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Phasing out nuclear power in Europe

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Abstract in Norwegian:

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Utfasing av atomkraft

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I 2011 ble et kraftverk på nordkysten av Japan (Fukushima) rammet av jordskjelv. Den påfølgende tsunamien var større enn kraftverket var dimensjonert for å tåle. Anleggets kjølesystem ble derfor satt ut av spill, og reaktorkjernen ble overopphetet og delvis nedsmeltet. Alle japanske atomkraftverk ble raskt stengt. I Europa var reaksjonene på atomkraftulykken varierende. Tyskland besluttet å stenge sine syv eldste atomkraftanlegg, samt fase ut øvrige atomkraftverk innen 2022. Belgia besluttet å fase ut tre atomkraftverk i 2015, samt fase ut øvrige anlegg innen 2025. I Frankrike, der atomkraft har en markedsandel på rundt 75 prosent, har det kommet signaler om at atomkraftens markedsandel skal reduseres til 50 prosent innen 2025. Andre land, spesielt i Øst-Europa, har ikke skrinlagt sine utbyggingsplaner, men mangler finansiering.

I et prosjekt finansiert av CREE og EU kommisjonen (ENTRACTE) har vi studert virkninger i de europeiske energimarkedene hvis alle land i Europa følger strategien til Tyskland og Belgia om å fase ut all atomkraft. Vi sammenlikner de europeiske energimarkedene i 2030 i tilfellet der atomkraftkapasitetene er i samsvar med dagens planer for utbygging og utfasing av atomkraft med et hypotetisk tilfelle der all atomkraft i alle (30) europeiske land er utfaset. Vi har lagt til grunn at EUs nylig vedtatte energi- og klimapolitikk for 2030 blir implementert, dvs. utslippene av drivhusgasser skal i 2030 være 40 prosent lavere enn i 1990, og fornybarandelen i sluttkonsumet av energi er minst 27 prosent.

Vi har benyttet den numeriske energimarkedsmodellen LIBEMOD til å studere virkninger av en fullstendig utfasing av atomkraft. Denne modellen beskriver energimarkedene i 30 Europeiske land, samt interaksjonen mellom landene gjennom handel med energi. Modellen dekker alle energivarer (flere typer kull, naturgass, olje, flere typer bioenergi og elektrisitet), og bestemmer utvinning, investeringer, produksjon, handel og konsum av energi, samt et konsistent sett av markedsklarerende priser. Produksjon av elektrisitet kan utføres med en rekke teknologier; kullkraft, gasskraft, oljekraft, biokraft, vannkraft, vindkraft, solkraft og atomkraft (som blir faset ut). Tilgangen til ressurser og karakteristiske trekk ved elektrisitetsteknologier varierer mellom land.

Når atomkraft fases ut reduseres tilbudet av kraft, og prisen på kraft stiger. Dette gir insentiver til å investere i andre elektrisitetsteknologier. Dermed stiger elektrisitetsproduksjonen og prisen på elektrisitet faller. Et sentralt spørsmål blir derfor hvor mye kraftproduksjonen alt i alt vil falle, samt hvilke teknologier som fyller opp (deler av) produksjonsnedgangen når EU implementerer sin klima- og energipolitikk for 2030. Vi finner at en atomkraftutfasing gir kun en marginal reduksjon i samlet produksjon av elektrisitet. Bortfallet av atomkraft fylles opp av gasskraft og fornybar kraftproduksjon, spesielt biokraft.

Phasing out nuclear power in Europe¹

Finn Roar Aune, Rolf Golombek and Hilde Hallre Le Tissier

Abstract

We explore the impact of an EU-wide nuclear phase-out by 2030 provided the EU energy and climate policy for 2030 is implemented. Using a numerical simulation model of the European energy industry (LIBEMOD), we find that a complete nuclear phase-out in Europe by 2030 has a moderate impact on total production of electricity (4 percent reduction) and only a tiny impact on total consumption of energy. Lower nuclear production is to a large extent replaced by more gas power and bio power. Whereas the 2030 EU target for the renewable share in final energy demand is (at least) 27 percent, we find that after a nuclear phase-out the renewable share is 29 percent. Total annual cost of a nuclear phase-out corresponds to 0.5 percent of GDP in Europe.

JEL classification: Q28; Q41; Q42 ; Q48 ; Q54

Key words: nuclear power, renewable electricity, CCS, carbon policy, energy modeling

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1 Introduction

Until the Fukushima accident in Japan in February 2011, nuclear power was by many seen as an important part of a low-carbon future. The accident sparked security concerns and anti-nuclear sentiments in many European countries causing three EU member states to phase out nuclear power. In Belgium, three reactors are to be phased out by 2015 and the remaining four reactors will be shut down by 2025. In Germany, the eight oldest reactors were shut down and a plan for a complete phase-out of nuclear by 2022 was agreed upon. In Switzerland, the parliament agreed not to replace any of the country's nuclear reactors, which will result in a complete phase-out by 2034.

For other EU countries, the response to the Fukushima accident was more mixed. For example, in France a European Pressurized Reactor (EPR) is under construction but the President has pledged to reduce the share of nuclear electricity production from 75 percent (2011) to 50 percent by 2025. In some East-European countries, there are plans to either extend the lifetime of current reactors (for example Bulgaria) or build new reactors (for example Romania), but currently plans are on hold because of lack of financing. Hence, the future of nuclear power in Europe is uncertain.

In this paper we examine the outcome if all EU member states follow the long-run strategy of Belgium, Germany and Switzerland to phase out nuclear power. We focus on two questions. First, to what extent will a phase-out of nuclear power be replaced by supply from other electricity technologies? Second, how will a phase-out change the composition of electricity technologies?

The short-run partial effect of a nuclear phase-out is lower supply of electricity, which, *cet. par.*, should increase the price of electricity, thereby providing incentives to invest in fossil-fuel based and renewable electricity production capacity. A higher price of electricity may also lead to substitution effects between consumption of electricity and consumption of primary energy. Hence, the effect of a nuclear phase-out may be smaller on total consumption of energy than on consumption of electricity. This suggests that in analyzing the impact of a nuclear phase-out a model that captures the whole energy industry, not only the electricity sector, should be used.

Of course, the impact of a nuclear phase-out depends on a number of factors. First, what is the guiding principle of investment in the electricity industry? One corner case is a centralized economy where the government solely decides investment in order to achieve some political goals, for example, a warranted level of electricity production. This is hardly a suitable description of the current energy industry in Europe. Rather, EU bodies and European governments impose energy and environmental goals and policy instruments and leave most investment and production decisions to the private sector – this is the approach taken in the present study. In particular, we will assume that profit maximization is the guiding principle of investment in the European energy industry.

Second, the time horizon of a nuclear phase-out is important. While a nuclear plant may be shut down immediately, it takes time to build up new generation capacity: To set up and run a new electricity

plant requires detailed planning, concessions, construction, and adjustment of facilities and technologies, which may easily take 10 years. Thus in this study we examine a nuclear phase-out for 2030 and hence short-run bottlenecks are not an issue.

Third, the impact of a nuclear phase-out will depend on costs of electricity, in particular costs of new power plants. In general, costs can be decomposed into three elements: cost of investment; cost of daily operation, which for thermal power reflects the cost of purchasing the amount of a fuel necessary to produces 1 kWh with the efficiency of the installed technology; and other costs, for example, ramp-up costs, costs of maintenance and fixed costs. These costs components differ between technologies and will change over time. For most renewable electricity technologies, for example, solar power and wind power, there are negligible costs of daily operation. For fuel based electricity technologies, including bio power, this cost component is, however, substantial. Over time, costs of investment of renewable electricity technologies like solar and wind power may continue to fall, see, for example, European Commission (2013) and Schröder (2013), and thus in the future these technologies may increase their market shares radically.

Nuclear power has low cost of operation but excessive start-up and ramp-up cost, and is therefore used as the base load technology. If nuclear is phased out, the short-run marginal cost curve of electricity shifts upwards. Similarly, the short-run marginal cost curve of electricity shifts downwards if solar and wind power is phased in to replace nuclear. If, *hypothetically*, the nuclear phase-out is replaced by solar and wind power with an annual production capacity equal to that of nuclear, the new “annual” short-run marginal cost curve will be below the “annual” short-run marginal cost curve prior to the nuclear phase-out; this is because of negligible marginal costs of solar and wind power. The average annual price of electricity may therefore fall. However, thinking in terms of an annual marginal cost curve may easily lead to false conclusions: due to the intermittency of solar and wind power, in periods with no sun and wind the price of electricity will be high, whereas in periods with lots of sun or wind and moderate demand the price will be low. Hence, price volatility will increase and the impact on the average annual price is not obvious.

Finally, we will assume that EU bodies will be successful in establishing efficient internal energy markets and that the EU energy and climate policy targets for 2030 are reached: to attain a renewable share in final energy consumption of (at least) 27 percent and to reduce GHG emissions by 40 percent relative to 1990, see European Council (2014). Hence, we will examine the case of a nuclear phase-out by 2030 under the assumption of competitive markets, profit-maximizing energy producers and implementation of the 2030 EU energy and climate policy. Needless to say, these key assumptions should be kept in mind when interpreting our results, and hence in Section 5 we will discuss how our main results are sensitive to these assumptions.

The discussion above suggests that an adequate analysis of a nuclear phase-out should incorporate a detailed modelling of different electricity technologies to determine how the market price of electricity will change. Because equilibrium prices determine the profitability of investment, and hence future supply of

electricity, also the determination of investment should be an integral part of the model to ensure consistency.

While a theoretical study for sure will determine the sign of several effects, for example, the impact on investment in renewable electricity, of course the magnitude of the effects cannot be determined. Moreover, even the sign of some effects are truly ambiguous. For example, a higher price of CO₂ emissions, which may reflect a stricter emissions target, will weaken the position of fossil-fuel based electricity relative to renewables, but it will also strengthen the position of gas-fired plants relative to coal- and oil-fired plants. Hence, the net effect on natural gas-fired plants is ambiguous. In addition, while the short-run partial effect of a nuclear phase-out is a higher price of electricity, which should improve the position of gas power, the introduction of new technologies, for example, gas-fired plants with integrated Carbon Capture and Storage (CCS) facilities, may weaken the position of conventional gas-fired plants. Again, the signs of the gross effects are clear, but the net effect on conventional gas-fired plants is ambiguous - to identify the net effect a numerical model is required.

In this study we use the numerical multi-good multi-period model LIBEMOD to analyze impacts of a nuclear phase-out. This model meets the requirements specified above: it covers the entire energy industry in 30 European countries (EU-27 plus Iceland, Norway and Switzerland, henceforth referred to as EU-30). In the model, eight energy goods, that is, three types of coal, oil, natural gas, two types of bioenergy and electricity, are extracted, produced, traded and consumed in *each* of the 30 European countries. In each country, electricity can be produced by a number of technologies; nuclear, fuel based technologies (using either steam coal, lignite, oil, natural gas or biomass as an input), fossil-fuel based CCS (using either steam coal or natural gas), hydro (reservoir hydro, run-of-river hydro and pumped storage hydro), wind power and solar. We make a distinction between plants with pre-existing capacities in the data year of the model (2009) and new plants; the latter are built if such investments are profitable.

All markets for energy goods are assumed to be competitive in 2030. While steam coal, coking coal and biofuel are traded in global markets in LIBEMOD, natural gas, electricity and biomass are traded in European markets, although there is import of these goods from non-European countries. For the latter group of energy goods, trade takes place between pairs of countries, and such trade requires electricity transmission lines/gas pipelines. These networks have pre-existing capacities in the data year of the model, but through profitable investments capacities can be expanded.

LIBEMOD determines all prices and quantities in the European energy industry as well as prices and quantities of energy goods traded globally. In addition, the model determines emissions of CO₂ by country and sectors (households; services and the public sector; manufacturing; transport; electricity generation).

In Section 2 we provide a description of LIBEMOD, focusing mainly on supply of electricity. This section builds on an earlier version of the model, see Aune et al. (2008). In the new version of the model more countries have been added (13 East-European countries); the end-user sectors have been refined (the service and public sector has been separated from the household segment); the modeling of wind power has

been changed and more renewable technologies have been included (run-of-river hydro and solar power); the modeling of natural gas has been refined; bioenergy has been split into biomass and biofuel; all data have been updated (the data year has been changed from 2000 to 2009) and the complete model has been recalibrated, see <http://www.frisch.uio.no/ressurser/LIBEMOD/>.

In LIBEMOD all electricity producers maximize profits subject to a number of technology-specific constraints. In particular, LIBEMOD offers a strategy to model profitable investment in solar power and wind power taking into account that i) the production sites of these technologies differ, that is, the number of solar and wind hours differ between sites, and ii) access to sites is regulated. Both wind power and solar power will in general use surface area that has an opportunity cost; we therefore make assumptions on how much land that may be available for this type of electricity production in each country. The endogenous determination of investment in solar power and wind power is based on a combination of technical factors – the degree to which production sites differ – political factors – the degree to which agents get access to production sites – and economic factors – the profitability of investment given access to a set of production sites. To the best of our knowledge, LIBEMOD is the first energy market model with endogenous prices and truly endogenous investment in renewable electricity.²

In addition, we make two other contributions to the literature. First, we present an overview of costs of producing electricity by comparing total cost of electricity, as well as different cost elements, between different electricity technologies. These cost elements have consistent assumptions about factors like duration of a new plant, rate of interest, operational hours throughout the year, and fossil fuel prices. We also compare our cost assumptions to other studies, see Section 3.

Second, in Section 4 we use the numerical model LIBEMOD to quantify the effects of a nuclear phase-out in EU-30 and test (in Section 5) the sensitivity of the equilibrium after a complete nuclear phase-out by varying factors like i) the GHG emissions target, ii) the policy instruments imposed by the EU, and iii) cost of electricity production, for example, cost of investment in CCS power stations. To the best of our knowledge, the impact of an EU-wide nuclear phase-out has not been examined earlier.³ We find that if the 2030 EU policy to reduce GHG emissions by 40 percent relative to 1990 and to reach a renewable share in final energy consumption of (at least) 27 percent is implemented, a complete nuclear phase-out in EU-30 by

² There is a number of energy models covering different parts of Europe. Most of these models are pure electricity models, see, for example, the ATLANTIS model (Gutschi et al., 2009) and the LIMES model (Haller et al., 2012). In contrast, LIBEMOD also covers fossil fuels and bio energy. Typically, pure electricity models have exogenous demand for electricity, whereas LIBEMOD endogenizes consumption of energy. Some of the pure electricity models offer very detailed description of production of electricity as well as the electricity infrastructure, see, for example, ATLANTIS, but less attention on investment. Others have a higher level of aggregation and minimize total costs (optimizing models), see, for example, LIMES. In most of the models, supply of renewable electricity contains a substantial fraction of exogenous elements, but improvements are expected.

³ There are, however, some studies on the impact of a nuclear phase-out in Germany. For example, Fürsch et al. (2012) find that nuclear will be replaced by more coal-fire power and new gas fire capacity in Germany, as well as with increased imports of electricity. Knopf et al. (2014) examine the impact on German electricity prices and CO₂ emissions under a number of scenarios, stressing that the effects critically depend on which scenario that is examined. Finally, Kunz and Weight (2014) find modest effects in their ex-post assessment of the first part of the German nuclear phase-out. They argue that the second and final phase of the German nuclear phase-out will not create any capacity shortages.

2030 has a moderate impact on total production of electricity (4 percent reduction) and only a tiny impact on total consumption of energy (1 percent reduction). A nuclear phase-out is to a large extent replaced by more natural gas power and renewable electricity, in particular bio power, but also some wind power and solar. More generally, the equilibrium composition of electricity technologies reflects the stringency of the climate target and whether some technologies are being promoted through subsidies.

2 Libemod

In this section we describe the numerical multi-market multi-good equilibrium model LIBEMOD. This model allows for a detailed study of the energy markets in Europe, taking into account factors like fossil fuel extraction, inter-fuel competition, technological differences in electricity supply, key characteristics of renewable electricity technologies, transport of energy through gas pipes/electricity lines and investment in the energy industry. The model determines all energy prices and all energy quantities invested, extracted, produced, traded and consumed in each sector in each of 30 European countries; EU-27 plus Iceland, Norway and Switzerland – henceforth referred to as EU-30. The model also determines all energy prices and quantities traded in world markets, as well as emissions of CO₂ by country and sector, see Figure 1.

Figure 1 The LIBEMOD model

2.1 General description

The core of LIBEMOD is a set of competitive markets for eight energy goods: natural gas, oil, steam coal, coking coal, lignite, biomass, biofuel and electricity. All energy goods are extracted, produced and consumed in each country in EU-30. Natural gas, biomass and electricity are traded in competitive European markets. Trade in natural gas requires gas pipes that connect pairs of countries. Similarly, trade in electricity requires electricity transmission lines that connect pairs of countries. There are competitive world markets for coking coal, steam coal, oil and bio fuel, but competitive domestic markets for lignite. While fuels are traded in annual markets, there are seasonal (summer vs. winter) and time-of-day markets for electricity.

In each country in EU-30 (henceforth referred to as a model country) there is demand for all types of energy from four groups of end users; the household sector, the service and the public sector, the industry sector and the transport sector. Demand from each end-user group (in each model country) is derived from a nested multi-good multi-period constant elasticity of substitution (CES) utility function; this is a truly non-linear function, making LIBEMOD a non-linear model.⁴ In addition, there is intermediate demand for fuels

⁴ There are also other non-linear functions in LIBEMOD, for example, in extraction of fossil fuels.

from fuel-based electricity producers; gas-fired power stations demand natural gas, bio power stations demand biomass, etc.

