may affect the efficiency of the policy.

6.5.4 Conclusions

Increased U.S. LNG exports lead to higher prices, lower consumption, and increasing production in the U.S. domestic market. Price effects will be lower in the long term after supplies are adjusted to meet demands. A 10% shortfall in production with 99.7 bcm of U.S. LNG exports results in a price increase of approximately $2/MMBtu relative to the Base Case in North American market. It is risky for natural gas exporters to commit to long-term contracts because unconventional production is uncertain, and resources can decline quickly. However, North American producers can dominate other producers in terms of profit. By contrast, increased U.S. exports reduce prices significantly in importing markets. For example, prices in Spain decrease by $2.7/MMBtu in 2020 under the High Exports compared with the Base Case. Increased LNG exportation results in positive effects on Asia and Europe.

High CO_2 prices under the Renewable Policy scenario lead to reductions in production in rapidly developing and developed regions in which the policy is applied. This production would be shifted to the least developed regions and lead to an increase in production and exports to rapidly developing and developing regions. LNG trading plays a key role in the Renewable Policy Scenario. Europe and Asia will acquire 30% more LNG imports than in the Base Case in 2040.

6.6 Case: European gas import pipelines

6.6.1 Overview

Energy supply security in Europe is a major policy concern and natural gas figures prominently in this area. The demand for natural gas in Europe is expected to increase due to environmental considerations as well as from the nuclear phase-out. However, the estimated domestic supply of natural gas in Europe is declining. Thus, in order to meet increasing demand Europe needs to import more natural gas. Several pipeline projects are competing to supply more natural gas to Europe. The Southern Corridor project would allow natural gas imports from the Caspian while the Nord Stream[19] and South Stream projects (underwater) would increase export options for Russian gas to Europe. The total capacity from these two Russian projects is larger than the current volume of gas flowing through Ukraine to Europe. These projects should improve supplies to Europe, but the possible Russian market power over Europe should not be underestimated. In addition, there are options of liquefied natural gas supplies to Europe such as from the United States. LNG offers flexibility to diversify suppliers for Europe. Analyses of impacts of these competing projects to supply natural gas to Europe are limited.

The purpose of this section is to investigate the European security of natural gas supplies as a result of the completion of the European pipeline projects mentioned above as well as the influence of U.S. LNG exports.

[19] Nord Stream started operating on October 8, 2012 with a capacity of 55 bcm/y.

The Nord Stream, South Stream, and Southern Corridor Projects have been incorporated into the WGM[20]. The WGM allows endogenous pipeline expansion via the pipeline operator's optimization problem. The pipeline operator considers expanding a particular pipeline endogenously if it is profitable. The WGM considers the cost of pipeline expansion in terms of the length and type of pipelines (on-shore or off-shore) and distinguishes between the cost for new construction and expansion. In this analysis, we largely focus on the flows from Russia to Europe given new pipeline capacity and the pipeline investment decisions. In the next section, we summarize the case studies; the Nord Stream Pipeline Case, European pipeline Case, and the European pipeline and U.S. LNG Export Case. Cases are not meant as a forecast of global natural gas production, consumption, prices and other elements but rather as a comparison against the Base Case[21].

6.6.2 Description of Cases

In this section, we discuss the assumptions for each case considered. In the Base Case, Europe does not have Nord Stream or any other pipeline projects, but the U.S. has export contracts of 21.9 bcm/y[22] to Europe and Asia. In the Nord Stream case, the pipeline starts operating in 2010 with an initial capacity of 27.5 bcm/y. The expected capacity in 2015 is 55 bcm/y. In the E.U.Pipeline Case in addition to the Nord Stream pipeline, three other pipelines are added. First, the South Stream project connects Russia and Romania with an initial capacity of 15.5 bcm/y. The pipeline will start operating in 2015 and can be expanded up to 63 bcm/y later. Second, the Southern Corridor project includes two pipelines: the first part connects Turkey and Azerbaijan with a capacity of 16 bcm/y; the second part links Turkey and Romania with an initial capacity of 10 bcm/y. This project will be fully operational by 2020 and the capacity may be expanded by 20% of initial capacity every five years. The European pipeline projects considered in this study are summarized in Table 6.15. The last case, E.U. Pipeline&U.S.LNG Case, includes all pipelines from the E.U. Pipeline Case as well as an increase in U.S. LNG export from 21.9 bcm to 99.9 bcm[23]. This case investigates the competition between U.S. LNG and Russian pipelines in the European gas market and determines how an increase in U.S. LNG imports influences the European gas market. A summary of the Cases considered is shown in Table 6.16.

Table 6.15 European Pipeline Projects

Project	Connection	Capacity (bcm/y)	Project Timeline, Starting Year Capacity (bcm)
Nord Stream	Russia-Germany	55	2011 (27.5 bcm) 2012 (55 bcm)
South Stream	Russian-Bulgaria	63	2015 (15.5 bcm) 2019 (63 bcm)
Southern Corridor	Part 1: Turkey-Azerbaijan	16	2018 (16 bcm)
	Part 2: Turkey-Romania	10	2018 (10 bcm)

Sources: (Nord Stream, 2012), (South Stream, 2012), and (Berdikeeva, 2012)

[20] Note that the World Gas Model used in this section is WGM2012. Further details for WGM version are provided in Table 4.2.
[21] The Base Case outcome is calibrated to fit global natuural gas trends in 2010 with multiple sources such as (European Commission ,2008) and (IEA,2007).
[22] 21.9 bcm is equal to amount specified in the LNG export license granted by DOE to Cheniere Energy in early 2012.
[23] 99.9 bcm is the total volume of the domestically produced LNG export licenses under review by DOE as of March,2012.

Table 6.16 Summary of Cases Considered

Cases	Abbreviation	Descriptions
Base	Base	Base Case without Nord Stream, South Stream nor Southern Corridor pipelines
Nord stream	Nord Stream	Only Nord Stream pipeline available
All pipelines available	E.U.Pipeline	Nord Stream, South Stream, and Southern Corridor pipelines available
Russian pipelines vs.U.S. LNG export	E.U.Pipeline&U.S.LNG	Nord Stream, South Stream, and Southern Corridor pipelines available along with exports from U.S

6.6.3 Results

We first comment on the flows from Russia to Europe. There are no flows from Russia to Germany or Romania under the Base Case because the Nord Stream and South Stream Pipelines are not considered. In the Base Case the Russian flows to European markets require using transit countries, namely Ukraine and Poland. However, flows through the Nord Stream Pipeline will increase greatly, from 0 bcm/y to 84.7 bcm/y (see Table 6.17) when the Nord Stream pipeline is available. Overall, the Russian flow patterns will change dramatically because Russian traders who want to maximize profit must consider avoiding transit fees by sending gas directly to Germany. For the Nord Stream Case, the flows via transit countries will decrease significantly between the Former Soviet Union and Poland (Ukraine) by 25 bcm (51 bcm) in 2030, and the influence of the new pipelines on shipment through the Ukraine and Poland will become even more pronounced by 2050 (Table 6.17).

In the E.U. Pipeline&U.S.LNG Case, three pipeline projects compete with one another and the U.S. exports. Table 6.18 depicts the summary of U.S. LNG exports set up in WGM. The confluence of all this natural gas supply creates a positive effect in Europe and increases consumption with lower prices (see Figure 6.11). However, while the new pipelines offer flexibility in the delivery of gas to Europe, Russian production levels do not significantly increase. The explanation is that Russia can increase profit at the same level of production. New pipelines reduce transit fees ($1.1 billion in 2020 and $2.75 billion in 2050) and increase the profits of Russian traders ($1.88 billion in 2020 and $2 billion in 2040). Moreover, under the E.U. Pipelines&U.S.LNG Case Russia will lose 25% of the European LNG market because of the increased volume of U.S. exports to Spain and the United Kingdom in 2050, as shown in Table 6.19. Therefore, Russia will increase the flow via pipelines by approximately 13% in 2050 to compensate for the loss of LNG market share.

Table 6.17 Comparison of Russian Flows to Europe by Pipelines in 2030 and 2050 (bcm/y)

Country Node	2030				2050			
	Base	Nord Stream	E.U. Pipeline	E.U.Pipeline & U.S.LNG	Base	Nord Stream	E.U. Pipeline	E.U.Pipeline& U.S.LNG
Poland	57	32	29.7	29.7	70	28	26	25.8
Ukraine	167	116	93.3	92.9	132	102	82	83.7
Germany	0	84.7	84.7	84.7	0	112	109	109.5
Romania	0	0	24.2	24.4	0	0	24.2	22.4

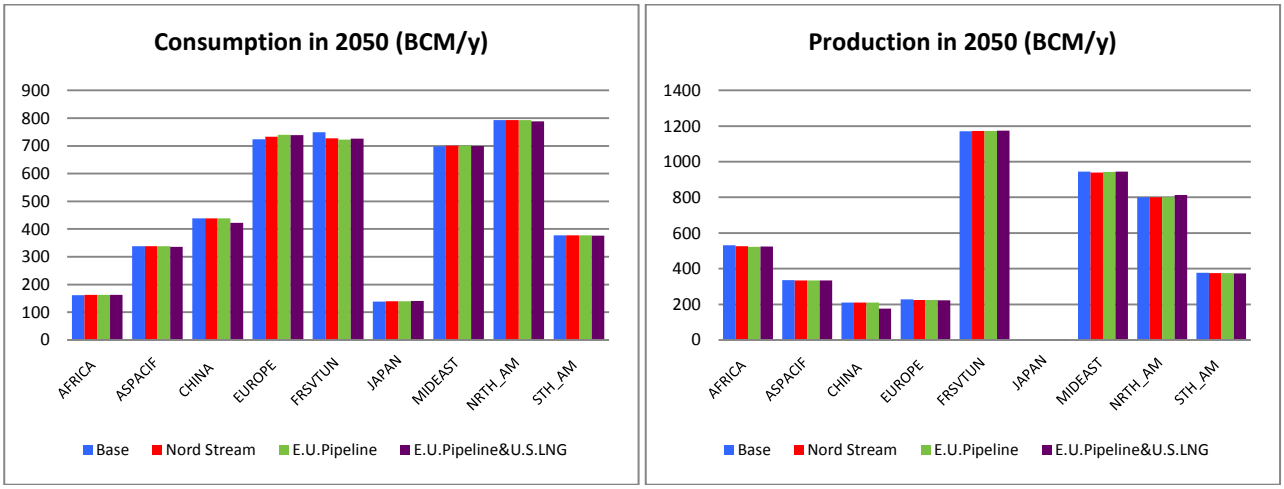


Figure 6.11 Consumption and production in 2050 bcm

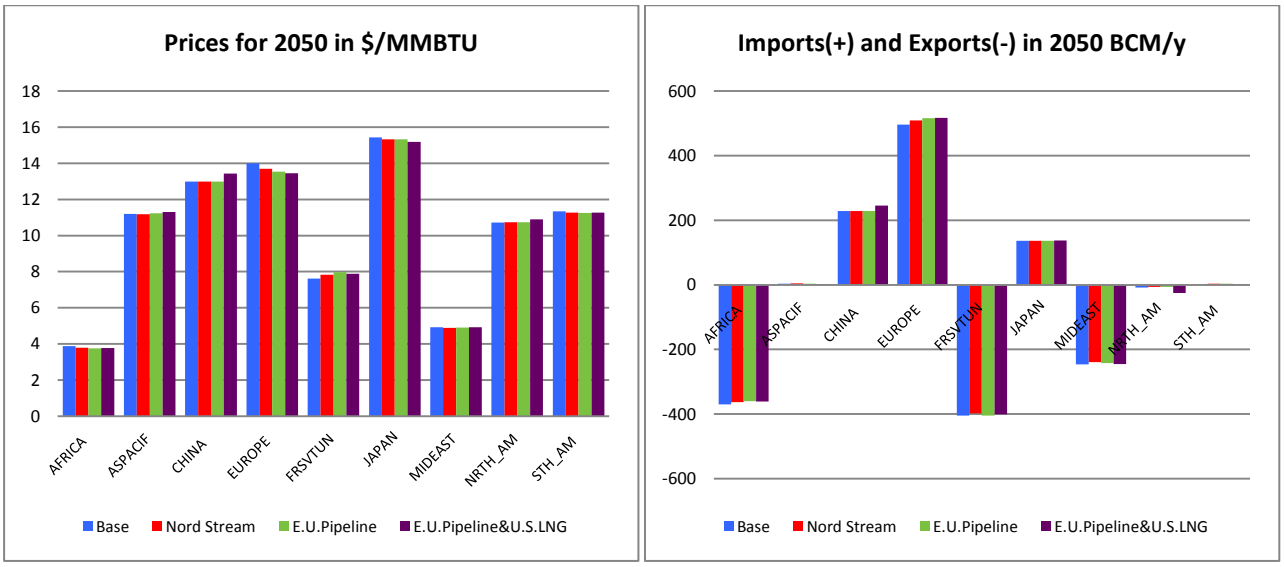


Figure 6.12 Prices for 2050 in $/MMBtu and Imports/ Exports in 2050 bcm

Table 6.18 WGM Export Terminals

WGM Terminal	Capacity	Actual Terminals	Export to
West Coast terminal	33.9 Mcm/d (12.3 bcm/y)	Jordan Cove	Asia
East Coast terminal	28.3 Mcm/d (10.3 bcm/y)	Cove Point	Europe
Gulf Coast terminal	206.7 Mcm/d (75.1 bcm/y)	Sabine Pass Cameron LNG Free Port Lake Charles	Asia and Europe

Table 6.19 Russian natural gas flows in bcm/y in 2020 and 2050

	Destination	2020		2050	
		Base	EU.Pipeline &US.LNG	Base	EU.Pipeline &US.LNG
LNG	Canada	0.00	2.58	0.00	1.96
	France	0.00	0.00	3.08	0.00
	Japan	16.41	15.07	25.09	23.59
	Netherlands	0.00	0.00	3.00	0.00
	Poland	0.00	0.00	0.00	0.00
	Spain	4.97	1.46	4.70	2.87
	U.K.	1.94	0.00	9.36	0.24
	Mexico	5.09	5.09	0.00	0.00
	LNG Total	**28.41**	**24.19**	**45.23**	**28.66**
Pipe	China	28.60	28.09	48.64	48.30
	Germany	0.00	63.77	0.00	109.53
	Bulgaria	0.00	21.24	0.00	24.42
	Kazakhstan	2.50	0.00	12.24	12.22
	Turkey	17.49	16.93	34.43	32.03
	Poland	50.24	29.70	70.61	25.84
	Ukraine	165.68	102.67	132.41	83.74
	Pipeline Total	**264.51**	**262.41**	**298.34**	**336.09**
Total Exports		**292.93**	**286.60**	**343.57**	**364.75**

It is interesting to note the investments for each pipeline. Initially, the Nord Stream pipeline will have a capacity of 55 bcm/y. Later, its capacity will be expanded to as high as more than 100 bcm/ in 2050. Nevertheless, the South Stream pipeline capacity will be 24.84 bcm/y in 2040 (see Table 6.20). The South Stream pipeline expands only half of its expected capacity (63 bcm). There are three reasons for the reduced expansion. First, this pipeline competes with another project, namely, the Southern Corridor, which can also deliver inexpensive gas from the Caspian region to the same consumption node, namely Romania. Second, South Stream expansion costs more as compared to the Southern corridor project because of the off-shore characteristics and longer distances. Finally, the WGM has a low pipeline capacity flowing out from Romania[24] to other European countries. Therefore, this consumption node cannot be treated as a transit area, which results in less expansion capacity.

[24] Several pipeline projects such as Nabucco pipeline and Azebijan-Georgia-Romania interconnector will use Romania as a transit country to Central Europe.

Table 6.20 Comparison of total pipeline capacities including expansion over time horizon (bcm)

Pipelines	2030			2050		
	Nord Stream	E.U. Pipeline	E.U.Pipeline & U.S.LNG	Nord Stream	E.U. Pipeline	E.U.Pipeline & U.S.LNG
Nord Stream	87.97	87.97	87.97	116.07	113.36	113.73
South Stream	n/a[25]	24.39	24.55	n/a	24.62	24.84
Southern Corridor	n/a	38.50	41.12	n/a	41.30	43.90

6.6.4 Conclusions and Findings

Nord Stream and South Stream pipelines reduce the flows through Poland and Ukraine (30% for the Nord Stream Case and 45% of the E.U.Pipeline case). The Nord Stream pipeline capacity is expanded almost all time periods for all cases, therefore the total capacity reaches more than 100 bcm/y in 2050. However, the South Stream pipeline capacity is not expanded as much due to competition with the Southern Corridor project and capacity issues. Also, the average European gas price drops 25 cents/MMBTU for the Nord Stream Case and 40 cents/MMBTU for the case involving all the pipelines, relative to the Base Case. In addition, U.S. LNG exports significantly displace Russian LNG forcing Russia to increase pipeline exports to Europe. Moreover, U.S. LNG exports reduce natural gas prices in importing countries (the United Kingdom and Spain).

[25] South Stream and Southern Corridor pipelines are not available under the Nord Stream Case.

7 TIMES analyses of developments in the Chinese energy and cement sectors

7.1 The situation in 2011

In 2011, the output of primary energy in China reached 3.18 billion tons of coal equivalents (tce), ranking first in the world. Of this, raw coal reached 3.52 billion tons; crude oil, 200 million tons; and refined oil products, 270 million tons. The output of natural gas ballooned to 103.1 billion m^3. The installed electricity generating capacity reached 1,056 GW, and the annual output of electricity was 4,690 TWh. A comprehensive energy transportation system has developed rapidly. The length of oil pipelines totaled more than 70,000 km, and the natural gas trunk lines exceeded 40,000 km. Electric power grids were linked up throughout the country, and electricity transmission lines of 330 kV or higher totaled 179,000 km.

China vigorously promotes energy conservation. During the 1981-2011 period, China's energy consumption increased by 5.82 percent annually, underpinning the 10 percent annual growth of the national economy. From 2006 to 2011, the energy consumption for every 10,000 Yuan of GDP dropped by 20.7%, saving energy equivalent to 710 million tce. The state implemented a series of energy-saving renovations, such as boilers, electrical machinery, buildings and installation of green lighting products. The gap between the overall energy consumption of China's high energy-consuming products and the advanced international level is narrowing. The energy utilization efficiency of new projects in the heavy and chemical industries, such as non-ferrous metals, building materials and petrochemicals, is up to the world's advanced level. The country has eliminated small thermal power units with a total generating capacity of 80 GW, saving more than 60 million tce annually. In 2011, coal consumption of thermal power supply per kWh was 37 grams of coal equivalent (gce) lower than in 2006, a decrease of 10%.

China has made tremendous efforts in developing new and renewable energy resources. In 2011, the installed generating capacity of hydropower reached 230 GW, ranking first in the world. Fifteen nuclear power generating units were put into operation, with a total installed capacity of 12.54 GW. Another 26 units, still under construction, were designed with a total installed capacity of 29.24 GW, leading the world. The installed generating capacity of wind power connected with the country's power grids reached 47 GW, ranking top in the world. Photovoltaic power generation also reported speedy growth, with a total installed capacity of 3 GW. Solar water heating covered a total area of 200 million m^2. The state also expedites the use of biogas, geothermal energy, tidal energy and other renewable energy resources. Non-fossil energy accounted for 8% of the total primary energy consumption, which means an annual reduction of more than 600 million tons of carbon dioxide (CO_2) emissions.

7.2 Effects of current national policies

7.2.1 11th Five-Year Plan target disaggregation

The 11th Five Year Plan (FYP) (2006-2010) placed more emphasis on energy savings than did previous plans. In 2006, the Chinese government upgraded resource conservation to the country's basic national policy level, and regarded the reduction of energy consumption per GDP unit by 20% compared with 2005 levels as an important index during 11th FYP. The Chinese government made comprehensive use of economic, legal and necessary administrative measures to nearly achieve the reduction target of energy saving. The energy consumption per GDP in 2010 declined 19.1% compared with 2005, which is equivalent to emissions reductions of more than 1.46 billion tCO_2. During the 11th FYP, China supported an average annual growth

rate of 11.2% in GDP, along with an average annual growth rate of 6.6% in energy consumption, and the energy consumption elasticity[26] dropped from 1.04 to 0.59 at the same time.

To achieve the national energy saving target, State Council agreed to divide it among different regions and provinces, thousands of high-energy-consuming enterprises and five major power generation companies. As a measure to guarantee the 12th Five Year Plan (2011-2015) by improving emission reduction statistics and the monitoring and verification system, the State Council approved "Statistical monitoring and assessment approaches of energy saving"[27] proposed by the National Development and Reform Commission (NDRC) and other departments. The State Council also designated that the energy consumption and accomplishments report on the major pollutant emission reduction targets of all regions and key enterprises must be evaluated, and a strict administrative accountability system would be implemented in the 12th FYP[28]. The accountability system covers breaking energy-saving targets into pieces, and accounting, monitoring, and assessing regularly, thus governments at all levels and key energy-consuming enterprises get specific, clear and binding energy conservation targets. The energy saving target accountability system was combined with the Official administrative system. It connects the accomplishment of energy-saving target with the promotion of government officials and enterprise development space by "the one ticket rejection" of energy-saving targets, which shows obvious administrative character.

7.2.2 Electricity

7.2.2.1 Energy Conservation Power Generation Dispatch (ECPGD) Program

The Energy Conservation Power Generation Dispatch Program[29] began in December 2007 with pilot projects in the provinces of Guizhou, Jiangsu, Sichuan, Henan and Guangdong. The ECPGD Program is complementary to the Program Closing Small Enterprises and focuses on prioritizing power generation from existing renewable, nuclear, efficient and clean coal power plants over other more carbon-intensive power plants. It is a major reform to the current pattern of power generation dispatch in China, intended to create a market mechanism by substituting the current base load power generation scheduling rule with an energy efficiency-based rule that favors low-carbon energy.

The table of priority categories of generating units is the foundation of ECPGD and is established by the provincial development and reform commission. It is adjusted according to the operating situation of generating units. The priority categories are as follows: (1) non-dispatchable wind power, solar power, oceanic power and hydro power; (2) dispatchable hydro, biomass, geothermal power and solid waste-fired units; (3) nuclear power; (4) coal-fired cogeneration units and units with comprehensive use of resources, including those using residual heat, residual gas, residual pressure, coal gangue, coal bed/coalmine methane, etc; (5) natural gas and coal gasification-based; (6) other coal-fired generating units, including cogeneration without heat load; (7) oil and oil product-based generating units. Chinese installed capacity and electricity generation by category in 2010 is shown in the following table. The installed capacity in 2010 reached about 966 GW (1056 GW in 2011) and the total electricity generation reached about 4,230 TWh (4,690 TWh in 2011).

[26] The energy consumption elasticity shows how many percentage of energy consumption is needed to support 1% GDP growth.
[27] http://www.gov.cn/gzdt/2012-08/26/content_2211103.htm
[28] The state council published regulation and other charge of the department implemented, such as NDRC, Ministry of Industry and Information Technology (MIIT). http://www.miit.gov.cn/n11293472/n11293832/n12843926/n13917012/14727727.html
[29] http://www.sdpc.gov.cn/zcfb/zcfbqt/2007qita/t20070828_156042.htm

Table 7.1 Shares of Chinese installed capacity and electricity generation in 2010

	Installed Capacity	Electricity Generation
Coal-fired	67.6%	76.8%
Gas	2.8%	1.7%
Other thermal	3.1%	2.2%
Nuclear	1.1%	1.8%
Wind Power	3.2%	1.2%
Hydropower	20.6%	16.0%
Pumped Storage	1.6%	0.2%

Source: China Electricity Council

Within each category, units are ranked according to their energy efficiency. Units with the same energy efficiency are further ranked according to their emission levels and water usage. Units are scheduled for generation only when all units in higher priority categories and ranks are operating at full capacity.

Local development and reform commissions organize the collection and management of load forecasting and load management and provide this information to industry, grid companies and power generation companies. The priority list for load management and dispatch is based on the information collected on individual plants and the load forecasts. There is no official estimate for energy-saving and emissions reduction resulting from the implementation of ECPGD, but it is likely to make the single greatest contribution to energy conservation in the electricity sector. This program has been implemented by State Grid in a few pilot provinces. According to estimates by the State Power Company, in 2011, Jiangsu, Henan and Sichuan power grids cumulatively saved 4.2 million tce, and reduced SO_2 emissions by 0.12 million tons.[30]

7.2.2.2 Shut down of small thermal power

"The State Council approved views of Development and Reform Commission, the Energy Office on accelerating shut down of small thermal power[31]",issued in 2007, clearly confirmed the implementing approach of the action to shut down small thermal power[32]. The National Development and Reform Commission is responsible for the work of shutting down small thermal power units in the whole country, and resolves all the targets into every province, autonomous regions, and municipality, and signs the target responsibility documents with each provincial people's government and State-owned Large Power Conglomerates at the same time. The Power Grid Enterprise and The Power Supervision Department cooperate actively and make appropriate policy measures to promote the work jointly.

The Power Supervision Department strengthens the supervision and management of small thermal power units, and establishes the supervision of information system. Those who don't meet the design requirements and the relevant provisions cannot get the power business license. Encourage the construction of large-scale power projects through a merger, reorganization or acquisition of small thermal power units, and implement the "Start the big, shut the small" after shutting down. The National

[30] http://www.sp.com.cn/dlyw/gndlyw/201206/t20120625_189145.htm
[31] http://www.gov.cn/zwgk/2007-01/26/content_509911.htm
[32] The small capacities include: (1) all conventional thermal power generating units of below 50 MW; (2) all conventional thermal power generating units of 100 MW and below that have been operating for over 20 years; (3) all conventional thermal power generating units of 200 MW and below that have reached the end of their design lives; (4) all coal fired generating units with a net heat rate at least 10% higher than the 2005 provincial average or at least 15% higher than the 2005 national average ; (5) all generating units that fail to meet environmental standards; (6) all generating units not complying with laws and regulations.

Development and Reform Commission increases the power source construction projects correspondingly in the province, autonomous regions and municipalities according to the capacity which has been shut down of each province, autonomous region and municipality. Each province, autonomous region and municipality should strengthen the management of small thermal power tariff, and decrease the on-line electricity price of all coal-fired (oil), which is no higher than the regional benchmark. They shall not implement a price subsidy, which means that it should continue to enforce the existing tariff even though prices are lower than the benchmark price of thermal power in this region.

During 11th FYP period, power industry shut down totally 76.8 GW of small thermal power, which exceeded the goal of 50 GW.

7.2.3 Industry

7.2.3.1 Eliminating outdated production capacity[33]

Closing plants of backward production capacity is part of the national energy saving and pollution reduction effort to meet the national target of 20 percent reduction in energy intensity by 2010. This program, which operates in parallel with plans to build larger, more efficient plants, is officially called "Eliminating backward production capacity", which is similar as The Program of Large Substituting for Small in Electricity sector. In order to promote the robust development of China's power industry, NDRC has required the closure of small-scale and back production capacity plants with high energy consumption and poor pollution control.

According to comprehensive working plan of energy saving and emission reduction of State Council, NDRC and Ministry of Environment Protection had jointly published the timetable of eliminating backward production capacity, required that each region should shut down the backward production which is not fit law or regulations, industry policy, environment standard or over standard.

This announcement required that local government should confirm the plant list which will be shut down. The target index will be allocated to the companies according to year and sector. The city government will sign obligation contracts with companies. The time, mode (stop production, back out, shut down, change production, reform production) and requirements are set clearly. The finance organization should draw back the loans which had been provided to the plants not suitable. The price control department should implement the different electricity price and water price during the shut-down period. The environment protection department should give the penalty to the company which emitted pollutions illegally.

[33] http://www.gov.cn/jrzg/2007-06/03/content_634545.htm

Table 7.2 Closure program implementation effect during 11th FYP

Closure Program	Total Cumulative Capacity of Closed Facilities During 11th FYP[34]
Closure of small-scale steel-making capacity	72 million tons
Closure of small-scale iron production capacity	120 million tons
Closure of small-scale coking plants	107 million tons
Closure of small-scale glass plants	45 million cases
Closure of small-scale cement production capacity	370 million tons
Closure of small-scale paper production capacity	11.3 million tons

Source: China's Policies and Actions for Addressing Climate Change (2011)

7.2.3.2 The Thousand Enterprises Program

The "Thousand Enterprises" refers to the most energy-intensive enterprises whose energy consumption was more than 180,000 tce in 2004, among the nine major energy consuming industries: iron and steel, nonferrous metals, coal, electricity, petroleum and petrochemicals, chemicals, building materials, paper and textiles. The total energy consumption of the Thousand Enterprises accounted for 33% of national energy consumption, and 47% of industrial energy consumption in 2004[35].

In 2006, the NDRC and other ministries jointly issued the "Energy Conservation Action plan of The Thousand Enterprises"[36] which clearly put forward the goal of saving 100 million tce during 2006-2010. 998 enterprises and local government signed the target responsibility documents of energy efficiency in 2006 (including 15 central enterprises which directly signed with the National Development and Reform Commission).

In order to achieve the Energy Conservation Action plan of The Thousand Enterprises, the NDRC implemented four measures:

1. *Signing target responsibility documents.* Enterprises were required to sign documents with local governments acknowledging energy-saving goals and terms for examination and evaluation. These documents defined the energy savings quantity the enterprises needed to achieve, procedures for examine and evaluate the object, and rules for examining the content of assessments, as well as incentive and penalty mechanisms[37]. Those industry executives and local government officials who did not achieve the energy-saving goals would be penalized by withholding opportunities for promotion.
2. *Energy audits.* The Thousand Enterprises started to implement energy audit planning in the fourth quarter of 2006. In the first half of 2007, the provincial energy conservation authorities organized experts and industry associations to review the enterprise energy audit reports and energy conservation plans and to help enterprises that initially failed audits take corrective actions.
3. *Energy utilization reporting system.* National Development and Reform Commission implemented a report filling system for annual reports on energy usage situations of key energy users. Enterprises were required to electronically submit annual reports of the previous year´s energy utilization to the local management department for energy conservation before the end of each March.

[34] http://www.gov.cn/jrzg/2011-11/22/content_2000047.htm
[35] http://www.ccchina.gov.cn/cn/NewsInfo.asp?NewsId=3777
[36] http://hzs.ndrc.gov.cn/newzwxx/t20060413_66111.htm
[37] http://www.energylabel.gov.cn/en/RelatedWorkandPromotionalActivities/detail/624.html

4. *Energy efficiency benchmarking*. In 2007, the National Development and Reform Commission issued a notice establishing benchmarking activities for evaluating energy efficiencies of key energy users, which were carried out in three energy-intensive industries: iron and steel, caustic soda and cement. Industry associations choose the benchmarks that were then confirmed by the NDRC, and collected data for the benchmarking activities, and provided guidance to companies to identify gaps and areas for improvement. State and local governments provided subsidies and incentives to benchmarking enterprises to support technological innovation.

The NDRC, which is the competent authority of the Thousand Enterprise Energy Conservation Action, is responsible for promulgating to the public information about energy utilization in the previous year in conjunction with the National Bureau of Statistics. According to the NDRC, the Thousand Enterprise Energy Conservation action saved a total of 150 million tons tce, and reduced nearly 400 million tons of CO2 emissions during 2006-2010.

7.2.4 Buildings

During the 11th FYP period, energy consumption and emissions of the building sector in China increased continuously, but at a lower rate than under 10th FYP. Compared with 2005, the energy consumption per unit of area increased by 19.7% in 2010, with an annual growth rate of 3.7%. Currently, CO2 intensity per unit of area in China is lower than in developed countries, not approaching 1/3 that of the US.[38]

Energy saving in buildings requires efficient use of energy during the construction and operation of buildings, as well as efficient use of heating, air conditioning, lighting, electrical equipment, and hot water supply. The mitigation policies and measures in the building sector mainly consist of regulations and standards for building design, market mechanisms such as promoting the installation of heating meters in old buildings, and subsidies for energy-saving appliances in buildings.

The Building Energy Conservation Project, implemented by the Ministry of Housing, Urban and Rural Development (MOHURD) in pursuit of 11th Five Year Plan Targets, has four dimensions[39]:

1) *Energy conservation in new buildings.* For new buildings, a 50 percent energy saving target was set, later increased to 65 percent in Beijing, Tianjin, Shanghai and Chongqing.
2) *Energy-saving renovation in existing buildings.* Strengthen the operation and management of energy-consuming equipment for buildings; optimize the thermal engineering performance of the surrounding structures of buildings; improve the work efficiency of heating, cooling, lighting, ventilation, water supply, drainage and pump systems.
3) *Energy saving in public and government buildings.* For public buildings, the indoor air temperature cannot be higher than 20°C in the winter, and cannot be lower than 26°C in the summer.
4) *Green building development.* In 2006, the Ministry of Construction and Ministry of Science and Technology jointly published the 'Green Building Assessment Standard' (GB/T50378-2006). This standard is voluntary and is assessed by provincial governors. As of 2010, 112 projects have been certificated using green building assessment labeling, and the total area of building space has exceeded 13 million m^2.

[38] http://news.dichan.sina.com.cn/2011/09/07/369805.html
[39] http://www.chinaeeb.gov.cn/root/iitemview.aspx?id=646

In 2007, the "Energy saving and emission reduction integrated working plan" issued by the State Council regulated mechanisms that large-scale public buildings report energy consumption statistics, conduct energy audits, produce energy efficiency publications, established energy consumption controls in 25 demonstration provinces, and set an energy savings target of 12.5 mtce. During 11th FYP, the accumulated total energy-efficient floor space constructed was 4.857 billion m^2, resulting in energy-savings of 46 million tce.

