CONGESTION AND REDISPATCH IN GERMANY

A MODEL-BASED ANALYSIS OF THE DEVELOPMENT OF REDISPATCH

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List of abbreviations

AC	alternating current
ACLM	alternating load flow models
BDEW	Bundesverband der Energie- und Wasserwirtschaft (Federal Association of Energy and Water Supply Industry)
BNetzA	Bundesnetzagentur für Elektrizität, Gas, Telekommunikation, Post und Eisenbahn (Federal Network Agency for Electricity, Gas, Telecommunications, Post and Railway)
CAES	compresses air energy storage
CCGT	combined cycle gas turbine
CWE	Central-Western-European
DBFZ	Deutsches Biomasse Forschungszentrum (German Biomass Research Center)
DC	direct current
DCLM	direct current load flow models
DCOL	direct current ohmic losses
DENA	Deutsche Energie-Agentur GmbH
DIANA	Dispatch And Network Anaylsis
DSM	demand side management
EEG	Erneuerbaren-Energien-Gesetz (renewable energy act)
ENTSO-E	European Network of Transmission System Operators for Electricity
EnWG	Energiewirtschaftsgesetz (energy industry act)

EWI	Energiewirtschaftliches Institut an der Universität zu Köln (Institute of Energy Economics at the University of Cologne)
FACTS	flexible AC transmission systems
IE Leipzig	Leipziger Institut für Energie (Leipzig Institute for Energy)
LMP	locational marginal price
ie^3	Institut für Energiesysteme, Energieeffizienz und Energiewirtschaft, Technische Universität Dortmund (Institute for Energy Systems, Energy Effciency and Energy Economics at the TU Dortmund University)
NTC	net transfer capacity
OCGT	open cycle gas turbine
PTDF	power transfer distripution factor
SC-OPF	security-constrained optimal power flow
TSO	transmission system operator
TYNDP	Ten-Year Network Development Plan

1 INTRODUCTION

1.1 Motivation of the Topic and Scope of the Dissertation

In general, the motivation for investigating the topic of this dissertation stems from the recognition of the inefficiencies of electricity system planning induced by the unbundling of transmission and distribution from generation and supply. These inefficiencies require new tools and methods to economically assess the developments of the whole system.

More specifically, the motivation derives from the observation of the recent trend towards a regional concentration of electricity supply and demand in Germany and the resulting increase of network congestion. In order to economically assess these developments a tool needs to be specified that allows an economic evaluation of the limits of the national transmission network under a regime of a single uniform German wholesale market price.

In the following the scope of the dissertation is outlined and both motivations, the general and the concrete one, are explained in more detail.

Scope of the dissertation

The scope of this dissertation is to develop a tool and methodology that allows an economic assessment of the impact of developments of the electricity market on the transmission grid in Germany. As holds true for models and concepts to investigate the electricity market, numerous tools and approaches to study the limited transport capacity of the transmission grid already exist. Nevertheless, the focus of these existing tools is either on international transport restrictions or on national transmission limits based on the concept of nodal or zonal pricing. Due to the fact that nodal or zonal pricing is not used as congestion management method in Germany, the conclusions drawn by use of these models are, however, only applicable to Germany to a limited degree. Consequently, the model developed in this dissertation is based on the concept of redispatch in order to replicate the German system.

Moreover, in addition to the specification of the model, the scope of the dissertation is to apply the model and to display the future development of redispatch costs and quantities in Germany. Thereby, the main focus is on the identification of the relevant triggers rather than on the determination or forecast of an exact development path of quantities and costs. Furthermore, the impact of network extensions is analyzed and evaluated.

The effect of the liberalization of the electricity market on system planning

Prior to the liberalization of the electricity market in Germany and Europe, the operation and development of the whole electricity supply system – i.e. generation and supply on the one hand and transmission and distribution on the other hand – was optimized simultaneously. The companies operating the transmission network at the same time owned and operated the generation plants and could therefore coordinate both branches optimally for a reliable functioning of the whole system.

The liberalization however, prescribed an unbundling of transmission and distribution – which are assumed to be natural monopolies and are regulated as such – from the potentially competitive stages of the value chain, namely generation and supply of electricity. As a consequence, since liberalization the decisions on the location of new constructions and the operation of power plants are taken independently of the induced effects on the transmission grid. Generation plant owners have neither an incentive to locate at spots beneficial to the network nor to incorporate the effect of their generation schedules on the grid in their operation planning as they do not have to bear the costs associated with this. Their operation and investment decisions are exclusively determined by their expectations about the development of the German and European electricity market.

The transmission system operators on the other hand are obliged to guarantee a reliable and secure operation of the transmission network. In order to provide adequate network extension and operation planning, they need to forecast the development of the electricity market. However, as they can neither influence the investment and operation decisions of power plant owners nor have complete information about it, their decisions are usually not efficient. This inefficiency is aggravated by the fact that network investment projects generally need much more time to be realized – i.e. usually more than ten years – as compared to power plant investment projects that can be realized within about five years. Consequently, network investment is always lagging behind.

In sum, the unbundling of transmission and distribution from generation and supply leads to certain inaccuracies and inefficiencies associated with the optimization of the whole system as outlined in the next two sections. Power plant owners, on the one hand, have misaligned incentives with respect to the location and operation of their plants as they do not bear the full costs of their actions. Network operators, on the other hand, make inefficient operation and investment decisions because they lack information. However, despite the fact that the two branches optimize their operations and investments individually and subsequently the economic perspective requires that both branches are taken into account simultaneously. Consequently, the effects of one branch on the other branch need to be incorporated in an economic evaluation of certain developments or policies.

The regional development of generation and demand

Today a trend towards a concentration of generation in the North of Germany can be observed and expected to accelerate in the future. Especially wind power plants and coal-based conventional plants have an incentive to locate near the coasts in order to maximize profit. The wind speeds in North Germany are generally higher than in the South of Germany so that the wind yield and thereby the generation and obtained feed-in remuneration is higher. Furthermore, numerous offshore wind power parks are planned or already started to be constructed in the North Sea and the Baltic Sea.

In addition, the construction of coal-fired plants is more profitable in the North than in the South. This can be explained by the fact that today hard coal is mostly imported rather than produced locally. Therefore, coal needs to be shipped from the harbors at the North Sea and Baltic Sea "down" the inland water ways to the power plants. Thus, the further South the plant is located the longer the distance the coal needs to be shipped and thus the higher the transport costs are. As there is one German wholesale price for electricity, the attainable revenues at the market are identical independent of the location of the plant. The production costs, however, are lower in the North due to the lower fuel price so that new constructions of coal-fired plants are more profitable in these regions.

Beside the trend towards a concentration of generation capacities in North Germany, already today a concentration of demand in the South and West of Germany can be observed. Due to the demographic and industrial development the already existing load centers in the South, in the Ruhr-

Area and in the Rhineland might increase further. In contrast, electricity demand might decrease in those regions in the North and East of Germany which are already today characterized by low demand.

The effect of the regional concentration of demand and supply on the transmission grid

The combination of both concentration trends leads to a future setting in which more and more electricity needs to be transported over large distances from North to South through the high-voltage transmission grid. However, the transmission grid, as it is installed in Germany today, was initially not constructed for large scale electricity transport but rather for balancing regional electricity excesses/shortages and assistance of ancillary services. As a consequence, the frequency and magnitude of congestion and redispatch measures in the transmission grid – that already today is temporarily overstrained – can be expected to rise in the future.

Congestion poses a cost to society so that it should be taken into account in public efforts to maximize welfare and in the evaluation of policy measures. As already mentioned above, the effect of a specific development of the market on the electricity system can only be assessed thoroughly if the impact of this development on the network and the associated costs are incorporated, too. Today, however, the economic assessment of policy measures and market developments primarily concentrates on the electricity market in isolation. The investigations of effects on the transmission network in turn mostly focus on (electro-) technical aspects and disregard the economic perspective. A true and complete evaluation, however, requires a combination of both an economic analysis of the impact on the electricity markets and an economic analysis of the impact on the transmission network.

1.2 Differentiation of Own Work from Existing Work at the Institute an Co-operations

The dissertation makes use of already existing knowledge, data and models of the Institute of Energy Economics at the University of Cologne (EWI). Furthermore, the dissertation evolved in close cooperation with the Institute for Energy Systems, Energy Efficiency and Energy Economics at the TU Dortmund University. In the following, the differentiation between own work and already existing work or co-operations is presented.

The dissertation is based on the already existing model DIANA of the Institute of Energy Economics, which is able to simulate the regional power plant dispatch for 288 hours of a specific year. This model was further developed by the author in the course of this dissertation mainly by

1. subdividing the initial one-staged optimization of dispatch and network into a two-staged optimization to better replicate reality,
2. refining and improving the implementation of redispatch,
3. refining and improving the implementation of power transfer distribution factor (PTDF) matrixes for a flow-based modeling of electricity flows and
4. expanding and improving the regionalization of the model from initially 18 regions to 31 in order to fit the underlying load flow model.

As mentioned above, the model makes use of PTDF matrixes. The respective factors were entirely specified by the Institute for Energy Systems, Energy Efficiency and Energy Economics at the TU Dortmund

University. Both the reference network of the modeled years and the network extensions were developed at the Institute at the TU Dortmund University. However, the specification of the matrixes was based on injection/withdrawal scenarios simulated by the model DIANA.

The regionalization of the model grounds in parts on existing databases – i.e. a power plant database and a database that contains the German wind power plants – at the Institute of Energy Economics at the University of Cologne. These databases were updated and expanded in the course of the dissertation. Furthermore, additional databases were set-up that contain the installed capacity of hydro-power plants, biomass power plants and photovoltaic plants. In addition, the method of regionalizing the input data was refined by the introduction of a distribution key based on postal codes. This method was applied to specify regional inputs for 31 network regions.

1.3 Outline of the Dissertation

The dissertation consists of three main parts. The composition and content of each of these parts is outlined in the following.

Part I "Methodological and Institutional Background"

In Part I the underlying main methodological and institutional concepts are explained. Chapter 2 illustrates the congestion management method used in Germany – namely cost-based redispatch. Its functioning is explained theoretically and the exact implementation in Germany is outlined.

Chapter 3 presents the fundamental concepts with respect to the transmission of electricity. First of all, the general physical basics of electricity transmission in meshed networks are explained. Subsequently, the different concepts of flow-based modeling of electricity transmission and their respective advantages and disadvantages as well as their applicability for economic models are discussed. Furthermore, the reasons for adopting the PTDF approach, as done in this dissertation, are outlined.

Part II "Methodology of Modelling Redispatch"

In Part II of the dissertation the developed model and the specification of the model inputs are presented. In Chapter 4 the redispatch model is introduced. The general outline and the regional dissolution of the model DIANA are illustrated, followed by an explanation of the implementation of the PTDF matrixes in the model. Finally, the mathematical formulation of the redispatch model is explained.

Chapter 5 depicts the adopted methodologies and assumptions for the regionalization of the model inputs. It is outlined how the conventional and CHP plant power fleet, electricity demand and renewable energies – i.e. hydropower, biomass, photovoltaic and wind power – are subdivided to the different regions in Germany.

Part III "Scenario Analysis"

Part III contains the results of the model, the analysis of the results and the conclusion. In Chapter 6 the development of redispatch quantities and costs in Germany and its relevant triggers are analyzed. First of all, the reference scenario is presented by an illustration of the assumptions, the resulting export/import balances induced by the power plant dispatch and the pending redispatch quantities and costs. Following this, three sensitivity scenarios – i.e. a scenario with changed assumptions concerning the development of the fuel price, a scenario with altered assumptions concerning the regional distribution of total electricity demand and a scenario with different assumptions concerning the growth of wind power plant capacities – are investigated. The assumptions and resulting regional export/import balances as compared to the reference scenario are outlined and the change of redispatch quantities and costs is specified.

In Chapter 7 it is shown how network extensions can relieve congestion and how this has to be evaluated economically. For this purpose the change of redispatch quantities and costs induced by a specific network extension is analyzed and the methodology to economically assess this extension is explained.

Finally, the main findings of the dissertation are summarized in Chapter 8, and a conclusion is drawn.

PART I: METHODOLOGICAL AND INSTITUTIONAL BACKGROUND

2 REDISPATCH – CONGESTION MANAGEMENT IN GERMANY

Already today, the German high voltage transmission grid experiences temporary but recurring congestion. In combination with the current trend of an increasing distance between generation and load the phenomenon of network congestion can be expected to aggravate in the future.

In order to relieve congestion there are a number of possible approaches such as nodal pricing and market splitting (both implicit auctions) or explicit auctions.[1] However, these methods fundamentally rely on the definition and/or occurrence of different price regions within the market. As the German electricity market is a one-price market per definition – i.e. there is only one wholesale electricity market price without any regional differentiation – an internal method needs to be applied that allows a perpetuation of the single price. Possible methods therefore are cost-based redispatch and market-based redispatch or countertrading respectively. For the German electricity system cost-based redispatch is adopted.

In the following, the German approach of cost-based redispatch is outlined. First, the general functioning and associated costs of redispatch are illustrated and explained in section 2.1. Afterwards, the specific procedure which is applied in Germany is highlighted (section 2.2).

1 See Wawer, T. (2007) or Consentec & frontier economics (2008), chapter 2 for an overview of the different methods.

2.1 Functioning of Redispatch

In order to illustrate the effects of congestion and the congestion management method redispatch, a simplified transmission network consisting of only two nodes is assumed in the following. In this way the electricity exchange between the two regions belonging to the same market can be outlined in analogy to trade flows between two perfectly competitive markets. In a first step the unlimited exchange of electricity between different network regions is depicted (section 2.1.1). Subsequently, in section 2.1.2 the effect of limited transport capacity between the regions and the thereby induced market splitting is outlined. Finally, the functioning of redispatch is explained (section 2.1.3) and the associated costs are shown (section 2.1.4).

2.1.1 Unlimited transport capacity

In case there is unlimited transport capacity the exchange of electricity between two regions of the same market is unbounded and can be illustrated in analogy to the full market integration of two markets. This is depicted in Figure 2.1.

The left graph of the figure represents the situation without electricity exchange. The two markets are operating in autarky. As can be seen, demand in region A is met by supply of region A at price P_A which is equal to the regional marginal costs of electricity supply. Vice versa, demand in region B is met by supply of region B at price P_B equal to the marginal costs of electricity supply in region B. There is no electricity exchange. As the regions are not homogenous neither with respect to demand nor with respect to supply – i.e. the height of demand as well as the shape of the supply functions differs – two different regional prices materialize.

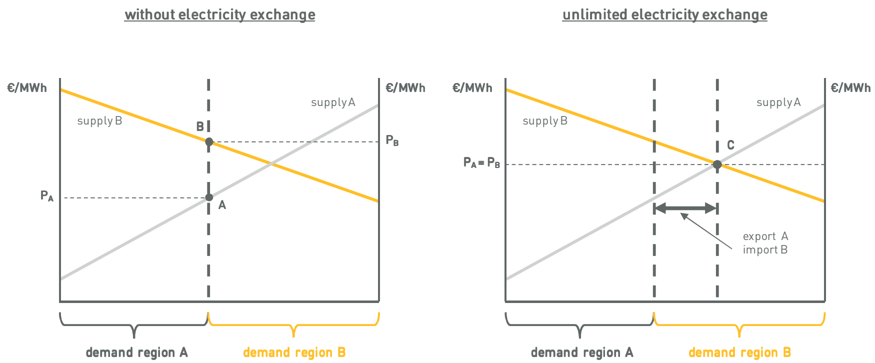

FIGURE 2.1: MARKET EQUILIBRIUM WITHOUT ELECTRICITY EXCHANGE (LEFT) AND WITH UNLIMITED ELECTRICITY EXCHANGE (RIGHT)

Source: Own illustration.

The right graph illustrates the situation with unlimited electricity exchange between two regions belonging to the same market. The market outcome will be such that the marginal costs of electricity supply of both regions are equal. In the figure, this is the case at point *C* at price $P_A = P_B$. At this price demand in region *A* is lower than supply in region *A*. Thus, electricity will be exported to region *B*. Vice versa, demand in region *B* is higher than supply in region *B* so that electricity is imported from region *A*. In sum, there is a flow of electricity from region *A* to region *B*. This situation is equal to the full market integration of two formerly distinct markets.

2.1.2 Limited transport capacity and market splitting

In case the transport capacity between the two regions is limited, it is possible that not enough electricity exchange can take place for an equalization of the marginal costs of electricity supply in the two regions. Without any redispatch or countertrading mechanism the market is split into two price regions as illustrated in Figure 2.2. This situation resembles the effect of an import/export quota on the integration and price convergence of two different markets.

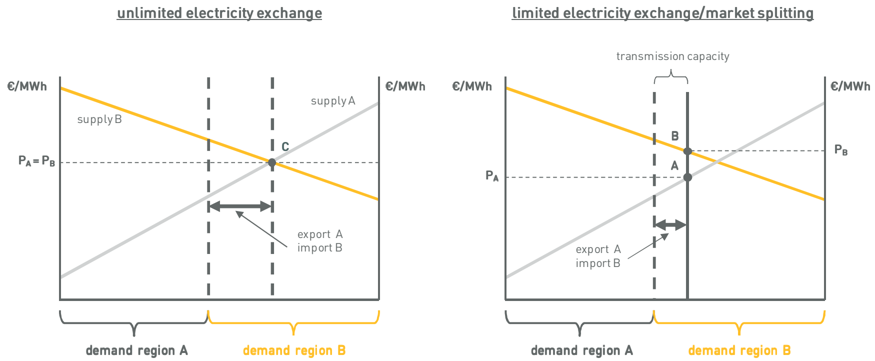

FIGURE 2.2: MARKET EQUILIBRIUM WITH UNLIMITED ELECTRICITY EXCHANGE (LEFT) AND WITH LIMITED ELECTRICITY EXCHANGE (RIGHT)

Source: Own illustration.

The graph on the left of the figure reproduces the market equilibrium with unlimited electricity exchange and full price convergence of Figure 2.1. In the right graph the situation with limited transmission capacity is depicted. As can be seen, the physical transmission capacity is not large enough for allowing all the desired electricity transmission so that only "partial market integration" can take place. In sum, the market is split into two regions *A* and *B* with two different prices P_A and P_B. Furthermore, the transmission capacity is entirely utilized still respecting the physical limits.

2.1.3 Limited transport capacity and redispatch

However, in a single price market design without regional price differentiation the market cannot be split into two price regions. Thus, a mechanism has to be established which guarantees that despite the single wholesale price, physical transport capacities are not overloaded. As already mentioned above this mechanism in Germany is cost-based redispatch whose functioning is illustrated in Figure 2.3.

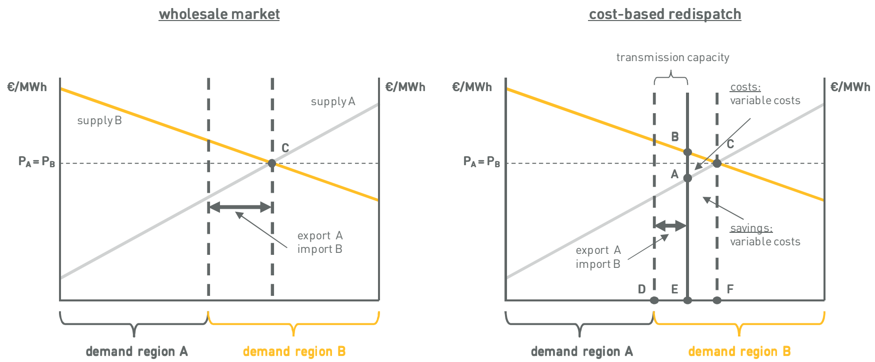

FIGURE 2.3: LIMITED TRANSPORT CAPACITY IN A UNIFORM PRICE MARKET AND THE COSTS OF REDISPATCH

Source: Own illustration.

In the left graph of the figure the market outcome of the wholesale market is depicted. Total demand is met at the price $P_A = P_B$, which equals the marginal costs of electricity supply at this demand. Obviously, demand in region *A* is lower than supply in region *A* while demand in region *B* exceeds supply in region *B*. Thus, the wholesale market outcome stipulates an export from region *A* to region *B*.

However, the resulting physical electricity flow from region *A* to region *B* (the distance between point *D* and *F*) exceeds the transmission capacity (equal to the distance between point *D* and *E*) as displayed in the right graph of the figure. Consequently, the electricity generation in both of the regions needs to be adjusted in order to change the physical flow between the regions in such a way that the transmission capacity limits are respected. This is achieved by redispatching the generation units: The export from region *A* has to be reduced by an amount equal to the distance between point *E* and *F*. For this purpose the most expensive generators – i.e. the generation units with the highest marginal costs of electricity generation – in region *A* are shut down (hereafter called "redispatched down"). On the other hand, electricity generation in region *B* has to be increased by the same amount equal to the distance between point *E* and *F* as demand still needs to be met. For this purpose, the cheapest available generators – i.e. the generation units not operating with the lowest marginal costs of electricity generation – are ramped up (hereafter called "redispatched up"). The decision which generator must be redispatched up and which must be redispatched down in the respective region is exclusively based on the thereby induced costs. Therefore, this redispatch mechanism is designated to be "cost-based".

2.1.4 The costs of redispatch

Redispatching means an ex post deviation from the market outcome and the specified generation schedules in real time. This involves two main costs:

First, the static effects are illustrated in Figure 2.3. Under the assumption that in the wholesale market demand is met at minimum costs (which is depicted in the figure), deviations from the market schedules induce higher variable costs of electricity generation.[2] On the one hand, the reduction of electricity generation in region *A* saves variable costs equal to the area *ACFE*. On the other hand, due to the increase of generation in region *B* additional variable generation costs equal to the area *BCFE* accrue. The netting of the cost savings and the additional costs yields a net cost equal to the area *ABC*. Consequently, redispatch leads to higher variable generation costs. These net costs of redispatch depend on the variable costs of the generation units redispatched up and down or more precisely on the difference between the respective variable costs of electricity generation.[3]

In addition to static costs, there are also dynamic costs of redispatch that are not illustrated in the figure. These dynamic costs accrue because the decision about redispatching takes place subsequently to the market-based operation decision of the power plants. Internal network congestion is detected and redispatching initialized in the course of short-term grid operation planning. Short-term operation planning investigates the network effects of the scheduled generation profiles, of the forecasts of the feed-in of renewable energies and of the load schedules. Specifically, dynamic costs are incurred due to the following relationship: The initial decision to operate at the wholesale market already incorporates the necessity to ramp up and down and thus the thereby induced costs in the course of time.[4] However, if power plants are redispatched up or down

[2] The variable costs of electricity generation are the fuel costs including costs (or savings) of changes of the efficiency factor due to full-load or part-load operation, the costs for CO_2-Certificates and other variable costs.

[3] In case the generation units that are redispatched up and down are identical with respect to their variable generation costs, the net cost is equal to zero. In general, net costs are lower the closer the two generators are located in the merit order e.g. if they use the same fuel.

[4] Ramp-up and ramp-down costs are mainly additional fuel costs that accrue during the starting process as well as costs associated with the stronger attrition of the plant.

additional costs accrue due to ramp-up and ramp-down processes necessary for attaining the desired “redispatch operation status”, as well as for returning to the scheduled operation status.

2.2 Cost-Based Redispatch in Germany

According to the German energy law, the *Energiewirtschaftsgesetz* (EnWG) of the year 2005, the four transmission system operators (TSO) are obliged and legitimated to take measures and adjustments in case the secure and safe operation of the electricity system is endangered. At first, network-related measures shall be initiated. If these measures are not effectual or fast enough the TSOs are obliged and legitimated to intervene by market-based mechanisms such as regulating power or redispatching.[5] Specifically, the four German TSOs use cost-based redispatch in order to relieve national congestion or congestion within their control zones respectively.

For this purpose, the TSOs contractually assure themselves the right to intervene in the scheduled generation profiles of the individual power plants in case of network congestion. The right to intervene is stipulated in the *Netzführungsvertrag* (grid control contract) while the exact reimbursement and settlement procedures are defined in the *Anschluss- und Netznutzungsvertrag* (grid connection and grid usage contract).[6] The individual contractual stipulations as well as the actual measures for

[5] See EnWG (2005), §13.

[6] See Consentec & frontier economics (2008), p. 5 – 6. An example for the stipulation of the right to intervene is shown in the model grid control contract and the model grid connection and grid usage contract of the Amprion GmbH, see Amprion (2009), section 6.2 and Amprion (2010), section 2.2. An example for the stipulation of the reimbursement of redispatch is given by the model grid connection and grid usage contract of the Amprion GmbH, see Amprion (2010), section 3.2 and annex D.

congestion management underlie the regulation of the *Bundesnetzagentur* (BNetzA).

As already mentioned in section 2.1.4, the necessity for redispatch arises as an output of the short-term grid operation planning. The initialized redispatch is operated contingent on the nodes the plants are located under the requirement of cost minimization. This means that the cheapest power plants available (notified by the power plant operators) should be used for upward redispatch while the most expensive available plants should be used for downward redispatch. On the one hand, the operators of the plants that are redispatched up are reimbursed by the TSOs for their actually incurred costs. This reimbursement generally incorporates the fuel costs and potentially part-load losses as well as the dynamic ramp-up costs. On the other hand, the power plant operators whose plants are redispatched down transfer the avoided fuel costs to the TSO. The respective cost specifications are updated and reported intermittently every three months by the operators.

As outlined in section 2.1.4, the net costs result from considering cost savings and additional costs of redispatch. According to the monitoring report of the BNetzA 2010 the costs for both national and cross-border redispatch amounted to 45 million Euros in the year 2008 and 25 million Euros in the year 2009.[7]

In general, the costs of ancillary services are excluded from the incentive regulation and are socialized as permanent non-influenceable cost component via the network charges.[8] However, the BNetzA has established

[7] See BNetzA (2010), p. 201.

[8] Cross-border redispatch and cross-border counter-trading in order to guarantee the usability of the auctioned cross-border transmission rights are not incorporated in the national congestion management. Their associated costs are netted against the auction

an incentive mechanism to reduce the costs of ancillary services of which congestion management is part of. Based on redispatch quantities that are extrapolated from the base year 2008 and an annually updated price development a cost reference is specified. This reference value is then included as budgeted cost into the revenue cap. In case the actually materialized costs exceed the reference value, the system operator has to endure a malus as he has to bear 25 percent of the additional cost. In contrast, undercutting the reference costs yields a bonus for the system operator as he is allowed to retain 25 percent of the savings.[9]

revenues and are thus not socialized in the network tariffs. See BNetzA (2009a), section 2.5.

9 See BNetzA (2010), p. 198 and BNetzA (2009b).

3 FLOW-BASED MODELLING OF ELECTRICITY TRANSMISSION – PTDF MATRIXES

In order to investigate electricity transmission, congestion and redispatch in the German transmission network, the electricity flows need to be modeled in such a way as to adequately reflect the true physical relationships within the transmission grid. This chapter outlines the relevant physics of electricity transmission that need to be respected and possible ways of modeling such electricity flows.

First, for a better understanding of the physics of electricity transport, the basic concepts of electricity transmission are outlined in section 3.1. This is followed by an overview of the different approaches to model the transmission of electricity (section 3.2). Finally, the applicability of the PTDF-approach for the scope of analysis within this dissertation is stipulated (section 3.3).

3.1 Basics of Electricity Transmission

The high voltage transmission grid throughout Europe is a network mainly consisting of meshed alternating current (AC) transmission lines (section 3.1.1) with some direct current (DC) lines (section 3.1.2) for connections oversee and/or longer distances. These two systems of electricity transmission differ fundamentally with respect to the physical transport of electricity. In the following, the physics of the two distinct techniques are outlined.

3.1.1 Electricity transmission in a meshed AC transmission network

As already mentioned above, Europe's high voltage transmission grid mainly consists of one synchronous interconnected meshed alternating current (AC) network. The power flow in such a meshed AC network follows electro-physical rules dependent on technical characteristics – e.g. the network topology of the grid or the pattern of load injection and withdrawal – rather than being "actively" controlled. Although there are some technical instruments to influence power flows such as line switching, phase shifting transformers, compensation devices or power electronic network controllers (FACTS, flexible AC transmission systems), the effect of these measures is very limited and they are usually applicable only at the expense of a loss in power quality and/or an increase in network power losses.

The physical relationship of electricity flows and voltages in electrical networks is stipulated in Kirchhoff's laws. According to ***Kirchhoff's first rule*** (or *Kirchhoff's nodal rule*) at any node in an electrical circuit, the sum of current flowing into a node I_k is equal to the sum of current flowing out of that node. Hereby, n is the total number of lines at that node and $k = \{1, \dots, n\}$ is one specific line.

$$\sum_{k=1}^{n} I_k = 0$$

According to ***Ohm's law,*** the current I in an alternating network is proportional to the inverse of the line impedance Z (and proportional to the voltage U) so that the power flows through a meshed grid are divided over the different lines in the network depending on the impedance.

$$I = \frac{U}{Z}$$

The line impedance is hereby the sum of the line's resistance R and the line's reactance X multiplied by the imaginary unit j.

$$Z = R + jX$$

Consequently, the combination of *Ohm's law* and *Kirchhoff's first law* stipulates that power does not directly and entirely flow from the source to the sink but is rather distributed to a certain extent all over the network. This is illustrated in Figure 3.1 for a simplified three-node network.

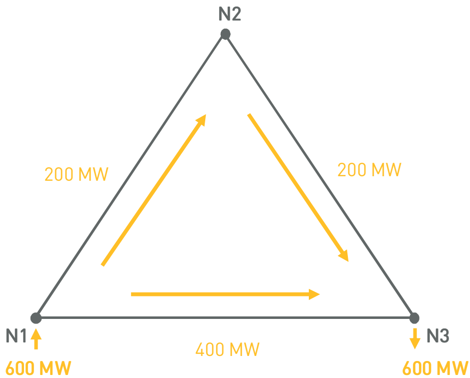

FIGURE 3.1: POWER FLOW IN A THREE-NODE AC NETWORK WITH ONE SOURCE AND ONE SINK

Source: Own illustration.

The figure displays a meshed network with three nodes *N1*, *N2* and *N3*. It is assumed that the lines connecting the three nodes are identical regarding length and impedance. Furthermore, it is assumed that *N1* is the source with an injection of 600 MW while *N3* is the sink with a withdrawal of 600 MW. As already mentioned, power flows in proportion to the inverse of the line impedance. As the line impedance (and length) of the route from

N1 over *N2* to *N3* is twice as high as the impedance of the direct route from *N1* to *N3*, 400 MW flow directly from *N1* to *N2* while 200 MW flow along the route from *N1* over *N2* to *N3*.

Because of the division of power flows over the network, as explained above, an incremental increase or decrease in generation or load at one node of the grid (e.g. one country) has effects on the electricity flows all over the interconnected electricity network. This holds true within national boundaries as well as across borders in the European meshed synchronous transmission grid. Thus, electricity trade invokes that each TSO in the network faces so-called *transit flows* as well as so called *loop flows* through its transmission network. While the "direct" flow from source to sink (via intermediate nodes) is usually referred to as transit flows, the flows through the remaining network are specified as loop flows.

The loop flows induced by the physics of electricity transmission are generally distinct from the *contract path* of cross-border electricity trade negotiated by power traders.[10] In addition, in a meshed synchronous AC network, it is not possible to trace down the power flows over a specific line to specific injections and withdrawals of electricity as *all* injections and withdrawals influence *all* flows. Consequently, the physics of electricity transmission fundamentally differ from the economics of electricity trade flows.

Due to the fact that electricity flows through the network according to physical laws, limits of the transmission infrastructure at one place have limiting effects on the flows through other lines as well. Even if the maximum line capacity of only one line is reached, further transmission through other lines becomes impossible. Thus, in an AC meshed

[10] An exception to this assertion is provided by the so called Flexible AC Transmission Systems (FACTS) that permit a certain control of the load flow. See Turvey (2006), p. 1458.

synchronous network *congestion* at one place curtails transmission throughout the whole system as illustrated in Figure 3.2.

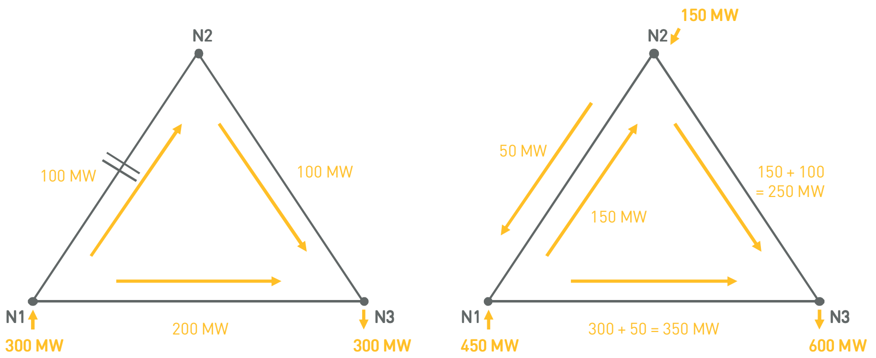

FIGURE 3.2: POWER FLOW IN A THREE-NODE AC NETWORK WITH LIMITED TRANSMISSION CAPACITY OF THE LINE BETWEEN N1 AND N2

Source: Own illustration.

In the figure it is assumed that the capacity of the line *N1_N2* is 100 MW while all other lines have a capacity of 600 MW. In the picture on the left it is shown that only 300 MW can be injected at *N1* due to the transmission capacity limits. Because 100 MW flow along the longer route over *N2* (which is thus entirely utilized) and 200 MW flow directly to *N3* the capacity limit of 100 MW of the line *N1_N2* restricts the total transmission of electricity. Thus, electricity transmission is limited although the line *N1_N3* still has 400 MW free capacities. In case 600 MW are withdrawn at *N3*, electricity injection at *N2* is needed as well. This is depicted in the right graph of the figure. At *N1* 450 MW and at *N2* 150 MW are generated while 600 MW are consumed at *N3*. The flow of 50 MW from *N2* to *N1* and the

150 MW from *N1* to *N2* cancel each other out yielding a net flow of 100 MW from *N1* to *N2* so that the line is not overloaded.

Summing up, the physical flow of electricity through a meshed synchronous AC network generally does not coincide with the contract path of trades at the power exchanges or bilateral negotiations. In addition, the limited transmission capacities of certain lines and the thereby induced congestion do have repercussions on the transmission capability of the whole meshed network. Finally, generation or demand changes as well as grid upgrades somewhere in the network do influence every line at least to a certain extent.

As all these effects potentially impose costs on or benefits to society[11] they have to be taken into account for the analysis and assessment of investments into the network infrastructure or policies affecting the generation and demand pattern not only from an electro-technical but also from an economical perspective. Nevertheless, modeling electricity transmission by means of contract-path based approaches – such as the concept of net transfer capacity (NTC) values – does not reflect the true physical flows and thus congestion adequately and is therefore inappropriate for a diligent analysis. Consequently, a flow-based approach is essential for a true understanding of the interactions.

3.1.2 Point-to-point electricity transmission with DC transmission lines

In contrast to alternating current lines, direct current (DC) lines differ fundamentally with respect to power flows. With direct current transmission no reactive power is needed. Hence, in a DC point-to-point

[11] Possible costs on society are for example the costs of congestion management or the costs of only partial instead of full market integration.

transmission line the direction of the power flow can be directly controlled by converter stations rather than being dependent on the network topology and the structure of injection into and withdrawal from the grid. As a result, the specific electricity transmission from point *N1* to point *N2* at the ends of the line or vice versa can be stipulated in advance and controlled exactly. For this purpose, DC lines require a converter station on both sides of the transmission line to integrate the electricity flow into the AC meshed network.

Figure 3.3 illustrates the power flow from source to sink in a two-node DC network. As can be seen the 600 MW injected at *N1* directly flow to *N2* without any loop flows through the adhering AC meshed synchronous transmission grid.[12]

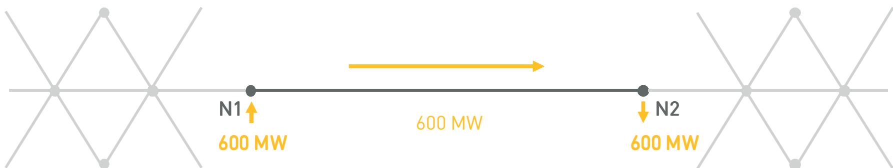

FIGURE 3.3: POWER FLOW IN A TWO-NODE DC NETWORK WITH ONE SOURCE AND ONE SINK

Source: Own illustration.

Thus, with a DC line no transit flows or loop flows exist so that the physical electricity flow resembles the contract path.[13] Furthermore, the transmission capability of the line is only determined by its own capacity rather than being dependent on the flow over other lines.

[12] In case the power flow through the DC line is very high, loop flows are also possible in a DC network. In that case the power in the parallel AC system might flow backwards inducing a loop flow.

[13] See Turvey (2006), p. 1458.

Despite this obvious advantage, the use of DC technology in Europe is rather limited. This can be explained by the fact that DC lines are usually more expensive than AC lines due to the necessity of converter stations. In general, the DC technology is only applied for (1) long distance electricity transmission (> 600 km); for (2) crossing long submarine distances such as between England and France; for (3) the connection of offshore wind parks to the mainland; and if (4) direct control of power flows between two areas is desired and/or if different AC synchronous systems shall be linked.

As explained above the physical flow of electricity through a point-to point DC transmission line does coincide with the contract path of trades at the power exchanges or bilateral negotiations. Consequently, modeling electricity transmission using contract-path based approaches (e.g. the NTC values) is appropriate for analyzing congestion and congestion management through such a line. However, as there are only few such lines in Europe, the scope of investigation is very limited if a contract-path-based approach is applied.

3.2 Outline of Different Approaches to Model Electricity Flows

As already mentioned, the European transmission grid mainly consists of meshed AC transmission lines. Consequently, the modeling of the transmission grid throughout Europe or within one European country requires an approach to appropriately simulate electricity flows in such an AC network.

There are different approaches to simulate load flows within an AC electricity network which have their individual advantages and disadvantages. Thus, the choice of method mainly depends on the specific application. In the following, the alternating-load flow approach (section 3.2.1), the direct current load flow approach (section 3.2.2) as well as the power transfer distribution factor (PTDF) approach (section 3.2.3) are illustrated. Hereby, a short description of the respective approach is given, followed by an explanation of its advantages and disadvantages especially with respect to its applicability for economic models. Finally, a short illustration of applications of the respective method in the recent technical/economic literature is given.

3.2.1 Alternating-current load flow approach

Alternating-Current Load Flow Models (ACLM) can be used to exactly replicate the physical conditions within an electricity network. Such models specify active and reactive power flows within a grid by determining a balance between injections and withdrawals at each incorporated network node. Hereby, network losses, reactive power demand and reactive power withdrawals of all network components are taken into account.[14]

The AC load-flow approach is adequate to determine flows within discretionary complex electricity grids. However, as the approach is non-linear an iterative solving algorithm is needed.[15] Furthermore, convergence of the load flow calculations cannot be guaranteed so that sometimes no solution is attainable.

Consequently, despite their accuracy – i.e. ACLMs are able to reproduce electricity flows nearly exactly – they are rather inappropriate for the incorporation of electricity flows and network restrictions in economic

[14] A more detailed explanation of the AC load flow approach is without the scope of this dissertation. For more general information see for example Handschin et al. (2009), pp. 1004 – 1005 or Groschke et al. (2009), pp. 17 – 18.

[15] Typical algorithms are the Newton-Raphson approach or the Gauss-Seidel approach.

models. Thus, they are predominantly used for technical purposes such as detailed investigations of electricity networks and network expansions. For such analyses reactive power flows play an important role which can be handled by AC load flow models.

One example of the few applications of an AC load flow model with an economic focus is given in Barth (2007). The developed model stochastically and simultaneously optimizes the power plant dispatch and grid operations within a distribution grid which is reproduced in detail. By use of this model the effects of the integration of distributed generation into the electricity system on system costs and CO_2-emissions are analyzed.

3.2.2 Direct-current load flow approach

In order to simplify the load flow calculations, the complex problem of electricity flows is linearized in Direct-Current Load Flow Models (DCLM). These models are able to approximate the active power flows within an electricity grid but rely on a number of simplifying assumptions – i.e. the line resistances are close to zero so that losses are neglected, the voltage angle differences are small and all voltages are constant and equal to 1.[16]

The approach has the advantage that due to the linearization no iterative problem solving is required but rather standard linear algorithms can be used.[17] However, disadvantages of DC models are that only active power

[16] A detailed explanation of DCLMs is without the scope of this dissertation. For more general information see e.g. Handschin et al. (2009), pp. 1005 – 1007 or Groschke et al. (2009), pp. 17 – 18. In Schweppe et al. (1988), pp. 272 – 274 or Stigler and Todem (2005), pp. 116 – 118 the derivation of a DCLM based on an ACLM is shown. Purchala et al. (2005a) investingate the usefulness of DC power flow for active power flow approximations by analyzing the underlying assumptions. Overbye et al. (2004) compare the results of DC load flow models and AC load flow models for the specification of locational marginal prices.

[17] A typical algorithm is the Simplex algorithm.

and no reactive power flows are incorporated and that network losses are neglected.[18] Thus, important technical aspects of electricity transmission are not covered by such an approach, leading to a specific inaccuracy of the results especially in case of geographically large electricity transmission grids.

Nevertheless, due to their linearity and their high speed of problem solving DC load flow models are well capable of being integrated into economic models. Hereby, DCLMs are primarily used for the modelling of national transmission restrictions based on the concept of nodal pricing. This application seems to be adequate as outlined in Overbye at al. (2004). They investigate the loss of accuracy of using DC models rather than AC models for the specification of locational marginal prices (LMPs) and conclude that the results of a DC model – i.e. the identified congestion patterns and the LMPs – are quite close to the result of an AC model.

In the following, an overview of the current literature that uses DC load flow models in combination with economic models is given: Stigler and Todem (2005) incorporate a direct current load flow model into a welfare maximizing economic model. They investigate Austria's electricity system and evaluate network extensions. Moreover, the authors determine the optimal use of the scarce resource transmission capacity by specifying nodal prices for the Austrian system.

In Green (2007) the welfare effects of nodal pricing on the electricity system in England and Wales is analyzed using a DCLM. Total welfare under a regime of nodal pricing is compared (1) to a system with nodal prices for generators and uniform prices for consumers and (2) to a system with

[18] There are methods that can approximate the network losses for DC load flow models. These are the so-called Direct Current Ohmic Losses (DCOL) models; see Handschin et al. (2009), pp. 1007 – 1008 for further details.

uniform prices for all market participants and counter-trading in case of network congestion. It is shown that total welfare is highest with nodal pricing and decreases for the second and third pricing rule in descending order.

Furthermore, the chair of Energy Economics and Public Sector Management at Dresden University of Technology developed a model of the European electricity market and transmission network using a DC load flow approach as outlined in Leuthold et al. (2008). Dietrich et al. (2005) use this DCLM in combination with the concept of nodal pricing to specify a model that maximizes total welfare. Hereby, the authors investigate the German electricity sector with special focus on the integration of onshore and offshore wind power as well as on a comparison of uniform and nodal pricing. Weigt (2006) extends the approach of Dietrich et al. (2005) by incorporating cross-border exchange and by taking a time-variant perspective. Kunz (2009) in turn uses the nodal pricing model with a focus on the electricity grid of Belgium and the Netherlands. He investigates the effect of the incorporation of possible network contingencies and the resulting preventive control actions on total welfare and nodal prices.

3.2.3 PTDF approach

As the DC approach, the power transfer distribution factor (PTDF) approach relies on a linearization of the electricity flows for determining load flows within a network. Hereby a specific PTDF factor ($\mathrm{PTDF}_{r_1,c}$) determines the change of the active power flow on a transmission line c resulting from an electricity injection at node r_1 and an electricity withdrawal at node r_2.

$$\mathrm{PTDF}_{r_1,c}=\frac{\Delta \mathrm{PhysFlow}_c}{\Delta \mathrm{Injection}_{r_1}}$$

Thus, the PTDF approach only incorporates active power flows and neglects network losses as well as reactive power flows. The simulations necessary to determine the PTDF matrix can either be performed with AC simulations or DC simulations.[19]

The advantage of PTDF matrixes is that the transaction volume has little influence on the specification of the PTDF so that they can be used for different situations independent on the actual injection/withdrawal situation.[20] Furthermore, the linear character of the matrixes allows an easy integration into linear economic models. Nevertheless, as already mentioned, the approach neglects any reactive power flows and network losses and requires simplifying linearization assumptions which leads to a certain inaccuracy of the results. In addition, changes of the network topology generally require an entirely new calculation of the matrix.

Still, the factors are valid for numerous situations. Lui and Gross (2002) empirically show that the approximation errors of keeping the same PTDFs are rather small in case of changes of the reactance of individual lines and in case of outages of individual lines. Baldick (2002) in turn theoretically demonstrates that PTDFs are rather independent of the injection/withdrawal scenario under the assumptions that the topology is fixed, voltages are held constant, and there are only minor network losses

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[19] This short outline of the PTDF approach is based on Groschke et al. (2009), p. 17 – 18. The implementation of PTDF matrixes in the model DIANA is explained in chapter 4 of this study. The technical details of the specification of PTDF matrixes are without the scope of this dissertation. For more information the interested reader is referred to Duthaler, C. L. (2007), Appendix and Duthaler et al. (2008). In Waniek, D. (2010), pp. 21 – 25 three different methods for the specification of the matrix are outlined.

[20] See Lui and Gross (2002) for an empirical and Baldick (2002) for a theoretical investigation of this assertion. Furthermore, this assertion was tested using the network model of the ie[3]. A comparison of the PTDF factors determined for 288 different injection/withdrawal situations (each hour of a model year) showed that these factors indeed only differ insignificantly if specified based on a different injection/withdrawal situation.

and small angles across the lines. In Waniek (2010) the margin of fluctuation and the resulting standard deviations of the PTDF factors in the course of a year are investigated and it is shown that this variations are negligibly small.

These assertions however only hold if the network is modeled on a nodal basis – i.e. each node of the network that should be analyzed is included in the calculations explicitly. Duthaler et al. (2008) showed that if the calculations are based on a zonal model – i.e. numerous nodes and lines are aggregated into different zones – the factors are highly influenced by the season and hour of the day, by topological changes and by the geographic distribution of generation. Thus, keeping fixed factors for an entire model year might lead to inaccurate results that do not truly reflect the physical situation in the transmission grid. Furthermore, the choice of the zones in general highly influences the magnitude of the factors. Consequently, if PTDF matrixes are used in a zonal model the choice of zones should reflect the true technical and physical conditions in the grid rather than being based on national borders. In Purchala et al. (2005b) an approach for the development of a zonal PTDF based model of the UCTE network is presented. The specification of PTDF factors hereby relies on different internal dispatch scenarios in order to achieve a higher universal validity of the factors.

So far the PTDF approach has been mainly used in economic models for the analysis of international physical electricity flows and trade flows. Apfelbeck et al. (2005) for example apply the model EMILIE-NET to investigate the market results of the central European electricity markets under the assumption of Cournot competition compared to the results under the assumption of perfect competition. Hereby, the behaviour of the main competitors and the competitive fringe is optimized in a game theoretic setting. The transmission restrictions between the different European markets are incorporated by means of PTDF factors and the corresponding transmission capacity limits are expressed as NTC values.

Kumar et al. (2004) develop a zonal congestion management method dependent on AC-based transmission congestion distribution factors and apply this method to the Indian and New England system. The individual nodes are classified into three different zones dependent on the effectiveness of changes of the electricity injection (redispatch) to solve congestion. The authors show that AC load flow based methods to specify the factors are more efficient for congestion management than a method based on DC load flow.

Waniek (2010) analyzes the economic and technical effects of a change from a transaction-based specification of transfer capacities – i.e. a specification of NTC-values – to a flow-based determination of the transmission capacities – i.e. a specification of PTDF factors and a security-constrained-optimal power flow (SC-OPF) approach – in the Central-Western European region (CWE). Hereby, a market and a network model are coupled to analyze the welfare effects on individual market participants and the effects on the physical load flows in the transmission grid. It is shown that such a change has welfare increasing effects and that the utilization of the existing transmission network is improved.

3.3 Adoption of the PTDF-Approach for the Investigation at Hand

Within this thesis the PTDF-approach is adopted to model electricity flows in the German transmission network. In the following it will be explained why this approach is chosen instead of one of the two other approaches for the analysis at hand (section 3.3.1). Following this, in section 3.3.2 it will be investigated if the simplifications and the disregard of certain technical aspects is eligible for the present study.

3.3.1 Reasons for the adoption of the PTDF approach

There are mainly four reasons for chosing the PTDF approach for the investigation in this study. While the first two arguments in the following hold for both the DC load flow and PTDF approach in comparison to the AC load flow approach, the last two arguments stipulate why the PTDF approach is prefered to the DC load flow approach.

First, PTDF matrixes are well integratable into the linear optimization model DIANA as the approach linearizes the electricity flows. This linear character of the PTDF approach makes it possible to solve the optimization problem by use of standard alogorithms provided by the ILOG CPLEX optimizer used for the model DIANA. Thus, no iterative solving algorithm is needed which would be required if the AC approach was used.

Second, although the PTDF approach neglects network losses and reactive power compared to the AC approach, this disadvantage can be disregarded in the context at hand. The focus of the study is on general trends and decisive drivers of the transmission of *active power* as well as the economic analysis of its limits. Thus, although network losses and reactive power play an important role in the context of electricity transmission they are more technical than economic aspects and accordingly are without the scope of this study.

Third, the PTDF approach is more convenient for the analysis at hand than the more detailed DC (or AC) approach. In contrast to the PTDF approach the DC approach allows to incorporate endogenous changes of the network topology and to investigate the individual network components in more detail. However, the focus of the dissertation is on the effect of different injection/withdrawal situations, on the utilization of the transmission grid and on the resulting redispatch quantitites and costs in a *given* transmission grid rather then on changes of the transmission grid itself. Thus, the additional information and dissolution of the physical interrelations within the transmission grid as well as the possible endogenous adjustments provided by the DC approach are obsolete in this context.

Fourth, the application of the DC approach would require the development of an own network model including the build-up of technical knowledge and network data, while the PTDF approach allows to adopt the relevant network data from external sources.[21] Consequently, due to the fact that the relevant knowledge is already existent at the Institute for Energy Systems, Energy Effciency and Energy Economics (ie³) at the TU Dortmund University (the cooperation partner) the PTDF approach is prefered.

3.3.2 Eligibility of the PTDF approach

As outlined in section 3.2.3 the suitability of using the PTDF approach to extimate load flows and the acceptability of its limitations and simplifications depends on the exact case of application. In the following it will be investigated whether the PTDF approach is eligible for the study at hand.

First, it is shown in section 3.2.3 that the approximation error of using a PTDF matrix for numerous injection/withdrawal situations in the course of

[21] The external cooperation partner for this dissertation is the Institute for Energy Systems, Energy Effciency and Energy Economics (ie³) at the TU Dortmund University. However, in general it is possible to use PTDF data for the redispatch model from any other source and for any other regional structure.

a year is limited if the network topology is held constant. Consequently, one matrix can be applied for a whole model year as the topology in the analysis at hand is assumed to be constant for this time period. In turn, a changed network topology requires the specification of an entirely new matrix. As the applied methodology incorporates network topology changes by determining a new matrix, the approach appropriately accounts for this characteristic of the PTDF method.

Nevertheless, the assertions concerning the use of PTDF matrixes explained above are only valid if applied to a nodal model. In principle, the model used in this study is a nodal model as each of the German 31 network nodes is incorporated into the calculations. As a consequence, the PTDF matrixes are adequate to resemble the hypothetical physical flows wihtin the hypothetical 31 network model. Conclusions about line utilization, congestion and congestion management are thus valid but only with respect to this hypothetical 31 node model.

However, the underlying idea behind the 31 node model is to resemble the true German high-voltage transmission network which consists of more than 200 nodes. Lines and nodes of the true network are hereby merged into only 31 nodes to simplify the model. Thus, the 31 node network is very detailed but still a type of "zonal model" of the German transmission grid. Drawing conclusions from this 31 node model on the true German transmission grid is only adequate with reasonable diligence.

It has to be kept in mind that in the context of a zonal model the PTDF factors are highly influenced by daytype, season and injection/withdrawal situation. In order to justify conclusions about the German transmission grid, the 31 nodes are stipulated in such as way as to reflect the true technical and physical conditions of the German grid. Furthermore, the level of aggregation is rather low compared to usually applied zonal models that include one or few zones per country. As already mentioned in footnote 20, the factors determined by the 31 node model are rather independent of the exact injection/withdrawal situation so that they can be used for different hours and scenarios.

In sum, it can be concluded that the way the PTDF approach is applied in the context of this study is a sufficient approximation of the physical flows in the German transmission grid. Besides, the aim of the study is not to detect and/or forecast congestion on individual specific lines in the true transmission network but rather to identify general trends and decisive influencing factors for the prospective development of network utilization and redispatch quantities and costs.

PART II: METHODOLOGY OF MODELLING REDISPATCH

4 THE REDISPATCH MODEL DIANA

The analysis of this study is based on the already existing power plant dispatch optimization model DIANA of EWI. The main extensions in the course of this dissertation are (1) the break-down of the initial one-stage optimization into a two-staged optimization and (2) the flow-based implementation of network restrictions including the flow-based calculation of redispatch in Germany.

In the following the general set-up of the model DIANA as well as the implementation of the concepts discussed in chapter 2 and chapter 3 in the model are presented. First, a general outline of the power plant dispatch model DIANA is given in section 4.1. This is followed by a description of the regional structure applied to the model in the course of this analysis (section 4.2). In the subsequent section 4.3 the application of PTDF matrixes in the model is illustrated. Then, the second optimization stage of the model – namely the redispatch model – is explained in greater detail by outlining the mathematical formulations used (section 4.4). Finally, the limitations of the modeling approach used are explained in section 4.5.

4.1 General Outline of the Dispatch Model DIANA

DIANA (dispatch and network analysis) is an intertemporal, linear, and multiregional European dispatch model with the objective to minimize the total costs of the power plant dispatch within Europe.[22] Besides this cost-minimizing dispatch of the wholesale market, DIANA also comprises the regulating power market. In addition to numerous technical and economic

[22] The description of the model DIANA is based on EWI's official DIANA model description written by the author of this thesis, see EWI (2011).

parameters the model is able to incorporate political constraints such as the promotion of renewable energy sources or specific provisions with respect to nuclear power plants. The model takes the limitations of the transmission grid between or within specific regions into account and therefore allows for an economic assessment of the transmission restrictions.

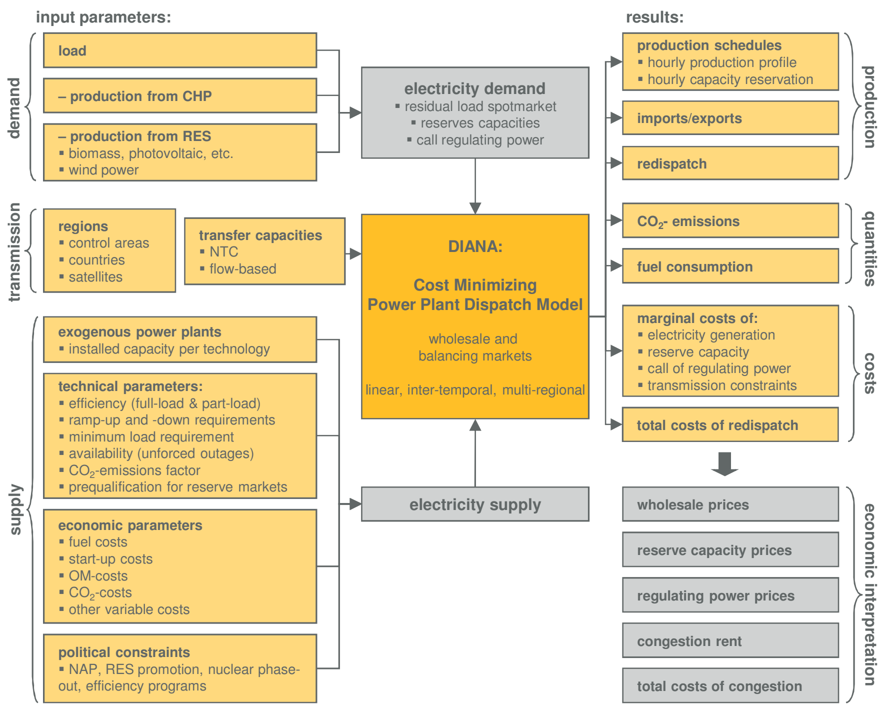

FIGURE 4.1: DIANA MODEL OVERVIEW

Source: Own illustration.

The model calculates 24 hours of a representative working day, Saturday, and Sunday respectively. This calculation is repeated for each of the four seasons of the year (spring, summer, autumn, winter). Thus, in sum, the model optimizes the power plant dispatch for 288 hours per year. An overview of the structure of DIANA is displayed in Figure 4.1.

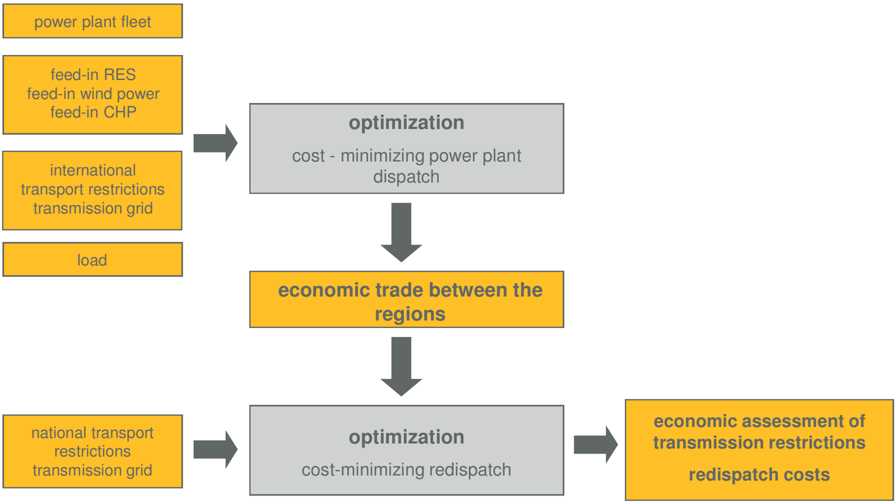

FIGURE 4.2: TWO-STAGED OPTIMIZATION IN DIANA

Source: Own illustration.

The model DIANA is set up in a two-staged optimization procedure. As can be seen in Figure 4.2, the model in a first step determines the cost-minimizing power plant dispatch that is interpreted as the outcome of the wholesale market in all modeled regions within Europe.[23] In the second

23 The model minimizes the total costs of the power plant dispatch. Thus it acts as a central planner with perfect information and perfect foresight. The model results of the central planner resemble the market outcome of a perfectly competitive market with perfect

stage, the model optimizes the redispatch for specified regions. The physical electricity flows that result from the wholesale market outcome are determined using PTDF factors (see chapter 3). These flows are tested against the limited transmission capacity between the regions and if necessary congestion is relieved by redispatching power plants.

4.2 The Regional Structure of the Model DIANA

In order to allow for an analysis and economic assessment of transmission constraints and redispatch, the covered territory is subdivided into numerous regions for which interregional transfer capacities are specified. In general, the model DIANA is adjustable with respect to the regional structure, which yields great flexibility. Thereby, the chosen regional dissolution depends on the scope of analysis and the availability of regional input data. The regional structure of Germany and the European electricity system applied in the course of this dissertation is illustrated in the following.

The key component of the model is a very detailed regional dissolution of Germany that allows displaying the current flows within the country. The regions are determined according to the node model of Germany and its neighboring countries of the Institute for Energy Systems, Energy Efficiency and Energy Economics (ie^3) at the TU Dortmund University as outlined below.[24]

foresight. Consequently, the model results are interpreted as the outcome of the wholesale market thereby abstracting form all types of strategic behavior, abuse of market power, etc.

[24] The following comments on the electro-technical node model of the ie^3 used for the determination of the PTDF matrixes are provided by the ie^3. This model was neither developed nor applied by the author of this dissertation. Rather the matrixes were

The node model is a simplified illustration of the German transmission grid consisting of 31 nodes and about 50 lines. The reduced grid model was specified based on publicly available information about the German grid. Hereby, multiple real network nodes were summarized regionally to single nodes. Furthermore, the line lengths were estimated by use of grid plans while the lines that are incorporated are the 380 kV and relevant 220 kV lines.

Due to the outlined simplifications, the identifiability of individual nodes and lines is lost. Furthermore, the reactive power in the grid model is not comparable to the reactive power in the real German transmission grid. This is – among other things – because of the different total length as well as the higher length of connections without injection and withdrawal induced by the aggregation of nodes into representative network regions and the aggregation of parallel systems. Nevertheless, the electric properties of the network are represented in sufficient adequacy in the model and it has already been used in numerous studies for identifying the exigency of network expansions. While the results of the model yield a good point of reference, they do not, however, substitute essential detailed examinations of network expansions.[25]

As the grid model of the ie^3 consists of 31 network nodes, 31 German regions need to be specified in DIANA. For this purpose, dependent on the geographic location of the network node, Germany is subdivided into 31 regions by aggregating the geographic extension of groups of postal codes. Because the geographic boundaries and extensions of the postal code

specified and provided to the author by the co-operation partner. For the sake of completeness a short model description is included here.

25 The node model of the ie^3 was used for instance in Waniek et al. (2008) to identify network congestion induced by the feed-in of wind power plants. For more detailed information on the model the interested reader is referred to this or other relevant publications of the ie^3.

areas in Germany are not identical, the specified network regions are not of equal shape and size. The resulting regional dissolution of Germany is illustrated in the left graph in Figure 4.3.

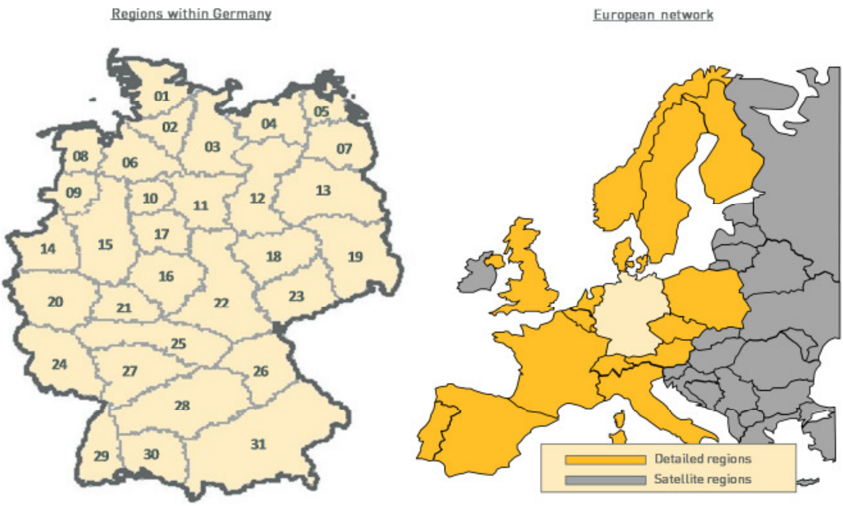

FIGURE 4.3: THE REGIONAL STRUCTURE OF THE MODEL DIANA

Source: Own illustration.

As the power plant dispatch calculated by DIANA is interpreted as the market outcome of the wholesale market, no restrictions of the transmission grid between the 31 German network regions are incorporated at this stage. This resembles the real market, as market players do not observe any transmission capacity limits within Germany so that the power plant dispatch is merely specified according to the minimization of the costs of generation. The transmission restrictions within Germany are considered subsequently by the use of PTDF factors at the second optimization stage at which the redispatch is calculated (see section 4.3 for further details).

Germany as a whole is integrated into the European interconnected network which is also modeled in a very detailed way. This is shown in the right graph of Figure 4.3. As can be seen, the countries included in the model are France, Switzerland, Italy, Austria, the Czech Republic, Poland, West- and East-Denmark, Sweden, Norway, Finland, the Netherlands, Belgium, Great Britain, and the Iberian Peninsula (Spain and Portugal as one region). Further countries are implemented in DIANA as so-called satellite countries. This implies that export and import capacities as well as a price curve for the regions are included in the calculations. The satellite price curves indicate to the explicitly modeled regions whether to import to or to export from these satellite countries. The regions defined as satellites are the countires in South-East Europe.

The limited transmission capacities of the cross-country interconnectors are implemented as net transfer capacity (NTC) values.[26] This again is in line with the real market, as trade between the different European markets is based on the allocation of transmission rights according to NTC values rather than being determined flow-based.[27]

26 In the model DIANA the limited transmission capacities are allocated efficiently in analogy to implicit auctions or market coupling respectively. In the real world, however, at many borders explicit auctions for the allocation of the transport capacity still prevail. The inefficiencies that might arise due to these explicit auctions are not incorporated in the model.

27 In reality no flow-based market coupling is implemented in Europe yet (at the date of creation of this dissertation). The benefit of switsching from an NTC-based to a flow-based market coupling by use of PTDFs is investigated in Bettzüge et al. (2009) and Waniek (2010).

4.3 The Application of PTDF Matrixes in the Model DIANA

As already mentioned flow-based transmission restrictions are incorporated in the model DIANA by using PTDF matrixes. In the following it is outlined how the respective matrixes are specified in cooperation with the Institute for Energy Systems, Energy Efficiency and Energy Economics at the TU Dortmund University (section 4.3.1) and how the matrixes are integrated into the model (section 4.3.2) to specify electricity flows.

4.3.1 Specification of PTDF-matrixes

For the outline of the specification of PTDF matrixes and the calculation of load flows in the model by the use of PTDF matrixes the subsequent definitions hold for all equations. The set $\mathrm{T} = \{1, 2, 3, \ldots, 288\}$ contains all modeled hours t while the set $\mathrm{R} = \{1, 2, 3, \ldots, \mathrm{m}\}$ includes all network regions r implemented in DIANA. The set $\mathrm{CON} = \{1, 2, 3, \ldots, \mathrm{q}\}$ contains all interconnectors c.

The PTDF matrixes used in DIANA are specified for one hour of a modeled year and used interchangeably for all other hours. This accounts for the property of PTDF matrixes that they do not vary substantially with respect to daytype, season and injection/withdrawal situation if applied to a nodal model with given network topology.[28]

First of all, the model DIANA is used to calculate the power plant dispatch for 288 hours without any national network restrictions. Thus, the results of the spot market are simulated and regional electricity injection and electricity withdrawal schedules are determined. Thes simulation results are transferred to the ie³. The ie³ then provides the set of PTDF factors

[28] See sections 3.2 and 3.3 for a more detailed explanation.

($\mathrm{PTDF}_{c,r}$) and the total available capacity ($\mathrm{Cap}_{c,t}$) for each line $c \in \mathrm{CON}$ for each of the modeled hour $t \in \mathrm{T}$.[29]

4.3.2 Calculation of load flows by use of PTDF-matrixes

Firstly, in order to specify the physical load flows in the network, the regional balance of each modeled region $r \in R$ – that is the electricity injections in the region minus the electricity withdrawal in the region at time t – is calculated for all hours $t \in \mathrm{T}$.

$$\mathrm{RegionBalance}_{r,t} = \mathrm{Injections}_{r,t} - \mathrm{Withdrawals}_{r,t}$$

The regional balance ($\mathrm{RegionBalance}_{r,t}$) is then multiplied with the respective regional PTDF factors ($\mathrm{PTDF}_{r,c}$) to specify the load flows through all transmission lines $c \in \mathrm{CON}$ of the actual hour t. The physical flow through a specific interconnector at hour t that results from the power plant dispatch is consequently specified according to the following formula:

$$\mathrm{PhysFlow}_{c,t}^{\mathrm{dispatch}} = \sum_{r \in R} \mathrm{RegionBalance}_{r,t} \times \mathrm{PTDF}_{r,c,t}$$

In case the resulting physical flow through the interconnector c is larger than the available capacity ($\mathrm{Cap}_{c,s}$) the line is congested and redispatch is required.

For a better understanding of the use of PTDF matrixes for specifying electricity flows, a PTDF matrix is illustrated in Table 4.1. As can be seen, all modeled regions $r = \{1, 2,3, \dots, m\}$ are listed top-down, while all transmission lines $c = \{1,2,3, \dots, n\}$ are listed from the left to the right thereby forming a matrix. Each combination of region and interconnector

[29] For the exact methodology for specifying PTDF matrixes the interested reader is referred to Duthaler, C. L. (2007), Appendix and Waniek, D. (2010), p. 21-25.

has a specific PTDF factor stating which fraction of the regional balance of region r flows through transmission line c (recall the formula given in section 3.2.3).

TABLE 4.1: EXAMPLE OF A PTDF MATRIX

	c_1	c_2	c_3	...	c_n
r_1	$PTDF_{(1,1)}$	$PTDF_{(2,1)}$	$PTDF_{(3,1)}$	$PTDF_{(...,1)}$	$PTDF_{(n,1)}$
r_2	$PTDF_{(1,2)}$	$PTDF_{(2,2)}$	$PTDF_{(3,2)}$	$PTDF_{(...,2)}$	$PTDF_{(n,2)}$
r_3	$PTDF_{(1,3)}$	$PTDF_{(2,3)}$	$PTDF_{(3,3)}$	$PTDF_{(...,3)}$	$PTDF_{(n,3)}$
...	$PTDF_{(1,..)}$	$PTDF_{(2,...)}$	$PTDF_{(3,...)}$	$PTDF_{(...,...)}$	$PTDF_{(n,...)}$
r_m	$PTDF_{(1,m)}$	$PTDF_{(2,m)}$	$PTDF_{(3,m)}$	$PTDF_{(...,m)}$	$PTDF_{(n,m)}$

Source: Own illustration.

Thus, in order to obtain the physical flow through line c the balances of all regions r are multiplied by the respective PTDF factors.

4.4 Mathematical Formulation of the Redispatch Model in DIANA

As already mentioned, the cost-minimizing dispatch of the power plants in DIANA does not account for the physical constraints imposed by the limited transport capacity. This is in line with the functioning of the spot markets of most of the Central European countries that do not incorporate any national transmission restrictions.[30] Due to the fact that the German

[30] This holds true for most European countries. Nevertheless, there are some exceptions. In the NordPool market, for example, national transmission restrictions are taken into

market design does not allow for different regional prices in case transmission lines are congested, the transmission system operators have to take corrective actions. This is necessary to align the physical flows of electricity to the physical capacities of the transmission grid and thereby to alleviate transmission congestion. The method by which this is achieved in Germany is cost-based redispatch (see chapter 2).

In DIANA redispatch is modeled by constructing a market for redispatch and by determining the respective redispatch demand and supply as explained in the following.[31] First, the linear objective function for redispatch in the second optimization stage of DIANA is outlined (section 4.4.1). Subsequently, the constraint concerning the redispatch market is explained (section 4.4.2). Furthermore, the specification of supply (section 4.4.3) and demand of redispatch (section 4.4.4) is illustrated. Finally, in section 4.4.5 the transmission constraints are outlined.

The following definitions hold true for all equations and constraints. The set $\mathrm{T} = \{1, 2, 3, \dots, 288\}$ contains all modeled hours t. The technologies i are contained in the set $\mathrm{I} = \{1, 2, 3, \dots, \mathrm{n}\}$ while the subset $\mathrm{I_{GER}} \subseteq \mathrm{I}$ is the set of all technologies in Germany. The set $\mathrm{R} = \{1, 2, 3, \dots, \mathrm{m}\}$ contains all network regions r included in DIANA with the subset $\mathrm{R_{GER}} \subseteq \mathrm{R}$ being constituted of all network regions in Germany. The set $\mathrm{CON} = \{1, 2, 3, \dots, \mathrm{q}\}$ contains all interconnectors c modeled in DIANA while the subset $\mathrm{CON_{GER}} \subseteq \mathrm{CON}$ is the set of all interconnectors located inside Germany.

account by the so called "market splitting" mechanism, which stipulates that the market is subdivided into predefined (national) price regions in case of transmission congestion.

31 In reality no such redispatch market exists, recall chapter 2.

4.4.1 The objective function

The objective function in the second optimization stage in DIANA is the function of the total cost of power plant redispatch, which is minimized subject to several constraints presented in the following sections. The total redispatch costs are the costs of upward redispatch plus the costs of downward redispatch.

(1) $$min\, TotalRedispatchCost = \mathrm{TotalRedispatchCosts}^{\mathrm{Up}} + \mathrm{TotalRedispatchCosts}^{\mathrm{Down}}$$

Hereby, the total costs of the upward redispatch are the variable costs and ramp-up costs of the necessary upward redispatch of power plants in sum over all hours of the year $\mathrm{t} \in \mathrm{T}$ for all regions $\mathrm{r} \in \mathrm{R}_{\mathrm{GER}}$ and all technologies $\mathrm{i} \in \mathrm{I}_{\mathrm{GER}}$ located in Germany. The variable costs are time dependent because they are driven by the fluctuation of the fuel price, while the ramp-up costs are contingent on the time the power plant is already shut down due to its wholesale market operations.

$$\mathrm{TotalRedispatchCosts}^{\mathrm{Up}} = \sum_{\mathrm{t}\in\mathrm{T}} \sum_{\mathrm{r}\in\mathrm{R}_{\mathrm{GER}}} \sum_{\mathrm{i}\in\mathrm{I}_{\mathrm{GER}}} \mathrm{RampUpCosts}_{\mathrm{t,r,i}} + \mathrm{VarCostsRedispatch}^{\mathrm{Up}}_{\mathrm{t,r,i}}$$

In contrast, the total redispatch costs of downward redispatch are net cost savings plus the ramp-up costs that occur one hour later in order to return the plant to its initial operation status. Specifically, they are the avoided variable costs of electricity generation plus the ramp-up costs one hour later in sum over all hours $\mathrm{t} \in \mathrm{T}$, all regions $\mathrm{r} \in \mathrm{R}_{\mathrm{GER}}$, and technologies

$i \in I_{GER}$. In general downward redispatch reduces the total costs of redispatch.[32]

$$\mathrm{TotalRedispatchCosts}^{\mathrm{Down}} = \sum_{t \in T} \sum_{r \in R_{GER}} \sum_{i \in I_{GER}} -\mathrm{VarCostsRedispatch}_{t,r,i}^{\mathrm{Down}} + \mathrm{RampUp\ Costs}_{t+1,r,i}$$

4.4.2 The redispatch market

The redispatch market in DIANA covers a predefined geographic area that is constituted of all network regions in Germany $r \in R_{GER}$. Economic theory stipulates that demand equals supply in a market setting. Of course this holds true for the redispatch market, even though in a figurative sense as illustrated in the following.

The redispatch balance constraint of the redispatch market specifies that the sum of the upward redispatch is equal to the sum of the downward redispatch of all regions $r \in R_{GER}$ belonging to the market for each point in time $t \in T$.

(2) $$\sum_{r \in R_{GER}} \mathrm{Redis}_{r,t}^{\mathrm{Up}} = \sum_{r \in R_{GER}} \mathrm{Redis}_{r,t}^{\mathrm{Down}}$$

This constraint guarantees that electricity injections and withdrawals are balanced in the system also after redispatch. The electricity generation reduced as downward redispatch must be offset by a congruent increase in

[32] In theory it is possible that the ramp-up costs are higher than the variable costs so that downward redispatch leads to net costs rather than to net cost savings. However, the parameters in the model are specified such that this never occurs. Downward redispatch in the model is always associated with a reduction of total costs.

generation as upward redispatch in order to guarantee system stability. Thus, downward redispatch is exactly equal to upward redispatch.

Hereby, the upward redispatch of a region r at a specific point in time t is the sum of the upward redispatch of all technologies $i \in I_r$ situated in the respective region. Vice versa, the downward redispatch of a region r at a specific point in time t is the sum of the downward redispatch of all technologies $i \in I_r$ in the region.

$$\mathrm{Redis}_{r,t}^{\mathrm{Up}} = \sum_{i \in I_r} \mathrm{TechRedis}_{i,t}^{\mathrm{Up}}$$

$$\mathrm{Redis}_{r,t}^{\mathrm{Down}} = \sum_{i \in I_r} \mathrm{TechRedis}_{i,t}^{\mathrm{Down}}$$

4.4.3 Specification of redispatch supply

By definition redispatch means that the initial dispatch of the power plants is changed to make the physical flows fit the regional transmission restrictions. Consequently, the quantity of potential redispatch provided by a power plant is restricted by the respective initial operation status. As these restrictions are different for upward and downward redispatch, the supply restriction will be explained separately in the following.

4.4.3.1 Upward redispatch supply constraint

As upward redispatch means that the production is increased, it can only be performed by power plants that are either in standby modus or are operating in part-load. Thus, the upward redispatch of a technology $i \in I_{GER}$ at a specific point in time $t \in T$ is at the maximum equal to the available capacity of the technology i minus the capacity already running at the spot market[33] minus the capacity reserved for positive regulation.[34]

(3) $$\mathrm{TechRedis}_{i,t}^{Up} \leq \mathrm{AvailCap}_{i,t} - \mathrm{Prod}_{i,t}^{Spot} - \mathrm{Reserve}_{i,t}^{Pos}$$

In sum, the supply of positive redispatch is equal to the available capacities that are neither running nor reserved. This is illustrated in Figure 4.4 by a stylized merit-order.

As can be seen, a certain number of generation units at the left part of the merit-order are operating in order to meet the demand of the wholesale market. These power plants are not available for positive redispatch. All other plants to the right of the electricity demand curve constitute the supply of positive redispatch.[35] In general, these are the mid-load and peak-load capacities. The model increases the generation of the power plants for upward redispatch starting with the one with the lowest variable

[33] In order to supply capacity to the negative reserve market a power plant must generate either in part-load or in full-load so that it can be shut down in case negative regulation is required. The capacity offered at the negative reserve market is equal to the production of the power plant. In contrast, in order to supply capacity to the positive reserve market a power plant must either operate in part-load or be in standby modus. Only the "free" production capacity can be offered as positive reserve as additional production has to be provided if positive regulation is required. In both cases, the electricity generated in order to be able to provide regulating power has to be marketed at the spot market and is thus contained in the parameter $\mathrm{Prod}_{i,t}^{Spot}$.