Extraction of all fossil fuels, as well as production of biomass, is modelled by standard supply functions. Energy is traded between countries. In addition, there are domestic transport and distribution costs for energy; these differ across countries, energy carriers and user groups.⁵ For all energy goods, there is a competitive equilibrium; this is the case i) for all goods traded in a model country, ii) for oil, steam coal, coking coal and bio fuel traded in world markets, and iii) for transport services of natural gas and electricity between model countries. The price of each transport service consists of a unit cost and a non-negative (endogenous) capacity term; the latter ensures that demand for transport does not exceed the capacity of the gas pipe/electricity line. The capacities for international transport consist of two terms: pre-determined capacities (according to observed capacities in the data year of the model) and investment in capacities; the latter is undertaken if it is profitable.

We now turn to electricity supply, which is the most detailed model block in LIBEMOD. In each model country there are eleven pre-existing (“old”) electricity technologies: steam coal power, lignite power, gas power, oil power, bio power, reservoir hydropower, run-of-river hydropower, pumped storage hydropower, nuclear power, waste power and a composite technology referred to as renewable. Moreover, there are four new fuel-based technologies using the same fuels (except lignite) as the pre-existing technologies and five new renewable technologies; reservoir hydropower, run-of-river hydropower, pumped storage hydropower, wind power and solar power.

In general, for each old fuel-based technology and each model country, efficiency varies across electricity plants. However, instead of specifying heterogeneous plants for each old technology (in each model countries), we model the supply of electricity from each old fuel-based technology (in each model countries) as if there were one single plant with decreasing efficiency; this implies increasing marginal costs. For each type of new fuel-based technology, we assume, however, that all plants have the same efficiency (in all model countries). Whereas for pre-existing technologies the capacity is exogenous (in each model country), for new plants the capacity is in general determined by the model.⁶

There are six types of costs involved in electricity supplied from combustion of fuels. First, there are non-fuel monetary costs directly related to production of electricity, formulated as a constant unit operating cost c^O . Let y_t^E (TWh) be the production of power in period t . Then the monetary cost in each period is $c^O y_t^E$, which must be summed over all periods to get the total annual operating costs. Second, there are fuel costs. Third, production of electricity requires that capacity is maintained: in addition to choosing an

⁵ End users also face different types of taxes, in particular value added taxes. The end-user price of an energy good is the sum of i) the producer price of this good, ii) costs of domestic transport and distribution of this energy good (which differ between countries, end-user groups and energy goods), iii) end-user taxes (which also differ between countries, end-user groups and energy goods), and finally iv) losses in domestic transport and distribution.

⁶ For the pre-existing electricity technologies, we use information from ENTSO-E (2011) on capacities for 2020. Thus, capacities that are expected to come online by 2020 are included in our study (as pre-existing technologies).

electricity output level, the producer is assumed to choose the level of power capacity (GW) that is maintained, K^{PM} , thereby incurring a unit maintenance cost c^M per power unit (GW). Fourth, if the producer chooses to produce more electricity in one period than in the previous period in the same season, he will incur start-up or ramping up costs. In LIBEMOD these costs are partly expressed as an extra fuel requirement, but also as a monetary cost per unit of started power capacity in each period.

For investments in new power capacity, K^{inv} , there are annualised capital costs c^{inv} related to the investment. Finally, for *new* plants there are costs related to connecting to the grid; these reflect either that the site of the plant is not located at the grid and/or that connecting a new plant to the grid requires upgrading of the grid and these costs may partly be borne by the plant. Under the assumption that the distance to the grid is increasing in the number of new plants, that is, increasing in new capacity, and/or costs of upgrading the grid is increasing and convex, the cost of grid connection, $c^{gc}(K^{inv})K^{inv}$, is also increasing and convex.

Each plant maximizes profits subject to a number of technology constraints; for example, i) maintained power capacity should be less than or equal to total installed power capacity, ii) production of electricity in a time period should not exceed the net power capacity multiplied by the number of hours available for electricity production in that time period, and iii) because power plants need some down-time for technical maintenance, total annual production cannot exceed a share of the maintained annual production capacity. For a more detailed discussion of electricity supply from fuel-based technologies, see Aune *et al.* (2008).

We now turn to the modelling of renewables. In LIBEMOD there are now three types of hydroelectricity technologies; reservoir hydro, run-of-river hydro and pumped-storage hydro. Relative to the modelling of electricity supply from fuel-based technologies, *reservoir hydro*, which has a reservoir to store water, has two additional technology constraints. First, the reservoir filling at the end of season s cannot exceed the reservoir capacity. Second, total use of water, that is, total production of reservoir hydro power in season s plus the reservoir filling at the end of season s , should not exceed total supply of water, that is, the sum of the reservoir filling at the end of the previous season and the seasonal inflow capacity (expressed in energy units, TWh).

For the *run-of-river hydro power* technology, which is an extension of the LIBEMOD model presented in Aune *et al.* (2008), there is per definition no reservoir. Like for reservoir hydro there is, however, a restriction on use of water relative to availability of water; production in each time period cannot exceed the inflow of water.

Finally, the *pumped storage hydro power* technology is characterized by buying electricity in one period (e.g. during the night) and using that energy to pump water up to the reservoir in order to produce electricity in a different (higher-price) period (e.g. during the day) by letting the water flow down through the generator. As demonstrated in Aune *et al.* (2008), the optimization problem of this technology is similar

to the one for fuel-based technologies, except that the pumped storage producer uses electricity (and not fuels) as an input.

Bio power is modelled in exactly the same way as electricity supply from fuel-based technologies. The only difference is that bio power uses (carbon free) biomass as an input. Similarly to fossil fuels, biomass is supplied competitively and there is one thermal efficiency rate of new bio power (independent of amount of investment and country). In contrast, for solar power and wind power we assume that production sites differ (with respect to solar hours and wind hours). Moreover, whereas we for solar and wind power also take into consideration the amount of land available for electricity generation, see sections 2.2 and 2.3, the equilibrium quantities of biomass are so low in our simulations that they mainly consists of waste and by-products from agriculture and industry, that is, products not requiring separate land to be manufactured. Therefore, we do not introduce a land use restriction for biomass for 2030.⁷

2.2 Wind power - modeling

We assume that wind sites differ with respect to annual wind hours and that the best site for wind power (in terms of annual wind hours) is developed for wind power production before the second best site is developed, and so on. This is formalized by $f(K)$, which shows average number of wind hours per year (measured in kh) as a decreasing function of aggregate capacity of wind power plants. By multiplying average number of wind hours per year by how much wind power that can (maximally) be produced each hour – K (measured in GW) – a measure of annual production of wind power is obtained. However, because production of wind power depends on the amount of the capacity that is actually maintained, K^{PM} , we define the annual energy (electricity production) capacity of wind power (measured in TWh) by $f(K^{PM})K^{PM}$.

Also for wind power we have some technical constraints. First, maintained power capacity should be less or equal to installed power capacity, which for a new power plant is equal to investment in electricity production capacity:

$$K^{PM} \leq K^{inv} \perp \lambda^E \geq 0 \quad (1)$$

where λ^E is the shadow price of installed power capacity.

⁷ For hypothetically higher biomass prices, other types of biomass products would be supplied, and some of these would have required agricultural land. Note that for biofuels, that is, energy carriers used in the transport sector, the alternative value of land may be substantial in several countries, see, for example, Searchinger *et al.* (2008). In 2012, 2 percent of the agricultural land was used for biofuel production in the EU. Because the growth in equilibrium consumption of biofuel is moderate in LIBEMOD, there is no need to introduce restrictions on land use for biofuel production in LIBEMOD.

Second, let ψ_t^W be the share in period t of the annual number of wind hours. This means that maximum production of wind power in period t is $\psi_t^W f(K^{PM})K^{PM}$, and hence there is an upper limit on production of electricity in this period:

$$y_t^E \leq \psi_t^W f(K^{PM})K^{PM} \perp \mu_t \geq 0 \quad (2)$$

where μ_t is the shadow price of the periodic energy capacity.

Finally, also for wind power there is need for technical maintenance. Therefore, total annual production ($\sum_t y_t^E$) cannot exceed a share (ξ) of the maintained annual production capacity:

$$\sum_t y_t^E \leq \xi \sum_t \psi_t K^{PM} \perp \eta \geq 0 \quad (3)$$

where ψ_t is the number of hours available for electricity production in period t (kh) and η is the shadow price of the annual energy capacity.

Note that we have (implicitly) assumed that if the installed capacity of some (new) wind power plants is not maintained, then these plants are located at sites with the lowest number of annual wind hours. This assumption will be fulfilled if producers maximize profits, as we assume. In fact, with profit-maximizing wind power producers (and no uncertainty) the entire invested capacity will be maintained in the model.

Like for fuel-based technologies, wind power has a constant operating unit cost, c^O , as well as a constant unit maintenance cost, c^M . However, there is of course no fuel cost and there are no start-up costs for a wind power plant. Therefore, the Lagrangian of the optimizing problem of new wind power is:

$$\begin{aligned} \mathcal{L}^E = & \sum_{t \in T} P_t^{YE} y_t^E - \sum_{t \in T} c^O y_t^E - c^M K^{PM} - c^{inv} K^{inv} - c^{gc} (K^{inv}) K^{inv} \\ & - \lambda^E \{ K^{PM} - K^{inv} \} - \sum_{t \in T} \mu_t \{ y_t^E - \psi_t^W f(K^{PM}) K^{PM} \} - \eta \left\{ \sum_{t \in T} y_t^E - \xi \sum_{t \in T} \psi_t K^{PM} \right\}. \end{aligned} \quad (4)$$

The first-order condition for produced electricity in each period is:

$$P_t^{YE} - c^O \leq \mu_t + \eta \perp y_t^E \geq 0. \quad (5)$$

This is a standard first-order condition, simply stating that an interior solution, that is, $y_t^E > 0$, requires that the difference between the price of electricity P_t^{YE} and the marginal operating cost of production c^O should be equal to the sum of two shadow prices. The first is the shadow price of the periodic energy capacity where $\mu_t > 0$ reflects that increased production in period t is not possible for a given maintained capacity K^{PM} . The second is the shadow price of the annual energy capacity η . Because the maximum number of operating hours during the year ($\xi \sum_{t \in T} \psi_t$) will, for reasonable values of ξ , always exceed the number of wind hours at the best site (see discussion below), we have $\eta = 0$.

The first-order condition for maintained capacity is:

$$\left(\sum_{t \in T} \mu_t \psi_t^W \right) (f(K^{PM}) + f'(K^{PM})K^{PM}) + \eta \xi \sum_{t \in T} \psi_t \leq c^M + \lambda^E \perp K^{PM} \geq 0. \quad (6)$$

This first-order condition states that the cost of increasing maintained capacity marginally – the sum of the maintenance cost (c^M) and the shadow price of installed capacity (λ^E) – should (in an interior solution) be equal to the value of increased annual production following from this policy. Increased maintained capacity raises potential periodic and annual electricity production. Therefore, the value of increased production is i) the shadow price of periodic energy capacity (μ_t) weighted by the wind share in this period (ψ_t^W) and summed over the year when the effect on annual production of wind power due to increased maintained capacity ($f(K^{PM}) + f'(K^{PM})K^{PM}$) is taken into account, plus ii) the value of increased potential annual production, which is the shadow price of the annual energy capacity (η) times the maximum number of operating hours during the year ($\xi \sum_{t \in T} \psi_t$).

Finally, the first-order condition for investment is given by

$$\lambda^E \leq c^{inv} + c^{gc}(K^{inv}) + \frac{dc^{gc}(K^{inv})}{dK^{inv}} K^{inv} \perp K^{inv} \geq 0. \quad (7)$$

This condition implies that if investment is positive, then the total annualised investment cost, which includes the marginal cost of connecting to the grid, must equal the shadow price of installed capacity (λ^E), i.e. the increase in operating surplus resulting from one extra unit of capacity. As always, in addition to the

FOCs with respect to the decision variables the FOCs with respect to the multipliers recover the original optimisation restrictions.

2.3 Wind power - calibration

We impose a linear function on $f(K^{PM})$:

$$f(K^{PM}) = a^W - b^W K^{PM}. \quad (8)$$

Because $f(K^{PM})$ shows average number of wind hours (per year) as a decreasing function of aggregate maintained capacity, a^W should be interpreted as the number of wind hours (per year) at the best site (in a country). We have determined this parameter by using information from Storm Weather Centre (2004), EEA (2009) and Hoefnagels et al. (2011). From these sources we found the “best” location for wind power in each model country, with annual load hours ranging from 1500 to 3700, see Table 1. The load hours are defined as the ratio between annual electricity output of a wind turbine and its rated capacity (for details on how this is estimated, see Hoefnagels et al. (2011)).⁸

Table 1 Efficient wind hours at best site and wind power potential in EU-30

In order to determine the value of b^W we have to solve the optimization problem of a profit-maximizing agent investing in new wind power. To simplify, we assume that maintained capacity is equal to invested capacity (which is the case for a profit-maximizing agent). We also assume that the price of electricity is constant over the year (P^{YE}), and hence we focus only on annual production (y^E). This implies that we have only one restriction on wind power production; this restriction is related to total annual production of wind power.⁹ The Lagrangian of the optimizing problem of new wind power is therefore:

$$\mathcal{L}^E = P^{YE} y^E - \sum_{t \in T} c^o y^E - c^M K^{PM} - c^{inv} K^{PM} - \gamma \{ y^E - f(K^{PM}) K^{PM} \}. \quad (9)$$

Note that relative to the real decision problem of a wind power producer, see (4), we have removed costs of grid connection ($c^{gc} (K^{PM}) K^{PM}$) because the price of electricity in (9) is measured at the production node.

⁸ The numbers in Table 1 show efficient wind hours: For a specific type of a wind mill, 1 MW installed capacity generates x MWh annually where x is defined as efficient wind hours. Note that efficient wind hours reflect both how many hours it blows throughout the year and the wind speed. As a rule of thumb, a doubling of wind speed leads to a tripling of amount of energy generated (MWh).

⁹ Restriction (3) will never bind because the amount of wind during the year is too low; see discussion above.

The first-order condition for annual produced electricity is:

$$P^{YE} - c^O \leq \gamma \perp y^E \geq 0. \quad (10)$$

Further, the first-order condition for investment is $\gamma(f(K^{PM}) + \frac{df(K^{PM})}{dK^{PM}}K^{PM}) \leq c^M + c^{inv}$. Using (8), this condition can be rewritten as:

$$\gamma(a^w - 2b^w K^{PM}) \leq c^M + c^{inv} \perp K^{PM} \geq 0. \quad (11)$$

Finally, the first-order condition wrt. the multiplier γ is $y^E \leq f(K^{PM})K^{PM}$. Using (8) and the fact that a profit-maximizing producer always will use the entire maintained capacity, this first-order condition can be rewritten as

$$y^E = (a^w - b^w K^{PM})K^{PM}. \quad (12)$$

Based on available data we solve the system (10), (11) and (12) by treating $y^E (> 0)$, P^{YE} and a^w as exogenous variables. Then this system determines γ (from (10)), K^{PM} and b^w . We now explain how we set values for y^E and P^{YE} .

Our calibration of b^w draws on Eerens and Visser (2008), which has data for wind power potential (TWh) in Europe for 2030. This report provides a technical potential for each country, which is then reduced by excluding all sites with wind speeds below 4 m/s and land where biodiversity issues could prevent development (all land registered in the Natura 2000 database, see Natura (2005), or as nationally designated areas). For each country the remaining generation potential, referred to as the market potential, has been categorised into three cost classes. These are labelled ‘‘Competitive’’, ‘‘Most likely competitive’’ and ‘‘Not competitive’’; the potential within the two first classes are sites with production costs below 0.071 €/kWh. Thus, the Eerens and Visser study provides information about profitable potential wind power production in 2030 (in a country) if the price of electricity is constant over the year and equal to 0.07 €/kWh in 2030.

Because wind power requires use of land, which typically has an opportunity cost, actual wind power production will only be a small share of potential wind power production. It is hard to estimate this share, but in this study we assume that if the price of electricity is 0.07 €/kWh in 2030, total production of wind

power in 2030 will be of the same magnitude as total production of electricity in EU-30 in our data year 2009 (3399 TWh). To be more specific, we assume that for the cost classes “Competitive” and “Most likely competitive” 10 percent of the wind power potential in 2030 will be available for electricity generation in 2030; this amounts to 3816 TWh, see Table 1. By fixing annual wind power production in 2030, y^E , to 10 percent of the potential wind power production if the annual price of electricity is 0.07 €/kWh in 2030 (P^{YE}), and using the values for a^W (wind hours at best site in a country) from Table 1, we can determine b^W (for each country) for the year 2030.

Finally, we have made some rough estimates of land use by wind power under the assumption that actual production of wind power amounts to 10 percent of potential wind power production in 2030. In the literature two approaches are common: either to include areas directly related to wind power production (the mills, access roads to the mills, and other facilities) or the entire area of the wind park (which may encompass areas used for, say, agricultural production between the mills). Therefore, estimates of land use vary significantly; it is in range of 0.4 to 1.4 hectare/MW according to REN21, 6.7 hectare/MW according to EWEA (2006), 24 hectare/MW according to the American Wind Energy Association and between 30 and 50 hectare/MW according to Manwell et al. (2009). Assuming an average annual operation time of (onshore) wind power of 2000 hours, the estimates imply that between 0.2 and 20 percent of the land mass of EU-30 will be affected if, hypothetically, wind power production amounts to 3816 TWh.

2.4 Solar power - modeling

The main solar power technologies are Centralized Solar Power (CSP) and Photovoltaics (PV). The latter is a method of generating electrical power by converting solar radiation into direct current electricity by using solar panels containing photovoltaic material. We have chosen to model PV, which, based on available cost estimates, seems to be the most promising technology.