7.2.5 Transportation

After China's Energy Conservation Law came into effect in 2007, the Ministry of Communication (MoC) established an energy saving coordination group and energy management office to take responsibility for energy saving policy decisions and management in the transportation sector. The MoC also set up several monitoring and service centers responsible for monitoring, auditing and promoting energy-saving technologies.

To promote energy efficiency in the transport sector, national and local governments are implementing a wide range of policies and measures including industrial strategies and supporting initiatives. The government also implements economic policies conducive to energy conservation such as a policy of tax reduction for the production and consumption of compact cars. In 2009, the government began collecting a fuel tax on petrol consumption, which was the first energy tax to be collected in China. Mandatory entry permits for manufacturers of clean energy vehicles have also been introduced to improve the investment environment, regulate the vehicle market and encourage manufacturers to invest in research and development. Some voluntary actions, such as the "drive one day less a month" program have been implemented to improve public awareness of climate change.

In 2000, China established its first national fuel efficiency standard, which was designed to reduce oil consumption and to encourage foreign automakers to introduce more fuel-efficient vehicle technologies into the Chinese market. The first national standard for vehicle fuel efficiency was enacted in July 2005 by the General Administration of Quality Supervision, Inspection and Quarantine and the Standardization Administration. This new standard was implemented in two stages: Stage 1, which aimed to improve fuel efficiency by 10 percent, took effect on July 1, 2005. Stage 2 took effect on January 1, 2008 with the goal of improving fuel efficiency by an additional 10 percent. A standard has been developed to set different fuel efficiency levels for different types of vehicles to be sold in China. The vehicle companies are asked to provide detailed information for fuel efficiency verification reports. Every vehicle sold must be tested to confirm that its fuel consumption meets specifications for that model.

Rail is the most commonly used mode of long-distance transportation in China. The Ministry of Railways is responsible for the construction and operation of the rail system. In the 11th Five-Year plan of railway construction, the Chinese government allocated about 1.25 trillion RMB to expand its railway system, with the goal of growing from 78,000 km in 2007 to 85,000 km in 2010 and 100,000 km in 2020. In December 2008, the State Council announced an economic stimulus package with a 2 trillion RMB investment plan. As a result of increased investment, the country's railway network is expected to expand further to 100,000 km in 2010 and 120,000 km in 2020. The Ministry of Railways is also paying greater attention to the development of a high-speed railway system that can compete with direct flights in the long distance transportation market. China Railway High-speed (CRH) has been utilized in several intercity rail system expansions in China. The goal is to extend the high-speed system to a length of 12,000 km with an average speed higher than 200km/h.

7.2.6 Agriculture

Targets for renewable energy in rural areas are identified in the 11th Five-Year Plan for renewable energy. The Ministry of Agriculture also published a Plan for Biogas Construction in Rural Areas in 2006 and several targets are set out in these plans. By the end of 2007, there were over 26.5 million rural households using household biogas digesters in China, saving 16 million tce annually, which is equivalent to emissions reduction of 44 million tons of CO_2.

7.2.7 Forestry

The 11th Five-Year Plan for forestry sets out mitigation policies and measures for this sector. The goal is for forest cover to reach 20 percent of total land cover in 2010, 23 percent in 2020 and 26 percent in 2050. The forest stock volume is targeted to reach 13.2 billion m^3. By the end of 2007, China had planted more than 51 billion trees throughout the country. In recent years, through measures such as collective forest property reform, farmers' enthusiasm for tree planting and forest protection has increased. At present, China has 54 million hectares of man-made forest, with its stock volume reaching 1.505 billion m^3.[40] The country's forest coverage has increased from 12 percent in the early 1980s to current level of 18.21 percent[41]. In 2006, the total area of the green belt and park areas in urban China reached 1.32 million ha with 35 percent green coverage. The government estimate that from 1980 to 2005, a total accumulated net sequestration of 3.06 billion tCO_2 was achieved by afforestation, 1.62 billion tCO_2 by forest management, and 430 million tCO_2 from deforestation were avoided.[42]

7.3 Effect of Current Policies in Key Industrial Sectors

Note that the following analysis is made for electricity sector only up to year 2020, which is the main period for 12th Five Year Plan and also has a conservative set to the development trends of nuclear power and renewable energy power generation. However, for the cement sector we expand our study year to 2050, in order to find the peak year.

7.3.1 Electricity sector

With the rapid development of economy, electric power construction in China has maintained a high growth momentum. The national total installed capacity increased from 391 GW in 2003 to 966 GW in 2010, which means an average annual growth rate of 13.8%. During the same time period, the national power generating capacity has increased from 1,905.2 TWh to 4,227.8 TWh and the average annual growth rate is 12.1%. The rapid development of power industry provides a solid foundation for the sustained and steady development of China's social economy (Table 7.3).

In 2010, China’s thermal power installed capacity had increased from 290 GW in 2003 to 710 GW. Net capacity increase reached 100 GW with the growth rate of 23.7% in 2006 where the development of thermal power generation was fastest. Although the growth rate has declined in recent years, the proportion of thermal power in the installed capacity is still more than 70%, as the main category of generator units in China. The installed thermal capacity and growth rates are shown in Table 7.4 and Figure 7.1.

[40] http://www.un.org/chinese/millenniumgoals/china08/7_1.html; http://www.cgf.org.cn/icc/dt_detail.asp?id=40
[41] http://www.scio.gov.cn/zfbps/ndhf/2008/200905/t307869_4.htm
[42] http://www.scio.gov.cn/zfbps/ndhf/2008/200905/t307869_4.htm

Table 7.3 Total installed capacity of power generator and power generating capacity (2003-2010)

Category \ Year		2003	2004	2005	2006	2007	2008	2009	2010
Installed Capacity	Total installed capacity (MW)	391,408	443,287	517,185	622,000	713,290	792,731	874,097	966,413
	Net installed capacity (MW)	34,837	50,979	73,898	104,815	91,290	79,441	81,366	91,240
	Growth Rate (%)	9.77	13.02	16.67	20.27	14.68	11.14	10.26	10.56
Power Generating Capacity	Total Power Generation (TWh)	1,905	2,187	2,475	2,834	3,256	3,451	3,681	4,228
	Growth Rate (%)	15.18	14.80	12.80	14.54	14.44	5.99	6.67	14.85

Source: The power industry's statistical annual reports, China Electricity Council

Table 7.4 Total installed thermal capacity (2003-2010)

	Total thermal power installed capacity (MW)	Proportion of total installed capacity (%)	Net increased capacity of thermal power (MW)	Growth rate than the previous year (%)
2003	289,771	74.03	24,224	9.12
2004	329,480	74.47	39,712	13.7
2005	391,376	75.67	61,896	18.78
2006	484,050	77.82	92,674	23.70
2007	554,420	77.73	70,370	14.54
2008	602,858	76.05	48,438	8.74
2009	651,076	74.49	48,218	8.00
2010	709,672	73.43	58,305	8.96

Among thermal power plant, coal-fired units are the absolutely main category. In 2010, the total installed capacity of thermal power units with single unit capacity exceeding 6 MW reached 704 GW, with a total generating capacity of 3,408 TWh. Of these, the installed capacity of coal-fired electricity was 647 GW, accounting for 91.9% of the total thermal power installed; the generating capacity reached 3,216 TWh, accounting for 94.4%. The installed capacity and generating capacity of thermal power generating technologies in 2010 are given in Table 7.5.

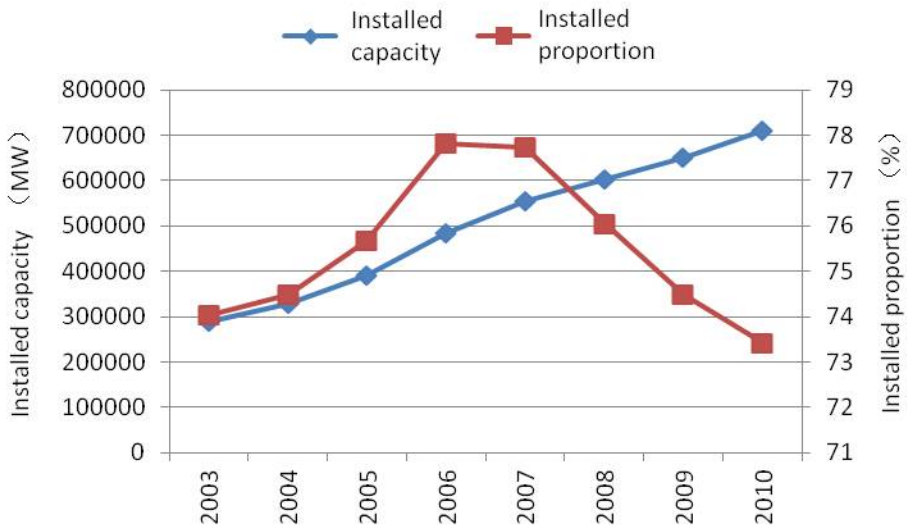


Figure 7.1 The total installed capacity of thermal power and proportional growth (2003-2010)
Source: The power industry's statistical annual reports, China Electricity Council

Table 7.5 The installed capacity of thermal power in 2010 (divided by technology)

Thermal Power Technology	Installed capacity			Generation		
	Capacity (MW)	Installed Proportion	Growth Rate	Generating Capacity (TWh)	Generating Proportion	Growth Rate
coal-fired	646,606	91.90%	9.20%	3,216.27	94.40%	13.46%
gas-fired	26,424	3.80%	9.96%	77.63	2.30%	37.25%
oil-fired	8,780	1.30%	6.68%	16.19	0.50%	-5.20%
coal gangue	8,368	1.20%	24.15%	361.00	1.10%	13.61%
Biomass	1,704	0.20%	56.66%	7.43	0.20%	42.33%
Waste	1,709	0.20%	31.20%	8.68	0.30%	28.70%
Residual heat, Residual pressure, Residual gas	10,071	1.40%	-13.82%	45.606	1.30%	-13.74%
Total	703,911	100%	9.09%	3,408.61	100%	13.43%

Source: The power industry's statistical annual reports, China Electricity Council

7.3.1.1 Reference Scenario

China Electricity Council predicted that the power demand in China in 2015 and 2020 would reach 6,310 TWh and 8,140 TWh, respectively. This report refers to this forecast as electricity demand under *Reference Scenario* in China in 2015 and 2020. When predicting the development of China's power industry in 2015 and 2020, the Reference Scenario considered the current situation of all kinds of power generation technologies in China and the development trends in the future comprehensively, and it also made a conservative assumption for the development trends of nuclear power and renewable energy power generation during 2010-2020. At the same time, it pointed out that the insufficient power demand could be fully satisfied by coal-fired units. The specific set of results is shown in Table 7.6.

Table 7.6 The development trends of power generation technologies under Reference Scenario

Power technology	Reference Scenario
Coal-fired power generation	Due to technological progress and structural optimization, the coal consumption of coal-fired power generator units is declining at a speed of about 2.2 grams of standard coal/ kWh per year, and it will decrease from 322 grams of standard coal/ kWh in 2010 to 300 grams of standard coal/ kWh in 2020, which means 5200 hours per year of equivalent operating hours. In addition, as the main choice to meet the newly-increased power demand of power generation industry, the coal-fired power generation will keep a rapid development momentum just as the past five years, and the newly built units are all supercritical and ultra-supercritical units of 600 MW or above.
Hydroelectric generation	Assume that 80% of explored and economic hydropower resources have been developed by 2020 in China, the total installed capacity of hydropower will reach 320 GW, which means equivalent operation hours of 3000 hours per year.
Nuclear electricity generation	According to China's long-term development plan of nuclear power, China's nuclear power installed capacity will reach 40 GW in 2020, but in fact the actual development of nuclear power in recent years is faster than this plan. Although the Fukushima nuclear accident has produced negative influence on nuclear power development in recent two years, nuclear power is still the important way to realize the sustainable development of carbon reduction in the long term. Assume that average 9 nuclear power units of 1 GW per year will be built during 2010-2020, the total amount will achieve 95 GW by 2020, and the annual operation hours will be equal to 7200 hours per year.
Wind power generation	Assume that wind power generation keeps rapid development continuously during 2010-2020, with an average annual construction of 14 GW. The total amount will reach 180 GW in 2020 and the equivalent operation hours will achieve 2100 hours per year.
Gas-fired power generation	Considering the limited natural gas in China being mainly used for supplying urban gas in the future, we assume that the installed capacity of gas-fired generator is only 40 GW in 2020; In addition, assume gas equivalent operation hours will reach 2000 hours per year considering some possible problems such as insufficient gas supply. The gas consumption of power generation will decrease at the speed of an annual rate of 0.0015 standard cubic meters per kWh from 0.194 standard cubic meters per kWh in 2010.
Biomass power generation	Because biomass power generation mainly includes straw power generation and is limited by resources and costs, the reference scenario assumes that the total capacity of the biomass power generation will reach 5 GW by 2020. In addition, we assume that its equivalent operation hours will reach 6500 hours per year with reference to the current running situation of straw generator.
Solar power generation	Considering the photovoltaic technology is still immature and high-cost, we assume that the total installed capacity of photovoltaic power generation in China will achieve 20 GW in 2020 and equivalent operation hours will reach 1400 hours per year.

7.3.1.2 GCAM Alternative Scenario

According to the predictions of the GCAM model, the demand for electric power in China in 2015 and 2020 should be controlled under 4,160 and 5,080 TWh. But GCAM's base year is 2005, and power generation in China has actually exceeded the forecast of GCAM, reaching 4,230 TWh in 2010. Therefore, we use GCAM's predictions of growth rate to calculate China's power demand in 2015 and 2020. According to the estimation, the demand for electric power in China needs to be controlled in 5,280 TWh and 6,450 TWh in 2015 and 2020, respectively. This chapter refers to this Alternative Scenario in China in 2015 and 2020. When predicting the development scenarios of China's power industry in 2015 and 2020, the Alternative Scenario made a more active and bold assumption to the development of nuclear power and renewable energy for the period 2010-2020 than reference scenario, considering the comprehensive requirements of sustainable development of energy to the resources and environment. As the reference scenario, the electricity demand could be fully satisfied by coal-fired units. The specific results are shown in Table 7.7.

Table 7.7 The development trend of power generation technologies under Alternative scenario

Power technology	Alternative Scenario
Coal-fired power generation	Due to technological progress and structural optimization, the coal consumption of coal-fired power generator units is declining at a speed of about 2.2 grams of standard coal/ kWh per year It will decrease accumulatively from 322 grams of standard coal/ kWh in 2010 to 300 grams of standard coal/ kWh in 2020, which means 5200 hours per year of equivalent operating hours. Due to the limitation of coal production and supplemental capacity and the requirement of carbon reduction, the power industry will give priority to develop the low carbon generation technologies such as nuclear power and renewable energy power. Therefor the expansion of coal-fired electricity industry will be slower than reference Scenario. As the same with reference scenario, the newly built units are all supercritical and ultra-supercritical units of 600000 kW or above.
Hydroelectric generation	Assume that 85% of explored and economic hydropower resources have been developed by 2020 in China, the total installed capacity of hydropower will reach 340 million kW, which means that the equivalent operation hours will reach 3000 hours per year.
Nuclear electricity generation	Assuming that the developing speed of nuclear power is faster than the reference scenario during 2010-2020, the total amount will reach 110 million kW in 2020, and annual operation hours will be equal to 7200 hours per year.
Wind power generation	Assume that Wind power generation keeps rapid development continuously during 2010-2020, with an average annual construction of 20 million kW. The total amount will reach 240 million kW in 2020 and the equivalent operation hours will achieve 2100 hours per year.
Gas-fired power generation	Considering the limited natural gas in China being mainly used for supplying urban gas in the future, we assume that the installed capacity of gas-fired generator is only 40 million kW in 2020; In addition, we assume gas equivalent operation hours will reach 2000 hours per year considering some possible problems such as insufficient gas supplement. The gas consumption of power generation will decrease at the speed of an annual rate of 0.0015 standard cubic meters per kWh from 0.194 standard cubic meters per kWh in 2010.
Biomass power generation	Biomass power generation is highly developed. Besides straw, other biomass resources, such as forest waste and municipal waste have also been used to generate power. The reference scenario assumes that the total capacity of the biomass power generation will reach 18 million kW by 2020. In addition, we assume that its equivalent operation hours achieve 6500 hours per year with reference to the current running situation of biomass generator units.
Solar power generation	Alternative scenario assumes that the developing speed of photovoltaic power is faster than the reference scenario during 2010-2020, and total installed capacity of photovoltaic power generation in China will achieve 30 million kW by 2020 and equivalent operation hours will reach 1400 hours per year.

7.3.1.3 Optimization scenarios

Optimization scenarios use the CHINA-TIMES model, consider seven power generation technologies such as coal-fired power, hydropower, nuclear power, wind power, gas-fired power, biomass power and IGCC generation, and can constitute a data set based on the real age of power unites in China's power industry in 2009. They also take the shut and cease of power units (all power units are decommissioned when they reach life expectancy) into account, and quantitatively consider the influence of carbon tax policy making on the options of generation technology in the power industry. Through the optimization of calculation, we could obtain a development route in which power generation industry has the lowest comprehensive accumulated total cost in the inspection period, which means the construction decision of generator units in electricity industry during the period of inspection. The comprehensive accumulated total cost mentioned above includes the construction and investment cost of power unites, operation and maintenance costs, fuel costs and carbon emissions (carbon tax) cost.

With regard to carbon tax policy, this report assumes that government will start to implement carbon tax of 100 yuan / ton of carbon dioxide in the power industry from 2016, and carbon tax will be increased by 20% per year. The estimated carbon emission in the electricity sector under the carbon tax is shown in Table 7.8.

Table 7.8 Electricity sector emissions under carbon tax policy

Year	2009	2010	2011	2012	2013	2014
Emission in Power Sector (100 million tons of CO_2)	28.18	28.46	28.74	29.03	29.31	29.60
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Emission in Power Sector (100 million tons of CO_2)	29.90	30.19	30.49	3.079	31.10	31.41

Table 7.9 lists the assumed life time that the model has made for all seven kinds of generator units. All units are decommissioned after reaching life expectancy. In addition, with regard to the fuel consumption of coal-fired generator units and the gas generator units, the model uses the same assumptions as reference scenario and alternative scenario. When it comes to nuclear power the main concern of the whole world is to improve the safety, and the efficiency of nuclear power in recent years has had almost no significant progress. Therefore, we assume that the fuel consumption rate of nuclear power plant has stabilized at the level of 10000 tons of natural uranium / million kW /60 years during the period of 2010-2020. As for the average annual operating hours of all types of generator units, this chapter also uses the same hypothesis as reference scenario and alternative scenario.

Table 7.9 Life expectancy of various types of generator units in optimal decision-making model

Types of gen-units	Coal fired	Gas power	Nuclear power	Hydroelectric power	Wind power	Biomass power	Photovoltaic power
[years]	30	30	60	70	20	20	20

The construction and investment cost of various types of generator units are shown in Table 7.10. In addition, the operation and maintenance cost of each generator unit accounts for 3% of construction and investment cost. The prices of coal, natural gas and natural uranium are shown in Table 7.11.

Table 7.10 The construction and investment cost of various types of generator units in optimal decision-making model [Yuan/ kW]

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal fired	4500	4478	4455	4433	4411	4389	4367	4345	4323	4302	4280	4259
Gas power	3300	3267	3234	3202	3170	3138	3107	3076	3045	3015	2984	2955
Nuclear power	13662	13662	13662	13662	13662	13662	13662	13662	13662	13662	13662	13662
Hydro power	9000	9010	9020	9030	9040	9050	9060	9070	9080	9089	9099	9110
Wind power	8242	7912	7595	7292	7000	6720	6451	6193	5945	5708	5479	5260
Biomass power	15000	14700	14406	14118	13836	13559	13288	13022	12761	12506	12256	12011
PV	14878	13390	12051	10846	9761	8785	7907	7116	6404	5764	5188	4669

Table 7.11 The prices of various types of fuel in optimal decision-making model

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal [Yuan/tce]	710	735	772	810	851	893	938	985	1034	1086	1140	1197
Natural gas [Yuan/m3]	1.500	1.515	1.530	1.545	1.561	1.577	1.592	1.608	1.624	1.641	1.657	1.674
Uranium [Yuan/kg]	674	691	708	726	744	763	782	801	821	842	863	885

In order to make the result more reasonable while considering the constraints of resources, manufacture capacity and installation capacity in power industry, this chapter sets upper limits for generator units' maximum possible installed capacity in the decision-making model, the maximum annual supply capacity of various types of fuel (coal/natural gas/uranium) and the annual maximum building capacity of various types of generator units, as the following three tables shows.

Table 7.12 Generator units' maximum installed capacity of a variety of renewable energy

Types of units	Hydroelectric power	Wind power	Biomass power	Solar power
[million kW]	300	600	50	600

Table 7.13 maximum annual supply capacity of various types of fuel

Types of fuel	Coal 100 million tce	Natural gas 100 million m^3	Uranium tonne
Maximum annual supply capacity	15	2000	50,000

Table 7.14 Annual maximum building capacity of various types of generator units

Types of units	Coal-fired power	Nuclear power	Hydroelectric power	Wind power	Gas power	Biomass power	Solar power
[million kW]	80	8	20	20	5	2	5

7.3.1.4 Analysis results

Based on the assumptions mentioned above we obtained 5 scenarios: the reference scenario (high power demand), alternative scenarios (GCAM low power demand), optimization scenario 1 (high power demand), optimization scenario 2 (GCAM low power demand) and optimization scenario 3 (average power demand), named BASE, ALTERNATIVE, OPT_BASE, OPT_ALTER and OPT_AVERAGE respectively.

Table 7.15 and Table 7.16 list the generating installed capacity and the power production per technology under the 5 scenarios in China in 2015 and 2020. As shown in these tables, the thermal power installed capacity will range between 963 million kW and 682 million kW in 2015, 60%~69% of total national power installed capacity, in which coal-fired thermal power is still the main force, 95~98% of total thermal power. In 2020, China's thermal power installed capacity will reach 740 million kW to 1190 million kW, 51~66% of total national power installed capacity, of which coal-fired installed capacity will remain 95%~97% of total thermal power, without significant change.

Table 7.15 Installed capacity and power production per technology under 5 scenarios in China in 2015 [GW/TWh]

Scenario	BASE	ALTERNATIVE	OPT_BASE	OPT_AVERAGE	OPT_ALTER
Coal-fired power	933/4,852	690/3,588	850/4,624	755/4,369	662/3,854
Gas power	30/60	33/66.4	20/39.5	20/39.5	20/39.5
Nuclear power	43/309	60/435	55/396	55/396	55/396
Hydroelectric power	284/852	278/834	253/761	254/761	254/761
Wind power	100/210	125/262	68/202	68/143	68/143
Biomass power	3/19.5	11/69.6	13/82	13/82	13/82
Solar photovoltaic	2/2.8	15/21.2	0/0	0/0	0/0
TOTAL	**1,395/6,305**	**1,212/5,276**	**1,259/5,843**	**1,165/5,345**	**1,072/4,864**

Table 7.16 Installed capacity and power production per technology under 5 scenarios in China in 2020 [GW/TWh]

Scenario	BASE	ALTERNATIVE	OPT_BASE	OPT_AVERAGE	OPT_ALTER
Coal-fired power	1,150/5,980	700/3,640	1,122/5,773	930/4,837	745/3,875
Gas power	40/80	40/80	45/89.5	45/89.5	45/89.5
Nuclear power	95/684	110/792	90/648	90/648	90/648
Hydroelectric power	320/960	340/1,020	353/1,060	353/1,060	353/1,060
Wind power	180/378	220/462	168/412	168/353	168/353
Biomass power	5/32.5	18/117	23/147	23/147	23/147
Solar photovoltaic	20/28	30/42	10/14	10/14	10/14
TOTAL	**1,810/8,142**	**1,458/6,153**	**1,811/8,142**	**1,619/7,148**	**1,434/6,453**

The installed capacity share of China's thermal generator units will greatly decline in the next decade. On one hand, renewable energy and nuclear power units will supply this reduction; on the other hand, new thermal power units are large-scale, high-efficiency supercritical or ultra-supercritical units. However, coal-fired power will still account for the vast majority of thermal generator units and the installed capacity of gas-power generation technology will probably not have a big breakthrough in the next decade.

Figure 7.2 and Figure 7.3 gives the variation trend of installed capacity and total generation of China’s power industry under the five scenarios from 2010 to 2020. From the results we can see that when the demand for electricity in 2020 reaches 8,142 TWh (equivalent to annual electricity consumption of 5,300 kWh per capita), and the power industry develops in accordance with conventional technology similar to the past few years (BASE scenario), China's total installed capacity will achieve 1,810 GW by 2020 in the BASE scenario. That is an increase of 87.4% compared with 966 GW in 2010. Among them, coal-fired units will rise from 680 GW in 2010 to 1,150 GW in 2020, contributing 73.4% of the total generating capacity.

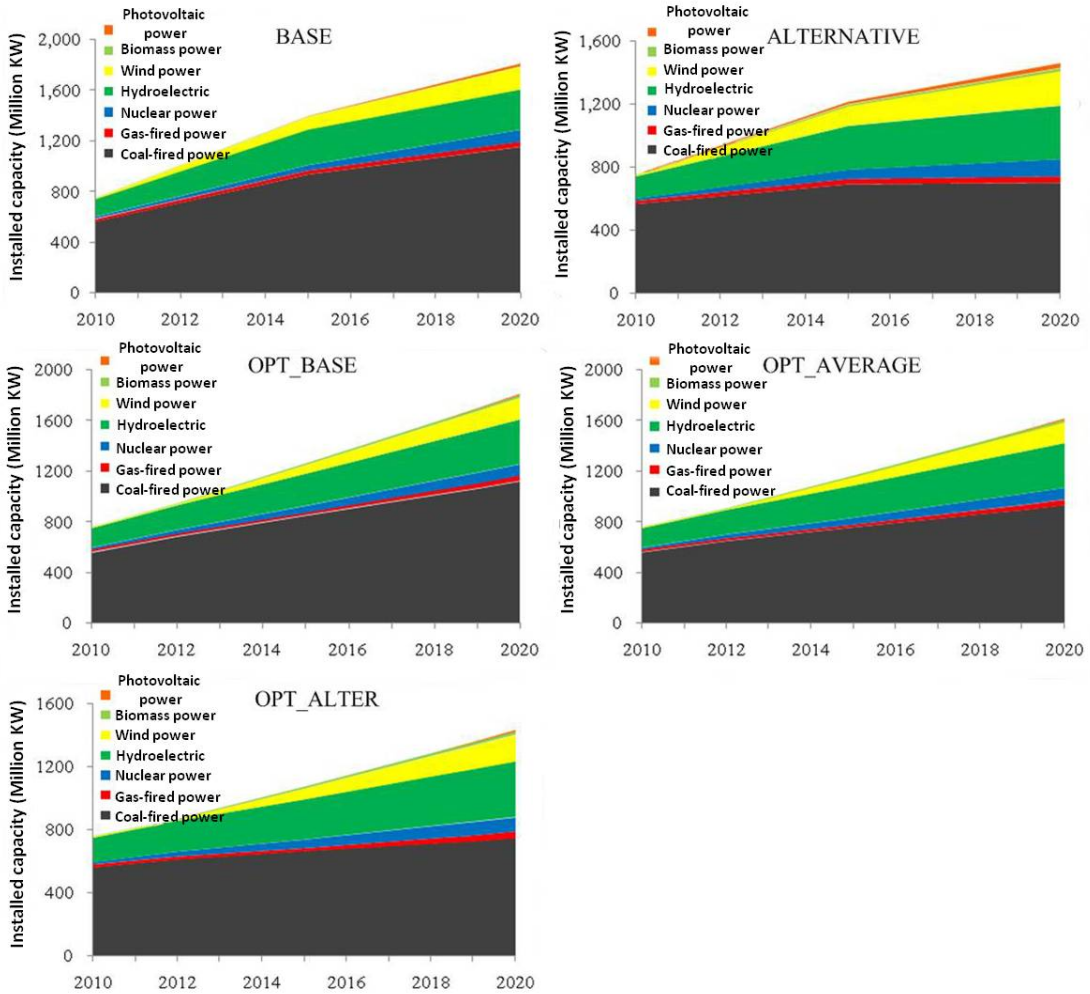


Figure 7.2 The trend of installed generating capacity in China under 5 scenarios from 2010 to 2020 [GW]

If we could apply all kinds of energy-saving measures comprehensively the demand for electricity in China will increase slowly to 6,450 TWh in 2020. If we also take more efforts than in the past few years to develop low carbon power generation technology of nuclear power and various renewable energy (alternative scenario), the total installed generating capacity in China will grow to 1,434 GW by 2020, 20% lower than the BASE scenario. The total installed capacity of coal-fired power generation will only increase to 700 GW and generating capacity of coal-fired electricity generation will account for 59.2% of total generating capacity. Gas-fired power generation, nuclear power, renewable energy power generation and other low-carbon power generation technologies will cumulatively contribute to 40.8% of total generating capacity by 2020. In three kinds of optimization scenarios, because the assumptions of power demand are between baseline scenario and optimization scenario, the overall development trend of various power generation technologies are similar to baseline and optimization scenarios. At the same time, since various optimization scenarios have taken into account the actual decision-making process of power industry, the development and decision-making of power generation technologies are more stable and continued.

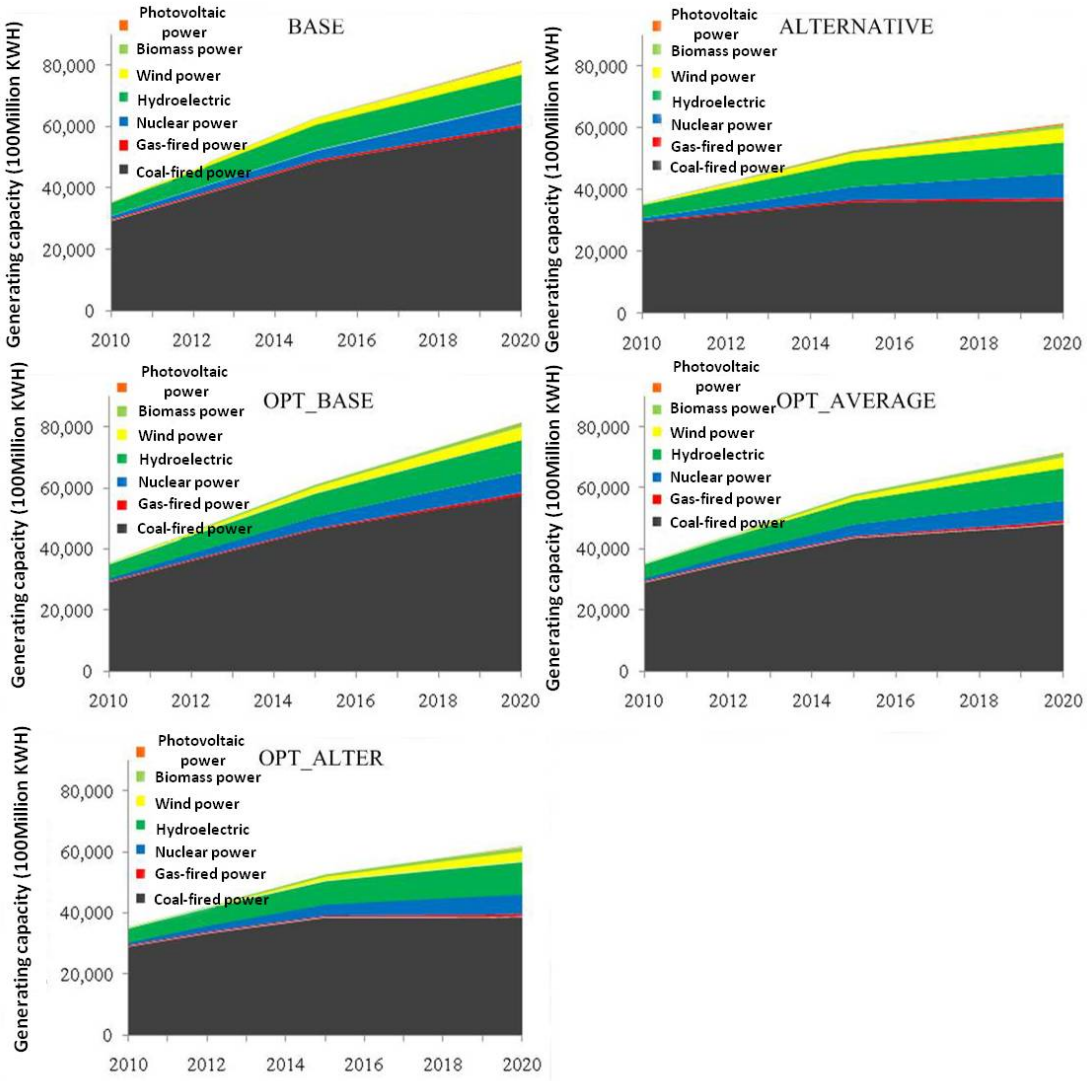


Figure 7.3 The trend of electricity generation under 5 scenarios from 2010 to 2020 [TWh]

According to the five scenarios mentioned above, coal-fired units' capacity structure in China will have a great change. Because nuclear power and renewable energy power generation can't fully meet the rapid growth of electricity demand in the future owning to the constraints of available resources, coal-fired power generation will still maintain a rapid growth momentum during the period 2010-2020, and is always the single power generation technology with the largest total installed capacity and generating capacity. With the continuous implementation of "Closure of small scale" policy of coal-fired generator units in China, combined with the fact that 600 MW and above supercritical and Ultra-supercritical generator units are becoming the absolute mainstream of newly-build coal-fired generator units. Coal-fired generator units between 50 and 100 MW will basically be out of the market by the end of 2015 under five scenarios, only accounting for 0.3-0.4% of total coal-fired generator units (Market share was 15.5% in 2009). The share of units between 100 and 300 MW will drop from 17.6% in 2009 to 10.6%-14.4%. Furthermore, the market share of 300-600 MW size coal-fired generator units will decline by about 10 %-points, only accounting for 15-20% of market share; and the market share of units above 600 MW will rise nearly 30 %-points, 70% of the total market in 2015. By 2020, the proportion of 600 MW and above generator units will account for more than 70% of total capacity of coal-fired units, and medium and small units below 300 MW only

account for 10% or less. This shows that with the rapid expansion and renewal of generator units in the next decade, coal-fired power generation industry in China will develop into a kind of modern industrial structure in which large and super large generator units are absolutely dominant with medium-sized and small units as effective supplements.

