McKinsey&Company

Electric Power and Natural Gas Practice

Transformation of Europe's power system until 2050

Including specific considerations for Germany

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Preface

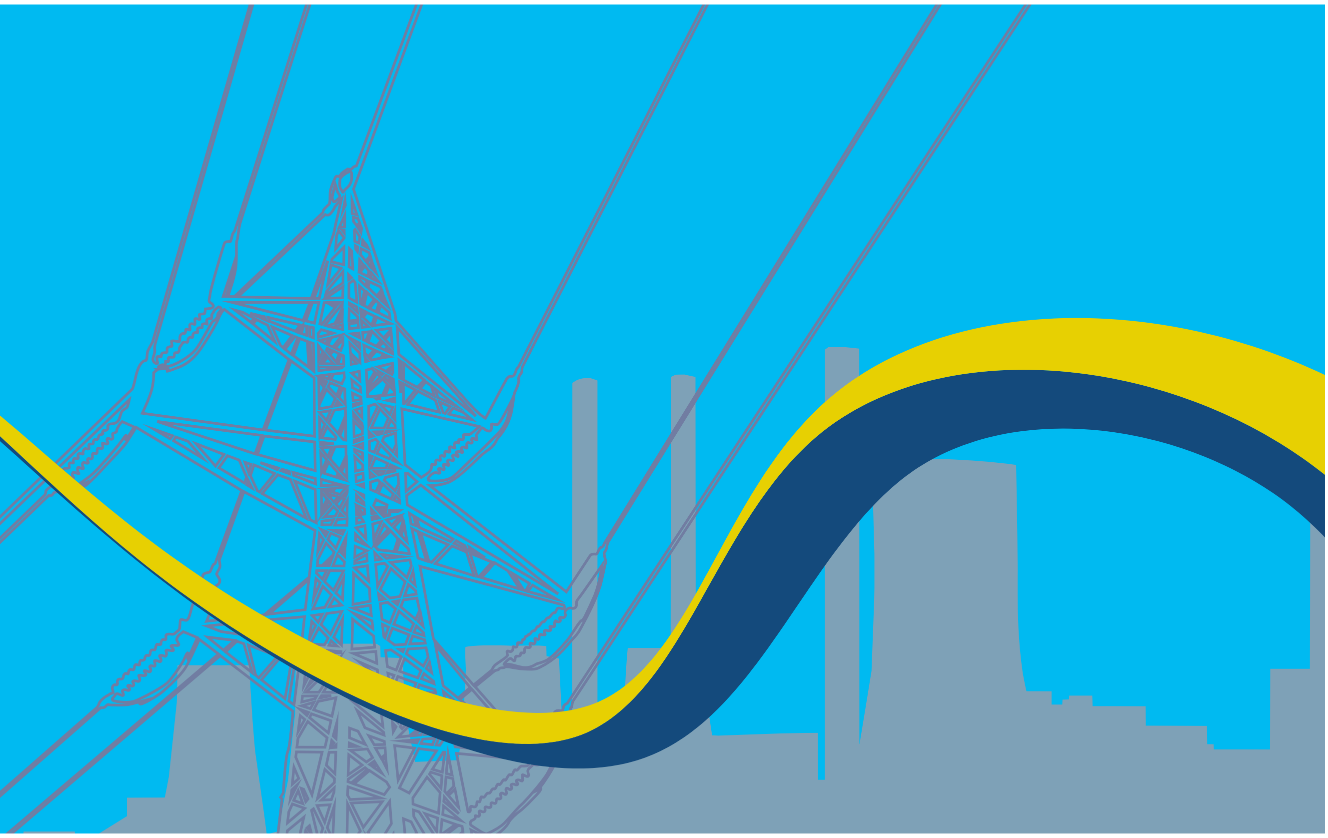
This report summarizes the main results of a study of potential developments of the European power sector for the years 2020 to 2050. It was prepared by McKinsey & Company, Inc., and supported by various academic institutes.

The purpose of this report is to provide a factual basis for discussions of European and national energy master plans. The underlying study built on different scenarios in order to understand implications of reaching emission reduction targets as recently proposed by the European Union (e.g., reduction of greenhouse gas emissions to 80 percent below 1990 levels in Europe by 2050) as well as of achieving an 80 percent renewable share in European power generation in 2050. Key messages have been derived for Europe and for Germany in particular.

The report does not address specific policies, political platforms, or governmental interventions. Instead, it offers an objective, fact-based analysis that uses scenarios as a starting point for discussion and agreement among stakeholders on the best way to manage Europe's transition to a low-carbon power system.

The results presented in this report are not meant to be recommendations, but rather descriptions of potential future outcomes under certain assumptions. We are aware that these assumptions are subject to ongoing changes over the next decades (e.g., licensing timelines, public acceptance of certain technologies) and therefore recognize potential changes and sensitivities. In order to be transparent, we have included one chapter that reveals main inputs as well as describes the models we have built and used for our analyses. Please do not hesitate to contact us for clarifying questions or deeper discussions.

Düsseldorf, October 2010



Summary of findings

The transformation of the European power system has started and is going to continue for many years to come. Fundamental changes are happening in European power demand and supply. Both Europe's and Germany's current transformation paths are leading to unnecessarily high cost. A cost-optimal transformation requires coordinated European action, and Germany in particular needs to rethink its options for transforming its power sector in a European context.

Three cost-optimal European pathways until 2050 compared with current power sector development

The evolution of the European[1] power sector until 2020 is largely predefined by the commitment of the European Union to reach a set of sustainability targets. These targets are known as the "20-20-20 targets." They consist of a reduction in EU greenhouse gas emissions of at least 20 percent below 1990 levels, a share of 20 percent of EU energy consumption to come from renewable sources, and a 20 percent reduction in primary energy use compared with projected levels by improving energy efficiency. Given the progress individual EU member states are making toward these targets, we assume for the purpose of this study that the targets will be met.

For 2050, leaders of the European Union and the G8 announced the objective to reduce greenhouse gas emissions to at least 80 percent below 1990 levels, if other parts of the world initiate similar efforts.[2] The European power sector would need to contribute even more than other sectors to these targets and reduce its greenhouse gas emissions to more than 95 percent below 1990 levels.[3] From a purely technical point of view, these targets for 2050 can be met. However, the transformation into a low-carbon system will require the European power landscape to undergo fundamental changes. For competitive power prices, it is of the utmost importance that the transformation follows an optimal economic path.

In order to understand the key challenges and implications of this transformation for the European power sector from 2020 to 2050, we based our assessment on three scenarios that assume a Europe-wide cost-optimal investment rationale[4] across power generation and trans-regional high-voltage transmission.[5] In the first scenario, Europe achieves a 95 percent reduction in greenhouse gas emissions in the power sector in 2050 over 1990 levels ("clean" scenario[6]). In the second scenario, Europe achieves two targets by 2050: a 95 percent reduction in greenhouse gas emissions in the power sector and an additional target of 80 percent renewables-fueled power generation ("green" scenario[7]). For comparison, we defined a third scenario, for which neither greenhouse gas emission targets nor predefined renewables targets are set beyond 2020 ("lean" scenario[8]).

All three scenarios assume a Europe-wide cost-optimal investment rationale. The current development of the electric power industry in Europe, however, does not follow this optimization rationale. Therefore, we examined the deviations between our cost-optimized scenarios and the extension of the pathway currently pursued based on national renewable energy action plans. The following insights summarize key results of our analysis.

Fundamental changes occurring to European power demand and supply

Achieving both emissions and renewables targets will significantly impact the development of the European power sector. Four key developments seem most important:

Power demand grows by 40 percent until 2050. In order to achieve aggressive emission reduction targets, all CO_2 emitting sectors have to make significant improvements (e.g., increase efficiency) and many will have to shift from primary, carbon-containing fuels to electric power (e.g., electric vehicles in transportation), as shown in the report *Roadmap 2050: A Practical Guide to a Prosperous, Low-carbon Europe* by the European Climate Foundation. As a result, European power demand will increase by 40 percent until 2050, from 3,500 TWh in 2020 to 4,900 TWh. Increasing power demand from fuel shifts and penetration of new technologies (e.g., heat pumps) outweigh decreasing demand from higher energy efficiency, even though energy efficiency measures of roughly 2 percent per year are assumed.[9] The net effect is an average growth in electricity demand of 1.1 percent per year from 2020 to 2050. Even though this rate is below the 1.5 percent demand growth per year between 1990 and 2007, it is important to realize that the dependence of Europe on electric power will increase not decrease.

Renewables and possibly nuclear replace coal and gas over time. In the "green" and "clean" scenarios, conventional coal- and gas-fired power generation would almost disappear over time and would be replaced by renewable energies (including hydro) or nuclear.[10] Current nuclear new-build activities are limited, but they would be essential in a "clean" scenario to achieve the emission targets in a cost-optimal manner. Carbon capture and storage (CCS) does – at most – have some role to play as a bridging technology in selected markets in the power sector.[11] Hydro and CCGT[12] plants gain special importance as relevant storage and low-cost backup capacities. Of course with significantly lower fossil fuel prices, which have already been observed in the past, CCS-based fossil technologies, i.e., gas and coal, might play a more significant role in the future power generation mix.

Supply and demand regions decouple. With an increasing share of renewables, power generation centers will shift toward the most attractive regions in Southern and Northern Europe as well as the Middle East and North Africa (e.g., the Desertec[13] project), if a cost-optimal path is followed. Thus, current self-sufficient or export regions with energy-intensive industries such as Central Europe will become increasingly dependent on imports (e.g., Germany, see below).

Current power market pricing mechanism likely to fail. The increasing penetration of intermittent renewable power generation in the European power market is likely to have two effects. First, power price volatility will increase significantly.[14] Second, with increasing renewables penetration, average operating cost and therefore marginal generation cost[15] decrease. Our analyses show that average marginal generation cost will fall below full generation cost. This means power generators will not earn their full cost anymore and will stop investing given the current remuneration schemes. This would impose a threat to the reliability of the electric power system. As a consequence, we foresee the need for major changes to the current remuneration schemes in the power sector to ensure sufficient support for existing power plants and investments in new power plants for backup purposes.

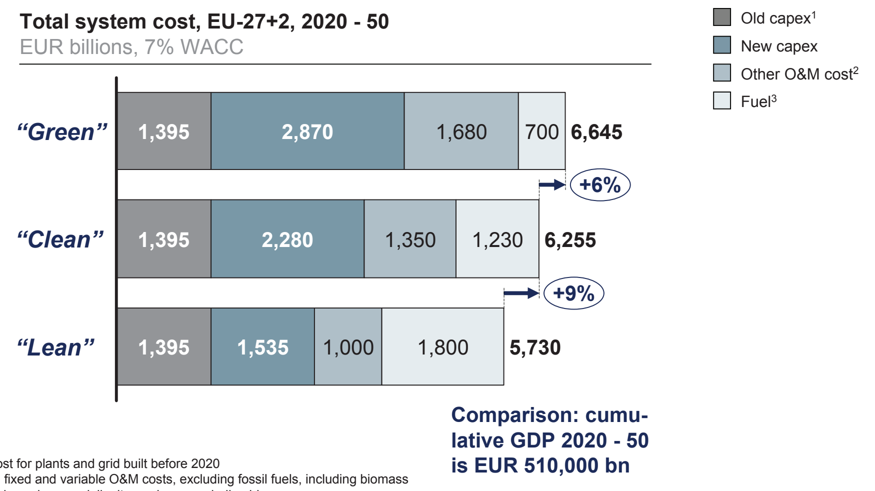
Europe's current transformation path leads to unnecessarily high cost

Reducing emissions and increasing the share of renewable energies will increase overall system costs. If executed in a cost-optimal way and with a European focus, total system cost would increase by about 15 percent in the "green" scenario compared with the "lean" scenario (Exhibit 1). However, the pathway Europe is currently following clearly deviates from the cost-optimal way and leads to additional total system cost of 30 to 35 percent on top of the "green" scenario.

Minimum additional total system cost of 15 percent in the "green" scenario. Compared with the "lean" scenario with its total system cost of roughly EUR 5,700 billion until 2050, achieving the "green" scenario would increase the total system cost of the European power sector by about 15 percent to EUR 6,600 billion. The increase is driven by achieving the two targets in the "green" scenario: achieving low emissions would add EUR 500 billion to 600 billion ("clean" scenario) and meeting the renewables target in parallel would add a further EUR 300 billion to 400 billion. The additional cost for achieving the renewables target assumes a successful execution of the Desertec project at the cost and volumes published in the white book *Clean Power from Deserts* by the Desertec Foundation. If the Desertec project cannot be implemented, the additional system cost would be EUR 300 billion to 400 billion (an additional 5 percent) on top of the "green" scenario.

Exhibit 1

Building a 95% decarbonized power sector in a cost-optimal way implies extra costs of ~ EUR 525 billion, equivalent to 9% of total system cost



1 Cost for plants and grid built before 2020
2 All fixed and variable O&M costs, excluding fossil fuels, including biomass
3 Only nuclear, coal, lignite, and gas, excluding biomass

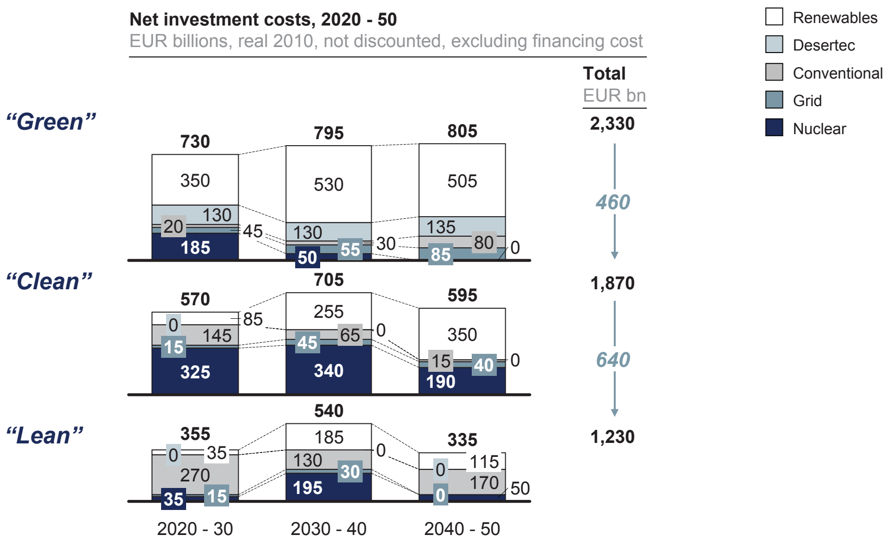
SOURCE: Desertec Foundation; McKinsey

On a yearly basis, average system cost in 2050 would rise from EUR 200 billion in the "lean" scenario to EUR 250 billion to 300 billion in the "green" scenario, constituting a 30 percent increase in the yearly system cost in 2050.

Besides the increase in system cost, it is important to realize that the cost structure of the European electric power system will change even more. The decreasing share of coal- and gas-fired plants implies that fuel costs will be replaced by investment costs for new renewables and nuclear capacities, which are more capital intensive. Capital expenditure investments from 2020 to 2050 in the "green" scenario are EUR 2,200 billion to 2,400 billion, versus EUR 1,800 billion to 2,000 billion and EUR 1,100 billion to 1,300 billion in the "clean" and "lean" scenario, respectively (Exhibit 2). The projected investments in the "green" scenario exceed the realistic investment budgets of the European power industry of around EUR 1,800 billion for that period[16]. Hence, additional sources of financing as well as investment certainty are necessary.

Exhibit 2

Net investment cost in the "green" scenario would be EUR 460 billion higher than in the "clean" scenario



SOURCE: Desertec Foundation; McKinsey

Following the current non-cost-optimal pathway leads to an additional cost increase of 30 to 35 percent compared with the "green" scenario. Europe is currently deviating from a cost-optimal approach in two aspects. First, rather than applying a European focus, every European country has its own targets, which in total do not achieve cost optimization. Second, the national plans (as defined in the national renewable energy action plans[17]) do not always pursue cost optimization in terms of type of renewable energy. If these non-optimal plans remain unchanged, they put Europe on a path where total system cost increases by 30 to 35 percent[18] compared with the cost-optimized "green" scenario. This roughly amounts to an additional EUR 2,000 billion in Europe, equivalent to the total income of 2 million families over the 30 years.[19] Compared with the "lean" scenario, the current path leads to a cost increase of 50 to 60 percent.

Cost-optimal transformation requires coordinated European action

Achieving a cost-optimal transformation in the "green" scenario requires coordinated European action because only then can cost-optimal renewables be built and capacities be connected to demand centers via the European transmission grid. In addition, only a European approach can satisfy the demand for backup capacity with limited fossil capacities at manageable cost. For the "clean" scenario, reaching a cost-optimal low-carbon solution requires large investments in nuclear generation.

