

Balancing of Intermittent Renewable Power Generation by Demand Response and Thermal Energy Storage

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Hans Christian Gils
born in Karlsruhe, Germany

First examiner: Prof. Dr. André Thess
Second examiner: Prof. Dr. Christian Dötsch

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Abstract

Balancing of intermittent renewable power generation from wind and solar energy is one of the central challenges within the energy system transformation towards a more sustainable supply. This work addresses the potential role of flexible electric loads and power-controlled operation of combined heat and power (CHP) plants in meeting increasing balancing needs in Germany. It conducts an enhancement of the cross-sectoral REMix model, which is designed for the preparation and assessment of energy supply scenarios based on a system representation in high spatial and temporal resolution. The analysis is composed of three fundamental parts. The first part is dedicated to the quantification of theoretical potentials for demand response (DR), district heating (DH) and industrial CHP in Europe. Special attention is given to the geographic distribution of potentials, as well as the derivation of hourly heat and electricity demand profiles. In the second part, the linear optimization model within REMix is extended by DR and the heating sector, enabling economic assessments of the balancing function of flexible electric loads and power-controlled heat supply. In the third part, REMix is applied to assess the future energy supply in Germany, making use of the model enhancements and identified potentials. In order to account for different renewable energy (RE) and grid capacity development paths, as well as transport and heat sector structures, nine scenarios are considered. For each scenario, least-cost dimensioning and operation of DR capacities, as well as heat supply systems are evaluated.

According to the REMix results, the application of DR is mostly limited to short time peak shaving of the residual load. This implies that its focus is on the provision of power, not energy. As a consequence of different cost structures, the exploitation of available DR potentials is attributed almost exclusively to industrial and commercial sector loads, whereas those in the residential sector are hardly accessed. The model results indicate that the temporal availability of DR potentials, as well as their characteristic intervention and shift times are particularly suited for a combination with PV power generation.

In the simulations, power-controlled heat supply has proven to be an effective measure to increase RE integration. It is achieved by a modified operation pattern of CHP and – to a lower extent – heat pumps (HP) enabled by thermal energy storage (TES) on the one hand, and an utilization of surplus power for heating purposes on the other. Due to the greater potential and thus longer storage times of TES, as well as the comparatively low investment costs of electric boilers, an enhanced coupling between power and heat sector is found to be especially favorable in combination with wind power utilization. Load shifting across all sectors provides substantial amounts of positive balancing power, which can substitute other firm generation capacity. The highest load reduction is achieved by controlled electric vehicle charging, lower contributions come from adjusted HP operation and other DR.

As a consequence of higher RE integration, load shifting and power-controlled heat supply can contribute substantially to CO₂ emission reductions in Germany. However, this is only the case if the additional balancing potentials are not applied as well for an economically motivated shift in power generation from low-emitting to high-emitting fuels. Furthermore, load flexibility and enhanced power-heat-coupling can enable energy supply cost reductions, arising from the substitution of back-up power plant capacity on the one hand, and a more cost-efficient power and heat supply on the other.

The model application reveals that electric load shifting and power-controlled CHP operation are not competing but complementary measures in the realization of higher RE integration and lower back-up capacity demand. Negative interferences between both balancing options are found to be very small. On the contrary, they even promote each other, for example in the reduction of RE curtailments. Based on the REMix results it can be concluded that both DR and power-controlled heat supply enabled by TES are important elements in a future German energy system mainly relying on renewable sources.

Zusammenfassung

Der Ausgleich der fluktuierenden Stromerzeugung aus Wind- und Solarkraftwerken stellt eine der zentralen Herausforderungen der Energiewende dar. In dieser Arbeit werden die möglichen Beiträge des Lastmanagements (LM) und des stromgeführten Betriebs von Kraft-Wärme-Kopplungs-Anlagen (KWK) zur Deckung des zukünftigen Lastausgleichsbedarfs in Deutschland untersucht. Die Analyse basiert auf einer Erweiterung des sektorübergreifenden Energiesystemmodells REMix, welches die Bewertung von Versorgungssystemen in hoher räumlicher und zeitlicher Auflösung ermöglicht.

Die Analyse erfolgt in drei wesentlichen Schritten. Der erste Teil der Arbeit ist der Bewertung der theoretischen Einsatzpotenziale des LM, sowie der netzgebundenen und industriellen KWK gewidmet. Dabei liegt ein Schwerpunkt auf der räumlichen Verteilung der Potenziale und der Ableitung stündlicher Wärme- und Strombedarfsprofile. Im zweiten Teil erfolgt eine Erweiterung des Optimierungsmodells in REMix um LM und den Wärmesektor. Diese ermöglicht eine ökonomische Bewertung der verschiedenen Lastausgleichsoptionen. Im dritten Teil wird das erweiterte REMix-Modell auf eine Untersuchung der zukünftigen Energieversorgung Deutschlands angewendet. Dabei werden neun Szenarien in Betracht gezogen, die sich im Ausbau von erneuerbaren Energien (EE), Speichern und Stromnetzen, sowie den Versorgungsstrukturen im Wärme- und Verkehrssektor unterscheiden. Für jedes Szenario erfolgt eine kostenminimierende Optimierung des Ausbaus und Einsatzes der verschiedenen Lastausgleichsoptionen.

Die REMix-Ergebnisse zeigen, dass LM in erster Linie zur Senkung der residualen Spitzenlast eingesetzt wird; der Fokus liegt folglich auf der Bereitstellung von Leistung, nicht von Arbeit. Aus der angenommenen Kostenstruktur ergibt sich, dass sich die Ausschöpfung der Potenziale nahezu ausschließlich auf die Industrie und den Gewerbesektor beschränkt, während jene in den Haushalten ungenutzt bleiben. Die Ergebnisse legen nahe, dass die zeitliche Verfügbarkeit flexibler Lasten und deren typische Verschiebedauern besonders für eine Kombination mit Photovoltaikstrom geeignet sind. Stromgeführte Wärmeerzeugung erweist sich als eine wirkungsvolle Maßnahme der EE-Integration. Diese wird einerseits durch einen dem EE-Dargebot angepassten Betrieb von KWK und Wärmepumpen mit thermischem Speicher, und andererseits durch die Nutzung von Überschussstrom zur Wärmeerzeugung bewirkt. Aufgrund der längeren Speicherdauern und größeren Einsatzpotenziale thermischer Speicher und der geringen Investitionskosten elektrischer Kessel erscheint eine verbesserte Kopplung zwischen Strom- und Wärmesektor vor allem in Regionen hoher Windenergienutzung zielführend.

Über alle Sektoren hinweg kann Strombedarfsflexibilität für die Bereitstellung positiver Ausgleichsleistung genutzt werden und somit die Vorhaltung von Kraftwerken ersetzen. Die höchste Bedarfsreduktion ergibt sich dabei durch das gesteuerte Laden von Elektrofahrzeugen, bei geringeren Beiträgen durch einen angepassten Wärmepumpenbetrieb sowie weiteres LM. Durch die Vermeidung der Abregelung von EE-Anlagen können LM und stromgeführter KWK-Betrieb einen Beitrag zur Senkung der CO₂-Emissionen leisten. Dies gilt jedoch nur wenn sie nicht vorwiegend für eine Steigerung der Stromerzeugung aus günstigeren, aber kohlenstoffintensiven Brennstoffen genutzt werden. Darüber hinaus können die zusätzlichen Lastausgleichstechnologien durch einen geringeren Bedarf an Reservekraftwerken, sowie günstigere Strom- und Wärmeerzeugung auch die Energieversorgungskosten senken.

Die REMix-Fallstudie zeigt, dass sich LM und stromgeführte KWK in der Erwirkung einer höheren EE-Integration und der Reduktion des Kraftwerksbedarfs ergänzen. Gegenseitige Beeinträchtigungen zwischen beiden Lastausgleichsoptionen sind gering; vielmehr begünstigen sie einander sogar z.B. hinsichtlich der Vermeidung von EE-Abregelung. Auf Grundlage der Ergebnisse lässt sich schlussfolgern, dass LM und eine verbesserte Kopplung zwischen Strom- und Wärmesektor wichtige Elemente einer überwiegend auf erneuerbaren Quellen basierenden Energieversorgung Deutschlands sind.

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List of Acronyms

AC	Air conditioning (Chapter 2), Alternating Current (all other chapters)
Bld	Building
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CDD	Cooling Degree Days
CHP	Combined Heat and Power
COP	Heat Pump Coefficient of Performance
CSP	Concentrated Solar Power
DC	Direct Current
DH	District Heating
DR	Demand Response
EU	European Union
EV	Electric Vehicle
FLH	Full Load Hours
GAMS	General Algebraic Modeling System
GHG	Greenhouse Gas
GIS	Geographic Information System
GT	Gas Turbine
HDD	Heating Degree Days
HP	Heat Pump
HVAC	Heating, Ventilation and Air Conditioning
HVDC	High Voltage Direct Current
HW	Hot Water
ICT	Information and Communication Technologies
Ind	Industry
NUTS	Nomenclature of Statistical Territorial Units
OECD	Organisation for Economic Co-operation and Development
PH	Process Heat
PV	Photovoltaic
RE	Renewable Energy
ResCom	Residential and Commercial Sector
SH	Space Heating
TES	Thermal Energy Storage
TYNDP	Ten Year Network Development Plan
VRE	Variable Renewable Energy

List of Symbols

Table 1 Parameters used in the quantification of demand response and cogeneration potentials.

Symbol	Unit	Parameter
A_{year}^I	Mt/a	Annual production capacity of process I.
$d^{N,I}$	1/h	Hour share in the annual electricity demand.
$f_{eq}^{N,I}$	%	Equipment rate with household appliance.
$f_{revision}^I$	1/100	Total annual hour share of revision outages.
n_{cycle}^I	1/a	Annual number of runs per unit of appliance I.
n_{FLH}	h/a	Annual full load hours.
$n_{HDD,d}$	K	Number of heating degree days on day d.
n_{hh}^N	-	Number of households in region N.
n_{pop}^N	-	Population number in region N.
$n_{yearLimit}^I$	1/a	Maximum number of DR load interventions per year.
$\bar{P}_{cycle}^I$	kW _{el}	Average unit load during one run of appliance I.
P_{flex}^I	MW _{el}	Potential load reduction of process/appliance I.
P_{free}^I	MW _{el}	Potential load increase of process/appliance I.
P_{maxCap}^I	MW _{el}	Installed electric capacity of appliance I.
$P_{unitCap}^I$	MW _{el}	Installed capacity per unit of appliance I.
$s_{increase}^I$	%	Share in unused capacity of process or appliance I that can be activated.
$s_{minimum}^I$	%	Minimum load share relative to installed capacity.
$s_{reduction}^I$	%	Share of the current load that can be reduced.
$s_{tertiary}^I$	%	Share of consumer class I in the annual tertiary sector demand.
$s_{util}^{N,I}$	%	Capacity utilization relative to maximum use except revision outage.
Δt_{cycle}^I	h	Duration of one run of appliance type I.
$t_{interfere}^I$	h	DR interference time (maximum duration of load change).
$t_{shiftMax}^I$	h	Maximum DR shifting time (maximum duration until balancing).
$U_{day}^{N,S}(j)$	TWh _{th}	Heat demand on day j.
$U_{spec,rel}^N$		Inhabitant specific heat demand in region N relative to the country average.
$U_{year}^{N,S}$	TWh _{th}	Annual heat demand.
$W_{spec}^{N,I}$	kWh/t	Specific electricity demand per output unit of process I.
$W_{tertiary}^N$	MWh/a	Annual tertiary sector electricity demand.
$W_{unit}^{N,I}$	kWh/a	Annual electricity demand per unit of appliance I.
$W_{year}^{N,I}$	TWh/a	Annual electricity demand of process or appliance I.
$\lambda_{building}$	%	Heat losses at heat distribution within buildings.
$\lambda_{network}$	%	Heat losses in the district heating network.
ϑ	K	Temperature.

Table 2 List of indexes used in the REMix-OptiMo modeling.

Index	Set
G	Heat group
H	Flexible loads shift class
I	DR process or appliance
K	Heat supply component
N	Model node / region
S	Heat demand sector
V	Resource class / Fuel type
X	Technology
Z	Heat Consumer Category

Table 3 Parameters and variables used in the modeling of demand response.

Symbol	Unit	Variable
C_{invest}	k€/a	Investment costs.
C_{op}	k€/a	Operation and maintenance costs.
$P_{addedCap}^{N,X}$	GW _{el}	Installed electric capacity of additionally DR consumers.
$P_{balanceInc}^{N,H}(t)$	GW _{el}	Balancing of earlier load increase in shift class H.
$P_{balanceRed}^{N,H}(t)$	GW _{el}	Balancing of earlier load reduction in shift class H.
$P_{increase}^{N,H}(t)$	GW _{el}	Demand response load increase in shift class H.
$P_{reduction}^{N,H}(t)$	GW _{el}	Demand response load reduction in shift class H.
$W_{levelInc}^{N,X}(t)$	GWh _{el}	Amount of increased and not yet balanced energy of technology X.
$W_{levelRed}^{N,X}(t)$	GWh _{el}	Amount of reduced and not yet balanced energy of technology X.
Symbol	Unit	Parameter
c_{OMFix}^X	%Invest/year	Operation and maintenance fix costs.
c_{OMVar}^X	k€/MWh	Operation and maintenance variable costs.
$c_{specInv}^X$	k€/MW	Specific investment cost.
$f_{annuity}^X$	-	Annuity factor.
i	%	Interest rate.
$n_{yearLimit}^X$	-	Annual limit of DR interventions.
$P_{existCap}^{N,X}$	GW _{el}	Installed electric capacity of all appliances in DR technology X.
$P_{maxCap}^{N,X}$	GW _{el}	Maximum installable electric capacity of all appliances in DR technology X.
$s_{flex}^{N,X}(t)$	-	Maximum load reduction in t relative to installed capacity.
$\bar{s}_{flex}^{N,X}$	-	Average load reduction potential relative to installed capacity.
$s_{free}^{N,X}(t)$	-	Maximum load increase in t relative to installed capacity.
$\bar{s}_{free}^{N,X}$	-	Average load increase potential relative to installed capacity.
Δt	h	Calculation time interval.
t_{amort}^X	a	Amortization time.
$t_{dayLimit}^X$	h	Waiting time between two DR interventions.
$t_{interfere}^X$	h	DR interference time (maximum duration of load change).
t_{shift}^H	h	DR shifting time (maximum duration until balancing).
η_{DR}^H	1/100	DR efficiency.

Table 4 Parameters and variables used in the modeling of electric vehicles.

Symbol	Unit	Variable
C_{op}	k€/a	Operation and maintenance costs.
$P_{balanceRed}^{N,X,H}(t)$	GW _{el}	Balancing of earlier load reduction of electric vehicles.
$P_{reduction}^{N,X,H}(t)$	GW _{el}	Delayed electric vehicle charging.
Symbol	Unit	Parameter
c_{OMVar}^X	k€/MWh	Operation and maintenance variable costs.
$d_{hour,EV}^{N,X}(t)$	1/h	Hourly share in annual demand.
$d_{peak,EV}^{N,X}$	1/h	Peak share in annual demand.
$f_{cap2Peak}^X$	-	Ratio of installed technology capacity and peak load.
s_{ccEV}^X	%	Share of electric vehicles available for controlled charging.
t_{shift}^X	-	Load shifting duration.
$W_{annual}^{N,X}$	TWh _{el}	Annual electricity demand of electric vehicles.

Table 5 Variables used in the modeling of heat supply technologies.

Symbol	Unit	Variable
C_{invest}	k€/a	Investment costs.
$C_{notSupplHeat}$	k€/a	Overall costs of not supplied heat.
C_{op}	k€/a	Operation and maintenance costs.
C_{WaT}	k€/a	Wear and tear costs due to changes in the output power.
$D_{fuel}^{N,X,K}$	GWh _{chem}	Annual fuel consumption.
$h_{supply}^{N,X}$	1/100	Demand share supplied by technology X .
$P_{gen}^{N,X,K}(t)$	GW _{el}	Power generation in heat and power plants in timestep t .
$P_{eq}^{N,X,K}(t)$	GW _{el}	Power generation equivalent of CHP plants (equivalent generation in condensing operation) for the same steam intake.
$P_{loadChangePos}^{N,X,K}(t)$	GW _{el}	Positive power generation change in timestep t .
$P_{loadChangeNeg}^{N,X,K}(t)$	GW _{el}	Negative power generation change in timestep t .
$Q_{addedCap}^{N,X,K}$	GW _{th}	Added thermal capacity of component.
$Q_{charge}^{N,X,K}(t)$	GW _{th}	Amount of heat charged into the storage.
$Q_{cond}^{N,X,K}(t)$	GW _{th}	Heat condensed in timestep t .
$Q_{discharge}^{N,X,K}(t)$	GW _{th}	Amount of heat fed from the storage to the network/consumer.
$Q_{gen}^{N,X,K}(t)$	GW _{th}	Heat supply of component in timestep t .
$Q_{notSupplied}^{N,S}(t)$	GW _{th}	Not supplied heat in sector S and timestep t .
$Q_{supply}^{N,S,X}(t)$	GW _{th}	Heat load of technology X in timestep t .
$U_{level}^{N,X,K}(t)$	GWh _{th}	Amount of heat currently available in the storage.
$W_{heat}^{N,X,K}$	GWh _{el}	Annual electricity consumption for heat production.

Table 6 Parameters used in the modeling of heat supply technologies.

Symbol	Unit	Parameter
a_1^K	-	Heat pump efficiency coefficient 1.
a_2^K	-	Heat pump efficiency coefficient 2.
$c_{dist}^{N,G}$	k€/MWh	Specific heat distribution costs.
$c_{fuel}^{V,Z}$	k€/MWh	Fuel costs.
$c_{notSupplied}$	k€/MWh	Specific costs of not supplied heat.
c_{OMFix}^X	% $_{Invest}$ /year	Operation and maintenance fix costs.
c_{OMVar}^X	k€/MWh	Specific operation and maintenance variable costs.
$c_{specInv}^X$	k€/MW	Specific investment cost.
c_{WaT}^X	k€/MW	Specific wear and tear costs.
$d^{N,S}(t)$	1/h	Hourly share in annual heat demand.
d_{min}^N	1/h	Minimum share in annual heat demand.
d_{peak}^N	1/h	Maximum share in annual heat demand.
$E_{annual}^{N,V}$	GWh _{chem}	Annual resource availability.
$f_{annuity}^X$	-	Annuity factor.
f_{avail}^C	%	Power plant availability
$f_{cap2Peak}^K$	-	Ratio of installed technology capacity and peak load.
$f_{cap2Min}^K$	-	Ratio of installed technology capacity and minimum load.
$h_{fixed}^{N,G}$	1/100	Fixed demand share supplied by heat group G .
$h_{max}^{N,G}$	1/100	Maximum demand share supplied by heat group G .
$h_{min}^{N,G}$	1/100	Minimum demand share supplied by heat group G .
i	%	Interest rate.
$Q_{demand}^{N,S}$	TWh _{th}	Hourly sectoral heat demand.
$Q_{existCap}^{N,X,K}$	GW _{th}	Existing thermal capacity of component.
s_{CHP}	%	CHP heat supply share.
$s_{cooling}^K$	-	Share of heat that can be cooled in back-pressure CHP plants.
$s_{distLoss}^{N,G}$	1/100	Heat distribution loss.
t_{amort}^X	a	Amortization time.
$U_{year}^{N,S}$	TWh _{th}	Annual sectoral heat demand.
β^K	-	CHP power loss coefficient.
$\eta_{CHP}^{N,K}$	1/100	Overall net CHP efficiency at the back-pressure point.
η_{charge}^K	1/100	Storage charging efficiency.
$\eta_{discharge}^K$	1/100	Storage discharging efficiency.
η_{el}^K	1/100	Net power generation efficiency.
$\epsilon_{HP}^{N,K}(t)$	1/100	Net heat pump coefficient of performance.
$\epsilon_{HP,max}^K$	1/100	Maximum heat pump coefficient of performance.
η_{self}^K	1/100	Storage self-discharge efficiency.
η_{th}^K	1/100	Net heat production efficiency.
σ_W^K	-	CHP electricity-to-heat generation ratio.
$\vartheta_{inletHP}^K$	-	Heat pump inlet temperature.
$\vartheta_{source}^N(t)$	-	Hourly average heat source temperature in node N .

Chapter 1

Introduction, State of Research and Outline

1.1 Background

Scarcity and climate impact of fossil fuels require a realignment of the global energy system. In order to achieve significant reductions in greenhouse gas (GHG) emissions, a more efficient primary energy usage and a shift to a sustainable supply are indispensable [103]. Against this background, governments all over the world have expressed their commitment to a more climate-friendly economy and established policies supporting the usage of renewable energy (RE) technologies [153]. With increasing RE share in energy supply, fossil fuels are gradually replaced, thereby cutting overall emissions. So far the focus has been mostly on the electricity sector, however, heat and transport demands must be taken into account as well. Renewable energy technologies are available to all sectors, and in some cases competing for the same resources (see Figure 1.1). Depending on the location on the globe, RE resource availability exhibits significant differences, both in quantity and quality [180].

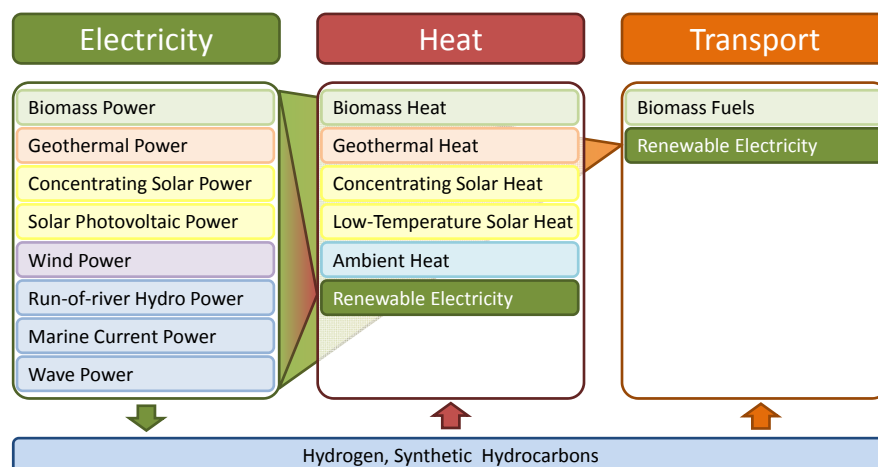


Figure 1.1 Renewable energy resource availability: utilization competition and interconnection between different demand sectors.

In the past years, solar photovoltaic (PV) and onshore wind power technologies have experienced significant cost reductions [15]. Both are increasingly contributing to the electricity supply in Europe and worldwide [153]. Due to the intermittent nature of wind speed and solar radiation, they can however provide firm capacity only to a very limited extent or not at all. Fluctuations in their power generation consequently need to be balanced by other technologies in the energy system. Available options comprise dispatchable renewable or conventional (i.e. fossil-fuel or nuclear) power plants, as well as energy storage, demand side measures and long-range load and generation balancing via power transmission. Dispatchable renewable power can be delivered by storage hydro, biomass and concentrating solar power (CSP) stations, which feature storage options for the fuel or working medium used, respectively. Energy storage systems include electricity-to-electricity storage, such as pumped hydro stations, batteries, flywheels or compressed air storage, but also thermal storage and production of synthetic hydrocarbons [25].

Currently, variable renewable energy (VRE) power generation fluctuations are mostly balanced by conventional power plants, transmission grids and pumped hydro stations. With even higher VRE capacities, balancing needs will continue to increase. This is particularly the case, if additional VRE capacities are installed for providing electricity – either directly or indirectly – to other demand sectors as well. Due to restricted biomass resources and limited availability of alternative RE technologies, electrification and synthetic fuel production are considered as promising options for achieving higher RE shares in the transport and heat sector [135]. Conventional power plants are already suffering reductions in their annual operation time caused by increasing VRE power generation [21]. With a steady VRE capacity expansion, this trend is expected to continue. Lower operation hours affect the power plant profitability, thus increasing the uncertainty about future investments in conventional technologies. Given the need to reduce conventional power generation in order to achieve emission reductions and the limited potentials for dispatchable RE and pumped hydro stations, additional balancing technologies will be needed in the future.

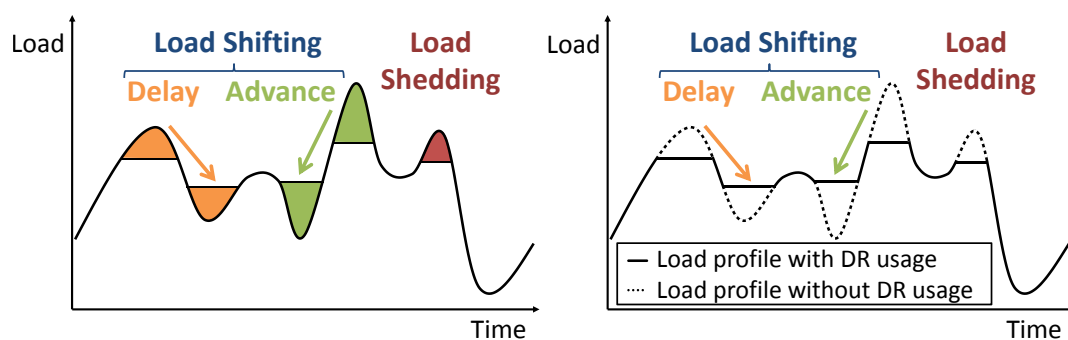


Figure 1.2 Mechanism and impact of the DR measures load shifting and load shedding.

Demand response (DR) actions are defined as 'changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized' ([67], page 21). In contrast

to demand side management, which also comprises energy efficiency measures and permanent and/or regular utility-driven changes in the demand pattern, DR is focused on load flexibility and short term customer action [3, 77]. It makes use of consumer demand elasticity, which is typically provided by thermal inertia, demand flexibility or physical storage. DR measures include load shedding, as well as load shifting to an earlier or later time (see Figure 1.2). Modifications in demand pattern are typically realized by direct or indirect load management programs [42, 115]. Existing DR measures include time-based rates on the one hand, and incentive based programs on the other [41].

The higher primary energy efficiency of cogeneration (combined heat and power, CHP) plants and heat pumps (HP) in comparison to alternative heat and power generation technologies enables primary energy savings and thus the mitigation of greenhouse gas emissions [126, 157]. To date, the operation of CHP and HP is mostly heat-controlled: it consequently follows the demand for heat. With regard to energy systems with high VRE shares, a reorientation of these units towards power-controlled mode needs to be pursued [18, 118, 127]. This implies an adjustment of the operation to the current power demand and RE generation, and consequently a decoupling of production and consumption of heat using thermal energy storage (TES). Furthermore, CHP supply systems can be complemented by the integration of an electric boiler or heat pump, which might be used to reduce or avoid VRE curtailments in times power generation exceeds demand, storage charging and grid capacity [128]. Figure 1.3 depicts the coupling between electricity and heat sector considered in this work. In CHP supply systems, it includes conventional peak boilers, which are used for the provision of heat in times of very high or low demand, as well as back-up supply.

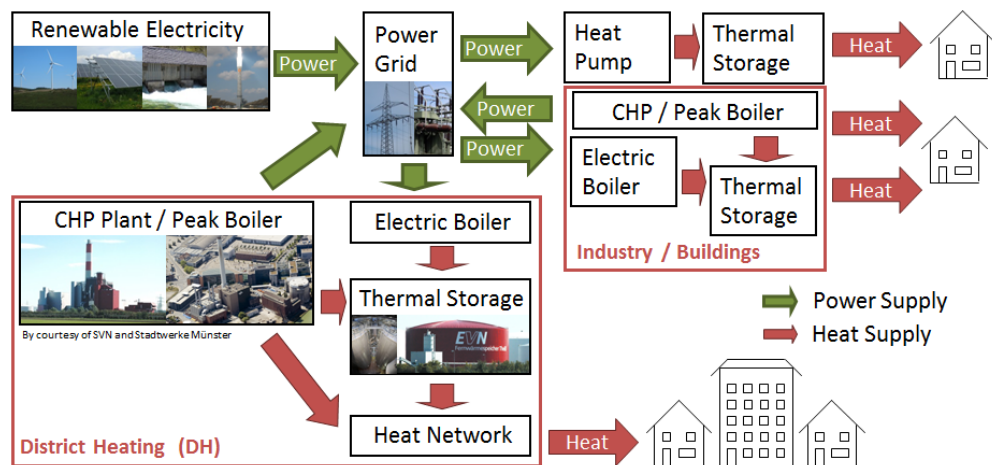


Figure 1.3 Thermal energy storage usage at the interface of power and heat sector.

Questions of load balancing demand arising from VRE power generation are addressed by energy systems analysis. Based on resource availability and energy demand studies, as well as an evaluation of techno-economical characteristics of technologies, the interaction of different system components is assessed in simplified but systematic model representations of real energy systems. Energy system models have been developed in many institutions all over the world with different scope, methods, as well as degree of detail [10, 37, 95].

1.2 State of Knowledge

Energy storage and load balancing are required on very different timescales, ranging from a few seconds to many months. Consequently, the applications of balancing technologies are manifold, and include the stabilization of power quality and grid frequency, load following, unit commitment, as well as plant operation optimization, seasonal storage and management of VRE feed-in [13, 25]. Whether a technology is suited for each of these applications, depends on its specific characteristics, such as power output, stored energy, efficiency, response time, run time and energy density. Referring to the time between charging and discharging, a distinction can be made between short-term, medium-term and long-term storage. Here, short-term is equivalent to storage times in the range of hours, medium-term in the range of days, and long-term in the range of weeks or months.¹ Most technologies are not restricted in their storage time by technical rather than by economic constraints. Load balancing technologies also differ substantially in their nontechnical characteristics, such as technology maturity, resource and unit availability, as well as costs and environmental impact. Detailed technology assessments are provided for example by [25, 64, 114, 198]. Advantages of DR and TES are the low environmental impact and infrastructure requirements, as well as the fact that no additional energy conversion is needed. For both DR and TES, centralized as well as decentralized solutions are available. Investment costs are comparatively low for large scale low temperature heat storage and industrial DR, but higher for higher storage temperatures and smaller DR consumers. TES efficiency is typically high, except for seasonal storage, which can have losses of more than 50% [64]. DR is mostly not connected with substantial energy losses. Exceptions are heating and cooling applications, which can have higher demand if load profiles are being changed [176]. In addition, the operation of the required communication infrastructure comes along with additional energy demand. An important shortcoming of DR is the temporal availability of loads. Particularly in residential and commercial sector, flexible loads are not at any time available to the same degree. Further restrictions can arise from limits in the duration and frequency of load interventions. With shifting times ranging from some minutes to a few days, DR can only provide short to medium-term storage [9, 13, 118].

Given the variety in temporal fluctuations of demand and VRE power generation on the one hand, and restrictions in technology potentials on the other, different balancing technologies will be needed in an European energy supply system with high VRE shares. The future load balancing demand in Europe has been studied in a number of model-based assessments including [94, 151, 155, 160]. They are, however, limited to electricity-to-electricity storage and/or power transmission grids, whereas other balancing options are not taken into account. The available literature on DR is mostly focused on qualitative analyses of benefits and challenges, technical description of modeling approaches of the DR behavior of specific loads, evaluation of DR field studies or identification of technical potentials. Detailed studies of DR

¹The assessment of very short-term balancing with reaction and operation times of seconds to minutes for purposes of power quality or grid frequency stabilization, for example provided by flywheels, capacitors or batteries, is beyond the scope of this work

utilization are typically restricted to selected loads and/or small geographic areas.

Without addressing specific loads, Strbac [181] has identified a broad range of potential benefits achieved by DR, including a higher profitability of power plants, avoidance of investments in additional generation or grid capacities, as well as increased VRE power integration. Assuming a market potential equivalent to 2% of the annual peak load and an 80% participation in DR, a possible benefit of € 53 billion achieved by smart meter installation and dynamic pricing on a European level has been estimated by [65].

Based on a review of existing studies and policy documents, as well as a quantitative analysis of the provision of reserve capacity in unforeseen events, Bradley et al. [22] conclude that an application of DR can generate economic benefits in the United Kingdom (UK). Taking into account load shifting of electric space and water heating, as well as controlled electric vehicle charging, Barton et al. [11] provide a model-based analysis of the potential DR application for the UK in hourly resolution. In three scenarios for the year 2050, they identify substantial reductions in VRE surplus power and residual load², as well as a higher power plant capacity utilization. Their model, however, does consider neither capital and operational costs, nor restrictions in power transmission. Bergaentzlé [16] assesses the impact of DR measures on electricity supply costs in a selection of interconnected European countries with different power plant park composition. Their application of a simple optimization model considers a peak and an off-peak demand period, and shows that DR can improve system efficiency and reliability and reduce costs in systems based on conventional generation. In a model-based assessment of the Azores island of Flores, Pina et al. [144] have shown that residential load shifting can delay investment in new generation capacity and increase operation times of existing power plants. The simulation of DR operation is, however, restricted to a number of representative demand and supply situations. The impact of DR on the electricity supply in Hawaii is assessed in [30]. The study relies on the application of a capacity expansion model in hourly resolution and reveals substantial cost reductions achieved by shifting of fictitious loads.

Without providing a quantitative assessment, Hamidi et al. [90], Soares et al. [174], Grunewald and Torriti [84] and Torriti [184] have identified DR resources in a broad range of processes and devices throughout all sectors. According to Grein and Pehnt [83], Stadler [177], Klobasa [111], shiftable and sheddable loads in Germany add up to several GW. Whether and to what extent these potentials can be economically exploited is, however, not analyzed. The impact of feedback and time-of-use tariffs on electricity demand and potential DR contribution has been investigated in field trials [86, 161, 185], as well as economic models [5, 82, 141, 200]. The cited case studies of DR utilization in today's electricity supply systems are focused on small geographic areas and single demand sectors or consumers, whereas the modeling approaches are applied exclusively to selected loads and exemplary demand profiles.

An enhanced coupling between the different energy demand sectors – power, heat and transport

²The residual load is defined as the grid load less VRE generation and represents the load that must be provided by dispatchable power plants or other balancing technologies.

– can facilitate a higher integration of renewable energy sources into all sectors. This includes power-controlled CHP operation, controlled electric vehicle charging, as well as flexible operation of heat pumps and hydrogen fuel electrolysis. With regard to the coupling between electricity and heat supply, the International Energy Agency [102] concludes that CHP with increased flexibility can play an important role in the balancing of RE power generation fluctuations.

According to national reports summarized in [26], substantial potentials for an extension of CHP in Europe are available. They are found in district heating (DH) supply, as well as the manufacturing industry and single objects, such as larger commercial or governmental buildings, universities, hotels and hospitals. The usage of small building CHP is thereby not limited to colder climates, but can be economically feasible also in southern European climates [24]. An assessment of the future heat supply in Denmark concludes that an extension of DH is not incompatible with heat saving measures [130]. This is important with regard to the building energy efficiency instruments and policies adopted by numerous European countries in their national regulatory framework [7].

Concerning a power-controlled CHP operation, Haeseldonckx et al. [89] show that the installation of TES enables a more steady and extended operation, whereas Pagliarini and Rainieri [139] highlight the potential shift of CHP operation to the most profitable hours. Both works concentrate on exemplary CHP supply systems, and do not account for their interaction with VRE power generation. A positive effect on CHP operation hours and thus profitability by TES is found also in small-scale building applications and warmer climates [24, 129]. Pardo et al. [140] study the impact of TES installation on dimensioning and operation of a sample HP system. Their simulation results suggest that TES allow for a higher system efficiency, as well as a HP size reduction. Considering a future Danish energy supply system with high wind shares, Hedegaard and Münster [92] underline that a flexible HP operation with TES enables a reduced need for peak generation capacity, but no major increases in VRE power integration. Potential benefits of TES utilization in cooling systems are identified in [40]. A model-based evaluation of different TES implementations in DH systems is provided by Nuytten et al. [136]. They conclude that the flexibility in CHP operation is significantly influenced by the TES location within the DH network, and higher for central than for decentralized units.

The existing literature on DR, as well as power-controlled CHP and HP operation is restricted to the analysis of exemplary systems, or selected aspects within the range extending from the quantification of potentials to an evaluation of the technical and economic system impact. However, a comprehensive assessment of their economic load balancing potential is so far.

1.3 Scope, Methodology and Structure of this Work

This work examines the potential contribution of alternative balancing options to the energy system transformation in Germany and Europe. It particularly concentrates on DR on the one hand, and power-controlled CHP operation enabled by thermal energy storage on the other.

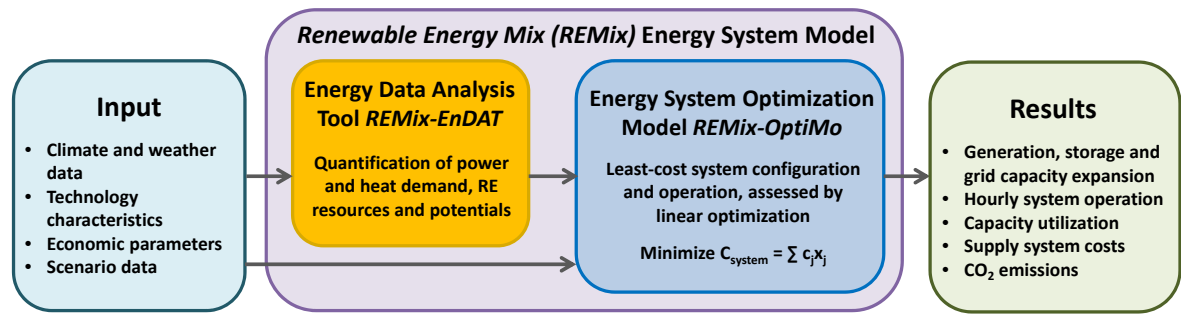


Figure 1.4 Main components and capabilities of the REMix model.

The analysis combines different aspects of previous research works, and overcomes some of their shortcomings. It comprises an quantification of theoretical potentials for DR and enhanced CHP utilization in Europe, as well as an evaluation of their economic competitiveness with alternative balancing options, relying on an hourly operation optimization model in high spatial and temporal resolution. The model-based analysis aims at a better understanding of the interaction between different balancing options, as well as their relation to the VRE supply structure. This includes the exploitation of available potentials on the one hand, and the hourly operating behavior on the other. The technology assessment is clearly focused on DR and power-controlled CHP operation, but takes into account also other balancing technologies, including long-term electricity-to-electricity storage, dispatchable CSP imports, transmission grid expansion, as well as flexible hydrogen fuel production, adjusted HP operation and controlled charging of electric vehicles. The central research questions addressed in this work can be formulated as follows:

- What are the theoretical potentials for DR and CHP in Europe?
- Is the exploitation of these potentials an economic alternative to other balancing options?
- What are the load balancing impact and typical operating behavior of DR and power-controlled CHP?
- How are they interacting with each other and alternative balancing technologies?
- To what extent can DR and power-controlled CHP reduce supply costs and CO₂ emissions?

The assessment of these research questions relies on the extension and application of the optimizing bottom-up energy system model REMix. REMix has been developed in the *Systems Analysis and Technology Assessment* department at the *German Aerospace Center* [125, 168, 180], and is composed of two main elements (see Figure 1.4). The energy data analysis tool REMix-EnDAT contains a global RE resource assessment in high spatial and temporal resolution, allowing for the derivation of future supply scenarios. It provides hourly generation profiles for all major RE technologies, aggregated to user defined regions [168, 180]. Furthermore, electricity and heat demand profiles as well as demand profiles for flexible consumers are generated in that part of the model. The supply and demand profiles are input to the multi-sectoral linear optimization model REMix-OptiMo, which determines

the least-cost operation of all system components during each hour of the year. This high temporal resolution is crucial for the assessment of systems with high VRE shares, given their occasionally very steep gradients in power generation. The optimization is not restricted to the hourly operating status, but can be extended to the installation of additional system components, such as power plants, storage and transmission lines. The comprehensive output includes technology full load hours and VRE curtailment, as well as system costs and CO₂ emissions.³

This work is composed of three fundamental parts. The first part is dedicated to an extension of REMix-EnDAT by European potentials for DR (Chapter 2) and CHP (Chapter 3). In doing so, hourly values of load flexibility and sectoral heat demands are derived in order to enable subsequent REMix-OptiMo simulations in high temporal resolution. DR potentials are quantified for all demand sectors and disaggregated to a high resolution grid. The evaluation of CHP potentials comprises DH on the one hand, and industrial consumers on the other. DH potentials are evaluated in a spatially explicit top-down approach, whereas industrial potentials are calculated as national sums and then disaggregated using regional business statistics. The high spatial resolution of all potentials allows for the consideration of differently dimensioned geographical regions in REMix-OptiMo.

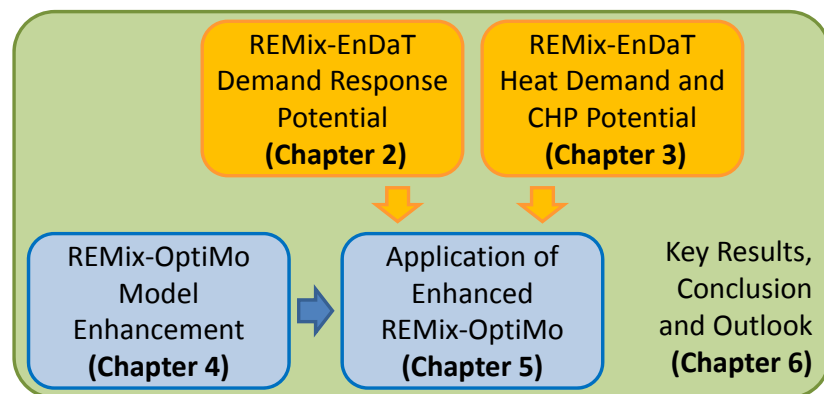


Figure 1.5 Structure of this work.

In the second part, the REMix-OptiMo implementation of DR and the heating sector is introduced (Chapter 4). Heat technologies implemented in the model include CHP, HP, TES, solar thermal collectors, as well as conventional and electric boilers. All technologies are described by a set of equations and in-equalities reflecting their operational boundary conditions.

In the third part, the extended REMix model is applied to assess the possible balancing contribution of DR and power-controlled operation of CHP and HP with thermal energy storage in Germany (Chapter 5). In order to account for different development paths of RE and grid capacity expansion, as well as transport and heat supply structures, a set of nine

³Additional REMix elements comprise REMix-PlaSMO and REMix-CEM. They enable the identification of optimal sites for RE power plants [180] and the derivation of least-cost capacity expansion planning [68], respectively. This work is limited to the enhancement and application of REMix-EnDAT and REMix-OptiMo.

scenarios is taken into account. Within the scenarios, least-cost dimensioning and operation of DR capacities and advanced heat supply systems are evaluated for various technology cost assumptions and system configurations.

In the final Chapter 6, the results of all parts are brought together, providing the basis for conclusions concerning the potential application of DR and thermal energy storage in highly renewable energy supply systems.

Even though they are interrelated by the overall scope of this thesis, the principal chapters 2 to 5 are presented as independent research works. Each of them commences with a brief overview of the state of research and concludes with a discussion of the methodology and results.

Chapter 2

Theoretical Demand Response Potential in Europe

In this chapter, theoretical demand response (DR) potentials in the EU-28, Norway, Switzerland and Liechtenstein are assessed.¹ Its aims are the characterization of electricity consumers that are able to shift or shed their load for a given period of time and the provision of an estimate of their loads in Europe. DR potentials are determined across all demand sectors: industry, as well as commercial and residential sector. Network load reductions achieved by the usage of costumer-owned on-site generation are not included in the analysis.

2.1 Introduction

Interventions in customer load can increase the profitability of power plants, assist a higher integration of VRE power generation and help to avoid investments in additional generation or grid capacities [22, 181]. Currently, the implementation of DR measures is mostly restricted to large industrial consumers. As a consequence of the development in information and communication technologies (ICT), as well as the emergence of new markets, residential and commercial consumers are, however, increasingly gaining interest [186]. Technical requirement for the participation in DR programs is the availability of an ICT infrastructure allowing for the transmission of and reaction to load, price and control signals. Markets for flexible loads range from on-site peak load reduction and increased internal PV consumption to participation in energy trade, provision of operating energy, as well as clearance of imbalances in the transmission system operator area and management of supply shortfalls [3, 4]. Communication channels include radio, telecommunication, as well as power lines [6, 113]. DR potentials have been identified and quantified in a broad range of processes and devices across all demand sectors [84, 90, 111, 174, 177, 184]. Those assessments are however limited to average values for single countries or selected electric loads. A comprehensive evaluation for the European continent is lacking so far.

When assessing the potential future contribution of DR to the system integration of VRE, the

¹This chapter relies on a previous publication of the author [80].

temporal availability of flexible loads is of particular importance [84]. The DR behavior of non-residential consumers is directly correlated to industrial production activity and business hours. In the residential sector, time-related electricity demands can be derived from an evaluation of household activity level and occupancy variance [124, 185]. In the work presented here, exemplary load profiles of all relevant consumers are either estimated or extracted from metered data available in literature. Based on these profiles, potentials for load reduction and increase are calculated for each hour of the year. In the context of balancing VRE fluctuations, also the duration of load interventions, as well as the shifting time and frequency of DR actions are of special importance. These parameters have decisive impact on the quality of the corresponding DR potentials.

The assessment of DR potentials provides the basis for the subsequent application of REMix-OptiMo. For this reason, it is adjusted to the model requirements and the particular focus of the scenario studies presented in Chapter 5. Given that the model application concentrates on future power supply systems with high VRE share, an extrapolation of DR potentials until the year 2050 is performed. In order to facilitate follow-up studies of regional differences in DR utilization, the geographical allocation of flexible consumers is evaluated as well.

The analysis is performed in five steps. First, the processes and appliances suitable for DR are identified (Section 2.2). Then, their characteristic load profiles are assessed (2.3). In the third step, the annual electricity demand and installed capacity in the year 2010 is quantified, and a flexible load share for each consumer is evaluated (2.4). Finally, the future development (2.5) and geographical distribution (2.6) of DR potentials are investigated. Results are presented and discussed in Section 2.7 and 2.8, respectively.

2.2 Methodology and Data

2.2.1 Disambiguation of the Theoretical Demand Response Potential

Given that the application of DR is subject to a variety of constraints, different kinds of potentials need to be treated separately. It can be distinguished between the theoretical, technical, economic and practical potential [57, 83]. The theoretical potential comprises all facilities and devices of the consumers suitable for DR, whereas the technical potential includes only those that can be controlled by the existing ICT infrastructure. A subset of the technical potential is the economic potential of all DR consumers that can be operated in a cost-efficient way. Another independent subset of the technical potential arises from the acceptance of load interventions, here labeled as social potential. The effectively usable, practical potential consists of the intersection of economic and social potential. This chapter is restricted to the assessment of the theoretical DR potential. Limitations for technical reasons not related to industrial production processes, costs or refusal to participate will at this point be neglected.² Figure 2.1 visualizes the different types of DR potentials.

²In the assessment of practical DR potentials presented in Chapter 5, both costs and social limitations of DR utilization will be taken into consideration.



Figure 2.1 Concept of theoretical and practical demand response potentials.

2.2.2 Identification of Flexible Loads and Required Parameters

In this study, a total of 30 different processes and appliances are taken into consideration. Shiftable loads typically feature one of the following characteristics: thermal storage (e.g. space heating, refrigerators), demand flexibility (e.g. washing, ventilation) or physical storage (e.g. cement industry, fresh water supply). Industrial load shifting may be limited by technical constraints, process requirements and availability of unutilized plant or machine capacity. For processes with very high utilization rates – as they are found in energy-intensive industries – only load shedding without previous or subsequent balancing can be implemented. In residential and commercial sector, typically both load shifting and shedding can be realized. Due to higher costs and losses of comfort caused in those sectors, this study evaluates load shedding only for energy-intensive industrial processes. Table 2.1 provides an overview of processes and appliances included. In accordance with the temporal resolution of the REMix model applied in this work, the analysis is limited to those DR consumers that can be shifted or shedded for at least one hour. Detailed descriptions of their technical properties and DR behavior can be gathered from the references cited in Table 2.1. The load shifting measures of power-controlled heat pump operation and controlled electric vehicle charging, which couple the electricity sector to the heating and transport sector, respectively, are not taken into account in this chapter. As a result of a differentiated model representation, they will be treated separately in the REMix-OptiMo application presented in Chapter 5. For this reason, throughout this work the term DR refers to shifting or shedding of the electric loads considered in this chapter.

Figure 2.2 illustrates the key parameters describing the DR potential. For each country, DR consumer and hour of the year, potential load increase P_{free} and load reduction P_{flex} are assessed. They are dependent on the parameters $s_{reduction}$ and $s_{increase}$, which reflect that only a share of the regular load or unused capacity might be available for load reduction or increase, respectively.³ The load shedding potential is given by the reducible load P_{flex} of the corresponding consumers. In case of load shifting, every load increase is followed by a decrease due and vice versa. Consequently, both load increase and decrease potential have a limiting effect on delaying or advancing of the operation of processes or devices. If demand is delayed to a later point in time, for example, it must be assured that the shifted load is smaller than P_{flex} and the balanced load smaller than P_{free} . Flexible loads are calculated

³In the assessment of the theoretical potential, $s_{reduction}$ and $s_{increase}$ are mostly set to one, as unlimited availability of DR consumer flexibility is assumed. Lower values are applied in the REMix-OptiMo application described in Chapter 5.

Table 2.1 Electricity consumers suited for DR participation. Action, duration, shifting time, upper limit, temperature and time dependencies for the potential DR appliances.

Process/Appliance	DR Action	t_{shift} h	$t_{interf.}$ h	n_{year} 1/a	$d(t)$	$d(\vartheta)$	Ref.
Energy-intensive Industries							
Electrolytic primary aluminum	Shedding	∞^a	4	40	No	No	[110]
Electrolytic copper refinement	Shedding	∞	4	40	No	No	[110]
Electrolytic zinc production	Shedding	∞	4	40	No	No	[110]
Electric arc steel-making	Shedding	∞	4	40	No	No	[110]
Chloralkali process	Shedding	∞	4	40	No	No	[110]
Cement mills	Shifting	24	3	365	Season, Hour	No	[110]
Mechanical wood pulp process	Shifting	24	3	365	No	No	[110]
Recycling paper processing	Shifting	24	3	365	No	No	[110]
Paper machines	Shifting	24	3	365	No	No	[110]
Calcium carbide production	Shifting	24	3	365	No	No	[85]
Cryogenic air liquefaction	Shifting	24	3	365	No	No	[110]
Industrial Cross-sectional Technologies							
Cooling in food industry	Shifting	24	2	1095	Season, Hour	No	[110]
Building Ventilation	Shifting	2	1	1095	Day	No	[110]
Commercial Sector							
Cooling in food retailing	Shifting	2	1	1095	Season, Hour	No	[177]
Cold storage	Shifting	2	2	1095	Season, Hour	No	[177]
Cooling in hotels/restaurants	Shifting	2	2	1095	Season, Hour	No	[177]
Ventilation	Shifting	2	1	1095	Day, Hour	No	[177]
Air conditioning	Shifting	2	1	1095	Hour	Yes	[177]
Storage water heater	Shifting	12	12	1095	Hour	Yes	[177]
Electric storage heater	Shifting	12	12	1095	Hour	Yes	[177]
Pumps in water supply	Shifting	2	2	1095	Hour	No	[121]
Waste water treatment	Shifting	2	2	1095	No	No	[88]
Residential Sector							
Freezer/Refrigerator	Shifting	2	1	1095	Season, Hour	No	[83, 177]
Washing Equipment ^b	Shifting	6	∞^c	∞	Season, Day, Hour	No	[110, 172]
Air conditioning	Shifting	2	1	1095	Hour	Yes	[178]
Storage water heater	Shifting	12	12	1095	Hour	Yes	[177]
Heat circulation pump	Shifting	2	1	1095	Hour	Yes	[177]
Electric storage heater	Shifting	12	12	1095	Hour	Yes	[177]

^a In the case of load shedding, the shifting time is infinite.

^b Includes machines, Tumble Drier and Dish washer.

^c Given that in every hour different devices are switched on, there is no general limit in duration and frequency of DR.

from characteristic load profiles and annual electricity demands. The latter are obtained from statistics or estimated based on industrial production capacities and equipment rates of domestic appliances. At this stage, it is assumed that shiftable loads can be both advanced or delayed. For restrictions related to the DR impact on consumer convenience, this assumption will be dropped in Chapter 5.

Power demand flexibility can be compared to a functional energy storage with limited storage period. Its charging capacity is determined by the flexible load, its reservoir capacity by the maximum duration of DR interventions $t_{interfere}$, and its maximum storage period by

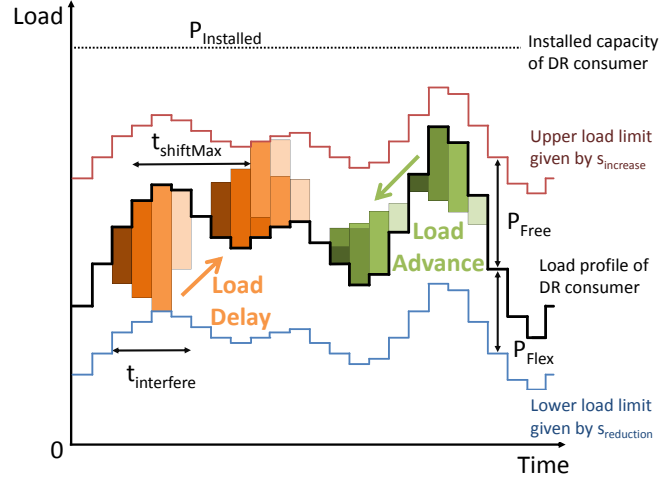


Figure 2.2 Parameters describing the DR application. $t_{interfere}$ limits the duration of DR interventions, $t_{shiftMax}$ the time between shifting and balancing of load. $s_{reduction}$ and $s_{increase}$ define consumer-specific load shares available for DR.

the shifting time $t_{shiftMax}$. The shifting time defines the maximum duration until load that has been advanced or delayed needs to be balanced again, whereas the intervention time reflects a limit in duration of changes in the normal demand pattern. Taking into account an annual limit in number of DR interventions $n_{yearLimit}$, the storable energy per year can be calculated. Parameters limiting DR are typically depending on process cycles, physical storage capacities for intermediate products or the thermal capacity of heated/cooled goods or rooms. The assumed values for interference and shift times, as well as frequency of DR events are summarized in Table 2.1.

2.3 Load Profiles of Demand Response Consumers

In order to analyze the temporal variability of the DR potential, exemplary load profiles are taken into account. As no own measurements have been performed, metered data and information about typical demand pattern available in literature are used. The hourly share $d_{DR}(t, \vartheta)$ in annual electricity demand is evaluated separately for all consumers suitable for DR. Depending on energy usage, load profiles are assumed to follow characteristic periodic seasonal, weekly and daily profiles. For technologies providing heat or cold, hourly demands are further correlated to outside temperature. Whether the electricity demand is assumed to depend on time t or ambient temperature ϑ is indicated in Table 2.1 for each DR consumer. Energy-intensive production processes are typically running at very high capacity utilization levels [142]. For this reason, a constant load is applied during all hours of the year. Only exception is the cement industry where utilization ranges between 40% and 100% [142, 192]. In addition to winter times – when construction activities are typically reduced – production is also lowered in the daytime on workdays. It is assumed that utilization in winter is by 20% lower than in summer, and in the daytime on workdays at all seasons reduced to two thirds of its night load. For industrial ventilation energy demand, a weekend decline of 40%

(Saturday) and 50% (Sunday) is assumed; commercial ventilation is furthermore reduced by 50% at night-time. The electricity demand of cooling appliances in private homes, retailing, hotels and restaurants is estimated to be by 10% lower in winter times than in summer; it additionally declines by 20% at night, given that the frequency of user interventions tends to go down. Based on metered data presented in [146], cold storages and industrial cooling are assumed to have lower demands on Saturdays (-5%), Sundays (-10%) and during peak network load hours in the morning (-50%). Pumps in the fresh water supply are also typically running during off-peak hours at night; here it is assumed that load is reduced by two thirds in the daytime. The operation of washing machines, tumble dryers and dish washers is mainly driven by the daily routine of its users; Prior [148] provides measured hourly usage profiles for different weekdays and seasons, which are used here. All periodical load profiles are summarized in Table A.1 to A.3 in Appendix A.

The energy demand of space and water heating, as well as air conditioning is strongly correlated to outside temperature. All technologies with temperature-dependent demand are assumed to follow the country-specific heating and cooling profiles obtained using the methodology introduced in Section 3.3 of this work.

2.4 Quantification of Flexible Loads

2.4.1 Industrial Demand Response Potentials

Energy-intensive Processes

DR potentials in energy-intensive industries are estimated based on production capacities A_{year} and specific energy demands W_{spec} found in literature and statistics. Annual electricity demands W_{year} and installed electrical capacities P_{maxCap} of each DR process I are calculated according to Eq. 2.1 and 2.2, taking into account the capacity utilization level s_{util} , total number of hours of the year and revision outages $f_{revision}$. Most industrial processes are operated at utilization levels below 100%; the actual production is consequently lower than the maximum production capacity. It is assumed that the production capacity reflects the quantity that can be manufactured if the unit is running at full load at all times except for its annual revision.

$$W_{year}^I = A_{year}^I \cdot W_{spec}^I \cdot s_{util}^I \quad (2.1)$$

$$P_{maxCap}^I = \frac{W_{year}^I}{8760h \cdot (1 - f_{revision}^I) \cdot s_{util}^I} \quad (2.2)$$

The potential load reduction $P_{flex}(t)$ in each hour is given by the difference between current load and minimum load of the process (see Eq. 2.3). Its value changes during the year according to the hourly demand share $d(t)$. The minimum process load is defined relative to the installed electrical capacity and given by parameter s_{min} . The potential load increase $P_{free}(t)$ is calculated from the difference between maximum load and current load, which is

at least temporarily greater than zero for all processes operated at less than 100% utilization. This difference is multiplied with parameter $s_{increase}$, reflecting the free production capacity share available for DR (see Eq. 2.4). Table 2.2 summarizes the assumed parameter values of all DR processes.

$$P_{flex}^I(t) = \underbrace{d^I(t) \cdot W_{year}^I}_{\text{Load in hour t}} - \underbrace{P_{maxCap}^I \cdot s_{min}^I}_{\text{Minimum Load}} \quad (2.3)$$

$$P_{free}^I(t) = \underbrace{(P_{maxCap}^I \cdot (1 - f_{revision}^I))}_{\text{Maximum Load}} - \underbrace{d^I(t) \cdot W_{year}^I}_{\text{Load in hour t}} \cdot \underbrace{s_{increase}^I}_{\text{Shiftable share}} \quad (2.4)$$

Table 2.2 Parameter used for the calculation of DR potentials in energy-intensive industries.