The PV technology requires land to produce electricity. Let Ω be *actual* use of land (measured in Gm^2) to produce solar power (in a country in a year). Under ideal conditions, the PV technology requires $\frac{1}{\chi} m^2$ to produce 1 kW momentarily, and therefore χ is the momentarily production of electricity (KW per m^2) under ideal conditions. The actual momentarily production capacity of solar under ideal conditions (measured in GW) is therefore

$$K = \chi \Omega. \tag{13}$$

Further, let $\hat{\Omega}$ be the amount of land available to solar power (in a country in a year) where $\Omega \leq \hat{\Omega}$. Then the maximum momentarily production capacity is $\hat{K} = \chi \hat{\Omega}$, and obviously we must have $K \leq \hat{K}$.

We now derive measures for annual energy capacity of solar power. First, let $\bar{\Omega}$ be annual solar irradiance (kWh per m^2) in a country. Then $\bar{\Omega}\Omega$ measures received energy by the solar panels throughout a year. Second, let $\bar{\theta}$ be the share of energy received by the solar panels that is actually transformed to solar power. Annual energy capacity of solar power (TWh) is then $\bar{\theta}\bar{\Omega}\Omega$. Alternatively, annual energy capacity can be expressed by zK where z measures annual solar hours (measured in kh), defined from the identity $zK \equiv \bar{\theta}\bar{\Omega}\Omega$. Using (13) this identity can be rewritten as

$$z\chi \equiv \bar{\theta}\bar{\Omega}. \quad (14)$$

So far we have implicitly assumed that each solar panel receives the same amount of energy. However, sites differ wrt. solar irradiance. We now assume that there is a continuum of sites (in a country) and these can be ranked according to their solar irradiance. Further, we assume that when solar production capacity is developed the best solar site is used before the second best site, etc. Hence, the more solar power that is developed, the lower is the average amount of energy received by the solar panels. This mechanism is captured by letting the measure of solar irradiance, $\bar{\Omega}$, be a downward sloping function of the capacity utilization: $\bar{\Omega} = \bar{\Omega}(\frac{K}{\hat{K}})$. Note that $\bar{\Omega}(\frac{K}{\hat{K}})$ should be interpreted as the average solar irradiance.

Using the identity (14), we now define our measure of annual solar hours:

$$z(\frac{K}{\hat{K}}) \equiv \frac{\bar{\theta}\bar{\Omega}(\frac{K}{\hat{K}})}{\chi}. \quad (15)$$

By letting ψ_t^S be the share of annual solar hours in period t , we have a measure of energy capacity of solar power in this time period: $\psi_t^S z(\frac{K^{PM}}{\hat{K}})K^{PM}$. Here we have substituted actual production capacity (K) by maintained production capacity (K^{PM}) because production requires that panels are maintained and we assume that producers always maintain the panels at the best sites (A profit-maximizing actor investing in solar will in fact maintain the entire installed capacity).

A producer investing in solar power faces the same type of technical constraints as an agent investing in wind power: First, maintained power capacity should be less or equal to installed power capacity, that is, $K^{PM} \leq K^{inv} \perp \lambda^E \geq 0$. Second, there is a restriction in periodic production of electricity: $y_t^E \leq \psi_t^S z(\frac{K^{PM}}{\hat{K}})K^{PM} \perp \mu_t \geq 0$. Finally, due to technical maintenance there is a restriction on total annual

production of electricity: $\sum_t y_t^E \leq \xi \sum_t \psi_t K^{PM} \perp \eta \geq 0$. In addition, because of limited availability of land for solar power, there is also a restriction on investment:

$$K^{inv} \leq \hat{K} \perp \bar{\lambda}^E \geq 0 \quad (16)$$

where $\bar{\lambda}^E$ is the shadow price of land. Thus for solar power, which has the same type of costs as wind power, the Lagrangian of the optimisation problem is:

$$\begin{aligned} \mathcal{L}^E = & \sum_{t \in T} P_t^{YE} y_t^E - \sum_{t \in T} c^O y_t^E - c^M K^{PM} - c^{inv} K^{inv} - c^{gc}(K^{inv}) K^{inv} - \\ & \lambda^E (K^{PM} - K^{inv}) - \bar{\lambda}^E (K^{inv} - \hat{K}) - \sum_{t \in T} \mu_t^M \left\{ y_t^E - \psi_t^S z \left(\frac{K^{PM}}{\hat{K}} \right) K^{PM} \right\} - \\ & \eta \left\{ \sum_{t \in T} y_t^E - \xi \sum_{t \in T} \psi_t K^{PM} \right\}. \end{aligned} \quad (17)$$

The first-order condition with respect to electricity produced in each period is the same as the one for wind power, see (5). The first-order condition for maintained capacity is

$$\sum_{t \in T} \mu_t^M \psi_t^S \left(z \left(\frac{K^{PM}}{\hat{K}} \right) + z' \left(\frac{K^{PM}}{\hat{K}} \right) \frac{K^{PM}}{\hat{K}} \right) + \eta \xi \sum_{t \in T} \psi_t \leq c^M + \lambda^E \perp K^{PM} \geq 0. \quad (18)$$

Finally, the first-order condition for investment is given by

$$\lambda^E - \bar{\lambda}^E \leq c^{inv} + c^{gc}(K^{inv}) + \frac{dc^{gc}(K^{inv})}{dK^{inv}} K^{inv} \perp K^{inv} \geq 0. \quad (19)$$

These conditions have similar interpretations as those for wind power.

2.5 Solar power - calibration

In the model it is assumed that all solar power is based on photovoltaic (PV) technology and organised as centralised power plants. The PV cells are assembled as modules that are used for electricity generation (IEA ETSAP 2011). There are several PV technologies on the market and under development. These are often divided into three categories; (i) first-generation PV systems based on crystalline silicon technology, (ii) second-generation thin film PV (based on several different materials) and (iii) third-generation PV which includes new technologies like concentrated PV, organic solar cells and dye sensitized solar cells. The first-

generation PV systems are fully commercial, whereas the second-generation are in the stages of early market deployment (IRENA 2012a). In the model we use technical data and costs of first-generation PV systems.

To estimate the potential of the solar resource in each model country data for solar insolation around the world from the NASA Surface Meteorology and Solar Energy database has been used, see NASA. This gives information about the monthly average insolation incident, measured in kWh/m²/day, based on a 22-year average. We use the data for tilted collectors, choosing the tilt angle that gives the highest annual average for each location.¹⁰

We have created a dataset with a “best” and “worst” location for solar insolation (kWh/m²/year) for each model country, see Table 2. These locations have been chosen based on an assessment of each model country using a map of PV potential in the EU regions, see Espon (2011) and sampling from the NASA database. The data have been aggregated to our two seasons (summer/winter).

*Table 2 Solar insolation kWh/m²/year
(Average radiation incident on an equator-pointed tilted surface)*

We assume that the function $\bar{\Omega} = \bar{\Omega}(\frac{K}{\hat{K}})$ is linear: $\bar{\Omega} = a^S - b^S \frac{K}{2\hat{K}}$. Because $\bar{\Omega}(\frac{K}{\hat{K}})$ should be interpreted as the average solar irradiance, the marginal solar irradiance is given by $a^S - b^S \frac{K}{\hat{K}}$. This means that a^S should be interpreted as the irradiance at the best solar site of a country. To determine the value of b^S note that if the entire amount of land for solar power is used ($K = \hat{K}$), then the marginal site receives a solar irradiance of $a^S - b^S$. From Table 2 we know, for each country, the values of a^S (best site) and $a^S - b^S$ (worst site), and hence we can find the value of b^S for each country.

In the model we assume that over time more land will be available for solar. In particular, we rely on Hoefnagels *et al.* (2011) which assumes that 0.5 percent of the agricultural land¹¹ will be made available for solar power plants in each model country by 2050. The increase of land available for solar power is captured by the function $h(T) = ke^{-l(T-2009)}$ where the parameters k and l are calibrated so that $h(2050) = 1$ ($k = 2.5, l = 0.0224$). This means that around 0.3 percent of the agricultural land will be made available for solar power plants in each model country in 2030. For EU-30 the share of total land mass used to solar power production would then be 0.2 percent in 2030.

IEA ETSAP (2011) has data for land use (m²/kW) for PV technologies. According to this study, the “typical current international range” for crystalline Si PV cells is between 6 and 9 m²/kW. In the model 7

¹⁰ There are various ways to measure solar irradiance. Global horizontal irradiance (GHI) is a measure of the density of the available solar resource per surface area. However, GHI can also be measured with tilted collectors that have a fixed optimal angle for the location or even with devices that track the sun. We use data for tilted collectors that have a fixed optimal angle.

¹¹ Data on agricultural land are gathered from The World Bank: <http://data.worldbank.org/indicator/AG.LND.AGRI.ZS>. According to this source, for EU-30 agricultural land amounts to 41 percent of total land mass.

m^2/kW has been used, which means that 7 m^2 is required to generate 1 kW instantly under optimal conditions. Hence, $\chi = \frac{1}{7}$. Based on the assumptions in IEA ETSAP (2011) and IPCC (2011), the maximum module efficiency of PV panels is assumed to be 18 %, that is, $\bar{\theta} = 0.18$. Finally, also for solar we assume that cost of investment is decreasing over time; the annual rate is set to three percent.

Above we derived that annual production of solar power can be calculated from $\bar{\theta}\bar{\Omega}\left(\frac{K}{\hat{K}}\right)\Omega$. Using i) $\bar{\theta} = 0.18$, ii) average solar insolation ($\bar{\Omega}\left(\frac{K}{\hat{K}}\right)$) by country from Table 2, and iii) the assumption that 0.3 % of the agricultural land will be made available for solar power plants in each model country in 2030 (Ω), we can calculate maximum solar power by country in 2030, see Table 3. According to this table, maximum solar power in 2030 amounts to 1620 TWh, which is close to 50 percent of total electricity production in EU-30 in 2009.

Table 3 Potential solar power production in 2030 by country (TWh)

3 Costs of electricity

A key factor in determining the impacts of a nuclear phase-out is costs of electricity, in particular cost of electricity from new power plants. Costs of electricity will affect to what extent a phase-out will be replaced by new capacity and also the mix of the electricity technologies, that is, the two main research questions in this paper.

Figure 2 shows average cost of new electricity in 2030 – measured in 2009 euro per MWh – by technology, that is, new gas power, new coal power, new bio power, new wind power, new solar, new CCS based on natural gas (termed gas CCS greenfield) and new CCS based on coal.

Figure 2 Average costs of electricity in 2030 (€2009/MWh)

In the figure costs have been split into three factors; costs of investment, costs of operation and maintenance (O&M), and fuel costs. Because Figure 2 provides information about costs in 2030, we have taken into account that costs of investment (per GW) will fall over time due to learning (see below). For fuel costs, we have used observed fuel prices in 2009 (including taxes) for electricity producers, averaged over EU-30, and specific assumptions about the efficiency of new fuel based plants (see below). For wind power and solar we show cost of electricity for very good locations in Europe (3500 wind hours and 2500 solar hours annually). As seen from Figure 2, average cost per MWh varies from 40.8 (wind power) to 79.4 (CCS gas greenfield). Note that in the model runs in Sections 4 and 5, we use the equilibrium fuel prices (not the observed fuel

prices in 2009) and the equilibrium load factors/wind hours/solar hours (not the stylized assumptions in Figure 2) to characterize the outcome under different scenarios. We now comment on the different cost factors in more detail.

3.1 Cost of investment and efficiency of new plants

The LIBEMOD model distinguishes between steam coal and lignite power plants, however it is only possible to invest in new steam coal plants. According to Burnard and Bhattacharya (2011), the super-critical (SC) technology is currently the standard for new plants in industrialised countries: despite emerging types of coal power plants like integrated gasification combined cycle (IGCC) and circulating flue gas desulphurisation (CFGD), the super critical and ultra-super critical pulverised coal plants continue to dominate the new orders. For coal power plants coming online in 2030 we have therefore used cost data for an ultra-super critical (USC) pulverised coal plant; the OECD (2010) estimate for this technology is 1737 €₂₀₀₉/kW (data from the Netherlands).

For natural gas the majority of the estimates from OECD (2010) are for combined cycle gas turbine (CCGT) plants. The estimates differ between the reporting countries. In the model the cost estimate from Belgium (957 €₂₀₀₉/kW) has been used, see Table 4, which is very close to the average of all the CCGT-estimates in the publication.

Table 4 Investment costs in 2010 (€2009/kW)

Tyma (2010) and Schröder et al. (2013) are among the few studies that provide cost estimates for new oil-fired power plants. After assessing the available sources an investment cost of 1411 €₂₀₀₉/kW was assumed.

The investment cost for new wind power plants was based on an assessment of various sources (Mott MacDonald 2010; OECD 2010; IPCC 2011; NVE 2011; Black & Veatch (2012) and IRENA 2012b). Offshore wind power is not included in the LIBEMOD model. The cost estimates for onshore wind in OECD (2010) range from 1419 €/kW to 2742 €/kW. In LIBEMOD it is assumed that the investment cost falls over time at a rate of 1 % per anno. Based on these considerations, in the LIBEMOD model the investment cost of a new wind power plant is 1576 €₂₀₀₉/kW for 2009 (1276 €₂₀₀₉/kW for 2030).

Numerous sources were reviewed for the cost of solar PV (OECD 2010; IEA 2011a; IEA ETSAP 2011; IPCC 2011; IRENA 2012a; Bazilian et al. 2013 and Schröder et al. 2013). An estimate of 2545 €₂₀₀₉/kW is used for 2009, which is towards the lower end of the estimates of these sources. The reason is partly that some of the publications are several years old, and that the cost of solar PV installations has been dropping dramatically in recent years. Schröder et al. (2013) goes even lower, using 1560 €/kW (for around

2012) after reviewing numerous sources. They base their decision on the dynamics of the solar power market in recent years and argue that this leaves even the lower estimates in the literature outdated. However, because the base year in the LIBEMOD model is 2009 a higher estimate than 1560 €/kW seems reasonable for 2009. However, we assume that investment cost per GW falls with 3 percent per anno from 2009 – this gives us 1342 €₂₀₀₉/kW for 2030.

IPCC (2011) defines biomass as “Material of biological origin (plants or animal matter), excluding material embedded in geological formations and transformed to fossil fuels or peat.” This wide definition of biomass, and also the variety of technologies that come under the term “bio power”, means that landing on a cost estimate for a generic biomass-based power plant is problematic. The cost of bio power depends on type of feedstock used, boiler technology, plant capacity and type of plant. The estimates from OECD (2010) vary considerably from country to country, mainly due to differences in the reported technologies. IEA ETSAP (2010a) has a range for typical values for a biomass CHP plant in 2010 and an estimate for expected costs in 2020. For new plants it seems reasonable to go with the lower end of the IEA ETSAP (2010a) estimates; we assume that the cost of a new biomass power plant is 2181 €₂₀₀₉/kW for both 2009 and 2030.

For the hydro technologies apart from pumped storage, cost data for Norway from the Norwegian Water Resources and Energy Directorate, for example, NVE (2011), has been used. The costs for other model countries are then based on this, but adjusted with an investment cost coefficient creating country specific costs for run-of-river and reservoir hydro plants. This coefficient is based on the load hours for each technology compared to Norway.

The cost of new pumped storage is taken from IEA ETSAP (2010b). In this technology brief they use 2900 €/kW for a typical large hydro power plant (with costs ranging from 1300 to 4500 €/kW). According to the IEA, for pumped storage costs can be up to twice as high as for equivalent plants without pumps. Based on this the investment cost for a new pumped storage plant in the model is set to 1.5 times the cost of a typical plant given by IEA ETSAP (2012b), that is, 4363 €/kW.

Efficiencies for new power plants (in 2030) have generally been taken from OECD (2010), which has efficiency estimates for plants coming online in 2015. Because of the assumption that the cost of a new plant (of a given technology) is the same for all model countries, the same applies for the efficiencies. However, for new pumped storage there is constant efficiency within each country, but these efficiencies differ across countries because of, e.g. topological differences. For each model country, the efficiency for new pumped storage is set equal to the efficiency of pumped storage in the base year. Table 5 shows the efficiencies used in the model for new power plants in 2030. For gas-fired power plants an efficiency of 60 percent is assumed, whereas for coal-fired power plants an efficiency of 46 percent is assumed. Finally, for bio power plants an efficiency of 40 percent is assumed, which builds on Table1 in IEA ETSAP (2010a).

Table 5 Efficiencies for new power plants in 2030

3.2 CCS technologies

We now turn to carbon capture and storage (CCS) technologies, which is a process to prevent CO₂ from being released into the atmosphere. A power plant with CCS is able to capture (most of) the CO₂ and transport it to a suitable location where it can be permanently stored, see The Global CCS Institute. CCS is still an immature technology, and there are various capture technologies under development. There are four different carbon capture and storage technologies in the LIBEMOD model; retrofit CCS for existing coal power plants, retrofit CCS for existing gas power plants, greenfield CCS coal power plants and greenfield CCS gas power plants. The greenfield plants are new gas and coal power plants complete with CCS. The costs of the two retrofit options are based on the CCS technology being retrofitted to an already existing power plant. A CO₂ capture level of 90 % is assumed for all CCS technologies.

The costs of greenfield gas and greenfield coal plants are taken from ZEP (2011).¹² The report distinguishes between several different types of power plants with CCS. After consultation with industry experts, a combined cycle gas turbine (CCGT) plant and an integrated gasification combined cycle (IGCC) coal power plant were chosen.¹³ The investment costs for these were 1829 €₂₀₀₉/kW and 3080 €₂₀₀₉/kW respectively for 2030, see Table 6.

For retrofit CCS costs there were fewer sources. When an already existing power plant is being retrofitted with CCS equipment, the investment costs involved will be power plant and site specific. These costs are therefore more difficult to predict. However, for the LIBEMOD model we assume that there is one retrofit technology for natural gas and one for coal. IEA GHG (2011) has investment costs for several different retrofit solutions for natural gas and coal power plants. After consultation with industry experts, we decided to use the costs for the “integrated retrofit” solution. For a natural gas plant the investment cost for this type of retrofit is 665 €₂₀₀₉/kW, whereas for a coal plant it is 1035 €₂₀₀₉/kW (for 2030). These estimates assume that the investment costs for all CCS technologies fall by 0.5 percent per anno.