Cost-optimal 80 percent renewables generation requires five times larger transmission grid capacities by 2050. Generating 80 percent of European power from renewables at optimal cost in 2050 ("green" scenario) requires a steep buildup of transmission capacities, reaching a larger than fivefold increase in trans-regional transmission capacities in 2050 compared with today. As optimal locations for wind and solar power are at the outer areas of Europe (coastal for wind and southern for solar) rather than at the center, renewable power needs to be transmitted to Central European demand centers via massively increased transmission grid capacities. Even in the "clean" scenario (40 to 45 percent renewables generation), transmission grid capacities will need to reach an almost fourfold increase in 2050 compared to today. Building these transmission grid capacities is significantly cheaper (but not easier with respect to regulation/permission and public acceptance) than placing renewables closer to demand centers but at inferior sites. Until 2020, a cost-optimal pathway would already require double the transmission grid capacities. Current European expansion plans for transmission grid capacities are only fulfilling half of this need,[20] proving that Europe is significantly deviating from a cost-optimal path. To enable optimal use of renewable energies, the total investment cost for trans-regional transmission infrastructure between 2020 and 2050 would be EUR 170 billion to 200 billion for a fivefold capacity increase. On the one hand, this contributes only 4 percent of total system cost and 8 percent of total investment cost. On the other hand, the investments will not happen without sufficient public acceptance, more efficient pan-European approval processes, and improved financial incentives.

National renewable energy action plans need to be aligned based on a European perspective. The cost-optimal approach for the "green" scenario is based on using the least expensive renewables at the best sites in Europe. However, current support for renewable energies is largely based on national targets (national renewable energy action plans), which lack pan-European coordination and often do not focus on cost-optimal solutions. A European renewable energy action plan with a pan-European coordinated approach to support the buildup of renewables is required to reach the targets in a cost-optimal way.

Old and new fossil power stations are needed to provide affordable backup capacity. The cost of keeping an old gas-fired power plant on line is only one-third the cost of building a new pumped storage facility. Further capacity extension of pumped storage is limited by availability of sites, and other potential solutions such as compressed air and hydrogen storage are estimated to be even more expensive. The impact on greenhouse gas emissions of using fossil plants for backup power would be limited as extreme weather events with high backup needs occur rarely.[21] However, in order to keep enough old power plants[22] available and build new ones over time, market mechanisms need to be adjusted. Otherwise, these valuable sources of backup power will be decommissioned and no new ones will be built.

Nuclear power provides the most cost-optimal supply option. In the "clean" scenario without a renewables target, nuclear turns out to be the most cost-optimal solution to reach low emission targets. Compared with the "green" scenario, system cost would be EUR 300 billion to 400 billion lower. In this scenario, nuclear would fuel up to 47 percent[23] of power generation in 2050 and would also be used to balance intermittent and volatile renewable capacities. In addition, 40 to 45 percent of generation in the "clean" scenario is supplied by renewables. The buildup of nuclear power will only happen if sufficient investment certainty is established. Lifetime extension of currently operating German nuclear power plants would further reduce the total system cost (but has not been assumed in our analysis for all scenarios).

Germany needs to rethink its options for transforming its power sector

We have identified three options for Germany to transform its power sector. It can try to shape a European coordinated approach ("full EU cooperation") or it can rely on an optimal national transformation ("optimized German self-sufficiency"). The first option would be cost-optimal but seems to have a low probability of success in the near to medium term given developments so far. The second option is currently being pursued, but costs are too high and need to be optimized. A third option could be a compromise between low system cost and ability to implement ("preferred partnerships").

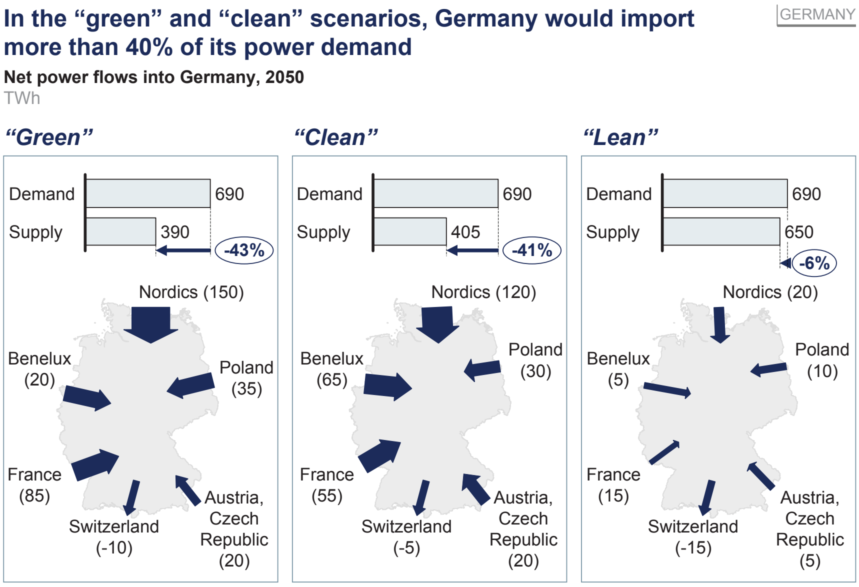
Option 1 ("full EU cooperation") requires Germany to take a shaping European role and rely on its neighbors. In the "clean" and "green" scenarios, renewable capacities are installed in the most attractive locations across Europe in order to be cost-optimal. This means that most renewable capacities are built outside of Germany. In addition, we assume that there will be no nuclear power plants operating in Germany in 2050. In combination, these two factors will make Germany dependent on imports for up to almost 50 percent (Exhibit 3) of its electric power demand in the "clean" and "green" scenarios. Hence, Germany is very exposed to European developments in these scenarios and would have to ensure that sufficient renewable and nuclear capacities are built across Europe as well as sufficient transmission capacities across Europe and into Germany.

Option 2 ("optimized German self-sufficiency") requires a comprehensive and balanced long-term plan to keep transformation cost under control. The self-sufficient "green" scenario (80 percent renewables in Germany) requires Germany to build up large amounts of renewable energies at less attractive sites. Hence, the national energy action plan for renewables needs to be adjusted and extended to achieve lower cost. In addition, Germany will need to keep conventional fossil plants operating in order to back up high-cost and intermittent renewable energies. The combination of less attractive sites for renewable energies in Germany, the nuclear phase-out, and the limited connectivity to other regions results in a 15 to 20 percent higher system cost for Germany compared with the European "green" scenario. It is important to remember that this is after optimizing current plans in Germany. If the German national renewable energy action plan is pursued and extended until 2050, additional costs relative to the "green" scenario are 30 to 35 percent, or almost twice as high as they need to be. An alternative path for optimizing cost would be to move from the "green" to the "clean" scenario as additional cost can be reduced from 30 to 35 percent to about 5 percent relative to the "green" scenario, but only if Germany adopts a massive carbon capture and storage (CCS) approach for about 50 percent of its power generation. It is worth mentioning that extending the lifetime of nuclear power plants in Germany (no new builds) would reduce overall system cost, but this would not overcome

Exhibit 3

In the "green" and "clean" scenarios, Germany would import more than 40% of its power demand

Net power flows into Germany, 2050
TWh



SOURCE: McKinsey

the challenge in the long term, since all existing German nuclear power plants would be decommissioned by 2050.[24]

Option 3 ("preferred partnerships") may be a good compromise for Germany between the cost-optimal and self-sufficiency path. In this option, Germany pushes a combination of the most economical renewable energies within Germany and starts preferred partnerships with other regions for additional wind and the most economical solar capacities. Examples of countries that could be advantageous cooperation partners include: the United Kingdom to develop significant on- and offshore wind potential, France to develop wind parks along the Atlantic coast, Southern European countries for attractive solar capacities, and Norway to further develop and optimally use large hydro reservoirs for balancing and potentially for export purposes. All these examples require grid buildup but only directly with the partner regions. Although this solution is not cost-optimal, it enables cooperation on highly attractive projects, reducing the cost for Germany compared with a go-it-alone solution. Such partnerships may also have the potential to catalyze Europe-wide solutions by attracting other countries to join the effort on the way.

□ □ □

None of these options is easy to implement. Nevertheless, it is worth the effort. If Germany were to continue along the current path of the 2020 national renewable energy action plan, the transformation could be 30 to 35 percent (EUR 300 billion to 350 billion) more expensive than in the cost-optimal “green” scenario. Hence, it is clear that Germany needs a comprehensive transformation plan that achieves targets for CO_2 emissions and renewables, while keeping total system cost under control. To manage the transition in the short term, four elements need to be part of a comprehensive energy concept: (1) significantly building up trans-regional transmission grid capacities, (2) optimizing and extending the national renewable energy action plan, (3) further developing mechanisms to push energy efficiency measures, and (4) extending the current power remuneration system to ensure sufficient investment incentives in new power plants and retention of existing power plants as sources of backup power.

We believe it necessary to incorporate the four elements into the German energy concept in the short term and to initiate a process in Germany with all relevant stakeholders to develop a viable and comprehensive solution for Germany, including European aspects.

Chapter end notes

1 Europe being defined here as the European Union, Norway, and Switzerland (EU-27+2).
2 Europe agreed to a target of 80 percent emission reduction in 2050 (compared with 1990 levels) in the G8 meeting in l'Aquila in July 2009, if global action is taken. In October 2009, the European Council set the appropriate abatement objective for Europe and other developed economies at 80 to 95 percent below 1990 levels by 2050.
3 *Roadmap 2050: A Practical Guide to a Prosperous, Low-carbon Europe* by the European Climate Foundation. In order to achieve 80 percent greenhouse gas savings, the power sector has to reduce emissions by 95 percent compared with the baseline in 2050. This translates into "allowed" remaining emissions of 60 million metric tons (Mt) of CO_2e. The power sector has to contribute more than other sectors as it can reduce emissions more easily than other areas (e.g., industrial processes) and, due to a fuel shift toward electricity, the power sector directly affects emissions of other sectors (e.g., electric vehicles).
4 We applied a macroeconomic optimization rationale. This differs from the current market development, which is driven by non-optimal boundary conditions, which in turn drive business investment decisions.
5 Investments in the distribution grid are not assessed in the context of this study.
6 "Clean" scenario: a CO_2 reduction of 95 percent is achieved and there are no specific renewables targets.
7 "Green" scenario: a CO_2 reduction of 95 percent is achieved and 80 percent of the electricity is produced by renewables (including 14 percent imports from the Desertec project).
8 "Lean" scenario: cost-optimal scenario of providing electricity for Europe in a world without CO_2 targets and without renewables targets (no cost for CO_2 considered).
9 Our assumptions for future power demand growth are in line with the detailed economic analysis conducted by the European Climate Foundation in its *Roadmap 2050*. Based on modeling by Oxford Economics, the study assumes that GDP in Europe will grow by an average of 1.8 percent per year and the industrial sector by 1.9 percent per year with a stronger focus on light industry and engineering until 2050. In the base case of 2050 electricity demand, 1 percent efficiency improvements per year are assumed, based on the *World Energy Outlook 2009.* Additional implementation of all the GHG abatement levers up to EUR 60 per metric ton of CO_2e add another 1 percent efficiency improvement per year, resulting in a total of roughly 2 percent efficiency improvements per year. The latter levers are based on an extension of McKinsey's report *Pathways to a Low-carbon Economy – Version 2 of the Global Greenhouse Gas Abatement Cost Curve*. Without these strong efficiency improvements, power demand would be even higher. Excluded are behavioral changes that affect the quality of life. It is assumed that demand-side management measures could reduce peak demand by up to 10 percent. Demand-side management will not have an effect on the total power demand over a period longer than days.
10 It is worth noting that investment certainty for nuclear is not a decision criterion in a macroeconomic cost-optimization rationale.
11 In order to achieve the 80 percent GHG reduction target for the full economy in 2050, a rollout of CCS in the industry sector is required as efficiency opportunities reach their limits. In the *Roadmap 2050* study, it is assumed that CCS is applied to 50 percent of heavy industry in Europe (cement, chemicals, iron and steel, petroleum and gas) by 2050, in order to reach the 80 percent GHG reduction target.
12 CCGT: combined cycle gas turbine.
13 The Desertec project is assumed in the "green" scenario to supply Europe with electricity originating from concentrated solar power in the Middle East and North Africa, as stated in the white book *Clean Power from Deserts* by the Desertec Foundation.
14 As long as the power supply from renewables is defined as "must take" (i.e., when it is available it has to be used), the remaining power demand has to be supplied by classic, mostly fossil sources, which will become marginal plants as a consequence. These marginal plants will bid into the power wholesale markets based on an "avoided-cost rationale," i.e., they will be willing to accept negative prices to not shut down as shutting down is costly and, once they have been switched off, they will require very high prices before they switch on again. This effect has already driven the increased volatility in the European wholesale power markets.
15 "Marginal generation cost" is the short-term operating cost of the most expensive generating unit producing power at any given point in time. Traditionally, this cost largely determines the price of electricity.

16 Based on a rough extrapolation of current investments plans, taking into account power demand growth.
17 Article 4 of the renewable energy directive (2009/28/EC) of the EU requires member states to submit national renewable energy action plans. These plans provide detailed roadmaps of how each member state expects to reach its legally binding 2020 target for the share of renewable energy in their final energy consumption.
18 Assessment based on an extrapolation of the German renewable energy action plans for 2020 and the *European RES-E Policy Analysis* by EWI published in 2010. The assessment does not include distribution cost and therefore could be even higher.
19 Assuming an average yearly disposable income of EUR 35,000 per household.
20 Given that Europe is currently building renewables based on national targets rather than at the most optimal sites, the current transmission grid expansion might be sufficient to ensure reliable supply, but it would certainly be far from cost-optimal.
21 Our estimates show that it would amount to a maximum of 5 Mt of CO_2 emissions per year (0.5 percent of current emissions).
22 This study assumed that as of 2020, those fossil plants that retire at the end of their defined lifetime (e.g., 30 years for gas-fired CCGT; 40 years for coal) would remain on line to provide backup capacity in the case of extreme weather events (e.g., extended periods without sun or wind generation).
23 For nuclear, we took the phase-out in Germany as a given. For Belgium, we assumed constant nuclear generation in response to the 2009 phase-out postponement. No nuclear buildup potential was assumed for Portugal, Ireland, Austria, Norway, Greece, Luxembourg, Malta, Cyprus, Estonia, and Latvia. For all other countries, we defined a maximum capacity. Buildup potential for these countries is based on figures from the "Nuclear Century Outlook" by the World Nuclear Association and follows an average between the WNA's high and low case.
24 Even if the lifetime of Germany's full nuclear capacity is extended to 60 years, imports would amount to almost 50 percent in 2050, as the newest German nuclear power plant (Neckarwestheim 2) would go off line in 2050. Intermediate years would see lower imports.

1 Objectives, approach, and scenario setup

This report assesses the evolution of the power sector of the European Union, Norway, and Switzerland (EU-27+2) for the years 2020 to 2050. As context, this chapter outlines the objectives, approach, and scenario setup of the underlying study.

Objectives: Contribute to fact base, particularly quantified costs

A primary objective of the effort was to provide a factual basis for discussion of the development of European and national energy master plans from 2020 to 2050, with a focus on quantifying costs and identifying cost-optimal pathways.

Our assessment starts at 2020, because the evolution of the European power sector until 2020 is largely predefined by the commitment of the European Union to reach a set of sustainability targets, known as the "20-20-20 targets." They consist of a reduction in EU greenhouse gas emissions of at least 20 percent below 1990 levels, a share of 20 percent of EU energy consumption to come from renewable sources, and a 20 percent reduction in primary energy use compared with projected levels by improving energy efficiency. Given the progress individual EU member states are making toward these targets, we assume for the purpose of this study that they will be met.

For 2050, leaders of the European Union and the G8 pledged to reduce GHG emissions by at least 80 percent below 1990 levels, if other parts of the world initiate similar efforts. An 80 percent target would translate into a reduction of Europe's GHG emissions from 5.9 billion metric tons of carbon dioxide equivalent (Gt CO_2e) in 1990 to 1.2 Gt CO_2e in 2050. For Europe to reach these targets, the power sector would need to contribute more than other industries and would be required to reduce its GHG emissions by more than 95 percent below 1990 levels (see also: *Roadmap 2050: A Practical Guide to a Prosperous, Low-carbon Europe* by the European Climate Foundation). Assuming this goal, GHG emissions from the power sector would need to shrink from 1.5 Gt CO_2e in 1990 to less than 0.1 Gt CO_2e in 2050.

A variety of recent studies have analyzed the ambition and feasibility of reaching an almost decarbonized power sector. For example, the report *Roadmap 2050* assessed several feasible low-carbon pathways, with the renewables share ranging from 40 percent to as much as 80 percent. A study by the European Renewable Energy Council and Greenpeace concluded that Europe could draw 100 percent of its power generation from renewable sources.

There is little disagreement that these targets can be met from a technical point of view. However, the transformation into a low-carbon system would require the European power landscape to undergo fundamental changes. And it is not clear what an economically optimal path would look like.

Approach: Compare and contrast current path with 3 cost-optimal paths

To shed light on the above questions, our study analyzed the cost and implications of adhering to one or both of two boundary conditions at the European level:

- Achieving the 95 percent GHG emission reduction target in power generation without a specific target for renewables.

- Achieving both the 95 percent GHG emission reduction and an 80 percent share of power generation from renewable energy sources.

These boundary conditions were translated into scenarios – "clean" and "green" respectively – and contrasted with a third "lean" scenario as a reference, defined by dropping both targets for GHG emission reduction and 80 percent renewable power production. This scenario is for reference only to estimate the cost difference of the current transformation path of the European power sector and the other two scenarios.

