



**Institute of Energy Economics
at the University of Cologne**

EWI Working Paper, No. 10/06

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December 2010

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Scenarios for an Energy Policy Concept of the German Government

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Abstract

In this article we demonstrate how challenging greenhouse gas reduction targets of up to 95% until 2050 can be achieved in the German electricity sector.¹ In the analysis, we focus on the main requirements to reach such challenging targets. To account for interdependencies between the electricity market and the rest of the economy, different models were used to account for feedback loops with all other sectors. We include scenarios with different runtimes and retrofit costs for existing nuclear plants to determine the effects of a prolongation of nuclear power plants in Germany. Key findings for the electricity sector include the importance of a European-wide coordinated electricity grid extension and the exploitation of regional comparative cost effects for renewable sites. Due to political restrictions, nuclear energy will not be available in Germany in 2050. However, the nuclear life time extension has a positive impact on end consumer electricity prices as well as economic growth in the medium term, if retrofit costs do not exceed certain limits.

Keywords: Roadmap 2050, GHG reduction, renewable energies, carbon capture and storage, power plant fleet optimization

JEL classification: C61,Q40

ISSN: 1862-3808

¹This article highlights selected results from a study undertaken by the Institute of Energy Economics at the University of Cologne (EWI) together with Prognos AG and Gesellschaft für Wirtschafts- und Strukturförderung mbH (GWS) for the German Government.

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1. Introduction

German climate protection targets as defined in the coalition agreement for the 17th legislative period are challenging. Within the agreement, the political parties CDU, CSU and FDP settled on a greenhouse gas reduction target of 40% until 2020 in comparison to the emissions in 1990. For 2050 the agreement is loose but states that the greenhouse gas reduction in Germany should be in line with international agreements envisioning a reduction of at least 80% in industrial countries. The coalition agreement furthermore emphasizes the need of energy efficiency improvements and states that renewable energies should be expanded continuously in order to play the predominant role in the future energy mix. Regarding conventional power plants, the usage of carbon capture and storage (CCS) techniques is encouraged. Within the transformation process to a low carbon emission energy system, the coalition agreement considers the prolongation of nuclear power plants in Germany as an option to reach climate protection targets without neglecting other targets: economically justifiable energy prices and a secure energy supply.¹

On the basis of this coalition agreement, the Federal Government commissioned a scenario analysis in order to identify ways of a technological and structural transformation process permitting to reach the climate targets. This article focuses on the scenario analysis of the electricity sector with consideration of the interdependencies between the electricity, heating and transportation sectors in Germany.

An overview of the scenario framework is given in Table 1. We analyze four scenarios (I–IV) where a CO₂ emission reduction in the energy sector of at least 40% until 2020 and of 85% is achieved until 2050. Compared to the transportation sector CO₂ abatement costs are relatively low in the electricity sector, so the CO₂ reduction target for the electricity sector is higher; in the scenarios it amounts to 95% in 2050. Within the reference scenario we compute the extrapolation of observable trends. This scenario does not include an explicit CO₂ emission target. While in the reference scenario the operational times of nuclear power plants are not extended, an extension of 4/12/20/28 years is possible in scenarios I to IV. The extension of nuclear power plants is an option in the determination of the overall cost-minimizing electricity mix and depends sensitively on the specific retrofit costs. The influence of different retrofit costs on the extension of operational times is thus taken into account by comparing the effects in scenarios IA to IVA and IB to IVB. In the scenarios IB to IVB higher retrofit costs as a suggestion of the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety were modeled. Even with a 28 years extension of

¹The prohibition of building new nuclear power plants according to the nuclear law remains enacted and is not questioned in the current coalition agreement (Atomgesetz, 2009). An extension of the remaining operational lifetimes for existing nuclear plants that have been determined in 2002 (“Atomkonsens”) is described as an option in the coalition agreement (Atomkonsens, 2002).

Table 1: Scenario framework

	I A/B	II A/B	III A/B	IV A/B	Reference
Greenhouse gas emissions	40 % (2020) 85 % (2050)	40 % (2020) 85 % (2050)	40 % (2020) 85 % (2050)	40 % (2020) 85 % (2050)	
Nuclear power extension	4 years	12 years	20 years	28 years	-
Energy efficiency improvement p.a.	endogenously	2.3–2.5 %	2.3–2.5 %	endogenously	1.7–1.9 %
Renewable energies					
–Gross generation share	$\geq 18\%$	$\geq 18\%$	$\geq 18\%$	$\geq 18\%$	$\geq 16\%$
–Primary energy share	$\geq 50\%$	$\geq 50\%$	$\geq 50\%$	$\geq 50\%$	$\geq 50\%$

the operational time of nuclear power plants, electricity generation by nuclear power is only a negligible option in the target year 2050. In all scenarios, demand for electricity decreases due to energy efficiency improvements.

In this article, we show different transformation processes leading to a low carbon emission energy system in 2050. Section 2 provides an overview of the relevant literature. Sections 3 and 4 describe the methodological approach and the assumptions of the model calculations. In Sections 5 and 6 we discuss the model results for the target year 2050 respectively for the transformation process to 2050. Section 7 summarizes and draws conclusions.

2. Literature overview

In recent years, a number of studies analyzed possible transformations to a more-or-less carbon free energy usage in Europe. These studies often focused on the electricity sector. Most of them assume: certain CO₂ emission targets or a target for electricity generation by renewables; optimistic developments of investments in energy efficiency; high potentials and learning curves for renewable energies over time. The published studies can be distinguished by the time horizon (e.g. 2030 or 2050), methods used to model the power market and by the criteria whether or not total costs are evaluated.² However, the main difference between the studies is the analytical approach: feasibility studies demonstrating that challenging climate protection targets can be technically achieved or economic scenario analysis determining the cost-efficient transformation to a low carbon emitting energy system.

Studies that mainly focus on the technical feasibility of a significant CO₂ reduction include Matthes et al. (2009), Hulme et al. (2009) or Capros et al. (2010). For example, Matthes et al. (2009) calculated a reduction of greenhouse gas emissions of 178 mio. tCO₂ (–17.8 percent compared to 2005). Erdmenger et al.