[34] It is assumed that capacity that is reserved for positive regulation cannot be used for redispatch. This accounts for the fact that even in case of transmission congestion, the system operator must guarantee a sufficient amount of reserve capacities to secure the system stability.

[35] The illustration neglects the idea that the capacity reserved for the positive reserve market must be deducted from the supply of positive redispatch. As already stated, the reserved capacity is not usable for positive redispatch. Some peak-load capacities are operating in order to supply reserves for the regulating power market although they have variable costs larger than the price $p*$. Consequently, not all capacity to the right of the demand curve in the merit order is available for upward redispatch.

generation costs in ascending order up to the point at which positive redispatch supply equals positive redispatch demand.

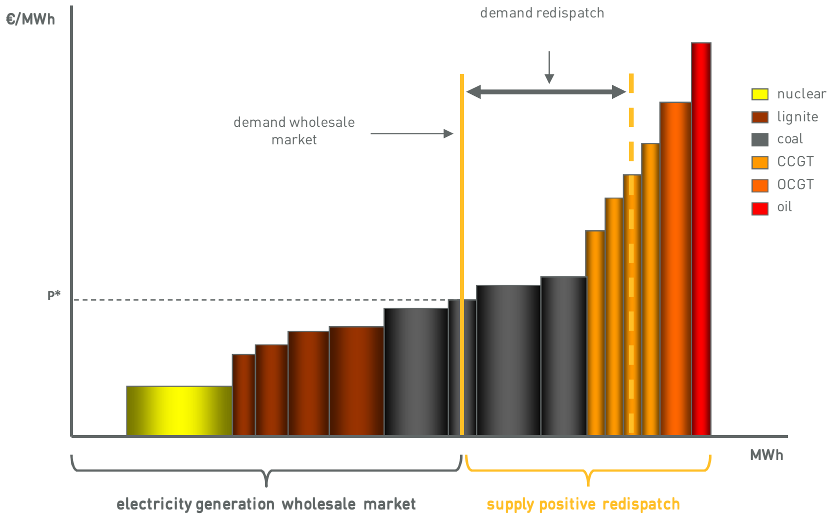

FIGURE 4.4: STYLIZED MERIT-ORDER OF POSITIVE REDISPATCH

Source: Own illustration.

In case not enough conventional generation is available for upward redispatch to meet redispatch demand a method of last resort is implemented in the model in order to guarantee the feasibility of optimization problem. This so called "dummy redispatch" represents either an artificial additional generation or a reduction of demand in analogy to demand side management. If required dummy redispatch is valued at a 10 % uplift on the most expensive conventional generation unit.[36] The

36 This 10 % uplift is arbitrarily chosen. A different uplift would be valid as well. It could be argued for example that the reduction of demand has to be valued at much higher costs.

necessity for dummy redispatch might arise either because in total too few conventional capacities are available or because the location of the remaining capacities does not allow resolving the congestion.

The application of dummy redispatch hereby can be interpreted as an indicator for the malfunctioning of the mechanism of cost-based redispatch. If it occurs, the system is no longer stable but other means to resolve congestion are required. Such means could for example be special installations connected to the network that can generate electricity and inject it into the transmission grid if required (in analogy to real power compensators). Another possibility is to set up a market for "redispatch reserves" that guarantees that always enough capacities are available similar to the idea of a capacity market or the functioning of the market for regulating power.

4.4.3.2 Downward redispatch supply constraint

Downward redispatch means that the production is decreased which can only be performed by power plants that are running either in full-load or in part-load. It is assumed that reserves for the negative regulating power market are always available for regulation so that the production of generation units for the negative reserve market is not usable for downward redispatch. Consequently, the downward redispatch of a technology $i \in I_{GER}$ at a specific point in time $t \in T$ is at the maximum equal to the spot market production of the respective technology minus the production reserved for negative regulation.

For the model, however, it is only necessary that dummy redispatch is valued at higher costs than conventional generation to make sure the dummy is used at last. Hereby, it is important to notice that if dummy redispatch is used the costs of redispatch are "biased" and no longer represent fundamental cost structures.

(4) $$\mathrm{TechRedis}_{i,t}^{Down} \leq \mathrm{Prod}_{i,t}^{Spot} - \mathrm{Reserve}_{i,t}^{Neg}$$

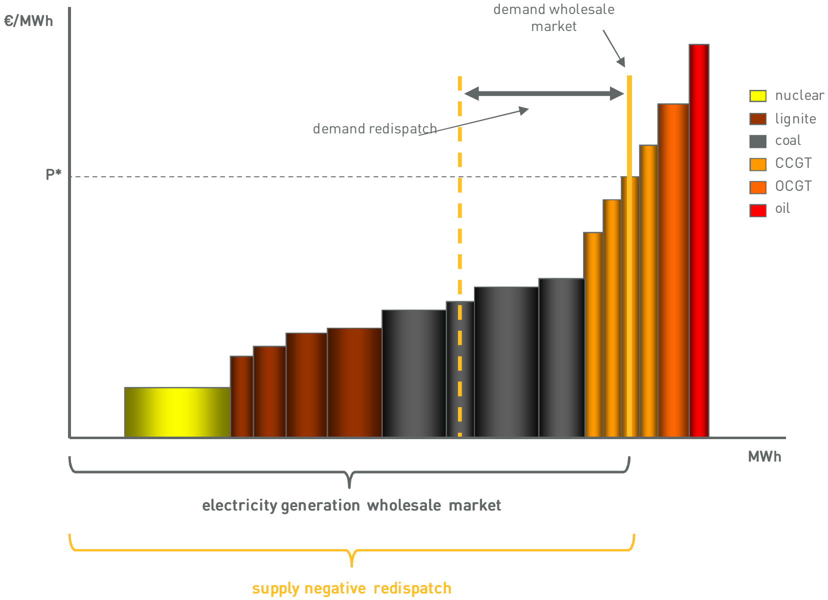

FIGURE 4.5: STYLIZED MERIT-ORDER OF NEGATIVE REDISPATCH

Source: Own illustration.

In sum, the supply of negative redispatch is equal to the capacities already running minus the capacity reserved as illustrated in Figure 4.5. Again, a certain number of generation units at the left part of the stylized merit-order are operating for meeting the demand of the wholesale market. These power plants are available for negative redispatch.[37] All other plants

[37] As already mentioned, the capacities running in order to provide reserve capacities are not usable for redispatch. Thus, in general not all generation units to the left of the demand

to the right of the electricity demand curve are not available for downward redispatch. The model decreases the electricity generation of the power plants for downward redispatch starting with the one with the highest variable generation costs in descending order up to the point at which negative redispatch supply equals negative redispatch demand.

In case all conventional generation is already shut down or the redispatching down of further plants does not contribute to resolve congestion, the method of last resort for downward redispatch is first the shut-down of wind power plants followed by the shut-down of the other renewable energies. Finally, also for downward redispatch dummy redispatch is implemented in the model. This downward dummy redispatch could thereby be interpreted as an increase of demand in analogy to demand side management. If either of the methods of last resort has to be used no variable costs are saved.

This implementation of the shut-down of renewable energies is in line with the regulations concerning the promotion of renewable energies in Germany: The shut-down of renewable energies is only allowed if no other action can resolve the network congestion. Furthermore, if this is necessary the reimbursement for the foregone feed-in is still paid to the owners of the renewable plants so that the costs of the reimbursement still accrue.[38]

curve in the merit order are available for downward redispatch. This aspect is neglected in the illustration.

[38] See EEG (2009), §12 and BNetzA (2011), chapter 2.

4.4.4 Specification of redispatch demand

The demand for redispatch in DIANA is determined according to physical rather than economic flows and thus is independent of the direction of economic trade flows. For a specific hour $t \in T$ there is only demand for (upward and downward) redispatch if the physical flow exceeds the physical line capacity of the respective transmission line $c \in CON_{GER}$. Hereby, the physical flow through a specific transmission line results from the geographic distribution of load and generation and is thus determined on basis of the first optimization stage – the power plant dispatch.

$$\begin{aligned} &\mathrm{RedisDemand}_{c,t} = \mathrm{PhysFlow}_{c,t}^{\mathrm{dispatch}} - \mathrm{Cap}_{c,t} && \text{if } \mathrm{PhysFlow}_{c,t}^{\mathrm{dispatch}} > \mathrm{Cap}_{c,t} \\ &\mathrm{RedisDemand}_{c,t} = 0 && \text{if } \mathrm{PhysFlow}_{c,t}^{\mathrm{dispatch}} \leq \mathrm{Cap}_{c,t} \end{aligned}$$

However, it is important to notice that total redispatch demand is not equal to the excessive electricity transmission summed up for all lines. If generators are redispatched up and down the flows in the whole network change. Thus, it is possible that the redispatch of two generators dissolves congestion at two or more interconnectors at the same time. In contrast, redispatching certain generators might dissolve congestion at one specific line but might aggravate or evoke congestion at other interconnectors contemporaneously. Consequently, there is no fixed redispatch demand to be met by redispatch supply that can be specified based on the dispatch outcome. Rather the demand for redispatch dynamically adjusts being an interplay between the different transmission restrictions and physical flows resulting from redispatch measures. The relevant transmission restrictions are explained in the following section.

4.4.5 Physical transmission constraints

As already explained in section 4.4.4 in DIANA transmission in Germany is restricted independently of the economic trade flows but rather by the simplified physical flows. If the physical flow through a specific interconnector $\mathrm{c} \in \mathrm{CON}_{\mathrm{GER}}$ at a specific point in time $\mathrm{t} \in \mathrm{T}$ is larger than the transmission capacity of the respective interconnector, the transmission line is congested. In order to relieve this congestion redispatch is required – i.e. there is redispatch demand.

The physical flow through an interconnector between region *A* and region *B* flowing from *A* to *B* is denoted by a positive sign. In contrast, the flow from *B* to *A* is denoted by a negative sign. As the transmission capacity must not be exceeded in either one of the directions, two transmission constraints are implemented for each interconnector $\mathrm{c} \in \mathrm{CON}_{\mathrm{GER}}$. These two constraints implemented for all interconnectors guarantee that neither the initial congested interconnectors nor any other interconnector within the transmission system in Germany is congested after redispatch. The first constraint states that the physical flow through the interconnector con at hour t induced by the initial geographic location of load and generation – i.e. the result of the dispatch model – plus the physical flow through the transmission line provoked by redispatch may not exceed the transmission capacity of the interconnector in the direction from *A* to *B*. Thus, it is called the "export capacity constraint".

(5) $$\mathrm{Cap}_{\mathrm{c,t}}^{\mathrm{exp}} \geq \mathrm{PhysFlow}_{\mathrm{c,t}}^{\mathrm{dispatch}} + \mathrm{PhysFlow}_{\mathrm{c,t}}^{\mathrm{redispatch}}$$

Vice versa, the physical flow through the interconnector con at hour t induced by the market outcome plus the physical flow through the transmission line provoked by redispatch may not exceed the transmission capacity of the interconnector in the direction from *B* to *A*. Thus, it is called the "import capacity constraint".

(6) $$\mathrm{Cap}_{c,t}^{imp} \geq \mathrm{PhysFlow}_{c,t}^{dispatch} + \mathrm{PhysFlow}_{c,t}^{redispatch}$$

Hereby, the physical flow through the specific line c provoked by redispatch are the regional redispatch balances of all German regions multiplied by the respective PTDF factors.

$$\mathrm{PhysFlow}_{c,t}^{redispatch} = \sum_{r \in R_{GER}} \mathrm{RedisRegionBalance}_{r,t} \times \mathrm{PTDF}_{r,c,t}$$

The redispatch region balances in turn are the net upward and downward redispatch of all technologies $i \in I_r$ located in region r.

The calculated electricity flows through internal German transmission lines provoked by the dispatch incorporate the regional balances and the thereby induced flows of other European countries. However, congestion and redispatch are only specified for the German interconnectors so that initial congestion as well as the change of electricity flows after redispatch through all cross-border interconnectors is neglected. This is a valid simplification for the analysis at hand as the redispatch costs in Germany include those costs accrued for dissolving internal congestion. The cost of cross-border transmission congestion relieve are compensated by the revenues of the auctioning of cross-border transmission rights.[39]

[39] See footnote 8 in chapter 2.

4.5 Limitations of the Redispatch Model in DIANA

Due to the linear character of the model DIANA and the thereby induced simplification of the operation constraints of power plants, the resulting generation schedules do not resemble reality exactly. The linearity of the model makes it impossible to model minimum load requirements and part-load losses directly. This results in a general overestimation of the variable cost savings of downward redispatch and a general underestimation of the variable costs of upward redispatch. As a net effect the costs of redispatch tend to be underestimated.

Furthermore, in the model it is assumed that redispatch is optimized only one hour in advance. Thus, redispatch is specified for each hour individually rather than being optimized for the whole modeled year simultaneously. This assumption reflects current German market design which does not explicitly require the TSOs to optimize consecutive hours.

However, in reality it might be the case that the TSOs trigger the same power plants for redispatch if congestion occurs for consecutive hours. Such a simultaneous optimization of all hours would lead to lower ramp-up costs because the ramping-up processes are coordinated and only accrue once. If this is (or becomes) common practice the costs of redispatch are overestimated in the model. Hereby, the overestimation is larger the more consecutive hours with congestion occur in the modeled scenario. Consequently, the overestimation failure would increases in the course of time as ever longer periods of congestion materialize (see chapter 6).

Summing up it can be said that the limitations of the modeling approach applied in the model DIANA to simulate redispatch generally tend to induce a net overestimation of the redispatch costs. This is explained by the fact the the net underestimation of costs due to the difficulties to model part-load losses and minimum load is rather small compared to the overestimation of costs due to the counting of hourly ramp-up and down processes. The magnitude of this overestimation increases the more congestion and thus redispatch is required.

5 THE REGIONALIZATION OF THE MODEL INPUTS

In general, data and forecasts on the German electricity system – i.e. installed capacities of generation technologies, the electricity demand and the feed-in of renewable energy sources – are available only in aggregate form on a national level. Sometimes, the individual *Bundesländer* publish and/or conduct own studies and forecasts that yield more regionalized information. Nevertheless, as the German electricity system in the study at hand consists of 31 German network regions (see chapter 4), the data on the electricity system need to be regionalized appropriately.

The methodology how this is done is outlined in this chapter. For this purpose the assumptions of the *Reference Scenario* in the scenario analysis in chapter 6 and chapter 7 are used exemplarily. In principle, however, entirely different aggregate assumptions for Germany could be used and then be regionalized applying the same methodology.

First of all, it will be explained how the individual conventional and CHP power plants are assigned to the network regions in Germany and how they are categorized (section 5.1). This is followed in section 5.2 by a description of how the total German load is allocated to the 31 regions and how the load structure is specified. Finally, it will be outlined in section 5.3 how the different renewable energy sources – namely hydropower, wind power, biomass and photovoltaic – are regionalized.

5.1 The Regionalization of the Conventional and CHP Power Plant Fleet

The allocation of the power plants to the network regions is based on postal codes. Therefore, a list is set up that contains all postal codes within

Germany as a first step. As already outlined in chapter 4, the geographic postal code areas are allocated to one of the 31 network regions in Germany. Consequently, Germany is subdivided into 31 geographic regions with boundaries equal to the boundaries of the postal code geographic areas. It is assumed that each generation unit that lies within the geographic boundaries of a network region injects into the respective node of the network model. Vice versa, each consumer situated within the geographic network area withdraws electricity from the respective node of the network model.

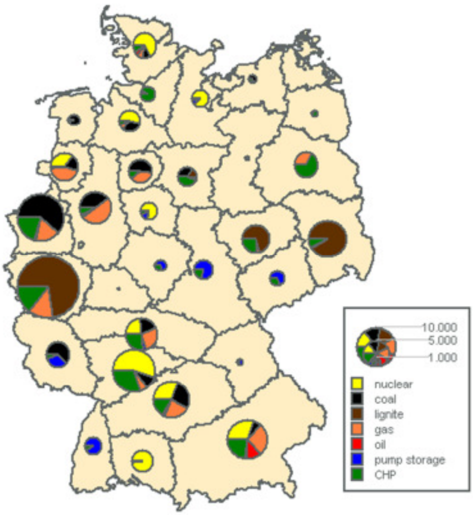

FIGURE 5.1: INSTALLED CAPACITY OF CONVENTIONAL AND CHP PLANTS IN GERMANY IN THE YEAR 2010

Source: Own illustration.

In order to allocate the plants to the network regions, the respective postal code is assigned to each of the power plants contained in the EWI power plant database. By comparing the list of postal codes and network regions with the postal code of each individual installation, the plants can be assigned to a network region. Figure 2.1 gives an overview of the regional distribution of installed capacities per fuel-type of conventional and combined heat and power (CHP) power plants in Germany in the year 2010. In total, there is an installed capacity of 85.4 GW conventional and 21.2 GW of CHP plants.[40] Hereby, the German conventional power plant fleet consists of 20.5 GW nuclear, 20.4 GW lignite-fired, 19.8 GW coal-fired, 16.1 GW gas-fired power stations and 7.4 GW pump-storage power plants (see Table 6.3).

In addition to the allocation to the network regions, the power plants are categorized in technology classes according to – among other things – their fuel-type, efficiency and year of commissioning. For each of these technology classes a specific set of technical and economic parameters is stipulated and used in the simulations of the model DIANA.

Furthermore, CHP power plants are distinguished into two groups: heat-assigned to the conventional plants and are classified as one of the technology classes. In contrast, the electricity generation of all heat-operated plants is specified according to technology-specific generation schedules. Their electricity feed-in is then incorporated within the optimization of the model as exogenous CHP electricity generation.

[40] These figures already incorporate the distinction between heat-operated and power-operated CHP plants as explained in the following.

5.2 The Regionalization of Load

As holds true for the generation capacities, also the total annual electricity demand in Germany needs to be allocated to the 31 network regions in DIANA. The starting point of this allocation is the information on load in the respective control area published by the four German TSOs on their websites. In addition, information concerning population density and industry density are used to further subdivide the electricity demand to the regions.[41] The resulting distribution of total electricity demand to the individual regions is illustrated in Figure 5.2 expressed in percentages.

Furthermore, a load structure is specified that scales total regional demand to the 288 hours simulated. Extreme values – i.e. extreme peak load and extreme load valleys – are retained and not evened out by averaging. This is important to be able to simulate also these extreme situations as these are in general exactly the situations in which congestion occurs.

[41] In Zhou and Bialek (2005), pp. 784 – 785 it is shown that the pattern of population is closely related to the pattern of electricity consumption in the year 2002 in Italy. Thus, it is assumed that household as well as industry electricity demand is correlated to the population density. These insights are transferred to Germany in this study to specify regional demand.

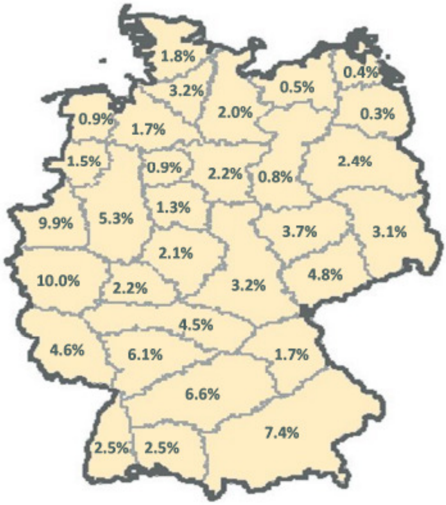

FIGURE 5.2: DISTRIBUTION (IN PERCENTAGE) OF TOTAL ELECTRICITY DEMAND IN GERMANY TO THE 31 NETWORK REGIONS
Source: Own illustration.

5.3 The Regionalization of Renewable Energies

In addition to conventional power plants and CHP plants, the German electricity system consists of a continuously increasing fleet of renewable energy sources. In Germany these sources can be divided into plants based on hydropower (section 5.3.1), biomass (section 5.3.2), photovoltaic (section 5.3.3), and wind power (section 5.3.4). In the section at hand it will be explained how these renewable sources are allocated to the 31 network regions and how their respective feed-in is specified.

In general, the starting point is a regionalized database of renewable plants combined with a feed-in structure representing the state of technology today. The forecast of capacity additions and technological progress for all renewable energy sources is based on the forecasts given in the *National Renewable Energy Action Plan for Germany* (NREAP-DE) and the *BMU-Leitszenario 2010* of the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety of the Federal Republic of Germany[42].

5.3.1 The regionalization of the feed-in of hydropower plants

In the following, the regionalization of the feed-in of hydropower plants in Germany today as well as for the modeled years 2015, 2020 and 2025 is explained. First, the regionalization of hydropower in Germany requires the allocation of the installed capacities to the network regions (section 5.3.1.1) and a specification of a feed-in structure (section 5.3.1.2). How these are combined to determine the regional feed-in of hydropower plants is outlined in section 5.3.1.3. Finally, the installed capacities and feed-in structure needs to be forecasted for prospective years in order to specify the regional feed-in of hydropower in the future. The respective methodology is explained in section 5.3.1.4.

5.3.1.1 Regionalized database of hydropower capacities in Germany

The regionalization of the installed capacity and electricity feed-in of hydropower plants in Germany is based on a database that contains all hydropower stations in Germany at the end of 2010. The hydropower generation plants are subdivided into *small hydropower plants (< 1 MW)*, *middle-sized hydropower plants (1 – 10 MW)*, *large hydropower plants*

[42] See NREAP-DE (2010) and BMU (2010).

(> 10 MW) and *storage hydropower plants.*[43] The small and middle-sized hydroelectric power station data is based on information available on the websites of the German transmission system operators (TSO) 50Hertz Transmission GmbH, Amprion GmbH, EnBW Transportnetzgesellschaft AG and TenneT TSO GmbH.[44] Data on large and storage hydropower plants was gathered individually. Starting with information already available at EWI's power plant database, the data was aligned and extended by information available on the internet[45] and verified by the figures given in a report of the *Bundesverband der Energie- und Wasserwirtschaft* (BDEW) on recent figures on renewable energy sources.[46]

The database contains information about the installed capacity and the geographic location (mailing address) of each individual hydropower plant. The postal code of each plant is compared to the list of postal codes in which each is allocated to one of the grid regions stipulated for Germany. In that way each individual hydroelectric power station can be assigned to a network region in Germany.

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[43] Storage hydro plants are plants that have a natural inflow to their water reservoir. Pump-storage plants in turn are not included as they are optimized in the model endogenously and are thus treated as conventional power plants.

[44] The German transmission system operators are obliged to publish detailed information on the capacities and feed-in of renewable energy sources connected (either directly or indirectly) to their transmission grid according to §52 of the Erneuerbare-Energien-Gesetz (EEG). Indirectly connected in this context means that generating capacities are connected to a distribution grid which itself in turn is connected to the respective transmission grid. See Amprion (2011), TenneT (2011), EnBW (2011) and 50Hertz (2011). For more details on the transparency requirements see EEG (2009).

[45] The main sources are the free encyclopedia Wikipedia and the internet sites of the operators of the large hydroelectric and storage hydroelectric plants. See Wikipedia (2010), RWE Innogy (2010), E.ON Wasserkraft (2010), LLK GmbH (2010), EnBW Kraftwerke (2010) Energiedienst (2010), RMD (2010), VERBUND (2010), Rheinkraftwerk (2010) and SWM (2010).

[46] See BDEW (2010), pp. 18 – 20.

TABLE 5.1: NUMBER AND INSTALLED CAPACITY OF HYDROPOWER PLANTS PER CATEGORY CONTAINED IN THE DATABASE FOR GERMANY AT THE END OF 2010

category	number of plants	installed capacity [MW]
small hydropower (< 1 MW)	6,727	623
middle-sized hydropower (1 – 10 MW)	316	867
large hydropower (> 10 MW)	84	2,220 (2,550)[1)]
storage hydropower	65	234
TOTAL	**7,192**	**3,944 (4,247)[1)]**

1) With and without assessing half of the installed capacity and electricity generation of the plants located at the border to and jointly operated with France, Austria, and Switzerland.

Source: Own figures.

In total the database contains 6,727 small hydroelectric plants with an installed capacity of about 623 MW, 316 middle-sized electric plants with an installed capacity of roughly 867 MW, 84 large hydropower plants with an installed capacity of 2,220 MW[47] and 65 storage hydro plants with an installed capacity of 234 MW. The figures are summarized in Table 5.1.

The installed capacity of the four categories of hydroelectric power plants in each of the network regions in Germany at the end of 2010 is illustrated in the left graph of Figure 5.3. In total, the installed capacity of plants contained in the database is equal to 3.9 GW. The electricity feed-in of hydropower in the year 2010 is equal to 19.8 TWh and specified according to the methodology explained in 5.3.1.2 and 5.3.1.3. The regional distribution of electricity generation is displayed in the right graph of Figure 5.3.

[47] Some large hydroelectric power stations are located at the border to France, Austria or Switzerland and are operated jointly so that part of the electricity generation and installed capacity is allocated to the foreign country rather than to Germany.

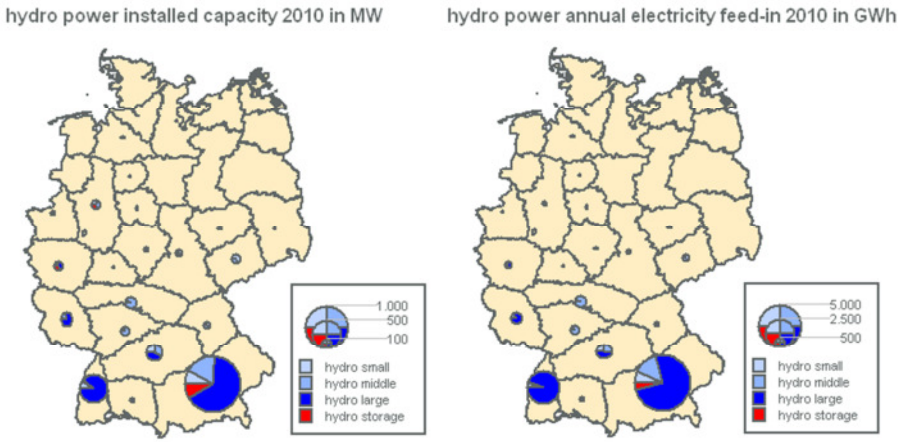

FIGURE 5.3: INSTALLED CAPACITY (LEFT) AND ANNUAL ELECTRICITY GENERATION (RIGHT) OF HYDROPOWER PLANTS IN GERMANY IN THE YEAR 2010

Source: Own illustration.

5.3.1.2 Determination of the feed-in structure of hydropower

In addition to the installed capacity of hydropower plants, also historical data on their annual feed-in of electricity was collected. For small and middle-sized plants this data stems from the information disclosure of the four German TSOs according to §52 of the EEG for a time span up to four years.[48] Date for large and storage hydropower plants was gathered from the plant operators' websites in case appropriate information was available.

As already explained above, the hydroelectric power stations are classified into four categories and are assigned to a network region. For each category and each network region the average annual full-load hours are

[48] See EEG (2009).

calculated based on historical data. This is done on a regional basis in order to capture the effect that the feed-in of hydroelectric power stations might differ quite extensively from region to region due to geographic conditions. The plants might be located at different rivers or at different parts of the same river yielding for example different flow rates and water levels and thus different electricity outputs per kW installed capacity. Furthermore, the determination of full-load hours is conducted for each individual category as the mode of operation of hydroelectric power plants is in general very diverse and dependent on the size of the plant.

TABLE 5.2: DISTRIBUTION OF THE TOTAL FULL-LOAD HOURS OF THE FOUR CATEGORIES OF HYDROPOWER PLANTS TO THE FOUR QUARTERS OF THE YEAR FOR THE YEAR 2010

		installed capacity [MW]			
quarter	full-load hours [%]	small hydro (< 1 MW)	medium-sized hydro (1 – 10 MW)	large hydro (> 10 MW)	storage hydro
1st quarter	28%	1,062	1,185	1,666	660
2nd quarter	27%	1,007	1,125	1,581	626
3rd quarter	20%	764	854	1,200	475
4th quarter	25%	923	1,032	1,450	574
TOTAL	**100%**	**3,755**	**4,195**	**5,897**	**2,335**

Source: Own calculations.

The resulting allocation of full-load hours of each of the hydropower categories to the respective quarter is also depicted in Figure 5.3 for Germany on average. By dividing the total hours per quarter (2,190 h) by the realized full-load hours the percental feed-in per kW installed capacity can be determined. This feed-in per kW is assumed to be constant for each hour of the day. Hourly fluctuations of the electricity output in the course of the day are neglected.[49] In sum, the above outlined approach yields an hourly constant feed-in structure per quarter for each of the hydropower plant categories differentiated for each of the network regions.

5.3.1.3 Regionalized feed-in schedules of hydropower

In order to determine the regional hourly feed-in schedules, first of all the installed capacities of all hydropower plants belonging to a certain category are summed up for each individual network region (see Figure 5.3 for an overview). The resulting total installed capacity per region and hydropower category (in kW) is then multiplied with its respective feed-in structure (%/kW). Summing up the feed-in schedules of all four hydropower categories consequently yields the total hydroelectric electricity generation schedule in the respective network region.

5.3.1.4 Specification of feed-in schedules of hydropower in prospective years

In order to specify the regional feed-in schedules of hydroelectric plants in the prospective years 2015, 2020 and 2025, first of all the projected installed capacity per category of hydroelectric plant has to be determined for each network region. Furthermore, the feed-in structure has to be adjusted to account for technological progress. These two inputs can then be used according to the same method outlined in 5.3.1.3 to specify the regional feed-in schedules for the prospective years.

The determination of growth of installed capacities for Germany in total is done on the basis of the National Renewable Energy Action Plan for

[49] The quality of the feed-in of especially storage hydro power plants can be improved by introducing hourly feed-in schedules. However, due to a lack of data this had to be omitted.

Germany (NREAP-DE) until 2020 and the BMU-Leitszenario 2010 of the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety of the Federal Republic of Germany[50] for the period 2020 – 2025.[51] The capacity additions for the four different hydropower categories from 2010 until 2015 are calculated as the difference between the database figures at the end 2010 and the prospected capacities per category in the year 2015 as outlined in the NREAP-DE. The installed capacity of the category storage hydro plants remains constant for the entire time period as it is assumed that the potential for these plants is already exhausted in Germany.

In Table 5.3 today's installed capacities per category as contained in the database and the prospected installed capacities and capacity additions for the years 2015, 2020 and 2025 are shown. It can be seen that only a moderate increase in capacities is predicted. This can be explained by the fact that most of the available locations for hydroelectric plants in Germany have been exploited by now. Extensions of installed capacities can nearly only be achieved by upgrading or replacing already existing installations. Upgrading might then lead to an increase of installed capacity and/or an increase of full-load hours due to technological progress and the thereby realized better utilization of the water flow.

The full-load hours of each pair of category and network region are then apportioned to the four quarters of the year. The electricity output of plants varies throughout the course of a year as the flow rate and water level of a specific river does vary from month to month. In general, it is highest in

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50 See NREAP-DE (2010) and BMU (2010).

51 In contrast to the NREAP-DE, which contains the same size categories as used in the study at hand, there are only two categories in the *BMU-Leitszenario 2010* – namely hydro plants < 1 MW and hydro plants > 1 MW. Therefore, it is assumed that the predicted growth for hydro plants > 1 MW holds for both plants of the size 1 – 10 MW and plants > 10 MW.

winter and spring due to the snow melting in Germany and especially in the Alps where most of the rivers themselves or their feeder rivers originate. In contrast, the flow rate and water level is lowest in summer and the beginning of autumn as there is relatively low rainfall and no snow melting. Based on a quarterly distribution of electricity output of hydro plants, the total full load-hours of all sub-categories are allocated to the four quarters of the year according to the percentages displayed in the second column of Table 5.2.

TABLE 5.3: INSTALLED CAPACITIES IN THE YEAR 2010, PROSPECTED INSTALLED CAPACITY AND INCREASE OF INSTALLED CAPACITY FOR THE YEARS 2015, 2020 AND 2025 OF HYDROPOWER PLANTS IN GERMANY

	2010	2010 – 2015		2015 – 2020		2020 – 2025	
category	installed capacity [MW]	installed capacity [MW]	increase of capacity [MW]	installed capacity [MW]	increase of capacity [MW]	installed capacity [MW]	increase of capacity [MW]
< 1 MW	623	534	-89	564	30	567	3
1 – 10 MW	868	1,012	145	1,043	31	1,077	34
> 10 MW	2,221	2,620	400	2,702	82	2,943	241
storage	235	235	0	235	0	235	0
TOTAL	**3,945**	**4,401**	**455**	**4,535**	**143**	**4,821**	**277**

Source: EWI, NREAP-DE (2010) and BMU (2010), own calculations.

The increases of installed capacity as explained above hold for Germany in total. Due to the fact that there are large discrepancies between different regions with respect to their potential for growth in installed capacity of hydropower plants, the total German increase has to be allocated appropriately to the 31 network regions.

TABLE 5.4: TOTAL AND PERCENTAL POTENTIAL GROWTH OF ELECTRICITY GENERATION OF HYDROPOWER PLANTS IN GERMANY PER *BUNDESLAND*

Bundesland	potential total growth [GWh/a]	potential total growth [%]
Brandenburg	90	0.36%
Berlin	4	0.02%
Bremen	38	0.15%
Baden-Württemberg	6,030	24.18%
Bayern	14,765	59.20%
Hessen	504	2.02%
Mecklenburg-Vorpommern	18	0.07%
Niedersachsen	793	3.18%
Nordrhein-Westfalen	714	2,85%
Rheinland-Pfalz	1,026	4.11%
Schleswig-Holstein	38	0.15%
Saarland	135	0.54%
Sachsen	450	1.80%
Sachsen-Anhalt	200	0.80%
Thüringen	137	0.55%
TOTAL	**24,941**	**100.00%**

Source: Wagner, E. (2008), own calculations.

This allocation is based on Wagner, E. (2008) who specifies the total possible increase of electricity generation of hydroelectric plants (in GWh) per *Bundesland*. First of all, it is assumed that technological progress is equal for all regions – i.e. the percental increase of full-load hours is the same for each *Bundesland*. As a result, the proportional potential growth of electricity generation can be assumed to be equal to the proportional growth of installed capacities per *Bundesland*. In that way, total German growth can be assigned to the *Bundesländer* according to the percentage displayed in Table 5.4.

The growth of each *Bundesland* is then further distributed to the network regions that lie within the respective geographic boundaries. This distribution is done in relation to the fraction of area each network region covers of the whole area of the *Bundesland*. The resulting percentage key for distributing an increase of installed capacities in Germany to the network regions is assumed to be constant in the relevant time period until 2025.

Combining the regional percentage key with the German-wide increase of installed capacities of the three categories in Table 5.3 yields the specific regional capacity additions for plants < 1 MW, plants between 1 MW and 10 MW and plants > 10 MW. By adding these regional capacity additions to the installed capacities contained in the hydropower plant database the respective regional installed capacities for the years 2015, 2020 and 2025 are determined.

In addition, due to technological progress, it can be expected that the installation of new plants and the upgrading of already existing plants lead to an increase of full-load hours even with a constant water flow. Consequently, the feed-in structures of the years 2015, 2020 and 2025 need to be adjusted accordingly. Hereby the specification of the feed-in structure for the years 2015 and 2020 is based on the predicted growth of full-load hours outlined in the *NREAP-DE*,[52] while the expected growth of full-load hours between 2020 and 2025 of the *BMU-Leitszenario 2010* is used for the

52 From 2015 until 2020 the full-load hours decrease for small hydroelectric plants (< 1 MW). A possible reason for this might be that due to the large exploitation of potential spots further plants are erected at inferior places.

feed-in structure of the year 2025.[53] The growth of full-load hours between 2010 and 2015 is the percental difference between the average full-load hours calculated based on the data collected in the hydropower plant database and the value predicted for 2015 in the *NREAP-DE*. As already stated, technological progress is assumed to be identical for all regions in Germany so that the individual regional full-load hours are all increased by the aggregate German growth rate of full-load hours. The resulting regional and category-specific full-load hours for the years 2015, 2020 and 2025 are then used to specify regional and category-specific feed-in structures in analogy to the method outlined in 5.3.1.2.

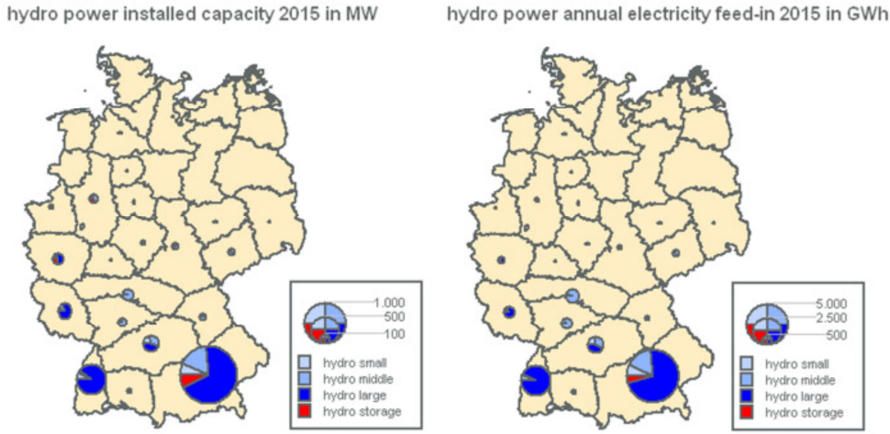

FIGURE 5.4: INSTALLED CAPACITY (LEFT) AND ANNUAL ELECTRICITY GENERATION (RIGHT) OF HYDROPOWER PLANTS IN GERMANY IN THE YEAR 2015

Source: Own illustration.

[53] See NREAP-DE (2010) and BMU (2010).

Combining the new feed-in structures with the respective regional installed capacities (using the same approach as depicted in 5.3.1.3) yields the regional feed-in schedules of hydroelectric power plants in Germany for the years 2015, 2020 and 2025. The resulting regional installed capacities and annual electricity generation are illustrated in Figure 5.4, Figure 5.5 and Figure 5.6.

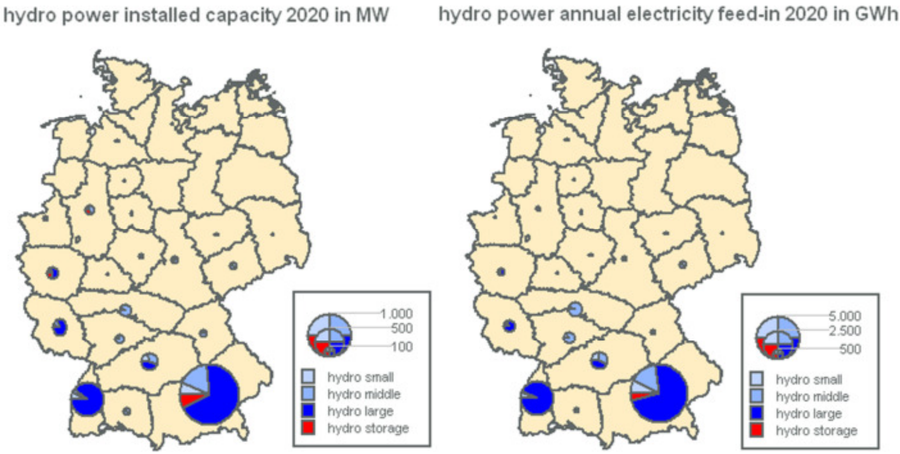

FIGURE 5.5: INSTALLED CAPACITY (LEFT) AND ANNUAL ELECTRICITY GENERATION (RIGHT) OF HYDROPOWER PLANTS IN GERMANY IN THE YEAR 2020

Source: Own illustration.

In total, there is an installed capacity of 4.4 GW and an electricity generation of 19.7 TWh of hydroelectric plants in the year 2015 in Germany. In the year 2020 the capacity slightly rises to 4.5 GW that generate about 20.7 TWh. In the year 2025 the installed capacity of hydropower plants is equal to 4.8 GW with an electricity generation of about 22.0 TWh.

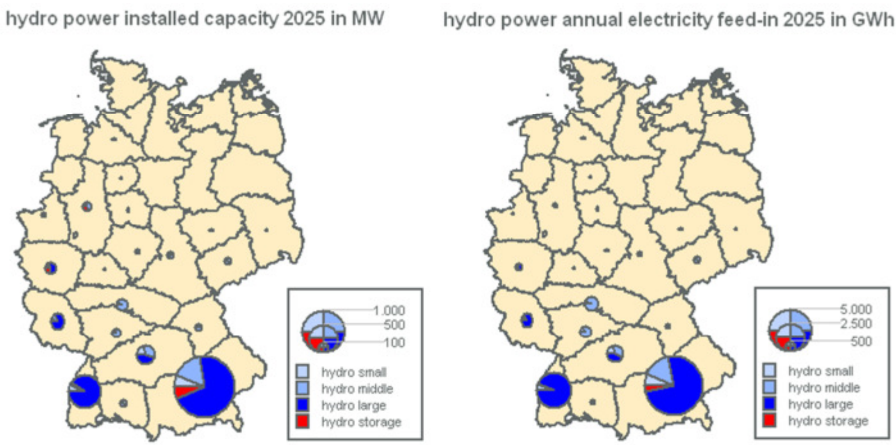

FIGURE 5.6: INSTALLED CAPACITY (LEFT) AND ANNUAL ELECTRICITY GENERATION (RIGHT) OF HYDROPOWER PLANTS IN GERMANY IN THE YEAR 2025

Source: Own illustration.

5.3.2 Regionalization of the feed-in of biomass power plants

In this section the regionalization of the feed-in of biomass power plants in Germany today and in the prospective years 2015, 2020 and 2025 is outlined. The section starts with a description of the allocation of the installed capacities to the network regions (section 5.3.2.1). Following this, it will be outlined how the feed-in structure is determined (section 5.3.2.2) and how the regional feed-in of biomass power plants is specified (section 5.3.2.3). Finally, in section 5.3.2.4 it will be explained how the installed capacity and feed-in structure of prospective years is forecasted to determine the regional electricity feed-in of the years 2015, 2020 and 2025.

5.3.2.1 Regionalized database of biomass capacities in Germany

The regionalized electricity feed-in of biomass power plants is based on a database that contains all installed biomass power plants at the end of 2010 in Germany. This database was set up by the data available on the websites of the four German TSOs.[54] The number and installed capacities of the gathered plants were additionally verified by the figures given in a report of the BDEW on recent figures on renewable energy sources[55] as well as by historical data on the installed capacities and generation published by the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety of the Federal Republic of Germany.[56]

The biomass power plant database contains information on installed capacity and the geographic location (mailing address) of each individual plant. Using the postal code, each biomass plant is allocated to a network region in Germany. In addition, the plants are categorized according to the aggregate state of the biomass used – i.e. gaseous, liquid and solid biomass. There is a fourth category of all remaining plants because not for all plants information on their aggregate state is available.

In total, the database contains 10,409 biomass power plants with an installed capacity of 5.0 GW. From these, 1,139 plants with an installed capacity of roughly 0.3 GW use liquid biomass and are thus classified as *bioliquid*. 804 plants with an installed capacity of 0.7 GW use solid biomass and are classified as *biosolid* and 3,242 plants with an installed capacity of around 1.9 GW use gaseous biomass and are classified as *biogas*. Finally, there is no information available on the aggregate state of the fuel of 5,224 plants with an installed capacity of 2.2 GW so that these are summarized in

[54] See footnote 44.
[55] See BMU (2011).
[56] See BDEW (2010), pp. 18 – 20.

the category *biorest*.[57] The exact category-specific figures are outlined in Table 5.5.

TABLE 5.5: NUMBER AND INSTALLED CAPACITY OF BIOMASS POWER PLANTS PER CATEGORY CONTAINED IN THE DATABASE FOR GERMANY AT THE END OF 2010

category	number of plants	installed capacity [MW]
biosolid	804	654
bioliquid	1,139	289
biogas	3,242	1,858
biorest	5,224	2,228
TOTAL	**10,409**	**5,029**

Source: Own figures.

As already mentioned, the total installed capacity of biomass plants in Germany contained in the database at the end of 2010 is equal to 5.0 GW. Total electricity feed-in of biomass in 2010 equals 26.4 TWh and is specified according to the methodology outlined in 5.3.1.2 and 5.3.1.3. In the left graph of Figure 5.7, the allocation of the capacities to the network regions is displayed, while the regional distribution of electricity feed-in is shown in the right graph.

57 Other sources further subdivide the fuel type categories in sub-categories based on the installed capacities. See DBFZ (2010) and EWI (2010), p. 65. However, as no forecast on the installed capacities and development of full-load hours of these subcategories are available in NREAP-DE (2010) and BMU (2010), no subcategories are specified here.

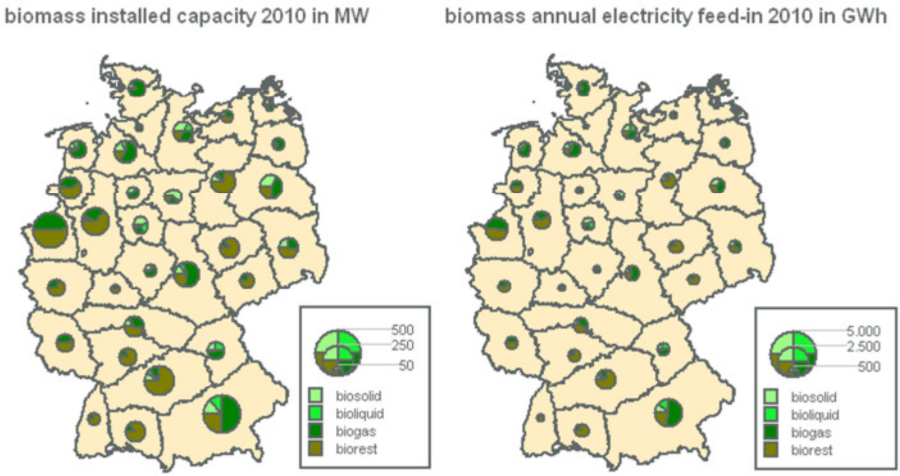

FIGURE 5.7: INSTALLED CAPACITY (LEFT) AND ANNUAL ELECTRICITY GENERATION (RIGHT) OF BIOMASS PLANTS IN GERMANY IN THE YEAR 2010

Source: Own illustration.

5.3.2.2 Determination of the feed-in structure of biomass

As stated above, biomass power plants can be categorized according to the aggregate state of the biomass used – namely solid, gaseous and liquid biomass. As the different aggregate states require different generation technologies the feed-in structures of the respective plants are diverse as well. Thus, a distinction between the three different types of biomass is made as explained in the following. Furthermore, for the remaining plants for which no information on the aggregate state is available an average feed-in structure is specified.

Under the assumption of a steady feed-in of biomass generators throughout all hours of the year the full-load hours can be used to calculate the hourly feed-in as percentage of installed capacity. For the year 2010 the full-load hours are calculated based on the installed capacities and generation outlined in the *NREAP-DE*.[58] It is assumed that the full-load hours are equal for each region in Germany so that no regional differentiation with respect to utilization and feed-in structure is made.

5.3.2.3 Regionalized feed-in schedules of biomass

The hourly feed-in schedule of biomass plants is specified as follows. First of all, the installed capacities of all biomass plants belonging to a certain category are summed up for each individual network region (see Figure 5.7 for an overview). Then, the total installed capacity per region and biomass category (in kW) is multiplied with its respective feed-in structure (%/kW). Summing up the feed-in schedules of the four biomass categories yields the total feed-in of biomass in the respective network region.

5.3.2.4 Specification of feed-in schedules of biomass in prospective years

The feed-in schedules of the prospective years are determined according to the methodology explained in 5.3.1.3 by multiplying the feed-in structure with the installed capacity. Thus, in order to specify the prospective feed-in schedules, a forecast of the feed-in structures as well as a forecast of installed capacities per category and region of the respective year is needed.

The increase of installed capacities of biomass power plants in Germany until 2020 is based on the *NREAP-DE* while the assumptions concerning the growth from 2020 to 2025 rely on the *BMU-Leitszenario 2010*.[59] The capacity additions per aggregate state from 2010 until 2015 are calculated

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[58] See NREAP-DE (2010).
[59] See NREAP-DE (2010) and BMU (2010).

as the difference between the database figures at the end of 2010 and the prospected capacities per category in the year 2015 as outlined in the *NREAP-DE*. Furthermore, the installed capacity of the category *biorest* is assumed to remain constant for the entire time period.[60]

TABLE 5.6: INSTALLED CAPACITIES IN THE YEAR 2010, PROSPECTED INSTALLED CAPACITY AND INCREASE OF INSTALLED CAPACITY FOR THE YEARS 2015, 2020 AND 2025 OF BIOMASS POWER PLANTS IN GERMANY

	2010	2010 – 2015		2015 – 2020		2020 – 2025	
category	installed capacity [MW]	installed capacity [MW]	increase of capacity [MW]	installed capacity [MW]	increase of capacity [MW]	installed capacity [MW]	increase of capacity [MW]
biosolid	654	2,130	1,476	2,564	434	2,647	83
bioliquid	289	237	-52	237	0	264	27
biogas	1,858	3,126	1,268	3,796	670	4,261	465
biorest	2,228	2,228	0	2,228	0	2,228	0
TOTAL	**5,029**	**7,721**	**2,811**	**8,825**	**4,165**	**9,400**	**575**

Source: EWI, NREAP-DE (2010) and BMU (2010), own calculations.

The installed capacities per category today as contained in the database and the prospected installed capacities and capacity additions for the years 2015, 2020 and 2025 are summarized in Table 5.6.

[60] A comparison of the proportion of each category of total installed capacities in 2010 outlined in the *NREAP-DE* with the proportion of the categories in the database shows that nearly all plants belonging to the category *biorest* actually have to be of the type *biosolid* in order to guarantee an equal relative distribution. Thus, the capacity additions of *biosolid* from 2010-2015 are calculated as the difference between the installed capacities of *biosolid* plus *biorest* of the database and the prospected installed capacities of solid biomass of the *NREAP-DE* in the year 2015.

There are large differences between the regions in Germany with respect to technical potential and actual growth of capacities of the three categories of biomass. In order to allocate the total increase of capacities to the different network regions the historical trend from the year 2005 to 2010 is extrapolated for the future until 2025. This historical trend is calculated based on the database of biomass capacities that originally stems from information given on the websites of the four German TSOs.[61] Of course, the validity of using the historical trend as prediction for the regional distribution of capacity additions is disputable. Firstly, it is questionable that this trend will prevail in the future. Furthermore, not all plants can be classified according to the aggregate state (category *biorest*) so that it is assumed that they are of type *biosolid*. As this is no assured information the calculated historical trend might be biased. Nevertheless, despite these drawbacks, any adjustments of the historical trend would be arbitrary as it is not clear how the regional distribution of new installations will change. Consequently, the historical trend is used as the best prediction available. In Table 5.7 the calculated historical regional distribution of new installations of the three categories for North, Central and South Germany in aggregate is displayed.

Based on the above outlined regional distribution key, the assumed capacity additions as specified in the *NREAP-DE* or *BMU-Leitszenario 2010* (see Table 5.6) for each biomass category can be allocated to the different network regions. By adding this capacity growth to the regional installed capacities already contained in the biomass database, the total regional installed capacities for the years 2015, 2020 and 2025 for the three categories are obtained.

[61] See Amprion (2011), TenneT (2011), EnBW (2011) and 50Hertz (2011).

TABLE 5.7: DISTRIBUTION OF THE INCREASES OF INSTALLED CAPACITIES OF BIOMASS IN GERMANY ON AVERAGE FOR THE YEARS 2005 – 2010

category	North	Central	South
biosolid	28.5%	39.5%	31.7%
bioliquid	32.6%	17.7%	49.7%
biogas	56.8%	22.9%	20.3%

Source: Amprion (2011), TenneT (2011), EnBW (2011) and 50Hertz (2011), own calculations.

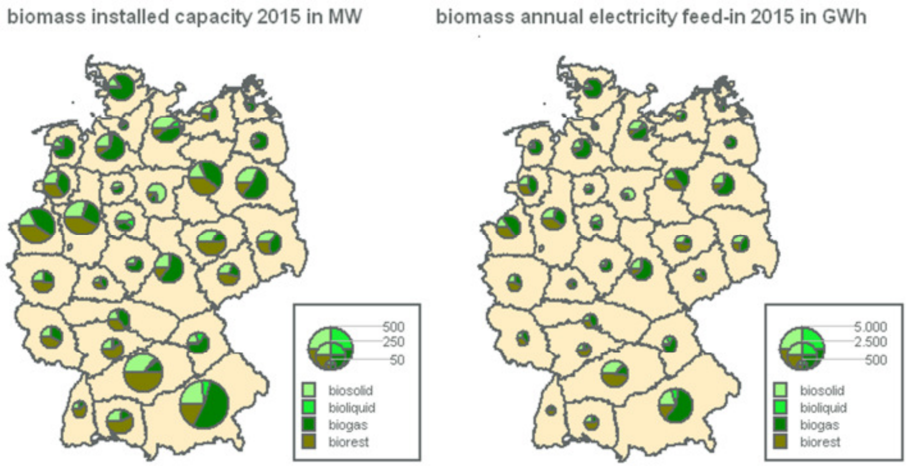


FIGURE 5.8: INSTALLED CAPACITY (LEFT) AND ANNUAL ELECTRICITY GENERATION (RIGHT) OF BIOMASS PLANTS IN GERMANY IN THE YEAR 2015

Source: Own illustration.

In addition to the installed capacities, also the full-load hours increase over time thereby accounting for technological progress. Thus, the feed-in structures need to be adjusted for prospective years using the methodology outlined in 5.3.1.2. For the years 2015 and 2020 the respective full-load hours are calculated based on the installed capacities and generation given in the *NREAP-DE* while the values of the *BMU-Leitszenario 2010* are used for the determination of the full-load hours in the year 2025.[62]

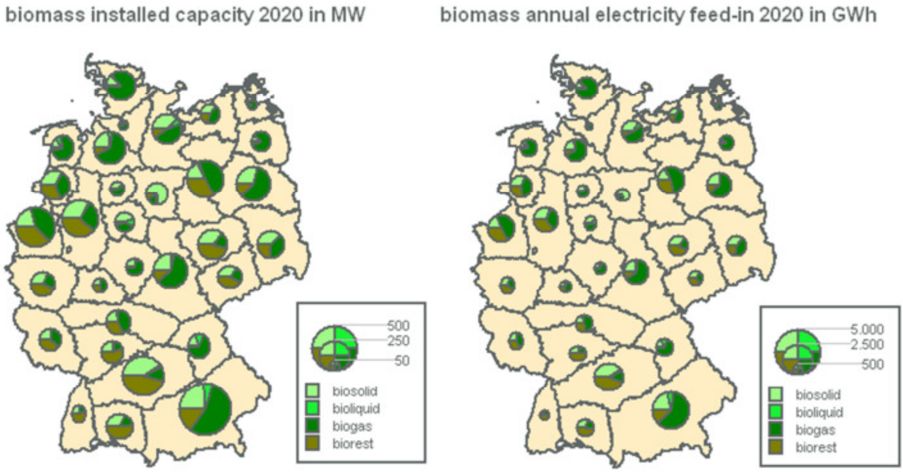


FIGURE 5.9: INSTALLED CAPACITY (LEFT) AND ANNUAL ELECTRICITY GENERATION (RIGHT) OF BIOMASS PLANTS IN GERMANY IN THE YEAR 2020

Source: Own illustration.

As outlined above, multiplication of the installed capacity and the feed-in structure yields the electricity feed-in of biomass per category and network region. Figure 5.8, Figure 5.9 and Figure 5.10 illustrate the resulting regional installed capacities and annual electricity generation of biomass in Germany. In the year 2015 there is an installed capacity of 7.7 GW and a feed-in of about 41.9 TWh in Germany. The capacity rises to 8.8 GW in the year 2020 generating about 49.6 TWh, whereas in the year 2025 the

62 See NREAP-DE (2010) and BMU (2010).

installed capacity of biomass equals 9.4 GW with an electricity generation of 51.3 TWh.

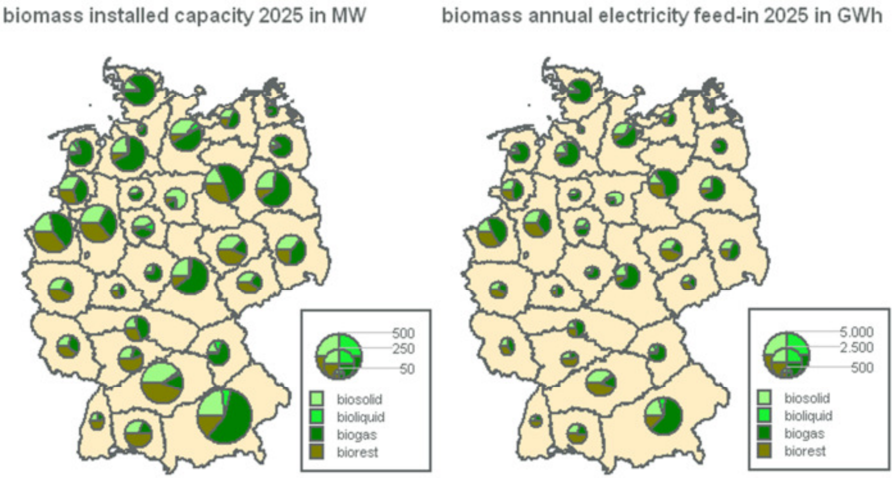


FIGURE 5.10: INSTALLED CAPACITY (LEFT) AND ANNUAL ELECTRICITY GENERATION (RIGHT) OF BIOMASS PLANTS IN GERMANY IN THE YEAR 2025

Source: Own illustration.

In order to check the calculated regional generation figures, they are compared to the technical potential of the different regions. The technical generation potential of biogas per *Bundesland* was specified in a study of the Institut für Energetik und Umwelt gGmbH[63] on behalf of the *Bundesland Sachsen-Anhalt* in the year 2007.[64] The respective figures are outlined in Table 5.8.

[63] At the end of the year 2007 the Institut für Energetik und Umwelt gGmbH was split into the Leipziger Institut für Energie GmbH (IE Leipzig) and the Deutsches Biomasse Forschungszentrum (DBFZ).

[64] See IE Leipzig (2007), p. 102.

TABLE 5.8: ESTIMATED TOTAL POTENTIAL OF THE FEED-IN OF BIOMASS IN GERMANY PER *BUNDESLAND*

Bundesland	potential [GWh/a]
Brandenburg	3,926
Berlin	194
Bremen	90
Baden-Württemberg	6,234
Bayern	15,135
Hessen	3,253
Hamburg	236
Mecklenburg-Vorpommern	3,919
Niedersachsen	13,719
Nordrhein-Westfalen	8,790
Rheinland-Pfalz	2,813
Schleswig-Holstein	4,052
Saarland	350
Sachsen	3,252
Sachsen-Anhalt	3,800
Thüringen	2,470
TOTAL	**72,233**

Source: IE Leipzig (2007).

The potential per *Bundesland* is then allocated to the network regions and used as an upper bound for feed-in of biogas capacities.[65] Comparing this

[65] The specification of biogas potential in IE Leipzig (2007) is based on the settlement structure, the agriculture structure and the land utilization of the *Bundesländer* in the year 2007. Thus, assuming the outlined figures as upper bounds for the growth of capacities neglects any structural changes until the year 2025. However, it can be assumed that the changes of the settlement structure, the agriculture structure and the land utilization until 2025 are not large enough to change the estimated potential in the magnitude of GW.

upper bound with the calculated electricity feed-in per network region shows that the maximum technical potential for electricity generation by biogas capacities is reached in none of the German regions until 2025. Thus, the calculated electricity feed-in of biogas per network region is a feasible path.[66]

5.3.3 Regionalization of the feed-in of photovoltaic power plants

In the following it will be explained how the feed-in of photovoltaic in German today and in the years 2015, 2020 and 2025 is regionalized. First of all, the methodology to allocate the installed capacities to the network regions is outlined (section 5.3.2.1). Then it is explained how the feed-in structure is specified (section 5.3.3.2) and how the regional feed-in of photovoltaic is calculated (section 5.3.3.3). In the last section 5.3.3.4 the determination of the regional feed-in of photovoltaic in the years 2015, 2020 and 2025 is illustrated.

5.3.3.1 Regionalized database of photovoltaic capacities in Germany

In order to specify a regionalized feed-in of photovoltaic a database of all installed photovoltaic power plants at the end of 2010 was set up for Germany. This database grounds on the data available on the websites of the four Germany TSOs[67] and was verified by the figures given in a report of the BDEW on recent figures on renewable energy sources.[68]

[66] Unfortunately no adequate source for the potential of solid and liquid biomass could be found so that only an upper bound for the increase of biogas capacities can be specified.

[67] See footnote 44.

[68] See BDEW (2010), pp.18 – 20.

TABLE 5.9: CATEGORIES OF PHOTOVOLTAIC PLANTS DIFFERENTIATED WITH RESPECT TO INSTALLED CAPACITY AND TYPE OF INSTALLATION

category	installed capacity [kW]	type of installation
pvtech_1	0 – 5	small residential roof top system (without ventilation)
pvtech_2	16 – 999	large residential roof top system (with ventilation)
pvtech_3	>1000	large free-standing elevated system

Source: EWI (2010) and own specifications.

As applies for the other renewable technologies also the photovoltaic database contains information on installed capacity and geographic location (mailing address) of each individual plant. Using the postal code, each photovoltaic plant is assigned to a network region in Germany in analogy to the methodology outlined for hydroelectric power plants. Furthermore, each plant is categorized according to its respective installed capacity as one of the three photovoltaic categories displayed in Table 5.9.[69] The underlying assumption of the classification is that photovoltaic units with an installed capacity smaller or equal to 5 kW are roof top systems without ventilation, units with an installed capacity between 16 and 999 kW are roof top systems with ventilation and units with an installed capacity larger or equal to 1 MW are free-standing elevated systems.

The database contains photovoltaic power plants with an installed capacity of 15.7 GW in total. Around 4.4 GW are classified as *pvtech_1*, 9.1 GW as *pvtech_2* and 2.2 GW as *pvtech_3*. The exact category-specific figures are summarized in Table 5.10. Due to the huge quantity of captured plants the exact number of plants is omitted.

[69] The categories are EWI's own specification and are also used in the model LORELEI of EWI. They were developed in the course of the project "European RES-E Policy Analysis", see EWI (2010).

TABLE 5.10: INSTALLED CAPACITY OF PHOTOVOLTAIC POWER PLANTS PER CATEGORY CONTAINED IN THE DATABASE FOR GERMANY AT THE END OF 2010

category	installed capacity [MW]
pvtech_1	4,401
pvtech_2	9,061
pvtech_3	2,235
TOTAL	**15,697**

Source: Own figures.

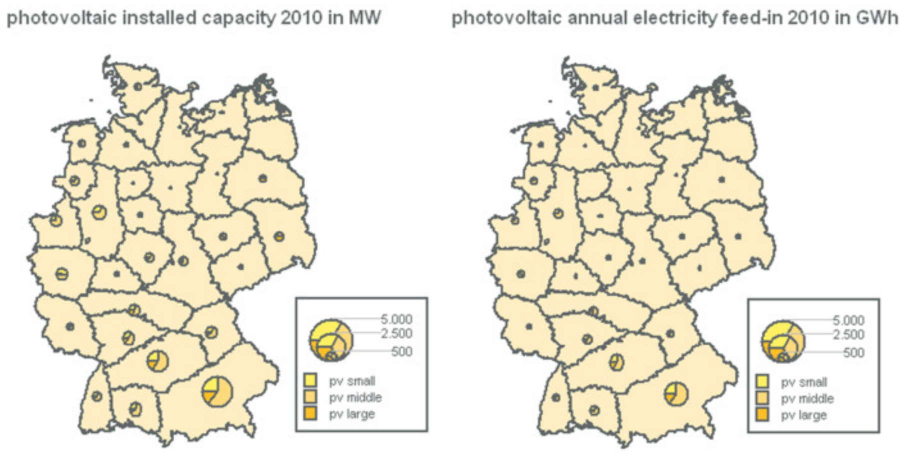


FIGURE 5.11: INSTALLED CAPACITY (LEFT) AND ANNUAL ELECTRICITY GENERATION (RIGHT) OF PHOTOVOLTAIC PLANTS IN GERMANY IN THE YEAR 2010

Source: Own illustration.

The total installed capacity of photovoltaic plants at the end of 2010 in Germany in the database amounts to 15.7 GW. Total electricity feed-in of photovoltaic in 2010 is equal to 9.5 TWh and specified according to the methodology outlined in 5.3.1.2 and 5.3.1.3. The allocation of the capacities to the network regions is illustrated in in the left graph of Figure 5.11. The regional distribution of electricity feed-in is displayed in the right graph of Figure 5.11.

5.3.3.2 Determination of the feed-in structure of photovoltaic

The specification of the feed-in structure of photovoltaic power plants is based on data on global irradiation and temperature of three regions in Germany (North, Central, and South) as well as on specific photovoltaic module characteristics for each category available at EWI.[70] While the module characteristics are assumed to be identical for whole Germany, the irradiation and temperature data differ. This allows accounting for the fact that the irradiation and temperature are usually higher the more southern the location. This consequently results in a higher energy output per kW installed capacity of photovoltaic in the South. Using the outlined information for each category and region, an optimal energy output per kW installed capacity can be determined and scaled to the 288 model hours.[71]

However, the real output per kW is usually lower than the optimal output due to e.g. efficiency losses of converters and cables. Thus, the optimal output structure is scaled down by a factor determined by the desired full-load hours per year. Hereby, the desired full-load hours are calculated based on the installed capacities and generation specified for the year 2010 in the *NREAP-DE*.[72]

70 The data concerning the irradiation originally stems from the database Meteonorm 6.0. All data was collected in the course of the project "European RES-E Policy Analysis", see EWI (2010), p. 71.

71 The calculation of the optimal energy output per model hour was adopted from the project "European RES-E Policy Analysis", too. See EWI (2010), p. 71.

72 See NREAP-DE (2010).

As a result, the approach outlined above yields an hourly changing feed-in structure for each of the photovoltaic categories for North, Central and South Germany. These feed-in structures are identical for each day (Saturday, Sunday, working day) of a quarter. However, hourly fluctuations in the course of a day – i.e. feed-in is highest during the noon hours and zero at night – as well as differences between the seasons – i.e. feed-in is higher during the summer months than during winter – are respected. The structure of North Germany is assigned to network region 1 to 13, the structure of Central Germany to network regions 14 to 23 and the structure of South Germany to network regions 24 to 31. As the assumed full-load hours increase over time, the feed-in structure is changing which results in increasing feed-in per kW in the course of time.

5.3.3.3 Regionalized feed-in schedules of photovoltaic

The hourly feed-in schedules of photovoltaic plants are specified in analogy to the methodology used for hydroelectric plants. In a first step, the installed capacities of all photovoltaic plants belonging to a certain category are summed up for each individual network region (see Figure 5.11 for an overview). Following this, the total installed capacity per region and photovoltaic category (in kW) is multiplied with its respective feed-in structure (%/kW). Summing up the feed-in schedules of the three photovoltaic categories yields the total feed-in of photovoltaic modules in the respective network region.

5.3.3.4 Specification of feed-in schedules of photovoltaic in prospective years

The specification of the regional feed-in schedules of photovoltaic plants in the prospective years 2015, 2020 and 2025 follows the methodology illustrated in 5.3.1.3: the respective feed-in structure is multiplied with the installed capacity per category and network region. Thus, the determination of future feed-in schedules requires a projection of the feed-in structures and a projection of the regional installed capacity per category for the respective year.

The assumed growth of total installed capacities of photovoltaic power plants in Germany until 2020 is based on the *NREAP-DE* while the assumptions concerning the growth from 2020 to 2025 grounds on the *BMU-Leitszenario 2010* of the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety of the Federal Republic of Germany.[73] In Table 5.11 the installed capacity for today as contained in the database, the prospected installed capacities for the years 2015 and 2020 of the *NREAP-DE* and the prospected capacities for 2025 given by the *BMU-Leitszenario 2010* as well as the respective capacity additions are summarized.

TABLE 5.11: INSTALLED CAPACITIES IN THE YEAR 2010, PROSPECTED INSTALLED CAPACITY AND INCREASE OF INSTALLED CAPACITY FOR THE YEARS 2015, 2020 AND 2025 OF PHOTOVOLTAIC POWER PLANTS IN GERMANY

	2010	2010 – 2015		2015 – 2020		2020 – 2025	
category	installed capacity [MW]	installed capacity [MW]	increase of capacity [MW]	installed capacity [MW]	increase of capacity [MW]	installed capacity [MW]	increase of capacity [MW]
photovoltaic	15,697	34,279	18,582	51,753	17,474	57,377	5,624

Source: EWI, NREAP-DE (2010) and BMU (2010), own calculations.

[73] See NREAP-DE (2010) and BMU (2010), which both have identical figures for prospected installed capacities of photovoltaic in the year 2020.

The total increase of capacities needs to be allocated to the three different categories of photovoltaic. The assumed growth of *pvtech_3* is aligned with the prospected increase of installed capacities of free-standing systems according to the *BMU-Leitszenario 2010*. Thus, it is assumed that in the year 2025 3,128 MW of installed capacities of photovoltaic belong to the category *pvtech_3*. The remaining growth of capacities has to be subdivided into growth of installed capacities of *pvtech_1* and growth of installed capacities of *pvtech_2*. For this purpose a forecast is developed based on an analysis of the historical development and expected future trends.

Furthermore, regarding the increase of installed capacities, there are significant differences between the distinct regions in Germany with respect to technical potential and actual growth of photovoltaic capacities. The technical potential is primarily conditional on the available roof top area that varies between the different residential areas – i.e. rural and urban settlements.[74] Consequently, the settlement set-up of the different network regions is crucial for the technical potential of photovoltaic. In Lödl, et al. (2010) the potential of photovoltaic in Germany per *Bundesland* is specified as displayed in Table 5.12. This potential is then allocated to the network regions and used as an upper bound for increases of installed capacity.[75]

[74] See Lödl, et al. (2010) for a procedure to specify the technical potential of photovoltaic for different regions in Germany.

[75] The specification of photovoltaic potential in Lödl, et al. (2010) is based on the settlement structure of the *Bundesländer* today. Thus, assuming the outlined figures as upper bound for the growth of capacities neglects any structural changes until the year 2025. However, it can be assumed that the changes of the settlement structure until 2025 are not large enough to change the estimated potential in the magnitude of GW.

TABLE 5.12: ESTIMATED POTENTIAL OF PHOTOVOLTAIC IN GERMANY PER *BUNDESLAND*

Bundesland	potential [GW]
Brandenburg	9.4
Berlin	2.4
Bremen	1.0
Baden-Württemberg	18.0
Bayern	25.3
Hessen	9.9
Hamburg	1.8
Mecklenburg-Vorpommern	5.7
Niedersachsen	21.1
Nordrhein-Westfalen	25.4
Rheinland-Pfalz	9.4
Schleswig-Holstein	5.8
Saarland	2.2
Sachsen	9.7
Sachsen-Anhalt	8.3
Thüringen	5.6
TOTAL	**161.0**

Source: Lödl, et al. (2010).

As the maximum technical potential in none of the German region is reached by now nor in the future, the actual growth of installed capacity is not restricted by this. Besides numerous "soft factors" such as the image of photovoltaic or the familiarity with the technology if neighbors or other close households already installed modules, the main driver of growth of capacities can be assumed to be the expected energy output of the installation. According to the German renewable energy act (EEG) owners of photovoltaic installations receive a feed-in tariff per generated kWh electricity.[76] Thus, the installation is more profitable the more electricity is generated. The electricity generation thereby depends on the irradiation angle, intensity and duration that are in turn conditional on the geographic location. Consequently, photovoltaic installations in South Germany are more profitable than in northern regions so that the largest percentage of growth of installed capacities can be assumed to accrue in the southern network regions.

In order to specify the regional distribution of the increase in capacities, the historical trend of the years 2008 – 2010 is extrapolated for the future until 2025. The trend is calculated using the database of photovoltaic capacities and therefore is based on the information given on the websites of the four German TSOs.[77] Using the historical trend is a valid assumption as already in the past the “soft factors” outlined above as well as the profitability of the installations were incorporated in the investment decision of households and other investors. Although the experienced trend will not inevitably prevail in the future, no secure predictions can be made about how the regional allocation of installations will change. Thus, any modifications of the historical trend would be arbitrary. Therefore, the historical trend is used as an approximation for the regional distribution of future increases of installed capacities of photovoltaic. Table 5.13 summarizes the calculated historical regional distribution of new installations of the three categories for North, Central and South Germany in aggregate.

[76] See EEG (2009), part 3, section 1 on general compensation prescriptions for the exact feed-in tariff specifications.

[77] See Amprion (2011), TenneT (2011), EnBW (2011) and 50Hertz (2011).

TABLE 5.13: DISTRIBUTION OF THE INCREASES OF INSTALLED CAPACITIES OF PHOTOVOLTAIC IN GERMANY ON AVERAGE FOR THE YEARS 2008 – 2010

category	North	Central	South
pvtech_1	9.8%	27.2%	63.0%
pvtech_2	16.0%	27.1%	56.9%
pvtech_3	9.5%	29.4%	61.1%

Source: Amprion (2011), TenneT (2011), EnBW (2011) and 50Hertz (2011), own calculations.

Combining the regional distribution key with the assumed future trend for the type of photovoltaic category yields a general distribution key. This key allows allocating an increase of capacity (in MW) to both the three categories and to the network regions. Thus, by multiplying this key with the capacity additions predicted for a specific year by the *NREAP-DE* or *BMU-Leitszenario 2010* (see Table 5.11), the regional increase of installed capacity for each category of photovoltaic for the relevant time period is obtained. Adding the capacity growth to the regional installed capacities contained in the photovoltaic database yields the respective total regional installed capacities for the years 2015, 2020 and 2025.

In addition to the increase of capacities also the feed-in structure needs to be adjusted to account for technological progress. The determination of the feed-in structure of different years – differentiated with respect to the assumed regional full-load hours – follows the same methodology as specified in 5.3.1.2. The desired full-load hours for the years 2015 and 2020 are calculated based on the installed capacities and generation specified in the *NREAP-DE*, while the desired full-load hours for the year 2025 are based on the capacity and generation values of the *BMU-Leitszenario 2010*. As these full-load hours increase in the course of time, technological progress (increased efficiency of the photovoltaic modules), is incorporated.

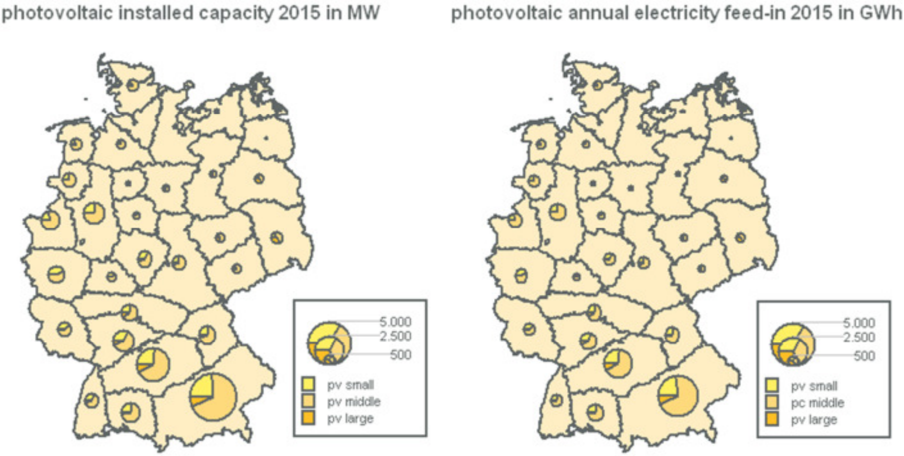


FIGURE 5.12: INSTALLED CAPACITY (LEFT) AND ANNUAL ELECTRICITY GENERATION (RIGHT) OF PHOTOVOLTAIC PLANTS IN GERMANY IN THE YEAR 2015

Source: Own illustration.

As already stated, combining the regional feed-in schedules of photovoltaic plants in the prospective years 2015, 2020 and 2025 with the installed capacities per category and network region yields the regional feed-in of photovoltaic plants of the respective years. Figure 5.12, Figure 5.13 and Figure 5.14 illustrate the resulting regional installed capacities and annual electricity generation of photovoltaic in Germany.

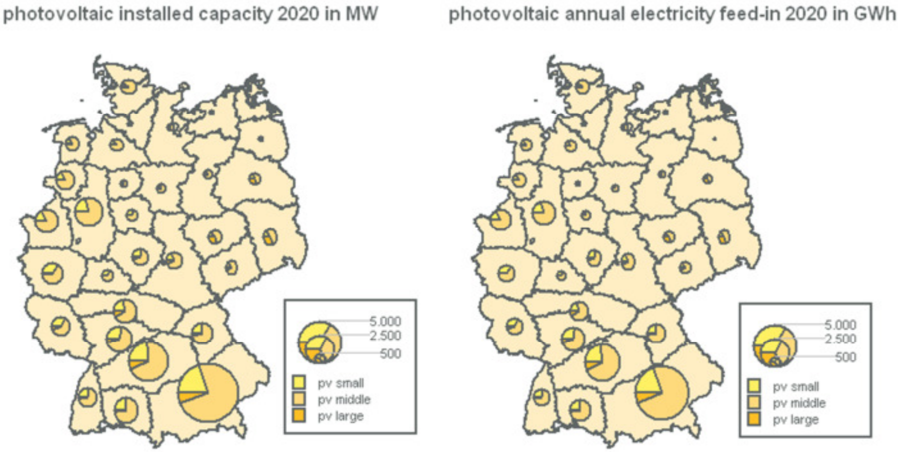


FIGURE 5.13: INSTALLED CAPACITY (LEFT) AND ANNUAL ELECTRICITY GENERATION (RIGHT) OF PHOTOVOLTAIC PLANTS IN GERMANY IN THE YEAR 2020

Source: Own illustration.