We kept all other factors constant, most importantly power demand projections until 2050 and the 2020 starting-point assumptions. Our assumptions on macroeconomic parameters, power demand, commodity prices, and cost of generation technologies are in line with those published recently in *Roadmap 2050*.

However, this report differs from *Roadmap 2050* in four important dimensions:

- *Scenario setup. Roadmap 2050* focused on assessing the cost and implications of pathways that all lead to 95% emission reduction in 2050 based on different, predefined shares of renewable energy production. In contrast, this study focused on scenarios that allow the cost and implications of achieving the GHG reduction with a fixed renewables target of 80 percent ("green") to be compared with a scenario without a predefined renewables target ("clean") and with a third scenario with neither GHG emission targets nor renewables targets ("lean") (further details are provided below).

- *Modeling approach.* This study modeled the generation mix from 2020 to 2050 endogenously. In contrast, *Roadmap 2050* predefined the 2050 generation technology mixes per scenario exogenously and followed a back-casting approach.

- *Geographic resolution* was increased from nine zones within the European Union, Norway, and Switzerland to 56 regions in the same area, incorporating detailed information on regional potential for different generation technologies.

- *Comparison to current pathways.* We included an estimate of the differences between the modeling results and the pathways currently pursued to highlight the implications and the need for action.

As discussed in more detail in the methodology chapter, we used three modeling tools to address 1) the placement of renewable units, 2) the placement of conventional generation units, and 3) the buildup of the transmission grid[1], and ran the models in a specific iterative sequence.

Apart from the two boundary conditions for emissions and renewables, all input parameters remained the same for the three scenarios: GDP evolution, power demand, commodity prices, investment cost, and the local potential of power generation technologies. This set of input parameters is described in more detail below. The common parameters facilitated comparison of the three scenarios and the synthesis of extra costs and implications. To assess the robustness of the results and identify the key levers for cost control, we performed several sensitivity analyses for the "green" and the "clean" scenarios.

Scenario setup designed to minimize total system cost

This section describes the setup of the three scenarios, along with the input parameters and assumptions for 2020 and the pathway and parameters for 2020 to 2050. For each scenario, the study provided a detailed perspective on the development of renewables and conventional generation and transmission infrastructure between 2020 and 2050. The study considered investments in and the operation of conventional and renewables generation units, and the transmission grid infrastructure.

The objective in the scenarios was to minimize – within given boundaries – the total cost from a macroeconomic perspective.

Scenario definitions

The assessment of the power landscape from 2020 to 2050 followed three scenarios that differ according to the two boundary conditions – 95 percent GHG emission reduction and renewables accounting for 80 percent of the generation mix in 2050 (Exhibit 4):

Clean, efficient buildup – "clean." The EU-27+2 countries achieve a GHG emission reduction of 80 percent in 2050 versus 1990. The power sector reduces its emissions by 95 percent compared with 1990 levels. No renewables generation targets are defined. Instead, renewable technologies compete with conventional generation technologies in terms of cost. The Desertec project is not realized.

Renewables-fueled – "green." As in the "clean" scenario, GHG emissions from the power sector are reduced by 95 percent by 2050 compared with 1990 levels. Renewables generation achieves a predefined target of 80 percent by 2050. The Desertec project, i.e., power imports from solar fields in the Middle East and North Africa, is assumed to be as described in the white book *Clean Power from Deserts: The DESERTEC Concept for Energy, Water and Climate Security* by the Desertec Foundation.

Unconstrained buildup – "lean." In the third scenario, no targets are defined for GHG emission reduction or renewables generation. The buildup of power plants is based on economic optimization in the absence of sustainability targets. We do not suggest that the third scenario is a desirable pathway; it serves purely for comparison with the cost-optimized "green" and "clean" scenarios.

Exhibit 4

We have defined 3 scenarios to assess the implications of a carbon-free power sector and an 80% share of renewables generation

Scenario definition

"Green"
- By 2050, EU-27+2 achieves 80% reduction in GHG emissions vs. 1990 levels, with power sector achieving reductions of 95%
- 80% generation from renewables (including Desertec)

"Clean"
- By 2050, power sector achieves 95% reduction in GHG emissions vs. 1990 levels
- No defined targets for renewables generation

"Lean"
- No defined targets for GHG emissions or renewables generation for power sector

Cost and implications assessed for 80% renewables generation

Cost and implications assessed for 95% GHG emission reduction

- 2020 is the common starting point for all scenarios
- Europe regarded as a power island[1]
- Demand assumed to be the same for all scenarios

1 No power flows to or from outside EU-27+2, except for Desertec in "green" scenario

SOURCE: McKinsey

By comparing the "clean" and "lean" scenarios, we can assess the cost and implications of a 95 percent reduction in GHG emissions in the power sector. Comparing the "green" and "clean" scenarios allows us to assess the cost and implications of an additional target of 80 percent renewables generation. All scenarios have 2020 as a common starting point and model the same geographic entity over the same period of time. All three scenarios have a set of common parameters discussed below.

Input parameters and assumptions: 2020

As a common starting point, this study assumed the fulfillment of the European "20-20-20 targets" and their respective implications for the power sector, including the transmission grid (discussed in the next chapter). This translates into the following input parameters and assumptions:

Emissions reduction/renewables share. The 2020 GHG emissions from the power sector are expected to be 800 million metric tons of carbon dioxide equivalent (Mt CO_2e). This is a reduction of 33 percent compared with its 2008 value of 1,200 Mt CO_2e, primarily driven by replacement of fossil fueled power plants through renewables and a switch from coal to gas. The share of renewable power generation for the EU-27+2 is assumed at 36 percent in 2020, up from 23 percent in 2008.

Norway and Switzerland included. The nature of an increasingly connected Europe requires the inclusion of non-EU members Norway and Switzerland, especially for grid-modeling purposes. Due to the relatively high share of renewable energy generation (especially from hydro power) in these countries,[2] the 2020 share of renewable power generation within the geographic boundaries of this study increases from 34 percent (EU-27) to 36 percent (EU-27+2).

Demand and breakdown of generation mix. For 2020, power demand in the EU-27+2 countries is expected to be 3,500 terawatt hours (TWh) compared with 3,300 TWh in 2008. In 2020, 785 TWh would be generated from renewable sources (largest shares: 485 TWh wind onshore and offshore, 250 TWh biomass), 475 TWh from hydro, 540 TWh from gas, 440 TWh from hard coal, 310 TWh from lignite, and 950 TWh from nuclear power.

Solar imports assumed for "green" scenario. In the "green" scenario, 60 TWh of electricity generation would originate from concentrated solar power (CSP) in the Middle East and North Africa (Desertec), replacing coal- and gas-fired generation in Europe. We assume the buildup of the Desertec project to occur as stated in the white book *Clean Power from Deserts: The DESERTEC Concept for Energy, Water and Climate Security* by the Desertec Foundation. We are aware that the Desertec project is in its early stages of development and still faces many obstacles to realization. However, it is relevant in size and impact for the future energy supply of Europe if it materializes. In order to recognize potential failure, we have analyzed sensitivities correlated to non-realization.

The transmission grid buildup between 2010 and 2020 as required for realizing the expected generation mix in Europe in a cost-optimal way was an integral part of the modeling effort. The results of this analysis are discussed in Chapter 2.

Pathways and parameters for 2020 to 2050

For general input parameters, this study followed the same assumptions and parameters as in the report recently published by the European Climate Foundation. Specifically, it is consistent with *Roadmap 2050* on GDP growth, power demand, energy efficiency, electric vehicle penetration, heat pump penetration, commodity prices, and the cost of generation technologies.

This section gives a short overview of the assumptions followed in *Roadmap 2050* – for a deeper understanding of the underlying drivers, please refer to the publication itself. In this study, we have elaborated relevant input parameters down to a more granular geographical level. The basic parameters are the same for the three scenarios.

GDP and population growth. GDP between 2020 and 2050 in the EU-27+2 is set to grow on average at 1.8 percent annually. In total, European GDP is expected to grow from EUR 13,050 trillion in 2020 to EUR 21,770 trillion in 2050 (in real terms). Population is expected to decrease from 494 million in 2020 to 476 million in 2050. Thus, GDP per capita is expected to nearly double between 2020 and 2050.

Commodity prices. For 2020, the prices for coal and natural gas are assumed to be USD 100 per metric ton, and USD 10 per million British thermal units (MMBtu), respectively (all numbers in real terms). Until 2030, the price evolution of coal, and natural gas follows the projections from the *World Energy Outlook 2009*, i.e., in 2030, coal would cost USD 109 per ton, and natural gas USD 15 per MMBtu in the European market. From 2030 to 2050, prices are assumed to stay constant at 2030 levels (in real terms), as there are no reliable projections on commodity prices beyond 2030.

GHG emissions. In 2020, GHG emissions for the European power sector are assumed to be 800 Mt CO_2e. To achieve a 95 percent decrease compared with 1990 levels, GHG emissions will need to drop below 100 Mt CO_2e.

Power demand. Power demand is projected to grow from 3,500 TWh in 2020 to 4,900 TWh by 2050, an increase of 40 percent. This represents an average growth in electricity demand of 1.1 percent per year from 2020 to 2050. This rate is below the 1.5 percent demand growth per year between 1990 and 2007. Power demand is determined by a series of drivers (Exhibit 5):

- *Base power demand.* The base power demand for Europe is expected to grow from 3,500 TWh in 2020 to 4,800 TWh in 2050. This assumes the given GDP growth of 1.8 percent per year and implementation of efficiency levers as referenced in the *World Energy Outlook 2009* (roughly 1 percent efficiency improvements per year).

- *Increased penetration of energy efficiency.* The base power demand is reduced by 1,400 TWh under the assumption that, on top of the energy-efficiency measures already implemented in the base power demand, the full set of measures discussed in McKinsey's GHG abatement cost curve[3] (with abatement cost below EUR 60 per t CO_2e) are implemented by 2030. For 2030 to 2050, we assume an extrapolation of the savings from energy-efficiency measures. This roughly implies an additional 1 percent efficiency improvement per year, leading to an overall improvement of roughly 2 percent per year.

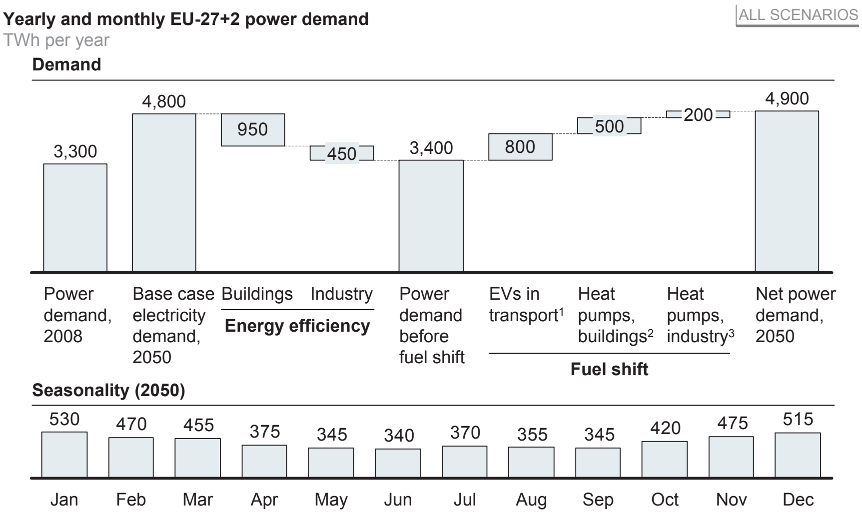
- *Fuel shift.* Electric vehicles and heat pumps. We assume a demand increase of 1,500 TWh due to electrification in the transport, buildings, and industrial sector. Electrification of the transport sector[4] is responsible for an increase of 800 TWh. Introduction of heat pumps for heating and cooling buildings (500 TWh) as well as industrial processes (200 TWh) increases demand by a further 700 TWh.

- *Evolution of power demand from 2020 to 2050.* Total power demand in 2020 is assumed to be 3,500 TWh and is expected to grow to 4,150 TWh in 2030, to 4,530 TWh in 2040, and to 4,900 TWh in 2050. The growth in electricity demand is an overlay of strong efficiency improvements and a rollout of electric vehicles and heat pumps over time.

- *Seasonal fluctuations.* The current seasonality of power demand, i.e., the variation of power demand over the year, is expected to rise until 2050 due to increased penetration of heat pumps. The 500 TWh heat pump power consumption for heating and cooling buildings was split based on population and the region's climatic conditions. We assumed heat pumps consume power mostly in the winter months (moderate and cold regions of Northern, Western, and Central Europe) or show a second demand peak in July and August (Southern Europe). Total resulting power demand per month varies by up to 55 percent over the year, with a maximum of 530 TWh in January, and a minimum of 340 TWh in June.

Exhibit 5

In 2050, power demand rises to 4,900 TWh and seasonality reaches 50%



1 Electrification of 100% LDVs and MDVs (partially plug-in hybrids); HDVs continue emitting ~ 10% while switching largely to biofuel or hydrogen fuel cells
2 90% of remaining primary energy demand converted to electricity (heating/cooling from heat pumps, assumed 4 times as efficient as primary fuel)
3 10% of remaining primary energy demand for combustion converted to electricity (heat from heat pumps, assumed 2.5 times as efficient as primary fuel)

SOURCE: European Climate Foundation; McKinsey

- *Level of demand-side management.* Demand-side management can help to "smooth-en out" the intermittent feed-in of renewable power generation and reduce peaks in power demand. The level of demand-side management determines the percentage by which the demand in any specific hour can be increased or decreased. The total demand per day remains unchanged. In this study, we assumed the level of demand-side management will increase from 2 percent in 2020 to 10 percent in 2050.[5] The values are based on *Roadmap 2050*, where 2050 values of 0 percent and 20 percent of demand side management were analyzed.

- *Cost of generation technologies.* All existing conventional power generation technologies plus CCS are considered in this study: nuclear (Generation III+), hard coal (with and without CCS), lignite (with and without CCS), OCGT[6] and CCGT.[7] For renewables generation, hydro (reservoirs, run-of-river), wind (onshore and offshore), solar (photovoltaic and concentrated solar power), biomass, and geothermal technologies are considered. Pumped hydro storage is also considered.

- *Technology evolution but no breakthroughs assumed.* This study assumed standard evolutions in technology but no technological breakthroughs in power generation or transmission. We assumed there will be an evolution but no breakthroughs in plant efficiency, no commercial introduction of breakthrough grid technologies (such as superconducting power transmission), and no new CO_2-free generation technologies (such as nuclear fusion). Future cost developments of generation technologies are estimated by applying learning rates. For established technologies, this is a rate of improvement per year; for new technologies, it is a reduction in cost per doubling of cumulative installed capacity. We used the same assumptions as in *Roadmap 2050*.

Buildup potential for nuclear, lignite, and CCS. We defined upper boundaries on generation or capacity for lignite, nuclear, and CCS at a regional level:

- *For lignite,* we assumed that the amount of lignite extracted per region would not exceed current levels. However, power generation from lignite would still grow due to improvements in power plant efficiency.

- *For nuclear,* we took the phase-out in Germany as a given[8]. For Belgium, we assumed a constant nuclear generation in response to the 2009 phase-out postponement. No nuclear buildup potential was assumed for Portugal, Ireland, Austria, Norway, Greece, Luxembourg, Malta, Cyprus, Estonia, and Latvia. For all other countries, we defined a maximum capacity. Buildup restrictions applied in our modeling for these countries are based on figures from the World Nuclear Association's "Nuclear Century Outlook"[9] and follow an average between the WNA's high and low case. At a European level, nuclear buildup along this boundary, as applied in our model, would lead to a total production of 2,300 TWh in 2050, or 2.4 times today's level. This would correspond to an annual growth rate of 2.2 percent.

- *For CCS,* we defined a maximum storage potential per region, based on the EU GeoCapacity project from 2008. The results of this project offer the most comprehensive assessment to date of CO_2 storage potential in Europe. For countries not covered in the GeoCapacity report, storage potential was estimated according to additional information on a national level. Based on this analysis, we estimate total storage potential within Europe at roughly 120 Gt CO_2e, or about 20 times Europe's total CO_2e emissions in 1990. We assume CCS technologies to be market-ready by 2020 at the same cost as stated in *Roadmap 2050*. This study did not consider any costs associated with further precommercial research and development.

Buildup potential for renewable energy technologies. For all renewable energy generation technologies, we defined upper boundaries on generation or capacity. We also defined site-specific load factors that ultimately drive economic attractiveness per site and technology.[10] For the buildup of additional intermittent renewables, cost for required backup capacities and extensions of high-voltage transmission capacities are included in the economic assessment.

Development of hydro generation. Hydro generation is expected to increase by 30 percent from 475 TWh in 2020 to 635 TWh in 2050. These numbers include power generation from run-of-river and reservoir-type units. The evolution is based on the growth assumptions of the *World Energy Outlook 2009* and further sources for Norway and Switzerland.[11] This growth rate for hydro generation is assumed to be equal in all three scenarios.

Use of biomass. Biomass is limited in supply to 5,000 TWh in primary energy value (approximately 12,000 million metric tons per year, including 20 to 30 percent likely imported to Europe, particularly bio-kerosene to be used in aircraft). This assumption is based on a comprehensive review by McKinsey[12], which also takes into account constraints on the availability of biomass, such as water scarcity and the need to avoid competition with food.