Process	A_{year} Mt/a	W_{spec} kWh/a	$f_{revision}$ %	s_{util} %	s_{min} %	$s_{increase}$ %	References
Aluminum electrolysis	3.8	14000	5%	100%	75%	0%	[110, 142, 149, 190]
Copper electrolysis	3.1	350	5%	95%	75%	0%	[44, 110, 190]
Zinc electrolysis	2.1	3400	5%	100%	75%	0%	[44, 78, 110, 190]
Electric steel production	90	525	5%	100%	0%	0%	[142, 190, 196]
Chloralkali - membrane	6.5	2100	5%	95%	50%	0%	[56, 110, 137]
Chloralkali - mercury	4.1	3600	5%	95%	30%	0%	[56, 110, 137]
Mechanical wood defibration	19	1500	5%	80%	0%	100%	[19, 110, 142, 189]
Wastepaper processing	72	250	5%	80%	0%	100%	[19, 20, 110, 162, 189]
Paper machines	118	425	5%	90%	70%	100%	[36, 110, 189]
Cement mills	338	110	5%	80%	50%	100%	[142, 190, 191]
Calcium carbide production	0.4	3100	5%	80%	0%	100%	[23, 85]
Air separation - Oxygen	23	238	5%	80%	60%	100%	[91]
Air separation - Nitrogen	14	160	5%	80%	60%	100%	[91]
Air separation - Argon	8	224	5%	80%	60%	100%	[91]

Industrial Cross-sectional Technologies

Flexible loads in the cross-sectional technologies cooling and ventilation are evaluated based on their annual electricity demand W_{year} . These demands are estimated using data from [51, 150, 179]. Dividing W_{year} by the number of full load hours n_{FLH} , the installed capacity is obtained (see Eq. 2.5). In contrast to energy-intensive processes, no revision outage is considered.

$$P_{maxCap}^I = \frac{W_{year}^I}{n_{FLH}^I} \quad (2.5)$$

In the assessment of potential load reduction and increase, fixed shares in current load $s_{reduction}$ and unused capacity $s_{increase}$ available for DR are assumed. They allow for the calculation of potential load reduction and increase according to Eq. 2.6 and 2.7. The upper limit of the latter is set by the installed capacity. Estimated energy demands, utilization levels and DR

shares of the industrial cross-sectional technologies are summarized in Table 2.3.

$$P_{flex}^I(t, \vartheta) = \underbrace{d^I(t, \vartheta) \cdot W_{year}^I}_{\text{Load in hour t}} \cdot \underbrace{s_{reduction}^I}_{\text{Shiftable share}} \quad (2.6)$$

$$P_{free}^I(t, \vartheta) = \underbrace{(P_{maxCap}^I - d^I(t, \vartheta) \cdot W_{year}^I)}_{\text{Unused Capacity}} \cdot \underbrace{s_{increase}^I}_{\text{Shiftable share}} \quad (2.7)$$

Table 2.3 Parameter used for the calculation of DR potentials in industrial cross-sectional technologies.

Process	W_{year} TWh/a	n_{FLH} h/a	$s_{reduction}$ %	$s_{increase}$ %	References
Cooling in food industry	31	5,840	50%	90%	[110, 150, 176, 179]
Building Ventilation	12	7,008	50%	0%	[51, 110, 150, 176, 179]

2.4.2 Flexible Loads in the Commercial Sector

Commercial sector DR potentials are available in the supply of cold, heat, water and ventilation, as well as in waste water treatment. Flexible loads in these applications are calculated based on their annual energy consumptions W_{year} . In the absence of country-specific data, they are approximated by multiplying the commercial sector demand W_{com} from [61, 100, 101] with average demand shares s_{com} of the relevant uses (see Eq. 2.8). According to survey data published in [17], 19.7% of the 2007 commercial sector electricity consumption in EU-27 countries was used for the supply of space heat and hot water, 12.6% for ventilation, 5.9% for pumps, 8.7% for cooling appliances and 2.9% for air conditioning. All other uses are not relevant to DR. With exception of space heating and air conditioning, which are assumed to depend on outside temperature, these shares are applied to all European countries. Pursuant to values estimated for Germany in [179], the electricity demand of cooling appliances is subdivided into food retailing (75%), cold storages (10%) and hotels/restaurants (15%).

$$W_{year}^I = W_{com} \cdot s_{com}^I \quad (2.8)$$

The air conditioning share in the sectoral demand s_{demand}^{AC} is approximated using long-term average cooling degree days (CDD) of each country [12]. It ranges between 0.5% in northern countries to 12% on the Mediterranean islands (see Table 2.4 and Table A.6 in Appendix A). These values rely on shares available for a number of countries on the one hand and the overall energy demand of air conditioning on the other. In the assessment of air conditioner and residential heat circulation pump full load hours, in addition to heating degree days (HDD) and CDDs, demand profiles for heat and cold are taken into account. Their calculation is described in Section 3.3. It is assumed that whenever the cooling demand surpasses 60% of

its peak value, the overall air conditioner park is running at the maximum load of 75% of its installed capacity. For lower demands, capacity utilization reaches 1.25-times the ratio between current and peak load. Resulting full load hours range between 136 in Estonia and 991 in Cyprus, with a European average of 467 hours (see Table A.6 in Appendix A). In countries without CDD, it is set to 100 hours/year.

Table 2.4 Air conditioning (AC) share in commercial electricity demand.

Annual number of CDD	s_{demand}^{AC}
<100	0.5%
<200	1.0%
<300	2.0%
<400	3.0%
<500	4.0%
<600	5.5%
<700	7.0%
<800	8.5%
<1000	10.0%
≥ 1000	12.0%

Annual full load hours (FLH) of hot water boilers n_{FLH}^{HW} and storage heaters n_{FLH}^{SH} are estimated for each country based on long-term average HDD collected by [59] (see Table A.6 in Appendix A). It is assumed, that the utilization is higher in colder climates according to the values in Table 2.5.

Table 2.5 Assumed annual full load hours for storage water heater (WH) and storage heater (SH).

Annual number of HDD	n_{FLH}^{HW} h/a	n_{FLH}^{SH} h/a
≤ 1000	175	200
≤ 2000	200	350
≤ 3000	225	500
≤ 4000	250	650
> 4000	275	800

With the annual electricity demands and FLH summarized in Table 2.5, the installed capacity is calculated according to Eq. 2.5. No procedural limitations of load shifting are considered in the commercial sector. Load shares $s_{reduction}$ and $s_{increase}$ available for DR are thus set to 100% of current load and unused capacity, respectively. Only exception is the waste water treatment, where pursuant to [88, 121] values of $s_{reduction}=20\%$ and $s_{increase}=50\%$ are applied. Based on annual demand, installed capacity and hourly load profiles, possible load reduction and increase are calculated according to Eq. 2.6 and 2.7, respectively.

2.4.3 Flexible Loads in the Residential Sector

Residential load shifting is evaluated for heating, cooling, air conditioning and washing equipment. The latter comprises washing machines, tumble dryers and dish washers. In

Table 2.6 Parameter used for the calculation of commercial sector DR potentials.

Process	s_{com} %	n_{FLH} h/a	References
Cooling in food retailing	6.5%	5840	[17, 110, 176, 179]
Cold storages	0.9%	5000	[17, 110, 176, 179]
Cooling hotels/restaurants	1.3%	5000	[17, 110, 176, 179]
Ventilation	12.6%	4380	[17, 110, 150]
Air conditioning	see Table A.6		[17, 176]
Storage water heater	1.5%	see Table A.6	[17, 164]
Storage heater	country values ^a		own assumptions
Pumps in water supply	3%	4380	[38, 120]
Waste water treatment	3%	5694	[88, 121]

^a Due to limited data availability only considered in Germany ($s_{com}=2\%$, $n_{FLH}=650$ h/a) and France ($s_{com}=5\%$, $n_{FLH}=500$ h/a).

contrast to the other sectors, residential DR loads are quantified in a bottom-up approach. Household numbers n_{HH} and country-specific equipment rates f_{eq} of relevant devices are obtained from [36, 51, 72, 97, 123, 170], or approximated using available data (see Table A.6 in Appendix A). Multiplying the resulting unit number with the specific capacity P_{unit} and energy consumption W_{unit} , country sums are calculated for each appliance type according to Eq. 2.9 and 2.10. Based on [17, 134], an annual refrigerator and freezer unit demand of 350 kWh is applied. For washing equipment, average power demands during use $\bar{P}_{cycle}$, as well as frequency n_{cycle} and duration of use Δt_{cycle} are taken into account (see Table 2.7). Relying on measured consumption data from [70, 165], annual demands are calculated (Eq. 2.11).

$$P_{maxCap}^I = n_{HH} \cdot f_{eq}^I \cdot P_{unit}^I \quad (2.9)$$

$$W_{year}^I = n_{HH} \cdot f_{eq}^I \cdot W_{unit}^I \quad (2.10)$$

$$W_{unit}^I = \bar{P}_{cycle}^I \cdot \Delta t_{cycle}^I \cdot n_{cycle}^I \quad (2.11)$$

Table 2.7 Parameter used for the calculation of residential sector DR potentials.

Device	W_{unit} kWh/a	$\bar{P}_{cycle}$ kW	Δt_{cycle} h	n_{cycle} 1/a	References
Washing machines	219	0.75	2	146	[51, 165]
Laundry drier	306	1.5	2	102	[51, 165]
Dish washer	270	0.65	2	208	[51, 70, 165]

In the calculation of annual space heating, hot water generation and air conditioning electricity consumption, unit capacities P_{unit} are multiplied with estimated FLH n_{FLH} (Eq. 2.12).

$$W_{unit}^I = P_{unit}^I \cdot n_{FLH}^I \quad (2.12)$$

Average capacities per dwelling are assumed with 1.65 kW for air conditioners, 2 kW for electric storage water heaters, 100 W for heat circulation pumps and 14 kW for electric storage heaters [17, 170, 176, 178, 195]. Country-specific air conditioner, water heater and storage heater FLH are obtained as described in Section 2.4.2. In the calculation of heat circulation pump FLH, an approach similar to that used for air conditioners is chosen. According to [176, 178], average annual operation time of heat circulation pumps in Europe is around 5000-6000 hours. This implies that not all pumps are switched off in summer. Here, a base load of 25% of the installed capacity is assumed for all countries. This base load is assigned to all hours with a demand below 15% of the annual peak. For higher demands, the load is assumed to be 1.67-times the ratio between current and peak load. If this ratio is higher than 0.6, circulation pumps are assumed to run at full load. It is assumed that all devices are available for DR; $s_{reduction}$ and $s_{increase}$ are thus set to 100%. Hourly load increase and decrease are then obtained using Eq. 2.6 and 2.7.

2.5 Extrapolation of Flexible Loads

DR potentials are also quantified for the scenario years 2020, 2030 and 2050. Therefore, the parameters defining flexible loads are extrapolated. They include industrial production output and specific demands, commercial sector electricity demand structure, as well as residential appliance energy consumption and equipment rates. Extrapolations are mostly based on statistics of recent developments. No changes in periodic load profile components are taken into consideration. However, outside temperature dependent profiles are affected by the assumed changes in heating and cooling limit temperature, described in Section 3.3.

Table 2.8 summarizes the applied changes in industrial production output ΔA_{year} , as well as output specific electricity demands ΔW_{spec} . Changes in overall production have been derived from an analysis of global and European industry statistics. All output reduction and increase is equally distributed over all current production sites, since shut-downs and new installation of factories cannot be anticipated. Constant changes in output are assumed, cyclical economic upturns and downturns are neglected. Given the high share of energy in overall production cost, efficiency is of high importance in the energy-intensive industries. Consequently, efficiency improvements are considered for all processes. The assumptions are based on past efficiency gains, as well as current best available technologies benchmarks. With no historical time series data available, energy demands of industrial cooling and ventilation are assumed to remain constant.

Future commercial sector DR potentials are influenced by the development of the overall sectoral demand on the one hand, and the demand shares of the relevant technologies on the other. According to the framework scenario used in the model application introduced in Section 5.2.2 of this work, the commercial sector final energy demand for electricity in the considered countries is assumed to increase by around one third on average until 2050. A peak value is assumed to be reached in 2040, afterward the trend is reversed. Country values

Table 2.8 Assumptions of future production capacities and specific energy demands of industrial DR consumers.

Process	ΔA_{year} %/a	ΔW_{spec} %/a
Electrolytic primary aluminum	-0.5%/a	-0.5%/a
Electrolytic copper refinement	± 0	-0.3%/a
Electrolytic zinc production	± 0	-0.3%/a
Electric arc steelmaking	+0.5%/a ^a	-0.5%/a
Chloralkali process	-0.2%/a ^b	-0.5%/a
Cement mills	± 0	-0.5%/a
Mechanical wood pulp process	± 0	-0.3%/a
Recycling paper processing	+1.9%/a ^c	± 0 ^d
Paper machines	+1.1%/a ^e	-0.3%/a
Calcium carbide production	-1%/a	-0.3%/a
Cryogenic air liquefaction	+0.5%/a	-0.3%/a

^a Additional to the growth of overall European production, it is considered that the share of electric steel increases linearly from 39% in 2005 to 75% in 2050.

^b It is assumed that all European Chlorine production is converted to the more efficient and less polluting membrane cell method until the year 2030.

^c Increase by 3%/a until 2020, and then by 1.5%/a.

^d Efficiency gains are assumed to be balanced by a higher energy demand of multiple recycling processes.

^e Increase by 1.5%/a until 2020, and then by 1%/a.

in 2050 range from 66% to 300% of the demand measured in 2010. Table A.5 in Appendix A provides all country-specific demand data. The consumption of cooled and frozen goods has increased in the past [39]. This trend is assumed to continue, causing an increase of the cooling share in commercial demand from 8.7% in 2010 to 10.0% in 2050. Also the ventilation share in sectoral demand is assumed to grow slightly, from 12.6% in 2010 to 13.0% in 2050. A steeper increase in demand is applied to air conditioning electricity demand: its share is assumed to reach 150% of the 2010 value in all countries. The electricity demand of electric water heating is assumed to decrease by 40% until 2050, due to fuel change and efficiency increase. The reduction is however compensated by a higher share of water heaters equipped with a storage – a doubling from 30% in 2010 to 60% in 2050 is assumed [107]. The 2010 electric storage space heater shares of 5% in France and 2% in Germany are assumed to decrease by 0.75% and 0.5% per decade, respectively. In Germany, the technology is completely phased out by 2040, in France, the decrease accelerates after 2030 and diminishes to a demand share of 1% in 2050. Also, the shares of water supply and waste water treatment are assumed to go down in the future – from 3.0% in 2010 to 2.5% in 2050. If not noted differently, all changes in demand shares are linearly extrapolated.

Residential DR potentials are strongly correlated to appliance equipment rates. In recent years, equipment rates of cooling and washing appliances have been stagnating in central and northern European countries [51]. Here, it is assumed that this level of saturation is

reached all over the continent until the year 2050. The equipment rates of residential storage space heaters are assumed to diminish in all countries to 1% by 2050. Electric storage water heating usage is also decreasing, but to minor extent. In contrast, equipment rates of heat circulation pumps are expected to rise. Country-specific values for the year 2050 can be obtained from Table A.6 in Appendix A. All equipment rates are assumed to change linearly over 40 years. Duration and frequency of washing equipment usage are kept constant for all scenario years, their average load is however assumed to decrease, such as the unit capacities of air conditioners and heat circulation pump and the annual energy consumption of cooling appliances (see Table 2.9). Future reductions in appliance energy demand are estimated based on [193].

Table 2.9 Assumed future domestic appliance characteristics.

Device	Parameter	unit	2010	2020	2030	2050
Refrigerator/Freezer	W_{unit}	kWh/a	350	250	175	100
Washing machines	$\bar{P}_{cycle}$	kW	0.75	0.55	0.40	0.30
Laundry drier	$\bar{P}_{cycle}$	kW	1.50	1.25	1.05	0.70
Dish washer	$\bar{P}_{cycle}$	kW	0.65	0.50	0.40	0.30
Air conditioner	P_{unit}	kW	1.65	1.50	1.35	1.10
Heat circulation pumps	P_{unit}	W	100	80	60	20

2.6 Geographic Allocation of Flexible Loads

The spatial distribution of DR potentials is assessed using high resolution GIS data and industrial production statistics. Population density and land use data allows for the allocation of flexible loads to grid cells of 0.0083° side length. At the equator, this corresponds to approximately one kilometer, in the investigation area the cell area ranges from 0.27 to 0.74 km^2 .

In energy-intensive industries, an identification of individual production plants is pursued. Geographic coordinates of facilities are determined, allowing for a detailed spatial allocation of flexible loads. Based on [190] and different industry associations, the production sites of aluminum, electric steel, copper, zinc, chlorine, calcium carbide and partially also cement industry are identified. The exact assignment of production capacities to factories cannot in all cases be extracted from statistics and are estimated where necessary. The remaining industrial DR potentials are allocated according to employment statistics of Eurostat, which are available for dedicated sectors and on NUTS-3 statistical region scale [60, 62].⁴

Given the high number of commercial sector consumers, a geographic allocation cannot account for individual sites. Instead, high resolution GIS data containing residential and commercial areas is used. Corine Land Cover provides European land use data in a spatial

⁴The initials NUTS are an abbreviation for 'Nomenclature of Statistical Territorial Units'. It is a hierarchical system for dividing up the economic territory of the European Union into smaller units, usually administrative districts within member countries. NUTS-2 regions are typically states, NUTS-3 regions counties. For details, see [63].

resolution of 100 meters [45]. It assigns each grid cell to one of 44 land use classes including settlement areas, agricultural use, forest and waterbodies. Here, only the categories continuous urban fabric, discontinuous urban fabric and industrial or commercial units are taken into account. The commercial sector DR potentials are equally distributed over all grid cells of these classes.

Residential DR potentials are allocated according to the population distribution. A population density map is provided by the Joint Research Centre (JRC) [76]. The map is scaled with regional Eurostat population statistics and prospects [61] containing data for all scenario years. With this approach, changes in the overall number of inhabitants only affect the population density in communities and not their spatial extension and distribution. Within each region, the population is allocated according to the JRC data.

2.7 Identified Theoretical Demand Response Potentials

2.7.1 Flexible Loads by Technology, Demand Sector and Country

Relying on the methodology and data presented, substantial amounts of flexible loads are identified. Aggregated over all countries and consumers, the hourly average load reduction potential through shedding and shifting adds up to 101 GW. With the assumed hourly load profiles, in the course of the year its value varies from 64 GW to 161 GW. Highest potentials are found in the residential sector, lowest in industry: annual averages reach around 21 GW in industry, 30 GW in commercial sector and 49 GW in residential sector. In industry, the reduction potential is almost constant throughout the whole year, whereas it ranges between 19 GW and 74 GW in commercial and 20 GW and 106 GW in residential sector.

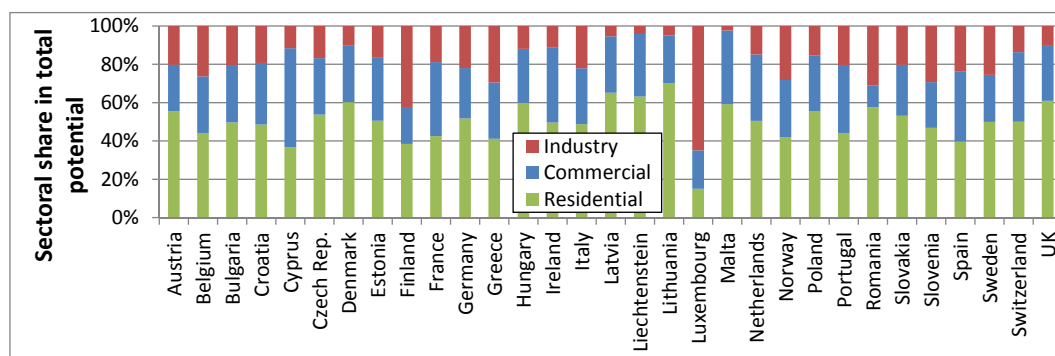


Figure 2.3 Sectoral shares in average load reduction potential by country.

The overall free load fluctuates between 742 GW and 839 GW, with an average of 803 GW. These very high values are linked to the overall installed electric capacity of the processes and appliances considered. This is particularly important in the residential sector, where cooling, heating, air conditioning and washing equipment account for theoretical load increase potentials of up to 681 GW. In comparison, free loads are much lower in the other demand sectors; in commercial sector they are found to vary between 102 GW and 156 GW, in industry between 2 GW and 8 GW, with average values of 145 GW and 5 GW, respectively.

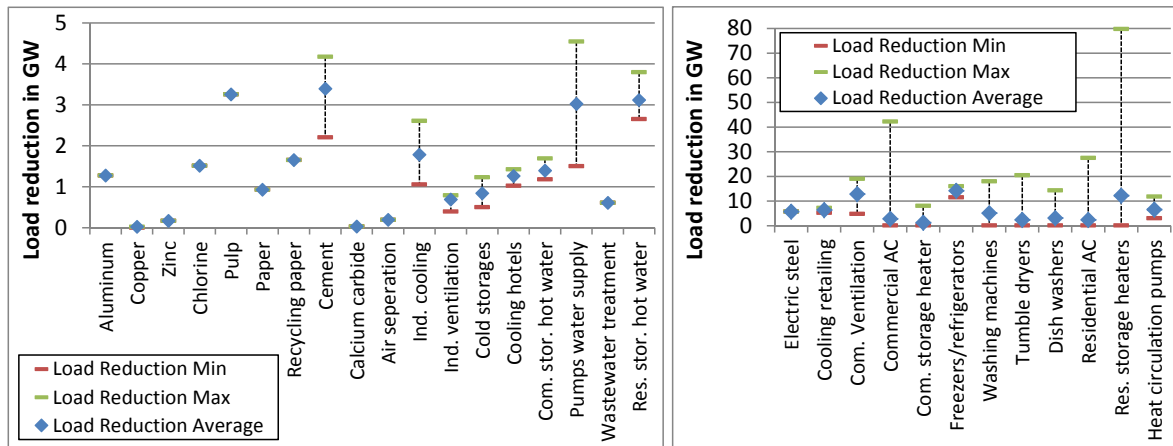


Figure 2.4 Average load reduction potential by technology. Note that left and right graph have different y-axis scale.

The share each demand sector holds in the yearly average of flexible loads shows significant differences between countries (see Figure 2.3). The residential share ranges from 15% in Luxembourg to 70% in Lithuania, whereas the commercial share varies from 11% in Romania to 52% in Cyprus and the industrial share from 2% in Malta to 65% in Luxembourg. Free loads are in all countries dominated by residential appliances: they provide over 80% of the overall potential, compared to 18% in commercial sector and 1% in industry.

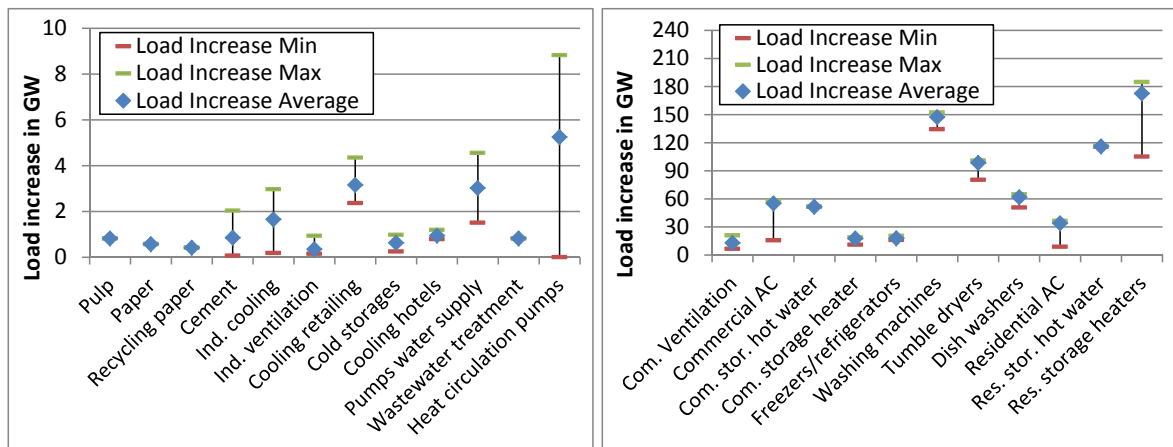


Figure 2.5 Average load increase potential by technology. Note that left and right graph have different y-axis scale.

Flexible loads are distributed very unevenly over the 30 processes and appliances analyzed. Taking into account annual averages, highest contributions to the overall reducible load are found in pulp and paper (6%) and steel (6%) industry, as well as residential space heating (19%), commercial ventilation (13%) and refrigerators/freezers in retailing (6%) and private households (14%). Industrial potentials furthermore include considerable loads of cement, aluminum electrolysis, Chloralkali process and cross-sectional technologies. Minor load reductions can be made available in the copper, zinc, calcium carbide and air liquefaction industry. The potential load reduction in commercial sector load is dominated by cooling and HVAC appliances, with smaller contributions from public water supply and treatment.

In residential sector, more than one third of the load reduction can be realized by shifting electricity consumption of storage heaters and heat circulation pumps. Cooling and washing equipment provide more than 20% each; lower but still substantial potentials are found for air conditioning and electric water heating. In contrast to the diversified distribution of reducible loads, free loads can almost completely be attributed to electric space heating (24%), storage water boilers (21%) and washing equipment (38%). Average, minimum and maximum load reduction and increase potentials of the dominating technologies are displayed in Figure 2.4 and Figure 2.5, respectively. Country values for all technologies are listed in Table A.9 and Table A.10 in Appendix A.

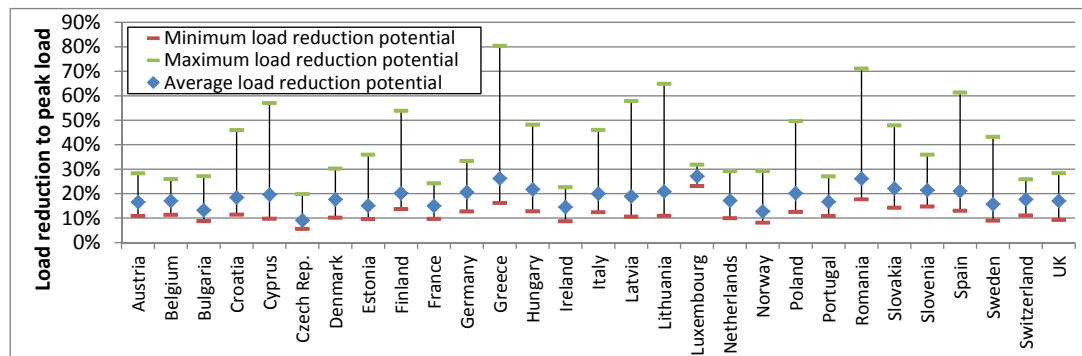


Figure 2.6 Minimum, maximum and average load reduction potential relative to the annual peak load, subdivided by country.

In order to assess the potential contribution of DR to power system stability, load reduction and increase are related to the annual peak load in each country. Figure 2.6 shows the ratios of annual minimum, maximum and average load reduction potential to the 2010 peak load. In most EU countries, the average reduction equals between 10% and 25% of peak load. A lower value is found in the Czech Republic, higher in Greece, Luxembourg and Romania. The ratio of maximum load reduction potential to peak load reaches very high values in countries with a widespread use of the electric space and water heating or air conditioning systems, which are assumed to be available for load shifting. In most countries, the potential load increase exceeds the 2010 peak load in at least one hour of the year (see Figure 2.7). This again results from the high overall capacity of residential appliances.

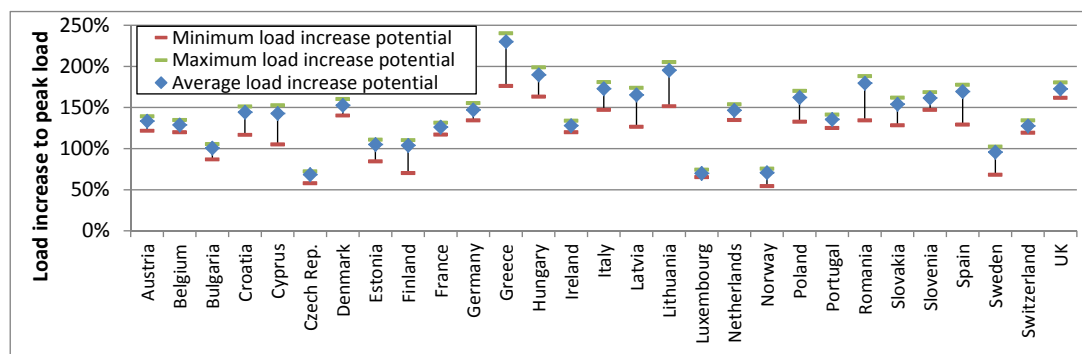


Figure 2.7 Minimum, maximum and average load increase potential relative to the annual peak load, subdivided by country.

2.7.2 Temporal Availability of Flexible Loads

The substantial difference between minimum and maximum values of some flexible loads displayed in Figure 2.4 and 2.5 indicates a strong temporal variation in the availability of DR potentials. They are particularly pronounced for space heating, ventilation and air conditioning, as well as residential washing equipment. Figure 2.8 illustrates the development of the daily load reduction average during one year for five representative technologies. It reflects the load profiles assumed in Section 2.3. With no load changes considered, DR potentials in energy-intensive industries – here the aluminum electrolysis is shown exemplary – are constantly available throughout the whole year. Also the power demand of retail cooling shows only minor variations. In contrast, shiftable loads in the provision of air conditioning and space heating are strongly influenced by outside temperature and have annual load curves contrasting each other. Particularly in air conditioning demand, where short-term reactions to temperature occur, high peaks in single days and hours can be observed. The variations in the load reduction potential profile of commercial ventilation are directly correlated to the assumed weekend demand decline.

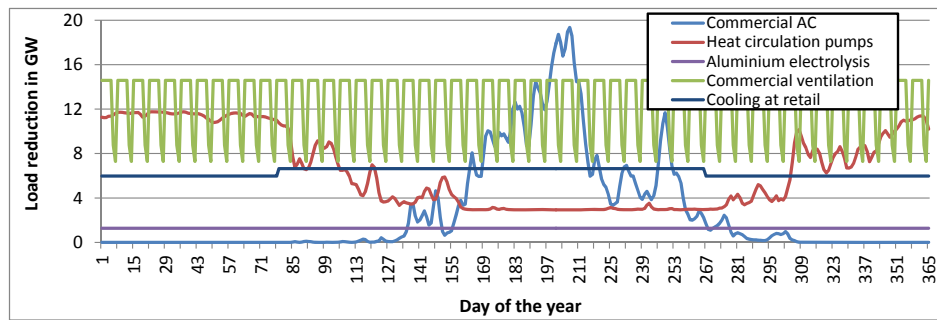


Figure 2.8 Daily load reduction average during one year for five representative DR loads.

Due to the high air conditioner share, the annual maximum of the overall theoretical load reduction potential is reached in summer times. In peak hours, the potential can be twice as high as on average. Hours with lowest reduction potential are found in the transition period between winter and summer, when both air conditioner and heat circulation use is low. Average daily reduction potentials are found to be lower on weekends than on working days. This results from reduced industrial and commercial demand.

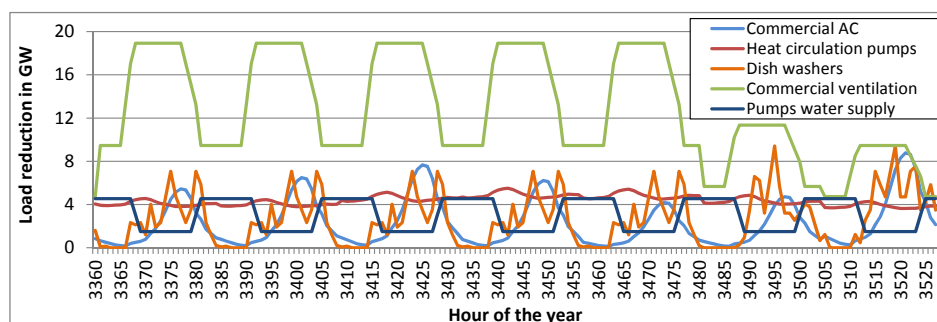


Figure 2.9 Daily load reduction average during one week for five representative DR loads.

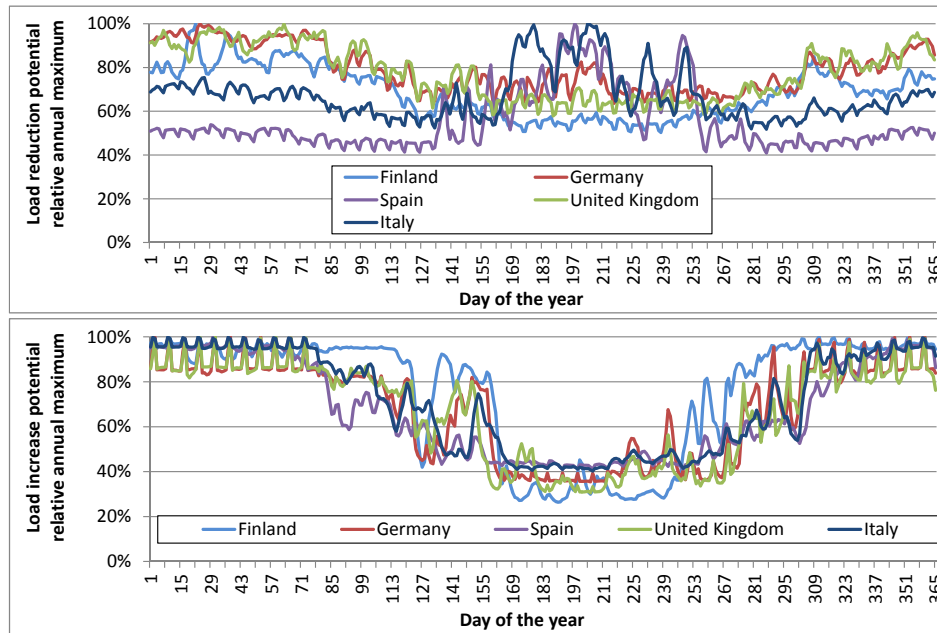


Figure 2.10 Daily load reduction (above) and increase (below) average during one year for five selected countries relative to the annual maximum.

The flexible load is varying considerably also within each day. This is illustrated for a selection of consumers and a representative spring week in Figure 2.9. Again, the DR potential provided by industry and cooling appliances is fairly constant throughout the day. The same applies to residential heat circulation pumps. In contrast to that, the DR availability of washing equipment, air conditioners and fans is heavily fluctuating. Due to the typical utilization cycles driven by daylight, working hours and temperature, potentials are mostly available during daytime. This coincides with the overall system load pattern.

The temporal availability of load flexibility arises from the composition of the overall DR potential. Differences between countries are primarily associated to the fraction of space heating and air conditioning. Figure 2.10 includes profiles for load reduction and increase in five representative European countries, normalized to the corresponding maximum potential. In northern European countries, the load reduction potential is higher in winter, whereas strong summer peaks can be observed in Spain and Italy. In Germany, where the industrial share in the potential is comparatively high, daily averages of load reduction show lowest fluctuations during the year. Also the load increase potentials are driven by electric heating demands: they are approximately by factor two higher in winter than in summer.

2.7.3 Spatial Distribution of Flexible Loads

DR potentials are concentrated to centers of population and energy intensive industry production. Figure 2.11 shows the potential load reduction density in each grid cell. Major cities and urban agglomerations can be easily identified there.

For further analysis of the spatial allocation of flexible loads, sums over each NUTS-3 statistical region are formed, and average values per km^2 and inhabitant are calculated. The

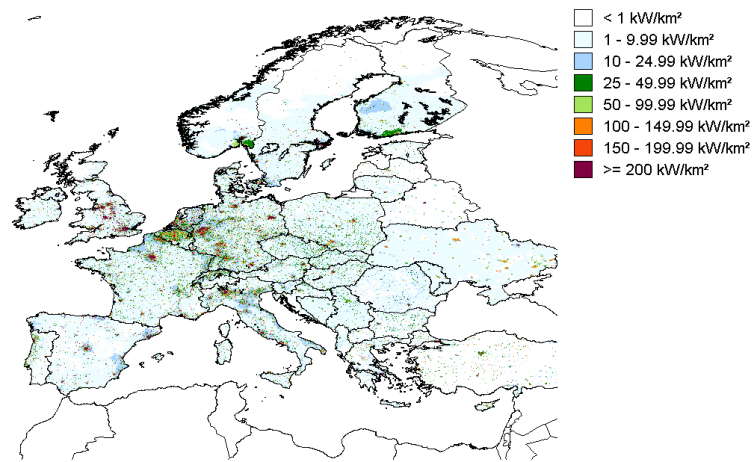
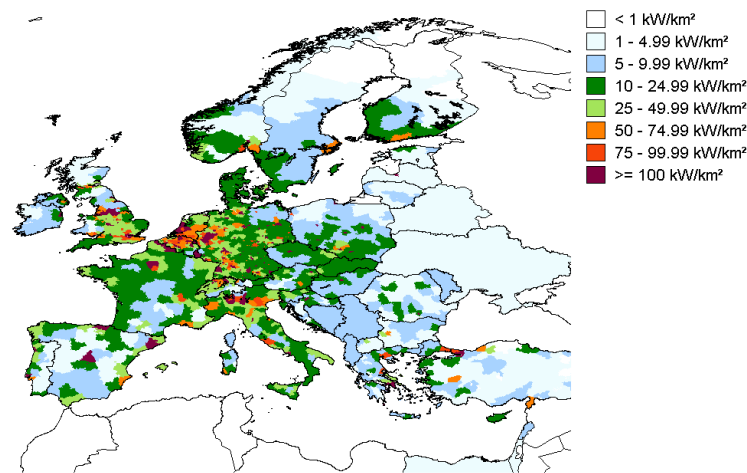
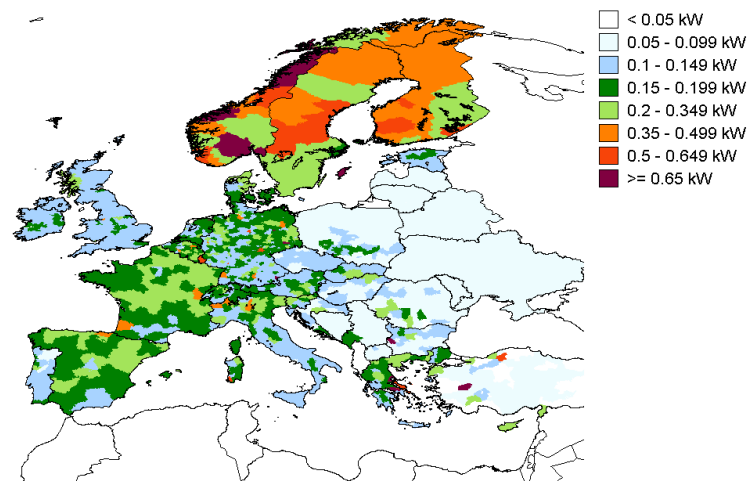
Figure 2.11 Density of the load reduction potential in kW/km².Figure 2.12 Regional density of the load reduction potential in kW/km².

Figure 2.13 Average per capita load reduction potential of each NUTS-3 region in kW.

regional density of load reduction potentials is displayed in Figure 2.12. It reaches high values not only in densely populated regions, but also those with a concentration of energy intensive energies. The highest values of more than 900 kW/km² are found in Paris, Inner London and the industrial city of Ludwigshafen am Rhein in Germany. Comparatively low densities

are present in sparsely populated areas, for example in north-eastern Germany, Scotland or northern Finland, Norway and Sweden. Taking into account population density, regions with high industrial and commercial DR potentials can be identified. In Figure 2.13, the per capita load reduction is shown for each region. Comparatively high values are found for example in the French region of Aquitaine, the Norwegian coast and Luxembourg.

Given that most increase potential through advancing load is provided by residential appliances, the geographic distribution is very similar to the population density.

2.7.4 Prospective Development of Demand Response Potentials

With the assumed future energy demands of DR consumers (see Section 2.5), a slight decrease of flexible loads until the year 2050 is obtained. Until 2020, the overall average load reduction potential increases by 2%, and then starts decreasing to 101% and 90% of the 2010 value in 2030 and 2050, respectively. Trends are different for the DR appliances and processes considered. Flexible loads are strongly increasing in paper and steel industry, as well as air conditioning, whereas they are significantly decreasing in electric space heating appliances (see upper diagram in Figure 2.14). The composition of national DR potentials determines how overall flexible load develops in the future. Due to the dominance of the steel industry in the DR potential, Luxembourg sees a steep increase in flexible load. In contrast, it is reduced by more than one fourth in countries with cold climates and comparatively high electric heating shares, including Austria, Norway and Switzerland (see lower diagram in Figure 2.14).

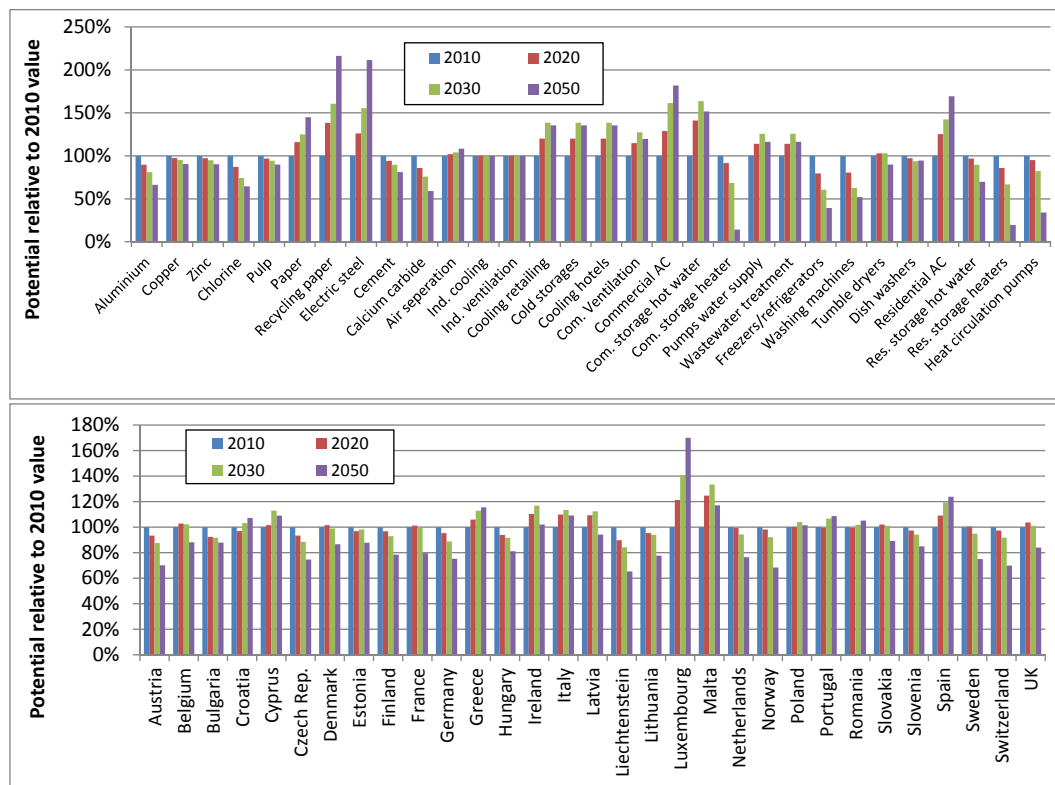


Figure 2.14 Future load reduction potential relative to 2010 values; subdivided by consumer (above) and country (below).

2.7.5 Demand Response Energy Storage Size

The load shifting potential is dominated by customers allowing only short interventions and shifting times (see Table 2.1). They include cooling processes in all sectors, air conditioning, ventilation, heat circulation pumps, fresh water supply and waste-water treatment. All these appliances can be interrupted for only one or two hours, and the reduced load typically needs to be recovered within the same time span. This limits the storage period of the functional storage provided by DR. Depending on the hour of the year, the energy that within two hours can be charged into the virtual storage by load reduction ranges from 43 GWh to 128 GWh. The temporal variation in storage capacity is correlated to the assumed load profiles of consumers participating in DR. The discharging has to begin immediately afterwards and is also limited to a duration of two hours.

Longer intervention times are found for washing equipment, as well as residential and commercial electric space and water heaters. With the assumed charging durations of up to twelve hours for electric heat production and six hours for washing equipment, the energy storage capacity is comparatively high. Due to its dependency on outside temperature and appliance usage pattern, it shows strong variations between 17 GWh and 707 GWh. Storage capacity of washing equipment load shifting can reach up to 207 GWh during daytime and goes down to zero at night. The much better storage function of washing and heating equipment comes along with shortcomings concerning acceptance and efficiency, respectively. With an assumed maximum shifting time of 24 hours, industrial DR provides medium term storage. According to the calculated load reduction potentials, between 59 GWh and 65 GWh can be stored within the applied maximum intervention time of four hours. Given that industrial DR includes load shedding, only between 25 GWh and 31 GWh of the stored demand has to be recovered within the following 24 hours.

2.8 Summary and Discussion

In this chapter, an assessment of theoretical DR potentials in Europe is presented. It includes 30 electricity consumers across all demand sectors, which can shift or shed their load for at least one hour. Special attention is given to the evaluation of temporal availability and geographic allocation of qualified consumers. The developed methodological framework can easily be adapted to other world regions or more detailed input data.

The analysis reveals substantial theoretical DR potentials in all demand sectors. By shedding or shifting, an average load reduction of around 100 GW can be achieved. This average value is equivalent to roughly one third of the minimum and one sixth of the peak load measured in the investigation area in 2010. Due to the changing load of the flexible consumers, the potentials show extensive variations during the course of the year. With the assumed demand profiles, the reducible load varies from 64 GW to 161 GW. The temporal availability of flexible loads is particularly important in residential and commercial sector, where in some hours of the year the summarized reduction potentials drop to less than 20% of their respective

annual maximum value. The annual curve of available DR potential is flatter in countries with high industrial shares. In contrast, variations are particularly pronounced in countries with great amounts of electric heating and air conditioning.

Residential and commercial load shifting are almost not limited by the available free capacity of DR appliances. Installed and unused capacities in the range of several hundred GW are available; the average load increase potential accounts for 803 GW. It is dominated by residential and commercial cooling, heating, air conditioning, ventilation and washing equipment, whereas industrial processes contribute less than 1% of the overall amount. These very high potentials of load increase could, however, only be accessed, if loads could be shifted without any temporal limitations. Given that load shifting is affected by the demand profiles of the corresponding consumers, as well as upper limits in shifting time, the overall free capacity can only be used to limited extent. Only those devices that would regularly run within the previous or following $t_{maxShift}$ hours are available in each hour. Especially residential load shifting is typically not limited by the available free capacities, but by the reducible capacities. In the evaluation of the calculated theoretical potentials, it needs to be taken into account that both load and DR potential of subsequent hours are influenced whenever a load reduction or increase is called. All shifted demand needs to be balanced within a given period of time, thus increasing or decreasing the load in one or several following hours. Potential load reduction and increase in each hour are not only correlated to the DR consumer demand profiles, but also to each other. Limitations in duration and frequency of DR interventions pose additional restrictions.

In the evaluation of the findings of this chapter it has to be considered that this assessment is limited to theoretical potentials. Restrictions in DR use resulting from the manifold technical, economic, legal and societal barriers have been disregarded completely. Additionally, the stated potentials include also those consumers that are already participating in DR programs, which might further reduce the accessible DR resources. On the other hand, the usage of on-site power generation could allow for additional grid load reductions, which are not taken into account here. The same applies for further consumers with demand flexibility not included in this assessment, as well as increased industrial demand flexibility provided by the installation of physical storage for intermediate products.

The results of this assessment rely on numerous assumptions and simplifications, affecting both the average potentials and their temporal availability throughout the year. Some of them might cause an over- or underestimation of the overall potentials, others a wrong distribution to or within the countries in the investigation area. In the absence of detailed statistics, country and consumer specific peculiarities are considered only to a minor degree. Calculated annual energy demands of flexible consumers rely on a number of assumptions with significant impact on the results. This is particularly important in the residential and commercial sector. The use of European averages in the calculation of demand shares of DR appliances in the commercial sector might relocate a certain share of the potential from one country to another. The same goes for the global assumptions made for the energy demands and usage pattern

of the residential washing and cooling appliances, which were applied to all countries in the investigation area. It has not been considered that the efficiency standard of devices varies between countries.

Industrial potentials are by large extend based on detailed production statistics. However, the assumed specific energy demands, utilization levels and minimum process loads might not apply to the same extend to all facilities. This is also the case for the annual utilization of cooling and ventilation equipment in industrial and commercial sector. Another important assumption is related to the load profiles. Given that no comprehensive database of metered load was available, exemplary load profiles found in literature were used. Consequently, neither country-specific household activity and appliance usage patterns, nor facility-specific industrial production cycles are reflected in the resulting hourly potentials. A more detailed analysis of national or regional DR potentials should rely on a broader database of metered load profiles, as well as technology and consumption characteristics.

The geographic allocation of flexible consumers provides a first approximation of the regional concentration of DR potentials. It is detailed and robust for industry, since single production sites have been identified. Also the usage of population density data for residential DR loads provides a realistic allocation. In contrast to that, the data set used for the commercial consumers represents a rough simplification of the real demand distribution.

The primary focus of this chapter is to gain an overview of the electricity consumers that might be used for DR and to provide a first estimate of its loads in Europe. Due to the large number of processes, appliances and countries considered, and the lack of country-specific consumption data, it does not reach the degree of detail of other, more focused studies. Even though they rely on various assumptions and approximations, the results of this assessment offer an indication in which regions and sectors high amounts of sheddable and shiftable loads can be accessed, and provide the ground for subsequent studies of the economic benefits of DR. Given the broad range of flexible loads identified here, it appears attractive to pursue DR programs in all consumer sectors. Whether and to what extent DR can compete with alternative balancing options will be evaluated exemplary for Germany in the REMix-OptiMo case study presented in Chapter 5. It relies on the calculated DR potentials and load profiles, and takes into account the participation of residential and commercial consumers in DR programs, as well as costs caused by shedding and shifting of loads.

Chapter 3

Heat Demand and Theoretical Cogeneration Potential in Europe

This chapter is focused on the assessment of the European heat demand and cogeneration potentials. It is subdivided to three sections: in Section 3.1, the European district heating (DH) potential is evaluated relying on a GIS-based approach. The subsequent Section 3.2 is dedicated to industrial cogeneration potentials in Europe. Dimensioning and operation of cogeneration (combined heat and power, CHP) plants are closely related to the temporal development of the heat demand during the year. For this reason, Section 3.3 provides a method for the approximation of high-resolution synthetic heating and cooling demand profiles. Based on the identified potentials, the contribution of flexible CHP operation to the balancing of fluctuations in VRE power generation will be analyzed in Chapter 5.

3.1 Quantification of District Heating Potentials

3.1.1 Introduction

Previous studies argue that there are significant possibilities of an extension of DH in most European countries, however without performing a detailed analysis [52, 194]. Germany's DH potentials have been quantified in bottom-up approaches making use of building statistics and satellite data in high spatial resolution [49, 55]. CHP potentials have been furthermore studied in national studies for the United Kingdom [106], Austria [167] and Denmark [133]. Just recently, [28] have presented a method for the quantification of European DH potentials relying on an assessment of regional heat demands and excess heat availability.

In this section, potentials for an extension of DH in Europe are evaluated.¹ Today, the share of DH in the residential and commercial space and water heating supply reaches over 40% in several countries including Denmark, Finland and Sweden [51]. It is mainly used in urban areas, but also in sparsely populated regions [71, 152]. The spectrum of DH heat sources ranges from conventional fossil or nuclear fueled power plants to biomass, solar thermal and

¹This section is based on previous publications of the author [79, 81]

geothermal energy [154]. Thermal waste treatment plants and industrial waste heat recovery can offer additional heat sources.

Even though thermal energy storage (TES) technologies can be integrated independent of the heat consumer, its usage appears particularly attractive in DH systems, given the lower relative losses of greater storage units and the lower temperature requirements in comparison to object supply and industrial process heat, respectively. DH storage systems are typically water basins or tanks, which feature comparatively simple and well-known technology, as well as low specific costs. Such storage systems are increasingly becoming an integral part of DH networks in different European countries, including Denmark, Sweden, Austria and Germany. However, they are still an exception rather than the norm. Existing DH-TES are used for the provision of back-up and peak load on the one hand, and for an optimized CHP operation, including reduced part load operation and down-regulation in times of low electricity prices, on the other [8]. In the past, low electricity spot prices have mostly occurred at night and weekends, they are however increasingly correlated to peak generation of VRE [87].

The analysis presented in this section is conducted in a spatially explicit top-down approach composed of four main steps: (1) an estimation of current and future annual space and water heating energy demand in the residential and commercial sector on country level, (2) an approximation of regional differences in specific demands, (3) a consideration of the spatial demand distribution and (4) an evaluation of the suitability to supply the demand with DH (see scheme in Figure 3.1). The analysis of DH potentials is performed for a total of 31 countries, including all 28 EU member countries, as well as Norway, Switzerland and Liechtenstein.

3.1.2 Current and Future Residential and Commercial Sector Heat Demand

The technological and economic potential for DH in a specific region is primarily defined by the overall heat demand on the one hand, and the demand density on the other. For the present analysis it is assumed that only heat demands in the residential and commercial sector can be provided by DH systems. Consequently, it is not accounted for primary and secondary sector demands. All heat demand for space heating (SH) and hot water (HW) generation is addressed, whereas process heat (PH) in the commercial sector is covered only to a limited extent. Present heat demands in residential and commercial sector are quantified for each country using detailed energy demand statistics. Its future development is then assessed with a simplified building stock model.

Current Demand

Main data source of residential and commercial energy consumption is the *Odyssee* energy indicator data base [51]. For all EU countries, as well as Norway and Switzerland, it provides historical data of final energy consumption for residential space heating, commercial space heating and residential water heating, all subdivided by fuel. It furthermore includes country

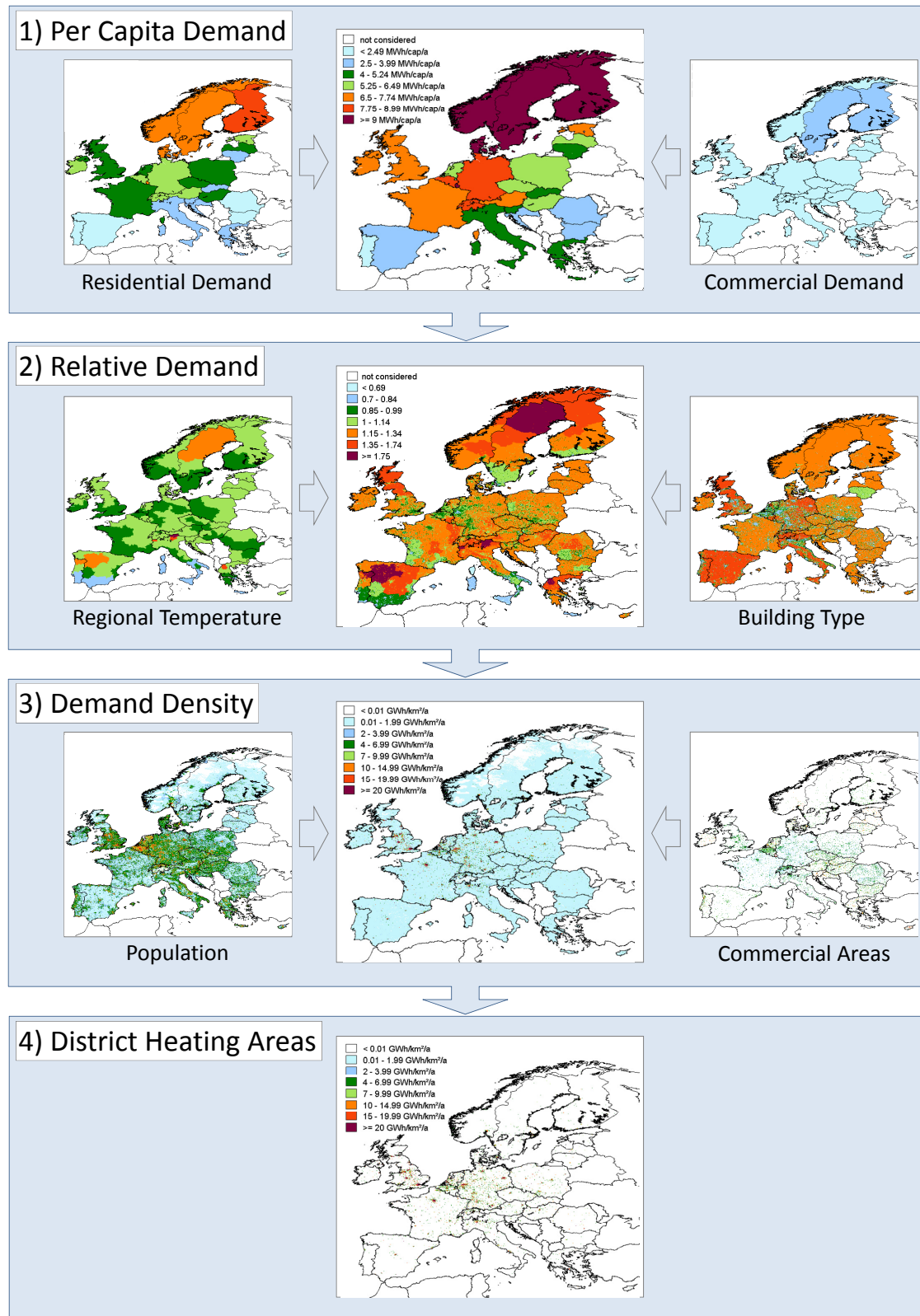


Figure 3.1 Schematic representation of the procedure in the assessment of DH potentials. In the first step, inhabitant-specific annual demands are evaluated (1). They are then weighted according to regional climate and building type (2), and spatially distributed using population and land-use statistics (3). Finally, a minimum demand density is applied in order to obtain potential DH supply areas (4).

data of dwelling stock and new construction by dwelling type, average floor area and specific space heat demand of existing and newly built dwellings, as well as total tertiary sector floor area and employment.² The database allows for the calculation of four useful energy demand categories for each country, distinguishing by energy usage (space or water heating) on the one hand, and demand sector (residential or commercial) on the other. Making use of final energy demand fuel shares and fuel specific annual conversion efficiencies, for each country, sector and usage an average conversion efficiency is estimated. Depending on the corresponding fuel shares, its values ranges from 75% to 90%.³ The database is furthermore used for the calculation of inhabitant specific floor areas, as well as residential and commercial space heating useful energy demands per m². The area-specific commercial sector space heating demand obtained in this manner is however based on the overall useful building area, and not the heated area. Considering statistics for Germany [21, 49], the heated share in overall floor area is estimated to 55%. Given that no further data sources could be made available, this value is applied to all countries in the investigation area.

The resulting inhabitant-specific residential useful energy demands calculated for the year 2008 range from 0.9 MWh/a in Malta to 7.8 MWh/a in Finland. In the commercial sector, inhabitant-specific demands are lower and vary from 0.4 MWh/a in Malta to 2.7 MWh/a in Luxembourg. The substantial differences between countries are related to climate, insulation standard, living areas as well as commercial sector employment share. Values for each country are displayed in Figure 3.2.

Estimate of Future Demand

The estimate of future residential and commercial useful energy demand for space heating relies on a simplified building stock model realized in a spreadsheet application.⁴ It takes into consideration temporal changes in population, inhabitant-specific average floor spaces and area-specific space heat demands in the building stock. Based on specific demand values of newly built, renovated and pulled down buildings, as well as rate and extent of energy-efficiency retrofits, the model iteratively calculates useful energy demand for space heating for each year until 2050. Residential and commercial building stock are treated separately, given that area-specific demands and modernization rates are typically different. The model additionally includes useful energy demands for hot water production in residential and commercial buildings. In the estimate of future of commercial sector demand, also sectoral employment numbers and heated floor space shares are considered. They are derived from statistical data provided in [51, 59].

For the assessment of future space heating demand, assumptions concerning the development

²Inhabitant-specific demand values for Liechtenstein are obtained from national statistics or assumed to be identical to those found in Austria.

³Assumed average annual conversion efficiency from final energy to useful heat are 65% for coal and biomass, 75% for Oil, 85% for natural gas and 98% for district heat and electricity

⁴The building stock model is an enhancement of a limited version for Germany developed by T. Nägler in the framework of [135].