In total there is an installed capacity of 34.3 GW and a feed-in of 26.6 TWh in the year 2015 in Germany. In the year 2020 the installed capacity is equal to 51.8 GW with an electricity generation of 41.4 TWh. In the year 2025 the installed capacity of photovoltaic equals 57.4 GW with a generation of 51.3 TWh.

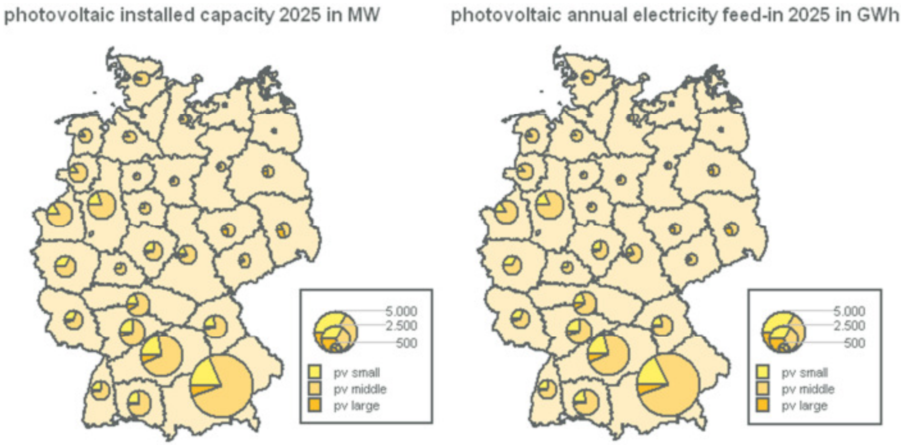


FIGURE 5.14: INSTALLED CAPACITY (LEFT) AND ANNUAL ELECTRICITY GENERATION (RIGHT) OF PHOTOVOLTAIC PLANTS IN GERMANY IN THE YEAR 2025

Source: Own illustration.

5.3.4 Regionalization of the feed-in of wind power plants

In the following section the determination of the regional feed-in of wind power plants in Germany for the years 2015, 2020 and 2025 is outlined. As holds true for the other renewable energy sources, also the determination of the feed-in of wind power is grounded on a regionalization of the installed capacities (section 5.3.4.1). However, in contrast to other renewable energies, the feed-in of wind power is simulated rather than being specified by a feed-in structure. How this is done is explained in section 5.3.4.1. The final section 5.3.4.3 outlines how the regional installed capacities in the prospective years are specified. These then are used as input for the simulation of the feed-in of wind power in the years 2015, 2020 and 2025.

5.3.4.1 Regionalized database of wind power capacities in Germany

The specification of the generation of wind power plants in Germany grounds on a database that contains all wind power plants *onshore* and *offshore* in Germany at the end of 2010. This power plant database was set up by aligning and extending an already existing power plant database of EWI with the information on the websites of the four German TSOs.[78] As the original database of EWI stems from mid-2008, it needed to be updated in order to include all installed facilities at the end 2010.

TABLE 5.14: CATEGORIES OF ONSHORE AND OFFSHORE WIND POWER PLANTS DIFFERENTIATED WITH RESPECT TO INSTALLED CAPACITY, DIAMETER OF ROTOR AND HUB HEIGHT

category	installed capacity [MW]	diameter of rotor [m]	hub height [m]
windtech_1	0 – 500	32	42
windtech_2	501 – 1,000	51	66
windtech_3	1,001 – 2,000	74	84
windtech_4	2,001 – 3,500	90	88
windtech_5	3,501 – 5,500	112	111
windtech_6	5,501 – 7,000	114	124
windtech_7	>7,000	130	140
offwindtech_1	5,000	120	90
offwindtech_2	8,000	155	110
offwindtech_3	10,000	175	130

Source: EWI (2010) and own specifications.

The database contains information on installed capacity and the geographic location (mailing address) of each individual wind power plant. Using the

78 See footnote 44.

postal code each wind power plant is assigned to a network region in Germany in analogy to the methodology outlined for hydroelectric power plants. Furthermore, information on the hub height and the diameter of the rotor is included in the database. These data are used in combination with the installed capacity for the determination of the electricity feed-in of wind power plants as outlined in 5.3.1.2.

TABLE 5.15: NUMBER AND INSTALLED CAPACITY OF THE ONSHORE AND OFFSHORE WIND POWER PLANTS PER CATEGORY CONTAINED IN THE DATABASE FOR GERMANY AT THE END OF 2010

category	number of plants	installed capacity [MW][2]
wintech_0[1]	12,031	12,786
windtech_1	711	205
windtech_2	1,472	1,109
windtech_3	4,621	8,224
windtech_4	1,225	2,791
windtech_5	200	1,202
windtech_6	24	207
windtech_7	3	18
offwindtech_1	12	60
offwindtech_2	0	0
offwindtech_3	0	0
TOTAL	**20,299**	**26,601**

1) wintech_0 are the wind power plants that already had a specific hub height and diameter of rotor in the database.
2) rounded values.

Source: Own figures.

The original database already contained specific hub heights and rotor diameters for each plant. However, as the new and updated plants were missing such information, an assignment of hub heights and diameters to the new plants was necessary. Based on the categories displayed in Table 5.14 for onshore and offshore plants the allocation is done according to the installed capacity of the wind power plants in the database.[79]

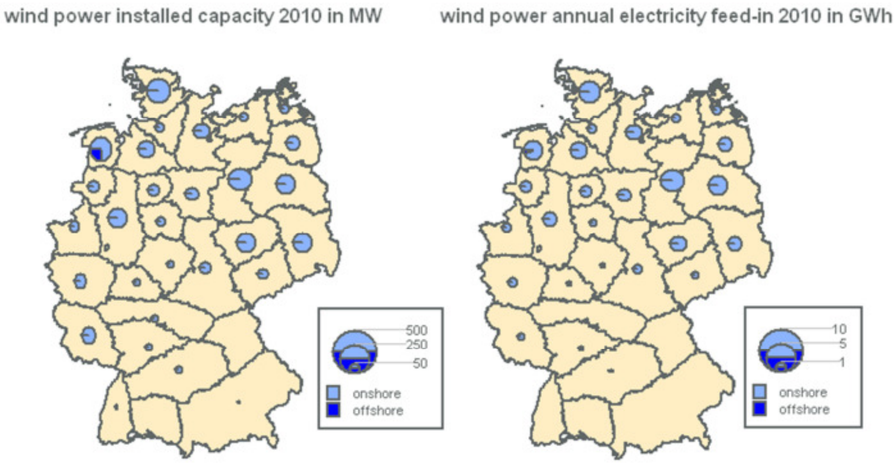


FIGURE 5.15: INSTALLED CAPACITY (LEFT) AND ANNUAL ELECTRICITY GENERATION (RIGHT) OF WIND POWER PLANTS IN GERMANY IN THE YEAR 2010

Source: Own illustration.

In sum, the database contains 20,287 onshore wind power plants with an installed capacity of about 26.5 GW at the end of 2010. Furthermore, there are 12 offshore wind power plants with an installed capacity of 0.6 GW. The exact category-specific figures are summarized in Table 5.15. The total electricity feed-in of wind power plants in the year 2010, as determined

[79] The categories are EWI's own specification and are also used in the model LORELEI of EWI. They were developed in the course of the project "European RES-E Policy Analysis", see EWI (2010).

according to the methodology specified in 5.3.4.2, is about 41.6 TWh onshore and 0.2 TWh offshore. The respective regional distribution is illustrated in Figure 5.15.

5.3.4.2 Simulation of the feed-in of wind power plants

In contrast to other renewable energies, the electricity feed-in of wind power plants is specified model-endogenously in DIANA. The model combines information of the wind power plant database – namely location, installed capacity, hub height and diameter of the rotor – with simulated hourly wind speed variation curves for each region (different curves for onshore and offshore). The simulation of the regional wind speed curves is based on historical wind speed data of a representative year.

It can be assumed that the structure and variation of wind speeds in Germany does not change fundamentally over time. Thus, the simulated hourly wind speed variation curves can be used for the simulation of the feed-in of wind power plants in the future as well. Consequently, only the wind power plant data needs to be adjusted for the relevant prospective years 2015, 2020 and 2025.

5.3.4.3 Specification of installed capacities of wind power in prospective years

The specification of the growth of total installed capacities of wind power plants onshore and offshore in Germany until 2025 is based on the *NREAP-DE* and the *BMU-Leitszenario 2010* of the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety of the Federal Republic of Germany.[80] Table 5.16 depicts the installed capacity for today as

[80] See NREAP-DE (2010) and BMU (2010), which both have identical figures with respect to the prospected installed capacities of wind power plants.

contained in the database, the prospected installed capacities for the years 2015, 2020 and 2025 given by the *BMU-Leitszenario 2010* as well as the capacity additions.

TABLE 5.16: INSTALLED CAPACITIES IN THE YEAR 2010, PROSPECTED INSTALLED CAPACITY AND INCREASE OF INSTALLED CAPACITY FOR THE YEARS 2015, 2020 AND 2025 OF WIND POWER PLANTS IN GERMANY

	2010	2010 – 2015		2015 – 2020		2020 – 2025	
category	installed capacity [MW]	installed capacity [MW]	increase of capacity [MW]	installed capacity [MW]	increase of capacity [MW]	installed capacity [MW]	increase of capacity [MW]
onshore	26,541	33,647	7,106	35,750	2,103	37,656	1,906
offshore	60	3,000	2,940	10,000	7,000	17,500	7,500
TOTAL	**26,601**	**36,647**	**10,046**	**45,750**	**9,103**	**55,156**	**9,406**

Source: EWI, NREAP-DE (2010) and BMU (2010), own calculations.

For onshore wind power plants there are large discrepancies between different regions in Germany regarding the potential and actual growth of installed capacities. Thus, the total German growth of capacities has to be assigned to the network regions respecting these regional differences.

For the allocation of onshore capacities it is hereby assumed that the recent trend of the regional distribution of new constructions as displayed in the wind power plant database for the years 2005-2010 remains constant for the relevant time period until 2025. This yields a percentage key for distributing an increase of installed capacities of onshore wind power plants in Germany to the network regions.

Multiplication of the regional distribution key with the capacity additions of installed capacities predicted for a specific year by the *BMU-*

Leitszenario 2010 (see Table 5.16) yields the regional increase of installed capacity of onshore wind power plants for the relevant time period.[81] By combining this figure with the regional installed capacities contained in the wind power plant database, the respective total regional installed capacities for the years 2015, 2020 and 2025 is specified.

Nevertheless, it still needs to be determined of which type and of how many wind power plants the total increase of installed capacity is set up. This is crucial as not only the installed capacity but also the structure of the wind park in a region – i.e. the set-up of different categories with different hub heights and diameters of the rotor – has a huge impact on the resulting electricity generation.

The decision on category types is based on an analysis of the historical trend for installing new wind power plants and on assumptions regarding the development of this trend in the future. As there has been a quite different trend for regions located in North, in Central and in South Germany in the past, a different trend is expected to materialize for these three sub-regions in the future as well. In general, a trend towards plants with higher hub heights, larger diameters of the rotor and larger installed MW – thus towards category *windtech_6* and *windtech_7* – is assumed.[82] Nevertheless, it is also expected that there will still be new installations of the older plant categories even though in decreasing magnitude. This assumption is based on the fact that the market entry of a new generation of wind power plants did not induce a total reduction of constructions of older wind power plant types in the past. This observation can be explained by the fact that the choice of the type of wind power plant does depend on

[81] Capacity additions either stem from the installation of entirely new plants or from repowering already existing plants.

[82] Herby it is assumed that *windtech_7* will only be available after 2015, while *windtech_6* is available already by now.

numerous factors such as the vicinity to settlements or geographic feasibility. Thus, it is not expected that in the future a new generation of wind power plants will replace the older ones immediately but rather gradually.

TABLE 5.17: INSTALLED CAPACITIES , PROPORTIONAL DISTRIBUTION OF OFFSHORE WIND POWER PER REGION IN GERMANY IN THE YEAR 2015, 2020 AND 2025 SPECIFIED IN THE *DENA NETZSTUDIE II*

	installed capacity [MW]			percentage of installed capacity [%]			network region
	2015	2020	2025	2015	2020	2025[1)]	
North Sea	**5,950**	**12,000**	**19,500**	**85.00%**	**85.71%**	**88.64%**	
Borkum	1,750	3,900		25.00%	27.86%	28.81%	8
Borkum II	1,950	4,250		27.86%	30.38%	31.39%	8
Helgoland	950	1,300		13.57%	9.28%	9.60%	1
Sylt	1,300	2,550		18.57%	18.51%	18.84%	1
Baltic Sea	**1,050**	**2,000**	**2,500**	**15.00%**	**14.29%**	**11.36%**	
Rostock	350	700		5.00%	5.00%	3.98%	4
Rügen	700	1,300		10.00%	9.29%	7.39%	5
TOTAL	**7,000**	**14,000**	**22,000**	**100.00%**	**100.00%**	**100.00%**	

1) The percentages for the individual regions in the North Sea or Baltic Sea for the year 2025 are specified in proportion to the percentages of the year 2020.

Source: EWI, NREAP-DE (2010) and BMU (2010), own calculations.

As for onshore wind power, also the total installed capacity of offshore wind power is based on the *BMU-Leitszenario 2010* (see Table 5.16). Nevertheless, a different methodology needs to be applied in order to specify the regional distribution of the total capacities. As there are almost no installations by now, there is no historical trend to be extrapolated. The distribution of installed capacities to sea regions is therefore based on the proportionate allocation used in the *Dena Netzstudie II* conducted by the

Deutsche Energie-Agentur GmbH (Dena).[83] In Table 5.17 the prospected installed capacities in different sea regions and their percental distribution of the *Dena Netzstudie II* is given. As can be seen, most of the new offshore installations are erected in the North Sea until 2025. This seems to be a plausible forecast. Investigating the offshore wind park projects already under construction or at least approved, it becomes obvious that most of these projects are indeed in the North Sea especially in the sea regions that will be connected to the grid at the coast of *Niedersachsen*.[84]

TABLE 5.18: INSTALLED CAPACITIES OF OFFSHORE WIND POWER PLANTS ROUNDED TO 5 MW PER NETWORK REGION FOR THE YEARS 2015, 2020 AND 2025

network region	installed capacity [MW]		
	2015	2020	2025
North Sea	**2,550**	**8,570**	**15,510**
1	960	2,750	10,535
8	1,585	5,820	4,975
Baltic Sea	**450**	**1,430**	**1,990**
4	150	500	695
5	300	930	1,295
TOTAL	**3,000**	**10,000**	**17,000**

Source: Own calculations.

As a next step, the offshore wind power parks located at the distinct sea regions need to be allocated to the network regions. This allocation is done according to the grid connection at the mainland. In the North Sea there

83 See Dena (2020), pp. 44 – 45, modified assumptions.

84 See Dena (2011) and OFW (2011). The websites www.offshore-wind.de by the Deutsche Energie Agentur (Dena) and www.ofw-online.de by the Offshore-Forum Windenergie GbR give detailed information as well as a list of offshore wind park projects.

are two possible mainland connections. One is close to the town *Norden* in *Niedersachsen* and thus in network region 8. The other one is close to the town *Büsum* in *Schleswig-Holstein* in network region 1. For the Baltic Sea the connections are close to *Rostock* in network region 4 and close to *Lubmin* in network region 5. The sea regions in Table 5.17 are assigned to the network regions accordingly (see Table 5.18).

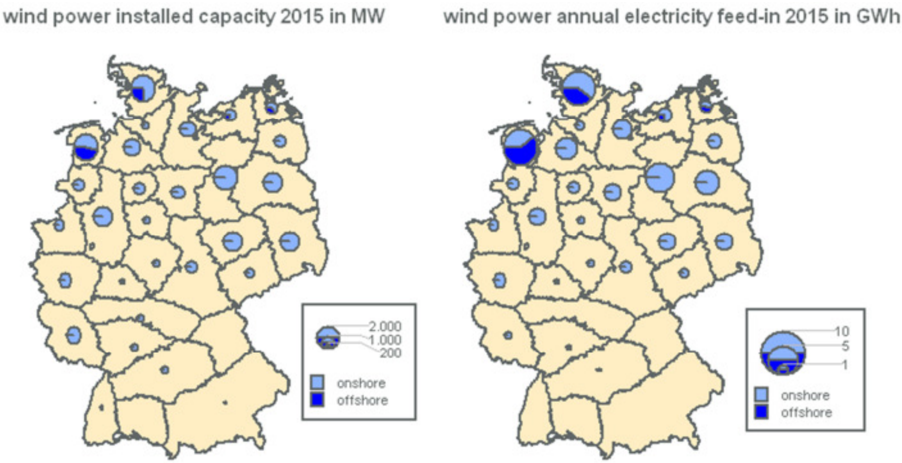


FIGURE 5.16: INSTALLED CAPACITY (LEFT) AND ANNUAL ELECTRICITY GENERATION (RIGHT) OF WIND POWER PLANTS IN GERMANY IN THE YEAR 2015

Source: Own illustration.

The percental distribution is then applied to the capacities prospected by the *BMU-Leitszenario 2010* in order to specify the installed capacities allocated to each of the mainland network regions. Hereby, the values are rounded to 5 MW to account for the typical dimensioning of offshore wind turbines. Despite the fact that there are potentially offshore wind turbines with a capacity larger than 5 MW (see Table 5.14), the investigation of the projects approved and under construction show that almost only 5 MW turbines will be constructed. Thus, it is assumed that for the time horizon 2010 until 2025 the new installed offshore wind turbines are all of category *offwindtech_1*.

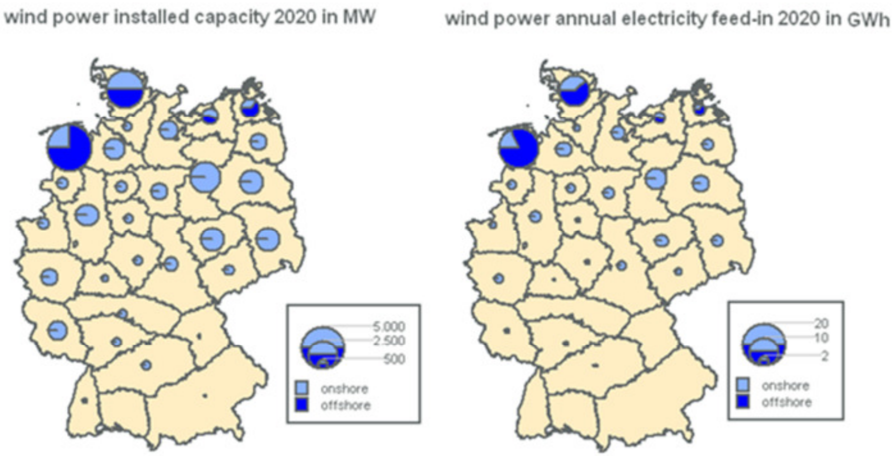


FIGURE 5.17: INSTALLED CAPACITY (LEFT) AND ANNUAL ELECTRICITY GENERATION (RIGHT) OF WIND POWER PLANTS IN GERMANY IN THE YEAR 2020
Source: Own illustration.

Combining the installed capacities of onshore and offshore wind power plants of each of the years with the hourly wind speed variation curves as outlined in 5.3.4.2 yields the wind power electricity feed-in for each region and year. In Figure 5.16, Figure 5.17 and Figure 5.18 the resulting regional installed capacities and annual electricity generation are illustrated.

In the year 2015 the installed capacity of onshore wind power is calculated to be 33.6 GW that generate about 57.1 TWh. The installed capacity of offshore plants is 3.0 GW with and electricity feed-in of 10.3 TWh. The installed capacity of wind power plants in the years 2020 rises to 35.7 GW onshore and 10.0 GW offshore with a generation of 69.1 TWh and 34.2 TWh respectively. Until 2025 the installed capacity increases to 36.8 GW onshore and 17.5 GW offshore. The electricity generation is then equal to 78.4 TWh onshore and 67.0 TWh offshore.

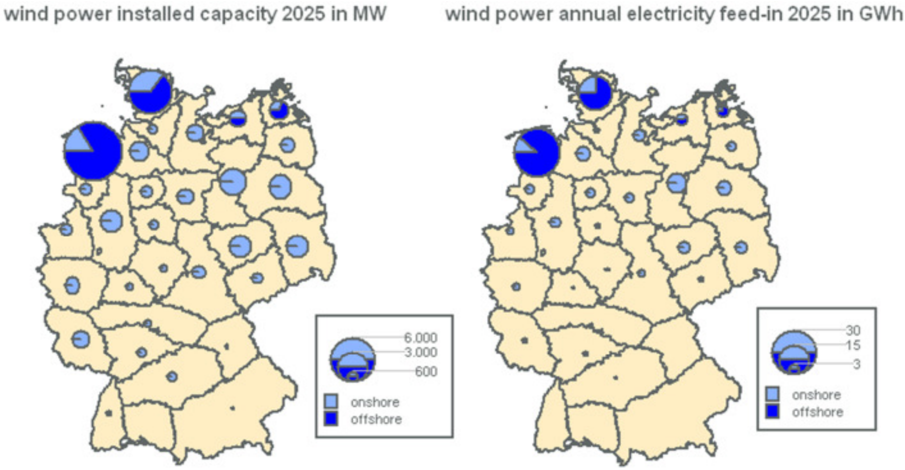


FIGURE 5.18: INSTALLED CAPACITY (LEFT) AND ANNUAL ELECTRICITY GENERATION (RIGHT) OF WIND POWER PLANTS IN GERMANY IN THE YEAR 2025

Source: Own illustration

PART III:SCENARIO ANALYSIS

6 THE DEVELOPMENT OF REDISPATCH QUANTITIES AND COSTS IN GERMANY AND ITS RELEVANT TRIGGERS

As already outlined in the introduction, redispatch costs and quantities can be expected to rise in the future. Today the costs of redispatch are still relatively moderate but already very variable. While the costs were equal to around 45 million Euros in the year 2008 they dropped to about 25 million Euros in the year 2009.[85]

Hereby, redispatch is determined by a complex interplay of different factors. The redispatch quantities are highly influenced, among other things, by the feed-in of wind power, the exact load structure and the regional distribution of conventional generation. Especially the feed-in of wind power is extremely variable and thus is not only an important driver of the magnitude but also of the annual fluctuation of redispatch quantities. However, the costs of redispatch are not only influenced by the required redispatch quantities but also by the technologies used. Due to the diversity of variable costs of different technologies, the same amount of redispatch may lead to substantially different redispatch costs. The costs are close to zero if the used technologies are similar and therefore have identical variable costs. In contrast, they are huge if the spread between the variable costs of the power plants used is very large.

In this chapter the development of redispatch costs and quantities and its relevant drivers are analyzed. For this purpose, as a first step a reference scenario is set up and the associated costs and quantities for the time horizon 2015 until 2025 are outlined (section 6.1). This scenario provides a

85 See BNetzA (2010), p. 201.

general intuition for the possible future redispatch costs and quantities. Based on the reference scenario three sensitivities are analyzed to investigate and identify relevant drivers for the redispatch costs and quantities. In each sensitivity analysis only one assumption is augmented in order to allow the attribution of the effect to the respective factor. In section 6.2 the effect of changed fuel price assumptions is examined. Hereby, both the regional distribution of installed capacities and the generation schedules are modified and the combined effect is outlined. Following this, in section 6.3 it is investigated how sensitive redispatch costs and quantities are to the magnitude of the growth of wind power capacities and the associated feed-in. The effect of a changed regional distribution of electricity demand is analyzed in section 6.4. While the sensitivity analysis concerning the fuel price assumptions and the sensitivity analysis with respect to the load structure is set-up in such a way as to expect an increase of redispatch, the sensitivity analysis concerning wind power is specified such as to attenuate redispatch quantities. Finally, in section 6.5 a conclusion about the model results concerning the general development and the decisive triggers for redispatch quantities and costs is drawn.

6.1 The Reference Scenario

The *Reference Scenario* serves as a reference case for all further investigations in this study. Hereby, the scenario relies on the assumptions given in different recently published studies and is consequently rather a mixture of assumptions than a reproduction of one individual study. While the assumptions concerning the development of fuel prices and model demand are based on the reference scenario of the study *Energieszenarien für ein Energiekonzept der Bundesregierung* on behalf of the Federal

Ministry of Economics and Technology published in August 2010,[86] the development of renewable energy sources relies on the *National Renewable Energy Action Plans* of the EU Member States (see chapter 5). Furthermore, the specification of the transmission capacities is based on information given by the European Network of Transmission System Operators for Electricity (ENTSO-E). Finally, the development of the conventional power plant fleet and the CHP capacities in Germany are determined endogenously. They are calculated by applying the assumption set of the *Reference Scenario* to the model DIME[87] of EWI.

Although the set of assumptions are specified on the supposition that the trends observable already today prevail in the future, the *Reference Scenario* should not be interpreted as a forecast of the prospective development. As there is high uncertainty regarding the development of the electricity market of today and of the future – e.g. the result of the on-going and re-launched discussion concerning the nuclear phase-out in Europe or the development of worldwide fuel prices – it seems to be impossible to specify a true forecast. Hence, the *Reference Scenario* should rather be interpreted as a possible development path that *could* materialize. As the aim of the dissertation is not to forecast the development of redispatch but to investigate and analyze the relevant drivers and their magnitude, the use of a possible development path as a reference is justified.

6.1.1 Description of the scenario assumptions

In the following the assumptions of the *Reference Scenario* are outlined. First of all, the development of demand is illustrated in section 6.1.1.1. This is followed by the description of the fuel price development in section

86 See EWI/GWS/Prognos (2010), Appendix, Table A 1-5.

87 A detailed description of this model can be found on the Institute's website.

6.1.1.2 and by an outline of the development of the conventional and CHP power plant fleet in section 6.1.1.3. Then the assumptions concerning renewable energy sources are summarized (section 6.1.1.4). Finally, the assumptions concerning the national transmission grid (section 6.1.1.5) and the international transmission capacities (section 6.1.1.6) are explained.

6.1.1.1 Electricity demand

The development of electricity demand from 2010 to 2025 is specified based on the assumptions of the reference scenario in the study *Energieszenarien für ein Energiekonzept der Bundesregierung* on behalf of the Federal Ministry of Economics and Technology published in August 2010.[88] Hereby, demand in the year 2015 and in the year 2025 is determined by interpolating the figures in EWI/GWS/Prognos (2010).

TABLE 6.1: DEVELOPMENT OF MODEL ELECTRICITY DEMAND FROM 2010 – 2025 IN THE *REFERENCE SCENARIO*

	2010	2015	2020	2025
model electricity demand (TWh)	538.9	540.2	530.1	522.6

Source: Own figures, specified on the basis of the reference scenario in EWI/GWS/Prognos (2010).

As can be seen in Table 6.1 the figures used as input to the model DIANA are different from the figures given in EWI/GWS/Prognos (2010) even for the year 2020. This is explained by the fact that model demand is not equal to net or gross electricity demand but is rather net electricity demand plus

[88] See EWI/GWS/Prognos (2010), Appendix, Table A 1-5.

network losses and traction power. Not included is the demand of pump-storage power plants as this demand is specified model-endogenously.

In general it is assumed that model demand slightly rises until the year 2015 from 538.9 TWh to 540.2 TWh. After 2015 the model demand decreases to 530.1 TWh in 2020 and to 522.6 TWh in 2025. Thus, already in the year 2020 demand is assumed to be lower than today.

6.1.1.2 Fuel prices

TABLE 6.2: DEVELOPMENT OF THE FUEL PRICES AND PRICES OF CO2-CERTIFICATES FROM 2010 UNTIL 2025 IN THE *REFERENCE SCENARIO*

year	oil [€/MWh_{th}]	gas [€/MWh_{th}]	hard coal [€/MWh_{th}]	lignite [€/MWh_{th}]	CO_2-Certificates
2010	39.00	17.00	9.60	1.43	13.00
2015	42.50	20.00	9.10	1.43	15.00
2020	47.60	23.10	10.10	1.43	20.00
2025	53.30	24.50	10.70	1.43	25.00

Source: Own figures, specified on the basis of the reference scenario in EWI/GWS/Prognos (2010).

In Table 6.2 the assumptions concerning the development of the fuel prices for the time horizon 2010 to 2025 are illustrated for the *Reference Scenario*. As holds true for model demand also the development of the fuel prices follows the assumptions of the reference scenario of the study EWI/GWS/Prognos (2010).[89] Based on the fuel prices given in the study of the Ministry, interpolation yields the fuel prices in real terms in €/MWh_{th} given in the table above.

[89] See EWI/GWS/Prognos (2010), p. 30.

6.1.1.3 Conventional and CHP power plant fleet

Based on the power plant fleet in Germany as outlined in chapter 5, the development of the installed capacities of the conventional and CHP power plants is forecasted as follows.

First, the time of decommissioning of each existing plant is specified based on the date of commissioning, the technology type and eventually the date of retrofit. Hereby, each technology class has its individual average lifetime. The average lifetime is combined with the individual date of commissioning to specify an individual probable date of decommissioning. Retrofit measures entail a prolongation of the lifetime.

In addition to the decommissioning of plants, the commissioning of new installations is determined in accordance to the development of fuel prices – i.e. the profitability of the power plants in the future – as well as the actual projects for new installations:

By use of EWI's investment model DIME[90] the total installed capacities (and thereby decommissioning and commissioning of new plants) of each technology in Germany are specified for the three modeled years. For this purpose the same assumptions as used for the *Reference Scenario* in this dissertation are implemented in the investment model. Thus, the general trend for new installations is calculated based on results of EWI's investment model DIME.

The allocation of the total new commissioned capacities to the network regions is then performed by aligning the capacities with the geographic location of existing projects for new generation plants. In that way increases of capacities of a specific technology only occur in network regions in which already today a project for a new plant is located.

[90] A description of the model DIME can be found in the Institute's website.

As a result, the following development of the conventional power plant fleet is assumed in the *Reference Scenario* (see Table 6.3): Concerning nuclear power plants, the nuclear phase-out recently declared by the German government is presumed.[91] Consequently, the installed capacity of nuclear power plants decreases to 12.1 GW in the year 2015 and then further to 8.1 GW in the year 2020. In the year 2025 there are no nuclear power plants in operation anymore.

TABLE 6.3: INSTALLED CAPACITY OF CONVENTIONAL AND CHP PLANTS IN GERMANY IN THE FROM 2010 – 2025 IN THE *REFERENCE SCENARIO*

	installed capacity [MW]			
	2010	2015	2020	2025
nuclear	20,475	12,053	8,102	0
coal	19,799	27,084	29,070	24,280
lignite	20,363	18,951	17,493	15,164
gas	16,112	20,772	18,447	17,599
oil	1,183	0	0	0
pump-storage	7,435	7,435	9,435	9,435
CHP	21,182	19,279	19,279	19,279
TOTAL	**106,550**	**105,574**	**101,826**	**85,757**

Source: Own calculations.

The installed capacities of coal-fired plants in contrast initially increase to 27.1 GW in the year 2015 and to 29.1 GW in the year 2020 until they drop to 24.3 GW in the year 2025. The installed capacities of lignite power plants slightly decrease during the relevant time period. In the year 2015 they are equal to 19.0 GW, equal to 17.5 GW in the year 2020 and equal to 15.2 GW in

[91] See German Bundestag (2011a) for the draft of the amendment of the Atomic Energy Law. This yields an exact outline of the nuclear phase out in Germany. German Bundestag (2011b) shows that this draft was finally adopted by the German Bundestag.

the year 2025. The same holds true for gas-fired plants.[92] The installed capacity decreases from 20.8 GW in 2015, to 18.5 GW in the year 2020 and finally to 17.6 GW in the year 2025. The installed capacities of pump-storage plants increase from 7.4 GW in the year 2015 to 9.4 GW in the year 2020 and then remain constant. The capacities of CHP plants are assumed to be constant for the whole time period. In sum, the installed capacities of conventional power plants decrease from 86.3 GW in the year 2015 to 82.5 GW in the year 2020 and then further drop to 66.5 GW in 2025. An illustration of the regional distribution of the installed capacities of the conventional and CHP power plants in the years 2015, 2020 and 2025 can be found in the appendix.

6.1.1.4 Renewable energy sources

For the EU-Member States the assumptions with respect to the installed capacity and annual electricity feed-in of renewable energy sources are based on the specifications outlined in the respective *National Renewable Energy Action Plan*. For specifying the year 2025 the figures of the year 2020 are extrapolated. Installed capacity and electricity feed-in of renewable energy sources in Switzerland are based on internal information of EWI.

Table 6.4 summarizes the installed capacities and electricity feed-in in Germany for the relevant time horizon. The exact determination of the figures is outlined in chapter 5.

[92] The category "gas-fired plants" consists of open cycle gas turbines (OCGT) and combined cycle gas turbines (CCGT).

TABLE 6.4: INSTALLED CAPACITY AND ELECTRICITY FEED-IN OF RENEWABLE ENERGY SOURCES IN GERMANY FROM 2010 – 2025 IN THE *REFERENCE SCENARIO*

technology	2010		2015		2020		2025	
	installed capacity (MW)	feed-in (GWh)	installed capacity (MW)	feed-in (GWh)	installed capacity (MW)	feed-in (GWh)	installed capacity (MW)	feed-in (GWh)
hydro[1)]	3,711	19,782	4,166	19,697	4,309	20,701	4,586	22,046
wind onshore	26,541	41,581	33,647	57,090	35,750	69,119	36,796	78,442
wind offshore	60	211	3,000	10,257	10,000	34,234	17,500	66,953
biomass[2)]	5,029	26,435	7,721	41,946	8,825	49,567	9,400	53,763
photovoltaic	15,697	9,529	34,279	26,579	51,753	42,048	57,377	51,273
TOTAL	**51,038**	**97,538**	**82,813**	**155,568**	**110,637**	**215,663**	**125,659**	**272,478**

1) Excluding pump-storage plants.

2) Including landfill gas, sewage gas and mine gas.

Source: Own calculations based on NREAP-DE (2010) and BMU (2010).

6.1.1.5 National transmission grid

The specification of the national transmission grid that is used for the determination of the PTDF matrixes is entirely conducted by the ie[3]. Nevertheless, for the sake of completeness, the respective parameterization is briefly outlined in the following. The matrixes used within this dissertation can be found in the appendix.

The basic grid model calibrated to represent the German transmission network as installed in the year 2008 is expanded to represent the basic state of the network in the years 2015, 2020 and 2025. For this purpose the retrofitting of 220 kV to 380 kV systems as well as the mid-term and long-term network extensions as identified by the European Network of

Transmission System Operators for Electricity (ENTSO-E) in their pilot-project *Ten-Year Network Development Plan* (TYNDP) are integrated.[93]

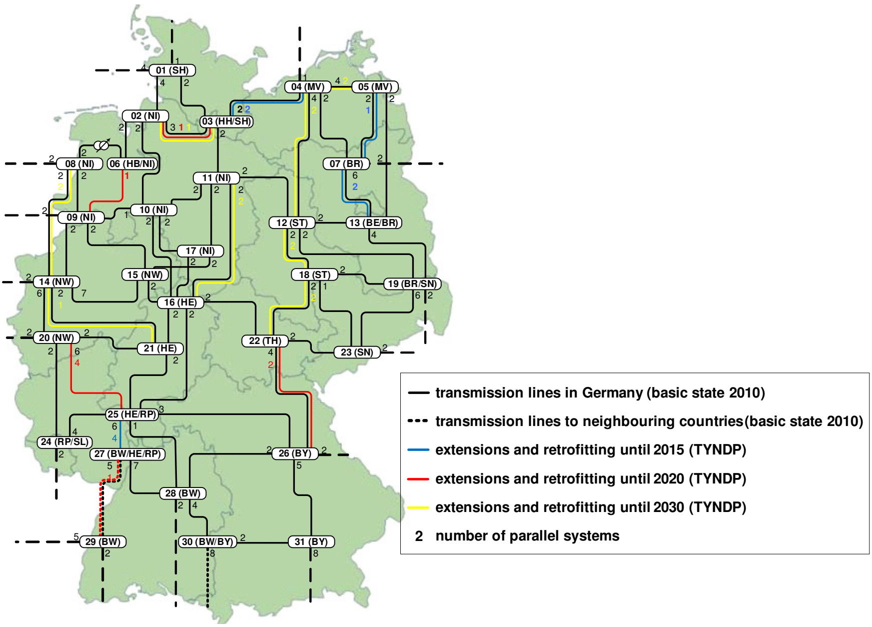


FIGURE 6.1: SIMPLIFIED NETWORK MODEL OF THE GERMAN TRANSMISSION GRID IN THE YEAR 2008 AND NETWORK EXTENSIONS IN THE *REFERENCE SCENARIO* UNTIL 2025

Source: ie3.

In Figure 6.1 the simplified network model in the year 2008 as well as the assumed network extensions until the year 2025 are illustrated. Hereby, network extensions until the year 2015 are indicated by a blue line, further

93 It has to be kept in mind that many of the transmission network extensions identified by the European Commission in their guidelines for TEN-Energy as Projects of Common Interest (see Decision No 1364/2006/EC) are delayed by now as outlined in MVV Consulting (2007). Thus, it is disputable whether or not the prospective extensions prescribed by the TYNDP will be realized on time.

extensions until the year 2020 by a red line and further extensions until the year 2025 by a yellow line. Additionally, the respective number of parallel systems is plotted.

The transmission capacity of each of the lines is equal to 1,777 MW for 380 kV and 286 MW for 220 kV lines. Hereby, it is assumed that only 90 % of the transmission capacity is “useable” and that redispatch is initiated in case more than 90 % of a line is utilized. Consequently, a 10 % safety margin is assumed to guarantee the well-functioning of the system to a certain safety degree.

6.1.1.6 International transmission capacity

The specification of PTDF matrixes allows a flow-based illustration of electricity transmission in the European meshed network. Nevertheless, trade between the individual European markets is restricted by fix transmission capacities expressed as NTC-values. Thus, assumptions concerning these values have to be specified as explained subsequently.

The transmission capacity values between the different countries are based on the publicly available data of the European Network of Transmission System Operators for Electricity (ENTSO-E). The ENTSO-E continuously publishes indicative values for net transfer capacities for continental Europe for the summer and winter season. The respective NTC values for summer 2010 and winter 2010/2011 are the starting point in this study and fixed for the year 2010.[94] The respective values for Germany are illustrated in Table 6.5.

For the years 2015, 2020 and 2025 the NTC values of the year 2010 are increased in case there is information on planned interconnector capacity

[94] See ENTSO-E (2010) and ENTSO-E (2011).

additions available that can be translated into NTCs. This information generally stems from the system adequacy forecast of the ENTSO-E or its predecessor associations.

TABLE 6.5: NET TRANSFER CAPACITY VALUES BETWEEN GERMANY AND THE NEIGHBOURING COUNTRIES IN THE YEAR 2010 IN *THE REFERENCE SCENARIO*

connection	summer		winter	
	export (MW)	import (MW)	export (MW)	import (MW)
DE – FR	3,200	2,600	3,200	2,700
DE – NL	4,000	3,900	3,850	3,000
DE – DKw	950	1,500	950	1,500
DE – DKe	550	550	600	585
DE – SE	600	600	600	610
DE – CH	2,060	4,400	1,500	3,500
DE – AT	1,600	1,600	2,200	2,000
DE – PL	800	1,200	1,200	1,100
DE – CZ	800	2,100	800	2,300

Source: ENTSO-E (2010) and ENTSO-E (2011).

6.1.2 Power plant dispatch

The electricity flows through the German transmission network depend on the net export/import balance of each region as these multiplied with the respective PTDF factors specify the flows. Hereby, it does not matter how the net export/import balance is set up – i.e. by low (or high) demand, by low (or high) conventional generation, by low (or high) feed-of renewable energies or a combination of these. For this reason, the detailed characterization of the results of the first-optimization stage in the model DIANA for each of the scenarios and model years – i.e. the power plant dispatch – rather focuses on the regional net export/import balance than on the exact feed-in schedules of conventional plants by fuel-type, the feed-in of renewables or the demand schedules. The latter are only briefly outlined on an annual basis.

TABLE 6.6: ANNUAL ELECTRICITY GENERATION, LOAD AND EXPORT/IMPORTS IN TWH FOR THE YEARS 2015, 2020 AND 2025 IN THE *REFERENCE SCENARIO*

	2015	2020	2025
nuclear	90.0	60.5	0
coal	117.0	119.9	116.6
lignite	141.0	128.0	110.2
gas	52.2	31.7	45.2
pump-storage (+)	8.2	10.2	14.4
pump-storage (-)	-10.8	-12.9	-18.8
renewable energies	155.6	215.7	272.5
CHP	74.8	74.8	74.8
exports/imports	-87.6	-97.6	-92.3
load	540.2	530.1	522.6

Source: Own figures.

Table 6.6 summarizes the results of the power plant dispatch optimization of the *Reference Scenario.* Hereby, the annual conventional electricity generation by fuel-type, the annual feed-in of renewable energies and CHP,[95] the annual demand and the annual net export/import balance of each of the modeled years is outlined. In the year 2015 total conventional electricity generation is equal to 400.0 TWh, the generation of renewable

[95] The category CHP hereby only incorporates the electricity generation of the plants specified as „heat-driven". The generation of the plants categorized as "power-driven" is included in the figures of the conventional generation diversified with respect to fuel.

energy sources equals 155.6 TWh and the generation of heat-operated CHP plants is equal to 74.8 TWh. Pump-storage plants generate 8.2 TWh but consume 10.8 TWh, thus their net balance equals -2.6 TWh. In combination with an electricity demand of 540.2 TWh, net exports amount to 87.6 TWh.

In the year 2020 annual conventional electricity generation drops to 340.0 TWh, while the generation of renewable energy sources increases to 215.7 TWh. Pump-storage plants generate 10.2 TWh and consume 12.9 TWh yielding a net electricity demand of 2.7 TWh. Subtracting the annual electricity demand of 530.1 TWh leaves net exports equal to 97.6 TWh.

In the year 2025 conventional electricity generation decreases further to 272.0 TWh, while renewable generation increases to 272.5 TWh. Pump-storage plants generate 14.4 TWh but consume 18.8 TWh and thus have a net balance of -4.4 TWh. In combination with an annual electricity demand of 522.6 TWh, the net exports slightly decrease to 92.3 TWh.

Figure 6.2, Figure 6.3 and Figure 6.4 illustrate the regional net export/import balance in the *Reference Scenario* for the years 2015, 2020 and 2025 respectively. A negative value indicates net exports while a positive value represents net imports. All the dispatch results that are illustrated for the *Reference Scenario* and the three other scenarios are also listed in tabular form the appendix.

In the left graphs the weighted average net export/import balance per quarter are shown. As can be seen, the northern regions are predominantly net exporters while the southern regions are predominantly net importers. Furthermore, especially in the northern regions the net export/import balance strongly varies with the quarter of the year. This can be explained by the fact that the electricity feed-in in the North of Germany is dominated by the feed-in of wind power plants. As the wind speeds and thus the electricity generation of wind power plants is generally higher in the winter and autumn months compared to the summer and spring months, the net exports increase during the first and fourth quarter of the year. While this effect is only moderate in the year 2015, it gains weight in the year 2020 and further in the year 2025 as the installed capacity of wind power plants especially in the North increases.

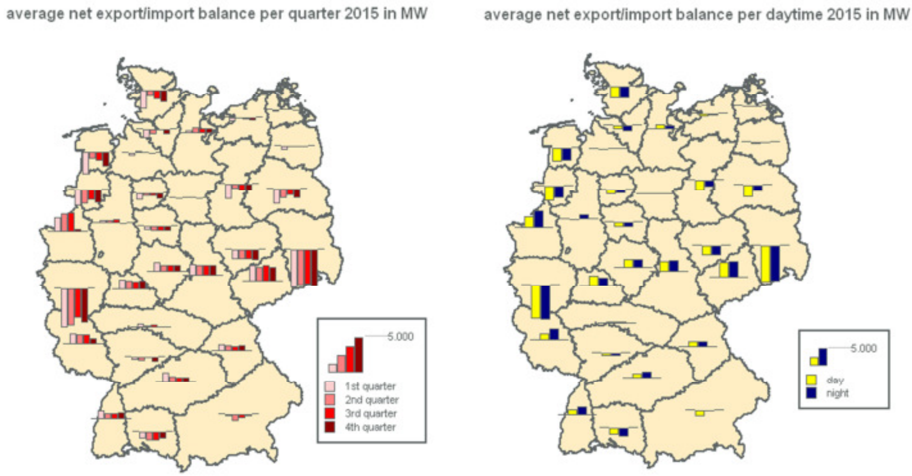


FIGURE 6.2: WEIGHTED AVERAGE NET EXPORT/IMPORT BALANCE PER QUARTER (LEFT) AND PER DAYTIME (RIGHT) IN GERMANY IN THE YEAR 2015 IN THE *REFERENCE SCENARIO*

Source: Own illustration.

The southern regions in contrast display a lower net import or a stronger net export during the second and third quarter. Because the installed capacities of photovoltaic are relatively high in these regions electricity generation is higher in summer and spring compared to autumn and winter. This trend further aggravates from 2015 to 2025, which is in line with the increase of installed capacities.

The regions that contain large installed capacities of base load – especially the lignite mining districts in *Nordrhein-Westfalen* and East Germany – display a rather constant export/import balance in the course of the year as base load capacities generate constantly throughout the year rather independently of the weather conditions.

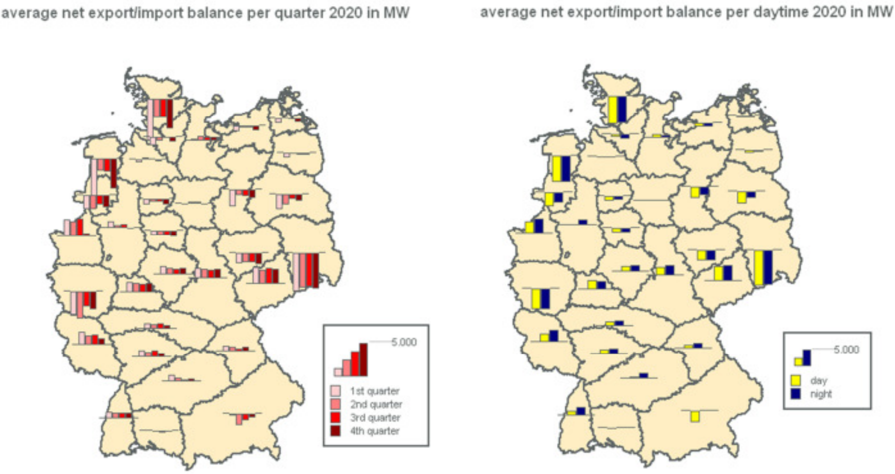


FIGURE 6.3: WEIGHTED AVERAGE NET EXPORT/IMPORT BALANCE PER QUARTER (LEFT) AND PER DAYTIME (RIGHT) IN GERMANY IN THE YEAR 2020 IN THE *REFERENCE SCENARIO*

Source: Own illustration.

In the right graphs of the figures the weighted average net export/import balances per daytime are illustrated. While the export/import balances of the northern regions in Germany are rather constant independently of the daytime, the export/import balances of the southern regions strongly vary between night and day. These regions import less or even export during the day, while they import more or have a balance close to zero at night. This can be explained by the already mentioned high installed capacities of photovoltaic plants in the southern regions. The feed-in of photovoltaic is positive during the day and highest around noon while it is equal to zero during the night. Consequently, there are fewer imports during the day hours than during the night hours. This holds true even though the lower electricity demand at night partially outweighs this effect. With increasing capacities of photovoltaic this trend further increases from 2015 to 2025.

A similar effect can be observed for regions in East and Central Germany which have a high share of (heat-driven) CHP plants and/or mid-load and peak capacities. These plants predominantly operate and thus generate electricity at daytime.

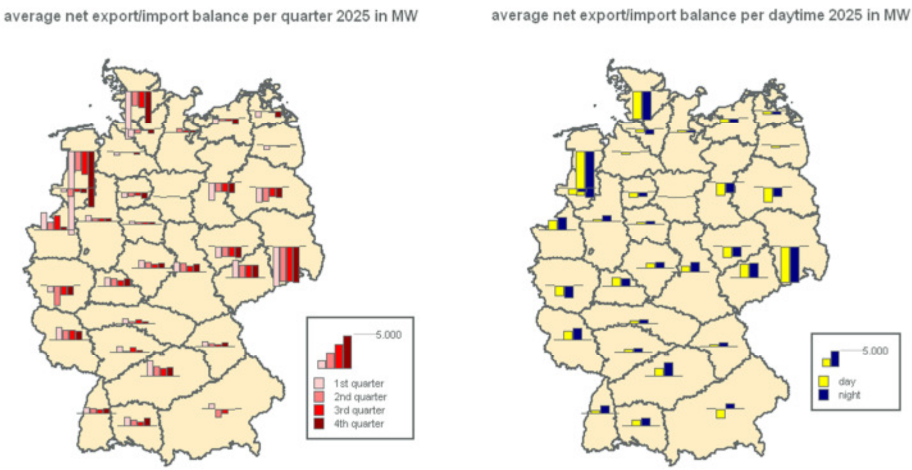


FIGURE 6.4: WEIGHTED AVERAGE NET EXPORT/IMPORT BALANCE PER QUARTER (LEFT) AND PER DAYTIME (RIGHT) IN GERMANY IN THE YEAR 2025 IN THE *REFERENCE SCENARIO*

Source: Own illustration.

In contrast to this, the weighted average export/import balance of the regions with a high share of wind power plants and/or base-load capacities is rather independent of the daytime and thus equal for day and night. As there is no systematic difference between the wind speeds during day and during night, no systematically lower or higher electricity feed-in can be observed. Similarly, base-load capacities generate irrespective of the daytime. Despite the fact that demand is higher at day than at night, there is no observable difference between the day and night export/import balances because the demand effect is not strong enough.

6.1.3 Development of redispatch quantities and costs

In the following, a general overview of the model results for the *Reference Scenario* is given in section 6.1.3.1. Subsequently, selected results are illustrated and explained. These are the line utilization and magnitude and frequency of congestion (section 6.1.3.2), as well as detailed results concerning the upward and downward redispatch quantities (section 6.1.3.3). The illustrated results of the *Reference Scenario* and the other scenarios can be found in the appendix in tabular form.

6.1.3.1 Overview of model results

In Table 6.7 an overview of the aggregated model results for the years 2015, 2020 and 2025 in the *Reference Scenario* are given. As expected, redispatch quantities and costs increase in the course of time despite the assumed investments into the transmission infrastructure. Maximum and average congestion per hour increases from 364 MW and 120 MW in the year 2015 to 1,331 MW and 252 MW in the year 2025. The same holds true for the frequency of congestion. While in the year 2015 congestion occurs in only 8.6 % of the hours, in the year 2020 already in 29.3 % of the hours one or more transmission lines are congested. The frequency increases further so that in the year 2025 in almost half of the hours (47.5 %) congestion occurs.

TABLE 6.7: OVERVIEW OF COSTS AND QUANTITIES OF REDISPATCH AND FREQUENCY AND MAGNITUDE OF NETWORK CONGESTION 2010 – 2025 IN THE *REFERENCE SCENARIO*

	2015	2020	2025
maximum congestion (MW)	364.3	1,093.7	1,331.0
maximum redispatch (MW)	2,542.9	4,137.9	9,791.9
average congestion (MW)	120.4	178.7	252.1
average redispatch (MW)	890.8	1,360.5	3,193.1
frequency of congestion (% of h)	8.6	29.3	47.5
redispatch quantities (GWh/a)	608.3	2,222.0	14,038.6
redispatch costs (Mio. €/a)	35.5	152.2	1,232.2

Source: Own illustration.

As congestion increases so does redispatch. While in the year 2015 the maximum redispatch is equal to about 2.5 GW, it rises to 9.8 GW in the year 2025. Average redispatch increases from 891 MW in 2015 to 3,193 MW in the year 2025. In total about 608 GWh are redispatched in the year 2015, about 2,222 GWh in the year 2020 and about 14,037 GWh in the year 2025.[96] Consequently, redispatch more than doubles in the course of ten years.

The costs of redispatch increase even stronger by a factor of about 35. While the costs are roughly 35.5 million Euros in the year 2015, they increase to 152.2 million Euros in the year 2020 and to 1,232.2 million Euros in the year 2020. However, as outlined in chapter 4, the cost figures

96 The impact of redispatching is determined by the respective PTDF factor rather than being a 100 percent effect. Consequently, more redispatch (in MW) than congestion (in MW) is needed to resolve congestion.

have to be analyzed with caution due to the limitations of the model approach. Furthermore, it has to be kept in mind that a higher level but constant relation of fuel prices could lead to exactly the same power plant dispatch and thus to an identical network and redispatch situation, but to much higher costs of redispatch. In addition, the use of dummy redispatch biases the results.[97] Dummy redispatch is valued by a ten percent markup on the most expensive technology used for upward redispatch. This markup however, is a convention rather than being a cost specified by fundamental factors. Consequently, in case dummy redispatch is used, the cost figures are arbitrary to a certain degree. Nevertheless, the cost figures are still valid for observing a general increasing trend of redispatch costs.

6.1.3.2 Line utilization, frequency and magnitude of congestion

In the left graph of Figure 6.5, Figure 6.6 and Figure 6.7 the weighted average line utilization in the *Reference Scenario* for the modeled years 2015, 2020 and 2025 is illustrated. The line utilization results from the export/import balance of the individual regions and the thereby induced physical flows (see section 6.1.2). Hereby, the line utilization is specified as the physical flow through the line divided by the transmission line capacity.[98] The color of the lines indicates the utilization rate: the green colored lines have very low, the red and orange colored lines very high utilization rates.

As can be seen, the average utilization of the transmission lines increases over time, predominantly in north-south direction. While in the year 2015

[97] See section 4.4.3.1 for a description of possible interpretations of dummy redispatch.

[98] The capacity of the transmission line used is the "usable" capacity that is relevant for redispatch (see section 6.1.1.5). Thus, it is equal to 90 % of the installed capacity.

the average line utilization is below 40 % for most of the transmission lines, it strongly increases for the years 2020 and 2025. Especially the lines that link North and South in the center of Germany as well as the lines at the very West of Germany display average line utilizations of between 40 % and 60 %. Furthermore, some transmission lines are utilized even above 60 %. As could be expected, these are the lines that connect the regions with high feed-in of (onshore and offshore) wind power. Nevertheless, transmission lines at the center of Germany are highly utilized, too.

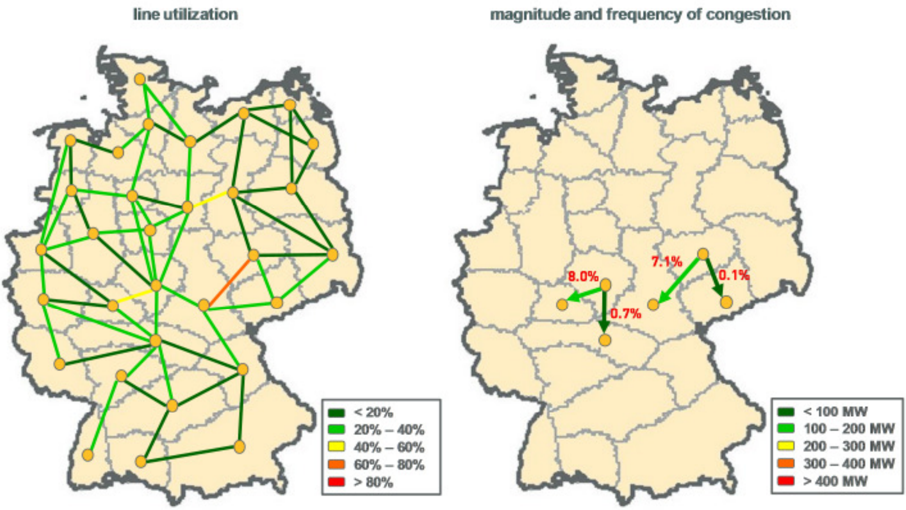


FIGURE 6.5: WEIGHTED AVERAGE LINE UTILIZATION (LEFT) AND FREQUENCY AND MAGNITUDE OF CONGESTION (RIGHT) IN GERMANY IN THE YEAR 2015 IN THE *REFERENCE SCENARIO*

Source: Own illustration.

In addition, the magnitude and frequency of congestion is displayed in the right graphs of the figures. The presence of an arrow indicates the occurrence of congestion at the respective transmission line while the orientation of the arrow shows in which direction the line is congested. Furthermore, the color of the arrow shows the weighted average magnitude of congestion – i.e. the average MW by which the transmission capacity is exceeded by the physical flow resulting from the wholesale market outcome. Finally, the percentage figure next to each of the arrows represents the frequency of congestion as it states the share of hours in which congestion occurs.

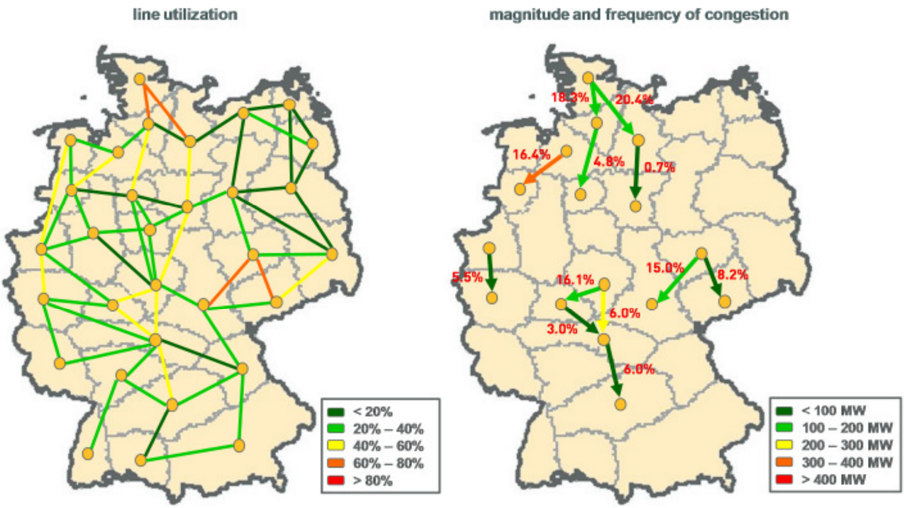


FIGURE 6.6: WEIGHTED AVERAGE LINE UTILIZATION (LEFT) AND FREQUENCY AND MAGNITUDE OF CONGESTION (RIGHT) IN GERMANY IN THE YEAR 2020 IN THE *REFERENCE SCENARIO*

Source: Own illustration.

As holds true for the line utilization, also the magnitude and frequency of congestion increases over time. In the year 2015 there is very infrequent and only modest congestion which occurs on only four lines at the center of Germany. In contrast, in the year 2020 already a larger number of transmission lines face congestion. Thereby, congestion occurs still at the center of Germany but more and more also along the transmission lines in north-south direction from the coast to the load centers in the South and West of Germany. Especially in the North the frequency of congestion is high and the transmission capacity is exceeded in about 20 % of the hours. This can be explained by the high electricity generation of wind power that is fed into the system irrespective of the market outcome. As a consequence, in many hours there are large net export balances in these regions that induce network congestion.

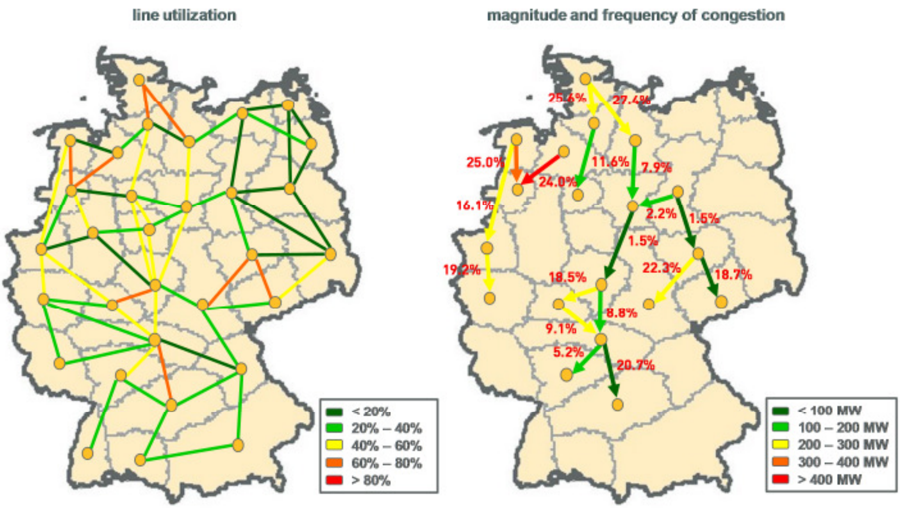


FIGURE 6.7: WEIGHTED AVERAGE LINE UTILIZATION (LEFT) AND FREQUENCY AND MAGNITUDE OF CONGESTION (RIGHT) IN GERMANY IN THE YEAR 2025 IN THE *REFERENCE SCENARIO*

Source: Own illustration.

However, the magnitude of congestion is still relatively moderate in the year 2020 as the excess of physical flow is on average below 200 MW on most lines. In the year 2025 even more lines in the north-south direction are congested and the magnitude and frequency of congestion in general increases further. The transmission line with the highest congestion is hereby the line between region 6 and region 9 in the North-West of Germany which on average faces congestion above 400 MW. The line which is most often congested in turn is the line between region 1 and region 3 and is congested in about 27 % of the hours.

6.1.3.3 Upward and downward redispatch

In case a transmission line is congested, redispatch is initiated to guarantee that the physical limits of the lines are respected. In order to obtain an understanding of how redispatch is functioning in the model, an exemplary situation – i.e. hour 10 in the year 2020 (10h, Saturday, 1st quarter) is depicted in Figure 6.8. In the right graph of the figure the location and magnitude of congestion is illustrated. As can be seen, there are three lines that are congested simultaneously. These are the transmission line from region 1 to region 2, the line from region 1 to region 3 and the line from region 6 to region 9. In sum over all three lines the physical flow excess over the transmission capacity is roughly equal to 1,022 MW.

In the left graph of the figure the resulting redispatch is depicted. As can be seen, coal-based power plants in region 14 and region 9 – thus south of the congestion – are redispatched up, while coal-based generation in region 1 and wind power in region 6 – thus north of the congestion – is redispatched down. Total redispatch amounts to 1,767 MW.

Which technologies are used for upward and downward redispatch hereby depends (despite the network load situation) on an interplay between the variable costa and ramp-up costs of the individual plants on the one hand and on the effectiveness of the plants to resolve the respective congestion on the other hand. The effectiveness in turn is specified by the PTDF factor (which is between 0 and 1) rather than being 100 %. As a result, it might be cost-efficient if upward redispatch is provided by a plant with higher costs but higher effectiveness: the required redispatch (in MW) might be lower than in case redispatch would be provided by a plant with lower costs but also lower effectiveness. The specification of the effectiveness by use of PTDF factors is moreover the reason for total redispatch being higher than total congestion.

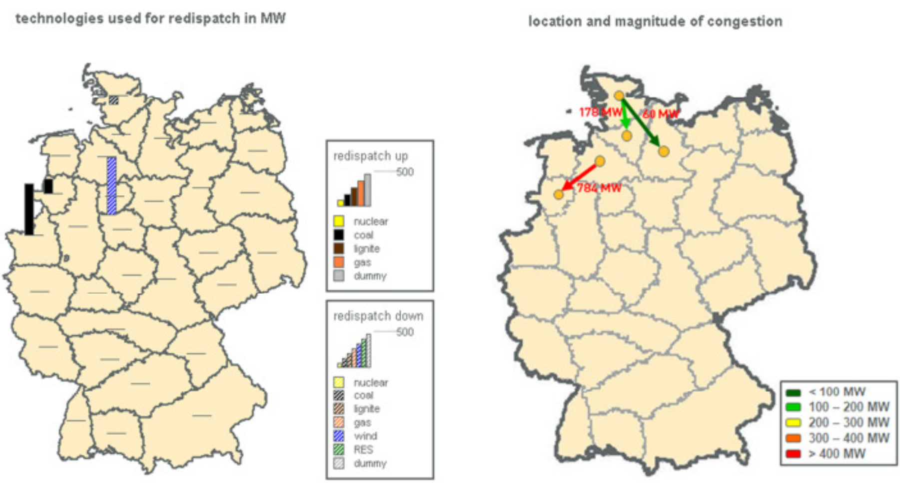


FIGURE 6.8: UPWARD AND DOWNWARD REDISPATCH PER TECHNOLOGY (LEFT) AND CONGESTION (RIGHT) AT HOUR 10 IN THE YEAR 2020 IN THE *REFERENCE SCENARIO*

Source: Own illustration.

In the left graphs of Figure 6.9, Figure 6.10 and Figure 6.11 the weighted average upward and downward redispatch per quarter in the years 2015, 2020 and 2025 in the *Reference Scenario* are illustrated. The weighted average redispatch is hereby the average magnitude in MW in case redispatch is initiated. As can be seen, the use of redispatch highly varies between the different quarters. In section 6.1.2 it is outlined that quarterly export/import balances are most pronounced in winter and autumn. Consequently, congestion does occur and thus redispatch is used predominantly during the first and fourth quarter as well. Furthermore, the figures illustrate that the average redispatch increases in the course of time in line with increasing export/import balances, line utilization and thus transmission of electricity from North to South.

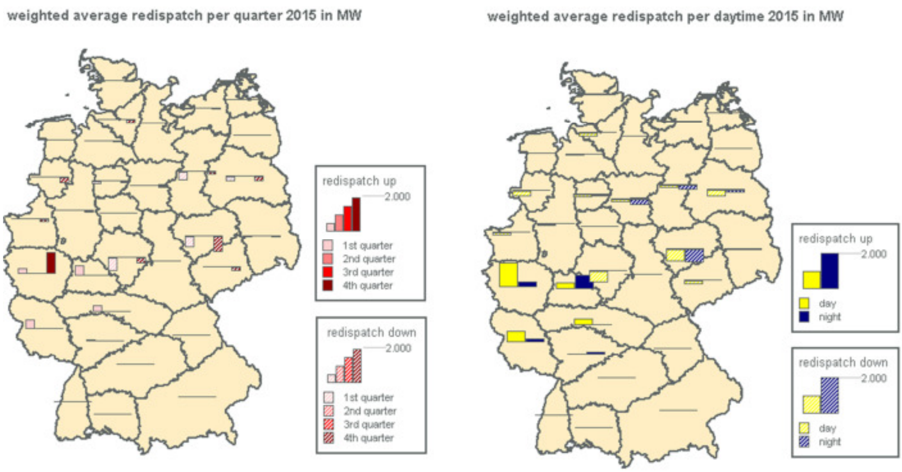


FIGURE 6.9: WEIGHTED AVERAGE UPWARD AND DOWNWARD REDISPATCH PER QUARTER (LEFT) AND PER DAYTIME (RIGHT) IN GERMANY IN THE YEAR 2015 IN THE *REFERENCE SCENARIO*

Source: Own illustration.

In the right graphs of the figures the average redispatch per daytime is illustrated. As can be seen, there is no systematic difference between day and night. While electricity demand and spot market generation systematically and strongly differ between day and night, the feed-in of wind power plants does not. Consequently, as congestion and thus redispatch can be observed at a rather constant height irrespective of the daytime, it can be concluded that the feed-in of wind power in the North of Germany is a main trigger for congestion.

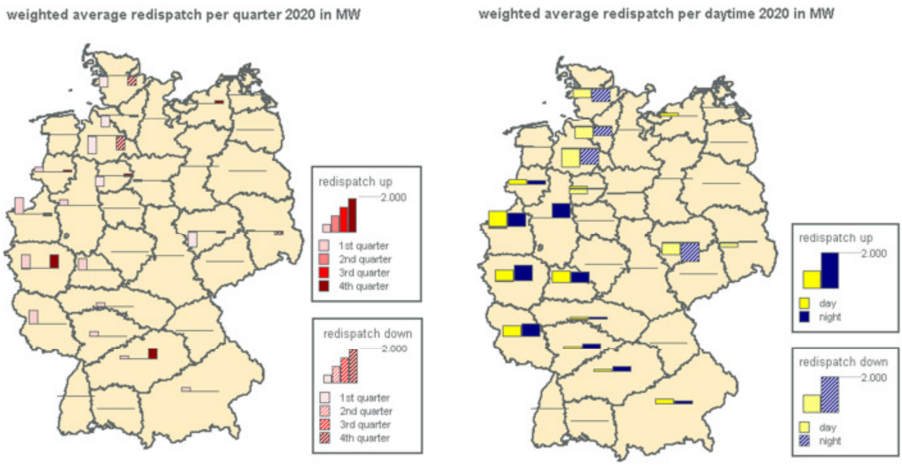


FIGURE 6.10: WEIGHTED AVERAGE UPWARD AND DOWNWARD REDISPATCH PER QUARTER (LEFT) AND PER DAYTIME (RIGHT) IN GERMANY IN THE YEAR 2020 IN THE *REFERENCE SCENARIO*

Source: Own illustration.

Nevertheless, upward and downward redispatch does differ between day and night for some regions. This can be explained by the fact that for upward redispatch only generation plants not operating at the wholesale market can be used, while downward redispatch can only be supplied by power plants operating. Therefore, a region dominated by base-load generation has a very different redispatch supply function over time than a region with mainly peak-load generation. As a result, the regional upward and downward redispatch schedules are not only dependent on the respective installed capacities, but also dependent on the wholesale market outcome and thus dependent on time.

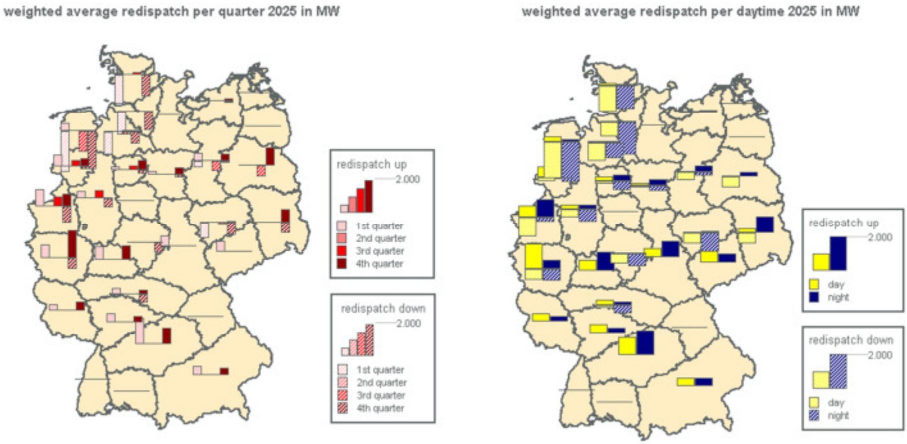


FIGURE 6.11: WEIGHTED AVERAGE UPWARD AND DOWNWARD REDISPATCH PER QUARTER (LEFT) AND PER DAYTIME (RIGHT) IN GERMANY IN THE YEAR 2025 IN THE *REFERENCE SCENARIO*

Source: Own illustration.

Furthermore, upward redispatch is mainly applied in West, the South-West and South Germany. These are the regions which are in the constrained off area of Germany *and* still have generation capacities not operating at the wholesale market. The respective generation technologies are predominantly old coal-based and gas-fired generation units, as can be seen in Figure 6.12, Figure 6.13 and Figure 6.14. In these figures the technology specific total annual amount of upward and downward redispatch in GWh for each of the network regions is illustrated for the years 2015, 2020 and 2025.

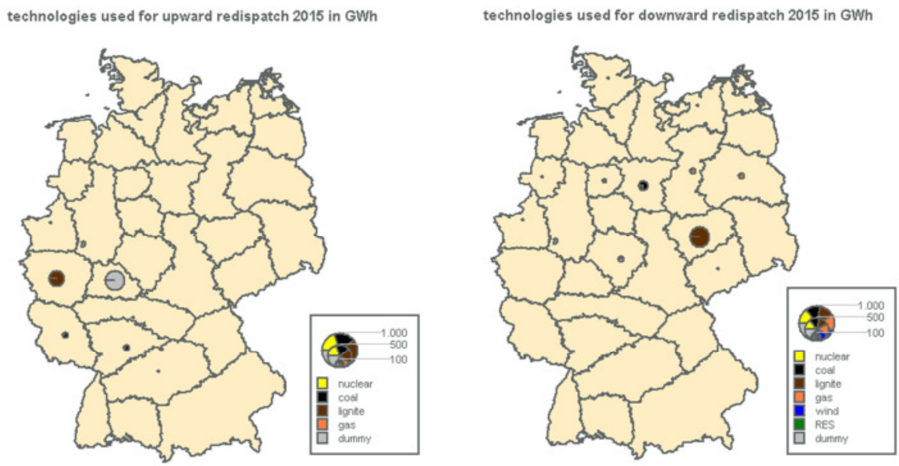


FIGURE 6.12: TECHNOLOGY-SPECIFIC UPWARD (LEFT) AND DOWNWARD REDISPATCH (RIGHT) IN GERMANY IN THE YEAR 2015 IN THE *REFERENCE SCENARIO*

Source: Own illustration.

In contrast, downward redispatch either occurs in the lignite-dominated regions in East Germany or in the regions at the coast with high installed capacities and feed-in of wind power plants. As can be seen in Figure 6.12, Figure 6.13 and Figure 6.14, an increasing amount of lignite-based generation is redispatched down in East Germany. Furthermore, at the coast predominantly coal-based generation and wind power is used for downward redispatch.

With respect to renewable energies the results show that, especially in the year 2025, wind power cannot be entirely integrated into the electricity system anymore but is partly shut down due to network congestion. In total in the year 2015 about 6 GWh, in the year 2020 about 692 GWh and in the year 2025 roughly 5,639 GWh of wind power generation cannot be integrated into the system but is rather redispatched down. For the other renewable energies the respective figures are 14 GWh, < 1 GWh and 27 GWh.

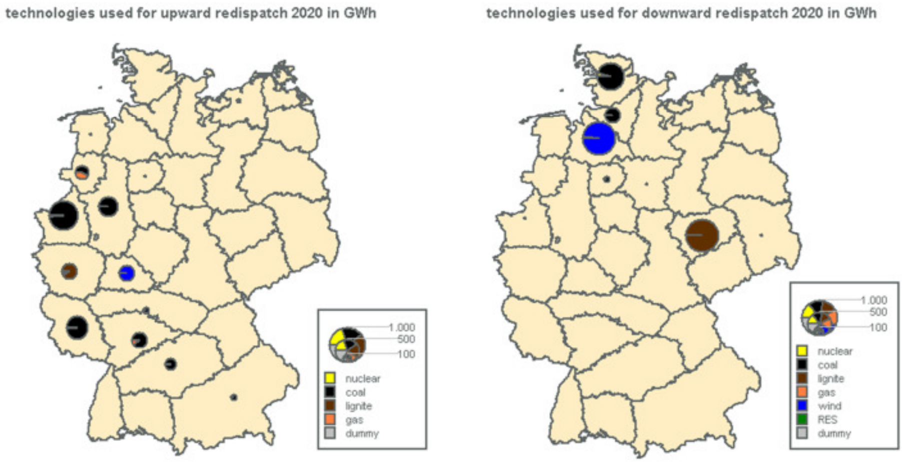


FIGURE 6.13: TECHNOLOGY-SPECIFIC UPWARD (LEFT) AND DOWNWARD REDISPATCH (RIGHT) IN GERMANY IN THE YEAR 2020 IN THE *REFERENCE SCENARIO*

Source: Own illustration.

The redispatched down wind generation (and other renewable generation) is substituted by carbon-intensive conventional generation that is used for upward redispatch. Therefore, a further increase of installed capacities of wind power plants does not automatically implicate a less carbon-intensive electricity generation. Only if the capacities are located "at the right place" the renewable generation can be integrated into the system from a transmission network perspective. Such transmission system integration in turn is a prerequisite for conventional generation actually being replaced by renewable energies. Otherwise, conventional generation becomes obsolete at the spot market but is still needed for redispatching and thus the stability of the transmission system.[99]

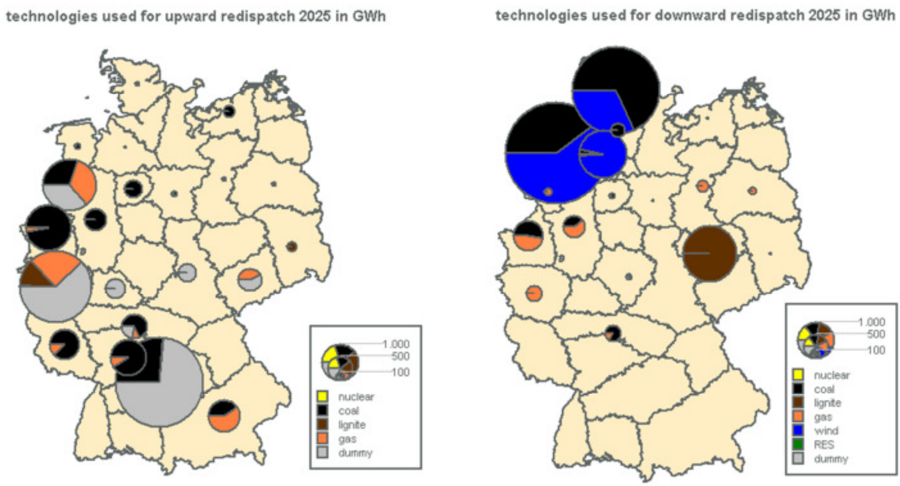


FIGURE 6.14: TECHNOLOGY-SPECIFIC UPWARD (LEFT) AND DOWNWARD REDISPATCH (RIGHT) IN GERMANY IN THE YEAR 2025 IN THE *REFERENCE SCENARIO*

Source: Own illustration.