Table 6 Investment costs of power plants with CCS in 2030 (€2009/kW)

¹² The ZEP report compares several studies on the costs of CCS greenfield power plants. Compared to other studies, see, for example, IEA (2013a), ZEPs costs are at the lower end of the scale. This is partly due to some of the estimates being older, and probably also to the difference in type of power plants. Because the technology is still new and untested in full-scale plants, it is to be expected that the estimates differ.

¹³ The IEA report Power Generation from Coal (Burnard and Bhattacharya, 2011) supports our coal plant choice by describing IGCC as “well placed to embrace CO₂-capture” and that the cost of CCS with this type of power plant is expected to be lower than for pulverised coal systems.

The cost of the integrated retrofit option only includes retrofitting the plant; the initial costs of the power plant are considered sunk. The costs in Table 6 do not cover the cost of transportation and storage of the CO₂. ZEP (2011) has cost data for these activities. According to this report, existing studies on *transportation costs* were inadequate for a review, so the costs in the report are based on input from EU-member states and in-house ZEP analysis.

The two main transport options for CO₂ from a power plant are through a pipeline network or with ship. We have chosen to base our estimates on the pipeline option.¹⁴ ZEP (2011) provides two sets of cost estimates for pipelines. One is for a typical capacity of 2.5 million tonnes per annum (Mtpa), which is considered to be appropriate for CCS demonstration projects and commercial natural gas plants with CCS, and the other is for a pipeline with typical capacity of 20 Mtpa,¹⁵ which is thought more realistic for commercial large-scale networks. The unit transportation costs for CO₂/tonne vary with distance and whether it is an onshore or offshore pipeline. We have assumed a cost of 6 €/tCO₂ for transportation. This is based on an offshore pipeline of 500 km with a capacity of 20 Mtpa.

Storage costs depend on factors like field capacity, well injection rate and type of reservoir, and are thought to vary considerably between sites. ZEP (2011) provides low, medium and high cost scenarios for storage depending on type of well (depleted oil and gas field or saline aquifer) and whether it is located onshore or offshore. In Europe there is more offshore than onshore capacity, and more capacity in saline aquifers than in depleted oil and gas fields (ZEP 2011). This means that the majority of the potential European storage sites are of the most expensive kind. There has also been public resistance to storage onshore near where people live due to the risk of leakages.¹⁶ Taking this into consideration we assume a storage cost of 10 €/tCO₂,¹⁷ which is based on depleted offshore oil and gas fields in ZEP's medium cost scenario.

Due to the carbon capture, CCS plants will incur an *efficiency penalty* compared to power plants without CCS. Most of the literature assumes that there is little difference in the actual efficiency penalty between greenfield plants and plants that are retrofitted. The difference in actual efficiency can mainly be attributed to the fact that older existing plants that are candidates for being retrofitted have a lower efficiency than a newly built plant made specifically for CCS. The reduction in efficiency for retrofits is plant specific, and the plants' efficiency will fall and costs increase depending on to what degree it is suitable for CCS (IEA GHG 2011). Many existing plants may not be good candidates for CO₂ capture due to being too small and/or too inefficient. Burnard and Bhattacharya (2011) assume that the higher the

¹⁴ The alternative to pipeline transportation of the CO₂ is ship. Transportation costs with ship are less dependent on distance and on the scale of the transport. However, to transport CO₂ by ship one has to factor in the costs of liquefaction.

¹⁵ It is assumed that the 20 Mtpa pipeline can serve a cluster of CO₂ sources and that it has double feeders from the source to the pipeline and double distribution pipelines.

¹⁶ According to the Special Eurobarometer, see European Commission (2011a), six out of ten people in Europe expressed concern when asked how they would feel about a deep underground CO₂ storage site within 5 km of their home. For an overview of studies looking at public perception and acceptance of CO₂ storage, see IPCC (2005).

¹⁷ None of the above estimates include costs for monitoring the storage sites. IPCC (2007) estimates it to lie between 0.05 and 0.09 €/tCO₂.

efficiency of the existing plant, the more favourable it will be to retrofit. Due to the limited experience with retrofit projects, there is considerable uncertainty regarding how low a power plants initial efficiency can be before the plant is unsuitable for retrofit.

According to industry experts at Gassnova, for coal plants there may also be a higher penalty for retrofitted plants if the damp from the turbine is not completely compatible with what the capture process requires. The IEA GHG study uses a 9 percentage point reduction for both greenfield and retrofitted plants. ZEP (2011) and NETL (2013) also use the same reduction across types of plants; 8 and 10 percentage points respectively.

Based on this literature and advice from industry experts, we assume that the penalty for natural gas plants (greenfield and retrofit) is an 8 percentage point reduction in efficiency compared to a new power plant without CCS, and likewise a 9 percentage point penalty for both types of coal power plants.

Figure 3 shows average costs of electricity from CCS plants. For CCS retrofit, cost of investment is solely CCS investment cost and fuel costs reflect efficiencies for good existing power plants. For all technologies we have used average EU-30 fuel prices for electricity generation in 2009. As seen from the figure, CCS coal is cheaper than CCS gas, and for both CCS coal and CCS gas retrofitting the most efficient plants is cheaper than building new CCS stations.

Figure 3 Average costs of CCS electricity in 2030 (€2009/MWh)

3.3 Grid connection costs

When investment is made in a new power plant, one of the cost components involved will be to get the plant connected to the grid. This additional cost of grid connection is in general not included in the cost estimates mentioned above. Cost of grid connection is made up of two elements; new transmission lines to connect the plant to the grid and reinforcement of the grid as a result of a new plant coming online.

We have assumed that the marginal cost of grid connection in a country for a specific technology is $a^G + b^G K^{inv}$ where a^G (cost of upgrading the grid) and b^G (cost of connecting to the grid) are parameters and K^{inv} is investment in a specific technology in the country. We assume that a^G does not depend on technology and country: According to GreenNet EU-27 (2006), the approach to cost allocation for grid reinforcement varies across Europe. In some countries the developers only pay for the connection to the grid, whereas in other they also have to cover a share of the grid integration costs. Further, we also assume that b^G does not depend on country (the relationship between the parameter and country observables is not clear), but it differs between technologies; location of thermal power is more flexible than wind power.

According to IRENA (2012b), the extra cost component linked to grid connection makes up between 9 and 14 % of total investment costs for onshore wind. It is therefore assumed that if the average wind power capacity in a LIBEMOD model country increases by 100 percent, then the (total) extra cost of grid connection for the marginal wind power plant is 10 % of the investment costs for wind power. We then assume that 20 % of this cost is linked to upgrading the grid (a^G) whereas 80 % of this cost is linked to actually connecting to the grid (b^G). The parameter value of upgrading the grid (a^G) is therefore 2.2 (M€/GW). Using information from Figure 5 in EIA (2012), the parameter value of connecting to the grid (b^G) is 1.2 (M€/GW²) for wind power and 3.6 (M€/GW²) for other technologies.¹⁸

3.4 Operation and maintenance cost

In the model we differentiate between fixed and variable operation and maintenance costs (O&M). Fixed O&M costs are costs that incur irrespective of use of the plant and therefore can be viewed as long-run maintenance costs, whereas variable O&M costs are linked to the maintenance of the capacity that has been used during a year. The OECD-publication “Projected Costs of Generating Electricity 2010” (OECD 2010) provides estimates for total O&M costs, so other sources have been used for the split between fixed and variable costs. Tidball et al. (2010), Black & Veatch (2012) and Mott MacDonald (2010) provide more detailed information about O&M costs. Schröder et al. (2013) provides a compilation of different studies and their assumptions for fixed and variable O&M costs for different technologies. Based on an assessment of these sources a dataset has been created.¹⁹

O&M costs from OECD (2010) have been used for natural gas, steam coal, lignite and nuclear power plants. For steam coal we assume that of the total O&M costs 54 percent are variable and 46 percent are fixed, whilst for lignite the allocation is 35 percent variable and 65 percent fixed. For natural gas (combined cycle) we assume that variable costs make up 55 percent, and for nuclear 4 percent variable and 96 percent fixed is assumed. For oil power Tyma (2010) provides an overview of personnel costs, fuel costs and chemical costs, which have been allocated to fixed and variable costs in keeping with the above definition. For bio power we have used IRENA (2012c), and assumed that 42 percent of the O&M costs are variable, and 58 percent are fixed.

In the overview made by Schröder et al. (2013) the majority of the studies on hydro power categorise all O&M costs as fixed. In their own dataset they report only fixed O&M. The O&M costs for pumped storage, reservoir and run-of-river hydropower in LIBEMOD are based on this.

The O&M costs for solar power are based on data from the technology briefs from IEA ETSAP (2011). The costs for wind power are based on OECD (2010) and IRENA (2012b). For wind power the four

¹⁸ The b^G parameter of hydro is zero because costs of connecting to the grid are already included in the investment costs of these technologies.

¹⁹ For the thermal technologies a 70 % load factor has been assumed.

studies evaluated by Tidball et al. (2010) differ considerably with respect to the allocation between fixed and variable costs. Two of the studies assume 100 percent fixed costs, and two assume 25 percent fixed costs and 75 percent variable costs. Schröder et al. (2013) compares O&M costs for onshore and offshore wind power from various sources and they vary between only fixed costs and a split between the two. In their cost proposal Schröder et al. (2013) assume all O&M costs are fixed. In LIBEMOD it is assumed a 25/75 split between fixed and variable costs.

For mature technologies the same O&M costs have been used for existing plants and new plants. For bio, solar and wind power the costs for new plants are based on the same sources, but they are lower than for existing plants reflecting cost reductions as these technologies mature over time, see Table 7.²⁰

For the CCS technologies the O&M costs for greenfield plants are taken from ZEP (2011) and for retrofitted plants from IEA GHG (2011). However, the O&M costs for retrofitted coal plants have been adjusted somewhat as they were lower than for greenfield plants.

Table 7 Operation and maintenance (O&M) costs for new power plants in 2030 (€2009)

4 Results

4.1 Scenarios

To examine the effects of a nuclear phase-out we consider a number of scenarios for 2030, see Table 8. In our reference scenario we assume that the nuclear capacities in 2030 reflect decisions taken in 2014 or earlier at the country level with respect to whether nuclear plants will be phased out or new nuclear capacity will come online before 2030, see Table 9. As indicated in Section 1, whereas some countries, for example, Belgium and Germany, have decided to completely phase out nuclear power, other countries, for example, Finland and the UK, are building or planning to build new nuclear stations. In addition, in several countries old nuclear stations will be decommissioned without being replaced. Based on information from The World Nuclear Association, IEA (2013b) and Eurelectric (2011) there may be a net decrease in nuclear capacity in EU-30 between 2009 and 2030 of about 23.2 GW, see Table 9, which amounts to roughly 20 percent of the 2009 nuclear capacity in EU-30. Hence, in the reference scenario total nuclear capacity in EU-30 is 23.2 GW lower than in the data year 2009.²¹

²⁰ The IEA ETSAP technology briefs and IRENA reports provide intervals for costs, so for the existing technologies the higher end of the interval has been used, whereas for new plants the costs are assumed to be towards the lower end.

²¹ For other electricity technologies we use data from ENTSO-E (2011), scenario B, on (predicted) capacities in 2020 by country. These reflect current capacities adjusted by planned investments and disinvestments. For the period 2020-30, profitable investments in these technologies are undertaken, see discussion in Section 2.

Table 8 Scenarios for 2030

Table 9 Nuclear policy in EU-30

In fall 2014, the EU decided that in 2030 GHG emissions should be 40 percent lower than in 1990. This policy distinguishes between the ETS sector (electricity generation and large carbon-intensive manufacturing firms) and the remaining sectors (non-ETS). Whereas the ETS sector has to reduce its GHG emissions by 43 percent relative to 2005, the corresponding number for the non-ETS sector is 30 percent. In addition, the renewable share in final energy consumption should be (at least) 27 percent; the EU Commission has indicated that the latter target may be reached if the emission targets are reached, see European Commission (2014b). All targets are at the EU level and hence not broken down to national targets.

In the reference scenario we follow the EU climate policy and hence have one common EU-30 target for emissions in the ETS sector – implemented by a common quota system – and one common EU-30 target for emissions in the non-ETS sector – implemented by a common uniform tax. Because LIBEMOD only covers CO₂, the most important GHG gas, we transform the GHG emissions targets to CO₂ targets.²²

Further, in the reference scenario we also impose an EU-wide renewable share in final energy consumption of 27 percent.²³ Currently, most European countries have different instruments to spur renewable production: according to Wind-Works, <http://www.wind-works.org/cms>, which shows selected renewable support programs worldwide with contract terms of at least 15 years, support among EU-30 countries varies typically between 50 and 100 €/MWh, and there are cases with financial support far above 100 €/MWh. However, the era of national tailor-made subsidies to new renewable generators may have come to an end: in some European countries with significant solar and wind capacity, for example, Spain, policy instruments to spur investment in renewables are now being removed. This is partly because the competitive position of solar and wind power has improved radically over the last 10 years, and partly

²² Our strategy to calculate CO₂ emission targets for EU-30 is mainly as follows. We use EEA (2013) to find GHG emissions for EU-27 in 1990, which is 40 percent above the 2030 emission target. Because Iceland, Norway and Switzerland each has committed to a conditional emissions reduction of at least 30 percent, we assume that also these countries will commit to a 40 percent GHG reduction by 2030. Based on Höglund-Isaksson (2010), which has projections for non-CO₂ emissions for ETS and non-ETS, we find CO₂ targets for ETS/non-ETS. Further, we take into account that LIBEMOD cannot distinguish between manufacturing firms that belong to the ETS sector (large carbon-intensive units) and those firms not covered by the ETS sector. When setting the CO₂ target for LIBEMOD we also take into consideration that in the transport sector there will likely be considerable substitution to other fuels towards 2030, something that is not captured by the LIBEMOD model: in the transport sector the CES demand structure gives little room for substitution due to the initial share of oil being very close to 100 percent. A more detailed description of the calculations of the LIBEMOD climate targets is available upon request.

²³ We define the share of renewables in final energy demand as i) the sum of renewable electricity production (except from bio power) and total use of bioenergy relative to ii) total consumption of electricity (less of electricity used in pumped storage hydro) and total consumption of primary energy among end users.

because the large transfers to the private sector are regarded as a financial problem. In addition, the EU Commission has recently adopted new rules on public support for projects aiming at environmental protection. The guidelines promote a gradual move to an EU-wide market-based support for renewable energy by replacing feed-in tariffs by feed-in premiums, the latter is supposed to expose renewable energy to market signals through bidding processes for allocation of public support, see European Commission (2014a).

In this study we assume that all countries currently providing support to a renewable technology will continue do so also in 2030. We draw on CEER (2015), supplemented by Wind-Works, to find the current renewable subsidies. To balance the current renewable domestic subsidies against the potential trend of phasing out this type of instrument, we impose a cut off rate of renewable subsidies of 20 €/MWh, see Table 10. In addition, if these domestic instruments are not sufficient to reach the renewable target of 27 percent, an EU-wide production subsidy to all producers of renewable electricity (bio power, hydro power, solar power and wind power) and an EU-wide subsidy to all end-users of bioenergy (biomass and biofuel) are implemented. The subsidies are identical measured per energy unit.

Table 10 Domestic renewable subsidies in all scenarios (€2009/MWh)

In the next two scenarios we reduce the capacities of nuclear power in all model countries that did not phase out nuclear power in the reference scenario by either 50 percent relative to 2009 (“50 % phase-out”) or by 100 percent (“100 percent phase-out”). The energy and climate goals, as well as the policy instruments are, however, the same as those in the reference scenario.

For the remaining scenarios we stick to the assumption that there has been a complete nuclear phase-out. We first explore the impact of other assumptions with respect to emissions targets. First, no energy and climate policy, referred to below as “No policy”. Second, a 40 percent GHG reduction under the assumption of no specific targets for ETS and non-ETS, that is, there is one common emissions target for EU-30. In this scenario (“Effective”) we use a common uniform CO₂ tax to reach the climate goal. Third, GHG emissions are to be reduced by only 20 percent (“High emissions”) relative to 1990, and fourth GHG emissions are to be reduced by 50 percent (“Low emissions”) relative to 1990. For the latter two scenarios we assume, like in the reference scenario, that there are ETS and non-ETS sector specific emissions targets, and the estimation of these targets follows the same procedure as in the reference case.

One new electricity technology that may replace nuclear power is CCS. Both the EU and the IEA have published reports estimating that this technology may have a great future potential; according to the Energy Roadmap, see European Commission (2011b; 2011c), the share of CCS in EU power generation in 2050 may become as high as one third. Likewise, the IEA Technology Roadmap from 2013, see IEA (2013a), predicts that in 2050 the annual amount of CO₂ captured and stored globally (in electricity generation and in manufacturing processes) may be around 8000 MtCO₂, which is roughly 25 percent of

current global emissions of CO₂. Costs of CCS are, however, high because of additional costs of investment (relative to conventional fossil fuel plants) and also due to additional energy use, see Section 3.2. In the scenario termed “Cheap CCS” we explore the market outcome if a substantial share of CCS investment costs (50 percent) is covered by the government. The energy and climate policy goals and instruments are the same as in the reference scenario.

In the scenarios above, the imposed share of renewables in final energy consumption was 27 percent (Except in the no policy scenario in which there was no requirement). In order to explore the effect of a higher renewable share we impose a renewable share of 35 percent in the scenario referred to as EU renewable target. The policy instruments to reach this target are the same ones as those in the reference scenario.