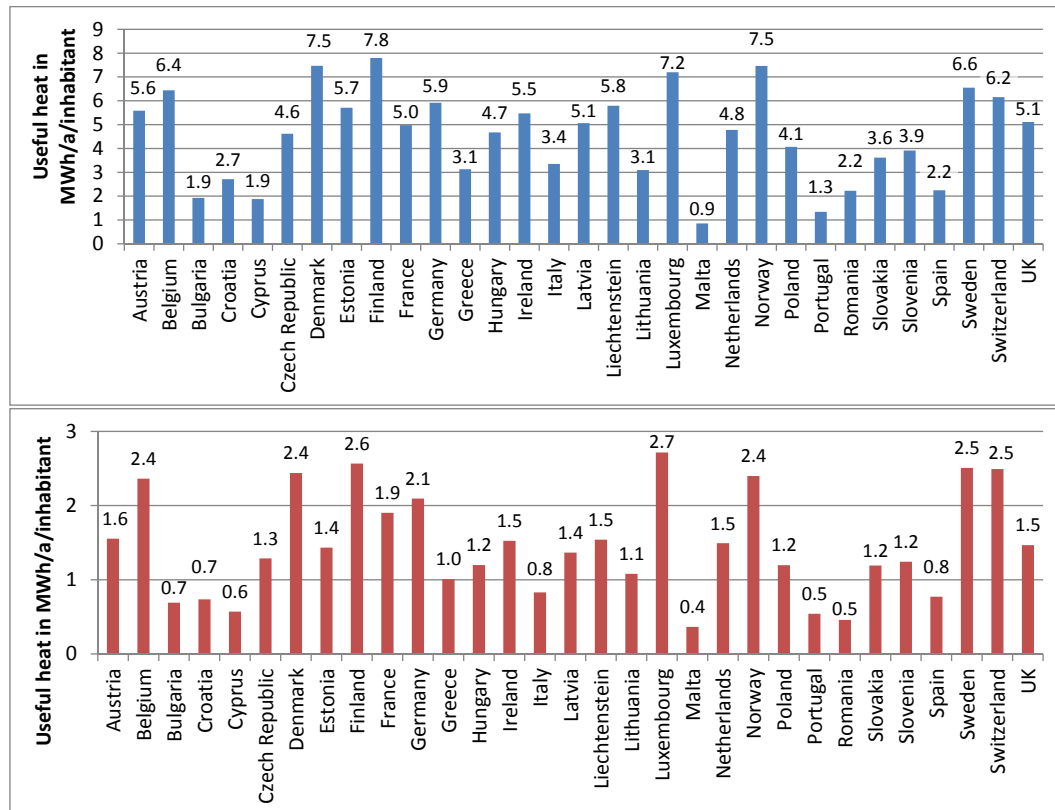


Figure 3.2 Inhabitant-specific useful energy demands for space and water heating in the year 2008. Values for the residential (above) and commercial sector (below). Note that y-axis have different scaling

of newly built, refurbished and demolished buildings are made. In order to achieve substantial demand reductions in the building sector, increased retrofit rates and depths are required, as well as steep reductions in specific space heat demands of newly built buildings. Given divergent trends during the past years, different values are applied for the European OECD countries on the one hand, and Non-OECD countries on the other (see Table B.1 in Appendix B for the list of countries). Consistent with [135, 163], in OECD Europe a retrofit rate of 2%, a retrofit depth of 50%, and a reduction in floor area specific space heat demand of newly built buildings to less than 10% of the 2010 value are assumed. In Non-OECD Europe a less dynamic development is considered. The specific space heat demand is assumed to decrease to approximately 30% of the 2010 value. Also the building refurbishment rate is ranging at a lower level: it rises by 0.25% per decade from 0.75% in 2008 to 1.75% in 2050. Efficiency gains achieved by retrofitting are assumed to 20% in 2008 and 40% in 2050 and a linear increase in between. In both OECD and Non-OECD countries, demolition rates of 0.5% and 1.5% of the building stock are applied in residential and commercial sector, respectively. Demolished and retrofitted buildings have specific demands equivalent to 120% and 130% of the overall building stock average in the corresponding year. Table B.2 in Appendix B summarizes the assumptions both for OECD and Non-OECD countries. Further input to the buildings stock model are the future development of floor areas, as well as hot

water demands. The trends applied are based on three general assumptions: (1) conditions in different European countries will converge, (2) energy efficiency will be increased and (3) trends do not or only very slowly go into reverse. Country-specific assumptions can be obtained from Table B.3 and B.4 in Appendix B. Taking into account improvements in efficiency and changes in fuel use, an increase of the average conversion efficiency (final energy to useful energy) to 92% until the year 2050 is assumed in the scenario. A linear trend is applied.

Based on these assumptions and the building stock model, future residential and commercial space and water heating demands are calculated. Figure 3.3 shows the development of the demand until 2050, relative to 2008 values. For each scenario year and demand sector, the lowest and highest country value is provided, reflecting differences in the trends between countries. Table B.5 in Appendix B provides detailed values for each country. Due to the high retrofit rate and passive house standard of new buildings, the overall demand in Europe is almost reduced by half until mid-century. The relative demand decrease is higher in the commercial sector, due to a more frequent building reconstruction and lower floor space expansion in comparison to the residential sector.

According to [49], commercial process heat demand includes space and water heating with each accounting for about 30%. This justifies a consideration of this demand in the assessment of district heating potentials. Given that no comprehensive data on commercial process heat is available, a simple estimate is made. In 2010, process heat was responsible for around 8% of Germany's commercial sector final energy demand [21]. This value is applied to all countries and kept constant until 2050. The overall commercial sector energy demand is assumed to decrease pursuant to the *Other Sector* demand in the global scenario discussed in [183] (see Table B.6 in Appendix B). Different developments are applied to the European OECD countries on the one hand, and the Non-OECD countries on the other. The resulting development of commercial sector process heat demand represents a rather ambitious scenario in terms of efficiency increase, and is as well displayed in Figure 3.3.

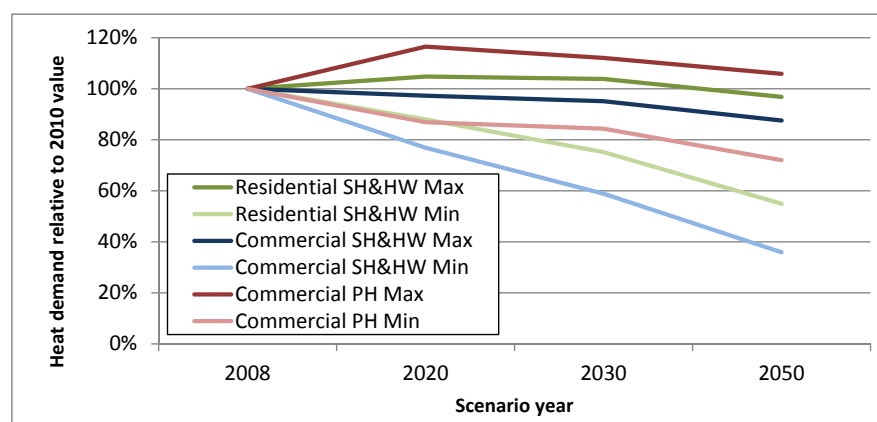


Figure 3.3 Future development of residential and commercial heat demand. Max. and min. represent the European countries with highest and lowest relative values, respectively.

3.1.3 GIS-based Approach for the Identification of DH Potentials

Using GIS data, the country heat demands are allocated spatially according to population and land use. Taking into account a minimum heat demand density threshold, agglomerations are identified and considered as areas suitable for DH. The GIS analysis is mostly performed in Idrisi 15.0, except from some first processing steps done in ESRI Arcview. Heat demand parameters of the areas suitable for DH are extracted from the GIS and further processed in a spreadsheet application to obtain summed-up potentials for each country. In the model, hot water and space heat are considered separately, allowing for a division between rather constant base load and temperature- and time-dependent variable load.

Development of a High-Resolution Demand Density Map

Dividing by the population number, country average per-capita values for both space heating and hot water demand in the residential and commercial sector are obtained from the overall demands listed in Table B.5 in Appendix B. In some cases, average demand values do not reflect the variety of climatic conditions within a country. For this reason, it is assumed that within each country the per-capita heat demand for both space heating and hot water generation in a particular region N is proportional to the heating degree days (HDD). Statistical time series of monthly HDD allows for the calculation of long-time average relative per-capita demands $U_{spec,rel}$ on the level of NUTS-2 statistical regions [58]. To assure that national average values of residential per-capita demands are not changed, each region's HDD number n_{HDD} is weighted with the regional share n_{pop} in national population according to Eq. 3.1.

$$U_{spec,rel}^N = \frac{n_{HDD}^N \cdot \sum_N n_{pop}^N}{\sum_N (n_{HDD}^N \cdot n_{pop}^N)} \quad (3.1)$$

The annual space heating demand depends not only on outside temperature but also on housing conditions such as dwelling size, inhabitant number, building type, architecture and insulation standard [49, 109, 171]. The lower surface-to-volume ratio of apartment buildings entails a relatively smaller specific space heat demand per square meter. Consequently, it has to be considered that the per-capita heat demand is lower in cities, which are generally dominated by multi-family apartment buildings. Given that no comprehensive statistics of all relevant parameters is available, it is assumed based on [49, 51, 55] that the per-capita heat demand in multi-family buildings is by 20% lower than in single family buildings. In order to apply this assumption to population density data, limits for the presence of different building types have been defined. For all areas with a population density above 5000 inhabitants/km² it is estimated that all buildings are multi-family homes, whereas areas with a density below 300 inhabitants/km² only host single-family buildings. Between those limits, relative per-capita demands increase linearly. This adjustment is only applied to residential space heating, but not to commercial heat demand and residential hot water demand. Again, the population of each grid cell must be considered in order to keep overall demand constant.

The model allows for the consideration of an upper limit in the share of buildings that can be

connected to a DH network without prior conversion of the building's heating infrastructure. The relevant heat demand can thus be reduced by the share of buildings without central water, steam or air heating system. In this assessment of a theoretical potential, it is assumed that most buildings can in principle be accessed: connection rates of 95% in 2010, 96% in 2020, 97% in 2030 and 98% in 2050 are applied.

In order to obtain heat density maps, the weighted per-capita demand values are combined with raster data sets representing the spatial distribution of residential and commercial consumers. For residential heat demand, the per-capita demand in each grid cell is multiplied with the number of inhabitants of the corresponding cell, which is calculated according to the procedure described in Section 2.6. As for demand response potentials (see Section 2.6), the spatial allocation of commercial heat demand is based on the Corine Land Cover data set [45]. It is assumed that commercial heat demand is distributed equally over all grid cells that have been assigned to the categories representing continuous urban fabric, discontinuous urban fabric and industrial or commercial units. Therefore, first of all the area share of each 1 km² cell attributed to one of these three categories is calculated. In the next step, the share of each cell in the total national area is computed. The resulting distribution is weighted with the relative HDD of each NUTS-2 region, according to Eq. 3.1, and then multiplied with total commercial heat demand. Future changes in land use pattern are not taken into account. By allocating the specific demands to residential and commercial areas, heat demand density maps with a spatial resolution of 0.0083°, equivalent to a cell area between 0.27 km² in northern Norway and 0.74 km² in southern Spain, are obtained.⁵

Identification of Potential District Heating Areas

The derived heat demand maps allow an identification of areas with high demand densities. A high heat density is crucial for the economic viability of DH systems, given that the overall costs are dominated by the capital costs of the distribution network. Areas suitable for DH are determined by taking into account only those with a density above a certain threshold value. Here, four different threshold values are considered in turn: 4 GWh/km²/a, 7 GWh/km²/a, 10 GWh/km²/a and 15 GWh/km²/a. These values have been selected based on an analysis of current DH systems in Europe: on the one hand by linking the measured DH heat supply

⁵A significant share of DH costs arises from the investment in the pipe network. Installation costs are different between countries, but also within a country, and are depending on the location, geometry, density and structure of the corresponding settlement [31, 143]. For this reason, a simplified distribution cost assessment method has been implemented in the GIS model. It relies on the assumption that the heat distribution cost per unit of energy delivered is determined by the number of buildings connected, the density of the settlement and the amount of heat supplied. Based on the total number of buildings in each grid cell, the approximate heat pipe length is calculated. In doing so, it is assumed that specific pipe lengths per building increase for lower building densities. Dividing the heat demand density by the total network length, the linear heat demand density is obtained. This value is used for an estimation of the average inner pipe diameter. Finally, investment costs for network and heat substations are calculated based on the linear heat demand density and average pipe diameter, taking into account higher costs in densely populated areas, resulting from more efforts for excavation, road shutoff, traffic diversion and piping [143]. A comprehensive description and application of this approach can be obtained from [81]. Given that in this work DH potentials are exclusively used as basis for the technology development scenario discussed in Chapter 5, DH heat distribution costs are not taken into account.

to the corresponding city areas, on the other hand by comparing DH statistics and results of the method presented here. After eliminating all grid cells with a demand density below the selected threshold value, neighboring cells of sufficiently high demand are grouped into agglomerations. In metropolitan areas those agglomerations can have sizes of many square kilometers, but there are also examples composed of one single cell. For further analysis, each agglomeration is assigned to one or various countries, and its average heat demand densities, as well as annual space and water heating demands are extracted. Using these values, agglomeration are grouped to classes representing different annual demands and thus thermal loads. Like this, the DH heat supply can later be subdivided to differently sized CHP technologies with characteristic techno-economic parameters.

Subdivision of the Potential to DH Size Classes

The DH assessment tool includes an independent model focusing on the supply of the identified potentials. It allows for an automatic assignment of a CHP technology with peak boiler to each agglomeration, as well as a subsequent calculation of installed capacities, efficiencies, power generation, costs and fuel demands of the supply infrastructure in heat-controlled operation mode. Its output is summarized to countries and technology classes in comprehensive spreadsheet files, containing additional information extracted from the GIS model, such as agglomeration areas, populations, geographical coordinates and hot water demand shares.

Based on the annual heat demands, each agglomeration is assigned by the model to one of four DH size classes, characterized by an approximate CHP electric capacity ranging from 50 kW-1 MW_{el}, 1-10 MW_{el}, 10-50 MW_{el} and >50 MW_{el}. In order to do so, the annual CHP heat production U_{CHP} of each agglomeration is calculated from the useful energy demand for space (U_{SH}) and water (U_{HW}) heating, heat distribution losses in buildings $\lambda_{building}$ and networks $\lambda_{network}$ and the CHP heat supply share s_{CHP} according to Eq. 3.2.

$$U_{CHP} = \frac{U_{HW} + U_{SH}}{(1 - \lambda_{building}) \cdot (1 - \lambda_{network})} \cdot s_{CHP} \quad (3.2)$$

Table 3.1 Technology input for the definition of DH size classes.

	DH-XL	DH-L	DH-M	DH-S
Min. Electric Capacity $P_{cap,CHP}$	50 MW	10 MW	1 MW	0.05 MW
Power-to-heat ratio σ_P	1.1	1.0	0.85	0.7
Min. Thermal Capacity $Q_{cap,CHP}$	45.5 MW	10 MW	1.25 MW	0.07 MW
Full Load Hours n_{FLH}	4500	4500	4500	4500
CHP Supply Share s_{CHP}	0.85	0.85	0.85	0.85
DH Network Loss $\lambda_{network}$	10%	10%	10%	10%
DH Building Loss $\lambda_{building}$	2%	2%	2%	2%
Min. Heat Demand U_{CHP}	212 GWh/a	47 GWh/a	5.8 GWh/a	0.33 GWh/a

With approximated CHP full load hours $n_{FLH} = U_{CHP}/Q_{cap,CHP}$ and power-to-heat ratios $\sigma_P = P_{cap,CHP}/Q_{cap,CHP}$, thermal $Q_{cap,CHP}$ and electric $P_{cap,CHP}$ CHP capacities are obtained.

Making use of these capacities, the DH potential is subdivided into four size classes, which will later be considered in the definition of a DH scenario (see Appendix E.2). Table 3.1 summarizes the assumed technology parameter, as well as the characteristic annual heat demands and power generation capacities of the size classes.

3.1.4 Resulting District Heating Potentials

Taking into account the demand of the year 2008 and the lowest considered minimum demand density of 4 GWh/km²/a, an overall DH potential of 5,792 PJ is identified in the investigation area. This is equivalent to 53% of the considered residential and commercial heat demand. The 24,232 agglomerations and the supplied heat are distributed rather unevenly over the countries; almost two thirds of the potential are located in Germany, France, Italy and the United Kingdom (see Figure 3.4). Climatic conditions, specific heat demands and urban population densities give rise to significant differences in the absolute and relative potential. Achievable shares of DH in overall heat supply range from 14% in Cyprus to 75% in the United Kingdom. Further countries with comparatively high shares include Switzerland, the Netherlands, Liechtenstein and Belgium. Regional potentials in Germany are described in Appendix B of this work.

The assessment reveals substantial potentials for an extension of DH in comparison to its current supply (Figure 3.4). They are particularly high in the UK, Germany, France, Belgium, Italy, Spain and the Netherlands. In contrast to that, in some Northern and Eastern European countries potentials are found to be in the range or even smaller than the heat supplied from DH in 2005.

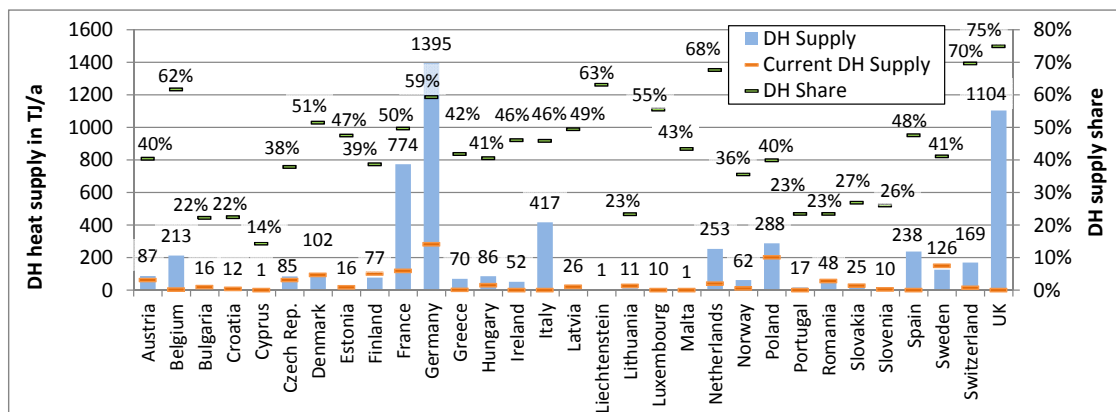


Figure 3.4 DH Potentials in Europe: achievable energy supply and market share for 2008 heat demand values.

More than 85% of the heat demand agglomerations identified are DH areas with annual demands below 50 GWh. Large cities with demands exceeding 200 GWh/a account for only four percent of the agglomerations. Taking into account annual heat supply, shares are reverse: more than 70% of the heat is fed to large city networks (DH-XL), whereas smaller systems (DH-M, DH-S) contribute only about 12% (see Figure 3.7).

The average heat supply per agglomeration indicates whether the country potential is domi-

nated by larger or smaller communities. Highest values are found in the UK, Switzerland, Belgium and the Netherlands, lowest in Norway, Slovenia and Sweden (see Figure 3.5).

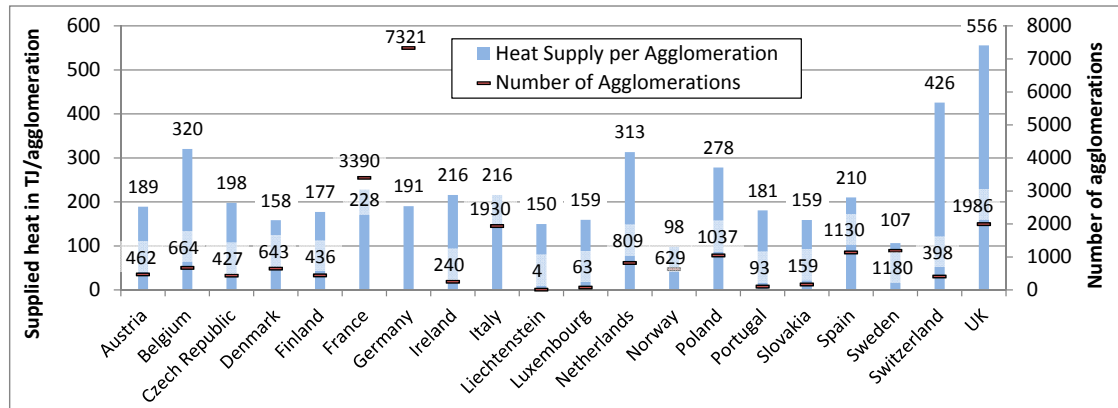


Figure 3.5 Number and average heat supply of agglomerations in each country for 2008 heat demand values.

By increasing the minimum heat demand density threshold, the number of grid cells found suitable for DH is smaller. This reduces the number and size of agglomerations, as also the overall potential. On the other hand, the average demand density increases, because less attractive areas are no longer connected to the network. Both effects have been studied by the application of different threshold values. The decrease in agglomerations and potential heat supply from DH is shown in the left diagram of Figure 3.6. Detailed values for each country and region can be obtained from Figure B.2 and B.3 in Appendix B.

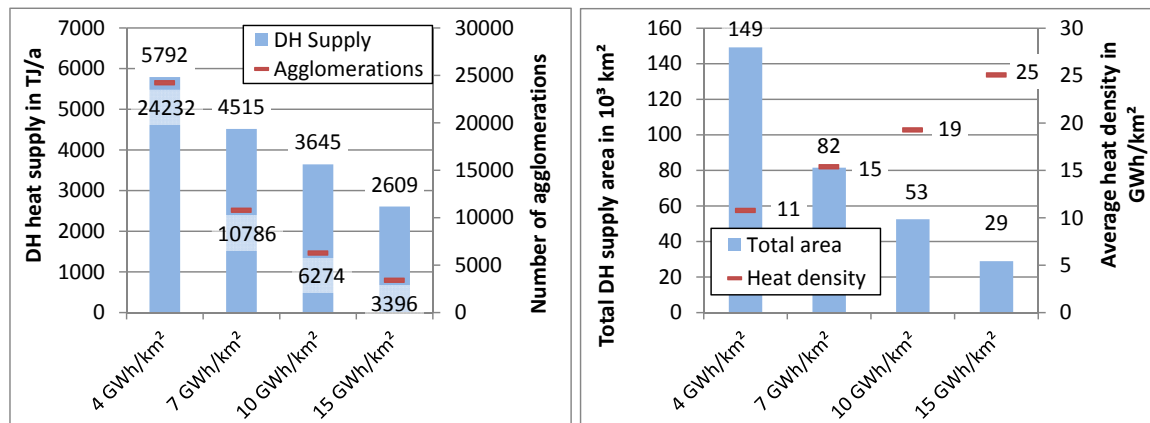


Figure 3.6 DH Potentials in Europe: overall energy and supplied areas for 2008 heat demand values.

An increase of the threshold value from 4 to 7 GWh/km²/a reduces the number of agglomerations by 55%. The overall sum of district heat, however, is only reduced by 22%. Consequently, the average heat supply per agglomerations increases by 75% from 0.24 PJ to 0.42 PJ. For the even higher threshold values of 10 and 15 GWh/km²/a, this tendency continues: the average heat supply in each DH area grows to 0.58 PJ and further to 0.77 PJ. The heat supply per agglomeration rises with increasing threshold value, because only the

most attractive agglomerations are still supplied with DH. This is also reflected by the subdivision of the potential to technology size classes, as well as heat density and area of supplied communities. The left diagram in Figure 3.7 shows that number and heat generation of smaller DH areas are much more affected by the increase of the threshold density than that larger ones. With a threshold of 15 GWh/km²/a, no agglomerations with annual consumptions below 6 GWh remain. Applying higher threshold values, the average heat density within supplied districts rises from 11 GWh/km²/a to 25 GWh/km²/a, and the overall supplied areas diminishes from 149,000 km² to 29,000 km² (see Figure 3.6, right).

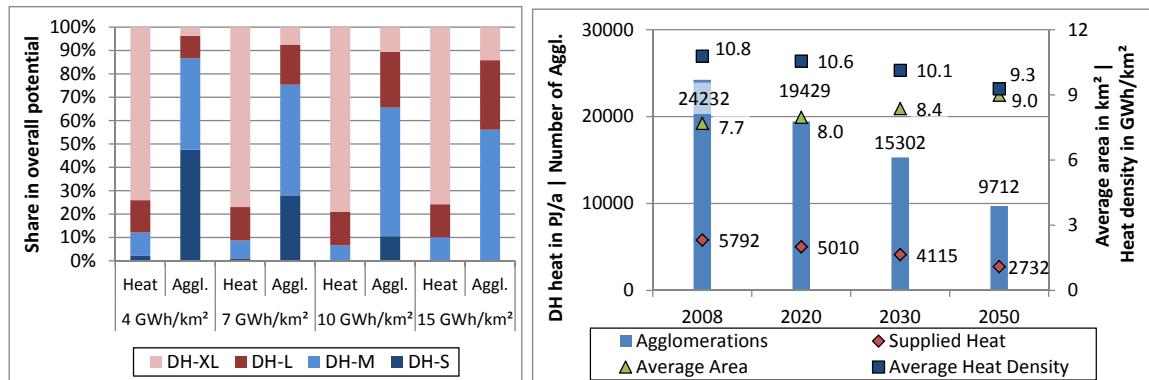


Figure 3.7 DH Potential in Europe: subdivision to technology size classes and dependency on the demand density threshold (left), and future development (right).

Taking into account population and heat demand projections, the DH potential is assessed also for the years 2020, 2030 and 2050. The right diagram in Figure 3.7 shows the resulting DH potential for a different minimum demand density of 4 GWh/km²/a. Different trends can be observed: due to the significant heat demand reductions assumed (see Section 3.1.2), potential heat supply and DH agglomeration number constantly decrease from 5,792 PJ in 24,232 agglomerations in 2008 to 2,732 PJ in 9,712 agglomerations in 2050, respectively. Similar to the application of higher minimum demand density values, a concentration to large systems is found: the average DH area rises from 7.7 km² to 9.0 km². On the other hand, the average heat demand density in DH agglomerations decreases from 10.8 to 9.3 GWh/km²/a. The achievable DH supply share declines from 53% to 43% of the overall residential and commercial useful energy demand for space and water heating. All DH potential values are summarized in Table B.7 to B.10 in Appendix B.

3.1.5 Summary and Discussion

The analysis reveals that up to 53% of Europe's residential and commercial heat demand can be supplied by DH. Potentials for additional DH usage are found in most European countries. Countries with greatest potentials in absolute numbers are Germany, France, Italy and the UK. Potential DH supply shares of more than 60% are found in Belgium, the Netherlands, Switzerland and the UK. Today, in those countries DH shares are below 15%. With regard to far-reaching energy efficiency policies in the building sector, it is shown that even for

a per-capita space heating demand reduction rate exceeding 1.5% per year, a considerable potential for DH remains. Also in the Mediterranean countries Italy, Portugal and Spain significant DH potentials are identified. In contrast to central Europe, they are however almost only found in major cities with very high population and thus demand densities. Whether their exploitation is economically feasible strongly depends on the DH network installation costs. Given that central heating systems are less common in those countries, it can be expected that costs for conversion to DH are comparatively high.

The DH potential depends on the assumed minimum demand density threshold: Applying higher values, the potential shrinks noticeably. Nonetheless, also for a 15 GWh/km²/a minimum demand density, areas with a DH potential of more than 2600 PJ, equivalent to one quarter of the considered demand, are identified. Smaller agglomerations are particularly sensitive to the choice of the minimum demand density threshold – many of them have comparatively low demand densities. The DH potential in metropolitan areas with very high population and demand density is much less sensitive to the applied minimum demand density. Compared to demand densities in existing DH systems, relatively low threshold values have been used for the identification of agglomerations, for two reasons. First, the heat demand density map tends to underestimate the demand because of the restriction to residential and commercial sector while neglecting industrial process heat demand. Second, the density map tends to blur demand in smaller settlements due to the spatial resolution of the data used. Particularly in small but dense settlements, the demand density can be much higher than found in the GIS approach used here. This is because the population potentially living in an area of few hectares is attributed to one or even more cells of a size up to 0.74 km², artificially reducing the demand density. As a consequence, the heat demand density of small villages is underestimated, which causes them not to be identified as potential DH areas by the method used here. The same effect typically appears at city boundaries and park areas within cities. The heat demand density in a small area that is actually supplied by district heat can be much higher than the assumed thresholds, but the demand distribution within a single cell cannot be assessed. This limits the opportunities to analyze details of the potential DH networks within one community. It can be concluded, that due to limited spatial resolution, this methodology is not suited for a comprehensive quantification of DH potentials in smaller communities. Consequently, the overall DH potentials are likely to be higher than those found here.

Even for the lowest threshold value used here, the DH supply in 2005 exceeds the potentials in some countries. This is the case for Finland, Slovakia, Bulgaria, Estonia, Lithuania, Romania and Sweden. In the Nordic countries, DH is already widely used not only in cities, but also in smaller villages. For the reasons of limited spatial resolution discussed earlier, it is likely that the demand density in smaller villages calculated here appears lower than it is in reality, causing them to remain below the threshold that is set. Furthermore, the assumption of a relatively low per-capita demand in cities might not be applicable to the same degree in all countries and regions. Additionally it is possible that the demand density in existing DH systems is indeed lower than the smallest threshold value.

The application of the GIS method for the assessment of future DH potentials may cause errors in countries and regions with fast growing population. With the use of maps containing the currently developed and populated areas, it is assumed that no new land is made available for building. Thus, the growth in population and commercial activities implies an increase of the heat demand density only in those cells already built-up in 2006. The opposite effect appears for population reductions. Communities are implicitly assumed to only grow or diminish in density, not in size. Changes in population distribution, for example caused by increasing urbanization are not reflected by the results.

3.2 Quantification of Industrial Cogeneration Potentials

3.2.1 Introduction

Industrial process heat demands with low seasonal fluctuations provide favorable conditions for the application of CHP. Such as in DH systems, the application of TES in industrial CHP supply can enable a decoupling of heat demand and production, and thus a power-controlled CHP operation. However, storage of industrial process heat with temperatures exceeding 100°C requires more sophisticated technologies, ranging from steam accumulators to latent or thermochemical storage systems [8].

The potential usage of industrial CHP in Germany has been previously assessed in [98], as well as [14, 99]. An even more detailed analysis is provided by [49], which considers the allocation of the overall heat demand to different temperature levels and single production sites. A comprehensive overview of industrial heat demands and CHP potentials in Europe is lacking so far. Determined by the availability of statistical data on energy use and industrial structure, the analysis presented here is limited to the EU-27 countries and Norway.

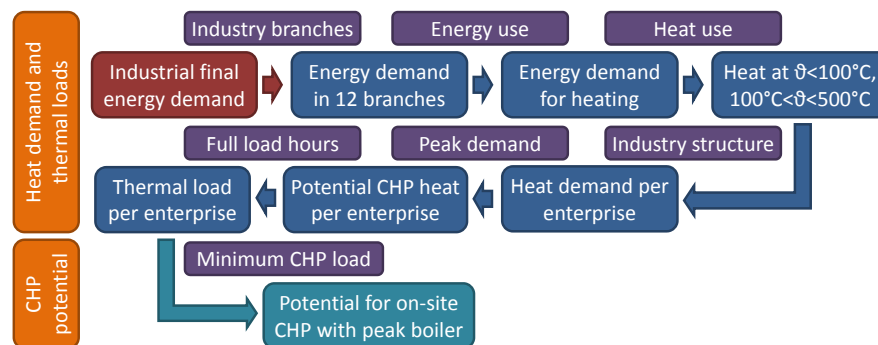


Figure 3.8 Procedure in the quantification of industrial CHP potentials.

Given the strong dependency of industrial heat demands on particular process requirements, the assessment of CHP potentials is performed independently for three company size classes in twelve different manufacturing branches. Based on statistics of energy use and industrial structure, specific demands per employee and per enterprise are calculated. To all industrial sites of sufficiently high demand, a CHP unit and a peak boiler are assigned. In doing so, technology and thermal capacity are determined by taking into account the overall demand, as well as temperature requirements and full load hours. Figure 3.8 provides

an overview of the methodology. The analysis is limited to technical CHP potentials, and forms the basis for the development of a European heat supply scenario in Chapter 5. A comprehensive economic assessment of CHP potentials lies beyond the scope of this work.

3.2.2 Industrial Heat Demand Analysis

A significant portion of industrial final energy consumption is used for heat generation. In contrast to the residential and commercial sectors, overall demands in industry are dominated by process heat (PH), whereas space heating (SH) and hot water (HW) play a secondary role. Amount and temperature of heat consumption in industrial facilities strongly depend on the corresponding production processes. For this reason, the assessment is done separately for twelve branches of industry. Each of these branches shows different characteristics concerning process heat temperature requirements, working hours and employee numbers. Table 3.2 provides the assignment of sub-branches to the branches considered in this work. Their number and composition are determined by the sectoral aggregations used in the data sources. Major source is the Eurostat statistics database, which provides detailed input on final energy demands per branch of industry and country [61]. The database contains disaggregated values for many more branches than those separated here and are summed up according to Table 3.2. In this analysis, the demands in 2009 are used.

Table 3.2 Classification of the different branches of industry in the Eurostat statistics and the CHP analysis presented here.

Branch	Sub-branches included
Metal	Basic metals, fabricated metal products, except machinery and equipment
Chemical	Chemical products, man-made fibers, coke, petroleum products, nuclear fuel
Minerals	Other non-metallic mineral products
Mining	Mining
Food	Food products, beverages and tobacco
Textile	Textiles, wearing apparel, dressing, dyeing of fur, leather, leather products
Paper/Print	Pulp, paper, paper products, publishing, printing, reproduction of recorded media
Transport Eq.	Motor vehicles, trailers and semi-trailers, other transport equipment
Machinery	Machinery, equipment n.e.c., office machinery, computers, electrical machinery, apparatus n.e.c., radio, television, communication equipment and apparatus, medical, precision and optical instruments, watches and clocks
Wood	Wood and wood products
Construction	Construction
Other	Rubber and plastic products, furniture; manufacturing n.e.c., Recycling

Based on [166], the overall final energy demand in each branch of industry is subdivided by its usage, such as process heat, mechanical energy or cooling.⁶ In this analysis, only the demands for space heat, hot water and process heat are relevant. Using [73], the process heat demand is further allocated to four temperature levels of $\vartheta < 100^\circ\text{C}$, $100^\circ\text{C} \leq \vartheta < 500^\circ\text{C}$, $500^\circ\text{C} \leq \vartheta < 1000^\circ\text{C}$ and $\vartheta \geq 1000^\circ\text{C}$. This division is essential for a proper analysis of the

⁶The analysis of final energy usage and process heat temperatures makes use of research prepared by M. Klein during his internship at the DLR-Institute of Engineering Thermodynamics, documented in [131].

CHP potential, as only heat demands below 500°C can be provided by CHP [50]. Furthermore, the CHP technology choice depends on the temperature requirements of the given branch of industry. Figure 3.9 and Table C.1 in Appendix C show the resulting shares of each energy use in the final energy demand of every branch. Due to the focus on industrial CHP application, all process heat demand at temperatures exceeding 500°C is excluded from the subsequent analysis.

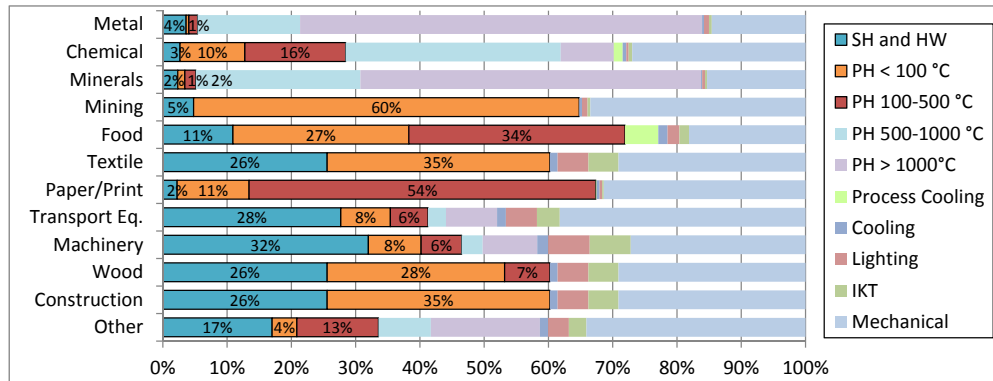


Figure 3.9 Energy usage in each of the considered branches of industry

As no data on final energy use and process heat temperatures is available for other countries, the shares calculated for Germany are also applied to the other European countries. Multiplying the relevant shares with the overall final energy demands, for each country and industry the final energy consumption of space heating, hot water generation and four process heat temperature classes is calculated. The final energy demand is converted to useful energy making use of country specific average conversion efficiencies. They are calculated based on the corresponding final energy demand fuel shares from [61] and fuel specific annual conversion efficiencies, and reach values ranging from 84% to 91%.⁷

Industrial CHP potentials in the scenario years 2020, 2030 and 2050 considered in the REMix application presented in Chapter 5 are calculated using the same method. In doing so, it is assumed that industrial heat demands across all branches develop according to the final energy demand scenario for the *industry* sector compiled in [183] (see Table B.6 in Appendix B). As in the residential and commercial sector, different developments are applied for OECD countries on the one hand, and Non-OECD countries on the other. Changes in energy usage and process heat demand temperatures are not taken into account. According to the scenario, it is assumed that in all European countries the industrial final energy demand increases by around 11% until the year 2020, before declining to roughly 90% of the 2009 value in 2050. An assessment of possible improvements and changes in production processes, which might change the demand structure, are beyond the scope of this study. Across all countries, the average conversion efficiency is assumed to increase linearly to 93% until the year 2050.

⁷ Assumed average annual conversion efficiency from final energy to useful heat are 75% for coal and biomass, 80% for Oil, 85% for natural gas and 98% for district heat and electricity

3.2.3 Calculation of Specific Demands per Enterprise and Employee

In order to estimate the potential number and size of on-site CHP units, the structure of each branch of industry is looked at in detail. Therefore, economic statistics provided in [59] are used. They include both the number of enterprises and employees, subdivided by enterprise size class. Here, three classes are used: businesses with less than 50 employees, between 50 and 250 employees and more than 250 employees. The data provided is much more detailed in terms of branches of industry than required; consequently some values have to be aggregated according to Table 3.2. Missing values in the statistics are estimated based on those of earlier years, as well as the employment and enterprise structure of other countries.

In the following, employee-specific useful energy demands for the three relevant heat products – space heat/hot water, process heat with $\vartheta < 100^\circ\text{C}$ and process heat with $100^\circ\text{C} \leq \vartheta < 500^\circ\text{C}$ – are calculated for each country and branch of industry. As a consequence of differences in products and processes both between and within branches, those specific numbers per employee show significant variations. The average values over all countries are shown for each branch in Figure 3.10. Using

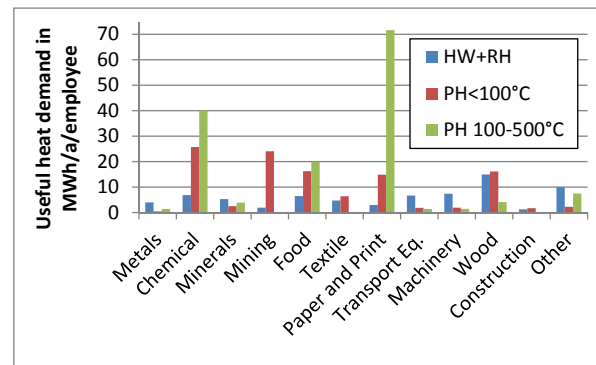


Figure 3.10 Specific annual industrial heat demands $< 500^\circ\text{C}$ in MWh/employee/a, European average for the year 2007

the number of enterprises in each size class, the heat demand per enterprise is calculated for each temperature range, enterprise size class, branch of industry and country.

3.2.4 Approach for the Determination of On-site Cogeneration Potentials

For each country, branch of industry and enterprise size, the potential for an on-site CHP production is assessed. The potential is subdivided to two temperature levels – below and above 100°C – and four CHP capacity classes. In a first step, the overall useful heat demand of each enterprise is reduced by a peak boiler share. Even though process heat demands are more constant during the year than space heat demands, CHP systems are typically not designed to cover the complete demand. Instead, a heat-only boiler is used in times of very high or very low demand, when it either exceeds the CHP unit's thermal capacity or goes below its minimum part-load generation. According to [50] it is assumed that across all branches of industry 25% of the space and water heating, as well as process heat demand is provided by the peak boiler. The remaining heat demand U_{CHP} is defined as CHP heat potential. Given that the operation pattern of process steam generators is correlated to plant production hours, typical working hours of each industry are taken into account [50]. The full load hours n_{FLH} are assumed differently not only for each industry, but also for the three

enterprise size classes. Table 3.3 includes all values used in this analysis. Dividing the CHP heat U_{CHP} by the corresponding estimated annual full load hours n_{FLH} , the required thermal capacity of the generation unit is obtained. The thermal capacity is converted into a electric capacity taking into account characteristic power-to-heat-ratios σ . If the electric capacity exceeds 50 kW, it is assumed that a on-site CHP production is possible. All heat demand in companies with demands below this limit is assumed to be out of range for on-site CHP production. It can, however, be supplied by hot water or steam networks connecting various industrial consumers, which will be considered in the case study discussed in Chapter 5. In all company size classes with sufficiently high thermal load for on-site generation, CHP and peak boiler generation are calculated separately.

Table 3.3 Assumed annual thermal full load hours n_{FLH} of the CHP units, subdivided by number of employees (empl.) per company.

Industry Branch	Annual full load hours		
	>250 empl.	50-250 empl.	<50 empl.
Metal	7600	7500	7400
Chemical	7000	5000	4000
Minerals	7000	5500	4000
Mining	4000	4000	4000
Food	4500	3500	3000
Textile	4000	4000	3500
Paper/Print	5500	4000	3500
Transport Eq.	7000	5500	4000
Machinery	7000	6000	5000
Wood	5500	5000	4500
Construction	4000	3500	3000
Other	4000	4000	4000

In total, four different CHP size classes are distinguished: units with electrical capacities exceeding 50 MW (Industry-XL), between 10-50 MW (Industry-L), between 1-10 MW (Industry-M) and 50 kW and 1 MW (Industry-S). Within each class, heat demands below 100°C (LT) and above 100°C (HT) are separated. This distinction are later used for the attribution of suitable CHP technologies in REMix-OptiMo. In this part of the analysis, no attribution of specific technologies is done.

3.2.5 Resulting Industrial Cogeneration Potentials

According to the applied methodology, almost 53% of Europe's industrial useful heat demand at temperatures below 500°C can be supplied by on-site CHP production. Country potentials correlate with the present industry structure, particularly concerning dominating branches of industry and average enterprise size. Attainable CHP shares range from 24% in Cyprus to 69% in Finland. Heat only boilers providing peak demand in companies with on-site CHP provide around 18% of overall demand. The remaining demand share of 29% occurs in industrial production sites with average thermal loads below the applied threshold values.

Nonetheless, a provision of this heat by a central CHP plant supplying a hot water or steam network to the surrounding industrial or residential area can be achieved. If not, individual heat supply systems without power production have to be used.

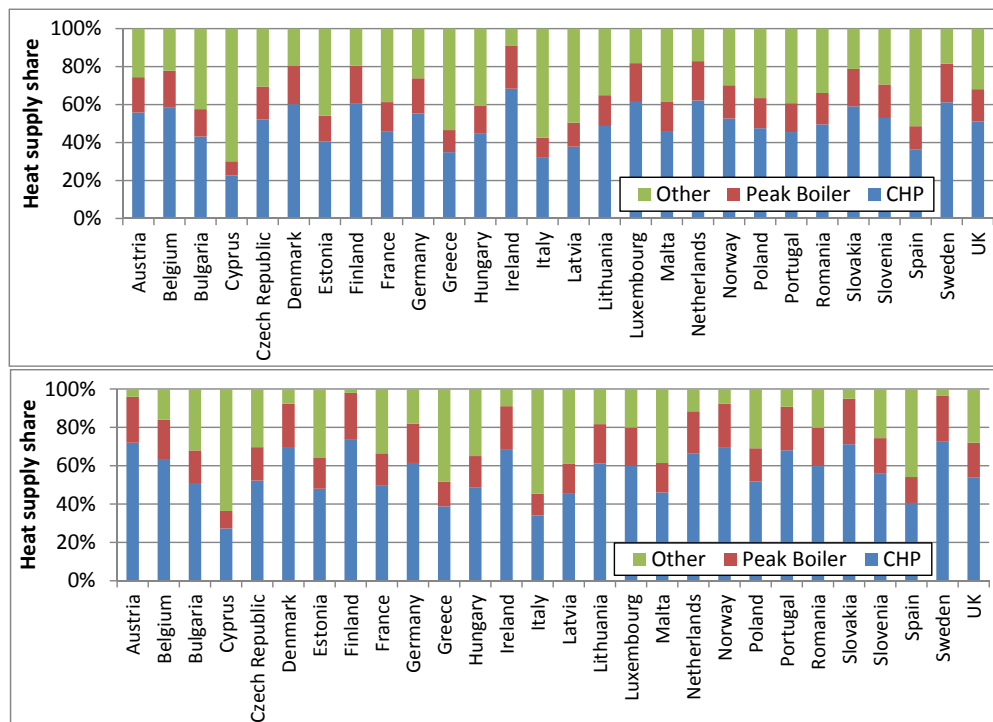


Figure 3.11 Achievable on-site CHP heat production share in industry, subdivided by country. The upper graph shows the potential for heat at temperatures below 100°C, the lower that for temperatures between 100°C and 500°C. All values of 2009.

Considering different temperature levels, a higher CHP share can be realized for demands at temperatures between 100°C and 500°C. On European average, 58% of this demand can be supplied by CHP, in contrast to 49% for demands below 100°C. The corresponding peak boiler shares account for 19% and 16%, respectively. It follows that the heat demand not accessible for onsite-CHP is smaller for process heat demand between 100°C and 500°C (23%) than for low-temperature heat demand (34%). Figure 3.11 summarizes the supply structure for each country and both temperature levels. The corresponding absolute energy quantities can be obtained from Table C.3 in Appendix C.

The subdivision of the potential to the assessed branches of industry in each country is related to the corresponding industry structure. Figure 3.12 shows the resulting distribution for each country. Major contributors are food, paper and chemical industry. Comparing branches, highest on-site CHP shares in overall supply can be achieved in Chemical (67%) and Transport Equipment (63%), lowest in Construction (12%), Metals (18%) and Wood (23%) industry.

The results show a dominance of CHP on-site generation by small units with electrical capacities below 10 MW (see Figure 3.13). CHP units with capacities below 1 MW provide 46%, those between 1 MW and 10 MW 44% of the overall CHP heat supply. In contrast,

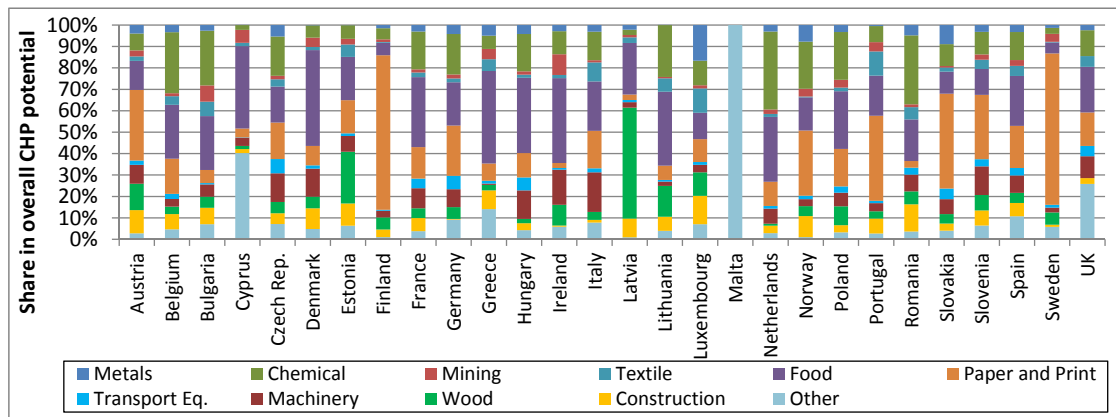


Figure 3.12 Distribution of industrial on-site CHP production potential to branches.

only 6% are produced in CHP with capacities between 10 MW and 50 MW, and 3% in those exceeding 50 MW. Except for the smallest devices, the CHP heat supply is dominated by heat at temperatures between 100°C and 500°C.

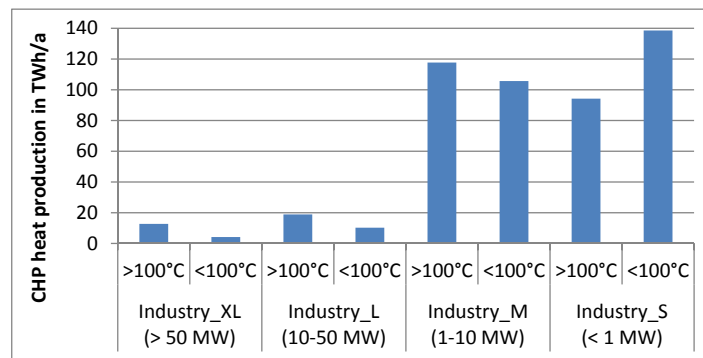


Figure 3.13 Subdivision of industrial CHP heat to capacity classes.

Pursuant to the applied evolution of the overall industrial final energy demand, the on-site CHP potential rises to 114% and 110% of the 2009 value in the year 2020 and 2030, respectively, before decreasing to 97% of the initial value until 2050. Country-specific potentials are summarized for each scenario year in Table C.4 to C.6 in Appendix C

3.2.6 Spatial Allocation of Industrial Heat Demand and Cogeneration Potentials

In order to facilitate REMix-OptiMo analyses on sub-country level, the spatial allocation of industrial heat demand and CHP potential is taken into account. Eurostat employment statistics [59] provide overall industrial employment for each NUTS-3 region and sectoral employment for each NUTS-2 regions. Both values are combined to sector-specific GIS maps containing the NUTS-3 shares in national employment, which are multiplied by the heat demand and CHP potential in each branch of industry. Figure 3.14 displays resulting regional heat demand density.

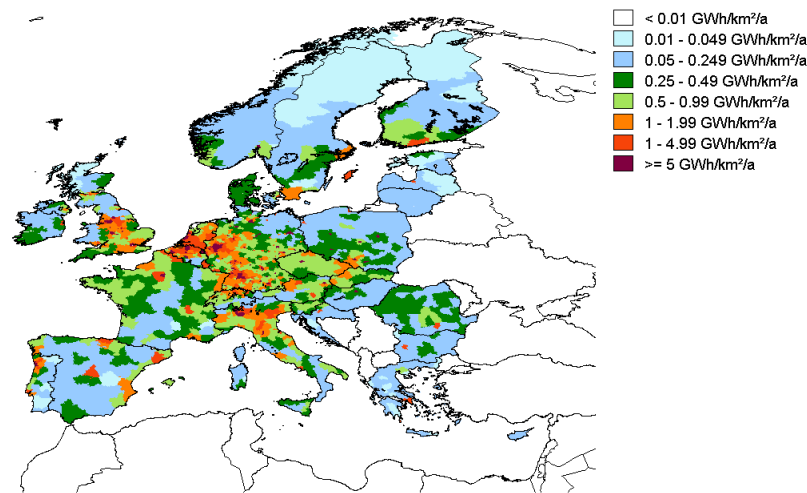


Figure 3.14 Spatial allocation of industrial heat demand at temperatures below 500°C.

3.2.7 Summary and Discussion

The results of the analysis suggest that more than half of Europe's industrial heat demand at temperatures below 500°C can be provided by on-site CHP production. The technical CHP potential is slightly higher for medium-temperature than for low-temperature heat demand, and predominantly located in the food, paper and chemical industry. Countries with particularly high accessible CHP shares include Finland, Ireland and Sweden.

The methodology relies on a number of assumptions that might cause an underestimation or overestimation of industrial CHP potentials. In some branches of industry, the demand per enterprise is found to be too low for the smallest available CHP unit. Consequently, the complete demand is assumed not to be accessible for CHP. This mainly but not exclusively affects the CHP potential in the smallest enterprise size class. The result is a low CHP share particularly in countries dominated by smaller facilities, as for example Italy or Spain. In reality, those smaller facilities could be either integrated into a nearby heating network, or share a CHP unit with other consumers in an industrial park. Furthermore, by supplying various facilities by only one CHP unit instead of various smaller ones, higher conversion efficiencies and power-to-heat-ratios could be achieved. The underestimation of the potential in small enterprises might at least partially be balanced by an overestimation in very big enterprises. Such companies typically distribute their production over various facilities, which cannot be extracted from the statistics. Another important approximation concerns the applied peak boiler share, which might cause both an overestimation or underestimation of the potential. An overestimation of the potential can furthermore result from the negligence of additional waste heat recovery measures. In industrial branches with high temperature heat demand, as for example the metal or chemical industry (see Figure 3.9), low temperature demands might be at least partially be covered by an increased utilization of heat recovery. In many cases, recovery is however hindered by limited temporal and spatial coincidence of thermal source and consumer. Process requirements or restricted possibility to concentrate and dissipate waste heat might pose additional barriers. An increased heat recovery would negatively affect

the CHP potential.

The predominance of particular branches of industry in overall on-site generation is also related to methodological aspects. Those branches with highest CHP shares – Transport Equipment and Chemical – are less dominated by small companies. The corresponding shares of enterprises with less than 50 employees relative to the overall number of enterprises are 88% and 84%, respectively, whereas in the branches Wood and Construction values above 98% are on hand. With a demand concentration to less and greater sites, thermal load and thus CHP potential are higher.

The equal distribution of overall heat demand to all employees of a particular branch of industry is responsible for the predominance of small CHP units in the potential. A concentration of energy intensive processes to greater installations is not taken into account.

Even though it is subject to a number of approximations, the analysis provides a solid first estimate for the technical CHP potential in Europe's industry. Follow-on research work will have to gain deeper insight into both heat demand and industrial structure of individual industrial sectors. Additionally, it has to account for country-specific differences in energy and heat usage. Whether and to what extent the identified potential can be tapped economically profitable will have to be analyzed in more focused studies. This is particularly important for heat demands at temperatures close to the applied upper limit of 500°C. An advanced discussion of the heat demand quantification method applied here, as well as future research opportunities is provided in [131].

3.3 Hourly Heating and Cooling Demand Profiles

An important aspect of REMix in general and the assessment of balancing options in particular is temporal resolution. For this reason, an improved representation of heat demand has been implemented in the model. In this section, the methodologies applied in the approximation of country specific hourly profiles of thermal loads are discussed. They include space heating, domestic hot water, industrial process heat, and domestic cooling.

3.3.1 Space Heating, Hot Water and Cooling Demand Profiles

The energy demand of space heating, hot water generation and air conditioning correlates closely with the outside temperature. Using a set of GIS maps containing European daily average temperatures in the year 2006 at a spatial resolution of 7 km [43], ambient air temperature profiles, as well as daily heating and cooling degree days (HDD/CDD) are calculated for each country and, where available, NUTS-2 statistical region. Daily shares U_d of the annual space heating demand U_{year} are calculated with an extended degree day method, which considers the HDD number $n_{HDD,d}$ not only of the current, but also the six preceding days (see Eq. 3.3). Previous days are weighted by multiplying with the members of the geometric series $(1/2)^a$ with $a = 0, 1, \dots, 6$. In the calculation of daily space and hot

water heating energy demands for each country, the HDDs in the NUTS-2 regions of each country are weighted according to its population share.

$$U_d = \frac{\sum_a \frac{1}{2^a} \cdot n_{HDD,d-a}}{\sum_a \frac{1}{2^a} \cdot \sum_{d=1}^{365} n_{HDD,d}} \cdot U_{year} \quad a = 0 \dots 6 \quad (3.3)$$

The assessment of future space heat demand considers a decreasing heating limit temperature enabled by energy-efficiency retrofits. Its value is assumed to drop by 1 K per decade, from 18°C in 2010 to 14°C in 2050. In contrast to that, a constant room temperature of 18°C is applied to all scenario years. Due to the change in heating limit, HDD number⁸ and thus space heat demand profile differ for each scenario year. Comfort and heating limit temperature have been chosen in such a way that the synthetic profile calculated using Eq. 3.3 shows best match with a reference demand profile of a German DH supplier. Hourly demands during each day are derived from same DH network load time series. Given that the measured profile shows a strong relation to weekday and outside temperature, different profiles are calculated for five ranges of average daily temperature, as well as working days on the one hand and weekend days on the other (see Figure 3.15 and Table D.1 in Appendix D). They represent average profiles of all days in the corresponding temperature range and weekday class.

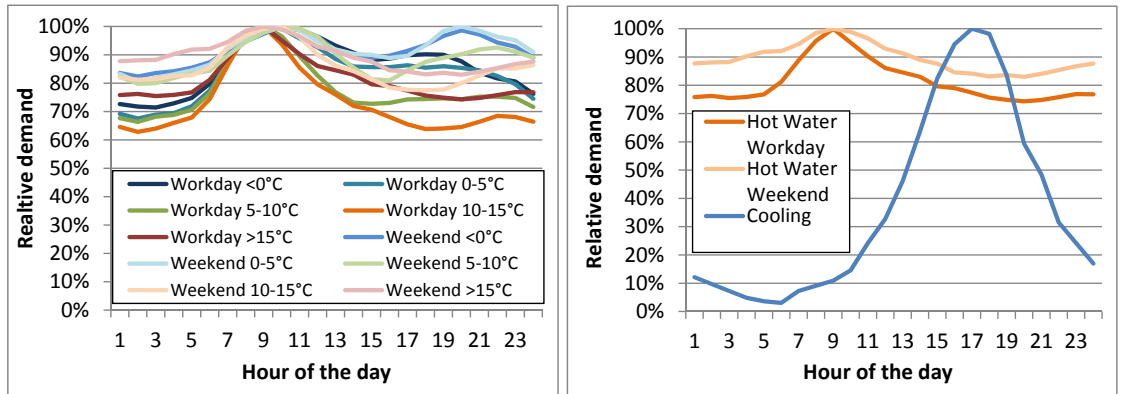


Figure 3.15 Hourly demand relative to day peak for space heating (left), as well as hot water and cooling (right).

With a difference of only 20% between the coldest and warmest day of the year, the daily hot water demand is assumed to be almost constant. This assumption is derived from the analysis of the same DH time series. The hourly demand within each day follows the measured load profile presented in [148].

Daily shares in annual air conditioning demand are also calculated according to Eq. 3.3. In the assessment of cooling demand, however, only the CDD of the current and previous day are taken into consideration. Within each day, the air conditioning power demand is assumed to peak in afternoon hours, in accordance with the representative profile shown in 3.15 [178]. The cooling limit temperature is assumed to decrease by 0.25°C per decade, from 18°C in 2010 to 17°C in 2050, entailing a future increase of the annual air conditioning operation

⁸HDD reflect the severity of the cold taking into account average air temperature ϑ_{air} and room temperature ϑ_{room} . It is zero for all temperatures above and $(\vartheta_{room} - \vartheta_{air})$ for temperatures below the heating limit.