²Keles et al. (2010) classified the studies/scenarios into three main groups: “moderate”, “climate protection” and “resource scarcity and high fossil fuel prices”.

(2009) presented measures and instruments for Germany to reduce CO₂ emissions until 2020. A reduction of energy generation is illustrated as the most important measure. Due to the long-term effects of decisions in the energy sector and due to the political targets or visions for 2050, several institutes calculated scenarios with a 80–100 percent energy supply by renewables (Zervos et al., 2010; Klaus et al., 2010). These studies mainly focus on the feasibility of a 100 percent supply based on renewable energies. However, the total costs of the electricity supply for the scenarios are not estimated in these studies. Ackermann and Troester (2009) is another example for a feasibility study for 2050 that focuses on the technical feasibility of a 100% power supply by renewables that explicitly takes transmission constraints of the electricity grid into account. Results of this study include: the need for a significant grid extension and the feasibility of a 100 percent renewable based electricity supply in Europe in order to reach 2050 goals.

Schlesinger et al. (2007) concentrate on modeling a cost-efficient transformation to a low carbon energy system. The study demonstrated among others how the usage of nuclear power plants can reduce economic costs while reducing CO₂ emissions. Nitsch and Wenzel (2009) as well as Kirchner et al. (2009) calculated scenarios with high renewable shares and a reduction of greenhouse gas emissions of at least 80 percent until 2050. The studies draw different conclusions concerning the effects of challenging CO₂ reduction targets on prices and total costs. Nitsch and Wenzel (2009) calculated increasing prices until 2024 and decreasing prices afterwards, due to a decrease of costs of renewable energy technologies after 2024. Kirchner et al. (2009) estimated higher electricity prices among others as a result of climate protection measures.

In our study “Scenarios for an Energy Policy Concept of the German Government” a greenhouse gas reduction of 80% and up to 95% for the electricity generation in the scenarios I–IV until 2050 is modeled. The results are based on a long-term investment and dispatch model of the European electricity markets (see Section 3). Feedback loops and interdependencies between the electricity market and the rest of the economy are taken into account.

3. Methodical approach

Greenhouse gases are emitted in several sectors of an economy: households, industries, trade and commerce and the transportation sector. An analysis on the reduction of greenhouse gas emissions in an economy while maintaining cost-efficiency requires a simultaneous analysis of all sectors. Reasons are differing CO₂ abatement costs in sectors as well as the efficient allocation of scarce input factors, such as biomass, between the sectors. For example, the transportation sector highly depends on liquid biomass if climate goals are to be achieved.

In the study, simulation models were used to analyze the effects in the specific sectors (Schlesinger et al., 2010; Distekamp et al., 2004). For the computations of the electricity and cogeneration system, a long-term investment and dispatch model for the European electricity and combined heat markets (DIME) is used. DIME is a dynamic optimization model that calculates a cost-minimal solution to meet electricity demand in Europe. A linear optimization model for renewable electricity integration (LORELEI) is used to construct cost-based developments of renewable expansion for Germany until 2050.

The interdependencies between the electricity sector and the rest of the economy are taken into account using an iterative approach. In order to find a consistent solution for achieving challenging greenhouse gas reduction targets, relevant variables are interchanged between the different models. For modeling the electricity and cogeneration systems, variables are iterated between the demand development estimation models (Schlesinger et al., 2010) and DIME. In DIME the demand for electricity and cogeneration is used as an input parameter. Some DIME results including the district and process heat generation, the German import and export balance of electricity generation and electricity prices are analogically used as input parameters to model the demand developments. This approach accounts for the interdependency between electricity prices and demand. The macroeconomic effects due to the developments in the electricity sector are modeled based on the investments and electricity prices in DIME.

3.1. Dispatch and Investment Model for Conventional Technologies

DIME is a linear optimization model for the conventional European electricity market. It is applied to simulate an hourly dispatch of conventional power plants leading to investment decisions regarding the supply side of the electricity sector. The objective function minimizes total discounted system costs.

Input parameters can be divided into three groups: demand side parameters, supply side parameters and political parameters. The demand met by conventional generation is called residual demand, which essentially is given by total demand minus the RES-E generation.³ The RES-E generation is computed in LORELEI (see next section).

Important input parameters for the supply side include the costs of generation (investment costs, operation and maintenance costs, fuel prices), technical parameters of conventional generation technologies (including minimum load, net efficiency and start-up times) and the amount of conventional capacities already existing within a country. Cross-country electricity transmission is constrained by net transfer capacities (NTC) as exogenous model parameters. Political input parameters include decisions on nuclear policy or the different RES-E regimes in the European countries.

³To be precise, electricity generation from waste and small-scale CHP technologies are also treated exogenously.

The timeframe of the model is from 2008 to 2050 in five-year steps. The dispatch of each year is represented by three typical days per season considering load and renewable generation – each day consists of 24 hours. Important model outputs are the structure of electricity generation, investment in power plants and long-run marginal costs of electricity generation.⁴

3.2. Optimization Model for Renewable Energies

LORELEI is a linear optimization model for renewable electricity deployment. Within the scenarios LORELEI is used to construct cost-based developments of renewable expansion for Germany until 2050. This includes the following elements: current renewable capacities as well as expected investments in coming years (until 2020) were taken into account as exogenous model inputs; long run capacity expansion (2020-2050) derived from cost minimization with LORELEI. Regarding the various renewable energy technologies, a number of specific assumptions were taken into account as will be discussed in subsection 4.2.

Important input parameters include the technical RES-E potential in every country, current and prospective RES-E generation costs and the amount and structure of already existing RES-E capacities within each country. In addition, current and prospective technical parameters of RES-E technologies are input parameters for the optimization process. Furthermore, the optimal RES-E deployment depends on the particular scenario. Under a quota system, capacities of a specific RES-E technology are constructed as long as the sum of marginal generation costs and certificate price exceed the generation costs of this specific RES-E technology.