This report follows the assumptions also used in *Roadmap 2050*, i.e.: 40 percent of the biomass potential goes to road transport, another 20 percent is used for air and sea transport, and the remaining 40 percent can be used for power generation. This represents a maximum potential of 600 TWh of power production from biomass or 12 percent of European power demand in 2050. The cost for biomass depends on its type and origin. The maximum potential of power production from biomass is utilized in the sensitivity analysis for "green" scenario without Desertec. In the "clean" and "green" scenarios, 300 to 400 TWh of electricity are produced by biomass power plants.

Solar fields in the Middle East and North Africa (Desertec). We assumed the Desertec project – the large-scale buildup of CSP generation capacities in the Middle East and North Africa and transport of the generated power to Europe via high-voltage direct current (HVDC) power lines – as a given in the "green" scenario. We followed assumptions made in the white book *Clean Power from Deserts: The DESERTEC Concept for Energy, Water and Climate Security* by the Desertec Foundation, including an installed capacity of 11 GW in 2020 and 100 GW in 2050, producing 60 TWh of generated power in 2020 and 700 TWh in 2050. A sensitivity analysis was performed for the case that the Desertec project cannot be implemented at the cost and volumes published in the white book.

Cost of power transmission. The expansion of the transmission grid considers both high-voltage alternating current (HVAC) lines and HVDC lines. For onshore connections between regions, the buildup of HVAC lines is assumed for expansions that do not exceed a factor of three above the currently installed capacity. For any further expansion of a specific connection beyond this level, the use of HVDC lines is assumed. For offshore connections, e.g., between the UK and the Netherlands, the use of HVDC[13] lines is assumed.

The technology for an HVDC grid is, in principle, available today. However, there are still some open issues such as the availability of HVDC breakers, which we assume will be solved by 2020. Costs for HVAC and HVDC lines were defined at a regional level, depending on the geographic location and the distance between load centers.

Modeling of the distribution grid was not part of this effort. Thus, we have neither assessed the implications of the different scenarios on distribution grid infrastructure nor have we included any cost figures. In principle, the more decentralized a power system, the greater the need for change to the distribution grid and the higher the cost.

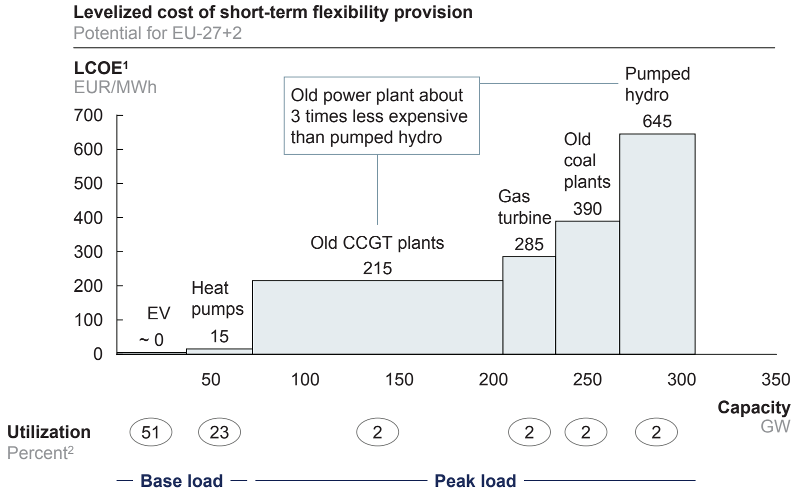
Technologies for backup power and flexibility. With growing shares of intermittent renewables generation, controllable generation technologies that provide reliable backup power are becoming increasingly important. Backup power is required along different time scales – from units that level intra-day fluctuations to units that back up fluctuations over one month and solutions that balance seasonal fluctuations.

For all three time horizons, this study assessed backup solutions' cost and estimated potential within Europe. We ranked the solutions based on their levelized cost for backup provision and excluded those that cost more than alternative solutions to satisfy the estimated backup needs (Exhibit 6).

Exhibit 6

Provision of short-term backup and flexibility – levelized cost curve of relevant measures

ALL SCENARIOS
ROUGH ESTIMATES



1 Levelized cost of electricity, 7% WACC
2 Based on rough assessment of load curve in 2050

SOURCE: McKinsey

Technologies considered in this assessment were all conventional power plants (as they are fully controllable), demand-side management measures, different storage options (pumped hydro, compressed air, hydrogen, battery), and transmission grid buildup. Even though transmission lines cannot provide controllable backup power, improved interconnectivity between geographic regions can level out local demand-supply imbalances and, therefore, reduce remaining demand for backup power.

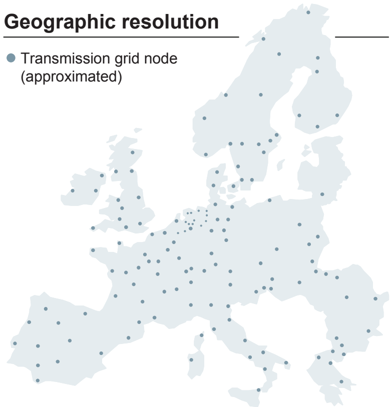
As an example, the exhibit shows an estimate of the short-term flexibility merit order curve for 2050 for a positive flexibility requirement (i.e., demand greater than supply). The figures indicate that by 2050, demand-side management and the use of old power plants could provide more than 150 GW of short-term flexibility needs at levelized cost[14] that is lower than newly built storage facilities. The assessment shows that Europe's flexibility needs can be satisfied in the most economic way by continuing to use existing fossil power plants or building new gas turbines over time, by using demand-side management measures, by increasing grid buildup, and by building up hydro generation. For this study we excluded other storage technologies, namely compressed air, hydrogen, and battery-type solutions, as – without technological breakthroughs – they are less attractive economically. The continued use of retired fossil power plants for backup in the event of extreme weather conditions[15] will cause additional emissions. Our estimates show that it would amount to a maximum of 5 Mt of CO_2 emissions per year (0.5 percent of current emissions), due to very low utilization rates for these plants.

Exhibit 7

System in scope spans EU-27+2 by region, 2020 - 50

ALL SCENARIOS

Geographic resolution



- EU-27+2, split into 56 regions
- 240 transmission nodes

Time resolution

- Assessment of years 2020 - 50
- Build up of renewable and conventional capacities, and modeling of net transfer capacities modeled with yearly resolution
- Dispatch of aggregated generators on hourly basis for key years 2020, 2030, 2040, 2050

SOURCE: McKinsey

The system in scope, as shown in Exhibit 7, was as follows:

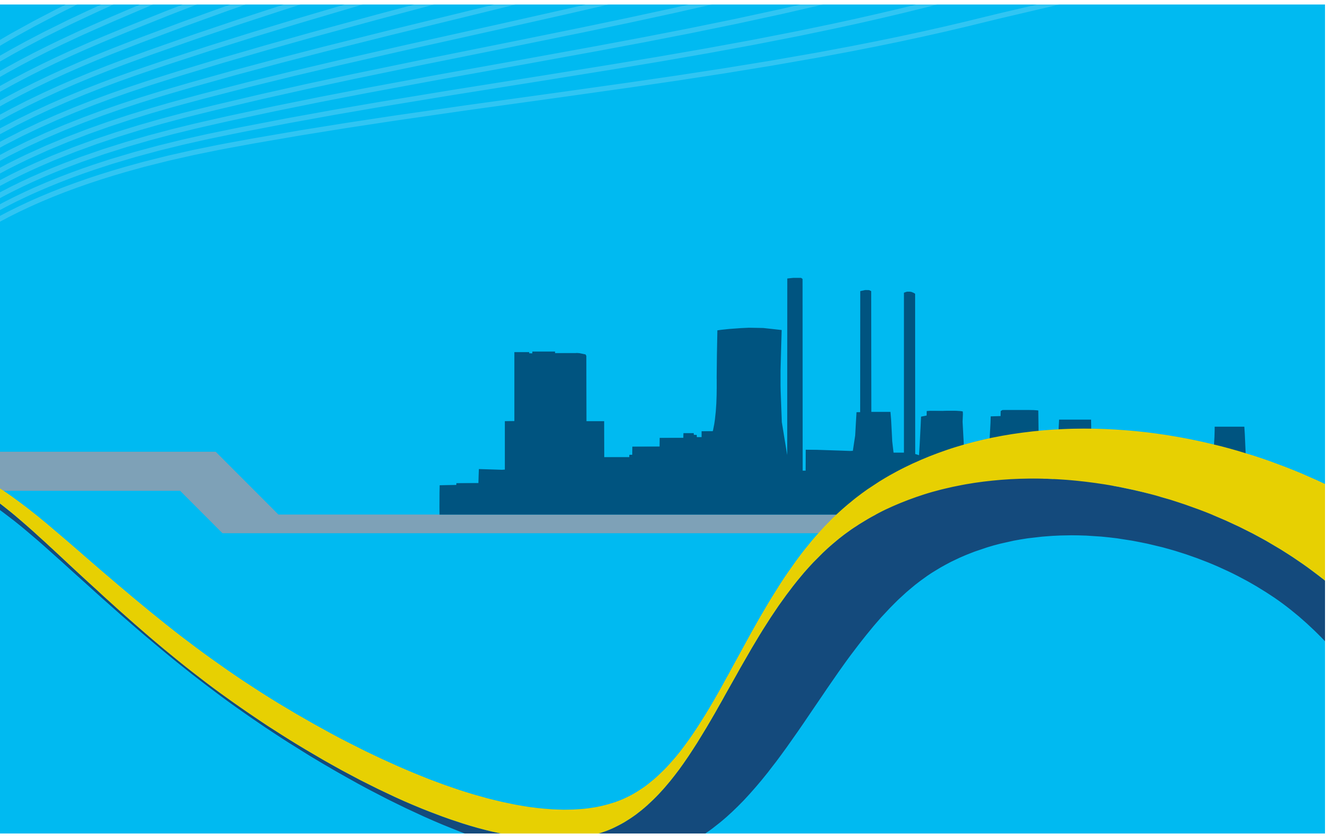
- *Geographic resolution* encompassed the European Union with all 27 member states, plus Norway and Switzerland (EU-27+2). This geographic entity is split into 56 regions. We determined power demand for each region based on the assumptions on baseline demand, electric efficiency, and fuel shift. Placement of renewable and conventional generation units is region-specific and subject to regional restrictions and generating properties (e.g., load factors for solar and wind). For the transmission grid, 240 transmission nodes are defined across the 56 regions.

- *Time resolution* encompassed the years 2020 to 2050. The buildup of generation capacities and transmission grid was modeled on a year-by-year basis. Renewables feed-in per region is determined with an hourly resolution for the years 2020, 2030, 2040, and 2050 and interpolated for every hour in the years in-between. Hourly renewables feed-in values for each year were used to model the buildup of a cost-optimal conventional and nuclear generation park.

With this scenario setup, this study is, to our knowledge, the first one to combine a long-range (2050) assessment at such a high level of granularity with a cost optimization approach to assess the cost and implications of possible pathways to a low-carbon power system in Europe.

Chapter end notes

1 Energynautics calculated the required grid buildup based on the renewables and conventional power generation data provided by McKinsey.
2 In 2008, Norway generated 99 percent of its 125 TWh power production by hydro, while Switzerland generated 55 percent of its demand of 62 TWh from renewable energy sources.
3 Carbon Abatement Cost Curve, McKinsey & Company, 2009.
4 It is assumed that, by 2050, 100 percent of light duty vehicles and medium duty vehicles are electrified.
5 For example, if the demand in a region is 100 MW within a specific hour in 2050, this demand can be increased or decreased by 10 MW. The difference in energy provided needs to be made up for in other hours of the day while not exceeding the level of flexibility in those hours.
6 OCGT: open cycle gas turbine.
7 CCGT: combined cycle gas turbine.
8 The decision of the government to extend the lifetime of the German nuclear power plants by 8 to 14 years has not been taken into account in the modeling as the decision has not come into law yet. The lifetime extension will affect the transition period up to 2050 but not after 2050, as all nuclear power plants would go off line before 2050.
9 http://www.world-nuclear.org/outlook/nuclear_century_outlook.html.
10 The potentials and load factors per technology and site as well as the cost per technology drive the overall attractiveness. Potentials and load factors per technology used in this study are based on analysis by McKinsey & Company, incorporating public sources, such as *Roadmap 2050* of the European Climate Foundation.
11 For Switzerland, assumptions from a report of the Swiss “Bundesamt für Energie” were used. For Norway, estimates are based on publications by the “International Journal of Hydropower and Dams” and Eurolectric 2007.
12 An overview of this study can be found in: “Biomass: Mobilizing a sustainable resource”; chapter in *Sustainable Bioenergy*, published by Environmental Finance; February 2010; B. Caesar, N. Denis, S. Fürnsinn, K. Graeser, U. Kempkes, J. Riese, and A. Schwartz.
13 Voltage Source Communicated (VSC)-HVDC lines assumed.
14 The utilization rates per flexibility option, and therefore the levelized cost, were calculated based on generic 2050 demand profiles. These profiles were generated based on our assumptions for overall demand evolution as well as daily, monthly, and yearly heat pump and electric vehicle demand profiles.
15 Extreme weather conditions were modeled as a combination of low wind and low solar generation in a wide area of Europe, plus high power demand. The extreme weather event is based on data from the past 40 years and allows maximum (80 percent) loading of the transmission lines in order to ensure N-1 security.



2 Scenario results and implications

For a better understanding of the cost-optimal scenarios, this chapter presents results and implications from the modeling. It begins with our assessment of the transmission grid required to realize the 2020 generation mix, which is used as the starting point for all scenarios. For 2020 to 2050, the evolution of the European power landscape is described for each of the three scenarios as defined in Chapter 1. We also present specific results for Germany.

Doubled grid capacities needed by 2020. If Europe's 20-20-20 targets, especially the renewables generation share of 36 percent, are to be achieved in a cost-optimal way, the capacity of Europe's transmission grid should more than double between today and 2020 (Exhibit 8).

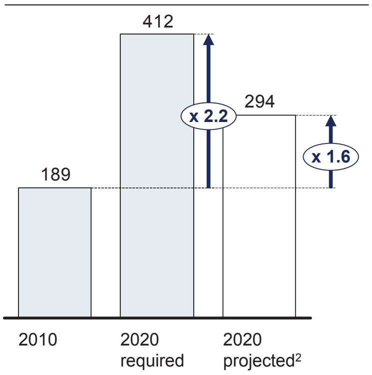
We compared the buildup requirement with the buildup currently in planning or under construction, as described in the *UCTE Transmission Development Plan*. The analysis shows that the transmission grid would see a 1.6-fold increase in capacities until 2020. That means the actual buildup is only half as fast as required and would be 10 years behind schedule by 2020.

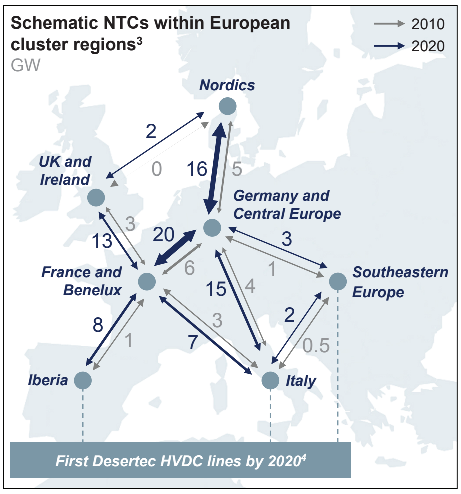
Exhibit 8

NTC buildup up to 2020 focused on Spain-France, Germany's western border, and Central Europe-Nordics

ALL SCENARIOS
GRID EVOLUTION 2010 - 20

Net transfer capacity (NTC) buildup required to achieve Europe's 2020 targets cost optimally vs. projected buildup
GW[1]





1 Absolute numbers resulting from geographic split chosen in this study
2 According to current planning status as reported in the *UCTE Transmission Development Plan*
3 56 regions grouped into 7 cluster regions
4 Only in "green" scenario

SOURCE: *UCTE Transmission Development Plan*; McKinsey

Transmission buildup has to be strengthened especially along Germany's western border, to enable imports that offset the planned nuclear phase-out; from Spain to France, to balance the increased renewables penetration on the Iberian peninsula; and to the Nordics, to make better use of Scandinavia's hydro resources for balancing an increasingly fluctuating generation portfolio.

Hurdels to overcome. With expenditures of about EUR 50 billion for a doubling of transmission grid capacities – around 10 percent of the total estimated investments by Europe's power industry from 2010 to 2020[1] – the slow or only partial realization of the required grid extension is not primarily a question of high cost. The main hurdles to overcome are low public acceptance, slow approval processes, and unattractive financial compensation.

Insufficient grid buildup would present regional power systems with major challenges in coping with intermittent renewable generation. With sufficient trans-regional transmission capacities, controllable generation capacities in other regions can be used to provide power whenever renewable generation is low within a region (i.e., no wind and no sun).[2] If trans-regional transmission grid buildup remains limited to the current planning as described in the *UCTE Transmission Development Plan*, an additional 70 GW of backup capacities would be required on top of the expected generation capacities by 2020.