A nuclear phase-out will decrease total supply of electricity in the short run and thereby push up investment in other electricity technologies because, *cet. par.*, the price of electricity will increase. It seems reasonable to expect that also production of renewable electricity will increase, including supply from solar and wind power. The intermittency of these technologies will easily cause more price volatility in the electricity market, and the probability of a black out - triggered if consumers of electricity at a point in time try to use more electricity than the amount of electricity fed into the system - will also increase. In order to cope with these challenges national regulators design and implement arrangements that seek to ensure an effective electricity market. In LIBEMOD there are national capacity markets, and each national regulator buys maintained capacity (from non-intermittent technologies except nuclear power) according to a rule of thumb; at least five percent of total maintained capacity should always be available for additional production. This potential production capacity is frequently referred to as balancing power. In the scenario termed “Balancing power” we examine the impact of tightening the rule of thumb by replacing 5 percent with 20 percent.

Finally, in the scenarios above economic growth coupled with an income elasticity shifts demand for fuels outwards over time. To calibrate the income elasticities we used information from the Current Policies Scenario of World Energy Outlook 2011 (IEA 2011b) on projected annual GDP growth rates, projected annual growth rates in energy consumption (for each sector and energy type) and energy prices along with the price elasticities in the LIBEMOD model. The income elasticities are calibrated as the non-price changes in consumption relative to the changes in GDP. Note that the Current Policies Scenario presupposes an annual global energy efficiency rate of 1.6 percent.

To test the importance of energy efficiency improvements we consider the corner case in which these improvements exactly neutralize the effect of economic growth: we assume that in each model country end-user demand for each fuel in 2030 is equal to demand in 2009 (the data year of the model). We refer to this scenario as “Energy efficiency”.

4.2 Impacts of a nuclear phase-out

Figure 4 shows installed capacity of electricity technologies in EU-30 in 2009, in the reference scenario (2030), under a 50 percent nuclear phase-out (2030) and under a complete phase-out by 2030. As indicated by the figure, total installed capacity increases sharply from the observed 2009 value (917 GW) to 1459 GW in the reference scenario. The increase is mainly due to economic growth between 2009 and 2030, but it also reflects the energy and climate policy in the reference scenario, see discussion in Section 5. Whereas the capacity share of nuclear was 14 percent in 2009, see Table 11, it fell to 7 percent in the reference scenario; the decrease reflects partly that by construction nuclear capacity is 23.2 GW lower in the reference scenario than in 2009, see Section 4.1, and also the increase in total installed capacity. Due to the energy and climate policy, also the capacity share of (conventional) fossil fuel power decreases (by 29 percentage points). In contrast, the combined capacity share of bio power, wind power and solar increases (by 36 percentage points).

Figure 4 Installed capacity by technology in EU-30 in 2009 and 2030 (GW)

Table 11 Capacity and production shares of electricity technologies in EU-30 in 2009 and 2030 (per cent)

Figure 5 shows how the changes in capacity (from the 2009 observation to the reference scenario) are transformed into changes in production of electricity. Whereas total capacity increases by 59 percent, the increase in total production of electricity is lower; 42 percent. The difference reflects that the operating time of the electricity technologies that experience reduced production is high (roughly 90 percent for nuclear and typically far above 50 percent for most fossil fuel based stations), whereas the operating time for wind power and solar power is low (significantly below 50 percent, see, for example, Table 1).

Figure 5 shows that total production of electricity is roughly at the same level in the reference scenario, under a 50 percent nuclear phase-out and also under a complete phase-out. The effect of a complete nuclear phase-out is, for a given energy and climate policy, a reduction in total production of electricity by only 4 percent although the market share of nuclear is as high as 17 percent in the reference scenario. The composition of technologies changes, however, radically. Natural gas is the big winner; it increases its production by almost 75 percent (from the reference scenario to a complete nuclear phase-out). Bio power production increases by 20 percent. After a complete nuclear phase-out, the share of renewables (bio, hydro, wind and solar) in electricity production is 78 percent, and the market share of bio power, wind power and solar is 35 percent, 21 percent and 9 percent, respectively, see Table 11. For both wind power and

solar, the capacity share is about 6 percentage points above the market share. This difference reflects the low number of wind and sun hours during a year, that is, low rates of capacity utilization.

Why does a nuclear phase-out, that is, the transition from the reference scenario to the complete phase-out scenario, lower total production of electricity by only four percent? First, note that (end-user) demand for electricity hardly changes: Demand for electricity depends on the growth rates between 2009 and 2030, but these are identical in all scenarios. Further, demand for electricity depends on all other energy prices, but as seen from Table 12 these do not change radically. Moreover, the effects of these price changes are small because the cross-price effects in end-user demand are assumed to be tiny.

In LIBEMOD the aggregate direct price elasticity of electricity is roughly -0.3, which suggests that a large change in the electricity price is required to induce a one percent response in equilibrium quantity. According to Table 12, the consumer price of electricity increases by 14 €/MWh, that is, by 14 percent, which is compatible with an electricity price elasticity of -0.3 and a reduction on electricity consumption by four percent.²⁴

The moderate quantity effect of a nuclear phase-out reflects that the new marginal cost curve of electricity cuts through the (almost unaltered) demand curve almost in the same point as in the reference scenario. This result depends critically on how the marginal cost curve of electricity shifts; other modeling and calibration assumptions might have generated a much larger effect on electricity production. To illustrate, we have run LIBEMOD when there is a complete nuclear phase-out, the energy and climate policy and the rate of capital depreciation are as in the reference scenario, but investment in power plants cannot be undertaken. Relative to the 100 percent phase-out scenario, electricity production then drops by more than 40 percent and the consumer price of electricity increases by much more than 100 percent.

In the 100 percent nuclear phase-out scenario (with endogenous investment), the marginal cost curve of electricity changes radically from the reference scenario; nuclear plants are replaced by the a small increase in production from technologies with low marginal cost - solar and wind - and a substantial increase in production from technologies with moderate marginal cost - bio power and gas power. Still, the new marginal cost, measured at the equilibrium quantity of the *reference scenario*, is almost identical to the marginal cost prior to the phase-out. This explains why the drop in equilibrium electricity production is only 4 percent.

Figure 5 Electricity production in EU-30 in 2009 and 2030 (TWh)

*Table 12a and 12b Producer and consumer prices in EU-30 in 2030.
(€2009/MWh or €2009/toe)*

²⁴ Because production of electricity cannot be stored, and there is a fixed net imports of electricity to EU-30, the change in production of electricity is equal to the change in consumption of electricity (before losses in transport and distribution).

In order to reach the climate targets under a complete nuclear phase-out, the ETS price is 28 €/tCO₂, whereas the non-ETS price is much higher; 238 €/tCO₂, see Figure 6. The difference reflects much more flexibility in the power sector than among the end users. In the electricity generation sector, LIBEMOD specifies a number of alternative technologies. The composition of these may change radically if prices are altered: for one equilibrium price vector a technology may become profitable and is thus phased in, whereas for another equilibrium price vector marginal units of a technology may become non-profitable and these plants are therefore phased out.

In contrast to the electricity generation sector, end-user demand is derived from nested CES utility functions, that is, there is no direct substitution between technologies. With a CES utility function even a moderate change in consumption requires significant price changes. However, in the real world large changes in end-user prices may trigger installation and use of alternative technologies, for example, solar panels for domestic heating and electric cars in the transport sector. Because LIBEMOD neglects end-user technology substitution, the model overestimates the non-ETS CO₂ price.

Figure 6 CO₂ prices in EU-30 in 2030 (€2009/tCO₂)

As specified above, we assume that there are some domestic subsidies to renewable technologies, see Table 10. If these are not sufficient to reach the EU target of a renewable share of 27 percent, an EU-wide renewable subsidy is provided. As seen from Figure 7, in the reference scenario the EU-wide subsidy has to be 9 €/MWh in order to reach the renewable target. Under a 50 percent phase-out, the required EU-wide subsidy is 1,3 €/MWh, whereas it is not necessary with a common EU renewable subsidy under a complete nuclear phase-out; in this case the increase in renewable production, triggered by the climate policy, is sufficient to reach the 27 percent renewable target. In fact, under a complete nuclear phase-out the renewable share in final energy consumption is 28.8 percent, see Figure 8.

Figure 7 Common renewable energy subsidy in EU-30 in 2030 (€2009/tCO₂)

Figure 8 Renewable share in final energy demand in EU-30 in 2030

Figure 9 shows how total consumption of energy varies across scenarios. Here we have merged consumption of primary energy and consumption of electricity. It is not obvious how to compare these; in the figure we have transformed consumption of electricity from nuclear, hydro, solar and wind power to consumption of primary energy by using a (standard) transformation rate of 11.63 MWh/toe. Using this transformation rate we see that consumption of energy is roughly at the same level in the three scenarios shown in Figure 9; the

effect of a nuclear phase-out is a decrease in total consumption of energy by 1 percent.²⁵ Note, however, that this result reflects the methodology of measuring energy consumption.

Figure 9 Energy consumption in EU-30 in 2009 and 2030 (Mtoe)

Table 12 shows (annual) producer and consumer prices by energy good in 2009 and in the three different scenarios. As seen from the Table, the absolute changes in consumer prices mirror the absolute changes on producer prices; this simply reflects that the difference between the consumer and the producer price is a fixed mark-up (that differs between countries, sectors and energy goods). Because of the mark-up, the percentage changes in prices are (much) higher for producer prices than for consumer prices. As seen from Table 12, most prices do not change that much. Measured in percentage, the producer prices that change the most are the ones for natural gas (23 percent) and biomass (11 percent). This reflects the significant increase in gas power production and bio power production, see discussion above, along with high costs of international transportation of natural gas and bio mass.

5 Robustness and welfare

The main results from Section 4 are that production of electricity in EU-30, as well as total consumption of energy in EU-30, are not much affected by an EU-wide nuclear phase-out in 2030. In contrast, the mix of electricity technologies depends on the extent to which nuclear is phased out: the more nuclear capacity that is phased out, the higher is renewable electricity production. A nuclear phase-out is almost entirely replaced by gas power and renewable electricity, that is, mainly bio power, but also some solar and wind power. We now examine how the equilibrium under a complete phase-out of nuclear power changes if one of the main assumptions of this scenario is changed.²⁶

5.1 Robustness

With *No policy* total capacity is 10 percent lower than in the 100 percent phase-out scenario, see Figure 4. However, total production of electricity is almost identical in the two cases, see Figure 5. With no policy, there is no price on CO₂-emissions. Therefore, generation from coal power, which has a high rate of

²⁵ Consumption of fuel-based electricity, for example, coal power, is measured by the use of coal (toe) to produce electricity.

²⁶ In all scenarios and Sections 4 and 5 we impose domestic renewable subsidies, see Table 10. To test the importance of the domestic subsidies, we have rerun the reference scenario under the assumption of no domestic subsidies. Hence, an EU-wide renewable subsidy has to be imposed to reach the renewable target of 27 percent (The ETS and non-ETS emission targets are as in Section 4). We find that the EU-wide renewable subsidy then has to be 11.5 €/MWh (9.0 €/MWh in the reference scenario) and the ETS price is 30.2 €/tCO₂ (11.9 €/tCO₂ in the reference scenario). Relative to the reference scenario in Section 4, supply of electricity decreases by 5 percent, and the renewable share in electricity production falls by 8 percentage points (to 59 percent). The main effects are lower supply of bio power (by almost 400 TWh), whereas production of gas power increases (by around 350 TWh). These effects reflect that total renewable subsidies have decreased.

capacity utilization, is large – its market share is roughly one third - whereas the market share of coal power in the complete phase-out scenario is 6 percent. The high level of coal power production tends to reduce the price of electricity and therefore production of gas power is substantially lower than in the 100 percent phase-out scenario. The market share of renewable is 60 percent, that is, much lower than in the complete phase-out scenario (78 percent), but radically higher than in 2009 (24 percent). Total consumption of energy is around 15 percent higher than in the 100 percent phase-out scenario, see Figure 9. This exercise suggests that the impact of a nuclear phase-out in the absence of a climate policy is mainly that nuclear is replaced by fossil fuel based production.²⁷

In the case of one climate target, and therefore one common price of emissions of CO₂ (“*Efficient*”), total electricity capacity is 6 percent above the capacity in the 100 percent phase-out scenario. Still, total production of electricity is marginally lower (2 percent) than in the 100 percent phase-out scenario. In order to reach the climate target a common uniform CO₂ tax at 46 €/tCO₂ has to be imposed, see Figure 6. This is more than 60 percent higher than the price of emissions in the ETS sector in the 100 percent phase-out scenario (28 €/tCO₂), and therefore conventional fossil fuel based technologies are punished harder in the efficient scenario. On the other hand, in the efficient scenario there is production of CCS coal (there is no CCS coal production in the complete phase-out scenario), but the level of production is tiny. Therefore, the market share of renewable electricity increases from 78 percent in the 100 percent phase-out scenario to 89 percent in the efficient scenario. With one climate target, total consumption of energy is 6 percent higher than in the complete nuclear phase-out scenario.

Under “*High emissions*” total emissions are 20 percent lower in 2030 than in 1990 (not 40 percent as in the 100 percent nuclear phase-out scenario). Production of electricity is then slightly (3 percent) higher than in the complete phase-out scenario, but the technology mix differs. Under High emissions there is substantial coal power production, which crowds out some of the gas-fired power production as well as some of the bio power production. The resulting market share of renewable is 73 percent, which is somewhat lower than in the 100 percent phase-out scenario (78 percent). Under “*Low emissions*”, that is, emissions are to be 50 percent lower than in 1990, production of electricity is almost identical to electricity production in the complete phase-out scenario. With a 50 percent emissions reduction, there is negligible production from conventional coal power and CCS coal, whereas total gas power production is slightly higher than in the complete phase-out scenario.²⁸ Therefore, the market share of renewable electricity is higher than in the complete phase-out scenario (83 percent vs. 78 percent).

In the scenarios examined in Section 4 there is no CCS gas power and no CCS coal power. If the government subsidizes 50 percent of all CCS investment costs (“*Cheap CCS*”), the effect on total production

²⁷ In order to determine the effect of a nuclear phase out in the case of no climate policy, the equilibrium with the nuclear capacities of the reference scenario should be compared with the equilibrium after a complete nuclear phase out (when there is no climate policy in both cases). Such an exercise confirms the conjecture above.

²⁸ Note that in the low emission scenario, there is substantial production of CCS gas power.

of electricity is negligible and the market share of CCS is only 5 percent. All of the CCS production is greenfield, that is, new stations with integrated CCS facilities.

As explained above, there are domestic renewable subsidies as well as an EU-wide renewable subsidy. The latter is offered only if the renewable share in final energy consumption is below 27 percent *without* the EU-wide renewable subsidy. Figure 8 shows the share of renewable in final energy consumption across scenarios. In the reference scenario, this share is 27 percent, that is, it is necessary to offer the EU-wide renewable subsidy in order to reach the renewable target of (at least) 27 percent. With a complete nuclear phase-out, the renewable share is 28.8 percent; this share is reached without an EU-wide renewable subsidy.

To explore the partial effect of a higher renewable share in final energy consumption (“*EU renewable target*”), we have imposed a renewable target of 35 percent when nuclear is fully phased out and emissions in 2030 are 40 percent below the 1990 level. The required EU-wide renewable subsidy is 17 €/MWh. With this renewable subsidy the price of emissions of CO₂ in the ETS sector decreases: the CO₂ price in the ETS sector is now 15 €/tCO₂, which is 13 euro lower than in the 100 percent phase-out scenario. A higher renewable share in final energy consumption increases total production of electricity slightly (by 3 percent). There is a significant increase in both wind power (by almost 240 TWh) and solar (by around 175 TWh), whereas production of bio power decreases (by around 65 TWh). The derived renewable share in electricity production becomes 83 percent (78 percent in the complete phase-out scenario).

In the scenarios discussed so far each national system operator has to make sure that in every time period (at least) 5 percent of total maintained capacity is available for reserve power production in case demand for electricity suddenly increases or supply suddenly drops.²⁹ The system operator has to buy idle and maintained capacity (from non-intermittent sources) to ensure that the 5 percent requirement is met. If this requirement is increased to 20 percent due to the increased market share of intermittent renewable electricity (“*Balancing power*”), installed capacity is only slightly affected, see Figure 4, whereas maintained capacity is increased by almost 200 GW. Hence, a higher share of the installed capacity of pre-existing plants is being maintained; it is much cheaper to meet the demand from the system operator by maintaining idle plants with low efficiency than to buy new power plants and maintain these. Because the increase in maintained capacity is of the same magnitude as the increase in capacity acquired by the national operators, the available capacity for electricity production is similar in the two cases. In fact, production of electricity is almost equal in these two cases, see Figure 5.

Above we have examined scenarios with a moderate rate of energy efficiency; end-user demand for energy increases steadily over time. If the rate of *Energy efficiency* is so high that end-user demand does not increase over time, that is, demand for energy in 2030 is equal to demand in 2009, production of electricity is as much as 18 percent lower than in the complete phase-out scenario. With lower demand for energy, the

²⁹ Because LIBEMOD is a deterministic model, the maintained capacity that is available for reserve power production is never actually used for electricity production.

equilibrium prices of CO₂ are also lower; these are now 3 €/tCO₂ in the ETS sector (28 €/tCO₂ in the 100 percent phase-out scenario) and 67 €/tCO₂ in the non-ETS sector (238 €/tCO₂ in the 100 percent phase-out scenario).

With a lower ETS price the competitive position of coal power is strengthened; this is the only electricity technology that increases its production relative to the complete phase-out scenario. Lower production from the other technologies reflects lower demand for energy; the producer price of electricity is 10 percent lower than in the complete phase-out scenario. The combination of higher coal power production and lower total production of electricity makes it necessary to offer an EU-wide renewable subsidy of 10 €/MWh to reach the renewable target of 27 percent. The derived renewable share in electricity production is 75 percent, that is, 3 percentage points lower than in the complete phase-out scenario.