Finally, it can be seen that a large amount of dummy redispatch is needed in the year 2025 (about 6,116 GWh/a). As explained in chapter 4, dummy redispatch is a method of last resort if not enough conventional capacities

99 A thorough discussion of this issue is beyond the scope of this dissertation. For further information the interested reader is referred to Dena (2010) that investigates which network extensions are necessary to integrate all kWh of wind power generation into the Germany transmission system.

are available for upward redispatch to resolve congestion. This lack might on the one hand originate from too few power plants installed in the respective regions or from a situation in which all plants are operating at the spot market or provide regulating power reserves and are thus not available for upward redispatch. On the other hand, the remaining capacities could be located in such a way that redispatching them up does not resolve congestion.

Dummy redispatch hereby represents the necessity to intervene in the transmission network by undefined other means except redispatch due to network congestion. These means could for example be special technical equipment installed at the network that can provide electricity generation if needed. Another possibility is a mechanism or market that guarantees the availability of a "redispatch reserve" similar to a capacity market or the market for regulating power. Irrespective of the actual definition of this dummy redispatch, the results indicate that the mechanism of cost-based redispatch as it is designed today sooner or later reaches its limits and becomes insufficient if the market develops as assumed in the *Reference Scenario*.

6.2 The Sensitivity Scenario "Fuel Price"

As already outlined in 6.1, the *Reference Scenario* is no forecast but rather a possible development path relying on numerous assumptions. However, as it is unknown whether the assumptions will materialize in the future, it has to be investigated how the model results are affected by changes of the most insecure assumptions. In the sensitivity *Scenario "Fuel Price"* it is analyzed how a different development of the fuel prices – i.e. a stronger increase of the oil and gas price – affects redispatch quantities and costs.

Of course, other assumptions concerning the development of the fuel prices – e.g. a more moderate increase of the oil and gas prices – could be investigated. Consequently, the setting applied in this section serves as an example of the influence of the changes of the fuel price assumptions.

First of all, the scenario assumptions will be outlined (section 6.2.1). This is followed by a description of the changes of the power plant dispatch in section 6.2.2. Finally, in section 6.2.3, the change of the redispatch quantities and costs will be illustrated.

6.2.1 Description of the scenario assumptions

The sensitivity scenario is basically identical to the *Reference Scenario* except the assumptions concerning the development of the fuel prices. As can be seen in Table 6.8, the development of the prices of coal and lignite are unchanged compared to the *Reference Scenario*. However, a stronger increase of the price of oil and gas is assumed. Consequently, the spread between the gas and coal price widens, which favors the dispatch of coal-fired power plants in comparison to the *Reference Scenario*. As an offsetting effect there is a higher price for CO_2-Certificates induced by the more carbon intensive operation of coal-fired plants. More carbon intensive operation leads to higher demand of CO_2-Certificates and thus to a higher price of these. Nevertheless, since this higher carbon price only partially offsets the effect of the larger spread between the coal and gas price, the electricity generation by coal fired plants is still favored in sum.

As a consequence to the different assumptions concerning prospective fuel prices and the thereby induced more frequent operation of coal-fired plants in comparison to gas-fired plants, the development of installed capacities of conventional power plants needs to be adjusted compared to the *Reference Scenario*. Due to the fact that coal-fired plants are more favored in the *Scenario "Fuel Price"* it is assumed that more of the new constructions of coal plants which are currently in planning status will actually materialize in the future. In contrast, some of the new constructions of gas-fired plants that are erected in the *Reference Scenario* are assumed to be abandoned in this scenario.

TABLE 6.8: DEVELOPMENT OF THE FUEL PRICES AND PRICES OF CO2-CERTIFICATES FROM 2010 – 2025 IN THE *SCENARIO "FUEL PRICE"*

year	oil [€/MWh_{th}]	gas [€/MWh_{th}]	hard coal [€/MWh_{th}]	lignite [€/MWh_{th}]	CO_2-Certificates
2010	39.00	17.00	9.60	1.43	13.00
2015	43.70	22.20	9.10	1.43	16.00
2020	51.89	25.64	10.10	1.43	21.90
2025	54.68	27.20	10.70	1.43	26.50

Source: Own figures.

In sum, the installed capacity of coal-fired plants in the *Scenario "Fuel Price"* is 2.4 GW higher in the year 2015 and 3.9 GW higher in the year 2020 and 2025 compared to the reference scenario. The installed capacity of gas-fired plants in each of the years is assumed to be 4.6 GW lower than in the in the *Reference Scenario*. The respective figures of installed capacity per technology can be found in the appendix. The geographical distribution of the change of installed capacities of conventional power plants and CHP plants in *Scenario "Fuel Price"* is illustrated in Figure 6.15.

As can be seen in the figure, the switch from gas-fired plants to coal-fired plants leads to a slightly higher concentration of installed capacity of power plants in the North of Germany as compared to the *Reference Scenario*. This is due to the fact that the plans for the erection of new coal plants mainly envision locations in the northern half of the country close to the coast facing comparatively lower fuel costs. At locations close to the coast the shipment costs for coal are close to zero, while these shipment costs increase the further south the location is and thus the longer the transport along the inland water ways is. In contrast, the plans for the erection of new gas-fired plants are more evenly spread around the country as there are no systematically different fuel costs with respect to the location.

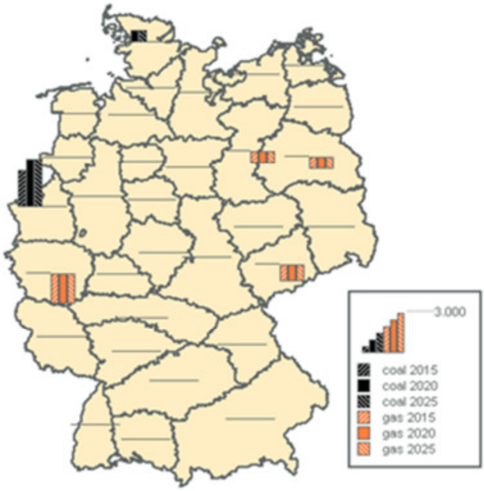


FIGURE 6.15: CHANGE OF INSTALLED CAPACITY OF CONVENTIONAL AND CHP POWER PLANTS IN GERMANY FROM 2015 - 2025 IN THE *SCENARIO "FUEL PRICE"*

Source: Own illustration.

However, the change of local concentration in the *Scenario "Fuel Price"* compared to the *Reference Scenario* is only moderate. Nevertheless, as the concentration of coal-fired plants is already higher in the northern regions compared to gas-fired plants in the *Reference Scenario* this aggravates even more in the *Scenario "Fuel Price"*. Hence, a high concentration of coal-fired generation capacity and electricity generation respectively is assumed in the North of Germany.

The combination of the changed regional distribution of installed capacities and the changed dispatch of plants induced by the modified fuel price assumptions leads to a different regional electricity feed-in structure. This changed feed-in structure in turn alters the electricity flows in the German transmission network. On the one hand, the changed flows affect the utilization of the electricity lines and thus the demand for redispatch. On the other hand, the changed dispatch structure – induced by the different installed capacities and different power plant dispatch decisions – alters the supply for upward and downward redispatch. The interplay of these two effects in comparison to the *Reference Scenario* is analyzed in the *Scenario "Fuel Price"*.

6.2.2 Power plant dispatch

In Table 6.9 the results of the optimization of the power plant dispatch in the *Scenario "Fuel Price"* are outlined by means of annual generation and demand. Comparing the results with the results of the *Scenario Reference* (see Table 6.6) yields the following: As expected, the generation of gas-fired plants is lower (by 28.9 TWh in the year 2015, by 16.6 TWh in the year 2020 and by 23.8 TWh in the year 2025) in the *Scenario "Fuel Price"*. In contrast, the generation of coal-fired plants is higher (by 19.3 TWh in the year 2015, by 17.8 TWh in the year 2020 and by 22.3 TWh in the year 2025) compared to the *Reference Scenario*.

With respect to the annual generation of nuclear, lignite and pump-storage plants there are only minor differences between the two scenarios. The feed-in of renewable energies and CHP as well as electricity demand are assumed to be identical in the two scenarios.

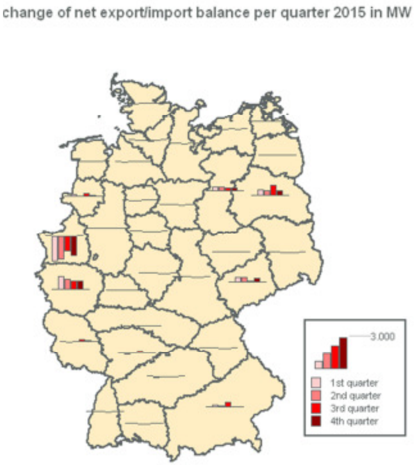
In the *Reference Scenario* net exports are by 8.4 TWh higher in the year 2015 than in the *Scenario "Fuel Price".* This can be explained by lower electricity exports to the coal-dominated eastern neighbor countries in case coal-fired generation is favored as in the *Scenario "Fuel Price"*. However, exports are rather identical in both scenarios in the year 2020 and 2025 as the higher generation of coal-fired plants in the *Scenario "Fuel Price"* is almost entirely offset by a decrease in gas-fired plants.

TABLE 6.9: ANNUAL ELECTRICITY GENERATION, LOAD AND EXPORT/IMPORTS IN TWH FOR THE YEARS 2015, 2020 AND 2025 IN THE *SCENARIO "FUEL PRICE"*

	2015	2020	2025
nuclear	89.9	60.5	0
coal	136.3	137.6	138.9
lignite	142.7	127.8	110.2
gas	23.2	15.1	21.4
pump-storage (+)	10.6	12.1	15.9
pump-storage (-)	-13.6	-15.6	-20.9
renewable energies	155.6	215.7	272.5
CHP	74.8	74.8	74.8
exports/imports	-79.3	-97.8	-90.2
load	540.2	530.1	522.6

Source: Own figures.

In sum, a shift of gas-fired to coal-fired generation can be observed as expected. How this affects the net export/import balance of the 31 network regions is illustrated in Figure 6.16, Figure 6.17 and Figure 6.18. Here, the change of the net export/import balance per quarter and per daytime in the *Scenario "Fuel Price"* in relation to the *Reference Scenario* is displayed. A negative figure indicates higher exports or lower imports respectively. Vice versa, a positive figure indicates higher imports or lower exports.



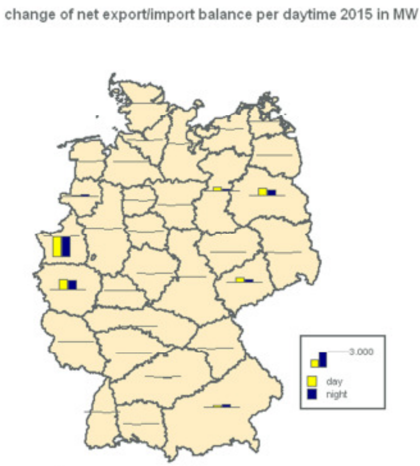


FIGURE 6.16: CHANGE OF WEIGHTED AVERAGE NET EXPORT/IMPORT BALANCE PER QUARTER (LEFT) AND PER DAYTIME (RIGHT) IN GERMANY IN THE YEAR 2015 IN THE *SCENARIO "FUEL PRICE"*

Source: Own illustration.

For all modeled years, the years 2015, 2020 and 2025, it can be seen that the regions with the strongest change of the net export/import balance are exactly the regions in which the installed capacities are different to the *Reference Scenario*. In region 1 and 14 there are additional coal-fired generation plants. As these plants tend to generate – their operation is favored compared to gas-fired plants – net exports increase in these regions. Vice versa, the net imports of the regions in which the installed capacities are lower compared to the *Reference Scenario* display stronger net imports. The respective regions are region 12, 13 and 23 in East-

Germany and region 20 in West-Germany.[100] Both of the above outlined effects can be observed for all modeled years, while the magnitude of the changes of the balances grows over time.

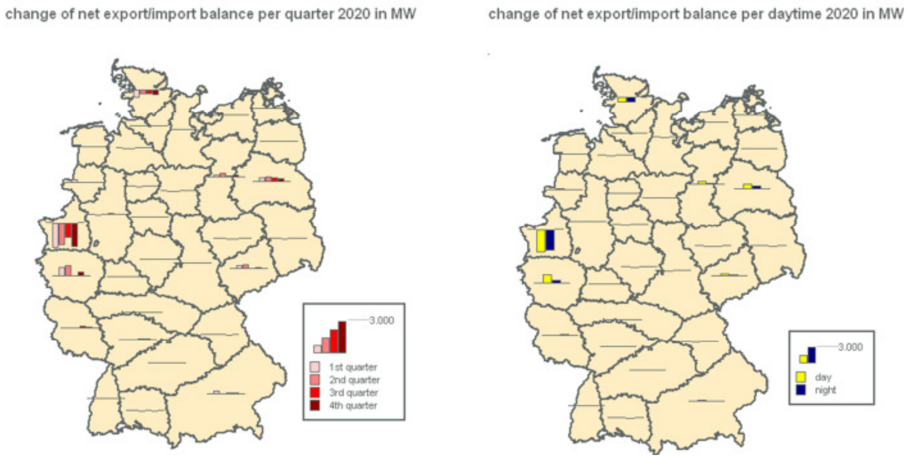


FIGURE 6.17: CHANGE OF WEIGHTED AVERAGE NET EXPORT/IMPORT BALANCE PER QUARTER (LEFT) AND PER DAYTIME (RIGHT) IN GERMANY IN THE YEAR 2020 IN THE *SCENARIO "FUEL PRICE"*

Source: Own illustration.

Furthermore, it can be seen that the change of the net export/import balance is more pronounced in the first two quarters than in the second half of the year and stronger during the day than during the night. This can be explained by the fact that the concerned technologies are predominantly mid- and peak-load capacities. Changes of the generation schedules are thus more pronounced during peak times (during the day) and times of

[100] The changed fuel price assumptions change the dispatch of power plants all over modeled Europe to some degree. However, the figures only illustrate the effect within Germany.

higher load in general (in winter). This again holds true for all modeled years while the magnitude of the changes of the net export/import balances increases in the course of time.

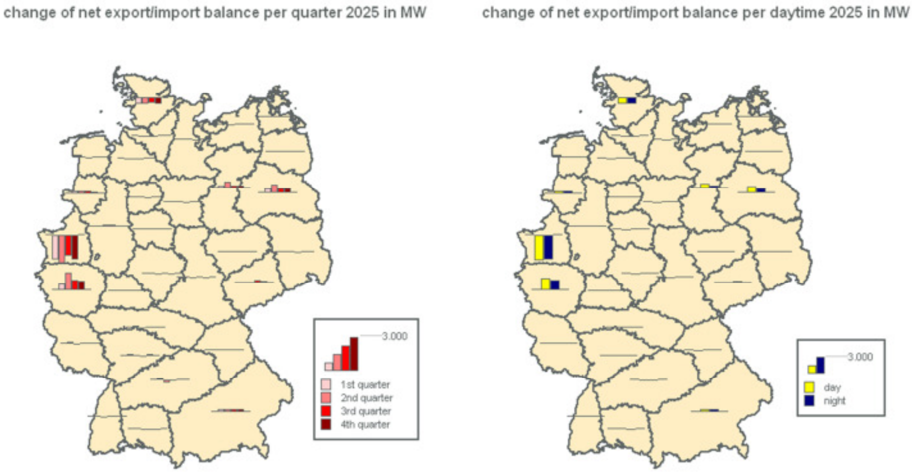


FIGURE 6.18: CHANGE OF WEIGHTED AVERAGE NET EXPORT/IMPORT BALANCE PER QUARTER (LEFT) AND PER DAYTIME (RIGHT) IN GERMANY IN THE YEAR 2025 IN THE *SCENARIO "FUEL PRICE"*

Source: Own illustration.

6.2.3 Development of redispatch quantities and costs

As a first step, the model results of the *Scenario "Fuel Price"* are outlined in relation to the results of the *Reference Scenario* in section 6.2.3.1. This is followed by a description of the change of the line utilization and magnitude and frequency of congestion (section 6.2.3.2). Detailed results concerning the upward and downward redispatch quantities can be found in the appendix. Finally, a summary of the results is given and a conclusion is drawn about the impact of the assumptions concerning the fuel prices on redispatch costs and quantities (section 6.2.3.3).

6.2.3.1 Overview of model results

Table 6.10 summarizes the general model results for the years 2015, 2020 and 2025 in the *Scenario "Fuel Price"*. As holds true for the *Reference Scenario*, redispatch quantities and costs increase in the course of time. However, maximum congestion is slightly lower for each of the modeled years (by 106.1 MW in the year 2015, by 87.2 MW in the year 2020 and by 14.9 MW in 2025). Average congestion in turn is higher in the years 2020 and 2025 in the *Scenario "Fuel Price"* than in the *Reference Scenario* (by 18.3 MW and 13.1 MW). Consequently, if congestion occurs it is generally more pronounced. Furthermore, the frequency of congestion is higher in the year 2020 and 2025 (by 12.1 percentage points and 2.6 percentage points respectively) while it is lower in the year 2015 (by 1.3 percentage points). Thus, already in 2020 in almost half of the hours one or more lines are congested in the *Scenario "Fuel Price"*.

The same picture can be observed with respect to redispatch. While in the year 2015 maximum and average redispatch is lower in the *Scenario "Fuel Price"* than in the *Reference Scenario* (by 270.0 MW and 160.6 MW respectively), they are higher for the other two modeled years (by 2,168.6 MW and 278.4 MW in the year 2020 and by 1,741.8 MW and 170.1 MW in the year 2025). In total, in the year 2015 179.7 GWh less redispatch is needed than in the *Reference Scenario*. In turn, in the year 2020 4,504.9 GWh and in 2025 3,105.5 GWh more redispatch is applied. Consequently, as expected redispatch is required more often and to a greater extent than in the *Reference Scenario*. However, this only materializes after the year 2015.

TABLE 6.10: OVERVIEW OF COSTS AND QUANTITIES OF REDISPATCH AND FREQUENCY AND MAGNITUDE OF NETWORK CONGESTION 2010 – 2025 IN THE *SCENARIO "FUEL PRICE"*

	2015	2020	2025
maximum congestion (MW)	258.2	1,006.5	1,316.1
maximum redispatch (MW)	2,272.9	6,306.5	11,533.7
average congestion (MW)	107.5	197.0	265.2
average redispatch (MW)	730.2	1,638.9	3,363.2
frequency of congestion (% of h)	7.3	41.4	50.1
redispatch quantities (GWh/a)	428.6	6,726.9	17.144.1
redispatch costs (Mio. €/a)	86.7	410.2	1,438.8

Source: Own illustration.

In contrast, the redispatch costs are higher in all modeled years in the *Scenario "Fuel Price"* than in the *Reference Scenario* (by 51.2 million Euros in the year 2015, by 258.0 million Euros in the year 2020 and by 206.6 million Euros in the year 2025). The fact that the costs in the year 2015 are higher despite less redispatch shows that the costs are partially driven by the level of fuel prices in addition to the interplay of availability of generation plants for redispatching, effectiveness and the network situation (line utilization and location of congestion). Hereby it is not possible to identify the dominant factor or to specify that such a dominant driver exists.

6.2.3.2 Line utilization and frequency and magnitude of congestion

In Figure 6.19, Figure 6.20 and Figure 6.21 the change of the weighted average line utilization compared to the *Reference Scenario* for the years 2015, 2020 and 2025 is illustrated in the left graphs of the figures. Hereby the color of the line indicates the change of the utilization rate in percentage points. A green colored transmission line has a lower utilization rate than in the *Reference Scenario*, a yellow, orange and red colored line has a higher utilization rate. All transmission lines that are not included have an utilization rate similar to the *Reference Scenario* – i.e. the change is between minus 2 and 2 percentage points.

In the right graph of the figures the change of the magnitude and frequency of congestion in the *Scenario "Fuel Price"* compared to the *Reference Scenario* is depicted for the years 2015, 2020 and 2025. The presence of an arrow indicates that congestion occurs at the respective connection in the *Scenario "Fuel Price"*. An arrow that is present in the *Reference Scenario* and is not included in the sensitivity scenario means that no congestion occurs at this line in the sensitivity. The color of the arrows illustrates the strength of the change of the weighted average magnitude of congestion – i.e. by how much MW the congestion at the respective line is higher or lower on average compared to the *Reference Scenario*. A green arrow indicates a decrease of magnitude, an orange and red arrow an increase and a yellow arrow a magnitude similar to the *Reference Scenario* (a change between -25 MW and +25 MW). Furthermore, the percentage figure next to each arrow represents the change of the frequency of congestion as it states by how many percentage points the frequency of congestion is higher or lower compared to the *Reference Scenario*.

As can be seen, in the year 2015 almost all lines have similar or even lower utilization rates in the *Scenario "Fuel Price"* than in the *Reference Scenario*. Especially in east-west direction transmission lines are less utilized. Taking a look at Figure 6.16, which displays the change of the net export/import balance, one can see that in region 14 much less electricity is imported (or even exported), while in region 20 less is exported.

Furthermore, in some regions in East Germany less is exported, too. As a consequence, the line utilization in east-west direction decreases.

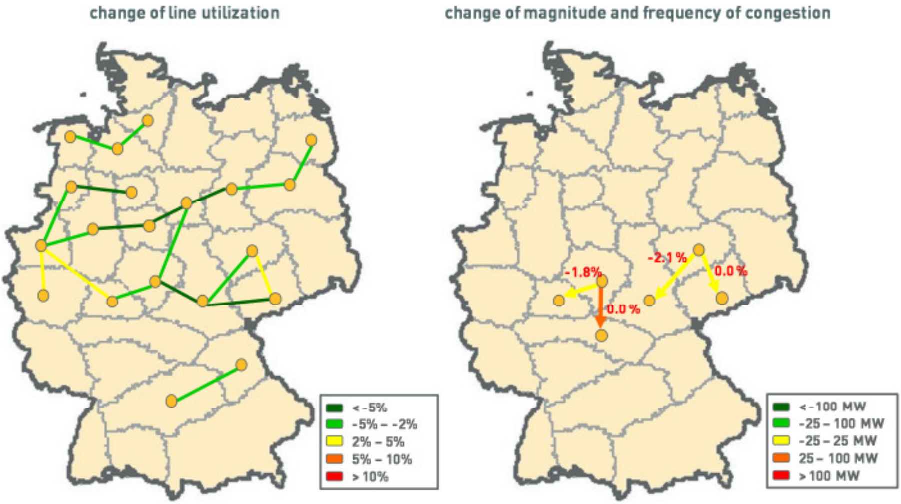


FIGURE 6.19: CHANGE OF WEIGHTED AVERAGE LINE UTILIZATION (LEFT) AND FREQUENCY AND MAGNITUDE OF CONGESTION (RIGHT) IN GERMANY IN THE YEAR 2015 IN THE *SCENARIO "FUEL PRICE"*

Source: Own illustration.

Furthermore, as can be seen in the right graph of the figures, for all modeled years the magnitude of congestion is similar or higher in the *Scenario "Fuel Price"*. In the year 2015 the same four lines are congested as in the *Reference Scenario*. For three of them the magnitude is similar, while the frequency of congestion is lower by up to 2.1 percentage points. Only for one transmission line the magnitude of congestion is higher on average. However, the frequency is identical to the *Scenario Reference*. This is in line with the observation that the line utilization in the year 2015 is generally lower in the *Scenario "Fuel Price"*. As a consequence of less congestion the redispatch is also lower as reported in Table 6.10.

In the year 2020 the utilization rate along the western border of Germany and in the east-west direction is still lower in the *Scenario "Fuel Price"* compared to the *Reference Scenario*. However, at the center of Germany along the north-south axis as well as from region 14 in south direction the line utilization increases. This can be explained by additional exports especially in region 1 and 14 induced by coal-based generation and by fewer exports or more imports in regions in the East and South of Germany (see Figure 6.17).

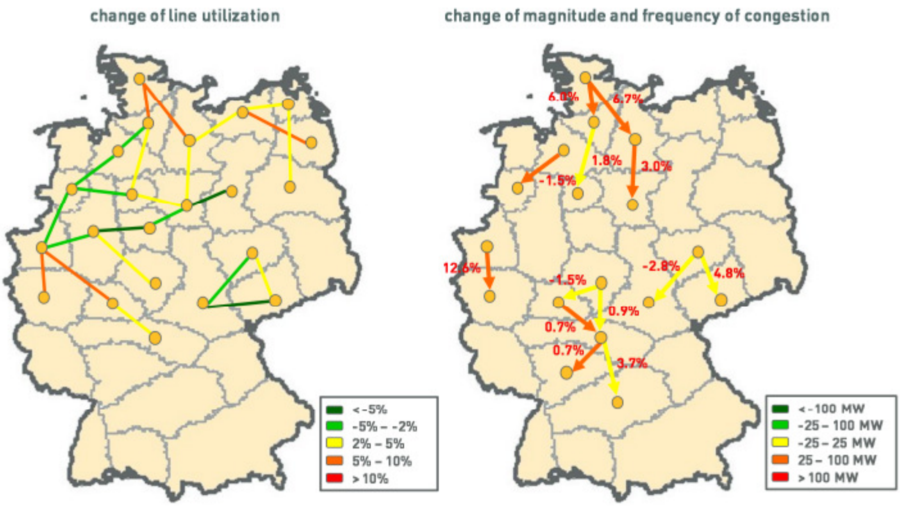


FIGURE 6.20: CHANGE OF WEIGHTED AVERAGE LINE UTILIZATION (LEFT) AND FREQUENCY AND MAGNITUDE OF CONGESTION (RIGHT) IN GERMANY IN THE YEAR 2020 IN THE *SCENARIO "FUEL PRICE"*

Source: Own illustration.

Compared to the *Reference Scenario* even more lines are congested and the magnitude and frequency of congestion is generally higher. Especially on the transmission lines from region 1 to region 2 and 3 and from region 6 to region 9 in north-south direction congestion, which is about 50 MW on average higher compared to the *Reference Scenario*, occurs. On the transmission lines starting in region 1, even the frequency increases by roughly 6 percentage points. In addition, the transmission line from region 14 to region 20 in West Germany is more often congested by 12.6 percentage points with congestion being roughly 60 MW higher. Thus, the change of the magnitude and frequency of congestion in the year 2020 mirrors the observations concerning the line utilization. In analogy to the findings for the year 2015, higher and more frequent congestion in the year 2020 in the *Scenario "Fuel Price"* induces more redispatch as compared to the *Reference* Scenario (seeTable 6.10).

The trend of higher line utilization prevails and intensifies in the year 2025. The line utilization on the path along the western border in the *Scenario "Fuel Price"* is similar to the line utilization in the *Reference Scenario*, while the path through the center of Germany in north-south direction is stronger utilized by up to 9 percentage points. Still the utilization rate of lines in East-West direction is lower in the *Scenario "Fuel Price"*. Again this change of line utilization is induced by higher exports in region 1 and 14 and lower exports in East Germany and region 20 evoked by a shift from gas-based to coal-based generation.

With respect to congestion it can be seen that in the *Scenario "Fuel Price"* in the year 2025 again more transmission lines face congestion – namely the line between region 10 and region 17 as well as the line between regions 14 to 21. Furthermore, the magnitude of congestion of the transmission lines in the north-south direction – partially already observed for the year 2020 – is higher by a magnitude between 25 MW and 100 MW on average. The same holds true for the frequency of congestion that is by up to 8 percentage points higher than in the *Reference Scenario*. For the year 2025 the observations concerning line utilization and congestion are once again in line with each other. Again more and higher congestion induces more redispatch as stipulated in Table 6.10.

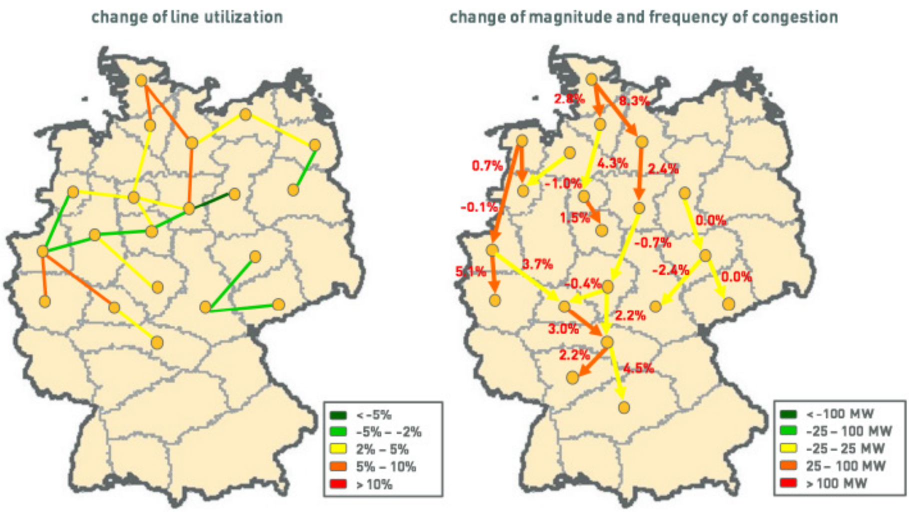


FIGURE 6.21: CHANGE OF WEIGHTED AVERAGE LINE UTILIZATION (LEFT) AND FREQUENCY AND MAGNITUDE OF CONGESTION (RIGHT) IN GERMANY IN THE YEAR 2025 IN THE *SCENARIO "FUEL PRICE"*

Source: Own illustration.

6.2.3.3 Summary and conclusion

Summing up it can be concluded that the impact of different fuel price assumptions on congestion and redispatch is ambiguous. While the change of the fuel prices induces redispatch to be lower in the year 2015 it induces the redispatch to be higher in the years 2020 and 2025. Only in these two modeled years the effect that is expected by the definition of the sensitivity actually materializes.

Redispatch costs, in turn, are always higher for each modeled year as a result of the changed fuel price assumption in the *Scenario "Fuel Price".* However, it is important to notice that redispatch costs are higher if *more* redispatch is required in the years 2020 and 2025, while they are also higher with *less* redispatch in the year 2015 *Scenario "Fuel Price"*. As already explained above this is due to fact that redispatch and its costs are determined by an interplay between the market outcome and thus the network situation, the availability of plants for redispatch and the effectiveness of these plants to resolve congestion.

Consequently, it can be concluded that the impact of different fuel price assumptions on redispatch and redispatch costs is not predictable as the impact is influenced by different factors. Therefore, the exact magnitude and direction of the effect has to be analyzed in a case by case study.

6.3 The Sensitivity Scenario "Wind Power"

Also the sensitivity *Scenario "Wind Power"* investigates the effect of a change of an underlying assumption on the quantities and costs of redispatch. Hereby, it is analyzed how redispatch changes if a less pronounced growth of installed capacities of wind power plants is assumed. In the *Reference Scenario* a very strong increase of capacities is already assumed so that an even stronger increase does not seem to be likely. Consequently, a less strong growth of capacities is adopted in this sensitivity as this is more likely to occur.

Again, the scenario assumptions are outlined at first (section 6.3.1). Following this, the changes of the power plant dispatch and of the net export/import balance of the region are explained (section 6.3.2). Finally, in section 6.3.3 it is analyzed how the changed assumptions concerning wind power affect the redispatch costs and quantities.

6.3.1 Description of the scenario assumptions

In the sensitivity *Scenario "Wind Power"* the effect of a less strong increase of installed capacities of onshore and offshore wind power plants is analyzed. Hereby, it is assumed that the growth of capacities between the year 2010 and 2025 is 20 % less than in the *Reference Scenario*. As explained in chapter 5, new installations and retrofit of wind power plants predominantly take place in the North of Germany. Consequently, the assumption of a less pronounced growth of capacities has a relatively higher impact on the feed-in of wind power in the northern regions while the effect on the southern regions is negligible.

TABLE 6.11: INSTALLED CAPACITY AND ELECTRICITY FEED-IN OF WIND POWER PLANTS IN GERMANY FROM 2010 – 2025 IN THE *SCENARIO "WIND POWER"*

technology	2010		2015		2020		2025	
	installed capacity [MW]	feed-in [GWh]	installed capacity [MW]	feed-in [GWh]	installed capacity [MW]	feed-in [GWh]	installed capacity [MW]	feed-in [GWh]
onshore	26,541	41,581	32,226	54,296	33,908	65,441	34,745	74,255
offshore	60	211	2,712	8,246	8,012	27,429	17,500	53,605
TOTAL	**26,601**	**41,792**	**34,938**	**62,542**	**41,920**	**92,870**	**48,756**	**127,860**

Source: Own calculations.

In Table 6.11 the installed capacities and electricity feed-in of onshore and offshore wind power plants in Germany in the *Scenario "Wind Power"* are given.

In Figure 6.22 the change of the installed capacity and electricity feed-in of wind power plants in the *Scenario "Wind Power"* as compared to the *Reference Scenario* is illustrated per region for the years 2015, 2020 and 2025. As can be seen, the largest reductions are located in the North of Germany.

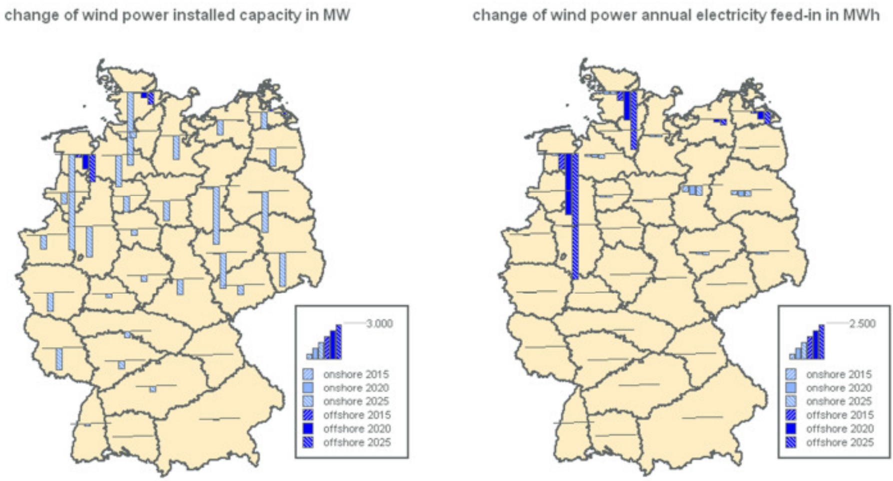


FIGURE 6.22: CHANGE OF INSTALLED CAPACITY (LEFT) AND ANNUAL ELECTRICITY GENERATION (RIGHT) OF WIND POWER PLANTS IN GERMANY FROM 2015 – 2025 IN THE *SCENARIO "WIND POWER"*

Source: Own illustration.

Of course, the reduced feed-in of wind power plants in Germany alters the flows within the transmission network in Germany. As there is less feed-in in the southern regions compared to the *Reference Scenario* less electricity needs to be transported in the direction from the North to the South. It can be expected that this has a dampening effect on the utilization and congestion of the transmission lines in the north-south direction. How the changed electricity flows induced by the reduction of feed-in of wind power effects the demand for and thereby the costs of redispatch is the object of investigation in the *Scenario "Wind Power"*.

6.3.2 Power plant dispatch

The reduced feed-in of wind power plants influences the whole power plant dispatch in Germany. In Table 6.12 the annual electricity generation of the conventional plants and renewable energies, electricity demand and the net export/import balance are shown. As assumed, the feed-in of renewable energy sources – i.e. the feed-in of wind power – is lower than in the *Reference Scenario*. In the year 2015 it is 4.8 TWh less, in the year 2020 it is 10.3 TWh less and in the year 2025 it is 17.3 TWh less. Furthermore, the feed-in of CHP plants, electricity demand and the generation of nuclear plants and pump-storage plants are similar to the *Reference Scenario*.

The reduction of the feed-in of wind power plants is almost entirely offset by an increase of the generation of conventional plants. Coal-fired plants generate 3.6 TWh more in the year 2015, 4.7 TWh more in the year 2020 and 1.4 TWh more in the year 2025 in the *Scenario "Wind Power"* compared to the *Reference Scenario*. Lignite power plants generate 0.7 TWh more in the year 2015, 0.9 TWh more in the year 2020 and 6.3 TWh more in the year 2025. The figures for gas-fired plants are 0.5 TWh, 2.8 TWh and 5.1 TWh respectively. Nevertheless, the increased conventional generation in Germany does not entirely compensate for the reduction of the feed-in of wind power plants so that net exports are reduced by 0.3 TWh, 2.2 TWh and 5.0 TWh in the *Scenario "Wind Power"*. Consequently, the reduced electricity generation of German wind power is substituted by German and foreign conventional electricity generation.

TABLE 6.12: ANNUAL ELECTRICITY GENERATION, LOAD AND EXPORT/IMPORTS IN TWH FOR THE YEARS 2015, 2020 AND 2025 IN THE *SCENARIO "WIND POWER"*

	2015	2020	2025
nuclear	90.0	60.5	0
coal	120.6	124.6	122.8
lignite	141.7	128.8	111.6
gas	52.7	34.5	50.3
pump-storage (+)	9.2	10.5	14.8
pump-storage (-)	-12.1	-13.3	-19.4
renewable energies	150.8	205.2	254.9
CHP	74.8	74.8	74.8
exports/imports	-87.3	-95.5	-87.3
load	540.2	530.1	522.6

Source: Own figures.

In total, there is a shift of wind power generation located predominantly in the northern regions of Germany to a conventional generation distributed more evenly in Germany and in other countries. How this changes the weighted average net export/import balances compared to the *Reference Scenario* is illustrated in Figure 6.23, Figure 6.24 and Figure 6.25.

It can be seen that the net export/import balances change in analogy to the modifications of the installed capacities of wind power (see Figure 5.15). The regions with large reductions in the installed wind capacities in the North of Germany – especially region 1 and 8 to which also feed-in of offshore wind power is allocated – face a decrease of net exports. This decrease is most pronounced in the first and fourth quarter, while it is rather moderate during the other two quarters. With respect to the daytime no systematic difference between the changed balances during day and during night can be observed. Again, this can be explained by the fact that the feed-in of wind power is generally higher during the winter month than during summer, while there is no systematic distinction between day and night. The above outlined observations hold true for all modeled years, while their magnitude increase over time in line with the changes of installed capacity.

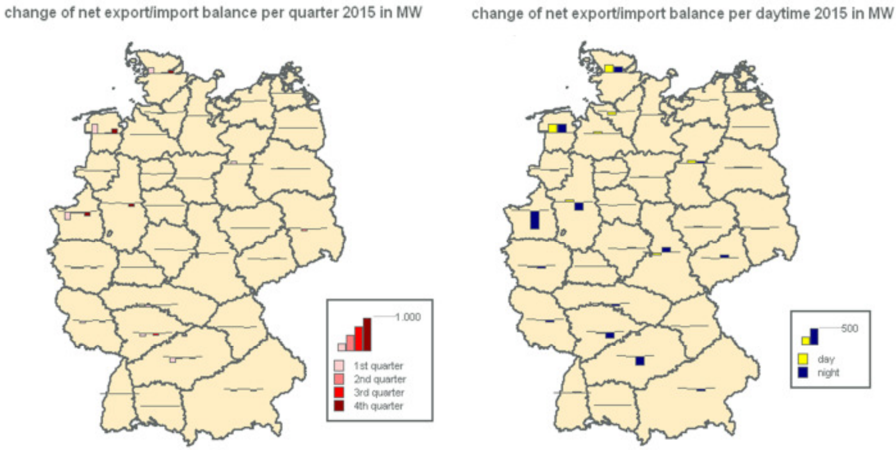


FIGURE 6.23: CHANGE OF WEIGHTED AVERAGE NET EXPORT/IMPORT BALANCE PER QUARTER (LEFT) AND PER DAYTIME (RIGHT) IN GERMANY IN THE YEAR 2015 IN THE *SCENARIO "WIND POWER"*

Source: Own illustration.

In contrast to this, the regions with high installations of base- and mid-load capacities – especially the lignite regions in the West and East of Germany but also regions in the South of Germany – face an increase of exports and thus a reduction of net imports or an increase of net exports. Consequently, the reduction of the feed-in of wind power is at least partially offset by an increased generation in Germany.[101] This effect materializes in all quarters but is especially strong during the first and to some extent during the fourth quarter compared to the second and third quarter. Furthermore, the effect is generally stronger during day than during night. Consequently, the impact of a reduced feed-in of wind power plants on the generation of mid-load and base-load capacities is stronger the higher the electricity demand is.

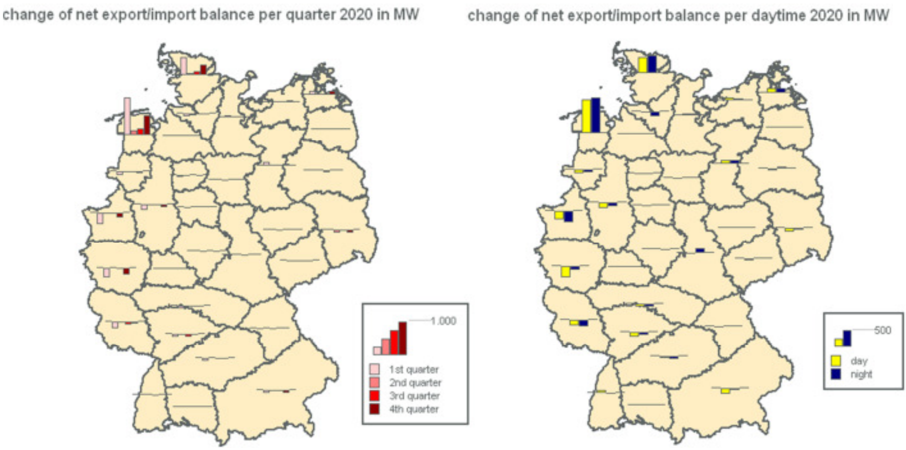


FIGURE 6.24: CHANGE OF WEIGHTED AVERAGE NET EXPORT/IMPORT BALANCE PER QUARTER (LEFT) AND PER DAYTIME (RIGHT) IN GERMANY IN THE YEAR 2020 IN THE *SCENARIO "WIND POWER"*

Source: Own illustration.

101 The modified feed-in of wind power in Germany changes the dispatch of power plants all over modeled Europe to some degree. However, the figures only illustrate the effect within Germany.

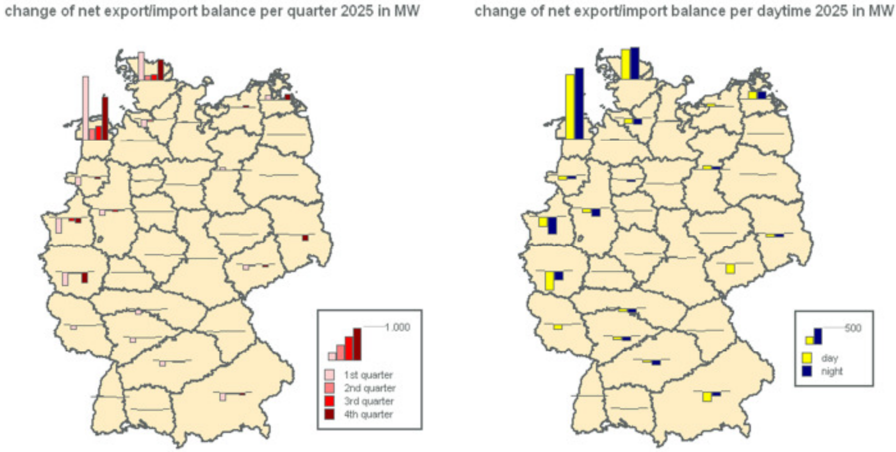


FIGURE 6.25: CHANGE OF WEIGHTED AVERAGE NET EXPORT/IMPORT BALANCE PER QUARTER (LEFT) AND PER DAYTIME (RIGHT) IN GERMANY IN THE YEAR 2025 IN THE *SCENARIO "WIND POWER"*

Source: Own illustration.

In total, the reduced installed capacities of wind power in the *Scenario "Wind Power"* yield lower electricity exports in the North of Germany and lower imports or higher exports in the center and the South of Germany. Consequently, the setting of this scenario tends to attenuate the transport of electricity from the North to the South and therefore disburdens the transmission network compared to the *Reference Scenario*.

6.3.3 Development of redispatch quantities and costs

In section 6.3.3.1 the general model results of the *Scenario "Wind Power"* are given and compared to the results of the *Reference Scenario*. Following this, the change of the line utilization and magnitude and frequency of congestion is outlined in section 6.3.3.2. Again, detailed results concerning the upward and downward redispatch quantities can be found in the appendix. Finally, a conclusion concerning the impact of the growth of wind power capacities on redispatch costs and quantities is drawn in section 6.3.3.3.

6.3.3.1 Overview of model results

In Table 6.13 an overview of the model results for the years 2015, 2020 and 2025 concerning redispatch and congestion in the *Scenario "Wind Power"* is given. As can be seen, maximum and average congestion are lower compared to the *Scenario Reference* for each modeled year (by 32.3 MW and 16.7 MW in the year 2015, by 155.4 MW and 39.3 MW in the year 2020 and by 232.3 MW and 61.2 MW in the year 2025). The frequency of congestion however is only lower in the year 2015 (by 1 percentage point) and the year 2025 (by 5.1 percentage points) but higher in the year 2020 (by 3.9 percentage points).

TABLE 6.13: OVERVIEW OF COSTS AND QUANTITIES OF REDISPATCH AND FREQUENCY AND MAGNITUDE OF NETWORK CONGESTION 2010 – 2025 IN THE *SCENARIO "WIND POWER"*

	2015	2020	2025
maximum congestion (MW)	332.0	938.3	1,098.7
maximum redispatch (MW)	1,991.3	2,895.3	7,450.0
average congestion (MW)	103.7	138.8	190.9
average redispatch (MW)	735.0	1,178.1	2,134.8
frequency of congestion (% of h)	7.6	33.2	42.4
redispatch quantities (GWh/a)	463.0	1,423.6	8.532.4
redispatch costs (Mio. €/a)	20.9	97.1	1,036.8

Source: Own illustration.

With respect to redispatch the same trend can be observed. Maximum and average redispatch is lower in each of the years in the *Scenario "Wind Power"* compared to the *Reference Scenario* (by 551.6 MW and 155.8 MW in the year 2015, by 1,242.6 MW and 182.4 MW in the year 2020 and by 2,341.9 MW and 1,058.3 MW in the year 2025). In total there is 145.3 GWh less redispatch in the year 2015, 798.4 GWh less redispatch in the year 2020 and 5,506.2 GWh less redispatch in the year 2025 in the *Scenario "Wind Power"* than in the *Reference Scenario*.

In analogy to redispatch quantities, the costs of redispatch are also lower in each of the years. In the year 2015 they are lower by about 14.6 million Euros, in the year 2020 by 55.1 million Euros and in the year 2025 by 195.4 million Euros lower compared to the *Reference Scenario*. As the fuel price assumptions are identical to the assumptions in the *Reference Scenario* the fact that redispatch costs are lower is either driven by the reduction of congestion or the more cost-efficient application of power plants for redispatch or a combination of both.

6.3.3.2 Line utilization and frequency and magnitude of congestion

In Figure 6.26, Figure 6.27 and Figure 6.28 the change of the weighted average line utilization and the frequency and magnitude of congestion is displayed for the *Scenario "Wind Power"* compared to the *Reference Scenario*. Hereby, the same annotations as explained in section 6.2.3.2 hold.

In the left graph of Figure 6.26 no lines are depicted. This means that in the year 2015 the line utilization is similar to the *Reference Scenario* – i.e. the change is between -2 and +2 percentage points. This can be explained by the fact that in the year 2015 there are only minor changes to the net export/import balances as illustrated in Figure 6.23.

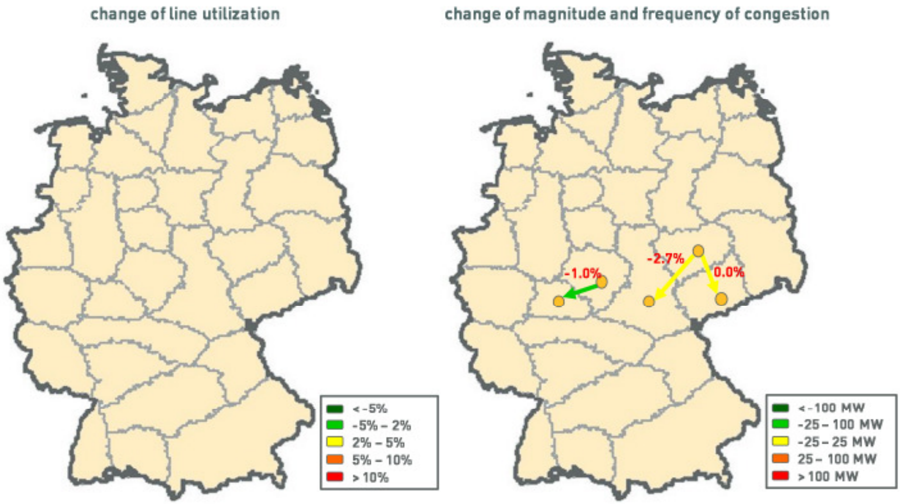


FIGURE 6.26: CHANGE OF WEIGHTED AVERAGE LINE UTILIZATION (LEFT) AND FREQUENCY AND MAGNITUDE OF CONGESTION (RIGHT) IN GERMANY IN THE YEAR 2015 IN THE *SCENARIO "WIND POWER"*

Source: Own illustration.

Congestion in turn is lower (see the right graph of the figure). On the one hand, only three compared to four lines face congestion. On the other hand, either the magnitude or frequency of congestion or both is lower than in the *Reference Scenario*. Thus, the reduced growth of wind power capacities leads to a reduction of congestion and thereby to lower redispatch and redispatch cost already in the year 2015 (see Table 6.13), even though less wind power capacities in the year 2015 only induce minor changes to the regional export/import balances.

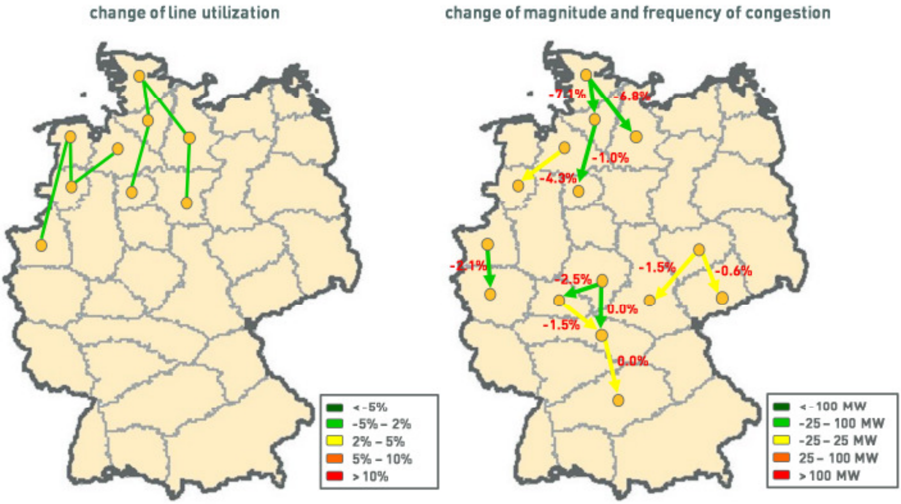


FIGURE 6.27: CHANGE OF WEIGHTED AVERAGE LINE UTILIZATION (LEFT) AND FREQUENCY AND MAGNITUDE OF CONGESTION (RIGHT) IN GERMANY IN THE YEAR 2020 IN THE *SCENARIO "WIND POWER"*

Source: Own illustration.

In the year 2020 the line utilization is either similar or lower in the *Scenario "Wind Power"* as compared to the *Reference Scenario*. Hereby, the transmission lines connecting the northern regions in north-south direction are less utilized up to 4.3 percentage points. This can be explained by the reduction of exports in region 1 and region 8 induced by the lower installed capacities and feed-in of (offshore and onshore) wind power (see in Figure 6.24).

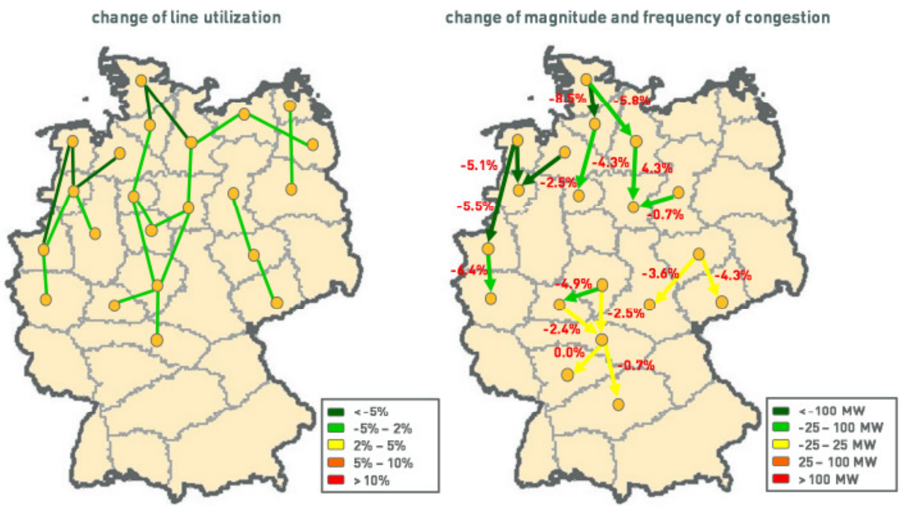


FIGURE 6.28: CHANGE OF WEIGHTED AVERAGE LINE UTILIZATION (LEFT) AND FREQUENCY AND MAGNITUDE OF CONGESTION (RIGHT) IN GERMANY IN THE YEAR 2025 IN THE *SCENARIO "WIND POWER"*

Source: Own illustration.

With respect to congestion it can be seen that in the year 2020 one line less is congested than in the *Reference Scenario*. Furthermore, the magnitude of congestion is either similar or lower by about 50 MW on average for all other transmission lines that face congestion. In addition, the frequency of congestion is lower (or identical). This is especially true for the lines starting in region 1 in the very North, the line from region 6 to region 9 and the transmission line connecting region 14 and region 20 in the West of Germany. As congestion and line utilization in the year 2020 is lower in the *Scenario "Wind Power"* so are redispatch quantities and redispatch costs (see Table 6.13). Hereby, the effect of a less pronounced growth of wind power capacities is stronger than in the year 2015 as redispatch is reduced by 36 % in comparison to 24 % in the year 2015.

In the year 2025 the observed trend of lower line utilization in the *Scenario "Wind Power"* prevails and intensifies. Most of the lines along the north-western border of Germany as well as in the center and the North of Germany in north-south direction are less utilized than in the *Reference Scenario*. Especially the utilization of the lines connecting region 1 in the North and the lines starting in region 8 and 6 in the North-West is lower by up to 9 percentage points. Taking a look at Figure 6.25 one can see that this is induced by a massive reduction of net exports in region 1 and region 8, a reduction of net imports in region 14 and an increase of exports in region 20.

6.3.3.3 Summary and conclusion

In sum, the less pronounced growth of installed capacities of wind power plants as assumed in the *Scenario "Wind Power"* has a dampening effect on congestion, redispatch quantities and redispatch costs in all modeled years. As explained in section 6.3.2, the less pronounced growth of wind power capacities induces a different power plant dispatch in Germany. In combination with the assumed lower feed-in of wind power this leads to changed regional export/import balancesand thus to lower average line utilization, to less congestion and to less redispatch.

The model results show that the growth rate of installed capacities of wind power plants in Germany has an unambiguous impact on redispatch quantities and costs. A higher growth rate can be expected to increase congestion and redispatch, a lower growth rate can be expected to have a dampening effect. However, this can only be concluded for the set of assumptions used here. If the wind power capacities were located at other regions or if the less strong increase of wind power feed-in induced a different adjustment of the German and European fleet of conventional plants and the electricity market, the impact on redispatch and congestion might be different.

6.4 The Sensitivity Scenario "Load Structure"

The sensitivity *Scenario "Load Structure"* investigates possible prospective changes of the regional distribution of total German electricity demand. Changes of the regional distribution might arise over time as the location of energy intensive industry as well as the density of population and thus household electricity demand is not fixed but rather changes in the course of time. Hereby, the sensitivity analyzes the effects of a shift of demand from the North and East of Germany to the West and South of Germany. Therefore, it is assumed that electricity demand will further concentrate in the load centres in the West and South.

First, the underlying scenario assumptions are outlined in section 6.4.1, followed by a description of the resulting power plant dispatch (section 6.4.2). Then, the effect on redispatch quantities and costs is analyzed in section 6.4.3.

6.4.1 Description of the scenario assumptions

While in the *Reference Scenario* it is assumed that the load structure remains constant and is identical to the structure estimated for the year 2010, in the *Scenario "Load Structure"* the following changes over time are assumed:

The shares of total German electricity demand of the less populated regions in the North of Germany stepwise decreases for each region individually. Until the year 2015 their shares decrease by 3.5 %, until the year 2020 by 7.0 % and until the year 2025 by 10.0 % compared to the year 2010. The affected regions are regions 1, 3, 4, 5, 6, 7, 8, 9, 10, and 12. These regions are already today sparsely populated with relatively few industries. In the scenario it is presumed that due to demographical changes and a decline of industry, electricity demand further decreases in the future. The shares of total demand in regions 2, 11, and 13 are assumed to remain constant as these regions are more densely populated with more industry and larger towns. Hence, no decline of population and industry is expected.

As total electricity demand in the *Scenario "Load Structure"* is expected to be identical to the total electricity demand in the *Reference Scenario*, the relative decreases of electricity demand in the North of Germany has to be outweighed by relative increases elsewhere in the country. For this purpose it is assumed that the shares of electricity demand of the highly populated and industry intensive load centers in the West and South of Germany further increase. Their shares increase by 0.83 % until the year 2015, by 1.67 % until the year 2020 and by 2.38 % until 2025 relative to their shares in the year 2010. The affected regions are regions 14, 15 and 20 in *Nordrhein-Westfalen* and the regions 28, 27 and 31 in *Bayern, Baden-Württemberg, Rheinland-Pfalz* and *Hessen*. For all other regions the shares of total German electricity demand are expected to prevail in the future.

In Figure 6.29 the regions affected by a percental change of the share of total electricity demand – either by an increase indicated by an upward arrow or by a reduction indicated by a downward arrow – are illustrated.

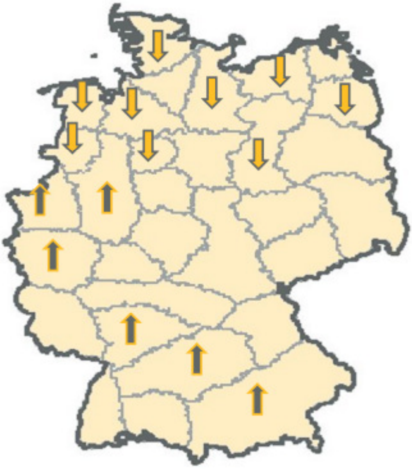


FIGURE 6.29: REGIONS AFFECTED BY A PERCENTAL CHANGE OF THEIR RESPECTIVE SHARE OF TOTAL ELECTRICITY DEMAND IN THE *SCENARIO "LOAD STRUCTURE"*

Source: Own illustration.

As can be seen, there is a shift of load from the North to the South and West of Germany. This shift of load alters the electricity flows in the German transmission network. More electricity generated near the coast – especially wind power – needs to be transported south as fewer electricity is consumed right in the North compared to the *Reference Scenario*. It can be expected that the shift of load aggravates the network situation as the already strongly utilized or congested connections between North and South are even more utilized. The impact of this change or intensification of electricity flows on the demand for and thereby the costs of redispatch are investigated in the *Scenario "Load Structure"*.

6.4.2 Power plant dispatch

In the sensitivity *Scenario "Load Structure"* demand is only regionally shifted but total demand is kept constant. Consequently, there are no changes to the power plant dispatch in Germany as the market only observes total German demand and is indifferent to the location of demand as long as it is located inside Germany. Nevertheless, a changed regional distribution of load does affect the net export/import balance of the 31 network regions. This is illustrated in Figure 6.30, Figure 6.31 and Figure 6.32.

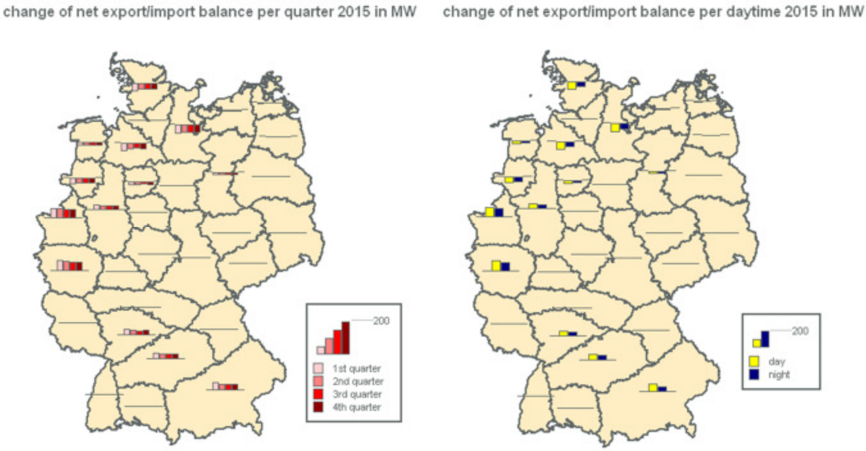


FIGURE 6.30: CHANGE OF WEIGHTED AVERAGE NET EXPORT/IMPORT BALANCE PER QUARTER (LEFT) AND PER DAYTIME (RIGHT) IN GERMANY IN THE YEAR 2015 IN THE *SCENARIO "LOAD STRUCTURE"*

Source: Own illustration.

As can be seen, there are only changes to the net export/import balances in the regions affected by the load shift. The regions with a decrease of its relative share of total demand face a general increase of net exports. In contrast, the regions experiencing a reduction of the relative share of load encounter an increase in net imports. This observation prevails for all three modeled years. Nevertheless, its magnitude increases in the course of time as more and more load is shifted from the North to the South.

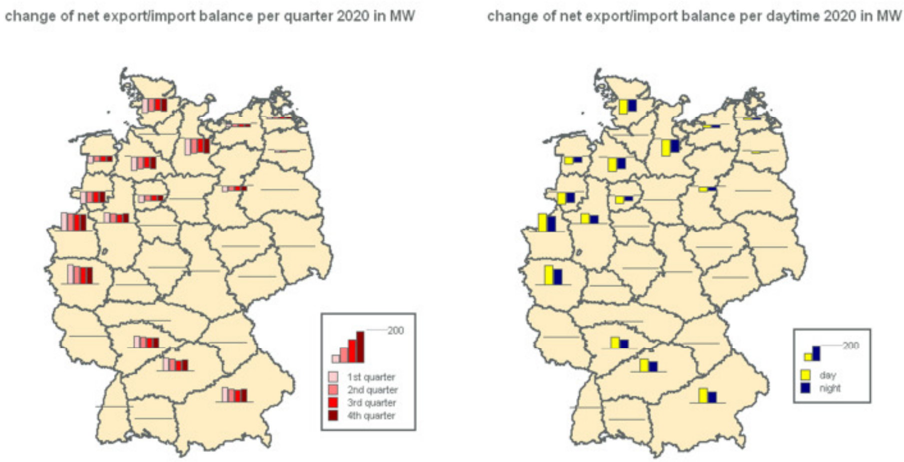


FIGURE 6.31: CHANGE OF WEIGHTED AVERAGE NET EXPORT/IMPORT BALANCE PER QUARTER (LEFT) AND PER DAYTIME (RIGHT) IN GERMANY IN THE YEAR 2020 IN THE *SCENARIO "LOAD STRUCTURE"*

Source: Own illustration.

Furthermore, the change of the net export/import balances is generally higher in the first quarter compared to the rather identical change in the other three quarters. This can be explained by the fact that a percental shift of total demand has the strongest net effect in times of high demand. High demand in turn generally occurs in the first quarter. The same holds true for the differentiation of daytimes. As load is generally higher during the day than during the night, the net change is higher during the day-hours as well.

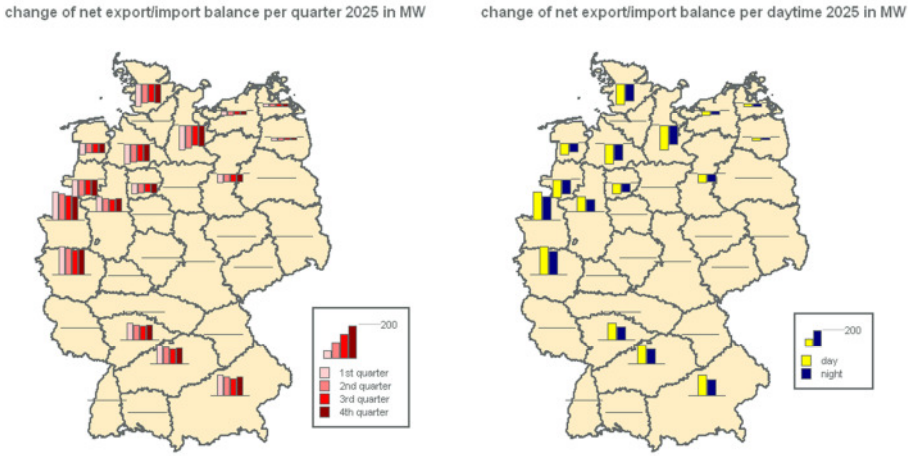


FIGURE 6.32: CHANGE OF WEIGHTED AVERAGE NET EXPORT/IMPORT BALANCE PER QUARTER (LEFT) AND PER DAYTIME (RIGHT) IN GERMANY IN THE YEAR 2025 IN THE *SCENARIO "LOAD STRUCTURE"*

Source: Own illustration.

As was already mentioned in section 6.4.1, the assumption of the *Scenario "Load Structure"* aggravates the load flow situation in the German transmission grid. Higher exports in the North combined with higher imports in the South and West intensify the transport of electricity in north-south direction. Thus, the network becomes even more stressed as compared to the *Reference Scenario*.

6.4.3 Development of redispatch quantities and costs

The structure of the section is the same as for the other two sensitivity scenarios. First of all, the general average model results are shown in 6.4.3.1. Following this the change of the line utilization and congestion is outlined and explained. For detailed illustrations of upward and downward redispatch the reader is referred to the appendix. Finally, in section 6.4.3.3 a conclusion on the impact of the change of the regional distribution of load on redispatch costs and quantities is drawn.

6.4.3.1 Overview of model results

In Table 6.14 an overview of the model results of the *Scenario "Load Structure"* concerning redispatch, redispatch costs and congestion is given. The results show that in the *Scenario "Load Structure"* not all relevant indicators are higher in comparison to the *Reference Scenario* as expected due to the set-up of the sensitivity scenario.

TABLE 6.14: OVERVIEW OF COSTS AND QUANTITIES OF REDISPATCH AND FREQUENCY AND MAGNITUDE OF NETWORK CONGESTION 2010 – 2025 IN THE SCENARIO *"LOAD STRUCTURE"*

	2015	2020	2025
maximum congestion (MW)	348.3	1,147.6	1,407.0
maximum redispatch (MW)	2,440.5	4,412.5	10,468.8
average congestion (MW)	131.1	184.8	258.1
average redispatch (MW)	1,053.6	1,334.4	3,273.6
frequency of congestion (% of h)	8.6	33.2	48.5
redispatch quantities (GWh/a)	784.5	2,509.4	15,157.8
redispatch costs (Mio. €/a)	38.3	170.6	1,334.3

Source: Own illustration.

The maximum and average congestion is higher for the modeled years 2020 and 2025 (by 53.9 MW and 6.1 MW in the year 2020 and by 76.0 MW and 6.0 MW in the year 2025) compared to the *Reference Scenario*. In the year 2015, however, maximum congestion is by 16.0 MW lower, while average congestion is by 10.7 MW higher as holds true for the other two years. The frequency of congestion is identical for the year 2015, but by 3.9 percentage points higher in the year 2020 and still by 1.0 percentage point higher in the year 2025.

The same ambiguity can be observed for redispatch. Maximum redispatch is higher in the year 2020 and 2025 (by 247.6 MW and 676.9 MW respectively). In the year 2015 however, it is by 102.4 MW lower. The average redispatch in turn is higher for the years 2015 (by 162.8 MW) and 2025 (by 80.5 MW). In contrast, in the year 2020 it is lower by 26.1 MW than in the *Reference Scenario*. Nevertheless, total redispatch is higher in the *Scenario "Load Structure"* in all modeled years (by 176.2 GWh in the year 2015, by 287.4 GWh in the year 2020 and by 1,119.2 GWh in the year 2025) compared to the *Reference Scenario.* Thus, expectations are met in sum.

The fact that total redispatch is higher is also reflected in the costs of redispatch. In the year 2015 costs are higher by 2.8 million Euros, in the year 2020 by 18.4 million Euros and in the year 2025 by 102.1 million Euros. Again, the fuel price assumptions are identical to the assumptions in the *Reference Scenario*. In addition, total market demand is identical and only shifted locally so that the market outcome and power plant dispatch is identical, too. Consequently, the higher redispatch costs are induced only by higher congestion. Potentially, a more cost-efficient resolving of congestion could outweigh this effect. However, the results show that this is not the case in the *Scenario "Load Structure".*

6.4.3.2 Line utilization and frequency and magnitude of congestion

In Figure 6.33, Figure 6.34 and Figure 6.35 the change of the weighted average line utilization (in the left graphs) and the magnitude and frequency of congestion (in the right graphs) in comparison to the *Reference Scenario* are illustrated for the years 2015, 2020 and 2025.

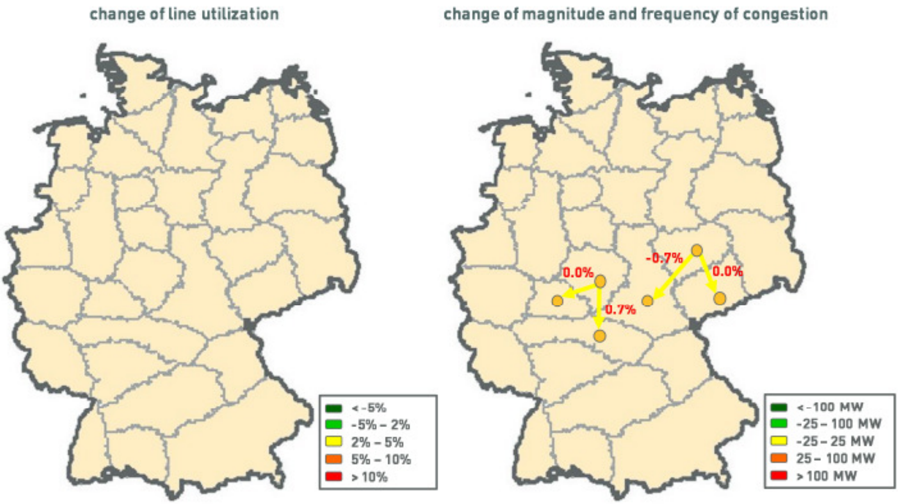


FIGURE 6.33: CHANGE OF WEIGHTED AVERAGE LINE UTILIZATION (LEFT) AND FREQUENCY AND MAGNITUDE OF CONGESTION (RIGHT) IN GERMANY IN THE YEAR 2015 IN THE *SCENARIO "LOAD STRUCTURE"*

Source: Own illustration.

In the year 2015 the average line utilization is not different from the *Reference Scenario* – i.e. the magnitude of change does not exceed -2 or +2 percentage points – so that no lines are depicted in the graph. Taking a look at Figure 6.30 one can see that the regional shift of load does induce only minor changes of the net export/import balances. As a consequence, the line utilization is similar to the *Reference Scenario*.

The same can be observed for the magnitude and frequency of congestion. The identical lines as in the *Reference Scenario* face congestion and neither magnitude nor frequency does differ significantly in the *Scenario "Load Structure".* The fact that there are only minimal changes of the line utilization and congestion situation is mirrored in the results summarized in Table 6.14. Maximum and average congestion as well as maximum and average redispatch are relatively close to the results of the *Reference Scenario.* However, the fact that total redispatch and redispatch costs are higher in the *Scenario "Load Structure*" in the year 2015 cannot be observed evidentaly in Figure 6.30.

In contrast to the year 2015, there is a slight increase between 2 and 5 percentage points of average line utilization of the connection between region 6 and region 9 in the North-West of Germany in the year 2020. As can be seen in Figure 6.31, the regional shift of load assumed in the *Scenario "Load Structure"* yields a reduction of net export or an increase of net imports in the regions in the South and West of Germany. In contrast, the regions in the North and East of Germany export less. This shift of load consequently induces a slightly higher transport of electricity from the North to the South and the West.

With respect to the magnitude of congestion, it can be seen that one more line is congested in the *Scenario "Load Structure"* than in the *Reference Scenario*. However, the magnitude of congestion for the other lines is similar. With respect to frequency of congestion, in turn, a slight increase can be observed especially in the North, North-West and West of Germany. Consequently, the trend of generally higher congestion and redispatch in the year 2020 in comparison to the *Reference Scenario* outlined in section

6.4.3.1 can be explained by a higher line utilization and more frequent congestion. Despite the fact that a higher average line utilization and stronger and more frequent congestion can be observed more evidently than in the year 2015, total redispatch is higher by 12 % in the year 2020, while it is higher by 29 % in the year 2015. Still, the increase of redispatch costs is relatively larger than in the year 2015 (12 % compared to 8 %).

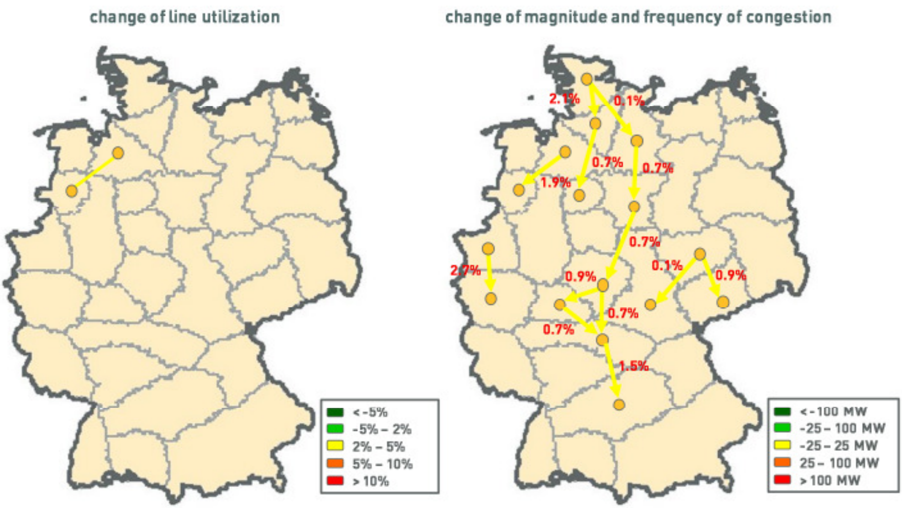


FIGURE 6.34: CHANGE OF WEIGHTED AVERAGE LINE UTILIZATION (LEFT) AND FREQUENCY AND MAGNITUDE OF CONGESTION (RIGHT) IN GERMANY IN THE YEAR 2020 IN THE *SCENARIO "LOAD STRUCTURE"*

Source: Own illustration.

In the year 2025 the observed trend for the year 2015 prevails and intensifies. The line utilization of several lines in the North and North-West is moderately higher in the *Scenario "Load Structure"* compared to the *Reference Scenario*. Further load is shifted from the North and East to the

West and South so that the changes of the regional net export/import balances still have the same direction as in 2020 but increase their respective magnitude (see Figure 6.32). This leads to a higher transport of electricity through the German high voltage transmission grid, which in turn yields higher line utilization.

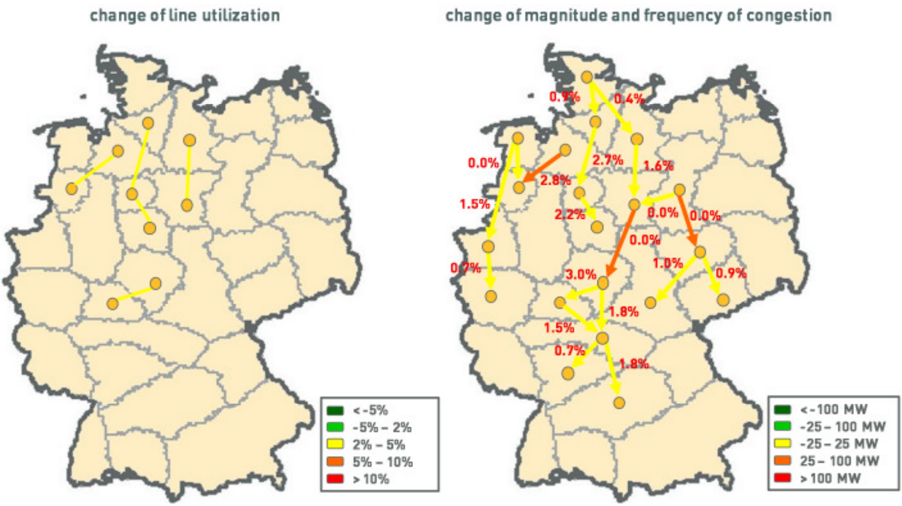


FIGURE 6.35: CHANGE OF WEIGHTED AVERAGE LINE UTILIZATION (LEFT) AND FREQUENCY AND MAGNITUDE OF CONGESTION (RIGHT) IN GERMANY IN THE YEAR 2025 IN THE SCENARIO *"LOAD STRUCTURE"*

Source: Own illustration.