Under a feed-in-tariff system, the investment decision for RES-E capacities is based on the difference between generation costs of a specific technology in a specific country and the tariff for this technology within this country. In addition, spot prices can also be decisive for investments under a feed-in-tariff system in the case that they exceed both the generation costs and the feed-in-tariff. This is more likely to happen in the long run under feed-in-tariff systems with substantial depression rates, when additional generation costs decrease due to learning curve effects. LORELEI outputs are the RES-E capacities built in every country, as well as the corresponding generation. Total variable and fixed costs of RES-E technologies also result from LORELEI calculations.

4. Political and economic assumptions for the electricity sector

4.1. Electricity demand and potential for cogeneration

The net electricity demand is assumed to decrease in all scenarios. In the reference scenario the reduction amounts to 6 percent until 2050. In the scenarios IA–IVB net demand will be reduced by 20 percent

⁴Marginal costs of electricity generation are estimated on the basis of the dual variables of the equilibrium conditions.

(scenario IV A) to 24 percent (scenario IB). Table 2 shows the assumed net as well as gross electricity demand for the different scenarios. The assumed consumption due to the extensive usage of electric mobility is overcompensated by the effects of the supposed investments in energy efficiency technologies of households as well as industries.⁵

Table 2: Net and (gross) electricity demand in TWh

Scenario	2008	2020	2030	2040	2050
Reference	537.6 (614.0)	507.1 (596.2)	497.6 (556.0)	503.3 (562.4)	503.7 (555.1)
I A	537.6 (614.0)	495.4 (552.7)	458.1 (507.8)	433.2 (475.0)	408.1 (440.6)
II A	537.6 (614.0)	496.3 (550.3)	468.2 (514.9)	448.9 (491.9)	427.5 (459.2)
III A	537.6 (614.0)	496.9 (551.4)	469.5 (514.1)	450.0 (491.7)	426.6 (459.2)
IV A	537.6 (614.0)	496.2 (551.0)	467.9 (512.2)	448.2 (488.1)	427.7 (463.1)
IB	537.6 (614.0)	491.7 (548.7)	457.6 (508.0)	432.8 (476.9)	406.7 (440.7)
IIB	537.6 (614.0)	493.2 (548.6)	467.7 (515.9)	449.5 (492.8)	426.0 (458.0)
IIIB	537.6 (614.0)	495.8 (552.6)	468.3 (515.7)	450.0 (494.3)	426.7 (459.5)
IV B	537.6 (614.0)	489.0 (546.8)	458.0 (505.7)	443.0 (486.7)	429.0 (463.3)

The shift to a mostly renewable based electricity generation leads to a significant reduction of the internal power consumption (−92 percent). The power losses in other conversion sectors decrease mainly due to the reduced coal extraction. Therefore, gross electricity demand decreases even more than net electricity demand.

The assumed demand for district heating decreases in the scenarios over time (−60 to 63 percent) as well as process heat in industries (−4 to 12 percent). For district heating, the usage of energy efficient technologies leads to a lower demand for heat in general. This holds true especially for the trade and commerce sector: less than 80 percent in 2050 compared to 2008. In 2050, industries account for 47–57 percent, the trade and commerce sector for 13 percent and private households for 30–40 percent. The potential demand for process heat decreases due to the supposed industrial structural change and progress in efficiency of material usage. Table 3 shows the potential for cogeneration in the scenarios for Germany.

⁵The electricity demand was modeled bottom-up by Prognos as described in Schlesinger et al. (2010).

Table 3: Potential for cogeneration (district and process heating) in TWh

Scenario	2008	2020	2030	2040	2050
Reference	129.8 (202.9)	124.6 (193.4)	118.0 (195.6)	108.9 (203.3)	99.3 (214.1)
I A	129.8 (202.9)	117.9 (196.5)	95.5 (192.7)	72.0 (191.8)	51.9 (194.4)
II A	129.8 (202.9)	114.8 (194.6)	94.3 (187.3)	73.3 (182.1)	54.9 (180.9)
III A	129.8 (202.9)	114.9 (196.6)	94.3 (187.3)	73.3 (182.1)	54.9 (180.8)
IV A	129.8 (202.9)	113.1 (194.0)	87.1 (188.3)	64.4 (185.0)	47.2 (180.1)
IB	129.8 (202.9)	117.9 (196.8)	95.5 (193.4)	72.0 (192.7)	51.9 (195.2)
II B	129.8 (202.9)	114.8 (194.6)	94.3 (187.6)	73.3 (182.6)	54.9 (181.6)
III B	129.8 (202.9)	114.9 (194.5)	94.3 (187.2)	73.3 (182.2)	54.9 (180.9)
IV B	129.8 (202.9)	113.7 (194.1)	87.7 (188.4)	65.0 (184.6)	47.1 (178.8)

4.2. Potential, costs and full load hours RES-E

The development of renewable energies in the different scenarios takes place depending on different technical as well as economical potentials in the European countries.

Using the example of Germany the potential for additional hydro power capacities is limited. The utilization of biomass for electricity generation is assumed to be bounded (41 TWh) due to the consumption of liquid biomass as a substitute for oil in the transportation sector. No potential limit for solar based electricity generation is assumed. Since the most favorable onshore wind sites are already utilized in Germany, an extension potential in the long run is only achievable by the repowering of the existing wind turbines. No limit is assumed in the scenarios regarding electricity generation by offshore wind sites.

Table 4 shows the assumed development of investment costs for renewable energies. Due to a higher production rate and technology improvements, the investment costs for renewable energies decrease over time.