The discussion above shows that total production of electricity does not differ much between scenarios (with the exception of the energy efficiency scenario) given that nuclear power is fully phased out. Moreover, from the discussion in Section 4 we know that this level does not differ much from the equilibrium production in the reference scenario. However, the mix of electricity technologies differs significantly between scenarios examined in this subsection. The equilibrium composition of electricity technologies reflects the stringency of the climate target, the climate policy instrument and whether some technologies are being promoted.

5.2 Welfare

In this section we will compare welfare between scenarios. We restrict attention to scenarios that are directly comparable to the reference scenario, that is, have the same overall renewable energy and climate targets and the same rates of energy efficiency as the reference scenario. Below we apply a standard economic welfare measure; we do not take into account other benefits and costs that may be related to a nuclear phase-out, for example, security concerns and social cohesion.

Figure 10 shows *annual* change in economic welfare in EU-30 relative to the reference scenario. For each scenario there are two bars. The right bar shows the net welfare gain relative to the reference scenario. The left bar shows the change in welfare by groups; we distinguish between electricity producers, other producers (those who extract fossil fuels or produce bio energy), end-users (households, services, manufacturing, transport), traders (actors building international pipelines/electricity lines and trade in energy across countries), and the government (the aggregate of all governments in EU-30 plus an EU agency that receives revenues from CO₂-taxes and pays the EU-wide renewable subsidy). Groups placed above (below) the horizontal zero line in Figure 10 gain (lose) relative to the reference scenario.

*Figure 10 Change in welfare components relative to reference scenario.
EU-30 in 2030 (millions €2009)*

As seen from Figure 10, a complete nuclear phase-out reduces annual economic welfare (relative to the reference scenario) by 62 thousand million euro, that is, by 62 billion euro. This corresponds to 0.5 percent of GDP in EU-30 in 2009. The net loss can be decomposed as follows:

- Electricity producers lose around 18 billion euro. Nuclear producers lose 24 billion, whereas other electricity producers either gain moderately or are insignificantly affected.
- Other producers gain around 8 billion euro, mainly due to higher producer prices to natural gas and bio mass.
- End users lose around 91 billion euro, mainly due to higher end-user prices of energy.
- The government gains around 39 billion euro, mainly due to no payment of an EU-wide renewable subsidy.
- The impact on traders' profit is tiny (1 billion euro).

To sum up, there is a net welfare loss in phasing out nuclear power. This loss (62 billion euro) is much larger than the drop in nuclear profit (24 billion euro): If the initial equilibrium was the first-best and the change in nuclear capacity was marginal, then, according to standard economic theory, the change in welfare would have been approximately equal to the drop in nuclear profit. Our results reflect that the change in nuclear capacity is by far non-marginal, and the initial state also deviates from the first-best outcome, for example, because the EU-30 tax system is not even second-best optimal and because of terms-of-trade effects (EU-30 is a large net importer of fossil fuels).

Figure 10 shows that total welfare in the *Efficient scenario* is somewhat lower (14 billion euro) than in the reference scenario. Hence, the cost of phasing out nuclear power is somewhat larger than the benefit of an efficient climate policy. Figure 11 provides information on the welfare components in the efficient scenario relative to the reference scenario: because the non-ETS price is much lower in the efficient scenario than in the reference scenario, end users gain from lower prices (273 million euro) whereas the government loses because of lower carbon tax revenue (-293 million euro). The other changes are more moderate.

*Figure 11 Welfare components in efficient scenario relative to reference scenario.
EU-30 in 2030 (millions €2009)*

The net welfare loss in the other scenarios in Figure 10 - *Cheap CCS*, *EU renewable target* and *Balancing power* – is of the same magnitude as the loss in the 100 percent phase-out scenario, but the welfare effect by group differs significantly. If the government covers half of the CCS investment cost (*Cheap CCS*), the government loses relative to the complete phase-out scenario (and even relative to the reference scenario)

because of the subsidies paid to CCS investors. End users gain relative to the complete phase-out scenario because CCS subsidies stimulate electricity production and hence lower the price of electricity.

In the *EU renewable target* scenario the EU agency pays large subsidies to renewable energy producers, and hence the government loses relative to the complete phase-out scenario (and even relative to the reference scenario). Renewable electricity producers, as well as bioenergy producers, receive these subsidies and therefore the groups “electricity producers” and “other producers” gain relative to the complete phase-out scenario. These subsidies increase supply of electricity, which lowers the equilibrium electricity price, thereby benefitting end users significantly (relative to the complete phase-out scenario), see Figure 11.

Finally, in the *Balancing power* scenario more of the pre-installed capacity is maintained and sold as reserve power capacity to national system operators. The welfare changes are similar to the ones in the 100 percent phase-out scenario except that the surplus of the electricity producers is slightly higher, whereas the surplus to the government is lower; these changes reflect sales/purchase of reserve power capacity.

Figure 12 shows producer surplus by electricity technology (except nuclear) relative to the reference scenario. As seen from the figure, in most scenarios a technology obtains a higher surplus than in the reference scenario, but there are two main exceptions. First, in the efficient scenario the ETS price of CO₂ is much higher than in the reference scenario (56 versus 12 €/tCO₂). This has severe impact on the profitability of coal power and gas power as these technologies have high emissions of CO₂.

Second, in the energy efficiency scenario demand for energy is lower than in the reference scenario, and therefore the equilibrium price of electricity is also lower. This tends to lower the profit of electricity producers. However, the composition of electricity technologies differs between the two scenarios: In the energy efficiency scenario the ETS price of CO₂-emissions is low, and therefore production of electricity using coal and natural gas is higher in the energy efficiency scenario than in the reference scenario. For these fossil fuel technologies, the quantity effect dominates the price effect, and hence their profits are higher in the energy efficiency scenario than in the reference scenario.

Figure 12 Change in electricity producer surplus by technology (except nuclear) compared to reference scenario. EU-30 in 2030 (millions €2009)

6 Concluding remarks

This paper has examined the impact of an EU-wide nuclear phase-out by 2030 under the assumption that GHG emissions in EU-30 are 40 percent lower in 2030 than in 1990 and the renewable share in final energy demand is (at least) 27 percent. To this end we have used the numerical multi-market, multi-period equilibrium model LIBEMOD, which gives a detailed description of the energy markets in EU-30 along with modelling of the global markets for coal, oil and biofuels. This model determines investment, extraction, production, trade and consumption of a number of energy goods in each of 30 European countries, along with consistent equilibrium prices that clear all markets, including tariffs for international transportation of natural gas and electricity.

In the electricity block of the model producers determine whether to set up a new plant and how much of the production capacity that should be used for electricity production in each time period – the remaining capacity can be sold to a system operator as reserve power capacity. An electricity producer maximizes profits subject to a number of technology constraints, some of these are technology neutral, others are technology specific. For solar and wind power the modeling takes into account that sites differ both within a country and between countries and it is also taken into account that access to sites are regulated. We calibrate the solar and wind parameters using expert information, for example, about amount and quality of land available for future solar and wind power production.

The model determines profitable investment in each electricity technology in each country that is consistent with the overall equilibrium. For nuclear, however, we assume that the 2030 capacity either a) reflects current approved plans for this technology (the reference scenario), or b) all countries reduce their 2009 capacity by (at least) 50 percent by 2030, or c) nuclear is completely phased out in all EU-30 countries by 2030. We define the effects of a nuclear phase-out as the difference between the equilibrium in case c) and the equilibrium in case a).

In 2009 the market share of nuclear was 26 percent. Still, we find that a nuclear phase-out by 2030 has minor impact on total production of electricity; total EU-wide electricity production drops by four percent. A nuclear phase-out triggers new production capacity, and nuclear is replaced by gas power and renewable production, in particular bio power, but also some wind power and solar. The impact on total energy consumption is marginal (1 percent reduction). We find that the annual cost of a nuclear phase-out is around 60 billion euro, which corresponds to 0.5 percent of GDP in EU-30 (in 2009).

We have run a number of other scenarios to examine how the equilibrium with a complete phase-out of nuclear power (case c above) changes if one of the main assumptions of this scenario is changed (but always keeping the assumption of a complete nuclear phase-out). With the exception of the scenario with high energy efficiency rates in demand for energy, we find the impact on both production of electricity and consumption of energy to be minor.

Still, other scenarios are possible. First, in future work one may have other assumptions about cost of investment and efficiency of technologies coming online in 2030; this may be the case for conventional fossil fuel electricity, CCS electricity and renewable electricity. For example, above we assumed that 0.3 percent of the agricultural land in EU-30 was available for solar production in 2030. In the 100 percent phase-out scenario, this restriction is binding for four countries only. However, a tightening of the land use restriction may have significant impact on the equilibrium solar power production. Further, we assumed that 10 percent of the wind power potential in Eerens and Visser (2008) was available for electricity generation in 2030. Under this assumption total production of wind power from old mills (plants existing in 2009) and new mills (plants coming online after 2009) amounts to almost 1000 TWh. Using the highest estimate of land use in Section 3.3 (50 hectare/MW), this level of production requires 5 percent of the EU-30 land mass. If the wind power potential assumption is altered from 10 percent to 5 percent (or alternatively to 25 percent), the market share of new wind power changes from 21 percent to 18 percent (or alternatively 23 percent).

Second, in the scenarios above all markets are assumed to be competitive; this is in line with the EU policy to transform the European electricity and natural gas markets into efficient (“internal”) markets. However, the transition has been partial and incremental. In particular, there have been setbacks due to concerns about national interests and energy security, see, for example, European Commission (2010). This suggests to run LIBEMOD under different assumptions about market structure; the market structure in LIBEMOD can be represented by a number of parameters that reflect the degree of deviation from the competitive outcome in different parts of the European energy industry, see Golombek et al. (2013).

Finally, we have assumed no uncertainty. Needless to say, actors in the energy market face a number of uncertainties, for example, future growth rates and prices. In the stochastic version of LIBEMOD, see Brekke et al. (2013), different sources of uncertainties can be imposed. The modeling of uncertainty in LIBEMOD is similar to the one in Debreu’s (1959, chapter 7) classic ‘Theory of Value’, where uncertainty is represented by a discrete event tree. In the stochastic LIBEMOD, each branch of Debreu’s event tree is called a scenario and is assigned a probability. The stochastic LIBEMOD determines investment under uncertainty along with a consistent set of equilibrium quantities and prices for each possible scenario. Hence, the model can be used to study the impact of a nuclear phase-out when actors face uncertainty in, for example, future growth rates. Alternatively, one can study the impact on the energy market of an uncertain nuclear policy; some countries may have decided to phase out nuclear whereas others are considering a partial phase-out or to expand their nuclear capacity.

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Table 1 Efficient wind hours at best site and wind power potential in EU-30

Country	Best (load hours)	Potential* 2030 (TWh)	Country	Best (load hours)	Potential* 2030 (TWh)
AT	2000	26.7	IE	3400	131.5
BE	2800	43.7	IS	3700	81.1
BG	2500	27.9	IT	2000	58.1
CH	1700**	0.4	LT	3000	74.4
CY	1500**	3.9	LU	2000	3
CZ	2093	51.9	LV	3000	85.3
DE	2500	367.3	MT	2000	0.7
DK	3200	75.2	NL	2800	55.3
EE	2500	67.2	NO	3700	162.1
ES	2500	170.0	PL	3000	364.4
FI	3100	441.1	PT	3000	46.8
FR	2500	452.4	RO	2000	47
GB	3400	440.9	SE	3100	456
GR	3000	44.3	SI	2000	1.9
HU	2000	21.4	SK	2000	13.9

Sources: Eerens and Visser (2008), EEA (2009), Hoefnagels et al. (2011a) and Storm Weather Centre (2004).

*10 % of the wind power potential in Hoefnagels et al. (2011a) under the assumption of a price of electricity at 0.07 €/kWh. Aggregated over all 30 countries, this amounts to 3816 TWh.

**According to our data sources these numbers should be somewhat lower than 2000 hours. In the LIBEMOD runs we still use 2000 hours to obtain a positive wind power production in the calibration equilibrium.

Table 2 Solar insolation in kWh/m²/year (Average radiation incident on an equator-pointed tilted surface)

Country	Best site kWh/m ² /yr	Worst site kWh/m ² /yr	Country	Best site kWh/m ² /yr	Worst site kWh/m ² /yr
AT	1386	1245	IE	1220	1089
BE	1143	1134	IS	1182	776
BG	1612	1509	IT	1989	1490
CH	1421	1366	LT	1300	1137
CY	2142	2044	LU	1207	1204
CZ	1216	1153	LV	1313	1165
DE	1272	1079	MT	2095	2078
DK	1287	1090	NL	1289	1090
EE	1248	1165	NO	1191	813
ES	2114	1601	PL	1181	1131
FI	1142	956	PT	1983	1965
FR	1817	1175	RO	1504	1358
GB	1291	1109	SE	1217	999
GR	2065	1516	SI	1568	1386
HU	1420	1254	SK	1285	1169

Sources: All data from the NASA Surface meteorology and solar energy database.

Table 3 Potential solar production in EU-30 in 2030 (TWh)*

Country	Potential production (TWh)	Country	Potential production (TWh)
AT	24.4	IE	28.4
BE	9.8	IS	13.2
BG	46.1	IT	142.7
CH	12.6	LT	19.6
CY	1.5	LU	0.9
CZ	15.4	LV	13.6
DE	116.9	MT	0.1
DK	18.3	NL	16.1
EE	6.9	NO	6.2
ES	299.4	PL	110.2
FI	15.5	PT	42.1
FR	252.4	RO	115.4
GB	120.4	SE	21.5
GR	86.5	SI	4.0
HU	45.7	SK	13.9

*Based on solar panel efficiency of 18%, maximum available land for solar power in 2030 (0.33 % of agricultural land in each country) and average insolation for each country.

Table 4 Investment costs in 2010 (€2009/kW)

Technology	LIBEMOD	IEA ETSAP (2010)	Schröder et al. (2013)	IEA (2010)	Mott MacDonald (2010) ¹	EU (2013) ²
Natural gas (CCGT)	957	800	800	775 – 1291	806	900
Coal (PC SC)	1737	1600	1200	1534 – 1988	2009	2800 ³
Oil	1411	-	400	-	-	-
Nuclear (EPR)	3260	2181	6000 ⁴	3228 – 5031	3270	4550
Biomass	2181	2181	-	1934 – 5482	-	-
Solar (PV)	2545	2400	1560	2405 – 3802	-	1950
Wind (onshore)	1576	-	1300	1419 - 1742	1707	1350

¹ The data from Mott MacDonald (2010) is for “nth of a kind plant” in their medium scenario.

² EU data is for 2015

³ EU coal plant is IGCC, not PC SC.

⁴ The data from Schröder et al. (2013) includes decommissioning and waste disposal.

Table 5 Efficiencies for new power plants in 2030

Technology	Efficiency
Bio	40 %
Coal	46 %
Coal CCS greenfield	37 %
Gas	60 %
Gas CCS greenfield	52 %

Table 6 Investment costs of power plants with CCS for 2030 (€2009/kW)

Type of CCS plant	Technology	Investment costs
Natural gas - greenfield	Combined Cycle Gas Turbine (CCGT)	1829 €/kW
Coal – greenfield	Integrated gasification combined cycle (IGCC)	3080 €/kW
Natural gas – retrofit	Integrated retrofit (CCGT)	665 €/kW
Coal – retrofit	Integrated retrofit (PC)	1035 €/kW

Table 7 Operation and maintenance (O&M) costs for new power plants in 2030 (€2009)

	Variable O&M costs €/MWh	Fixed O&M costs €/kW/year
Natural gas	2.2	11.6
Coal	3.6	18.8
Lignite	3.7	22.6
Oil	27.9	6.1
Nuclear	5.8	68.7
Bio	2.8	80.7
Pumped storage	-	20.0
Reservoir hydro	-	20.0
Run-of-river	-	58.8
Solar PV	-	25.4
Wind	7.4	19.5
CCS coal greenfield	3.3	57.2
CCS coal retrofit	7.1	51.4
CCS gas greenfield	2.8	33.7
CCS gas retrofit	3.9	46.8

Table 8 Scenarios for 2030

Reference	Nuclear capacities reflect decisions after 2010. 40 percent GHG reduction in 2030 relative to 1990. Separate targets for ETS and non-ETS sectors.
50 percent phase-out	Nuclear capacities reduced by 50 percent in 2030 relative to 2009. 40 percent GHG reduction in 2030 relative to 1990. Separate targets for ETS and non-ETS sectors.
100 percent phase-out	Complete nuclear phase out by 2030. 40 percent GHG reduction in 2030 relative to 1990. Separate targets for ETS and non-ETS sectors.
No climate policy	Complete nuclear phase out by 2030. No climate target.
Efficient	Complete nuclear phase out by 2030. 40 percent GHG reduction in 2030 relative to 1990. One common emission target for ETS and non-ETS sectors.
High emissions	Complete nuclear phase out by 2030. 20 percent GHG reduction in 2030 relative to 1990. Separate targets for ETS and non-ETS sectors.
Low emissions	Complete nuclear phase out by 2030. 50 percent GHG reduction in 2030 relative to 1990. Separate targets for ETS and non-ETS sectors.
Cheap CCS	Complete nuclear phase out by 2030. 40 percent GHG reduction in 2030 relative to 1990. Separate targets for ETS and non-ETS sectors. The EU covers 50 percent of CCS investment costs.
EU renewable target	Complete nuclear phase out by 2030. 40 percent GHG reduction in 2030 relative to 1990. Separate targets for ETS and non-ETS sectors. One common EU target for share of renewable energy of 40 percent.
National renewable policy	Complete nuclear phase out by 2030. 40 percent GHG reduction in 2030 relative to 1990. Separate targets for ETS and non-ETS sectors. Subsidies to renewable energy in selected countries.
Balancing power	Complete nuclear phase out by 2030. 40 percent GHG reduction in 2030 relative to 1990. Separate targets for ETS and non-ETS sectors. Increased requirement of balancing power.
Energy efficiency	Complete nuclear phase out by 2030. 40 percent GHG reduction in 2030 relative to 1990. Separate targets for ETS and non-ETS sectors. High energy efficiency rates that exactly neutralizes the effect of economic growth on demand for energy.