Again, the higher line utilization induces additional lines to be congested. Furthermore, the magnitude of congestion is higher for the line between region 6 and region 9 as well as for two lines in the center and the East of Germany by up to 33 MW. In addition, the frequency of congestion is either identical or higher than in the *Reference Scenario*. These findings resemble the general model results (see Table 6.14) as higher and more frequent congestion yields higher redispatch and redispatch costs. Still, the relative increase is only moderate as redispatch costs and total redispatch in the year 2025 are both only 8 % higher than in the *Reference Scenario*.

6.4.3.3 Summary and conclusion

Summing up it can be said that a shift of load from the East and the North of Germany to the load centers in the West and the South of Germany induces an increase of congestion, redispatch and redispatch costs in all modeled years. As total demand in Germany is kept constant, the market outcome and power plant dispatch is identical to the *Reference Scenario*. Therefore, the increase of redispatch can entirely be attributed to the change of the regional export/import balances and the thereby induced higher transport of electricity through the German high voltage transmission grid.

Consequently, the shift of load as stipulated in the *Scenario "Load Structure"* has an unambiguous effect on redispatch costs and quantities. If load is shifted from the West and South to the North and East of Germany in contrast, the change of the export/import balances would change signs so that redispatch quantities and costs are reduced. Nevertheless, it is not clear what the impact of a combination of both set-ups would be on redispatch costs and quantities. Therefore, the exact magnitude and direction of the effect has to be analyzed on a case by case study.

6.5 Conclusion

The model results of the *Reference Scenario* in combination with the analysis of the sensitivity scenarios show that the prospective development of redispatch costs and quantities is highly influenced by the development of numerous decisive factors. It is shown that each of the factors – namely the development of the installed capacities of wind power plants, the development of the fuel prices and thereby the power plant fleet as well as the development of the regional distribution of load – has an observable impact on the development of congestion and redispatch individually.

However, as it is not clear how each of these factors will actually develop, it is hard to forecast the respective impact on redispatch costs and quantities. Rather, it is only possible to investigate more or less likely scenarios to obtain a bandwidth of possible development paths of redispatch costs and quantities induced by the respective factor.

Furthermore, only one factor was changed per sensitivity in the analysis. In reality all factors develop at the same time. How such an interplay of changing factors actually influences the network situation and thus redispatch costs and quantities is even more unclear. Again, the investigation of different scenarios might yield a general understanding of possible development paths of redispatch costs and quantities while a true forecast is impossible.

7 ECONOMIC ASSESSMENT OF NETWORK EXTENSIONS

In chapter 6 it was shown that increasing quantities of redispatch will be needed in the future. Hereby, the magnitude of the growth of redispatch quantities depends on the actual materialization of the feed-in of renewable energies, installed capacities of conventional plants, fuel prices and the regional distribution of load. Nevertheless, these higher quantities – irrespective of their exact magnitude – generally bring along increasing redispatch costs, which have to be borne by society.

In order to curtail the costs of redispatch, the transmission grid can be extended by additional lines or upgrades of already existing lines. In this way the transport capacity of the network is increased so that larger amounts of electricity can be transported. As a result, the intensity and frequency of congestion is decreased, leading to a reduction of the demand for redispatch and thereby to a reduction of the associated costs. The effect of the network extension on redispatch quantities and costs hereby not only depends on the transport capacity upgrade in MW. It is rather determined by an interplay between the location of the respective line and the effect on other lines on the one hand, and the development of the regional injection/withdrawal situation on the other hand.

In this chapter the effect of a network extension on redispatch quantities and costs on the basis of the scenarios depicted in chapter 6 is analyzed and it is shown how such an extension can be evaluated economically. First of all, the methodology of an economic assessment is explained (section 7.1) followed by a specification of the investigated network extension in section 7.2. Subsequently, the effect of the extension on redispatch is illustrated (section 7.3). Finally, a conclusion about the model results and their applicability for an economic assessment of the network extension will be drawn in section 7.4.

7.1 Methodology of Economic Assessment of Network Extensions

Economic theory stipulates that investments are desirable as long as the benefits of these investments are larger than the investment costs. By acting in accordance to this principle total welfare is increased. Of course, this assertion holds true for investments in the electricity transmission infrastructure as well. Consequently, a sound economic evaluation first of all requires a specification of the benefits of the investment. Following this, the costs of the investment have to be specified and weighted against the benefits to determine whether the investment is profitable or not.

In the following, the general principles of an economic evaluation of network extensions are outlined first (section 7.1.1). Subsequently, the benefits of a network extension are illustrated in section 7.1.2.

7.1.1 Economic evaluation of network extensions

Transferring the general principle of a cost/benefit analysis, as mentioned in the preface of this section, to the limits of the national electricity transmission network and network extensions yields the following. An economic assessment of the transmission capacity extension requires a comparison between the investment costs of the capacity addition and the induced reduction in network costs (the benefit). As long as the investment in the transmission network accrues benefits – i.e. reduces the costs of congestion – that are larger than the investment costs, the network extension is profitable to society.

In the optimum, the costs of a marginal unit of an additional network extension are just equal to the marginal benefit – i.e. the marginal congestion cost reduction – induced by it. Consequently, from an economic perspective it is not necessarily optimal to expand the network until no congestion costs and thus no congestion accrues anymore. The optimal limit of investment is rather reached as soon as the benefits are overcompensated by the costs of further expansions, which can be expected to be the case in a situation in which some congestion still prevails.[102]

Within this thesis it is shown how to evaluate network extensions from an economic perspective. The aim is to illustrate how to investigate whether a specific investment is socially preferable – thus, whether the benefits are larger than the investment costs – rather than showing how to specify the social optimum of network extensions.[103] For this purpose, the changes of redispatch costs due to a network extension are determined. As explained below, the changes of the redispatch costs are the benefits of the network extension.

The specification of the costs of the investment is neglected here. The exact investment costs of an expansion of the transmission network depend on numerous factors such as whether an already existing line at a given route is extended or a new route needs to be set up, the geographical and

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[102] See for example Spiecker et al. (2009), p. 322.

[103] The used model does not identify the optimum of network investments because extensions are specified exogenously rather than being determined endogenously. Furthermore, because of the physical characteristics of the meshed transmission network and the thereby induced correlations and interplays between numerous factors such a problem would usually be non-linear (so that no standard algorithms can be used). The specification of the optimum is thus a very demanding and complex task, which requires the use of non-standard algorithms such as a genetic algorithm. See Weise (2009) for an introduction to genetic algorithms and other optimization algorithms.

environmental conditions along the route, political restrictions and so on.[104] Consequently, the determination of the investment costs can only be conducted on a case-by-case study with very detailed technical information and is therefore beyond the scope of this thesis.

7.1.2 The benefits of a network extension

The benefits of a network extension can be identified by investigating the change of the welfare induced by the investment in the static market setting already introduced in chapter 2.[105] Hereby, the specification of the welfare effect of a network extension depends on the character of the relevant transmission line. It is different for extensions of interconnectors between two markets compared to an extension of internal transmission lines within a market with cost-based redispatch as internal congestion management. The static welfare effects in the known market setting of both applications are illustrated in Figure 7.1.[106]

In the left graph of the figure the static effect of a network extension between two markets – i.e. region A and region B – on welfare is shown.[107]

[104] A benchmark value for the costs of increases of the transmission capacity of the high-voltage transmission grid is 1 million Euros per kilometer for a classical 380 KV system. However, the costs might vary strongly from this benchmark from case to case.

[105] Again, the analysis and illustration relies on the assumption of a perfectly competitive market. If markets are not perfectly competitive, increases of the transmission capacity between two markets have repercussions on the competitive structure in each of them. This in neglected in the thesis.

[106] A complete economic welfare analysis would require not only a static but also a dynamic analysis. The latter includes an investigation of the welfare effect of different demand and supply and thus export/import situations in the course of time a well as an analysis of the dynamic adjustments of demand and supply. For the sake of simplicity this is neglected in the illustration.

[107] The figure and the whole illustration are based on the assumption of perfect competition. Thus, in case of an interconnector linking two markets, the effect of a network extension on the competitiveness of the individual markets and the resulting welfare effects are neglected. Furthermore, the effect of additional transmission capacity on the reliability of

With an interconnector that has a given transmission capacity, the price in market *A* is equal to P_A, while the price in market *B* is higher and equal to P_B (recall Figure 2.2). There is an export from region *A* to region *B* equal to the transmission capacity. As this capacity is not large enough to allow all desired electricity exchange, the prices do not convergence entirely. The limits of the transmission capacity thus impose a welfare loss to society equal to the triangle *ABC*.

In case of an investment in the interconnector that increases its transmission capacity, the exports from region *A* to region *B* increase by an amount equal to the additional transport capacity. The prices of the two markets further converge. In market *B* the price decreases from P_B to $P_{B'}$ while it increases from P_A to $P_{A'}$ in market *A*. Despite the increase in electricity exchange, full market convergence cannot be reached and there is still a welfare loss to society due to the limited transmission capacity. However, the welfare loss is now equal to the triangle *A'B'C* and therefore decreased by the area *ABB'A'*.[108]

the system or the possibility for mutual assistance in anciliary services is not considered here. In addition, an efficient allocation of the scarce transport capacity is assumed. Any problems concerning the allocation and design of transmission rights are neglected. Turvey (2006), pp. 1461 – 1471, gives an overview of possible inefficiencies, numerous approaches and practical examples of transmission capacity allocation.

108 The focus of the illustration is only on the change of welfare despite the fact that a change of welfare also has a distribution effect. However, as the analysis at hand focuses on the profitability of the network extension from a total welfare perspective, rather than from the perspective of individual market participants, this distribution effect is not explained here. For an illustration of the changes of consumer and producer surplus in both markets induced by network extensions the interested reader is referred to Turvey (2006), pp. 1458 – 1459.

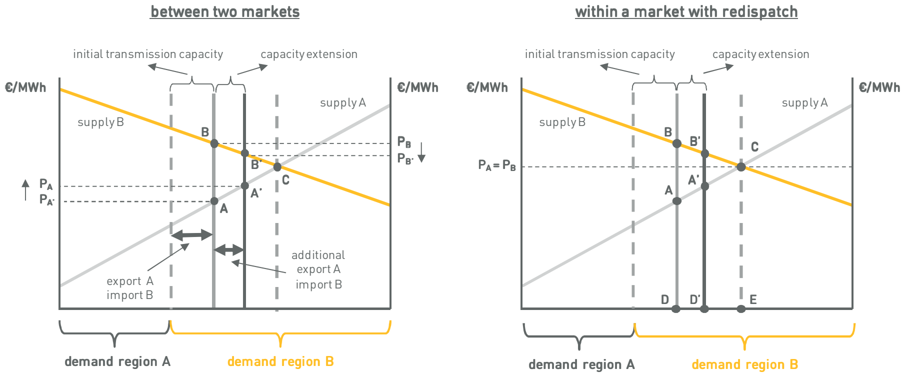

FIGURE 7.1: WELFARE EFFECT OF A NETWORK EXTENSION BETWEEN TWO MARKETS (LEFT) AND WITHIN A MARKET WITH REDISPATCH (RIGHT)

Source: Own illustration.

The effect on welfare changes if the relevant transmission line is an internal line rather than an interconnector between two markets. In the right graph of the figure the effect on welfare of an internal line extension in a market with cost-based redispatch as internal congestion management regime is depicted. In order to guarantee a uniform market price, redispatch is needed if the internal transmission capacity limit is exceeded (recall Figure 2.3).

In the initial situation supply in region *A* has to be reduced by an amount equal to the difference between point *E* and *D*. Hence, variable costs equal to the area *ACED* are saved. In contrast, supply in region *B* has to be increased by the same amount inducing additional variable production costs equal to *BDEC*.[109] Netting cost savings and additional costs leaves a net welfare loss equal to the triangle *ABC*. If the transmission capacity is

[109] The dynamic ramp-up and ramp-down costs are neglected in this illustration.

increased less redispatch is required so that the net welfare loss decreases by an amount equal to the area *ABB´A´* and is now equal to the triangle *A´B´C*.[110]

In the illustration it is shown that, despite a different line of argumentation, the change of welfare of a network extension in a static setting is identical irrespective of the type of transmission line – i.e. of whether the line is an interconnector between two markets or an internal transmission line. However, if dynamic effects are included this is no longer the case as outlined in the following.

If internal redispatching is needed additional ramp-up and ramp-down costs accrue which do not occur for a cross-border interconnector (or nodal/zonal pricing). Due to the fact that the limited transmission capacity is immediately incorporated and respected in case of cross-border electricity trade or in case of nodal/zonal pricing no post-market adjustments are needed.

Furthermore, the prevailing regional price differences between two markets (or induced by nodal/zonal pricing) have dynamic repercussions on electricity demand and supply as explained in the following. In a market without regional price differentiation generators only take the electricity generation costs into account while they completely disregard the congestion costs when deciding on the location of the plant. In addition, also consumers do not account for congestion and the induced costs when choosing a specific settlement. With regional price differences, however, both incorporate network congestion or rather the impact on the electricity

[110] In general, network extensions induce a reduction of congestion costs. However, due to the physical characteristics of the meshed network, it is also possible that a network extension increases congestion at other lines thereby increasing the welfare loss caused by the limited transmission capacity in sum over the whole system.

price when choosing their siting. Under such a regime of regional prices generators have an incentive to settle in high price regions or markets while consumers in contrast have an incentive to settle in low price regions. This leads to changes of the supply and demand structure in the different regions over time which in turn alters the price difference and the welfare analysis in general.

These dynamic adjustment processes do not occur in case of limits of internal transmission lines under a regime of redispatching. Neither electricity producer nor consumers observe any price differences nor do they have to bear the costs according to the costs-by-cause principle. As a result, recurring congestion does not induce any dynamic adjustment processes if internal redispatching is applied.

Summing up, the benefit of network extensions under a regime of cost-based redispatch is merely the reduction of the above outlined welfare loss (the reduction of the costs of congestion) due to redispatching. This welfare loss or cost of congestion is determined by the ramp-up and ramp-down costs as well as the variable costs and cost-savings of the generators redispatched. There are no other dynamic effects. As a consequence, the change of redispatch (congestion) costs for 288 hours of a year, for different model years and potentially for different demand/supply scenarios by use of the redispatch model DIANA is a valid estimation of the benefits of a network extension.

7.2 Description of the Considered Network Extension

In chapter 6 the redispatch costs and quantities of a reference scenario as well as three sensitivity scenarios are investigated. In the course of this investigation the line utilization and the average magnitude and frequency of congestion for each individual line are analyzed. It can be shown that from the year 2020 onwards for all considered scenarios the line connecting region 6 and 9 is the one that faces the *highest weighted average congestion*. Hereby, congestion is measured as the excess of electricity flow over the line capacity in MW. In turn, it can be shown that the line connecting region 1 and 3 is the line that most *frequently* faces congestion.

Analytically it cannot be specified whether an upgrade of a line with a higher magnitude of congestion or an upgrade of a line with a higher frequency of congestion has the greatest effect on redispatch quantities and costs. The exact impact of a line upgrade depends on the interplay between different factors such as the exact location of the line, the used technologies for redispatch and the influence of the line upgrade on other lines. It is also possible that an upgrade of a different line, which is neither the one with the highest congestion nor the line with the most frequent congestion, has the largest effect on redispatch quantities and costs.

Nevertheless, in this chapter the line with the highest magnitude of congestion – namely the line between region 6 and region 9 is upgraded as example. As this connection is only installed in the year 2020 and is non-existent beforehand, the investigated line extension is no real upgrade but rather a larger initial installation. Hereby, it is assumed that an additional parallel system is installed so that there are two parallel lines rather than one.

As shown in chapter 3, a change of the network topology requires the determination of a new PTDF matrix. Consequently, the additional line is integrated in the network model of the ie[3] and an entirely new PTDF matrix is specified (see appendix). This matrix in turn is then integrated into the model DIANA and the modeled years 2020 and 2025 are recalculated for all four scenarios.

7.3 Evaluation of the Network Extension by Use of the Model DIANA

As already mentioned, an economic evaluation of the network extension requires the weighting of costs and benefits. However, due to its complexity, its dependency on the exact situation and the partially unpredictable political process, the specification of the costs of the network upgrade of the line between region 6 and 9 is omitted. As a result, the focus in this chapter is on the determination of the benefits of the network extension and an according fluctuation margin.

In the course of this investigation all four scenarios are recalculated with the new PTDF matrix for the years 2020 and 2025 (see appendix). While the matrix changes, all other assumptions of the scenarios are retained. Consequently, neither the power plant dispatch at the wholesale market nor the regional weighted average net export/import balances alter. The line utilization and the congestion situation, however, do change as a consequence of the line upgrade.

In the following, the model results of all four scenarios are illustrated in section 7.3.1 to section 7.3.4. Again, the model results underlying the respective graphs can be found in the appendix. Subsequently, the results are summarized and a range of the impact of the network extension is constructed in section 7.3.5.

7.3.1 Effect of the network extension on redispatch in the Reference Scenario

In Figure 7.2 and Figure 7.3 the change of the weighted average line utilization for the *Reference Scenario* is shown in the left graphs. Hereby, the line utilization with the new PTDF matrix is compared to the initial line utilization of the scenario as investigated in chapter 6. The style of illustration and the meaning of the colors are identical to the annotations in chapter 6.

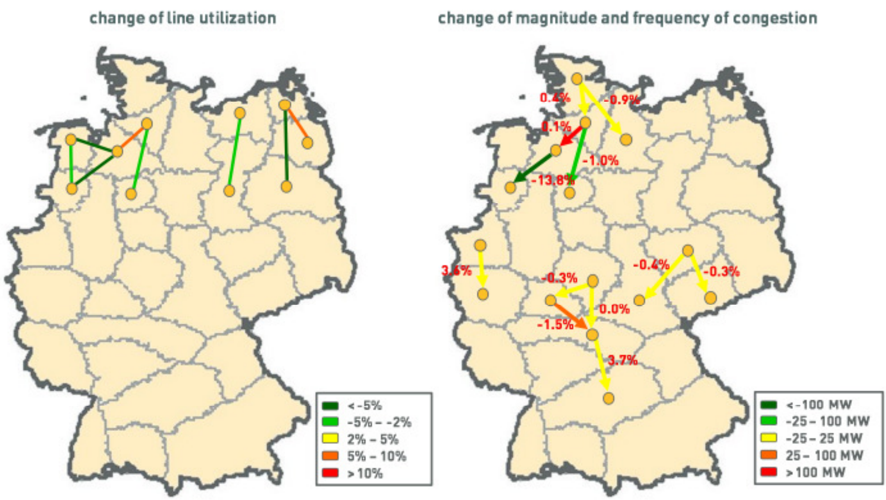

FIGURE 7.2: CHANGE OF WEIGHTED AVERAGE LINE UTILIZATION (LEFT) AND FREQUENCY AND MAGNITUDE OF CONGESTION (RIGHT) IN GERMANY IN THE YEAR 2020 IN THE *REFERENCE SCENARIO*

Source: Own illustration.

As can be seen, the upgrade of the connection between region 6 and region 9 does not only influence the utilization of lines in the direct neighborhood to the respective line, but other lines are affected, too. This can be explained by the fact that the change of network topology at one connection influences all PTDF factors in the whole system to a certain degree. Consequently, identical regional export/import balances yield different electricity flows and thus different line utilization rates everywhere.

In the graphs it is shown that especially the lines in the north-south direction in the very North are affected. Hereby, it is important to notice that on the one hand some lines are utilized less, while on the other hand the utilization of other lines increases. The upgraded line faces a strong reduction of utilization by more than 19 percentage points in both modeled years. The preceding line – namely the line connecting region 2 and 6 – in turn faces an increase of line utilization above 5 percentage points. Due to the fact that more electricity can flow through the line connecting region 6 and 9, more electricity is transported via the connection 2 and 6 so that its utilization rate increases.

In the right graph of the figures the change of the magnitude and frequency of congestion as compared to the calculations in chapter 6 is illustrated. Again, the scheme of the illustration is identical to the preceding chapter.

In Figure 7.2 it can be seen that in the year 2020 most of the overloaded lines face congestion with rather similar magnitude and frequency as in the initial calculations. Nevertheless, congestion between region 2 and 11 does no longer occur as a result to the network extension. In contrast, congestion does now occur between region 2 and 6 which was not the case without the extension. This resembles the higher line utilization already mentioned before. Furthermore, it can be observed that the magnitude of congestion of the upgraded connection is strongly decreased by about 278 MW on average, while the frequency of congestion is lower by 13.8 percentage points.

The outlined trend prevails and further aggravates for the year 2025. All lines that face congestion in the initial situation are also congested now with the network extension. Frequency and magnitude are similar for the lines in the center of Germany. The lines in north-south direction in the very North, however, face a decrease of average congestion of 25 MW to about 100 MW. The same holds true for the frequency of congestion which is lower by about 2 to 17 percentage points. Especially the upgraded line is less congested with a lower magnitude and frequency. On the other hand, the connection between region 14 and region 20 faces higher congestion by roughly 30 MW on average. This is due to the fact that more electricity is transported along the route at the western border in north-south direction as a consequence of the line upgrade in the North.

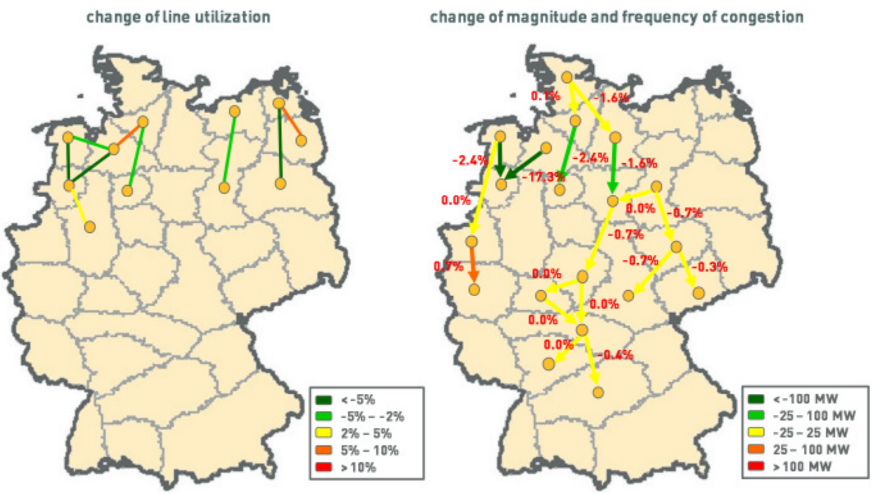

FIGURE 7.3: CHANGE OF WEIGHTED AVERAGE LINE UTILIZATION (LEFT) AND FREQUENCY AND MAGNITUDE OF CONGESTION (RIGHT) IN GERMANY IN THE YEAR 2025 IN THE *REFERENCE SCENARIO*

Source: Own illustration.

The effect of the network extension on the indicators already depicted in chapter 6 is summarized in Table 7.1 for the *Reference Scenario*. Hereby, the change of the indicators is stated in absolute as well as in relative terms.

TABLE 7.1: OVERVIEW OF THE CHANGE OF COSTS AND QUANTITIES OF REDISPATCH AND THE FREQUENCY AND MAGNITUDE OF NETWORK CONGESTION 2020 – 2025 IN THE *REFERENCE SCENARIO*

	2020		2025	
	absolute	relative	absolute	relative
maximum congestion (MW)	-464.6	-42.5%	-630.0	-47.3%
maximum redispatch (MW)	-1,326.9	-32.1%	-744.8	-7.6%
average congestion (MW)	-44.5	-24.9%	-48.8	-19.4%
average redispatch (MW)	-501.6	-36.9%	-463.2	-14.5%
frequency of congestion (% of h)	1.9	6.5%	-2.0	-4.2%
redispatch quantities (GWh/a)	-958.3	-43.1%	-1,755.7	-12.5%
redispatch costs (Mio. €/a)	-74.9	-49.2%	-203.3	-16.5%

Source: Own illustration.

It can be seen that maximum and average congestion decreases for both modeled years. Maximum congestion is strongly decreased by 42.5 % in the year 2020 and by 47.3 % in the year 2025. This strong reduction occurs due to the fact that the line facing the maximum congestion in the initial situation is exactly the one upgraded. The effect on average congestion is less pronounced but still negative. It is reduced by 24.9 % in the year 2020 and by 19.4 % in the year 2025. However, the results concerning the frequency of congestion are ambiguous. The frequency of congestion is increased for the year 2020 by 1.9 percentage points but is reduced by 2.0 percentage points in the year 2025.

As holds true for congestion, also maximum and average redispatch decrease as a consequence of the network extension. Maximum redispatch is reduced by 32.1 % and average redispatch by 36.9 % in the year 2020. This strong decrease indicates that the highest redispatch in the initial situation is required to resolve congestion at the now upgraded line. In the year 2025 the figures display a reduction of 7.6 % and 14.5 % respectively. In total, in the year 2020 about 43.1 % and in the year 2025 about 12.5 % less redispatch is required.

In line with the reduction of congestion and redispatch, also the redispatch costs strongly decrease due to the network extension. In the year 2020 about 49.7 % of the costs are reduced, while in the year 2025 the reduction is equal to 16.5 %.

In sum, the network extension has a strong dampening effect on redispatch quantities and costs in the *Reference Scenario*. However, in relative terms, the impact decreases in the course of time. Furthermore, the upgraded line between region 6 and region 9 is no longer the line with the highest magnitude of congestion, which is the connection between region 16 and region 25 in the year 2020 and the connection between region 1 and region 3 in the year 2025.

7.3.2 Effect of the network extension on redispatch in the Scenario "Fuel Price"

The change of the weighted average line utilization for the *Scenario "Fuel Price"* is illustrated in the left graphs of Figure 7.4 and Figure 7.5. Again, the line utilization with the new PTDF matrix is compared to the initial line utilization.

Comparing the graph with Figure 6.6 one can see that the change of the line utilization in the year 2020 in the *Scenario "Fuel Price"* is identical to the change in the *Reference Scenario* except that the utilization of the line between region 2 and 6 is less strongly increased. For the year 2025 the same holds true with the exception of the connection between region 6 and region 8. This line is not affected by a change of the utilization rate while in the *Reference Scenario* it is.

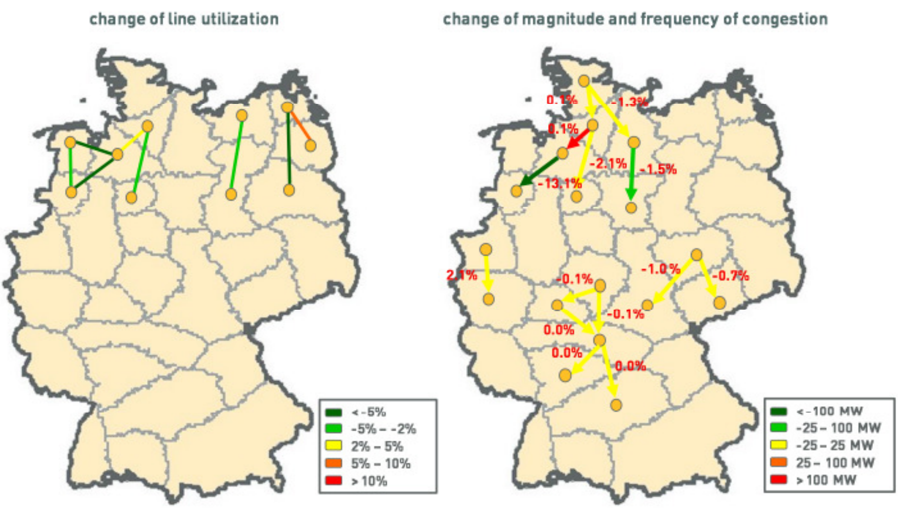

FIGURE 7.4: CHANGE OF WEIGHTED AVERAGE LINE UTILIZATION (LEFT) AND FREQUENCY AND MAGNITUDE OF CONGESTION (RIGHT) IN GERMANY IN THE YEAR 2020 IN THE *SCENARIO "FUEL PRICE"*

Source: Own illustration.

In the right graph of the figure the change of the frequency and magnitude of congestion compared to the situation without the network extension is depicted. As can be observed for the *Reference Scenario*, also in the *Scenario "Fuel Price"* the line between region 2 and region 6 in the year 2020 infrequently faces congestion although it does not without the network upgrade. All other lines facing congestion are identical to the initial situation with the frequency and magnitude of congestion being rather similar. One exception is the line from region 3 to region 11 for which average congestion decreases by 36 MW. This is induced by the fact that with the line upgrade more electricity is transported along the western border in south direction. Furthermore, the upgraded line between region 6 and region 9 faces a reduction of congestion of 366 MW on average and a reduction of the frequency of congestion of 13.1 percentage points due to the network extension.

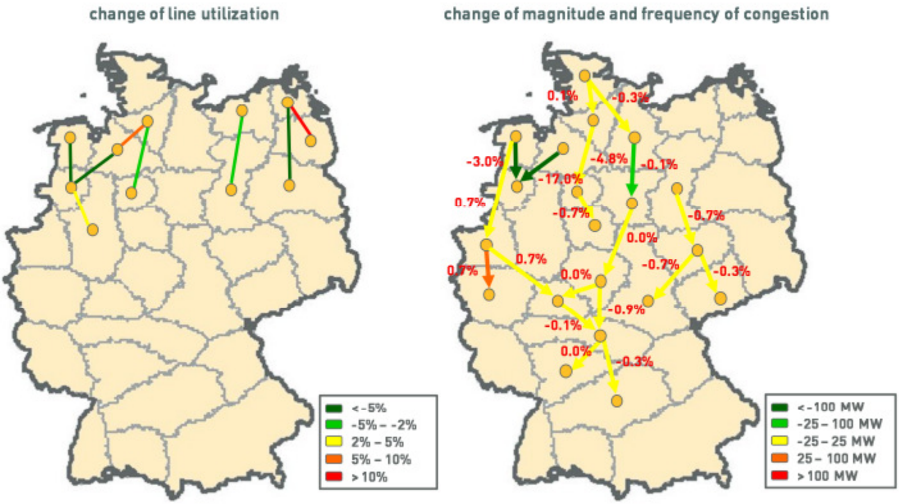

FIGURE 7.5: CHANGE OF WEIGHTED AVERAGE LINE UTILIZATION (LEFT) AND FREQUENCY AND MAGNITUDE OF CONGESTION (RIGHT) IN GERMANY IN THE YEAR 2025 IN THE *SCENARIO "FUEL PRICE"*

Source: Own illustration.

The observations are similar in the year 2025. All lines that are congested in the situation without the network extension are also congested in the situation with extension. Hereby, the frequency and magnitude of congestion of most lines changes only marginally. However, the magnitude of congestion of the line between region 3 and region 11 is on average by 43 MW lower as more electricity is transported along the path at the western border. Furthermore, the magnitude of congestion of the upgraded line is reduced by 375 MW and its frequency is reduced by 17.0 percentage points. In addition, the magnitude of congestion of the line between region 8 and 9 is reduced by 107 MW. This shows that the network extension also affects neighboring lines because less electricity is transported along these in case the connection between region 6 and 9 is upgraded by an additional parallel system.

In Table 7.2 the impact of the network extension on the congestion and redispatch indicators in the *Scenario "Fuel Price"* is outlined. Again, the change of the indicators is stated in absolute and relative terms.

In the *Scenario "Fuel Price"* maximum and average congestion are lower for both modeled years. In the year 2020 maximum congestion is strongly reduced by 43.2 % and average congestion is by 16.1 % lower in the case of the network extension. In the year 2025 the respective figures are a reduction of 37.2 % and a decrease of 14.8 %. The frequency of congestion in turn is only slightly reduced by 0.7 % in the year 2020 and is identical in the year 2025.

The reduction of redispatch due to the network extension is even stronger. Maximum redispatch is by 49 % lower in the year 2020 and by 18.4 % lower in the year 2025. Average redispatch decreases by 48 % in the year 2020 and by 11.7 % in the year 2025. In total redispatch quantities are cut by more than half in the year 2020 by a reduction of 65.6 %. In the year 2025 the effect is much less pronounced and quantities are reduced by only 9.6%. This shows that in the *Scenario "Fuel Price"* especially in the year

2020 the extension of the line between region 6 and 9 has a strong dampening impact on redispatch quantities. In the year 2025 the impact of the extensions is relatively weaker.

TABLE 7.2: OVERVIEW OF THE CHANGE OF COSTS AND QUANTITIES OF REDISPATCH AND THE FREQUENCY AND MAGNITUDE OF NETWORK CONGESTION FROM 2020 – 2025 IN THE *SCENARIO "FUEL PRICE"*

	2020		2025	
	absolute	relative	absolute	relative
maximum congestion (MW)	-434.7	-43.2%	-490.0	-37.2%
maximum redispatch (MW)	-3,092.3	-49.0%	-2,121.6	-18.4%
average congestion (MW)	-31.8	-16.1%	-39.3	-14.8%
average redispatch (MW)	-787.2	-48.0%	-393.8	-11.7%
frequency of congestion (% of h)	-0.3	-0.7%	0.0	0.0%
redispatch quantities (GWh/a)	-4,414.2	-65.6%	-1,638.4	-9.6%
redispatch costs (Mio. €/a)	-288.3	-70.3%	-189.5	-13.2%

Source: Own illustration.

The same holds true for redispatch costs. While the costs are by 70.3 % lower in the year 2020 due to the network extension, they are reduced by only 13.2 % in the year 2025. In absolute terms the reduction of costs decreases over time, too.

Summing up, it can be said that, as in the *Reference Scenario*, the network extension reduces redispatch costs and quantities in the *Scenario "Fuel Price"*. This effect decreases from 2020 to 2025 in relative and absolute terms. Furthermore, as a consequence of the line upgrade, the connection between region 6 and 9 is no longer the line with the highest congestion as in the *Reference Scenario*. In the *Scenario "Fuel Price"* the most congested line is now the connection between region 1 and 3 in both years.

7.3.3 Effect of the network extension on redispatch in the Scenario "Wind Power"

In the left graph of Figure 7.6 and Figure 7.7 it is illustrated how the weighted average line utilization in the year 2020 and 2025 in the *Scenario "Wind Power"* changes due to the network extension. As explained for the other two scenarios, the line utilization with the new PTDF matrix is compared to the initial line utilization.

The change of the line utilization in the year 2020 and the year 2025 is again very similar to the change in the *Reference Scenario* (see Figure 7.2 and Figure 7.3). However, as the *Scenario "Wind Power"* is specified such that less wind power generation in the North is fed into the system, less electricity needs to be transported in the north-south direction. This results in lower line utilization in the initial situation without network extension and also in a less pronounced change of line utilization in case the network is upgraded. Instead of changing by between 5 and 10 percentage points as in the *Reference Scenario*, the line utilization rate between region 2 and 6 and between region 5 and 7 only changes by 4.6 percentage points in the year 2020. In the year 2025 in turn, the utilization rate between region 6 and 8 is reduced more than in the *Reference Scenario*, while the utilization rate between region 9 and 15 in contrast does not change at all. Consequently, due to the fact that the line utilization in north-south direction is lower in the *Scenario "Wind Power"*, the impact of the network extension on the line utilization is less strong, too.

The change of the frequency and magnitude of congestion compared to the situation without the network extension is illustrated in the right graph of the figures.

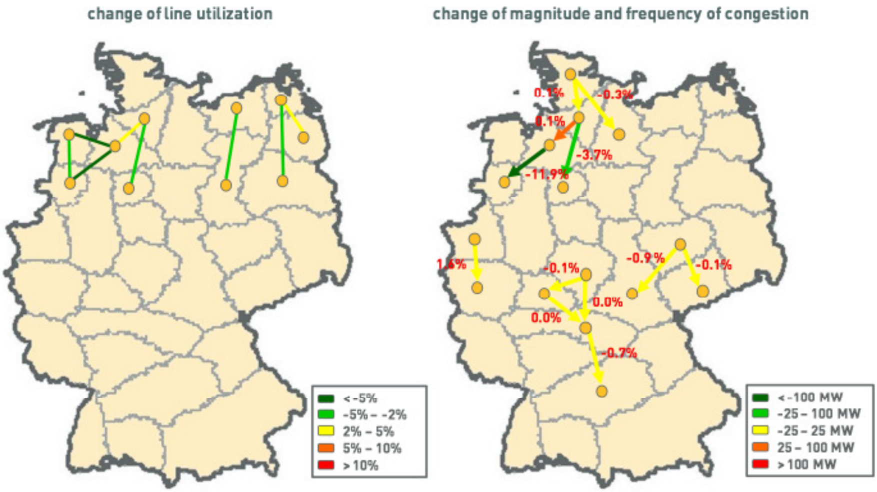

FIGURE 7.6: CHANGE OF WEIGHTED AVERAGE LINE UTILIZATION (LEFT) AND FREQUENCY AND MAGNITUDE OF CONGESTION (RIGHT) IN GERMANY IN THE YEAR 2020 IN THE *SCENARIO "WIND POWER"*

Source: Own illustration.

Again, in the year 2020 the same transmission lines are congested as without network extension. One exception is the line between region 2 and region 6 which only faces congestion in case the network is extended. For most of the other lines the magnitude and frequency of congestion is similar to the initial situation. In addition to the extended connection, only the line between region 2 and 10 faces a decrease of the average magnitude of congestion of about 32 MW. The strongest impact can nevertheless be observed for the line between region 6 and 9. For this connection the frequency of congestion is reduced by 11.9 percentage points and the magnitude of congestion is decreased by 270 MW on average due to the network upgrade.

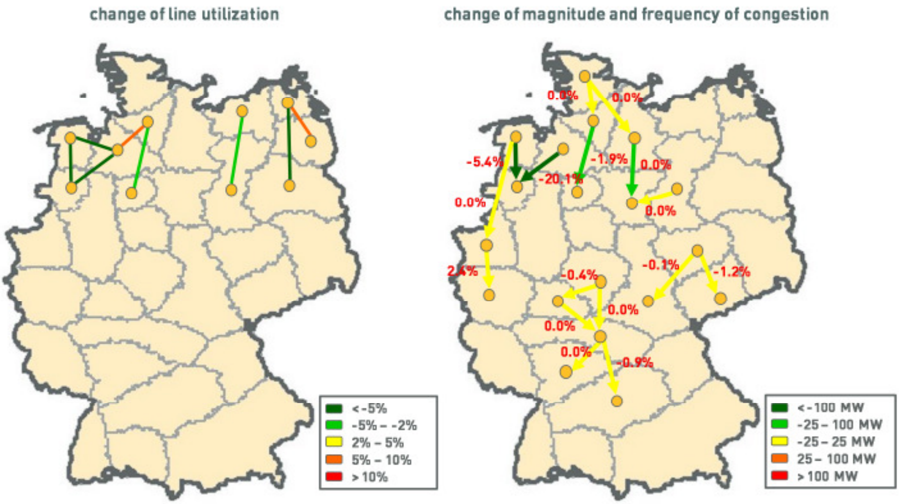

FIGURE 7.7: CHANGE OF WEIGHTED AVERAGE LINE UTILIZATION (LEFT) AND FREQUENCY AND MAGNITUDE OF CONGESTION (RIGHT) IN GERMANY IN THE YEAR 2025 IN THE *SCENARIO "WIND POWER"*

Source: Own illustration.

In the year 2025 all lines that are congested without the extension are also congested in case the network is upgraded between region 6 and region 9. Again, for most of the lines the magnitude and frequency of congestion is similar for both network situations. However, the lines between region 2 and 10 and between region 3 and 11 in north-south direction face a lower magnitude of congestion in the range of 25 MW to 100 MW. This again can be explained by the fact that the extension of the transmission line allows more electricity to be transported along the western border so that less is transported through the center in south direction. Furthermore, the magnitude of congestion is decreased for the upgraded line between region 6 and 9 by 308 MW on average, while the frequency of congestion decreases by 20.1 percentage points. In addition, the magnitude of congestion of the parallel line from region 8 to region 9 is by 107 MW lower and 5.4 percentage points less frequent.

The effect of the extension of the transmission line between region 6 and region 9 is summarized for the *Scenario "Wind Power"* in Table 7.3 for the relevant indicators in relative and absolute terms.

TABLE 7.3: OVERVIEW OF THE CHANGE OF COSTS AND QUANTITIES OF REDISPATCH AND THE FREQUENCY AND MAGNITUDE OF NETWORK CONGESTION FROM 2020 – 2025 IN THE *SCENARIO "WIND POWER"*

	2020		2025	
	absolute	relative	absolute	relative
maximum congestion (MW)	-369.5	-39.4%	-547.8	-49.9%
maximum redispatch (MW)	-940.9	-32.5%	-1,221.5	-16.4%
average congestion (MW)	-32.1	-23.1%	-47.2	-24.7%
average redispatch (MW)	-341.6	-29.0%	-320.1	-15.0%
frequency of congestion (% of h)	-7.2	-21.7%	-3.4	-8.0%
redispatch quantities (GWh/a)	-686.5	-48.2%	-1,278.6	-15.0%
redispatch costs (Mio. €/a)	-19.8	-20.4%	-503.7	-48.6%

Source: Own illustration.

In this scenario maximum and average congestion are reduced in the year 2020 and even more in the year 2025 compared to the situation without the network upgrade in absolute and relative terms. In the year 2020 maximum congestion is lower by 39.4 % and lower by 49.9 % in the year 2025. The figures for average congestion are 23.1 % and 24.7 % respectively. The frequency of congestion however is reduced stronger for the year 2020 (21.7 %) as compared to the reduction in the year 2025 (8.0 %).

As holds true for congestion, redispatch is also reduced in both modeled years in case the transmission line between region 6 and region 9 is extended. While maximum redispatch is by 32.5 % lower in the year 2020, it is still by 16.4 % lower in the year 2025. Average redispatch is reduced by 29.0 % and 15.0 % respectively. In total, about 48.2 % of redispatch is reduced in the year 2020 and 15.0 % of the redispatch quantities are reduced in 2025 in case the network is upgraded. Thus, in contrast to congestion, the reduction of redispatch in the *Scenario "Wind Power"* is stronger in the year 2020 than in the year 2025 in relative terms. In absolute terms the same trend prevails as can be observed for congestion (except for average redispatch).

The impact of the network extension on the costs of redispatch exhibits the same trend as for congestion. Costs are reduced by 20.4 % in the year 2020 and by 48.6 % in the year 2025. Hence, the reduction of the costs increases in relative and absolute terms in the course of time.

In sum, the network extension decreases redispatch costs and quantities with increasing magnitude in absolute and relative terms over time in the *Scenario "Wind Power".* This is in contrast to the observations for the *Reference Scenario* and the *Scenario "Fuel Price".* Still, similar to the other scenarios, the line that is extended is no longer the line with the strongest congestion. In the year 2020 the line with the highest congestion on average is now the connection between region 18 and region 22 and the connection between region 21 and region 25 in the year 2025.

7.3.4 Effect of the network extension on redispatch in the Scenario "Load Structure"

The change of the weighted average line utilization in the year 2020 and 2025 in the *Scenario "Load Structure"* is depicted in the left graph of Figure

7.8 and Figure 7.9. Again, the line utilization with the new PTDF matrix is compared to the initial line utilization.

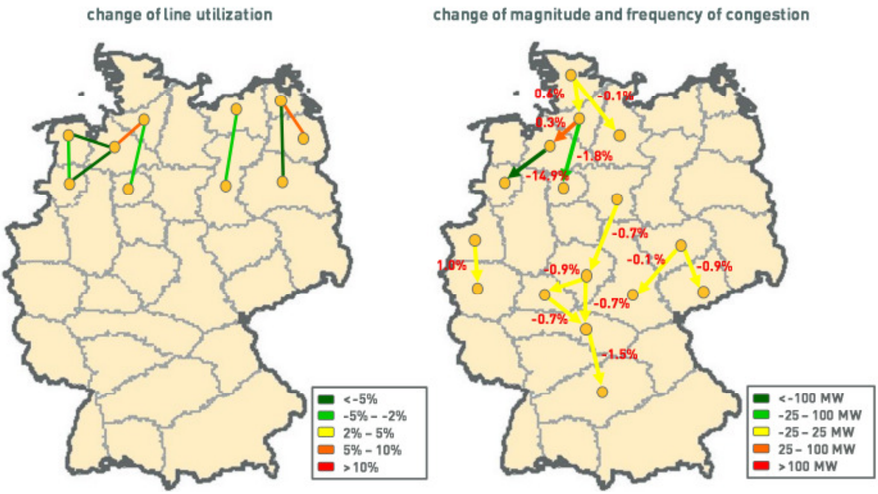

FIGURE 7.8: CHANGE OF WEIGHTED AVERAGE LINE UTILIZATION (LEFT) AND FREQUENCY AND MAGNITUDE OF CONGESTION (RIGHT) IN GERMANY IN THE YEAR 2020 IN THE *SCENARIO "LOAD STRUCTURE"*

Source: Own illustration.

As can be seen, once again the change of the line utilization in the year 2020 and the year 2025 is similar to the change in the *Reference Scenario* as illustrated in Figure 7.2 and Figure 7.3. In the year 2020 the changes are identical in magnitude. In the year 2025 an even stronger decrease of line utilization can be observed as the utilization rate between region 8 and 9 decreases by about 6 percentage points instead of about 5 percentage points in the *Reference Scenario*. This stronger decrease of line utilization induced by the network extension can be explained by the fact that the utilization of the transmission grid in the *Scenario "Load Structure"* in north-south direction is larger in the initial situation than in the *Reference Scenario*. As the initial utilization rate is higher, the impact of the line upgrade – i.e. the reduction of the utilization rate – is stronger.

In the right graph of the figures the impact of the network extension on the frequency and magnitude of congestion is illustrated. In the *Scenario "Load Structure"* the results show that in the year 2020 generally the same transmission lines are congested with and without network extension just as for the other scenarios. However, in case the line between region 6 and 9 is upgraded, congestion additionally occurs between region 2 to region 6, while the transmission line between region 3 and 11 is no longer congested.

Furthermore, it can be seen that the magnitude and frequency of congestion is similar to the initial situation for most of the transmission lines. Only the magnitude of congestion of the line between region 2 and 10 decreases by 30 MW on average and occurs 1.8 percentage points less frequently. This can be explained by the fact that with the network extension more electricity can be transported along the western border. In addition, the magnitude of congestion of the upgraded line between region 6 and 9 is reduced by 283 MW on average and the frequency of congestion is decreased by 14.9 percentage points.

Also in the year 2025, all lines that are congested without the extension are also congested in case the network is upgraded between region 6 and region 9. Thereby, the magnitude and frequency of congestion is similar with and without network extension for almost all lines. Only for the upgraded line and the transmission line between region 8 and 9 the magnitude of congestion is reduced by 401 MW and 116 MW respectively. Furthermore, the frequency of congestion is reduced by 18.3 and 2.4 percentage points. In contrast, the line between region 14 and 20 is stronger (by about 29 MW on average) and more frequently congested. This again is induced by the increase of electricity transport in north-south direction along the western border.

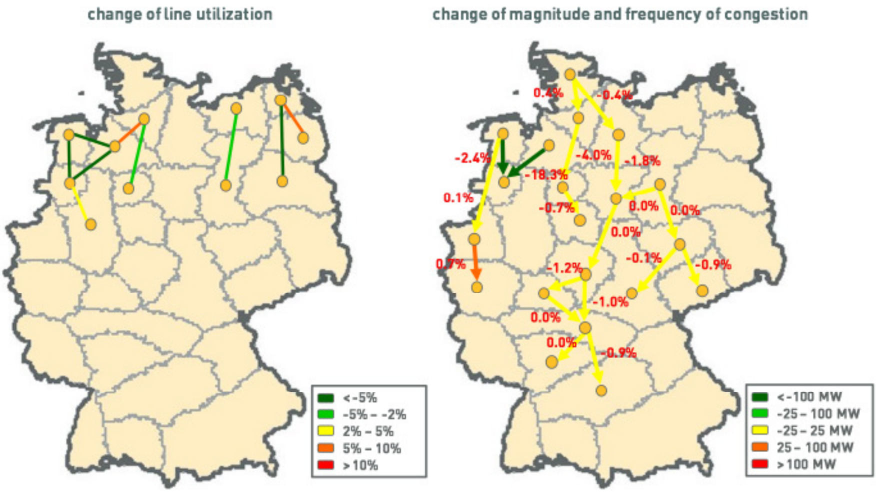

FIGURE 7.9: CHANGE OF WEIGHTED AVERAGE LINE UTILIZATION (LEFT) AND FREQUENCY AND MAGNITUDE OF CONGESTION (RIGHT) IN GERMANY IN THE YEAR 2025 IN THE *SCENARIO "LOAD STRUCTURE"*

Source: Own illustration.

An overview of the changes of the relevant indicators in the *Scenario "Load Structure"* induced by the upgrade of the transmission line between region 6 and 9 is given in Table 7.4 in absolute and relative terms.

Similar to the other scenarios, also in this scenario maximum and average congestion are reduced in the year 2020 and 2025 in comparison to the situation without line extension. Maximum congestion is reduced by 43.5 % in the year 2020 and by 48.2 % in the year 2025. Average congestion in turn is by 24.0 % lower in the year 2020 and by 20.4 % lower in the year 2025. Furthermore, the frequency of congestion is reduced by 5.1 % in the year 2020 and by 1.9 % in the year 2025.

TABLE 7.4: OVERVIEW OF THE CHANGE OF COSTS AND QUANTITIES OF REDISPATCH AND THE FREQUENCY AND MAGNITUDE OF NETWORK CONGESTION FROM 2020 – 2025 IN THE *SCENARIO "LOAD STRUCTURE"*

	2020		2025	
	absolute	relative	absolute	relative
maximum congestion (MW)	-499.0	-43.5%	-678.6	-48.2%
maximum redispatch (MW)	-1,419.9	-32.2%	-819.4	-7.8%
average congestion (MW)	-44.4	-24.0%	-52.7	-20.4%
average redispatch (MW)	-419.1	-31.4%	-470.7	-14.4%
frequency of congestion (% of h)	-1.7	-5.1%	-0.9	-1.9%
redispatch quantities (GWh/a)	-1,071.2	-42.7%	-2,014.9	-13.3%
redispatch costs (Mio. €/a)	-83.0	-48.7%	-202.1	-15.2%

Source: Own illustration.

The effect of the line upgrade on redispatch matches the observations for congestion. Average and maximum redispatch are by 31.4 % and 32.2 % lower in the year 2020 respectively. In the year 2025 the effect is relatively weaker as average and maximum redispatch are reduced by only 14.4% and 7.8 %. Finally, total redispatch quantities are reduced by 42.7% in the year 2020 and by 13.3 % in the year 2025. Consequently, as could already be observed in the *Reference Scenario*, in the *Scenario "Load Structure"* the impact of the line extension between region 6 and 9 is in relative terms higher for the year 2020 than for the year 2025 but in both cases negative.

The same holds true for the impact on redispatch costs. In the year 2020 costs are reduced by 48.7 % and by 15.2 % in the year 2025. In absolute terms, however, the impact increases in the course of time.

In sum, the impact of the line extension on redispatch quantities and costs is ambiguous in the *Scenario "Load Structure"*. While in relative terms, the reduction decreases from 2020 to 2025, in absolute terms the decrease of quantities and costs is higher in the year 2025 than in the year 2020. Again, the connection extended between region 6 and region 9 is no longer the line with the highest magnitude of congestion on average. This is the connection between region 16 and region 25 in the year 2020, while in 2025 the line between region 1 and region 3 is the one facing the highest congestion on average.

7.3.5 Summary and range of impact of the network extension

In Table 7.5 the change of the relevant indicators induced by the network extension are summarized for all four scenarios in absolute terms for the year 2020. The same information is given in Table 7.6 for the year 2025. Hereby, the grey-colored cell indicates the scenario with the lowest reduction, whereas the yellow-colored cell denotes the highest reduction. The difference between these two extremes can be used as a bandwidth of a likely reduction of the respective indicator that can be achieved by extending the line between region 6 and region 9 by an additional parallel line.

As can be seen, none of the scenarios has always the highest or lowest absolute reduction of all indicators. This holds true within one of the two years as well as for both years in sum. Consequently, the impact of the network reduction on the redispatch indicators in real terms is variable and cannot be explained analytically by the height of redispatch without the extension. The range of change of each of the indicators is outlined in the following.

Maximum congestion can be expected to be reduced by 369.5 MW to 499.0 MW in the year 2020. In the year 2025 a reduction of 490.0 MW to 678.6 MW can be achieved. Consequently, the amplitude as well as the level of the bandwidth of the reduction increases in the course of time. The attainable reduction becomes higher, but the exact figure becomes more uncertain. The same holds true for average congestion which can be reduced by 31.8 MW to 44.5 MW in the year 2020 and by 39.9 MW to 52.7 MW in the year 2025.

TABLE 7.5: SUMMARY OF THE CHANGE OF COSTS AND QUANTITIES OF REDISPATCH AND THE FREQUENCY AND MAGNITUDE OF NETWORK CONGESTION IN THE YEAR 2020 IN ABSOLUTE TERMS

	Reference	Fuel Price	Wind Power	Load Structure
maximum congestion (MW)	-464.6	-434.7	-369.5	-499.0
maximum redispatch (MW)	-1,326.9	-3,092.3	-940.9	-1,419.9
average congestion (MW)	-44.5	-31.8	-32.1	-44.4
average redispatch (MW)	-501.6	-787.2	-341.6	-419.1
frequency of congestion (% of h)	1.9	-0.3	-7.2	-1.7
redispatch quantities (GWh/a)	-958.3	-4,414.2	-686.5	-1,071.2
redispatch costs (Mio. €/a)	-74.9	-288.3	-19.8	-83.0

Source: Own illustration.

The only exception to this with respect to congestion is the frequency of congestion. While it can be expected that the frequency is reduced between 0.3 % and 7.2 % in the year 2020, only a reduction of <0.1 % to 3.4 % is attainable in the year 2025. Thus, the effect of the network extension on the frequency of congestion diminishes in the course of time.

The trend observed for the congestion indicators does not hold for the redispatch indicators. Maximum redispatch can be expected to be decreased by 940.9 MW to 3,092.3 MW in the year 2020. In the year 2025, only a decrease of maximum redispatch between 744.8 MW and 2,121.6 MW can be expected. Furthermore, according to the model results average redispatch decreases in the year 2020 between 234.6 MW and 787.2 MW, while in the year 2025 only a decrease of 320.1 MW to 470.7 MW can be expected. Consequently, for these two indicators the amplitude and the level of the range decrease over time. The attainable reduction is lower but more certain in the year 2025 than in the year 2020.

TABLE 7.6: SUMMARY OF THE CHANGE OF COSTS AND QUANTITIES OF REDISPATCH AND THE FREQUENCY AND MAGNITUDE OF NETWORK CONGESTION IN THE YEAR 2025 IN ABSOLUTE TERMS

	Reference	Fuel Price	Wind Power	Load Structure
maximum congestion (MW)	-630.0	-490.0	-547.8	-678.6
maximum redispatch (MW)	-744.8	-2,121.6	-1,221.5	-819.4
average congestion (MW)	-48.8	-39.3	-47.2	-52.7
average redispatch (MW)	-463.2	-393.8	-320.1	-470.7
frequency of congestion (% of h)	-2.0	0.0	-3.4	-0.9
redispatch quantities (GWh/a)	-1,755.7	-1,638.4	-1,278.6	-2,014.9
redispatch costs (Mio. €/a)	-203.3	-189.5	-503.7	-202.1

Source: Own illustration.

The reduction of total annual redispatch quantities shows a different trend in the course of time than average and maximum redispatch. In the year

2020 quantities can be expected to be reduced between 686.5 GWh/a and 4,414.4 GWh/a, while in the year 2025 the reduction can be expected to be between 1278.6 GWh/a and 2014.9 GWh/a. Consequently, as for the other two indicators, the amplitude of the bandwidth of reductions becomes smaller. However, the minimal attainable reductions become larger over time (and the maximum lower).

Despite the fact that the influence of the line upgrade on redispatch decreases or is at least ambiguous in the course of time, the impact on the redispatch costs is an increasing reduction. While in the year 2020 between 19.8 million Euros and 288.3 million Euros can be expected to be saved per year, the cost reductions increase to between 189.5 million and 503.7 million Euros in the year 2025.[111]

7.4 Conclusion

The model results show that an extension of the transmission network between region 6 and region 9 has a dampening effect on the redispatch costs in all considered scenarios. Thus, irrespective of the exact materialization of the underlying scenario assumptions, an increase of the transmission capacity can be expected to reduce costs.[112]

[111] The same uncertainites and problems with respect to the cost figures as already explained in chapter 6 hold for the model results in chapter 7. Consequently, the outlined values have to be interpreted with caution.

[112] In general, network extensions induce a reduction of congestion costs. However, due to the physical characteristics of the meshed network, it is also possible that a network extension increases congestion at other lines thereby increasing the redispatch costs. See footnote 110.

Nevertheless, the results indicate that the magnitude of the cost savings is highly influenced by the respective scenario and its underlying assumptions. Thus, the cost savings attainable are uncertain and dependent on an interplay of different factors, in the same manner as the development of redispatch costs in general is uncertain (see section 6.5).

In order to account for this uncertainty, the model DIANA can be applied to analyze different scenarios and to specify a range of possible redispatch cost reduction paths. This range of cost reductions can form the basis of a cost/benefit analysis of the investment project. For the final judgment of whether a specific investment in the transmission infrastructure is socially desirable or not, it is important to keep the respective weaknesses of the chosen method of a cost/benefit analysis in mind.

8 SUMMARY AND CONCLUSION

Summary of the scope of the dissertation, its implementation and results

In this dissertation a model to analyze the impact of recent developments of the electricity market on the national high-voltage transmission network from an economic perspective is developed. The purpose is to design a tool that allows including the costs induced on the network into an economic assessment in order to obtain a complete economic picture. Existing models and tools either focus on international transmission restrictions or on national restrictions based on the concepts of nodal or zonal pricing. However, international transmission restrictions are not the focus of the dissertation. Furthermore, nodal or zonal pricing is not used as a congestion management method in Germany. Hence, in order to allow a reasonable application to the German electricity system and respective inferences, the goal of the newly developed model is to reproduce the actual German market design of cost-based redispatch as accurately as possible.

For this purpose, the concept of PTDF matrixes is integrated into the dispatch model DIANA of EWI in a first step. Thereby the physical characteristics of electricity transmission can be modeled within a linear economic electricity market model. Although some physical features such as reactive power or network losses are neglected, which leads to a certain inaccuracy of the results, it can be argued that the model is still suitable for an economic analysis.

Furthermore, the concept of cost-based redispatch for network congestion relief is integrated into the model in a second step. Hereby, the model is subdivided into a two-stage linear optimization model. While the first stage comprises the optimization of the power plant dispatch, the second stage optimizes the use of redispatch subject to the limited transmission capacities.

In addition to the specification of the model, the model is applied to the prospective development of the German electricity system by use of a scenario analysis. By this means, the development of redispatch costs and quantities in Germany in the prospective years are highlighted. It can be shown that despite investments in the transmission infrastructure, the costs and quantities of redispatch increase in the course of time. Although the magnitude of this increase varies from scenario to scenario, a general trend of increasing costs and quantities can be observed for all scenarios. In addition, it can be observed that more and more dummy redispatch is applied by the model which indicates that cost-based redispatch as congestion management method sooner or later becomes insufficient to solve network congestion if congestion evermore increases.

Furthermore, the model results show that all investigated factors – namely the development of the fuel prices, the growth of capacities of wind power plants and the regional distribution of electricity demand – are relevant triggers for the development of network congestion and thereby redispatch. Dependent on the exact development of these three triggers, the transport of electricity from the North to the South of Germany may either decrease or increase. Hereby, increased electricity transport generally induces higher congestion and redispatch, while lower electricity transport generally induces less congestion and redispatch.

It is important to keep in mind that the investigated scenarios are no forecast but rather possible development paths of redispatch costs and quantities in the future. By use of the model the impact of individual factors on redispatch can be analyzed by varying one factor per scenario only.

Nevertheless, a true forecast of redispatch costs and quantities is impossible. This is due to the fact that the exact development of the set of factors cannot be determined with certainty. Furthermore, as already mentioned, by use of the model the impact of one individual factor can be investigated only. In reality, however, all factors change simultaneously. The impact of such a set of changing factors on the network situation is unclear because, due to the physical characteristics of the transmission of electricity, an analytical inference about the impact is rather impossible. Still, the model provides a general understanding of the development of redispatch costs and quantities.

Finally, the developed model is used to analyze a hypothetical network extension. It can be shown that increasing the transmission infrastructure generally leads to lower congestion and thus to lower redispatch costs and quantities. The change of congestion costs has to be weighted against the costs of the investment in order to judge whether the investment is socially optimal or not. Nevertheless, the limitations of the meaningfulness of the model results, as described above, have to be kept in mind for the assessment of network extensions, too. Furthermore, the used cost/benefit analysis method has to be chosen with care to fit the respective object of study suitably.

Conclusion

To conclude, the model results show that network congestion and the thereby induced costs can be expected to increase in the future. Due to the continued increase of redispatch quantities and costs, the incorporation of the impact of developments of the electricity market on the transmission network gains importance, too. While today, with relatively moderate redispatch costs, the neglect of the network in an economic assessment –

e.g. of policy measures – might be still acceptable, this will no longer be the case in the future. The model developed in this thesis is a tool that exactly allows this incorporation.

Moreover, the foreseeable development of the electricity market makes network extensions indispensable. Such network extensions, however, should not only be evaluated from a technical perspective, but should also be judged economically. As shown, the developed model can be used for such an economic assessment of investments in the transmission infrastructure.

Finally, the model results show that the current German market design of cost-based redispatch becomes insufficient for resolving congestion from a technical perspective. The use of dummy redispatch in the model herbey indicates a regional shortage of generation capacity available for redispatch (or the need to curtail demand). As a consequence, the results in this dissertation reveal the necessity to change the market design in the future (e.g. by introducing price regions or a capacity market for redispatch) in order to guarantee a secure and stable functioning of the electricity system.

Outlook and further research

The transmission of electricity through a meshed network – and thus network congestion, redispatch and redispatch costs – is strongly influenced by the details of the network topology on the one hand and the exact replication of the injection/withdrawal situation on the other hand. The more accurate the true transmission grid and the injection/withdrawal situation are depicted, the more accurate are the results with respect to redispatch and redispatch costs. Thus, further research should focus on a better modeling of these.

The model developed in this thesis strongly simplifies the physics of electricity transmission. It only incorporates active power flows within a given network while network losses and reactive power is neglected. Moreover, changes of the topology can only be included by an exogenous change of the PTDF matrix. Potential improvements of the PTDF approach should therefore be applied and thereby be incorporated in the model in order to enhance the model results. Furthermore, an incorporation of endogenous changes of the network topology would make new and additional objects of investigation feasible. For this purpose, switching from the PTDF approach to a DC model could be worthwhile in this regard.

In addition, the injection/withdrawal situation calculated by the model is also only a simplified reproduction of reality. The model specifies 288 hours of a year. These hours are only "average hours" per daytype and season. Very extreme situations – e.g. extremely high feed-in of wind power in the North – are neglected in the calcuations to a certain degree. However, exactly these extremes are the situations in which most congestion and redispatch occurs. Consequently, situations with very high congestion and redispatch are potentially averaged out by use of these model hours.

Further research should therefore focus on a better replication of the true injection/withdrawal situations including the extremes. One possibility is to expand the model to 8,760 hours per year so that all extreme situations are included. Alternatively, the choice of daytypes could be improved. The current specification of the 288 hours relies on a distinction with respect to the level of load. Thus, the days of the week and the season are the decisive distinguishing characteristics for the injection/withdrawal situation. However, with the proceeding increase of the feed-in of wind power and photovoltaic, the classical picture of a load-determined injection/withdrawal situation alters. Instead of using classical daytypes, using model hours that reproduce representative wind feed-in and photovoltaic feed-in situations would better replicate the crucial injection/withdrawal situation from a market as well as network perspective.

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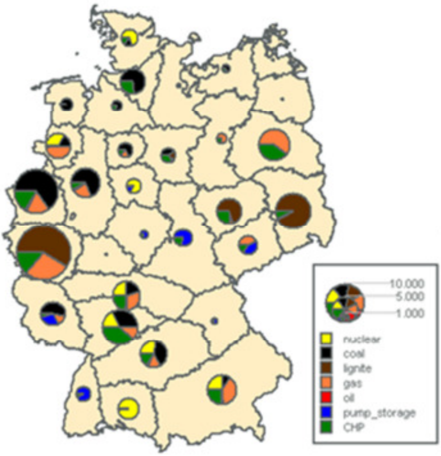
Appendix

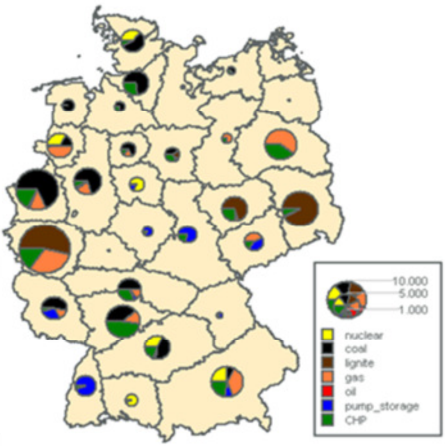
A. Assumptions

A.1 Regional distribution of installed capacity of conventional and CHP power plants in Germany in the *Reference Scenario*

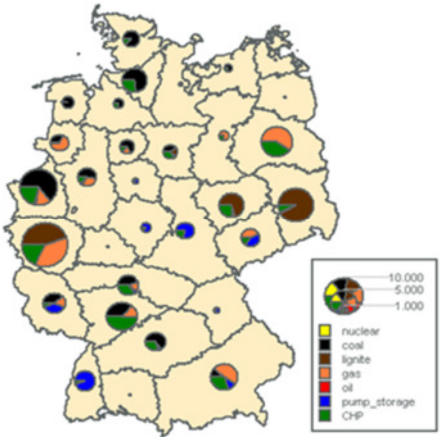
2015



2020



2025



A.2 Installed capacity of conventional and CHP power plants in Germany in the years 2015, 2020 and 2025

	SCENARIO "FUEL PRICE" installed capacity [MW]			
	2010	2015	2020	2025
nuclear	20,475	12,053	8,102	0
coal	19,799	19,495	32,991	28,200
lignite	20,363	18,951	17,493	15,164
gas	16,112	16,168	13,843	12,995
oil	1,183	0	0	0
pump-storage	7,435	7,435	9,435	9,435
CHP	21,182	19,279	19,279	19,279
TOTAL	**106,550**	**103,381**	**101,143**	**85,073**

A.3 PTDF Matrixes Chapter 6 (Source: ie^3)

2015 (Chapter 6)																															
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
01-02	0.230	-0.037	0.051	0.028	0.023	-0.025	0.020	-0.009	-0.005	-0.008	0.015	0.017	0.018	-0.003	-0.001	0.004	0.002	0.014	0.015	0.000	0.003	0.009	0.012	0.002	0.003	0.006	0.003	0.004	0.003	0.004	0.005
01-03	0.222	0.045	-0.061	-0.034	-0.028	0.031	-0.024	0.010	0.006	0.009	-0.018	-0.021	-0.022	0.003	0.001	-0.004	-0.003	-0.017	-0.018	0.000	-0.003	-0.011	-0.015	-0.003	-0.004	-0.008	-0.004	-0.004	-0.004	-0.005	-0.006
02-03	-0.009	0.138	-0.189	-0.104	-0.087	0.095	-0.074	0.032	0.018	0.029	-0.054	-0.065	-0.069	0.010	0.002	-0.014	-0.008	-0.051	-0.056	0.000	-0.010	-0.034	-0.046	-0.008	-0.011	-0.023	-0.012	-0.014	-0.012	-0.015	-0.020
02-06	0.119	0.128	0.108	0.071	0.063	-0.252	0.057	-0.073	-0.028	0.056	0.056	0.055	0.055	-0.018	0.000	0.028	0.041	0.046	0.048	0.000	0.018	0.036	0.042	0.010	0.016	0.025	0.016	0.017	0.015	0.017	0.022
02-10	0.139	0.156	0.117	0.056	0.043	0.102	0.034	0.025	0.002	-0.077	0.014	0.026	0.031	0.004	-0.003	-0.008	-0.025	0.018	0.022	0.000	-0.003	0.008	0.016	0.000	-0.001	0.005	0.000	0.001	0.001	0.002	0.004
03-04	0.087	0.076	0.101	-0.179	-0.137	0.053	-0.107	0.019	0.012	0.024	0.000	-0.070	-0.095	0.007	0.004	-0.007	0.008	-0.058	-0.071	0.000	-0.006	-0.037	-0.055	-0.007	-0.010	-0.025	-0.012	-0.014	-0.012	-0.015	-0.022
03-11	0.125	0.106	0.148	0.042	0.023	0.072	0.010	0.023	0.012	0.015	-0.071	-0.016	0.004	0.006	-0.001	-0.012	-0.018	-0.010	-0.003	0.000	-0.007	-0.008	-0.005	-0.003	-0.005	-0.005	-0.005	-0.004	-0.004	-0.004	-0.004
04-05	0.032	0.028	0.037	0.107	-0.189	0.020	-0.097	0.007	0.005	0.011	0.008	-0.003	-0.079	0.003	0.002	-0.002	0.006	-0.017	-0.044	0.000	-0.003	-0.016	-0.032	-0.004	-0.005	-0.014	-0.006	-0.007	-0.007	-0.008	-0.012
04-07	0.008	0.007	0.009	0.026	-0.002	0.004	-0.031	0.002	0.002	0.003	0.002	0.000	-0.017	0.001	0.001	0.000	0.002	-0.004	-0.010	0.000	-0.001	-0.004	-0.007	-0.001	-0.001	-0.004	-0.002	-0.002	-0.002	-0.002	-0.003
04-12	0.033	0.028	0.039	0.137	0.078	0.019	0.036	0.007	0.004	0.006	-0.010	-0.054	0.016	0.002	0.000	-0.003	-0.001	-0.027	-0.005	0.000	-0.002	-0.011	-0.007	-0.002	-0.002	-0.005	-0.002	-0.002	-0.002	-0.002	-0.003
05-07	0.021	0.019	0.025	0.070	0.152	0.013	-0.116	0.005	0.004	0.008	0.006	0.000	-0.045	0.002	0.002	-0.001	0.005	-0.010	-0.028	0.000	-0.002	-0.010	-0.020	-0.003	-0.003	-0.009	-0.004	-0.005	-0.005	-0.006	-0.009
05-13	0.018	0.015	0.020	0.059	0.120	0.011	-0.001	0.004	0.003	0.006	0.004	-0.004	-0.051	0.002	0.001	-0.001	0.003	-0.011	-0.026	0.000	-0.001	-0.009	-0.018	-0.002	-0.002	-0.007	-0.003	-0.004	-0.003	-0.004	-0.006
06-08	0.122	0.131	0.111	0.073	0.064	0.249	0.058	-0.075	-0.028	0.058	0.058	0.056	0.056	-0.018	0.001	0.029	0.042	0.048	0.049	0.000	0.018	0.037	0.043	0.011	0.016	0.026	0.016	0.017	0.015	0.018	0.022
06-09																															
07-13	0.008	0.007	0.009	0.030	0.049	0.005	0.131	0.002	0.001	0.002	0.000	-0.007	-0.044	0.001	0.000	-0.001	0.000	-0.009	-0.016	0.000	-0.001	-0.006	-0.010	0.000	-0.001	-0.002	-0.001	-0.001	0.000	0.000	-0.001
08-09	0.033	0.037	0.029	0.016	0.013	0.092	0.011	0.170	-0.117	-0.003	0.008	0.009	0.010	0.002	-0.011	0.001	-0.001	0.007	0.008	0.000	0.001	0.005	0.007	0.003	0.002	0.004	0.003	0.003	0.004	0.004	0.004
08-14	0.042	0.044	0.039	0.028	0.025	0.072	0.024	0.111	0.056	0.030	0.024	0.023	0.023	0.022	0.002	0.014	0.020	0.020	0.021	0.000	0.010	0.017	0.019	0.009	0.010	0.014	0.011	0.011	0.011	0.012	0.013
09-10	-0.096	-0.098	-0.094	-0.082	-0.077	-0.037	-0.074	0.050	0.112	-0.180	-0.093	-0.079	-0.074	0.035	0.002	-0.060	-0.099	-0.070	-0.069	0.000	-0.036	-0.061	-0.063	-0.020	-0.030	-0.043	-0.030	-0.031	-0.028	-0.031	-0.037
09-14	0.030	0.031	0.029	0.022	0.021	0.036	0.020	0.043	0.114	0.034	0.023	0.020	0.019	-0.020	0.011	0.015	0.023	0.018	0.018	0.000	0.009	0.016	0.016	0.005	0.008	0.011	0.007	0.008	0.007	0.008	0.009
09-15	0.021	0.023	0.018	0.011	0.009	0.037	0.008	0.058	0.099	0.018	0.008	0.008	0.008	0.025	-0.035	0.000	0.002	0.006	0.007	0.000	0.001	0.004	0.005	0.003	0.002	0.004	0.003	0.003	0.004	0.004	0.004
10-11	0.001	0.005	-0.004	-0.015	-0.016	0.005	-0.016	0.005	0.006	0.040	-0.041	-0.023	-0.017	-0.019	0.001	-0.003	0.001	-0.016	-0.016	0.000	-0.002	-0.010	-0.013	-0.002	-0.003	-0.007	-0.003	-0.004	-0.003	-0.004	-0.006
10-16	0.049	0.053	0.044	0.022	0.016	0.040	0.012	0.022	0.023	0.096	0.026	0.014	0.010	0.011	0.008	-0.035	0.037	0.002	0.004	0.000	-0.019	-0.012	-0.002	-0.009	-0.013	-0.010	-0.012	-0.011	-0.010	-0.010	-0.009
17-10	-0.069	-0.080	-0.056	-0.021	-0.014	-0.059	-0.010	-0.028	-0.030	-0.180	0.013	-0.002	-0.008	-0.009	0.012	0.001	0.117	-0.003	-0.005	0.000	0.000	-0.002	-0.003	-0.001	0.000	-0.002	-0.001	-0.001	-0.001	-0.001	-0.002
11-12	0.009	0.012	0.006	-0.121	-0.134	0.010	-0.141	0.008	0.009	0.031	0.105	-0.212	-0.149	0.006	0.009	0.001	0.044	-0.144	-0.135	0.000	-0.005	-0.076	-0.107	-0.011	-0.013	-0.047	-0.018	-0.023	-0.020	-0.026	-0.038
11-16	0.055	0.051	0.061	0.056	0.051	0.037	0.047	0.016	0.013	0.036	0.109	0.063	0.047	0.007	0.006	-0.032	0.041	0.036	0.037	0.000	-0.017	0.008	0.024	-0.005	-0.009	0.002	-0.007	-0.005	-0.004	-0.003	0.001
17-11	-0.059	-0.047	-0.074	-0.090	-0.088	-0.030	-0.086	-0.004	0.004	0.014	-0.172	-0.109	-0.087	0.004	0.015	-0.015	0.102	-0.079	-0.078	0.000	-0.012	-0.049	-0.064	-0.011	-0.014	-0.032	-0.017	-0.019	-0.017	-0.021	-0.027
12-13	0.002	0.003	0.001	-0.027	-0.080	0.002	-0.114	0.002	0.002	0.007	0.023	0.062	-0.139	0.001	0.002	0.002	0.010	0.010	-0.056	0.000	-0.001	-0.009	-0.036	-0.003	-0.003	-0.012	-0.005	-0.006	-0.006	-0.008	-0.011
12-18	0.034	0.031	0.038	0.059	0.045	0.023	0.034	0.010	0.008	0.021	0.047	0.109	0.032	0.005	0.005	-0.005	0.021	-0.186	-0.013	0.000	-0.005	-0.065	-0.034	-0.006	-0.008	-0.025	-0.010	-0.012	-0.010	-0.013	-0.018
12-19	0.013	0.012	0.014	0.013	-0.005	0.009	-0.018	0.004	0.004	0.010	0.022	0.053	-0.022	0.002	0.003	0.001	0.011	0.000	-0.072	0.000	-0.001	-0.015	-0.046	-0.004	-0.004	-0.015	-0.006	-0.008	-0.007	-0.009	-0.013
13-19	0.019	0.017	0.021	0.049	0.074	0.012	0.087	0.005	0.004	0.009	0.013	0.021	0.106	0.002	0.002	-0.001	0.007	-0.010	-0.059	0.000	-0.002	-0.016	-0.038	-0.003	-0.004	-0.012	-0.005	-0.006	-0.005	-0.006	-0.009
14-15	-0.053	-0.052	-0.054	-0.053	-0.052	-0.041	-0.051	-0.025	-0.036	-0.061	-0.061	-0.054	-0.051	-0.002	-0.139	-0.054	-0.075	-0.051	-0.050	0.000	-0.033	-0.049	-0.048	-0.021	-0.028	-0.036	-0.028	-0.029	-0.027	-0.029	-0.033
14-20	0.087	0.088	0.085	0.076	0.074	0.096	0.072	0.107	0.111	0.087	0.081	0.074	0.071	0.120	0.122	0.068	0.089	0.069	0.069	0.000	0.048	0.065	0.065	0.035	0.041	0.052	0.043	0.045	0.044	0.046	0.049
14-21	-0.003	-0.003	-0.004	-0.006	-0.006	0.000	-0.007	0.003	0.003	-0.004	-0.006	-0.007	-0.007	0.005	0.004	-0.011	-0.004	-0.007	-0.007	0.000	-0.022	-0.009	-0.008	-0.007	-0.010	-0.009	-0.009	-0.009	-0.008	-0.008	-0.008