Another effect of insufficient grid expansion would be curtailment of renewable generation. In times of high renewable energy feed-in within a region, sufficient trans-regional transmission infrastructure allows the distribution of surplus energy to neighboring countries or even more distant regions. Without sufficient grid capacities (and in the absence of major storage capacities), such renewables feed-in could not be absorbed by the system and would need to be curtailed. If there is no further grid buildup beyond the level foreseen in the *UCTE Transmission Development Plan*, curtailment of renewable energy would increase from less than 2 percent in 2020 to up to 14 percent in 2050.

As the starting point of our further modeling, we assume in this study that sufficient grid buildup will be achieved to ensure a cost-optimal power system in 2020.

2.1 Toward a low-carbon power sector – "clean" scenario

In this scenario, by 2050 Europe's power sector achieves GHG emission reductions of roughly 95 percent compared with its 1990 levels. The different generation technologies compete in terms of lowest system cost to ensure that the low-carbon power system is realized at minimal cost. No renewables generation targets are set. Instead, renewable power generation is determined by the objective to minimize total system cost.[3]

Results for Europe

In the "clean" scenario, renewables and nuclear provide 90 percent of Europe's power by 2050, decreasing greenhouse gas emissions in the power sector by 95 percent versus 1990 levels. The total system cost for this low-carbon power system would be EUR 6,255 billion between 2020 and 2050, or 1.2 percent of Europe's cumulative GDP. The necessary expansion of the power infrastructure (generation and transmission grid) would require investments of EUR 1,870 billion. Beyond 2020, the transmission grid would need to increase 1.8-fold (almost fourfold compared with 2010). In 2050, Central Europe would become a large power importer.

Renewables and nuclear would provide 92 percent of the power by 2050. Exhibit 9 shows the evolution of the European power generation mix from 2020 to 2050. The balanced power generation mix in 2020 – renewable units (including hydro) accounting for 36 percent, nuclear for 27 percent, and fossil-fuel-based units for 37 percent of total generation – transforms into a mix dominated in roughly equal parts by renewables and nuclear generation. Together, renewable power sources, including hydro power, and nuclear power would account for more than 90 percent of generation in 2050. Fossil-fuel-based technologies would account for only about 10 percent.

Wind power would provide 22 percent of generation in 2050; solar and biomass would provide about 2 percent and 6 percent, respectively; geothermal and others would contribute another 2 percent.

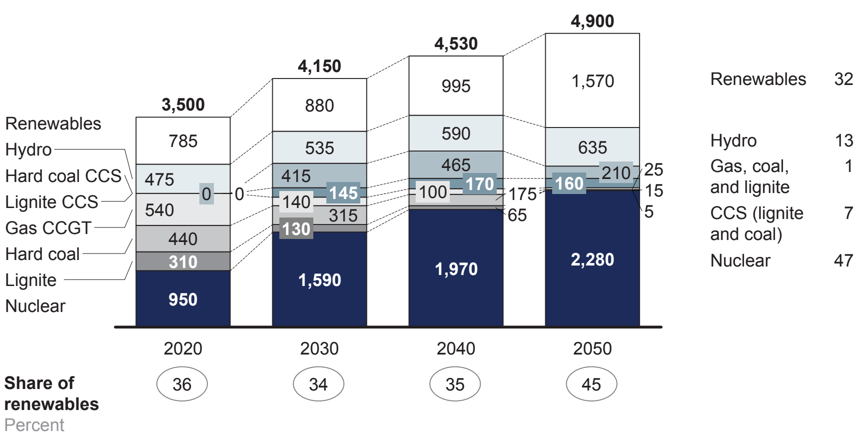
Exhibit 9

In the "clean" scenario, EU-27+2 power generation would achieve a 45% share of renewables

"CLEAN" SCENARIO

Development of EU-27+2 power generation landscape, 2020 - 50
TWh

Shares in 2050
Percent



SOURCE: McKinsey

Renewables generation (excluding hydro) would grow moderately between 2020 and 2040 – the compounded annual growth rate of 1.2 percent would be similar to the power demand growth in the same period. After 2040, renewables generation would grow on average by 4.5 percent per year. This growth would be driven by the increasing cost competitiveness of renewables technologies relative to other clean generation technologies, as renewable technologies run down a learning curve.

The share of nuclear generation in total power generation would grow from 27 percent in 2020 to 38 percent in 2030, 44 percent in 2040, and 47 percent in 2050. For this study, the maximum buildup of nuclear was defined based on an average of the "high" and "low" scenarios from the World Nuclear Association's "Nuclear Century Outlook."

As nuclear generation growth would be limited, and renewables generation technologies would – before 2040 – only be cost-competitive at the most favorable sites, CCS generation would be used as an alternative low-carbon technology to satisfy overall demand.

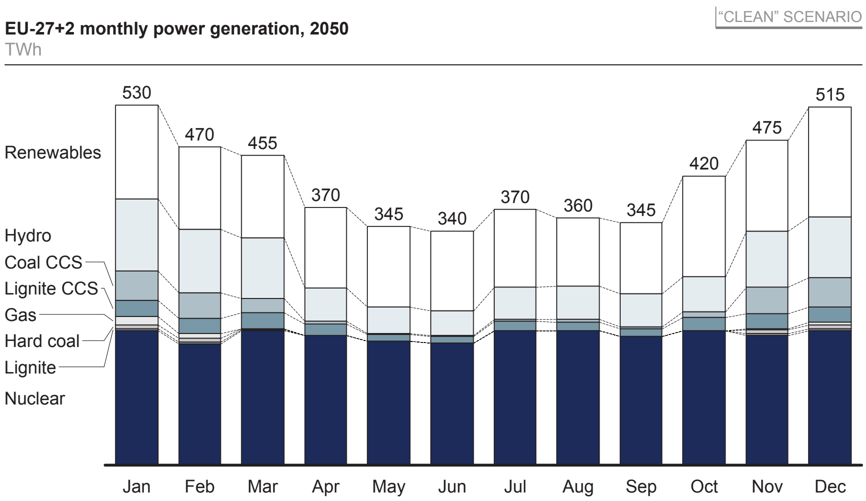
The relevance of fossil CCS. With the current gas price assumptions based on the *World Energy Outlook 2009* (USD 15 per million British thermal units for 2030), CCS, especially gas-based CCS, has only a minor role to play as a bridging technology in the power sector, as nuclear power would be the least-cost option.

However, a sensitivity analysis of gas prices shows that gas CCS would become cost competitive with nuclear power at a price of roughly USD 9 per million British thermal units, assuming similarly high load factors of 90 percent for gas CCS as assumed for nuclear power.

In the past, gas prices have already been at this level. At such a gas price level, gas CCS would be much more relevant in the "clean" scenario and could even become a dominant technology. In this context, permitting and licensing procedures as well as public acceptance

Exhibit 10

In 2050, nuclear would provide the base load for the entire year, while hydro and hard coal would be used primarily in winter



SOURCE: McKinsey

will significantly influence the future power mix. This holds true specifically for nuclear, but may also become relevant for CCS technologies.

Exhibit 10 shows the seasonal fluctuations of power demand and supply in 2050. Nuclear power would provide the "base load" over the full year. Renewables feed-in would be stronger in winter, driven by a higher level of generation from wind power and increased use of biomass in this season. However, this higher generation would not be large enough to buffer the higher demand in winter. Thus, the "clean" scenario would need hydro, hard coal CCS, and lignite CCS power plants to satisfy the demand peaks during the winter months.

Seasonality of demand would have a significant effect on the expected profitability of operating fossil fuel plants. As a consequence of the increased seasonality and the generation mix in 2050, hard coal CCS plants would be used almost exclusively during winter months. This applies, even more so, for the remaining fossil-fuel plants without CCS. While those plants in 2050 may generate only very small amounts of power in order not to exceed the limits on CO_2 emissions, they would still be used on winter days with high demand and low renewable generation. From a purely economic perspective, keeping these fossil plants online even with utilization rates as low as 4 percent is an optimal decision, as only fixed operating cost needs to be paid to provide the required capacity.

However, given current power market remuneration schemes, this would likely not be an optimal decision from a utility point of view.

The utilization of new hard coal CCS plants would still be high at around 70 to 80 percent before 2040 but would drop thereafter to around 50 percent. While these investments are optimal from an economic point of view, the low utilization rates foreseeable in the long term pose challenges from a business perspective.

Generation mix consisting of 92 percent nuclear and renewables would reduce average marginal cost. The marginal cost of renewable power, especially of solar and wind, is close to zero. Nuclear power shows a similar cost pattern, with high investment cost but very low fuel and operating costs. As these technologies would dominate the "clean" European power mix in 2050, average marginal cost would fall below full generation cost by 2050. This effect would be the strongest in the summer months, when nuclear and renewable generation would provide up to 97 percent of power.

Assuming current market mechanisms are maintained, nuclear power would be the price-setting technology for much of the time in the summer, with a marginal cost of around EUR 10 per MWh.

In winter months, when nuclear and renewables would generate only 85 percent of the power required, less efficient "old" plants would often set the prices, with a marginal cost of approximately EUR 100 per MWh. The average annual marginal generation cost would fall to EUR 35 per MWh, i.e., to below the full generation cost, which includes all expenditures related to the production of power, such as depreciation of fixed assets. If the current remuneration scheme is maintained, power generators would then no longer earn their full cost and would stop investing.

Greenhouse gas emissions would decrease by 95 percent versus 1990 levels. GHG emissions would decrease from 800 Mt CO_2e in 2020 to 450 Mt in 2030, 255 Mt CO_2e in 2040, and 60 Mt CO_2e in 2050. This means that GHG emissions would decline by more than 95 percent between 1990 and 2050.

Total system cost of the low-carbon power system would be EUR 6,255 billion between 2020 and 2050, or 1.2 percent of Europe's cumulative GDP. In the "clean" scenario, the total cost of the low-carbon power system would amount to EUR 6,255 billion. This would represent 1.2 percent of the cumulative GDP of the EU-27+2 from 2020 to 2050. The total cost includes annualized investment, operating, and fuel costs for the period from 2020 to 2050. We have translated all investments into annualized investment cost over the projected lifetime of the asset and assume a cost of capital of 7 percent[4]:

- *Total cost* would increase over time in line with the increase in power demand. In 2020, Europe would pay EUR 175 billion for its power system. This total cost would increase to EUR 200 billion in 2030, EUR 230 billion in 2040, and EUR 240 billion in 2050. In this cost-optimal pathway, total cost is dominated by capital-intensive nuclear power, with an increasing share of capital expenditures and a sharp reduction in fuel cost. Within the total cost, annualized investment cost would increase by 40 percent over the same time period, from EUR 100 billion in 2020 to EUR 140 billion in 2050. Expenditures for conventional fuels[5] would increase from EUR 45 billion in 2020 to EUR 50 billion in 2030. They would be stable at EUR 50 billion in 2040 and decrease to EUR 30 billion in 2050.

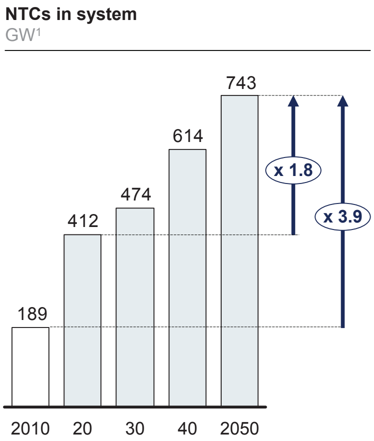
- *Investments of EUR 1,870 billion in power infrastructure required.* In the "clean" scenario, net investments[6] from 2020 to 2050 amount to a total of EUR 1,870 billion. In the first decade, 2020 to 2030, net investments of EUR 570 billion are required, followed by EUR 705 billion in the 2030s, and EUR 595 billion in the 2040s. While investments in the first two decades (2020 to 2040) would be dominated by nuclear power plants (EUR 665 billion in both decades), investment in the last decade up to 2050 would be driven by EUR 350 billion investments in renewable energy.

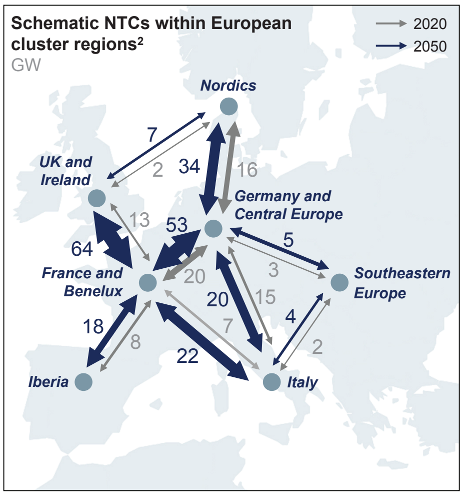
Beyond 2020, transmission grid capacity would need a further 1.8-fold increase. In the decade from 2020 to 2030, the necessary increase in the transmission grid would be fairly moderate (+15 percent) as only a small share of renewables generation would be added to the power system, and conventional units would be added close to load centers. In the subsequent decades, the placement of renewable and nuclear generation capacities would become more decoupled from load centers. This decoupling would occur in response both to the limited number of cost-optimal renewable sites close to load centers, resulting in a shift toward more cost-efficient sites in the "outer" European regions, and to restrictions on nuclear power, resulting in a shift of generation to those countries that allow nuclear expansion and have attractive renewables sites. These shifts imply that a grid expansion of around 25 percent in each decade (2030 to 2050) will be needed to link centers of supply and demand and to ensure reliability in extreme weather conditions (Exhibit 11).

Exhibit 11

Grid infrastructure would almost quadruple with a strong buildup especially between Central and Western Europe

"CLEAN" SCENARIO





1 Absolute numbers resulting from geographic split chosen in this study
2 56 regions grouped into 7 cluster regions
SOURCE: McKinsey

Renewable buildup between 2030 and 2040 would focus mainly on wind power. To integrate this source into the European power system and make it available for consumers, the grid would have to be upgraded especially between Central Europe, France, Benelux, and the UK.

Grid upgrading beyond 2030 would consist partly of HVDC installations. In 2050, more than 35 percent of net transfer capacities (NTCs) is expected to be of the DC type, to transport renewable and nuclear power from the supply centers (especially France and the UK) to the load centers in Central Europe.

Net investments for the extension of the transmission grid infrastructure amount to EUR 100 billion, or about 5 percent of overall investment cost. We emphasize that these investments address only the transmission grid infrastructure. In the context of this study, we have not assessed investments in the distribution grid. It is likely that they will become necessary within the next decade, especially if an increasing share of electric vehicles and "smart" home appliances needs to be supported by the power system infrastructure.

In 2050, Central Europe would become a large power importer. The buildup of transmission grids would be driven to a large extent by increasing supply-and-demand imbalances across Europe. By 2050, Central Europe,[7] including Germany, is expected to import about 345 TWh, or 25 percent, of its overall power demand of 1,450 TWh. This deficit would be largely a result of Germany's nuclear phase-out policy and the less attractive renewable sites in Central Europe. The majority of the power would be imported from France and Benelux, which would have a generation surplus of about 285 TWh. For example, France would see an increase in its exportable generation, i.e., above domestic demand, from 170 TWh in 2020 to 340 TWh in 2050. Most of this would come from a strong buildup of nuclear generation, which would increase from 470 TWh in 2020 to 680 TWh in 2050 in this scenario. In 2050, the UK and Ireland would export about 75 TWh, Scandinavia about 120 TWh of power. Italy would be a net importer of about 170 TWh, while South-Eastern Europe would be a net exporter of 25 TWh. Spain and Portugal (Iberia), on the other hand, would export 10 TWh of power via France to other European regions.

Results for Germany

In a cost-optimal pathway, Germany would need to import power and thus has a major interest in successful European cooperation and the expansion of the trans-regional transmission grid.

In all scenarios, German power demand grows by roughly 30 percent[8] until 2050 due to the net effect of increased efficiency measures and a fuel shift toward electric vehicles and heat pumps. In the "green" scenario, Germany imports 41 percent of its demand by 2050. To handle the supply requirements, the grid connecting Germany to other countries will need to increase fivefold.

Germany would need to import up to 41 percent of its electricity in 2050. Given the economically less attractive renewables sites in Germany and the nuclear phase-out[9], Germany will have to import more and more clean electricity over time from neighboring regions. In 2020, Germany's electricity supply and demand is expected to be balanced. By 2030, however, the scenario results show that Germany will have to import 8 percent and, in 2050, 41 percent of its electricity. Besides imports, German demand in 2050 would be met by 31 percent renewables, 2 percent conventional power plants, 26 percent conventional power plants with CCS, and 0 percent nuclear energy.

International transmission would have to increase fivefold. The imported electricity would originate mainly from Sweden, Denmark, and Norway as well as from France and, together, would provide more than 80 percent of Germany's electricity imports. The rest would originate mostly from the Benelux, United Kingdom, Ireland, and Poland and to a minor extent from Iberia and Southeastern Europe.

To enable the power flows into Germany, the international grid connections would have to be strengthened significantly. The NTCs along Germany's borders would need to increase threefold between today and 2020 and more than fivefold until 2050. The grid along the western border would have to increase ninefold.

2.2 Toward a low-carbon power sector with 80 percent renewables generation – "green" scenario

In this scenario, besides a 95 percent GHG emission reduction versus 1990 levels, Europe achieves a renewables generation target of 80 percent by 2050 and also realizes the buildup of 100 GW of solar power generation in the Middle East and North Africa by 2050 (Desertec).