Table 4: Investment costs for renewable technologies in $\text{€}_{2008}/\text{kW}$

	2020	2030	2040	2050
Large hydro power	3,850	4,180	4,950	5,500
Small hydro power	2,750	2,970	3,080	3,190
Onshore wind sites	1,030	985	960	950
Offshore wind sites	2,400	1,670	1,475	1,350
Photovoltaics	1,375	1,085	1,015	1,000
Biomass	2,300	2,200	2,125	2,075
Geothermal power	10,750	9,500	9,000	9,000
Concentrated solar power	4,188	3,677	3,064	2,554

4.3. Extension of grid infrastructure in Germany and Europe

The scenarios are based on the assumption that the national electricity grids as well as the cross-border transmission capacities in Europe will be expanded significantly. An expansion of the European electricity

grid is pivotal to achieve a single European electricity market, supports the integration of renewable technologies, as well as the overall stability of the German and European electricity system. Table 5 gives an overview of the assumed expansion of the net transfer cross-border capacities in Europe.

Table 5: Electricity grid extension (based on NTC calculations)

< 1,500 MW	1,500–4,000 MW	> 4,000 MW
POR–ES	UK–BEL	ES–FR
NED–BE	BEL–FR	FR–IT
BE–GER	CH–FR	IT–CH
GER–DEN	DEN–NOR	FR–UK
GER–CZ	GER–SWE	FR–GER
CZ–AUS	GER–POL	CH–GER
AUS–POL	POL–RUS	IT–AUS
SWE–POL	POL–LIT	AUS–GER
POL–SLO	POL–BEL	
AUS–SLO	POL–UKR	
AUS–HUN		
AUS–CRO		
CRO–IT		

The main focus of grid expansion in the scenarios is the connection of Scandinavia and the United Kingdom to central Europe, the enhancement of net transfer capacities between the Iberian Peninsula and France as well as the interconnections between Italy and the Alps region. The net transfer cross-border capacities in Europe are assumed to triple until 2050 which is similar as in Ackermann and Troester (2009). Additionally, a significant improvement of the national grids until 2050 is supposed. The grid extension and Europe-wide network enables electricity transfer from solar sites at the Mediterranean and wind power stations in Northern Europe. This allows compensating or supporting conventional generation by imports from wind and solar power stations in periods with high demand. Hence, the grid extension contributes to assure enough capacity to meet peak demand.

4.4. Fuel and CO₂ prices

Table 6 shows the fuel prices assumed for power plants and CO₂ prices in the scenarios. 2008 was known as a high energy price year. The fuel prices are based on international market prices and transportation costs to the power plants. The coal price is assumed to decrease in the mid term but to increase in the long run up to 3.9€/GJ. For domestic lignite a constant price (0.4€/GJ) is assumed. Despite the currently existing excess supply and low prices of natural gas we assumed a significant increase up to 8.8 €/GJ. Price for biomass is assumed to increase to 13.9€/GJ. Total CO₂ emissions depend on various drivers such as RES-E feed-in, utilization of nuclear power, electricity demand and fossil fuel generation mix. Consequently, CO₂ prices differ slightly between the scenarios (IA–IV B).

Table 6: Fuel costs in €₂₀₀₈/GJ and CO₂ prices in €₂₀₀₈/t CO₂

	2008	2020	2030	2040	2050
Coal	4.8	2.8	3.0	3.3	3.9
Lignite	0.4	0.4	0.4	0.4	0.4
Natural Gas	7.0	6.4	7.2	8.0	8.8
Biomass	8.3	12.0	13.9	13.9	13.9
CO ₂ price (ref. scenario)	22.0	20.0	30.0	40.0	50.0
CO ₂ price (IA–IV B)	22.0	18.6–23.3	35.7–42.8	55.3–58.8	74.1–75.6

4.5. Technical and economic parameters for power plants

Several assumptions were made regarding the development of investment costs and technical parameters such as the lifetime of conventional power plants. Technologies not in use today: Coal 'innovative': 4 percent higher net efficiency as state of the art power stations from today; lignite 'innovative': novel drying process leads to a net efficiency of 48 percent; and CCS-technologies: available from 2025 with lower net efficiencies than technologies without CCS. Table 7 shows the assumed investment costs for new conventional power plants over time.

Table 7: Investment costs for conventional power plants in €₂₀₀₈/kW

	2020	2030	2040	2050
Lignite	1,850	1,850	1,850	1,850
Lignite (innovative)	1,950	1,950	1,950	1,950
Coal	1,300	1,300	1,300	1,300
Coal (innovative)	2,250	1,875	1,763	1,650
CCGT	950	950	950	950
OCGT	400	400	400	400
IGCC-CCS	-	2,039	1,985	1,781
CCGT-CCS	-	1,173	1,132	1,020
Coal CCS	-	1,848	1,800	1,751
Coal-CCS (innovative)	-	2,423	2,262	2,101
Lignite-CCS	-	2,498	2,450	2,402

The scenarios I–V were computed with two different sets of retrofit costs for nuclear power plants. In the scenarios “A”, retrofit costs were assumed to be 25 €/kW per additional year of operational time extension. In the “B” scenarios, the retrofit costs for nuclear power plants are specific to the plant. Table 8 presents the retrofit costs in both the A and B (in brackets) scenarios.

Table 8: Retrofits costs for nuclear power plants for A and (B) scenarios in €₂₀₀₈/kW

	Scenario I	Scenario II	Scenario III	Scenario IV
Neckarwestheim 1	100 (0)	300 (764)	500 (2,038)	700 (3,057)
Biblis B	100 (81)	300 (484)	500 (1,371)	700 (2,016)
Biblis A	100 (86)	300 (514)	500 (1,457)	700 (2,142)
Isar 1	100 (114)	300 (683)	500 (1,936)	700 (2,847)
Philippsburg 1	100 (112)	300 (674)	500 (2,022)	700 (2,921)
Unterweser	100 (74)	300 (446)	500 (1,338)	700 (1,933)
Brunsbüttel	100 (130)	300 (778)	500 (2,335)	700 (3,372)
Grafenrheinfeld	100 (78)	300 (941)	500 (1,569)	700 (2,196)
Gundremmingen B	100 (78)	300 (1,012)	500 (1,636)	700 (2,259)
Gundremmingen C	100 (466)	300 (1,087)	500 (1,708)	700 (2,329)
Philippsburg 2	100 (431)	300 (1,149)	500 (1,724)	700 (2,299)
Grohnde	100 (441)	300 (1,176)	500 (1,765)	700 (2,353)
Brokdorf	100 (438)	300 (1,241)	500 (1,825)	700 (2,409)
Krümmel	100 (449)	300 (1,273)	500 (1,873)	700 (2,472)
Isar 2	100 (429)	300 (1,286)	500 (1,857)	700 (2,429)
Emsland	100 (451)	300 (1,354)	500 (1,956)	700 (2,558)
Neckarwestheim 2	100 (920)	300 (1,533)	500 (2,146)	700 (2,759)

5. Scenario Results 2050

The challenging climate protection goals lead to a structural change of the German and European electricity generation mix. This section highlights selected results for 2050 in comparison to 2008.