2015 continued (Chapter 6)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
16-15	0.032	0.030	0.035	0.044	0.046	0.016	0.047	-0.004	-0.010	0.034	0.044	0.048	0.048	-0.014	-0.044	0.083	0.030	0.053	0.050	0.000	0.049	0.061	0.052	0.028	0.039	0.045	0.038	0.038	0.035	0.038	0.041
17-15	0.090	0.089	0.093	0.089	0.086	0.058	0.083	0.014	0.008	0.112	0.114	0.091	0.083	-0.007	-0.044	0.064	0.171	0.080	0.078	0.000	0.039	0.068	0.071	0.025	0.034	0.049	0.035	0.037	0.034	0.037	0.043
16-17	-0.038	-0.038	-0.037	-0.022	-0.016	-0.030	-0.012	-0.018	-0.019	-0.054	-0.044	-0.019	-0.011	-0.011	-0.017	0.050	-0.110	-0.002	-0.004	0.000	0.028	0.018	0.004	0.013	0.020	0.015	0.018	0.017	0.015	0.015	0.014
16-21	0.086	0.085	0.088	0.089	0.088	0.067	0.086	0.041	0.040	0.095	0.102	0.093	0.087	0.027	0.042	0.153	0.097	0.093	0.085	0.000	-0.144	0.098	0.082	-0.004	-0.011	0.034	-0.004	0.003	0.002	0.007	0.021
22-16	0.028	0.023	0.033	0.081	0.095	0.016	0.105	0.004	0.001	0.002	0.028	0.095	0.110	0.000	-0.005	-0.048	0.000	0.153	0.130	0.000	-0.016	0.230	0.152	0.011	0.009	0.088	0.020	0.030	0.025	0.036	0.062
16-25	0.051	0.050	0.051	0.048	0.045	0.039	0.043	0.024	0.024	0.059	0.060	0.050	0.043	0.016	0.027	0.099	0.060	0.047	0.040	0.000	0.016	0.050	0.036	-0.040	-0.061	-0.013	-0.051	-0.043	-0.042	-0.037	-0.024
18-19	-0.002	-0.002	-0.003	-0.013	-0.027	-0.001	-0.036	0.000	0.000	0.001	0.003	0.007	-0.040	0.000	0.001	0.003	0.002	0.090	-0.074	0.000	0.001	0.014	-0.036	-0.001	-0.001	-0.005	-0.002	-0.003	-0.003	-0.004	-0.006
18-22	0.035	0.031	0.039	0.069	0.070	0.022	0.070	0.009	0.007	0.019	0.041	0.096	0.072	0.004	0.004	-0.009	0.018	0.202	0.065	0.000	-0.006	-0.080	0.019	-0.004	-0.007	-0.017	-0.007	-0.007	-0.006	-0.007	-0.009
18-23	0.003	0.003	0.004	0.005	0.002	0.002	-0.001	0.001	0.001	0.003	0.006	0.012	-0.001	0.001	0.001	0.001	0.003	0.041	-0.009	0.000	0.000	0.001	-0.033	-0.001	-0.001	-0.005	-0.002	-0.003	-0.002	-0.003	-0.005
23-19	-0.015	-0.013	-0.016	-0.032	-0.040	-0.010	-0.044	-0.004	-0.003	-0.008	-0.015	-0.030	-0.048	-0.002	-0.002	0.000	-0.008	-0.018	-0.066	0.000	0.002	0.014	0.059	0.003	0.004	0.014	0.005	0.006	0.005	0.006	0.009
20-21	-0.067	-0.065	-0.069	-0.076	-0.078	-0.053	-0.079	-0.036	-0.035	-0.069	-0.076	-0.079	-0.080	-0.026	-0.034	-0.098	-0.069	-0.083	-0.081	0.000	-0.157	-0.087	-0.083	-0.062	-0.086	-0.083	-0.082	-0.080	-0.076	-0.078	-0.080
20-24	-0.029	-0.028	-0.029	-0.034	-0.036	-0.024	-0.037	-0.018	-0.017	-0.028	-0.031	-0.035	-0.037	-0.013	-0.014	-0.036	-0.028	-0.038	-0.039	0.000	-0.037	-0.040	-0.041	-0.136	-0.055	-0.050	-0.057	-0.057	-0.061	-0.058	-0.054
20-25	-0.049	-0.048	-0.050	-0.059	-0.062	-0.039	-0.063	-0.027	-0.026	-0.048	-0.055	-0.061	-0.064	-0.019	-0.023	-0.065	-0.048	-0.066	-0.067	0.000	-0.069	-0.070	-0.070	-0.074	-0.104	-0.086	-0.097	-0.093	-0.088	-0.089	-0.087
21-25	0.015	0.015	0.014	0.006	0.002	0.012	-0.001	0.007	0.008	0.021	0.019	0.006	0.000	0.005	0.012	0.043	0.022	0.001	-0.005	0.000	0.175	0.001	-0.010	-0.074	-0.109	-0.060	-0.096	-0.088	-0.084	-0.080	-0.069
22-23	-0.018	-0.016	-0.021	-0.048	-0.063	-0.011	-0.074	-0.004	-0.002	-0.005	-0.016	-0.042	-0.078	-0.001	0.000	0.015	-0.004	-0.013	-0.108	0.000	0.006	0.089	-0.177	-0.002	0.000	-0.012	-0.004	-0.006	-0.006	-0.009	-0.016
22-26	0.025	0.023	0.026	0.036	0.038	0.017	0.038	0.009	0.008	0.022	0.029	0.042	0.040	0.005	0.008	0.024	0.022	0.063	0.042	0.000	0.004	0.100	0.043	-0.013	-0.016	-0.093	-0.023	-0.031	-0.025	-0.034	-0.055
24-25	-0.018	-0.017	-0.019	-0.022	-0.023	-0.012	-0.024	-0.005	-0.005	-0.019	-0.022	-0.024	-0.024	-0.002	-0.008	-0.029	-0.019	-0.026	-0.025	0.000	-0.034	-0.028	-0.026	0.194	-0.054	-0.032	-0.037	-0.029	-0.010	-0.019	-0.024
25-26	-0.026	-0.025	-0.029	-0.045	-0.051	-0.019	-0.055	-0.010	-0.009	-0.020	-0.029	-0.048	-0.056	-0.006	-0.007	-0.015	-0.019	-0.059	-0.064	0.000	0.002	-0.066	-0.074	0.007	0.021	-0.161	-0.003	-0.025	-0.015	-0.037	-0.089
25-27	-0.006	-0.006	-0.007	-0.011	-0.013	-0.005	-0.015	-0.004	-0.004	-0.004	-0.006	-0.012	-0.015	-0.003	-0.002	0.001	-0.003	-0.014	-0.017	0.000	0.007	-0.014	-0.019	-0.006	0.017	-0.034	-0.120	-0.099	-0.092	-0.085	-0.061
25-28	-0.002	-0.002	-0.002	-0.004	-0.005	-0.002	-0.005	-0.001	-0.001	-0.002	-0.002	-0.004	-0.005	-0.001	-0.001	-0.001	-0.002	-0.005	-0.006	0.000	0.001	-0.005	-0.006	-0.001	0.004	-0.009	-0.012	-0.028	-0.014	-0.022	-0.016
28-26	-0.015	-0.014	-0.016	-0.025	-0.027	-0.010	-0.029	-0.005	-0.004	-0.012	-0.017	-0.026	-0.030	-0.002	-0.004	-0.010	-0.011	-0.032	-0.034	0.000	-0.002	-0.037	-0.040	0.008	0.006	-0.092	0.027	0.051	0.025	0.028	-0.025
26-31	0.007	0.007	0.007	0.011	0.012	0.005	0.012	0.002	0.002	0.006	0.008	0.012	0.013	0.001	0.002	0.006	0.006	0.016	0.015	0.000	0.002	0.021	0.019	-0.005	0.000	0.060	-0.011	-0.019	-0.020	-0.046	-0.151
27-28	-0.007	-0.006	-0.007	-0.012	-0.014	-0.005	-0.016	-0.004	-0.003	-0.005	-0.007	-0.013	-0.016	-0.003	-0.002	-0.002	-0.004	-0.015	-0.018	0.000	0.004	-0.016	-0.020	-0.002	0.011	-0.038	0.034	-0.111	-0.014	-0.081	-0.058
27-29	0.000	0.000	0.000	0.000	-0.001	-0.001	-0.001	-0.002	-0.002	0.001	0.001	0.000	-0.001	-0.002	0.000	0.004	0.002	0.000	-0.001	0.000	0.007	0.001	-0.001	-0.009	0.013	-0.001	0.028	0.003	-0.138	-0.021	-0.014
30-28	0.004	0.003	0.004	0.007	0.008	0.003	0.009	0.002	0.002	0.002	0.003	0.007	0.009	0.002	0.001	0.000	0.002	0.008	0.010	0.000	-0.004	0.007	0.011	0.002	-0.009	0.013	-0.020	-0.044	0.016	0.129	0.071
30-31	-0.012	-0.011	-0.013	-0.021	-0.024	-0.008	-0.026	-0.004	-0.003	-0.009	-0.014	-0.022	-0.026	-0.002	-0.003	-0.008	-0.009	-0.026	-0.029	0.000	-0.002	-0.028	-0.033	0.007	0.003	-0.059	0.017	0.029	0.024	0.067	-0.206

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	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
01-02	0.231	-0.026	0.040	0.022	0.018	-0.014	0.015	-0.006	-0.005	-0.005	0.012	0.014	0.014	-0.002	-0.001	0.003	0.002	0.011	0.012	0.000	0.002	0.007	0.009	0.002	0.002	0.005	0.003	0.003	0.003	0.003	0.004
01-03	0.220	0.031	-0.048	-0.026	-0.022	0.017	-0.018	0.007	0.006	0.006	-0.014	-0.016	-0.017	0.003	0.001	-0.004	-0.002	-0.013	-0.014	0.000	-0.003	-0.008	-0.011	-0.002	-0.003	-0.006	-0.003	-0.004	-0.003	-0.004	-0.005
02-03	-0.014	0.096	-0.149	-0.082	-0.067	0.054	-0.056	0.022	0.020	0.019	-0.044	-0.051	-0.053	0.009	0.003	-0.011	-0.008	-0.040	-0.043	0.000	-0.008	-0.026	-0.035	-0.006	-0.008	-0.020	-0.010	-0.011	-0.010	-0.012	-0.017
02-06	0.153	0.162	0.142	0.090	0.078	-0.182	0.069	-0.067	-0.049	0.068	0.070	0.068	0.067	-0.022	-0.001	0.034	0.050	0.056	0.058	0.000	0.021	0.043	0.050	0.012	0.018	0.032	0.019	0.020	0.018	0.021	0.027
02-10	0.123	0.135	0.108	0.049	0.037	0.068	0.028	0.021	0.011	-0.085	0.008	0.020	0.025	0.005	-0.003	-0.011	-0.029	0.014	0.017	0.000	-0.005	0.004	0.012	-0.001	-0.002	0.003	-0.001	0.000	0.000	0.001	0.003
03-04	0.083	0.073	0.094	-0.181	-0.138	0.042	-0.106	0.019	0.017	0.023	-0.002	-0.070	-0.094	0.008	0.005	-0.007	0.007	-0.058	-0.071	0.000	-0.006	-0.036	-0.055	-0.008	-0.010	-0.028	-0.012	-0.015	-0.013	-0.017	-0.024
03-11	0.115	0.100	0.133	0.033	0.016	0.055	0.004	0.022	0.018	0.012	-0.077	-0.021	-0.002	0.008	0.000	-0.014	-0.021	-0.015	-0.008	0.000	-0.008	-0.011	-0.009	-0.004	-0.006	-0.008	-0.005	-0.006	-0.005	-0.005	-0.006
04-05	0.031	0.028	0.035	0.107	-0.187	0.016	-0.094	0.008	0.007	0.011	0.008	-0.003	-0.077	0.003	0.003	-0.002	0.007	-0.016	-0.043	0.000	-0.002	-0.016	-0.032	-0.004	-0.005	-0.014	-0.006	-0.008	-0.007	-0.009	-0.013
04-07	0.008	0.007	0.009	0.026	-0.002	0.004	-0.031	0.002	0.002	0.003	0.002	0.000	-0.017	0.001	0.001	0.000	0.002	-0.004	-0.010	0.000	-0.001	-0.004	-0.007	-0.001	-0.001	-0.004	-0.002	-0.002	-0.002	-0.002	-0.003
04-12	0.030	0.027	0.035	0.134	0.075	0.015	0.032	0.006	0.005	0.005	-0.011	-0.055	0.014	0.002	0.001	-0.004	-0.002	-0.028	-0.006	0.000	-0.002	-0.011	-0.008	-0.002	-0.002	-0.006	-0.002	-0.003	-0.002	-0.003	-0.003
05-07	0.021	0.019	0.024	0.071	0.154	0.011	-0.112	0.005	0.005	0.008	0.006	0.001	-0.042	0.002	0.002	-0.001	0.005	-0.009	-0.027	0.000	-0.002	-0.010	-0.020	-0.003	-0.003	-0.010	-0.005	-0.006	-0.005	-0.007	-0.010
05-13	0.016	0.015	0.019	0.059	0.119	0.009	-0.002	0.004	0.004	0.006	0.003	-0.004	-0.052	0.002	0.001	-0.001	0.003	-0.011	-0.026	0.000	-0.001	-0.009	-0.018	-0.002	-0.002	-0.007	-0.003	-0.004	-0.003	-0.004	-0.006
06-08	0.079	0.083	0.073	0.047	0.041	0.158	0.037	-0.081	-0.002	0.039	0.038	0.036	0.036	-0.013	0.002	0.019	0.028	0.030	0.031	0.000	0.011	0.023	0.027	0.006	0.009	0.017	0.010	0.011	0.009	0.011	0.014
06-09	0.151	0.160	0.140	0.088	0.076	0.322	0.067	0.024	-0.094	0.060	0.066	0.065	0.065	-0.020	-0.006	0.031	0.045	0.054	0.056	0.000	0.019	0.040	0.048	0.012	0.017	0.031	0.018	0.020	0.018	0.021	0.026
07-13	0.006	0.005	0.007	0.026	0.044	0.003	0.124	0.001	0.001	0.001	-0.002	-0.009	-0.048	0.001	0.000	-0.001	0.000	-0.009	-0.017	0.000	-0.001	-0.005	-0.010	0.000	0.000	-0.002	0.000	0.000	0.000	0.000	0.001
08-09	-0.001	0.000	-0.002	-0.004	-0.004	0.020	-0.004	0.159	-0.101	-0.017	-0.008	-0.005	-0.004	0.004	-0.011	-0.006	-0.011	-0.005	-0.004	0.000	-0.003	-0.004	-0.004	0.001	-0.002	-0.003	-0.001	-0.001	0.000	0.000	-0.001
08-14	0.037	0.039	0.035	0.025	0.023	0.063	0.021	0.106	0.055	0.027	0.022	0.021	0.020	0.021	0.001	0.013	0.018	0.018	0.018	0.000	0.008	0.015	0.017	0.008	0.008	0.012	0.009	0.010	0.010	0.011	0.012
09-10	-0.071	-0.071	-0.072	-0.065	-0.062	0.012	-0.059	0.054	0.099	-0.168	-0.080	-0.065	-0.059	0.033	0.002	-0.052	-0.090	-0.057	-0.056	0.000	-0.031	-0.049	-0.051	-0.016	-0.024	-0.037	-0.024	-0.026	-0.023	-0.026	-0.031
09-14	0.040	0.042	0.038	0.028	0.025	0.058	0.023	0.042	0.105	0.037	0.027	0.024	0.023	-0.022	0.010	0.016	0.025	0.021	0.021	0.000	0.010	0.017	0.019	0.005	0.008	0.013	0.008	0.009	0.008	0.009	0.011
09-15	0.029	0.031	0.027	0.016	0.014	0.055	0.012	0.058	0.092	0.021	0.011	0.011	0.011	0.023	-0.035	0.002	0.004	0.009	0.010	0.000	0.002	0.006	0.008	0.004	0.003	0.005	0.004	0.005	0.005	0.005	0.006
10-11	0.001	0.005	-0.004	-0.015	-0.016	0.005	-0.016	0.005	0.006	0.040	-0.041	-0.023	-0.017	0.003	0.001	-0.003	0.001	-0.016	-0.016	0.000	-0.002	-0.010	-0.013	-0.002	-0.003	-0.007	-0.003	-0.004	-0.003	-0.004	-0.006
10-16	0.047	0.050	0.043	0.021	0.016	0.034	0.011	0.021	0.024	0.096	0.025	0.014	0.010	0.011	0.008	-0.034	0.037	0.003	0.005	0.000	-0.018	-0.011	-0.001	-0.007	-0.012	-0.009	-0.010	-0.009	-0.009	-0.009	-0.008
17-10	-0.065	-0.073	-0.055	-0.020	-0.013	-0.048	-0.009	-0.026	-0.032	-0.178	0.014	-0.001	-0.007	-0.009	0.012	0.002	0.118	-0.002	-0.004	0.000	0.001	-0.001	-0.003	-0.001	0.000	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001
11-12	0.012	0.014	0.010	-0.115	-0.127	0.011	-0.134	0.008	0.010	0.033	0.108	-0.206	-0.142	0.006	0.010	0.004	0.046	-0.138	-0.129	0.000	-0.003	-0.069	-0.102	-0.011	-0.012	-0.049	-0.018	-0.023	-0.020	-0.028	-0.040
11-16	0.052	0.048	0.056	0.052	0.048	0.029	0.044	0.015	0.015	0.035	0.107	0.060	0.044	0.008	0.007	-0.033	0.040	0.034	0.035	0.000	-0.016	0.006	0.023	-0.004	-0.008	0.003	-0.005	-0.003	-0.004	-0.002	0.002
17-11	-0.052	-0.043	-0.063	-0.081	-0.079	-0.019	-0.078	-0.003	0.001	0.017	-0.166	-0.101	-0.079	0.004	0.016	-0.012	0.106	-0.072	-0.070	0.000	-0.010	-0.042	-0.057	-0.010	-0.012	-0.031	-0.015	-0.018	-0.016	-0.020	-0.026
12-13	0.003	0.004	0.003	-0.025	-0.076	0.003	-0.109	0.002	0.002	0.008	0.024	0.064	-0.136	0.001	0.003	0.002	0.011	0.011	-0.054	0.000	0.000	-0.008	-0.034	-0.003	-0.003	-0.012	-0.005	-0.007	-0.006	-0.008	-0.012
12-18	0.034	0.031	0.037	0.058	0.044	0.019	0.033	0.010	0.010	0.022	0.048	0.110	0.032	0.005	0.006	-0.004	0.022	-0.183	-0.012	0.000	-0.005	-0.059	-0.031	-0.006	-0.008	-0.030	-0.010	-0.013	-0.011	-0.014	-0.019
12-19	0.012	0.012	0.013	0.013	-0.005	0.007	-0.018	0.004	0.004	0.010	0.023	0.053	-0.022	0.002	0.003	0.001	0.011	0.001	-0.071	0.000	-0.001	-0.015	-0.045	-0.003	-0.004	-0.015	-0.006	-0.007	-0.007	-0.009	-0.013
13-19	0.017	0.015	0.018	0.046	0.070	0.009	0.082	0.004	0.004	0.008	0.012	0.020	0.103	0.002	0.002	-0.001	0.006	-0.010	-0.059	0.000	-0.002	-0.015	-0.037	-0.003	-0.003	-0.012	-0.004	-0.005	-0.004	-0.006	-0.008
14-15	-0.049	-0.049	-0.050	-0.049	-0.048	-0.038	-0.047	-0.023	-0.035	-0.058	-0.058	-0.050	-0.047	-0.001	-0.138	-0.051	-0.072	-0.047	-0.045	0.000	-0.030	-0.044	-0.043	-0.018	-0.024	-0.034	-0.025	-0.026	-0.024	-0.027	-0.030
14-20	0.085	0.086	0.083	0.073	0.070	0.097	0.067	0.103	0.106	0.084	0.077	0.070	0.067	0.117	0.120	0.064	0.086	0.065	0.064	0.000	0.044	0.059	0.061	0.032	0.036	0.049	0.039	0.041	0.040	0.042	0.046
14-21	-0.003	-0.003	-0.004	-0.006	-0.006	0.000	-0.007	0.003	0.003	-0.004	-0.006	-0.007	-0.007	0.005	0.004	-0.011	-0.004	-0.008	-0.007	0.000	-0.022	-0.009	-0.008	-0.007	-0.010	-0.009	-0.009	-0.009	-0.008	-0.008	-0.008
16-15	0.026	0.024	0.027	0.037	0.039	0.006	0.041	-0.006	-0.008	0.030	0.039	0.042	0.042	-0.014	-0.045	0.078	0.026	0.046	0.044	0.000	0.045	0.053	0.046	0.024	0.034	0.042	0.033	0.034	0.031	0.033	0.037
17-15	0.080	0.078	0.082	0.079	0.076	0.040	0.074	0.011	0.011	0.106	0.107	0.083	0.074	-0.007	-0.045	0.058	0.165	0.071	0.069	0.000	0.035	0.059	0.063	0.022	0.029	0.046	0.031	0.032	0.030	0.034	0.040

2020 continued (Chapter 6)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
16-17	-0.037	-0.037	-0.036	-0.022	-0.016	-0.027	-0.012	-0.018	-0.020	-0.054	-0.044	-0.020	-0.012	-0.012	-0.017	0.048	-0.110	-0.003	-0.005	0.000	0.026	0.016	0.003	0.011	0.017	0.013	0.015	0.014	0.013	0.013	0.012
16-21	0.080	0.078	0.081	0.082	0.081	0.057	0.079	0.038	0.042	0.092	0.097	0.086	0.080	0.027	0.042	0.151	0.093	0.085	0.079	0.000	-0.145	0.088	0.076	-0.002	-0.009	0.042	0.000	0.007	0.005	0.013	0.027
22-16	0.019	0.016	0.023	0.070	0.084	0.008	0.094	0.002	0.000	-0.004	0.019	0.083	0.098	-0.001	-0.007	-0.055	-0.006	0.136	0.117	0.000	-0.018	0.206	0.139	0.012	0.011	0.105	0.024	0.036	0.029	0.043	0.070
16-25	0.049	0.048	0.049	0.046	0.043	0.035	0.041	0.023	0.026	0.059	0.060	0.048	0.042	0.017	0.028	0.101	0.060	0.044	0.039	0.000	0.021	0.045	0.035	-0.032	-0.051	0.001	-0.040	-0.032	-0.033	-0.026	-0.012
18-19	-0.002	-0.002	-0.003	-0.013	-0.027	-0.001	-0.036	0.000	0.000	0.001	0.002	0.006	-0.040	0.000	0.001	0.003	0.002	0.089	-0.074	0.000	0.001	0.012	-0.036	-0.001	-0.001	-0.002	-0.002	-0.002	-0.002	-0.003	-0.005
18-22	0.034	0.031	0.037	0.069	0.070	0.019	0.069	0.010	0.010	0.020	0.043	0.098	0.073	0.005	0.005	-0.007	0.019	0.207	0.067	0.000	-0.006	-0.072	0.021	-0.005	-0.007	-0.025	-0.008	-0.009	-0.007	-0.009	-0.012
18-23	0.003	0.003	0.004	0.005	0.002	0.002	-0.001	0.001	0.001	0.003	0.006	0.012	-0.001	0.001	0.001	0.001	0.003	0.041	-0.009	0.000	0.000	0.001	-0.033	-0.001	-0.001	-0.005	-0.002	-0.003	-0.002	-0.003	-0.005
23-19	-0.014	-0.012	-0.015	-0.030	-0.038	-0.008	-0.042	-0.004	-0.004	-0.008	-0.014	-0.029	-0.046	-0.002	-0.002	0.000	-0.007	-0.017	-0.065	0.000	0.001	0.014	0.059	0.003	0.003	0.013	0.004	0.005	0.004	0.006	0.008
20-21	-0.058	-0.057	-0.060	-0.067	-0.069	-0.044	-0.070	-0.032	-0.034	-0.062	-0.068	-0.070	-0.070	-0.024	-0.031	-0.090	-0.063	-0.073	-0.072	0.000	-0.149	-0.078	-0.074	-0.053	-0.073	-0.073	-0.070	-0.069	-0.066	-0.068	-0.070
20-24	-0.025	-0.024	-0.025	-0.030	-0.032	-0.020	-0.033	-0.016	-0.016	-0.025	-0.028	-0.031	-0.033	-0.012	-0.013	-0.031	-0.024	-0.034	-0.035	0.000	-0.032	-0.036	-0.036	-0.130	-0.047	-0.043	-0.049	-0.049	-0.053	-0.050	-0.047
20-25	-0.041	-0.040	-0.042	-0.051	-0.053	-0.031	-0.055	-0.023	-0.023	-0.042	-0.047	-0.053	-0.055	-0.017	-0.020	-0.056	-0.042	-0.057	-0.058	0.000	-0.059	-0.062	-0.061	-0.063	-0.089	-0.072	-0.082	-0.079	-0.076	-0.075	-0.073
21-25	0.018	0.018	0.017	0.009	0.006	0.013	0.002	0.009	0.011	0.025	0.023	0.009	0.003	0.007	0.014	0.050	0.027	0.004	-0.001	0.000	0.184	0.001	-0.006	-0.062	-0.092	-0.040	-0.079	-0.071	-0.070	-0.064	-0.051
22-23	-0.019	-0.017	-0.021	-0.051	-0.065	-0.010	-0.076	-0.005	-0.004	-0.007	-0.018	-0.045	-0.080	-0.002	-0.001	0.012	-0.006	-0.020	-0.110	0.000	0.006	0.076	-0.179	0.000	0.002	0.002	-0.001	-0.003	-0.003	-0.006	-0.011
22-26	0.017	0.016	0.018	0.025	0.026	0.011	0.026	0.006	0.007	0.016	0.021	0.030	0.027	0.004	0.006	0.018	0.016	0.045	0.030	0.000	0.003	0.073	0.031	-0.008	-0.010	-0.065	-0.015	-0.021	-0.016	-0.023	-0.036
24-25	-0.013	-0.013	-0.014	-0.017	-0.018	-0.007	-0.018	-0.002	-0.004	-0.015	-0.017	-0.019	-0.019	-0.001	-0.006	-0.024	-0.015	-0.020	-0.020	0.000	-0.028	-0.023	-0.021	0.199	-0.046	-0.025	-0.029	-0.022	-0.008	-0.013	-0.017
25-26	-0.029	-0.028	-0.031	-0.050	-0.057	-0.019	-0.061	-0.012	-0.012	-0.024	-0.034	-0.054	-0.062	-0.008	-0.009	-0.020	-0.023	-0.068	-0.070	0.000	0.000	-0.080	-0.080	0.007	0.020	-0.148	-0.003	-0.024	-0.013	-0.036	-0.079
25-27	-0.009	-0.008	-0.009	-0.015	-0.018	-0.007	-0.020	-0.006	-0.005	-0.006	-0.009	-0.016	-0.019	-0.004	-0.003	-0.001	-0.005	-0.018	-0.021	0.000	0.006	-0.020	-0.024	-0.008	0.016	-0.034	-0.120	-0.099	-0.097	-0.085	-0.062
25-28	-0.002	-0.002	-0.002	-0.004	-0.005	-0.002	-0.005	-0.001	-0.001	-0.002	-0.002	-0.004	-0.005	-0.001	-0.001	-0.001	-0.002	-0.005	-0.006	0.000	0.001	-0.005	-0.006	-0.001	0.004	-0.009	-0.012	-0.028	-0.014	-0.022	-0.016
28-26	-0.015	-0.015	-0.016	-0.026	-0.029	-0.009	-0.031	-0.005	-0.005	-0.013	-0.018	-0.029	-0.032	-0.003	-0.005	-0.012	-0.013	-0.036	-0.036	0.000	-0.003	-0.044	-0.042	0.008	0.006	-0.083	0.028	0.052	0.026	0.028	-0.018
26-31	0.007	0.007	0.008	0.011	0.012	0.004	0.011	0.002	0.002	0.007	0.009	0.013	0.013	0.001	0.002	0.008	0.007	0.019	0.015	0.000	0.003	0.027	0.020	-0.006	-0.001	0.057	-0.012	-0.020	-0.020	-0.047	-0.138
27-28	-0.009	-0.008	-0.009	-0.015	-0.017	-0.006	-0.019	-0.004	-0.004	-0.006	-0.009	-0.016	-0.019	-0.003	-0.003	-0.004	-0.006	-0.019	-0.021	0.000	0.002	-0.021	-0.023	-0.001	0.010	-0.036	0.032	-0.111	-0.006	-0.078	-0.056
27-29	-0.001	-0.001	-0.001	-0.002	-0.002	-0.002	-0.003	-0.002	-0.002	0.000	0.000	-0.002	-0.003	-0.002	-0.001	0.002	0.000	-0.002	-0.003	0.000	0.004	-0.001	-0.003	-0.008	0.009	-0.002	0.022	0.002	-0.110	-0.017	-0.014
30-28	0.005	0.005	0.005	0.009	0.011	0.004	0.013	0.003	0.003	0.004	0.005	0.009	0.012	0.002	0.002	0.001	0.003	0.010	0.013	0.000	-0.002	0.010	0.014	0.002	-0.007	0.014	-0.019	-0.044	0.010	0.126	0.070
30-31	-0.012	-0.011	-0.013	-0.021	-0.025	-0.007	-0.027	-0.004	-0.004	-0.010	-0.014	-0.023	-0.027	-0.002	-0.003	-0.009	-0.010	-0.027	-0.030	0.000	-0.002	-0.029	-0.033	0.006	0.004	-0.048	0.017	0.029	0.020	0.067	-0.176

2025 (Chapter 6)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
01-02	0.231	-0.026	0.040	0.022	0.018	-0.014	0.015	-0.006	-0.005	-0.005	0.012	0.014	0.014	-0.002	-0.001	0.003	0.002	0.011	0.012	0.000	0.002	0.007	0.009	0.002	0.002	0.005	0.003	0.003	0.003	0.003	0.004
01-03	0.220	0.031	-0.048	-0.026	-0.022	0.017	-0.018	0.007	0.006	0.006	-0.014	-0.016	-0.017	0.003	0.001	-0.004	-0.002	-0.013	-0.014	0.000	-0.003	-0.008	-0.011	-0.002	-0.003	-0.006	-0.003	-0.004	-0.003	-0.004	-0.005
02-03	-0.014	0.096	-0.149	-0.082	-0.067	0.054	-0.056	0.022	0.020	0.019	-0.044	-0.051	-0.053	0.009	0.003	-0.011	-0.008	-0.040	-0.043	0.000	-0.008	-0.026	-0.035	-0.006	-0.008	-0.020	-0.010	-0.011	-0.010	-0.012	-0.017
02-06	0.153	0.162	0.141	0.090	0.078	-0.182	0.069	-0.067	-0.049	0.068	0.070	0.068	0.067	-0.022	-0.001	0.034	0.050	0.056	0.058	0.000	0.021	0.043	0.050	0.012	0.018	0.032	0.019	0.020	0.018	0.021	0.027
02-10	0.123	0.135	0.108	0.049	0.037	0.068	0.028	0.021	0.011	-0.085	0.008	0.020	0.025	0.005	-0.003	-0.011	-0.029	0.014	0.017	0.000	-0.005	0.004	0.012	-0.001	-0.002	0.003	-0.001	0.000	0.000	0.001	0.003
03-04	0.083	0.073	0.094	-0.181	-0.138	0.042	-0.106	0.019	0.017	0.023	-0.002	-0.070	-0.094	0.008	0.005	-0.007	0.007	-0.058	-0.071	0.000	-0.006	-0.036	-0.055	-0.008	-0.010	-0.028	-0.012	-0.015	-0.013	-0.017	-0.024
03-11	0.115	0.100	0.133	0.033	0.016	0.055	0.004	0.022	0.018	0.012	-0.077	-0.021	-0.002	0.008	0.000	-0.014	-0.021	-0.015	-0.008	0.000	-0.008	-0.011	-0.009	-0.004	-0.006	-0.008	-0.005	-0.005	-0.005	-0.005	-0.006
04-05	0.031	0.028	0.035	0.107	-0.187	0.016	-0.094	0.008	0.007	0.011	0.008	-0.003	-0.077	0.003	0.003	-0.002	0.007	-0.016	-0.043	0.000	-0.002	-0.016	-0.032	-0.004	-0.005	-0.014	-0.006	-0.008	-0.007	-0.009	-0.013
04-07	0.008	0.007	0.009	0.026	-0.002	0.004	-0.031	0.002	0.002	0.003	0.002	0.000	-0.017	0.001	0.001	0.000	0.002	-0.004	-0.010	0.000	-0.001	-0.004	-0.007	-0.001	-0.001	-0.004	-0.002	-0.002	-0.002	-0.002	-0.003
04-12	0.030	0.027	0.035	0.134	0.075	0.015	0.032	0.006	0.005	0.005	-0.011	-0.055	0.014	0.002	0.001	-0.004	-0.002	-0.028	-0.006	0.000	-0.002	-0.011	-0.008	-0.002	-0.002	-0.006	-0.002	-0.003	-0.002	-0.003	-0.003
05-07	0.021	0.019	0.024	0.071	0.154	0.011	-0.112	0.005	0.005	0.008	0.007	0.001	-0.042	0.002	0.002	-0.001	0.005	-0.009	-0.027	0.000	-0.002	-0.010	-0.020	-0.003	-0.003	-0.010	-0.005	-0.006	-0.005	-0.007	-0.010
05-13	0.017	0.015	0.019	0.059	0.119	0.009	-0.002	0.004	0.004	0.006	0.003	-0.004	-0.052	0.002	0.001	-0.001	0.003	-0.011	-0.026	0.000	-0.001	-0.009	-0.018	-0.002	-0.002	-0.007	-0.003	-0.004	-0.003	-0.004	-0.006
06-08	0.079	0.083	0.073	0.047	0.041	0.158	0.037	-0.081	-0.002	0.039	0.038	0.036	0.036	-0.013	0.002	0.019	0.028	0.030	0.031	0.000	0.011	0.023	0.027	0.006	0.009	0.017	0.010	0.011	0.009	0.011	0.014
06-09	0.151	0.160	0.140	0.088	0.076	0.322	0.067	0.024	-0.094	0.060	0.066	0.065	0.065	-0.020	-0.006	0.031	0.045	0.054	0.056	0.000	0.019	0.040	0.048	0.012	0.017	0.031	0.018	0.020	0.018	0.021	0.026
07-13	0.006	0.005	0.007	0.026	0.044	0.003	0.124	0.001	0.001	0.001	-0.002	-0.009	-0.048	0.001	0.000	-0.001	0.000	-0.009	-0.017	0.000	-0.001	-0.005	-0.010	0.000	0.000	-0.002	0.000	0.000	0.000	0.000	0.001
08-09	-0.001	0.000	-0.002	-0.004	-0.004	0.020	-0.004	0.159	-0.101	-0.017	-0.008	-0.005	-0.004	0.004	-0.011	-0.006	-0.011	-0.005	-0.004	0.000	-0.003	-0.004	-0.004	0.001	-0.002	-0.003	-0.001	-0.001	0.000	0.000	-0.001
08-14	0.037	0.039	0.035	0.025	0.023	0.063	0.021	0.106	0.055	0.027	0.022	0.021	0.020	0.021	0.001	0.013	0.018	0.018	0.018	0.000	0.008	0.015	0.017	0.008	0.008	0.012	0.009	0.010	0.010	0.011	0.012
09-10	-0.071	-0.071	-0.071	-0.065	-0.062	0.012	-0.059	0.054	0.099	-0.167	-0.080	-0.065	-0.059	0.033	0.002	-0.052	-0.090	-0.057	-0.056	0.000	-0.031	-0.049	-0.051	-0.016	-0.024	-0.037	-0.024	-0.026	-0.023	-0.026	-0.031
09-14	0.040	0.042	0.038	0.028	0.025	0.058	0.023	0.042	0.105	0.037	0.027	0.024	0.023	-0.022	0.010	0.016	0.025	0.021	0.021	0.000	0.010	0.017	0.019	0.005	0.008	0.013	0.008	0.009	0.008	0.009	0.011
09-15	0.029	0.031	0.027	0.016	0.014	0.055	0.012	0.058	0.092	0.021	0.011	0.011	0.011	0.023	-0.035	0.002	0.004	0.009	0.010	0.000	0.002	0.006	0.008	0.004	0.003	0.005	0.004	0.005	0.005	0.005	0.006
10-11	0.001	0.005	-0.004	-0.015	-0.016	0.005	-0.016	0.005	0.006	0.040	-0.041	-0.023	-0.017	0.003	0.001	-0.003	0.001	-0.016	-0.016	0.000	-0.002	-0.010	-0.013	-0.002	-0.003	-0.007	-0.003	-0.004	-0.003	-0.004	-0.006
10-16	0.047	0.050	0.043	0.021	0.016	0.034	0.011	0.021	0.024	0.096	0.025	0.014	0.010	0.011	0.008	-0.034	0.037	0.003	0.005	0.000	-0.018	-0.011	-0.001	-0.007	-0.012	-0.009	-0.010	-0.009	-0.009	-0.009	-0.008
17-10	-0.065	-0.073	-0.055	-0.020	-0.013	-0.048	-0.009	-0.026	-0.032	-0.178	0.014	-0.001	-0.007	-0.009	0.012	0.002	0.118	-0.002	-0.004	0.000	0.001	-0.001	-0.003	-0.001	0.000	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001
11-12	0.012	0.014	0.010	-0.115	-0.127	0.011	-0.134	0.008	0.010	0.033	0.108	-0.206	-0.142	0.006	0.010	0.004	0.046	-0.138	-0.129	0.000	-0.003	-0.069	-0.102	-0.011	-0.012	-0.049	-0.018	-0.023	-0.020	-0.027	-0.040
11-16	0.052	0.048	0.056	0.052	0.048	0.029	0.044	0.015	0.015	0.035	0.107	0.060	0.044	0.008	0.007	-0.033	0.040	0.034	0.035	0.000	-0.016	0.006	0.023	-0.004	-0.008	0.003	-0.005	-0.003	-0.004	-0.002	0.002
17-11	-0.052	-0.043	-0.063	-0.081	-0.079	-0.019	-0.078	-0.003	0.001	0.017	-0.166	-0.101	-0.079	0.004	0.016	-0.012	0.106	-0.072	-0.070	0.000	-0.010	-0.042	-0.057	-0.010	-0.012	-0.031	-0.015	-0.017	-0.016	-0.019	-0.026
12-13	0.003	0.004	0.003	-0.025	-0.076	0.003	-0.109	0.002	0.002	0.008	0.024	0.064	-0.136	0.001	0.003	0.002	0.011	0.011	-0.054	0.000	0.000	-0.008	-0.034	-0.003	-0.003	-0.012	-0.005	-0.007	-0.006	-0.008	-0.012
12-18	0.034	0.031	0.037	0.058	0.044	0.019	0.033	0.010	0.010	0.022	0.048	0.110	0.032	0.005	0.006	-0.004	0.022	-0.183	-0.012	0.000	-0.005	-0.059	-0.031	-0.006	-0.008	-0.030	-0.010	-0.013	-0.011	-0.014	-0.019
12-19	0.012	0.012	0.013	0.013	-0.005	0.007	-0.018	0.004	0.004	0.010	0.023	0.053	-0.022	0.002	0.003	0.001	0.011	0.001	-0.071	0.000	-0.001	-0.015	-0.045	-0.003	-0.004	-0.015	-0.006	-0.007	-0.007	-0.009	-0.013
13-19	0.017	0.015	0.018	0.046	0.070	0.009	0.082	0.004	0.004	0.008	0.012	0.020	0.103	0.002	0.002	-0.001	0.006	-0.010	-0.059	0.000	-0.002	-0.015	-0.037	-0.003	-0.003	-0.012	-0.004	-0.005	-0.004	-0.006	-0.008
14-15	-0.049	-0.049	-0.050	-0.049	-0.048	-0.038	-0.047	-0.023	-0.035	-0.058	-0.058	-0.050	-0.047	-0.001	-0.138	-0.051	-0.072	-0.046	-0.045	0.000	-0.030	-0.044	-0.043	-0.018	-0.024	-0.034	-0.025	-0.026	-0.024	-0.027	-0.030
14-20	0.085	0.086	0.083	0.073	0.070	0.097	0.067	0.103	0.106	0.084	0.077	0.070	0.067	0.117	0.120	0.064	0.086	0.065	0.064	0.000	0.044	0.059	0.061	0.032	0.036	0.049	0.039	0.041	0.040	0.042	0.046
14-21	-0.003	-0.003	-0.004	-0.006	-0.006	0.000	-0.007	0.003	0.003	-0.004	-0.006	-0.007	-0.007	0.005	0.004	-0.011	-0.004	-0.007	-0.007	0.000	-0.022	-0.009	-0.008	-0.007	-0.010	-0.009	-0.009	-0.009	-0.008	-0.008	-0.008
16-15	0.231	-0.026	0.040	0.022	0.018	-0.014	0.015	-0.006	-0.005	-0.005	0.012	0.014	0.014	-0.002	-0.001	0.003	0.002	0.011	0.012	0.000	0.002	0.007	0.009	0.002	0.002	0.005	0.003	0.003	0.003	0.003	0.004
17-15	0.220	0.031	-0.048	-0.026	-0.022	0.017	-0.018	0.007	0.006	0.006	-0.014	-0.016	-0.017	0.003	0.001	-0.004	-0.002	-0.013	-0.014	0.000	-0.003	-0.008	-0.011	-0.002	-0.003	-0.006	-0.003	-0.004	-0.003	-0.004	-0.005

2025 continued (Chapter 6)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
16-17	0.025	0.024	0.027	0.037	0.039	0.006	0.041	-0.006	-0.008	0.030	0.039	0.041	0.042	-0.014	-0.045	0.078	0.026	0.046	0.044	0.000	0.045	0.053	0.046	0.024	0.034	0.042	0.033	0.034	0.031	0.033	0.037
16-21	0.080	0.078	0.082	0.079	0.076	0.040	0.074	0.011	0.011	0.106	0.107	0.083	0.074	-0.007	-0.045	0.058	0.165	0.071	0.069	0.000	0.035	0.059	0.063	0.022	0.029	0.046	0.031	0.032	0.030	0.034	0.040
22-16	-0.037	-0.037	-0.036	-0.022	-0.016	-0.027	-0.012	-0.018	-0.020	-0.054	-0.044	-0.020	-0.012	-0.012	-0.017	0.048	-0.110	-0.003	-0.005	0.000	0.026	0.016	0.003	0.011	0.017	0.013	0.015	0.014	0.013	0.013	0.012
16-25	0.080	0.078	0.081	0.082	0.081	0.057	0.079	0.038	0.042	0.092	0.097	0.086	0.080	0.027	0.042	0.151	0.093	0.085	0.078	0.000	-0.145	0.088	0.076	-0.002	-0.009	0.042	0.000	0.007	0.005	0.013	0.027
18-19	0.019	0.016	0.023	0.070	0.084	0.008	0.094	0.002	0.000	-0.004	0.019	0.083	0.098	-0.001	-0.007	-0.055	-0.006	0.136	0.117	0.000	-0.018	0.206	0.139	0.012	0.011	0.104	0.024	0.036	0.029	0.043	0.070
18-22	0.049	0.048	0.049	0.046	0.043	0.035	0.041	0.023	0.026	0.059	0.060	0.048	0.042	0.017	0.028	0.101	0.060	0.044	0.039	0.000	0.021	0.045	0.035	-0.032	-0.051	0.001	-0.040	-0.032	-0.033	-0.026	-0.012
18-23	-0.002	-0.002	-0.003	-0.013	-0.027	-0.001	-0.036	0.000	0.000	0.001	0.002	0.006	-0.040	0.000	0.001	0.003	0.002	0.089	-0.074	0.000	0.001	0.012	-0.036	-0.001	-0.001	-0.002	-0.002	-0.002	-0.002	-0.003	-0.005
23-19	0.034	0.031	0.037	0.069	0.070	0.019	0.069	0.010	0.010	0.020	0.043	0.098	0.073	0.005	0.005	-0.007	0.019	0.207	0.067	0.000	-0.006	-0.072	0.021	-0.005	-0.007	-0.025	-0.008	-0.009	-0.007	-0.009	-0.012
20-21	0.003	0.003	0.004	0.005	0.002	0.002	-0.001	0.001	0.001	0.003	0.006	0.012	-0.001	0.001	0.001	0.001	0.003	0.041	-0.009	0.000	0.000	0.001	-0.033	-0.001	-0.001	-0.005	-0.002	-0.003	-0.002	-0.003	-0.005
20-24	-0.014	-0.012	-0.015	-0.030	-0.038	-0.008	-0.042	-0.004	-0.004	-0.008	-0.014	-0.029	-0.046	-0.002	-0.002	0.000	-0.007	-0.017	-0.065	0.000	0.001	0.014	0.059	0.003	0.003	0.013	0.004	0.005	0.004	0.006	0.008
20-25	-0.058	-0.057	-0.060	-0.067	-0.069	-0.044	-0.070	-0.032	-0.034	-0.062	-0.068	-0.070	-0.070	-0.024	-0.031	-0.090	-0.063	-0.073	-0.072	0.000	-0.149	-0.078	-0.074	-0.053	-0.073	-0.073	-0.070	-0.069	-0.066	-0.068	-0.070
21-25	-0.025	-0.024	-0.025	-0.030	-0.032	-0.020	-0.033	-0.016	-0.016	-0.025	-0.028	-0.031	-0.033	-0.012	-0.013	-0.031	-0.024	-0.034	-0.035	0.000	-0.032	-0.036	-0.036	-0.130	-0.047	-0.043	-0.049	-0.049	-0.053	-0.050	-0.047
22-23	-0.041	-0.040	-0.042	-0.051	-0.053	-0.031	-0.055	-0.023	-0.023	-0.042	-0.047	-0.053	-0.055	-0.017	-0.020	-0.056	-0.041	-0.057	-0.058	0.000	-0.059	-0.062	-0.061	-0.063	-0.089	-0.072	-0.082	-0.079	-0.076	-0.075	-0.073
22-26	0.018	0.018	0.017	0.009	0.006	0.013	0.002	0.009	0.011	0.025	0.023	0.009	0.003	0.007	0.014	0.050	0.027	0.004	-0.001	0.000	0.184	0.001	-0.006	-0.062	-0.092	-0.040	-0.079	-0.071	-0.070	-0.064	-0.051
24-25	-0.019	-0.017	-0.021	-0.051	-0.065	-0.010	-0.076	-0.005	-0.004	-0.007	-0.018	-0.045	-0.080	-0.002	-0.001	0.012	-0.006	-0.020	-0.110	0.000	0.006	0.076	-0.179	0.000	0.002	0.002	-0.001	-0.003	-0.003	-0.006	-0.011
25-26	0.017	0.016	0.018	0.025	0.026	0.011	0.026	0.006	0.007	0.016	0.021	0.030	0.027	0.004	0.006	0.018	0.016	0.045	0.030	0.000	0.003	0.073	0.031	-0.008	-0.010	-0.065	-0.015	-0.021	-0.016	-0.023	-0.035
25-27	-0.013	-0.013	-0.014	-0.017	-0.018	-0.007	-0.018	-0.002	-0.004	-0.015	-0.017	-0.019	-0.019	-0.001	-0.006	-0.024	-0.015	-0.020	-0.020	0.000	-0.028	-0.023	-0.021	0.199	-0.046	-0.025	-0.029	-0.021	-0.008	-0.013	-0.016
25-28	-0.029	-0.028	-0.031	-0.050	-0.057	-0.019	-0.061	-0.012	-0.012	-0.024	-0.034	-0.054	-0.062	-0.008	-0.009	-0.020	-0.023	-0.068	-0.070	0.000	0.000	-0.080	-0.080	0.006	0.020	-0.148	-0.003	-0.024	-0.013	-0.035	-0.079
28-26	-0.009	-0.008	-0.009	-0.015	-0.018	-0.007	-0.020	-0.006	-0.005	-0.006	-0.009	-0.016	-0.019	-0.004	-0.003	-0.001	-0.005	-0.018	-0.021	0.000	0.006	-0.020	-0.024	-0.008	0.016	-0.034	-0.120	-0.099	-0.097	-0.085	-0.062
26-31	-0.002	-0.002	-0.002	-0.004	-0.005	-0.002	-0.005	-0.001	-0.001	-0.002	-0.002	-0.004	-0.005	-0.001	-0.001	-0.001	-0.002	-0.005	-0.006	0.000	0.001	-0.005	-0.006	-0.001	0.004	-0.009	-0.012	-0.028	-0.014	-0.022	-0.016
27-28	-0.015	-0.015	-0.016	-0.026	-0.029	-0.009	-0.031	-0.005	-0.005	-0.013	-0.018	-0.029	-0.032	-0.003	-0.005	-0.012	-0.013	-0.036	-0.036	0.000	-0.003	-0.044	-0.042	0.008	0.006	-0.083	0.028	0.052	0.025	0.028	-0.018
27-29	0.007	0.007	0.008	0.011	0.012	0.004	0.012	0.002	0.002	0.007	0.009	0.013	0.013	0.001	0.002	0.008	0.007	0.019	0.016	0.000	0.003	0.027	0.020	-0.006	-0.001	0.058	-0.012	-0.019	-0.020	-0.046	-0.137
30-28	-0.009	-0.008	-0.009	-0.015	-0.017	-0.006	-0.019	-0.004	-0.004	-0.006	-0.009	-0.016	-0.019	-0.003	-0.003	-0.004	-0.006	-0.019	-0.021	0.000	0.002	-0.021	-0.023	-0.002	0.010	-0.036	0.032	-0.111	-0.006	-0.078	-0.055
30-31	-0.001	-0.001	-0.001	-0.002	-0.002	-0.002	-0.003	-0.002	-0.002	0.000	0.000	-0.002	-0.003	-0.002	-0.001	0.002	0.000	-0.002	-0.003	0.000	0.004	-0.001	-0.003	-0.008	0.009	-0.002	0.021	0.002	-0.110	-0.018	-0.014

A.3 PTDF Matrixes Chapter 7 (Source: ie³)

	2020 (Chapter 7)																														
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
01-02	0.232	-0.024	0.041	0.022	0.018	-0.012	0.015	-0.006	-0.006	-0.005	0.012	0.014	0.015	-0.002	-0.001	0.003	0.002	0.011	0.012	0.000	0.002	0.007	0.010	0.002	0.002	0.005	0.003	0.003	0.003	0.003	0.005
01-03	0.219	0.030	-0.049	-0.027	-0.022	0.015	-0.019	0.007	0.007	0.006	-0.015	-0.017	-0.018	0.003	0.001	-0.004	-0.003	-0.013	-0.014	0.000	-0.003	-0.009	-0.012	-0.002	-0.003	-0.007	-0.003	-0.004	-0.003	-0.004	-0.006
02-03	-0.018	0.092	-0.153	-0.084	-0.069	0.046	-0.058	0.022	0.022	0.018	-0.045	-0.052	-0.055	0.009	0.003	-0.012	-0.009	-0.041	-0.045	0.000	-0.008	-0.027	-0.036	-0.006	-0.009	-0.020	-0.010	-0.012	-0.010	-0.013	-0.017
02-06	0.167	0.177	0.155	0.098	0.085	-0.151	0.076	-0.064	-0.058	0.074	0.077	0.074	0.073	-0.024	-0.002	0.037	0.054	0.061	0.064	0.000	0.022	0.046	0.055	0.013	0.019	0.035	0.021	0.022	0.020	0.023	0.030
02-10	0.117	0.129	0.103	0.045	0.034	0.055	0.025	0.020	0.014	-0.087	0.005	0.018	0.022	0.006	-0.003	-0.012	-0.031	0.011	0.015	0.000	-0.006	0.002	0.010	-0.001	-0.003	0.002	-0.001	-0.001	-0.001	0.000	0.002
03-04	0.080	0.071	0.091	-0.183	-0.139	0.036	-0.107	0.018	0.019	0.022	-0.003	-0.072	-0.096	0.008	0.005	-0.007	0.006	-0.058	-0.072	0.000	-0.007	-0.037	-0.056	-0.008	-0.010	-0.028	-0.013	-0.015	-0.013	-0.017	-0.024
03-11	0.111	0.096	0.130	0.031	0.014	0.047	0.002	0.022	0.021	0.010	-0.079	-0.023	-0.004	0.008	0.000	-0.014	-0.022	-0.016	-0.010	0.000	-0.008	-0.012	-0.010	-0.004	-0.006	-0.009	-0.006	-0.006	-0.005	-0.006	-0.007
04-05	0.030	0.027	0.034	0.107	-0.188	0.014	-0.095	0.007	0.008	0.011	0.008	-0.003	-0.078	0.004	0.003	-0.002	0.006	-0.017	-0.044	0.000	-0.003	-0.016	-0.032	-0.004	-0.005	-0.015	-0.007	-0.008	-0.007	-0.010	-0.014
04-07	0.007	0.007	0.008	0.026	-0.002	0.003	-0.031	0.002	0.002	0.003	0.002	0.000	-0.017	0.001	0.001	0.000	0.002	-0.004	-0.010	0.000	-0.001	-0.004	-0.008	-0.001	-0.001	-0.004	-0.002	-0.002	-0.002	-0.002	-0.003
04-12	0.029	0.026	0.034	0.133	0.074	0.013	0.032	0.006	0.006	0.005	-0.012	-0.056	0.013	0.003	0.001	-0.004	-0.002	-0.028	-0.007	0.000	-0.003	-0.011	-0.008	-0.002	-0.002	-0.006	-0.003	-0.003	-0.002	-0.003	-0.004
05-07	0.021	0.018	0.023	0.071	0.154	0.010	-0.112	0.005	0.005	0.008	0.006	0.001	-0.042	0.003	0.002	-0.001	0.005	-0.009	-0.027	0.000	-0.002	-0.010	-0.020	-0.003	-0.003	-0.010	-0.005	-0.006	-0.005	-0.007	-0.010
05-13	0.016	0.014	0.018	0.058	0.119	0.007	-0.002	0.004	0.004	0.005	0.003	-0.004	-0.052	0.002	0.001	-0.001	0.003	-0.011	-0.026	0.000	-0.001	-0.009	-0.018	-0.002	-0.002	-0.007	-0.003	-0.004	-0.003	-0.004	-0.006
06-08	0.061	0.065	0.057	0.037	0.033	0.121	0.029	-0.083	0.009	0.032	0.030	0.029	0.028	-0.010	0.003	0.015	0.023	0.024	0.025	0.000	0.009	0.018	0.021	0.005	0.008	0.014	0.008	0.008	0.007	0.009	0.011
06-09	0.107	0.113	0.099	0.062	0.054	0.228	0.047	0.017	-0.066	0.043	0.047	0.046	0.046	-0.014	-0.004	0.022	0.032	0.038	0.040	0.000	0.013	0.029	0.034	0.009	0.012	0.022	0.013	0.014	0.013	0.015	0.019
07-13	0.006	0.005	0.007	0.026	0.044	0.003	0.124	0.001	0.001	0.001	-0.002	-0.009	-0.048	0.001	0.000	-0.001	0.000	-0.009	-0.017	0.000	-0.001	-0.006	-0.010	0.000	0.000	-0.002	0.000	0.000	0.000	0.000	0.001
08-09	-0.014	-0.014	-0.014	-0.011	-0.011	-0.008	-0.010	0.157	-0.093	-0.022	-0.013	-0.011	-0.010	0.006	-0.011	-0.009	-0.015	-0.009	-0.009	0.000	-0.005	-0.008	-0.008	0.000	-0.003	-0.005	-0.002	-0.002	-0.001	-0.002	-0.004
08-14	0.036	0.038	0.034	0.024	0.022	0.061	0.020	0.106	0.055	0.027	0.021	0.020	0.020	0.021	0.001	0.012	0.018	0.018	0.018	0.000	0.008	0.014	0.016	0.008	0.008	0.012	0.009	0.010	0.010	0.011	0.012
09-10	-0.062	-0.061	-0.063	-0.059	-0.057	0.031	-0.055	0.055	0.093	-0.163	-0.076	-0.061	-0.055	0.031	0.001	-0.050	-0.087	-0.054	-0.052	0.000	-0.029	-0.046	-0.048	-0.015	-0.023	-0.035	-0.023	-0.024	-0.022	-0.025	-0.030
09-14	0.045	0.047	0.042	0.031	0.028	0.069	0.025	0.043	0.101	0.039	0.029	0.026	0.025	-0.023	0.010	0.017	0.027	0.022	0.022	0.000	0.010	0.018	0.020	0.006	0.008	0.014	0.009	0.009	0.008	0.010	0.012
09-15	0.033	0.035	0.030	0.018	0.016	0.064	0.014	0.058	0.090	0.023	0.013	0.013	0.013	0.022	-0.035	0.003	0.005	0.010	0.011	0.000	0.002	0.007	0.009	0.004	0.003	0.006	0.004	0.005	0.005	0.006	0.006
10-11	0.001	0.005	-0.003	-0.015	-0.016	0.005	-0.016	0.005	0.006	0.040	-0.041	-0.023	-0.017	0.003	0.001	-0.003	0.001	-0.016	-0.015	0.000	-0.002	-0.010	-0.013	-0.002	-0.003	-0.007	-0.003	-0.004	-0.003	-0.004	-0.006
10-16	0.046	0.049	0.042	0.021	0.015	0.032	0.011	0.021	0.025	0.095	0.025	0.013	0.010	0.011	0.008	-0.034	0.036	0.002	0.004	0.000	-0.018	-0.011	-0.002	-0.007	-0.012	-0.009	-0.010	-0.010	-0.009	-0.009	-0.008
17-10	-0.063	-0.071	-0.054	-0.019	-0.013	-0.044	-0.008	-0.026	-0.033	-0.177	0.015	-0.001	-0.006	-0.009	0.012	0.002	0.119	-0.001	-0.003	0.000	0.001	0.000	-0.002	-0.001	0.000	-0.001	0.000	-0.001	-0.001	-0.001	-0.001
11-12	0.012	0.014	0.010	-0.115	-0.127	0.011	-0.134	0.008	0.010	0.033	0.108	-0.206	-0.142	0.006	0.010	0.004	0.046	-0.138	-0.129	0.000	-0.003	-0.069	-0.102	-0.011	-0.012	-0.049	-0.018	-0.023	-0.020	-0.028	-0.040
11-16	0.050	0.046	0.055	0.051	0.047	0.026	0.043	0.015	0.016	0.034	0.107	0.059	0.043	0.008	0.007	-0.033	0.039	0.034	0.034	0.000	-0.017	0.006	0.022	-0.005	-0.008	0.003	-0.006	-0.004	-0.004	-0.002	0.002
17-11	-0.050	-0.040	-0.061	-0.080	-0.078	-0.015	-0.077	-0.003	-0.001	0.018	-0.165	-0.100	-0.078	0.003	0.016	-0.012	0.107	-0.072	-0.070	0.000	-0.009	-0.042	-0.057	-0.010	-0.012	-0.031	-0.015	-0.017	-0.015	-0.019	-0.026
12-13	0.003	0.004	0.003	-0.025	-0.076	0.003	-0.109	0.002	0.003	0.008	0.024	0.064	-0.136	0.001	0.003	0.002	0.011	0.011	-0.054	0.000	0.000	-0.008	-0.034	-0.003	-0.003	-0.012	-0.005	-0.007	-0.006	-0.008	-0.012
12-18	0.033	0.030	0.036	0.058	0.044	0.017	0.032	0.010	0.011	0.021	0.047	0.110	0.032	0.005	0.006	-0.004	0.022	-0.183	-0.012	0.000	-0.005	-0.059	-0.032	-0.006	-0.008	-0.030	-0.011	-0.013	-0.011	-0.014	-0.019
12-19	0.012	0.011	0.013	0.013	-0.005	0.007	-0.018	0.004	0.004	0.010	0.022	0.053	-0.022	0.002	0.003	0.001	0.011	0.001	-0.071	0.000	-0.001	-0.015	-0.045	-0.004	-0.004	-0.015	-0.006	-0.007	-0.007	-0.009	-0.013
13-19	0.016	0.015	0.018	0.046	0.070	0.008	0.081	0.004	0.005	0.008	0.012	0.020	0.103	0.002	0.002	-0.001	0.006	-0.010	-0.059	0.000	-0.002	-0.015	-0.037	-0.003	-0.003	-0.012	-0.004	-0.005	-0.004	-0.006	-0.008
14-15	-0.049	-0.049	-0.050	-0.049	-0.047	-0.037	-0.047	-0.023	-0.035	-0.058	-0.058	-0.050	-0.047	-0.001	-0.138	-0.051	-0.072	-0.046	-0.045	0.000	-0.030	-0.043	-0.043	-0.018	-0.024	-0.034	-0.025	-0.026	-0.024	-0.027	-0.030
14-20	0.085	0.087	0.084	0.073	0.070	0.099	0.068	0.104	0.106	0.085	0.078	0.070	0.067	0.117	0.120	0.064	0.086	0.065	0.064	0.000	0.044	0.059	0.061	0.032	0.036	0.050	0.039	0.041	0.040	0.042	0.046
14-21	-0.003	-0.003	-0.004	-0.006	-0.006	0.001	-0.007	0.003	0.002	-0.004	-0.006	-0.006	-0.007	0.005	0.004	-0.010	-0.004	-0.007	-0.007	0.000	-0.022	-0.009	-0.008	-0.007	-0.010	-0.009	-0.009	-0.009	-0.008	-0.008	-0.008

2020 continued (Chapter 7)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
16-15	0.024	0.022	0.026	0.036	0.039	0.003	0.040	-0.006	-0.007	0.029	0.038	0.041	0.041	-0.014	-0.045	0.078	0.026	0.046	0.043	0.000	0.045	0.053	0.045	0.024	0.033	0.042	0.033	0.033	0.031	0.033	0.037
17-15	0.076	0.075	0.079	0.077	0.075	0.034	0.072	0.011	0.013	0.105	0.105	0.082	0.073	-0.006	-0.045	0.058	0.164	0.070	0.068	0.000	0.035	0.058	0.062	0.021	0.029	0.045	0.030	0.032	0.030	0.033	0.039
16-17	-0.036	-0.037	-0.036	-0.021	-0.016	-0.025	-0.012	-0.018	-0.020	-0.054	-0.044	-0.019	-0.011	-0.012	-0.017	0.049	-0.110	-0.003	-0.005	0.000	0.026	0.016	0.004	0.011	0.017	0.014	0.015	0.014	0.013	0.013	0.012
16-21	0.078	0.077	0.080	0.081	0.080	0.053	0.078	0.038	0.043	0.091	0.096	0.086	0.079	0.027	0.042	0.150	0.093	0.084	0.078	0.000	-0.145	0.087	0.075	-0.002	-0.009	0.042	0.000	0.007	0.005	0.012	0.027
22-16	0.018	0.015	0.022	0.069	0.083	0.006	0.094	0.002	0.001	-0.004	0.019	0.083	0.098	-0.001	-0.007	-0.055	-0.006	0.136	0.117	0.000	-0.018	0.206	0.139	0.012	0.011	0.104	0.024	0.036	0.029	0.043	0.070
16-25	0.048	0.047	0.049	0.045	0.043	0.033	0.040	0.023	0.027	0.058	0.060	0.048	0.041	0.017	0.028	0.100	0.060	0.044	0.038	0.000	0.021	0.044	0.035	-0.032	-0.051	0.001	-0.040	-0.032	-0.033	-0.026	-0.012
18-19	-0.002	-0.002	-0.003	-0.013	-0.026	-0.001	-0.036	0.000	0.000	0.001	0.002	0.006	-0.040	0.000	0.001	0.003	0.002	0.089	-0.074	0.000	0.001	0.012	-0.036	-0.001	0.000	-0.002	-0.002	-0.002	-0.002	-0.003	-0.005
18-22	0.033	0.030	0.036	0.069	0.069	0.017	0.069	0.009	0.010	0.019	0.042	0.097	0.072	0.005	0.005	-0.007	0.019	0.206	0.066	0.000	-0.006	-0.072	0.021	-0.005	-0.007	-0.025	-0.008	-0.009	-0.007	-0.009	-0.012
18-23	0.003	0.003	0.004	0.004	0.002	0.002	-0.001	0.001	0.001	0.003	0.005	0.012	-0.001	0.001	0.001	0.001	0.003	0.041	-0.009	0.000	0.000	0.000	-0.033	-0.001	-0.001	-0.005	-0.002	-0.003	-0.002	-0.003	-0.005
23-19	-0.013	-0.012	-0.014	-0.030	-0.037	-0.007	-0.042	-0.004	-0.004	-0.008	-0.014	-0.029	-0.046	-0.002	-0.002	0.000	-0.007	-0.017	-0.065	0.000	0.001	0.014	0.059	0.003	0.003	0.013	0.004	0.005	0.004	0.006	0.008
20-21	-0.057	-0.056	-0.059	-0.066	-0.068	-0.041	-0.069	-0.032	-0.034	-0.062	-0.068	-0.070	-0.070	-0.025	-0.031	-0.090	-0.062	-0.073	-0.072	0.000	-0.149	-0.077	-0.073	-0.053	-0.073	-0.073	-0.070	-0.069	-0.066	-0.068	-0.070
20-24	-0.024	-0.024	-0.025	-0.030	-0.032	-0.019	-0.033	-0.016	-0.016	-0.024	-0.027	-0.031	-0.033	-0.012	-0.013	-0.031	-0.024	-0.034	-0.034	0.000	-0.031	-0.036	-0.036	-0.130	-0.047	-0.042	-0.049	-0.049	-0.053	-0.050	-0.047
20-25	-0.040	-0.039	-0.041	-0.050	-0.053	-0.029	-0.055	-0.023	-0.024	-0.041	-0.047	-0.053	-0.055	-0.017	-0.021	-0.056	-0.041	-0.057	-0.058	0.000	-0.058	-0.061	-0.060	-0.063	-0.089	-0.071	-0.082	-0.079	-0.076	-0.075	-0.072
21-25	0.017	0.018	0.017	0.009	0.005	0.013	0.002	0.008	0.011	0.025	0.023	0.009	0.003	0.007	0.014	0.050	0.026	0.004	-0.001	0.000	0.184	0.001	-0.006	-0.062	-0.092	-0.040	-0.079	-0.071	-0.070	-0.064	-0.051
22-23	-0.018	-0.016	-0.021	-0.050	-0.065	-0.009	-0.076	-0.005	-0.005	-0.007	-0.018	-0.045	-0.080	-0.002	-0.001	0.012	-0.006	-0.020	-0.110	0.000	0.006	0.077	-0.179	0.000	0.002	0.002	-0.001	-0.003	-0.003	-0.006	-0.010
22-26	0.016	0.016	0.017	0.025	0.025	0.010	0.025	0.006	0.007	0.015	0.020	0.030	0.027	0.004	0.006	0.018	0.016	0.045	0.030	0.000	0.003	0.073	0.030	-0.008	-0.010	-0.066	-0.015	-0.021	-0.016	-0.023	-0.036
24-25	-0.013	-0.012	-0.014	-0.017	-0.018	-0.006	-0.018	-0.002	-0.004	-0.015	-0.017	-0.018	-0.019	-0.001	-0.006	-0.024	-0.015	-0.020	-0.020	0.000	-0.028	-0.023	-0.021	0.199	-0.046	-0.025	-0.029	-0.021	-0.008	-0.013	-0.016
25-26	-0.029	-0.027	-0.031	-0.050	-0.056	-0.017	-0.061	-0.012	-0.013	-0.023	-0.033	-0.054	-0.062	-0.008	-0.009	-0.019	-0.023	-0.068	-0.070	0.000	0.000	-0.080	-0.080	0.007	0.020	-0.148	-0.003	-0.024	-0.013	-0.036	-0.079
25-27	-0.008	-0.008	-0.009	-0.015	-0.017	-0.006	-0.020	-0.006	-0.005	-0.006	-0.009	-0.015	-0.019	-0.004	-0.003	-0.001	-0.005	-0.018	-0.021	0.000	0.006	-0.020	-0.023	-0.008	0.016	-0.034	-0.120	-0.099	-0.097	-0.085	-0.062
25-28	-0.002	-0.002	-0.002	-0.004	-0.005	-0.002	-0.005	-0.001	-0.001	-0.002	-0.002	-0.004	-0.005	-0.001	-0.001	-0.001	-0.002	-0.005	-0.006	0.000	0.001	-0.005	-0.006	-0.001	0.004	-0.009	-0.012	-0.028	-0.014	-0.022	-0.016
28-26	-0.015	-0.014	-0.016	-0.026	-0.029	-0.008	-0.031	-0.005	-0.006	-0.013	-0.018	-0.028	-0.032	-0.003	-0.005	-0.012	-0.013	-0.036	-0.036	0.000	-0.003	-0.044	-0.042	0.008	0.006	-0.083	0.028	0.052	0.026	0.028	-0.018
26-31	0.007	0.007	0.007	0.011	0.011	0.004	0.011	0.002	0.002	0.006	0.009	0.013	0.013	0.001	0.002	0.008	0.007	0.019	0.015	0.000	0.003	0.027	0.019	-0.006	-0.001	0.057	-0.012	-0.020	-0.020	-0.047	-0.138
27-28	-0.008	-0.008	-0.009	-0.015	-0.017	-0.006	-0.019	-0.004	-0.004	-0.006	-0.009	-0.016	-0.019	-0.003	-0.003	-0.004	-0.006	-0.019	-0.021	0.000	0.002	-0.021	-0.023	-0.001	0.010	-0.036	0.032	-0.111	-0.006	-0.078	-0.056
27-29	-0.001	-0.001	-0.001	-0.002	-0.002	-0.002	-0.003	-0.002	-0.002	0.000	0.000	-0.002	-0.003	-0.002	-0.001	0.002	0.000	-0.002	-0.003	0.000	0.004	-0.001	-0.003	-0.008	0.009	-0.002	0.022	0.002	-0.110	-0.017	-0.013
30-28	0.005	0.005	0.005	0.009	0.011	0.004	0.012	0.003	0.003	0.003	0.005	0.009	0.012	0.002	0.002	0.001	0.003	0.010	0.013	0.000	-0.002	0.010	0.014	0.002	-0.007	0.014	-0.019	-0.044	0.010	0.126	0.069
30-31	-0.012	-0.011	-0.013	-0.021	-0.024	-0.006	-0.027	-0.004	-0.004	-0.010	-0.014	-0.022	-0.027	-0.002	-0.004	-0.009	-0.010	-0.027	-0.030	0.000	-0.002	-0.029	-0.033	0.006	0.004	-0.048	0.017	0.029	0.020	0.067	-0.176

2025 (Chapter 7)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
01-02	0.232	-0.024	0.041	0.022	0.018	-0.012	0.015	-0.006	-0.006	-0.005	0.012	0.014	0.015	-0.002	-0.001	0.003	0.002	0.011	0.012	0.000	0.002	0.007	0.010	0.002	0.002	0.005	0.003	0.003	0.003	0.003	0.005
01-03	0.219	0.030	-0.049	-0.027	-0.022	0.015	-0.019	0.007	0.007	0.006	-0.015	-0.017	-0.018	0.003	0.001	-0.004	-0.003	-0.013	-0.014	0.000	-0.003	-0.009	-0.012	-0.002	-0.003	-0.007	-0.003	-0.004	-0.003	-0.004	-0.006
02-03	-0.018	0.092	-0.153	-0.084	-0.069	0.046	-0.058	0.022	0.022	0.018	-0.045	-0.052	-0.055	0.009	0.003	-0.012	-0.009	-0.041	-0.045	0.000	-0.008	-0.027	-0.036	-0.006	-0.009	-0.020	-0.010	-0.012	-0.010	-0.013	-0.017
02-06	0.167	0.177	0.155	0.098	0.085	-0.151	0.076	-0.064	-0.058	0.074	0.077	0.074	0.073	-0.024	-0.002	0.037	0.054	0.061	0.064	0.000	0.022	0.046	0.055	0.013	0.019	0.035	0.021	0.022	0.020	0.023	0.030
02-10	0.117	0.129	0.103	0.045	0.034	0.055	0.025	0.020	0.014	-0.087	0.005	0.018	0.022	0.006	-0.003	-0.012	-0.031	0.011	0.015	0.000	-0.006	0.002	0.010	-0.001	-0.003	0.002	-0.001	-0.001	-0.001	0.000	0.002
03-04	0.080	0.071	0.091	-0.183	-0.139	0.036	-0.107	0.018	0.019	0.022	-0.003	-0.072	-0.096	0.008	0.005	-0.007	0.006	-0.058	-0.072	0.000	-0.007	-0.037	-0.056	-0.008	-0.010	-0.028	-0.013	-0.015	-0.013	-0.017	-0.024
03-11	0.111	0.096	0.130	0.031	0.014	0.047	0.002	0.022	0.021	0.010	-0.079	-0.023	-0.004	0.008	0.000	-0.014	-0.022	-0.016	-0.010	0.000	-0.008	-0.012	-0.010	-0.004	-0.006	-0.009	-0.006	-0.006	-0.005	-0.006	-0.007
04-05	0.030	0.027	0.034	0.107	-0.188	0.014	-0.095	0.007	0.008	0.011	0.008	-0.003	-0.078	0.004	0.003	-0.002	0.006	-0.017	-0.044	0.000	-0.003	-0.016	-0.032	-0.004	-0.005	-0.015	-0.007	-0.008	-0.007	-0.009	-0.014
04-07	0.007	0.007	0.008	0.026	-0.002	0.003	-0.031	0.002	0.002	0.003	0.002	0.000	-0.017	0.001	0.001	0.000	0.002	-0.004	-0.010	0.000	-0.001	-0.004	-0.008	-0.001	-0.001	-0.004	-0.002	-0.002	-0.002	-0.002	-0.003
04-12	0.029	0.026	0.034	0.133	0.074	0.013	0.032	0.006	0.006	0.005	-0.012	-0.056	0.013	0.003	0.001	-0.004	-0.002	-0.028	-0.007	0.000	-0.003	-0.011	-0.008	-0.002	-0.002	-0.006	-0.003	-0.003	-0.002	-0.003	-0.004
05-07	0.021	0.018	0.023	0.071	0.154	0.010	-0.112	0.005	0.005	0.008	0.006	0.001	-0.042	0.003	0.002	-0.001	0.005	-0.009	-0.027	0.000	-0.002	-0.010	-0.020	-0.003	-0.003	-0.010	-0.005	-0.006	-0.005	-0.007	-0.010
05-13	0.016	0.014	0.018	0.058	0.119	0.007	-0.002	0.004	0.004	0.005	0.003	-0.004	-0.052	0.002	0.001	-0.001	0.003	-0.011	-0.026	0.000	-0.001	-0.009	-0.018	-0.002	-0.002	-0.007	-0.003	-0.004	-0.003	-0.004	-0.006
06-08	0.061	0.065	0.057	0.037	0.032	0.121	0.029	-0.083	0.009	0.032	0.030	0.029	0.028	-0.010	0.003	0.015	0.023	0.024	0.025	0.000	0.009	0.018	0.021	0.005	0.008	0.014	0.008	0.008	0.007	0.009	0.011
06-09	0.107	0.113	0.099	0.062	0.054	0.228	0.047	0.017	-0.066	0.043	0.047	0.046	0.046	-0.014	-0.004	0.022	0.032	0.038	0.040	0.000	0.013	0.029	0.034	0.009	0.012	0.022	0.013	0.014	0.013	0.015	0.019
07-13	0.006	0.005	0.007	0.026	0.044	0.003	0.124	0.001	0.001	0.001	-0.002	-0.009	-0.048	0.001	0.000	-0.001	0.000	-0.009	-0.017	0.000	-0.001	-0.006	-0.010	0.000	0.000	-0.002	0.000	0.000	0.000	0.000	0.001
08-09	-0.014	-0.014	-0.014	-0.011	-0.011	-0.008	-0.010	0.157	-0.093	-0.022	-0.013	-0.011	-0.010	0.006	-0.011	-0.009	-0.015	-0.009	-0.009	0.000	-0.005	-0.008	-0.008	0.000	-0.003	-0.005	-0.002	-0.002	-0.001	-0.002	-0.004
08-14	0.036	0.038	0.034	0.024	0.022	0.061	0.020	0.106	0.055	0.027	0.021	0.020	0.020	0.021	0.001	0.012	0.018	0.018	0.018	0.000	0.008	0.014	0.016	0.008	0.008	0.012	0.009	0.010	0.010	0.011	0.012
09-10	-0.062	-0.061	-0.063	-0.059	-0.057	0.031	-0.055	0.055	0.093	-0.163	-0.076	-0.061	-0.055	0.031	0.001	-0.050	-0.087	-0.054	-0.052	0.000	-0.029	-0.046	-0.048	-0.015	-0.023	-0.035	-0.023	-0.024	-0.022	-0.025	-0.030
09-14	0.045	0.047	0.042	0.031	0.028	0.069	0.025	0.043	0.101	0.039	0.029	0.026	0.025	-0.023	0.010	0.017	0.027	0.022	0.022	0.000	0.010	0.018	0.020	0.006	0.008	0.014	0.009	0.009	0.008	0.010	0.012
09-15	0.033	0.035	0.030	0.018	0.016	0.064	0.014	0.058	0.090	0.023	0.013	0.013	0.013	0.022	-0.035	0.003	0.005	0.010	0.011	0.000	0.002	0.007	0.009	0.004	0.003	0.006	0.004	0.005	0.005	0.006	0.006
10-11	0.001	0.005	-0.003	-0.015	-0.016	0.005	-0.016	0.005	0.006	0.040	-0.041	-0.023	-0.017	0.003	0.001	-0.003	0.001	-0.016	-0.015	0.000	-0.002	-0.010	-0.013	-0.002	-0.003	-0.007	-0.003	-0.004	-0.003	-0.004	-0.006
10-16	0.046	0.049	0.042	0.021	0.015	0.032	0.011	0.021	0.025	0.095	0.025	0.013	0.010	0.011	0.008	-0.034	0.036	0.002	0.004	0.000	-0.018	-0.011	-0.002	-0.007	-0.012	-0.009	-0.010	-0.010	-0.009	-0.009	-0.008
17-10	-0.063	-0.071	-0.054	-0.019	-0.013	-0.044	-0.008	-0.026	-0.033	-0.177	0.015	-0.001	-0.006	-0.009	0.012	0.002	0.119	-0.001	-0.003	0.000	0.001	0.000	-0.002	-0.001	0.000	-0.001	0.000	-0.001	-0.001	-0.001	-0.001
11-12	0.012	0.014	0.010	-0.115	-0.127	0.011	-0.134	0.008	0.010	0.033	0.108	-0.206	-0.142	0.006	0.010	0.004	0.046	-0.138	-0.129	0.000	-0.003	-0.069	-0.101	-0.011	-0.012	-0.049	-0.018	-0.023	-0.020	-0.027	-0.040
11-16	0.050	0.046	0.055	0.051	0.047	0.026	0.043	0.015	0.016	0.034	0.107	0.059	0.043	0.008	0.007	-0.033	0.039	0.034	0.034	0.000	-0.017	0.006	0.022	-0.005	-0.008	0.003	-0.006	-0.004	-0.004	-0.002	0.002
17-11	-0.050	-0.040	-0.061	-0.080	-0.078	-0.015	-0.077	-0.003	-0.001	0.018	-0.165	-0.100	-0.078	0.003	0.016	-0.012	0.107	-0.072	-0.070	0.000	-0.009	-0.042	-0.057	-0.010	-0.012	-0.031	-0.015	-0.017	-0.015	-0.019	-0.026
12-13	0.003	0.004	0.003	-0.025	-0.076	0.003	-0.109	0.002	0.003	0.008	0.024	0.064	-0.136	0.001	0.003	0.002	0.011	0.011	-0.054	0.000	0.000	-0.008	-0.034	-0.003	-0.003	-0.012	-0.005	-0.007	-0.006	-0.008	-0.012
12-18	0.033	0.030	0.036	0.058	0.044	0.017	0.032	0.010	0.011	0.021	0.047	0.110	0.032	0.005	0.006	-0.004	0.022	-0.183	-0.012	0.000	-0.005	-0.059	-0.032	-0.006	-0.008	-0.030	-0.011	-0.013	-0.011	-0.014	-0.019
12-19	0.012	0.011	0.013	0.013	-0.005	0.007	-0.018	0.004	0.004	0.010	0.022	0.053	-0.022	0.002	0.003	0.001	0.011	0.001	-0.071	0.000	-0.001	-0.015	-0.045	-0.004	-0.004	-0.015	-0.006	-0.007	-0.007	-0.009	-0.013
13-19	0.016	0.015	0.018	0.046	0.070	0.008	0.081	0.004	0.005	0.008	0.012	0.020	0.103	0.002	0.002	-0.001	0.006	-0.010	-0.059	0.000	-0.002	-0.015	-0.037	-0.003	-0.003	-0.012	-0.004	-0.005	-0.005	-0.006	-0.008
14-15	-0.049	-0.049	-0.050	-0.049	-0.047	-0.037	-0.046	-0.023	-0.035	-0.058	-0.058	-0.050	-0.047	-0.001	-0.138	-0.051	-0.072	-0.046	-0.045	0.000	-0.030	-0.043	-0.043	-0.018	-0.024	-0.034	-0.025	-0.026	-0.024	-0.026	-0.030
14-20	0.085	0.087	0.084	0.073	0.070	0.099	0.068	0.104	0.106	0.085	0.078	0.070	0.067	0.117	0.120	0.064	0.086	0.065	0.064	0.000	0.044	0.059	0.061	0.032	0.036	0.050	0.039	0.041	0.040	0.042	0.046
14-21	-0.003	-0.003	-0.003	-0.006	-0.006	0.001	-0.007	0.003	0.002	-0.004	-0.006	-0.006	-0.007	0.005	0.004	-0.010	-0.004	-0.007	-0.007	0.000	-0.022	-0.009	-0.008	-0.007	-0.010	-0.009	-0.009	-0.009	-0.008	-0.008	-0.008
16-15	0.232	-0.024	0.041	0.022	0.018	-0.012	0.015	-0.006	-0.006	-0.005	0.012	0.014	0.015	-0.002	-0.001	0.003	0.002	0.011	0.012	0.000	0.002	0.007	0.010	0.002	0.002	0.005	0.003	0.003	0.003	0.003	0.005
17-15	0.219	0.030	-0.049	-0.027	-0.022	0.015	-0.019	0.007	0.007	0.006	-0.015	-0.017	-0.018	0.003	0.001	-0.004	-0.003	-0.013	-0.014	0.000	-0.003	-0.009	-0.012	-0.002	-0.003	-0.007	-0.003	-0.004	-0.003	-0.004	-0.006