Results for Europe

In the "green" scenario, Desertec and hydro would provide 14 and 13 percent, respectively, to the generation mix in 2050; other renewables 53 percent, and nuclear 13 percent. GHG emissions would decrease by 95 percent versus 1990 levels. Total cost would be EUR 6,645 billion, which is equivalent to 1.3 percent of Europe's cumulative GDP between 2020 and 2050. Buildup of the power infrastructure (generation and transmission grid) would require investments of EUR 2,330 billion. Beyond 2020, the transmission grid would need to increase 2.5-fold (a 5.5-fold increase compared with 2010). In 2050, Southern European regions would export power, some of it originating in the Middle East and North Africa. Central Europe would become the largest importer.

Hydro and Desertec would provide 13 to 14 percent of the generation mix respectively; other renewables would provide 53 percent and nuclear 13 percent. Exhibit 12 shows the evolution of the European power generation mix between 2020 and 2050. The balanced power generation mix of 2020 would transform into a mix dominated by renewables and nuclear generation. Together, they would account for 93 percent of the total generation mix by 2050. This would include hydro power and Desertec, accounting for 13 and 14 percent of generation, respectively. Technologies based on fossil fuels (i.e., gas, lignite, hard coal) would generate only 7 percent of the total in 2050. CCS technologies would play only a marginal role. In 2050, hard coal and lignite CCS would provide about 190 TWh or only about 5 percent of the total power generated. This is because providing power through nuclear plants is less expensive than using CCS plants. From a European economic perspective, it is cheaper in many cases to build additional nuclear capacity in one region and to add new transmission capacity, than to build CCS capacities in the regions where nuclear buildup potential is restricted.

Nuclear generation would drop from 950 TWh in 2020 to 630 TWh in 2050. Due to growing demand, its share of total generation would fall from 27 percent in 2020 to 13 percent in 2050. In renewables generation, wind power would provide the largest share in 2050 – 1,725 TWh. Solar power (photovoltaic and concentrated solar power in Europe) and biomass technologies would account for 480 TWh and 385 TWh, respectively. Other technologies, such as geothermal, would provide an additional 70 TWh.

Concentrated solar power from outside Europe (Desertec) would contribute a significant share (i.e., 14% or 700 TWh) to the total power production in 2050. We assume this project to be realized as currently described in the white book. We are aware that the Desertec project is in its early stages of development and still faces many obstacles to realization. However, it is relevant in size and impact for the future energy supply of Europe if it materializes. In order to recognize potential failure, we have analyzed sensitivities correlated to non-realization.

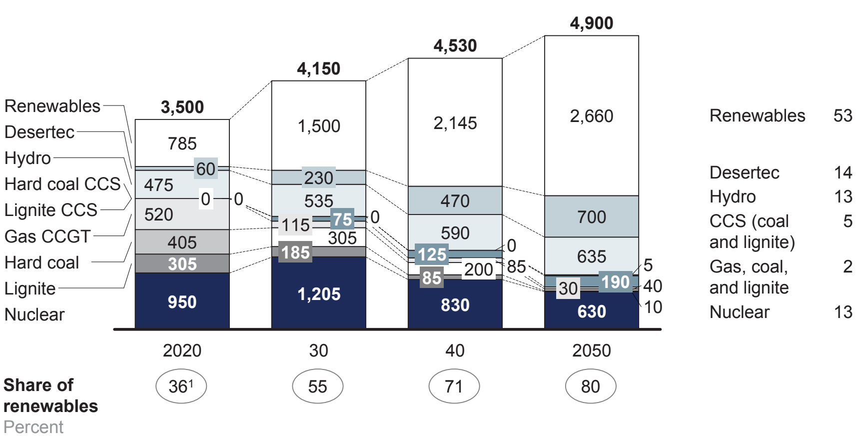
Exhibit 12

In the "green" scenario, EU-27+2 power generation would achieve an 80% share of renewables

"GREEN" SCENARIO

Development of EU-27+2 power generation landscape, 2020 - 50
TWh

Shares in 2050
Percent



1 Including Desertec, renewables share would increase to 38%

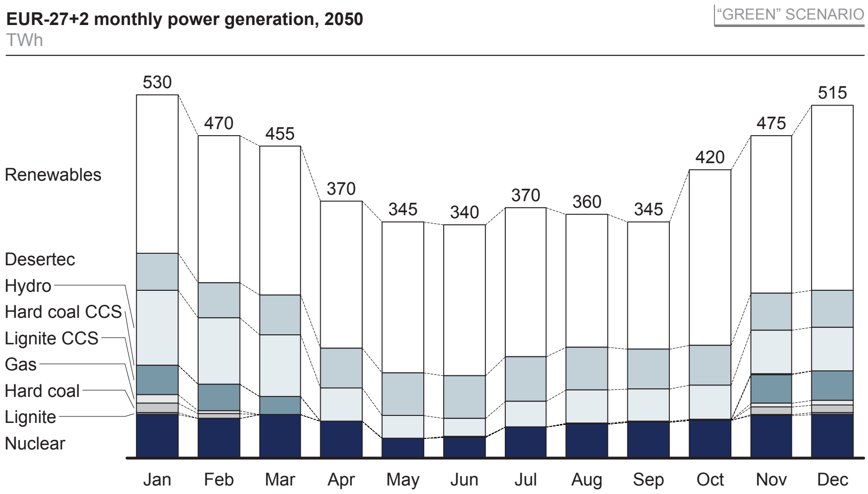
SOURCE: Desertec Foundation; McKinsey

In 2050, wind and solar power would provide about 2,200 TWh, or 40 percent, of overall demand. To back this up in an extreme weather event, about 730 GW of controllable power capacities would be required. This includes roughly 200 GW of additional backup requirement that would be used mainly as a reserve for an extreme weather event with very low renewable power generation over an extended time period.[10]

The least expensive way to support this provision of backup power beyond the capacities used for actual generation would be to keep conventional power plants connected to the grid. On a yearly basis, this would require only one-third the cost of providing this backup power with a new pumped storage facility and would cost at least four times less than other storage options such as compressed air.

Exhibit 13

In 2050, nuclear and hydro would balance generation in summer, while hard coal and lignite CCS would be used only in winter



SOURCE: McKinsey

As Exhibit 13 shows, nuclear and renewables generation would operate throughout the year. In the summer months when demand is lower, they would provide almost 100 percent of the required power. Renewables feed-in would even be strong enough to reduce the share of supply required from nuclear, leading to lower utilization rates of nuclear plants in the summer and a yearly utilization of approximately 75 percent.

Hydro and conventional power plants would satisfy the higher demand in winter months. This would result in very low utilization rates for conventional units compared with today.

Seasonality of demand would have a significant effect on the expected profitability of operating fossil-fuel plants. As demand assumptions in the "green" scenario are the same as in the "clean" scenario, seasonality of demand also leads to low utilization rates of most conventional units. Yet in contrast to the "clean" scenario, controllable nuclear capacity is replaced in the "green" scenario largely by intermittent renewable capacity. This increases the need for plants that provide power only in hours of peak residual demand[11], especially during the winter months. Beyond the above-mentioned backup plants, the remaining 100 GW of fossil capacity without CCS would operate at an average utilization rate of 10 percent, with some plants at only 4 percent utilization. The challenge of ensuring the continued profitable operation of these plants will be even greater than in the "clean" scenario.

Generation mix consisting of 93 percent renewables and nuclear generation would reduce average marginal cost and increase volatility. As in the "clean" scenario, more than 90 percent of the power in the "green" scenario is generated by renewables and nuclear, both technologies with low marginal cost. In the "green" scenario, the effect of low marginal cost is even stronger as renewable technologies with almost zero marginal cost generate 80 percent of the European power supply. Thus, in 2050, marginal generation cost falls to a yearly average of around EUR 15 per MWh, which is less than

30 percent of the full generation cost. If today's marginal-cost-based remuneration schemes were then still in force, producing electric power would on average no longer be a profitable business.

In 2050, the effect of the 735 GW of intermittent renewables-generating capacities (165 GW solar PV, 570 GW wind) would be to increase the volatility of power production by renewables, thereby also increasing the volatility of marginal cost. For example, at times when 60 percent of these 735 GW intermittent capacities are fully utilized, they would supply 100 percent of average European power demand at almost zero marginal cost. At times of low wind and sun, on the other hand, marginal cost would be much higher, up to EUR 100 per MWh.

Greenhouse gas emissions would decrease by 95 percent versus 1990 levels. CO_2e emissions from the European power sector would decrease from 800 Mt CO_2e in 2020 to 450 Mt CO_2e in 2030, 255 Mt CO_2e in 2040, and 60 Mt CO_2e in 2050. This means that GHG emissions would drop by more than 95 percent between 1990 and 2050.

Total cost would be EUR 6,645 billion or 1.3 percent of Europe's cumulative GDP between 2020 and 2050. The total cost of the power system with 80 percent renewables generation and a GHG emission reduction of 95 percent would be EUR 6,645 billion. This is equivalent to 1.3 percent of the cumulative GDP of the EU-27+2 countries combined.

- *Total cost* would increase over time. In 2020, Europe would pay EUR 175 billion for its power system. This figure would increase to EUR 215 billion in 2030, EUR 245 billion in 2040, and EUR 260 billion in 2050. Annualized investment cost would almost double over the same time period, from EUR 100 billion in 2020 to EUR 170 billion in 2050. On the other hand, expenditures for conventional fuels would decrease fourfold, from EUR 45 billion in 2020 to EUR 10 billion in 2050.

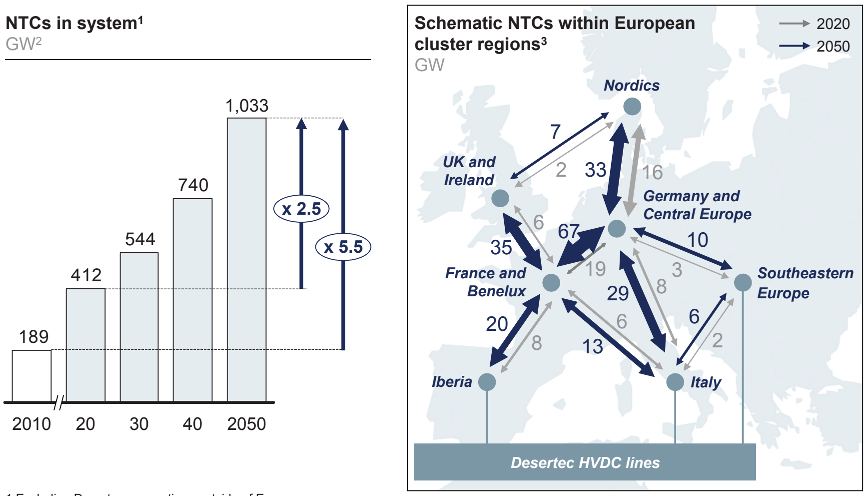
- *Investments of EUR 2,330 billion in power infrastructure required.* In the "green" scenario, net investments between 2020 and 2050 amount to EUR 2,330 billion. In the 2020s, net investments of EUR 730 billion are required, followed by EUR 795 billion in the 2030s, and EUR 805 billion in the 2040s. Of the total investments, roughly 80 percent would be for renewable generation technologies, including Desertec.

Beyond 2020, the transmission grid would need a further 2.5-fold increase. The cumulative capacities of the transmission grid would need to be expanded 5.5-fold compared with 2010 levels and 2.5-fold compared with 2020 (Exhibit 14). The expansion is necessary because wind and solar capacities are mostly built in the outlying regions of Europe: wind power in the northwestern part and solar along Europe's southern perimeter. With Desertec, 14 percent of Europe's power would be generated beyond Europe's southern border. In contrast, Central Europe[12] would account for 32 percent of Europe's power demand, but only 20 percent of its generation, as it has less attractive sites for renewables generation and nuclear power built up in only some Central European countries.

Exhibit 14

In the "green" scenario, strong NTC buildup to be expected especially with Central and Western Europe

"GREEN" SCENARIO



1 Excluding Desertec connections outside of Europe
2 Absolute numbers resulting from geographic split chosen in this study
3 56 regions grouped into 7 cluster regions

SOURCE: McKinsey

Within Western and Central Europe, this strong buildup would result in the need for a "copper plate" configuration by 2050, enabling large power flows across regions.

Interconnections from Southern Europe to Western and Central Europe would need to increase by 45 GW[13] (25 GW installed in 2020), of which 40 GW or 60 percent would be HVDC lines. A further 100 GW of HVDC lines would connect the Middle Eastern and North African solar fields to Europe's grid. This implies that Europe would build an extensive HVDC grid.

Net investments for this extension of the trans-regional transmission grid infrastructure would amount to EUR 185 billion, about 8 percent of total investments. In 2050, the capital cost for these new investments would account for EUR 15 billion, 6 percent of the total system cost of EUR 260 billion per year.

In 2050, Southern European regions would export power, partly originating from Desertec. Central Europe would become the largest importer. The power generated on solar fields in the Middle East and North Africa would flow through Southern Europe to the importing regions of Central Europe, which would import about 545 TWh, 37 percent of its overall power demand.

Italy would use its solar power imports of 260 TWh from the Middle East and North Africa to satisfy its domestic demand – to the rest of Europe, its import-export balance is close to zero. Iberia, possessing more attractive renewable sites of its own, and thus higher domestic generation than Italy, would export 300 TWh and at the same time import 260 TWh of the Middle Eastern and North African solar power.

Desertec solar power imports would also reduce the surplus generation of France and Benelux to 35 TWh, only 12 percent of the 285 TWh in the "clean" scenario. The UK and Ireland would remain an exporter of power, with the surplus of 20 TWh coming predominantly from wind generation. Scandinavia would become a major exporter, with 145 TWh of exports in 2050.

However, the more balanced picture on a yearly basis does not mean that power flows would decrease. On the contrary, the higher share of renewables would cause higher balancing flows, resulting in the need for a fivefold increase in transmission grid capacities compared with today's levels.

The relevance of Desertec. The setup of the "green" scenario assumes successful execution of the Desertec project at the cost and volumes published in the white book *Clean Power from Deserts* by the Desertec Foundation. The validation of the cost assumptions as well as the feasibility of the project was outside the scope of this study.

At the same time, our analysis shows that 80 percent of production by renewables inside Europe – excluding Desertec – is possible. In this case, the 700 TWh originally assumed from Desertec in 2050 would be primarily replaced by biomass, wind, and solar, each contributing 200 to 300 TWh.

However, this replacement would impact the power flows inside of Europe as well as the total system cost. Without Desertec, power flows from South to North will be reduced. At the same time, total system cost would increase by roughly 5 percent compared with the "green" scenario because the technologies assumed to replace Desertec have a higher full generation cost.

Results for Germany

In the "green" scenario, Germany would import up to 43 percent of its electricity in 2050, and grid connections crossing Germanys borders would have to increase 10-fold. In order to pursue a cost-optimal pathway, Germany would have a very strong interest in ensuring the success of the grid buildup.

Germany would import up to 43 percent of its electricity in 2050. The economically less attractive renewables sites in Germany and the nuclear phase-out[14] will lead Germany to import more and more clean electricity over time: in 2030, around 22 percent, in 2040, 28 percent, and in 2050, 43 percent. The power generated inside of Germany in 2050 would consist of the following mix: 45 percent renewable power (including hydro), 4 percent conventional power plants, 8 percent conventional power plants with CCS, and 0 percent nuclear power.

International transmission would have to increase 10-fold. Imported electricity would be transmitted into Germany mainly via the Nordic countries and France. To enable power flows into Germany, the surrounding trans-regional grid would have to be strengthened significantly. The NTCs along Germany's borders would need to increase threefold by 2020 and 10-fold by 2050. The grid along the western border would have to increase 12-fold.

2.3 Neither CO_2 emission targets nor renewables share – "lean" scenario

To assess the extra cost and implications of the "green" and "clean" scenarios, we modeled a third scenario: after 2020, Europe abandons its GHG emission targets and any renewables target share. We summarized the results in the "lean" scenario, which represents a cost-optimized evolution for the European power sector assuming no sustainability measures after 2020.

For comparability reasons, we assumed overall power demand to be the same as in the "clean" and "green" scenarios. Renewables generation technologies are built where they are cost competitive with the most economical conventional generating units.

As described earlier, we designed this scenario specifically to quantify the additional system cost that an optimized CO_2-free scenario would incur compared with an unconstrained scenario. This third scenario is not intended to be a desirable pathway.

Results for Europe

In the "lean" scenario, conventional fossil generation would cover Europe's demand growth and provide nearly half of Europe's generation by 2050. Greenhouse gas emissions would increase versus 1990 levels. The total system cost of the power system between 2020 and 2050 would be EUR 5,730 billion, or 1.1 percent of GDP. Investment cost would be EUR 1,230 billion. Transmission grid buildup beyond 2020 would be small, and power exchanges between countries would remain constant at their 2020 level.

Conventional fossil generation would cover Europe's demand growth and provide nearly half of Europe's generation by 2050. The sum of the power generated with hydro and other renewable energy sources would remain constant from 2020 through 2050. As in the other scenarios, we assumed that European hydro generation would grow from 475 TWh in 2020 to 635 TWh in 2050. With neither a CO_2 emission limit nor a CO_2 price, renewables generation technologies could compete against conventional power plants only in the most attractive sites. This constraint would even lead to a small decrease in generation fueled by other renewables after 2020, as some of the old renewables generation capacity would be decommissioned and not replaced. Nuclear generation would experience a slight decrease due to the German phase-out but otherwise remain constant at roughly 900 TWh.