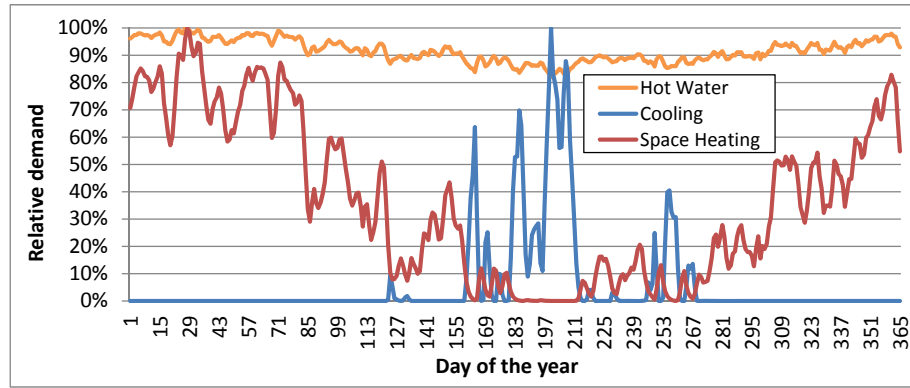


Figure 3.16 Daily demand relative to annual peak for space heating, hot water and cooling.

hours. Figure 3.16 shows resulting space heating, hot water and air conditioning load profiles for Germany and the year 2010. It contains daily values relative to annual peak demand.

3.3.2 Industrial Process Heat Demand

Industrial CHP operation is typically driven by process heat demand instead of space heat demand. For this reason, an approximation of industrial process heat load profiles is performed. It relies on the assessment of industrial heat demands discussed in Section 3.2, and takes into account the demand shares (Table C.1 in Appendix C) and full load hours (Table 3.3) of each company size class and manufacturing branch.

It is assumed that temporal variations in process heat demand are correlated to the annual full load hours through characteristic working schedules. Production utilization levels are attributed to each hour of the year and chosen such that the corresponding number of annual full load hours is obtained. The process heat load profiles are defined by 120 values: 24 hourly time slices each for Mondays, Tuesdays to Thursdays, Fridays, Saturdays and Sundays. For each of them, an utilization level relative to the installed capacity is estimated. Depending on the overall working hours, it is considered that production and thus heat demand is halted or reduced on weekends and during nighttime. Furthermore, every scheduled production down time is followed by a heat demand peak resulting from re-heating requirements. Single industrial processes, for example in the chemical or steel industry are not run continuously but batch-wise. In the calculation of process heat demand profiles, it is not explicitly accounted for regular gradients at shorter timescales. In contrast, it is assumed that batch processes at different production lines or industrial sites are organized with time offsets such that an approximately constant profile results.

In order to reflect different industrial production cycles, the overall heat demand is subdivided to eight full load hour classes. Each class represents the demand of all industrial sites producing at annual full load hours within a certain range. The class with least annual full load hours n_{FLH} includes the demand of all production sites operating at $2500 < n_{FLH} \leq 3250$, the subsequent that with $3250 < n_{FLH} \leq 3750$ hours and so on. Given the concentration of annual operation hours to values between 3000 and 5000, the lower FLH classes comprise smaller ranges than the upper. Industry branches operating at more than 8000 annual full load

hours are assumed to have a constant demand throughout the whole year. For all demand within each FLH class, one annual load profile is considered. It is derived from the FLH number in the middle between lower and upper limit, and is supposed to reflect typical working schedules in the corresponding FLH range. Figure 3.17 shows the relative thermal load of each full load hour class during one week. The exact definition of industrial demand classes and the corresponding shares in overall demand are summarized in Table C.2 in Appendix C and D.2 in Appendix D, respectively. The profiles shown are applied to all weeks of the year; seasonal changes in process heat demand are consequently not taken into account.

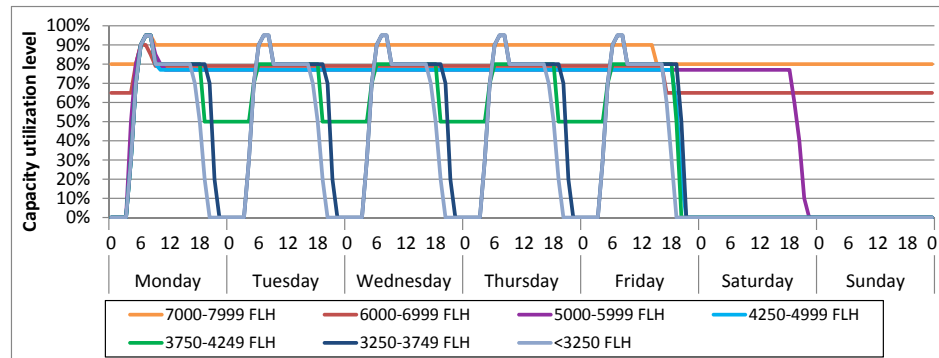


Figure 3.17 Industrial Process Heat Demand Profile.

The hot water share in the aggregated space and water heating demand extracted from the statistics is assumed to be identical to the corresponding commercial sector value (see Section 3.1.2). Depending on the country, hot water shares range between 10% and 41% in the year 2009 and between 27% and 63% in the year 2050, respectively. Industrial hot water demands are assumed to follow the corresponding process heat profile, whereas the annual space heating demand is allocated according to the profiles derived in Section 3.3.1.

The overall industrial demand profile is obtained by superimposing the profiles of all FLH classes, each of them weighted with its corresponding demand share. Given different industry structures and climates, for each country in the investigation area a characteristic load profile is obtained. The consideration of changes in future space heating demand (see Section 3.3.1) requires a separate load profile for each scenario year. In the calculation of load profiles, no distinction between different process heat temperature levels is made; it is consequently assumed that all heat demand follows the same pattern.

Bearing in mind that production hours can vary not only from one branch to another, but also between companies of the same branch, the sample profiles can only provide a rough approximation of real world demands. Nonetheless, they can be used for an indicative assessment of the hourly operation of industrial heat supply technologies in the REMix-OptiMo application discussed in Chapter 5.

Chapter 4

Implementation of the Heating Sector and Flexible Electric Loads in REMix-OptiMo

This chapter is dedicated to the implementation of flexible electric and thermal loads into REMix-OptiMo. A realistic and manageable model representation of these balancing options is the central requirement of the subsequent assessment of their potential future utilization. After a brief introduction to the background of energy system modeling and linear programming (Section 4.1), the REMix-OptiMo model concept and structure is presented (Section 4.2). Based on this, the model representation of power generation, storage and transmission technologies, which have been implemented previously, is discussed qualitatively (Section 4.3), before detailed technical descriptions of the modeling of flexible power consumers and heat technologies developed within the scope of this work are provided (Section 4.4 and 4.5). The chapter concludes with a short overview of the REMix-OptiMo main equations (Section 4.6), and a discussion of the model enhancement (Section 4.7).

4.1 REMix-OptiMo Modeling Approach

Research questions of energy system analysis are typically addressed by the application of models providing a simplified representation of real world technologies and systems. Such models differ vastly in their methodology, as well as specific focus, ranging from the analysis of single technologies to the integrated and cross-sectoral assessment of the global energy usage [10, 37, 95]. The first generation models designed for the assessment of the overall energy system have been limited to the accounting of annual energy inputs and outputs for aggregated world regions. In order to better reflect seasonal and daily variations, a higher temporal resolution has been increasingly considered in many energy system models. This is particularly important concerning fluctuating renewable energies, which feature a highly intermittent power output. Furthermore, the evaluation of limitations in transport capacities requires a geographic disaggregation of demand and supply. For this reason, multi-node

models are becoming more and more state-of-the-art in energy system modeling.

In order to compare different possible system configurations concerning a specific criterion, such as costs, energy losses or GHG emissions, energy system models typically make use of optimization algorithms. In doing so, different mathematical approaches are applied, including linear programming, mixed-integer linear programming, quadratic programming and non-linear programming. All these approaches have in common that an objective function is minimized or maximized under a set of constraints. They, however, differ in the mathematical formulation of the objective function and constraints, which influences the complexity of the problem and thus its solution time. Given that REMix-OptiMo relies on a linear programming approach, the mathematical formulation of such problems will be introduced in detail. For a comprehensive overview of formulation and solution, as well as advantages and disadvantages of other optimization methods, refer to [104].

The standard problem of linear programming consists of a linear objective function that has to be optimized under the consideration of a set of linear constraints limiting the solution space:

$$\max / \min \{ \mathbf{c}^T \mathbf{x} \mid \mathbf{A} \mathbf{x} = \mathbf{b}, \mathbf{x} \geq 0 \}. \quad (4.1)$$

It is characterized by a function

$$z = c_0 + \sum_{j=1}^n c_j \cdot x_j \quad (4.2)$$

with the n -dimensional vectors $x_j = (x_1, x_2, \dots, x_n)$ of decision variables and $c_j = (c_1, c_2, \dots, c_n)$ of objective function coefficients, which is maximized or minimized under the constraints

$$\sum_{j=1}^n a_{ij} \cdot x_j = b_i \quad \text{for } i = 1, 2, \dots, m \quad (4.3)$$

$$x_j \geq 0 \quad \text{for } j = 1, 2, \dots, n. \quad (4.4)$$

In Eq. 4.3, the m -dimensional vector $b_i = (b_1, b_2, \dots, b_m)$ contains the constraint constants, whereas the $n \times m$ -matrix composed of a_{ij} represents the technology parameter.

The development and improvement of solution procedures of linear programming problems is a vital field of mathematical research. The most common solution algorithm is the Simplex method, introduced by Dantzig [33]. Other approaches include the interior point method of Karmarkar [105] and the ellipsoid method of Khachiyan [108]. A profound introduction to the these and other solution algorithms is for example provided by [156].

The main advantage of linear programming compared to other optimization approaches consists in its efficiency in the solution of large equation systems. It typically provides mathematically unique solutions with a comparatively high traceability. The central downside of linear programming lies in the inability to integrate non-linear nexuses into the optimization. Additionally, it sometimes establishes extreme solutions, which are very unstable against parameter variations [116].

4.2 REMix-OptiMo Model Environment

REMix-OptiMo is a deterministic linear optimization program realized in GAMS.¹ It has been developed as core element of the REMix modeling environment, with the aim of providing a powerful tool for the preparation and assessment of future energy supply scenarios based on a power supply system representation in high spatial and temporal resolution. Starting with renewable energy technologies, different power generation technologies have been included in the model. Previous model applications range from least-cost green-field capacity expansion analysis [168] to validation of long-term scenarios of European power supply [180] and impact assessment of electric mobility on renewable energy integration [125]. REMix-OptiMo has been continuously enhanced in level of detail and technology number. Recently, it has been furthermore integrated into a configuration system, which significantly increased the model functionality and flexibility.² REMix-OptiMo is set up in a modular structure. Four different types of modules can be distinguished: basic modules, support modules, technology modules and scenario modification modules. Table 4.1 provides an overview of the module types and features some examples. Modules can be easily added, as well as switched on and off. A number of basic and support modules are always required, whereas most technology modules are completely independent of each other.

Table 4.1 REMix-OptiMo module types

Type	Functionalities	Examples
Basic	Provision of model framework, linking of demand and supply, accounting	Power and heat balance, power and heat demand, emission and fuel consumption accounting
Support	Model output, data validation, data processing	Creation of output files, automated plotting, consistency checks
Technology	Representation of technology characteristics	Conventional power plants, heat pumps, electric cars
Scenario	Automated input data provision	Scaling of input data from one to other data nodes

REMix-OptiMo is a multi-node model. Demand and supply within predefined regions are aggregated to model nodes, which can be connected through electricity grids. Within the nodes, all generation units of each technology are grouped and treated as one single power or heat producer. Solution time has always been a critical issue in the REMix-OptiMo development; it increases approximately according to a power function with the numbers of

¹General Algebraic Modeling System (GAMS) is a modeling system for mathematical programming and optimization (www.gams.com).

²The REMix-OptiMo Management Tool OMaT provides a number of improvements in model application and troubleshooting. A graphical user interface enables an easier handling, including faster changes in technology and scenario input data, as well as technologies considered. With the graphical interface, scenarios, scenario modifications and sensitivity analysis cases are easily set up and managed. Another important feature is automated input parameter consistency checks, which identify missing, implausible and contradictory data. OMaT has been designed and implemented predominantly by Dominik Heide at DLR.

model nodes and technologies. Simple measures to reduce solution time include aggregation in space, time and technology. For this reason, the model allows for quick and automatized changes of spatial and temporal resolution. A distinction is made between data nodes on the one hand and model nodes on the other. Input in data node resolution is aggregated or distributed to model nodes according to a user-defined mapping. If required, model runs can be limited to one or a few model nodes. Typically, the system operation during one year is optimized. The model, however, also allows for the consideration of shorter periods. Default temporal resolution is one hour, but can be decreased in order to reduce the model solution time. Variables and parameters described as hourly values in this section always refer to one time-step. If temporal resolution is reduced, average values of the high resolution data input are formed. REMix-OptiMo relies on a perfect foresight modeling approach and optimizes over the overall time horizon. This implies the assumption of a foreseeable future within the chosen optimization interval and thus the negligence of forecasting uncertainties.

REMix-OptiMo is designed to offer a high flexibility concerning geographical or technological focus. All modules can in principle be applied to regions of all sizes, ranging from world regions to single cities. To date the model input data is however clearly focused on the assessment of Germany, Europe, Northern Africa and the Middle East.

Most technology modules not only allow for technology operation, but optionally also for capacity expansion analyses. Additional power plant, transmission line or storage capacity can be optimized by the model according to the available potentials and system requirements.³ Investments in new capacities consider the technology costs, as well as an amortization time and interest rate. They allow for the calculation of proportionate capital costs for the chosen optimization interval. Given that the REMix-OptiMo model used in this work relies on simple linear programming, any non-integer value of additional capacities can be realized. This implies that technically unrealistic capacity expansions might result. In order to avoid this problem, other modeling approaches as for example mixed-inter linear programming, have to be applied. They, however, come along with longer model solution times.

In order to broaden the spectrum of model application, selected technologies have been implemented with different degree of detail. They include concentrated solar power, conventional power plants and electric vehicles, which have been special foci of other studies [69, 125]. REMix-OptiMo is characterized by its objective function, boundary conditions and constraints. The latter are parametrized using a comprehensive set of input data. Model variables comprise technology-specific power generation, heat production, power transmission and storage in each time step and model region. If a capacity expansion is considered, the additional capacities in each region are furthermore taken into account. The objective function that is minimized contains the sum of system costs in the overall investigation area. Its composition depends on the set of active technology modules (see Section 4.6). Constraints arise from

³The additional optimization of capacities increases the model solution time, and can therefore be switched on and off by the usage of Boolean parameters. Boolean parameters are furthermore used for the definition of technological characteristics, which are not identical for all technologies represented by one specific module (see e.g. CHP module description in Section 4.5.9)

technology-specific model equations and inequalities on the one hand, and the power and heat balance on the other. They are introduced in the following Sections 4.3 to 4.6.

4.3 Modeling of Power Generation, Storage and Grids

After the enhancement done in the framework of this thesis, REMix-OptiMo comprises around 20 technology modules, describing power generation technologies, heat production technologies or balancing options. The latter include storage, demand response, transmission grids, as well as electric vehicles and hydrogen production for the transport sector. Figure 4.1 provides an overview of the detailed set-up of the model, as well as the available technologies modules.

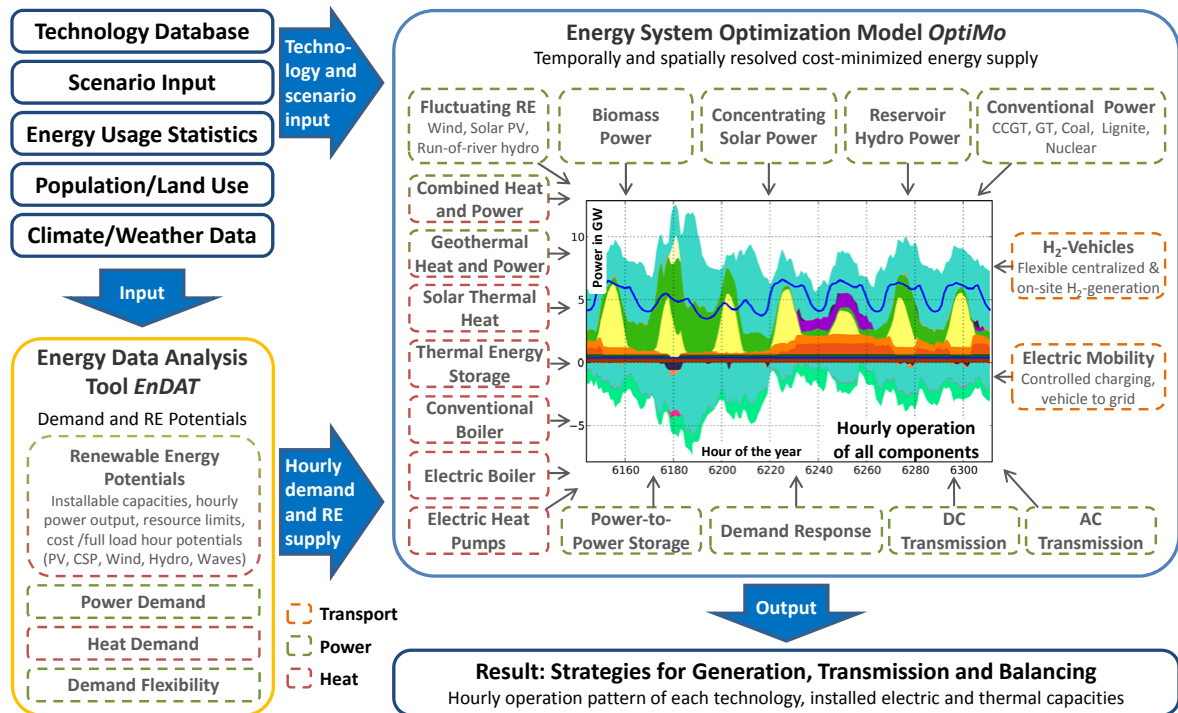


Figure 4.1 Detailed structure of REMix-EnDAT and REMix-OptiMo.

In each module, parameters, variables, equations and inequalities required for the representation of respective technical and economic characteristics are defined. Typically, a number of approximations and simplifications need to be done in the modeling process, striking a balance between a true to life mathematical description of technological characteristics and a reduction in the degree of complexity allowing for reasonable computing time. Power generation, storage and grid technologies are mostly represented by their available and maximum installable capacity, investment and operation costs, as well as efficiency.

In its previous set-up, REMix-OptiMo was focused on power supply and demand. A detailed discussion of mathematical equations representing the essential characteristics of power generation, storage and transmission technology modules can be obtained from [125, 168, 180]. All technology modules not developed within the scope of this work are described qualitatively in the following.

4.3.1 Renewable Energy Power Generation

Renewable electricity generation technologies in REMix-OptiMo comprise offshore wind, onshore wind, solar photovoltaic (PV), concentrated solar (CSP), hydro run-of-river, reservoir hydro, biomass and geothermal power. Given that both biomass and geothermal heat can also be used for a combined heat and power generation, these technologies have been included into the corresponding modules introduced in Section 4.5.8 and 4.5.9, respectively.

Fluctuating Renewable Energies

Intermittent renewable power technologies without storage - such as wind, PV and hydro run-of-river - are treated in one module. REMix-EnDAT provides maximum installable capacities and normalized hourly power generation profiles for each technology. The maximum capacity sets the upper limit for capacity optimization.⁴ Curtailments of fluctuating renewable power can be enabled, and the model assures that the hourly power output equals sum of grid feed-in and curtailment. Electricity costs consider investment, as well as fixed and variable operation and maintenance expenditures.

Reservoir Hydro Power

In contrast to run-of-river stations, reservoir hydroelectric power plants have a storage option. This enables both the provision of adjustable renewable electricity and pumped hydro storage. The REMix-OptiMo module of reservoir hydro stations takes into account capacities of all major plant components: turbine, storage reservoir and pump. A capacity expansion of turbines and pumps can be included in the assessment, as well as revision outages and minimum turbine flow rates. The added turbine and pump capacity are independent of each other and linked to respective capital expenditures. Hourly time series provide the average natural inflow to the water reservoirs in each data node.

Concentrating Solar Power

CSP plants can be equipped with thermal energy storage and back-up firing systems allowing for a round the clock power generation. In REMix-OptiMo, the installed capacities of all components can be either defined by the user or optimized by the model. If the power plant dimensioning is optimized, fixed values of solar multiple and TES size can be considered. Alternatively, the dimensioning of all components can be optimized separately. An upper limit to the power generation share of the back-up unit can be defined. Down regulation of the solar power output is optional. With all capacities set, REMix-OptiMo optimizes the hourly operation of CSP plants. The hourly thermal output of the solar field is provided as an input by REMix-EnDAT. The TES energy balance takes into consideration hourly changes in the storage level caused by charging, discharging and self-discharging, according to Eq. 4.39. Thermal energy losses arising during storage charging and discharging can be defined.

⁴The calculation of fluctuating renewable power generation potentials and hourly time series with REMix-EnDAT is thoroughly described in [168, 180]

4.3.2 Conventional Power Generation

Conventional power plants comprise nuclear, hard coal, brown coal and gas stations. A fundamental difference to all other REMix-OptiMo technology modules is the integration of power plant construction dates. The overall installed capacity is broken down to commissioning decades. According to the power plant age, different technological parameters can be applied. This is particularly important regarding power block efficiencies and variable operation costs. Additional features are the optional consideration of internal power consumption, minimum full load hours, power change wear and tear costs, as well as carbon capture and storage (CCS) technology. Technology capacity expansion can be included with or without setting upper threshold values.

4.3.3 Electricity-to-electricity Energy Storage

This module is designed to represent storage technologies with electric power input and output, such as pumped hydro storage, compressed air storage or batteries. Energy storage unit and converter unit are modeled separately in REMix-OptiMo. Hourly power input, output and storage level are limited by the corresponding installed capacities. Storage capacity optimization can be performed either with or without maximum installable capacities and a fixed storage-to-converter ratio. Resource limits and capital costs are assessed independently for storage and converter unit. Losses during charging, discharging and storing can be considered, and are integrated into the hourly storage level balance equation equivalent to the implementation in the thermal storage module (see Eq. 4.39).

4.3.4 Transmission Grids

In the current model set-up, Alternating Current (AC) and Direct Current (DC) transmission grids are included. Their representation is focused on the electricity exchange between greater model regions, and do not account for single grid nodes. Distribution grids are not considered in the model.

Alternating Current Transmission Grid

In contrast to detailed models applied in the transmission grid extension planning, the AC grid representation in REMix-OptiMo exhibits a high degree of abstraction. The technological representation relies on a DC load flow approximation, which implies that nonlinear power flows and losses are considered as linear. This modeling approach relies on [93], a detailed description of the representation in REMix-OptiMo is provided by [180]. The AC grid model does not take into account single lines or nodes, but aggregated links between regions. The module calculates the matrices describing the mapping of power flows over links to power injections into the modeled regions. It is considered that the impedance of the links scales with the link length, however generalized electric resistances and inductive reactances are applied. Grid losses are assumed to be proportional to the power transmission. Module input are existing interconnections, distances between regions and transmission line maximum

capacities (net transfer capacities, NTC), output is the active power flow over transmission lines in each time-step.

Direct Current Transmission

High voltage direct current (HVDC) technology can combine long distance power transport with comparatively low losses. In this module, DC power transmission technologies with different capacities and voltages can be implemented. Concerning costs and transmission losses, a differentiation between underground or sea cables on the one hand, and overhead lines on the other, can be made. HVDC interconnections and transmission capacities between model nodes can be user-defined or added in the optimization. This allows for the development of grid extension scenarios. Power losses are taken into account based on distances between the model nodes and scale linearly with power transmission.

4.4 Modeling of Flexible Electric Loads

In this section, concept and modeling details of flexible power consumption in REMix-OptiMo are introduced. It contains all equations and inequalities implemented in the demand response technology module. REMix-OptiMo input generally consists of sets and parameters. Parameters provide the technology and scenario input data for the GAMS optimization, whereas sets are the indices that specify the domains of parameters, variables and equations. The most important sets used in the following are technologies (X), model nodes (N_{model}), load shift classes (H_{DR}), heat groups (G_{heat}) and heat supply components (K_{heat}). In order to enable the assessment of various scenario years with one model configuration, an additional set $Y_{scenario}$ containing all years has been implemented. It is typically used for the application of different scenario and technology input parameter. Given that in its current configuration, REMix-OptiMo is designed for the simulation of the system dispatch during one selected scenario year, all equations are however only applied to one element of the set $Y_{scenario}$. Consequently, the corresponding variable dimension Y has only one value, and is for this reason not explicitly included in the representation of model equations. For better readability of the model equations, parameters and variable are displayed differently. By derogation from the mathematical convention used in Eq. 4.1, in the following variables are always written in bold font and parameters in normal font. All model variables introduced in this chapter can have only positive values. In order to make the model description more readable, the corresponding boundary conditions are generally not included in the representation of equations. All equations posing a constraint are denoted with the equality symbol " $\stackrel{!}{=}$ ", all others with the common symbol " $=$ ".

4.4.1 Demand Response Modeling Concept

Flexible consumers are modeled in REMix-OptiMo as electricity storage with limitations in storage time and availability. The latter includes temporal fluctuations in charging and discharging capacity on the one hand, and restrictions in frequency and duration of use on the

other. In case of load shifting, the storage time of DR is limited by the maximum shifting time $t_{shiftMax}$. It defines until when load increases and decreases have to be balanced at latest. Typically, load shifting provides a certain flexibility regarding the time that passes before loads need to be balanced again. This implies that all shifting times $t_{shift} \leq t_{shiftMax}$ can be realized. Consequently, the balancing of previous load shifts in time step t ranges between an upper limit set by the delta of all shifted and not yet balanced load and a lower limit defined by the delta of still unbalanced load shifts conducted until $t - t_{shiftMax}$. Equation 4.5 and 4.6 reflect the corresponding conditions for the balancing load $P_{balanceRed}$ of a previous load reduction $P_{reduction}$. In contrast to load shifting, for shedded load no balancing is required.

$$P_{balanceRed}^{N,X}(t) \leq \sum_{t'=0}^t \left(\frac{P_{reduction}^{N,X}(t')}{\eta_{DR}^X} - P_{balanceRed}^{N,X}(t') \right) \quad (4.5)$$

$$P_{balanceRed}^{N,X}(t) \geq \sum_{t'=0}^{t-t_{shiftMax}} \frac{P_{reduction}^{N,X}(t')}{\eta_{DR}^X} - \sum_{t'=0}^t P_{balanceRed}^{N,X}(t') \quad (4.6)$$

$$\forall N \in N_{model}, \forall X \in X_{DR}$$

An implementation of the accurate load balancing equations 4.5 and 4.6 into REMix-OptiMo turned out to be inexpedient. The multiple usage of temporal sums that connect all time-steps of the annual calculation lead to extremely long model solutions times. In order to reduce model solution time, fixed shifting times are implemented instead. This implies that the moment of balancing of shifted load is already set when the load is increased or reduced at first. Of course, this approximation affects the flexibility of DR. The impact of fixed shifting times on the model representation of load modifications can be reduced by the definition of various shifting times for each DR technology. One and the same consumer with a maximum shifting time of three hours can be, for example, be shifted for one hours, two hours or three hours. Of course, the model then needs to assure that all flexible load is only shifted once. Figure 4.2 exemplary shows the distribution of the flexible load provided by one DR technology to various shift classes.

The linear programming approach of REMix-OptiMo requires some further approximations in the modeling process. Without the consideration of discrete programming methods, it is not possible to directly link the DR operation of different time-steps. This affects the realization of limitations in the duration of DR load changes, as well as intervals between load interferences. Instead of measuring these time spans directly, restrictions in duration and frequency are implemented by

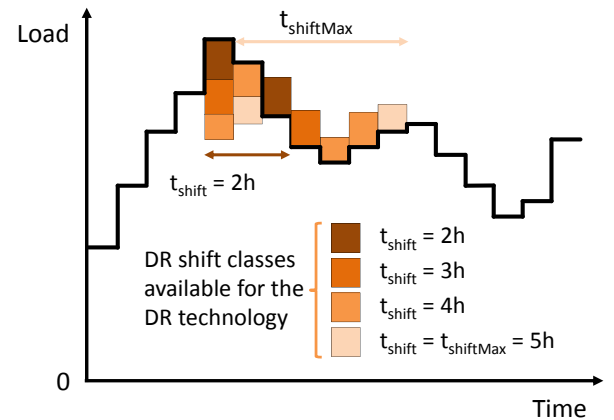


Figure 4.2 Exemplary illustration of the DR modeling concept in REMix-OptiMo

assessing the amount of reduced or increased demand within predefined periods. In the REMix-OptiMo power balance, flexible loads are considered as additional demand in case of load increase and additional generation in case of load reduction.

The developed modeling concept requires the introduction of a set H_{DR} containing the DR shifting classes with all possible shift times of each DR technologies $X \in X_{DR}$. Each member of the set H is explicitly associated to one DR technology X . The mapping of DR shifting classes to DR technologies is done in REMix-OptiMo and can be easily adjusted.

For each DR shifting class H , node N and time-step t , four variables are included in the optimization: load reduction $P_{reduction}(t)$, load increase $P_{increase}(t)$, balancing of previous load reductions $P_{balanceRed}(t)$ and balancing or previous load increases $P_{balanceInc}(t)$. Duration of load interference and amount of shifted load are assessed for each DR technology X , node N and time-step t making use of fictitious DR storage levels for both delayed $W_{levelRed}(t)$ and advanced loads $W_{levelInc}(t)$, which contain all shifted and not yet balanced energy.

REMix-OptiMo input to the DR module comprises available flexible loads, as well as their technical and economic characteristics. The latter include shifting time t_{shift} , interference time $t_{interfere}$, efficiency η_{DR} , waiting time between two subsequent DR interventions $t_{dayLimit}$ and annual limit $n_{yearLimit}$ on the one hand, and specific access costs $c_{specInv}$, annual provision costs c_{OMFix} , as well as specific application costs c_{OMVar} on the other. Available loads are characterized by the overall electric capacity of DR consumers P_{maxCap} , the capacity that is already equipped with the required ICT infrastructure $P_{existCap}$, and the hourly availability of these capacities for a load reduction $s_{flex}(t)$ and load increase $s_{free}(t)$. Normalized hourly values of flexible loads are obtained by dividing the hourly maximum load decrease and increase $P_{flex}(t)$, $P_{free}(t)$ by the maximum capacity P_{maxCap} . In addition to the operation of DR resources, an expansion of the DR capacity $P_{addedCap}$ by the exploitation of untapped potentials can be optimized. In the following, all equations defining the DR usage in REMix-OptiMo are introduced in detail.

4.4.2 Demand Response Model Equations

Installed Electric Capacity of Demand Response Consumers

The electric capacity of processes and appliances that can in principle contribute to DR is limited by the available potential P_{maxCap} according to Eq. 4.7. It is composed of those loads already manageable via an ICT infrastructure P_{exCap} and those that can be accessed by investing in DR P_{adCap} . If no DR capacity installation is considered, P_{adCap} is set to zero.

$$P_{existCap}^{N,X} + P_{addedCap}^{N,X} \stackrel{!}{\leq} P_{maxCap}^{N,X} \quad \forall N \in N_{model}, \forall X \in X_{DR} \quad (4.7)$$

Load Shifting, Shedding and Balancing

All shifted loads need to be balanced after a given shift time t_{shift} . This concerns both load reduction ($\mathbf{P}_{red}, \mathbf{P}_{balRed}$) and load increase ($\mathbf{P}_{inc}, \mathbf{P}_{balInc}$) and has been implemented according to Eq. 4.8 and 4.9, respectively. If load is shedded instead of shifted, no balancing is required, thus: $\mathbf{P}_{balRed}(t) \stackrel{!}{=} 0$. Equation 4.8 and 4.9 contain a DR efficiency η_{DR} , describing a potential increase in energy demand caused by load shifting.

$$\mathbf{P}_{balanceRed}^{N,H}(t) \stackrel{!}{=} \frac{\mathbf{P}_{reduction}^{N,H}(t - t_{shift}^H)}{\eta_{DR}^H} \quad (4.8)$$

$$\mathbf{P}_{balanceInc}^{N,H}(t) \stackrel{!}{=} \mathbf{P}_{increase}^{N,H}(t - t_{shift}^H) \cdot \eta_{DR}^H \quad (4.9)$$

$$\forall t, \forall N \in N_{model}, \forall H \in H_{DR} \quad (4.10)$$

Maximum load decrease $\mathbf{P}_{reduction}$ and increase $\mathbf{P}_{increase}$ in each hour of the year are defined by the overall installed capacity and its current availability for DR given by $s_{flex}(t)$ and $s_{free}(t)$, respectively. Bearing in mind that the loads of one and the same DR technology X can be used by various shifting classes H , it must be assured that the overall load shift is lower than the available potential, as described by Eq. 4.11 and 4.12. The assignment of shifting classes to DR technologies is in the following denoted by the symbol $\mapsto$.

$$\sum_{H \mapsto X} \left(\mathbf{P}_{reduction}^{N,H}(t) + \mathbf{P}_{balanceInc}^{N,H}(t) \right) \stackrel{!}{\leq} \left(\mathbf{P}_{existCap}^{N,X} + \mathbf{P}_{addedCap}^{N,X} \right) \cdot s_{flex}^{N,X}(t) \quad (4.11)$$

$$\sum_{H \mapsto X} \left(\mathbf{P}_{increase}^{N,H}(t) + \mathbf{P}_{balanceRed}^{N,H}(t) \right) \stackrel{!}{\leq} \left(\mathbf{P}_{existCap}^{N,X} + \mathbf{P}_{addedCap}^{N,X} \right) \cdot s_{free}^{N,X}(t) \quad (4.12)$$

$$\forall t, \forall N \in N_{model}, \forall X \in X_{DR}$$

In the model, a storage level $\mathbf{W}_{level}(t)$ is defined for both reduced and increased loads. It represents the amount of all shifted and not yet balanced load, comparable to a storage filling level. Its hourly balances are given by Eq. 4.13 and 4.14, respectively.

$$\Delta t \cdot \sum_{H \mapsto X} \left(\mathbf{P}_{reduction}^{N,H}(t) - \mathbf{P}_{balanceRed}^{N,H}(t) \cdot \eta_{DR}^H \right) \stackrel{!}{=} \mathbf{W}_{levelRed}^{N,X}(t) - \mathbf{W}_{levelRed}^{N,X}(t-1) \quad (4.13)$$

$$\Delta t \cdot \sum_{H \mapsto X} \left(\mathbf{P}_{increase}^{N,H}(t) \cdot \eta_{DR}^H - \mathbf{P}_{balanceInc}^{N,H}(t) \right) \stackrel{!}{=} \mathbf{W}_{levelInc}^{N,X}(t) - \mathbf{W}_{levelInc}^{N,X}(t-1) \quad (4.14)$$

$$\forall t, \forall N \in N_{model}, \forall X \in X_{DR}$$

The DR storage level is used for restricting shifted and not yet balanced energy and thus duration of DR interventions. Its upper limit is calculated from the maximum duration of DR interventions $t_{interfere}$ and the average available DR load $\bar{s}_{flex}$ of the corresponding technology,

as described by Eq. 4.15 and 4.16. Due to temporal variations of load flexibility, for some technologies this formulation provides only an approximate limit in DR duration.

$$W_{levelRed}^{N,X}(t) \stackrel{!}{\leq} \left(P_{existCap}^{N,X} + P_{addedCap}^{N,X} \right) \cdot \bar{s}_{flex}^{N,X} \cdot t_{interfere}^X \quad (4.15)$$

$$W_{levelInc}^{N,X}(t) \stackrel{!}{\leq} \left(P_{existCap}^{N,X} + P_{addedCap}^{N,X} \right) \cdot \bar{s}_{free}^{N,X} \cdot t_{interfere}^X \quad (4.16)$$

$$\forall t, \forall N \in N_{model}, \forall X \in X_{DR}$$

In most cases, DR loads cannot be advanced, delayed, as well as shedded. For this reason, Boolean parameters defining the available DR measures are implemented. If no shedding or delaying of load is allowed, load reduction, DR storage level and balancing are set to zero: $P_{reduction}(t) = P_{balanceRed}(t) = W_{levelRed}(t) \stackrel{!}{=} 0 \forall t$. Analogically, it is implemented that load increase is only possible for technologies X with capability of advancing demand.

Limits in Frequency of Demand Response

DR utilization may be limited in frequency (see Chapter 2). In REMix-OptiMo, two different restrictions are implemented, both posing limits to the amount of shifted or shedded energy. One affects the annual number of DR applications $n_{yearLimit}$ and thus overall DR energy (Eq. 4.17 and 4.18), whereas the other can be applied to limit the DR utilization within a predefined time-span $t_{dayLimit}$ (Eq. 4.19 and 4.20). The calculation of maximum amounts of shifted or shedded energy again relies on the average DR potential, as well as the maximum duration of DR interventions. Restrictions in duration and frequency of DR interferences included in the model are implemented as optional, and can be easily activated or deactivated.

$$\sum_t \sum_{H \mapsto X} P_{reduction}^{N,H}(t) \stackrel{!}{\leq} \left(P_{existCap}^{N,X} + P_{addedCap}^{N,X} \right) \cdot \bar{s}_{flex}^{N,X} \cdot t_{interfere}^X \cdot n_{yearLimit}^X \quad (4.17)$$

$$\sum_t \sum_{H \mapsto X} P_{increase}^{N,H}(t) \stackrel{!}{\leq} \left(P_{existCap}^{N,X} + P_{addedCap}^{N,X} \right) \cdot \bar{s}_{free}^{N,X} \cdot t_{interfere}^X \cdot n_{yearLimit}^X \quad (4.18)$$

$$\begin{aligned} \sum_{H \mapsto X} P_{reduction}^{N,H}(t) &\stackrel{!}{\leq} \left(P_{existCap}^{N,X} + P_{addedCap}^{N,X} \right) \cdot \bar{s}_{flex}^{N,X} \cdot t_{interfere}^X \\ &\quad - \sum_{t'=1}^{t'=t_{dayLimit}^X} \sum_{H \mapsto X} P_{reduction}^{N,H}(t-t') \end{aligned} \quad (4.19)$$

$$\begin{aligned} \sum_{H \mapsto X} P_{increase}^{N,H}(t) &\stackrel{!}{\leq} \left(P_{existCap}^{N,X} + P_{addedCap}^{N,X} \right) \cdot \bar{s}_{free}^{N,X} \cdot t_{interfere}^X \\ &\quad - \sum_{t'=1}^{t'=t_{dayLimit}^X} \sum_{H \mapsto X} P_{increase}^{N,H}(t-t') \end{aligned} \quad (4.20)$$

$$\forall t, \forall N \in N_{model}, \forall X \in X_{DR}$$

Demand Response Costs

REMIX-OptiMo considers annualized DR investment C_{invest} and operation C_{op} costs. Pre-requisite for DR is the equipment of flexible loads with an ICT infrastructure allowing for automatized or manual changes in demand. Making loads available can thus require an investment, which is assessed according to Eq. 4.21. The annuity $f_{annuity}$ is calculated based on amortization time t_{amort} and interest rate i as described in Eq. 4.22. DR costs are obtained from specific values per unit of installed capacity in case of investment ($c_{specInv}$) and fixed operational costs (c_{OMFix}), and per unit of shifted energy in case of variable operational cost (c_{OMVar}).

$$C_{invest} = \sum_N \sum_X P_{addedCap}^{N,X} \cdot c_{specInv}^X \cdot f_{annuity}^X \quad (4.21)$$

$$f_{annuity}^X = \frac{i \cdot (1+i)^{t_{amort}^X}}{(1+i)^{t_{amort}^X} - 1} \quad \forall X \in X_{DR} \quad (4.22)$$

The operational cost reflect the expenditures caused by the provision and utilization of flexible loads and are calculated according to Eq. 4.23.

$$C_{op} = \sum_N \sum_X \sum_{H \mapsto X} \sum_t \left(P_{reduction}^{N,H}(t) + P_{increase}^{N,H}(t) \right) \cdot c_{OMVar}^X + \sum_N \sum_X P_{addedCap}^{N,X} \cdot c_{specInv}^X \cdot c_{OMFix}^X \quad (4.23)$$

4.4.3 Controlled Charging of Electric Vehicles

A previous REMIX analysis has been focused on the impact of electric vehicles (EV) on the energy system [125]. There, a very detailed model representation of battery charging states and controlled charging modes, as well as vehicle-to-grid technology has been implemented and applied. In order to reduce the model complexity and solution time, in this work the consideration of EVs is limited to controlled charging and a simplified representation. The equations used are based on those developed for the representation of DR consumers and allow for a delayed charging of EVs. As for DR, different shifting classes H_{EV} are applied to each EV technology $X \in X_{EV}$. There is however no mapping from shifting classes to technologies, which implies that each shift time t_{shift} is assumed to be available for all EV types. Capacity optimization of EV with controlled charging function is not considered. The load available for shifting is given by the overall annual electricity demand of electric vehicles $W_{annual,EV}$, the hourly demand fraction $d_{hour,EV}(t)$ and the share of EVs available for controlled charging s_{ccEV} (see Eq. 4.24). Delayed load is balanced after the shift time t_{shift} according to Eq. 4.25. An increase in electricity demand arising from a modified charging behavior is not taken into account. Controlled EV charging is limited by the available charging capacity. The upper boundary is provided by the product of the maximum load of uncontrolled charging $d_{peak,EV}$

and the ratio $f_{cap2Peak}$ defining the charging power relative to the annual peak load (Eq. 4.26).

$$\sum_H P_{reduction}^{N,X,H}(t) \stackrel{!}{\leq} W_{annual,EV}^{N,X} \cdot d_{hour,EV}^{N,X}(t) \cdot s_{ccEV}^X \quad (4.24)$$

$$P_{balanceRed}^{N,X,H}(t) \stackrel{!}{=} P_{reduction}^{N,X,H}(t - t_{shift}^H) \quad (4.25)$$

$$\sum_H P_{balanceRed}^{N,X,H}(t) + W_{annual,EV}^{N,X} \cdot d_{hour,EV}^{N,X}(t) \stackrel{!}{\leq} W_{annual}^{N,X} \cdot d_{peak,EV}^{N,X}(t) \cdot f_{cap2Peak}^X \quad (4.26)$$

$$\forall t, \forall N \in N_{model}, \forall X \in X_{EV}$$

The cost assessment of controlled EV charging is limited to variable operational costs C_{op} , which are from specific charging control costs c_{OMVar} calculated according to Eq. 4.27.

$$C_{op} = \sum_N \sum_X \sum_H \sum_t P_{reduction}^{N,H}(t) \cdot c_{OMVar}^X \quad (4.27)$$

4.5 Modeling of Heat Demand and Supply

In this section, the REMix-OptiMo implementation of heat demand and supply is addressed. Primary emphasis of the modeling process is the representation of the coupling between heat and power market by CHP and HP technologies. After introducing the modeling concept in Section 4.5.1, the implementation of heat demand and supply are discussed in Section 4.5.2 to 4.5.9. In order to reduce the extent of this section, a couple of equations that are used in the modeling of various supply technologies are summarized in Section 4.5.3.

4.5.1 Concept of the Heating Sector Representation in REMix-OptiMo

In total, seven different heat supply technology components $K \in K_{heat}$ are implemented: CHP plants, geothermal power and heat plants, heat pumps, conventional boiler, electric boiler, solar thermal heat and thermal energy storage. A central scope of the modeling process has been the provision of a maximum flexibility in the combination of components to comprehensive supply systems. In addition, the economic competition of different supply options was intended to be reflected as detailed as possible.

Not all components can serve as stand-alone heat supply system: solar thermal heat and thermal energy storage are modeled as secondary components, which can only be used in combination with a principal heat component. Principal components include CHP, geothermal heat, heat pumps, electric boilers and conventional boilers. The latter three can be used both as principal or secondary component. Different components can be combined to supply technologies without further limitations. In the following, a combination of components is always referred to as technology. The mapping between components and technologies, which defines the composition of each technology $X \in X_{heat}$, is reflected by the symbol $K \mapsto X$ in all equations of this section. Each technology must be composed of at least one principal component. The technology example in Figure 4.3 shows a biogas DH supply system composed of

a CHP plant, a conventional peak boiler, an electric boiler, a thermal storage and solar heat panels.

For heat supply technologies composed of various components, the contribution of each component to the hourly heat supply is elementary optimization result. The dimensioning of supply components is defined relative to the annual peak or minimum load of the corresponding technology. It can be either set to a fixed value or endogenously determined by REMix-OptiMo. This allows for the identification of least-cost heat supply system configurations. The model structure assures that each technology covers its demand independently. This is an important difference to the power supply system, where all generation capacities and consumers are typically interconnected by a grid. In the heat sector model, it must be avoided that for example building heat pumps can contribute to the supply of spatially separate DH networks.

In order to additionally reflect the competition of selected technologies for a specific market segment, the model provides the possibility to assign various technologies to one heat group $G \in G_{heat}$. This enables, for example, an evaluation of least-cost supply shares of combined cycle gas turbines and coal-fired steam turbines in large DH systems. The share each heat group holds in the overall supply can either be predefined or determined by the model. All technologies must be assigned to exactly one heat group ($X \mapsto G$). If no competition between technologies is assessed, the set of heat groups G_{heat} is identical to that of heat technologies X_{heat} . This can be the case if the analysis is based on a scenario of installed capacities or technology market shares.

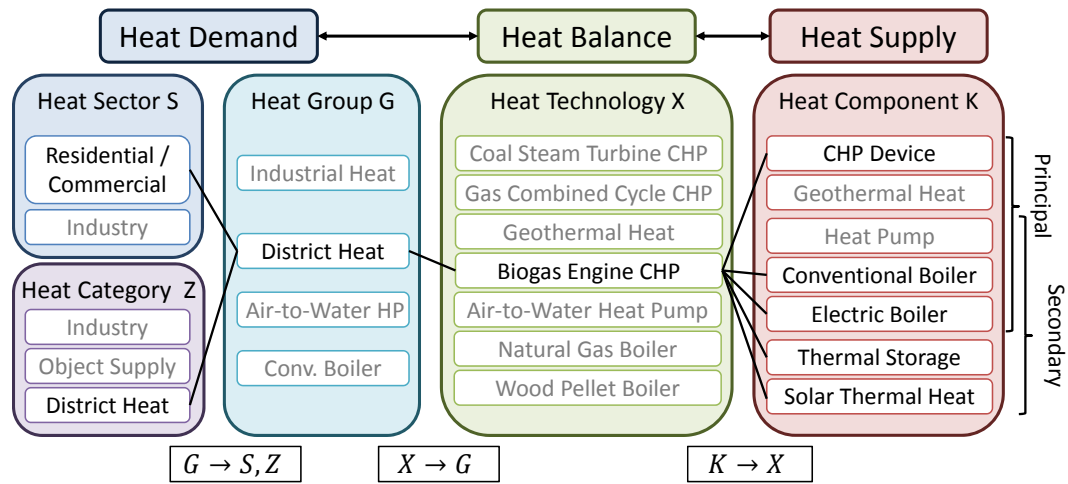


Figure 4.3 Structure of the heating sector model in REMix-OptiMo with all heat components K and examples for technologies X , groups G , categories Z and demand sectors S .

Each heat group G is attributed to a heat demand sector $S \in S_{heat}$, for example, industry or residential and commercial consumers. This selection defines the heat demand profile applied. From this construction arises that technologies that are used in various heat demand sectors are contained several times in the model. Their corresponding heat groups are then associated to different sectors ($G \mapsto S$). An additional assignment of each heat group G to

Table 4.2 Stages of heat supply optimization in REMix-OptiMo.

St.	Optimization scope	Optimized variables
1	Optimization of hourly technology component operation	Q_{gen}
2	+ Optimization of technology component dimensioning	$Q_{gen}, Q_{addedCap}$
3	+ Optimization of technology shares within the heat group	$Q_{gen}, Q_{addedCap}, h_{supply}^X$
4	+ Optimization of the heat group share in sectoral demand	$Q_{gen}, Q_{addedCap}, h_{supply}^X, h_{supply}^G$

a specific consumer category $Z \in Z_{heat}$ is used for the definition of fuel costs. This reflects the fact that one and the same fuel can have different prices depending on the consumer and its annual energy demand. Consumer categories may for example include industry, DH or building supply.

REMix-OptiMo reflects restrictions in annual fuel or heat source availability, as they may occur for biomass or geothermal heat. If different technologies compete for the same resource, the model assesses its optimum allocation to the technologies.

The complex structure of the heat sector representation provides a very high flexibility in the model application. It comprises four different stages of optimization, which can be easily selected by a set of Boolean parameters and are summarized in Table 4.2.

4.5.2 Heat Demand Model Equations

The overall heat demand can be split to different sectors within REMix-OptiMo. In the model application discussed in Chapter 5, two sectors are considered: industry on the one hand, and residential and commercial consumers on the other. The hourly heat demand $Q_{demand}(t)$ is calculated from the annual sum U_{year} and the hourly demand share $d(t)$. Within each demand sector S , the heat demand is covered by all technologies associated to one of the sectoral heat groups. The share h_{supply} each heat group holds in the supply can be either set to a fixed value or optimized. If an optimization is performed, lower and upper limits can be taken into account. Equation 4.28 has been implemented in the model to make sure that all heat group shares neither exceed their corresponding maximum value h_{max} , nor stay below the set minimum value h_{min} . Heat group shares that are not optimized are set to a predefined value h_{fixed} according to Eq. 4.29.

$$h_{min}^{N,G} \leq \sum_{X \mapsto G} h_{supply}^{N,X} \leq h_{max}^{N,G} \leq 1 \quad (4.28)$$

$$\sum_{X \mapsto G} h_{supply}^{N,X} \stackrel{!}{=} h_{fixed}^{N,G} \quad (4.29)$$

$$\forall N \in N_{model}, \forall G \in G_{heat}$$

If various technologies X are assigned to a heat group G , their combined heat supply share is limited to the group share. The technology supply shares are optimization result.

The product of technology supply share h_{supply} and hourly demand Q_{demand} defines the upper limit of the heat supply $Q_{supply}(t)$ of technology X according to Eq. 4.30. All heat that

cannot be supplied by the corresponding technologies is accounted for as unsatisfied demand $Q_{notSupplied}$, which creates additional costs $C_{notSupplHeat}$ (see Eq. 4.31 and 4.32).

$$Q_{supply}^{N,S,X}(t) \stackrel{!}{\leq} Q_{demand}^{N,S}(t) \cdot h_{supply}^{N,X} \quad \forall N \in N_{model} \quad (4.30)$$

$$\sum_{X \mapsto S} Q_{supply}^{N,S,X}(t) = Q_{demand}^{N,S}(t) - Q_{notSupplied}^{N,S}(t) \quad \forall N \in N_{model}, \forall S \in S_{heat} \quad (4.31)$$

$$C_{notSupplHeat} = \sum_N \sum_S \sum_t Q_{notSupplied}^{N,S}(t) \cdot c_{notSupplied} \quad (4.32)$$

4.5.3 Basic Heat Supply Model Equations

Each technology component has been programmed in an individual REMix-OptiMo module. It contains the equations and inequalities required for the representation of technical and economic constraints and relations. A number of equations is applied to different heat supply components, including heat production limit and component dimensioning, as well as investment and operation costs. They are introduced in the following.

Heat Generation Limit and Thermal Capacity Expansion

For all components, the hourly heat production Q_{gen} is lower or equal to the installed thermal capacity, composed of a exogenously defined existing capacity $Q_{existCap}$ and the endogenous optimization result $Q_{addedCap}$, as described by Eq. 4.33.

$$Q_{gen}^{N,X,K}(t) \stackrel{!}{\leq} (Q_{addedCap}^{N,X,K} + Q_{existCap}^{N,X,K}) \quad \forall t, \forall N \in N_{model}, \forall K \in K_{heat}, \forall K \mapsto X \quad (4.33)$$

The determination of heat production capacities differs for principal components on the one hand, and secondary components on the other. The installed capacity of secondary components is smaller or equal a limiting heat load given by the sectoral peak demand $d_{peak} \cdot U_{year}$, the supply share of the corresponding technology h_{supply} and the component-specific dimensioning parameter $f_{cap2Peak}$. The latter represents the thermal capacity of the component relative to the annual peak load of the corresponding heat supply technology and is exogenously defined either as fixed value, or as upper limit. In the case that the component dimensioning is fixed, Eq. 4.34 needs to be fulfilled, whereas in the case of an capacity optimization Eq. 4.35 is applied. Exogenously defined capacities of secondary components are not considered, $Q_{existCap}$ in Eq. 4.33 is consequently set to zero.

$$Q_{addedCap}^{N,X,K} \stackrel{!}{=} f_{cap2Peak}^K \cdot d_{peak}^N \cdot U_{year}^{N,S} \cdot h_{supply}^{N,X} \quad (4.34)$$

$$Q_{addedCap}^{N,X,K} \stackrel{!}{\leq} f_{cap2Peak}^K \cdot d_{peak}^N \cdot U_{year}^{N,S} \cdot h_{supply}^{N,X} \quad (4.35)$$

$$\forall N \in N_{model}, \forall K \in K_{heat}, \forall K \mapsto X, \forall X \mapsto S$$

For primary components, three different capacity dimensioning strategies are distinguished:

1. Dimensioning is not optimized and installed capacities are provided and not optimized: no capacities are added ($Q_{addedCap} = 0$).
2. Dimensioning is not optimized and installed capacities are optimized: additional capacities are determined according to Eq. 4.36, with fixed value of $f_{cap2Peak}$.

$$Q_{addedCap}^{N,X,K} + Q_{existCap}^{N,X,K} \stackrel{!}{=} f_{cap2Peak}^K \cdot d_{peak}^N \cdot U_{year}^{N,S} \cdot h_{supply}^{N,X} \quad (4.36)$$

$$\forall N \in N_{model}, \forall K \in K_{heat}, \forall K \mapsto X, \forall X \mapsto S$$

3. Dimensioning is optimized without any restriction and installed capacities may or may not be provided: no direct upper limit is applied to the installation of additional capacities. The capacity can be implicitly limited by the corresponding heat group supply share.

Heat Cost Calculation

The cost calculation is identical for most heat supply components. On the one hand, the proportional capital cost C_{invest} of newly installed systems is considered (Eq. 4.37), on the other hand fixed and variable heat supply costs C_{op} (Eq. 4.38). Overall costs are determined from specific investment $c_{specInv}$, as well as fixed c_{OMFix} and variable c_{OMVar} operational costs. The latter include heat distribution costs, which are calculated for each unit of supplied heat and are defined by the model parameter c_{dist} .

$$C_{invest}^X = \sum_N \sum_{K \mapsto X} Q_{addedCap}^{N,X,K} \cdot c_{specInv}^X \cdot f_{annuity}^X \quad (4.37)$$

$$C_{op}^X = \sum_N \sum_{K \mapsto X} \sum_{X \mapsto G} \sum_t Q_{gen}^{N,X,K}(t) \cdot \left(c_{OMVar}^X + \left(1 - s_{distLoss}^{N,G} \right) \cdot c_{dist}^{N,G} \right) + \sum_N \sum_{K \mapsto X} Q_{addedCap}^{N,X,K} \cdot c_{specInv}^X \cdot c_{OMFix}^X \quad (4.38)$$

$$\forall X \in X_{heat}$$

Further conditions and restrictions in the operation of heat supply components are described in the subsequent Sections 4.5.4 to 4.5.9.

4.5.4 Thermal Energy Storage Model Equations

The thermal energy storage module in REMix-OptiMo is designed to represent a broad range of different technologies. It can be used for high temperature latent heat storage units, as well as DH water tanks or buffer storage devices in individual buildings. Central equation is the storage balance, which reflects all variations in the filling level. It assures that in every time-step the change in storage level U_{level} equals the sum of storage input Q_{charge} , output $Q_{discharge}$ and self discharge η_{self} (Eq. 4.39). Losses arising at charging (η_{charge}) or discharging ($\eta_{discharge}$) are also considered in the balance equation. The module only

considers the energy content, not the temperature gradation within the storage. A limit in storage charging Q_{charge} or discharging $Q_{discharge}$ capacity has not been implemented.

$$\begin{aligned} \Delta t \cdot \left(Q_{charge}^{N,X,K}(t) \cdot \eta_{charge}^K - \frac{Q_{discharge}^{N,X,K}(t)}{\eta_{discharge}^K} \right) - \frac{1}{2} \left(U_{level}^{N,X,K}(t) + U_{level}^{N,X,K}(t-1) \right) \cdot \eta_{self}^K \\ \stackrel{!}{=} U_{level}^{N,X,K}(t) - U_{level}^{N,X,K}(t-1) \end{aligned} \quad (4.39)$$

$\forall t, \forall N \in N_{model}, \forall K \in K_{TES}, \forall K \mapsto X$

The storage filling level is limited by the installed storage capacity according to Eq. 4.40.

$$U_{level}^{N,X,K}(t) \stackrel{!}{\leq} U_{addedCap}^{N,X,K} \quad \forall t, \forall N \in N_{model}, \forall K \in K_{TES}, \forall K \mapsto X \quad (4.40)$$

The storage capacity $U_{addedCap}$ is defined by the annual peak demand of the corresponding heat technology and the storage-to-peak factor $f_{stor2Peak}$, which represents the number of peak demand hours that can be stored. Depending on the selected mode, $f_{stor2Peak}$ is used as fixed value (Eq. 4.41) or upper limit in a storage capacity optimization (Eq. 4.42).

$$U_{addedCap}^{N,X,K} \stackrel{!}{=} f_{stor2Peak}^K \cdot d_{peak}^N \cdot U_{year}^{N,S} \cdot h_{supply}^{N,X} \quad (4.41)$$

$$U_{addedCap}^{N,X,K} \stackrel{!}{\leq} f_{stor2Peak}^K \cdot d_{peak}^N \cdot U_{year}^{N,S} \cdot h_{supply}^{N,X} \quad (4.42)$$

$$\forall N \in N_{model}, \forall K \in K_{heat}, \forall K \mapsto X, \forall X \mapsto S$$

Operational costs of thermal storages are calculated according to 4.43. For the investment costs calculation, Eq. 4.37 is used, substituting $Q_{addedCap}$ by $U_{addedCap}$ and using specific investment costs ($c_{specInv}$) referring to the storage reservoir size.

$$\begin{aligned} C_{op}^X = \sum_N \sum_{K \mapsto X} \sum_{X \mapsto G} \sum_t \left(Q_{charge}^{N,X,K}(t) \cdot \left(c_{OMVar}^X + \left(1 - s_{distLoss}^{N,G} \right) \cdot c_{dist}^{N,G} \right) \right) \\ + \sum_N \sum_{K \mapsto X} U_{addedCap}^{N,X,K} \cdot c_{specInv}^X \cdot c_{OMFix}^X \quad \forall X \in X_{TES} \end{aligned} \quad (4.43)$$

4.5.5 Solar Heat Model Equations

The hourly heat output Q_{gen} of solar thermal collectors is assessed based on the installed capacity $Q_{addedCap}$ and country-specific solar heat production profiles r_{solar} . Depending on the availability of a cooling device for heat that can be neither used nor stored – which is optional in the model – the solar heat output is calculated according to 4.44 or 4.45, respectively.

$$Q_{gen}^{N,X,K}(t) \stackrel{!}{=} Q_{addedCap}^{N,X,K} \cdot r_{solar}^N(t) \quad (4.44)$$

$$Q_{gen}^{N,X,K}(t) \stackrel{!}{\leq} Q_{addedCap}^{N,X,K} \cdot r_{solar}^N(t) \quad (4.45)$$

$$\forall t, \forall N \in N_{model}, \forall K \in K_{solarHeat}, \forall K \mapsto X$$

The installed capacity of solar thermal collectors is expressed relative to the base load d_{min} and not the peak load. The capacity-to-base value $f_{cap2Base}$ of installed capacity can be provided as fixed or maximum value. Capacities are then calculated either according to Eq. 4.46 or 4.47. Investment and operation costs are obtained using Eq. 4.37 and 4.38, respectively.

$$Q_{addedCap}^{N,X,K} \stackrel{!}{=} f_{cap2Base}^K \cdot d_{min}^N \cdot U_{year}^{N,S} \cdot h_{supply}^{N,X} \quad (4.46)$$

$$Q_{addedCap}^{N,X,K} \stackrel{!}{\leq} f_{cap2Base}^K \cdot d_{min}^N \cdot U_{year}^{N,S} \cdot h_{supply}^{N,X} \quad (4.47)$$

$$\forall t, \forall N \in N_{model}, \forall K \in K_{solarHeat}, \forall K \mapsto X, \forall X \mapsto S$$

4.5.6 Electric Heat Pump Model Equations

Heat pump efficiencies are strongly depending on the temperature difference $\Delta\vartheta$ between heat source and heat sink. Given the considerable seasonal variations in ambient temperature, this is particularly important in the case of air source heat pumps. For this reason, the optional consideration of a heat source temperature profile has been implemented into the model. If a heat source temperature profile is provided, hourly values of heat pump coefficients of performance (COP) ε_{HP} are calculated using Eq. 4.48 and 4.49, taking into account the hourly average heat source temperature in each model node $\vartheta_{source}(t)$, as well as the average inlet temperature $\vartheta_{inletHP}$ of the corresponding heat application. For all temperature differences $\Delta\vartheta$ below a minimum value, a constant maximum efficiency is applied, which for higher temperature differences decreases exponentially determined by the constants a_1 and a_2 . This approximation relies on the analysis of measured data provided by [158, 159]. Alternatively, a constant COP ($\varepsilon_{HP}(t) = \varepsilon_{HP,max} \forall t$) can be applied to HP technologies relying on heat sources featuring only minor fluctuations in temperature.

$$\Delta\vartheta(t) = \vartheta_{inletHP}^K - \vartheta_{source}^N(t) \quad (4.48)$$

$$\varepsilon_{HP}^{N,K}(t) = \begin{cases} a_1^K \cdot \exp(a_2^K \cdot \Delta\vartheta(t)) & \text{for } \Delta\vartheta \geq 20K \\ \varepsilon_{HP,max}^K & \text{for } \Delta\vartheta < 20K \end{cases} \quad (4.49)$$

In REMix-OptiMo, electric heat pumps can be used either as primary or secondary heat supply component. In both cases, the hourly electricity demand is calculated from heat production and efficiency according to Eq. 4.50. The hourly HP output $Q_{gen}(t)$ is thereby restricted according to Eq. 4.33.

$$P_{elHeat}^{N,X,K}(t) = \sum_t \frac{Q_{gen}^{N,X,K}(t)}{\varepsilon_{HP}^{N,K}(t)} \quad \forall t, \forall N \in N_{model}, \forall K \in K_{HP}, \forall K \mapsto X \quad (4.50)$$

Depending on whether a technology is applied as primary or secondary component, HP capacities can be either provided or optimized with optional consideration of an upper limit (see Section 4.5.3). Investment and operation costs are obtained using Eq. 4.37 and 4.38, respectively.