2025 continued (Chapter 7)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
16-17	0.024	0.022	0.026	0.036	0.039	0.003	0.040	-0.006	-0.007	0.029	0.038	0.041	0.041	-0.014	-0.045	0.078	0.026	0.046	0.043	0.000	0.045	0.053	0.045	0.024	0.033	0.042	0.033	0.033	0.031	0.033	0.037
16-21	0.076	0.075	0.079	0.077	0.075	0.034	0.072	0.011	0.013	0.105	0.105	0.082	0.073	-0.006	-0.045	0.058	0.164	0.070	0.068	0.000	0.034	0.058	0.062	0.021	0.029	0.045	0.030	0.032	0.030	0.033	0.039
22-16	-0.036	-0.037	-0.036	-0.021	-0.016	-0.025	-0.012	-0.018	-0.020	-0.054	-0.044	-0.019	-0.011	-0.012	-0.017	0.049	-0.110	-0.003	-0.005	0.000	0.026	0.016	0.004	0.011	0.017	0.014	0.015	0.014	0.013	0.013	0.012
16-25	0.078	0.077	0.080	0.081	0.080	0.053	0.078	0.038	0.043	0.091	0.096	0.086	0.079	0.027	0.042	0.150	0.093	0.084	0.078	0.000	-0.145	0.087	0.075	-0.002	-0.009	0.042	0.000	0.007	0.005	0.012	0.027
18-19	0.018	0.015	0.022	0.069	0.083	0.006	0.093	0.002	0.001	-0.004	0.019	0.082	0.097	-0.001	-0.007	-0.055	-0.006	0.136	0.117	0.000	-0.018	0.206	0.139	0.012	0.011	0.104	0.024	0.035	0.029	0.043	0.070
18-22	0.048	0.047	0.049	0.045	0.043	0.033	0.040	0.023	0.027	0.058	0.060	0.048	0.041	0.017	0.028	0.100	0.060	0.044	0.038	0.000	0.021	0.044	0.035	-0.032	-0.051	0.001	-0.040	-0.032	-0.033	-0.026	-0.012
18-23	-0.002	-0.002	-0.003	-0.013	-0.026	-0.001	-0.036	0.000	0.000	0.001	0.002	0.006	-0.040	0.000	0.001	0.003	0.002	0.089	-0.074	0.000	0.001	0.012	-0.036	-0.001	0.000	-0.002	-0.002	-0.002	-0.002	-0.003	-0.005
23-19	0.033	0.030	0.036	0.069	0.069	0.017	0.069	0.009	0.010	0.019	0.042	0.097	0.072	0.005	0.005	-0.007	0.019	0.206	0.066	0.000	-0.006	-0.072	0.021	-0.005	-0.007	-0.025	-0.008	-0.009	-0.007	-0.009	-0.012
20-21	0.003	0.003	0.004	0.004	0.002	0.002	-0.001	0.001	0.001	0.003	0.005	0.012	-0.001	0.001	0.001	0.001	0.003	0.041	-0.009	0.000	0.000	0.000	-0.033	-0.001	-0.001	-0.005	-0.002	-0.003	-0.002	-0.003	-0.005
20-24	-0.013	-0.012	-0.014	-0.030	-0.037	-0.007	-0.042	-0.004	-0.004	-0.008	-0.014	-0.029	-0.046	-0.002	-0.002	0.000	-0.007	-0.017	-0.065	0.000	0.001	0.014	0.059	0.003	0.003	0.013	0.004	0.005	0.004	0.006	0.008
20-25	-0.057	-0.056	-0.059	-0.066	-0.068	-0.041	-0.069	-0.032	-0.034	-0.062	-0.068	-0.070	-0.070	-0.025	-0.031	-0.090	-0.062	-0.073	-0.072	0.000	-0.149	-0.077	-0.073	-0.053	-0.073	-0.073	-0.070	-0.069	-0.066	-0.068	-0.069
21-25	-0.024	-0.024	-0.025	-0.030	-0.032	-0.019	-0.033	-0.016	-0.016	-0.024	-0.027	-0.031	-0.033	-0.012	-0.013	-0.031	-0.024	-0.034	-0.034	0.000	-0.032	-0.036	-0.036	-0.130	-0.047	-0.042	-0.049	-0.049	-0.053	-0.050	-0.047
22-23	-0.040	-0.039	-0.041	-0.050	-0.053	-0.029	-0.055	-0.023	-0.024	-0.041	-0.047	-0.053	-0.055	-0.017	-0.021	-0.056	-0.041	-0.057	-0.058	0.000	-0.058	-0.061	-0.060	-0.063	-0.089	-0.071	-0.082	-0.079	-0.076	-0.075	-0.072
22-26	0.017	0.018	0.017	0.009	0.005	0.013	0.002	0.008	0.011	0.025	0.023	0.009	0.003	0.007	0.014	0.050	0.026	0.004	-0.001	0.000	0.184	0.001	-0.006	-0.062	-0.092	-0.040	-0.079	-0.071	-0.070	-0.064	-0.051
24-25	-0.018	-0.016	-0.021	-0.050	-0.065	-0.009	-0.076	-0.005	-0.005	-0.007	-0.018	-0.045	-0.080	-0.002	-0.001	0.012	-0.006	-0.020	-0.110	0.000	0.006	0.077	-0.179	0.000	0.002	0.002	-0.001	-0.003	-0.003	-0.006	-0.010
25-26	0.016	0.016	0.017	0.025	0.025	0.010	0.025	0.006	0.007	0.015	0.020	0.030	0.027	0.004	0.006	0.018	0.016	0.045	0.030	0.000	0.003	0.073	0.030	-0.008	-0.010	-0.066	-0.015	-0.021	-0.016	-0.023	-0.035
25-27	-0.013	-0.012	-0.014	-0.017	-0.018	-0.006	-0.018	-0.002	-0.004	-0.015	-0.017	-0.018	-0.019	-0.001	-0.006	-0.024	-0.015	-0.020	-0.019	0.000	-0.028	-0.023	-0.021	0.199	-0.046	-0.025	-0.029	-0.021	-0.008	-0.013	-0.016
25-28	-0.029	-0.027	-0.031	-0.050	-0.056	-0.017	-0.061	-0.012	-0.013	-0.023	-0.033	-0.054	-0.062	-0.008	-0.009	-0.019	-0.023	-0.067	-0.070	0.000	0.000	-0.080	-0.080	0.007	0.020	-0.148	-0.003	-0.024	-0.013	-0.035	-0.079
28-26	-0.008	-0.008	-0.009	-0.015	-0.017	-0.006	-0.020	-0.006	-0.005	-0.006	-0.009	-0.015	-0.019	-0.004	-0.003	-0.001	-0.005	-0.018	-0.021	0.000	0.006	-0.020	-0.023	-0.008	0.016	-0.034	-0.120	-0.099	-0.097	-0.085	-0.062
26-31	-0.002	-0.002	-0.002	-0.004	-0.005	-0.002	-0.005	-0.001	-0.001	-0.002	-0.002	-0.004	-0.005	-0.001	-0.001	-0.001	-0.001	-0.005	-0.006	0.000	0.001	-0.005	-0.006	-0.001	0.004	-0.009	-0.012	-0.028	-0.014	-0.022	-0.016
27-28	-0.015	-0.014	-0.016	-0.026	-0.029	-0.008	-0.031	-0.005	-0.006	-0.013	-0.018	-0.028	-0.032	-0.003	-0.005	-0.012	-0.013	-0.036	-0.036	0.000	-0.003	-0.044	-0.042	0.008	0.006	-0.083	0.028	0.052	0.026	0.028	-0.018
27-29	0.007	0.007	0.007	0.011	0.012	0.004	0.012	0.002	0.002	0.007	0.009	0.013	0.013	0.001	0.002	0.008	0.007	0.019	0.015	0.000	0.003	0.027	0.020	-0.006	-0.001	0.058	-0.012	-0.019	-0.020	-0.046	-0.137
30-28	-0.008	-0.008	-0.009	-0.015	-0.017	-0.006	-0.019	-0.004	-0.004	-0.006	-0.009	-0.016	-0.019	-0.003	-0.003	-0.004	-0.006	-0.019	-0.021	0.000	0.002	-0.021	-0.023	-0.002	0.010	-0.036	0.032	-0.111	-0.006	-0.078	-0.055
30-31	-0.001	-0.001	-0.001	-0.002	-0.002	-0.002	-0.003	-0.002	-0.002	0.000	0.000	-0.002	-0.003	-0.002	-0.001	0.002	0.000	-0.002	-0.003	0.000	0.004	-0.001	-0.003	-0.008	0.009	-0.002	0.021	0.002	-0.110	-0.018	-0.014

B. Model Results Dispatch

B.1 Weighted average net export/import balance per quarter in Germany in the year 2015, 2020 and 2025

region	REFERENCE SCENARIO net export/import balance [GW]											
	2015				2020				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1	-2.50	-0.97	-1.12	-1.60	-5.58	-2.50	-2.50	-3.92	-6.43	-1.97	-2.17	-4.38
2	-1.04	-0.64	-0.18	-0.60	-1.05	-0.55	-0.04	-0.64	-1.02	-0.70	-0.28	-0.68
3	0.42	0.81	0.64	0.66	0.23	0.70	0.50	0.52	0.11	0.63	0.41	0.44
4	-0.59	-0.18	-0.22	-0.45	-0.84	-0.26	-0.32	-0.69	-0.96	-0.37	-0.45	-0.89
5	-0.22	0.10	0.02	-0.11	-0.60	0.05	-0.12	-0.53	-0.90	0.00	-0.26	-0.86
6	-0.34	0.21	0.06	-0.14	-0.40	0.21	0.00	-0.21	-0.53	-0.01	-0.13	-0.38
7	-0.50	-0.06	-0.15	-0.17	-0.62	-0.12	-0.23	-0.25	-0.70	-0.16	-0.29	-0.31
8	-2.86	-0.92	-1.02	-1.86	-6.57	-1.52	-1.75	-3.97	-10.83	-2.66	-3.03	-7.22
9	-2.10	-1.79	-1.34	-1.73	-1.86	-1.83	-1.19	-1.52	-0.56	-0.99	-0.54	-0.63
10	-0.87	-0.42	-0.44	-0.80	-0.79	-0.43	-0.41	-0.80	-0.78	-0.68	-0.51	-0.90
11	-0.18	0.11	0.18	-0.05	-0.09	0.31	0.25	-0.09	-0.17	0.00	0.15	-0.24
12	-1.93	-0.69	-0.88	-0.96	-2.21	-0.85	-0.98	-1.10	-2.43	-1.16	-1.23	-1.32
13	-1.99	-1.17	-0.92	-1.12	-1.96	-1.26	-0.72	-0.98	-2.02	-1.87	-1.13	-1.33
14	1.86	2.41	2.49	0.34	2.20	1.94	2.42	0.40	2.42	1.05	2.00	0.55
15	0.33	0.39	0.57	-0.16	0.86	0.38	0.55	-0.01	0.94	0.50	0.58	0.57
16	1.14	0.98	0.91	0.95	1.07	0.90	0.77	0.86	1.02	0.87	0.71	0.79
17	-0.57	-0.63	-0.60	-0.67	-0.63	-0.69	-0.69	-0.74	0.52	0.45	0.34	0.39
18	-1.17	-1.14	-1.14	-1.32	-1.34	-1.18	-1.24	-1.39	-1.47	-1.29	-1.33	-1.50
19	-4.82	-4.59	-4.51	-4.79	-4.95	-4.57	-4.53	-4.74	-5.07	-4.57	-4.55	-4.74
20	-4.89	-4.77	-3.71	-4.32	-3.06	-3.51	-1.97	-2.33	-0.93	-2.61	-1.17	-1.16
21	1.35	1.21	1.10	1.18	1.29	1.14	1.02	1.12	1.24	1.10	0.97	1.07
22	1.47	1.37	1.29	1.34	1.33	1.22	1.07	1.17	1.26	1.21	0.95	1.07
23	2.17	1.87	2.07	1.86	2.29	1.84	2.10	2.00	2.33	1.68	1.77	1.75
24	1.37	1.21	1.19	0.77	1.66	1.22	1.36	0.89	1.72	1.32	1.33	1.18
25	0.46	0.31	0.40	0.04	0.85	0.65	0.84	0.49	0.83	0.40	0.63	0.45
26	0.87	0.73	0.60	0.80	0.79	0.61	0.46	0.69	0.74	0.54	0.37	0.62
27	-0.44	-0.47	-0.14	-0.65	0.88	0.61	0.92	0.51	0.86	0.20	0.76	0.34
28	1.19	0.83	0.60	0.61	0.98	0.48	0.25	0.35	2.05	1.31	0.99	1.23
29	1.00	0.83	0.83	0.92	0.90	0.74	0.74	0.85	0.86	0.81	0.65	0.78
30	-0.86	-1.04	-1.05	-0.98	0.15	-0.09	-0.20	-0.01	1.21	0.93	0.71	1.01
31	-0.23	-0.93	-0.49	-0.20	-0.25	-1.46	-0.88	-0.51	0.81	-1.09	-0.64	-0.08

region	SCENARIO "FUEL PRICE"											
	net export/import balance [GW]											
	2015				2020				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1	-2.51	-0.95	-1.11	-1.59	-6.19	-2.90	-2.85	-4.43	-7.01	-2.54	-2.62	-4.92
2	-1.09	-0.66	-0.30	-0.61	-1.02	-0.52	-0.03	-0.58	-1.06	-0.70	-0.30	-0.66
3	0.42	0.81	0.64	0.66	0.23	0.70	0.50	0.52	0.11	0.63	0.41	0.44
4	-0.60	-0.23	-0.22	-0.45	-0.78	-0.25	-0.32	-0.67	-0.94	-0.38	-0.44	-0.88
5	-0.22	0.10	0.02	-0.11	-0.60	0.05	-0.12	-0.53	-0.90	0.00	-0.26	-0.86
6	-0.35	0.26	0.08	-0.12	-0.45	0.20	0.02	-0.17	-0.54	-0.02	-0.19	-0.33
7	-0.50	-0.06	-0.15	-0.17	-0.62	-0.12	-0.23	-0.25	-0.70	-0.16	-0.29	-0.31
8	-2.92	-0.97	-1.05	-1.87	-6.54	-1.47	-1.74	-3.92	-10.76	-2.68	-3.02	-7.19
9	-1.86	-1.70	-0.99	-1.61	-1.57	-1.79	-1.13	-1.42	-0.34	-0.78	-0.27	-0.47
10	-0.89	-0.48	-0.40	-0.79	-0.78	-0.44	-0.39	-0.74	-0.71	-0.65	-0.53	-0.83
11	-0.16	0.17	0.15	-0.03	-0.10	0.31	0.26	-0.07	-0.15	0.01	0.07	-0.18
12	-1.56	-0.31	-0.56	-0.64	-1.94	-0.49	-0.81	-0.88	-2.19	-0.62	-0.98	-1.06
13	-1.43	-0.67	-0.08	-0.67	-1.56	-0.82	-0.29	-0.63	-1.61	-1.20	-0.72	-0.97
14	-0.21	0.52	1.22	-1.31	0.17	0.11	1.18	-1.58	0.52	-1.18	0.30	-1.37
15	0.35	0.43	0.59	-0.11	0.82	0.41	0.71	0.11	1.05	0.62	0.71	0.68
16	1.16	0.99	0.90	0.95	1.08	0.91	0.79	0.86	1.03	0.87	0.72	0.79
17	-0.57	-0.63	-0.61	-0.67	-0.62	-0.69	-0.69	-0.74	0.52	0.45	0.34	0.39
18	-1.17	-1.13	-1.12	-1.31	-1.34	-1.25	-1.25	-1.35	-1.47	-1.27	-1.33	-1.46
19	-4.81	-4.70	-4.57	-4.91	-4.94	-4.64	-4.51	-4.68	-5.06	-4.56	-4.55	-4.73
20	-3.81	-3.90	-2.99	-3.63	-2.35	-2.67	-1.86	-1.95	-0.38	-1.18	-0.40	-0.47
21	1.35	1.21	1.10	1.18	1.29	1.14	1.02	1.12	1.24	1.10	0.97	1.07
22	1.53	1.40	1.27	1.34	1.36	1.23	1.08	1.19	1.29	1.20	0.99	1.06
23	2.65	2.37	2.24	2.24	2.57	2.24	2.11	2.15	2.44	1.78	1.99	1.88
24	1.33	1.30	1.41	0.90	1.68	1.25	1.57	1.01	1.88	1.23	1.39	1.27
25	0.46	0.32	0.51	0.09	0.93	0.68	0.87	0.58	1.00	0.40	0.69	0.56
26	0.88	0.73	0.60	0.80	0.79	0.61	0.46	0.69	0.74	0.54	0.38	0.62
27	-0.57	-0.47	0.07	-0.59	0.91	0.67	1.10	0.66	1.03	0.28	0.72	0.50
28	1.04	0.77	0.60	0.59	1.05	0.48	0.30	0.46	2.19	1.11	0.95	1.28
29	1.02	0.85	0.82	0.95	0.98	0.77	0.76	0.88	0.89	0.80	0.69	0.81
30	-0.86	-1.04	-1.05	-0.98	0.15	-0.09	-0.20	-0.01	1.21	0.93	0.71	1.01
31	0.02	-0.74	-0.03	-0.09	0.04	-1.42	-0.72	-0.38	1.03	-0.87	-0.37	0.17

region	SCENARIO "WIND POWER" net export/import balance [GW]											
	2015				2020				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1	-2.30	-0.93	-1.07	-1.48	-5.11	-2.44	-2.40	-3.65	-5.66	-1.81	-1.98	-3.81
2	-1.06	-0.68	-0.21	-0.63	-1.12	-0.59	-0.07	-0.64	-1.24	-0.76	-0.31	-0.70
3	0.45	0.82	0.66	0.67	0.27	0.71	0.52	0.54	0.16	0.64	0.43	0.46
4	-0.57	-0.19	-0.22	-0.43	-0.78	-0.26	-0.30	-0.65	-0.93	-0.36	-0.42	-0.81
5	-0.18	0.11	0.03	-0.08	-0.50	0.06	-0.09	-0.41	-0.74	0.01	-0.21	-0.68
6	-0.30	0.23	0.10	-0.13	-0.40	0.21	0.03	-0.19	-0.48	0.01	-0.12	-0.37
7	-0.48	-0.05	-0.14	-0.16	-0.59	-0.11	-0.22	-0.24	-0.67	-0.15	-0.28	-0.29
8	-2.60	-0.89	-0.98	-1.71	-5.60	-1.39	-1.57	-3.43	-9.11	-2.34	-2.63	-6.06
9	-2.13	-1.80	-1.35	-1.78	-1.96	-1.83	-1.21	-1.57	-0.79	-0.93	-0.54	-0.70
10	-0.86	-0.42	-0.42	-0.80	-0.84	-0.44	-0.40	-0.81	-0.85	-0.68	-0.51	-0.92
11	-0.16	0.13	0.21	-0.08	-0.09	0.29	0.26	-0.08	-0.16	0.01	0.15	-0.27
12	-1.84	-0.67	-0.84	-0.93	-2.09	-0.82	-0.97	-1.05	-2.32	-1.13	-1.19	-1.26
13	-1.93	-1.15	-0.91	-1.11	-1.93	-1.24	-0.78	-0.98	-2.06	-1.86	-1.13	-1.30
14	1.64	2.36	2.45	0.20	1.90	1.92	2.39	0.26	1.99	1.04	1.88	0.39
15	0.33	0.41	0.53	-0.26	0.70	0.37	0.55	-0.08	0.76	0.46	0.50	0.52
16	1.16	0.99	0.91	0.94	1.08	0.89	0.79	0.85	1.03	0.87	0.70	0.80
17	-0.56	-0.63	-0.60	-0.67	-0.63	-0.69	-0.68	-0.74	0.52	0.45	0.35	0.39
18	-1.15	-1.12	-1.12	-1.28	-1.31	-1.22	-1.23	-1.37	-1.44	-1.28	-1.33	-1.53
19	-4.80	-4.66	-4.55	-4.82	-4.93	-4.65	-4.55	-4.81	-5.06	-4.58	-4.57	-4.92
20	-4.95	-4.84	-3.68	-4.37	-3.30	-3.47	-1.99	-2.50	-1.31	-2.66	-1.23	-1.46
21	1.35	1.21	1.10	1.19	1.29	1.15	1.03	1.12	1.25	1.10	0.98	1.08
22	1.50	1.41	1.28	1.35	1.37	1.26	1.06	1.19	1.28	1.22	0.95	1.09
23	2.18	1.87	2.08	1.91	2.26	1.84	2.10	1.97	2.18	1.62	1.78	1.67
24	1.28	1.20	1.22	0.73	1.48	1.22	1.29	0.83	1.60	1.32	1.31	1.14
25	0.38	0.30	0.40	0.03	0.76	0.64	0.82	0.46	0.68	0.38	0.61	0.42
26	0.88	0.73	0.60	0.80	0.79	0.61	0.45	0.69	0.74	0.54	0.37	0.62
27	-0.55	-0.48	-0.21	-0.68	0.79	0.60	0.85	0.48	0.69	0.17	0.73	0.33
28	1.03	0.77	0.59	0.57	0.89	0.48	0.23	0.32	1.89	1.31	0.95	1.19
29	1.02	0.84	0.85	0.94	0.92	0.74	0.73	0.88	0.90	0.81	0.66	0.78
30	-0.86	-1.04	-1.05	-0.98	0.15	-0.09	-0.20	-0.01	1.21	0.93	0.71	1.01
31	-0.28	-0.92	-0.48	-0.27	-0.33	-1.47	-0.91	-0.59	0.60	-1.14	-0.70	-0.15

region	SCENARIO "LOAD STRUCTURE" net export/import balance [GW]											
	2015				2020				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1	-2.54	-1.01	-1.16	-1.64	-5.66	-2.58	-2.57	-3.99	-6.55	-2.08	-2.27	-4.49
2	-1.04	-0.64	-0.18	-0.60	-1.05	-0.55	-0.04	-0.64	-1.02	-0.70	-0.28	-0.68
3	0.37	0.77	0.60	0.62	0.13	0.62	0.42	0.44	-0.02	0.51	0.30	0.32
4	-0.60	-0.19	-0.23	-0.46	-0.86	-0.29	-0.34	-0.71	-0.99	-0.40	-0.48	-0.92
5	-0.23	0.10	0.01	-0.12	-0.62	0.03	-0.13	-0.54	-0.93	-0.02	-0.28	-0.88
6	-0.38	0.17	0.03	-0.18	-0.48	0.14	-0.06	-0.28	-0.64	-0.11	-0.22	-0.48
7	-0.51	-0.06	-0.15	-0.17	-0.64	-0.13	-0.24	-0.26	-0.73	-0.18	-0.31	-0.33
8	-2.89	-0.94	-1.04	-1.88	-6.62	-1.55	-1.79	-4.00	-10.89	-2.72	-3.08	-7.27
9	-2.14	-1.82	-1.37	-1.77	-1.93	-1.89	-1.25	-1.59	-0.65	-1.08	-0.63	-0.72
10	-0.89	-0.44	-0.46	-0.82	-0.84	-0.47	-0.44	-0.84	-0.84	-0.73	-0.56	-0.95
11	-0.18	0.11	0.18	-0.05	-0.09	0.31	0.25	-0.09	-0.17	0.00	0.15	-0.24
12	-1.95	-0.71	-0.90	-0.98	-2.25	-0.88	-1.01	-1.12	-2.48	-1.20	-1.28	-1.37
13	-1.99	-1.17	-0.92	-1.12	-1.96	-1.26	-0.72	-0.98	-2.02	-1.87	-1.13	-1.33
14	1.92	2.46	2.54	0.38	2.31	2.04	2.51	0.49	2.57	1.19	2.13	0.68
15	0.36	0.42	0.60	-0.13	0.92	0.43	0.60	0.04	1.03	0.58	0.65	0.64
16	1.14	0.98	0.91	0.95	1.07	0.90	0.77	0.86	1.02	0.87	0.71	0.79
17	-0.57	-0.63	-0.60	-0.67	-0.63	-0.69	-0.69	-0.74	0.52	0.45	0.34	0.39
18	-1.17	-1.14	-1.14	-1.32	-1.34	-1.18	-1.24	-1.39	-1.47	-1.29	-1.33	-1.50
19	-4.82	-4.59	-4.51	-4.79	-4.95	-4.57	-4.53	-4.74	-5.07	-4.57	-4.55	-4.74
20	-4.83	-4.72	-3.66	-4.27	-2.95	-3.41	-1.88	-2.23	-0.78	-2.47	-1.04	-1.02
21	1.35	1.21	1.10	1.18	1.29	1.14	1.02	1.12	1.24	1.10	0.97	1.07
22	1.47	1.37	1.29	1.34	1.33	1.22	1.07	1.17	1.26	1.21	0.95	1.07
23	2.17	1.87	2.07	1.86	2.29	1.84	2.10	2.00	2.33	1.68	1.77	1.75
24	1.37	1.21	1.19	0.77	1.66	1.22	1.36	0.89	1.72	1.32	1.33	1.18
25	0.46	0.31	0.40	0.04	0.85	0.65	0.84	0.49	0.83	0.40	0.63	0.45
26	0.87	0.73	0.60	0.80	0.79	0.61	0.46	0.69	0.74	0.54	0.37	0.62
27	-0.41	-0.44	-0.11	-0.62	0.95	0.67	0.98	0.57	0.95	0.29	0.84	0.43
28	1.23	0.86	0.63	0.64	1.05	0.55	0.31	0.42	2.15	1.40	1.07	1.33
29	1.00	0.83	0.83	0.92	0.90	0.74	0.74	0.85	0.86	0.81	0.65	0.78
30	-0.86	-1.04	-1.05	-0.98	0.15	-0.09	-0.20	-0.01	1.21	0.93	0.71	1.01
31	-0.19	-0.89	-0.45	-0.17	-0.16	-1.39	-0.81	-0.44	0.93	-0.98	-0.54	0.03

C. Model Results Redispatch Chapter 6

C.1 Weighted average line utilization and frequency and magnitude of congestion in Germany in the years 2015, 2020 and 2025

	REFERENCE SCENARIO (Chapter 6)								
	line utilization [% of capacity]			frequency of congestion [% of hours]			magnitude of congestion [MW]		
line	2015	2020	2025	2015	2020	2025	2015	2020	2025
L-01-02	32.52%	64.15%	64.75%	0.00%	18.30%	25.60%	0	153	260
L-01-03	31.29%	64.41%	67.61%	0.00%	20.39%	27.38%	0	148	296
L-02-03	9.09%	9.20%	12.35%	0.00%	0.00%	0.00%	0	0	0
L-02-06	24.60%	36.17%	23.73%	0.00%	0.00%	0.00%	0	0	0
L-02-10	30.30%	46.82%	55.98%	0.00%	4.76%	11.61%	0	106	188
L-03-04	15.66%	18.35%	24.75%	0.00%	0.00%	0.00%	0	0	0
L-03-11	22.29%	41.73%	50.22%	0.00%	0.74%	7.89%	0	16	132
L-04-05	7.72%	10.17%	13.71%	0.00%	0.00%	0.00%	0	0	0
L-04-07	12.36%	22.08%	31.80%	0.00%	0.00%	0.00%	0	0	0
L-04-12	5.94%	15.39%	19.80%	0.00%	0.00%	0.00%	0	0	0
L-05-07	6.49%	9.13%	11.79%	0.00%	0.00%	0.00%	0	0	0
L-05-13	11.41%	12.36%	17.79%	0.00%	0.00%	0.00%	0	0	0
L-06-08	18.43%	25.46%	19.85%	0.00%	0.00%	0.00%	0	0	0
L-06-09	-	58.33%	68.40%	-	16.37%	23.96%	-	348	489
L-07-13	10.43%	8.68%	10.89%	0.00%	0.00%	0.00%	0	0	0
L-08-09	16.41%	28.90%	62.35%	0.00%	0.00%	25.00%	0	0	391
L-08-14	23.80%	41.18%	59.60%	0.00%	0.00%	16.07%	0	0	221
L-09-10	24.58%	14.98%	15.95%	0.00%	0.00%	0.00%	0	0	0
L-09-14	28.78%	36.84%	35.86%	0.00%	0.00%	0.00%	0	0	0
L-09-15	18.09%	32.75%	41.71%	0.00%	0.00%	0.00%	0	0	0
L-10-11	16.25%	16.50%	21.41%	0.00%	0.00%	0.00%	0	0	0
L-10-16	26.74%	37.92%	42.97%	0.00%	0.00%	0.00%	0	0	0
L-17-10	21.15%	32.41%	47.30%	0.00%	0.00%	0.00%	0	0	0
L-11-12	46.23%	31.70%	33.53%	0.00%	0.00%	2.23%	0	0	145
L-11-16	34.81%	42.37%	46.72%	0.00%	0.00%	1.49%	0	0	53
L-17-11	28.64%	26.39%	35.83%	0.00%	0.00%	0.00%	0	0	0
L-12-13	13.75%	10.09%	10.73%	0.00%	0.00%	0.00%	0	0	0
L-12-18	18.46%	28.45%	33.74%	0.00%	0.00%	1.49%	0	0	41

	REFERENCE SCENARIO continued (Chapter 6)								
	line utilization [% of capacity]			frequency of congestion [% of hours]			magnitude of congestion [MW]		
line	2015	2020	2025	2015	2020	2025	2015	2020	2025
L-12-19	9.05%	8.52%	11.42%	0.00%	0.00%	0.00%	0	0	0
L-13-19	10.59%	14.32%	17.92%	0.00%	0.00%	0.00%	0	0	0
L-14-15	20.49%	21.58%	17.88%	0.00%	0.00%	0.00%	0	0	0
L-14-20	33.08%	47.82%	57.44%	0.00%	5.51%	19.20%	0	76	204
L-14-21	19.37%	30.73%	40.04%	0.00%	0.00%	0.00%	0	0	0
L-16-15	11.64%	13.40%	17.26%	0.00%	0.00%	0.00%	0	0	0
L-17-15	39.37%	39.33%	30.42%	0.00%	0.00%	0.00%	0	0	0
L-16-17	28.91%	39.79%	40.03%	0.00%	0.00%	0.00%	0	0	0
L-16-21	50.87%	58.91%	62.68%	8.04%	16.07%	18.45%	134	174	218
L-22-16	29.36%	23.14%	24.32%	0.00%	0.00%	0.00%	0	0	0
L-16-25	36.78%	46.78%	54.80%	0.74%	5.95%	8.78%	12	204	153
L-18-19	13.73%	9.14%	8.41%	0.00%	0.00%	0.00%	0	0	0
L-18-22	60.68%	69.23%	76.14%	7.14%	15.03%	22.32%	120	172	217
L-18-23	38.74%	63.82%	72.79%	0.15%	8.18%	18.75%	0	25	40
L-23-19	36.98%	42.36%	44.67%	0.00%	0.00%	0.00%	0	0	0
L-20-21	19.82%	21.55%	24.70%	0.00%	0.00%	0.00%	0	0	0
L-20-24	23.22%	25.14%	27.77%	0.00%	0.00%	0.00%	0	0	0
L-20-25	24.60%	26.95%	32.32%	0.00%	0.00%	0.00%	0	0	0
L-21-25	35.27%	41.37%	49.27%	0.00%	2.98%	9.08%	0	85	185
L-22-23	32.28%	24.22%	25.59%	0.00%	0.00%	0.00%	0	0	0
L-22-26	26.72%	26.32%	32.76%	0.00%	0.00%	0.00%	0	0	0
L-24-25	17.70%	20.35%	20.20%	0.00%	0.00%	0.00%	0	0	0
L-25-26	14.82%	18.51%	19.06%	0.00%	0.00%	0.00%	0	0	0
L-25-27	27.16%	39.63%	47.62%	0.00%	0.00%	5.21%	0	0	129
L-25-28	34.88%	49.52%	63.97%	0.00%	5.95%	20.68%	0	20	47
L-28-26	18.48%	21.81%	26.42%	0.00%	0.00%	0.00%	0	0	0
L-26-31	17.17%	23.81%	32.44%	0.00%	0.00%	0.00%	0	0	0
L-27-28	16.83%	20.11%	29.63%	0.00%	0.00%	0.00%	0	0	0
L-27-29	26.75%	24.49%	24.81%	0.00%	0.00%	0.00%	0	0	0
L-30-28	15.26%	19.42%	26.47%	0.00%	0.00%	0.00%	0	0	0
L-30-31	17.86%	20.91%	21.05%	0.00%	0.00%	0.00%	0	0	0

	SCENARIO "FUEL PRICE" (Chapter 6)								
	line utilization [% of capacity]			frequency of congestion [% of hours]			magnitude of congestion [MW]		
line	2015	2020	2025	2015	2020	2025	2015	2020	2025
L-01-02	31.08%	69.88%	71.43%	0.00%	24.26%	28.42%	0	205	301
L-01-03	32.75%	72.47%	76.31%	0.00%	27.08%	35.71%	0	215	345
L-02-03	10.00%	11.13%	13.99%	0.00%	0.00%	0.00%	0	0	0
L-02-06	19.93%	32.91%	22.76%	0.00%	0.00%	0.00%	0	0	0
L-02-10	28.81%	49.30%	59.53%	0.00%	6.55%	15.92%	0	109	177
L-03-04	14.03%	23.02%	28.29%	0.00%	0.00%	0.00%	0	0	0
L-03-11	22.78%	46.43%	55.39%	0.00%	3.72%	10.27%	0	63	201
L-04-05	7.97%	12.76%	15.60%	0.00%	0.00%	0.00%	0	0	0
L-04-07	14.22%	27.68%	35.45%	0.00%	0.00%	0.00%	0	0	0
L-04-12	6.89%	17.28%	21.72%	0.00%	0.00%	0.00%	0	0	0
L-05-07	7.63%	9.55%	12.00%	0.00%	0.00%	0.00%	0	0	0
L-05-13	11.72%	14.90%	19.68%	0.00%	0.00%	0.00%	0	0	0
L-06-08	14.49%	24.26%	18.53%	0.00%	0.00%	0.00%	0	0	0
L-06-09	-	56.12%	67.75%	-	14.88%	22.92%	-	402	489
L-07-13	7.50%	7.96%	8.80%	0.00%	0.00%	0.00%	0	0	0
L-08-09	16.69%	29.84%	64.31%	0.00%	0.00%	25.74%	0	0	401
L-08-14	23.94%	41.86%	60.78%	0.00%	0.00%	15.92%	0	0	247
L-09-10	18.24%	12.83%	18.01%	0.00%	0.00%	0.00%	0	0	0
L-09-14	23.96%	32.54%	31.27%	0.00%	0.00%	0.00%	0	0	0
L-09-15	19.16%	34.32%	43.47%	0.00%	0.00%	0.00%	0	0	0
L-10-11	18.19%	20.38%	24.46%	0.00%	0.00%	0.00%	0	0	0
L-10-16	27.39%	39.88%	44.96%	0.00%	0.00%	0.00%	0	0	0
L-17-10	21.64%	34.28%	49.46%	0.00%	0.00%	1.49%	0	0	27
L-11-12	35.21%	24.30%	25.43%	0.00%	0.00%	0.00%	0	0	0
L-11-16	32.49%	41.58%	46.51%	0.00%	0.00%	0.74%	0	0	42
L-17-11	22.77%	22.25%	31.87%	0.00%	0.00%	0.00%	0	0	0
L-12-13	11.57%	9.39%	10.09%	0.00%	0.00%	0.00%	0	0	0
L-12-18	17.29%	28.12%	33.06%	0.00%	0.00%	1.49%	0	0	42
L-12-19	9.12%	8.93%	11.84%	0.00%	0.00%	0.00%	0	0	0
L-13-19	10.71%	13.34%	16.14%	0.00%	0.00%	0.00%	0	0	0
L-14-15	17.39%	18.79%	15.63%	0.00%	0.00%	0.00%	0	0	0
L-14-20	37.43%	53.72%	65.39%	0.00%	18.15%	24.26%	0	136	267
L-14-21	23.62%	36.55%	45.51%	0.00%	0.00%	3.72%	0	0	11

	SCENARIO "FUEL PRICE" continued (Chapter 6)								
	line utilization [% of capacity]			frequency of congestion [% of hours]			magnitude of congestion [MW]		
line	2015	2020	2025	2015	2020	2025	2015	2020	2025
L-16-15	12.09%	15.97%	19.41%	0.00%	0.00%	0.00%	0	0	0
L-17-15	32.84%	34.21%	26.97%	0.00%	0.00%	0.00%	0	0	0
L-16-17	29.66%	41.74%	41.92%	0.00%	0.00%	0.00%	0	0	0
L-16-21	47.32%	57.05%	62.22%	6.25%	14.58%	18.01%	113	185	214
L-22-16	24.01%	21.63%	24.37%	0.00%	0.00%	0.00%	0	0	0
L-16-25	35.42%	47.90%	56.26%	0.74%	6.85%	11.01%	93	184	158
L-18-19	12.16%	7.47%	7.43%	0.00%	0.00%	0.00%	0	0	0
L-18-22	57.34%	66.56%	73.81%	5.06%	12.20%	19.94%	111	182	220
L-18-23	42.38%	68.36%	74.68%	0.15%	12.95%	18.75%	6	26	41
L-23-19	37.39%	41.89%	44.28%	0.00%	0.00%	0.00%	0	0	0
L-20-21	19.78%	21.60%	25.11%	0.00%	0.00%	0.00%	0	0	0
L-20-24	23.16%	26.13%	28.84%	0.00%	0.00%	0.00%	0	0	0
L-20-25	24.88%	28.45%	33.73%	0.00%	0.00%	0.00%	0	0	0
L-21-25	34.91%	43.48%	52.05%	0.00%	3.72%	12.05%	0	165	256
L-22-23	25.82%	19.14%	21.98%	0.00%	0.00%	0.00%	0	0	0
L-22-26	25.09%	26.11%	32.71%	0.00%	0.00%	0.00%	0	0	0
L-24-25	17.26%	20.14%	20.23%	0.00%	0.00%	0.00%	0	0	0
L-25-26	14.31%	17.27%	18.12%	0.00%	0.00%	0.00%	0	0	0
L-25-27	27.48%	41.33%	49.48%	0.00%	0.74%	7.44%	0	71	201
L-25-28	36.21%	51.85%	65.93%	0.00%	9.67%	25.15%	0	27	47
L-28-26	16.32%	20.86%	25.60%	0.00%	0.00%	0.00%	0	0	0
L-26-31	17.28%	25.01%	33.84%	0.00%	0.00%	0.00%	0	0	0
L-27-28	17.87%	21.39%	30.39%	0.00%	0.00%	0.00%	0	0	0
L-27-29	26.99%	24.91%	25.44%	0.00%	0.00%	0.00%	0	0	0
L-30-28	16.20%	20.27%	27.29%	0.00%	0.00%	0.00%	0	0	0
L-30-31	16.68%	19.41%	19.50%	0.00%	0.00%	0.00%	0	0	0

	SCENARIO "WIND POWER" (Chapter 6)								
	line utilization [% of capacity]			frequency of congestion [% of hours]			magnitude of congestion [MW]		
line	2015	2020	2025	2015	2020	2025	2015	2020	2025
L-01-02	31.39%	60.86%	58.74%	0.00%	11.16%	17.11%	0	115	156
L-01-03	30.05%	61.38%	61.72%	0.00%	13.54%	21.58%	0	99	208
L-02-03	9.10%	9.01%	12.01%	0.00%	0.00%	0.00%	0	0	0
L-02-06	25.06%	35.67%	23.79%	0.00%	0.00%	0.00%	0	0	0
L-02-10	28.90%	44.41%	51.93%	0.00%	3.72%	7.29%	0	32	151
L-03-04	15.98%	17.62%	22.27%	0.00%	0.00%	0.00%	0	0	0
L-03-11	20.91%	39.49%	46.21%	0.00%	0.00%	3.72%	0	0	106
L-04-05	7.90%	9.92%	12.71%	0.00%	0.00%	0.00%	0	0	0
L-04-07	12.73%	20.53%	28.54%	0.00%	0.00%	0.00%	0	0	0
L-04-12	5.67%	14.33%	17.95%	0.00%	0.00%	0.00%	0	0	0
L-05-07	6.51%	8.34%	10.31%	0.00%	0.00%	0.00%	0	0	0
L-05-13	10.88%	11.22%	15.72%	0.00%	0.00%	0.00%	0	0	0
L-06-08	17.62%	26.16%	21.03%	0.00%	0.00%	0.00%	0	0	0
L-06-09	-	54.74%	62.64%	-	12.05%	21.43%	-	353	385
L-07-13	10.20%	8.91%	11.30%	0.00%	0.00%	0.00%	0	0	0
L-08-09	14.53%	24.60%	53.22%	0.00%	0.00%	19.94%	0	0	174
L-08-14	22.63%	38.15%	53.65%	0.00%	0.00%	10.57%	0	0	119
L-09-10	24.09%	15.01%	15.00%	0.00%	0.00%	0.00%	0	0	0
L-09-14	28.36%	35.20%	32.83%	0.00%	0.00%	0.00%	0	0	0
L-09-15	17.62%	31.10%	38.47%	0.00%	0.00%	0.00%	0	0	0
L-10-11	15.35%	16.32%	20.09%	0.00%	0.00%	0.00%	0	0	0
L-10-16	26.03%	36.74%	40.90%	0.00%	0.00%	0.00%	0	0	0
L-17-10	20.30%	31.10%	44.84%	0.00%	0.00%	0.00%	0	0	0
L-11-12	46.20%	31.34%	33.60%	0.00%	0.00%	1.49%	0	0	107
L-11-16	33.93%	41.02%	44.69%	0.00%	0.00%	0.00%	0	0	0
L-17-11	28.07%	25.16%	34.51%	0.00%	0.00%	0.00%	0	0	0
L-12-13	14.03%	10.14%	10.26%	0.00%	0.00%	0.00%	0	0	0
L-12-18	17.85%	27.30%	31.69%	0.00%	0.00%	0.00%	0	0	0
L-12-19	9.35%	8.01%	10.29%	0.00%	0.00%	0.00%	0	0	0
L-13-19	10.33%	13.52%	16.49%	0.00%	0.00%	0.00%	0	0	0
L-14-15	20.40%	21.12%	16.94%	0.00%	0.00%	0.00%	0	0	0
L-14-20	31.67%	46.13%	53.84%	0.00%	3.42%	12.80%	0	39	173
L-14-21	20.00%	30.55%	39.07%	0.00%	0.00%	0.00%	0	0	0

SCENARIO "WIND POWER" continued (Chapter 6)									
	line utilization [% of capacity]			frequency of congestion [% of hours]			magnitude of congestion [MW]		
line	2015	2020	2025	2015	2020	2025	2015	2020	2025
L-16-15	12.30%	13.56%	17.11%	0.00%	0.00%	0.00%	0	0	0
L-17-15	38.73%	37.82%	28.49%	0.00%	0.00%	0.00%	0	0	0
L-16-17	28.27%	38.72%	38.20%	0.00%	0.00%	0.00%	0	0	0
L-16-21	49.55%	56.96%	59.85%	6.99%	13.54%	13.54%	88	143	176
L-22-16	30.17%	23.36%	23.76%	0.00%	0.00%	0.00%	0	0	0
L-16-25	35.47%	45.16%	52.39%	0.00%	5.95%	6.25%	0	128	165
L-18-19	13.79%	9.23%	8.57%	0.00%	0.00%	0.00%	0	0	0
L-18-22	59.99%	68.03%	74.44%	4.46%	13.54%	18.75%	137	153	200
L-18-23	37.55%	62.26%	69.70%	0.15%	7.59%	14.43%	9	24	35
L-23-19	36.88%	41.90%	43.82%	0.00%	0.00%	0.00%	0	0	0
L-20-21	20.68%	21.76%	24.65%	0.00%	0.00%	0.00%	0	0	0
L-20-24	23.16%	24.87%	27.54%	0.00%	0.00%	0.00%	0	0	0
L-20-25	24.95%	26.95%	32.10%	0.00%	0.00%	0.00%	0	0	0
L-21-25	34.72%	40.29%	47.28%	0.00%	1.49%	6.70%	0	87	202
L-22-23	32.28%	23.96%	26.04%	0.00%	0.00%	0.00%	0	0	0
L-22-26	25.93%	25.47%	31.65%	0.00%	0.00%	0.00%	0	0	0
L-24-25	17.29%	19.68%	19.90%	0.00%	0.00%	0.00%	0	0	0
L-25-26	15.55%	18.46%	18.62%	0.00%	0.00%	0.00%	0	0	0
L-25-27	26.92%	39.35%	46.66%	0.00%	0.00%	5.21%	0	0	115
L-25-28	34.81%	49.28%	62.78%	0.00%	5.95%	19.94%	0	18	46
L-28-26	17.80%	21.28%	25.89%	0.00%	0.00%	0.00%	0	0	0
L-26-31	16.50%	23.21%	31.29%	0.00%	0.00%	0.00%	0	0	0
L-27-28	16.85%	20.06%	29.16%	0.00%	0.00%	0.00%	0	0	0
L-27-29	27.39%	24.70%	25.03%	0.00%	0.00%	0.00%	0	0	0
L-30-28	15.49%	19.51%	26.38%	0.00%	0.00%	0.00%	0	0	0
L-30-31	18.03%	20.99%	21.85%	0.00%	0.00%	0.00%	0	0	0

SCENARIO "LOAD STRUCTURE" (Chapter 6)

line	line utilization [% of capacity]			frequency of congestion [% of hours]			magnitude of congestion [MW]		
	2015	2020	2025	2015	2020	2025	2015	2020	2025
L-01-02	33.12%	65.41%	66.52%	0.00%	20.39%	26.49%	0	157	268
L-01-03	31.58%	65.26%	68.81%	0.00%	20.54%	27.83%	0	160	304
L-02-03	9.65%	9.22%	12.00%	0.00%	0.00%	0.00%	0	0	0
L-02-06	24.65%	36.87%	24.57%	0.00%	0.00%	0.00%	0	0	0
L-02-10	30.81%	48.25%	57.98%	0.00%	5.51%	14.29%	0	121	186
L-03-04	15.89%	18.68%	25.16%	0.00%	0.00%	0.00%	0	0	0
L-03-11	22.76%	43.36%	52.51%	0.00%	1.49%	9.52%	0	32	149
L-04-05	7.96%	10.35%	14.05%	0.00%	0.00%	0.00%	0	0	0
L-04-07	12.92%	22.67%	32.70%	0.00%	0.00%	0.00%	0	0	0
L-04-12	6.26%	16.00%	20.65%	0.00%	0.00%	0.00%	0	0	0
L-05-07	6.73%	9.20%	11.92%	0.00%	0.00%	0.00%	0	0	0
L-05-13	11.48%	12.70%	18.30%	0.00%	0.00%	0.00%	0	0	0
L-06-08	19.20%	26.82%	21.41%	0.00%	0.00%	0.00%	0	0	0
L-06-09	-	61.23%	72.47%	-	18.30%	26.79%	-	366	515
L-07-13	10.18%	8.48%	10.58%	0.00%	0.00%	0.00%	0	0	0
L-08-09	16.28%	28.91%	62.38%	0.00%	0.00%	25.00%	0	0	392
L-08-14	24.23%	42.21%	61.06%	0.00%	0.00%	17.56%	0	0	232
L-09-10	24.80%	15.35%	15.82%	0.00%	0.00%	0.00%	0	0	0
L-09-14	29.48%	38.22%	37.79%	0.00%	0.00%	0.00%	0	0	0
L-09-15	18.55%	33.82%	43.22%	0.00%	0.00%	0.00%	0	0	0
L-10-11	15.23%	16.49%	21.61%	0.00%	0.00%	0.00%	0	0	0
L-10-16	27.14%	38.94%	44.41%	0.00%	0.00%	0.00%	0	0	0
L-17-10	21.74%	33.77%	49.30%	0.00%	0.00%	2.23%	0	0	23
L-11-12	46.36%	31.82%	33.72%	0.00%	0.00%	2.23%	0	0	149
L-11-16	35.18%	43.42%	48.17%	0.00%	0.74%	1.49%	0	16	85
L-17-11	28.93%	27.20%	37.06%	0.00%	0.00%	0.00%	0	0	0
L-12-13	13.61%	10.06%	10.70%	0.00%	0.00%	0.00%	0	0	0
L-12-18	18.63%	29.27%	34.99%	0.00%	0.00%	1.49%	0	0	71
L-12-19	8.97%	8.59%	11.63%	0.00%	0.00%	0.00%	0	0	0
L-13-19	10.69%	14.65%	18.52%	0.00%	0.00%	0.00%	0	0	0
L-14-15	20.64%	21.88%	18.21%	0.00%	0.00%	0.00%	0	0	0
L-14-20	32.72%	48.43%	58.49%	0.00%	8.18%	19.94%	0	64	220
L-14-21	19.71%	30.75%	40.07%	0.00%	0.00%	0.00%	0	0	0

	SCENARIO "LOAD STRUCTURE" continued (Chapter 6)								
	line utilization [% of capacity]			frequency of congestion [% of hours]			magnitude of congestion [MW]		
line	2015	2020	2025	2015	2020	2025	2015	2020	2025
L-16-15	12.01%	13.34%	17.05%	0.00%	0.00%	0.00%	0	0	0
L-17-15	40.05%	40.79%	32.33%	0.00%	0.00%	0.00%	0	0	0
L-16-17	29.19%	40.63%	41.18%	0.00%	0.00%	0.00%	0	0	0
L-16-21	51.36%	60.36%	64.69%	8.04%	16.96%	21.43%	138	191	219
L-22-16	30.18%	23.17%	24.32%	0.00%	0.00%	0.00%	0	0	0
L-16-25	36.81%	47.84%	56.40%	1.49%	6.70%	10.57%	22	206	155
L-18-19	13.47%	9.19%	8.46%	0.00%	0.00%	0.00%	0	0	0
L-18-22	61.02%	70.26%	77.58%	6.40%	15.18%	23.36%	144	185	231
L-18-23	39.15%	64.58%	73.86%	0.15%	9.08%	19.64%	22	24	41
L-23-19	37.42%	42.81%	45.30%	0.00%	0.00%	0.00%	0	0	0
L-20-21	20.22%	21.52%	24.54%	0.00%	0.00%	0.00%	0	0	0
L-20-24	22.90%	25.16%	27.83%	0.00%	0.00%	0.00%	0	0	0
L-20-25	24.54%	26.97%	32.38%	0.00%	0.00%	0.00%	0	0	0
L-21-25	35.11%	41.86%	50.33%	0.00%	3.72%	10.57%	0	87	186
L-22-23	32.00%	24.66%	26.19%	0.00%	0.00%	0.00%	0	0	0
L-22-26	26.96%	26.89%	33.62%	0.00%	0.00%	0.00%	0	0	0
L-24-25	17.83%	20.35%	20.20%	0.00%	0.00%	0.00%	0	0	0
L-25-26	15.40%	18.59%	19.06%	0.00%	0.00%	0.00%	0	0	0
L-25-27	27.14%	40.12%	48.42%	0.00%	0.00%	5.95%	0	0	137
L-25-28	34.97%	50.04%	64.87%	0.00%	7.44%	22.47%	0	19	46
L-28-26	18.15%	22.20%	27.11%	0.00%	0.00%	0.00%	0	0	0
L-26-31	17.19%	24.20%	33.31%	0.00%	0.00%	0.00%	0	0	0
L-27-28	16.91%	20.25%	29.95%	0.00%	0.00%	0.00%	0	0	0
L-27-29	27.23%	24.47%	24.77%	0.00%	0.00%	0.00%	0	0	0
L-30-28	15.42%	19.40%	26.42%	0.00%	0.00%	0.00%	0	0	0
L-30-31	17.78%	20.71%	20.77%	0.00%	0.00%	0.00%	0	0	0

C.2 Weighted average upward redispatch per quarter in Germany in the years 2015, 2020 and 2025

region	REFERENCE SCENARIO (Chapter 6) weighted average upward redispatch [MW]											
	2015				2020				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1	0	0	0	0	0	0	0	0	0	0	138	0
2	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	7
4	0	0	0	0	55	0	0	229	78	0	0	173
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	100	108
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	58	0	0	0	403	0	60	77
9	0	0	0	0	326	0	0	148	634	0	330	446
10	0	0	0	0	0	0	0	168	226	0	271	508
11	0	0	0	113	81	0	0	0	204	0	61	343
12	0	0	0	0	0	0	0	0	400	0	0	379
13	0	0	0	0	0	0	0	0	22	0	0	945
14	78	0	0	0	883	0	0	120	893	0	547	692
15	0	0	0	0	389	0	0	0	371	0	422	31
16	0	0	0	0	0	0	0	0	0	0	0	0
17	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	117
19	0	0	0	0	105	0	0	0	43	0	0	727
20	326	0	0	1,156	728	0	0	720	739	0	8	1,473
21	548	0	0	0	620	0	0	0	722	0	0	789
22	0	0	0	0	0	0	0	0	580	0	0	0
23	0	0	0	0	0	0	0	0	571	0	0	0
24	498	0	0	0	716	0	0	7	314	0	0	454
25	355	0	0	0	264	0	0	38	295	0	13	275
26	0	0	0	0	0	0	0	0	0	0	0	0
27	95	0	0	0	340	0	0	11	474	0	0	294
28	22	0	0	0	185	0	0	625	1,420	0	0	899
29	0	0	0	0	0	0	0	0	0	0	0	0
30	0	0	0	0	0	0	0	0	0	0	0	0
31	0	0	0	0	239	0	0	0	471	0	0	357

ewi

region	SCENARIO "FUEL PRICE" (Chapter 6) weighted average upward redispatch [MW]											
	2015				2020				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1	0	0	0	0	0	0	0	0	0	0	462	0
2	0	0	0	0	0	0	0	256	0	0	505	259
3	0	0	0	0	0	0	0	0	0	0	0	269
4	0	0	0	0	116	0	0	200	127	0	0	208
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	25
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	69	0	0	88	112	0	0	0
9	0	0	0	0	365	0	0	20	593	0	426	458
10	0	0	0	0	0	0	0	18	267	0	0	598
11	0	0	0	0	252	0	0	0	117	0	0	296
12	0	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	560
14	0	0	0	0	759	0	0	163	954	0	384	214
15	0	0	0	0	479	0	0	181	366	0	339	0
16	0	0	0	0	0	0	0	0	0	0	0	0
17	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	54	0	0	0	259
19	0	0	0	0	130	0	0	495	103	0	0	516
20	246	0	0	1,087	1,152	0	0	1,242	1,108	0	5	1,436
21	404	0	0	0	471	0	0	0	644	0	143	936
22	9	0	0	0	254	0	0	0	588	0	0	0
23	0	0	0	0	423	0	0	0	794	0	0	0
24	171	0	0	0	536	0	0	383	349	0	27	586
25	182	0	0	0	192	0	0	195	298	0	42	456
26	0	0	0	0	0	0	0	0	0	0	0	0
27	124	0	0	0	401	0	0	416	550	0	127	508
28	38	0	0	0	623	0	0	390	1,850	0	119	898
29	0	0	0	0	0	0	0	0	0	0	0	0
30	0	0	0	0	0	0	0	0	0	0	0	0
31	65	0	0	0	305	0	0	140	429	0	213	481

region	SCENARIO "WIND POWER" (Chapter 6)											
	weighted average upward redispatch [MW]											
	2015				2020				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1	0	0	0	0	0	0	0	0	0	0	93	0
2	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	33	0	0	68
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	133	22
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	126	0	0	0
9	0	0	0	0	338	0	0	0	393	0	114	194
10	0	0	0	0	12	0	0	0	209	0	121	259
11	0	0	0	59	7	0	0	0	23	0	0	303
12	0	0	0	0	0	0	0	0	354	0	0	0
13	0	0	0	0	0	0	0	0	146	0	0	0
14	0	0	0	0	677	0	0	0	911	0	178	288
15	0	0	0	0	322	0	0	0	263	0	0	0
16	0	0	0	0	0	0	0	0	0	0	0	0
17	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	176	0	0	0	186
19	0	0	0	0	37	0	0	76	51	0	0	796
20	207	0	0	1,055	683	0	0	490	598	0	0	883
21	371	0	0	0	572	0	0	0	636	0	0	0
22	0	0	0	0	0	0	0	0	441	0	0	0
23	0	0	0	0	0	0	0	0	344	0	0	0
24	437	0	0	56	451	0	0	0	266	0	75	291
25	200	0	0	0	78	0	0	0	255	0	7	268
26	0	0	0	0	0	0	0	0	0	0	0	0
27	208	0	0	0	251	0	0	0	357	0	0	324
28	0	0	0	0	117	0	0	335	1,412	0	0	594
29	0	0	0	0	0	0	0	0	0	0	0	0
30	0	0	0	0	0	0	0	0	0	0	0	0
31	0	0	0	0	328	0	0	0	273	0	0	290

region	SCENARIO “LOAD STRUCTURE” (Chapter 6) weighted average upward redispatch [MW]											
	2015				2020				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1	0	0	0	0	0	0	0	0	0	0	123	0
2	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	66
4	0	0	0	0	30	0	0	186	99	0	0	173
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	108
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	62	0	0	179	377	0	60	77
9	0	0	0	0	351	0	0	260	603	0	345	442
10	0	0	0	0	0	0	0	0	255	0	239	444
11	0	0	0	0	81	0	0	0	204	0	0	333
12	0	0	0	0	0	0	0	0	565	0	0	379
13	0	0	0	0	0	0	0	0	38	0	0	1,007
14	0	0	0	0	943	0	0	331	944	0	652	766
15	0	0	0	0	380	0	0	0	386	0	422	43
16	0	0	0	0	0	0	0	0	0	0	0	0
17	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	209
19	0	0	0	0	105	0	0	0	43	0	0	717
20	310	0	0	1,489	701	0	0	811	807	0	8	1,484
21	648	0	0	0	535	0	0	0	605	0	100	1,031
22	0	0	0	0	0	0	0	0	594	0	0	0
23	0	0	0	0	0	0	0	0	595	0	0	0
24	309	0	0	0	637	0	0	285	351	0	133	460
25	229	0	0	0	186	0	0	60	296	0	13	295
26	0	0	0	0	0	0	0	0	0	0	0	0
27	185	0	0	0	383	0	0	18	501	0	0	325
28	4	0	0	0	179	0	0	678	1,480	0	88	863
29	0	0	0	0	0	0	0	0	0	0	0	0
30	0	0	0	0	0	0	0	0	0	0	0	0
31	31	0	0	0	242	0	0	0	508	0	0	383

C.3 Weighted average downward redispatch per quarter in Germany in the years 2015, 2020 and 2025

region	REFERENCE SCENARIO (Chapter 6) weighted average downward redispatch [MW]											
	2015				2020				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1	28	0	0	28	574	0	0	493	1,505	0	0	1,164
2	0	0	0	204	693	0	0	79	1,268	0	0	981
3	0	0	0	0	0	0	0	0	0	0	0	0
4	44	0	0	44	0	0	0	0	71	0	0	81
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	66	958	0	0	757	1,220	0	182	615
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	2,163	0	1,118	2,025
9	0	0	0	290	0	0	0	0	0	0	0	161
10	142	0	0	111	515	0	0	63	0	0	0	222
11	273	0	0	93	37	0	0	53	0	0	0	158
12	404	0	0	137	0	0	0	0	307	0	513	82
13	237	0	0	288	0	0	0	0	0	0	590	0
14	0	0	0	137	0	0	0	130	0	0	0	857
15	0	0	0	126	0	0	0	0	0	0	0	476
16	686	0	0	317	0	0	0	0	0	0	0	543
17	0	0	0	0	0	0	0	0	0	0	0	0
18	567	0	0	840	889	0	0	124	835	0	179	704
19	10	0	0	9	0	0	0	282	0	0	0	575
20	0	0	0	0	3	0	0	0	0	0	0	603
21	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0	0	0	0
23	0	0	0	190	0	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0	0	0	0	0	0
25	0	0	0	0	15	0	0	0	73	0	0	417
26	0	0	0	0	0	0	0	0	0	0	0	0
27	0	0	0	0	0	0	0	0	0	0	0	0
28	0	0	0	0	0	0	0	0	0	0	0	0
29	0	0	0	0	0	0	0	0	0	0	0	0
30	0	0	0	0	0	0	0	0	0	0	0	0
31	0	0	0	0	0	0	0	0	0	0	0	0

region	SCENARIO "FUEL PRICE" (Chapter 6) weighted average downward redispatch [MW] 2015				2020				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1	0	0	0	0	1,173	0	0	785	1,850	0	142	1,195
2	0	0	0	284	548	0	0	284	605	0	49	661
3	0	0	0	0	0	0	0	0	0	0	0	0
4	44	0	0	14	245	0	0	0	399	0	0	48
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	948	0	0	497	1,240	0	314	661
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	2,434	0	1,004	1,658
9	0	0	0	0	0	0	0	226	0	0	0	332
10	350	0	0	24	0	0	0	390	0	0	0	237
11	358	0	0	207	0	0	0	77	0	0	0	245
12	0	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	394	201	0	0	1,065
15	0	0	0	0	755	0	0	726	0	0	0	650
16	237	0	0	756	0	0	0	337	0	0	0	429
17	0	0	0	0	0	0	0	0	0	0	0	0
18	486	0	0	882	748	0	0	494	830	0	277	581
19	0	0	0	0	0	0	0	608	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	245
21	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0	0	0	0	0	26
25	0	0	0	0	271	0	0	282	52	0	0	601
26	0	0	0	0	0	0	0	0	0	0	0	0
27	0	0	0	0	0	0	0	0	0	0	0	0
28	0	0	0	0	0	0	0	0	0	0	627	0
29	0	0	0	0	0	0	0	0	0	0	0	0
30	0	0	0	0	0	0	0	0	0	0	0	0
31	0	0	0	0	0	0	0	0	0	0	0	0

region	SCENARIO "WIND POWER" (Chapter 6) weighted average downward redispatch [MW]											
	2015				2020				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1	71	0	0	0	466	0	0	335	918	0	0	741
2	0	0	0	0	551	0	0	0	238	0	0	703
3	0	0	0	0	0	0	0	0	0	0	0	0
4	14	0	0	0	0	0	0	0	0	0	0	134
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	858	0	0	493	1,088	0	185	638
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	1,030	0	114	854
9	0	0	0	251	0	0	0	0	0	0	0	359
10	268	0	0	0	310	0	0	0	74	0	0	287
11	252	0	0	15	107	0	0	79	0	0	0	103
12	0	0	0	123	0	0	0	0	400	0	448	82
13	0	0	0	338	0	0	0	0	0	0	111	0
14	0	0	0	0	0	0	0	0	536	0	0	590
15	0	0	0	126	0	0	0	0	751	0	0	544
16	140	0	0	0	0	0	0	0	0	0	0	495
17	0	0	0	0	0	0	0	0	0	0	0	0
18	455	0	0	753	933	0	0	76	889	0	0	643
19	0	0	0	9	0	0	0	87	0	0	0	462
20	0	0	0	0	0	0	0	0	0	0	0	444
21	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0	0	0	0
23	0	0	0	169	0	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0	0	0	0	0	0
25	0	0	0	0	0	0	0	0	829	0	0	391
26	0	0	0	0	0	0	0	0	0	0	0	0
27	0	0	0	0	0	0	0	0	0	0	0	0
28	0	0	0	0	0	0	0	0	0	0	0	0
29	0	0	0	0	0	0	0	0	0	0	0	0
30	0	0	0	0	0	0	0	0	0	0	0	0
31	0	0	0	0	0	0	0	0	0	0	0	0

region	SCENARIO “LOAD STRUCTURE” (Chapter 6) weighted average downward redispatch [MW]											
	2015				2020				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1	28	0	0	28	590	0	0	347	1,493	0	0	1,177
2	0	0	0	225	599	0	0	194	570	0	0	1,063
3	0	0	0	0	0	0	0	0	0	0	0	0
4	44	0	0	44	0	0	0	0	399	0	362	81
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	66	980	0	0	666	1,275	0	221	620
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	2,186	0	1,118	2,023
9	0	0	0	249	0	0	0	0	0	0	0	278
10	290	0	0	111	47	0	0	152	0	0	0	130
11	284	0	0	35	28	0	0	53	0	0	0	155
12	404	0	0	138	517	0	0	0	391	0	513	105
13	0	0	0	355	0	0	0	0	0	0	476	65
14	0	0	0	102	0	0	0	271	0	0	0	719
15	0	0	0	126	0	0	0	0	0	0	0	476
16	375	0	0	71	0	0	0	0	0	0	0	438
17	0	0	0	0	0	0	0	0	0	0	0	0
18	638	0	0	793	940	0	0	195	878	0	282	709
19	0	0	0	9	0	0	0	289	0	0	0	648
20	0	0	0	0	0	0	0	0	0	0	0	669
21	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0	0	0	0
23	0	0	0	186	0	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0	0	0	0	0	9
25	0	0	0	0	122	0	0	0	124	0	0	441
26	0	0	0	0	0	0	0	0	0	0	0	0
27	0	0	0	0	0	0	0	0	0	0	0	0
28	0	0	0	0	0	0	0	0	0	0	0	0
29	0	0	0	0	0	0	0	0	0	0	0	0
30	0	0	0	0	0	0	0	0	0	0	0	0
31	0	0	0	0	0	0	0	0	0	0	0	0

C.4 Technology-specific upward and downward redispatch in Germany in the years 2015, 2020 and 2025