The entire growth in demand of approximately 40 percent or 1,400 TWh would be covered by conventional fossil generation technologies – hard coal, lignite, and gas. In the "lean" scenario, their combined share of the generation mix increases from 37 percent in 2020 to 55 percent in 2050. Within the conventional technologies, the cost-optimal composition of the generation mix depends heavily on the assumptions made regarding fuel cost and CO_2 emission prices. The cost-optimal mix in our study relies strongly on hard coal, given the assumptions included in the *World Energy Outlook 2009* and the absence of a CO_2 price. Introducing a CO_2 price in the "lean" scenario would lead to a shift in power production from coal-fired power plants to gas-fired plants. Obviously, this reduces CO_2 emissions and potentially increases the flexibility of the thermal generation fleet.

Greenhouse gas emissions would increase by up to 28 percent versus 1990 levels. In the "lean" scenario, GHG emissions would increase from 800 Mt CO_2e in 2020 to up to 1,900 Mt CO_2e in 2050. This means that GHG emissions could more than double between 2020 and 2050 in this scenario and increase by up to 28 percent compared to 1,500 Gt in 1990. Relying mostly on gas-fired power plants after 2020 would keep emissions roughly constant after 2020.[14]

Total cost of the power system between 2020 and 2050 would be EUR 5,730 billion, or 1.1 percent of GDP. Without committing to further GHG emission reduction or renewables generation targets beyond 2020, Europe would spend a total of EUR 5,730 billion on its power system between 2020 and 2050. This would be equal to about 1.1 percent of its cumulative GDP in the same period:

- *Between 2020 and 2050,* total cost per year would increase by 20 percent, while the electricity supply would grow by 40 percent. The increase would be driven primarily by expenditures for conventional fuels, which would increase by roughly 80 percent from EUR 45 billion in 2020 to EUR 80 billion in 2050. Annualized investment would remain roughly constant from 2020 to 2050. Unlike the other scenarios, in which investments would flow predominantly into capital-intensive technologies, such as renewables, nuclear, and CCS power plants, the generation park in the "lean" scenario would remain dominated by conventional fossil plants with low specific investment cost but higher operating cost.

- *Investment cost would be EUR 1,230 billion.* Total investment cost would be EUR 1,230 billion, or on average EUR 40 billion per year. In the 2020s, net investments of EUR 355 billion would be required, followed by EUR 540 billion in the 2030s, and dropping to EUR 335 billion in the 2040s. This number is roughly half of the required investment volume of the high-renewable "green" scenario, and 40 percent less than the investment total of the "clean" scenario.

Transmission grid buildup beyond 2020 would be very small. As in the other scenarios, the "lean" scenario also requires a doubling of trans-regional transmission grid capacity by 2020 in order to make optimal use of the assumed 36 percent share of renewables generation in 2020. Between 2020 and 2050, the grid would need to be further increased 1.4-fold compared with 2020 levels. This is roughly 1 percent per year and in total less than the currently planned buildup between 2010 and 2020. Compared with other components in the total cost per year, grid expenditures would be negligible. Between 2020 and 2050, they would account for less than 2 percent of the total cost. The buildup of trans-regional transmission lines would focus on HVAC technology.

No increase in power exchange over 2020 level. The dominance of conventional generation, which has limited site restrictions (with the exception of lignite and nuclear plants in some countries) and could thus be built anywhere in Europe in the "lean" scenario, would allow each country to balance its own demand. This degree of autonomy would be reflected in the low transmission grid buildup beyond 2020, and is confirmed by the import-export balances of the European cluster. For instance, Central Europe with Germany – the largest net importer in the "clean" and "green" scenarios – would have net exports of 15 TWh per year (around 1 percent of total demand).

Results for Germany

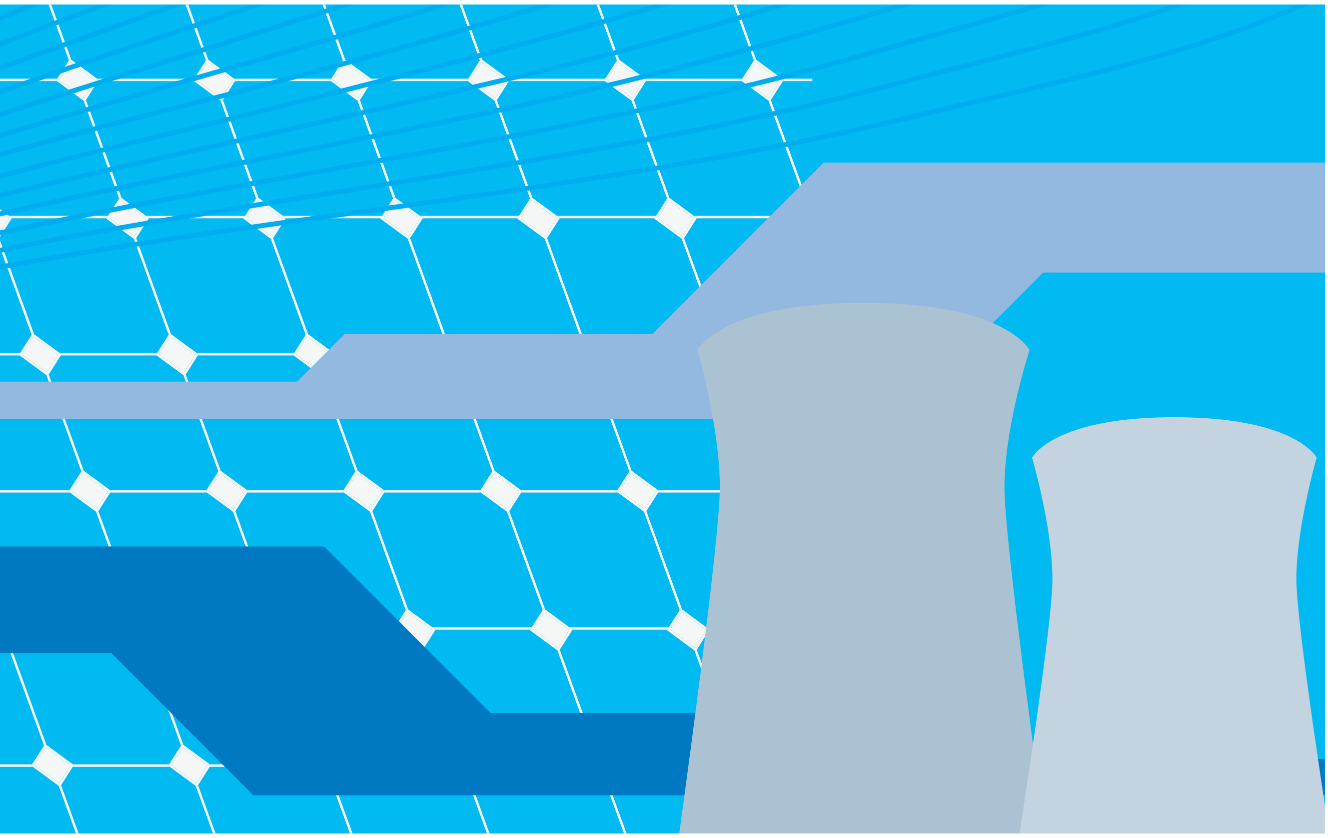
In the "lean" scenario, Germany would have a self-sufficient electricity supply in 2050. International transmission capacity would have to increase 1.2-fold by 2020 but would only require a further 1.4-fold increase by 2050 in the absence of targets for reducing CO_2 emissions and increasing the share of generation from renewables.

Germany would be self-sufficient in 2050 with regard to electricity supply. Renewables (including hydro) would supply 16 percent of the generation mix by 2050. A small share of about 6 percent of power demand would still be imported while conventional power plants would supply the rest.

Trans-regional transmission would have to increase 1.2-fold by 2020 but would only require a further 1.4-fold increase by 2050. To support power exchange for balancing purposes, the trans-regional grid would have to increase 1.2-fold by 2020, as a strong buildup of renewables generation is assumed until 2020. A further 1.4-fold increase would be required between 2020 and 2050. The net import-export balance across Germany's borders would be roughly 40 TWh by 2050. In this scenario, the main source of imports to Germany would be Scandinavia with 20 TWh in 2050. These imports would occur mostly during winter months, when Scandinavian reservoir hydro power would contribute to meeting German power demand.

Chapter end notes

1 Based on current investment plans. It was estimated that the European power sector invests about EUR 45 billion to 50 billion per year in power system infrastructure.
2 High interconnection between regions reduces overall requirements for controllable generation capacities, as the regional probability of simultaneous incidents of low-renewable power feed-in (i.e., no wind in Norway, Spain, and Germany) and demand fluctuations are reduced by interconnecting Europe.
3 Total system cost includes annualized investment cost, operational cost, and fuel cost for the time period from 2020 to 2050. All investments are discounted over the economic lifetime of the asset at a capital cost of 7 percent.
4 For investments whose lifetime ends after 2050, only depreciation is taken into account up to 2050. Similarly, for investments before 2020 whose lifetime ends after 2020, only the post-2020 depreciation is taken into account. The latter applies equally to all scenarios.
5 Natural gas, uranium, lignite, and hard coal.
6 Net amount spent on power system infrastructure in real 2010 values. Neither discounted nor annualized over the lifetime of the asset. Investments before 2020 are not considered.
7 Comprises Germany, Austria, Switzerland, Poland, the Baltics, Czech Republic, Slovakia, Hungary, and Slovenia.
8 Assumed growth in electricity demand in Germany is below European growth as other countries in Europe are currently less developed, and faster growth in those regions is assumed until 2050.
9 The decision of the government to extend the lifetime of the German nuclear power plants by 8 to 14 years has not been taken into account in the modeling as the decision has not come into law yet. The lifetime extension will affect the transition period to 2050 but not 2050, as all nuclear power plants would go off line before 2050. Such a lifetime extension would reduce the total system cost for Germany by EUR 35 billion from 2020 to 2050.
10 Beyond the additional backup plants, controllable power is provided by 270 GW of conventional power generation on capacities (nuclear, hard coal, lignite, and gas) and another 260 GW of controllable renewable capacities, such as reservoir hydro, pumped storage, and biomass.
11 Remainder between „must-run“ renewable units and the demand at any given point in time.
12 Germany, Switzerland, Austria, Poland, Czech Republic, Slovakia, Slovenia, and Hungary.
13 Sum of the interconnections Spain-France, Italy-France, Italy-Austria, Italy-Switzerland, and Romania-Hungary.
14 The decision of the government to extend the lifetime of the German nuclear power plants by 8 to 14 years has not been taken into account in the modeling as the decision has not come into law yet. The lifetime extension will affect the transition period up to 2050 but not after 2050, as all nuclear power plants would go off line before 2050. Such a lifetime extension would reduce the total system cost for Germany by EUR 35 billion from 2020 to 2050.



3 Non-optimal pathways

In this study, we modeled cost-optimal pathways to assess the differences between the "green," "clean," and "lean" scenarios. Pursuing such cost-optimal pathways requires strong European coordination in order to achieve cost-optimal allocation of renewable capacities, sufficient grid expansion, and cost-efficient provision of backup power. Insufficient coordination would lead to significant cost increases. To assess the robustness of the results and identify the key levers that need to be managed to keep cost under control, we performed several sensitivity analyses for the "green" and "clean" scenarios.

Non-optimal buildup of the "clean" scenario

We assessed restrictions on building up nuclear power in Europe as well as striving for power self-sufficiency in Germany (Exhibit 15).

Exhibit 15

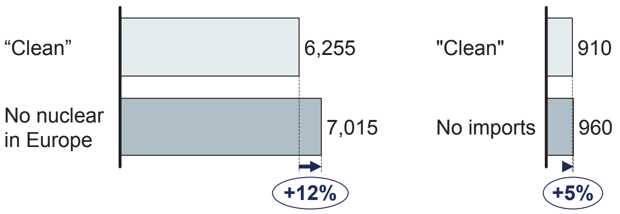
Not using nuclear power increases total cost by 12% in Europe, ensuring power self-sufficiency in Germany increases cost by 5%

Financial effects of not using nuclear power in Europe/Germany
EUR billions, cumulative, 2020 - 50

"CLEAN" SCENARIO

	Europe: CCS instead of nuclear power	Germany: Complete power self-sufficiency
Assumptions	▪ Based on the "clean" scenario ▪ Entire nuclear power generation 2020 - 50 replaced by CCS (2,300 TWh in 2050, 53,000 TWh total)	▪ Based on the "clean" scenario ▪ Germany ensures power self-sufficiency ▪ Use of CCS in Germany instead of imports (285 TWh in 2050, total 3,900 TWh)

Financial effects



SOURCE: McKinsey

Sensitivities for the "clean" scenario show that a non-cost-optimal choice of conventional power technologies (including nuclear power) would increase total cost by up to 12 percent or EUR 760 billion in Europe. Pursuing national self-sufficiency in Germany while reaching the emission targets would raise cost by an additional EUR 50 billion in the "clean" scenario in Germany.

Replacing nuclear with coal CCS technology would increase cost by 12 percent. If restrictions are placed on the production of nuclear power in Europe, other CO_2-free technologies would need to contribute more to meet the 95 percent emission reduction target. Replacing 100 percent of production from nuclear power plants with coal CCS (roughly 53,000 TWh for the period 2020 to 2050), for example, would increase the total system cost by 12 percent or EUR 760 billion. Fully replacing nuclear with CCS plants would mean eventually reaching the limit of the assumed CO_2 storage capacity[1] of roughly 120 Gt, requiring the development of additional storage capacity or other ways to cope with the captured CO_2.

Striving for power self-sufficiency in Germany would increase total system cost for German supply by EUR 50 billion. In the “clean” scenario, Germany would rely on imports of clean electricity from other regions of Europe for 41 percent of its power. In its effort to achieve power self-sufficiency, Germany would have to produce an extra 285 TWh in 2050 in a CO_2-free manner. Ensuring power self-sufficiency between 2020 and 2050 in Germany, while achieving the GHG targets by increasing production from CCS power plants, would raise total system cost by EUR 50 billion. At the same time, this path would imply the construction of a massive CCS pipeline network in Germany to transport the additional 150 to 300 Mt CO_2 through Germany each year.

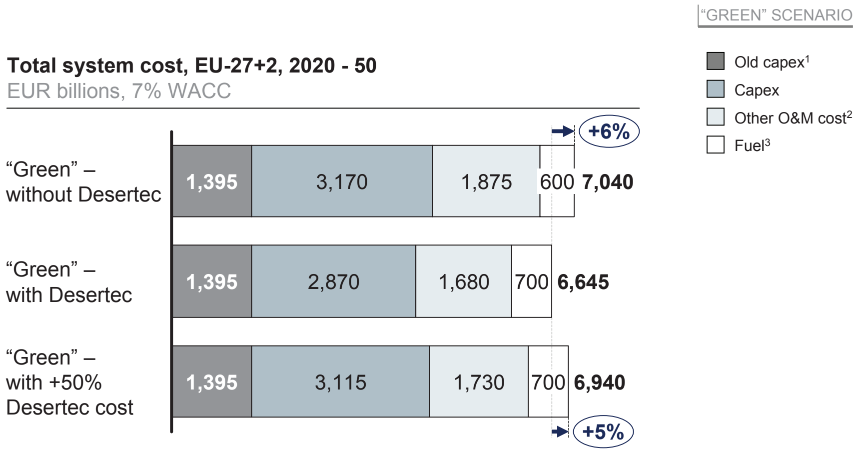
Non-optimal buildup of the “green” scenario

We assessed restrictions on the buildup of Desertec and a more costly implementation of the Desertec project. We also estimated the cost for non-optimal buildup of renewable capacities inside Europe and especially within Germany. Sensitivities for the “green” scenario show that, if Desertec is not built or if it experiences a 50 percent cost overrun, the total system cost in Europe would increase by roughly 5 percent. Extending the current national renewable energy action plans to 2050 could increase cost by 30 to 35 percent. This increase roughly amounts to EUR 2,000 billion in Europe, which is roughly equal to the total income of 2 million families over the 30 years[2].

Not building Desertec or a Desertec cost overrun would add roughly 5 percent to total system cost. Our analysis shows that 80 percent of production by renewables inside Europe – excluding Desertec – would be possible at an additional cost of 6 percent of the total system cost on top of the “green” scenario (Exhibit 16). If the large-scale buildup of solar fields in the Middle East and North Africa is not realized, the total cost of achieving the 80 percent renewables generation target would increase by EUR 395 billion to a total of EUR 7,040 billion. This increase would be driven by the rising cost of placing renewables generation in less attractive sites in Europe to make up for the 700 TWh that cannot be imported from renewable energy sources in the Middle East and North Africa. Our study did not include a detailed assessment of the cost of realizing the Desertec project with approximately 100 GW of CSP plants in the Middle East and North Africa. We used all estimates as published in the white book *Clean Power from Deserts* by the Desertec Foundation. Assuming the project cost increases by 50 percent over these estimates, the cost overrun would increase the total system cost from EUR 6,645 billion in the “green” scenario to EUR 6,940 billion. This 5 percent increase would make the total system cost comparable with the sensitivity of providing 80 percent of production by renewables inside Europe.