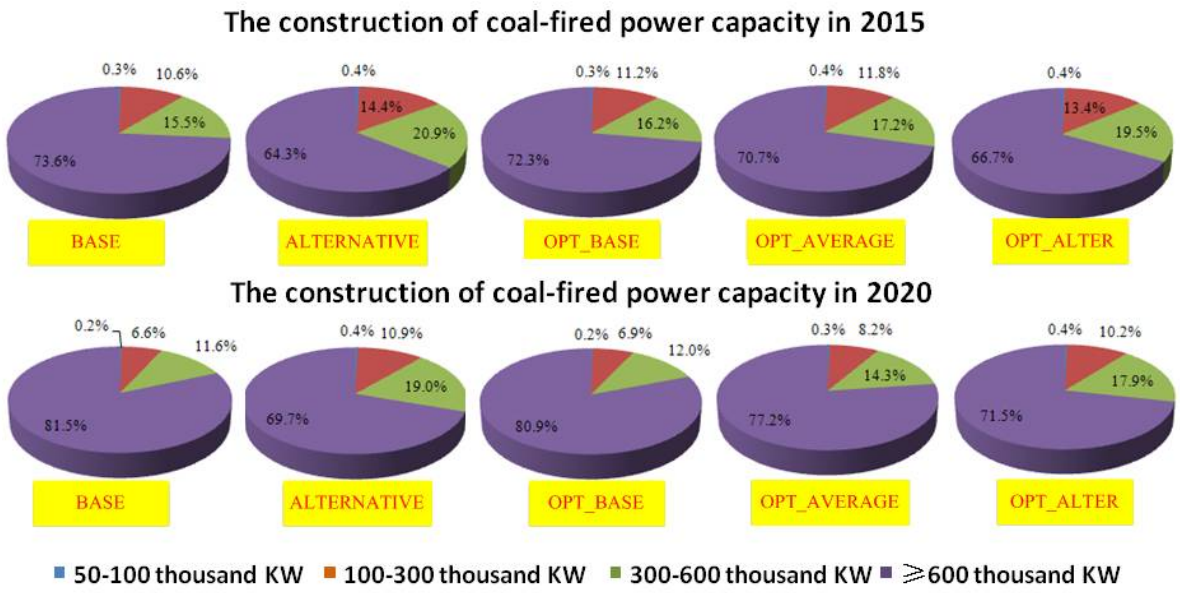


Figure 7.4 The construction of coal-fired generator units in China in 2015 and 2020 under 5 scenarios

Widely using large scale coal-fired generator units will decrease the demand of coal in China. Just as shown in Figure 7.5, the demand of coal in China will reach to almost 2.1 billion tons in 2015 under standard scenario, while in the alternative scenario, the coal demand is only 1.6 billion tons. The demand of coal will be between 1.5 and 2.5 billion tons in 2020. According to this, different power development strategy and technical route will have great influence on the demand of coal. Considering demand and supply, it is possible for China to reduce the demand of coal greatly and thus to cut down the emission of greenhouse gas caused by coal consumption.

Based on the results mentioned above, this project further calculated the total carbon emissions of power industry under different scenarios (black part) and the reduction of carbon dioxide emissions and reduction ratio through the development of gas-fired power generation, nuclear and renewable energy power generation. The results show that the total carbon dioxide emissions of power industry in China will maintain between 3 and 5 billion tons. The development of renewable and nuclear energy power generation technology will replace coal-fired power to satisfy the power demand, as well as realizing the emission reduction potential of nearly 2 billion tons of carbon dioxide compared to the BASE scenario.

Compared with the extreme scenarios in which all electricity is provided by coal-fired generator units, the large-scale application of low-emission power generation technologies can help to reduce 2,217 billion tons of carbon dioxide. Among them, the gas-fired power generation, nuclear power, hydroelectric power, wind power, biomass power generation and photovoltaic power generation are respectively contributed 1.7%, 29%, 37.4%, 16.9%, 4.3% and 1.5% of total reduction of carbon emissions. That is to say, hydropower, nuclear power and wind power will become the main means of reducing carbon emissions in China's power generation industry in the long time perspective.

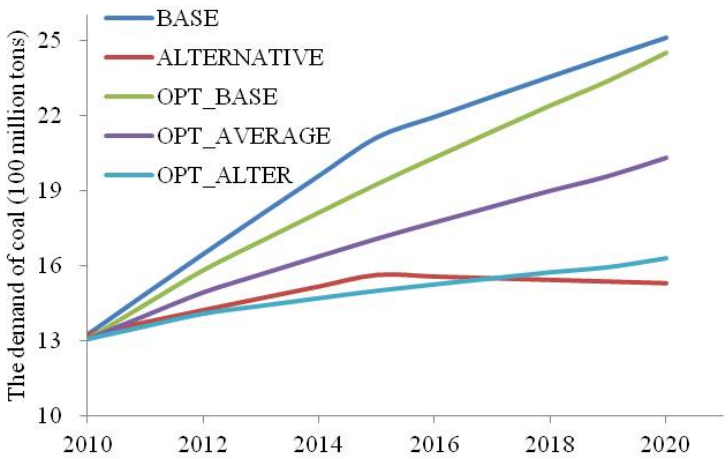


Figure 7.5 The demand of coal in China's power industry during 2010-2020 under Five Scenarios

From the results of scenario analysis, the reduction of greenhouse gas emissions brought by the improved efficiency of coal-fired generator units has played a certain role, which makes the emission reduction of carbon dioxide lie between 222 ~ 366 million tons, accounting for 9.1%~16% of the total carbon dioxide emission reduction in the electric power industry. In the baseline scenario, the improved efficiency of coal-fired units brings the highest carbon dioxide emission reduction, which reaches 366 million tons. While in the alternative scenario where priority is given to renewable energy, nuclear power and other alternative power generation technology, the proportion of the coal-fired units declined compared to the baseline scenario. As a result, the carbon dioxide emission reduction it brought decreased. Consequently, the efficiency of the coal-fired generator units has the potential to improve the carbon dioxide emission reduction. However, the amount of the reduction is limited, which is closely related to the declining proportion of coal-fired units in the entire power generation industry.

Table 7.17 The reduction of CO_2 emissions compared to base year (100 million tons)

	BASE	ALTERNATIVE	OPT_BASE	OPT_AVERAGE	OPT_ALTER
Renewable energy	12.54	14.68	14.32	14.05	14.10
Photovoltaic	0.25	0.37	0.12	0.12	0.14
Biomass power	0.30	1.05	1.29	1.30	1.32
Wind power	3.38	4.13	3.61	3.15	3.16
Hydropower	8.61	9.13	9.30	9.48	9.49
Nuclear power	6.13	7.08	5.69	5.80	5.79
Gas-fired power	0.41	0.42	0.45	0.44	0.45
Coal-fired power	3.66	2.22	3.47	2.96	2.36
Total reduction	22.71	24.42	23.91	23.3	22.71
Total Emission	**50.21**	**30.68**	**49.01**	**40.71**	**32.68**

7.3.1.5 GCAM Chinese electricity production results beyond 2020

The current analysis for the electricity sector in China is made only up to year 2020, which is the main period for the 12th Five Year Plan. As supplement, GCAM results related to development of the electricity production in China up to 2095 for the scenarios Reference, 650 ppm, 450 ppm and Global 20-20-20 are shown in Figure 7.6.

The electricity production is increasing rapidly in all four scenarios, and is more than three times higher in 2095 than in 2015. It is lowest in the Reference scenario and highest in the 450 ppm scenario where it is more than five times higher in 2095 than in 2015. The 650 ppm and the 450 ppm scenarios are dominated by nuclear production and production from fossil fuels with CCS. In the Global 20-20-20 scenario the production portfolio is dominated by production from renewable sources and particularly solar resources. The development is similar to the GCAM results at global level shown in Figure 3.19, Figure 3.20, Figure 3.33 and Figure 3.34. However, at global level the electricity production in Global 20-20-20 is more than doubled than in the 650 ppm scenario and 60-70% higher than in the 450 ppm scenario. This is not the case for China where the production is highest in the 450 ppm scenario.

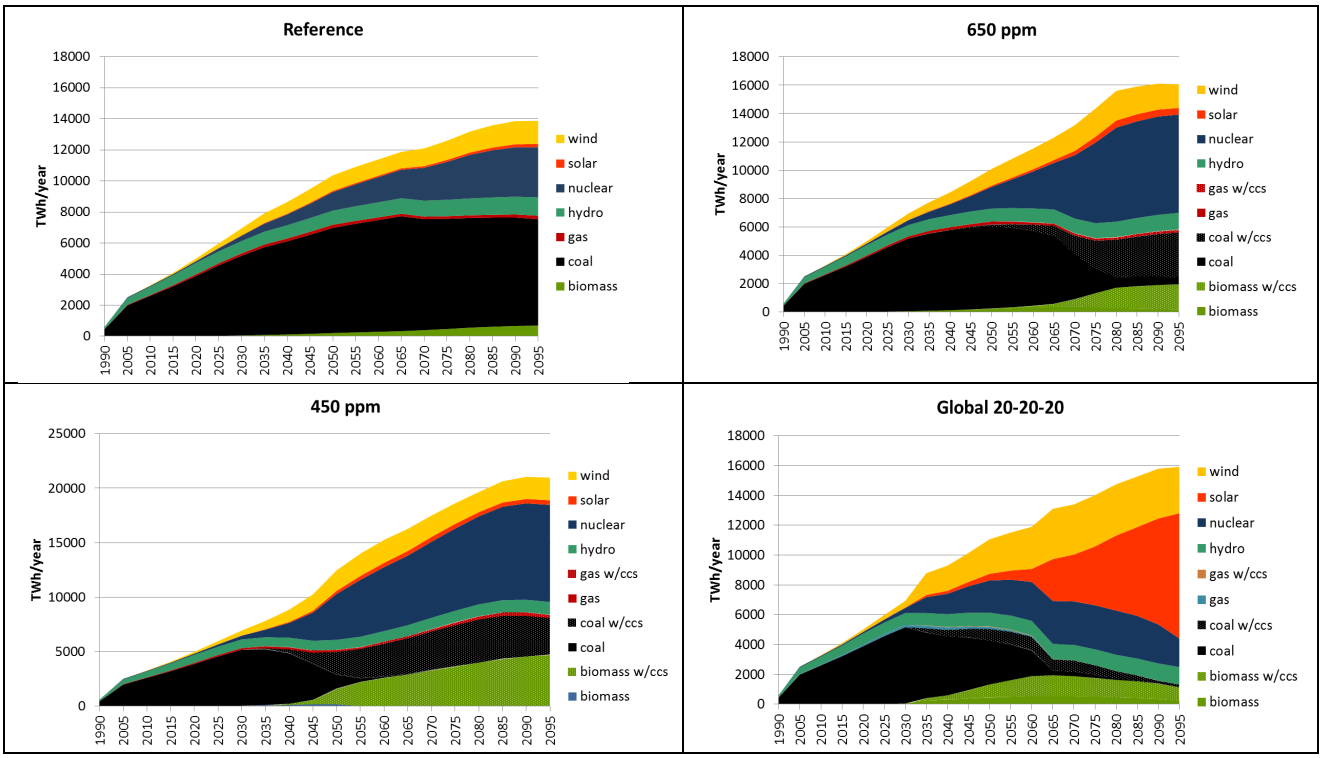


Figure 7.6 Development of electricity production in China for the four main GCAM scenarios

Comparing GCAM Reference scenario for 2020 with the TIMES results, the production in the TIMES scenario is much higher than for GCAM. In the GCAM Reference scenario the production is 5,076 TWh/year while in all the TIMES scenarios the production is from 6,153 TWh/y (Alternative) to 8,142 TWh/year (BASE and OPT_BASE). Coal is dominating the production in both the GCAM and the TIMES scenarios. In the TIMES scenarios ALTERNATIVE and OPT_ALTER the coal production is at the same level as in the GCAM Reference scenario (3,864 TWh/year) while it is much higher in the scenario BASE (5,980 TWh/year), OPT-BASE (5,773 TWh/y) and OPT_AVERAGE (4,837 TWh/y).

The hydro power part of an electricity system with large share of renewables can be very important for balancing variable production from wind and solar resources if the production is connected to reservoirs for storing the energy. In the TIMES scenarios the production from hydro is much more limited than in the GCAM scenarios. In the TIMES scenarios in 2020 the hydro power production is in the range 320-353 TWh/year, while in the GCAM Reference scenario the production is 637 TWh/Year and is increasing to as much as 1,174 TWh/year in 2095. Particularly in the Global 20-20-20 with very high share of solar production, a high hydro power production will be important to back up the production when the radiation is limited.

7.3.2 Conclusions

We can conclude from the calculations of the five different scenarios that the development route in power industry before 2020 is different when the assumed future power demand varies.The biggest variable is the developing speed and the scale of the coal-fired power generation in the next decade. However, because the future power demand forecast is directly affected by the speed of China's economic development, industrial policy, population growth rate and other factors in the future to a great extent, and predictions of these factors in the next decade from different research institutions have great uncertainty, it is difficult to predict China's power demand accurately before 2020. But according to comprehensive comparison of power demand research from many research institutions in China and in other countries combined with the basic judgment from this report's researcher, we assume that China's power demand is likely to locate in the scale between the high power demand of baseline scenario and the low power demand of alternative scenario in 2020.

From the calculations of the development route in power industry in various scenarios, we concluded that vigorously developing nuclear power and renewable energy power generation in China is the key to the inhibition of the rapid growth momentum of coal consumption and CO2 emissions in power industry. Because of the limitation of resource and generator units' construction capacity, nuclear and renewable energy cannot fully satisfy the requirement of increasing electricity demand in the future, but only be a supplement of newly built coal-fired power generator units. The faster the future power demand is growing, the greater the increasing speed and scale expansion of the coal-fired power generator units in the future will be, and the greater difficulties China's power industry will be faced with to realize the sustainable development of low carbon. Consequently, continuing to implement the basic national policy of energy saving and emission reduction, transforming the pattern of economic development, adjusting industrial structure and developing modern service industry with high technology and low intensity of energy will play a crucial and decisive role for Chinas power industry and finally help to realize the sustainable development.

7.3.3 Cement sector

7.3.3.1 Energy consumption and emission status

Along with the sustained and rapid economic growth in China, the cement sector as an important basic industry has developed rapidly in recent years, and the volume of produced cement remains consistently the first in the world, approximately accounting for half of the world's total volume currently. Figure 7.7 describes China's cement production and annual growth rate since 2005. It can be seen that the volume of produced cement increased by 74.7% from 1.069 billion tons in 2005 to 1.868 billion tons in 2010, showing an obvious upward trend. The growth rate of cement production remained above 10% in these five years, except for 2008 when the rate was 4.33% due to the financial crisis.

Energy consumption per unit of product decreases year by year as the backward production capacity is phased out and energy-saving technological transformation measures upgrade. The comprehensive energy consumption per ton of cement dropped drastically by 19.8% from 129.4 kg coal equivalent in 2005 to 103.8 kg coal equivalent in 2009. However, driven by the rapid growth momentum in the cement production in recent years, the total energy consumption in the cement sector remains on the rise, with an increase of 30.8% from 1.17 billion tons coal equivalent in 2005 to 1.53 billion tons coal equivalent in 2009.

Yet, the overall soot and SO_2 emissions tend to decrease in the cement industry in recent years, while NOx and CO_2 emissions show a clear upward trend. In 2009, the cement sector contributed 10% of the national NOx emissions, the third emitter after thermal power generation and vehicle emissions, and 12% of the national CO_2 emissions, the second largest emitter. In addition, the cement sector, one of the polluting industries, was responsible for 5% of the national SO_2 emissions and 35% of soot emissions in 2009.

7.3.3.2 Policy effect analysis

Four policy scenarios are constructed based on the development plan for the cement sector:

Table 7.18 Policy scenarios for the cement sector

Scenario	Abbreviation	Description
Baseline scenario	BS	Assumptions are based on the current development and technological status (including the 11th Five-Year Plan period)
New technologies scenario	NTS	Residual heat power generation technologies are introduced after 2010 and oxyfuel cement production CCS and other carbon reduction technologies after 2020.
Structure optimization scenario	SOS	Cement industrial restructuring and technological upgrading is accelerated. Backward production capacity is eliminated by phasing out shaft kiln year by year to control the proportion below 5% in 2020. New technologies are promoted. Specifically, residual waste cogeneration technologies will contribute more than 80% in 2015 and back-end grinding technologies using over 30% of admixture will exceed 80%.
Low-carbon cement scenario	LCS	*Low-carbon Cement Standards* for trial implementation puts caps on the emission per unit cement, namely 740 kg CO_2/ ton for high-grade cement and 585kg CO_2/ton for low-grade cement.

Baseline scenario (BS)

BS is built based on the current development and technologies and the future development of technologies. Figure 7.7 and Figure 7.7 show the ratio of kiln types in front-end clinker production and the ratio of back-end grinding technologies respectively.

In terms of the front-end process, shaft kiln will be phased out and the dry-process production line, especially the clinker production line with a capacity of over 4500 tonne/day, will increase substantially and become the mainstream technologies after 2010, especially after 2015. In terms of the back-end grinding process, technologies using over 30% of alternative admixture will occupy a larger share after 2020.

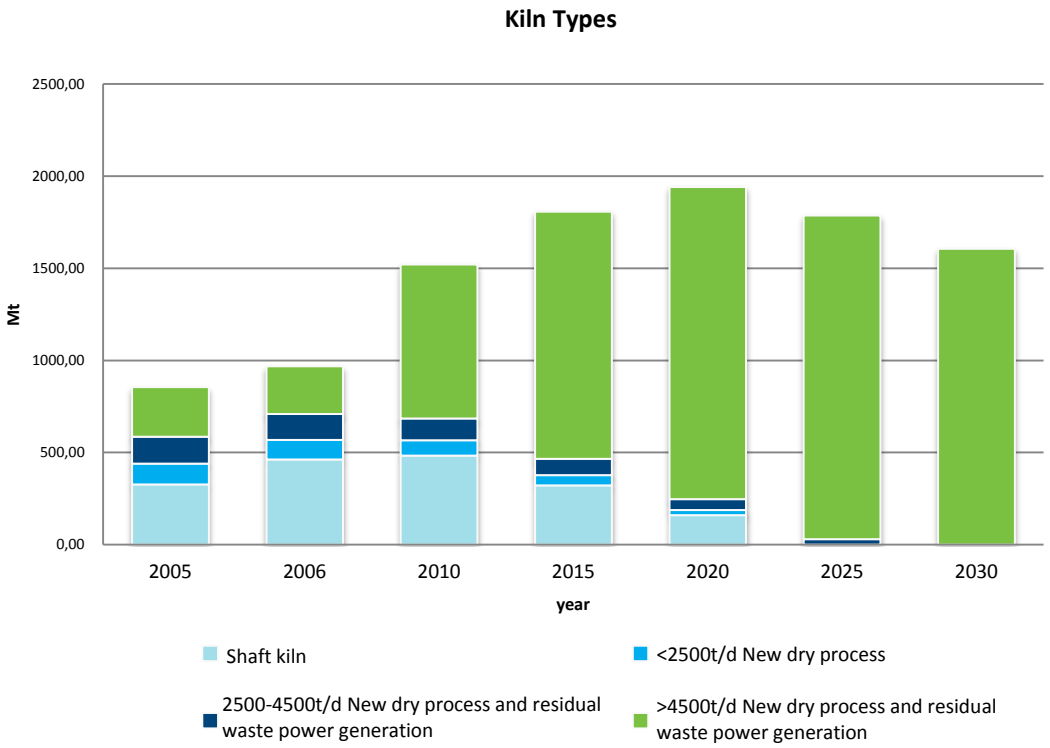


Figure 7.7 Baseline Scenario composition of clinker production technologies

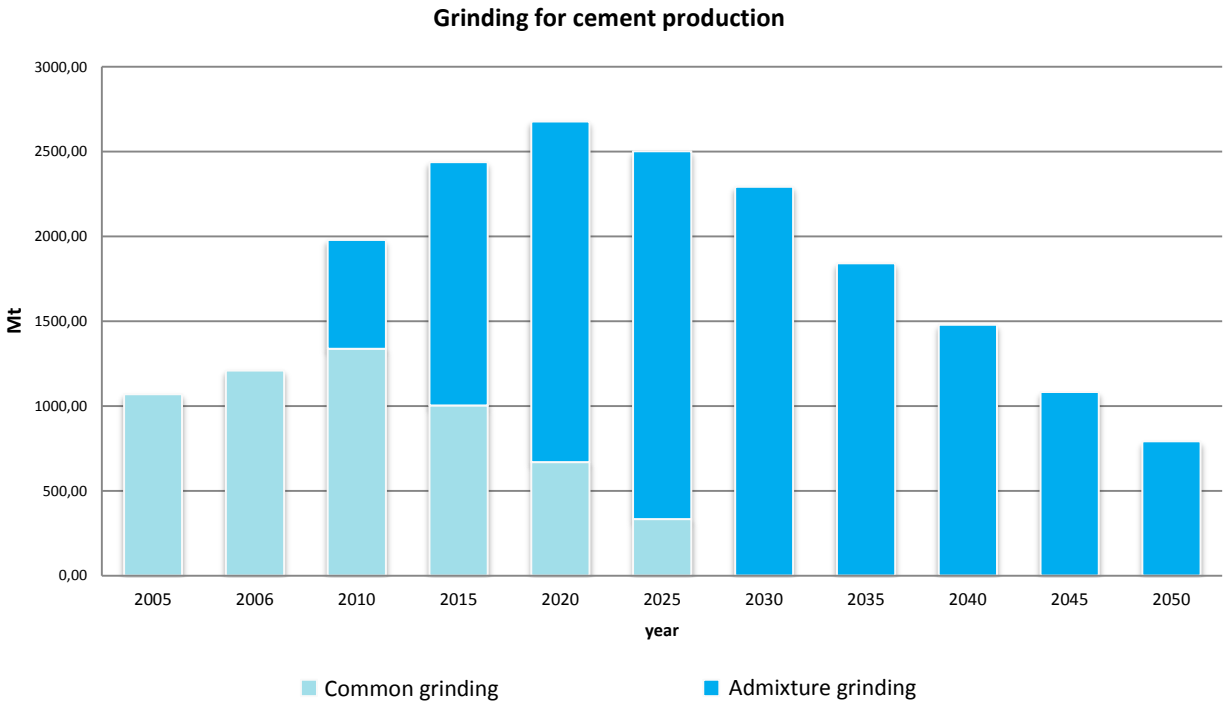


Figure 7.8 Baseline Scenario composition of cement production technologies

New technology scenario (NTS)
Taking into account of residual heat power generation technologies after 2010 and oxyfuel cement production, CCS and other carbon reduction technologies after 2020, output and economic results are assessed under the same constraints, and the following technical composition is obtained.

From 2010 onwards, clinker production technologies with a capacity of over 4500 tonne/day will become the mainstream and expand year after year. Residual heat cogeneration and large-scale clinker production line technologies will be more combined during 2010-2030. Oxyfuel technologies will play a role in the large-scale production lines after 2020 and dominate the market after 2030, while CCS technologies will take obvious effect in the cement production sector after 2035, especially after 2040.

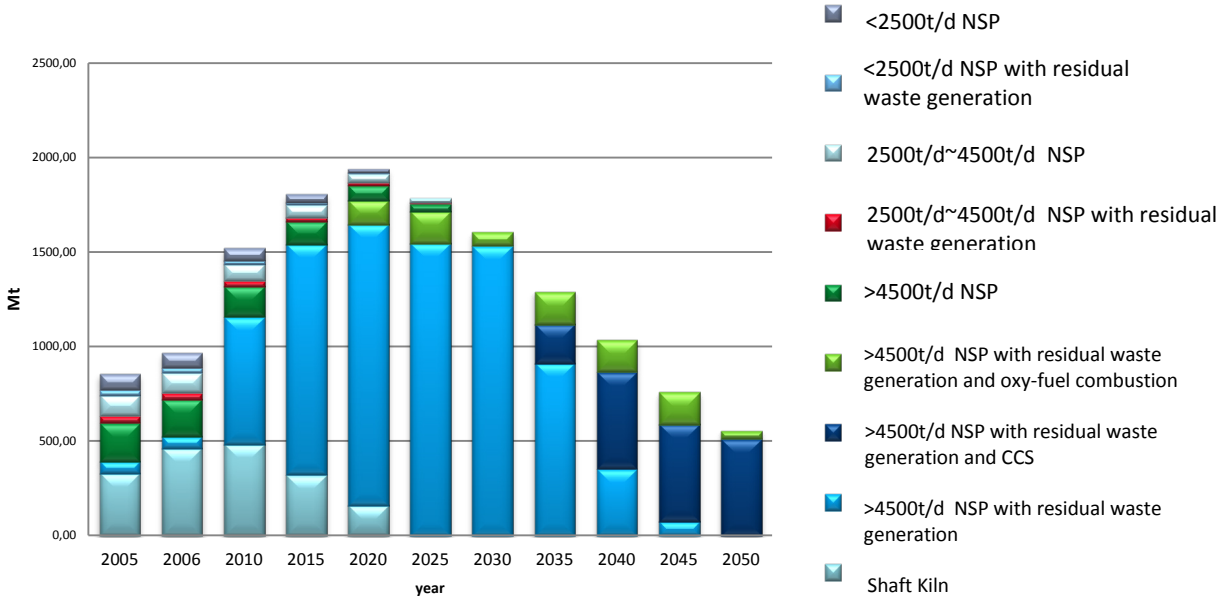


Figure 7.9 New Technology Scenario composition of major cement technologies

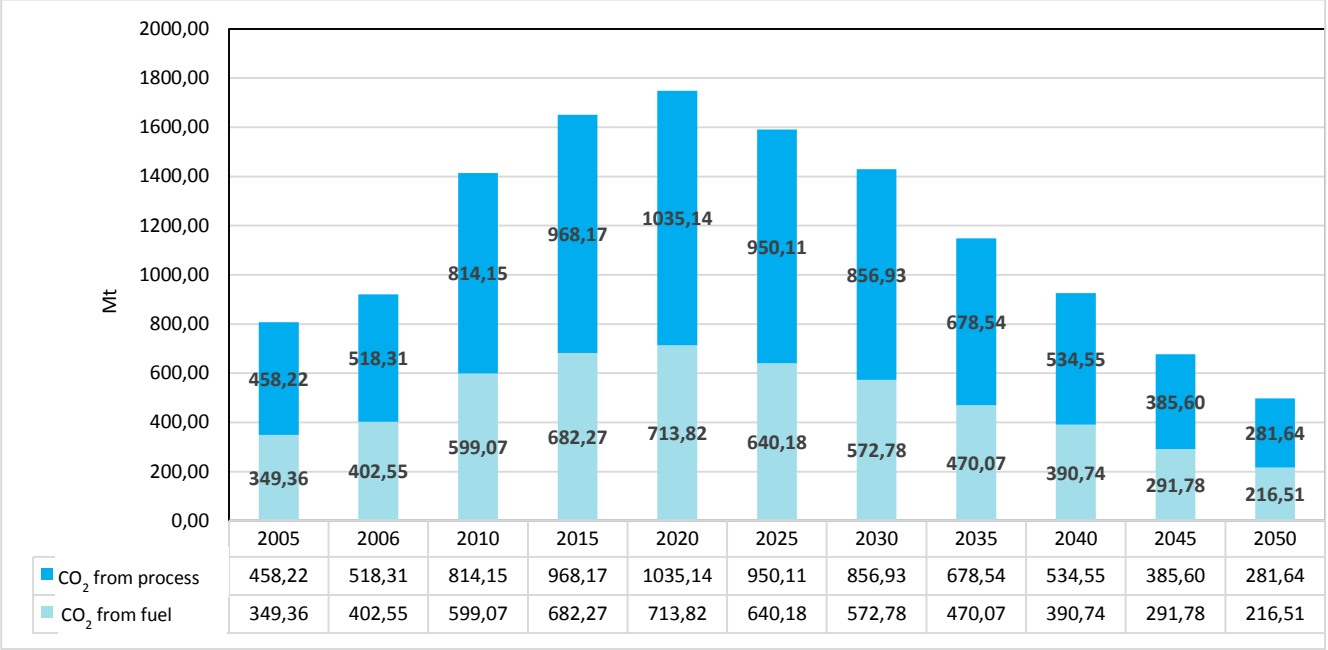
In the scenario with more efficient dry-process production line and oxygen-enriched combustion, residual heat power generation and CCS technologies, residual heat power generation generally occupies a large proportion and creates more technical advantages when loaded on the larger-scale production line. Shaft kiln will be completely eliminated in 2020 and waste heat power generation, the dominant technology in the new dry-process clinker production will have a capacity of over 4500 tonne/day during 2010-2040. While the oxyfuel technology will be applied from 2020, the CCS technology, not vigorously promoted in the cement sector, will be introduced in 2035 and used more in low-carbon scenarios.

Carbon emissions in this scenario are as shown below. Emissions from the production process and fuel combustion are separated to track and analyze CO_2 emissions.

Structure optimization scenario (SOS) and low-carbon cement scenario (LCS)
A major measure to optimize and upgrade the cement industrial structure is to eliminate backward production capacity and accelerate the promotion of new technologies. In terms of backward production capacity, the shaft kiln will be phased out year by year, and its ratio will be reduced to 5% in 2020. In terms of new technologies, residual heat power generation will be applied in 80% of the production in 2015 and

so will back-end grinding using over 30% admixture. In addition, the proportion of shaft kiln will reach the minimum and the ratio of new dry process production line with a capacity of 4500t/d increase by 8% over the BS level in 2010 and reach the maximum in 2020. Elimination of backward production capacity makes more space for the development of advanced technologies, especially large-scale clinker production line.

Low-carbon Cement Standards for trial implementation puts caps on the emission per unit cement, namely 740 kg CO_2/ tonne for high-grade cement and 585 kg CO_2/tonne for low-grade cement. In this scenario, the ratio of large-scale dry process production lines using residual heat power generation is about 15% higher than the BS level in 2015 and oxygen-enriched combustion is included selection list early, and the proportion of the two technologies will reach high in 2020.



	2005	2006	2010	2015	2020	2025	2030	2035	2040	2045	2050
CO_2 from process	458,22	518,31	814,15	968,17	1035,14	950,11	856,93	678,54	534,55	385,60	281,64
CO_2 from fuel	349,36	402,55	599,07	682,27	713,82	640,18	572,78	470,07	390,74	291,78	216,51

Figure 7.10 CO_2 emissions under New Technology Scenario

7.3.3.3 Comprehensive evaluation

From an overall perspective, the most effective policy scenario is the low-carbon cement scenario in which emission reduction results are obvious from 2010. Driven by carbon emission as the objective, this scenario also reduces the emissions of conventional pollutants most drastically in an indirect manner, which highlights the effect of advanced energy-saving technologies.

In terms of carbon emissions, the new technology scenario improves the emissions data after 2015 relative to the baseline scenario. More specifically, carbon reduction is more prominent during 2015-2030 than during 2030-2050. The mandatory *Low-carbon Cement Standards* significantly reduces carbon emissions and limits the emission within a lower magnitude since 2015. In this scenario, CCS technologies will be more used after 2030, contributing to the negative growth of carbon emissions.

With respect to the consumption of raw materials, technological adjustment by introducing new technologies and phasing out old technologies has little effect on the consumption of raw materials, but the phase-out of old technologies increases admixture consumption to some extent and reduces limestone

and coal use. *Low-carbon Cement Standards* leads to a sharp reduction of limestone consumption after 2015, while the proportion of admixture slightly decreases and that of coal and power consumption remains almost the same.

Of the system cost, raw material costs account for a slightly higher proportion under the new technology scenario than under the low-carbon cement scenario, while the admixture-based cement grinding technology takes up a lower proportion. Large-scale dry-process production line using residual heat power generation is less seen under the new technology scenario. CCS technologies generate costs to a certain extent under the low-carbon cement scenario and rarely used in the other two scenarios until 2035.

8 Development of the European electricity sector

8.1 The situation today

Figure 8.1 shows the generation capacity in the EU in 2010. Renewable resources, including waste made up 32 % of total installed capacity, while non GHG emitting resources, including nuclear power, made up 47 %.