The contribution of renewable technologies increases significantly, especially in scenarios I to IV. This leads to a gross electricity share of renewables of 77 to 81 percent in the scenarios I to IV (trend scenario: 54 percent). Largely, the development of offshore wind energy sites is the driver for a higher generation by renewables in Germany.

The shift to a mainly renewable based electricity generation mix leads to a significant reduction of CO₂ emissions in the German electricity sector (96 to 97 percent in the scenarios I to IV).

Due to the assumed continuance of national renewable policies in Europe until 2020, the electricity generation of photovoltaics increases (continuance of a feed-in-tariff system) in Germany in the first ten years of the modeled horizon. Afterwards, the assumed cost-efficient European renewable support scheme leads to very low growth rates for photovoltaics in Germany, as specific costs of solar-based energy generation are significantly lower in Mediterranean countries.

The potential of biomass is limited by different land usage opportunities as well as future settlement dispersion. The available potential also faces usage opportunities: the bulk of biomass is required in the mobility sector where other substitution options are scarce. The remaining biomass potential is used for electricity generation.

Main reasons for the reduction of CO₂ emissions in Germany beside the increase in renewable feed-in are:

- reduced electricity demand especially in Germany, but also a slow-down of demand-growth in the other European countries;
- change in fossil fuel based generation (CCS-technologies);
- an increase of net imports (mainly nuclear power and renewables).

The total share of electricity generation by conventional power plants decreases from 84 percent in 2008 to 19 to 24 percent in the scenarios I to IV in 2050. Fossil fuel generation mainly takes place in highly efficient coal-fired power plants with carbon capture and storage in 2050. These plants are designed for combined heat and power generation to achieve higher overall fuel efficiency levels. Furthermore, it allows for an increase in plant utilization, as revenue streams from electricity generation alone may not be sufficient to cover the significant investment costs of such plants. Figure 1 shows the electricity generation structure in Germany in 2050 for the different scenarios.

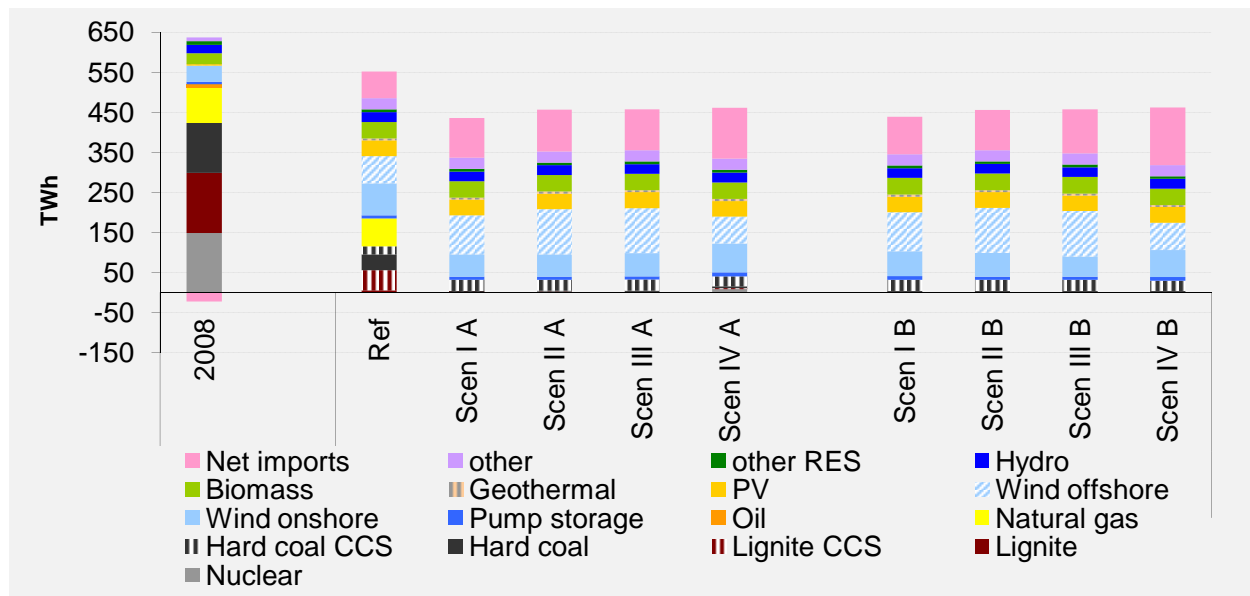


Figure 1: Electricity generation by fuels in TWh

In all scenarios the net imports of Germany increase significantly compared to the year 2008. In the scenarios I to IV the share of net imports accounts for 22 to 31 percent in 2050 (reference scenario: 12 percent). The imports follow from the cost-efficient approach to reach reduction targets and are based

on two main assumptions: the supposed coordinated extension of the European electricity grid and the European-wide cost efficient renewable support policies beginning by 2020.

Both assumptions lead to a different spatial electricity generation pattern compared to today. Marginal cost-wise, the cheapest conventional generation option is nuclear power and the cheapest renewable generation technologies are wind energy sites in UK and solar based technologies in Southern Europe, especially the Mediterranean. Both generation options are not available in Germany in 2050. This leads to a situation in which a significant part of the German electricity demand is met by imports from European countries with more cost-efficient generation options.