Exhibit 16

Not building Desertec increases cost of "green" scenario by 6% – an increase in Desertec project cost could have the same effect



1 Cost for plants and grid built before 2020
2 All fixed and variable O&M costs, excluding fossil fuels, including biomass
3 Only nuclear, coal, lignite, and gas, excluding biomass

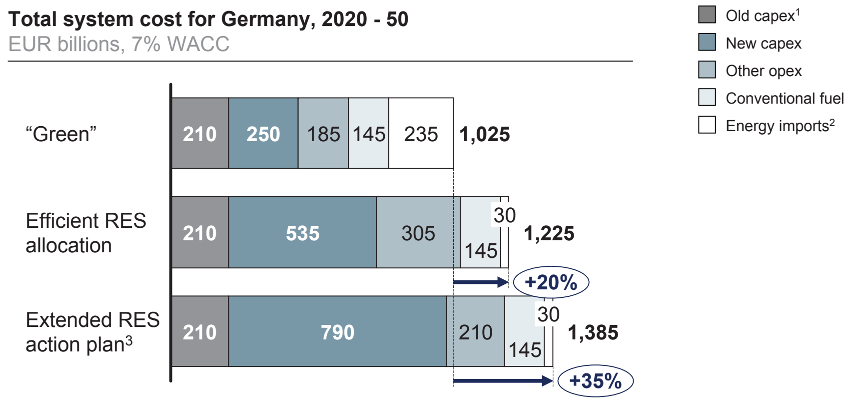
SOURCE: McKinsey

Implementing self-sufficiency in Germany would increase cost by at least 20 percent. Following a self-sufficient approach and achieving 80 percent renewables production inside of Germany, while pursuing a cost-optimal pathway for the allocation of renewables, would lead to an additional system cost of 20 percent compared with the European "green" scenario (Exhibit 17). Roughly 34 percent of German power demand would be supplied by wind capacity and another 11 percent by biomass. The remaining 35 percent renewables would be split between solar PV, hydro, geothermal, and other renewables.

Non-optimal buildup of renewable capacities in Europe and especially Germany could lead to additional cost increases of 30 to 35 percent. Currently, all countries of the European Union are required to publish national renewable energy action plans that provide detailed roadmaps of how each member state expects to reach its national 2020 target for the share of renewable energy in its final energy consumption. These action plans lack pan-European coordination and do not necessarily focus on cost-optimal solutions. For example, the German renewable energy action plan for renewable power generation foresees a total of 52 GW of installed photovoltaic (PV) capacity in 2020. Given the relatively high cost of solar PV power generation in Germany, this is not a cost-optimal pathway. Despite the fact that the average yearly full sun hours in Portugal, Spain, and Greece are 1.5 times higher than in Germany, the German buildup plan foresees increasing the capacity installed in Germany by 2020 to a figure 2.5 times greater than the combined total of these three countries (Exhibit 18).

Exhibit 17

Reaching 80% renewable generation in Germany could cost an additional 30 - 35%, based on extrapolation of renewable energy action plan



1 Cost for plants and grid built before 2020
2 Cost for energy imports are calculated based on the average cost for total European generation per year
3 Assuming Germany achieves 80% renewable generation itself via a non-optimal renewable generation park. 160 TWh provided by solar PV, further 400 TWh cost-optimally (mostly wind and biomass). This is based on extending the national German renewable action plan

SOURCE: McKinsey

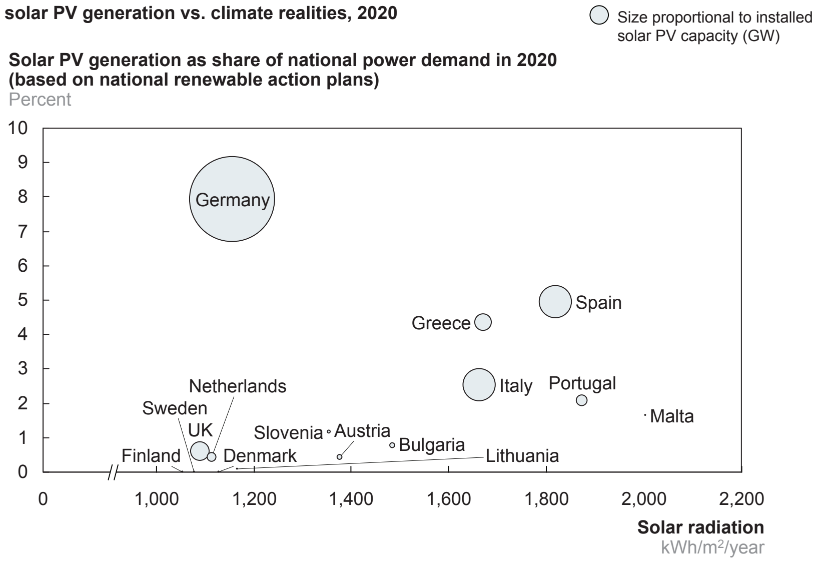
Assuming that Germany achieves 80 percent renewables production inside of Germany in 2050, by extrapolating the expected growth in solar PV capacity[3] from the current action plan and placing the remaining renewables in a cost-optimal manner, system cost would amount to roughly 30 to 35 percent more than in the cost-optimized European "green" scenario (Exhibit 17). This amounts to roughly EUR 300 billion to 350 billion additional cost for Germany. A 30 to 35 percent increase in total system cost in Europe would amount to roughly EUR 2,000 billion, or the total income of 2 million families over the 30 years.

As reported in *European RES-E Policy Analysis*, published in April 2010 by the Institute of Energy Economics at the University of Cologne (EWI), the Institute also assessed the cost of non-optimal pathways (2008 to 2020). This analysis shows that the non-optimal path for Europe is 33 percent more expensive than the optimal pathway.

Exhibit 18

Current national renewable action plans neglect climate realities and lead to inefficient distribution of renewables, especially solar PV

Planned solar PV generation vs. climate realities, 2020



SOURCE: National renewable action plans submitted to EU Commission; McKinsey

Detailed grid modeling has not been performed for these non-optimal scenarios. Nevertheless, other studies[4] have shown that significant transmission grid buildup is required in any case, for example, to bring the power from the large wind-parks in the North to demand centers in the South.

On the one hand, this assessment demonstrates that national pathways – in contrast to a coordinated pan-European approach – are more expensive, even after cost optimization. On the other hand, it also shows that optimizing national renewable energy action plans – by focusing on the most economical renewables, such as wind – can yield massive upsides compared with non-optimal national approaches. Particularly for Germany, this optimization could amount to savings of roughly 150 billion from 2020 to 2050.

Chapter end notes

1 In this case, a total of 53,000 TWh of CCS replacing nuclear power would add to already produced 12,000 TWh of CCS in the basic "clean" scenario, leading to a total volume of approximately 60 Gt CO_2e for the power sector alone.
2 Assuming an average yearly disposable income of EUR 35,000 per household.
3 The German action plan currently assumes a growth in solar PV capacity by 36 GW per decade until 2020; extending this growth to 2050 would lead to an installed capacity of approximately 160 GW. To reach the 80 percent renewables production, a further 400 TWh have been placed in a cost-optimal way (mostly wind and biomass) inside Germany.
4 For example: "Netzstudie 1" by the "Deutsche Energie Agentur" (Dena).

Methodology and cost assumptions

Methodology

This study used three modeling tools in an iterative process to assess the evolution of the European power system (Exhibit 19). The models work separately and exchange specifically defined data sets.

The target function of the modeling process is to provide supply to a given European power demand at the lowest total system cost from an economic perspective, while adhering to the boundary conditions given in the scenarios. This implies that the decisions made in the process do not necessarily reflect viable business decisions.

The three steps of the iterative process are:

1. *Placement of renewable capacities.* The renewables model places the most economic renewables at the most attractive sites across Europe. The model is a McKinsey proprietary tool that differentiates sites for various renewable technologies per region by financial and geographic attractiveness and their respective maximum potential. Renewable buildup is either determined by a predefined renewable generation share or by maximum full generation cost. For the "clean" and the "lean" scenarios, the target was to reduce the overall system cost in "competition" with conventional generation units. Starting from the most economical option, the tool placed renewable units until a given threshold was reached for full generation cost set by "competing" conventional units in a given year. Additional cost effects of increased grid and backup requirements due to additional renewable generation were taken into account.[1]

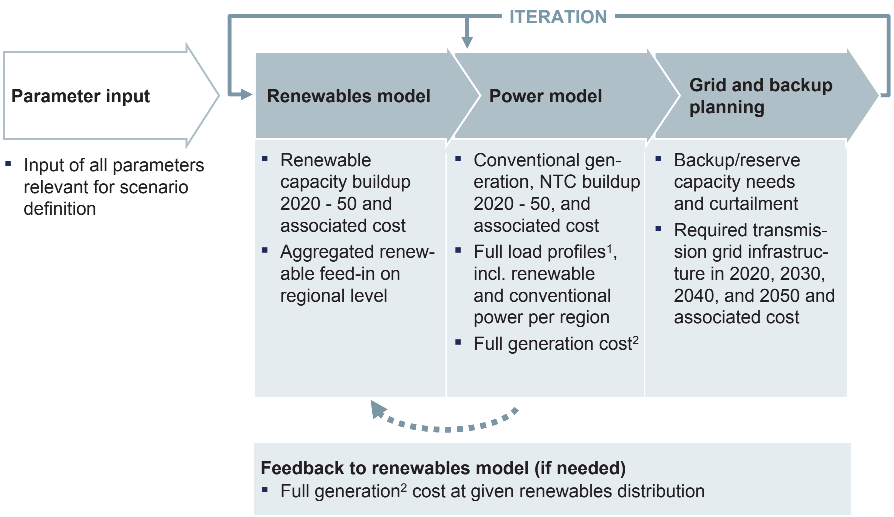
2. *Placement of conventional capacities and net transfer capacities.* The power model is a modeling tool based on the commercial power market modeling tool "Plexos" and used by McKinsey to model placement of conventional generation units, initial grid buildup, and hourly generator dispatching. It ensures that the residual demand after subtracting renewable generation is satisfied. Constraints such as regional site availabilities (e.g., nuclear and CCS) and GHG emission reduction targets are taken into account. A cost-optimal solution is developed by considering investment and operational costs both for generation technologies and for net transfer capacities. The target function is to satisfy demand (net of renewables generation) at the lowest cost. As an output, the model provides detailed information on conventional generation and net transfer capacities built within/between regions, as well as hourly dispatching profiles.

3. *System stress test and transmission grid expansion planning.* Based on the power system determined by modeling the renewable and conventional generation capacities, the grid model ensures system reliability at the same level as today. The model is built in DIgSILENT PowerFactory, a commercial power system calculation tool, and represents the European transmission system of all ENTSO-E members. The model consists of 240 nodes representing load centers within Europe. Transmission lines between the load centers are aggregated; both HVAC and HVDC lines are considered. The model performs a stress test on the reliability of the power system configuration in extreme weather events for the years 2020, 2030, 2040, and 2050. This simulation examines the ability of the power system to satisfy demand under extreme conditions such as no generation from wind and solar power. To ensure system reliability, the model expands net transfer capacities or places additional backup and reserve power into the system.

Exhibit 19

We used 3 models in an iterative process

ALL SCENARIOS



1 Through integration of renewables feed-in profiles into the power model
2 In EUR/MWh; in contrast to marginal generation cost, annualized capital cost taken into account

SOURCE: Energynautics; McKinsey

Cost assumptions

All relevant assumptions on future technology cost are based on the report *Roadmap 2050*. These assumptions are the result of extensive consultations involving major European utilities, equipment manufacturers, and NGOs. These consultations took place in late 2009 / early 2010. The technology cost assumptions used are shown in Exhibit 20.

Total cost for generation per technology includes capex, fixed opex, variable opex, and fuel cost. Future reductions in these costs (e.g., technology improvements leading to lower investment cost for renewable technologies) were incorporated on a yearly basis using the findings presented in *Roadmap 2050*. Cost figures for conventional fuel result from the commodity price assumptions described in chapter 2. For biomass, fuel cost assumptions are differentiated by country, considering regional differences in type and availability of biomass.

Exhibit 20

Technology cost assumptions

		Capex (EUR/KW)		Fixed opex	Variable opex	Life-time
		2020	2050	% of capex	EUR/MWh	Years
Non-renewable	**Gas CCGT (CCS)**	700 - 800 (1,500 - 1,600)	600 - 700 (900 - 1,100)	~ 2 (2 - 3)	~ 1 (~ 2)	30 (30)
	Coal[1] (CCS)	1,400 - 1,600 (2,700 - 2,900)	1,150 - 1,350 (1,750 - 1,950)	~ 1 (3 - 4)	~ 1 (~ 3)	40 (40)
	Nuclear	2,700 - 3,300[2]	2,600 - 3,200[2]	~ 3	7 - 9[3]	45
Renewable	**Biomass**	1,900 - 2,300	1,300 - 1,600	~ 1	38 - 65[4]	30
	Wind offshore	2,300 - 2,700	1,900 - 2,300	~ 3	~ 0	25
	Wind onshore	1,000 - 1,200	900 - 1,200	~ 2	~ 0	25
	Solar PV	1,300 - 1,400	800 - 1,200	~ 1	~ 0	25
	Solar CSP	3,700 - 4,300	2,200 - 2,600	3 - 4	~ 0	30
	Geo-thermal	2,400 - 3,000[5]	1,800 - 2,200[5]	~ 3	~ 0	30

1 Cost assumptions are further specified for hard coal and lignite
2 Assumptions on nuclear capex in France lower than in rest of Europe
3 Including cost for uranium and for nuclear waste disposal
4 Including fuel cost for biomass; fuel cost differ between countries
5 Cost for enhanced geothermal 100 - 200% higher

SOURCE: European Climate Foundation; McKinsey

Chapter end notes

1 To account for additional grid requirements, the specific investment cost for renewable capacities was increased in regions that are already net power exporters in a certain year and decreased in regions that are net importers. In regions that are net exporters, for each MW of newly installed renewable capacity, the cost of building 0.8 MW of additional grid capacities was added to the specific investment cost of renewable energies. For importing regions, the specific investment cost of renewable capacities was reduced accordingly, only with a lower factor. To account for additional backup requirements, for each MW of intermittent renewable energy (solar, wind), the fixed operational cost of keeping a retired plant operational as backup power has been considered. These costs were only applied to model the cost-efficient buildup of the generation park (to model a “fair competition” of renewables and conventional generation capacities). Determination of the total system cost was based on a system-wide cost analysis reflecting the resulting total requirements for backup and grid buildup.

Glossary

Capex	In EUR; capital expenditures for generation or grid infrastructure. Includes the annualized investment and financing cost
CCGT	Combined cycle gas turbine (power plant)
CCS	Carbon capture and storage technologies, i.e., the set of processes allowing the on-site capture of CO_2 emissions from burning of fossil fuels, and the subsequent storage of the emitted CO_2 in underground formations
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent, i.e., specific value of the intensity of a greenhouse gas, expressed in the greenhouse effect of carbon dioxide, e.g., 21 for CH_4 (methane), 310 for N_2O (nitrous oxide)
Conventional power	Hard coal, lignite, and gas-fueled power plants (fossil plants) and nuclear plants
CSP	Concentrated solar power (plant)
Desertec	As defined in the white book *Clean Power from Deserts: The DESERTEC Concept for Energy, Water and Climate Security* by the Desertec Foundation. This project would include construction of 100 GW concentrated solar power plants in various locations in the Middle East and North Africa by 2050, providing up to 700 TWh of power via an HVDC grid connection to Europe in 2050
EU-27+2	The European Union and its 27 members, Norway, and Switzerland
EUR	Euro (real 2010)
EWI	Institute of Energy Economics at the University of Cologne
Full generation cost	In EUR per MWh. Total system cost accrued in a time period within one or more regions, divided by the corresponding electricity generated
GHG	Greenhouse gas in the context of the Kyoto Protocol, i.e., CO_2 (carbon dioxide), CH_4 (methane), N_2O (nitrous oxide), HFC/PFC (hydrofluorocarbons), and SF_6 (sulfur hexafluoride)
Gt	Gigaton(s), i.e., 10^9 metric tons
HVAC	High-voltage alternating current
HVDC	High-voltage direct current

Investment cost	In EUR. Cash out for buildup of generation or grid infrastructure in the year of buildup. Not discounted, not annualized
kWh	Kilowatt hour(s)
Mt	Megaton(s), i.e., 10^6 metric tons
MWh	Megawatt hour(s)
NTC	Net transfer capacity; an interregional connector in the transmission grid infrastructure
Opex	In EUR. Operational expenditures related to the generation of electricity
Power sector	In this study, grouping of all electric-power-producing businesses
Renewable power sources	All power generation technologies that either are fuel-free, e.g., wind and solar, or are fueled from non-fossil sources, such as biomass or hydro power
t	Metric ton
Total system cost	In EUR. Total cost (capital expenditure and operating expenditure) accrued in the power sector in order to supply the electricity required in one or more regions in the relevant time period. Cost for distribution networks within regions are excluded
TWh	Terawatt hour(s)
USD	United States dollar (real 2010)

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