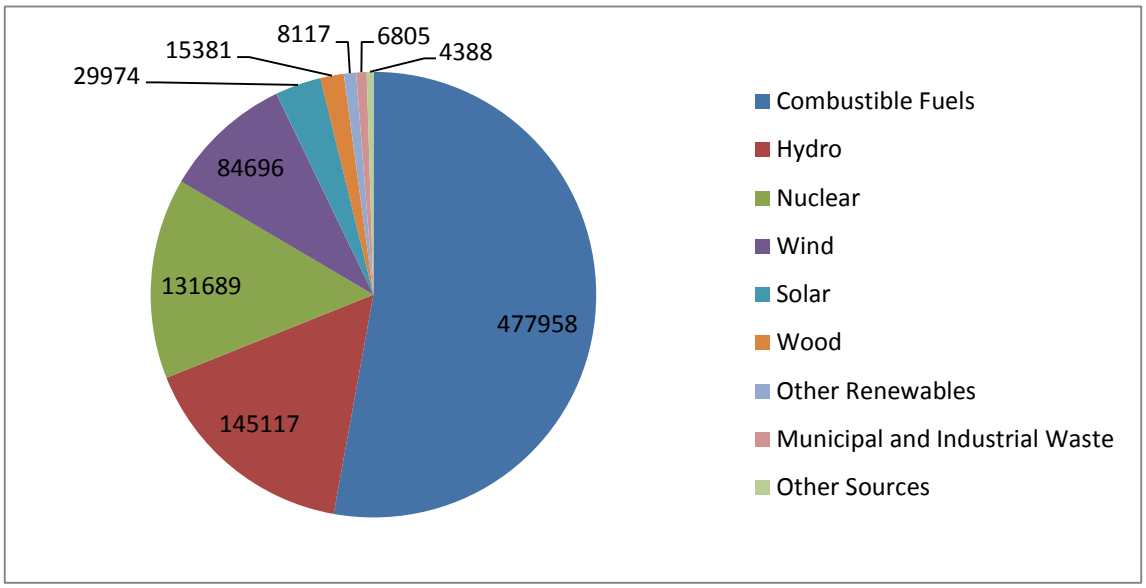


Figure 8.1 Generation capacity in the EU by type of fuel in 2010 [GW] (European Commission, 2012c)

Figure 8.2 shows the corresponding electricity generation in 2010. In this context renewables make up only 21 % of the total but renewables plus nuclear 48 %. These shares naturally are caused by the low load factors of renewables and the high load factors of nuclear power.

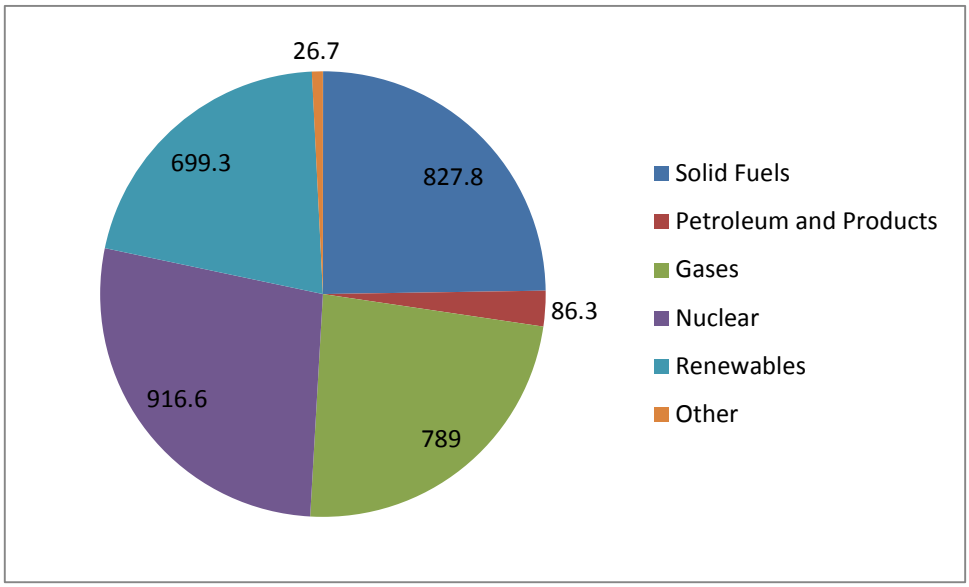


Figure 8.2 Electricity generation in the EU by type of fuel in 2010 [TWh] (European Commission, 2012c)

While the figures above show the EU total, there are large differences within the EU. The following figure illustrates some of these differences.

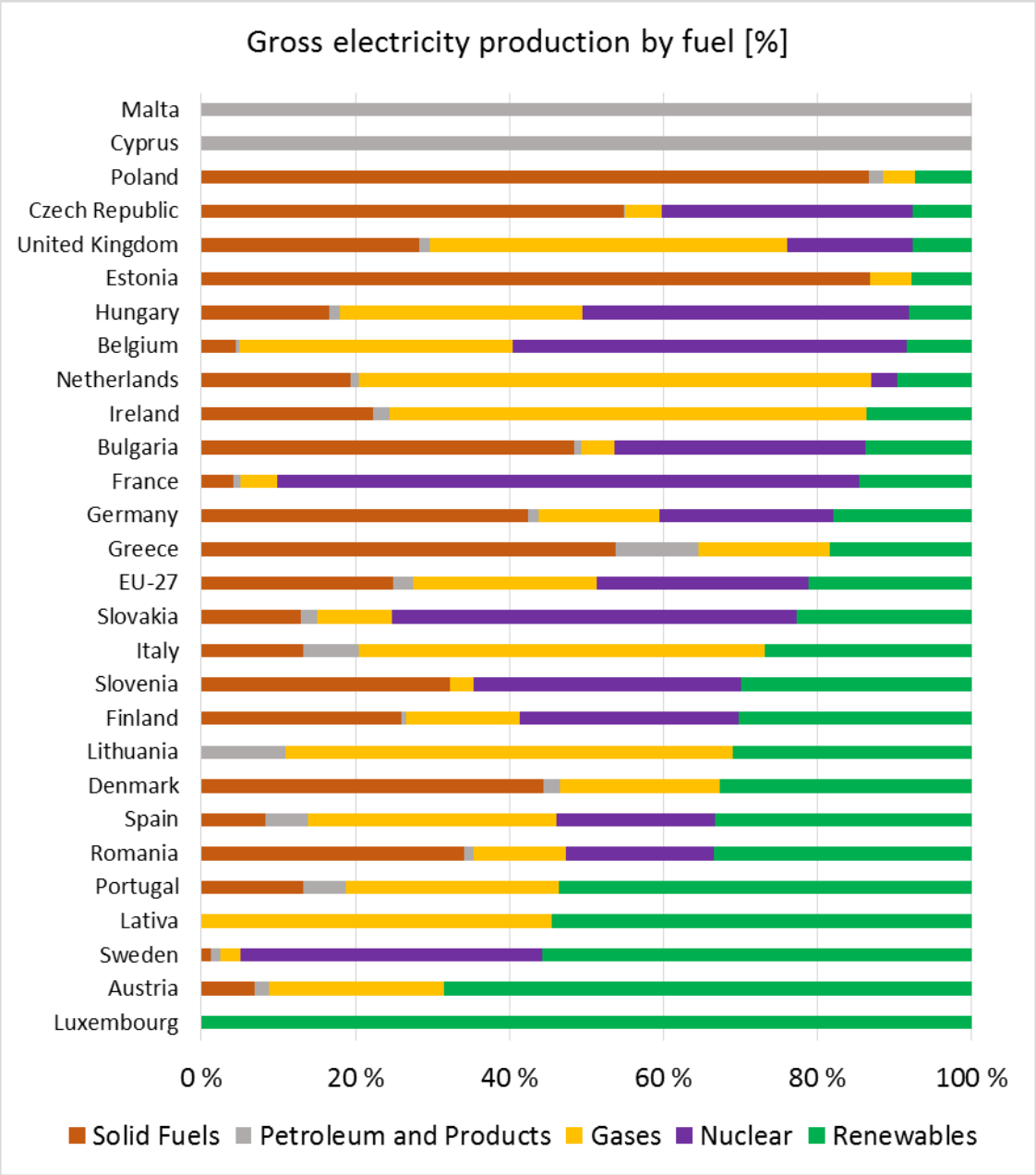


Figure 8.3 Shares of national electricity generation in EU-27 in 2012 (%)[43]

While some countries like Luxembourg, Austria and Sweden have very high renewable shares in their electricity generation, Poland, the Czech Republic, and UK have very low shares. Some countries, notably France, Slovakia and Belgium have high shares of nuclear power, while many countries have none at all. The Netherlands, Ireland and Italy get more than 50 % from their electricity production from natural gas, but most other countries have various shares of gas. Coal totally dominates electricity generation in Poland

[43] Source: http://ec.europa.eu/energy/publications/doc/2012_energy_figures.pdf

and Estonia, and also has very large shares in the Czech Republic and Greece. Sweden, France, Austria and Belgium use very little coal.

The future of the European electricity sector is presently receiving a lot of attention. In the medium term, the sector is vital in reaching the EU 20-20-20 policy targets for 2020. In the longer term, the Energy Roadmap 2050 published by the European Commission in 2011 (European Commission, 2011b) sets out a number of scenarios in order to explore possible routes towards decarbonisation. The scenario analysis undertaken is of an illustrative nature, examining the impacts, challenges and opportunities of possible ways of modernizing the energy system. They are not "either-or" options but focus on the common elements which are emerging and support longer-term approaches to investments. The Roadmap seeks to develop a long-term European technology-neutral framework in which these policies will be more effective. It argues that a European approach to the energy challenge will increase security and solidarity and lower costs compared to parallel national schemes by providing a wider and more flexible market for new products and services.

It is outside the scope of this report to present detailed results from the scenario studies of Energy Roadmap 2050, but a number of conclusions can be drawn (for further comments and arguments, cf. European Commission, 2011b):

- Decarbonisation is possible – and can be less costly than current policies in the long-run
- Higher capital expenditure and lower fuel costs
- Electricity plays an increasing role
- Electricity prices rise until 2030 and then decline
- Household expenditure will increase
- Energy savings throughout the system are crucial
- Renewables rise substantially
- Carbon capture and storage has to play a pivotal role in system transformation
- Nuclear energy provides an important contribution
- Decentralisation and centralised systems increasingly interact

The scenario results for decarbonisation scenarios all assume that global climate action is taken. First, it is important to note that the EU's energy system needs high levels of investment even in the absence of ambitious decarbonisation efforts. Second, scenarios indicate that modernizing the energy system will bring high levels of investment into the European economy. Third, decarbonisation can be an advantage for Europe as an early mover in the growing global market for energy-related goods and services. Fourth, it helps in reducing its import dependency and exposure to the volatility of fossil fuel prices. Fifth, it brings significant air pollution and health co-benefits (European Commission, 2011b).

8.2 Long-term development of the European power sector analysed by EMPIRE

The EMPIRE model (*European Model for Power system Investment with (high shares of) Renewable Energy*) is a new power system model designed in the LinkS project to analyze optimal expansion of the European power system while taking into account long-term climate change mitigation strategies. The study of future development of the European electricity sector done with the EMPIRE model includes three GCAM policy scenarios: The 650 ppm scenario, the 450 ppm scenario and the Global 202020 scenario (see Chapter 3). These scenarios represent a good diversity in terms of stringency and variety for climate change mitigation policies. EMPIRE uses CO_2 prices, fuel prices, electricity demand, and electricity production from GCAM as

input data for the European electricity system. In the following sections, we focus on optimal generation and transmission capacity expansion in the European electricity sector in each policy scenario. Note also that the EMPIRE model is still under development, and the results presented in this chapter are preliminary. The mathematical formulation of the EMPIRE model and the link to GCAM is presented in the Appendix.

8.2.1 A brief look at the GCAM results for the European power sector

Figure 8.4 shows the European electricity mix in 2050 as computed by GCAM for the different policy scenarios. It is clear from the figure that both the policy instruments implemented and the stringency of a given policy make significant impact on the results. For instance, the 450 ppm and 650 ppm scenarios only differ in the target level for end-of-century CO_2 concentration. However, in the 650 ppm scenario annual consumption of electricity lies below the Reference scenario level, while for the 450 ppm the consumption is higher. In addition to lower electricity production, emissions reduction in the 650 ppm scenario is achieved by lower shares of gas and coal, and a higher share nuclear energy, in the production mix compared to the Reference scenario. According to these results, switching from fossil fuels to nuclear, and implementing end-use efficiency improvements are sufficient measures in the European power sector to reach the less ambitious CO_2 concentration level of 650 ppm.

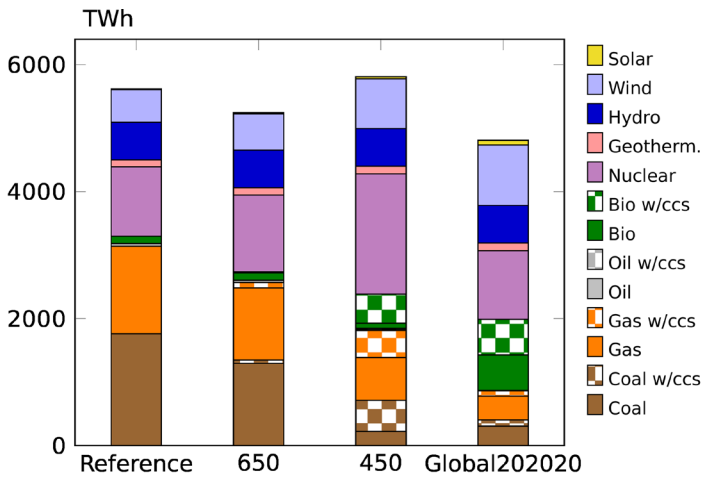


Figure 8.4 The GCAM computed European (i.e. GCAM regions WE + EE) electricity mix in 2050 in different policy scenarios.

For the 450 ppm scenario the emission reduction policy has a more dramatic effect. This scenario involves a much earlier adoption and wide deployment of CCS technology, a decrease in the use of unabated fossil fuel technologies and a strong increase of nuclear power in the energy mix. In addition, this scenario includes more use of wind energy and generation using bio fuel with CCS.

In the Global 202020 policy scenario, which comprise progressive targets for renewable energy shares, emission reduction and efficiency improvements, we see more penetration of wind energy than the other scenarios, less use of nuclear power and a significant use of bio fuel for electricity production, both with and without CCS. Total share of renewable generation in 2050 production mix in Global 202020 is 59 %, while the share of variable generation from wind and solar power is about 21 % (compared to 10 % in the Reference scenario and 14 % in the 450 ppm scenario). This makes the Global 202020 scenario particularly

interesting from a power system perspective as generation from wind and solar is intermittent and non-controllable, which generally increase the need for capacity from back-up generation, transmission system and storages. As the EMPIRE model considers a high number of operational scenarios when computing optimal investments it is well suited for such a scenario.

8.2.2 The European power production mix and investments in generation capacity

Table 8.1 lists the country nodes implemented in the European power system models EMPIRE and EMPS. In addition, EMPS has separate nodes for offshore wind production for each country with a coastline.

Table 8.1 Countries in EMPIRE and EMPS models

Country code and name					
AT	Austria	FR	France	NL	Netherlands
BA	Bosnia and Herzegovina	GB	Great Britain	NO	Norway
BE	Belgium	GR	Greece	PL	Poland
BG	Bulgaria	HR	Croatia	PT	Portugal
CH	Switzerland	HU	Hungary	RO	Romania
CZ	Czech Republic	IE	Ireland	RS	Serbia
DE	Germany	IT	Italy	SE	Sweden
DK	Denmark	LT	Lithuania	SI	Slovenia
EE	Estonia	LU	Luxemburg	SK	Slovakia
ES	Spain	LV	Latvia		
FI	Finland	MK	Macedonia		

The setup of the EMPIRE simulations for the different policy scenarios from GCAM is performed in the following steps (see also Appendix):

1. Total electricity demand in Western and Eastern European regions as calculated by CGAM is distributed to individual European countries for each stage and scenario according to their relative share of total demand in 2010.
2. CO_2 prices and fuel prices for each stage and scenario are taken from GCAM.
3. EMPIRE identifies investments in new generation and transmission capacity in and between the nodes (countries) where the profit is highest.
4. The resulting share of each technology in the yearly production mix is required to be within a 3% band of the corresponding GCAM result for each stage and scenario.
   Exceptions from this rule were made for nuclear energy, which was required to be within a 40 % band of the GCAM computed values, and wind and solar energy which only had a lower limit of 3 %, not an upper limit. This allowed the EMPIRE model to replace some nuclear energy with intermittent renewable energy production relative to the GCAM results, which is justified by observing attitudes towards these technologies in Europe today (e.g. nuclear phase out in many countries and support schemes for renewables being implemented across the continent).

Figure 8.5 shows the electricity production mix in Europe computed by the EMPIRE model, while installed generation capacity is shown in Figure 8.6.

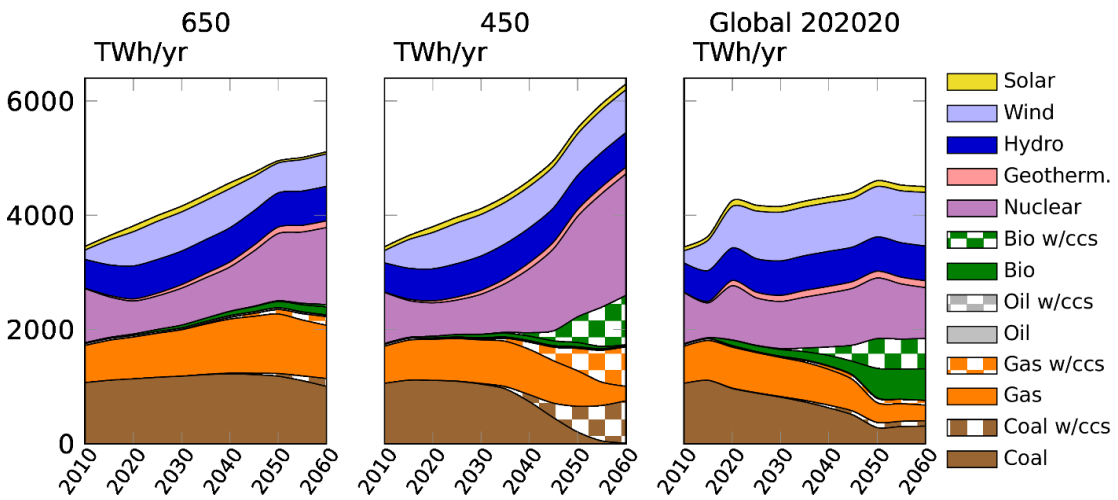


Figure 8.5: Generation mix in Europe computed by EMPIRE

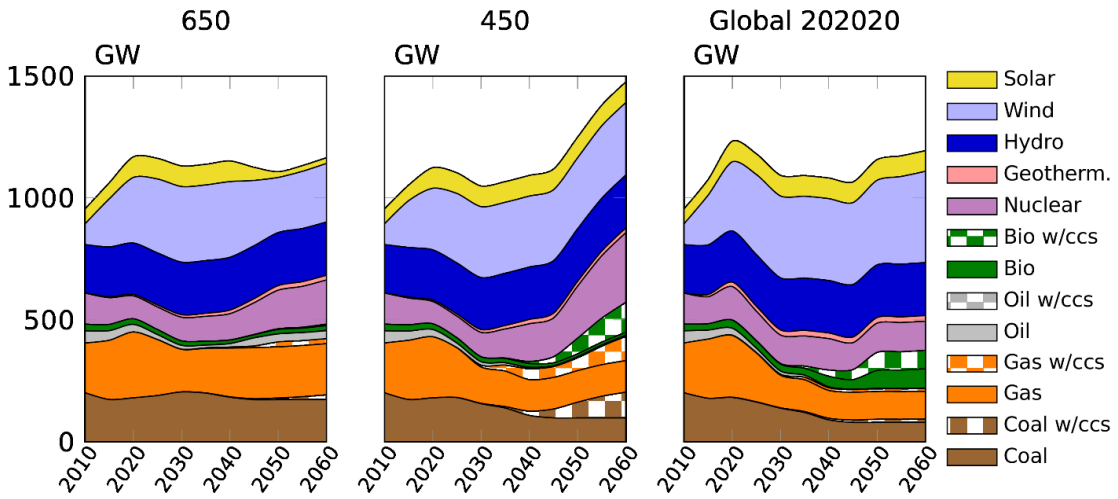


Figure 8.6: Installed capacity in Europe computed by EMPIRE

Up until 2020 the production mix and installed capacities for the 650 ppm and 450 ppm policy scenarios are almost indistinguishable. In both scenarios, electricity production increases, while at the same time nuclear generation decreases. The additional energy required comes from wind generation, and in both scenarios there are substantial investments in new wind capacity. By 2020, the installed wind capacity is 252 GW in the 450 ppm scenario and 268 GW in the 650 ppm scenario, roughly a threefold increase from the initial level of 85 GW.

Beyond 2020 the difference between the 650 ppm and 450 ppm scenarios becomes more significant, in particular with respect to the use of fossil fuels. As the initial gas, coal and oil capacities are decommissioned, there are substantial reinvestments in unabated technologies using these fuels in the 650 ppm scenario. In the 450 ppm scenario (and in the Global 202020 scenario), the EMPIRE model computes less investments in fossil fuel technologies without CCS. In the 450 ppm scenario, however, there are investments in gas and coal plants with CCS. These investments start from 2030, and by 2050 there is about 120 GW of CCS power generation capacity using fossil fuels. At the end of the analysis horizon, the total

electricity demand is much higher in the 450 ppm scenario than the two others which is reflected in the total generation capacity. Both the 650 ppm scenario and the Global 202020 scenario have about 1200 GW of total installed capacity at the end of the horizon, while in the 450 ppm scenario the total capacity is 1500 GW, more than a 50% increase compared to the initial system. Much of the difference is due to higher investments in nuclear power and CCS technologies.

Note that the 650 ppm scenario is run with the assumption that older generation capacity is automatically decommissioned when expected life time is reached, so the investment algorithm has to compensate for the growth in demand as well as re-invest the decommissioned capacity. In the 450 ppm and Global 202020 scenarios, however, old generation capacity is *not* decommissioned. In these scenarios, investments are only driven by the growth in demand.

When considering country-wise results for generation capacity and production mix in 2050, Figure 8.7 and Figure 8.8, respectively, it is clear that some investments and production profiles are quite robust across scenarios. Especially investments in new wind generation capacity in countries such as France, Great Britain, Italy, Poland and Norway, are similar in the different policy scenarios (in particular as a share of the total wind investments in Europe). In countries such as Spain and the Netherlands, on the other hand, investments in new wind capacity are substantial in the policy scenarios where there is a lot of wind, namely the 450 ppm and Global 202020 scenarios, but in the 650 ppm scenario these investments do not occur to the same degree. These results give an indication to where in Europe the wind resources are most valuable, not just in terms of where one can expect the highest production per installed capacity, but also where wind production is most useful for covering demand in the system. The wind capacity investments are also interesting to study in the context of transmission expansion, which is done in the next section.

A country that is particularly interesting to analyze a bit more detailed is Germany. The German investments in generation capacity change dramatically across all scenarios. From mostly relying on unabated coal and gas in the 650 ppm scenario, to installing a high share of coal CCS and bio CCS in the 450 ppm scenario and lastly to a generation mix of mostly unabated coal and bio CCS in the Global202020 scenario. Investments in intermittent renewables, wind and solar, do not occur to a significant degree in any scenario. These results indicate that the EMPIRE model use Germany to facilitate the European energy mix required to match GCAM results, and that in terms of intermittent renewables the resources are more valuable in other places. Current German policies on the use of support mechanisms for renewables, such as feed-in tariffs, are not included in this analysis. One possible conclusion one may draw based on these results is that the planned German energy system transition, the so-called *Energiewende*, would not be possible in a European wide policy scheme without targeted national support instruments.

8.2.3 Investments in new transmission capacity

The optimal cumulative investments in transmission capacity by 2050, computed by the EMPIRE model, are shown in Figure 8.9. The amount of new capacity are 60 GW, 96 GW and 108 GW for the 650 ppm, the 450 ppm and the Global 202020 scenarios, respectively. To put these numbers into perspective it is worth mentioning that the total initial transfer capacity between countries is around 67 GW. Thus, according to the EMPIRE model, significant reinforcements in the transmission system are required for an optimal development of the European power system.

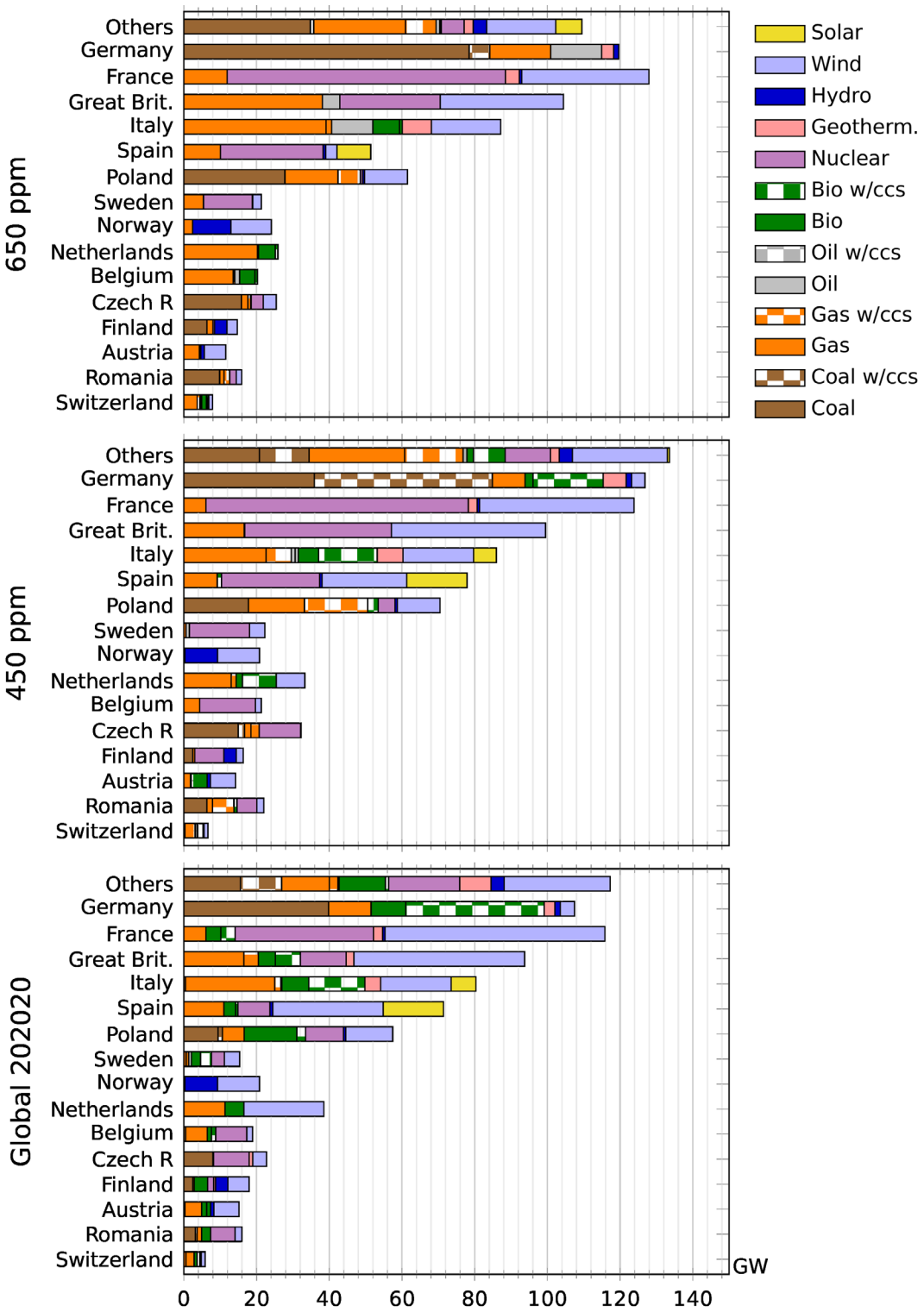


Figure 8.7: Country-wise investments in generation capacity in 2050 for the 15 countries with highest electricity demand. Note: For the 650 ppm scenario only investment additions are shown, i.e. reinvestments in capacity following decommissioning are not included.

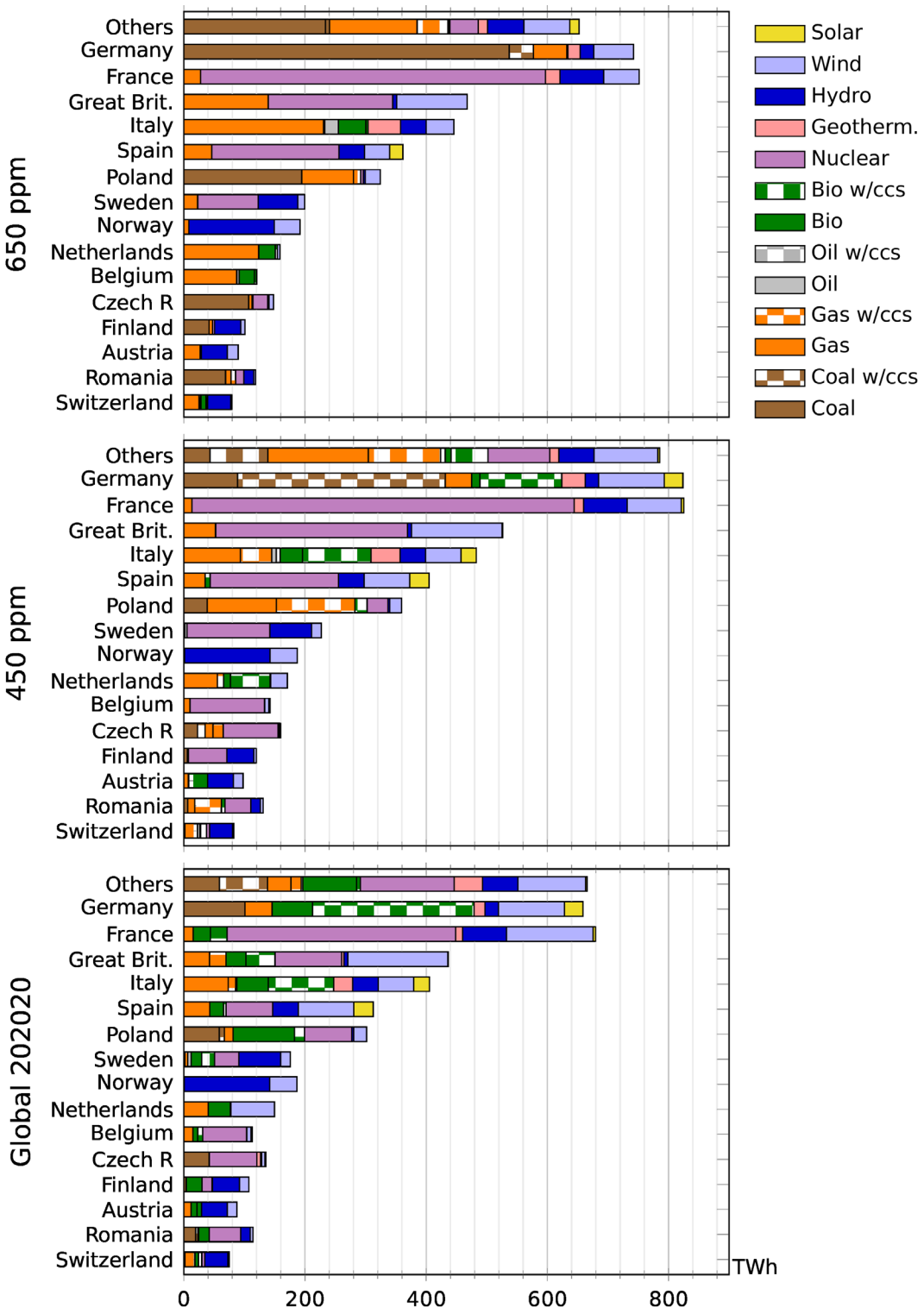


Figure 8.8: Country-wise generation mix in 2050 for the 15 countries with highest electricity demand.