	REFERENCE SCENARIO 2015 (Chapter 6)													
	redispatch [GWh/a]													
	upward						downward							
region	nuclear	coal	lig	gas	dummy	TOTAL	nuclear	coal	lignite	gas	wind	RES	dummy	TOTAL
1	0.0	0.0	0.0	0.0	0.0	0	0.0	2.9	0.0	0.0	0.0	0.0	0.0	3
2	0.0	0.0	0.0	0.0	0.0	0	0.0	5.4	0.0	0.0	0.0	0.0	0.0	5
3	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
4	0.0	0.0	0.0	0.0	0.0	0	0.0	4.1	0.0	0.0	0.0	0.0	0.0	4
5	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
6	0.0	0.0	0.0	0.0	0.0	0	0.0	0.9	0.0	0.0	0.0	0.0	0.0	1
7	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
8	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
9	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	3.8	0.0	0.0	0.0	4
10	0.0	0.0	0.0	0.0	0.0	0	0.0	26.9	0.0	0.0	0.0	0.0	0.0	27
11	0.0	0.0	1.5	0.0	0.0	1	0.0	79.0	23.1	2.3	0.0	0.0	0.0	104
12	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	39.1	0.0	0.0	0.0	39
13	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	42.1	0.0	0.0	0.0	42
14	0.0	5.1	0.0	0.0	0.0	5	0.0	0.0	0.0	1.8	0.0	0.0	0.0	2
15	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	1.7	0.0	0.0	0.0	2
16	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	8.4	13.6	22.5	44
17	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
18	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	322.0	0.0	0.0	0.0	0.0	322
19	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	1.3	0.0	0.0	0.0	1
20	0.0	1.3	207.0	0.0	0.0	208	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
21	0.0	0.0	0.0	0.0	288.2	288	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
22	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
23	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	7.5	0.0	0.0	0.0	7
24	0.0	43.4	0.0	0.0	0.0	43	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
25	0.0	9.3	0.0	0.0	0.0	9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
26	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
27	0.0	50.1	0.0	0.0	0.0	50	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
28	0.0	2.4	0.0	0.0	0.0	2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
29	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
30	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
31	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
TOT	0.0	111.7	208.5	0.0	288.2	608	0.0	119.1	345.2	99.6	8.4	13.6	22.5	608

region	upward						downward							
	REFERENCE SCENARIO 2020 (Chapter 6) redispatch [GWh/a]													
	nuclear	coal	lig	gas	dummy	TOTAL	nuclear	coal	lignite	gas	wind	RES	dummy	TOTAL
1	0.0	0.0	0.0	0.0	0.0	0	21.1	519.7	0.0	0.0	0.0	0.0	0.0	541
2	0.0	0.0	0.0	0.0	0.0	0	0.0	214.0	0.0	0.0	0.0	0.0	0.0	214
3	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
4	0.0	15.6	0.0	0.0	0.0	16	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
5	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
6	0.0	0.0	0.0	0.0	0.0	0	0.0	9.6	0.0	0.0	692.0	0.0	0.0	702
7	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
8	0.0	6.9	0.0	0.0	0.0	7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
9	0.0	94.1	0.0	69.0	0.0	163	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
10	0.0	2.2	0.0	0.0	0.0	2	0.0	35.5	0.0	0.0	0.0	0.0	0.0	36
11	0.0	0.0	1.1	0.0	0.0	1	0.0	0.0	2.1	2.4	0.0	0.0	0.0	4
12	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
13	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
14	0.0	557.2	0.0	9.8	0.0	567	0.0	0.0	0.0	8.5	0.0	0.0	0.0	9
15	0.0	259.6	0.0	0.0	0.0	260	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
16	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
17	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
18	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	704.6	0.0	0.0	0.0	0.0	705
19	0.0	0.0	1.4	0.0	0.0	1	0.0	0.0	11.1	0.0	0.0	0.0	0.0	11
20	0.0	3.2	176.5	10.5	8.5	199	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0
21	0.0	0.0	0.0	0.0	203.7	204	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
22	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
23	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
24	0.0	364.0	0.0	5.6	0.0	370	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
25	0.0	45.3	0.0	0.0	0.0	45	0.0	1.0	0.0	0.0	0.0	0.0	0.0	1
26	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
27	0.0	177.3	0.0	21.1	0.0	198	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
28	0.0	138.4	0.0	0.0	3.9	142	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
29	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
30	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
31	0.0	47.1	0.0	0.0	0.0	47	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
TOT	0.0	1,711.0	178.9	116.0	216.0	2,222	21.1	780.1	717.8	10.9	692.0	0.0	0.0	2,222

region	REFERENCE SCENARIO 2025 (Chapter 6)													
	redispatch [GWh/a]													
	upward						downward							
	nuclear	coal	lig	gas	dummy	TOTAL	nuclear	coal	lignite	gas	wind	RES	dummy	TOTAL
1	0.0	18.2	0.0	0.0	0.0	**18**	0.0	2,642.0	0.0	0.0	1,245.2	0.0	0.0	**3,887**
2	0.0	0.0	0.0	0.0	0.0	**0**	0.0	184.3	0.0	0.0	0.0	0.0	0.0	**184**
3	0.0	0.0	0.0	0.0	0.4	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
4	0.0	121.7	0.0	0.0	0.0	**122**	0.0	6.8	0.0	0.0	0.0	0.0	0.0	**7**
5	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
6	0.0	9.4	0.0	0.0	0.0	**9**	0.0	43.6	0.0	0.0	1,325.7	16.7	2.6	**1,389**
7	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
8	0.0	33.4	0.0	0.0	0.0	**33**	0.0	2,031.6	0.0	0.0	3,051.9	0.0	0.0	**5,084**
9	0.0	474.5	0.0	534.3	565.1	**1,574**	0.0	0.0	0.0	63.4	0.0	0.0	0.0	**63**
10	0.0	273.5	0.0	0.0	0.0	**273**	0.0	24.5	0.0	8.8	0.0	0.0	0.0	**33**
11	0.0	35.6	9.6	4.6	0.0	**50**	0.0	5.4	2.9	0.0	0.0	0.0	0.0	**8**
12	0.0	0.0	0.0	20.7	0.0	**21**	0.0	0.0	0.0	133.3	0.0	0.0	0.0	**133**
13	0.0	0.0	0.0	13.6	0.0	**14**	0.0	0.0	0.0	77.5	0.0	0.0	0.0	**78**
14	0.0	1,223.0	0.0	38.4	0.0	**1,261**	0.0	310.0	0.0	280.1	0.0	0.0	0.0	**590**
15	0.0	304.8	0.0	0.0	0.0	**305**	0.0	130.1	0.0	195.9	0.0	0.0	0.0	**326**
16	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	16.4	10.3	16.1	**43**
17	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
18	0.0	0.0	1.5	0.0	0.0	**2**	0.0	0.0	1,771.9	0.0	0.0	0.0	0.0	**1,772**
19	0.0	0.0	108.2	0.0	0.0	**108**	0.0	0.0	7.6	0.0	0.0	0.0	0.0	**8**
20	0.0	10.4	346.5	700.6	1,713.6	**2,771**	0.0	0.0	0.0	198.3	0.0	0.0	0.0	**198**
21	0.0	0.0	0.0	0.0	295.2	**295**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
22	0.0	0.0	0.0	0.0	266.6	**267**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
23	0.0	0.0	0.0	175.8	237.1	**413**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
24	0.0	492.6	0.0	72.1	0.0	**565**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
25	0.0	283.4	0.0	38.4	95.7	**417**	0.0	195.6	0.0	40.2	0.0	0.0	0.0	**236**
26	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
27	0.0	784.3	0.0	80.9	0.0	**865**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
28	0.0	1,063.9	0.0	2.2	2,942.1	**4,008**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
29	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
30	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
31	0.0	263.1	0.0	383.6	0.0	**647**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
TOT	**0.0**	**5,391.7**	**465.9**	**2,065.2**	**6,115.8**	**14,039**	**0.0**	**5,573.8**	**1,782.4**	**997.4**	**5,639.2**	**27.0**	**18.7**	**14,039**

region	SCENARIO "FUEL PRICE" 2015 (Chapter 6) redispatch [GWh/a]													
	upward						downward							
	nuclear	coal	lig	gas	dummy	TOTAL	nuclear	coal	lignite	gas	wind	RES	dummy	TOTAL
1	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
2	0.0	0.0	0.0	0.0	0.0	0	0.0	3.7	0.0	0.0	0.0	0.0	0.0	4
3	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
4	0.0	0.0	0.0	0.0	0.0	0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	3
5	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
6	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
7	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
8	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
9	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
10	0.0	0.0	0.0	0.0	0.0	0	0.0	40.5	0.0	0.0	0.0	0.0	0.0	40
11	0.0	0.0	0.0	0.0	0.0	0	0.0	59.2	22.2	0.0	0.0	0.0	0.0	81
12	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
13	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
14	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
15	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
16	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	15.7	11.6	5.3	33
17	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
18	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	262.8	0.0	0.0	0.0	0.0	263
19	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
20	0.0	0.0	104.4	0.0	0.0	104	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
21	0.0	0.0	0.0	0.0	159.2	159	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
22	0.0	0.0	0.0	0.0	0.6	1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
23	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
24	0.0	23.5	0.0	0.0	0.0	23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
25	0.0	62.8	0.0	0.0	0.0	63	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
26	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
27	0.0	55.4	0.0	0.0	0.0	55	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
28	0.0	5.4	0.0	0.0	0.0	5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
29	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
30	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
31	0.0	12.7	0.0	0.0	0.0	13	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
TOT	0.0	159.8	104.4	0.0	159.9	424	0.0	106.6	285.0	0.0	15.7	11.6	5.3	424

region	SCENARIO "FUEL PRICE" 2020 (Chapter 6) redispatch [GWh/a] upward						downward							
	nuclear	coal	lig	gas	dummy	TOTAL	nuclear	coal	lignite	gas	wind	RES	dummy	TOTAL
1	0.0	0.0	0.0	0.0	0.0	**0**	183.1	2,909.9	0.0	0.0	0.0	0.0	0.0	**3,093**
2	0.0	13.5	0.0	0.0	0.0	**13**	0.0	269.4	0.0	0.0	0.0	0.0	0.0	**269**
3	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
4	0.0	80.5	0.0	0.0	0.0	**80**	0.0	48.3	0.0	0.0	0.0	0.0	0.0	**48**
5	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
6	0.0	0.0	0.0	0.0	0.0	**0**	0.0	51.0	0.0	0.0	667.7	0.0	0.0	**719**
7	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
8	0.0	13.7	0.0	0.0	0.0	**14**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
9	0.0	108.9	0.0	10.6	0.0	**120**	0.0	0.0	0.0	133.6	0.0	0.0	0.0	**134**
10	0.0	0.2	0.0	0.0	0.0	**0**	0.0	15.4	0.0	0.0	0.0	0.0	0.0	**15**
11	0.0	32.9	2.6	0.0	0.0	**36**	0.0	0.0	6.0	0.0	0.0	0.0	0.0	**6**
12	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
13	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
14	0.0	826.2	0.0	0.0	0.0	**826**	0.0	112.7	0.0	198.3	0.0	0.0	0.0	**311**
15	0.0	248.5	0.0	0.0	0.0	**249**	0.0	713.0	0.0	107.0	0.0	0.0	0.0	**820**
16	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	18.6	13.9	7.3	**40**
17	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
18	0.0	0.0	0.7	0.0	0.0	**1**	0.0	0.0	1,121.1	0.0	0.0	0.0	0.0	**1,121**
19	0.0	0.0	26.4	0.0	0.0	**26**	0.0	0.0	40.0	0.0	0.0	0.0	0.0	**40**
20	0.0	4.1	318.9	109.1	1,612.3	**2,044**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
21	0.0	0.0	0.0	0.0	309.5	**309**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
22	0.0	0.0	0.0	0.0	16.7	**17**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
23	0.0	0.0	0.0	0.0	55.5	**56**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
24	0.0	693.6	0.0	38.1	0.0	**732**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
25	0.0	268.8	0.0	0.0	29.2	**298**	0.0	104.4	0.0	6.1	0.0	0.0	0.0	**110**
26	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
27	0.0	401.7	0.0	32.7	0.0	**434**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
28	0.0	664.5	0.0	0.0	504.6	**1,169**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
29	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
30	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
31	0.0	259.6	0.0	43.2	0.0	**303**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
TOT	**0.0**	**3,616.7**	**348.7**	**233.8**	**2,527.8**	**6,727**	**183.1**	**4,224.0**	**1,167.1**	**445.1**	**686.4**	**13.9**	**7.3**	**6,727**

region	SCENARIO "FUEL PRICE" 2025 (Chapter 6) redispatch [GWh/a] upward: nuclear	coal	lig	gas	dummy	TOTAL	downward: nuclear	coal	lignite	gas	wind	RES	dummy	TOTAL
1	0.0	30.4	0.0	0.0	0.0	**30**	0.0	4,418.5	0.0	0.0	1,324.9	0.0	0.0	**5,743**
2	0.0	37.4	0.0	0.0	0.0	**37**	0.0	318.3	0.0	0.0	0.0	0.0	0.0	**318**
3	0.0	0.0	0.0	0.0	17.7	**18**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
4	0.0	183.4	0.0	0.0	0.0	**183**	0.0	28.1	0.0	0.0	0.0	0.0	0.0	**28**
5	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
6	0.0	0.7	0.0	0.0	0.0	**1**	0.0	41.9	0.0	0.0	1,130.3	3.5	0.0	**1,176**
7	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
8	0.0	8.9	0.0	0.0	0.0	**9**	0.0	1,944.5	0.0	0.0	3,755.6	0.0	0.0	**5,700**
9	0.0	560.4	0.0	211.5	595.4	**1,367**	0.0	0.8	0.0	236.2	0.0	0.0	0.0	**237**
10	0.0	296.9	0.0	0.0	0.0	**297**	0.0	25.4	0.0	13.2	0.0	0.0	0.0	**39**
11	0.0	49.0	6.1	0.0	0.0	**55**	0.0	0.8	12.1	0.0	0.0	0.0	0.0	**13**
12	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
13	0.0	0.0	0.0	7.4	0.0	**7**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
14	0.0	1,026.0	0.0	0.0	0.0	**1,026**	0.0	1,056.3	0.0	296.3	0.0	0.0	0.0	**1,353**
15	0.0	291.9	0.0	0.0	0.0	**292**	0.0	404.5	0.0	197.5	0.0	0.0	0.0	**602**
16	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	18.1	11.5	4.2	**34**
17	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
18	0.0	0.0	13.6	0.0	0.0	**14**	0.0	0.0	1,451.6	0.0	1.8	0.0	0.0	**1,453**
19	0.0	0.0	95.8	0.0	0.0	**96**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
20	0.0	10.8	364.4	360.4	3,939.2	**4,675**	0.0	1.0	0.0	63.5	0.0	0.0	0.0	**64**
21	0.0	0.0	0.0	0.0	160.9	**161**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
22	0.0	0.0	0.0	0.0	231.8	**232**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
23	0.0	0.0	0.0	0.0	626.0	**626**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
24	0.0	513.2	0.0	77.5	0.0	**591**	0.0	0.0	0.0	1.7	0.0	0.0	0.0	**2**
25	0.0	451.3	0.0	23.0	0.0	**474**	0.0	335.4	0.0	13.5	0.0	0.0	0.0	**349**
26	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
27	0.0	1,068.3	0.0	84.5	0.0	**1,153**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
28	0.0	1,328.7	0.0	2.2	3,772.7	**5,103**	0.0	0.0	0.0	0.0	6.5	26.5	0.0	**33**
29	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
30	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
31	0.0	493.7	0.0	203.0	0.0	**697**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
TOT	**0.0**	**5,350.9**	**479.9**	**969.6**	**9,343.7**	**17,144**	**0.0**	**8,575.5**	**1,463.7**	**822.0**	**5,237.3**	**41.5**	**4.2**	**17,144**

	SCENARIO "WIND POWER" 2015 (Chapter 6)													
	redispatch [GWh/a]													
	upward						downward							
Region	nuclear	coal	lig	gas	dummy	TOTAL	nuclear	coal	lignite	gas	wind	RES	dummy	TOTAL
1	0.0	0.0	0.0	0.0	0.0	0	0.0	18.9	0.0	0.0	0.0	0.0	0.0	19
2	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
3	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
4	0.0	0.0	0.0	0.0	0.0	0	0.0	0.9	0.0	0.0	0.0	0.0	0.0	1
5	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
6	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
7	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
8	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
9	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	3.3	0.0	0.0	0.0	3
10	0.0	0.0	0.0	0.0	0.0	0	0.0	50.8	0.0	0.0	0.0	0.0	0.0	51
11	0.0	0.0	0.8	0.0	0.0	1	0.0	130.5	0.0	7.1	0.0	0.0	0.0	138
12	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	9.7	0.0	0.0	0.0	10
13	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	26.6	0.0	0.0	0.0	27
14	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
15	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	1.7	0.0	0.0	0.0	2
16	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	1.7	2.0	0.0	4
17	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
18	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	207.0	0.0	0.0	0.0	0.0	207
19	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	1
20	0.0	0.0	103.4	0.0	0.0	103	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
21	0.0	0.0	0.0	0.0	122.1	122	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
22	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
23	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	2.2	0.0	0.0	0.0	2
24	0.0	110.0	0.0	0.0	0.0	110	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
25	0.0	45.3	0.0	0.0	0.0	45	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
26	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
27	0.0	81.5	0.0	0.0	0.0	81	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
28	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
29	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
30	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
31	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
TOT	0.0	236.8	104.2	0.0	122.1	463	0.0	201.1	207.0	51.2	1.7	2.0	0.0	463

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Region	SCENARIO "WIND POWER" 2020 (Chapter 6) redispatch [GWh/a]													
	upward						downward							
	nuclear	coal	lig	gas	dummy	TOTAL	nuclear	coal	lignite	gas	wind	RES	dummy	TOTAL
1	0.0	0.0	0.0	0.0	0.0	**0**	0.0	186.3	0.0	0.0	0.0	0.0	0.0	**186**
2	0.0	0.0	0.0	0.0	0.0	**0**	0.0	103.9	0.0	0.0	0.0	0.0	0.0	**104**
3	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
4	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
5	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
6	0.0	0.0	0.0	0.0	0.0	**0**	0.0	47.6	0.0	0.0	476.0	0.0	0.0	**524**
7	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
8	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
9	0.0	65.4	0.0	129.7	0.0	**195**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
10	0.0	0.8	0.0	0.0	0.0	**1**	0.0	40.7	0.0	0.0	0.0	0.0	0.0	**41**
11	0.0	0.0	0.5	0.0	0.0	**0**	0.0	9.7	1.0	4.4	0.0	0.0	0.0	**15**
12	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
13	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
14	0.0	308.8	0.0	0.0	0.0	**309**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
15	0.0	146.1	0.0	0.0	0.0	**146**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
16	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
17	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
18	0.0	0.0	2.3	0.0	0.0	**2**	0.0	0.0	552.9	0.0	0.0	0.0	0.0	**553**
19	0.0	0.0	1.5	0.0	0.0	**1**	0.0	0.0	1.1	0.0	0.0	0.0	0.0	**1**
20	0.0	2.2	123.1	4.9	0.0	**130**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
21	0.0	0.0	0.0	0.0	150.4	**150**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
22	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
23	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
24	0.0	234.8	0.0	0.0	0.0	**235**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
25	0.0	8.2	0.0	0.0	0.0	**8**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
26	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
27	0.0	105.2	0.0	19.2	0.0	**124**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
28	0.0	57.3	0.0	0.0	20.0	**77**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
29	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
30	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
31	0.0	43.1	0.0	0.0	0.0	**43**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
TOT	**0.0**	**972.0**	**127.4**	**153.9**	**170.3**	**1,424**	**0.0**	**388.1**	**555.0**	**4.4**	**476.0**	**0.0**	**0.0**	**1,424**

Region	SCENARIO "WIND POWER" 2025 (Chapter 6) redispatch [GWh/a] upward						downward							
	nuclear	coal	lig	gas	dummy	TOTAL	nuclear	coal	lignite	gas	wind	RES	dummy	TOTAL
1	0.0	12.2	0.0	0.0	0.0	**12**	0.0	1,894.9	0.0	0.0	179.2	0.0	0.0	**2,074**
2	0.0	0.0	0.0	0.0	0.0	**0**	0.0	196.8	0.0	0.0	0.0	0.0	0.0	**197**
3	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
4	0.0	15.5	0.0	0.0	0.0	**16**	0.0	3.5	0.0	0.0	0.0	0.0	0.0	**4**
5	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
6	0.0	9.0	0.0	0.0	0.0	**9**	0.0	59.1	0.0	0.0	1,115.9	11.0	0.0	**1,186**
7	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
8	0.0	13.2	0.0	0.0	0.0	**13**	0.0	1,588.6	0.0	0.0	132.9	0.0	0.0	**1,722**
9	0.0	199.4	0.0	285.9	113.4	**599**	0.0	0.0	0.0	23.6	0.0	0.0	0.0	**24**
10	0.0	54.6	0.0	0.0	0.0	**55**	0.0	32.4	0.0	0.0	0.0	0.0	0.0	**32**
11	0.0	16.1	4.8	0.0	0.0	**21**	0.0	5.2	1.6	0.0	0.0	0.0	0.0	**7**
12	0.0	0.0	0.0	4.7	0.0	**5**	0.0	0.0	0.0	169.5	0.0	0.0	0.0	**169**
13	0.0	0.0	0.0	1.9	0.0	**2**	0.0	0.0	0.0	7.3	0.0	0.0	0.0	**7**
14	0.0	593.9	0.0	1.6	0.0	**596**	0.0	185.7	0.0	144.5	0.0	0.0	0.0	**330**
15	0.0	104.4	0.0	0.0	0.0	**104**	0.0	169.6	0.0	182.0	0.0	0.0	0.0	**352**
16	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	10.3	6.3	29.1	**46**
17	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
18	0.0	0.0	2.4	0.0	0.0	**2**	0.0	0.0	1,697.7	0.0	0.0	0.0	0.0	**1,698**
19	0.0	0.0	64.1	0.0	0.0	**64**	0.0	0.0	12.1	0.0	0.0	0.0	0.0	**12**
20	0.0	6.7	207.5	259.5	1,111.2	**1,585**	0.0	0.8	0.0	174.4	0.0	0.0	0.0	**175**
21	0.0	0.0	0.0	0.0	209.1	**209**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
22	0.0	0.0	0.0	0.0	116.0	**116**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
23	0.0	0.0	0.0	89.4	23.8	**113**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
24	0.0	297.3	0.0	25.1	0.0	**322**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
25	0.0	193.6	0.0	4.4	0.0	**198**	0.0	425.5	0.0	73.0	0.0	0.0	0.0	**498**
26	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
27	0.0	586.7	0.0	29.6	0.0	**616**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
28	0.0	603.8	0.0	1.1	2,866.0	**3,471**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
29	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
30	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
31	0.0	355.4	0.0	49.0	0.0	**404**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
TOT	**0.0**	**3,062.0**	**278.8**	**752.2**	**4,439.5**	**8,532**	**0.0**	**4,562.1**	**1,711.5**	**774.3**	**1,438.3**	**17.2**	**29.1**	**8,532**

Region	upward nuclear	upward coal	upward lig	upward gas	upward dummy	upward TOTAL	downward nuclear	downward coal	downward lignite	downward gas	downward wind	downward RES	downward dummy	downward TOTAL
	SCENARIO "LOAD STRUCTURE" 2015 (Chapter 6) redispatch [GWh/a]													
1	0.0	0.0	0.0	0.0	0.0	0	0.0	5.7	0.0	0.0	0.0	0.0	0.0	6
2	0.0	0.0	0.0	0.0	0.0	0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	3
3	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
4	0.0	0.0	0.0	0.0	0.0	0	0.0	3.5	0.0	0.0	0.0	0.0	0.0	3
5	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
6	0.0	0.0	0.0	0.0	0.0	0	0.0	0.9	0.0	0.0	0.0	0.0	0.0	1
7	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
8	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
9	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	13.1	0.0	0.0	0.0	13
10	0.0	0.0	0.0	0.0	0.0	0	0.0	80.3	0.0	0.0	0.0	0.0	0.0	80
11	0.0	0.0	0.0	0.0	0.0	0	0.0	140.2	21.2	12.2	0.0	0.0	0.0	174
12	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	39.3	0.0	0.0	0.0	39
13	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	32.6	0.0	0.0	0.0	33
14	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	1.3	0.0	0.0	0.0	1
15	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	1.7	0.0	0.0	0.0	2
16	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	12.6	14.8	29.1	57
17	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
18	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	360.1	0.0	0.0	0.0	0.0	360
19	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.8	0.0	0.0	0.0	1
20	0.0	1.2	225.1	0.0	0.0	226	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
21	0.0	0.0	0.0	0.0	297.9	298	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
22	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
23	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	12.2	0.0	0.0	0.0	12
24	0.0	63.9	0.0	0.0	0.0	64	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
25	0.0	100.3	0.0	0.0	0.0	100	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
26	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
27	0.0	92.2	0.0	0.0	0.0	92	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
28	0.0	1.8	0.0	0.0	0.0	2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
29	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
30	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
31	0.0	2.0	0.0	0.0	0.0	2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
TOT	0.0	261.4	225.1	0.0	297.9	784	0.0	233.5	381.2	113.2	12.6	14.8	29.1	784

Region	SCENARIO "LOAD STRUCTURE" 2020 (Chapter 6)													
	redispatch [GWh/a]													
	upward						downward							
	nuclear	coal	lig	gas	dummy	TOTAL	nuclear	coal	lignite	gas	wind	RES	dummy	TOTAL
1	0.0	0.0	0.0	0.0	0.0	0	31.4	601.2	0.0	0.0	0.0	0.0	0.0	633
2	0.0	0.0	0.0	0.0	0.0	0	0.0	237.4	0.0	0.0	0.0	0.0	0.0	237
3	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
4	0.0	13.8	0.0	0.0	0.0	14	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
5	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
6	0.0	0.0	0.0	0.0	0.0	0	0.0	14.9	0.0	0.0	786.4	0.0	0.0	801
7	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
8	0.0	11.4	0.0	0.0	0.0	11	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
9	0.0	100.4	0.0	110.7	0.0	211	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
10	0.0	0.0	0.0	0.0	0.0	0	0.0	10.2	0.0	0.0	0.0	0.0	0.0	10
11	0.0	0.0	1.1	0.0	0.0	1	0.0	2.6	2.1	2.9	0.0	0.0	0.0	8
12	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	34.0	0.0	0.0	0.0	34
13	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
14	0.0	589.0	0.0	9.8	0.0	599	0.0	0.0	0.0	17.8	0.0	0.0	0.0	18
15	0.0	301.4	0.0	0.0	0.0	301	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
16	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
17	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
18	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	749.1	0.0	0.0	0.0	0.0	749
19	0.0	0.0	1.4	0.0	0.0	1	0.0	0.0	11.4	0.0	0.0	0.0	0.0	11
20	0.0	3.2	198.6	10.5	17.8	230	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
21	0.0	0.0	0.0	0.0	245.9	246	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
22	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
23	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
24	0.0	385.3	0.0	5.6	0.0	391	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
25	0.0	52.3	0.0	0.0	0.0	52	0.0	8.0	0.0	0.0	0.0	0.0	0.0	8
26	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
27	0.0	192.5	0.0	21.1	0.0	214	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
28	0.0	161.0	0.0	0.0	13.0	174	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
29	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
30	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
31	0.0	63.6	0.0	0.0	0.0	64	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
TOT	0.0	1,873.9	201.0	157.7	276.7	2,509	31.4	874.3	762.6	54.6	786.4	0.0	0.0	2,509

region	SCENARIO "LOAD STRUCTURE" 2025 (Chapter 6)													
	redispatch [GWh/a]													
	upward						downward							
	nuclear	coal	lig	gas	dummy	TOTAL	nuclear	coal	lignite	gas	wind	RES	dummy	TOTAL
1	0.0	8.1	0.0	0.0	0.0	8	0.0	2,756.7	0.0	0.0	1,420.4	0.0	0.0	4,177
2	0.0	0.0	0.0	0.0	0.0	0	0.0	267.8	0.0	0.0	0.0	0.0	0.0	268
3	0.0	0.0	0.0	0.0	4.3	4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
4	0.0	121.7	0.0	0.0	0.0	122	0.0	52.1	0.0	0.0	0.0	0.0	0.0	52
5	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
6	0.0	2.8	0.0	0.0	0.0	3	0.0	78.7	0.0	0.0	1,591.0	23.4	9.4	1,702
7	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
8	0.0	41.6	0.0	0.0	0.0	42	0.0	2,029.1	0.0	0.0	3,125.8	0.0	0.0	5,155
9	0.0	482.0	0.0	536.6	474.0	1,493	0.0	0.0	0.0	127.9	0.0	0.0	0.0	128
10	0.0	242.9	0.0	0.0	0.0	243	0.0	17.0	0.0	9.3	0.0	0.0	0.0	26
11	0.0	30.5	9.6	0.6	0.0	41	0.0	9.2	3.0	0.0	0.0	0.0	0.0	12
12	0.0	0.0	0.0	19.8	0.0	20	0.0	0.0	0.0	158.4	0.0	0.0	0.0	158
13	0.0	0.0	0.0	15.3	0.0	15	0.0	0.0	0.0	66.8	0.0	0.0	0.0	67
14	0.0	1,393.1	0.0	52.1	0.0	1,445	0.0	320.9	0.0	287.3	0.0	0.0	0.0	608
15	0.0	326.7	0.0	27.9	0.0	355	0.0	124.4	0.0	225.0	0.0	0.0	0.0	349
16	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	18.4	12.0	21.4	52
17	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
18	0.0	0.0	2.7	0.0	0.0	3	0.0	0.0	1,906.4	0.1	0.6	0.0	0.0	1,907
19	0.0	0.0	125.8	0.0	0.0	126	0.0	0.0	8.5	0.0	0.0	0.0	0.0	9
20	0.0	11.2	429.5	790.4	1,969.7	3,201	0.0	0.0	0.0	219.7	0.0	0.0	0.0	220
21	0.0	0.0	0.0	0.0	338.4	338	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
22	0.0	0.0	0.0	0.0	273.1	273	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
23	0.0	0.0	0.0	177.5	252.8	430	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
24	0.0	521.4	0.0	92.3	0.0	614	0.0	0.0	0.0	0.6	0.0	0.0	0.0	1
25	0.0	333.6	0.0	43.0	115.6	492	0.0	226.4	0.0	40.2	0.0	0.0	0.0	267
26	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
27	0.0	811.5	0.0	82.1	0.0	894	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
28	0.0	1,093.0	0.0	2.2	3,227.8	4,323	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
29	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
30	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
31	0.0	265.0	0.0	409.4	0.0	674	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
TOT	0.0	5,685.3	567.6	2,249.2	6,655.7	15,158	0.0	5,882.3	1,917.9	1,135.2	6,156.2	35.3	30.8	15,158

D. Model Results Redispatch Chapter 7

D.1 Weighted average line utilization and frequency and magnitude of congestion in Germany in the years 2015, 2020 and 2025

	REFERENCE SCENARIO (Chapter 7)							
	line utilization [% of capacity]		frequency of congestion [% of hours]			magnitude of congestion [MW]		
line	2020	2025	2015	2020	2025	2015	2020	2025
L-01-02	64.48%	65.12%		18.75%	25.74%		155	267
L-01-03	63.89%	67.03%		19.49%	25.74%		139	309
L-02-03	9.47%	11.91%		0.00%	0.00%		0	0
L-02-06	41.32%	29.29%		0.15%	0.00%		106	0
L-02-10	44.59%	53.41%		3.72%	9.23%		64	161
L-03-04	17.71%	23.94%		0.00%	0.00%		0	0
L-03-11	40.27%	48.58%		0.00%	6.25%		0	105
L-04-05	9.92%	13.36%		0.00%	0.00%		0	0
L-04-07	21.55%	31.20%		0.00%	0.00%		0	0
L-04-12	12.58%	15.45%		0.00%	0.00%		0	0
L-05-07	14.30%	20.99%		0.00%	0.00%		0	0
L-05-13	7.31%	10.40%		0.00%	0.00%		0	0
L-06-08	9.63%	16.55%		0.00%	0.00%		0	0
L-06-09	38.54%	45.64%		2.53%	6.70%		70	105
L-07-13	8.72%	10.92%		0.00%	0.00%		0	0
L-08-09	25.36%	56.51%		0.00%	22.62%		0	281
L-08-14	40.90%	59.54%		0.00%	16.07%		0	217
L-09-10	13.20%	17.21%		0.00%	0.00%		0	0
L-09-14	38.35%	37.26%		0.00%	0.00%		0	0
L-09-15	34.25%	43.82%		0.00%	0.00%		0	0
L-10-11	16.45%	21.42%		0.00%	0.00%		0	0
L-10-16	37.52%	42.62%		0.00%	0.00%		0	0
L-17-10	31.82%	46.71%		0.00%	0.00%		0	0
L-11-12	31.82%	33.61%		0.00%	2.23%		0	147
L-11-16	41.85%	46.19%		0.00%	0.74%		0	64
L-17-11	25.72%	35.01%		0.00%	0.00%		0	0
L-12-13	10.10%	10.69%		0.00%	0.00%		0	0
L-12-18	28.04%	33.29%		0.00%	0.74%		0	58

line	REFERENCE SCENARIO continued (Chapter 7) line utilization [% of capacity] 2015	2020	2025	frequency of congestion [% of hours] 2015	2020	2025	magnitude of congestion [MW] 2015	2020	2025
L-12-19		8.42%	11.24%		0.00%	0.00%		0	0
L-13-19		14.12%	17.68%		0.00%	0.00%		0	0
L-14-15		21.63%	17.95%		0.00%	0.00%		0	0
L-14-20		48.52%	58.59%		9.08%	19.94%		73	233
L-14-21		30.94%	40.38%		0.00%	0.00%		0	0
L-16-15		13.53%	17.50%		0.00%	0.00%		0	0
L-17-15		38.38%	29.27%		0.00%	0.00%		0	0
L-16-17		39.50%	39.78%		0.00%	0.00%		0	0
L-16-21		58.49%	62.36%		15.77%	18.45%		171	206
L-22-16		22.96%	23.99%		0.00%	0.00%		0	0
L-16-25		46.45%	54.56%		5.95%	8.78%		193	143
L-18-19		9.16%	8.41%		0.00%	0.00%		0	0
L-18-22		68.85%	75.74%		14.58%	21.58%		173	207
L-18-23		63.43%	72.39%		7.89%	18.45%		25	39
L-23-19		42.19%	44.50%		0.00%	0.00%		0	0
L-20-21		21.45%	24.49%		0.00%	0.00%		0	0
L-20-24		25.17%	27.80%		0.00%	0.00%		0	0
L-20-25		26.84%	32.08%		0.00%	0.00%		0	0
L-21-25		41.23%	49.05%		1.49%	9.08%		147	177
L-22-23		24.12%	25.48%		0.00%	0.00%		0	0
L-22-26		26.04%	32.52%		0.00%	0.00%		0	0
L-24-25		20.60%	20.40%		0.00%	0.00%		0	0
L-25-26		18.38%	18.74%		0.00%	0.00%		0	0
L-25-27		39.37%	47.30%		0.00%	5.21%		0	117
L-25-28		49.13%	63.47%		5.95%	20.24%		17	49
L-28-26		21.74%	26.36%		0.00%	0.00%		0	0
L-26-31		23.44%	31.91%		0.00%	0.00%		0	0
L-27-28		19.90%	29.35%		0.00%	0.00%		0	0
L-27-29		24.44%	24.78%		0.00%	0.00%		0	0
L-30-28		19.08%	26.02%		0.00%	0.00%		0	0
L-30-31		21.10%	21.21%		0.00%	0.00%		0	0

	SCENARIO "FUEL PRICE" (Chapter 7)								
	line utilization [% of capacity]			frequency of congestion [% of hours]			magnitude of congestion [MW]		
line	2015	2020	2025	2015	2020	2025	2015	2020	2025
L-01-02		70.19%	71.80%		24.40%	28.57%		211	308
L-01-03		71.96%	75.74%		25.74%	35.42%		216	336
L-02-03		10.76%	13.24%		0.00%	0.00%		0	0
L-02-06		37.79%	28.15%		0.00%	0.00%		0	0
L-02-10		47.19%	56.98%		4.46%	11.16%		101	190
L-03-04		22.27%	27.42%		0.00%	0.00%		0	0
L-03-11		45.04%	53.76%		2.23%	10.12%		27	158
L-04-05		12.41%	15.21%		0.00%	0.00%		0	0
L-04-07		27.01%	34.77%		0.00%	0.00%		0	0
L-04-12		14.10%	17.45%		0.00%	0.00%		0	0
L-05-07		17.13%	22.90%		0.00%	0.00%		0	0
L-05-13		8.17%	11.16%		0.00%	0.00%		0	0
L-06-08		8.66%	17.40%		0.00%	0.00%		0	0
L-06-09		36.81%	45.26%		1.79%	5.95%		36	114
L-07-13		7.97%	8.84%		0.00%	0.00%		0	0
L-08-09		26.08%	58.42%		0.00%	22.77%		0	294
L-08-14		41.60%	60.71%		0.00%	16.67%		0	236
L-09-10		12.10%	19.80%		0.00%	0.00%		0	0
L-09-14		33.96%	32.66%		0.00%	0.00%		0	0
L-09-15		35.74%	45.56%		0.00%	0.00%		0	0
L-10-11		20.39%	24.65%		0.00%	0.00%		0	0
L-10-16		39.50%	44.61%		0.00%	0.00%		0	0
L-17-10		33.72%	48.88%		0.00%	0.74%		0	21
L-11-12		24.31%	25.47%		0.00%	0.00%		0	0
L-11-16		41.10%	45.97%		0.00%	0.74%		0	20
L-17-11		21.62%	31.07%		0.00%	0.00%		0	0
L-12-13		9.39%	10.07%		0.00%	0.00%		0	0
L-12-18		27.72%	32.62%		0.00%	0.74%		0	60
L-12-19		8.80%	11.68%		0.00%	0.00%		0	0
L-13-19		13.17%	15.91%		0.00%	0.00%		0	0
L-14-15		18.84%	15.67%		0.00%	0.00%		0	0
L-14-20		54.37%	66.53%		20.24%	25.00%		138	295
L-14-21		36.73%	45.94%		0.00%	4.46%		0	11

line	line utilization [% of capacity]			frequency of congestion [% of hours]			magnitude of congestion [MW]		
SCENARIO "FUEL PRICE"continued (Chapter 7)									
	2015	2020	2025	2015	2020	2025	2015	2020	2025
L-16-15		16.10%	19.75%		0.00%	0.00%		0	0
L-17-15		33.29%	25.87%		0.00%	0.00%		0	0
L-16-17		41.46%	41.68%		0.00%	0.00%		0	0
L-16-21		56.67%	61.91%		14.43%	18.01%		180	202
L-22-16		21.43%	24.16%		0.00%	0.00%		0	0
L-16-25		47.59%	56.03%		6.70%	10.12%		193	161
L-18-19		7.47%	7.43%		0.00%	0.00%		0	0
L-18-22		66.20%	73.42%		11.16%	19.20%		188	210
L-18-23		67.97%	74.29%		12.20%	18.45%		25	41
L-23-19		41.73%	44.10%		0.00%	0.00%		0	0
L-20-21		21.50%	24.96%		0.00%	0.00%		0	0
L-20-24		26.14%	28.89%		0.00%	0.00%		0	0
L-20-25		28.32%	33.52%		0.00%	0.00%		0	0
L-21-25		43.29%	51.83%		3.72%	11.90%		152	264
L-22-23		19.04%	21.88%		0.00%	0.00%		0	0
L-22-26		25.84%	32.47%		0.00%	0.00%		0	0
L-24-25		20.38%	20.44%		0.00%	0.00%		0	0
L-25-26		17.11%	17.90%		0.00%	0.00%		0	0
L-25-27		41.03%	49.19%		0.74%	7.44%		50	190
L-25-28		51.40%	65.46%		9.67%	24.85%		24	46
L-28-26		20.80%	25.54%		0.00%	0.00%		0	0
L-26-31		24.61%	33.35%		0.00%	0.00%		0	0
L-27-28		21.16%	30.13%		0.00%	0.00%		0	0
L-27-29		24.88%	25.42%		0.00%	0.00%		0	0
L-30-28		19.90%	26.86%		0.00%	0.00%		0	0
L-30-31		19.58%	19.65%		0.00%	0.00%		0	0

	SCENARIO “WIND POWER” (Chapter 7)								
	line utilization [% of capacity]			frequency of congestion [% of hours]			magnitude of congestion [MW]		
line	2015	2020	2025	2015	2020	2025	2015	2020	2025
L-01-02		61.16%	59.08%		11.31%	17.11%		122	167
L-01-03		60.89%	61.20%		13.24%	21.58%		91	192
L-02-03		9.25%	11.55%		0.00%	0.00%		0	0
L-02-06		40.49%	28.87%		0.15%	0.00%		44	0
L-02-10		42.33%	49.58%		0.00%	5.36%		0	124
L-03-04		17.07%	21.58%		0.00%	0.00%		0	0
L-03-11		38.13%	44.71%		0.00%	3.72%		0	49
L-04-05		9.71%	12.38%		0.00%	0.00%		0	0
L-04-07		20.08%	28.00%		0.00%	0.00%		0	0
L-04-12		11.78%	13.98%		0.00%	0.00%		0	0
L-05-07		12.93%	18.48%		0.00%	0.00%		0	0
L-05-13		6.60%	8.96%		0.00%	0.00%		0	0
L-06-08		9.88%	13.66%		0.00%	0.00%		0	0
L-06-09		36.11%	41.74%		0.15%	1.34%		83	77
L-07-13		8.94%	11.34%		0.00%	0.00%		0	0
L-08-09		21.41%	47.87%		0.00%	14.58%		0	67
L-08-14		37.91%	53.63%		0.00%	10.57%		0	116
L-09-10		13.14%	15.92%		0.00%	0.00%		0	0
L-09-14		36.59%	34.05%		0.00%	0.00%		0	0
L-09-15		32.52%	40.45%		0.00%	0.00%		0	0
L-10-11		16.25%	20.08%		0.00%	0.00%		0	0
L-10-16		36.37%	40.58%		0.00%	0.00%		0	0
L-17-10		30.56%	44.31%		0.00%	0.00%		0	0
L-11-12		31.44%	33.70%		0.00%	1.49%		0	108
L-11-16		40.53%	44.21%		0.00%	0.00%		0	0
L-17-11		24.53%	33.77%		0.00%	0.00%		0	0
L-12-13		10.15%	10.24%		0.00%	0.00%		0	0
L-12-18		26.90%	31.28%		0.00%	0.00%		0	0
L-12-19		7.91%	10.13%		0.00%	0.00%		0	0
L-13-19		13.33%	16.27%		0.00%	0.00%		0	0
L-14-15		21.19%	16.99%		0.00%	0.00%		0	0
L-14-20		46.83%	54.97%		5.06%	15.18%		52	184
L-14-21		30.74%	39.37%		0.00%	0.00%		0	0

	SCENARIO "WIND POWER" continued (Chapter 7)								
	line utilization [% of capacity]			frequency of congestion [% of hours]			magnitude of congestion [MW]		
line	2015	2020	2025	2015	2020	2025	2015	2020	2025
L-16-15		13.70%	17.31%		0.00%	0.00%		0	0
L-17-15		36.94%	27.46%		0.00%	0.00%		0	0
L-16-17		38.45%	37.99%		0.00%	0.00%		0	0
L-16-21		56.59%	59.59%		13.39%	13.10%		137	181
L-22-16		23.17%	23.44%		0.00%	0.00%		0	0
L-16-25		44.86%	52.19%		5.95%	6.25%		118	157
L-18-19		9.25%	8.58%		0.00%	0.00%		0	0
L-18-22		67.67%	74.08%		12.65%	18.60%		150	192
L-18-23		61.88%	69.33%		7.44%	13.24%		23	38
L-23-19		41.74%	43.66%		0.00%	0.00%		0	0
L-20-21		21.66%	24.44%		0.00%	0.00%		0	0
L-20-24		24.88%	27.54%		0.00%	0.00%		0	0
L-20-25		26.82%	31.82%		0.00%	0.00%		0	0
L-21-25		40.15%	47.08%		1.49%	6.70%		71	194
L-22-23		23.88%	25.94%		0.00%	0.00%		0	0
L-22-26		25.20%	31.42%		0.00%	0.00%		0	0
L-24-25		19.93%	20.10%		0.00%	0.00%		0	0
L-25-26		18.31%	18.34%		0.00%	0.00%		0	0
L-25-27		39.09%	46.34%		0.00%	5.21%		0	102
L-25-28		48.88%	62.27%		5.21%	19.05%		18	47
L-28-26		21.22%	25.84%		0.00%	0.00%		0	0
L-26-31		22.85%	30.78%		0.00%	0.00%		0	0
L-27-28		19.84%	28.88%		0.00%	0.00%		0	0
L-27-29		24.66%	24.99%		0.00%	0.00%		0	0
L-30-28		19.17%	25.93%		0.00%	0.00%		0	0
L-30-31		21.21%	22.04%		0.00%	0.00%		0	0

	SCENARIO "LOAD STRUCTURE" (Chapter 7)								
	line utilization [% of capacity]			frequency of congestion [% of hours]			magnitude of congestion [MW]		
line	2015	2020	2025	2015	2020	2025	2015	2020	2025
L-01-02		65.76%	66.92%		20.98%	26.93%		157	269
L-01-03		64.72%	68.21%		20.39%	27.38%		147	299
L-02-03		9.57%	11.62%		0.00%	0.00%		0	0
L-02-06		42.30%	30.53%		0.30%	0.00%		67	0
L-02-10		45.91%	55.24%		3.72%	10.27%		90	170
L-03-04		18.00%	24.32%		0.00%	0.00%		0	0
L-03-11		41.82%	50.76%		0.00%	7.74%		0	128
L-04-05		10.09%	13.67%		0.00%	0.00%		0	0
L-04-07		22.11%	32.05%		0.00%	0.00%		0	0
L-04-12		13.05%	16.18%		0.00%	0.00%		0	0
L-05-07		14.72%	21.61%		0.00%	0.00%		0	0
L-05-13		7.42%	10.62%		0.00%	0.00%		0	0
L-06-08		10.23%	15.98%		0.00%	0.00%		0	0
L-06-09		40.54%	48.54%		3.42%	8.48%		82	114
L-07-13		8.52%	10.62%		0.00%	0.00%		0	0
L-08-09		25.27%	56.21%		0.00%	22.62%		0	276
L-08-14		41.91%	60.96%		0.00%	17.71%		0	222
L-09-10		13.43%	16.97%		0.00%	0.00%		0	0
L-09-14		39.82%	39.33%		0.00%	0.00%		0	0
L-09-15		35.39%	45.43%		0.00%	0.00%		0	0
L-10-11		16.46%	21.64%		0.00%	0.00%		0	0
L-10-16		38.53%	44.03%		0.00%	0.00%		0	0
L-17-10		33.14%	48.66%		0.00%	1.49%		0	8
L-11-12		31.95%	33.80%		0.00%	2.23%		0	151
L-11-16		42.87%	47.59%		0.00%	1.49%		0	63
L-17-11		26.49%	36.19%		0.00%	0.00%		0	0
L-12-13		10.07%	10.66%		0.00%	0.00%		0	0
L-12-18		28.83%	34.52%		0.00%	1.49%		0	53
L-12-19		8.47%	11.44%		0.00%	0.00%		0	0
L-13-19		14.45%	18.27%		0.00%	0.00%		0	0
L-14-15		21.93%	18.28%		0.00%	0.00%		0	0
L-14-20		49.15%	59.67%		9.23%	20.68%		85	249
L-14-21		30.98%	40.43%		0.00%	0.00%		0	0

	SCENARIO "LOAD STRUCTURE"continued (Chapter 7)								
	line utilization [% of capacity]			frequency of congestion [% of hours]			magnitude of congestion [MW]		
line	2015	2020	2025	2015	2020	2025	2015	2020	2025
L-16-15		13.46%	17.30%		0.00%	0.00%		0	0
L-17-15		39.78%	31.09%		0.00%	0.00%		0	0
L-16-17		40.32%	40.91%		0.00%	0.00%		0	0
L-16-21		59.91%	64.33%		16.07%	20.24%		187	223
L-22-16		22.98%	23.99%		0.00%	0.00%		0	0
L-16-25		47.49%	56.13%		5.95%	9.52%		220	168
L-18-19		9.20%	8.46%		0.00%	0.00%		0	0
L-18-22		69.85%	77.16%		15.03%	23.21%		176	220
L-18-23		64.17%	73.44%		8.18%	18.75%		25	40
L-23-19		42.62%	45.11%		0.00%	0.00%		0	0
L-20-21		21.43%	24.34%		0.00%	0.00%		0	0
L-20-24		25.19%	27.86%		0.00%	0.00%		0	0
L-20-25		26.86%	32.14%		0.00%	0.00%		0	0
L-21-25		41.67%	50.11%		2.98%	10.57%		92	179
L-22-23		24.55%	26.06%		0.00%	0.00%		0	0
L-22-26		26.60%	33.37%		0.00%	0.00%		0	0
L-24-25		20.59%	20.39%		0.00%	0.00%		0	0
L-25-26		18.45%	18.74%		0.00%	0.00%		0	0
L-25-27		39.84%	48.11%		0.00%	5.95%		0	124
L-25-28		49.64%	64.38%		5.95%	21.58%		20	46
L-28-26		22.13%	27.04%		0.00%	0.00%		0	0
L-26-31		23.80%	32.77%		0.00%	0.00%		0	0
L-27-28		20.04%	29.68%		0.00%	0.00%		0	0
L-27-29		24.42%	24.74%		0.00%	0.00%		0	0
L-30-28		19.06%	25.96%		0.00%	0.00%		0	0
L-30-31		20.92%	20.91%		0.00%	0.00%		0	0

D.2 Weighted average upward redispatch per quarter in Germany in the years 2015, 2020 and 2025

region	REFERENCE SCENARIO (Chapter 7) weighted average upward redispatch [MW]											
	2015				2020				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1					0	0	0	0	0	0	160	0
2					290	0	0	0	383	0	55	206
3					0	0	0	0	0	0	0	0
4					50	0	0	218	92	0	0	195
5					0	0	0	0	0	0	0	0
6					274	0	0	0	201	0	166	215
7					0	0	0	0	0	0	0	0
8					0	0	0	213	86	0	60	110
9					0	0	0	236	318	0	235	425
10					0	0	0	229	272	0	209	501
11					7	0	0	0	163	0	176	300
12					0	0	0	0	565	0	0	379
13					0	0	0	0	113	0	0	372
14					331	0	0	40	310	0	395	658
15					94	0	0	0	408	0	78	99
16					0	0	0	0	0	0	0	0
17					0	0	0	0	0	0	0	0
18					0	0	0	0	0	0	0	209
19					0	0	0	0	180	0	0	606
20					62	0	0	609	893	0	8	1,450
21					769	0	0	0	627	0	0	909
22					0	0	0	0	706	0	0	0
23					0	0	0	0	575	0	0	0
24					737	0	0	0	286	0	0	452
25					286	0	0	6	285	0	13	245
26					0	0	0	0	0	0	0	0
27					372	0	0	1	452	0	0	315
28					193	0	0	0	1,254	0	0	887
29					0	0	0	0	0	0	0	0
30					0	0	0	0	0	0	0	0
31					285	0	0	0	518	0	0	389

region	SCENARIO "FUEL PRICE" (Chapter 7) weighted average upward redispatch [MW]											
	2015				2020				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1					0	0	0	0	0	0	109	0
2					286	0	0	342	392	0	542	285
3					0	0	0	0	0	0	0	353
4					105	0	0	204	135	0	0	208
5					0	0	0	0	0	0	0	0
6					126	0	0	0	181	0	0	16
7					0	0	0	0	0	0	0	0
8					15	0	0	0	151	0	0	0
9					0	0	0	417	348	0	310	465
10					94	0	0	0	293	0	0	600
11					76	0	0	0	130	0	0	303
12					0	0	0	0	0	0	0	0
13					0	0	0	0	0	0	0	560
14					193	0	0	7	483	0	0	74
15					323	0	0	0	343	0	0	0
16					0	0	0	0	0	0	0	0
17					0	0	0	0	0	0	0	0
18					190	0	0	0	0	0	0	128
19					294	0	0	261	108	0	0	558
20					256	0	0	676	1,249	0	2	1,563
21					521	0	0	0	651	0	135	767
22					0	0	0	0	673	0	0	0
23					742	0	0	0	854	0	0	0
24					535	0	0	0	300	0	50	570
25					75	0	0	48	299	0	42	379
26					0	0	0	0	0	0	0	0
27					347	0	0	484	561	0	127	517
28					282	0	0	387	1,746	0	62	851
29					0	0	0	0	0	0	0	0
30					0	0	0	0	0	0	0	0
31					265	0	0	0	423	0	245	479

region	SCENARIO “WIND POWER” (Chapter 7) weighted average upward redispatch [MW]											
	2015				2020				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1					0	0	0	0	0	0	122	0
2					0	0	0	0	115	0	0	406
3					0	0	0	0	0	0	0	0
4					0	0	0	0	70	0	0	68
5					0	0	0	0	0	0	0	0
6					201	0	0	0	0	0	133	73
7					0	0	0	0	0	0	0	0
8					0	0	0	81	41	0	0	0
9					1	0	0	76	158	0	0	126
10					124	0	0	74	131	0	121	199
11					0	0	0	0	53	0	0	423
12					0	0	0	0	410	0	0	0
13					0	0	0	0	112	0	0	0
14					20	0	0	0	488	0	131	77
15					20	0	0	0	43	0	0	91
16					0	0	0	0	0	0	0	0
17					0	0	0	0	0	0	0	0
18					0	0	0	0	0	0	0	0
19					0	0	0	44	81	0	0	672
20					10	0	0	227	786	0	0	1,011
21					673	0	0	0	604	0	0	0
22					0	0	0	0	450	0	0	0
23					78	0	0	0	458	0	0	0
24					425	0	0	107	174	0	0	302
25					98	0	0	0	255	0	0	257
26					0	0	0	0	0	0	0	0
27					359	0	0	0	385	0	0	264
28					117	0	0	271	1,321	0	0	622
29					0	0	0	0	0	0	0	0
30					0	0	0	0	0	0	0	0
31					360	0	0	0	281	0	0	279

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region	SCENARIO "LOAD STRUCTURE" (Chapter 7) weighted average upward redispatch [MW]											
	2015				2020				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1					0	0	0	0	0	0	129	0
2					396	0	0	0	405	0	55	348
3					0	0	0	0	0	0	0	75
4					55	0	0	178	107	0	0	195
5					0	0	0	0	0	0	0	0
6					274	0	0	0	102	0	166	108
7					0	0	0	0	0	0	0	0
8					0	0	0	242	77	0	60	110
9					0	0	0	236	275	0	230	454
10					0	0	0	302	252	0	243	509
11					7	0	0	0	169	0	94	297
12					0	0	0	0	565	0	0	379
13					0	0	0	0	129	0	0	411
14					325	0	0	125	457	0	414	630
15					94	0	0	0	368	0	53	99
16					0	0	0	0	0	0	0	0
17					0	0	0	0	0	0	0	0
18					0	0	0	0	0	0	0	209
19					0	0	0	0	172	0	0	706
20					89	0	0	648	903	0	8	1,575
21					894	0	0	0	693	0	65	1,151
22					0	0	0	0	886	0	0	0
23					0	0	0	0	546	0	0	0
24					733	0	0	139	288	0	33	460
25					226	0	0	43	296	0	13	254
26					0	0	0	0	0	0	0	0
27					381	0	0	10	476	0	0	332
28					200	0	0	0	1,385	0	176	850
29					0	0	0	0	0	0	0	0
30					0	0	0	0	0	0	0	0
31					339	0	0	0	519	0	0	385

D.3 Weighted average downward redispatch per quarter in Germany in the years 2015, 2020 and 2025

region	REFERENCE SCENARIO (Chapter 7) weighted average downward redispatch [MW]											
	2015				2020				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1					452	0	0	346	1,494	0	0	1,069
2					0	0	0	0	431	0	0	479
3					0	0	0	0	0	0	0	0
4					0	0	0	0	184	0	0	112
5					0	0	0	0	0	0	0	0
6					0	0	0	0	73	0	0	87
7					0	0	0	0	0	0	0	0
8					0	0	0	0	2,070	0	732	1,365
9					0	0	0	0	284	0	0	250
10					524	0	0	27	0	0	0	332
11					37	0	0	53	0	0	0	230
12					0	0	0	0	489	0	513	28
13					0	0	0	0	0	0	564	0
14					0	0	0	275	251	0	0	736
15					0	0	0	65	0	0	0	655
16					951	0	0	420	651	0	0	484
17					0	0	0	0	0	0	0	0
18					894	0	0	387	897	0	167	723
19					0	0	0	436	0	0	0	496
20					0	0	0	0	0	0	0	550
21					0	0	0	0	45	0	0	0
22					0	0	0	0	0	0	0	0
23					0	0	0	0	0	0	0	0
24					0	0	0	0	0	0	0	0
25					0	0	0	0	356	0	0	407
26					0	0	0	0	0	0	0	0
27					0	0	0	0	0	0	0	0
28					0	0	0	0	0	0	0	0
29					0	0	0	0	0	0	0	0
30					0	0	0	0	0	0	0	0
31					0	0	0	0	0	0	0	0

region	SCENARIO "FUEL PRICE" (Chapter 7)											
	weighted average downward redispatch [MW]											
	2015				2020				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1					627	0	0	695	1,813	0	0	1,185
2					0	0	0	0	237	0	0	465
3					0	0	0	0	0	0	0	0
4					0	0	0	0	399	0	0	48
5					0	0	0	0	0	0	0	0
6					0	0	0	0	73	0	0	126
7					0	0	0	0	0	0	0	0
8					0	0	0	0	2,133	0	674	1,387
9					0	0	0	43	486	0	0	300
10					0	0	0	0	67	0	121	283
11					0	0	0	22	313	0	0	265
12					0	0	0	0	157	0	0	0
13					0	0	0	0	0	0	0	0
14					368	0	0	74	1,180	0	391	1,154
15					1,081	0	0	514	0	0	0	767
16					0	0	0	62	526	0	0	470
17					0	0	0	0	0	0	0	0
18					798	0	0	431	835	0	249	563
19					0	0	0	721	0	0	0	0
20					0	0	0	0	0	0	0	216
21					0	0	0	0	261	0	0	0
22					0	0	0	0	0	0	0	0
23					0	0	0	0	0	0	0	0
24					0	0	0	0	0	0	0	26
25					0	0	0	0	544	0	0	503
26					0	0	0	0	0	0	0	0
27					0	0	0	0	0	0	0	184
28					0	0	0	0	0	0	516	0
29					0	0	0	0	0	0	0	0
30					0	0	0	0	0	0	0	0
31					0	0	0	0	0	0	0	0

region	SCENARIO "WIND POWER" (Chapter 7) weighted average downward redispatch [MW] 2015				2020				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1					337	0	0	304	878	0	0	790
2					0	0	0	0	458	0	0	544
3					0	0	0	0	0	0	0	0
4					0	0	0	0	223	0	0	109
5					0	0	0	0	0	0	0	0
6					0	0	0	0	108	0	0	36
7					0	0	0	0	0	0	0	0
8					0	0	0	0	863	0	0	391
9					0	0	0	0	769	0	0	223
10					339	0	0	0	93	0	0	416
11					150	0	0	60	10	0	0	139
12					0	0	0	0	385	0	450	82
13					0	0	0	0	0	0	115	0
14					0	0	0	0	236	0	0	815
15					0	0	0	0	903	0	0	700
16					199	0	0	0	645	0	0	720
17					0	0	0	0	0	0	0	0
18					1,013	0	0	126	879	0	0	653
19					0	0	0	0	0	0	0	1,097
20					0	0	0	0	87	0	0	378
21					0	0	0	0	266	0	0	0
22					0	0	0	0	0	0	0	0
23					0	0	0	0	0	0	0	0
24					0	0	0	0	22	0	0	0
25					0	0	0	0	756	0	0	439
26					0	0	0	0	0	0	0	0
27					0	0	0	0	0	0	0	0
28					0	0	0	0	0	0	0	0
29					0	0	0	0	0	0	0	0
30					0	0	0	0	0	0	0	0
31					0	0	0	0	0	0	0	0

SCENARIO "LOAD STRUCTURE" (Chapter 7)

region	2015				2020				2025			
	weighted average downward redispatch [MW]											
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1					513	0	0	421	1,482	0	0	1,129
2					0	0	0	0	336	0	0	364
3					0	0	0	0	0	0	0	0
4					0	0	0	0	241	0	0	104
5					0	0	0	0	0	0	0	0
6					0	0	0	0	73	0	0	88
7					0	0	0	0	0	0	0	0
8					0	0	0	0	2,157	0	711	1,400
9					0	0	0	0	544	0	0	294
10					564	0	0	134	0	0	0	333
11					37	0	0	53	0	0	0	265
12					0	0	0	0	411	0	513	78
13					0	0	0	0	0	0	601	0
14					0	0	0	275	149	0	0	820
15					0	0	0	206	0	0	0	613
16					1,089	0	0	300	765	0	0	576
17					0	0	0	0	0	0	0	0
18					901	0	0	463	945	0	279	742
19					0	0	0	569	0	0	0	496
20					0	0	0	0	0	0	0	624
21					0	0	0	0	130	0	0	0
22					0	0	0	0	0	0	0	0
23					0	0	0	0	0	0	0	0
24					0	0	0	0	0	0	0	0
25					67	0	0	0	480	0	0	375
26					0	0	0	0	0	0	0	0
27					0	0	0	0	0	0	0	0
28					0	0	0	0	0	0	0	0
29					0	0	0	0	0	0	0	0
30					0	0	0	0	0	0	0	0
31					0	0	0	0	0	0	0	41

D.4 Technology-specific upward and downward redispatch in Germany in the years2020 and 2025

	REFERENCE SCENARIO 2020 (Chapter 7)													
	redispatch [GWh/a]													
	upward						downward							
region	nuclear	coal	lig	gas	dummy	TOTAL	nuclear	coal	lignite	gas	wind	RES	dummy	TOTAL
1	0.0	0.0	0.0	0.0	0.0	0	11.9	440.8	0.0	0.0	0.0	0.0	0.0	453
2	0.0	37.9	0.0	0.0	0.0	38	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
3	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
4	0.0	9.0	0.0	0.0	0.0	9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
5	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
6	0.0	18.0	0.0	0.0	0.0	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
7	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
8	0.0	8.4	0.0	0.0	0.0	8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
9	0.0	9.3	0.0	0.0	0.0	9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
10	0.0	6.0	0.0	0.0	0.0	6	0.0	34.8	0.0	0.0	0.0	0.0	0.0	35
11	0.0	0.0	0.5	0.0	0.0	0	0.0	0.0	2.1	2.4	0.0	0.0	0.0	4
12	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
13	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
14	0.0	52.6	0.0	0.0	0.0	53	0.0	0.0	0.0	18.1	0.0	0.0	0.0	18
15	0.0	5.0	0.0	0.0	0.0	5	0.0	4.3	0.0	0.0	0.0	0.0	0.0	4
16	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	7.8	4.5	5.7	18
17	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
18	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	719.9	0.0	0.0	0.0	0.0	720
19	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	11.5	0.0	0.0	0.0	0.0	11
20	0.0	2.3	37.9	10.5	22.4	73	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
21	0.0	0.0	0.0	0.0	252.5	253	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
22	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
23	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
24	0.0	333.3	0.0	5.6	0.0	339	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
25	0.0	30.3	0.0	0.0	0.0	30	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
26	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
27	0.0	162.4	0.0	1.9	0.0	164	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
28	0.0	126.8	0.0	0.0	0.0	127	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
29	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
30	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
31	0.0	128.7	0.0	2.5	0.0	131	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
TOT	0.0	930.0	38.4	20.5	274.9	1,264	11.9	479.8	733.4	20.5	7.8	4.5	5.7	1,264

region	REFERENCE SCENARIO 2025 (Chapter 7) redispatch [GWh/a]													
	upward						downward							
	nuclear	coal	lig	gas	dummy	TOTAL	nuclear	coal	lignite	gas	wind	RES	dummy	TOTAL
1	0.0	31.5	0.0	0.0	0.0	**31**	0.0	2,612.8	0.0	0.0	1,187.0	0.0	0.0	**3,800**
2	0.0	96.3	0.0	0.0	0.0	**96**	0.0	37.1	0.0	0.0	0.0	0.0	0.0	**37**
3	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
4	0.0	124.6	0.0	0.0	0.0	**125**	0.0	18.0	0.0	0.0	0.0	0.0	0.0	**18**
5	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
6	0.0	51.0	0.0	0.0	0.0	**51**	0.0	23.8	0.0	0.0	0.0	0.0	0.0	**24**
7	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
8	0.0	11.0	0.0	0.0	0.0	**11**	0.0	1,934.6	0.0	0.0	2,430.3	0.0	0.0	**4,365**
9	0.0	276.5	0.0	103.0	0.0	**379**	0.0	55.6	0.0	138.9	0.0	0.0	0.0	**195**
10	0.0	287.9	0.0	0.0	0.0	**288**	0.0	74.2	0.0	22.0	0.0	0.0	0.0	**96**
11	0.0	34.7	27.8	4.0	7.6	**74**	0.0	8.3	15.9	0.0	0.0	0.0	0.0	**24**
12	0.0	0.0	0.0	19.8	0.0	**20**	0.0	0.0	0.0	133.5	0.0	0.0	0.0	**134**
13	0.0	0.0	0.0	10.9	0.0	**11**	0.0	0.0	0.0	74.2	0.0	0.0	0.0	**74**
14	0.0	399.1	0.0	25.4	0.0	**424**	0.0	486.9	0.0	288.4	0.0	0.0	0.0	**775**
15	0.0	160.3	0.0	0.0	0.0	**160**	0.0	207.5	0.0	232.8	30.1	0.0	0.0	**470**
16	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	32.1	32.8	26.4	**91**
17	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
18	0.0	0.0	2.7	0.0	0.0	**3**	0.0	0.0	1,758.7	0.0	1.2	0.0	0.0	**1,760**
19	0.0	0.0	122.6	0.0	0.0	**123**	0.0	0.0	6.5	0.0	0.0	0.0	0.0	**7**
20	0.0	10.7	335.1	819.2	2,010.7	**3,176**	0.0	0.0	0.0	180.6	0.0	0.0	0.0	**181**
21	0.0	0.0	0.0	0.0	300.3	**300**	0.0	0.0	0.0	0.0	3.0	0.0	0.0	**3**
22	0.0	0.0	0.0	0.0	325.0	**325**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
23	0.0	0.0	0.0	161.0	254.8	**416**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
24	0.0	435.0	0.0	72.8	0.0	**508**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
25	0.0	274.4	0.0	40.6	110.2	**425**	0.0	189.4	0.0	40.2	0.0	0.0	0.0	**230**
26	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
27	0.0	829.1	0.0	70.0	0.0	**899**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
28	0.0	1,036.3	0.0	1.6	2,786.1	**3,824**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
29	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
30	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
31	0.0	262.4	0.0	350.7	0.0	**613**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
TOT	**0.0**	**4,320.9**	**488.3**	**1,679.0**	**5,794.7**	**12,283**	**0.0**	**5,648.3**	**1,781.1**	**1,110.6**	**3,683.7**	**32.8**	**26.4**	**12,283**

region	upward: nuclear	upward: coal	upward: lig	upward: gas	upward: dummy	upward: TOTAL	downward: nuclear	downward: coal	downward: lignite	downward: gas	downward: wind	downward: RES	downward: dummy	downward: TOTAL
	SCENARIO "FUEL PRICE" 2020 (Chapter 7) – redispatch [GWh/a]													
1	0.0	0.0	0.0	0.0	0.0	**0**	10.7	1,293.5	0.0	0.0	0.0	0.0	0.0	**1,304**
2	0.0	61.5	0.0	0.0	0.0	**62**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
3	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
4	0.0	83.1	0.0	0.0	0.0	**83**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
5	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
6	0.0	16.6	0.0	0.0	0.0	**17**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
7	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
8	0.0	7.6	0.0	0.0	0.0	**8**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
9	0.0	5.5	0.0	0.0	0.0	**5**	0.0	0.0	0.0	5.6	0.0	0.0	0.0	**6**
10	0.0	6.2	0.0	0.0	0.0	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
11	0.0	21.9	1.0	0.0	0.0	**23**	0.0	0.0	0.6	0.0	0.0	0.0	0.0	**1**
12	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
13	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
14	0.0	172.3	0.0	0.0	0.0	**172**	0.0	48.4	0.0	9.7	0.0	0.0	0.0	**58**
15	0.0	98.3	0.0	0.0	0.0	**98**	0.0	359.5	0.0	22.5	0.0	0.0	0.0	**382**
16	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	1.6	0.0	0.0	**2**
17	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
18	0.0	0.0	2.5	0.0	0.0	**2**	0.0	0.0	541.6	0.0	0.0	0.0	0.0	**542**
19	0.0	0.0	7.3	0.0	0.0	**7**	0.0	0.0	18.9	0.0	0.0	0.0	0.0	**19**
20	0.0	3.3	51.7	0.0	295.7	**351**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
21	0.0	0.0	0.0	0.0	171.3	**171**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
22	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
23	0.0	0.0	0.0	0.0	48.8	**49**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
24	0.0	386.7	0.0	0.0	0.0	**387**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
25	0.0	75.2	0.0	0.0	0.0	**75**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
26	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
27	0.0	214.1	0.0	0.0	0.0	**214**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
28	0.0	396.1	0.0	0.0	29.2	**425**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
29	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
30	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
31	0.0	150.8	0.0	6.0	0.0	**157**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
TOT	**0.0**	**1,699.3**	**62.5**	**6.0**	**544.9**	**2,313**	**10.7**	**1,701.4**	**561.2**	**37.8**	**1.6**	**0.0**	**0.0**	**2,313**

region	SCENARIO "FUEL PRICE" 2025 (Chapter 7)													
	redispatch [GWh/a]													
	upward						downward							
	nuclear	coal	lig	gas	dummy	TOTAL	nuclear	coal	lignite	gas	wind	RES	dummy	TOTAL
1	0.0	7.2	0.0	0.0	0.0	**7**	0.0	4,329.8	0.0	0.0	1,286.4	0.0	0.0	**5,616**
2	0.0	87.7	0.0	0.0	0.0	**88**	0.0	45.9	0.0	0.0	0.0	0.0	0.0	**46**
3	0.0	0.0	0.0	0.0	46.4	**46**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
4	0.0	179.1	0.0	0.0	0.0	**179**	0.0	28.1	0.0	0.0	0.0	0.0	0.0	**28**
5	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
6	0.0	24.4	0.0	0.0	0.0	**24**	0.0	17.7	0.0	0.0	0.0	0.0	0.0	**18**
7	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
8	0.0	15.9	0.0	0.0	0.0	**16**	0.0	1,816.9	0.0	0.0	2,818.9	0.0	0.0	**4,636**
9	0.0	318.4	0.0	92.7	13.6	**425**	0.0	88.1	0.0	286.8	0.0	0.0	0.0	**375**
10	0.0	278.4	0.0	0.0	0.0	**278**	0.0	39.4	0.0	13.2	0.0	0.0	0.0	**53**
11	0.0	52.5	37.3	0.0	0.0	**90**	0.0	0.8	24.2	0.0	0.0	0.0	0.0	**25**
12	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	10.3	0.0	0.0	**10**
13	0.0	0.0	0.0	7.4	0.0	**7**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
14	0.0	304.1	0.0	0.0	0.0	**304**	0.0	1,590.6	0.0	317.4	0.0	0.0	0.0	**1,908**
15	0.0	128.3	0.0	0.0	0.0	**128**	0.0	574.0	0.0	203.4	31.2	0.0	0.0	**809**
16	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	28.8	26.7	7.1	**63**
17	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
18	0.0	0.0	5.0	0.0	0.0	**5**	0.0	0.0	1,463.5	0.0	2.9	0.0	0.0	**1,466**
19	0.0	0.0	100.1	0.0	0.0	**100**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
20	0.0	10.5	314.0	382.3	4,389.5	**5,096**	0.0	1.0	0.0	70.0	0.0	0.0	0.0	**71**
21	0.0	0.0	0.0	0.0	167.5	**167**	0.0	0.0	0.0	0.0	8.4	5.5	3.3	**17**
22	0.0	0.0	0.0	0.0	221.1	**221**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
23	0.0	0.0	0.0	0.0	617.0	**617**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
24	0.0	445.6	0.0	56.8	0.0	**502**	0.0	0.0	0.0	1.7	0.0	0.0	0.0	**2**
25	0.0	430.7	0.0	14.5	0.0	**445**	0.0	327.6	0.0	13.5	0.0	0.0	0.0	**341**
26	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
27	0.0	1,117.4	0.0	86.1	0.0	**1,204**	0.0	2.4	0.0	0.0	0.0	0.0	0.0	**2**
28	0.0	1,309.9	0.0	2.2	3,563.2	**4,875**	0.0	0.0	0.0	0.0	5.1	15.3	0.0	**20**
29	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
30	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
31	0.0	491.8	0.0	187.0	0.0	**679**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
TOT	**0.0**	**5,202.0**	**456.5**	**829.0**	**9,018.2**	**15,506**	**0.0**	**8,862.3**	**1,487.8**	**906.0**	**4,191.8**	**47.5**	**10.3**	**15,506**

Region	SCENARIO "WIND POWER" 2020 (Chapter 7)													
	redispatch [GWh/a]													
	upward						downward							
	nuclear	coal	lig	gas	dummy	TOTAL	nuclear	coal	lignite	gas	wind	RES	dummy	TOTAL
1	0.0	0.0	0.0	0.0	0.0	0	0.0	124.8	0.0	0.0	0.0	0.0	0.0	125
2	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
3	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
4	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
5	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
6	0.0	26.4	0.0	0.0	0.0	26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
7	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
8	0.0	1.1	0.0	0.0	0.0	1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
9	0.0	1.0	0.0	0.0	0.0	1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
10	0.0	17.3	0.0	0.0	0.0	17	0.0	47.7	0.0	0.0	0.0	0.0	0.0	48
11	0.0	0.0	0.0	0.0	0.0	0	0.0	14.5	5.7	4.4	0.0	0.0	0.0	25
12	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
13	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
14	0.0	0.3	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
15	0.0	0.3	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
16	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	2.2	0.4	0.0	3
17	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
18	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	537.4	0.0	0.0	0.0	0.0	537
19	0.0	0.0	0.6	0.0	0.0	1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
20	0.0	0.7	6.0	0.0	0.0	7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
21	0.0	0.0	0.0	0.0	176.8	177	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
22	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
23	0.0	0.0	0.0	5.2	0.0	5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
24	0.0	167.1	0.0	0.0	0.0	167	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
25	0.0	7.7	0.0	0.0	0.0	8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
26	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
27	0.0	148.2	0.0	19.2	0.0	167	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
28	0.0	64.8	0.0	0.0	0.0	65	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
29	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
30	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
31	0.0	83.8	0.0	10.9	0.0	95	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
TOT	0.0	518.5	6.5	35.2	176.8	737	0.0	187.0	543.1	4.4	2.2	0.4	0.0	737

Region	SCENARIO "WIND POWER" 2025 (Chapter 7) redispatch [GWh/a] upward						downward							
	nuclear	coal	lig	gas	dummy	TOTAL	nuclear	coal	lignite	gas	wind	RES	dummy	TOTAL
1	0.0	16.1	0.0	0.0	0.0	**16**	0.0	1,833.3	0.0	0.0	163.2	0.0	0.0	**1,996**
2	0.0	6.8	0.0	0.0	0.0	**7**	0.0	44.4	0.0	0.0	0.0	0.0	0.0	**44**
3	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
4	0.0	26.8	0.0	0.0	0.0	**27**	0.0	16.1	0.0	0.0	0.0	0.0	0.0	**16**
5	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
6	0.0	19.4	0.0	0.0	0.0	**19**	0.0	43.1	0.0	0.0	0.0	0.0	0.0	**43**
7	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
8	0.0	2.7	0.0	0.0	0.0	**3**	0.0	990.9	0.0	0.0	80.9	0.0	0.0	**1,072**
9	0.0	37.9	0.0	0.0	0.0	**38**	0.0	49.3	0.0	87.8	0.0	0.0	0.0	**137**
10	0.0	40.2	0.0	0.0	0.0	**40**	0.0	87.1	0.0	8.8	0.0	0.0	0.0	**96**
11	0.0	14.0	8.6	0.0	0.0	**23**	0.0	7.8	12.9	0.0	0.0	0.0	0.0	**21**
12	0.0	0.0	0.0	16.2	0.0	**16**	0.0	0.0	0.0	165.7	0.0	0.0	0.0	**166**
13	0.0	0.0	0.0	1.5	0.0	**1**	0.0	0.0	0.0	7.6	0.0	0.0	0.0	**8**
14	0.0	83.4	0.0	1.6	0.0	**85**	0.0	339.9	0.0	212.2	0.0	0.0	0.0	**552**
15	0.0	17.1	0.0	0.0	0.0	**17**	0.0	314.9	0.0	206.9	0.0	0.0	0.0	**522**
16	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	19.2	17.6	37.9	**75**
17	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
18	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	1,686.6	0.0	0.0	0.0	0.0	**1,687**
19	0.0	0.0	49.5	0.0	0.0	**49**	0.0	0.0	28.8	0.0	0.0	0.0	0.0	**29**
20	0.0	6.8	153.8	372.1	1,333.8	**1,867**	0.0	1.0	0.0	159.3	0.0	0.0	0.0	**160**
21	0.0	0.0	0.0	0.0	198.3	**198**	0.0	0.0	0.0	0.0	8.0	5.5	3.9	**17**
22	0.0	0.0	0.0	0.0	118.3	**118**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
23	0.0	0.0	0.0	94.8	25.7	**121**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
24	0.0	211.1	0.0	25.1	0.0	**236**	0.0	1.4	0.0	0.0	0.0	0.0	0.0	**1**
25	0.0	207.2	0.0	7.8	0.0	**215**	0.0	529.1	0.0	82.5	0.0	0.0	0.0	**612**
26	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
27	0.0	524.0	0.0	26.7	0.0	**551**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
28	0.0	552.5	0.0	1.1	2,685.8	**3,239**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
29	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
30	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
31	0.0	275.6	0.0	91.2	0.0	**367**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
TOT	**0.0**	**2,041.8**	**211.9**	**638.1**	**4,362.0**	**7,254**	**0.0**	**4,258.5**	**1,728.3**	**930.8**	**271.3**	**23.1**	**41.9**	**7,254**

	SCENARIO "LOAD STRUCTURE" 2020 (Chapter 7)													
	redispatch [GWh/a]													
	upward						downward							
Region	nuclear	coal	lig	gas	dummy	TOTAL	nuclear	coal	lignite	gas	wind	RES	dummy	TOTAL
1	0.0	0.0	0.0	0.0	0.0	0	17.4	518.7	0.0	0.0	0.0	0.0	0.0	536
2	0.0	50.5	0.0	0.0	0.0	51	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
3	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
4	0.0	8.3	0.0	0.0	0.0	8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
5	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
6	0.0	18.0	0.0	0.0	0.0	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
7	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
8	0.0	9.5	0.0	0.0	0.0	10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
9	0.0	9.3	0.0	0.0	0.0	9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
10	0.0	7.9	0.0	0.0	0.0	8	0.0	40.6	0.0	0.0	0.0	0.0	0.0	41
11	0.0	0.0	0.5	0.0	0.0	0	0.0	0.0	2.1	2.4	0.0	0.0	0.0	4
12	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
13	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
14	0.0	76.0	0.0	0.0	0.0	76	0.0	0.0	0.0	18.1	0.0	0.0	0.0	18
15	0.0	5.0	0.0	0.0	0.0	5	0.0	13.5	0.0	0.0	0.0	0.0	0.0	14
16	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	8.6	6.1	7.5	22
17	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
18	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	783.8	0.0	0.0	0.0	0.0	784
19	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	15.0	0.0	0.0	0.0	0.0	15
20	0.0	2.7	49.1	10.5	31.6	94	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
21	0.0	0.0	0.0	0.0	293.9	294	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
22	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
23	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
24	0.0	333.5	0.0	5.6	0.0	339	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
25	0.0	36.5	0.0	0.0	0.0	36	0.0	4.4	0.0	0.0	0.0	0.0	0.0	4
26	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
27	0.0	173.6	0.0	15.8	0.0	189	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
28	0.0	144.4	0.0	0.0	0.0	144	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
29	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
30	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
31	0.0	153.4	0.0	2.5	0.0	156	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
TOT	0.0	1,028.7	49.6	34.4	325.5	1,438	17.4	577.2	800.9	20.5	8.6	6.1	7.5	1,438

Region	SCENARIO “LOAD STRUCTURE” 2025 (Chapter 7) redispatch [GWh/a] upward						downward							
	nuclear	coal	lig	gas	dummy	TOTAL	nuclear	coal	lignite	gas	wind	RES	dummy	TOTAL
1	0.0	25.4	0.0	0.0	0.0	**25**	0.0	2,709.9	0.0	0.0	1,364.2	0.0	0.0	**4,074**
2	0.0	103.4	0.0	0.0	0.0	**103**	0.0	37.6	0.0	0.0	0.0	0.0	0.0	**38**
3	0.0	0.0	0.0	0.0	4.9	**5**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
4	0.0	122.2	0.0	0.0	0.0	**122**	0.0	37.1	0.0	0.0	0.0	0.0	0.0	**37**
5	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
6	0.0	38.0	0.0	0.0	0.0	**38**	0.0	25.0	0.0	0.0	0.0	0.0	0.0	**25**
7	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
8	0.0	11.4	0.0	0.0	0.0	**11**	0.0	1,938.7	0.0	0.0	2,614.3	0.0	0.0	**4,553**
9	0.0	259.7	0.0	45.8	0.0	**306**	0.0	58.5	0.0	195.4	0.0	0.0	0.0	**254**
10	0.0	289.3	0.0	0.0	0.0	**289**	0.0	78.8	0.0	22.0	0.0	0.0	0.0	**101**
11	0.0	35.7	27.8	4.0	2.2	**70**	0.0	8.3	23.2	0.0	0.0	0.0	0.0	**31**
12	0.0	0.0	0.0	19.8	0.0	**20**	0.0	0.0	0.0	158.7	0.0	0.0	0.0	**159**
13	0.0	0.0	0.0	12.2	0.0	**12**	0.0	0.0	0.0	79.1	0.0	0.0	0.0	**79**
14	0.0	499.5	0.0	35.8	0.0	**535**	0.0	498.9	0.0	300.8	0.0	0.0	0.0	**800**
15	0.0	163.6	0.0	0.0	0.0	**164**	0.0	205.1	0.0	256.6	30.4	0.0	0.0	**492**
16	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	37.1	36.3	35.1	**108**
17	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
18	0.0	0.0	2.7	0.0	0.0	**3**	0.0	0.0	1,906.2	0.0	2.5	0.0	0.0	**1,909**
19	0.0	0.0	130.2	0.0	0.0	**130**	0.0	0.0	6.5	0.0	0.0	0.0	0.0	**7**
20	0.0	12.0	359.0	909.6	2,170.1	**3,451**	0.0	0.0	0.0	205.2	0.0	0.0	0.0	**205**
21	0.0	0.0	0.0	0.0	383.7	**384**	0.0	0.0	0.0	0.0	8.4	0.2	0.0	**9**
22	0.0	0.0	0.0	0.0	349.5	**349**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
23	0.0	0.0	0.0	160.7	267.1	**428**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
24	0.0	440.9	0.0	77.3	0.0	**518**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
25	0.0	287.3	0.0	42.8	144.9	**475**	0.0	222.4	0.0	40.2	0.0	0.0	0.0	**263**
26	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
27	0.0	851.6	0.0	86.2	0.0	**938**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
28	0.0	1,067.2	0.0	1.9	3,025.0	**4,094**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
29	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
30	0.0	0.0	0.0	0.0	0.0	**0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
31	0.0	287.7	0.0	384.8	0.0	**672**	0.0	0.5	0.0	0.0	0.0	0.0	0.0	**1**
TOT	**0.0**	**4,494.8**	**519.8**	**1,780.9**	**6,347.4**	13,143	**0.0**	**5,820.6**	**1,935.9**	**1,257.9**	**4,057.0**	**36.4**	**35.1**	13,143