4.5.7 Electric and Conventional Heat Boiler Model Equations

Both electric heating devices and conventional heat boilers are available as principal and secondary components of a heat supply system. Their maximum hourly heat production, capacity expansion and costs are calculated according to the equations in Section 4.5.3.

Beyond that, the electric boiler technology module accounts for the hourly electricity consumption P_{elHeat} , which is obtained by dividing the heat generation Q_{gen} by the thermal efficiency η_{th} of the boiler equivalent to Eq. 4.50.

The technology module representing conventional boilers is applied independent of the fuel and thermal capacity. In order to reduce the model complexity, all conventional boilers used as secondary component, for example as peak supply and back-up unit in DH systems are assumed to rely on the same fuel as the corresponding principal component. With the boiler efficiency η_{th} , the fuel consumption D_{fuel} in each time-step is calculated pursuant to Eq. 4.51.

$$D_{fuel}^{N,X,K}(t) = \frac{Q_{gen}^{N,X,K}(t)}{\eta_{th}^K} \quad \forall t, \forall N \in N_{model}, \forall K \in K_{boiler}, \forall K \mapsto X \quad (4.51)$$

For conventional boilers serving as principal components, a fuel type V has to be defined. Based on the hourly values, annual fuel demands D_{annual} are assessed using Eq. 4.52. If fuel consumption is constricted by resource availability - as it might be the case for biomass-fired boilers - Eq. 4.53 is considered. It assures that the overall fuel consumption stays below the annual resource limit E_{annual} of fuel V .

$$D_{annual}^{N,X,V} = \sum_t \sum_{K \mapsto X} \sum_{X \mapsto V} D_{fuel}^{N,X,K}(t) \quad \forall X \in X_{heat}, \forall V \in V_{fuel} \quad (4.52)$$

$$\sum_{X \mapsto V} D_{annual}^{N,X,V} \stackrel{!}{\leq} E_{annual}^{N,V} \quad \forall V \in V_{fuel} \quad (4.53)$$

In the calculation of annual fuel costs, the consumer category Z each technology is assigned to is taken into account. This assignment defines the specific fuel cost value applied. The technology fuel costs C_{fuel} in the overall study area are obtained by multiplying the specific fuel costs c_{fuel} with the overall fuel consumption D_{fuel} pursuant to Eq. 4.54.

$$C_{fuel}^X = \sum_N \sum_V D_{annual}^{N,V,X} \cdot c_{fuel}^{V,Z} \quad \forall X \in X_{heat}, X \mapsto Z \quad (4.54)$$

4.5.8 Geothermal Heat and Power Model Equations

Geothermal energy can be used for both heat and power supply. Electricity generation, however, requires high temperature resources, which are only available in deep underground. Due to the low temperature of the accessible resource, a coupled production of heat and power from geothermal energy cannot be achieved in central Europe. This implies that separate heating and power stations need to be constructed if both outputs are supposed to be used. Depending on the plant requirements, stations can be connected parallel or in series. The geothermal energy module in REMix-OptiMo comprises three different types of technology:

power stations, heat stations, as well as combined heat and power stations. Plants with both heat and power production use only one geothermal heat source. An increase in heat output consequently reduces the power generation and vice versa. The output proportion can be in each time-step adjusted to the current demand situation. The hourly heat and power output of geothermal units is limited by the existing ($Q_{existCap}$, $P_{existCap}$) and newly installed ($Q_{addedCap}$, $P_{addedCap}$) capacity, as well as its availability given by f_{Avail} . For power-only stations, Eq. 4.55 is applied, for stations with heat supply Eq. 4.56. The electric efficiency of geothermal power production is represented by η_{el} . Heat production Q_{gen} of power-only plants and power generation P_{gen} of heat-only plants are set to zero for all time-steps.

$$P_{gen}^{N,X,K}(t) \stackrel{!}{\leq} \left(P_{addedCap}^{N,X,K} + P_{existCap}^{N,X,K} \right) \cdot f_{avail}^K \quad (4.55)$$

$$\forall t, \forall N \in N_{model}, \forall K \in K_{geo}, \forall K \mapsto X$$

$$Q_{gen}^{N,X,K}(t) + \frac{P_{gen}^{N,X,K}(t)}{\eta_{el}^K} \stackrel{!}{\leq} \left(Q_{addedCap}^{N,X,K} + Q_{existCap}^{N,X,K} \right) \cdot f_{Avail}^K \quad (4.56)$$

$$\forall t, \forall N \in N_{model}, \forall K \in K_{geo}, \forall K \mapsto X$$

The installed capacity $Q_{addedCap}$ of geothermal technologies providing heat can be related to the technology share in overall supply by defining a fixed capacity-to-peak demand factor $f_{cap2Peak}$, and is then calculated according to Eq. 4.34. It can also be optimized independent of the technology share in the overall supply, and is then not limited by any equation. If the capacity is provided, and no further installation is allowed, the added capacities $Q_{addedCap}$ and $P_{addedCap}$ have a fixed value of zero.

The annual utilization of geothermal heat and power is limited by the available resource E_{annual} . In REMix-OptiMo, the geothermal resource can be subdivided into different classes, for example differing in the temperature level and borehole depth. Each geothermal component $K \in K_{geo}$ must be assigned to exactly one resource class $V \in V_{geo}$. Equation 4.57 describes the resource limitation of each class.

$$\sum_{K \mapsto V} \sum_t \left(Q_{gen}^{N,X,K}(t) + \frac{P_{gen}^{N,X,K}(t)}{\eta_{el}^K} \right) \stackrel{!}{\leq} E_{annual}^{N,V} \quad \forall N \in N_{model}, \forall V \in V_{geo} \quad (4.57)$$

Geothermal energy investment costs are calculated according to Eq. 4.37, operational costs according to 4.58.

$$\begin{aligned} c_{op}^X = & \sum_N \sum_{K \mapsto X} \sum_t \left(\left(\frac{P_{gen}^{N,X,K}(t)}{\eta_{el}^K} + Q_{gen}^{N,X,K}(t) \right) \cdot \frac{\eta_{el}}{\eta_{th}} \cdot c_{OMVar}^X \right) \\ & + \sum_N \sum_{K \mapsto X} \sum_{X \mapsto G} \sum_t \left(Q_{gen}^{N,X,K}(t) \cdot \left(1 - s_{distLoss}^{N,G} \right) \cdot c_{dist}^{N,G} \right) \\ & + \sum_N \sum_{K \mapsto X} \left(Q_{addedCap}^{N,X,K} \cdot c_{specInv}^X \cdot c_{OMFix}^X \right) \quad \forall X \in X_{geo} \end{aligned} \quad (4.58)$$

4.5.9 Combined Heat and Power Model Equations

The CHP module of REMix-OptiMo can be applied to three different technology classes: back-pressure CHP with fixed ratio of electricity to heat output, CHP with adjustable steam extraction and power-only plants. The integration of power-only generation in the same technology module enables the consideration of fuel resource limits, as it can be necessary for biomass, which can be used both in CHP and condensing power plants. The additional degree of freedom resulting from the adaptable proportion of power and heat production causes a more complex system of equations and constraints compared to other heat generators.

Hourly power and heat production are limited by the sum of existing ($P_{existCap}$, $Q_{existCap}$) and newly installed ($P_{addedCap}$, $Q_{addedCap}$) capacity according to Eq. 4.59 and 4.60, respectively. CHP capacity model input are thermal capacities, which are used to calculate electric capacities based on the ratio σ_W of maximum power generation in CHP operation $P_{CHP,max}$ and maximum heat production $Q_{gen,max}$. For power-only technologies represented with the CHP module, electric capacities are provided instead.

$$P_{gen}^{N,X,K}(t) \stackrel{!}{\leq} \left(Q_{addedCap}^{N,X,K} + Q_{existCap}^{N,X,K} \right) \cdot (\sigma_W^K + \beta^K) \cdot f_{avail}^K \quad (4.59)$$

$$Q_{gen}^{N,X,K}(t) + Q_{cond}^{N,X,K}(t) \stackrel{!}{\leq} \left(Q_{addedCap}^{N,X,K} + Q_{existCap}^{N,X,K} \right) \cdot f_{avail}^K \quad (4.60)$$

$$\forall t, \forall N \in N_{model}, \forall K \in K_{CHP}, \forall K \mapsto X$$

The overall heat production consists of supplied heat Q_{gen} and condensed heat Q_{cond} . In steam extraction CHP plants, the condensed heat is used for an additional power generation in condensing mode, whereas in back-pressure units it remains idle and needs to be cooled. The power loss coefficient β defines the additional power generation that can be realized in condensing mode, and is consequently set to zero for CHP devices without flexible heat extraction. For power-only plants no usable or condensed heat is considered: $Q_{gen}(t) = Q_{cond}(t) \equiv 0 \forall t$. Furthermore, β is set to one and σ_W to zero, which adjusts the equations and in-equalities introduced in this section to technologies without any heat extraction. The availability factor f_{avail} reflects possible plant revision outages. CHP capacities can be either provided exogenously, endogenously calculated according to a predefined capacity-to-peak ratio $f_{cap2Peak}$ or freely optimized, as described for principal heat components in Section 4.5.3.

$$P_{gen}^{N,X,K}(t) = \underbrace{Q_{gen}^{N,X,K}(t) \cdot \sigma_W^K}_{P_{CHP}} + \underbrace{Q_{cond}^{N,X,K}(t) \cdot (\sigma_W^K + \beta^K)}_{P_{cond}} \quad (4.61)$$

$$\forall t, \forall N \in N_{model}, \forall K \in K_{CHP}, \forall K \mapsto X$$

Equation 4.61 establishes a relationship between power and heat generation in CHP plants. In extraction CHP plants, the overall power supply P_{gen} can be composed of two parts: CHP

power generation calculated from supplied heat Q_{gen} and electricity-to-heat ratio σ_W on the one hand, and power generation in condensing mode on the other. The latter is achieved by feeding additional steam (Q_{cond}) to the turbine, at the expense of a reduced output of useful heat (Q_{gen}). This implies that an increased power generation in condensing mode always goes along with loss of useful heat. Eq. 4.61 is not applied to power-only plants.

In CHP units without adjustable heat extraction, the power generation cannot be higher than in the back-pressure point of maximum heat and power generation ($Q_{gen} = Q_{gen,max}$ and $P_{CHP} = P_{CHP,max}$). The flexibility of power generation can, however, be increased by the installation of a cooler. By cooling heat that cannot be supplied to a consumer, which reduces Q_{gen} at the expense of a higher Q_{cond} , the power generation can be augmented. In REMix-OptiMo, the heat condensation Q_{cond} in back-pressure CHP units can be limited to any value between 0% and 100% of the available thermal capacity and is adjusted by the cooling share $s_{cooling}$ (Eq. 4.62). By cooling useful heat, the overall CHP efficiency decreases. If no cooler is available, it is $Q_{cond}(t) \equiv 0 \forall t$.

$$Q_{cond}^{N,X,K}(t) \stackrel{!}{\leq} \left(Q_{addedCap}^{N,X,K} + Q_{existCap}^{N,X,K} \right) \cdot f_{avail}^K \cdot s_{cooling}^K \quad (4.62)$$

$$\forall t, \forall N \in N_{model}, \forall K \in K_{CHP}, \forall K \rightarrow X$$

The resulting CHP operation modes are shown in Figure 4.4. For back-pressure CHP units, only working points on the blue line can be realized, whereas extraction CHP units can theoretically operate at any point within the triangle formed of the y-axis, the blue and the green line.

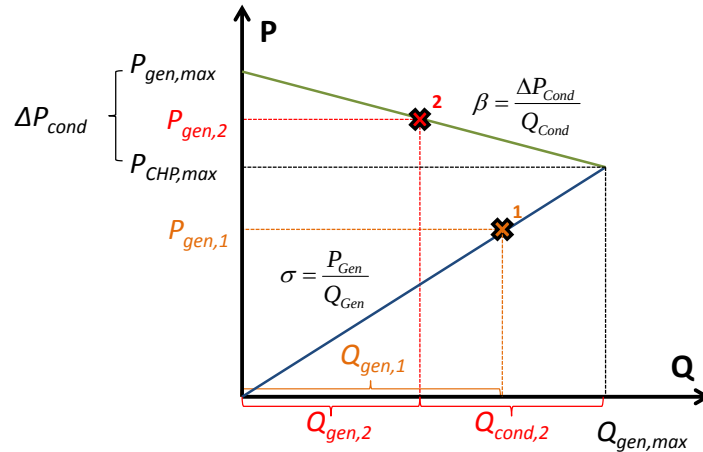


Figure 4.4 Operation modes of CHP plants in REMix-OptiMo. Point 1 and 2 show possible operation modes of back-pressure and extraction CHP, respectively. Ratios between power and heat output are given by the electricity-to-heat ratio σ_W and power loss coefficient β .

The fuel demand of CHP plants is calculated based on the power generation equivalent P_{eq} , which equals the electricity generation plus the electricity that could have additionally been generated in condensation operation (see Eq. 4.63). For back-pressure CHP and power-only plants, power generation and power generation equivalent have the same value. The hourly

fuel demand D_{fuel} is determined pursuant to Eq. 4.64, considering technology-specific overall efficiencies η_{CHP} , electricity-to-heat ratios σ_W and power loss coefficients β . Annual fuel consumptions D_{annual} of the overall CHP heat supply system, potentially including a peak boiler, are subsequently calculated according to Eq. 4.52. For fuels V with restricted resource availability, Eq. 4.53 must be furthermore fulfilled. Based on annual fuel consumptions, the fuel costs C_{fuel} are obtained by multiplying with the specific fuel costs c_{fuel} .

$$P_{eq}^{N,X,K}(t) = P_{gen}^{N,X,K}(t) + Q_{gen}^{N,X,K}(t) \cdot \beta^K \quad (4.63)$$

$$D_{fuel}^{N,X,K}(t) = \frac{P_{eq}^{N,X,K}(t)}{\eta_{CHP}^K} \cdot \frac{(1 + \sigma_W^K)}{(\beta^K + \sigma_W^K)} \quad (4.64)$$

$$\forall t, \forall N \in N_{model}, \forall K \in K_{CHP}, \forall K \mapsto X$$

The annualized investment costs of CHP capacity expansion are calculated pursuant to Eq. 4.65. They are scaled with the maximum power generation capacity of newly built plants.

$$C_{invest}^X = \sum_N \sum_K Q_{addedCap}^{N,X,K} \cdot (\beta^K + \sigma_W^K) \cdot c_{specInv}^X \cdot f_{Annuity}^X \quad \forall X \in X_{CHP} \quad (4.65)$$

In order to reflect costs that may arise when the plant output is adjusted, power change wear and tear costs are implemented. Hourly changes in power output are determined using Eq. 4.66 for positive and Eq. 4.67 for negative values. The resulting costs are obtained by multiplying the power change with specific wear and tear costs.

$$P_{loadChangePos}^{N,X,K}(t) \stackrel{!}{\geq} P_{gen}^{N,X,K}(t) - P_{gen}^{N,X,K}(t-1) \quad (4.66)$$

$$P_{loadChangeNeg}^{N,X,K}(t) \stackrel{!}{\geq} - (P_{gen}^{N,X,K}(t) - P_{gen}^{N,X,K}(t-1)) \quad (4.67)$$

$$\forall t, \forall N \in N_{model}, \forall K \in K_{CHP}, \forall K \mapsto X$$

CHP operational costs are assessed using Eq. 4.68. It comprises specific power generation variable costs c_{OMVar} , wear and tear costs c_{WaT} , heat distribution costs c_{dist} and fixed power plant costs c_{OMFix} . For power-only technologies, the added thermal capacities $Q_{addedCap}$ are substituted by added electric capacities $P_{addedCap}$ both in 4.65 and 4.68.

$$\begin{aligned} C_{op}^X = & \sum_N \sum_{K \mapsto X} \sum_t (P_{gen}^{N,X,K}(t) \cdot c_{OMVar}^X) \\ & + \sum_N \sum_{K \mapsto X} \sum_t \left(P_{loadChangePos}^{N,X,K}(t) + P_{loadChangeNeg}^{N,X,K}(t) \right) \cdot c_{WaT}^X \\ & + \sum_N \sum_{K \mapsto X} \sum_{X \mapsto G} \sum_t \left(Q_{gen}^{N,X,K}(t) \cdot \left(1 - s_{distLoss}^{N,G} \right) \cdot c_{dist}^{N,G} \right) \\ & + \sum_N \sum_{K \mapsto X} \left(Q_{addedCap}^{N,X,K} \cdot (\beta^K + \sigma_W^K) \cdot c_{specInv}^X \cdot c_{OMFix}^X \right) \end{aligned} \quad (4.68)$$

$$\forall X \in X_{CHP}$$

4.6 Energy Balance Equations and Objective Function

The global energy balance equations in REMix-OptiMo merge demand and generation of heat and power. They assure that both heat and power generation are balanced with the corresponding demands in each calculation time step. The corresponding modules collect the required information from all technology modules used in the current model run.

On the demand side, the power balance equation 4.69 includes hourly grid load P_{demand} , power demand of electric vehicles P_{EV} , electric heating P_{elHeat} and hydrogen production P_{H2Prod} , as well as DR load increase $P_{increase}$, DR load reduction balancing $P_{balanceRed}$, storage charging P_{charge} , export P_{export} and grid losses $P_{gridLoss}$. The other side of the power balance comprises all types of power plant output P_{gen} , DR load reduction $P_{reduction}$, DR load increase balancing $P_{balanceInc}$, storage discharge $P_{discharge}$, import P_{import} and not supplied power $P_{notSupplPow}$.

$$\begin{aligned} & \sum_N \left(P_{demand}^N(t) + \sum_X \left(P_{EV}^{N,X}(t) + P_{elHeat}^{N,X}(t) + P_{increase}^{N,X}(t) + P_{balanceRed}^{N,X}(t) \right) \right) \\ & + \sum_N \sum_X \left(P_{charge}^{N,X}(t) + P_{export}^{N,X}(t) + P_{gridLoss}^{N,X}(t) + P_{H2Prod}^{N,X}(t) \right) \stackrel{!}{=} \\ & \sum_N \sum_X \left(P_{gen}^{N,X}(t) + P_{reduction}^{N,X}(t) + P_{balanceInc}^{N,X}(t) + P_{discharge}^{N,X}(t) + P_{import}^{N,X}(t) \right) \\ & + \sum_N P_{notSupplPow}^N(t) \quad \forall t \end{aligned} \quad (4.69)$$

Given that different heat supply systems are not interconnected, supply and demand need to be balanced for each technology and node. The heat balance equation 4.70 guarantees that for each technology and node the supplied heat Q_{supply} equals the sum of heat generation Q_{gen} and net storage discharge $Q_{discharge} - Q_{charge}$, reduced by the distribution losses.

$$\begin{aligned} Q_{supply}^{N,X}(t) & \stackrel{!}{=} (1 - s_{distLoss}^{N,G}) \cdot \sum_{K \mapsto X} \left(Q_{gen}^{N,X,K}(t) + Q_{discharge}^{N,X,K}(t) - Q_{charge}^{N,X,K}(t) \right) \\ & \forall t, \forall N \in N_{model}, \forall X \in X_{Heat}, X \mapsto G \end{aligned} \quad (4.70)$$

The objective function of REMix-OptiMo to be minimized summarizes the costs of all used technologies to overall system costs. They arise from capacity expansion investment C_{invest} , costs of operation C_{op} , fuel C_{fuel} and pollution $C_{pollution}$, as well as penalties for not supplied heat $C_{notSupplHeat}$ and power $C_{notSupplPow}$.

$$\min \left\{ C_{notSupplHeat} + C_{notSupplPow} + \sum_X \left(C_{invest}^X + C_{op}^X + C_{fuel}^X + C_{pollution}^X \right) \right\} \quad (4.71)$$

4.7 Discussion of the Model Implementation

In this section, the REMix-OptiMo implementation of the heating sector and flexible electric loads, which has been the focus of the model enhancement realized in this work, is discussed. A broader discussion of the strengths and weaknesses of the underlying modeling approach is

provided by [125, 168, 180].

The integration of the heating sector into REMix-OptiMo provides a broad field of new model applications. They range from targeted capacity and dispatch optimization evaluation of selected heat supply and thermal energy storage technologies to the assessment of specific heat market segments and in-depth analyses of the coupling between power, heat and transport sector. The latter especially concerns power-controlled operation of CHP and electric heating, aiming at a better integration of renewable power generation. The spectrum of technologies implemented in REMix-OptiMo has been furthermore extended by demand response, which provides the basis for a detailed assessment of electric load shifting and shedding.

Bearing in mind that the model complexity and thus solution times increases with the number of variables and constraints, a reasonable level of detail had to be found in the modeling of the additional balancing technologies. This implies that technological characteristics cannot be reflected to the same degree as in other models focused on particular sectors of the energy system, or smaller geographical assessment areas.

Certain simplifications are related to the linear programming approach used in the model. In contrast to mixed-integer models, no information about the current operation status of system components or technology classes is maintained. Furthermore, no limitations in capacity expansion to discrete power plant sizes is possible without the use of mixed-integer methods. An additional restriction is posed by the limitation to linear constraints. All non-linear effects must be either neglected or approximated by linear functions.

In the model implementation of DR, load decrease and increase are not considered globally, but can be attributed directly to predefined technologies. This modeling concept allows for an evaluation of the load shifting behavior of individual processes or appliances. Due to its massive impact on the model solution time, a consideration of flexible shift times could not be realized. A work-around was found by the development of a shift class concept, which assigns one or various fixed shift times to each DR technology. With this formulation the model can endogenously determine the interval between the load modification and its balancing, which is equivalent to the application of flexible shift times. It, however, causes an increase in the number of variables in the model, and thus the complexity of the mathematical problem.

Other simplifications in the model representation of DR are associated to the chosen linear programming approach. Given that the DR activity status in each hour of the year is not reflected, limitations in DR load interventions had to be implemented making use of a fictitious storage level. As the calculation of the maximum energy that can be shifted before a balancing must start relies on average values of the available potential, this approach cannot completely assure that maximum load intervention durations are not surpassed. On the other hand, it might also reduce the possibilities of load shifting, when the calculated maximum storage level is reached already in a shorter period. Both effects are particularly important for DR technologies with highly fluctuating power demand. The DR storage level is furthermore used for the consideration of limitations in frequency of load shifting and shedding. This implies that these limitations are not applied to the number of hours DR is used or halted, but

to the amount of energy shifted or shedded within a certain period. For highly fluctuating demand profiles of DR technologies, this approximation results in an underestimation of the available potential in peak demand hours, and an overestimation in off-peak hours.

The representation of the heating sector is focused on those technologies directly related to power generation and demand. Heat supply technologies, which are more independent of other sectors, such as conventional boilers and solar thermal heat, are considered with a comparatively lower level of detail. In the model, different heat demand profiles can be considered, allowing for a more realistic representation of the operation of heat supply technologies. Like this, distinct sectors, but also temperature levels can be treated separately. The REMix-OptiMo implementation is generally not technology-specific. This provides the advantage that, for example, different TES technologies can be represented by one and the same module. The downside of this approach is that technology-specific characteristics cannot in all cases be reflected.

Concerning the representation of CHP technologies, major simplifications include the negligence of minimum load, as well as minimum operating and resting periods. The relevance of this approximation depends significantly on the applied heat load profile, the dimensioning of the CHP unit as well as the availability of alternative heat supply options. In addition to this, no technical restrictions in power plant ramping are taken into account. From these approximations arises that the range of possible operation modes displayed in Figure 4.4 is much broader than in reality. The triangle area shown in the figure does not account for minimum-load, as well as other technical restrictions. Another simplification consists in the consideration of planned and unplanned CHP outages by an availability factor⁵. By multiplying the installed capacity with the power plant availability, it is implicitly assumed that outages are equally distributed over all hours of the year. Given that revision outages are typically realized during summer time, when power and heat demand are lower, this approximation causes an underestimation of available capacity in winter and an overestimation in summer. An important approximation in the modeling of TES concerns the negligence of charging and discharging capacity limits, which may cause an overestimation of the heat input or output in single time-step, and thus flexibility of the corresponding heat supply technology. The integration of heat source temperatures into the heat pump technology module enables a consideration of daily and seasonal variations in the efficiency. In this way, it can for example be reflected that the power demand of air-source heat pumps increases disproportionately at lower ambient temperatures.

The model enhancement introduced in this chapter provides the basis for REMix-OptiMo assessments of flexible electric loads, as well as the nexus between power and heat supply. Making use of the enhanced model, all available balancing options can be compared in their interaction and impact on the overall energy supply system. In the subsequent chapter, it is applied in a case study focused on the balancing capability of these technologies in a highly renewable power system in Germany.

⁵This approach is also used for most other technologies in REMix-OptiMo, see [125, 168].

Chapter 5

REMix-OptiMo Application for the Assessment of Load Balancing in Germany

Based on the REMix-OptiMo enhancements introduced in Chapter 4, the potential future usage of flexible electric and thermal loads is assessed. In doing so, both capacity extension and operation of DR and TES are evaluated. The scenario input to the model takes into account the DR and CHP potentials quantified in Chapter 2 and 3.

The chapter starts with a brief introduction of the concept of the model application (Section 5.1). In Section 5.2, the framework scenarios are characterized, followed by a detailed introduction of the scenario set-up (Section 5.3) and the REMix-OptiMo input (Section 5.4). The description of input data is focused on those elements which have been prepared in this work. Finally, results of the model application are presented in Section 5.5 and discussed in Section 5.6.

5.1 Scope and Procedure of the Scenario Assessment

The REMix-OptiMo application aims at a better understanding of the potential future contribution of electric load shifting and power-controlled operation of CHP and HP – hereinafter referred to as *power controlled heat supply* – to the balancing of VRE power generation fluctuations in Germany. In order to evaluate a broad range of possible future energy supply structures, nine scenarios are taken into account. The scenarios differ in overall RE share, contribution of the most important VRE technologies wind and PV, transport sector energy supply, as well as availability of chemical long term storage, major transmission grid expansion and dispatchable solar power import. Germany is not considered as an island system, but as part of an interconnected European environment. The scenarios are focused on an European supply system with renewable electricity shares exceeding 80%, as they are envisioned in Germany for the year 2050. Nonetheless, also lower RE shares, as they might be realized until 2020 or 2030 are considered. The scenarios are introduced in detail in Section 5.3.

Across all scenarios, the exogenously provided model input includes installed capacities of power plants, transmission lines and pumped hydro storage, as well as heating market shares

of CHP and HP technologies. On the contrary, a model-endogenous capacity expansion is performed for DR, as well as the different components of CHP and HP supply systems, including TES and electric boilers. Furthermore, conventional power plants in terms of gas turbines can be installed if required for the avoidance of supply gaps. In selected scenarios, additional storage and transmission capacities are available as investment options as well.

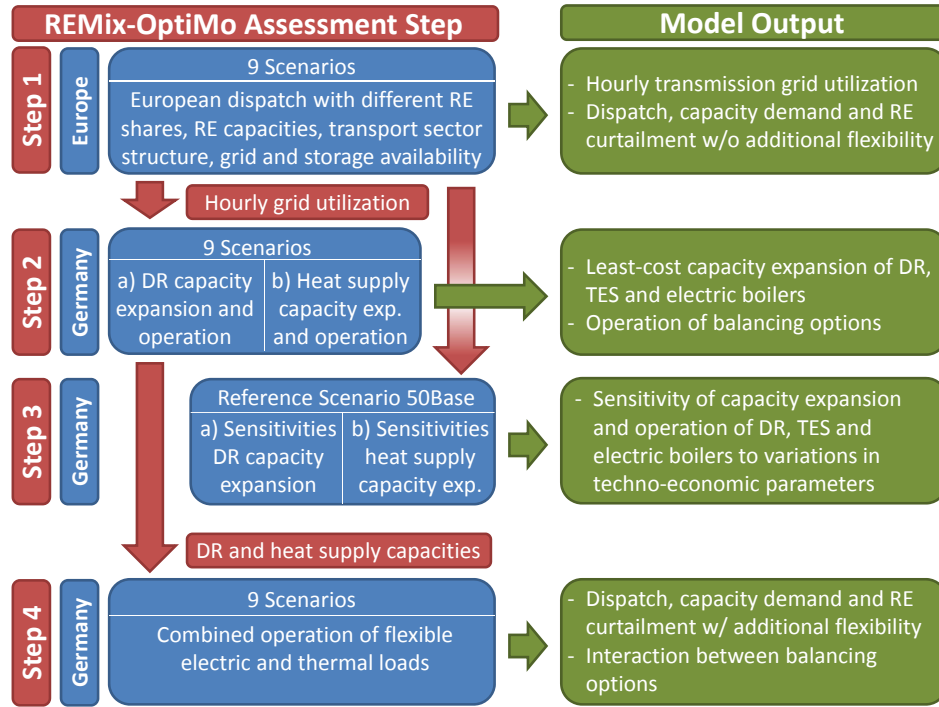


Figure 5.1 Procedure of the REMix model application in this work.

In order to reduce the model solution time, the assessment of flexible electric and thermal loads is performed in a four step approach using different levels of technological and geographical detail (see Figure 5.1). The first set of model runs in step 1 is designed to provide the hourly operation of power plants, storage and transmission grids for six German and ten European regions in each of the scenarios. Electricity shortages can be avoided by a model endogenous installation of additional power plant, and in some scenarios also storage or grid capacity. Flexible electric loads, as well as the power-controlled operation of heat supply systems are not taken into account in the model runs for Europe.

In the subsequent steps 2, 3 and 4, capacity expansion and operation of power plants and balancing technologies within single model regions in Germany are studied in separate model runs. In these steps, power transmission between regions is not included in the optimization. Instead, the hourly export or import of each region is taken from the step 1 model results and used as fixed power inflow or outflow. Capacity expansion is analyzed separately for DR on the one hand (step 2a), and the heat supply components as well as TES in CHP and HP systems on the other (step 2b). For a better understanding of the sensitivity of the results to variations in technology and scenario input, a number of additional runs with deviating system configurations and techno-economic key parameters are evaluated for the reference

scenario (step 3). In the model runs of the final step 4, interaction between flexible electric loads and power-controlled heat supply are analyzed. In doing so, the DR and heat supply capacity expansion obtained in step 2 are taken into account. Given that the REMix-OptiMo solution time significantly increases with the number of regions considered, not all European countries are taken into account. Instead, the assessment is limited to the countries shown in Figure 5.2. They include all neighboring countries of Germany, as well as Northern Europe and the western parts of Southern Europe and Northern Africa.

The selection of countries has been focused on the consideration of the potential storage options in Norway (reservoir hydro) and dispatchable concentrated solar power (CSP) generation in Northern Africa, which might be connected to Central Europe via HVDC lines. In order to better represent grid restrictions within Germany, the country is subdivided into six model regions. This subdivision takes into account the control areas of the four transmission system operators.¹ Denmark is divided into two regions also for transmission grid aspects. Given that there are no grid limitations within model regions, and the fact that there are no AC transmission lines and no synchronous network coupling between Jutland and the Danish Archipelago, they are assigned to separate model regions.

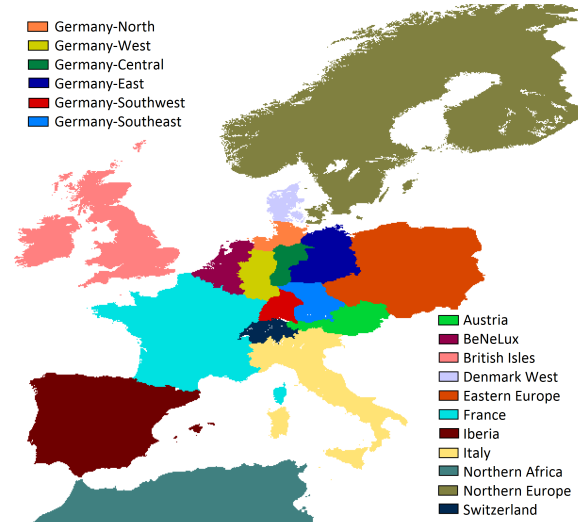


Figure 5.2 REMix-OptiMo regions.

5.2 Framework Scenario Input

The REMix application² is focused on a future European energy supply structure with high RE shares in all demand sectors. Its demand and supply structure relies on two comprehensive scenario studies, which are oriented towards ambitious GHG emission reduction targets: the German *Langfristszenarien 2011* on the one hand [135], and the pan-European *TRANS-CSP* on the other [187]. Given that the latter is limited to the electricity sector, a simplified European heat supply scenario is developed. Due to the particular focus of this work, it is limited to technologies operating at the interface between power and heat sector, namely CHP and electric heat pumps. All other heat supply is not represented in the model, which implies that its costs and emissions are not considered. The same applies to transport sector energy demand except for passenger car utilization.

¹The 20 grid regions considered in the *Regionenmodell* of the transmission system operators in Germany are aggregated to six regions according to Table E.1 in Appendix E

²In order to increase the readability of the text, in the following the detailed model name REMix-OptiMo is mostly shortened to REMix. Both names are used as synonyms in this chapter.

5.2.1 Framework Scenario for Germany: Langfristszenarien 2011

Energy demand and supply in Germany are assumed to develop according to [135]. It provides technically feasible and consistent development paths of the German energy system. They fulfill the political goals concerning emissions reductions, RE expansion and efficiency improvements stated in the German *Energiekonzept*, including renewable shares of 60% in final energy consumption, and 80% in electricity demand, as well as reductions in primary energy demand of 50% and CO₂ emission of 80% [163]. Target year of the study is 2050. In addition to these political goals, the scenarios consider a number of premisses concerning the usage of biomass, chemical energy storage, as well as renewable electricity in heat and transport sector. On the long run, renewable electricity is assumed to contribute to the provision of high temperature process heat, as well as low temperature building heat. The RE share in the transport sector is increased by hybrid and full-electric vehicles on the one hand, and hydrogen or methane propelled vehicles on the other. The study discusses three transport sector development paths differing in the market shares of the available technology options. As a consequence of the electrification of other energy demand sectors, the overall electricity demand does not decrease as strongly as determined in the political goals.

According to the study, the future power supply in Germany relies on five pillars: domestic VRE (wind, solar PV and run-of-river hydro), adjustable domestic RE (biomass, geothermal), power-controlled domestic CHP, highly flexible fossil fuel back-up stations and import of dispatchable renewable power (CSP). Due to the controversial public debate, the low technology development status, as well as considerable economic and environmental uncertainties, an event of carbon capture and storage (CCS) technology is not accounted for.

5.2.2 Framework Scenario for Europe: TRANS-CSP

In order to consider comparable circumstances all over the assessment area, scenarios reflecting similar developments and a future supply mainly based on RE are defined also for the other European countries. They are originally relying on the *TRANS-CSP* scenario [187], which provides a framework for an integrated supply system of Europe, Northern Africa and the Middle East with an 80% RE share. The scenario is particularly focused on the interaction between VRE and adjustable CSP. It highlights the substantial contribution of CSP imports to a reduction of conventional power plant and storage capacities in Europe. The original *TRANS-CSP* scenario has been validated with REMix-OptiMo in the framework of [180].

5.2.3 Heat Supply Scenario

Based on the assessment of future heat demand and CHP potential, heat supply scenarios for both industrial and small consumers are developed. In consideration of the targets formulated in the framework scenarios, it is generally assumed that CHP, HP and RE shares in overall supply will be rising. The future DH supply is estimated for each country relying on the current diffusion and the potentials assessed in Chapter 3. According to the subdivision of the

potential established there, the overall scenario DH supply is distributed to four technology size classes. Complementary to DH supply, future market shares of electric air-to-water and ground-to-water HP, as well as building CHP systems are assessed in accordance with the scenarios for Germany presented in [135]. The industrial heat supply scenario relies on the analysis of demand and CHP potential introduced in Section 3.2. In addition to on-site CHP production, connection to a heat network and heat recovery discussed there, the usage of industrial heat pumps is taken into account.³ A detailed description of the scenario is provided in Appendix E.2 of this work.

5.3 Basic Structure of the Scenarios

The scenarios regarded have been selected with focus on the RE supply structure on the one hand, and the availability of balancing options on the other. Given that previous REMix applications [125, 168] have revealed solar power imports, grid extension and flexible hydrogen electrolysis as very powerful balancing options, this work concentrates on cases where they are not available. In this section, the nine scenarios are described qualitatively: an overview of their key characteristics is provided in Table 5.1. A more detailed introduction of technology and scenario input data is comprised in the subsequent Section 5.4.

- **Scenario 50Base:** Scenario 50Base is used as reference case in this work. It represents an European scenario for the year 2050 with a VRE supply share exceeding 60%, and limited availability of flexibility. With no long-term storage and solar power imports, as well as limited grid extension and inflexible transport sector power demand, a significant part of the load balancing must be provided by conventional power plants. In the transport sector, it presumes a very favorable development of EV technologies. According to the scenario, in the year 2050 all passenger-car mileage is assumed to be covered by EV and plug-in hybrid vehicles. The remaining transport sector energy supply is provided by efficient conventional vehicles and biofuels. It is assumed that the overall car fleet develops uniformly all over Europe. Based on the values for Germany, the number of cars in each country is scaled with population and specific number of cars per inhabitant in the year 2008. In contrast to other scenarios, hydrogen is neither used as fuel, nor as storage medium in 50Base.

The power generation capacities in Germany are based on those determined in scenario C of [135]. They are however increased in order to compensate for the non-consideration of renewable electricity import as described in [169].⁴ This implies a higher supply share of domestic, fluctuating renewable power sources. The European scenario relies on the *TRANS-CSP* scenario.

³In the scenario, fixed market shares are assumed for all technologies. This implies that heat technologies and heat groups in REMix are identical, and that no competition between technologies is considered (see Section 4.5.1 for the description of the modeling approach).

⁴In the original scenario C, RE electricity imports account for 1 TWh in 2020, 19 TWh in 2030 and 43 TWh in 2050, in scenario A even for 62 TWh in 2050.

- **Scenario 50H₂T:** The main characteristic of scenario H₂T is the usage of hydrogen as fuel in the transport sector. It is based on scenario A of [135], where the EV market penetration – including both fully electric vehicles and plug-in hybrid electric vehicles – is limited to 50% of passenger-car transport by the year 2050. The remaining cars are propelled by bio-fuels, conventional fuels or hydrogen. The power demand for hydrogen production in Germany relies on assumptions concerning biomass fuel usage, EV dissemination and sectoral CO₂ emission reduction goals [135]. In the other European countries, a hydrogen production for vehicle propulsion in a comparable order of magnitude is derived from the respective mobility demands. It is assumed that most hydrogen is produced at decentralized gas stations. This implies that no further hydrogen distribution infrastructure is required. In contrast to the original scenario in [135], hydrogen is only used as fuel, and not as chemical storage medium. In order to cover the additional power demand of the hydrogen production, the overall power plant capacity is higher than in scenario 50Base. This includes both conventional and renewable energies. The overall VRE power supply share in Europe of 64% is slightly higher than in the reference scenario.
- **Scenario 50H₂St:** In this scenario, a model endogenous installation of hydrogen production and storage as long-term storage option is considered. Hydrogen is produced in alkali-electrolysis, stored in pressurized underground salt caverns and reconverted to electricity in high-efficient CCGT power plants. The need for suitable salt caverns implies both an overall limitation and regional differences of the storage potential, given by the geological resource availability. To which extent a storage can provide balancing power also to neighboring regions depends on the power grid capacity. Except for the availability of an additional storage technology, scenario 50H₂St relies on the input data of 50Base.
- **Scenario 50Grid:** This scenario features the same demand and supply structure as 50Base. In contrast to the reference case, it considers a model endogenous expansion of the electric power transmission capacity by additional DC lines. This includes both the enhancement of existing lines and installation of new links between neighboring regions. The corresponding technology input is introduced in Section 5.4.5.
- **Scenario 50PV and Scenario 50Wind:** Scenario 50PV and 50Wind are variations of 50Base concerning the installation of solar PV panels and onshore wind turbines in Germany. It is assumed that the PV and onshore wind capacity in each region is by 50% higher, respectively. In order to keep the overall power generation constant, the installed capacity of offshore wind turbines is reduced. In doing so, region and technology-specific annual full load hours (FLH) are taken into account. The modified power plant structure goes along with changes in geographical distribution, as well as temporal availability of VRE power generation.

- **Scenario 50CSP:** This scenario is characterized by an import of adjustable electricity from CSP plants in Northern Africa⁵ to Europe, as it is envisioned in the original scenarios in [135]. Installed power generation and import capacities are applied accordingly, taking into account the values of scenario C. The virtual installation of CSP plants in Europe results in less fluctuations in residual load and thus balancing demand. As in 50Grid, the installation of additional DC transmission capacity within Europe is subject to REMix optimization in this scenario.
- **Scenario 30Base and Scenario 20Base:** Scenario 30Base and 20Base represent intermediate steps within the development path to a highly renewable European energy supply in 2050. Assumptions concerning demand and supply structure rely on those developed in scenario C of [135] for the years 2020 and 2030. They are characterized by a much lower VRE power generation share of 31% in 20Base and 46% in 30Base.

Table 5.1 REMix-OptiMo application scenario overview.

	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
RE share Europe ^a	83%	84%	83%	83%	83%	83%	87%	61%	44%
Variable RE share Europe ^a	61%	64%	61%	61%	61%	61%	52%	46%	31%
RE share Germany ^a	90%	86%	89%	91%	89%	90%	91%	69%	45%
Variable RE share Germany ^a	70%	68%	69%	70%	70%	70%	64%	55%	34%
PV capacity Germany [GW]	76	80	76	76	114	76	67	67	54
Wind onshore cap. Germ. [GW]	55	62	55	55	55	83	51	50	41
Wind offshore cap. Germ. [GW]	35	37	35	35	25	19	31	25	10
CSP import cap. Germ. [GW]	0	0	0	0	0	0	7	0	0
H ₂ electrolysis cap. Germ. [GW]	0	37	0	0	0	0	0	0	0
Endogenous H ₂ storage installation			+						
Endogenous grid extension				+			+		

^a Represents the share that would be reached, if no VRE were curtailed or lost.

5.4 Demand, Supply and Infrastructure Input Data

In this section, the REMix-OptiMo input parameters are established. They are composed of technical and economic specifications describing each technology represented in the model on the one hand, and scenario parameters concerning installed capacities and available resources in each model region on the other. The global model set-up and the technology modules used in this assessment are displayed in Figure 4.1 and described in Section 4.3 to 4.5. In the following paragraphs, key input parameter concerning demand, supply, storage and grid infrastructure will be briefly introduced. The description is more detailed for those technologies, which have been implemented into the model in the framework of this study. Detailed tables containing the scenario capacities of all systems assets, as well as techno-economic input can be found in Appendix E of this work.

⁵Here and in the following, *Northern Africa* refers to the REMix model region constituted by Algeria, Morocco and Tunisia.

5.4.1 Heat and Power Demand

The electricity demand is assessed separately for *conventional* consumers on the one hand, and *new* consumers on the other. The latter include HP, EV and hydrogen production. The gross electricity demand of conventional consumers is assumed to develop according to the framework scenarios introduced in 5.2. They imply the future energy efficiency gains considered there (see [135, 187]). To date, the new consumers do not significantly contribute to overall power demand. Due to the assumed fuel change in the heat and transport sector, they are however expected to have an increasing electricity demand in the future. The heat and power demand in Germany, as well as the overall assessment area is summarized in Table 5.2. Table E.4 in Appendix E provides demand values for each model region. Table 5.2 also contains the annual electric and thermal peak loads in Germany.

Table 5.2 Heat and power demand in the overall assessment area and Germany (left), as well as annual peak loads in Germany (right).

		Overall assessment area				Germany				Germany			
		Annual demand in TWh				Annual demand in TWh				Annual peak load in GW			
		20Base	30Base	50H ₂ T	Other	20Base	30Base	50H ₂ T	Other	20Base	30Base	50H ₂ T	Other
Electricity	Conventional	3241	3070	2889	2889	576	485	425	425	91.8	77.3	67.7	67.7
	HP	50	79	100	100	8	13	16	16	4.4	7.0	8.9	8.9
	EV	98	270	230	399	21	56	44	80	5.4	14.7	11.5	21.1
	H ₂ prod.	0	0	519	0	0	0	100	0	0	0	36.7	0
	Total electr.	3389	3418	3738	3388	605	554	586	522	96.1	90.4	91.0	88.3
Heat	Res./Com.	2507	2153	1601	1601	560	469	333	333	184.7	153.6	108.4	108.4
	Industrial	809	794	735	735	147	144	132	132	33.5	32.8	30.5	30.5
	Total heat	3316	2947	2337	2337	707	513	465	465	213.3	182.1	135.6	135.6

Annual heat and power demands are temporarily and spatially disaggregated. Comparable to residential and commercial heat demand (see Chapter 3), the disaggregation of power demand relies on a high-resolution GIS map of land use. A detailed description of the methodology is provided in [168]. The hourly power demand of conventional consumers is assumed to follow the national grid load measured by the European transmission grid operators.⁶ Consistent with the meteorological data used in the calculation of VRE power generation profiles, the time series of the year 2006 are applied. Like this, correlations between air temperature, wind speed and power demand are implicitly accounted for.

In this work, two different heat demand sectors are considered: residential and commercial consumers on the one hand, industrial consumers on the other. For each model region, scenario year and demand sector, a separate hourly demand profile is provided. The calculation of space heat, hot water and process heat demand profiles is described in Section 3.3. In order to obtain characteristic sectoral profiles, the time series of different heat applications are superimposed, taking into account the year and country-specific demand shares derived in

⁶The grid load is here defined as hourly average power input to the grid. It includes grid losses, and excludes hydro storage pumping power demand and power generator own consumption.

Section 3.1.2 and 3.2.2. The spatial allocation of heat demands to sub-national regions in Germany and Denmark is done according to the methodologies introduced in Section 3.1.3 for the residential and commercial, and Section 3.2.6 for industrial demand.

5.4.2 Power Supply

The power generation capacity input is mainly based on the framework scenarios introduced in Section 5.2. Minor adjustments have been made in order to account for the non-consideration of solar power imports in most scenarios, additional electricity demand in heat and transport sector, as well as recent RE capacity expansion, technology development and adjustment of political targets. A detailed description of the modifications applied to the original scenarios is provided in [169]. Figure 5.3 provides an overview of the technologies represented in REMix in this assessment. With the flexible, power-controlled operation of CHP plants being one of the specific foci, a comparatively detailed technological subdivision of CHP is considered. The distinction between public and industrial CHP results from the consideration of characteristic sectoral heat demand profiles. Public CHP here refers to all units supplying residential and commercial demands.

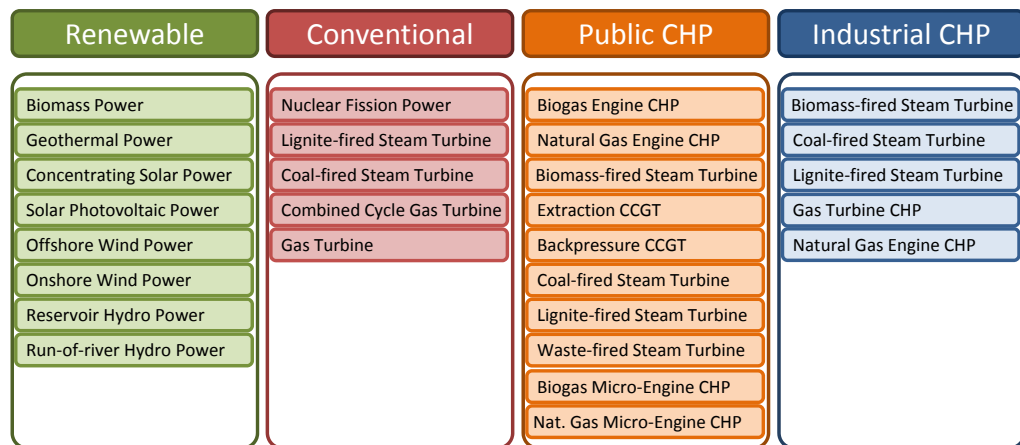


Figure 5.3 Power generation technologies considered in the scenario assessment.

Renewable Energies

The REMix-OptiMo assessment comprises renewable power generation in solar PV, CSP, offshore and onshore wind, as well as geothermal, biomass, run-of-river and reservoir hydro power plants. In this work, a model endogenous RE capacity expansion is not considered, thus, only the operation is subject to optimization. The framework scenarios provide a development path for a fast and uniform RE capacity expansion throughout Europe.

The power generation of solar PV, wind and run-of-river hydro power plants is dependent on the availability of the intermittent resources. For each technology and region, hourly generation profiles are incorporated into REMix-OptiMo. They have been calculated using meteorological data on the one hand, and technological characteristics on the other (see [168]). The generation profiles applied in this work rely on data for the year 2006 and represent an

average annual RE availability, compared to other recent meteorological years. In REMix-OptiMo, the hourly grid feed-in is obtained by multiplying the normalized generation profile with the installed capacity. No variable costs of fluctuating renewable power generation and curtailment are considered.

CSP plants can decouple their power production from the solar irradiation by the usage of a TES and a fossil-fueled back-up system. However, the solar share in power generation is determined by the resource availability provided as hourly profile by REMix-EnDAT (see [168]). Based on [188], the thermal output capacity of solar fields is assumed to be three times as high as the thermal turbine capacity, equivalent to a solar multiple of three. For the TES to power block capacity ratio a value of twelve is applied. In order to provide firm capacity, all CSP plants are equipped with a natural gas-fired back-up system allowing for full load power block operation. The power generation efficiency is assumed with 37%, plant availability and TES round-trip efficiency with 95% each [180]. Except for scenario 50CSP, CSP plants are only considered in the southern European countries France, Italy, Portugal and Spain. Deployment starts already before 2020, and is noticeably increasing in the subsequent decades. In scenario 50CSP, additional CSP capacities in Morocco, Algeria and Tunisia are taken into account. For power transfer, point-to-point connections of a maximum transmission capacity of 1.5 GW from isolated parks of CSP plants in Northern Africa to European demand centers and current locations of power plants are considered. CSP generation systems and HVDC line are considered as an integrated asset. For system stability reasons, the maximum power input to the AC grid at each HVDC endpoint is limited to a converter capacity of 3 GW. CSP plant sites and HVDC line endpoints are chosen according to [188]. Potential HVDC corridors connecting Europe and Northern Africa have been analyzed in detail in [96].

In contrast to CSP and VRE technologies, biomass and geothermal power generation are not subject to temporal variations in resource availability. It is, however, limited by the overall annual inventory of biomass fuel or geothermal heat. This work relies on the assessment of geothermal and biomass potentials presented in [168]. The biomass power generation potential is restricted by the available sustainable resource on the one hand, and the biofuel utilization in heat and transport sector on the other. According to the scenario, biomass is mostly used in CHP plants. Power generation without heat use is only considered for solid biomass. Techno-economic model input include a power plant availability of 95%, an electric efficiency of 29% in 2020, 29.5% in 2030 and 30.5% in 2050, as well as variable generation costs of 2 €/MWh_{el} [32, 135].

Different qualities of geothermal resources are not taken into account in this work. It is assumed that the net electric efficiency of geothermal power plants can be enhanced in the future, to an average value of 9.5% in 2020, 10% in 2030, and 11% in 2050 [199].

Reservoir hydro power features characteristics of both variable and dispatchable renewable power plants. The input to the water reservoir is subject to irregular and regular fluctuations depending on climate and weather. However, the power generation can be adjusted within the restrictions given by reservoir size, filling level and minimum water flow rate. The latter

assures that the downstream water resource availability is not jeopardized. In this work, a norm minimum flow rate equivalent to 25% of the annual discharge average is applied. In regions where the water inflow to the reservoirs goes below this threshold in single time-steps, the minimum flow rate is reduced to the respective values. It is taken into account that some reservoir hydro stations have pumps allowing for the provision of negative balancing power. Generally, a turbine efficiency of 90%, a pumping efficiency of 89%, and a temporal availability of 98% are applied [135]. The hourly water inflow is assumed according to [168]. According to the framework scenarios, reservoir hydro potentials in Europe are already almost completely exploited. Minor increases in turbine capacity are only assumed for the Alpine countries, whereas an expansion of reservoir capacity is considered also in other countries. Installed RE power generation capacities in each scenario year and region are summarized in Table E.6 and E.7, the corresponding techno-economic parameter in Table E.13 to Table E.15 in Appendix E.

The renewable energy generation capacities in Germany are allocated to the 6 German regions taking into account the current capacities and the assumption that future capacity expansion takes place equally over all regions.

Conventional Power Plants

The substantial RE capacity expansion envisioned by the framework scenarios changes the required conventional power plant park not only in size, but also in composition. Given its lower specific GHG emissions, as well as faster ramping and cold starting speed, gas-fired stations gradually replace lignite, coal and nuclear power plants. The lower emissions are particularly crucial as no CCS technologies are considered in the framework scenarios.

Such as for RE, the power generation capacity of nuclear, lignite, coal and gas power plants is limited to the scenario values. Only exception are gas turbines (GT), which can be endogenously installed by the model in order to avoid unsupplied load. Like this, it is assured that sufficient generation capacity is available also in times of low VRE power generation. The amount of additionally installed GT indicates whether the exogenously defined normative scenario provides enough power plant capacity. In this work, it is furthermore used for the assessment of system changes triggered by the availability of additional balancing options. Two of the scenario variations assessed in Section 5.5.4 and 5.5.5 consider a power plant capacity expansion also for CCGT. Independent of the scenario year, capital costs of 400 €/kW for gas turbines and 700 €/kW for CCGT are applied. For both technologies, an amortization time of 25 years and annual fixed operational costs equivalent to 4% of the investment are considered. Investments in additional power plants are realized with an interest rate of 6%, which is also applied to all other technology capacity expansion considered in this work.

The hourly output of conventional power plants is only restricted by the installed and available capacity, and not dependent on any intermittent resource. Technology-input data comprise gross and net efficiencies, power plant availabilities, as well as specific power generation and output change wear and tear costs. They are summarized for all technologies in Table E.16 in

Appendix E.

According to the framework scenarios, the installed conventional power plant capacity in Germany is reduced from approximately 85 GW in 2010 to 81.2 GW in 2020, 59.3 GW in 2030 and 29.2 GW in 2050. The 2050 capacity is equivalent to roughly one third of the annual peak demand.

Combined Heat and Power Plants

The CHP production is subdivided to a broad range of different technologies, plant sizes and fuels. For each DH size class introduced in Chapter 3, a set of technologies is incorporated in REMix-OptiMo. They include coal, lignite, waste and biomass-fired steam turbines, as well as back-pressure and extraction CCGT and engine CHP plants fueled with natural gas or biogas.⁷ Building CHP units are considered with natural gas or biogas fuel use. CHP heat for supply of industrial consumers is assumed to be produced in lignite, coal or biomass-fired steam turbines, gas turbines and natural gas engine CHP.

In the subdivision to technologies and development of the scenario, available biomass potentials are considered, as well as the current supply structure in public and industrial CHP. For industrial CHP, also the sectoral structure defining the demand temperature distribution is taken into account.⁸ Furthermore, the fuel specific power plant capacities specified by the framework scenarios are taken into account as upper limit of the overall CHP capacity. It is assumed that newly installed CHP units rely on renewable energies or natural gas, and that lignite and coal CHP are gradually phased out. Table E.9 to E.11 in Appendix E show the resulting pathway of the overall installed electric capacity for each technology and country.

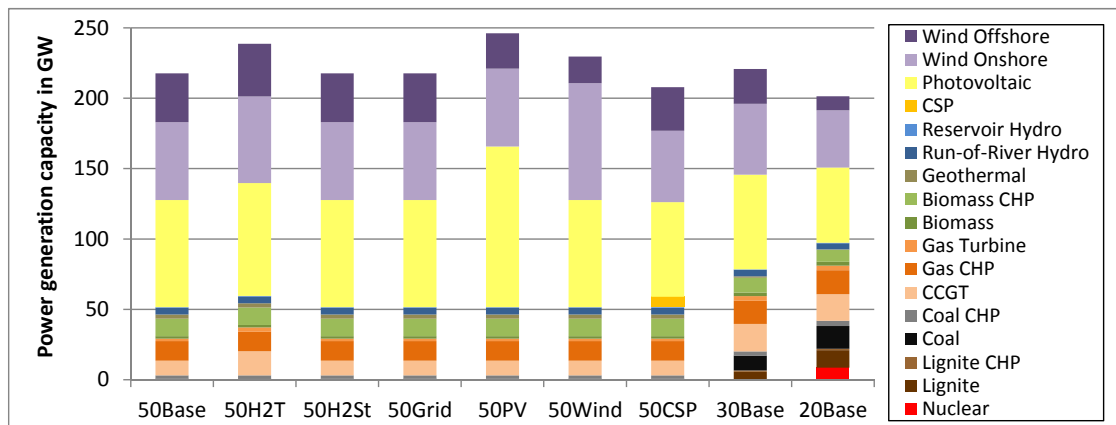


Figure 5.4 Scenario comparison of the German power generation capacity structure.