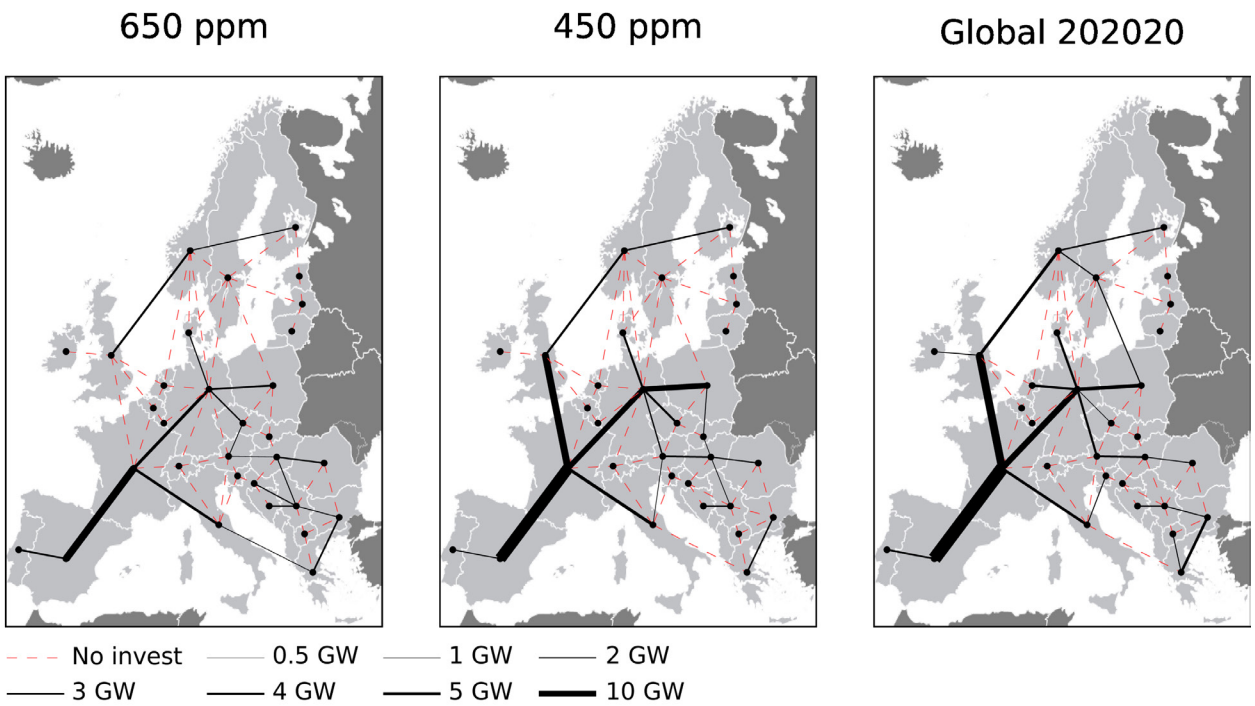


Figure 8.9 Cumulative investments by 2050 in exchange corridors between countries in the EMPIRE model

The Global 202020 scenario is especially interesting with respect to generation and transmission capacities, as it is the policy scenario with the lowest demand in 2050 compared to the two others. However, in terms of generation capacity, investments are just as high as in the 650 ppm scenario, and in terms of transmission capacity the Global 202020 scenario has by far the highest investments. As indicated in the introduction, a key feature of the Global 202020 scenario is the high penetration of wind energy, which cannot be dispatched the same way as conventional power generation technologies. Balancing supply and demand everywhere in the system, at all times, requires either local back-up capacity or a strong grid which is able to support high flows of power from surplus regions to deficit regions (or a mix of the two strategies). It is clear that the EMPIRE model, based on the cost assumptions made in the simulations, favors transmission capacity expansion for balancing a system with high shares of intermittent renewables.

When considering which links are most important to reinforce a few examples stand out. In all the policy scenarios the corridors Spain – France, France – Germany, Spain – Portugal, France – Italy, Germany – Poland, Germany – Sweden, UK – Norway and Norway – Sweden see substantial investments. There is a clear indication that increasing the transfer capacity between North and South, and westwards, in continental Europe is an economical strategy. The size of investments in these corridors varies across scenarios, which is not surprising given the large differences in the generation capacity mix.

An interesting difference between the 650 ppm scenario and the two others is the investments in capacity for the UK – France interconnection. In the 650 ppm scenario this link is not reinforced at all, but in the 450 ppm and Global 202020 scenarios between 12 and 14 GW of new transfer capacity is installed. The reason for this is likely the fact that in the 650 ppm scenario the UK has more conventional power generation capacity available, which reduces the need to connection with neighboring regions as demand can be covered locally.

8.2.4 Conclusion

This brief analysis has illustrated how the EMPIRE – GCAM modelling framework can be used to assess optimal development of the European power system for different policy scenarios. Although there are significant differences between the scenarios, some results are robust across all the scenarios. In particular, the locational investments in new wind generation and which transmission corridors to reinforce stand out in that respect. France, Great Britain, Italy, Poland, and Norway are promising places to develop new wind generation capacity, and investments in generation should be accompanied by large investments in transmission capacity from Spain going north to Germany.

This analysis does not reflect all current European policies, such as support schemes for renewables in different countries, though including that in further studies could be interesting.

8.3 European scenarios analysed by EMPS

While the EMPIRE model performs a *perfect foresight optimization* over the whole period of analysis, EFI's Multi-area Power Market Simulator EMPS model is *myopic* – it considers only one stage at a time. However, the number of operational steps used at each stage of the simulation differs considerably between the models, as shown in Table 8.2. The EMPS model aggregates available statistical input data such as demand, wind, solar and hydro inflow data from 75 statistical years into five different price periods for each of the 52 weeks. This gives a total of *19,500* possible operational situations per stage (year) as basis for calculation of the annual operational cost. Note that the weekly price periods are not of equal size nor are they strictly sequential.

In comparison, the current version of EMPIRE uses national wind and solar data from only one statistical year (2006 in this analysis). A selection algorithm combines hourly values from these renewable statistics with load data from the period 2006-2011 into three different combination scenarios; giving a total of *666* possible operational situations per stage (see also Appendix).

Table 8.2 Number of operational steps at each stage

Model	Number of steps within each stage (2015,…,2060)		
EMPS	75 (years) x 52 (weeks) x 5 (price periods)	=	19 500
EMPIRE	3 (comb.) x (4 (norm. seasons) x 48 (hours) + 6 (high season) x 5 (hours))	=	666

In the next sections, we examine how the differences in optimization algorithm and operational detail may influence the investment decisions made by the two models. The EMPS and EMPIRE models are further documented in the Appendix to this report.

8.3.1 Analysis

To enable a comparison of the two models all input parameters to the EMPS model, such as generation capacities per country, annual country demand, and marginal production costs are taken from EMPIRE and GCAM simulations. The simulations are set up in such a way that the resulting investments in transmission capacity from the two models are comparable. Even though the EMPS model also has the ability to invest in generation and transmission capacity, the analysis performed here only includes investments in new transmission capacities. The generation capacities on each stage are taken from EMPIRE.

Since the EMPS model cannot have an annual energy production constraint per type, which would be required if strict comparison with GCAM simulations where to be made, both models have been run with unrestricted usage of all available conventional generation capacities. "Free" production from wind and solar energy is used whenever available, while thermal generation is utilized according to merit order based on marginal production costs in both models. The results presented in this section is therefore not directly comparable to the EMPIRE results tuned to GCAM in the previous section.

The renewables wind, hydro and solar are limited by time series from historical data. Using specific marginal production costs and available generation capacity as input, EMPS runs each stage and scenario with 75 annual time series of hydro inflow, wind resources and solar radiation to capture multiple market solutions caused by renewable production that vary in time and location. The resulting annual energy production therefore deviates from the energy calculated by EMPIRE. For each stage *N* (see Figure 12.5) the investment algorithm calculates socio-economic profitable investments in cross border transmission capacities to exploit the variable generation and minimize price differences between countries. When evaluating profitability of an investment in a new transmission line, a 30 % excess profit compared to net investment cost is required to accept the investment (z_k in Table 12.1). EMPIRE includes new transmission capacity as continuous variables in the optimization problem, while EMPS will iteratively add capacity in discrete steps as described in Section 12.2.2.

Table 8.3 through Table 8.8 summarizes the key results for the three scenarios. It is worth noting in the 450 ppm scenario that a shift in marginal cost levels (given from GCAM) between gas and coal causes increased coal production towards the end of the period. In the Global 202020 scenario, increasing wind and solar production in the last two stages pushes biomass out of the market, since biomass has higher marginal cost than gas and coal in this scenario. Furthermore, we notice that neither the 650 ppm nor the 450 ppm scenario satisfy the RES-E shares that would be expected in Europe according to the 20-20-20 targets. Note, however, that Table 8.6 to Table 8.8 are given for the whole model as listed in Table 8.1 and not only EU-27, so specific numbers are not directly comparable with current EU targets.

Table 8.3 Average annual generation in 450 ppm scenario calculated by EMPS [TWh/y]

450	Bio	Wind/PV	Nuclear	Gas	Coal	Hydro	Oil	Geo
2015	0	281	888	227	1678	551	0	25
2020	0	369	989	369	1444	562	0	38
2025	9	425	1003	829	1047	567	0	52
2030	33	791	868	895	862	570	2	69
2035	42	791	895	1080	830	570	5	86
2040	136	862	1076	1369	460	570	4	108
2045	270	745	1052	1338	843	569	5	109
2050	527	833	1052	1131	1309	569	2	109
2055	702	910	1052	969	1648	569	1	109
2060	869	975	1052	874	1860	569	1	109

Table 8.4 Average annual generation in 650 ppm scenario calculated by EMPS [TWh/y]

650	Bio	Wind/PV	Nuclear	Gas	Coal	Hydro	Oil	Geo
2015	0	280	887	109	1805	550	0	25
2020	0	359	982	158	1713	556	0	35
2025	0	403	978	408	1587	562	0	48
2030	8	618	842	583	1488	564	2	61
2035	18	618	874	799	1407	563	9	75
2040	21	618	923	1037	1291	563	14	88
2045	26	501	1052	1233	1234	563	21	101
2050	38	583	1052	1228	1369	563	18	109
2055	46	666	1052	1095	1508	564	10	109
2060	60	732	1052	984	1654	565	3	109

Table 8.5 Average annual generation in Global 202020 scenario calculated by EMPS [TWh/y]

G2020	Bio	Wind/PV	Nuclear	Gas	Coal	Hydro	Oil	Geo
2015	0	276	892	281	1611	558	0	25
2020	8	715	1108	760	994	566	0	96
2025	49	733	1072	793	845	571	0	99
2030	90	825	978	821	736	573	1	105
2035	127	825	1030	885	669	573	3	109
2040	223	847	1033	867	643	573	3	109
2045	374	730	954	872	750	573	2	109
2050	248	1020	954	941	779	573	0	109
2055	39	1438	953	690	757	574	0	109
2060	28	1500	952	619	751	574	0	109

Table 8.6 Key figures for scenario 450 ppm (totals for whole simulated system)

450 ppm		2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
	Load [TWh]	3635	3763	3926	4078	4286	4575	4945	5519	5943	6291
EMPS	Vol.of RES [TWh]	831	931	1001	1393	1402	1567	1583	1928	2181	2413
	Share of RES [%]	*22*	*24*	*25*	*34*	*32*	*34*	*32*	*34*	*36*	*38*
EMPIRE	Vol.of RES [TWh]	901	1018	1122	1524	1547	1716	1863	2108	2371	2634
	Share of RES [%]	*24*	*27*	*28*	*37*	*36*	*37*	*37*	*38*	*39*	*41*

Table 8.7 Key figures for scenario 650 ppm (totals for whole simulated system)

650 ppm		2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
	Load [TWh]	3635	3786	3971	4152	4358	4570	4761	4978	5042	5145
EMPS	Vol.of RES [TWh]	830	915	965	1189	1198	1202	1089	1183	1275	1356
	Share of RES [%]	*22*	*24*	*24*	*28*	*27*	*26*	*22*	*23*	*25*	*26*
EMPIRE	Vol.of RES [TWh]	901	999	1079	1314	1333	1350	1299	1366	1456	1555
	Share of RES [%]	*24*	*26*	*27*	*31*	*30*	*29*	*27*	*27*	*28*	*30*

Table 8.8 Key figures for scenario Global 202020 ppm (totals for whole simulated system)

Global 202020		2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
	Load [TWh]	3627	4225	4140	4109	4202	4283	4381	4594	4518	4488
EMPS	Vol.of RES [TWh]	834	1288	1353	1489	1525	1642	1676	1840	2050	2101
	Share of RES [%]	*23*	*30*	*32*	*36*	*36*	*38*	*38*	*40*	*45*	*46*
EMPIRE	Vol.of RES [TWh]	902	1447	1533	1659	1697	1831	2007	2002	2308	2354
	Share of RES [%]	*24*	*34*	*37*	*40*	*40*	*42*	*45*	*43*	*51*	*52*

Table 8.9 shows the total cumulative investments in the European transmission system for each state in the EMPS model for all three scenarios, while Table 8.11 shows the new transmission capacity for each state as a percentage of the cumulative total in the last stage (2060). The corresponding results from EMPIRE are shown in Table 8.10 and Table 8.12. The stages where the models make new investments in the system with more than 10 % of the cumulative invested in 2060 are indicated with a green background in the tables. Figure 8.10 shows these results graphically.

Note that the two models EMPIRE and EMPS have different starting points, 2010 and 2015 respectively, for when they start adding new transmission capacity. Both models show a need for large initial investments in transmission capacity so EMPIRE has similar results in 2010 as EMPS has in 2015, while there are no investments in transmission capacity in EMPIRE in either of the scenarios for 2015.

Table 8.9 EMPS: Total cumulative expansion of cross border capacities [GW]

Scenario	2010	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
450	-	73	74	79	104	117	141	157	187	194	197
650	-	108	111	114	128	143	152	155	161	165	165
Global202020	-	85	100	111	128	135	157	166	194	232	248

Table 8.10 EMPIRE: Total cumulative expansion of cross border capacities [GW]

Scenario	2010	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
450	84	84	91	91	105	107	130	144	149	170	183
650	113	113	118	118	122	122	123	125	133	138	141
Global202020	107	107	151	151	151	154	161	174	221	277	291

Table 8.11 EMPS: Expansion of cross border capacities per year in percentage of total new installed in 2060.

Scenario	2010	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
450	-	37	0	2	13	6	12	8	15	4	1
650	-	65	2	2	9	9	6	2	3	2	0
Global202020	-	34	6	4	7	3	9	3	11	15	6

Table 8.12 EMPIRE: Expansion of cross border capacities per year in percentage of total new installed in 2060

Scenario	2010	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
450	46	0	4	0	8	1	12	8	3	12	7
650	80	0	3	0	3	0	1	1	6	4	2
Global202020	37	0	15	0	0	1	2	4	16	19	5

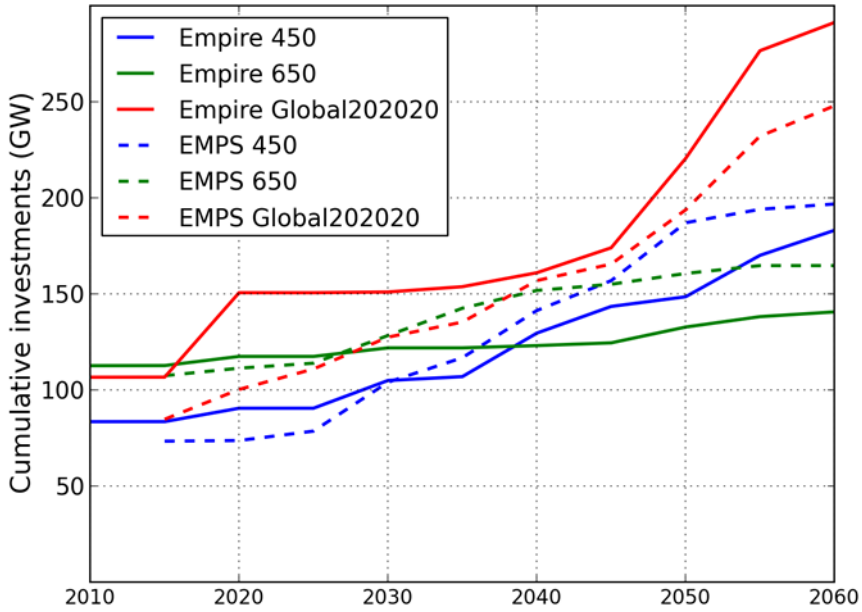


Figure 8.10 Cumulative investments in EMPIRE and EMPS [GW]

From Table 8.9 and Table 8.11 it is clear that with the current assumptions and simplifications in the model, the European transmission system is initially underdeveloped and there is a significant potential for improving the total socio-economic costs at the start of the simulation. For all scenarios, the EMPS model invests most of the new transmission capacity at the first stage (year 2015). The EMPIRE simulations give similar results as shown in Table 8.10 and Table 8.12.

For all scenarios, the EMPIRE model will invest more in the first stages. After stage 2030, however, the EMPS model will invest more in transmission capacity than EMPIRE in the 450 ppm and 650 ppm scenarios. In the Global 202020 scenario, EMPIRE will always invest more than EMPS. The following section will take a closer look at the differences between the model results, with particular emphasis on the 450 ppm scenario.

8.3.2 Investment strategies in the 450 ppm scenario

Figure 8.11 and Figure 8.12 show the cumulative investments in transmission capacity for stages 2015 and 2050 in the 450 ppm scenario for both models EMPS and EMPIRE. The dashed lines in the figure indicate that there is no *new* capacity invested and a solid line indicates that the model has invested in new capacity proportional to the line width.

In Stage 2015 shown in Figure 8.11, there are similar investments for both models, with the main corridors from the Netherlands through Germany towards Poland and from Germany through France towards Spain. In addition there is increase in the capacity to Italy although the two models differ in which connections that should be upgraded. EMPIRE will connect Norway and Great Britain already in the first stage while EMPS does not find it profitable to make this connect before a later stage (2045).

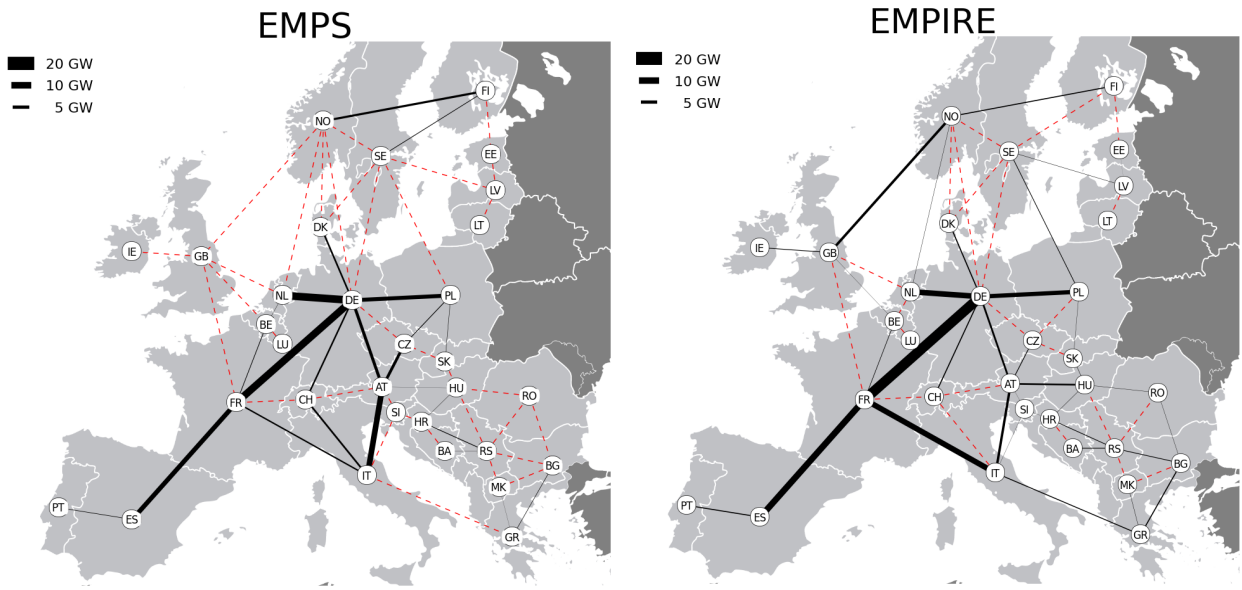


Figure 8.11 Transmission capacity investment in 2015 in 450 ppm scenario

In stage 2050 the cumulative investments have increased further for both models, as shown in Figure 8.12. Both models invest in the same channels, though with some difference in size. The EMPS model increases the capacity between France and Germany on every stage between 2040 and 2050. In the stages 2055 and 2060 there are no significant investments between these two countries.

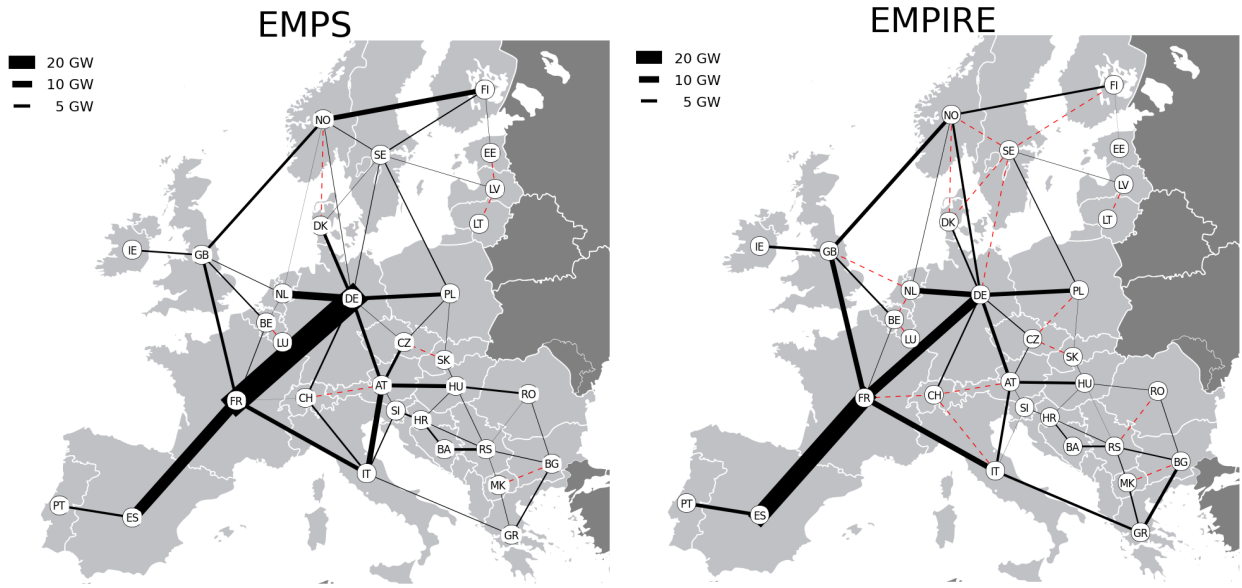


Figure 8.12 Transmission capacity investment in 2050 in 450 ppm scenario

Figure 8.13 shows the expected annual energy mix for all countries in 2015 after new transmission capacity is included, for both models EMPS and EMPIRE. At stage 2015 the EMPIRE model has found it optimal to invest in 11 GW more transmission capacity than the EMPS and thus has the ability to replace more of the expensive fuel types in some countries with cheaper ones imported from other countries. Figure 8.15 shows the same information for stage 2050.

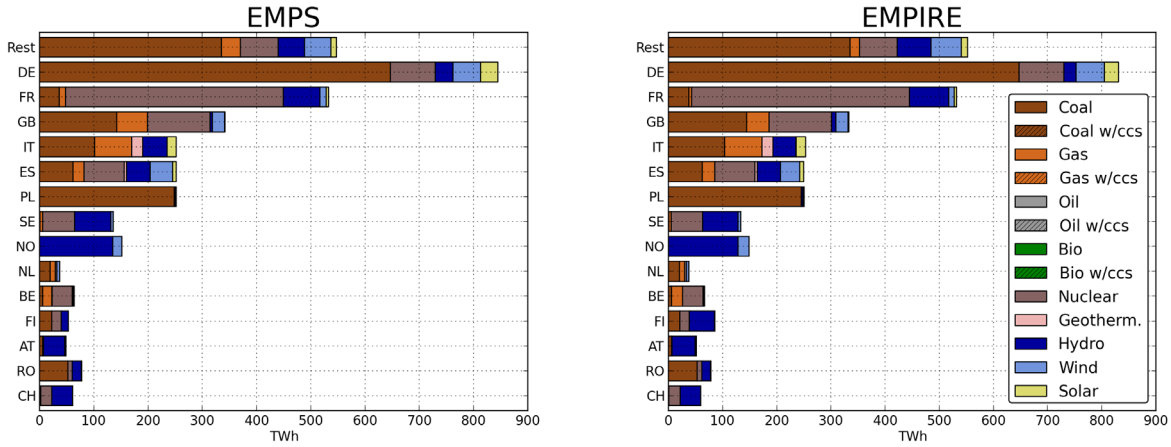


Figure 8.13 Energy mix in 2015 in 450 ppm scenario

Figure 8.14 (a) shows the difference in resulting energy mix between EMPS and EMPIRE. There is an increase in use of gas production and decrease in some small amount of coal in addition to quite a large change in hydro production going from EMPIRE to EMPS model. The differences in renewable production such as hydro, wind and solar power are caused by differences in the marked modelling and the resolution of the input data. *Note that there is an error in Finnish hydro production in the EMPIRE data that should be disregarded in this comparison.* Figure 8.14 (b) shows the difference in energy balances in EMPS after investments are completed vs. the original energy balance ("EMPS inv.-orig."). The increase in transmission capacities enables a shift from expensive gas units towards cheaper coal units.

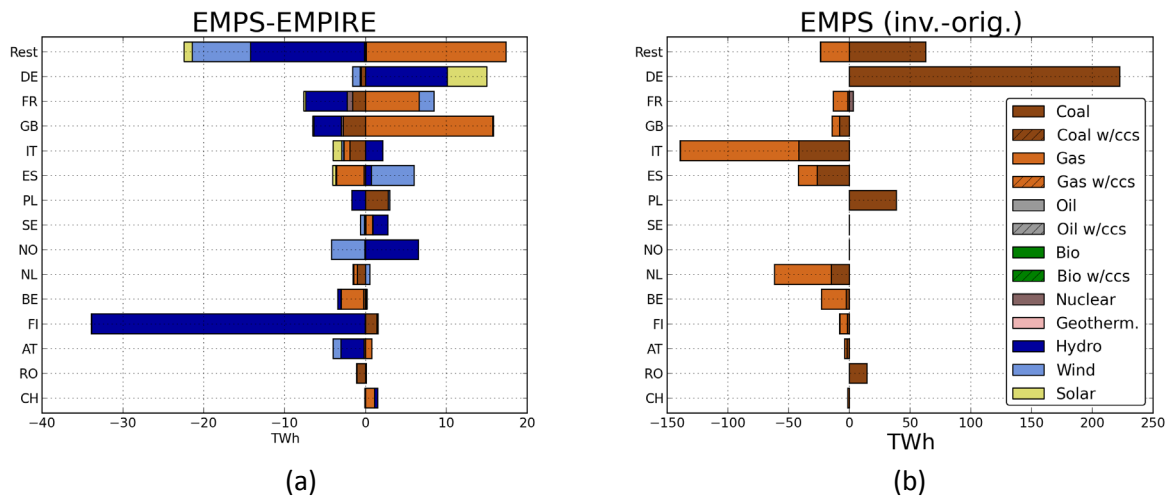


Figure 8.14 Difference in energy mix in 2015 in 450 ppm scenario

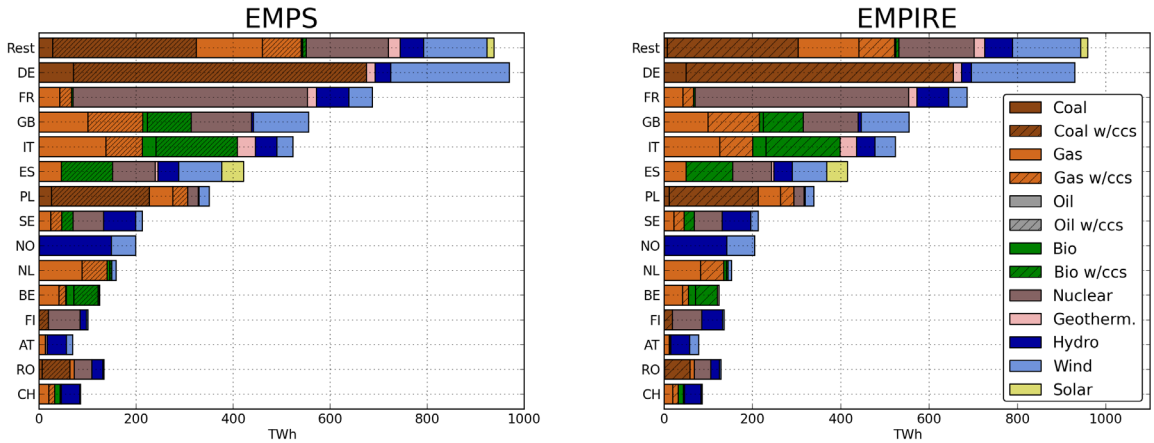


Figure 8.15 Energy mix in 2050 in 450 ppm scenario

For State 2050 the shift in energy mix between the two models is mainly from renewables, specially hydro and wind in the EMPIRE model, to coal, gas, hydro and wind in the EMPS model (Figure 8.16 (a)). Figure 8.16 (b) shows only minor adjustments of fossil generation after investments. *Again, the Finnish hydro production in the EMPIRE data should be disregarded in this comparison.*

Figure 8.17 (a) shows for Stage 2015 the expected percentage of time in which the power is flowing from one area to another, given by the length of the arrow relative to the length of the connection. Figure 8.18 (a) shows the same for Stage 2050. With a flow in one direction 100 % of the time the arrow is the full length between the areas, independent of the amount of energy transmitted, while with the flow going both directions in equal share of time the arrow has zero length. Figure 8.17 (b) and Figure 8.18 (b) show the corresponding use of each line (TWh), given by the width of the line, defined here as the sum of the absolute value of the flow for all simulated hours in the marked model independent of direction.

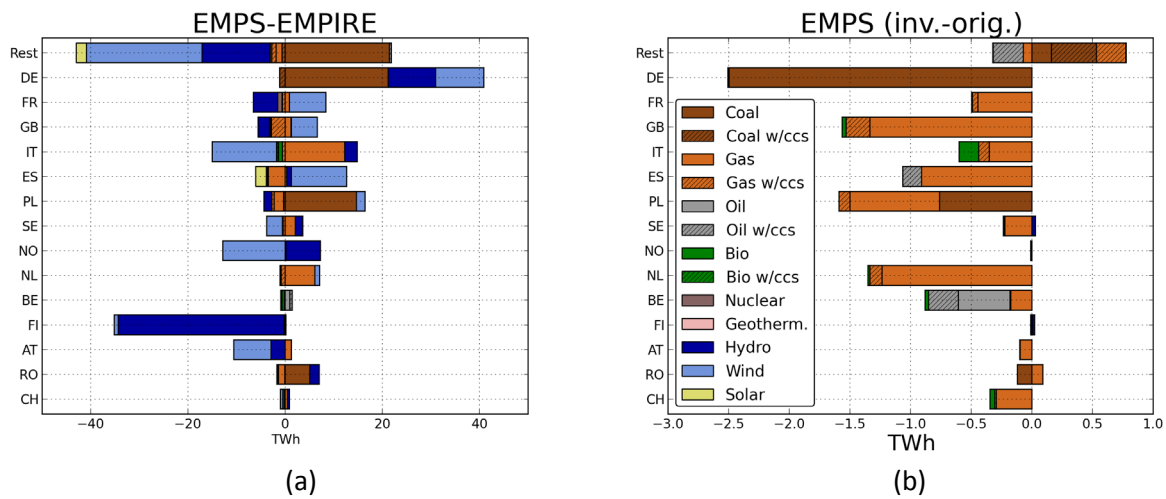
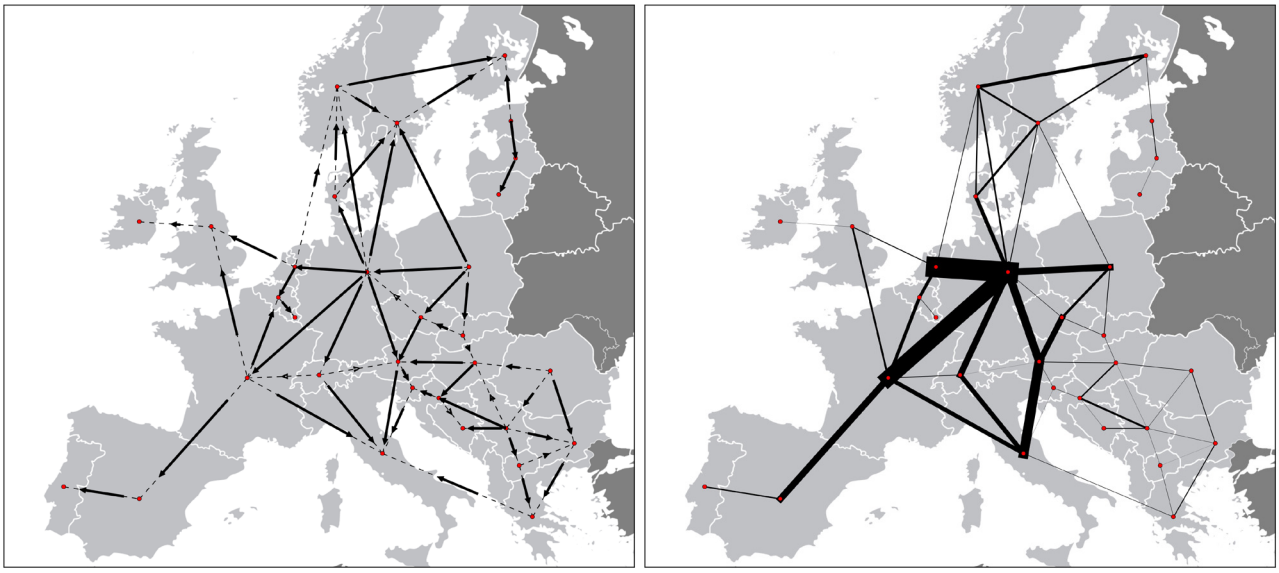


Figure 8.16 Difference in energy mix for EMPS and EMPIRE in 2050 in 450 ppm scenario

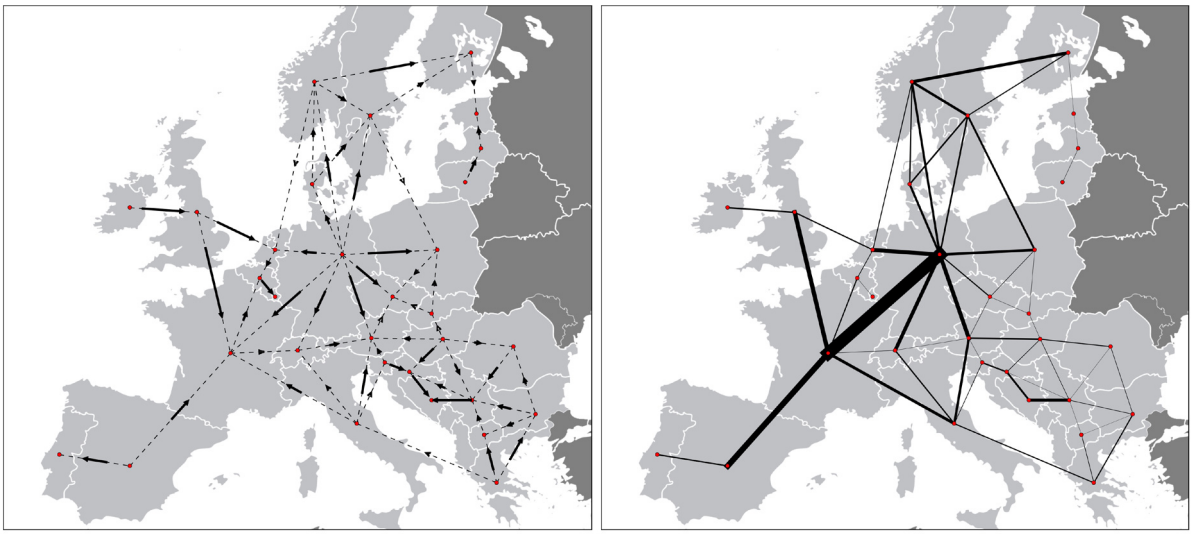


(a) (b)

Figure 8.17 Flow duration and line use in 2015 in 450 ppm scenario

In 2015 the main power flow is through the corridors between Germany and Spain through France and Germany and Italy through France and Switzerland. The flow is going from Germany in southern direction almost 100 % of the time for both corridors.