In the reference scenario, the higher CO₂ and fuel prices and the larger share of renewables lead to an increase of electricity generation costs and therefore to an increase in wholesale prices and to a slight increase in retail prices compared to the year 2008.

Wholesale prices in the scenarios I to IV are lower than in the reference scenario for several reasons. First, as electricity demand is lower in all of Europe in 2050, the need for covering peak demand spikes is reduced. Second, the strong increase in renewable energy feed-in leads to many periods in which renewables are price setting in the wholesale market, which means that wholesale prices are zero during these hours. Third, the large-scale expansion of the European transmission grid makes it possible that the different renewable sources can partly balance each others intermittent feed-in characteristics. This portfolio effect enables that the remaining fossil plants can be dispatched more efficiently than today, which reduces their long-run marginal costs.

However, retail prices in the scenarios I to IV are similar to the prices in the trend scenario.⁶ This is mainly due to higher costs for renewable support, which outweighs the positive price effects in the wholesale market.

6. The transformation of the electricity market until 2050

The challenging climate protection goals lead to a structural change of power plant capacities over the next 40 years. Despite decreasing electricity demand, gross capacity installed increases in the short and medium term. This development is due to the transformation to a renewable based and Pan-European power mix (25 percent RES-E in 2008 and 67–70 percent in 2050).

⁶Exceptionally, the retail price for large industries is lower due to the high influence of wholesale prices for these industries (considering exceptional rules).

6.1. The impact of an extension of operating time for nuclear power plants

The main difference between the scenarios I–IV A is the extension of the operating time for nuclear power plants in Germany. In scenario I A all German nuclear power plants will have been decommissioned in 2030 whereas in scenario IV A some nuclear power plants will still be utilized in 2050. Due to the operating time for nuclear power plants, the power plant mix, capacity utilization and the gross electricity generation differs between the scenarios. Nuclear power plants are the cheapest option for baseload electricity generation, thus the maximum possible prolongation of operational time is always used in these scenarios. In this setting retrofit costs of 25€ per kW and operational year were assumed.

Renewable energies – especially wind and solar technologies – contribute less to cover peak demand than conventional power plants. Therefore, back-up capacities are needed to ensure that demand can always be met. Consequently, total installed capacity increases in the medium term and stagnates or slightly decreases in the long term. Figure 2 shows the installed capacities in the scenarios I–IV until 2050.

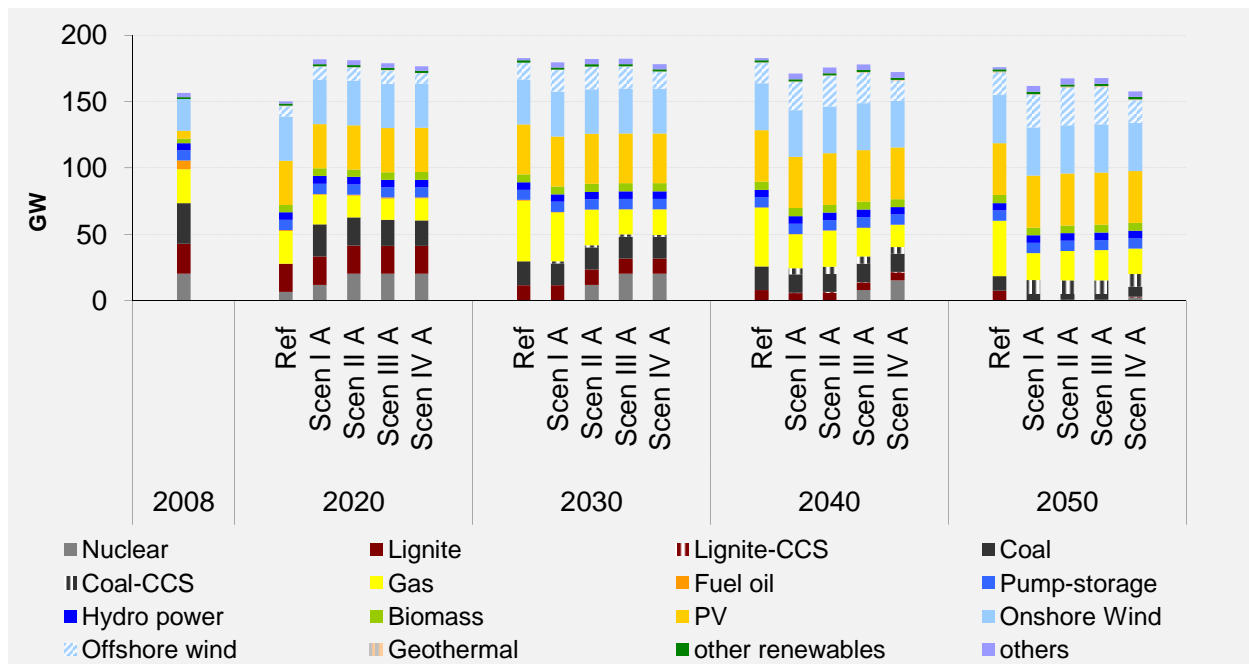


Figure 2: Installed capacities by fuel in GW

The phase out of nuclear power plants causes an additional need for capacity in the short and medium term in the respective scenarios. In general, these capacity requirements are either met by longer economic lifetimes of existing installations or the commissioning of new gas fired power plants. The reasons are higher utilization rates realized by other plants and higher power prices, both supporting the profitability of other

capacity, if less nuclear capacity is in the market. Both decreased net exports of electricity and increased domestic generation from fossil fuel based power stations contribute to the substitution of nuclear power.