⁷The heat supply scenario also accounts for an expansion of geothermal DH. Given that it is not related to the power sector, it is, however, not part of this work.

⁸CHP technology characteristics are not only correlated to generation capacity, but also to the temperature of the extracted heat. In order to reduce the model complexity, it is implicitly assumed that industrial heat at temperatures below and above 100°C are provided by separate CHP units with different electricity-to-heat ratios. A heat extraction at higher temperatures goes along with a reduced power output and thus a lower electricity-to-heat ratio. In a real application, very likely only one CHP unit with an electricity-to-heat ratio between the two extrema would be deployed.

In the REMix model runs on European level (step 1), all CHP units are strictly heat-controlled and no additional supply components are taken into account. In the subsequent studies of the power-heat-coupling, a power-controlled operation can be realized by the installation of TES, as well as conventional and electric boilers. Furthermore, the dimensioning of fossil-fueled CHP units can be adjusted by the model. A capacity optimization of biomass CHP is not performed, given that the limited biomass resource availability has been considered in the exogenous scenario definition. The average heat distribution losses in DH networks are assumed to decrease from 14% of produced heat in 2010 to 13% in 2020, 12% in 2030 and 10% in 2050. These values are applied independent of technology DH network size.

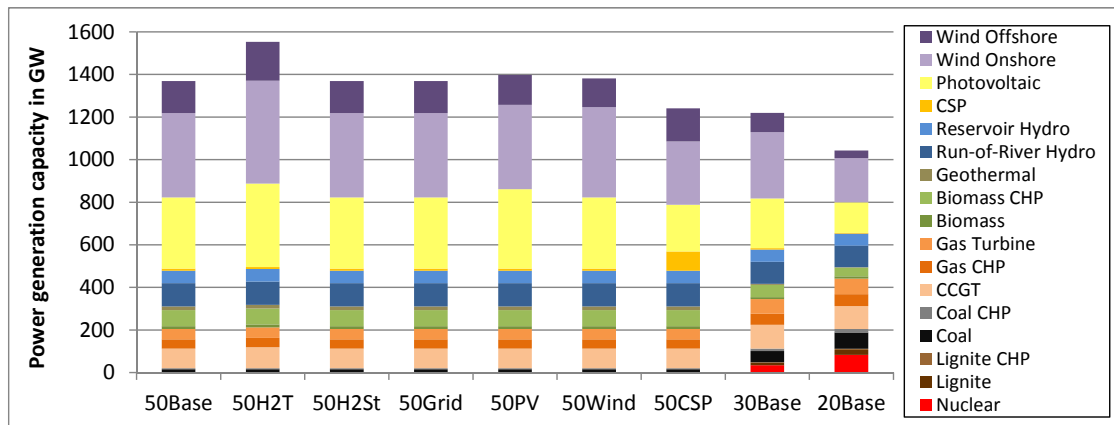


Figure 5.5 Scenario comparison of the European power generation capacity structure.

Essential CHP parameters include overall efficiencies, electricity-to-heat ratios, and plant availabilities. In addition, power loss coefficients of steam turbines with flexible heat extraction, as well as cooling shares of back-pressure CHP technologies are taken into account. Specific variable operational costs are applied both for generated electricity and changes in the power output. The techno-economic parameters of all CHP technologies are summarized in Table E.19 in Appendix E. It includes the dimensioning relative to the peak demand, which is applied in step 1, and for renewable CHP also step 2 to 4 REMix simulations.

Figure 5.4 provides an overview of installed power generation capacities in Germany for all scenarios. Due to the low operation hours and capacity credit of weather dependent technologies, the overall gross capacity increases moderately for higher RE supply shares. The power generation system in 2050 is dominated by wind and PV, reaching combined shares in total capacity between 72% and 79%. Given the much lower FLH of PV in comparison to offshore wind power, the total capacity is highest in scenario 50PV. With 246 GW, it exceeds the assumed peak load almost by factor three.

Also the European power plant park is dominated by VRE technologies, but to a lower extent than in Germany (see Figure 5.5). Depending on the scenario, PV and wind reach combined shares ranging from 37% (20Base) to 68% (50H₂T). Analogous to power demand and generation, the overall installed capacity is highest in scenario 50H₂T. In contrast, the capacity needs are smallest in those scenarios with comparatively low VRE share: 20Base, 30Base and

50CSP. Table E.5 to E.11 in Appendix E comprise installed capacities for all technologies, scenarios and model regions. Using REMix, it is assessed whether these endogenously defined scenario capacities can provide a secure supply during each hour of the year or whether model endogenous installation of additional power plants is required.

5.4.3 Heat Supply

In the step 1 model runs, CHP and HP operation is strictly heat-controlled, and no further supply components are considered in REMix. The impact of a power-controlled operation enabled by additional components is assessed in the subsequent steps. Selected CHP and HP supply systems can be extended by conventional peak boilers, electric boilers and thermal energy storage. Their technical and economic characteristics will be introduced in the following paragraphs. Figure 5.6 and Table E.20 in Appendix E summarize the heat supply technologies and attributed components used in step 2 to 4 of the scenario assessment.

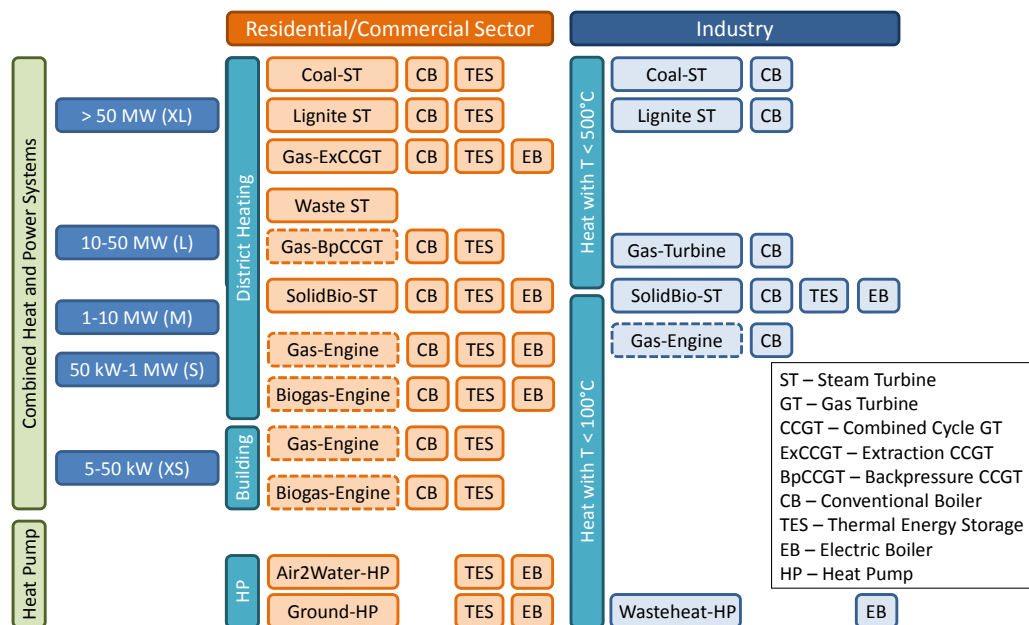


Figure 5.6 Heat production technologies and components considered in the scenario assessment. Backpressure CHP technologies are highlighted with dotted frames.

Electric Heat Pumps

Two domestic HP technologies are considered in this work: air-to-water on the one hand, and ground-to-water HP on the other. It is taken into account that the coefficient of performance (COP) of air-source technologies is given by the temperature spread between heat sink and ambient air (see model description Section 4.5.6). The heat sink temperature depends on the heat usage and the type and design of the heating system. Given that the model does not distinguish between space and water heating, an average inlet temperature for both applications is applied. Based on [159], a maximum COP of 4.2 is assumed for the year 2010 and a temperature spread of $\Delta\vartheta=20$ K. It is reduced to 3.4 for $\Delta\vartheta=30$ K, and further to

2.8 and 1.9 for $\Delta\vartheta=40$ K and $\Delta\vartheta=60$ K, respectively. Future technology enhancements are taken into account by considering higher COP values for the scenario years. The reference maximum COP at $\Delta\vartheta=20$ K increases to 4.4 in the year 2020, 4.6 in 2030 and 4.9 in 2050. Ground-to-water HP use the near surface geothermal heat as heat source. In winter times, when space heating demand is higher, the soil is typically warmer than the ambient air. This allows for lower temperature spreads and thus higher COP values. Seasonal variations of the ground temperature are comparatively small, reaching around 10 K in Germany. They are neglected in this work, and a constant COP value throughout the year is used. Relying on [145, 158], it is estimated to 3.4 in the year 2010, and assumed to improve to 3.6 in 2020, 3.8 in 2030 and 4.2 in 2050. The increasing COP results from technology improvement and a decreasing heat sink inlet temperature.

Constant COP values are also applied to large HP in industrial heat supply or DH systems. They imply the availability of a heat source without seasonal variations in temperature, such as waste heat stream or a TES return flow. Here, COP values of 3.4 in the year 2020, 3.6 in 2030 and 3.9 in 2050 are used, equivalent to a temperature spread of 30 to 40 K. Table E.21 in Appendix E summarizes the techno-economic parameters, including investment and fixed operational costs of all HP technologies.

In the step 1 REMix runs, domestic air-to-water and ground-to-water heat pumps are designed to provide 70% and 75% of peak demand, respectively. Large HP in industry can supply up to 80% of the maximum thermal load. The remaining heat load is covered by an electric boiler, which is used also as back-up and thus dimensioned for the provision of peak demand. In the subsequent heat supply capacity expansion assessment of step 2 and 3, HP design, as well as enhancement by TES are subject to optimization.

Thermal Energy Storage

TES enable an increased flexibility in CHP and HP operation. In the heat supply capacity expansion runs they are available as investment option for selected HP and CHP systems. The assessment is focused on the utilization of low-temperature TES in DH and building heat supply, whereas industrial high temperature process heat receives less attention. This is reflected by the attribution of TES to the considered CHP technologies (see Figure 5.6). Depending on the CHP and consumer characteristics, different maximum storage sizes are used. It is assumed that in industrial or building CHP lower average ratios of TES capacity to thermal peak demand can be realized than in DH systems. The maximum TES size $f_{Cap2Peak}$ that can be built is assumed with twelve hours of peak demand for DH-CHP, seven for building CHP and six for industrial CHP. TES size for heat pumps are limited to values of five hours (domestic) and four hours (industry). These values are a result of estimates concerning restrictions in space availability analyzed in [135].

According to the REMix-OptiMo implementation introduced in Section 4.5.4, TES technologies are characterized by charge, discharge and self-discharge losses, as well as capital and operation costs. In this work, six TES technologies are considered. Depending on storage

size and application, different efficiencies and investment costs are applied. It is assumed that costs and self-discharge losses decrease for larger units. Implicitly considering a technology development, in later scenario years lower investment costs are applied. Variable operation costs are neglected in this work. Table E.22 in Appendix E summarizes all TES input parameters as they have been extracted and derived from [29, 32, 175, 197]. Generally, the TES inlet temperature needs to be higher than that of the heating system. For HP systems, this implies a higher temperature spread, and thus a reduced COP. This effect is considered by taking into account a TES charging efficiency of 80%, which is equivalent to an approximate increase in temperature spread of 10 K in comparison to the direct heat use.

Electric Boilers

Direct electric heating provides a less capital intensive, but also less efficient alternative to electric heat pumps. In step 2 and 3 of the assessment, secondary component electric boilers are available as investment option for installation in selected DH and industrial CHP systems, where they can be used for the utilization of surplus VRE generation ('power-to-heat'). In all cases, the electric boiler capacity is limited to fivefold the annual peak demand of the corresponding technology. Independent of the boiler size, an annual efficiency of 99% is applied. Specific investment and operational costs are assumed to decrease for larger units. Table E.23 in the Appendix E contains all electric boiler input parameters.

Conventional Boilers

Conventional boilers typically serve as CHP back-up and peak supply technology. They are included in the capacity optimization of CHP supply systems. There, an individual boiler technology is defined for each CHP technology. Boilers of the same size class and fuel feature the same set of techno-economic parameters. It is generally assumed that gas-fired boilers have a slightly higher efficiency than those relying on solid fuels, that specific investment and fixed operational costs are lower for larger units, and that variable operational costs are higher for coal or solid biomass. A comprehensive overview of the model input parameters is provided in Table E.24 in appendix E.

Solar Thermal Heat

In one sensitivity of the step 3 model runs, selected DH systems can be extended with solar heat supply. The solar DH systems are characterized by their capital and operational costs. Here, investment costs of $380 \text{ k€}/\text{MW}_{th,Peak}$ and fixed operational costs of 2% are applied. In a first approximation, the solar heat production is assumed to follow the same profile as the PV power generation during the year. A cooling of the solar heat production in times when it exceeds the demand and TES capacity is possible.

5.4.4 Electricity-to-electricity Storage

In this assessment, two different storage technologies with electric energy input and output are considered: pumped storage hydro and hydrogen storage. The currently installed pumped hydro capacity in Europe of 35.2 GW and 282 GWh is assumed to be available throughout all scenarios. A capacity expansion, which might be possible in at least some countries in the assessment area, is not taken into account. To all storage units, a charging efficiency of 89%, a discharging efficiency of 90%, and an annual availability of 98% are applied.

In scenario 50H₂St, a model endogenous installation of hydrogen storage can be realized. Due to the comparatively high conversion losses and low storage losses, as well as high converter and low storage investment costs, hydrogen is particularly attractive to fulfill a long term storage function. It can, however, also be used for short storage cycles, and thus compete with DR and TES. Hydrogen is assumed to be produced with a 70% efficiency in alkali-electrolysis and then stored in pressurized underground salt caverns. For reconversion, hydrogen is used as fuel in combined cycle gas turbines with 57% electric efficiency. The availability of salt caverns limits the application of the storage technology. Table E.7 in Appendix E summarizes the applied hydrogen storage potentials, as they have been quantified in [168]. Cavern volumes are particularly high in *Iberia*, *Northern Europe* and Northern Germany, whereas in Southern Germany, *BeNeLux* and the Alpine countries, almost no storage capacity can be built. Technically, hydrogen can also be stored in pressurized storage tanks. This much more expensive option without geographical limitations is however not included in this work. A profound description of the technical and economic characteristics of different storage technologies is provided in [198]. Table E.17 in Appendix E summarizes the parameters used in this work.

5.4.5 Electricity Transmission Grid

Today's European power transmission relies on AC grids, complemented by some DC transmission lines connecting asynchronous grid areas. In the scenario assessment, both an extended European AC transmission grid, and an overlay DC grid are taken into account. The AC grid representation is, however, limited to the highest voltage level of 380 kV, which is typically used for long-distance transmission. The transmission grid representation in REMix-OptiMo relies on the NTC values of the year 2010 published by the European Network of Transmission System Operators for Electricity (ENTSO-E). In addition to the existing grid capacity, power lines currently under construction or planned under the ENTSO-E *Ten-Year-Network-Development-Plan* (TYNDP) [53] are taken into account. It is assumed that all projects are realized in due time. This includes strengthening and extension of both AC and DC lines. Concerning the installation of DC power lines in Germany, the *Netzentwicklungsplan Strom 2013* (NEP) is considered [66]. The three DC corridors characterized there are implemented into REMix-OptiMo. TYNDP and NEP provide the grid structure in the scenario years 2020 and 2030. For the scenario year 2050, a further increase in power transmission capacity between selected German regions is taken into account. Without additional grid

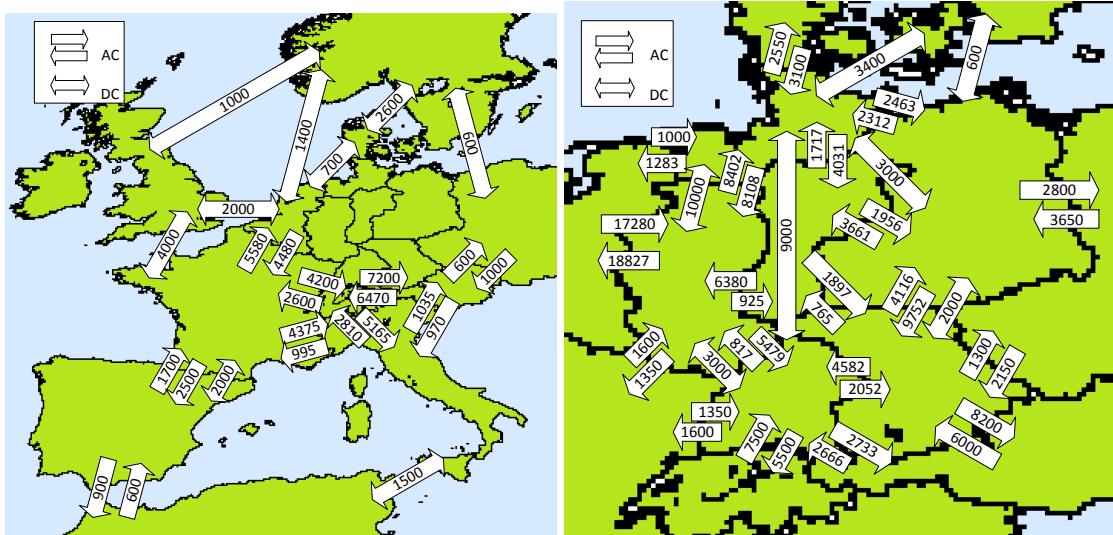


Figure 5.7 Transmission grid net transfer capacities in the scenario year 2050 in Europe (left) and Germany (right).

capacity connecting the offshore and onshore wind regions in the north of Germany to its south, significant shares of the power generation would have to be curtailed. Thus, in order to increase the consistency of RE capacity expansion and grid scenario, a strengthening of the DC lines planned in the NEP is assumed, as well as the construction of an additional line connecting the regions *North* and *East*. Figure 5.7 shows the AC and DC transmission capacity in the 2050 scenarios without model endogenous grid extension. The corresponding Figures E.4 and E.5 for scenario 20Base and 30Base can be found in Appendix E.

Currently existing or planned DC lines feature different rated power capacities, ranging from 250 MW to 1500 MW. Independent of the power capacity, DC transmission losses are assumed with 0.45%/100 km on land and 0.27%/100 km in sea cables. Additional 0.7% is lost at conversion from and to AC [188]. For AC lines, power transmission losses of 2%/100 km are applied. They are calculated based on [138] and an assumed average utilization of 60%. In scenario 50Grid and 50CSP, DC power lines can be installed by the model. The grid capacity expansion is limited to point-to-point DC connections between neighboring model regions. HVDC lines with a nominal power P_{nom} of 1500 MW can be added up to an overall capacity of 30 GW per connection. The corresponding cost assumptions are summarized in Table E.18 in Appendix E.

5.4.6 Demand Response

Availability and Aggregation of Demand Response Potentials

In the assessment of theoretical DR potentials presented in Chapter 2, no limitations in shifting of residential and commercial loads have been taken into account. Due to the high impact on comfort and working routines caused by changes in the consumption pattern, the theoretical potential is reduced to an approximated social potential for the REMix-OptiMo case studies.

Therefore, the parameters $s_{reduction}$ and $s_{increase}$ in equation 2.6 and 2.7 are partly adjusted to values below 100% according to Table 5.3. The estimates reflect the load shifting impact a particular device has on user convenience. For this reason, different values are applied to storage heating or cooling devices on the one hand, and washing equipment or air conditioning on the other. Procedural limits of industrial and commercial DR have already been considered in the assessment of theoretical potentials (see Table 2.2, 2.3 and 2.6). The assumed DR availability of residential and commercial loads given by the values in Table 5.3 represent a rather optimistic estimate, if compared to the outcome of field studies assessing participation of residential consumers in DR [34, 86].

Table 5.3 Assumed customer participation in demand response measures.

Process/Consumer	$s_{reduction}$			$s_{increase}$		
	2020	2030	2050	2020	2030	2050
Freezer/Refrigerator	80%	80%	80%	100%	100%	100%
Washing Machines	13%	15%	20%	8%	10%	15%
Tumble Dryer/Dish Washers	25%	30%	40%	8%	10%	15%
Res. air conditioning	25%	30%	40%	100%	100%	100%
Res. circulation pump	83%	85%	90%	100%	100%	100%
Res. storage heater/water heater	100%	100%	100%	90%	90%	90%
Retail cooling	45%	50%	60%	100%	100%	100%
Cold storage	55%	60%	70%	90%	90%	90%
Gastronomy cooling	23%	25%	30%	90%	90%	90%
Com. ventilation	23%	25%	30%	100%	100%	100%
Com. air conditioning	18%	20%	25%	100%	100%	100%
Com. storage heater/water heater	100%	100%	100%	90%	90%	90%
Pumps in water supply	90%	90%	90%	90%	90%	90%
Ind. ventilation	50%	50%	50%	100%	100%	100%

The consideration of load shifting and shedding has a comparatively high impact on the REMix-OptiMo solution time. For this reason, the processes and appliances considered in Chapter 2 are aggregated to DR technologies. All consumers of one technology are assumed to have the same techno-economic DR characteristics, including costs, limits in frequency, efficiency, as well as shifting and intervention time. This aggregation affects the ability to represent specific features of single consumers. In this work, the 30 consumers discussed in Chapter 2 are summarized to 7 technologies according to Table 5.4. Depending on the maximum shifting time, between 1 and 8 shifting classes are defined for each of the technologies, adding up to a total of 30 classes. Each shifting class is characterized by a shifting time, and a DR efficiency (see model description in Section 4.4). For some DR technologies, it is assumed that longer shifting times go along with higher energy losses (see Table 5.4).

Demand Response Technology Parameters

The considered DR technologies differ in shifting and intervention time, as well as frequency and cost of DR utilization. Depending on the appliances and processes included, also the

Table 5.4 Grouping of DR loads and techno-economic parameter of DR shift classes.

Technology	Consumers/processes included	t_{shift} hours	η_{DR} %
HeatingAC-Res	Residential air conditioning, freezers, refrigerators, heat circulation pumps	1, 2	97%
HVAC-ComInd	Commercial and industrial ventilation and air conditioning, retail cooling	1, 2	97%
CoolingWater-ComInd	Cooling industry and catering, cold stores, water supply and treatment	1, 2, 3 4, 5, 6	98%, 97.5%, 97%, 96.5%, 96%, 95.5%
ProcessShift-Ind	Pulp, paper, cement, CaC ₂ and air separation industry	2, 4, 8, 12, 16, 24, 36, 48	99% 99%
WashingEq-Res	Dish washers, washing machines, tumble dryers	1, 2, 4, 6	100%
StorHeat-ResCom	Residential and commercial electric storage space and water heaters	1, 2, 4, 6, 8, 10, 12	98%, 97.5%, 97%, 96.5% 96%, 95.5%, 95%
ProcessShed-Ind	Aluminum, copper, zinc, steel and chlorine industry	8760	100%

applicable DR measures – load shedding, load advance and load delay – are limited. Energy-intensive manufacturing processes are assumed to be available only for load shedding, whereas residential, commercial and cross-sectional industry consumers can be shifted either or both to an earlier or later moment. Interference times are shorter for heating and cooling appliances without thermal storage, and longer for technologies providing physical or thermal storage. Off-times between two interventions are primarily relevant for heating and cooling without storage, whereas annual limits are only applied to industrial consumers. Specific investment costs are lower in industry and commercial sector, where single DR loads are typically higher, whereas operational costs are assumed to be lower for residential appliances. In the estimation of investment costs, unit cost value of 25€ per residential appliance and 50€ per commercial and industrial cross-sectional technologies are considered. To all technologies, an interest rate of 6% and an amortization time of 20 years is applied. The operational DR costs reflect the expenditures arising from the maintenance and utilization of the required ICT infrastructure, as well as compensation for losses in production output and comfort. All techno-economic parameter are summarized in Table 5.5. It provides also the average annual load reduction availability $\bar{s}_{flex}$ in Germany in the year 2050.

Within Germany and Denmark, the DR potentials are distributed to subregions according to the corresponding consumers. Therefore, the allocation method discussed in Section 2.7.3 is applied. Table E.12 in Appendix E provides the available potentials for each region and DR technology.

5.4.7 Electric and Hydrogen Vehicles

Electric vehicles (EV) are assumed to have a substantial share in future passenger transport. Depending on the scenario, EV cover up to 100% of the overall mileage. These high shares imply substantial additional electricity demands, but also load flexibility, which can be

Table 5.5 Techno-economic parameter of DR technologies, extracted or derived from [36, 85, 135, 142, 170].

Technology	DR Measure	$t_{interf.}$ hours	t_{dayLim} hours	n_{year} 1/a	$c_{specInv}$ k€/MW	c_{OMFix} %/year	c_{OMVar} €/MWh	$\bar{s}_{flex}^{2050,GER}$ %
HeatingAC-Res	Delay	1	4	none	250	3%	10	9%
HVAC-ComInd	Delay	1	4	none	10	3%	5	8%
CoolingWater-ComInd	Advance/Delay	2	8	none	5	3%	20	31%
ProcessShift-Ind	Advance/Delay	3	24	365	0	0	150	44%
WashingEq-Res	Delay	8760	none	none	30	3%	50	1%
StorHeat-ResCom	Advance	12	none	none	20	3%	10	4%
ProcessShed-Ind	Shedding	4	24	40	0	0	1000	66%

harnessed for the balancing of VRE fluctuations. EV charging is assumed to follow the hourly profile shown in Figure 5.8, a change in daily demand is not taken into account. In the step 2 to step 4 model runs, it is assumed that a certain share of the hourly vehicle fleet charging demand can be made available for controlled charging. This share increases for later scenario year, from 15% in 2020 to 30% in 2030 and 60% in 2050 [147]. Charging demand can be shifted to a later moment, however limited by a maximum shifting time and the installed charging capacity. For the latter, a value twice as high as the peak demand is applied. As for DR, fixed shifting times t_{shift} are taken into account: EV charging can be either shifted by 2 hours, 4 hours, or 8 hours. For the operational costs of controlled charging, a value of 10 €/MWh is applied.

In scenario 50H₂T, hydrogen is used as passenger car fuel. Consistent with [135], the electrolysis is operating locally at the hydrogen filling stations. All filling stations are equipped with a hydrogen storage dimensioned to 12 hours of full load production. The corresponding electricity demand is calculated using an electrolyzer efficiency of 67%. The electrolyzer capacity sums up to 37 GW in Germany and 189 GW in the overall assessment area. The annual hydrogen demand can be produced in the avail-

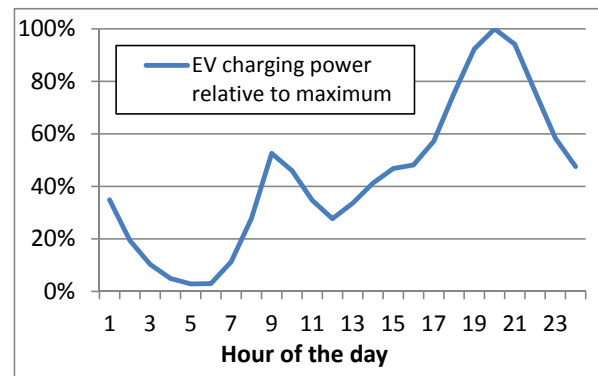


Figure 5.8 Uncontrolled EV charging profile [147].

able electrolyzer capacity within 3000 FLH. The electrolyzer dimensioning and storage availability allow for an adjustment of hydrogen production to VRE power generation.

The annual electricity demand of EV and hydrogen production for transportation in Germany are assumed according to [135]. The corresponding demands in the other countries in the assessment area are estimated using passenger mileage statistics. A detailed description of the transport sector scenarios is provided in [147, 169]. The resulting demands are summarized for each country, scenario and year in Table E.4 in Appendix E.

5.5 REMix-OptiMo Results

Using REMix-OptiMo, the least-cost hourly operation of all system assets is assessed from a macroeconomic view. The model considers the installed capacities and – where available – limits in capacity expansion for all power and heat generation, storage, flexible load and transmission grid technologies. System costs calculated by REMix are composed of annuities of investment costs on the one hand, and operational costs on the other. The latter arise from plant maintenance, fuel demand, CO₂ emission certificates, as well as penalties for not supplied heat and power. REMix takes into account only the capital costs of newly installed assets, and excludes those of already existing.

5.5.1 Step 1: European Power Plant, Storage and Grid Operation

In the step 1 REMix model runs, no flexible electric or thermal loads are taken into account. This implies that DR, controlled EV charging and power-controlled heat supply are not available. The discussion of the results is consequently focused on other system components, namely conventional and renewable power plant operation, as well as storage and transmission grid utilization. Attention is furthermore given to the demand of additional power plant capacity and curtailment of VRE generation.

Power Supply Structure

Figures 5.9 visualizes the electricity balance of Germany for all scenarios. It reflects the dominance of RE in general and VRE in particular in the overall supply. The RE share after consideration of curtailment and losses reaches around 80% in all 2050 scenarios, and is highest in 50CSP (82%). Renewable and fossil-fueled CHP contribute between 24% (20Base) and 27% (50Wind). At the same time, the conventional condensing power generation is strongly reduced, from 38% in the year 2020 to values between 5% (50H₂St) and 4.5% (50CSP) in 2050. On the demand side, storage losses, grid losses and new consumers amount for up to 27% in the 2050 scenarios. Their share is particularly high for scenario 50H₂T, where the transport sector electricity demand is highest. The new consumer demand is dominated by the transport sector, whereas HP account for less than 2%.

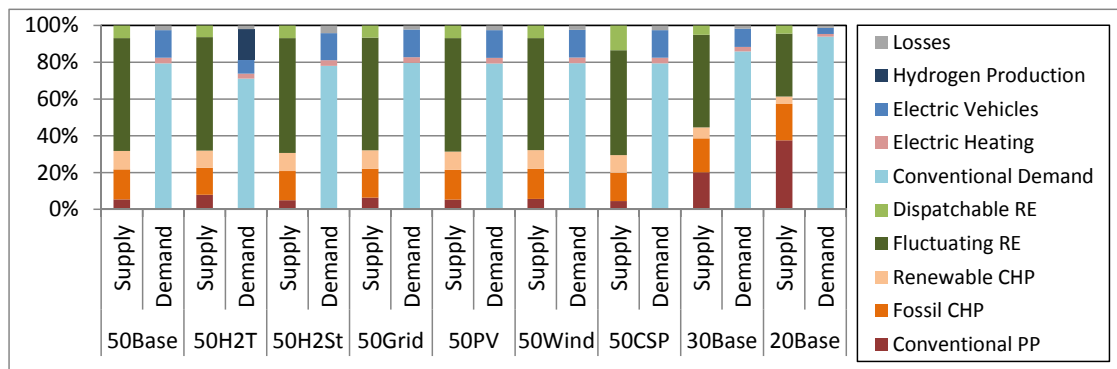


Figure 5.9 Scenario comparison of the German power balance.

The contribution of each technology to the power generation in Germany is shown in Figure 5.10. According to the assumptions, those scenarios representing later stages of the transformation feature much higher RE shares at the expense of a lower conventional power plant output. In the 2050 scenarios, the overall power generation in Germany is highest in the scenario 50H₂T and 50Grid, and lowest in 50CSP. This results from the higher overall electricity demand, increased export and higher import, respectively. In all scenarios, wind power is the major power source in Germany. It provides between 135 TWh (22%) in 20Base and 271 TWh (45%) in 50H₂T. Solar PV accounts for a power generation ranging from 52 TWh (9%) in 20Base to 108 TWh (20%) in 50PV. Additional RE generation comes from hydro ($\approx 5\%$ in 2050), geothermal ($\approx 4\%$ in 2050) and biomass ($\approx 12\%$ in 2050) power plants. The CSP import in scenario 50CSP accounts for 39 TWh (7%), and corresponds to an average annual capacity utilization of around 5200 FLH. Dominant conventional fuel is natural gas, contributing between 16% and 20% of the overall generation. The hard coal power supply share decreases from 14% in scenario 20Base to less than 4% in the year 2050. Differences in the supply structure are mostly found for wind, PV, as well as gas and coal-fired condensing power plants. They are triggered by the assumed RE capacities on the one hand, and the available balancing technologies and thus differences in curtailments on the other.

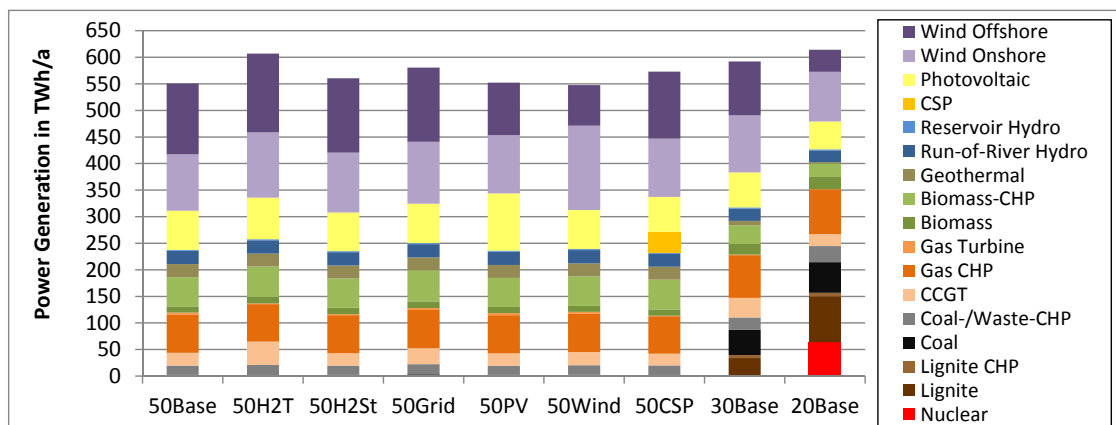


Figure 5.10 Scenario comparison of the German power supply structure.

According to the scenario input, a similar power supply structure is found on European scale (see Figure 5.11). Due to higher capacities of adjustable RE technologies, particularly reservoir hydro, biomass and CSP, the VRE generation share is by 2% to 6% lower than in Germany. Furthermore, the CHP share is by 7% to 8% lower than in Germany, at the expense of more conventional power generation. The overall RE share is, however, almost identical and in some scenarios (50H₂T, 50Grid and 50CSP) even higher. The highest RE share of more than 84% is reached in 50CSP and goes along with a conventional power generation share of only 8%. In the other scenarios for the year 2050, RE deliver around 80% of the supply, fossil-fueled CHP and condensing power plants the remaining 20%. VRE power generation is particularly high in scenario 50H₂T, where hydrogen production causes a higher overall demand, as well as scenario 50Grid, where curtailments are significantly reduced by the installation of additional power lines. Except for scenario 20Base, wind power is the

dominant power source with generation shares between 28% (30Base) and 40% (50H₂T). In contrast to Germany, solar PV is not the second most important RE power source. This results from the much higher biomass and hydro power shares: depending on the scenario, they reach between 7% and 13% for biomass and between 13% and 15% for hydro power. Nonetheless, solar PV accounts for up to 11% of the total generation. In all scenarios other than 50CSP, where the CSP supply share reaches 14%, CSP plays only a minor role in the European power supply. Compared to Germany, the natural gas power generation has a slightly lower share, whereas the contribution of coal is around 0.5% higher. Nuclear and lignite fired power plants are only available in the earlier scenario years; their power production reaches 18% (7%) and 6% (3%) in 20Base (30Base), respectively.

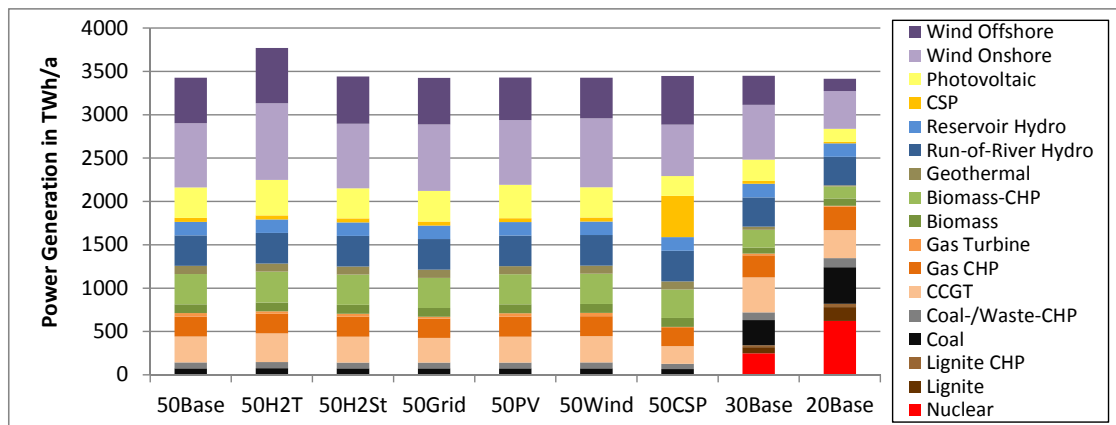


Figure 5.11 Scenario comparison of the European power supply structure.

Generation, Storage and Transmission Capacity Demand

Additional gas turbine capacity installation is required in all scenarios (see Figure 5.12). Without the consideration of further balancing options, the scenario capacities are not sufficient for an uninterrupted power supply. In the reference scenario 50Base, the model endogenous capacity expansion in Germany accounts for almost 23 GW. Changes in the VRE supply structure cause a slight increase in the required gas turbine capacity. This implies that both solar PV and onshore wind cannot provide firm capacity to the same amount as the offshore wind plants they are substituting in scenario 50PV and 50Wind. A comparatively low demand for additional capacity is found in scenario 50H₂T. It results from a higher conventional power plant scenario capacity on the one hand (see Figure 5.4), and a different demand pattern on the other. Due to a lower EV share and flexible electrolyzer operation, lower residual peak loads occur. In scenario 50H₂St, gas turbine capacity is partially replaced by hydrogen storages with a total capacity of 6.26 GW and 1.7 TWh. The slight decrease in combined gas turbine and storage capacity in comparison to the reference case 50Base is supposedly enabled by sharing hydrogen storage capacity beyond the country's borders. Within Germany, hydrogen storage is almost exclusively built in the *North* region, where highest potentials are available. The storage located there, however, mostly substitutes GT capacity in Germany *West* and other regions. Even though DC lines with a total transmission capacity of more

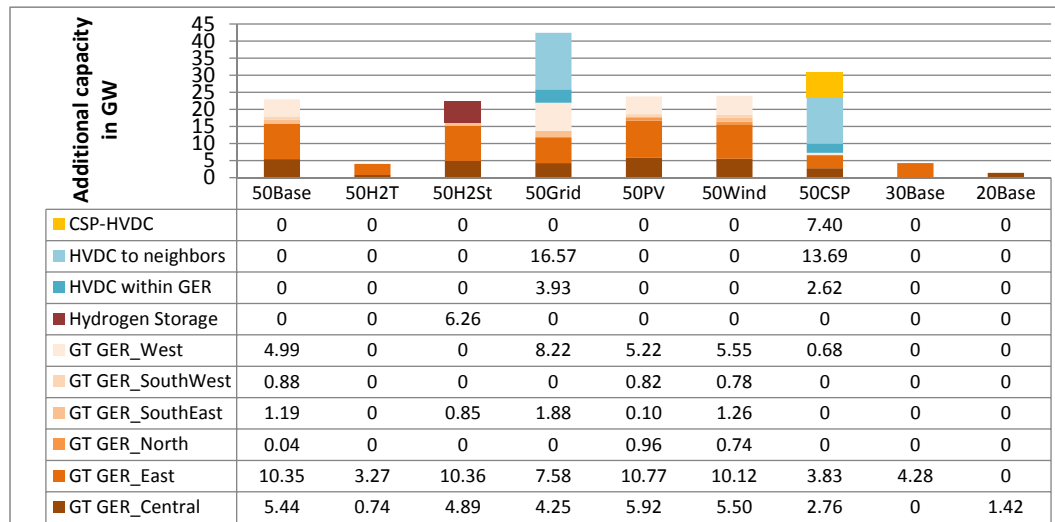


Figure 5.12 Scenario comparison of additional generation, storage and transmission capacity in Germany.

than 20 GW are installed within Germany and to its neighbors, the gas turbine capacity is reduced by only 1.7 GW in scenario 50Grid. The firm capacity that can be accessed by the DC grid is consequently very low. The substitution of domestic VRE capacity by dispatchable CSP power import reduces the required gas turbine capacity by two thirds to 7 GW. This reduction is twice as high as the capacity of the CSP-HVDC systems of 7.4 GW. It is achieved in combination with almost 14 GW of additional DC lines to neighboring countries, which – in contrast to scenario 50Grid and as a result of the CSP-HVDC systems – can provide firm capacity also to Germany, or reduce the firm capacity Germany provides to other countries. Throughout all 2050 scenarios, most GT installation is located in the regions *East*, *West* and *Central*, whereas in *North*, *Southwest* and *Southeast*, almost no capacity expansion takes place. In the earlier scenario years, much lower amounts of additional gas turbines are needed; they account for 4.3 GW and 1.4 GW, respectively.

In the overall assessment area, the model endogenous gas turbine capacity installation in the reference scenario 50Base adds up to 110 GW. On European scale, similar effects to those in Germany can be observed in most scenarios. A substitution of offshore wind capacity by PV or onshore wind capacity in Germany causes a slight increase of 1 GW in gas turbine installation. In contrast, reductions can be achieved by the availability of additional balancing options, such as hydrogen storage (-5%), grid extension (-7%), hydrogen-based transport (-49%) or CSP power imports (-67%). In all cases, the decrease in gas turbine capacity goes along with the need for additional grid infrastructure or hydrogen electrolysis and storage facilities. The combined gas turbine and hydrogen storage capacity in scenario 50H₂St is by 60 MW (0.05%) higher than the gas turbine capacity in the reference case. The installation of hydrogen storage is very much concentrated to the regions Germany *North* and *Northern Europe*, which account for 67% and 21% of the overall capacity, respectively. Its overall capacity reaches 9.3 GW and 3.2 TWh. The results of scenario 50Grid confirm that additional transmission lines can provide firm capacity only to a comparatively limited extent.

Although DC lines with a total capacity of 47 GW are added, the gas turbine installation is reduced only by 7.5 GW. In contrast to the separate assessment of Germany, the combined CSP-HVDC (81 GW) and gas turbine capacity (37 GW) in scenario 50CSP exceeds the gas turbine capacity in 50Base. This might be either caused by limited grid capacity between those countries with and those without CSP-HVDC systems, or by limitations in the solar resource availability. Additionally to the CSP-HVDC lines, within Europe a total transmission capacity of 38 GW is added. In scenario 20Base and 30Base, the required additional GT capacity is much lower than in all other scenarios and reaches 8 GW and 34 GW, respectively. This first and foremost implies that the power plant park envisaged in the scenario input comes closer to the required capacity than in the 2050 scenarios.

Power Transmission Grid Utilization and Extension

The REMix-OptiMo results provide insight into the utilization of long distance power transmission in high RE supply systems. Generally, electricity exchange between the regions is increasing with RE power generation share on the one hand, and available grid infrastructure on the other. It is highest in the CSP import scenario 50CSP, where the electricity transmitted over HVDC lines associated to CSP power plants in *Northern Africa* alone (434 TWh) accounts for more than the overall grid transfers in the reference scenario 50Base (367 TWh). Taking into account also the grid utilization within Europe, the annual transfers in 50CSP sum up to a total of 797 TWh. Due to the model endogenous DC grid capacity extension, an increased power transmission is furthermore observed in scenario 50Grid (383 TWh). Lowest values are found in scenario 20Base (216 TWh) and 30Base (279 TWh). Hydrogen use in the transport sector in scenario 50H₂T (367 TWh) and hydrogen storage in 50H₂St (368 TWh) have only a minor impact on annual electricity transmission over model region borders, whereas the different regional allocation of VRE generation in 50PV (359 TWh) and 50Wind (346 TWh) causes a slight decrease in grid utilization. DC power transmission is dominating over AC in all scenarios except 30Base and 20Base, which feature a reduced DC grid capacity.

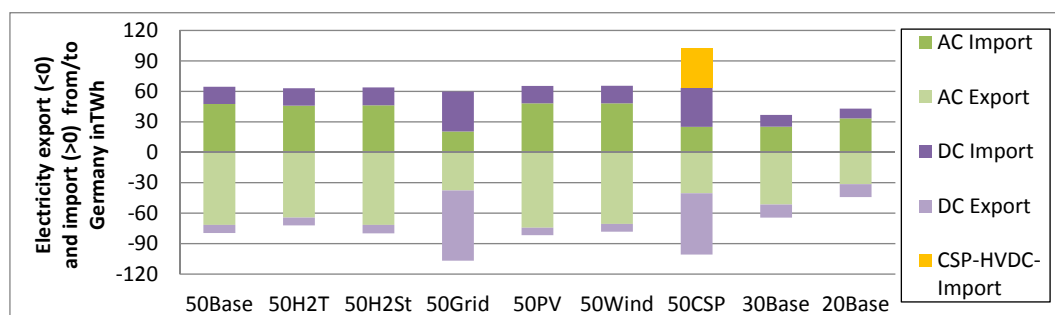


Figure 5.13 Scenario comparison of the annual electricity exchange between Germany and neighboring countries.

Germany is a net electricity exporter in all scenarios except 50CSP (see Figure 5.13). Annual imports from neighboring countries are comparable for all 2050 scenarios. Ranging between 60 TWh and 65 TWh, they are almost not affected by changes in RE supply, grid or storage infrastructure. In the earlier scenarios years, imports reach roughly two thirds of the 2050 values. Electricity imports from *Northern Africa* account for additional 39 TWh in scenario 50CSP. Germany's electricity export is influenced to a higher extent by the scenario assumptions. In the reference scenario 50Base, annual exports account for 80 TWh. They are slightly increased to 82 TWh by a higher PV generation share, and decreased to 78 TWh by a higher onshore wind share. The consideration of hydrogen electrolysis reduces the exports by 9%, whereas the installation of hydrogen storage does not have any impact. Enabled by additional DC lines – especially to France and Switzerland – exports are highest for scenario 50Grid (107 TWh) and 50CSP (101 TWh). In contrast, lowest values are detected in the scenarios with lower RE shares.

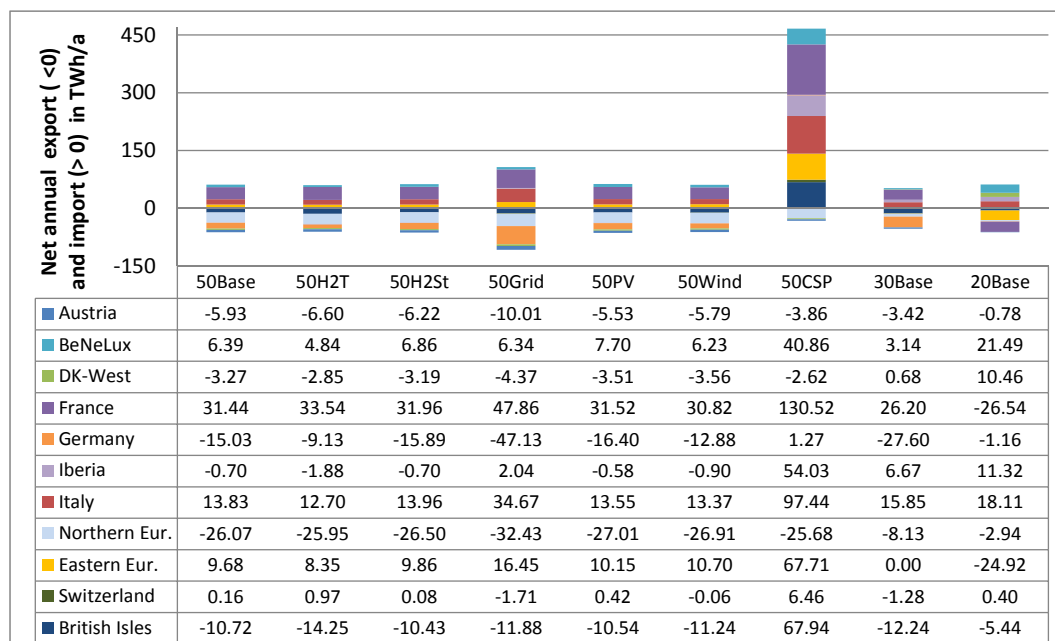


Figure 5.14 Scenario comparison of the annual power transfer balance between European countries.

Annual import-export balances are displayed for each scenario and country in Figure 5.14. They show similar pattern for all 2050 scenarios except 50Grid and 50CSP. Major electricity exporters are *Northern Europe*, Germany and the *British Isles*, whereas net imports are highest in *France* and *Italy*. With the exception of *Switzerland* – which generally has a very equalized transfer balance – the additional transmission lines available in scenario 50Grid do not change the algebraic sign but only the amount of net imports and exports. In contrast, CSP power imports have a substantial impact on annual export balances. With the exception of *Austria*, *Denmark West* and *Northern Europe*, all European countries become net electricity importers. The excess of imports is particularly distinct in *France*, *Italy*, *Eastern Europe*, the *British Isles* and the *Iberian Peninsula*. Due to the assumed development of supply and grid infrastructure,

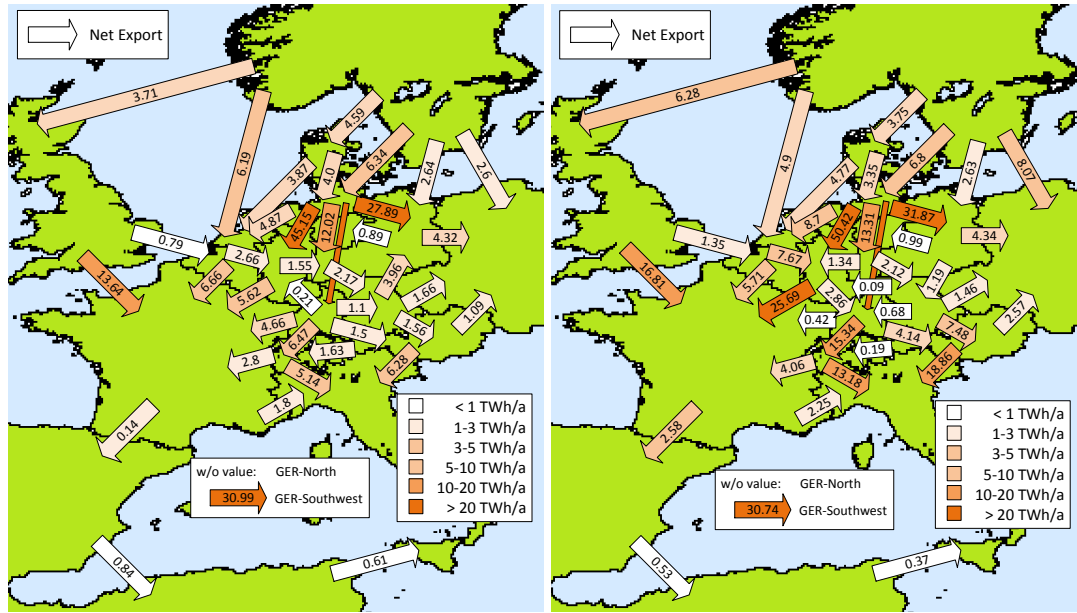


Figure 5.16 Annual net electricity transfers over region borders exemplary for scenario 50Base (left) and 50Grid (right), all values in TWh/a

from *Germany-North*, *Northern Europe*, *Denmark-West* and the *British Isles* to *France*, *Italy*, *BeNeLux* and *Eastern Europe*. The additional DC lines have particular impact on the exports from *Germany-North* to *BeNeLux*, *France* and through *Switzerland* and *Austria* to *Italy*, but also on those from *Northern Europe* to *Eastern Europe* and the *British Isles*.

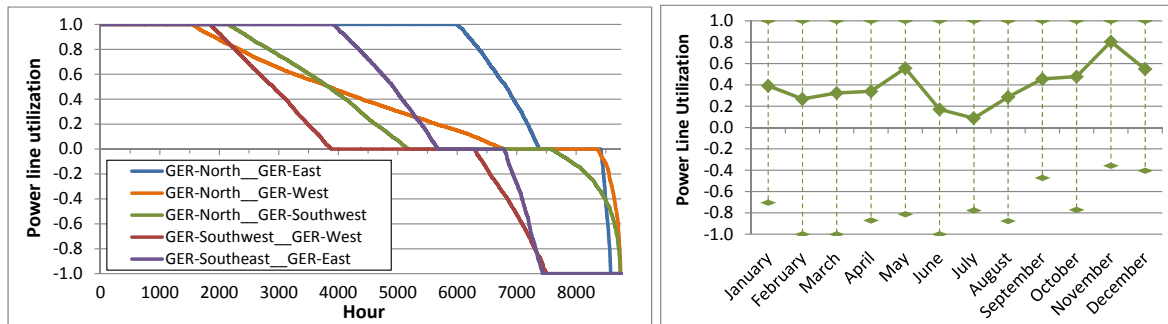


Figure 5.17 Annual load duration curves of the DC lines within Germany (left) and maximum, minimum and average utilization of the interconnection between the Germany-North and Germany-Southwest (right) in scenario 50Base.

Seasonal variations in direction and intensity of trans-European electricity flows have been studied with REMix-OptiMo in a previous study [180]. For this reason, in this work only the utilization of the DC lines within Germany are discussed. The left side of Figure 5.17 shows the annual load duration curve of the five domestic DC connections in scenario 50Base. Values greater than zero stand for a transmission from the first to the second region in the description, and those smaller than zero for the opposite direction. The charts reflect the dominance of wind power exports from *Germany-North* to the regions *West*, *Southwest* and *East*, but also significant flows from the southern regions to *East* and *West*. This is underlined by the diagram in the right side of Figure 5.17, where seasonal variations in

the utilization level of the interconnection between the regions *North* and *Southwest* are displayed. The southward transmission features two peaks in late spring and late autumn. Due to solar PV power generation, the average capacity utilization is, however, significantly reduced in summer. This impact of PV can be observed also in the power transfers over the lines connecting the southernmost regions to their direct neighbors in the north. Differences between the scenarios are generally found to be comparatively small.

Electricity-to-electricity Storage Utilization

The annual electricity-to-electricity storage energy input exhibits substantial differences between the scenarios (Figure 5.18). Across the assessment area, it ranges from 18 TWh in 50H₂T to 78 TWh in 50H₂St, equivalent to 0.5% and 2.3% of the annual demand. Additional storage availability in scenario 50H₂St does almost not affect the utilization of pumped hydro storage. In contrast, DC transmission extension reduces the electricity input by 12% to 50 TWh. The higher onshore wind generation share in Germany has a decreasing, the higher PV share an increasing effect on storage operation. Storage utilization is generally lowest in the scenarios with less VRE capacity. Figure 5.18 also shows that between one fifth (20Base) and almost half (50H₂St) of the overall storage usage is located in Germany. The annual number of full storage cycles is found to be by 2% to 8% lower in Germany than on European average. Exceptions are scenario 50PV, where the German value exceeds the European average by 8%, and scenario 20Base, where the storage utilization in Germany is by 31% lower.

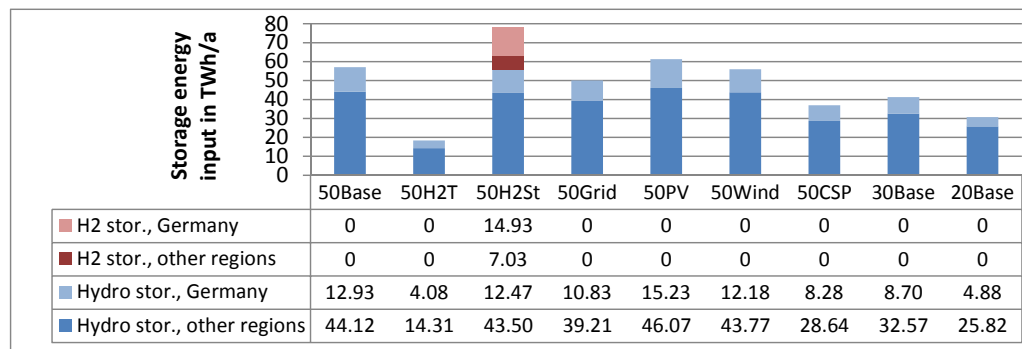


Figure 5.18 Scenario comparison of the annual storage input in the overall assessment area.

Electricity Losses and VRE Curtailment

Electricity losses are highest in scenarios with intense grid or storage utilization. In 50CSP, overall losses in the assessment area account for 60 TWh, in 50H₂St for 53 TWh. The comparatively low storage operation in 50H₂T goes along with reduced losses of only 32 TWh. The losses of 40 TWh detected in the reference case 50Base are slightly decreased by a higher onshore wind capacity and increased by a higher PV capacity in Germany. Even though it is characterized by substantial amounts of transmitted electricity, losses are comparatively small in 50Grid (36 TWh). This results from the lower specific transmission losses of DC power

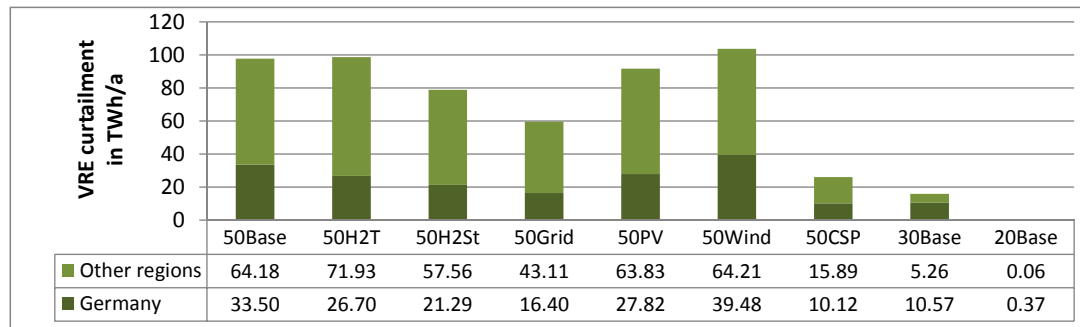


Figure 5.19 Scenario comparison of annual VRE curtailments in the overall assessment area.

lines, which are predominantly used. As a consequence of lower grid and storage utilization, losses are smallest in scenario 20Base (25 TWh) and 30Base (32 TWh).

Renewable electricity generation is curtailed when it exceeds the sum of demand and available grid and storage capacity. It increases with installed VRE capacity and geographic simultaneity of solar, wind or hydro resource availability. In the reference scenario 50Base, 98 TWh are curtailed, 33 TWh of which in Germany. This corresponds to 3% and 10% of overall VRE generation, respectively. Changes in VRE capacity in Germany cause an increase in curtailment by 6 TWh if more onshore wind is used (50Wind) and a decrease by the same amount if more PV is used (50PV). Both effects are almost exclusively located in Germany. In scenario 50H₂T, overall curtailments amount to almost the identical value as in the reference case; the higher VRE capacity is balanced by the flexible operation of almost 190 GW of electrolyzers. The geographical distribution is however different: higher values are found mostly in *Eastern Europe* and *Iberia*, lower in Germany and the *British Isles*. Additional storage and grid capacity available in scenario 50H₂St and 50Grid reduce the curtailments to 79 TWh and 60 TWh respectively. Given that most hydrogen storage capacity is built in Germany, approximately 65% of the reduction is realized there. Additional DC lines have particularly high impact on VRE curtailments in *Austria*, *Italy* and *Germany-Southwest* if relative numbers are considered, and *France*, *Germany-North*, as well as the *British Isles* if absolute numbers are considered. Even lower curtailments of 26 TWh are found in scenario 50CSP, which combines a lower VRE share with an increased grid capacity. In Germany, the proportional reduction is marginally lower than in the other regions. In the earlier scenario years, curtailments are lowest and amount to 16 TWh in 30Base and 0.4 TWh in 20Base, respectively.