In 2050 both the use and the energy flow are reduced in most the transmission lines, and for one of the larger connections, France towards Spain, the direction of energy flow has changed. Despite this reduction, which is also present in the stages between 2015 and 2045, the EMPS investment model found it profitable to make considerable new investments in the later stages (2045 and 2050).



(a) (b)

Figure 8.18 Duration and line use in 2050 in 450 ppm scenario

The connection between France and Spain is studied in more detail below as this is one of the connections with the highest level of new investments in both models. It is also interesting as there is a significant change in the usage of the connection with the energy initially flowing from France to Spain in 2015, while it goes more in the opposite direction in 2050. There is also less total flow, even larger periods with zero flow, in 2050 as shown in Figure 8.19.

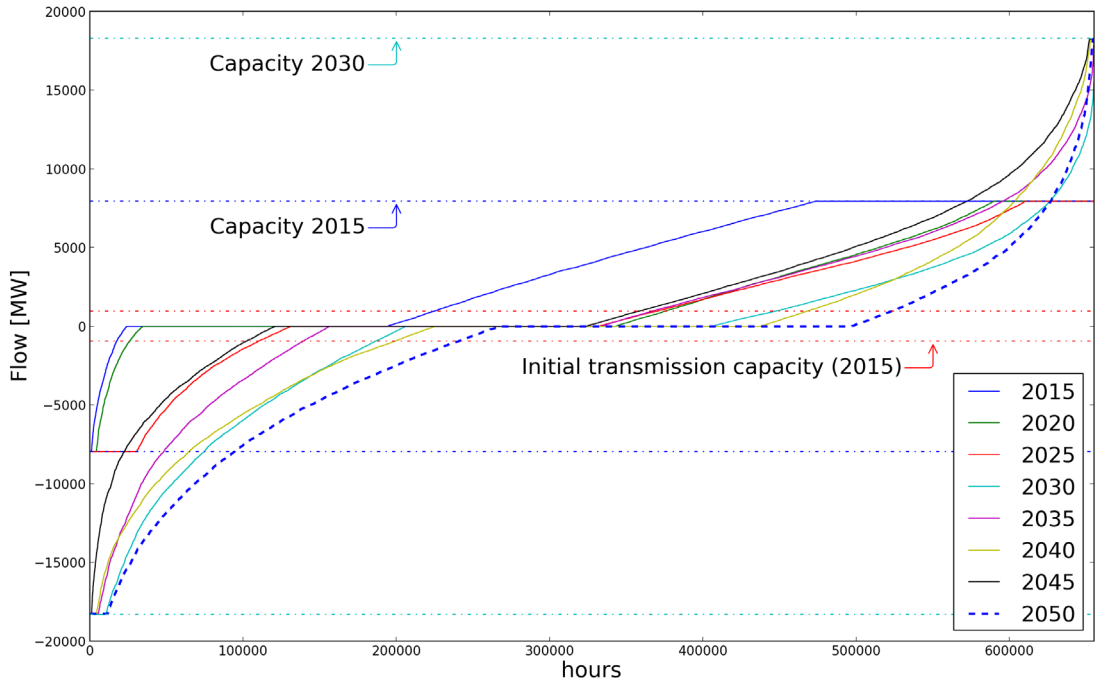
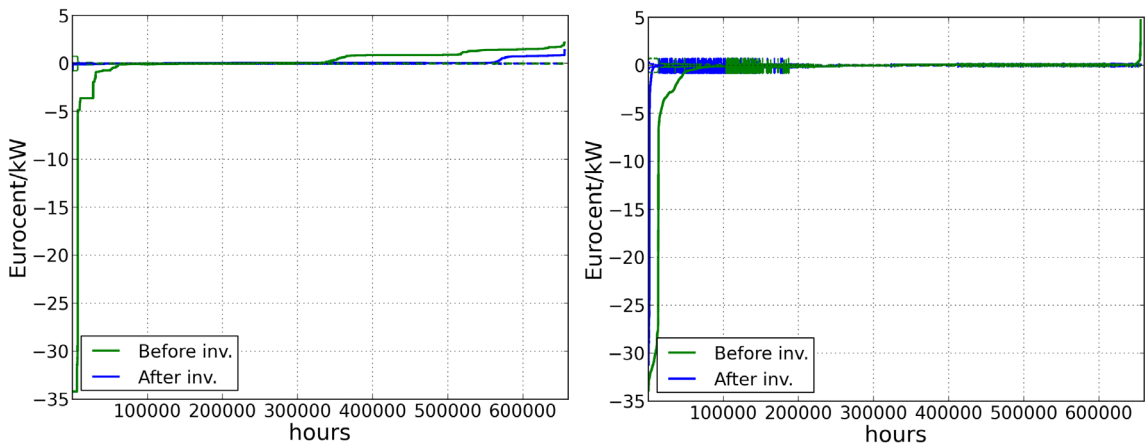


Figure 8.19 Duration curve of flow [MWh/h] from France to Spain in 450 ppm scenario

It is clear from the figure above that this connection is clearly underdeveloped in Stage 2015. The figure also shows how the energy in 2015 is going mainly from France towards Spain (positive values) and how this changes towards more import to France in later stages.



(a) 2015 (b) 2030

Figure 8.20 Price difference between France and Spain for year 2015 and 2030 in 450 ppm scenario

Figure 8.20 shows the duration curves of price differences between France and Spain for stage 2015 and 2030 both before and after investments. Because 2% loss on the transmission lines is included in the model there will be a region around zero price difference, given as dotted lines in the figure, where there can be a deviation from zero even though the connections is not constrained. Without any losses in the transmission system, the price difference between two areas would be zero unless the power flow between them is constrained. In 2015 the connection is initially constrained more than 68 % of the time with price differences in the range of -35.0 to 2.0 Eurocent/kW. With the new investments, the amount of time with price difference is reduced to approximately 28 % with a price difference range of from -0.7 to 1.4 Eurocent/kW. In stage 2030 the probability for price difference is smaller, around 22.12 %, with price differences in the range between -33 and 4.7 Eurocent/kW. Thus, the expected annual operative profit for the connection in 2015 and 2030 is higher than the annualized investment cost, shown as the red bars at 2015 and 2030 in Figure 8.21.

Since the EMPS model invests in sequential steps, not accounting for future development of the system when making an investment decision at any given step, it might overinvest in the initial stages. Looking at the average annual operative profits for the connection between France and Spain in Figure 8.21 this seem to be the case for this connection in the 450 ppm scenario, as there is very small price differences between these two countries in the stages 2020 through 2025 and 2040 through 2050.

The "After investment" bar in Figure 8.21 for 2030 is a little lower than what would be expected, which would be between the curves for "Investment cost" and "Needed excess profit limit", as is seen for 2015. This indicates that the investment algorithm has not converged at the final iteration step (41). This could be mitigated by tuning investment parameters such as the number of iteration steps and the allowed transmission investment capacities (see also Table 12.2).

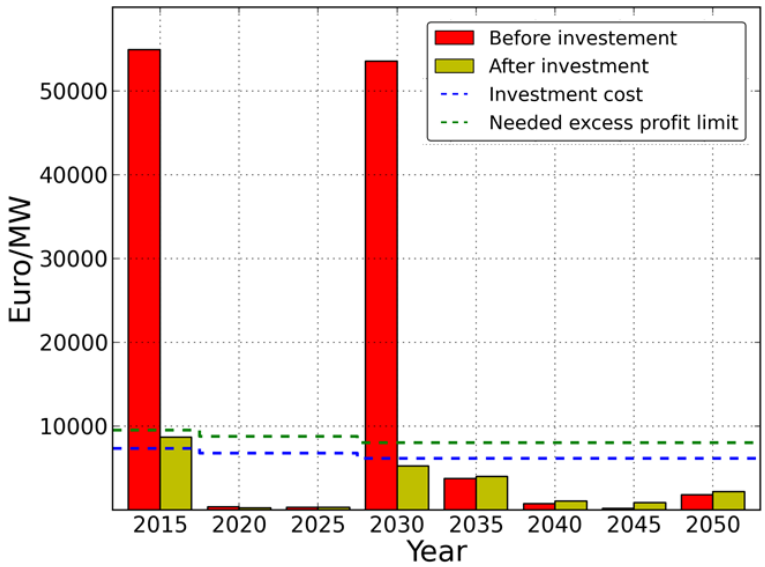


Figure 8.21 Average annual operative profits for connection between France and Spain.

8.3.3 Operational and investment costs

Table 8.13 shows cumulative operational and investment costs for the three scenarios, discounted to Stage 2010 with an interest rate of 5 % pa. The (annual) operational cost at each simulated stage is multiplied by 5 before it is discounted to account for the 5 years between the stages. The total cost of the investment is calculated assuming a lifetime of 20 years, and to account for the rest value only the period between the time of investment and the last stage of the scenario study is used. Figure 8.22 shows the operating costs for each 5-year period of the Global 202020 scenario as example.

Table 8.13 Operational and investment cost.

Scenario	**EMPS** [Billion Euro]			**EMPIRE** [Billion Euro]		
	Operation	**Investment**	**Total**	**Operation**	**Investment**	**Total**
450 ppm	1868.03	9.74	1877.77	1360.67	12.95	1373.62
650 ppm	1429.68	10.88	1440.56	1047.15	14.47	1061.62
Global 202020	1647.24	11.71	1658.95	1317.59	16.52	1334.11

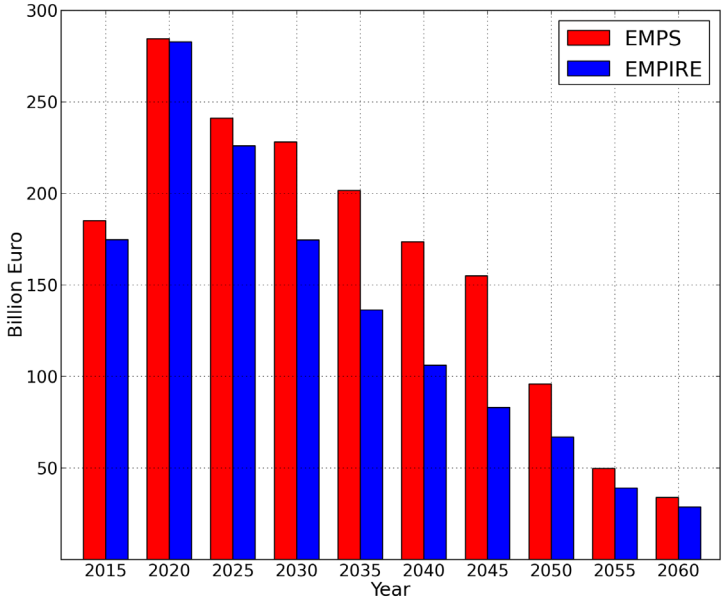
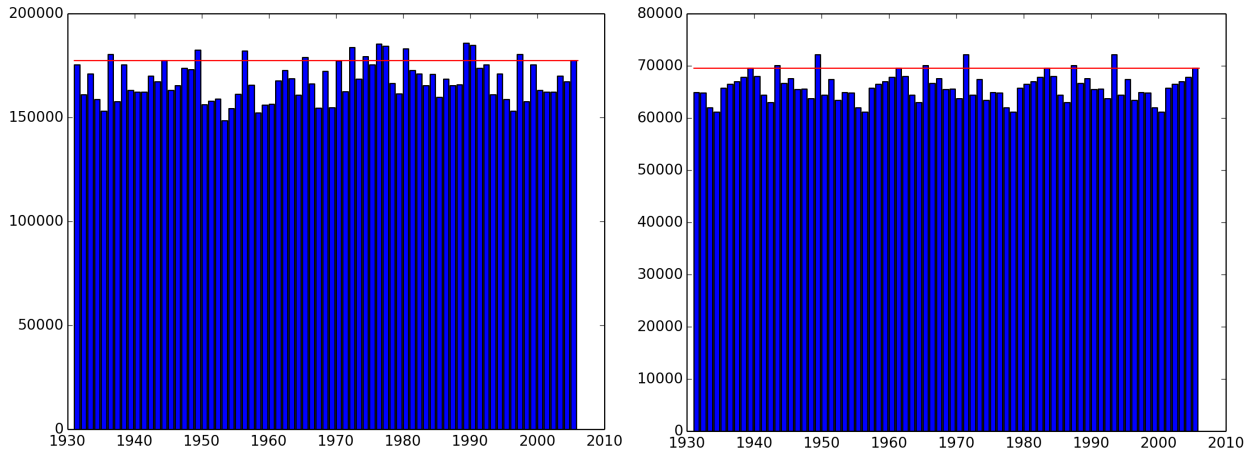


Figure 8.22 5-year operational cost for Global 202020 scenario

The Global 202020 scenario has the largest amount of investments in both models according to Table 8.9 (EMPS) and Table 8.10 (EMPIRE), and has the highest discounted investment costs. However, although the 650 ppm scenario has the least amount of investments, the discounted costs are higher than the 450 scenario. This is due to the discounting of investments spread over the whole period for the 450 ppm scenario, while most of the investments in the 650 scenario occurs already in 2010/2015, see Table 8.11 and Table 8.12.

In all scenarios, the EMPIRE model has lower operational costs (and thus lower total costs) than EMPS. All fossil fuel costs, efficiencies and capacities as well as quota prices are equal for the two models, so the difference is caused by the assumptions on expected average energy content of renewables due to selection of operational steps, shown in Table 8.2. When a higher amount of "free" renewable production is

assumed, this will lead to the lower operational cost in the current simulations. Figure 8.23 shows how the available average wind and solar energy in 2006 used by EMPIRE compares to the 75 years used by EMPS. 2006 has considerably higher amount of "free" wind and solar energy available than the average for the whole period. Depending on the single statistical year used by EMPIRE, the difference can in principle be either lower, higher or equal to the EMPS simulations. Note the different scales on the two figures.



(a) European wind energy (TWh/year) (b) European solar energy (TWh/year)

Figure 8.23 Average available European wind and solar energy in 1931-2006

An additional explanation for the different operational cost is the calculation of water values for hydro power (corresponding to marginal fuel costs for thermal production). In EMPS, water values are re-calculated as part of the EMPS simulation depending on the operational situation in each of the 19,500 cases, while the EMPIRE model requires this value as input to the model. In the simulations above, EMPIRE uses a fixed value of 0.2 Eurocent/kWh for all hydro power production while EMPS has values in the range from 0.0 to 37.5 Eurocent/kWh with a mean value of 4.2 Eurocent/kWh. Clearly, this would lead to higher total cost of the energy from hydro production in the EMPS model.

8.3.4 Summary

The EMPS model has its strength in the detailed simulation of the operation of the power system for each stage in the investment procedure, in particular the stochastic variation of wind, hydro and solar energy and the corresponding utilization of storage capacities. However, it will make investments based on information available for the given stage only. The EMPIRE model, on the other side, uses a simpler operational model but has the ability to evaluate future development of the system when making a decision on the investment for the specific states. It can postpone a profitable investment for single stage based on the expected profitability over the whole analysis period.

This analysis shows that the two models, with their strengths and weaknesses, propose similar future development of the transmission system for a given scenario. Both models invest in the same main corridors although with some differences in timing, sizes and topology. It is not possible from the current comparison to conclude that one investment strategy is "more correct" that the other.

Since the EMPS model does not have perfect foresight, one could expect it to invest more at earlier stages and be prone to overinvest in transmission capacity in some cases. This is not a general observation from

the current case, however, as differences go in both directions. It is clear that the differences in operational costs are important for the outcome of the simulations. The selection of representative years and operational situations in EMPIRE is therefore very important for the model to make a correct decision regarding new investments. In the current case, EMPIRE has used a more "optimistic" year to estimate renewable resources. If different years with less renewable resources where chosen, the resulting investment strategies could have been different. This should be explored in further studies with the EMPIRE model.

9 Linking regional models

9.1 Introduction

Each model in the LinkS project considers different perspectives and has different strong and weak points. The purpose of model interaction is to obtain better overall results (and answer more complex questions) by taking the output from one model as input to other models. Another way would be to redo each model to incorporate all the aspects together. This latter approach is not feasible in general given the huge amount of resources it would require. Thus, our approach was a numerically based "soft link" between models as opposed to new model development. In effect, selected output data of one model became the input data for another.

The LinkS partners agreed to use the 650 ppm policy scenario from GCAM as a starting point for regional model interaction. The purpose of this effort was to tune large-scale energy models including the Global Change Assessment Model (GCAM), the World Gas Model (WGM), the TIMES model, and EMPIRE based on the same policy scenario. Initially, GCAM was set to be the upstream model. First, each of the separate models: WGM, EMPIRE, and TIMES had to be calibrated bilaterally to GCAM outputs.

In order to clarify the procedure of how these various models integrated with WGM, the following steps were used:

- Step 1: The output from the 650 ppm policy scenario by GCAM (e.g. prices, quantities) was sent to WGM, EMPIRE, and TIMES models.
- Step 2: WGM used the GCAM-generated CO_2 prices ($/KCM) for each region and each year to calibrate natural gas demand worldwide.
- Step 3: WGM passed European natural gas prices to EMPIRE by European node and year.
- Step 4: Using these WGM gas prices, EMPIRE sent natural gas consumption, by European node and year back to WGM.
- Steps 3 and 4 were repeated twice and the results were examined. This rest of this chapter describes the results.

9.2 Tuning WGM to GCAM 650 ppm scenario

The goal of this step was to tune the WGM to the GCAM 650 ppm scenario. In this case, we used the carbon prices from the GCAM model, and then calibrated the consumption of WGM to GCAM consumption references using a five percent tolerance as follows:

- First, the WGM regions were mapped according to GCAM regional ones.
- Second, GCAM 650 ppm carbon prices (1990$) were converted to 2005$, then the CO_2 prices were applied to the market agents on the supply side (see also Section 6.3).
- Third, the year 2010 was selected as the base year for calibration. We calibrated WGM consumption in BCM/Y according to the GCAM reference values.
- Lastly, we defined a five percent maximum deviation for this calibration. This means WGM consumption output that is above or below five percent of GCAM values needed to be recalibrated.

It is important to see the comparison of the results between the GCAM and WGM consumption after several runs. Table 9.1 summarizes the model versions while Figure 9.1 and Table 9.2 show the comparison between the calibrated WGM and GCAM gas consumption output and the percentage of deviation.

Table 9.1 Description of GCAM-WGM cases

Case	Description
WGM650cal	Results from WGM after calibration
WGM650	Result from WGM before calibration
GCAM650	Reference from GCAM

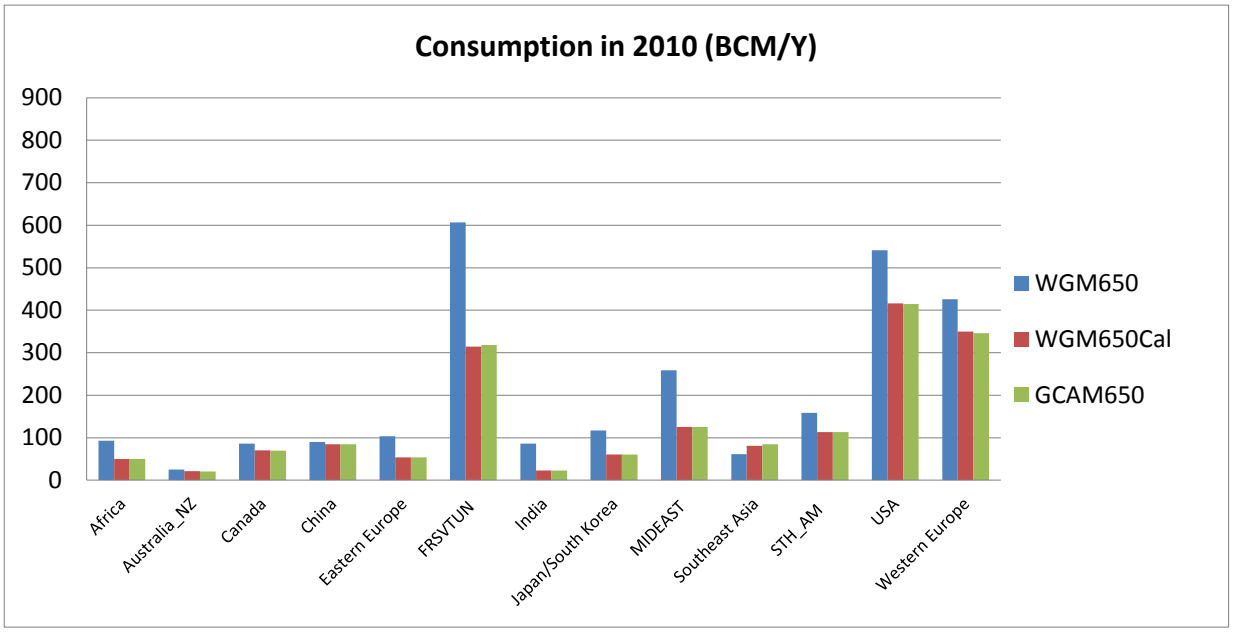


Figure 9.1 Comparison of global gas consumption in 2010 [BCM/y]

Table 9.2 Comparison of original and calibrated gas consumption in 2010 [BCM/y]

	WGM650Cal	GCAM 650	% Difference
Africa	50.00	50.08	0.17
Australia_NZ	21.03	20.96	0.35
Canada	70.11	69.25	1.22
China	84.50	84.50	0.00
Eastern Europe	53.65	53.74	0.16
FRSVTUN	314.40	318.18	1.20
India	22.90	23.09	0.82
Japan/South Korea	60.14	60.59	0.75
MIDEAST	125.40	125.53	0.10
Southeast Asia	80.65	84.57	4.85
STH_AM	113.30	113.47	0.15
USA	416.28	414.39	0.46
Western Europe	349.81	345.88	1.12

As a result of the above procedure, we were able to calibrate WGM output to GCAM reference values within a five percent deviation for most regions as indicated in Table 9.2. For the Former Soviet Union and Middle East regions, GCAM consumption levels were much less than WGM for the starting year (e.g. 2010), see Figure 9.1, but after 2030 all results got closer. South East Asia and Middle East projected consumption in 2050 increased twofold when compared to 2010 consumption.

9.3 Interaction between the WGM and the EMPIRE models

In this step, we iterated European Gas prices to EMPIRE after the calibration described above. WGM natural gas prices are more realistic than GCAM prices since they take into account seasonal difference and market power, common in some of the current natural gas markets.

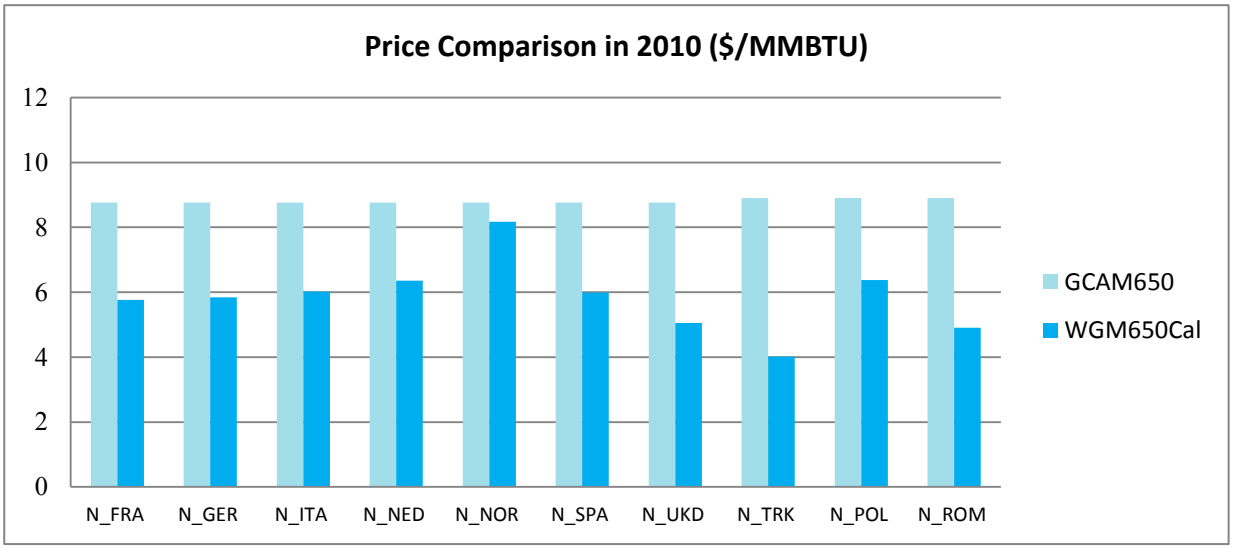


Figure 9.2 Comparison of European 2010 Prices [$/MMBtu]

When comparing GCAM and WGM prices, it is important to note that GCAM prices are uniform over the year and are only given for two nodes in Europe (Western Europe and Eastern Europe). Unlike GCAM prices, WGM prices are well defined to represent trends close to real natural gas markets and with greater spatial detail; see the comparison between the two models for 2010 in Figure 9.2. In particular, the WGM prices differ by location. For example, the consuming countries that are close to producing countries have lower prices due to cheaper transportation costs.

In this step, we used European natural gas consumption for the power sector from EMPIRE, then calibrated WGM accordingly, and then iterated the second European natural gas prices back to EMPIRE. In the calibration process, we selected 2015 as a calibration year because the EMPIRE model started investments in 2010 with the realization of these investments in 2015. The convergence for calibration again was a five percent tolerance (as the case with GCAM) based on the difference of two gas consumption outputs (e.g., WGM consumption and EMPIRE power sector consumption) otherwise the calibration process was repeated. At the end of the calibration process (after two iterations) the WGM generated modified natural gas prices for the power sector in Europe for EMPIRE, see Figure 9.3.

Table 9.3 Description of WGM-EMPIRE cases

Case	Description
WGM650cal	The first European gas prices iterated by WGM calibrated to GCAM650
WGM_EMPIRE650	The second prices iterated by WGM after calibrated to references from EMPIRE

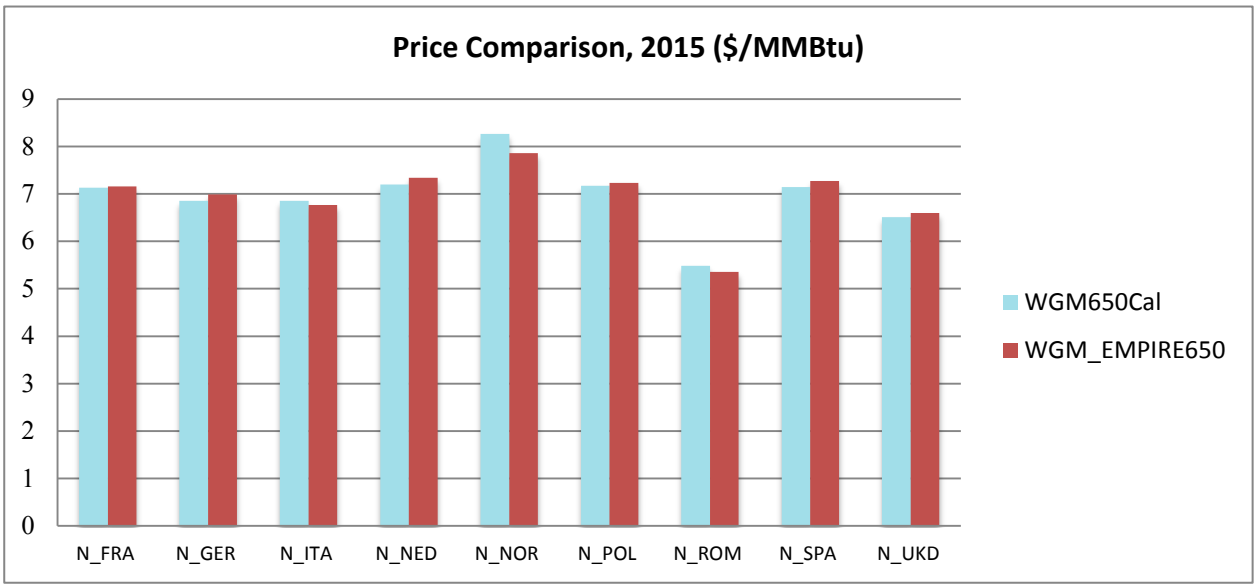


Figure 9.3 WGM 2015 prices comparison for Iteration 1 and 2 with EMPIRE

9.4 Interaction between the WGM and the TIMES models

9.4.1 Model interaction

In the case of China, the WGM take into account seasonal aspects and market power while the TIMES model gives better references for Chinese consumption since this model takes into account various Chinese sectors including agriculture and industry. Thus, we “linked” the WGM gas supply with TIMES to see how the results changed.

The WGM cannot directly generate natural gas supply curves but rather solves the entire market equilibrium (complementarity problem) to determine production levels. However, the WGM can indirectly calculate supply curves by repeatedly running it and only adjusting the slope factor (SF) of a node’s demand curve. This was the procedure that was used to generate indirect supply curves for use in the TIMES model. Under this approach, the demand curves for all the nodes were adjusted by a supply factor to induce these supply curves indirectly. In particular, as shown in Figure 9.4, based on a demand slope factor whose value was varied, an equilibrium supply curve was indirectly generated. This supply factor is multiplied by the slope of the existing WGM demand curve and by default takes on the value of 1 for the Base Case. Ten different SFs were implemented to construct a ten-point Chinese supply curve. As shown in Figure 9.5, these ten points resulted in a non-decreasing (generally increasing) supply curve estimate.