While Germany is still a net exporter of electricity in 2020, significant amounts of electricity are imported in 2030. Shorter prolongations of nuclear power lead to fewer net exports in the short and medium term. Furthermore, gas fired plants increase their utilization in scenarios with shorter operation times of nuclear power stations (e.g. scenarios IA and IIA). Electricity generation by conventional power plants decreases continuously until 2050 due to the high feed-in of RES-E into the European power system. While gas and lignite play a minor role in electricity generation in the long run, a certain amount of coal plants remain profitable. Coal fired plants gain a cost advantage compared to gas and lignite in the long run for a number of reasons: relatively low hard coal prices; lignite has a disadvantage compared to hard coal in CHP generation due to the location of mine-mouth lignite plants⁷; high carbon prices penalize lignite fired plants stronger since CO₂ capture rates of CCS plants are below 100 percent.

Electricity generation by renewables increases significantly over time. Until 2020 a national support scheme for RES-E in Germany is assumed allowing for an expansion of PV capacities. From 2030 onwards, the assumed coordination of European RES-E policies leads to a strong increase of wind generation in UK and solar power at the Mediterranean. Due to the expansion of the European transmission network increasing amounts of electricity can be imported. In Germany, the majority of domestic RES-E is windpower: both onshore and offshore.

The phase out of nuclear power increases the utilization rates of fossil fuel based plants. In the long run average utilization rates of coal fired power plants increase compared to 2008. Compared to 2008, lignite-fired plants realize less full load hours on average. Generally, old hard coal and lignite power stations are used as back-up technologies and therefore realize low utilization rates. On the other hand the utilization rate of newly installed coal and lignite plants with CCS is above average. Although gas fired power plants contribute significantly to the substitution of nuclear power in the short term, their utilisation rate decreases over time and only operate in a few hours in the long run. This is due to two effects: the clean spark spread becomes increasingly unfavourable for gas plants and the volatile infeed of renewables requires large amounts of back-up capacity, which is provided by cheap gas turbines. These plants recover their investment costs through a peak load or capacity price mechanism. Such a mechanism is implemented in the used electricity market model: In periods when capacity is scarce, i.e. the restriction of required minimum capacity for peak load coverage is binding, the modeled generation capacity earns a scarcity rent. This rent corresponds

⁷The transport of lignite is usually not cost-effective due to its low calorific value.

to the shadow price of the peak load capacity constraint in this period. The cost minimization mechanism consistently assigns shadow prices according to the input involved. Therefore, the capacity scarcity rent is exactly high enough to remunerate investment costs of the least utilized peak load plant over the plant lifetime.⁸

Turning back to the model results, Figure 3 shows the retail prices for households, trade and commerce, industries and energy intensive industries in the scenarios. The end consumer prices consist of the wholesale and sales component, a grid usage tariff, a levy for additional renewable costs and taxes. The differences between the end consumer groups depend on the amount of consumed electricity, the demand structure and different regulations concerning taxes and levies in Germany. For example, a limit for the renewable based levy applies for industries and energy intensive industries are entirely exempt from this levy.

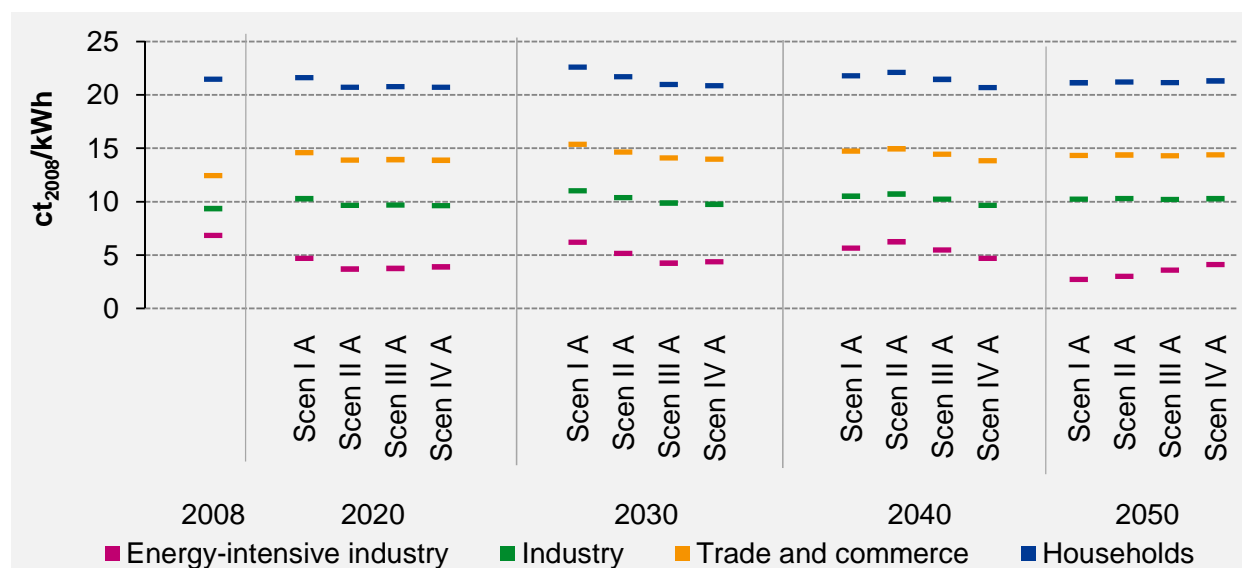


Figure 3: Electricity prices for end-consumer in ct_{2008}/kWh

The retail prices for all consumer groups increase in the scenarios until 2030 and then decrease to a similar level as today in 2050. In the short run retail prices increase due to the much higher generation costs for renewable energies compared to fossil fuels. In the long run the import option and the learning curves of renewable energies lead to a price decrease until 2050. In general, shorter operational times of nuclear power plants lead to higher prices particularly in the short and medium term. In the long run prices are

⁸There are various market designs that could support such capacity payments. One example could be market-driven price spikes, whose duration, height and frequency lead to investment cost recovery for all plants in the long run, subject to potential competition with new entrants. Another example could be regulated capacity markets, e.g. through auctioning of the required minimum capacity to securely cover expected peak load. The issue of choosing an optimal market design to support efficient investment in generation capacity is clearly a field where additional research is needed (Finon and Pignon, 2008; Moreno et al., 2010).

similar in all scenarios but highest in scenario IV A due to catch-up effects concerning the substitution of nuclear power.