Table 9 Nuclear policy in EU-30

COUNTRY	POLICY	PLANNED CAPACITY CHANGE
Belgium	Complete phase-out by 2025.	866 MWe phase-out by 2015 5077 MWe phase-out by 2025
Bulgaria	Plans to extend lifetime of current reactors. Plans for a new reactor on hold due to lack of financing.	
Czech Rep	National energy plan to 2060 assumes 50% nuclear capacity, however plans for two reactors are put on hold after the government refused to provide state support.	1200 MWe in 2026 1200 MWe in 2028
Finland	One EPR reactor under construction, expected to be in commercial operation by 2016. Another two reactors planned.	1720 MWe in 2016 1600 MWe around 2020 1200 MWe in 2024
France	One EPR reactor under construction. The current President has pledged to reduce the share of electricity from nuclear to 50% by 2025.	1750 MWE in 2016
Germany	Closed down 8 reactors in March 2011. Plans for complete phase-out by 2022.	8336 MWe shut down in 2011 12003 MWe phase-out by 2022
Hungary	Plans for two new reactors under government ownership.	1200 MWe in 2023 1200 MWe in after 2025
Italy	Plans to revive the national nuclear industry rejected by referendum in 2011.	
Lithuania	Closed down two reactors in 2009 due to EU safety concerns. Plans for one new reactor, expected to start operating in 2022.	1350 MWe in 2022
Netherlands	Previous decision on phase-out was reversed in 2006. However, plans for new reactors are on hold due to economic uncertainties.	
Poland	Cabinet decision to move to nuclear power in 2005. Currently two planned reactors.	3000 MWe in 2024 3000 MWe in 2035
Romania	Two new reactors planned, but currently lacking financing.	720 MWe in 2019 720 MWe in 2020
Slovakia	Plans for new reactors outlined in the 2008 Energy Security Strategy, aiming to keep the share of electricity from nuclear at 50%.	940 MWe in by 2015 1500 MWe in by 2025
Slovenia	Considering capacity expansion, but no plans confirmed.	
Spain	Political uncertainty surrounding nuclear future. No plans for new reactors, but in 2011 the legal limitation to plant operating lives was removed (previously 40 years).	
Sweden	Phase-out plan from 1980 repealed in June 2010. Currently plans to uprate/replace old units when decommissioned.	
Switzerland	Parliament decision in June 2011 to not replace any reactors. Complete phase-out by 2034.	1102 MWe phase-out by 2022 (net) 985 MWe phase-out by 2030 (net) 1165 MWe phase-out by 2034 (net)
United Kingdom	Plans for several new reactors between 2023 and 2030. Government goal is 16 GWe new capacity by 2030.	16000 MWe by 2030

Table 10 Renewable subsidies in the National renewable policy scenario (€2009/MWh)

Country	Bio power	Reservoir hydro power	Run-of-river	Solar power	Wind power
AT	20	0	0	0	0
BE	0	0	0	0	0
BG	20	20	20	20	20
CH	0	20	20	20	0
CY	20	0	0	20	20
CZ	20	20	20	20	20
DE	0	20	20	20	20
DK	0	0	0	0	0
EE	0	0	0	0	0
ES	20	20	20	0	20
FI	0	0	0	0	0
FR	20	20	20	20	20
GB	20	20	20	20	0
GR	20	20	20	0	20
HU	0	0	0	0	0
IE	20	20	20	0	20
IS	0	0	0	0	0
IT	20	0	0	20	0
LT	0	0	0	0	0
LU	20	20	20	20	20
LV	0	0	0	0	0
MT	0	0	0	0	0
NL	0	0	0	0	0
NO	0	0	0	0	0
PL	0	0	0	0	0
PT	20	20	20	0	20
RO	0	0	0	0	0
SE	0	0	0	0	0
SI	0	20	20	20	0
SK	20	20	20	20	20

Table 11 Capacity and production shares of electricity technologies in EU-30 in 2009 and 2030 (percent)

	2009		Reference		100% Phase-out	
	Capacity share	Production share	Capacity share	Production share	Capacity share	Production share
Nuclear power	14.0	25.7	8.1	18.5	0.0	0.0
Oil power	6.8	0.0	2.2	0.0	2.2	0.0
Coal power	21.2	26.3	9.5	4.1	9.2	3.2
Coal power CCS	0.0	0.0	0.5	1.1	1.8	4.1
Gas power	24.0	23.6	19.5	21.0	20.1	23.7
Gas power CCS	0.0	0.0	0.0	0.0	0.0	0.0
Bio power	2.0	2.8	12.1	24.8	15.7	34.3
Hydropower	20.7	15.6	17.3	11.7	16.9	11.9
Wind power	8.1	3.9	18.9	12.2	21.6	15.1
Solar power	1.8	0.4	10.7	4.6	11.6	5.5
Other renewable	1.3	1.8	1.1	2.0	1.0	2.1

Table 12a Producer and consumer prices in EU-30 in 2030 (€2009/MWh or €2009/toe)

	Reference		50% Phase-out		100% Phase-out		No climate policy		Efficient		High emissions	
	Producer	Consumer	Producer	Consumer	Producer	Consumer	Producer		Producer		Producer	
							Consumer	Consumer	Consumer	Consumer		
Electricity price	56	121	59	123	61	126	47	110	63	129	58	122
Natural gas price	176	605	183	611	188	619	207	376	188	484	218	486
Steam coal price	111	493	111	449	112	430	114	136	113	374	112	237
Coking coal price	207	372	207	380	208	397	206	233	208	447	207	316
Lignite price	40	214	38	222	30	231	147	162	1	246	101	208
Oil price	554	1787	554	1786	554	1789	562	1156	559	1333	559	1355
Biofuel price	1270	1540	1270	1540	1270	1540	1275	1550	1274	1548	1274	1547
Biomass price	71	202	80	204	90	210	39	270	103	219	76	202

Table 12b Producer and consumer prices in EU-30 in 2030 (€2009/MWh or €2009/toe)

	Low emissions		Cheap CCS		EU renewable target		National renewable policy		Balancing power		Energy Efficiency	
	Producer	Consumer	Producer	Consumer	Producer	Consumer	Producer		Producer		Producer	
							Consumer	Consumer	Consumer	Consumer	Consumer	
Electricity price	61	127	55	119	53	117	56	120	61	126	54	118
Natural gas price	168	747	183	597	164	593	172	603	189	619	167	408
Steam coal price	112	599	110	277	112	526	112	550	112	430	111	311
Coking coal price	208	452	207	350	207	354	207	368	207	396	207	347
Lignite price	0	374	56	207	44	200	41	211	31	230	53	191
Oil price	550	2332	554	1777	554	1787	554	1788	554	1788	553	1317
Biofuel price	1263	1528	1270	1540	1272	1464	1270	1540	1270	1540	1224	1492
Biomass price	94	213	63	199	118	194	66	200	90	210	58	192

Figure 1 The LIBEMOD model

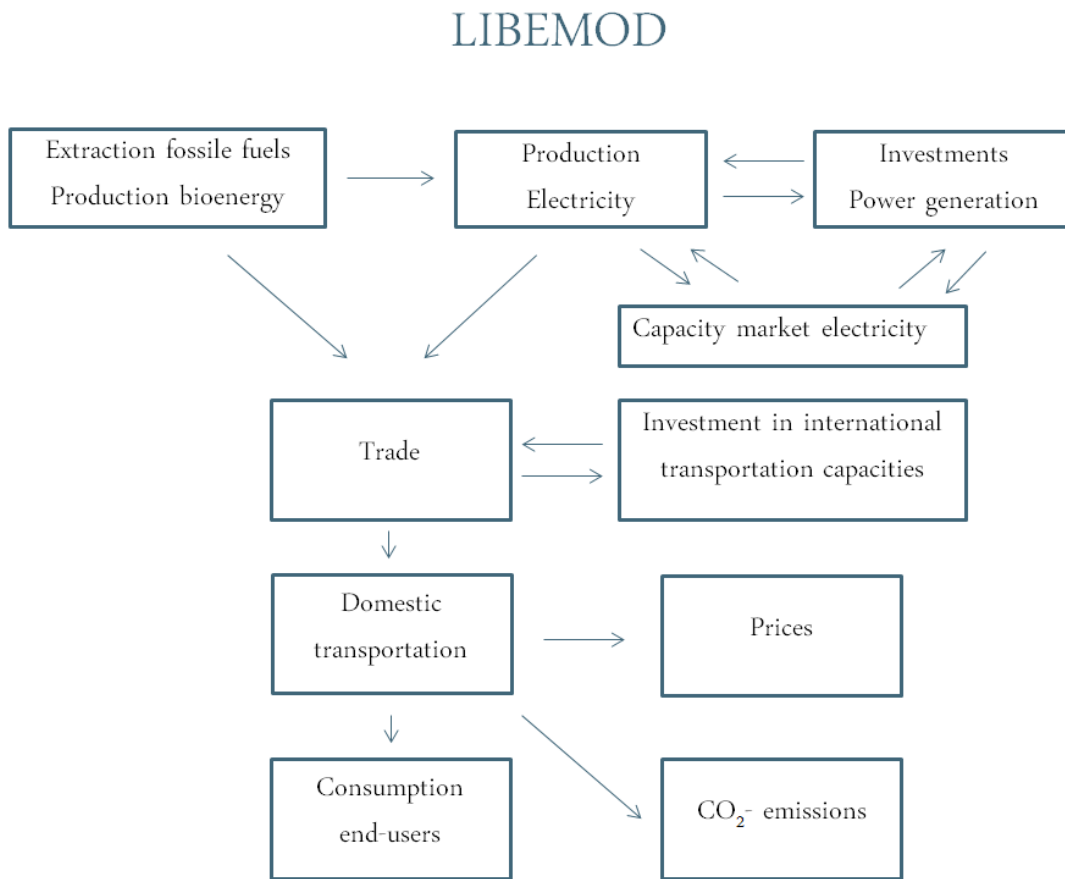
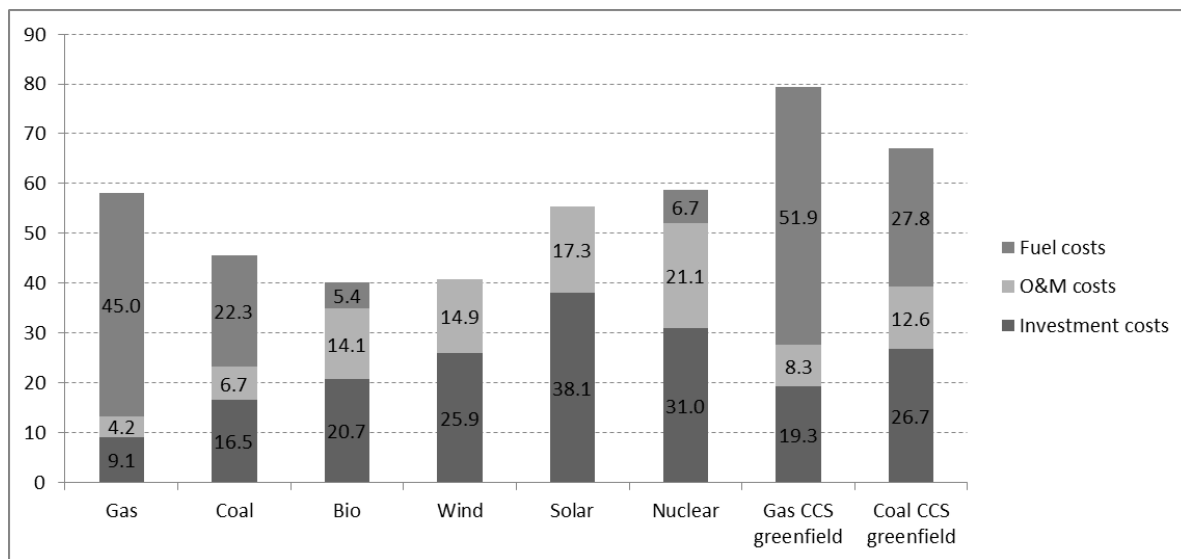
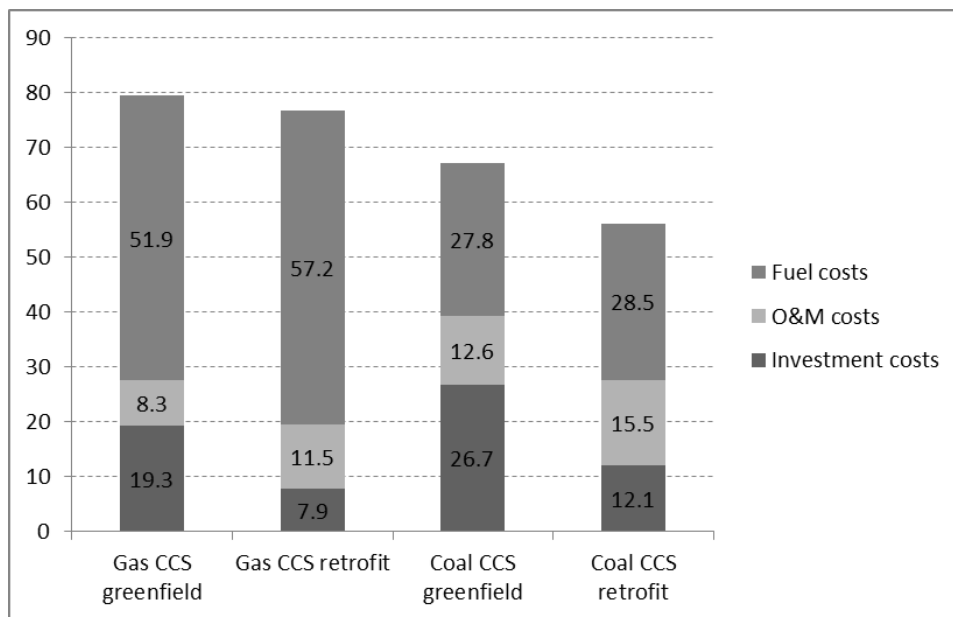


Figure 2 Average costs of electricity in 2030 (€2009/MWh)



Fuel prices: Coal and gas prices in EU30 in 2009, bio based on Schröder et al. (2013), nuclear from OECD (2010).
 Load hours: 70% for coal, gas, nuclear, CCS and bio. Wind and solar based on good locations in Europe (3500 and 2500 hours)

Figure 3 Average costs of CCS electricity in 2030 (€2009/MWh)



Sources: ZEP (2011), IEA GHG (2011) and own assumptions.

Efficiencies: For greenfield gas 52 % and greenfield coal 37 %. For retrofit an 8 percentage point reduction from «good» existing plants for coal and gas.

Fuel prices: Coal and gas prices in EU 30 in 2009.

Figure 4 Installed capacity by technology in EU-30 in 2009 and 2030 (GW).

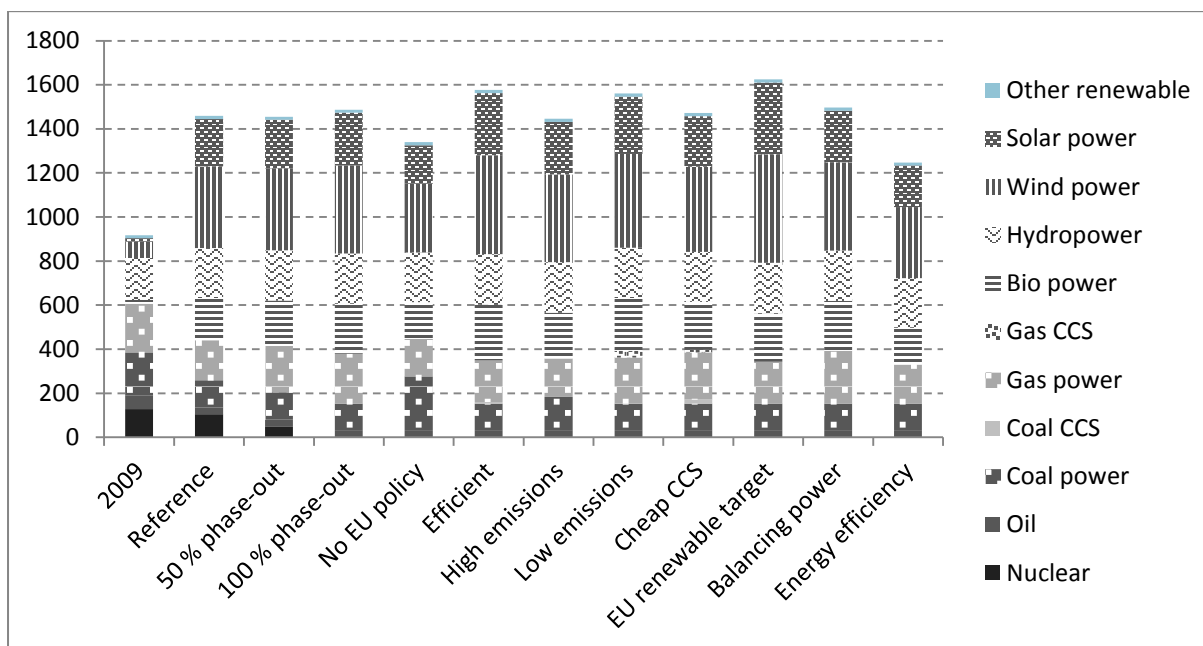


Figure 5 Electricity production in EU-30 in 2009 and 2030 (TWh).