Taking into account the regional distribution within Germany, it appears that most curtailments occur in *Germany-North*, which accounts for up to 83% of the total. On the other hand, only very little VRE power remains unused in the south. This allocation of curtailments is affected most by the changes in the VRE supply structure considered in scenario 50PV and 50Wind. There, the share of the *North* region is reduced to 57% and 44%, at the expense of higher curtailments in the regions *Southeast* and *East*, respectively.

Power Plant Full Load Hours

In the reference scenario 50Base, FLH in Germany reach approximately 6600 h/a for biomass power plants, 3150 h/a for coal, 2300 h/a for CCGT and 150 h/a for gas turbines (see Figure 5.20). The power plant operation is increased when additional grid capacity is available, as well as in scenario 50Wind and 50H₂T. In contrast, lower FLH are found for scenario 50H₂St and 50PV. CSP imports have an increasing impact on coal power plant FLH, whereas gas-fired stations are operated less than in the reference scenario. Conventional power plant capacity utilization is always highest for the technology with lowest variable operational costs: nuclear power plants in 2020, lignite power plants in 2030, and coal power plants in 2050.

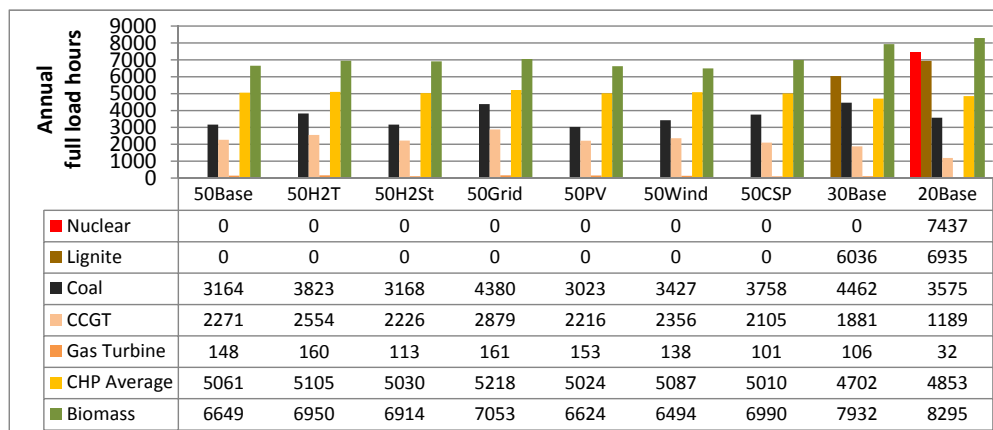


Figure 5.20 Scenario comparison of power plant and CHP FLH in Germany.

On average over all technologies and scenarios, annual conventional power plant FLH are by approximately 17% lower in Germany than on European average. This is related to the higher supply share of RE technologies with low capacity credit and annual operation hours, namely solar PV and onshore wind. Higher FLH in the other European regions are particularly found for power plants fired with coal, biomass and natural gas, whereas for those relying on nuclear and lignite fuel, comparable values are reached. Comparing the scenarios, differences in capacity utilization are particularly pronounced in 20Base, 50H₂St, 30Base and 50PV. In contrast, in the scenarios with additional grid capacity the FLH in Germany are much closer to or even higher than the European averages. As in Germany, capacity utilization in Europe is highest for nuclear power plants, followed by lignite, hard coal, CCGT and gas turbines. With the exception of 50CSP, coal-fired power plants reach over 4900, CCGT over 3000 annual FLH in all scenarios.

The higher FLH of CHP in comparison to condensing power plants result from their must-run characteristic as heat-supplier on the one hand, and the higher efficiency on the other. In the reference scenario for Germany, technology-specific annual CHP FLH reach values between 3918 h/a and 6480 h/a (Figure 5.21). Differences are related to fuel type, heat demand profile, plant dimensioning, as well as operational degrees of freedom. Electric FLH are generally lower for CHP technologies with flexible heat extraction. This arises from the limiting effect of the heat supply on the maximum power generation (see Figure 4.4).

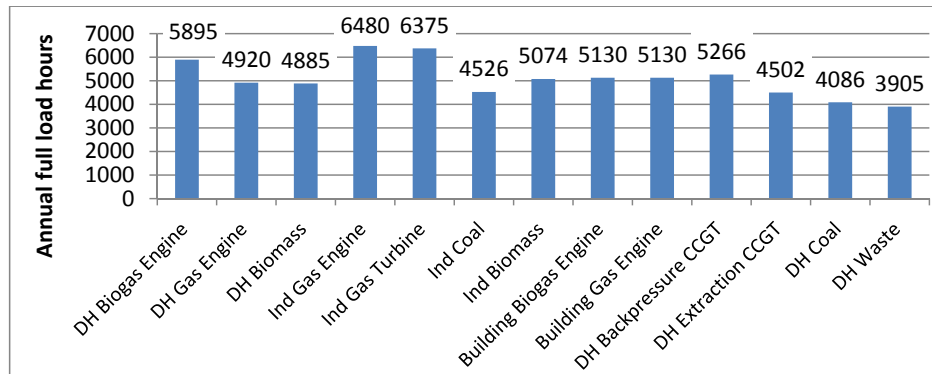


Figure 5.21 Technology comparison of the electric CHP FLH in Germany in scenario 50Base.

In contrast to that, backpressure CHP plants can increase their power production using the assumed cooling device. Due to the flatter annual load duration curve of the heat demand, FLH are higher for industrial CHP units. This is particularly the case for gas turbines and engines, which are dimensioned to cover 60% of the thermal peak load and reach more than 6000 FLH per year. Independent of the demand sector, biomass-fired CHP units have higher operation hours than coal fired, an effect that can be attributed to the CO₂ emission costs causing higher variable generation costs of coal CHP. Condensing power generation in CHP plants is mostly attributed to technologies relying on biomass. The comparatively low capacity utilization of waste-fired CHP arises from their assumed dimensioning to cover all heat demand without peak boiler use.

Comparing the scenarios, CHP FLH are highest in 50Grid and 50H₂T, triggered by additional transfer capacity and power demand, respectively (see Figure 5.20). In contrast, lowest values are found for the earlier scenario years assessed in 20Base and 30Base. CHP FLH are slightly increased by a higher wind generation share in Germany, and slightly decreased by a higher PV share, additional storage and CSP power import. In the majority of the scenarios, the European average CHP FLH are by 2% to 3% higher than those in Germany. The contrary situation is found in the scenarios with additional DC lines, as well as 20Base and 30Base.

5.5.2 Step 2a: Demand Response Capacity Optimization

In step 2 and 3 of the REMix-OptiMo application, the capacity expansion of DR and heat supply systems in Germany is analyzed for all scenarios and selected sensitivities. Within each German model region, power plant operation, storage utilization, curtailment and gas turbine capacity expansion are assessed again, now with the availability of additional balancing options. Hourly power export and import profiles are obtained for each region from the step 1 model runs and used as fixed power inflow or outflow. This implies that the electricity grid cannot be used for further power balancing.

Demand Response Capacity Expansion and Utilization

In the step 2a model runs, the model endogenous exploitation of DR potentials is assessed. For each DR technology, maximum installable capacities, hourly profiles of flexible and

free loads, as well as a set of techno-economic parameters and a number of shifting classes are provided. The model can tap the available potential by investing in DR instead of, for example, gas turbine capacity or conventional power plant fuel. Additional load shifting can be realized by controlled EV charging.

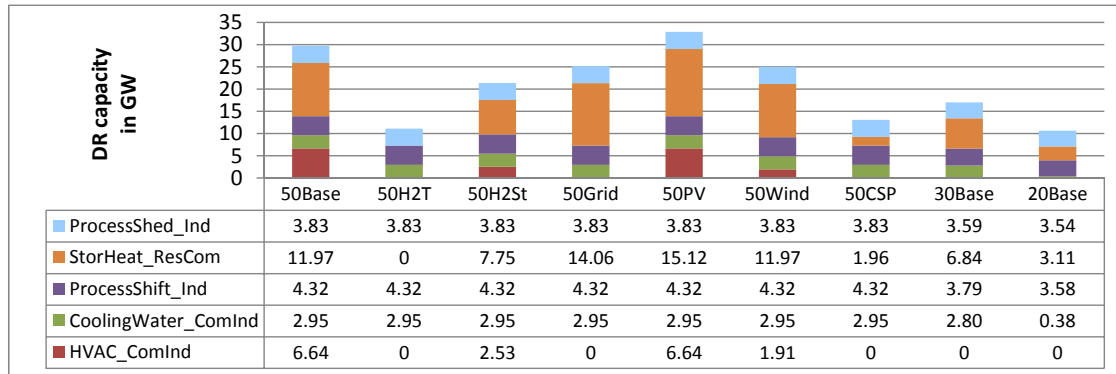


Figure 5.22 Scenario comparison of DR capacities in Germany, subdivided by technology.

Figure 5.22 shows that DR capacity is installed across all scenarios. The exploitation of the potential is however limited to some of the available DR technologies. Given that no installation costs are applied, the energy-intensive industries summarized in *ProcessShed-Ind* and *ProcessShift-Ind* are fully accessed in all scenarios and throughout all regions. Except for scenario 20Base, this is also the case for the loads aggregated in *CoolingWater-ComInd*, which includes commercial and industrial cooling processes, as well as water pumping and treatment. In some scenarios, additional DR capacity is installed in the categories *HVAC-ComInd* and *StorHeat-ResCom*. The former comprises commercial and industrial ventilation and air conditioning, the latter residential and commercial space and water heating. Due to their higher costs and low temporal availability, the remaining residential DR categories *WashingEq-Res* and *HeatingAC-Res* are not exploited in any scenario. The overall DR capacity differs by a factor of more than three between the scenarios. It ranges from 10.6 GW in scenario 20Base to 32.9 GW in 50PV.

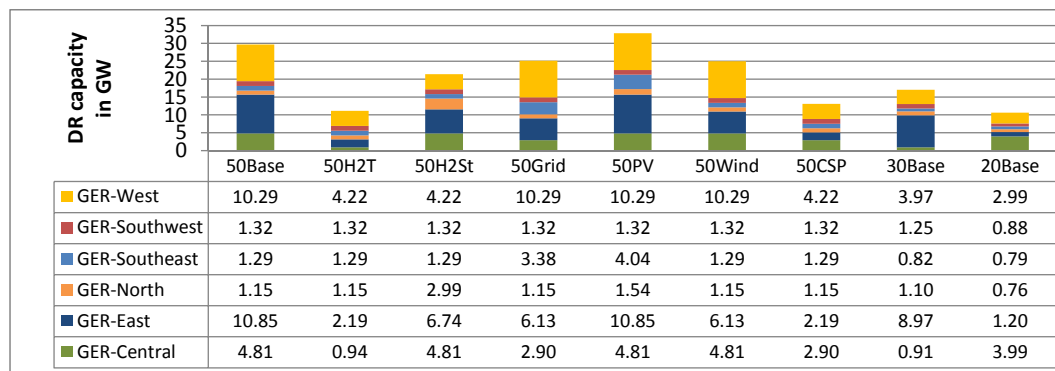


Figure 5.23 Scenario comparison of regional DR capacities.

The exploitation of DR potentials varies widely not only between scenarios, but also between geographical regions (see 5.23). It is lowest in the region *Southwest*, where in all

scenarios only industrial potentials are accessed. In most scenarios, this also applies to the regions *Southeast* and *North*. Exceptions are scenario 50Grid and 50PV in *Southeast*, and 50H₂St and 50PV in *North*. On the contrary, the additionally accessed potential is mostly located in the regions *West*, *East* and *Central*. Their share in the overall DR capacity tends to increase with the degree of DR development and ranges between 66% in scenario 50H₂St and 87% in 50Base. Technology-specific DR capacity installation data for each region are available in Table F.8 to F.13 in Appendix F.

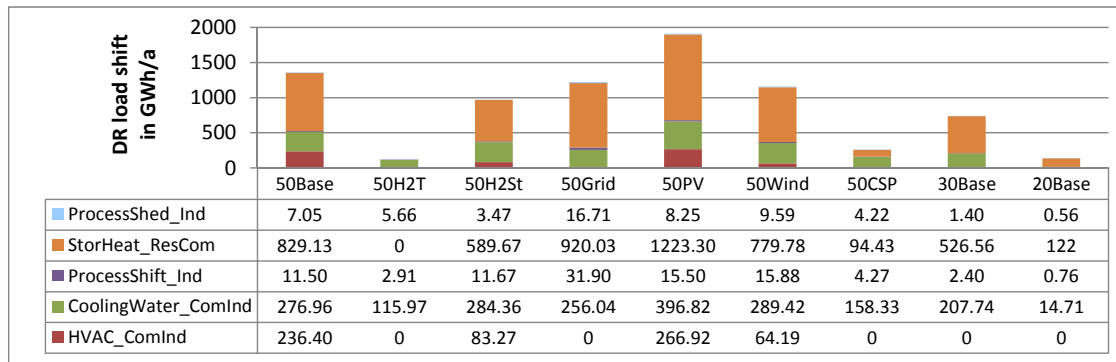


Figure 5.24 Scenario comparison of DR utilization in Germany, subdivided by technology.

Figure 5.24 shows the annual application of the DR capacity. It summarizes the shifted and shedded energy throughout the year and across all model regions in Germany. Between the scenarios substantial differences of more than factor 15 are found. The overall DR energy expenditure ranges from 125 GWh/a in scenario 50H₂T to 1.9 TWh/a in 50PV, equivalent to 0.02% and 0.36% of the respective annual demand.

Even though energy-intensive industrial processes have a substantial or even dominant part in DR capacity, they contribute only between 1% and 5% of the shifted and shedded energy. On the contrary, cooling, ventilation and heating applications throughout all demand sectors account for the lion's share in overall DR energy. This distribution is related to the considerable differences in commitment costs.

On average over all scenarios, the annual DR energy per unit of installed capacity, which can be considered equivalent to technology FLH, ranges from 1.7 for industrial load shedding to 78 for *CoolingWater-ComInd* loads. Comparing the scenarios, differences in annual utilization are lowest for the categories *StorHeat-ResCom* and *HVAC-ComInd*, and highest for *ProcessShift-Ind* and *ProcessShed-Ind*.

All DR technologies can be used with various shifting times (see Table 5.4). The REMix-OptiMo results show that mostly the longer available shifting times are requested. Depending on the scenario, between 60% and 70% of the shifted energy of *CoolingWater-ComInd* loads is advanced or postponed by five or six hours, and at most 2% by one hour. Similar distributions are found for the appliances in *StorHeat-ResCom*, 80% of which are shifted by six hours or more, as well as the industrial processes, 75% of which are shifted by 24 hours or more. Regional differences in DR utilization are found to be even more pronounced than for the accessed capacity (see Figure 5.25). This can be directly associated to the regional distribution

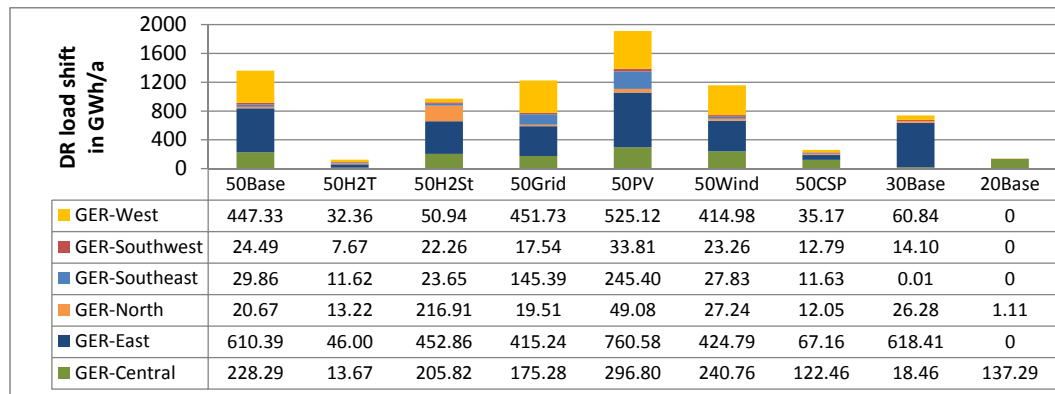


Figure 5.25 Scenario comparison of regional DR application.

of capacities on the one hand and utilization of the different DR technologies on the other. Those technologies accounting for most energy shift – *StorHeat-ResCom*, *CoolingWater-ComInd* and *HVAC-ComInd* – are not accessed across all regions, which causes a concentration of DR usage to some regions. Most energy shift is realized in Germany *East*, *Central* and *West*, least in *Southwest* and *Southeast*. Noticeable are the substantially higher DR activity in the *North* region for scenario 50H₂St, as well as in *Southeast* for 50Grid and 50PV. They arise from changes in regional residual loads due to additional storage and grid availability or different geographical distribution of VRE generation.

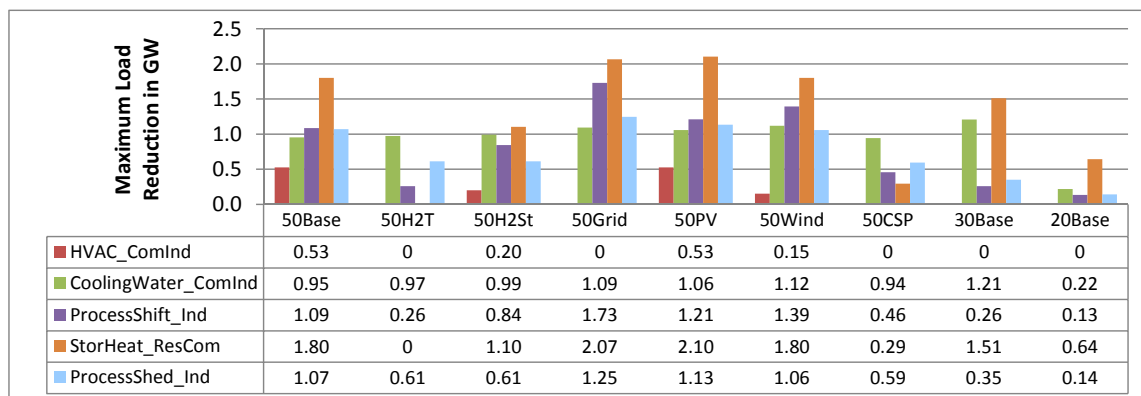


Figure 5.26 Scenario comparison of the maximum DR load reduction in Germany, subdivided by technology.

Depending on the scenario, the maximum load reduction achieved by DR measures during the course of the scenario year is allocated differently to the available consumers (Figure 5.26). Energy-intensive processes provide up to 3.5 GW of load reduction, whereas *StorHeat-ResCom*, *CoolingWater-ComInd* and *HVAC-ComInd* account for up to 2.1 GW, 1.2 GW and 0.5 GW, respectively. Highest peak load reduction values are obtained in the scenario 50Grid, 50PV and 50Wind, lowest in 20Base and 50H₂T. The DR load increase is dominated by the storage space and water heating systems summarized in *StorHeat-ResCom*, reaching almost 5 GW in scenario 50PV. Instead, *CoolingWater-ComInd*, *ProcessShift-Ind* and *HVAC-ComInd* enable load enhancements of up to approximately 1.2 GW, 0.6 GW and 0.5 GW, respectively. Across all German regions, DR categories and scenarios, the maximum

Table 5.6 Scenario comparison of the annual number of hours with DR load reduction and increase in Germany.

DR technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Hours with Load Reduction									
CoolingWater-ComInd	1724	896	1809	1354	1766	1659	1246	1327	454
HVAC-ComInd	1817	3	1669	19	1884	1028	21	15	20
ProcessShed-Ind	15	22	18	26	24	31	17	5	4
ProcessShift-Ind	33	30	67	82	58	70	36	23	13
StorHeat-ResCom	3382	0	3760	3439	4209	3069	1660	2373	1475
Hours with Load Increase									
CoolingWater-ComInd	2015	939	2067	1612	1878	1849	1410	1574	582
HVAC-ComInd	1709	3	1529	17	1794	951	22	14	25
ProcessShift-Ind	95	37	163	209	146	142	73	36	23
StorHeat-ResCom	2070	0	2464	2632	2874	1903	865	1486	1052

simultaneous load reduction adds up to 4 GW in scenario 50Grid and the maximum load increase to 5.6 GW in 50PV. These loads are equivalent to 4.6% and 6.3% of the annual peak load in the corresponding scenarios.

Even though both overall energy expenditure and load change are comparatively low compared to the annual electricity demand and peak load, DR measures are applied frequently. In scenario 50PV, the number of hours with load changes amounts to more than 7500, which implies that the available DR capacities are used during more than 85% of the time. Also in 50Base, 50H₂St, 50Grid and 50Wind, more than 5900 operation hours are reached. Significantly lower values are found for the remaining scenarios: 4700 for 30Base, 3500 for 50CSP, 2800 for 20Base and only 1600 for 50H₂T. Table 5.6 summarizes the annual hours of load increase and decrease for all DR technologies.

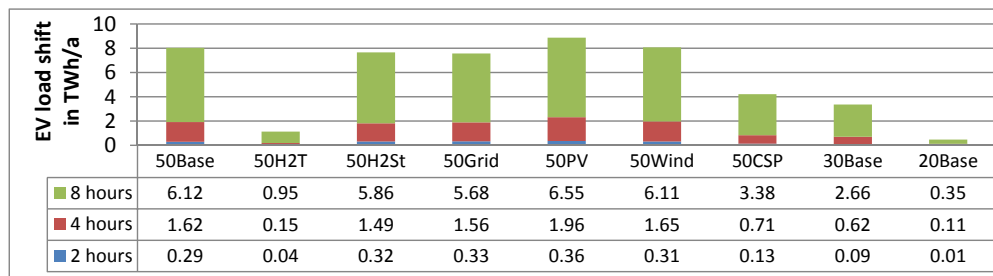


Figure 5.27 Scenario comparison of the energy shifted by controlled EV charging in Germany.

According to the REMix simulations, the demand flexibility provided by controlled EV charging substantially contributes to the overall load shifting. Figure 5.27 shows the annual sum of postponed electricity demand for all scenarios, subdivided by the shifting time. It adds up to more than 8.8 TWh in scenario 50PV. Comparable values are found also for 50Base, 50H₂St, 50PV and 50Wind. In contrast, those scenarios with lower VRE share and flexible hydrogen production are again characterized by a much lower demand for load shifting. Generally, the shifted energy of controlled EV charging is much higher than for the other DR technologies. Most vehicle charging is shifted by the maximum time of eight hours, whereas

the minimum time of two hours is hardly applied. Comparing the postponed EV charging with the annual electricity demand and the availability for charging control it appears that significant shares of the load shifting potential are harnessed. Particularly high values are reached in scenario 30Base (19.9%) and 50PV (18.4%), in contrast to only 4.3% in 50H₂T. Centers of controlled EV charging are Germany *East*, *Central* and *West*, whereas least use is made in *Southeast*.

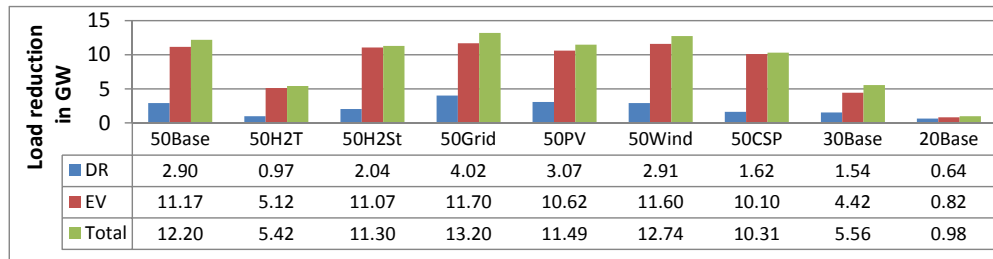


Figure 5.28 Scenario comparison of the residual peak load reduction through DR and controlled EV charging in Germany.

In Figure 5.28, the maximum load reduction enabled by DR and controlled EV charging is displayed. In scenario 50Grid, it reaches 13.2 GW, equivalent to almost 15% of the annual peak load or 43% of the annual minimum load. At the lower end, only 1 GW or 1% of peak load are used in scenario 20Base. The differences between the maximum values indicate that load reduction achieved by EV charge control and other DR technologies cannot be added to an overall load reduction potential. This results from the temporal variations in DR load availability. The maximum EV load reduction of around 11.7 GW in the 2050 scenarios equals roughly 55% of the evening charging peak.

Load Shifting Impact on Capacity Demand and VRE Curtailment

DR and controlled EV charging, hereinafter referred to as *load shifting*, considerably diminish the demand for additional power plant capacity. It is shown for the step 1 model runs (w/o DR) and step 2a model runs (w/ DR) in Figure 5.29. Particularly high reductions are realized in the 2050 scenarios without hydrogen usage: it reaches 11.9 GW in 50Grid, 11.4 GW in 50Wind, 10.7 GW in 50Base and 10.5 GW in 50PV. This corresponds to a reduction by half compared to the model runs without load shifting. In scenario 50H₂St, also the converter power (-0.7 GW) and reservoir size (-0.1 TWh) of hydrogen storage installation are affected. Taking into account both additional generation and storage capacity, a reduction of 6.5 GW can be realized. In the remaining scenarios – 50CSP, 30Base, 20Base and 50H₂T – the GT capacity endogenously built in the step 1 model runs is much lower, and so is the decline achieved by load shifting. It amounts to 3.8 GW, 1.4 GW, 0.5 GW and 0.4 GW respectively.

The regionally unbalanced installation of additional GT identified in Section 5.5.1 is reflected by the load shifting impact on capacity demand. Starting from comparatively low values, the capacity expansion in the regions *North*, *Southwest* and *Southeast* is mostly reduced to zero by the availability of DR and controlled EV charging. This implies that in

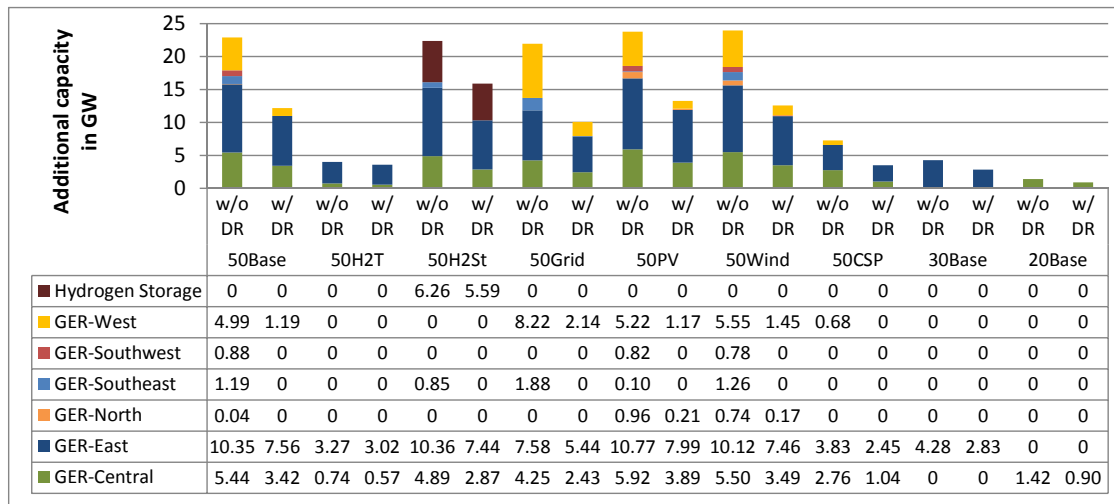


Figure 5.29 Scenario comparison of additional GT and storage capacities in Germany in the model runs without (w/o DR) and with (w/ DR) load shifting.

those regions, the exploitation of DR potentials does not compete with the installation of additional generation capacity, but with the operation of existing power plants. Given the substantial investment costs of the DR technologies with low commitment costs, this has a potentially reducing impact on the DR application. This effect will be further assessed in one of the input variations in Section 5.5.4. Considering the regions with higher GT installation, it appears that load shifting has most impact in Germany *West*, where up to 6 GW can be avoided by load shifting and shedding. This can be associated to the comparatively high EV fleet and DR potential located there.

DR and controlled EV charging affect also RE curtailments in Germany, however, to a much lower degree. Depending on the scenario, reductions between 4 GWh (20Base) and 1.1 TWh (50PV) are reached. In contrast to that, in scenario 50H₂St, a slight increase in curtailment by 0.4 TWh is found. It results from the partial substitution of hydrogen storage by DR in the *North* region. On average, the reduction in curtailments is highest in Germany *Southeast* and *West*, and lowest in *North* and *Southwest*.

Load Shifting Impact on Power Plant and Storage Operation

Across all scenarios, the utilization of conventional and CHP power plants is reduced by the availability of load shifting, whereas the biomass power generation increases. The level of impact is directly correlated to the utilization of DR and EV controlled charging. In scenario 20Base, 30Base and 50H₂T, which are characterized by a comparatively low load shifting activity, the decline of conventional power generation stays below 0.6%. More substantial reductions are achieved in the remaining scenarios, ranging from 2.3% (0.6 TWh) in 50H₂St to 4.3% (1.3 TWh) in 50PV. The negative impact on CHP electricity output is of similar magnitude, reaching up to 1.3 TWh (50Wind), too. It is higher in scenarios with more load shifting. The biomass power generation increases by up to 7.2% (50PV) or 0.9 TWh, and is also correlated with the amount of shifted demand.

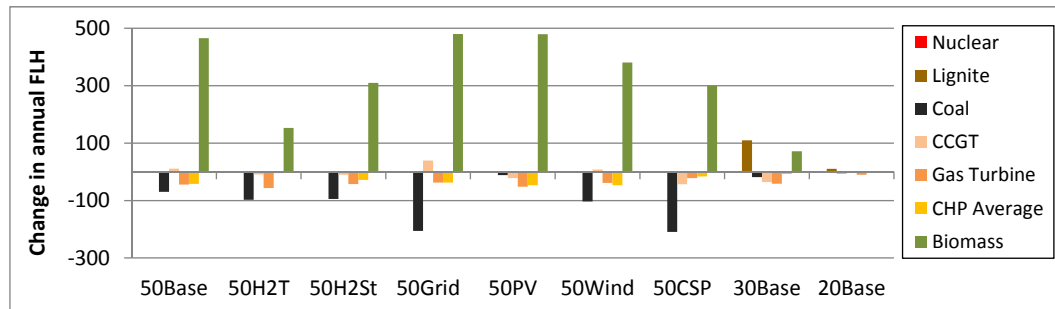


Figure 5.30 Scenario comparison of the change in power plant FLH triggered by electric load shifting.

The decrease in overall conventional power generation is not equally distributed over all technologies (see Figure 5.30). Annual utilization of coal power plants decrease across all scenarios, by values ranging from 5 h/a in scenario 20Base to 209 h/a (-6%) in 50CSP. The same trend is found for gas turbines, which face FLH reductions between 20% and 40%. Given the already low operation times in the system without load shifting, this corresponds to only 10 to 60 h/a. Concerning the utilization of CCGT power plants, much lower and opposed impacts are observed. The spectrum extends from a reduction of 43 h/a (-2%) in scenario 50CSP to an increase of 39 h/a (+1.4%) in 50Grid. The lignite and nuclear capacities available in the earlier scenario years can slightly increase their operation. The decline in CHP FLH is comparatively low; it accounts for 0.3 (20Base) to 47 h/a (50PV), equivalent to 0.01% and 0.9%. The most significant change in utilization can be observed for biomass power generation: its annual FLH rise by up to 480 h/a, which is equivalent to more than 7%. The magnitude of additional output is clearly related to the load shifting activity. Load shifting appears to provide cheaper storage function than the available pumped hydro and hydrogen storage facilities. The storage electricity input decreases in all scenarios, by values ranging from 0.21 TWh in 20Base to 4.2 TWh in 50H₂St. Relative reductions mostly range between 15% and 25%, except for scenario 50Grid (-29%), 50H₂T (-7%) and 20Base (-4%). The latter are characterized by a very low storage utilization due to the balancing effect of flexible hydrogen electrolysis and a much lower VRE supply share, respectively.

Load Shifting Impact on System Costs

The implementation of DR measures can reduce the annual costs of the considered part of the energy supply system. These costs include variable operational costs of all assets, as well as investment and fixed operational costs of endogenously installed system components. The REMix-OptiMo results reveal cost reductions by the use of DR and controlled EV charging between 0.02 billion euro in scenario 20Base and 0.68 billion euro in 50Wind (see Figure 5.31). Relating the decrease in costs with the shifted energy (DR and EV), specific benefits between 0.02 and 0.07 €/kWh are obtained. Highest values are achieved in scenario 50Grid and 50Wind, lowest in 30Base.

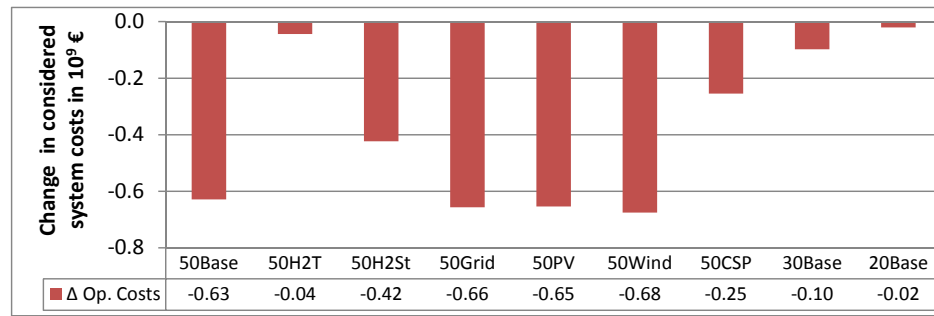


Figure 5.31 Scenario comparison of the load shifting impact on the considered energy system costs in Germany.

5.5.3 Step 2b: Heat Supply Capacity Optimization

This part of the REMix-OptiMo application aims at a better understanding of the potential load balancing provided by an optimized dimensioning and increased operational flexibility of heat supply systems related to the power sector. Therefore, the model is configured to evaluate the least-cost configuration and operation of CHP and HP systems. In addition to these main heat supply technologies, the model endogenous capacity optimization includes TES, as well as conventional and electric boilers according to Figure 5.6. Dimensioning and operation of CHP and HP supply in Germany are assessed for each of the scenarios. The simulations identify optimized TES and electric boiler capacities, as well as the impact of a flexible heat generation on the power system operation and efficiency. As in the DR capacity expansion model runs, power transmission between regions is not further taken into account. Instead, hourly export and import values obtained in the European model runs are used.

Dimensioning of Flexible Heat Supply Systems

The results show that heat storage capacities are installed throughout all scenarios, regions and considered heat supply technologies (see Figure 5.32). Their overall thermal capacity reaches up to 195 GWh in scenario 50Wind, which is equivalent to almost four times the available pumped hydro storage electric capacity of 52 GWh. Highest TES capacities are established in biomass-fired industrial CHP systems, as well as DH systems relying on natural gas and biogas. Differences in TES capacity between the 2050 scenarios are mostly small. In the reference case 50Base, a total capacity of 164 GWh is reached. It is lower by 1.5 GWh, 8.8 GWh, 9.1 GWh, 9.7 GWh and 17.2 GWh in scenario 50PV, 50H₂St, 50Grid, 50H₂T and 50CSP, respectively. In the remaining scenarios 30Base and 20Base, less balancing is required, reducing the TES capacity to 72 GWh and 27 GWh, respectively. Technology-specific differences between the different scenario years are not only related to the balancing power demand, but also the heat supply scenario. This can, for example, be seen in the TES capacities of building CHP systems, which in 2020 and 2030 is mostly supplied by natural gas and in 2050 by biogas. TES in HP supply account for between 2% (20Base) and 15% (50Grid) of the overall TES capacity installed. They are to a higher degree affected by lower VRE shares and hydrogen production than those in CHP systems.

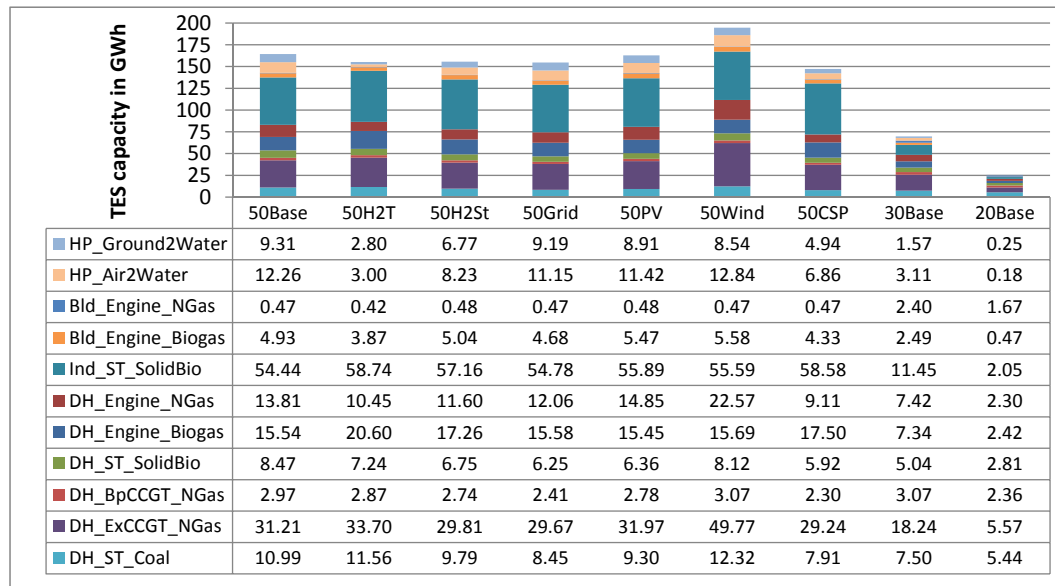


Figure 5.32 Scenario comparison of TES capacities in Germany. The classes indicate the main heat supply technology according to Figure 5.6. For HP supply, they include the heat source, for CHP they are composed of consumer, CHP technology and fuel. Consumers are either DH, industry (Ind) or buildings (Bld).

The regional distribution of TES is more balanced and less sensitive to the scenario set-up than it is for DR. On average over all scenarios, one quarter of the overall TES capacity is located in the *West* region, around 20% each in *North* and *East*, and between 10% and 12% in *Southwest*, *Southeast* and *Central*. Comparing the 2050 scenarios, only in 50Wind major deviations from this allocation are found: the share of the *East* region rises to more than 26%, at the expense of lower values particularly in *North* and *Southeast*. Scenario 30Base sees slightly higher shares in *East* and *North*, 20Base in Germany *Central*.

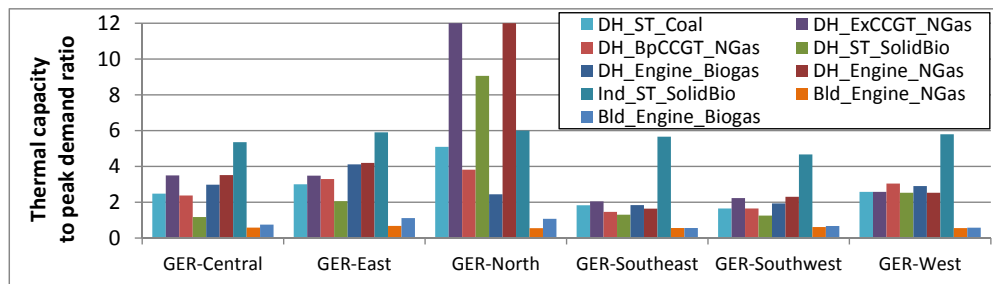


Figure 5.33 Regional TES capacity to peak demand ratios for heat supply in Germany, scenario 50Base.

Figure 5.33 provides further insight into the regional and technological TES allocation. It shows the storage capacity relative to the annual peak demand of the corresponding CHP supply system in scenario 50Base. This ratio is equivalent to the minimum number of hours the demand can be covered by the TES. The results indicate a concentration of TES to regions with high wind power generation; it is by far highest in region *North*, and lowest in the south of the country. This picture is the same for TES in CHP and in HP systems. Concerning different CHP technologies, TES are particularly attractive in combination with biomass-fired

industrial CHP, as well as gas and biogas-fired DH CHP. The limiting storage capacities of six hours for industrial CHP and twelve hours for DH-CHP are reached only in few cases, mostly for industrial biomass CHP and in *Germany-North*. Comparatively small TES capacities are installed in building CHP and coal-fired DH CHP systems.

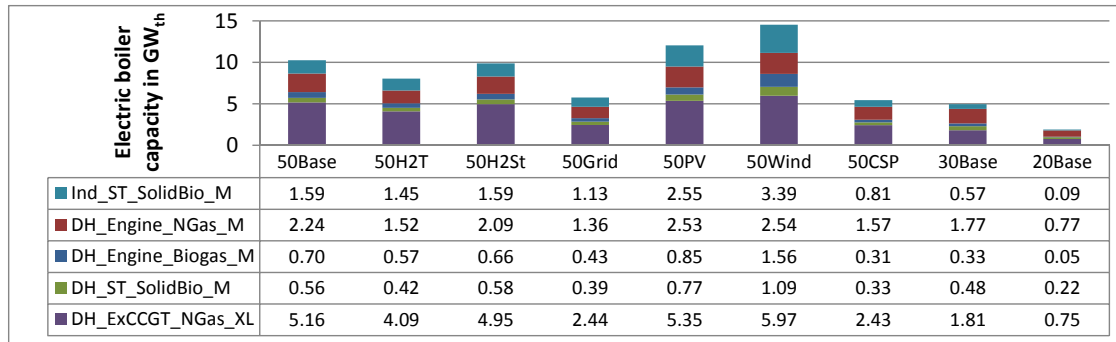


Figure 5.34 Scenario comparison of the electric boiler capacities in Germany.

Electric boilers can reduce both CHP fuel demand and VRE curtailment. In this work, they are available as investment option to complement five selected CHP technologies. The results in Figure 5.34 show that highest electric boiler capacities are installed in DH CHP systems relying on natural gas, as well as industrial biomass CHP. Much lower capacities are found for renewable DH supply, which is supposedly related to the lower fuel costs of the corresponding conventional boilers and the lower TES capacity compared to industrial biomass CHP. Comparing the scenarios, a correlation between electric boiler installation and VRE curtailments determined in the step 1 model runs can be identified. In the 2050 scenarios, overall capacities are highest in 50Wind (14.5 GW_{th}) and 50PV (12.1 GW_{th}), and lowest in 50Grid (5.8 GW_{th}) and 50CSP (5.4 GW_{th}). Due to lower VRE shares, in the earlier scenario years even less electric boilers are installed.

The regional distribution of electric boilers in CHP supply is much less balanced than for TES (see Figure 5.35). Throughout all scenarios it clearly reflects the VRE curtailments determined in the previous model runs. Depending on the scenario, between 48% and 90% of the overall capacity is located in the regions *North* and *West*. With shares exceeding 70%, the concentration to those regions is particularly high in scenario 20Base, 50H₂T and 30Base. Due to the different geographical distribution of VRE capacities, their shares are lower in scenario 50PV and 50Wind. The same applies to scenario 50Grid, where additional DC lines reduce the curtailments in Germany *West*. At the opposite end of the scale, there is almost no electric boiler installation realized in region *Southwest*.

Calculating the average regional ratio of electric boiler to CHP TES capacity in the 2050 scenarios, values of up to 0.12 GW/GWh are obtained. They tend to be higher in scenarios and regions with great amounts of curtailed VRE generation. Comparatively high average values are again found in Germany *North* (0.1 GW/GWh) and *West* (0.08 GW/GWh), whereas lowest values are present in *Southwest*. Between the scenarios, smaller differences are found: average values over all regions and technologies range from 0.04 GW/GWh in 50CSP to 0.08 GW/GWh in 50PV.

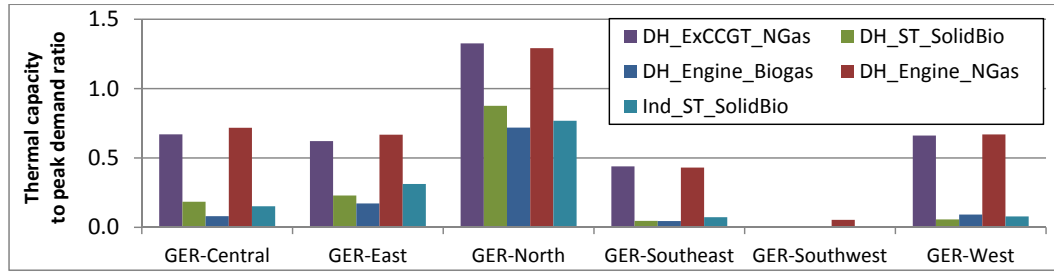


Figure 5.35 Regional electric boiler capacity to peak demand ratios for heat supply in Germany, scenario 50Base.

Figure 5.35 provides the electric boiler capacity to peak demand ratio, broken down by region and technology for scenario 50Base. As for TES, a concentration to the wind power dominated regions appears. Highest values are present in the *North* region, where the capacity of electric boilers supplementing gas-fired DH CHP technologies even exceeds the corresponding annual peak demands ($f_{Cap2Peak} > 1$). In contrast, almost no electric boilers are installed in *Germany-Southwest*. Due to the higher fuel costs, natural gas-fired technologies generally feature a more generous boiler dimensioning than renewable CHP.

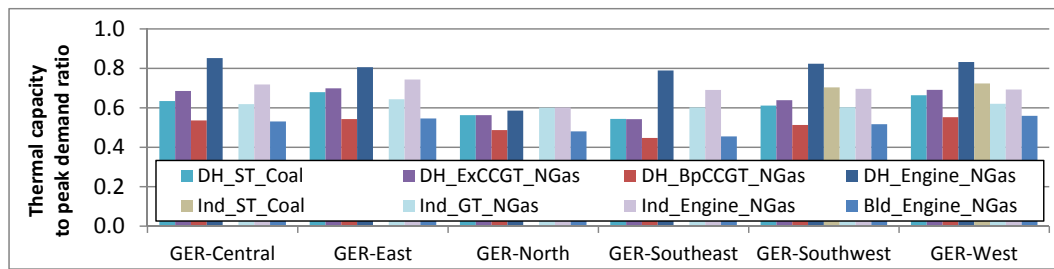


Figure 5.36 Regional CHP capacity to peak demand ratios for heat supply in Germany, scenario 50Base.

The results of the model endogenous CHP dimensioning in scenario 50Base are shown for all considered technologies and each German region in Figure 5.36. The capacity to peak demand ratio features notable differences both between technologies and regions. Independent of the technology, highest CHP capacity expansions are realized in Germany *East*, *West* and *Central*, whereas the smallest dimensioning is found in the regions *North* and *Southeast*. This reflects the regional demand for additional capacity identified in the step 1 model runs. Comparing technologies, the increase in capacity to peak demand ratio relative to the values applied in the previous model runs is highest for gas-fired engine CHP in industry and DH systems, and lowest for industrial coal and gas turbine CHP. The CHP dimensioning is similar across all scenarios for the year 2050, and slightly higher in the earlier scenario years.

Figure 5.37 displays the dimensioning of HP and HP-TES for each technology and region in scenario 50Base, relative to the corresponding annual peak demand. The model endogenous HP design is similar to the predefined values used in the step 1 model runs: the average capacity-to-peak ratios over all regions reach 0.84 for industrial HP (+5%), 0.72 for air-to-water HP (-4%) and 0.69 for ground-source HP (-1%). Regional differences are comparatively small, with averages ranging from 0.72 in Germany *East* to 0.78 in *Southwest*. Like in CHP

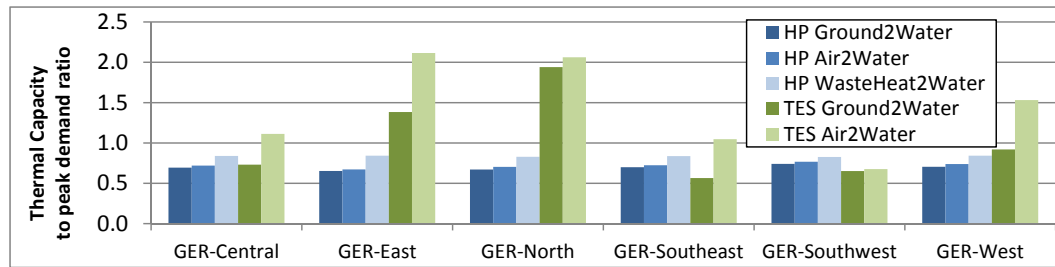


Figure 5.37 HP capacity to peak demand ratio in Germany for scenario 50Base.

systems, TES sizes are greatest in the wind power regions *North* and *East*, and lowest in southwestern Germany. Relative TES sizes range between 0.6 and 2.1 times the annual peak demand, with higher values found for air-to-water HP. The different supply and balancing systems applied in the 2050 scenarios have virtually no influence on HP dimensioning; for air-source HP capacity to peak ratios between 0.72 and 0.73, for air-source HP between 0.69 and 0.71, and for industrial HP between 0.83 and 0.84 are found. In contrast to that, a much smaller dimensioning appears in the earlier scenario years. In 20Base, it reaches 0.61 for ground-source HP, 0.66 for air-source HP and 0.74 for industrial HP, in 30Base 0.51, 0.57 and 0.74, respectively. This design implies that a higher supply share must be covered by the electric peak boiler.

Operation of Thermal Energy Storage and Electric Boilers

The available TES enable a considerable decoupling of heat production and consumption. Depending on the scenario, up to 6.2% of the annual heat production in CHP and HP systems are stored (see Figure 5.38). Highest values are achieved in the scenarios dominated by PV or onshore wind power: 50PV (16.8 TWh) and 50Wind (16.2 TWh). A more diverse VRE power plant park and additional flexibility in terms of hydrogen storage or grid capacity reduce the TES energy input to 15 TWh (50Base), 14.6 TWh (50H₂St) and 13.6 TWh (50Grid), respectively. Considering the 2050 scenarios, most effective alternatives to TES utilization are CSP import (11.8 TWh) and flexible hydrogen electrolysis (8.4 TWh). Such as the installed capacity, the TES energy input in 30Base and 20Base is much lower than in most 2050 scenarios: it reaches 9.8 TWh and 4.6 TWh, respectively, equivalent to 3.6% and 1.7% of the corresponding annual demand.

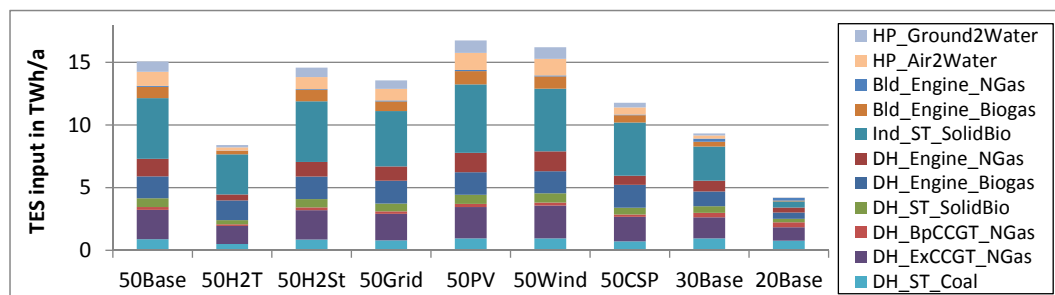


Figure 5.38 Scenario comparison of the annual TES energy input in Germany.

Comparison of Figure 5.32 and 5.38 reveals substantial differences in TES utilization levels both between heat supply systems and scenarios. Considering different CHP technology classes, highest ratios of energy input to storage capacity are found for building CHP, followed by small DH and large DH systems. Values for the 2050 scenarios range from 43-79 charging cycles for TES in extraction CCGT systems to 75-193 in natural gas-fired building CHP. Comparing the scenarios, highest CHP-TES utilization levels are reached in 20Base and 30Base. On average, 173 and 140 annual full charging cycles are realized, respectively. In the 2050 scenarios, much lower values are found, ranging from only 53 in 50H₂T to 101 in 50PV. TES in domestic HP supply feature annual cycling numbers between 52 and 119, and tend to be higher for air-source HP. Scenario averages amount to values between 71 in 20Base and 116 in 50PV. On average over all technologies and scenarios, TES utilization is highest in the regions *Southwest* (energy to capacity ratio 140) and *West* (125), and lowest in *North* (87) and *Southeast* (100).

Heat losses in TES account for 5% to 13% of the annual input. On average, they are highest in 50H₂T (9%), and lowest in 20Base (6%), which is consistent with the differences in TES utilization found in the respective scenarios. The lower number of cycles in 50H₂T goes along with longer periods between charging and discharging and thus higher losses.

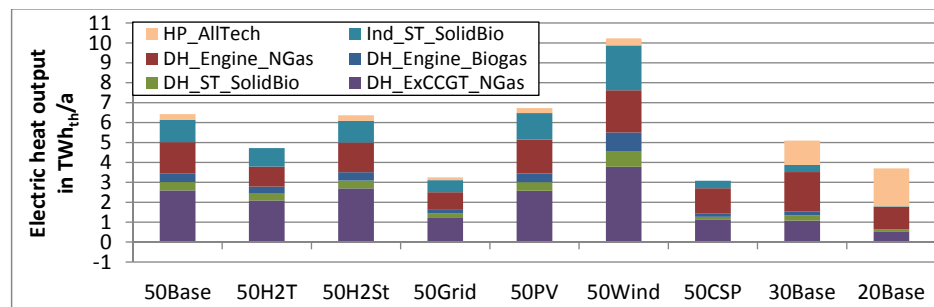


Figure 5.39 Scenario comparison of the annual electric boiler heat production in Germany.

Figure 5.39 shows the electric boiler heat production in each scenario. For HP, it accounts for the change in electric boiler output triggered by flexible HP dimensioning, as well as the provision of a thermal storage. Such as for TES, differences between the scenarios in annual utilization are more substantial than for installed capacity. Considering only the 2050 scenarios, the additional electric heat generation differs by more than factor three. It ranges from 3 TWh in 50CSP to 10 TWh in 50Wind. In the reference scenario 50Base, the electric heat production amounts to 6.4 TWh, 78% of which originate from boilers incorporated into DH systems, 18% from industrial CHP and 4% from the additional utilization of HP peak boilers. Hydrogen storage availability and higher PV power generation have only minor impact on the electric boiler heat production. On the contrary, CSP import and transmission grid extension reduce the heat production by around 50%, whereas a higher onshore wind supply causes an increase by almost 60%. In scenario 20Base and 30Base, the additional electric boiler output is lower than in most 2050 scenarios, reaching 3.7 TWh and 5.1 TWh, respectively. In the earlier scenario years, boilers in HP systems account for much higher

shares in the overall electric heat production. They contribute 52% in 20Base and 24% in 30Base, compared to values between 0% and 4% in the 2050 scenarios. This arises from the smaller HP dimensioning realized in 20Base and 30Base, which causes a much higher electric boiler share in the overall heat supply of up to 15%. In most other scenarios, only a slightly higher electric boiler usage in HP supply compared to the reference case with heat-controlled operation is detected. In contrast to that, a slight reduction in boiler output is found for scenario 50CSP (-4 GWh) and 50H₂T (-50 GWh). Both effects are related to the HP design, as well as the utilization of the corresponding TES.

Electric boilers in CHP supply reach much higher FLH than TES, ranging from 237 to 1472 h/a. They are highest if associated to natural gas engine CHP, and lowest in extraction CCGT systems. Comparing the scenarios, utilization is highest in 20Base (951 h/a) and 30Base (780 h/a). Instead, lowest values are found for scenario 50PV (537 h/a) and 50Grid (539 h/a). Annual FLH of electric boilers in CHP supply exhibit substantial differences between the German regions. The average over all scenarios and technologies is by far highest in Germany *North* (591 h/a), and lowest in *Southeast* (219 h/a). In the other regions it ranges between 286 and 341 h/a.

Due to their design as back-up units, electric boilers in HP supply have much lower annual FLH, especially in the scenarios for the year 2050. They range between 25 and 109 h/a in the 2050 scenarios, 67 and 233 h/a in 30Base and 136 and 478 h/a in 20Base.

Impact of Power-controlled Heat Supply on Capacity Demand and VRE Curtailment

Figure 5.40 compares the model endogenous capacity expansion of GT and hydrogen storage in the step 1 (w/o TES) and the step 2b (w/ TES) model runs for all scenarios. In step 1, HP and CHP have a predefined dimensioning and are operated strictly according to heat demand, whereas in step 2b, the dimensioning is optimized by REMix, and a power-controlled operation can be enabled by additional installation of TES, electric and conventional boilers. As a result of different design and operation of heat supply systems, the demand for additional power plant or storage capacity is reduced by more than 10% in all scenarios for the year 2050. The highest absolute decrease of 4.5 GW is found in scenario 50Wind, the lowest of 600 MW in 50H₂St. Taking into account the corresponding increase in CHP capacity, net capacity reductions between 300 MW (50H₂T) and 3.6 GW (50Wind) are achieved. Compared to the step 1 model run with heat-controlled CHP operation, minor use of the hydrogen storage investment option is made in scenario 50H₂St (-2.1 GW and -0.5 TWh). Given that GT installation is not increased at the same time, it can be concluded, that hydrogen storage is substituted by TES and a higher electric CHP capacity. In scenario 20Base, the additional GT capacity is by 23% lower than in the heat-controlled mode; due to a greater CHP dimensioning, the overall capacity expansion is however increased by 180 MW or 13%. In 30Base, the demand for additional capacity is reduced by approximately 550 MW or 13%, compared to step 1 assessment. As for DR, the impact is not equally distributed over all regions. The average net capacity reduction is highest in region *West*, *Central* and *East*, and lowest in *North*

and *Southwest*. Considering relative changes, the impact is reverse. This allocation is again related to the installed capacities provided by the scenario.

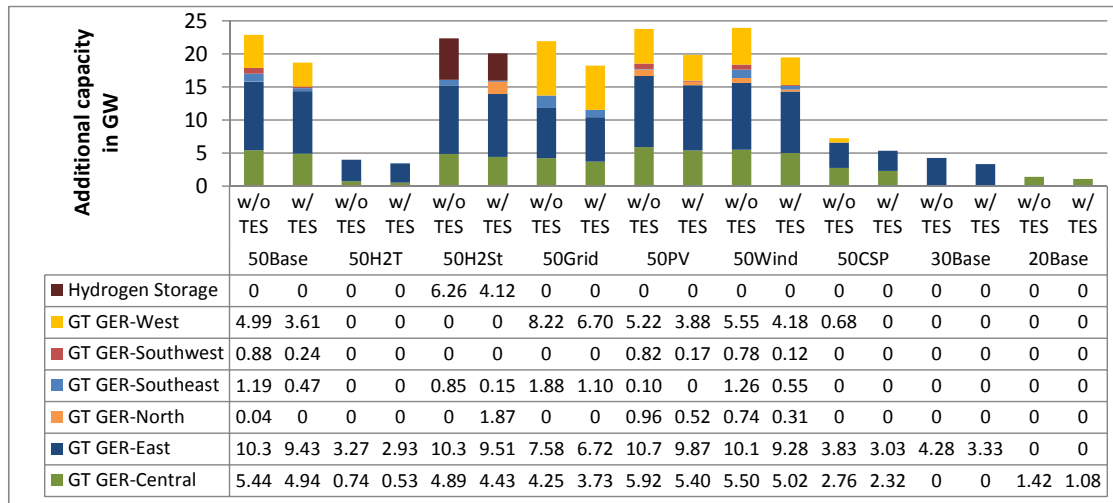


Figure 5.40 Scenario comparison of additional GT and storage capacities in Germany in the model runs without (w/o TES) and with (w/ TES) model endogenous heat supply dimensioning and power-controlled heat supply.