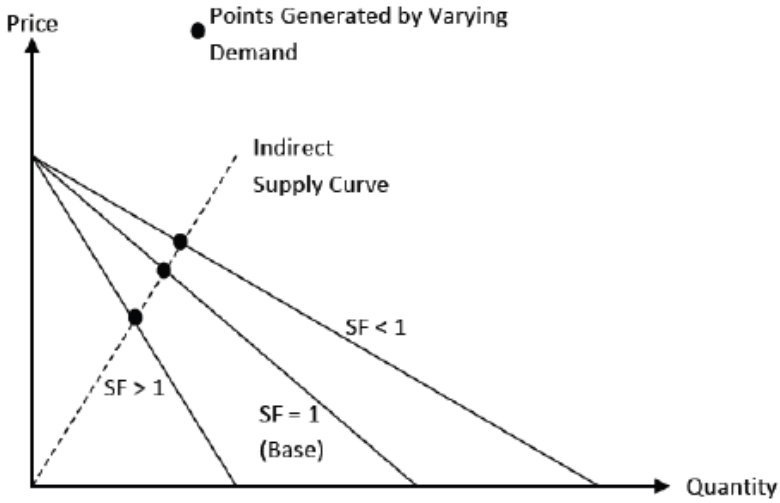


Figure 9.4 WGM Indirect Supply Curve

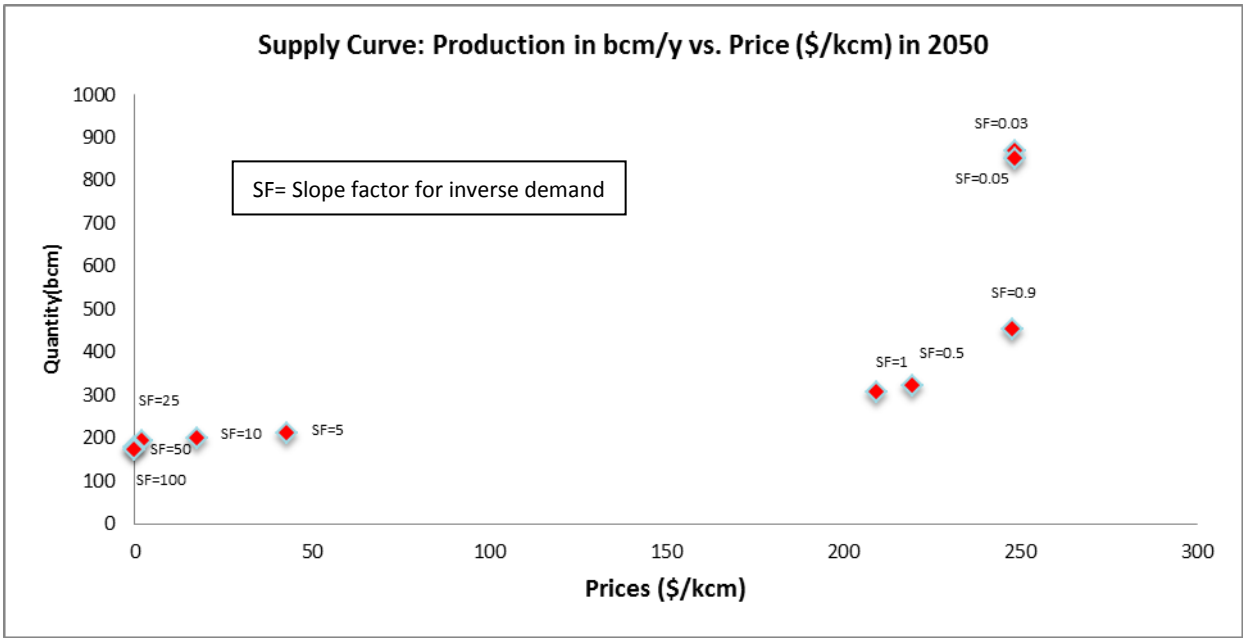


Figure 9.5 Chinese Supply Curve in 2050

In a separate scheme, the WGM was also set up to iteratively produce (indirect) natural gas supply curves to the TIMES model. The TIMES model uses this supply curve for natural gas instead of its normal one-point supply curve. Afterward, TIMES sends Chinese natural gas consumption back to the WGM. These WGM-generated supply curves were prepared by changing the slope of the demand curve in WGM. The TIMES model implemented WGM ten-points supply curves for Chinese natural gas production from 2010 to 2050 and iterated the Chinese consumption in bcm/y back to WGM. The WGM was recalibrated with Chinese consumption according to references from the TIMES model up to a tolerance of 5% as indicated in the Case, namely 650WGM_Chinese_Demand[44]. Overview of the iterative process is depicted in Figure 9.6. The three Cases we used in this study are shown in Table 9.4 Cases and Descriptions.

[44] 5% tolerance was applied to all years except 2050 where there was about a 12% difference due capacity constraint limitations.

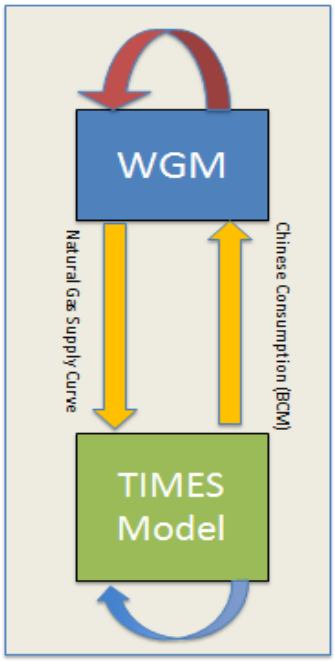


Figure 9.6 WGM-TIMES Model Interaction

Table 9.4 Cases and Descriptions

Cases	Abbreviation	Descriptions
650ppm with GCAM	650WGM	WGM Base Case incorporated CO_2 Costs from GCAM 650 ppm Scenario and calibrated to consumption from GCAM
WGM_TIMES interaction	650WGM_Chinese _Demand	WGM Chinese consumption is calibrated to the reference from TIMES model
Reference from TIMES Model	TIMES_Ref	Chinese consumption output from TIMES model

9.4.2 Results

The comparison of the results is shown in Figure 9.7. The consumption from the TIMES model (TIMES_Ref) for China reaches approximately 500 bcm by 2050. When comparing the 650WGM_Chinese_Demand Case to the 650WGM Case, there is a considerable gap between these two consumption levels (280 bcm). Given the anticipated difference in the demand and supply in the Chinese gas market, we use the WGM to analyze how China will meet this imbalance. In particular, one question to answer is, who will be the main natural gas supplier to China and what will be the main sources of Chinese imports, i.e., pipelines or LNG? In 2050, as indicated in the 650WGM_Chinese_Demand Case, Chinese consumption rises to 437.4 bcm from 90 bcm in 2010. Of this, about 246 bcm is produced domestically, 141.6 bcm is supplied from pipelines, accounting for 32.2% of total consumption, and 49.69 bcm is imported by LNG as indicated in Table 9.5. Under the 650WGM_Chinese_Demand Case, Chinese domestic production increases by about 25% compared to the 650WGM Case and reaches its maximum domestic production capacity.

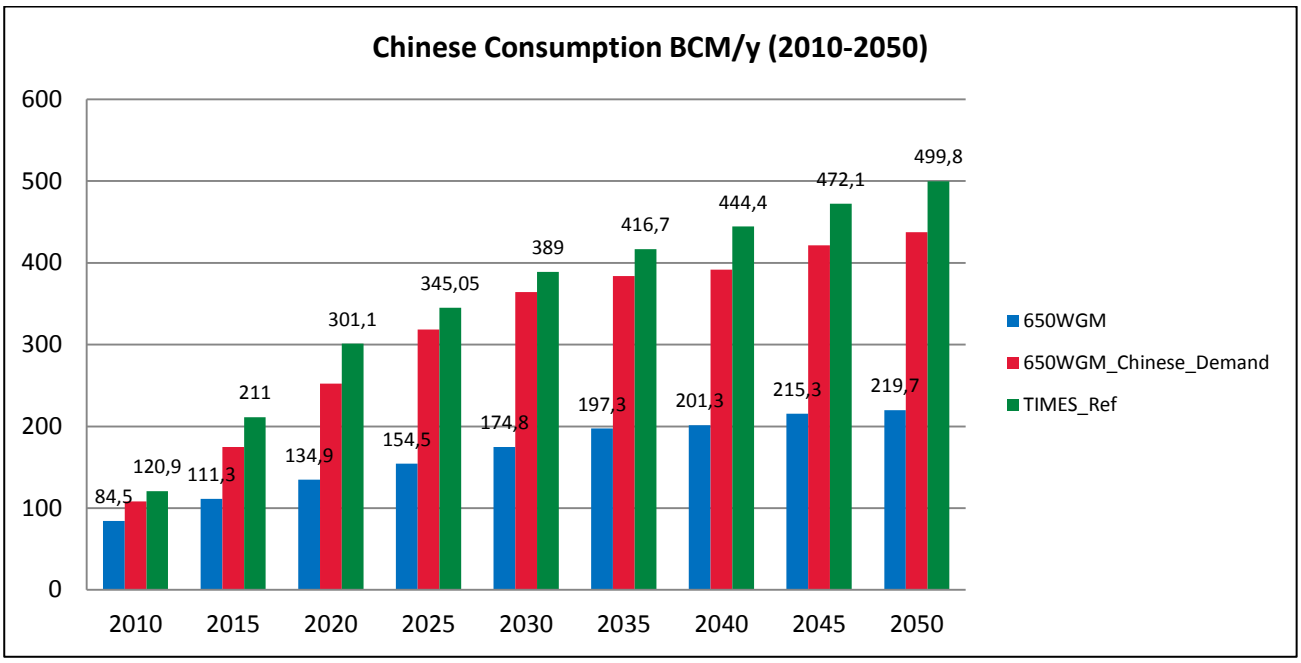


Figure 9.7 Comparison of Chinese Consumption

Table 9.5 Chinese Production, Imports by Pipelines, and Imports by LNG (bcm)

	Domestic Production bcm		Imports By Pipelines bcm		Imports By LNG bcm	
Year	**650WGM**	**650_Chinese_demand**	**650WGM**	**650_Chinese_demand**	**650WGM**	**650_Chinese_demand**
2010	77.21	84.42	0	0	7.32	23.68
2015	108.92	133.57	0	19.69	2.42	21.41
2020	134.94	185.21	0	51.81	0	15.31
2025	154.51	187.04	0	102	0	29.61
2030	166.47	189.9	8.32	132.08	0	42.42
2035	178.83	190.01	18.51	142.27	0	51.51
2040	181.73	189.92	18.51	150.37	0	51.52
2045	205.1	236.85	10.18	133.14	0	51.5
2050	209.48	246.04	10.18	141.66	0	49.69

China requires a lot more imports by pipelines and LNG to meet growing demand. Approximately 70 bcm of imports by pipelines come from the Caspian region (Kazakhstan). In term of regional price results, Figure 9.8 shows that in 2050, China and the Asia-Pacific region prices increase 40% and 10% respectively while prices for the rest of the world are unaffected.

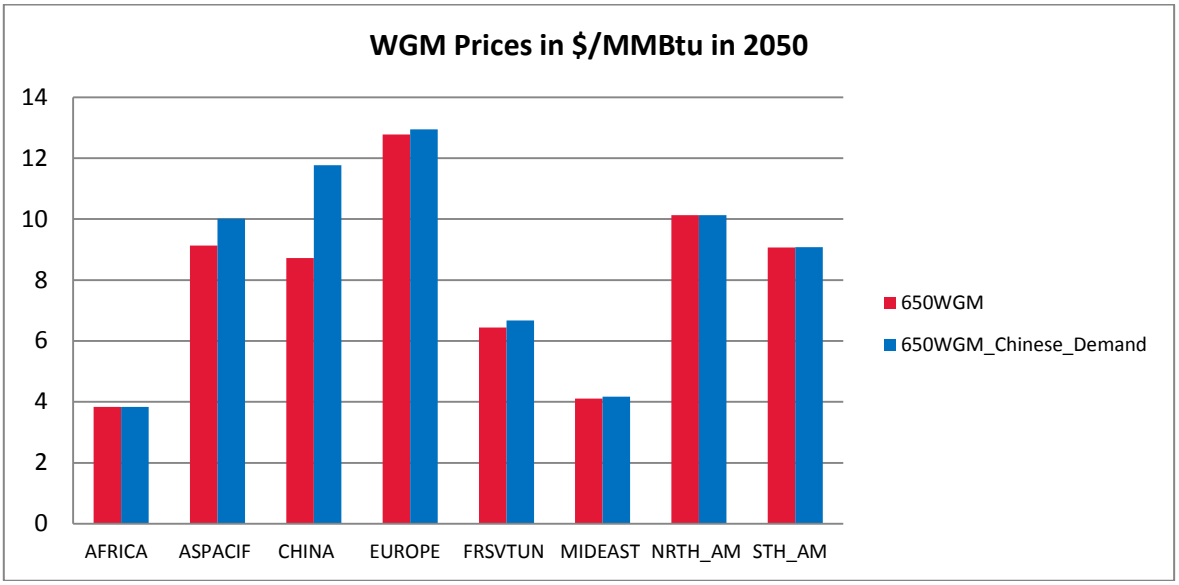


Figure 9.8 Comparison of Regional Natural Gas Prices

Increased consumption in China would significantly impact Asia because one of the main suppliers for the Asian market, namely Kazakhstan, exports more to China but less to the rest of Asia. In the 650WGM Case, China is self-sufficient and meets demand by domestic production but when demand rises up to nearly 500 bcm in 650WGM_Chinese_demand, China requires more imports by pipelines, mainly from the Caspian region. This situation causes the maximum expansion of pipelines connecting China and Central Asia as well as LNG import capacity expansion.

9.4.3 Conclusions

The main findings based on the results from the TIMES-WGM iterative procedure is that Chinese consumption reaches 500 bcm in 2050 by incorporating the WGM-generated supply curves fed to the TIMES model. By contrast, the Chinese consumption is much lower, at only 219.7 bcm when this procedure is not used (i.e., in the GCAM 650 ppm case). In order to meet this demand of 500 bcm, China imports in 2050 ten times as much gas by LNG and pipeline than without these supply curves. Therefore, Chinese prices increase about 40% as compared to the standard GCAM 650 ppm case. However, this extra Chinese demand has a small effect for faraway regions such as Europe and North America but does influence the Asian supply. Hence, Asian prices are approximately 15-18% higher when this procedure is used because China has increased its imports (e.g., from Kazakhstan). Less inexpensive gas is therefore available for Asia.

10 Discussion and main findings

The main research questions that led to the establishment of the LinkS project were the following: *How can we correlate scenarios for the energy system between a very long-term and global level and a regional level; and what additional insights will such a correlation yield?* The project was designed to analyse how global long-term strategies can be used as guidelines for the development of energy supply and technology deployment in regional energy systems. In order to produce recommendations for policy development and regional energy investment strategies, both quantitative and qualitative research were applied. An Executive Summary of the LinkS project is published as a separate *Technical Report A7373*.

The term "linking" has multiple interpretations in this project beyond the one stated in the title:

- "*Linking Global and Regional Energy Strategies*"
- Linking different energy system models (GCAM, WGM, TIMES, EMPIRE, EMPS)
- Linking policy analysis and energy system modeling
- Linking international research teams

Our main findings are summarized below for each of these interpretations.

10.1 Linking global and regional energy strategies

As an overall approach in the project, we used the global long-term model GCAM as the "top model" that gave long-term guidelines for the development of energy and climate change mitigation in different regions of the world. The advantage of this model is that we can quantify long-term global developments within each scenario and thus examine the links between e.g. Europe, USA and China endogenously under various policy and technology assumptions. Similar modeling exercises limited to EU level have to assume parallel global developments and give these as external parameters to the analysis.

On the other hand, a general disadvantage in Integrated Assessment models is the low spatial detail within each region. Thus, while GCAM sets the long-term general trends, regional bottom-up models with greater spatial and technology detail are necessary to give more specific recommendations within each region. We have done this for EU and China. In the latter case, however, Chinese 5-year planning currently does not look further than 2020 for the energy system so a longer-term correlation has not been possible.

As the world's largest emitter of CO_2 China is a crucial country for introduction of efficient climate change mitigation strategies. China has enormous resources of renewable energy and has one of the highest investment rates in wind energy in the world. Furthermore, in the 12th FYP (2011-2015) several policies for energy efficiency improvement and emissions reductions are introduced, but due to the continued strong growth in the Chinese economy total emissions still increase. The actual growth in China is larger than estimated in the current GCAM projections so it remains to be seen if future 5-year plans manage to overcome the growth and bring emissions down to the level they need to be to significantly limit the atmospheric concentrations of CO_2 by the end of the century.

In the case of Europe, we have better access to data and future projections for the energy sector, and have performed a detailed long-range investment analysis on country level with two different energy system models (EMPS and EMPIRE). On country level, there are faster developments in Europe than estimated by GCAM, e.g. the growth of wind and solar energy combined with nuclear decommissioning in Germany. This

is caused by the ambitious policies for energy efficiency, renewable energy and emissions reductions introduced in the EU and in each country the last years. Due to these targeted policies and regulations, Europe is able to develop its energy system much faster than estimated by a global model that basically follows cost-optimal algorithms.

Based on these observations we constructed the "Global 20-20-20" scenario where there is no single global carbon market as main instrument for climate change mitigation. Instead, each region introduces its own appropriate policies. In our scenario, all world regions copied the EU 20-20-20 policies at different points in time, but in principle each region can design and introduce their own policies independently of each other. Provided these regional policies are sufficiently strong and correctly timed, a set of independent regional policies seems to give almost as large emissions reductions as a global carbon market but at a somewhat higher socio-economic cost. Our Global 20-20-20 scenario resulted in a CO_2-e concentration of 505 ppm by the end of this century at a carbon price of \$300/tCO_2 compared to almost \$800/tCO_2 for the 450 ppm scenario, with only a minor increase in total socio-economic cost. This may therefore be a feasible approach in the lack of a single global agreement.

Since a CO_2 tax is one of the most likely instruments to use in a global emission reduction scheme, we used the World Gas Model to examine the impacts of such a tax in different regions. We used the resulting global CO_2 price from the 650 ppm scenario in GCAM (which is the scenario with highest shares of natural gas) and analyzed the effects in different gas markets.

In the US market, the best option of policy implementation would be if the CO_2 tax was imposed on consumers as this will give the lowest loss of consumer surplus. For Germany, however, the best option would be if the tax was dynamically adjusted between consumers and producers from one time period to another. The best carbon tax allocation is on the consumer side until 2030 when it is best to apply the tax to the suppliers, then again on the consumers. These results are caused by the mixed structure of the German market where some part is subject to the market power from large suppliers like Russia and Norway, and some are not. Thus, while some German players are price-takers, others set the price from an oligopolistic perspective. The decisions made by rival players that set the price consequently affect the supply decisions of price-taker players.

The regional analysis for the electricity sector in China is made only up to year 2020, which is the main period for the 12th Five Year Plan. The actual electricity demand is already higher than estimated in the GCAM scenarios, which are tuned to 2005 as base year. Nuclear and renewable power generation can't fully meet the rapid growth of demand due to the constraints of available resources. Thus, coal-fired power generation will still maintain a rapid growth momentum in China during the period 2010-2020, and will maintain the position as the power generation technology with the largest total installed capacity and highest energy production. However, due to extensive modernization and use of larger-scale units, it is possible to limit the CO_2 emissions from the Chinese power industry to between 3 and 5 billion tonnes by 2020.

A final example of the benefits of linking global and regional strategies is the simplified analysis of carbon leakage in the GCAM model. Introduction of an early carbon tax in a single or a few regions will create a difference in production cost between these and other regions without such a tax. However, as more and more regions join the climate mitigation efforts, whether by accession to a global carbon market or by introducing regionally specific policies, this apparent cost advantage will gradually disappear.

10.2 Linking different energy system models

The original ambitions in the LinkS project were to soft-link multiple energy system models with different technological, spatial and temporal resolution, and iterate these into a sufficient convergence in selected regions:

- GCAM – human, energy and agricultural systems, global, long-range, 5-year time steps
- WGM – global natural gas system model, 5-year time steps with 2 demand levels (seasons)
- TIMES - Chinese energy system model with annual resolution and multiple demand levels to 2020 implemented in TIMES
- EMPIRE – European electricity system model with investments in 5-year time steps to 2060 and multiple operational stages (666 per year)
- EMPS – European electricity system model with investments in 5-year time steps to 2060 and multiple operational stages (19,500 per year)

By running GCAM as the global "top model" it was possible to use long-term results from this model as input for the regional models and WGM, typically CO_2 prices, fuel prices and demand. However, iterating for convergence turned out to be a bigger challenge than anticipated. In the GCAM-WGM case, the latter has a much higher resolution in terms of gas market players and can therefore tune its results to more detailed and realistic market data than GCAM. Also, while GCAM finds a cost-minimizing result through market equilibriums, WGM is a complementarity model with single player optimization. Thus, it was difficult to iterate the two models into a single converged solution.

Even bigger challenges were encountered when we tried to iterate a triangle between electricity and gas models in a single region under GCAM projections. As summarized in Chapter 9 *Linking regional models,* each model initially got the same input data from GCAM but when the two regional models (WGM-EMPIRE for Europe and WGM-TIMES for China) where iterated the converged regional solution did not match the original GCAM solution anymore. We eventually abandoned the approach of convergence for a triangle of models; GCAM-WGM-EMPIRE and GCAM-WGM-TIMES, respectively, and stayed with a bilateral soft-link where each model received its input from GCAM.

In the case of Europe, however, we went one step further in comparing two different models for long-term expansion of the electricity system; the new EMPIRE model developed by an ongoing PhD task in LinkS and the existing EMPS model expanded with an investment algorithm. EMPIRE uses a perfect foresight LP investment algorithm with 666 operational situations per year, while EMPS has a single stage (myopic) investment algorithm with a much higher operational detail (19,500 situations per year). The former thus has a more mathematically stringent investment algorithm while the latter has a much better representation of variable renewable production. From the present analysis, it is not possible to conclude that one result is more "correct" that the other since there is no systematic difference between the results from the two models. In particular, the results from the EMPIRE model are sensitive to the choice of statistical data for "free" renewable energy from wind and solar resources.

The analysis illustrated how the EMPIRE-GCAM modelling framework can be used to assess optimal development of the European power system for different policy scenarios. Although there are significant differences between the scenarios, some results are robust across all the scenarios. In particular, the locational investments in new wind generation and which transmission corridors to reinforce stand out in that respect. France, Great Britain, Italy, Poland, and Norway are promising places to develop new wind generation capacity, and investments should be accompanied by large investments in transmission capacity

from Spain going north to Germany. The results are sufficiently similar to indicate that either model would be a feasible tool to use for electricity system expansion planning in a 50-year perspective.

10.3 Linking policy analysis and energy system modelling

It is a challenging task also to link the fundamentally different areas of policy analysis and energy system modelling, and a huge amount of time and efforts has been spent to achieve this in the LinkS project. The mathematical structure of GCAM allows the introduction of different policy measures as input to the analysis, but for more technology oriented models this ability is typically limited to adjustment of input parameters like CO_2 taxes, fuel prices, demand reductions etc. It is generally not possible to give regional energy and climate policy instruments as direct input to bottom-up energy system models. We therefore chose to perform the policy-modelling linking in several stages:

1. Defined policy measures were introduced in GCAM (global carbon market, Global 20-20-20 etc)
2. Results from the GCAM analyses were taken as input to the regional models
3. Results from the regional models where discussed in a policy context

In this way, we were able to formulate some initial policy measures, quantify these in a multi-level numerical process and then discuss the outcome on both a global and a regional level, see Chapter 4. In particular, the Global 20-20-20 scenario is an interesting example of this approach. We formulated a hypothetical global policy where the EU's 20-20-20 targets are extended in time and space to include all world regions and showed how this regional approach could yield reasonably high emissions reductions. Afterwards, we discussed how feasible the specific 20-20-20 measures would be in the regions of USA, EU and China.

The main conclusion is that bottom-up, regionally independent policy measures could yield significant climate change mitigation results. Naturally, each region should be allowed to find its own appropriate measures; the EU 20-20-20 approach is just an example. In principle, three main steps can be considered when approaching a specific region:

1. **Climate policy anchorage**
   - From which policy level do the (climate) policy initiatives stem?
   - Might indicate political will and priority
     - ➢ *The regional situation must be understood and accepted*
2. **Issue linkage**
   - To what extent are climate policy initiatives linked to other relevant policy fields?
   - Climate-specific and climate-relevant policies
     - ➢ *Define acceptable climate-relevant policies if climate-specific politics are controversial*
3. **Interdependencies**
   - Identify patterns of economic and political interaction and mutual dependencies as a path for common solutions
     - ➢ *Reinforce positive ones, avoid negative ones*

10.4 Linking international research teams

Last, but not least, the 5 years of the LinkS project have given the opportunity to link several world-class research teams:

- Joint Global Change Research Institute (JGCRI), Maryland, USA
- Dept of Civil and Environmental Engineering, University of Maryland, USA
- Center for Integrative Environmental Research (CIER), University of Maryland, USA
- Energy, Environment and Economy Institute (3E), Tsinghua University, China
- Dept. of Industrial Economics and Technology Management, NTNU, Norway
- Dept. of Electrical Power Engineering, NTNU, Norway
- Market-Grid Analysis group, SINTEF Energy Research, Norway
- Policy and Governance group, SINTEF Energy Research, Norway

In addition to the scientific knowledge and modelling expertise, each of the international partners has contributed with detailed knowledge about their countries' energy system and policies. This has enabled a detailed analysis of global and regional energy strategies, linked with regional policy analyses. Tsinghua University has provided valuable insights into Chinese energy and climate policies to the other teams. Similarly, the complex policy implementation of the Global 20-20-20 scenario in GCAM was enabled by detailed input from the European partners.

The main disadvantage of this large and inhomogeneous group has been the geographical distances and thus the infrequent physical meetings. Physical meetings are crucial to develop an efficient and well integrated research team. Throughout the duration of the project, we have arranged two physical workshops each year in addition to shorter periods of staff exchange. This has ensured a good atmosphere of multi-disciplinary collaboration and research, although more frequent physical meetings might have improved the work even further.

At the time of writing, the LinkS team has submitted 11 peer-reviewed international papers (of which 7 are published or accepted for publishing), published 9 books and reports (not including this TR) and held 55 presentations at various international conferences. The final conference of LinkS was arranged in Oslo 28 August with 30 participants. Two part-funded PhD dissertations are delivered at University of Maryland, while the 3rd is still on-going. Furthermore, one PhD study is on-going at NTNU and one at Tsinghua University.

10.5 Recommendations for further work

The LinkS project had very high ambitions of linking strategies, models and research teams. We are not aware of any other projects attempting to reach these objective on such a broad scale. A lot of interesting multi-disciplinary work is performed and increased insights have been achieved during these years, but there are still unanswered questions that should be given attention in further research activities. The most relevant topics we have noted are the following:

- Closing the feedback loop from the regional bottom-up models to CGAM by adjusting input parameters and constraints according to more detailed regional analyses. In particular, the representation of variable renewable energy resources and local infrastructure challenges may introduce new or modified constraints.
- Continue the analyses of independent regional policies in GCAM by expanding the Global 20-20-20 scenario to encompass several regionally differentiated policies.
- Perform detailed bottom-up studies under the global scenarios in more regions than the EU and China.
- Include more nationally or regionally specific policies in the regional studies; targeted RES support schemes, certificate markets, feed-in tariffs etc .
- Continue the bottom-up energy system studies in China beyond 2020.
- Further analyses of the differences between perfect foresight and myopic investment analyses in Europe. In particular, the effect of statistical year for renewables in EMPIRE merits further analysis e.g. by re-running the comparison with a year with particularly low renewable resources and a year with average renewable resources.

With regards to the model linking, we do not recommend further attempts to converge three or more models in the same loop; bilateral iterations between two models at a time is challenging enough.

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12 Appendices

12.1 The EMPIRE model

The EMPIRE model (*European Model for Power system Investment with (high shares of) Renewable Energy*) is a new power system model designed in the LinkS project to analyze optimal expansion of the European power system while taking into account long-term climate change mitigation strategies. This chapter will present the formulation of the EMPIRE model and the link to GCAM.

12.1.1 Setup and notation

To simplify the exposition of the EMPRE model, a short review of the model setup and notation is provided here. The model comprises a set of nodes, a set of generators and a set of lines, denoted by N, G and L, respectively. The nodes are defined on a country level as shown in Figure 12.1. Each generator belongs to a technology class from a set T, and represents the aggregate installed capacity of that given technology at that specific node. Lines connecting a pair of nodes in the system model represent exchange capabilities across all border-crossing transmission lines between the two countries and approximate net transfer capacities (NTC).

The model considers investments and operation in five year time periods, from 2010 till 2060. We let the set $\mathsf{I} = \{1,\ldots,11\}$ index these time periods such that, for $i \in \mathsf{I}$, $i = 1$ corresponds to 2010—2014, $i = 2$ corresponds to 2015—2019, etc. In each time period we consider a number of operational hours, indexed by a set H. The set of operational hours is sub-divided into seasons. Within a season hours are consecutive and temporal constraints such as ramping can be enforced. The set of all seasons is denoted by S.

When there is a relation between elements in two sets, say $a \in \mathsf{A}$ and $b_1, b_2, \ldots, b_N \in \mathsf{B}$ are related in some sense, the following notation is used for the subset of elements in B which are related to a,

$$\mathsf{B}_a = \{b \mid b \in \mathsf{B},\ b \text{ related to } a\} = \{b_1, \ldots, b_N\}. \tag{12.1}$$

Examples are for instance $\mathsf{G}_n = \{g \in \mathsf{G} \mid g \text{ at node } n\}$ which is the set of all generators at node $n \in \mathsf{N}$, and $\mathsf{H}_s = \{h \in \mathsf{H} \mid h \text{ in season } s\}$ which are the (ordered) set of all hours in season $s \in \mathsf{S}$. Vectors containing multiple variables are distinguished from scalars by the use of a boldface font; $\mathbf{w} = \left[w_{ijk} \right]_{i \in \mathsf{I},\, j \in \mathsf{J},\, k \in \mathsf{K}}$. If only a subset of these variables is considered, this is indicated by a subscript denoting the fixed variable, e.g. $\mathbf{w}_i = \left[w_{ijk} \right]_{j \in \mathsf{J},\, k \in \mathsf{K}}$.

12.1.2 Mathematical formulation

The EMPIRE model is a dynamic capacity expansion model for a simplified version the European power system. The model includes an investment stage and an operation stage and is formulated as a two-stage stochastic optimization problem (Birge and Louveaux, 2011). The investment decisions are made under operational uncertainty with respect to load profiles and production from intermittent resources.

The objective is to minimize the net present value of the expected total system costs, which is the discounted sum of the investments and expected optimal operational costs. Thus the model objective is

$$\min_{\mathbf{x}} z = \sum_{i \in \mathsf{I}} \delta_i \times \left\{ \sum_{g \in \mathsf{G}} c_{gi}^{\text{gen}} x_{gi}^{\text{gen}} + \sum_{l \in \mathsf{L}} c_{li}^{\text{tran}} x_{li}^{\text{tran}} + \mathrm{E}_{\xi} \left[Q_i(\mathbf{x}_{1:i}, \xi) \right] \right\}, \tag{12.2}$$

where $\delta_i = (1+r)^{-5i}$ is the discount factor at interest rate r,

$\mathbf{x}^{\bullet} = (\mathbf{x}^{\text{gen}\bullet}, \mathbf{x}^{\text{tran}\bullet})$ are investment decision variables (for generation and transmission capacity),

$\mathbf{c}^{\bullet} = (\mathbf{c}^{\text{gen}\bullet}, \mathbf{c}^{\text{tran}\bullet})$ are the associated investment costs,

$Q_i(\mathbf{x}_{1:i}, \xi)$ is the least cost of operation in period i given total cumulative investments until this point

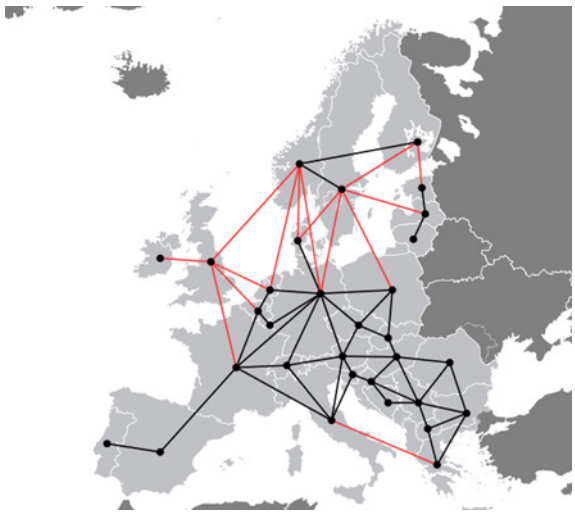

Figure 12.1 Location of nodes and lines in the EMPIRE model. Black lines indicate HVAC and red lines HVDC.

The vector ξ is the collection of all parameters that are unknown at the time of the investment. We assume that the probability distribution of ξ is discrete with probabilities $p_\omega = \text{Prob}(\xi = \xi_\omega),\ \omega \in \Omega$, which means the expectation in Eq. (6.2) is just a finite sum,

$$\min_{\mathbf{x}} z = \sum_{i \in \mathsf{I}} \delta_i \times \left\{ \sum_{g \in \mathsf{G}} c_{gi}^{\text{gen}} x_{gi}^{\text{gen}} + \sum_{l \in \mathsf{L}} c_{li}^{\text{tran}} x_{li}^{\text{tran}} + \sum_{\omega \in \Omega} p_\omega Q_{i\omega}(\mathbf{x}_{1:i}, \xi_\omega) \right\}. \tag{12.3}$$

An important part of EMPIRE is the modelling of optimal operation of the system when given the investments, also referred to as the *second stage problem* in this setup. For period $i \in \mathsf{I}$ and scenario $\omega \in \Omega$ the second stage problem is that of determining production levels of generating units as well as line power flows, i.e. $\mathbf{y}_{i\omega}^{\bullet} = (\mathbf{y}_{i\omega}^{\text{gen}\bullet}, \mathbf{y}_{i\omega}^{\text{pump}\bullet}, \mathbf{y}_{i\omega}^{\text{flow}\bullet}, \mathbf{y}_{i\omega}^{\text{ll}\bullet})$, such that the total cost is minimized while fulfilling the power balance under technical constraints. Assuming that the generators have linear cost functions, this problem can stated as

$$Q_{i\omega}(\mathbf{x}_{1:i}, \xi_\omega) = \min_{\mathbf{y}_{i\omega}} \sum_{n \in \mathsf{N},\, h \in \mathsf{H}} \alpha_h \times \left(\sum_{g \in \mathsf{G}_n} \left[q_{gi}^{\text{gen}} y_{ghi\omega}^{\text{gen}} \right] + q_{ni}^{\text{VoLL}} y_{nhi\omega}^{\text{LL}} \right), \tag{12.4}$$
$$\text{subject to } \mathbf{y}_{i\omega} \in Y(\mathbf{x}_{1:i}, \xi_\omega),$$

where q_{gi}^{gen} is the marginal cost of running generator g in time period i and q_{ni}^{VoLL} is the cost of using the load shedding variable $y_{nhi\omega}^{\text{LL}}$ at node n. The factor α_h represents the total number of hours in a year

represented by the operational hour h. Summing a variable/parameter scaled by α_h for all $h \in \mathsf{H}$ yields an annual figure. E.g., $\sum_{h\in\mathsf{H}} \alpha_h \xi^{\text{load}}_{nhi\omega}$ is the total electric energy consumption for node n in year i, scenario ω. The set $Y(\mathbf{x}_{1:i}, \boldsymbol{\xi}_\omega)$ comprises both load constraints for nodes and technical constraints for generators, pumps and line flows. These constraints are reviewed in the following section.