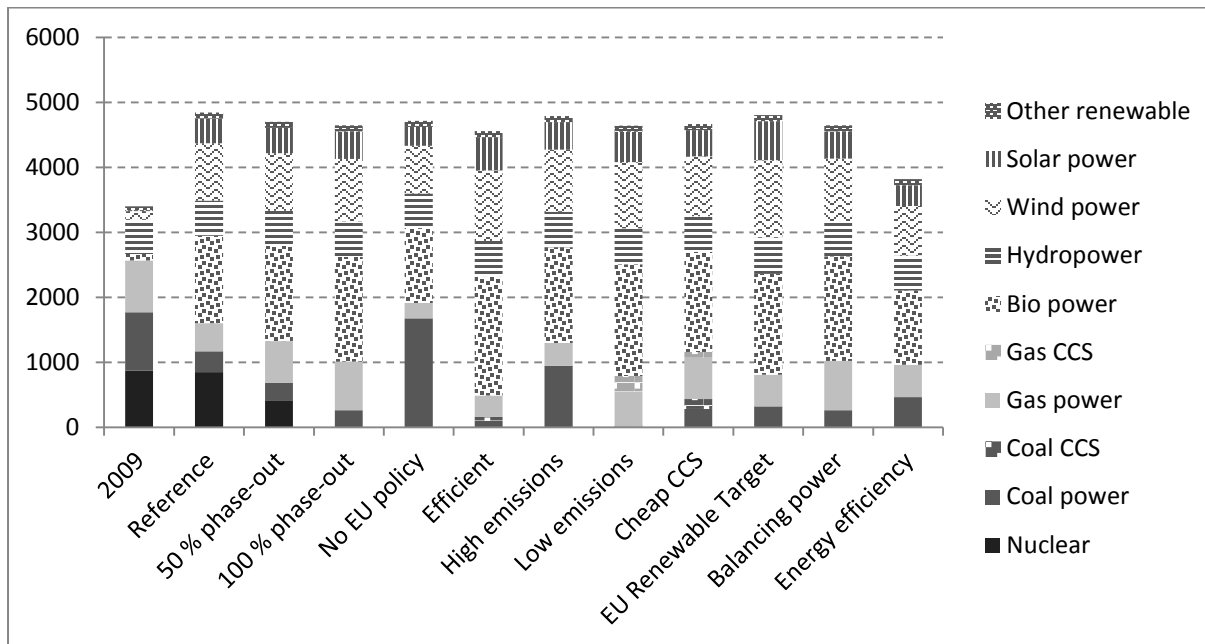


Figure 6 CO₂ prices in EU-30 in 2030 (€2009/tCO₂).

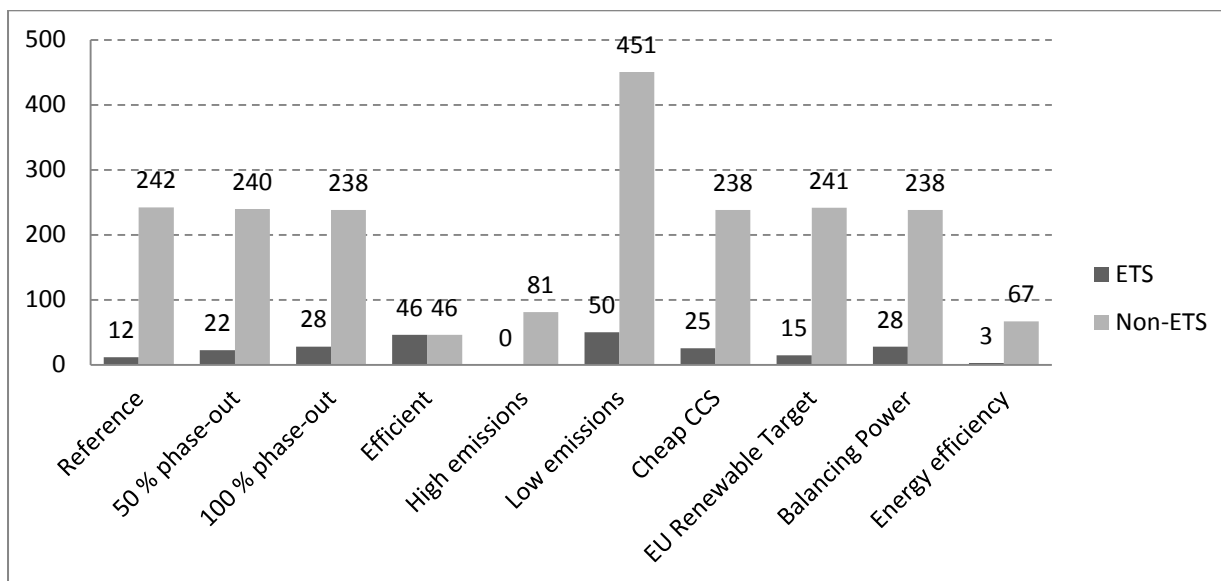


Figure 7 Common renewable energy subsidy in EU-30 in 2030 (€2009/MWh).

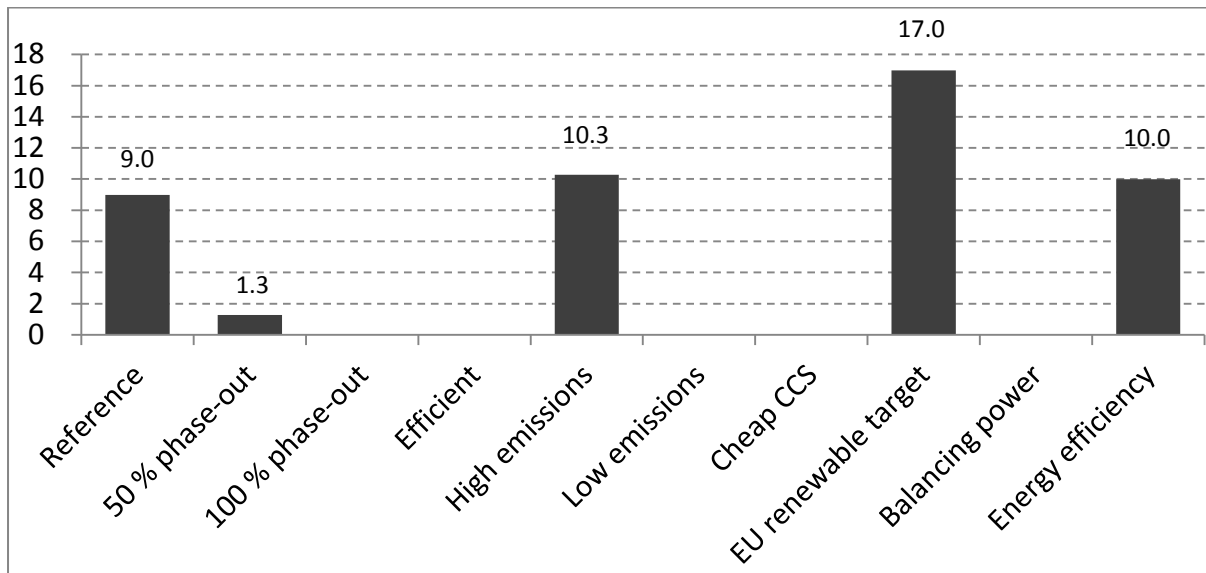


Figure 8 Renewable share in final energy demand in EU-30 in 2009 and 2030.

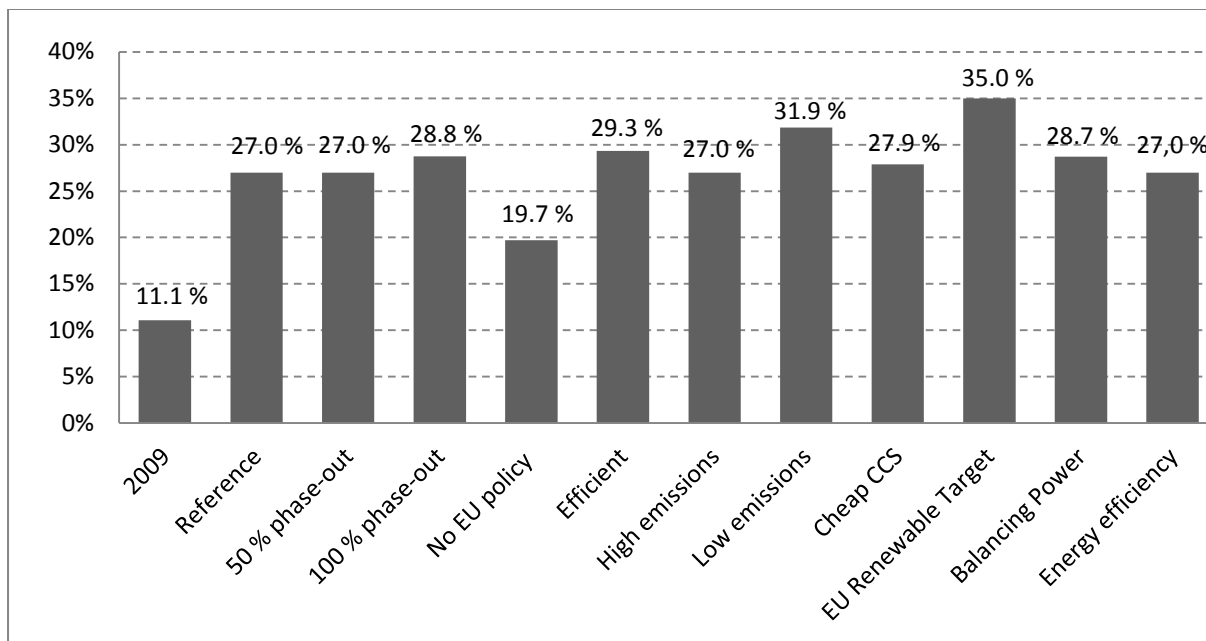


Figure 9 Energy consumption in EU-30 in 2009 and 2030 (Mtoe).

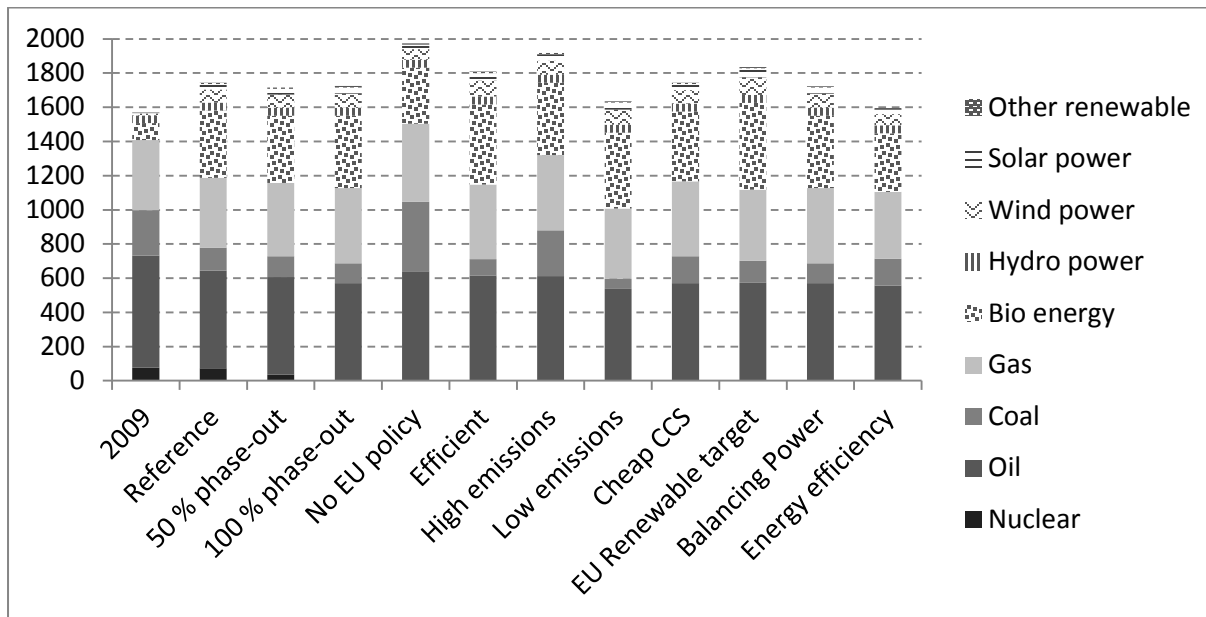


Figure 10 Change in welfare components relative to reference scenario. EU-30 in 2030 (Millions €2009)

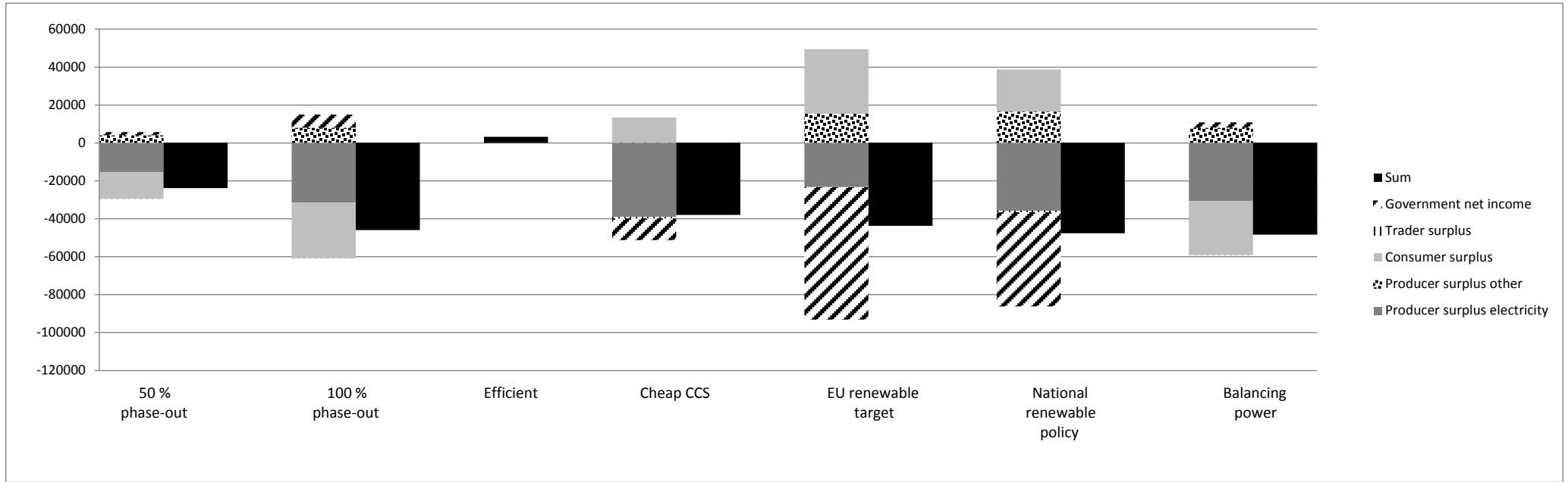


Figure 11 Welfare components in efficient scenario relative to reference scenario.
EU-30 in 2030 (Millions €2009)

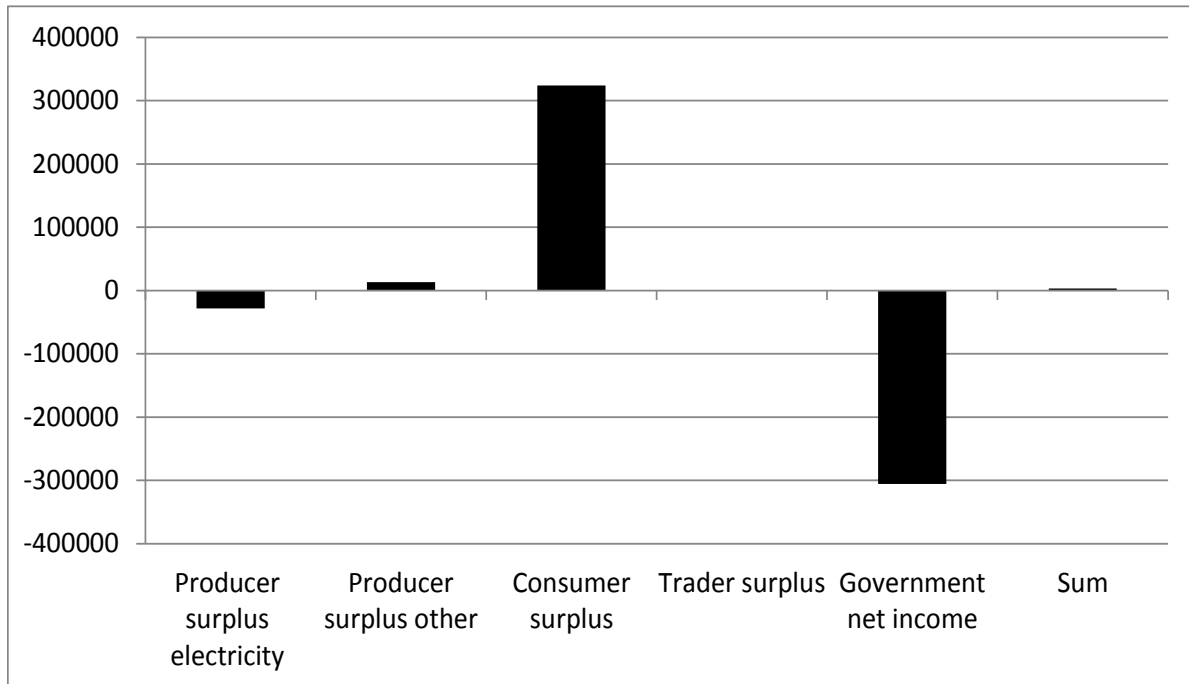


Figure 12 Change in electricity producer surplus by technology (except nuclear) compared to reference scenario. EU-30 in 2030 (Millions €2009)