6.2. The impact of different retrofit investment costs

The scenarios I–IV were computed with two different sets of retrofit costs as shown in table 8 (subsection 4.5). In scenario I–IV A the option to prolong the operational time for nuclear power plants was taken for each nuclear power plant. For higher retrofit cost this is not the case. Figure 4 shows the maximal possible extension and the installed capacities (retrofit option taken) in the scenarios I–IV B. Shorter prolongations are associated with relatively lower retrofit costs and therefore are more profitable than longer extensions (e.g. scenario IB in comparison to IV B). The analysis of the impact of different retrofit costs shows similarities with the analysis of different operational times. The nuclear power capacities decommissioned due to the higher retrofit costs in the scenarios I–IV B are also substituted by coal and gas capacities. In the short term a higher utilization of conventional power plants substitute the generation by nuclear power plants. This is backed by additional electricity imports and lower exports (in 2020).

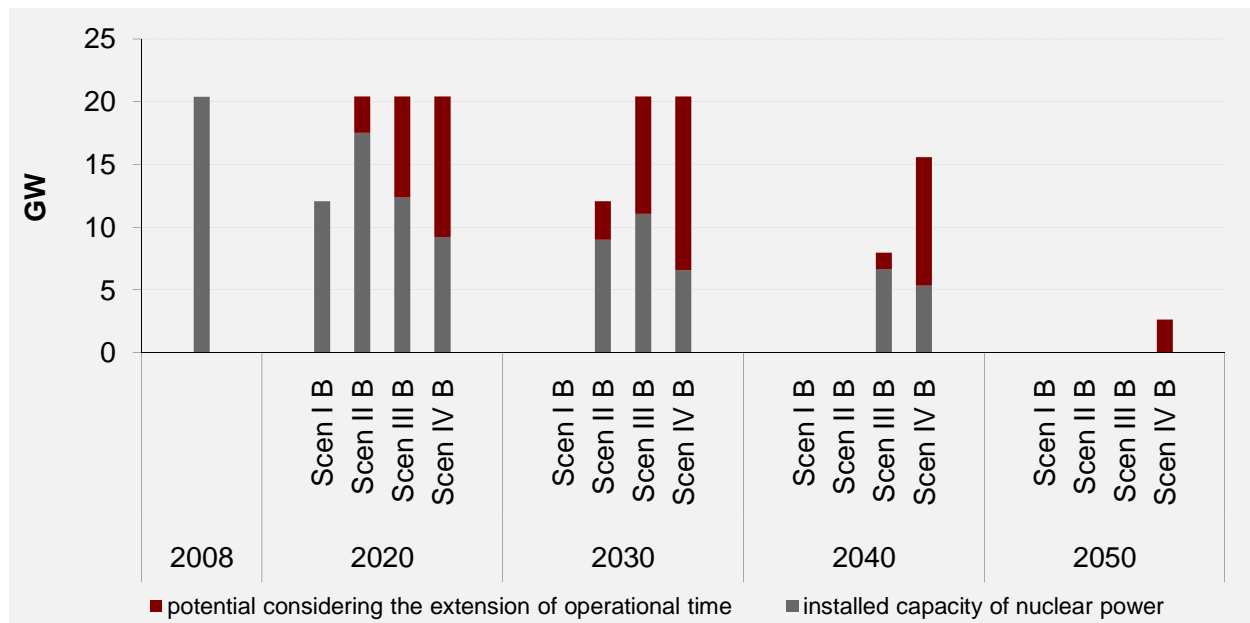


Figure 4: Installed capacities of nuclear power plants in GW

Higher retrofit costs and therefore less prolonged nuclear power stations have several inflating impacts on wholesale prices (as compared to scenarios I–IV A). Decommissioned nuclear power plants need to be replaced by either investments in new power plants, a higher utilization of existing capacity or imports (or lower exports as in 2020). Investments in new installations increase the marginal costs in the long term.

Furthermore, retrofit investments have to be recovered by nuclear plants and thus increase long run marginal costs of this technology. Due to the merit order effect power stations with higher marginal costs are more often price setting and therefore the wholesale price is higher. As discussed above, nuclear power generation is substantially replaced by additional gas based generation. This leads to higher marginal costs due to relatively high variable costs of gas power stations.

7. Conclusions

The CO₂ reduction targets are achieved as required by political request in the scenarios I-IV A/B and electricity prices remain relatively stable over time. Although prices increase in the long run due to the ambitious CO₂ reduction targets, the increment is surprisingly low. Thereby, the power system needs to change substantially from a national to a supranational- and from a fossil-fuel based to a renewable based energy system. However, the extension of the European electricity grid, an international climate protection agreement as well as the European coordination of renewable policies are major conditions for the transformation of the electricity market as described in this paper. Each single one of them is undeniably a great challenge.

An international climate protection agreement in the short or medium term is important to provide similar conditions for industries in a globalised business environment. A reliable decision on the operational time of nuclear power plants in Germany is needed to provide planning reliability for investors in power plants as the political uncertainty causes higher generation costs due to higher market risks. Pricing mechanisms need to focus more on back-up and balancing capacities as well as the integration of renewable energies. An expansion of the European electricity grid is key to achieve a single European electricity market. Moreover, such a grid supports the integration of renewable technologies and contributes to the overall stability of the German and European electricity system. The Europe-wide coordinated development of renewable energies is important to minimize the additional costs of renewable generation. The technical, legal and political requirements for a commercial use of power plants with carbon capture and storage need to be resolved. A decreasing energy demand over all sectors in Europe is crucial to achieve CO₂ reduction targets and political action is needed to initiate energy efficiency investments and behavior. The realization of such a long-term ambitious energy concept requires coordinated political and economic actions. However, perhaps even more important is a social consensus about the need of an environment-friendly energy system with economically justifiable prices and a secure supply. Without such social consensus, it is inconceivable that society would be willing to accept such extraordinary burdens and risks to achieve climate protection targets.

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