12.1.3 The operational constraints

The need for investments is mainly driven by the load constraints. These constraints state that at every node $n \in \mathsf{N}$ and in all operational hours $h \in \mathsf{H}$, there has to be a balance between generation $y^{\text{gen}}_{ghi\omega}$, and import (including losses) $y^{\text{flow}}_{ahi\omega}$, on one hand, and the demand for electricity $\xi^{\text{load}}_{nhi\omega}$, energy used for pumping in pumped storage plants $y^{\text{pump}}_{nhi\omega}$, as well as exports on the other. For the operational problem $Q_{i\omega}(\mathbf{x}_{1:i}, \boldsymbol{\xi}_\omega)$, $i \in \mathsf{I}$ and $\omega \in \Omega$, the load constraints are thus stated as

$$\sum_{g\in\mathsf{G}_n} y^{\text{gen}}_{ghi\omega} + \sum_{a\in\mathsf{A}^{\text{in}}_n} (1-\eta^{\text{line}}_a) y^{\text{flow}}_{ahi\omega} - \sum_{a\in\mathsf{A}^{\text{out}}_n} y^{\text{flow}}_{ahi\omega} - y^{\text{pump}}_{nhi\omega} + y^{\text{LL}}_{nhi\omega} = \xi^{\text{load}}_{nhi\omega}, \; n \in \mathsf{N}, h \in \mathsf{H}. \tag{12.5}$$

In situations where the available generation capacity and import are insufficient to cover demand at a node n the model can use $y^{\text{LL}}_{nhi\omega}$ as a slack variable at a cost q^{VoLL}_{ni}.

For all the generators $g \in \mathsf{G}$ we constrain the production to be less than the available capacity in every hour,

$$y^{\text{gen}}_{ghi\omega} \le \xi^{\text{gen}}_{ghi\omega} \times \left((1-\rho_{gi})\bar{x}^{\text{gen}}_{g0} + \sum_{j=1}^{i} x^{\text{gen}}_{gj}\right), \quad g \in \mathsf{G}, h \in \mathsf{H}, i \in \mathsf{I}, \omega \in \Omega. \tag{12.6}$$

The installed capacity for a particular generator in period $i \in \mathsf{I}$ is the sum of the non-retired initial capacity, which is the initial capacity $\bar{x}^{\text{gen}}_{g0}$ times a factor representing the non-retired share $(1-\rho_{gi}) \in (0,1)$, and the cumulative investments in periods $1,\ldots,i$. Generators are divided into two classes by the availability factor $\xi^{\text{gen}}_{ghi\omega} \in (0,1)$, dispatchable and intermittent, respectively. For the dispatchable generators, availability factors are constant across operational hours $h \in \mathsf{H}$ and scenarios $\omega \in \Omega$. These factors represent the average share of installed capacity available for production, which is assumed to be less than the maximum installed capacity due to planned and unplanned outages. For the intermittent technologies solar and wind, the availability factors are interpreted as normalized production values. This means that for every scenario $\omega \in \Omega$, $\{\xi^{\text{gen}}_{ghi\omega}\}_{h\in\mathsf{H}}$ is a (yearly) production profile for intermittent generator $g \in \mathsf{G}^{\text{Intermittent}}$. These production profiles are based on historical wind and solar production data, and are assumed to be the same for all $i \in \mathsf{I}$.

For thermal power plants we also impose constraints on the possible ramp-up from one hour to the next. This is limited to a given share of the installed capacity, described by the following equation

$$y^{\text{gen}}_{ghi\omega} - y^{\text{gen}}_{g(h-1)i\omega} \le \gamma^{\text{gen}}_g \times \left((1-\rho_{gi})\bar{x}^{\text{gen}}_{g0} + \sum_{j=1}^{i} x^{\text{gen}}_{gj}\right), \quad g \in \mathsf{G}^{\text{Thermal}}_s, s \in \mathsf{S}, h \in \mathsf{H}_s, i \in \mathsf{I}, \omega \in \Omega, \tag{12.7}$$

where γ^{gen}_g is the ramp rate for generator $g \in \mathsf{G}^{\text{Thermal}}_s$.

For regulated hydro power generators there is a limit on total production over a season,

$$\sum_{h \in \mathsf{H}_s} y^{\text{gen}}_{ghi\omega} \le \xi^{\text{RegHydroLim}}_{gsi\omega}, \quad g \in \mathsf{G}^{\text{RegHydro}}, s \in \mathsf{S}, i \in \mathsf{I}, \omega \in \Omega. \tag{12.8}$$

The seasonal energy limit $\xi^{\text{RegHydroLim}}_{gsi\omega}$, represents the water available for generation.

Due to the highly aggregate representation of the European transmission system we only consider upper bounds on line flows, thus treating every line independently of the others and neglecting loop flows. The capacity of each of the lines is bounded by the initial capacity and the cumulative investments,

$$y^{\text{flow}}_{ahi\omega} \le \overline{x}^{\text{tran}}_{l0} + \sum_{j=1}^{i} x^{\text{tran}}_{lj}, \quad l \in \mathsf{L}_n, a \in \mathsf{A}_l, h \in \mathsf{H}, i \in \mathsf{I}, \omega \in \Omega. \tag{12.9}$$

For pumped storage plants the model includes a constraint on the pump capacity, equivalent to Eq. (12.6). We assume that at the beginning of a season $s \in \mathsf{S}$ in period $i \in \mathsf{I}$ the upper reservoir at node $n \in \mathsf{N}$ is $w^{\text{init upper}}_{nsi}$. To keep track of the upper[45] reservoir water balance in a season $s \in \mathsf{S}$ (for time period $i \in \mathsf{I}$ and scenario $\omega \in \Omega$) the model includes constraints on the form

$$w^{\text{upper}}_{n(h-1)i\omega} + \eta^{pump}_n y^{\text{pump}}_{nhi\omega} - y^{\text{gen,pump}}_{nhi\omega} = w^{\text{upper}}_{nhi\omega}, \quad n \in \mathsf{N}, h \in \mathsf{H}_s, \tag{12.10}$$

where $w^{\text{upper}}_{nhi\omega}$ is the upper reservoir energy contents at node n in hour h, $\eta^{pump}_n \in (0,1)$ is the pump efficiency, $y^{\text{pump}}_{nhi\omega}$ is the pump load and $y^{\text{gen,pump}}_{nhi\omega}$ is the generation from the plant. The upper reservoir energy contents variables are all limited by the reservoir capacity, $w^{\text{upper}}_{nhi\omega} \le \overline{w}^{\text{upper}}_n$, and we assume that at the end of a season the reservoir content is back to the initial level $w^{\text{init upper}}_{nsi}$.

12.1.4 Problem size reduction

In order to limit the computational effort in solving the EMPIRE model the number of hours used to represent a year has been significantly reduced. One year of operation has been modelled using eight representative days (48 consecutive hours) from different seasons. In addition, the model includes six periods with only five consecutive hours where we experience peak load in the six nodes with the highest load in the system.

12.1.5 Soft-linking GCAM and EMPIRE

Careful considerations lie behind the link between GCAM and the EMPIRE model. The idea is to disaggregate the GCAM results to country level and expand the temporal resolution while at the same time conserving the top-level equilibrium solution. This section will briefly go through how consistency between assumptions in the two models is achieved.

1) Generation capacity investment costs: In (Clarke et al, 2008) GCAM assumptions about investment capital costs for a unit capacity, fixed annual O&M costs and economic life time are found for all technologies. Using these parameters an annualized fixed cost associated with an investment is computed and the cost coefficient for an investment decision variable is calculated by summing all the

[45] For pumped storage plants we assume that the lower reservoir has significantly more energy capacity than the upper reservoir. Thus, constraints involving the lower reservoir capacity has been neglected.

payments done within the analysis horizon. Costs for transmission capacity investments are treated the same way, but the data is collected from SUSPLAN (de Joode, J et al., 2011).

2) Generation costs: The marginal cost of production q_i for a given generator technology is calculated as the sum of marginal cost of fuel, marginal cost of emissions and variable O&M costs. For a generator with heat rate hr_i and variable O&M costs $c_{\text{vO\&M}}$ this can be parameterized as

$$q_i = hr_i \times (p_{if} + (1 - rf^{\text{CCS}}) \times e_f \times p_{i,\text{CO}_2}) + c_{\text{vO\&M}} \tag{12.11}$$

where p_{if} is the price of fuel f in period i, e_f is the fuel carbon contents and p_{i,CO_2} is the carbon tax in period i. The factor rf^{CCS} is the share of captured carbon (only relevant for CCS technologies). Note that the fuel prices and the carbon emission tax are determined in the GCAM equilibrium solution while the other parameters are inputs and therefore part of the assumptions.

3) Regional demand: Having a good estimate of future demand for electricity is crucial when developing an investment plan for new generation capacity and infrastructure. Using an integrated assessment model such as GCAM to estimate demand is particularly appealing since substitution effects and price elasticity are endogenously accounted for. As the EMPIRE model requires hourly load profiles at a country level, the regional annual demands from GCAM were disaggregated according to the following procedure (for every $n \in \mathsf{N}$, $i \in \mathsf{I}$, $\omega \in \Omega$)

   a) The regional annual demand from GCAM in period i is divided between the country members according to their 2010 share of regional demand in the ENTSO-E statistical database (ENTSO-E, 2012). We denote by $e_{n,i}$ the resulting annual demand for node n in period i.

   b) Construct a new load series $\{\xi^{\text{load}}_{hni\omega}\}_{h\in\{1,..,8760\},\omega\in\Omega}$ from a base load series $\{\xi^{\text{load}}_{hn0\omega}\}_{h\in\{1,..,8760\},\omega\in\Omega}$ (based on ENTSO-E hourly load data) using

$$\xi^{\text{load}}_{hni\omega} = \xi^{\text{load}}_{hn0\omega} + \frac{(e_{n,i} - e_{n,0})}{8760}. \tag{12.12}$$

   The new series sums up to $e_{n,i}$, yielding the right regional demand, and has the same variability as the base series.

4) Energy share constraints: For every $i \in \mathsf{I}$ the EMIPRE model aims at producing the same regional energy mix as GCAM. The rationale behind this approach is that the fuel market equilibrium from GCAM can best be preserved when not only the fuel prices, but also the fuel offtakes are matched. Thus, since we are using GCAM fuel prices in Eq. (12.11) we also need to use the corresponding fuel quantities, which can be achieved by constraining the energy mix to match in both models. Since EMPIRE is a stochastic model, it is the expected value of the energy mix in EMPIRE which matches that of GCAM, which means that in period $i \in \mathsf{I}$ we have the following constraint for GCAM technology $t \in \mathsf{T}^{\text{GCAM}}$,

$$\left| \sum_{\omega\in\Omega} p_\omega \left(\sum_{h\in\mathsf{H}} \sum_{g\in\mathsf{G}} \alpha_h y^{\text{gen}}_{ghi\omega} \right) \right| \le \beta_{ti} e_i^{\text{Europe}}. \tag{12.13}$$

In Eq. (12.13) β_{ti} is the share in the total European energy mix technology t in period i, and e_i^{Europe} is the European annual electricity consumption in period i. Both parameters are part of the GCAM equilibrium solution and depend on the policy scenario in question.

12.1.6 Preparation of the Stochastic Data/Construction of the Numerical Scenarios

Each scenario $\omega \in \Omega$ consists of both deterministic data (which is constant throughout all scenarios) and stochastic data (which is generally different among different scenarios.) Time series corresponding to both types of data were obtained from historical records. The parameters in the model considered stochastic are wind energy production, hydro energy production, solar energy production, and the load of the system. Quality hourly data for one entire year of operation was acquired for each parameter with exception of the load, for which we had five years of operation recorded.

To achieve the dual purpose of modeling stochasticity and reduce the size of the problem, it was decided that the data for each scenario ω would come from a sample of consecutive hours. The samples would be randomly chosen, so that a) each scenario would get generally different data, and b) on average, the mean and variance of the sampled data would match that of the original series. Additional considerations were taken regarding seasons, missing observations in the historical series, the availability of five years of observation for load, the replication into the 11 five year periods, and the artificial seasons for peak loads.

The data preparation process is given by the following algorithm: Let τ_{nh}^{sol}, τ_{nh}^{hyd} and τ_{nh}^{wind} be the solar, hydro and wind production in a given node n and historic hour h, respectively, and τ_{nhy}^{load} be the load in the system in node n, historic hour h and historic year y; with $h \in H = \{1,...,8762\}$, and $y \in Y = \{1,...,5\}$.

1) If there are missing observations in any of the matrices, these are obtained by either linear extrapolation of the closest available hours, or replicating those values in case the missing observations are at the beginning or the end of the respective series.

2) Make an ordered partition of the set of indices H into four season sets H_s such that $H = \{H_1,...,H_4\}$. The number of elements of each H_s is 2190.

3) For each scenario ω do
   a) For each sampling season s, obtain a random number ρ_s between 1 and 2190 - $(l+1)$, where l is the length of the sampling season used to model the entire season (in our case, 48 hours)

   b) Select a random year y^* for the load parameter.

   c) Build the series $\xi_{hni\omega}^{type}$, $\xi_{hgi\omega}^{load}$ as

$$\xi_{nhi\omega}^{type} = \tau_{nh^*}^{type},$$
$$\xi_{nhi\omega}^{load} = \tau_{nh^*y^*}^{load}, \qquad type = \{sol, wind, hyd\}, n \in N, h \in H.$$

   where h^* is determined by the season s to which h belongs to the randomly selected index ρ_s. Notice that all five year periods $i \in I$ have the same sampled seasons.

4) Form the first peak season by summing up the historic load for all generators in a given hour $h \in H$, for the selected year y^*:

$$\tau_{hy^*}^{load*} = \sum_{\forall n} \tau_{nhy^*}^{load}$$

a) Select the hour h with the highest load value, $\overline{h}$.

b) The first peak season is made of the hours interval $\left[\overline{h}-2, \overline{h}+2\right]$ at the selected year y^*; the interval is used for all the parameters in all scenarios.

5) Form the other five peak seasons by obtaining the maximum load per node $\tau_{ny^*}^{load*} = \max_h \{\tau_{nhy^*}^{load}\}$, then selecting the five nodes $n_1, \ldots, n_5$ with the largest load. Peak season i+1 will be formed by the hours $\left[\overline{h}_i - 2, \overline{h}_i + 2\right]$, where $\overline{h}_i$ is the hour with the largest hour load for node i. The intervals are used for all the parameters for all scenarios.

6) Check that the sampled seasons $\xi_{hni\omega}^{type}$, $\xi_{hni\omega}^{load}$ match the expected mean for each five-year period $i \in I$. If they don't, perform an algebraic transformation so that each five year period has a sampled time series which matches its own mean.

By putting together the sampled seasons for each scenario, and the common peak seasons, we can generate the time series for node, season and five year block needed in the analysis.

12.2 EFI's Multi-area Power Market Simulator EMPS

12.2.1 The EMPS model

The EMPS model (Wolfgang et al, 2009, Jaehnert et al, 2013) is a stochastic optimization model for multiple electricity markets that maximizes the expected total economic surplus in the system. As EMPS was initially designed for the Nordic power system, one of EMPS' strengths is an advanced representation of long- and short-term storage capabilities. The objective of the model is the maximization of the social welfare, through the dispatch of generation and transmission, given a consumption profile. There is no significant production cost for hydro power, but with a limited amount of water available in the reservoirs as well as a season dependent inflow the determination of an optimal strategy for hydro power generation is a complex problem. The goal is to find the strategy that minimizes the expected annual operation cost, taking into account the climatic uncertainties (Flataboe et al, 1998). In this process, EMPS executes two phases: the S*trategy calculation phase* and the *Market simulation phase*. In the first phase, water values for each reservoir are calculated as option values of the stored energy for different operational strategies. In the second phase, the operation of the power system is simulated for the different stochastic outcomes (climatic years). The process is illustrated in Figure 12.2.

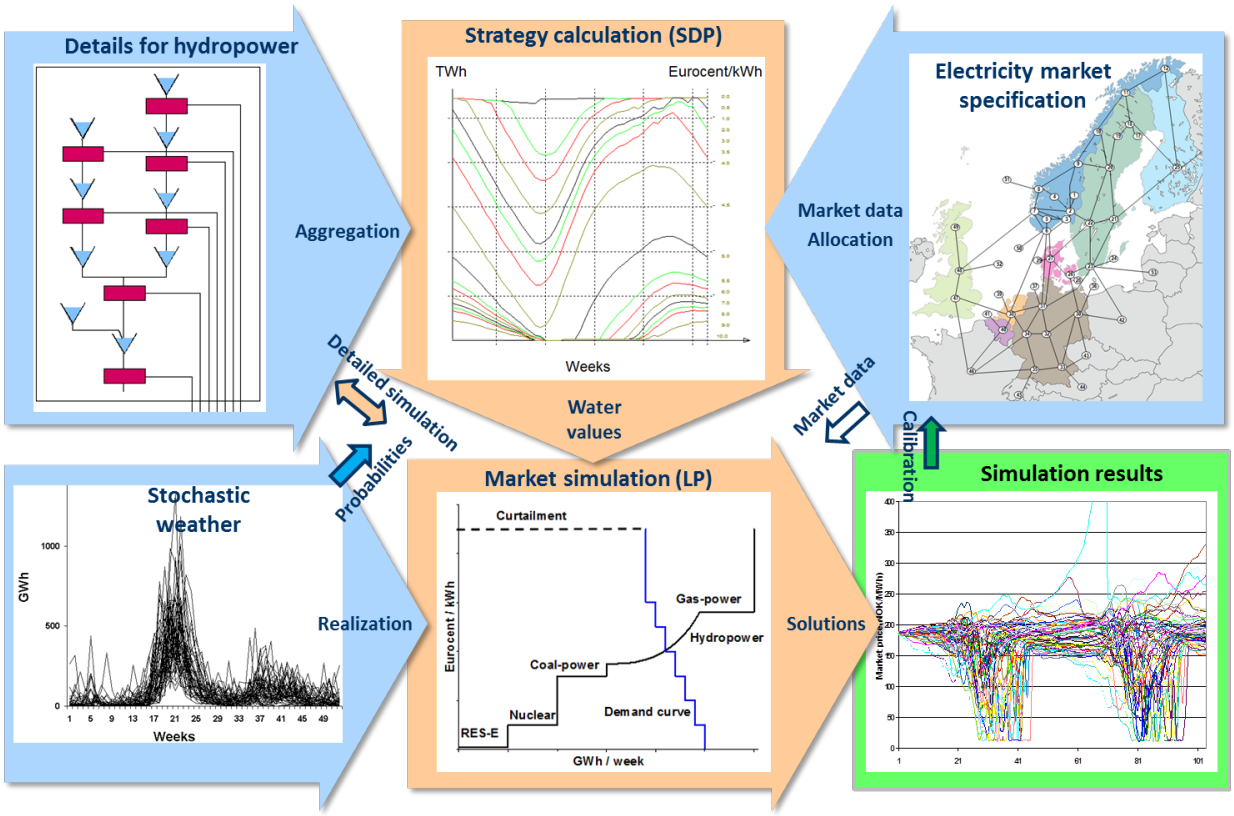

Figure 12.2 Strategy calculation and Market simulation phases in the EMPS model

The expected operation cost can be formulated as:

$$\alpha(x_k) = E\left\{\min\left[\sum_{k=1}^{K} L(u_k) + S(x_K)\right]\right\} \tag{12.14}$$

where

$\alpha(x_k)$	= Expected operation cost in rest of planning period
x_k	= State vector, (reservoir content)
k	= Stage index, *1* to K
K	= Total number of stages in the problem
u_k	= Decision vector
L	= Immediate cost associated with u
S	= Value of stored energy at the end of the period

L is the cost associated with the decision vector. Here it is expressed as the cost for operating the hydrothermal power system against the market.

$$L(u_k) = \sum_{i=1}^{M} c_{i,k} \cdot y_{i,k} \tag{12.15}$$

where

$$\sum_{i=1}^{M} y_{i,k} = F_k - u_k \tag{12.16}$$

i	=	Market option index
M	=	Number of market options
$c_{i,k}$	=	The cost of market option *i* in stage *k*
$y_{i,k}$	=	The share of generation that goes to option *i* in stage *k*
F_k	=	Power delivered at fixed price

In the LinkS scenarios each European country is considered as a single node (characterized by an endogenously determined internal supply and demand balance) with distinct import and export transmission capacities to the neighboring countries. The main inputs to the model include costs and capacities for generation, transmission and consumption of electricity and information about historical climate variables like temperatures, hydro inflow, wind, solar radiation; typically with hourly resolution. Generation is separated into several renewable production capacities like wind, solar, hydro, geo-thermal and bio, and non-RES production capacities of coal, gas, oil, nuclear etc. Figure 12.3 is a graphical representation of the components that typically are modeled for each area. In the LinkS scenarios, the hydropower system is modeled with a single reservoir and aggregated relevant variables describing the system. This hydropower module can be expanded to handle complex river systems with multiple power plants in series or parallel. Based on demand, exchange, marginal costs and expected value of hydropower (water values) in each area, an optimal market balance is calculated for each time step as shown in Figure 12.4.

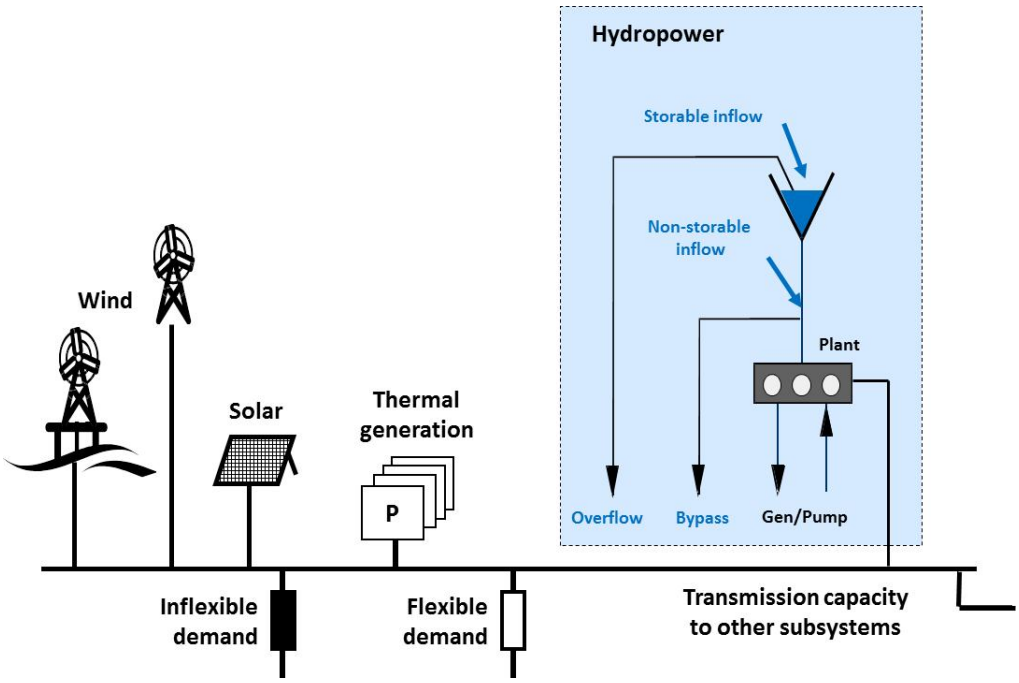

Figure 12.3 Typical components per area in EMPS model

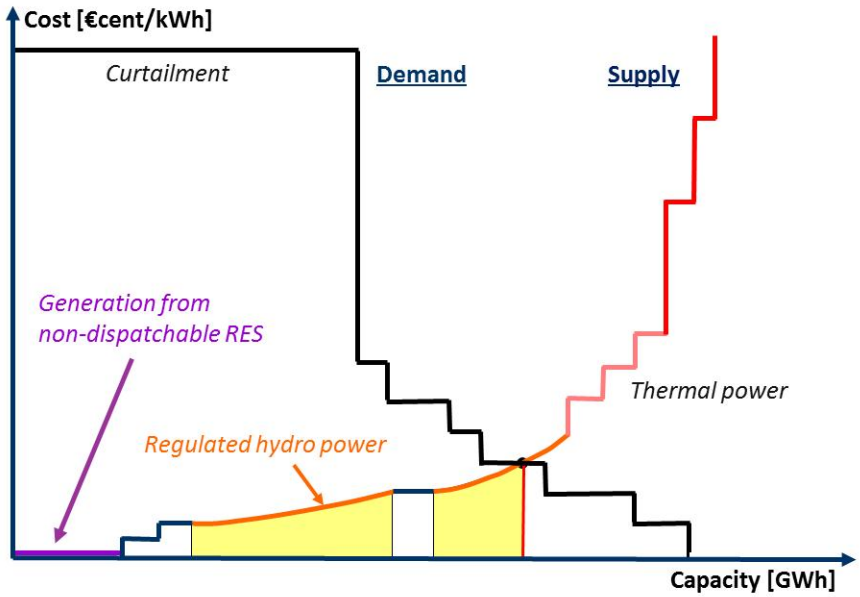

Figure 12.4 Optimal market balance for each area and time step

12.2.2 The EMPS Investment model

The EMPS model maximizes expected total economic surplus for a given system, but a recent expansion enables the model to evaluate profitable investments in generation capacity and transmission capacities in the system (Jaehnert et al, 2012, Graabak and Wolfgang 2012, Jaehnert et al, 2013). By running the model through a sequence of time steps, an investment plan over several decades can be established. At the first

step, the model is solved with initial generation and transmission capacities between the nodes. Bottlenecks in the transmission system will then lead to price differences between nodes, indicating a potential for arbitrage. Next, the model checks which investments are profitable at simulated electricity prices. This calculation includes a comparison between the average annual marginal operating profits of the investments over all simulated climatic years and the annualized investment costs. The algorithm is illustrated in Figure 12.5.

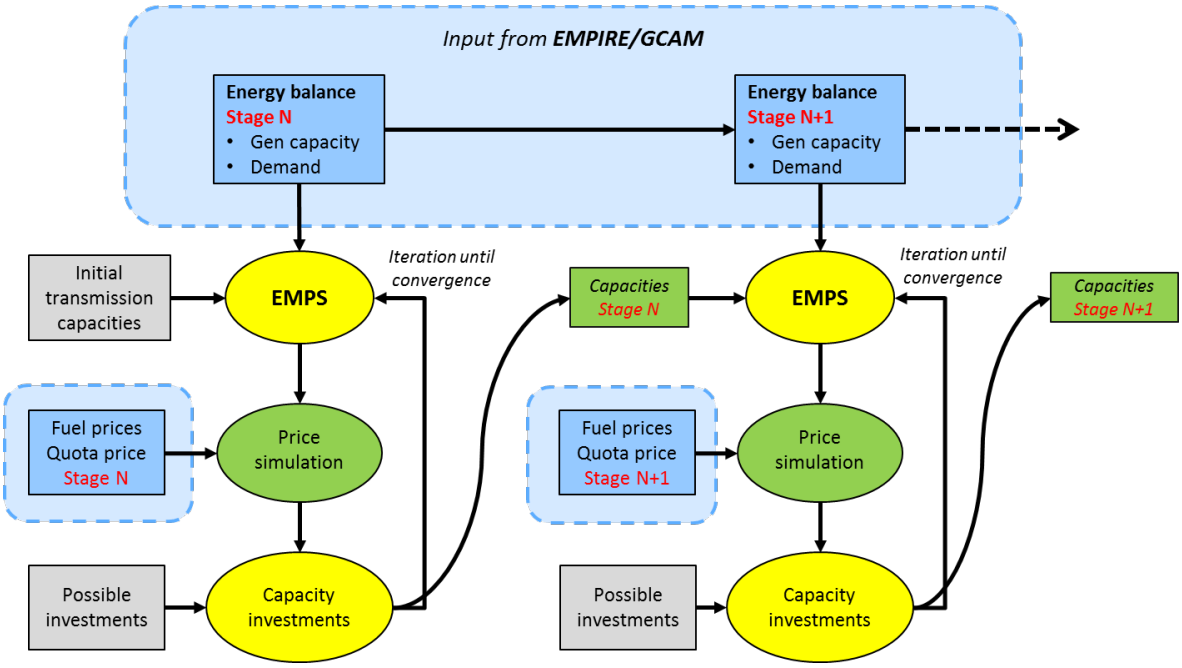

Figure 12.5 Investment algorithm in the EMPS model

Table 12.1 List of symbols for operating profits calculation

Symbol	Explanation
Sets	
I	Climate scenarios; e.g. {1931, …, 2012}
L	Within-week time periods. If the simulation has been carried out with sequential time steps, L refers to the set of sequential periods within the week.
K	Possible investments in transmission lines
Indices	
i	Index for an element in set I
l	Index for an element in set L
t	Index for week-number {1,…,52}
k	Index for investments
Parameters	
h_l	Number of within-week hours in price-segment l
m_k	Area-number for investment k

n_k	2nd area-number for investments in transmission lines. Line defined from m_k to n_k.
p_{i,t,l,m_k}	Power price (in Eurocent/kWh)
c_k^{inv}	Annualized investment cost (in Euro/MW per year)
I^{numb}	Number of scenarios / elements in I
$t_{m^k n^k}$	Loss for transmission line from area *m* to area *n*
z_k	Needed excess profit to increase investment (as a share of investment costs)
I_k^{inv}	Invested amount (in MW)
Variables	
π_k^{op}	Average annual operating profits (in Euro per MW per year)
π_k^{tot}	Average annual profits (in Euro per MW per year)

For each time step, the gains of having 1 MW extra capacity are checked. In the EMPS model, the full transmission capacity will always be utilized to send power towards the high-price area if the price difference is large enough to pay for the losses. Therefore, the average annual operating profits for transmission lines can be calculated by Eq. (12.17).

$$\pi_k^{op} = \frac{\sum_{\substack{t\in\{1,\dots,52\}\\ i\in I, l\in L}} \max\left\{0;\ \left[\mathrm{p}_{i,t,l,m_k}\left(1-t_{m^k n^k}\right)-\mathrm{p}_{i,t,l,n_k}\right];\left[\mathrm{p}_{i,t,l,n_k}\left(1-t_{n^k m^k}\right)-\mathrm{p}_{i,t,l,m_k}\right]\right\} h_l \cdot 10}{I^{numb}},\quad \forall k \in K^{Trans} \tag{12.17}$$

When the operating profits for all investment alternatives have been calculated the benefits of extra capacity are compared with investment costs. We now interpret the simulated average annual operating profits as the expected annual operating profits, account taken for uncertain weather variables. Then the expected annual profit of investing in 1 MW extra capacity for investment *k* is:

$$\pi_k^{tot} = \pi_k^{op} - \mathrm{c}_k^{inv},\quad \forall k \in K \tag{12.18}$$

In every round of the investment algorithm loop, we consider whether the capacity for a specified investment alternative should be increased, decreased or be unchanged. The capacity is increased if the following condition is satisfied:

$$\frac{\pi_k^{tot}}{\mathrm{c}_k^{inv}} > z_k \tag{12.19}$$

The capacity of a given investment alternative can never be reduced below the initial capacity for current Stage *N*, cf. the box "Initial transmission capacities" in Figure 12.5. However, if additional capacity has been phased in during the investment algorithm loop, that capacity can be phased out again in a later iteration. The condition for phasing out capacity is:

$$\pi_k^{tot} < 0 \tag{12.20}$$

From (12.19) and (12.20) it follows that the investment algorithm has converged if, for all investment alternatives, the following criteria are satisfied:

$$\begin{aligned} &\text{If } I_k^{inv} > 0: \quad \pi_k^{tot} \in \left[0, \mathrm{c}_k^{inv} z_k\right] \\ &\text{If } I_k^{inv} = 0: \quad \pi_k^{tot} < \mathrm{c}_k^{inv} z_k \end{aligned} \tag{12.21}$$

The motivation for including a threshold value for adding new investments is two-fold. Firstly, it is in principle impossible to get exactly $\pi_k^{tot} = 0$ for all investment alternatives. Therefore, we must establish an interval that can give a possibility for convergence for the algorithm. Secondly, the price will be reduced when an investment is carried out. Therefore, both of practical reasons for the algorithm and seen from the perspective of an investor, there should be some excess profits prior to the investment.

When no more profitable investments can be found for Stage *N* or the number of iterations within the stage reaches a certain threshold, the investment model will continue with next Stage *N+1* using the transmission capacities found in previous Stage *N*. This one-step algorithm is sub-optimal compared to a perfect-foresight investment model, however, with a balanced future development path (e.g. gradually increasing demand and fuel prices) the approach should be close to the optimal investment strategy.

While EMPIRE includes new transmission capacity as continuous variables in the optimization problem, the EMPS will iteratively add capacity in steps. Table 12.2 lists the capacity evaluated at a given iteration in the EMPS investment analysis.

Table 12.2 Transmission investment capacity for given iteration in EMPS model

Iteration	1 – 4	6 – 9	10 – 12	13 – 20	21 - 22	23 – 41
Capacity [MW]	5000	2500	1000	500	100	50

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