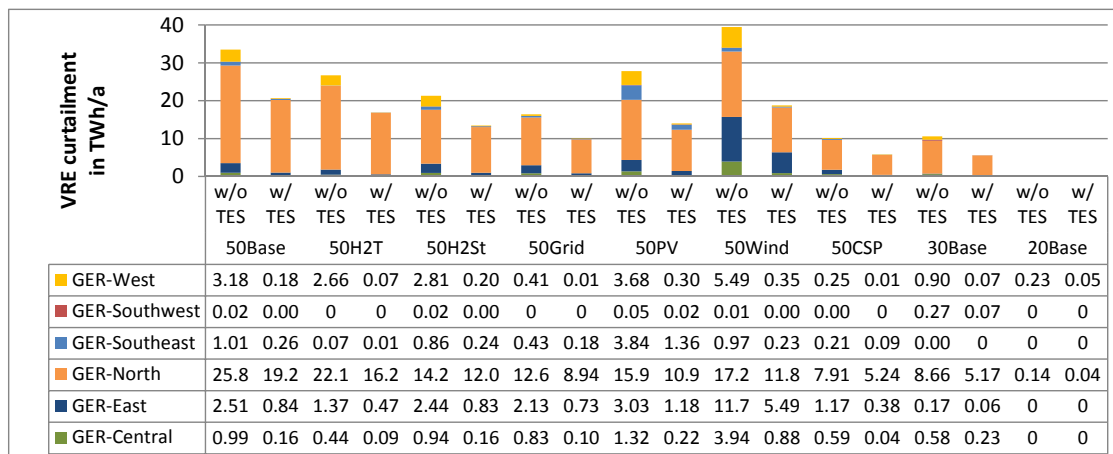


Figure 5.41 Scenario comparison of RE curtailment in Germany in the model runs model runs without (w/o TES) and with (w/ TES) model endogenous heat supply dimensioning and power-controlled heat supply.

Increased flexibility in the operation of HP and CHP supply systems proves to be a powerful measure for the reduction of VRE curtailment in Germany (see Figure 5.41). The availability of TES, as well as conventional and electric boilers, cuts the amount of wasted electricity by up to three quarters. Highest impacts are registered in scenario 20Base (-76%), 50Wind (-52%), 50PV (-50%) and 30Base (-47%), lowest in 50Base (-38%), 50H₂T (-37%) and 50H₂St (-37%). The additional VRE integration reaches highest values in scenario 50Wind (21 TWh), 50PV (14 TWh) and 50Base (13 TWh). The substantial reductions in curtailment are achieved through two actions, which are also being applied in combination: a CHP down-regulation in times of high RE production on the one hand, and electric heat

generation from RE surplus on the other. This will be further discussed in the following Section 5.5.6. Reductions in curtailment are realized throughout all regions, however primarily in Germany *North* and *West*.

Impact of Power-controlled Heat Supply on Power Plant and Storage Operation

Power-controlled CHP and HP operation have a much higher impact on power plant utilization than load shifting. Throughout all scenarios, the increased flexibility in the heating sector promotes a higher utilization of the power plants with lowest variable costs. This mostly benefits biomass, but also coal, lignite and nuclear power plants (see Figure 5.42). Increases in FLH of up to 1400 h/a (+21%) hours can be realized compared to the step 1 model runs with heat-controlled CHP and HP operation. On the contrary, the power output of gas-fired generation units, as well as CHP stations is reduced. The only exception is scenario 20Base, where the GT power generation increases slightly. The gain in coal power plant FLH in the 2050 scenarios ranges from 450 h/a (+12%) in scenario 50CSP to 850 h/a (+28%) in 50PV. On the other hand, CCGT operation declines by at least 60 h/a (-2%) in scenario 50H₂T and at most 151 h/a (-7%) in 50Base. CHP power generation is to a much higher degree affected by the changed supply infrastructure. Average reductions in FLH reach up to 560 h/a in scenario 50Wind, equivalent to 11% of the output in heat-controlled operation mode. Similar values are found for 50PV and 50Base and 50H₂St, lower values between 4% and 7% in all other cases. In the earlier scenario years, a different picture is found: a higher CHP and HP flexibility primarily favors the generation in lignite power plants. In 20Base, also nuclear power stations can increase their FLH. As in the 2050 scenarios, the operation of CCGT and CHP plants is lowered, however to a lesser extent.

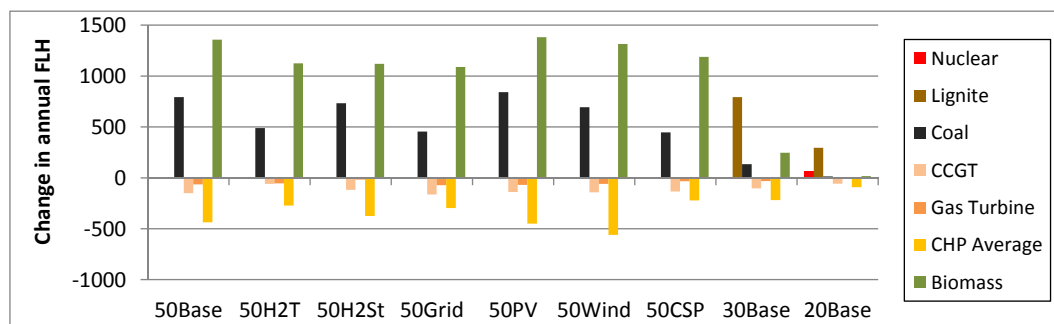


Figure 5.42 Scenario comparison of the change in power plant FLH In Germany triggered by model endogenous heat supply dimensioning and power-controlled heat supply.

The impact of power-controlled heat supply on overall annual power generation in CHP ranges between -0.2% in 20Base and -8% in 50Wind, for biomass between +0.2% in 20Base and +21% in 50PV. For conventional power plants opposed trends are observed: the change in overall power output ranges between a decrease by 5% to an increase by 3%. In contrast to all other scenarios, a growth in conventional power output is found in 30Base, 50H₂St and 20Base. The impact of different power plant operation on CO₂ emissions will be analyzed in the following Section 5.5.6.

The availability of alternative technologies for the provision of balancing power negatively affects the electricity-to-electricity storage utilization across all scenarios. The impact is highest in scenario 50H₂St, where due to the lower hydrogen storage capacities, the annual energy input declines by 9 TWh, equivalent to 32% of the total electricity stored. In the other scenarios, the reduction amounts to values ranging from 19% in 20Base to 34% in 50H₂T.

Impact of Power-controlled Heat Supply on System Costs

Model endogenous heat supply dimensioning and power-controlled operation of CHP and HP supply systems allow for a lowering of overall system costs. The considered capital and operation costs can be reduced by up to 1.5 billion euro (see Figure 5.43). Highest impact is found in scenario 50Wind, lowest in the earlier scenario years. The cost reduction results from higher VRE power integration, as well as the shift to less cost-intensive power generation capacities. The average cost reduction arising from each unit of stored or electrically produced heat exhibits similar values in all scenarios for the year 2050: they amount to 0.05 to 0.09 €/kWh for TES usage and 0.15 to 0.23 €/kWh for electric boiler heat, respectively. In scenario 30Base (0.04 €/kWh for TES, 0.08 €/kWh for electric heat) and 20Base (0.03 €/kWh for TES, 0.03 €/kWh for electric heat), lower values are found.

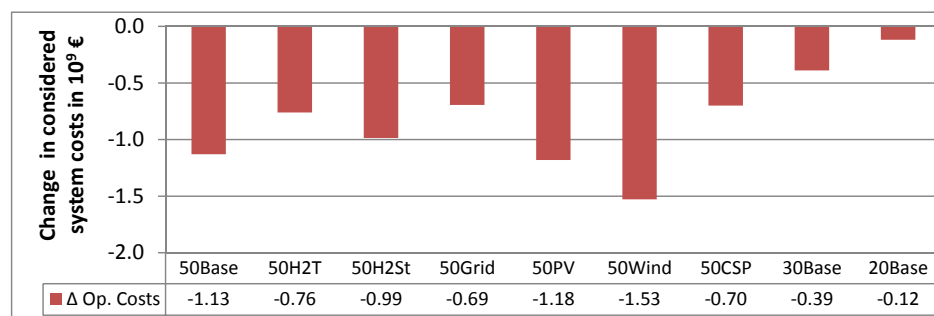


Figure 5.43 Scenario comparison of the change in the considered energy system costs in Germany triggered by model endogenous heat supply dimensioning and power-controlled heat supply.

5.5.4 Step 3a: Sensitivity Analysis of DR Capacity Optimization

In order to assess the sensitivity of DR capacity expansion and operation to changes in technology parameters and scenario input, a number of selected variations are analyzed in supplementary model runs. They are limited to the reference scenario 50Base, and focused on DR potentials and costs arising from their exploitation. Given that future investment and operation costs of DR are subject to major uncertainty, a broad range of values is taken into account, ranging from one forth to four times those used in the previous model runs. By increasing the overall potential and eliminating restrictions in temporal availability, specific requirements for load shifting and shedding are studied in detail. Further variations assess the impact of a reduced availability of alternative balancing options. In one case it is assumed that controlled EV charging cannot be realized, in the other a model endogenous reduction of

conventional power plant capacity is enabled. The latter aims at an evaluation of the interaction between DR and the power plant park provided by the input scenario. Table 5.7 provides an overview of the considered variations. For each of them, the impact on exploitation and utilization of DR potentials, as well as on capacity demand and VRE curtailment is assessed.

Table 5.7 Overview of input modifications considered in the sensitivity runs of DR capacity optimization.

Variation	Applied changes
DR Cost++	Costs for exploitation, provision and call of the DR potential multiplied by four
DR Cost+	Costs for exploitation, provision and call of the DR potential doubled
DR Cost–	Costs for exploitation, provision and call of the DR potential reduced by half
DR Cost––	Costs for exploitation and provision of DR reduced by half, for DR usage to a quarter
Frequency+	No limitations in DR frequency of use
Potential+	Doubled DR potential in <i>ProcessShed-Ind</i> , <i>ProcessShift-Ind</i> and <i>CoolingWater-ComInd</i>
ShiftTime+	DR intervention times doubled ^a , DR shifting time doubled ^b
No EV-Flex	No controlled charging of electric vehicle batteries
Red. Cap.	Extended model endogenous capacity dimensioning of conventional power plants ^c

^a With exception of *ProcessShift-Ind*, where a multiplication with 1.5 is applied.

^b With exception of *HVAC-ComInd* and *HeatingAC-Res*, where no changes are applied.

^c Capacities of coal and gas power plants set to zero and capacity expansion extended to CCGT.

Impact on Demand Response Capacity Expansion and Utilization

Figure 5.44 shows the DR capacity expansion for all variations of scenario 50Base. Assuming higher DR costs, the overall capacity is reduced by up to two thirds in comparison to the reference case. If costs are doubled, consumers in *StorHeat-ResCom* are no longer used for DR and those in *CoolingWater-ComInd* and *HVAC-ComInd* to a lower extent. Due to the dominance of *StorHeat-ResCom* appliances in the base case, the reduction of the overall accessed potential reaches almost 60%. A further doubling in costs eliminates all DR installation in *HVAC-ComInd* systems, and cuts the overall DR capacity only by around 15%.

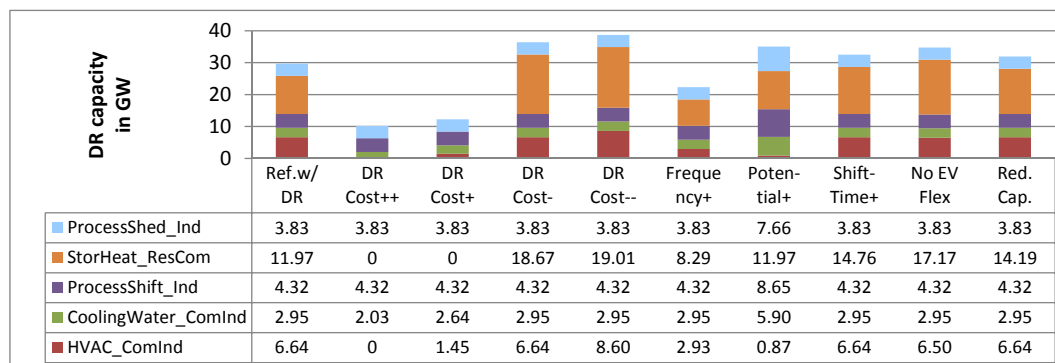


Figure 5.44 Impact of input variations on DR capacities in Germany.

If DR installation and operation costs are halved, around 7 GW of additional DR capacity are accessed (variation *DR Cost–*). The increase can be fully attributed to storage space and water heating systems. The impact of a further operation cost reduction (*DR Cost––*) is

considerably lower: the overall capacity increase adds up to less than 3 GW and is mostly associated to consumers in *HVAC-ComInd*. Even at much lower costs, the DR potentials of the residential appliances summarized in *HeatingAC-Res* and *WashingEq-Res* are not exploited in any scenario or region.

The elimination of restrictions in annual operation hours causes a substantial decrease in the DR capacity of *StorHeat-ResCom* and *HVAC-ComInd (Frequency+)*. On the contrary, an increase in *StorHeat-ResCom* capacity results from the application of longer shift and intervention times (*ShiftTime+*). A higher DR potential increases the exploited DR capacity, but also changes its composition: industrial potentials are accessed preferably, whereas those in *StorHeat-ResCom* and *HVAC-ComInd* are used less. Inflexible EV charging and a reduced availability of conventional power plants go along with a higher DR capacity; it increases by approximately 5 GW and 2 GW, respectively.

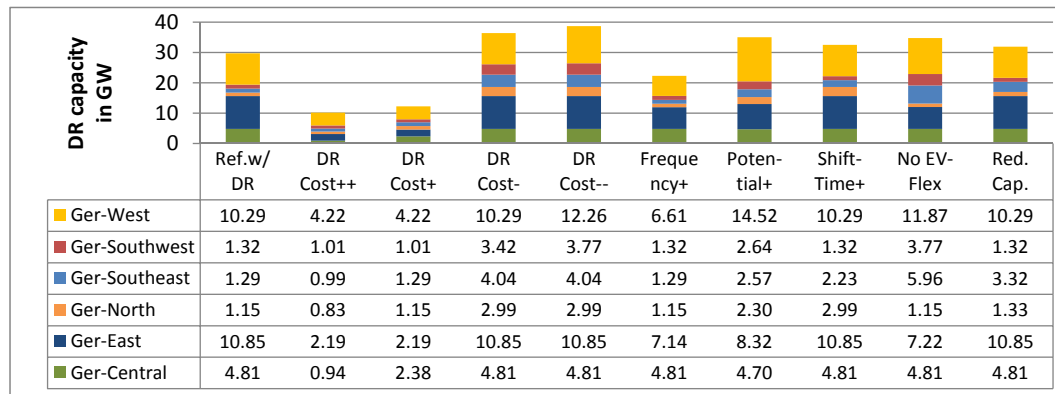


Figure 5.45 Impact of input variations on regional DR capacities in Germany.

The regional impact of the DR parameter variations shows substantial differences (see Figure 5.45). Reductions in DR capacity expansion caused by higher costs are mostly located in the regions *East*, *Central* and *West*. Lower costs, instead, have highest impact on DR capacity in the regions *Southeast*, *Southwest* and *North*. These differences can be related to the regional and technological allocation of DR capacities found in the step 2 model run. At lower costs, the usage of the more expensive DR technologies *CoolingWater-ComInd*, *StorHeat-ResCom* and *HVAC-ComInd* is expanded to more regions, at higher costs it is eliminated also in those regions where it is accessed in the reference case. In the other variations, a more regionally balanced distribution of the DR capacity is obtained, too. The possibility of a more frequent DR application (*Frequency+*) only affects the DR installation in Germany *West* and *East*, where the capacities of *StorHeat-ResCom* and *HVAC-ComInd* are reduced. Higher potentials (*Potential+*) cause an increase in capacity across all regions except *Central* and *East*; there, the loads in *HVAC-ComInd* is substituted by other DR technologies. Instead, longer intervention and shift times (*ShiftTime+*) change the DR capacities only in the regions *Southeast* and *North*, where higher capacities of *CoolingWater-ComInd* and *StorHeat-ResCom* are accessed. Regional values of installed DR capacity can be obtained from Table F.26 to F.31 in Appendix F.

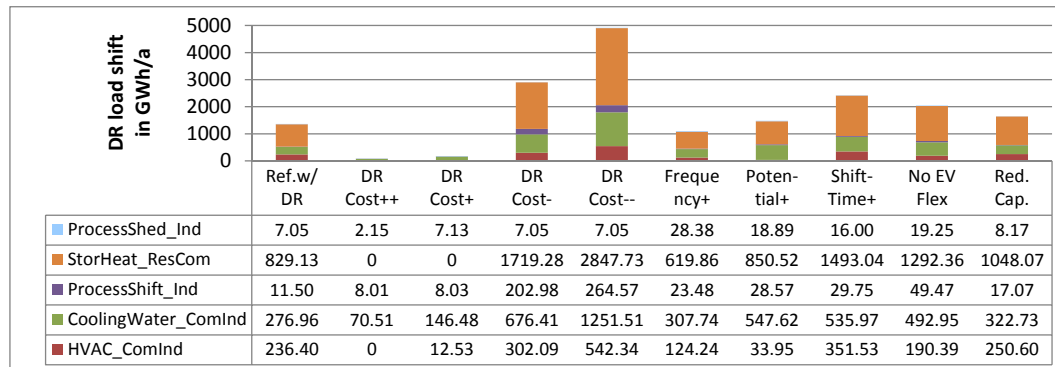


Figure 5.46 Impact of input variations on DR energy shift in Germany.

The impact of the parameter variations on the annual utilization of DR capacities is much more pronounced than it is on the capacity (see Figure 5.46). A doubling and quadruplication in operational costs cuts the shifted or shedded energy by 87% and 94%, respectively. Instead, it is raised by more than factor two, if costs are halved. The DR loads summarized in the technologies *StorHeat-ResCom* and *CoolingWater-ComInd* account for most of the additional load shift. However, the relative increase in shifted energy is particularly in energy-intensive processes. Even lower operational costs cause an additional doubling, again mostly associated to the DR technologies *StorHeat-ResCom* and *CoolingWater-ComInd*.

If no annual limits or waiting periods are applied, contrary trends are found for the considered DR technologies. The shifted and shedded load of consumers in *CoolingWater-ComInd*, *ProcessShift-Ind* and *ProcessShed-Ind* increases by up to factor four, whereas less use is made of those in *StorHeat-ResCom* and *HVAC-ComInd*. A shift in utilization between DR technologies is also found in variation *Potential+*, where the shifting of *HVAC-ComInd* loads is substituted by mostly by *CoolingWater-ComInd*. Longer shift and intervention times (*ShiftTime+*) enable a doubling of DR usage, which is almost equally distributed over all technologies. Supposing that EV charging cannot be controlled or less conventional power plant capacity is available, DR is used more often for peak load reduction. This is reflected by a higher utilization of industrial DR potentials, which feature a comparatively constant availability. Across all variations, opposed trends for different DR technologies must be seen in relation with the changes in installed DR capacities displayed in Figure 5.44.

The impact of the input variations on the regional allocation of DR load shifting is similar to that on installed DR capacities. Changes in costs, as well as longer shift times and higher potentials tend to increase the relative share of regions with low DR utilization in the base case. Nonetheless, highest impacts in absolute numbers are found in the regions with more intense DR application. Reflecting the installed DR capacities, the overall reduction in DR utilization caused by the consideration of less restrictions in frequency is completely located in the regions *West* and *Central*. The increase in DR utilization triggered by the reduced availability of alternative balancing options is disproportionately high in regions with low contribution in the base case. For some of the other regions, even decreasing values are found. Figure 5.47 shows the regional distribution of shifted and shedded loads in all variations.

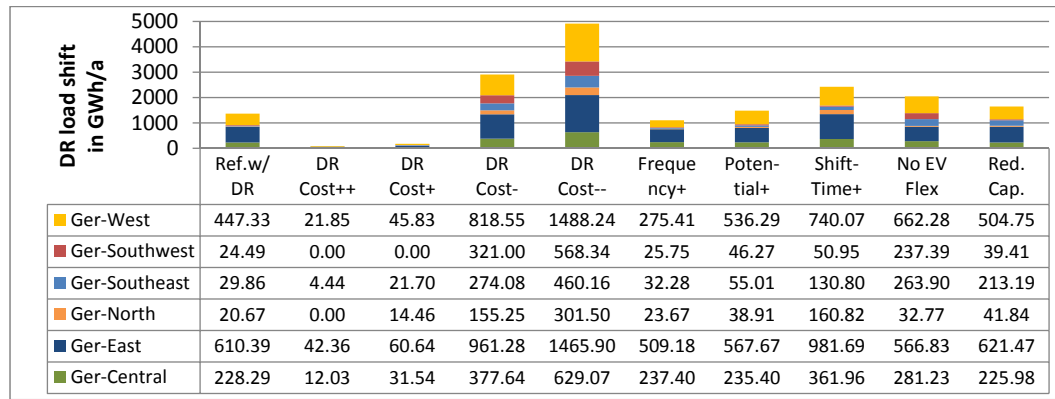


Figure 5.47 Impact of input variations on regional DR energy shift in Germany.

When analyzing the annual energy shift per unit of installed DR capacity, highest average values over all technologies and regions are found in variation *DR Cost--* (127 h) and *ShiftTime+* (75 h), lowest in *DR Cost+* (14 h) and *DR Cost++* (8 h). The annual number of utilization hours is mainly influenced by the ratio of investment and operation costs on the one hand, and the temporal availability of the potential on the other. This is also reflected by the technology-specific utilization. It is highest for those DR consumers with high investment and low operational costs – *StorHeat-ResCom* and *CoolingWater-ComInd* – and lowest for those with contrary cost structure – *ProcessShed-Ind* and *ProcessShift-Ind*.

The differences between technologies also affect the average regional DR capacity utilization. It is generally higher in those regions, where potentials of consumers offering low operational costs are tapped. As a result, regional differences are higher when the DR application is concentrated to some regions, and lower when it is more balanced. In variations with comparatively high DR utilization, regional differences are smaller, and highest values are found in *Southwest*, *East* and *Central*.

If lower costs are applied, DR partially substitutes controlled EV charging as power balancing option: EV load shifting is reduced by 970 GWh in variation *DR Cost--* and 450 GWh in *DR Cost-*. In contrast, controlled EV charging is applied to a higher extent in variation *DR Cost++* (+240 GWh), *DR Cost+* (+150 GWh), *Potential+* (+130 GWh), *Frequency+* (+100 GWh) and *ShiftTime+* (+20 GWh). The highest impact is registered for the extended capacity optimization of conventional power plants, which causes an increase in shifted energy by 26% from 8 TWh/a to 10.1 TWh/a. The additional controlled charging is mostly located in the regions *Southeast*, *Southwest* and *West*.

The input parameter variations not only affect the amount of shifted and shedded energy, but also the residual peak load reduction achieved. If only DR is considered, it ranges from 1.6 GW to 4.8 GW. Compared to the reference case (2.9 GW), the maximum load reduction is higher in all variations except *DR Cost++* (1.6 GW) and *DR Cost+* (2.3 GW). It reaches 4.8 GW in *No EV-Flex*, 4.7 GW in *Potential+*, 4.0 GW in *ShiftTime+*, 3.8 GW in *DR Cost--*, 3.3 GW in *DR Cost-*, as well as *Frequency+*, and 2.6 GW in *Red. Cap*. Differences between the variations are much lower than for the annual load shift displayed in Figure 5.46 and Figure

5.47. In variation *DR Cost--*, for example, the shifted energy is by factor four higher than in the reference case, whereas the maximum load reduction is increased only by 30%. Similar effects can be observed for higher costs, frequency and shift time. In contrast, variation *Potential+* combines a low DR utilization with a comparatively high load reduction. This is related to the high amount of available industrial DR potentials. The peak load reduction provided by EV charge control is almost not affected by the DR input parameter variations. It is not increased in any case, and reduced by 110 MW at most (*DR Cost--*).

Impact on Capacity Demand and VRE Curtailment

The impact of the DR input parameter variations on GT capacity expansion and VRE curtailment is mostly low. Required GT installation ranges from 10.7 GW in *Potential+* to 13.3 GW in *DR Cost++*, equivalent to maximum deviations from the reference case of -12% and +10%, respectively (see Figure 5.48). This result implies that the firm capacity substituted by DR does not scale linearly with the exploitation of the potential. A much higher impact on the required additional GT capacity is found for uncontrolled EV charging: it increases by more than 45% to 17.8 GW. This underlines the important role of flexible EV power demand in the scenarios considered here. The extended capacity expansion assessment performed in variation *Red. Cap* reveals that DR can partially substitute GT and CCGT capacities considered in the scenario. Aggregated over the regions *Southeast*, *Southwest* and *North*, the overall capacity of conventional power plants is reduced by around 430 MW. It is substituted by more than 2 GW of additional DR capacity, which is almost exclusively located in the *Southeast* region. The minor reductions in conventional power plant capacity found in the other model regions can be attributed to a technology change from coal to gas stations and the higher availability of the latter. The CCGT share in overall gas power plant capacity is similar to the scenario values throughout all regions. It is slightly higher in the regions *East* and *Central*, and lower in all other regions. Differences in CCGT capacity between the exogenous scenario input and endogenous installation range from -0.78 GW in *West* to +0.23 GW in *East*.

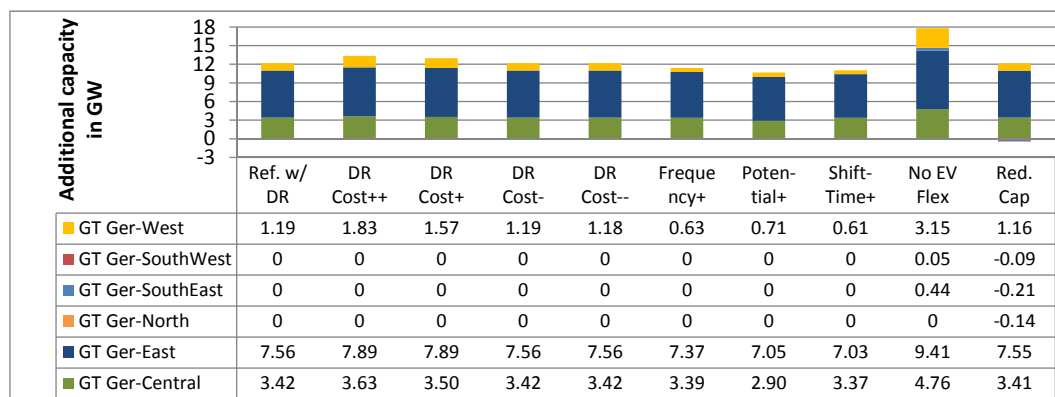


Figure 5.48 Impact of input variations on additional generation and storage capacities in Germany.

Enhanced DR utilization triggered by lower costs, more frequent application or higher potentials can reduce VRE curtailments only to a minor extent by up to 0.4 TWh, equivalent to 1.2% of total curtailed electricity. These cuts are by factor four to seven lower than the corresponding increases in load shifting. Even higher ratios are found for the decrease of DR energy and increase in curtailment in variation *DR Cost+* and *DR Cost++*. Due to the significant reduction of shiftable power demand, an increase in curtailment by 0.4 TWh is seen in the variation without controlled EV charging. The additional load shifting measures enabled by changes in the power plant park assessed in variation *Red. Cap* come along with a minor reduction in curtailment by 0.03 TWh (0.1%). Table F.27 to F.31 in Appendix F comprises the resulting curtailments in all variations.

5.5.5 Step 3b: Sensitivity Analysis of Heat Supply Capacity Optimization

In this section, the sensitivity of design and operation of enhanced heat supply systems to selected changes in the techno-economic model input parameters of scenario 50Base is assessed. The variations are focused on the investment and operational costs of TES and electric boilers. Additionally, the impact of higher TES losses, solar district heating and a more diverse electric heating application are evaluated. As for DR, a validation of the conventional power plant scenario capacities is performed. Table 5.8 provides an input of the considered variations.

Table 5.8 Overview of the input modifications considered in the sensitivity runs of heat supply capacity optimization.

Variation	Applied changes
TES Cost+	TES investment costs doubled
TES Cost−	TES investment costs reduced by half
TES Cost−−	TES investment costs reduced to a quarter
TES Loss+	TES self-discharge losses doubled, reduced TES charging and discharging efficiency ^a
EB Cost+	Electric boiler investment and variable operation costs doubled
Solar DH	Consideration of solar district heating for selected technologies ^b
El. Heat+	Increased availability of electric heating in DH systems ^c
Red. Cap.	Extended model endogenous capacity expansion of conventional power plants ^d

^a Charging and discharging efficiency of CHP-TES set to 90%, HP-TES discharge efficiency to 95%.

^b Solar DH available in systems using *DH-Engine-NGas*, *DH-Engine-Biogas* and *DH-ST-SolidBio*.

^c Electric boilers can additionally be installed in CHP systems relying on *DH-BpCCGT-NGas* and *DH-ST-Coal*. Furthermore, in *DH-Engine-Biogas*, *DH-ST-SolidBio* and *Ind-ST-SolidBio*, heat pumps can be installed as substitute or supplement to electric boilers.

^d Capacities of coal and gas power plants set to zero and capacity expansion extended to CCGT.

Impact on Dimensioning of Flexible Heat Supply Systems

The installed TES capacity is to a high degree dependent on the applied investment costs (see Figure 5.49). If costs are doubled, the overall TES installation is reduced by one

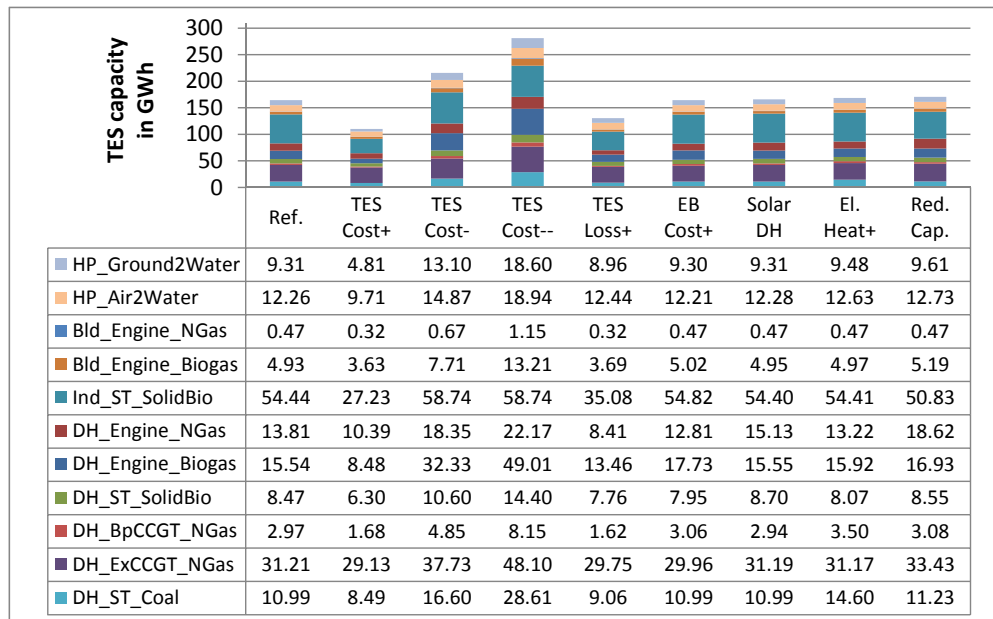


Figure 5.49 Impact of the input variations on TES Capacities in Germany.

third, equivalent to 54 GWh. In contrast, halved and quartered costs cause an increase by 51 GWh (+31%) and 117 GWh (+71%), respectively. Not all technologies are affected equally: the impact of an increase in costs is most pronounced for industrial CHP, biogas and backpressure-CCGT systems, as well as ground-source HP, and least pronounced for building CHP, air-source HP and DH systems with extraction CHP units. Reduced investment costs have particular high influence on TES installation in building CHP, coal and biogas-fired DH-CHP and backpressure CCGT, whereas the impact on industrial CHP and other gas-fired DH-CHP is relatively small. The substantial differences between technologies are related to the applied upper limits and its exploitation in the reference case (compare Table E.22 and Figure 5.32). Comparing the regions within Germany, the TES installation in *North* appears to be much less sensitive to cost variations than that in all other regions. This is supposedly related to the high wind power generation and curtailment, which is partially stored into TES.

The consideration of higher TES losses reduces the installed TES capacity by more than one fifth. The effect is higher for backpressure natural gas CHP, and lower for extraction turbine gas CHP and biomass DH-CHP. The variations not directly related to heat storage have only minor impact on the TES installation: the consideration of solar DH, additional electric heating and a modified conventional power supply increases the overall capacity by 1%, 2% and 4%, respectively. In contrast to that, higher electric boiler costs do not change the overall TES capacity.

Taking into account specific technologies, greater differences between the variations can be determined. The installation of solar DH goes along with an extension of TES capacities in the corresponding systems, whereas all other CHP technologies are almost not affected. Given that the solar option is only used in combination with natural gas engine CHP and solid biomass DH-CHP, only there a notable TES capacity increase is seen. In DH systems relying on biogas, no solar heat installation takes place, which implies that it is not competitive to the

alternative supply components.

The additional TES installed in case of broader application of electric heating is almost completely associated to systems not equipped with an electric boiler in the reference case (backpressure CCGT and coal DH). The consideration of higher electric boiler costs favors the TES installation in biogas DH, at the expense of a decrease in natural gas and solid biomass-fired DH-CHP systems. The enhanced optimization of the conventional power plant park leads to an increase in TES capacity throughout almost all CHP and HP technologies. It is highest for natural gas and biogas-fired DH-CHP systems. On the contrary, less TES are installed in industrial biomass-CHP heat supply.

The overall electric boiler capacity is almost not affected by variations of TES technology parameter input. The same applies to the consideration of solar DH and a modified conventional power generation structure. The variations, however, change the allocation to the different technologies. Higher TES costs and losses tend to have positive impact on the electric boiler capacity in renewable CHP systems and negative impact on those associated to gas-fired CHP technologies. The contrary effect is detected for lower TES investment costs. The higher electric boiler investment costs applied in variation *EB Cost+* cause a reduction in installed capacity by more than one third from 10.2 GW to 6.4 GW. With cuts of up to 60%, the capacity in renewable CHP systems is affected to a disproportionately higher extent. The electric boiler heat production capacity in variation *El. Heat+* is around 26% higher than in the reference case. This growth arises from a boiler capacity of around 2.4 GW in CHP systems without electric heating option in the reference case on the one hand, and approximately 1.5 GW of HP capacity on the other. The latter partially substitute electric boilers, not only in the corresponding supply systems, but to a lower extent also those associated to other CHP technologies.

Impact on Operation of Thermal Energy Storage and Electric Boilers

The annual TES energy input is much less influenced by changes in TES investment cost than the installed capacity (see Figure 5.50). It is reduced by 1.5 TWh (10%) in the variation with double costs, and increased by 0.9 TWh (6%) and 1.5 TWh (10%) in those with lower costs, respectively. This implies that the annual TES utilization features substantial differences between the variations. In variation *TES Cost+*, the number of full TES charging cycles is by more than 36% higher than in the reference case. On the contrary, TES utilization drops by 20% in *TES Cost-* and by 36% in *TES Cost--*. A different situation is found in case of higher storage losses (*TES Loss+*): the 28% reduction in annual TES heat input comes close to the 21% decrease in capacity, and the utilization is lowered by only 7%.

The usage of TES associated to building CHP and ground source HP appears to be most sensitive to changes in costs, whereas it is most robust for those in DH-CHP systems relying on natural gas. For industrial biomass CHP, almost no increase in utilization is found in the variations with lower costs. This is related to the applied upper limits in capacity, which are already reached in the reference case. The assumption of higher storage losses has most

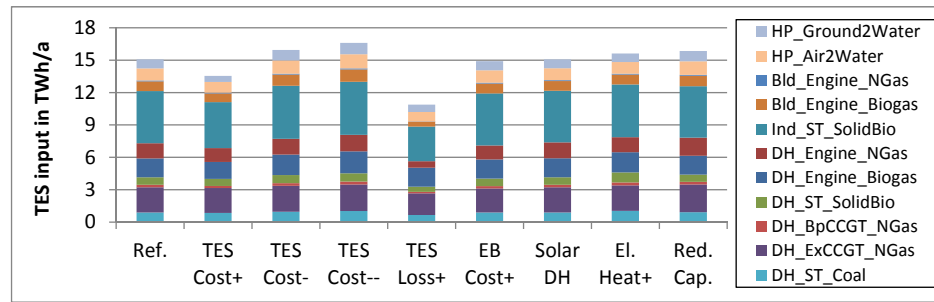


Figure 5.50 Impact of the input variations on annual TES energy input.

significant impact on the TES utilization in building CHP, and lowest on that in biogas-CHP and extraction CCGT DH systems.

Such as the capacity installation, also the TES energy input is only to a minor extent affected by the other parameter and scenario variations. In variation *El. Heat+* an increase by 4%, in *EB Cost+* a decrease by 1% are determined. The former is mostly associated to additional electric boiler and heat pump capacities in renewable, coal, and backpressure-CCGT district heating, the latter to natural gas-fired DH-CHP. The considered solar DH does not influence the overall TES energy input, it however favors the CHP technologies using solar heat. In variation *Red. Cap.*, the TES input is found to be 5% higher than in the reference case. This mostly results from a higher storage utilization in HP and natural gas-fired CHP systems. The change in TES utilization triggered by cost variations is found to be similar in all model regions. It tends to be higher in southern Germany. The same applies to the impact of higher storage losses. Solar DH and additional electric heat have highest influence on the TES usage in the *North* region, a modified power supply on that in southern Germany.

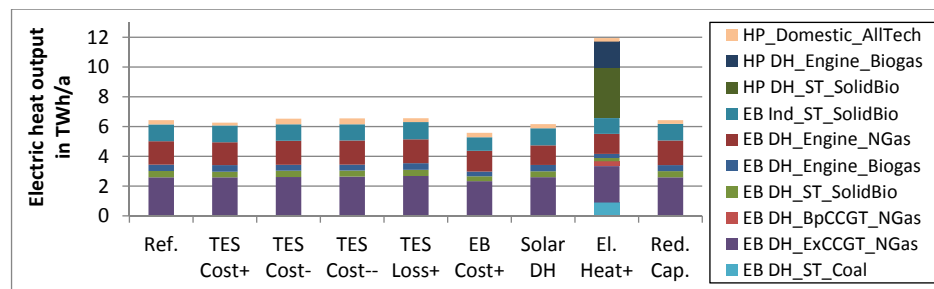


Figure 5.51 Impact of the input variations on the annual heat production of electric boilers.

Figure 5.51 shows that the overall electric boiler heat production is only to a very limited extent linked to the applied TES costs. Decrease and increase determined in the corresponding variations do not exceed 2.2% (0.17 TWh) of the heat output in the reference case. The impact of TES costs on the annual utilization hours of electric boilers in CHP systems is even lower, as most of the ceased or added heat production occurs in HP supply systems. It turns out that the electric boiler usage in renewable CHP systems increases with higher TES costs and decreases with lower TES costs, whereas for HP and fossil fuel CHP a reverse trend is found. In contrast to the negative effect on both TES utilization and electric boiler capacity expansion, higher storage losses cause an increase in electric heat production by around 1.7%. Different

trends are found for electric boiler heat in HP supply on the one hand, and CHP supply on the other. The former is found 1.6% lower, the latter 2.6% higher than in the reference case. The consideration of solar DH reduces the provision of electric heat by 3.4%. This decrease is completely associated to a displacement by solar heat in natural gas engine (-17%) and solid biomass DH systems (-6%). The modified power supply structure assessed in variation *Red. Cap* does not change the overall electric heat production, but causes a slight shift from HP boilers to CHP boilers. A doubling of electric boiler costs and the resulting decrease in capacity installation cuts the electric heat production by 11%. Consequently, a noticeable increase in annual utilization is determined. The average FLH across all technologies are by 37% higher than in the reference case.

The consideration of additional technologies causes a drastic enhancement of the electric heat production. The overall increase of 5.6 TWh of heat output is almost exclusively provided by electric HP in DH systems, whereas electric boilers in CHP supply contribute only to a minor extent, and those in HP systems not at all. For DH technologies disposing over both electric heat sources, a shift in heat output to the more efficient HP technology is seen. Nonetheless, the annual FLH of the corresponding electric boilers are found to be higher than in the reference case. Table F.32 to F.43 in Appendix F provide detailed results for each technology, region and variation.

Impact on Capacity Demand and VRE Curtailment

Most of the considered parameter and scenario variations have only marginal impact on the demand for power generation capacity. Deviations in the sum of additional GT and CHP installation from the reference case do not exceed 1%. Notable increases by 50 MW and 114 MW are realized in *El.Heat+* and *TES Cost+*, decreases by 54 MW and 64 MW in *EB Cost+* and *TES Cost--*, respectively. A slightly higher net capacity reduction by 190 MW (1%) is found in variation *Red. Cap.*; it is completely located in Germany *North*. The model endogenous installation of conventional power plants tends to favor GT over CCGT: across all regions the technology shift sums up to almost 1.5 GW.

VRE curtailment is almost not influenced by the considered TES input parameter variations. It is increased by 0.2 TWh (1%) in variation *TES Cost+*, and reduced by 0.18 TWh (0.9%) in *TES Cost--*, 0.15 TWh (0.7%) in *TES Cost--* and 0.04 TWh (0.2%) in *TES Loss+*. The consideration of solar heat and a different conventional power park structure trigger minor increases by 0.08 TWh and 0.01 TWh. Highest impact is found for changes in electric boiler utilization: an increase in boiler costs goes along with 0.58 TWh (2.8%) of additional curtailments, whereas the extension of electric heating causes a decrease by 0.74 TWh (3.6%).

5.5.6 Step 4: Operation Optimization with all Flexibility Options

In order to assess the interaction between different balancing technologies, the results from the DR and heat supply capacity expansion optimizations obtained in the step 2 model runs are combined. Taking into account the installed capacities for DR, TES, CHP, as well as

conventional and electric boilers, an additional REMix simulation is carried out for each scenario. There, a capacity expansion is only possible for gas turbines, and in scenario 50H₂St also hydrogen storages. In the following it will be analyzed, whether and to what extent the utilization of power plants, storages, load shifting and electric heating is affected by the availability of competing balancing options.

Interaction between Flexible Thermal and Electric Loads

Figure 5.52 provides the annual DR load shift for all scenarios, comparing the case without (w/o TES) and with increased flexibility (w/ TES) in the heating sector. It appears that the additional balancing options can have a positive or negative impact on DR utilization. The spectrum ranges from a decrease in shifted and shedded energy by 200 GWh (-17%) in scenario 50Grid to an increase by 151 GWh (+13%) in 50Wind. Even higher relative reductions by 35%, 28% and 27% are found in scenario 50H₂T, 20Base and 30Base, respectively, whereas an enhancement of DR utilization is determined only in 50H₂St and 50Wind. The availability of TES and electric boilers not only affects the overall energy, but also the composition of DR measures. Load shifting and shedding of consumers summarized in the categories *ProcessShift-Ind*, *ProcessShed-Ind* and *HVAC-ComInd* is favored at the expense of those in *CoolingWater-ComInd* and *StorHeat-ResCom*. Power-controlled heat supply also changes the regional distribution of DR application. Across all scenarios, an increase in load shifting in the *North* region, and a decrease in *Southwest*, *Southeast* and *West* is seen. In the remaining regions, a positive impact is found in scenario 50Base, 50H₂St and 50Wind, and a negative in all other. Changes in regional energy shift range between -100% and +150%. Detailed values can be obtained from Table F.44 to F.49 in Appendix F.

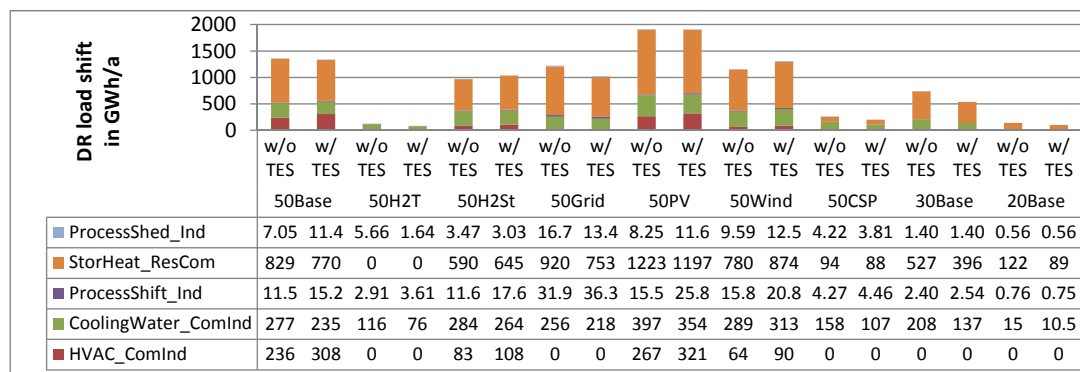


Figure 5.52 Comparison of DR energy shift in Germany in the cases without (w/o TES) and with increased flexibility (w/ TES) in the heating sector.

For controlled EV charging, opposed trends are determined, too (see Figure 5.53). Higher values of postponed energy demand are found in all 2050 scenarios, lower in the earlier scenario years. The change triggered by power-controlled heat supply ranges from -25% in scenario 30Base to +22% in 50H₂T. The highest absolute increase in load shifting is present in scenario 50Wind (+1.16 TWh). Regional impacts of the additional flexibility in the heating sector on controlled EV charging exhibit substantial differences: mostly positive changes are

found in Germany *North, East, Southwest* and *Central*, mostly negative in *Southeast* and *West*. It is most pronounced in the *North* region, where more than a doubling is achieved in scenario 50H₂T and 50CSP.

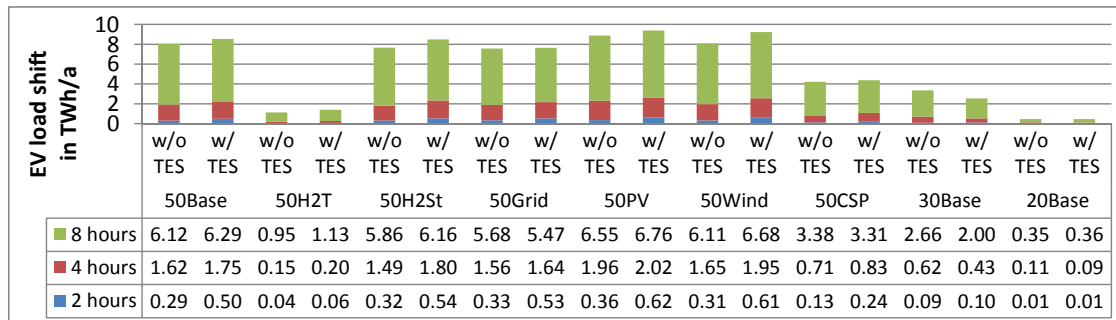


Figure 5.53 Comparison of controlled EV charging in Germany in the case without (w/o TES) and with increased flexibility (w/ TES) in the heating sector.

Except for scenario 30Base, the maximum reduction in residual peak load realized by DR and EV charging is slightly enhanced by the availability of TES (see Figure 5.54). The increasing effect ranges from 0.01 GW (0.1%) in scenario 50H₂St to 0.5 GW (4%) in 50Wind. In some scenarios, opposed impacts on load reduction by DR on the one, and EV on the other hand are determined.

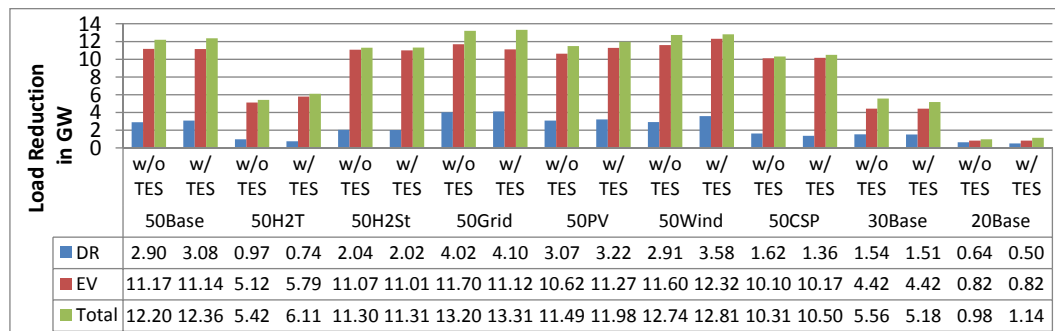


Figure 5.54 Comparison of the maximum load reduction through DR and controlled EV charging in Germany in the case without (w/o TES) and with increased flexibility (w/ TES) in the heating sector.

In the upper part of Figure 5.55, the annual TES heat input is compared for the systems without (w/o DR) and with consideration (w/ DR) of DR load shifting. In the scenarios for the year 2050, the additional flexibility has an upward effect on the utilization of TES in CHP systems and a downward effect on those in HP supply. In all cases except 50H₂T, the negative impact exceeds the positive, causing a net reduction in TES energy input. It is, however, very small and reaches values between 0.02 TWh in 50H₂St and 0.3 TWh in 50Wind, equivalent to 0.1% and 1.8% respectively. The increase in CHP-TES input ranges between 1.4% and 3%, the decrease in HP-TES input between 13% and 30%. In the earlier scenario years, the TES utilization decreases for both HP and CHP systems. Load shifting changes also the regional allocation of TES energy input. An increasing impact is found for the regions *Southwest* and *North*, a decreasing effect for all other regions.

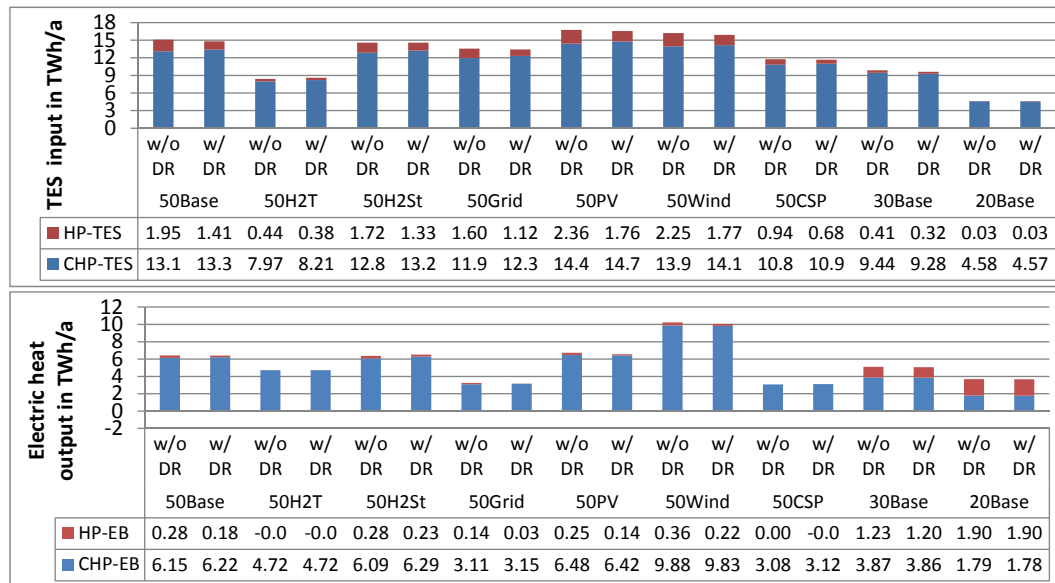


Figure 5.55 Comparison of the annual TES energy input (above) and electric boiler heat production (below) in Germany in the case without (w/o DR) and with DR (w/ DR).

The interference between DR and electric boiler utilization appears to be very small. With the exception of scenario 50H₂St, where a slight increase in electric heat output of 2% is detected, minor decreases of 0.1% to 2.1% are determined. It mostly arises from a lower utilization of HP peak boilers, which also overcompensates the slight increase in CHP systems observed in some scenarios. The lower part of Figure 5.55 shows the annual electric heat production in CHP and HP supply systems for the step 2 and step 4 model runs. For HP, the change in peak boiler utilization compared to heat-controlled operation is considered, which can also be negative. Across all scenarios, the consideration of load shifting increases the electric boiler utilization in Germany *North* and decreases it in *Southeast* and *West*. In all other regions, mostly negative impacts are seen, except for scenario 50H₂T in *Central*, 50CSP and 30Base in *Southwest*, as well as 50H₂St and 50Wind in *East*. Table F.44 to F.49 in Appendix F provides detailed results for each technology, scenario and region.

Combined Impact on Capacity Demand and VRE Curtailment

By employing electric load shifting and power-controlled operation of CHP and HP, the demand for additional power generation capacity can be significantly reduced. In the following paragraphs, the results of the step 1 model runs with reduced availability of balancing technologies (ref.) are compared with the step 4 model runs with availability of both electric load shifting and power-controlled heat supply (flex).

Depending on the scenario configuration, the decrease in GT and storage installation ranges between one fifth and two thirds (see Figure 5.56). Except for those considering hydrogen fuel or storage usage, it exceeds 50% across all scenarios for the year 2050. Highest impacts are found for 50Grid (-64%) and 50CSP (-61%), lowest in 50H₂T (-22%). These relative reductions correspond to GT capacities of up to almost 14 GW in scenario 50Grid. Com-

parable amounts are determined also in scenario 50PV, 50Wind and 50Base, whereas those in all other scenarios are by at least 50% lower. This is related to the much lower capacity demand in the corresponding systems without availability of additional flexibility. Taking into account the slight increase in CHP capacity implemented in the heat supply dimensioning optimization, the net reduction in overall capacity accounts for values between 16% in 50H₂T and 59% in 50Grid.

As in the step 2 model runs, the regional impact on GT installation is divided. In Germany *North*, *Southwest* and *Southeast*, the comparatively low additional GT installation found in the reference case without additional flexibility is reduced to zero. The sole exception arises from the substitution of hydrogen storage by GT in the *North* region and scenario 50H₂St. On the other hand, the lion's share of the overall reduction in capacity demand is located in Germany *Central*, *East* and *West*. In most scenarios, the additional balancing options cannot eliminate all GT installation in those regions.

Comparing the capacity reduction achieved by load shifting and power-controlled heat supply alone with their combined effect, insight into the interaction of different balancing options can be gained. Across all scenarios, the combined impact stays below the sum of the separate impacts, reaching between 66% (50H₂St) and 90% (50Grid) of the added capacity reduction. Comparable values are determined also in scenario 50PV (89%), 50H₂T (88%), 50Base (86%) and 50Wind (85%), whereas those in 30Base (81%), 50CSP (78%) and 20Base (75%) are found to be slightly lower. The separate impacts of load shifting and power-controlled heat supply can be obtained from Figure 5.29 and Figure 5.40, respectively.

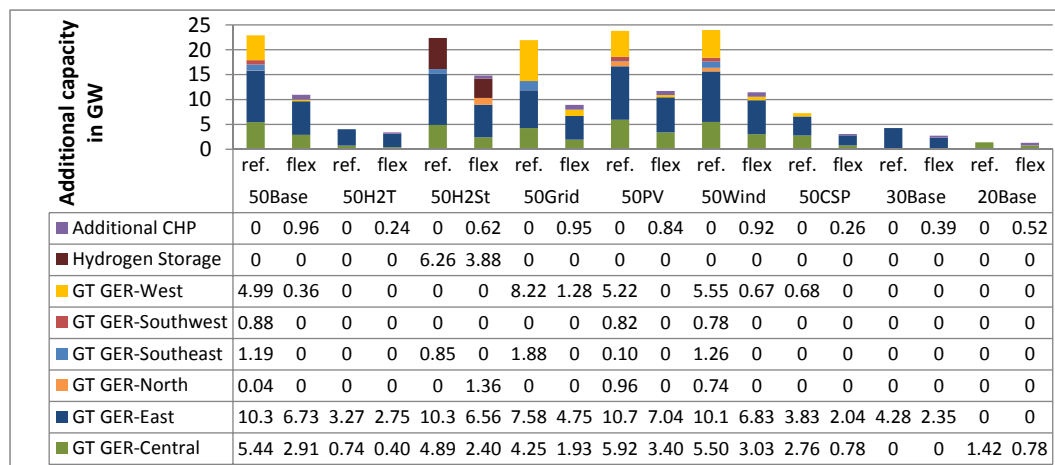


Figure 5.56 Comparison of the additional GT and storage capacities in Germany in the REMix runs without (ref.) and with (flex) load shifting and power-controlled heat supply.

In the considered scenarios, up to 22 TWh of VRE curtailment can be avoided by a more flexible heat supply and electricity demand (see Figure 5.57). To what extent the VRE integration is promoted depends on the power plant structure on the one hand, and the availability of balancing options on the other. Particularly high values are reached in the scenarios with supply systems unilaterally dominated by PV or onshore wind power. At the other end of the scale, only 0.3 TWh of curtailments are cut in scenario 20Base,

which is however equivalent to 77% of the total curtailed energy. In contrast to that, relative reductions are lowest in scenario 50H₂T (38%) and 50H₂St (40%). In the step 2 model runs, power-controlled heat supply has proven to be a very effective measure for the reduction of curtailments. Consequently, the results in Figure 5.57 are similar to the heat supply capacity expansion model runs (see Figure 5.41). Taking into account the sum of the reductions achieved in the separate assessments of load shifting and heat supply optimization, the interaction between both balancing options is assessed. It appears that the overall reduction in curtailment achieved by the combined consideration of all flexibilities exceeds the added values of the separate assessments by up to 14% (50H₂St). This implies that even though load shifting and power-controlled heat supply mutually reduce each others utilization, their intelligent coupling fosters an even higher VRE integration. The only exception is scenario 20Base, where the combined reduction equals the sum of the two values obtained in the step 2 model runs.

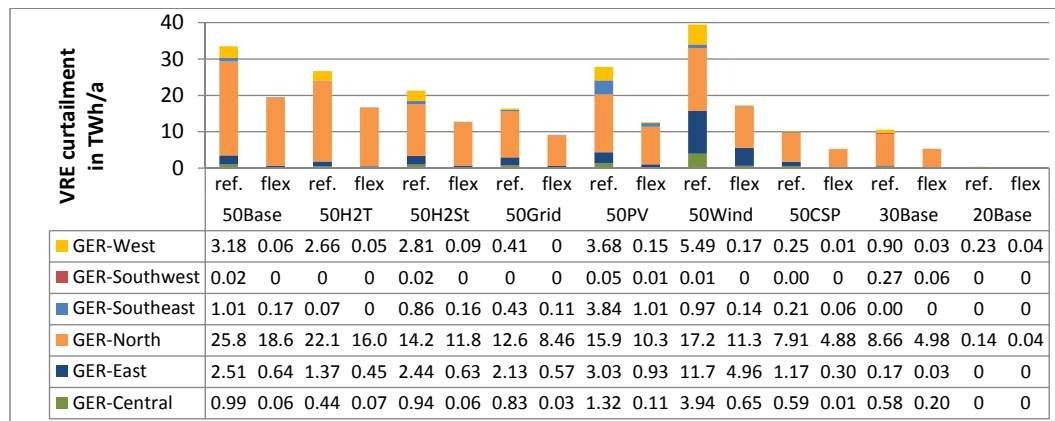


Figure 5.57 Comparison of the VRE curtailment in Germany in the REMix runs without (ref.) and with (flex) load shifting and power-controlled heat supply.

Combined Impact on Power Plant and Storage Utilization

Load shifting and power-controlled heat supply have partially parallel and partially opposite impact on power plant operation (compare Figure 5.30 and Figure 5.42). Both balancing options favor a higher biomass, lignite and nuclear power generation, at the expense of lower CHP and gas power plant FLH. In contrast, their impact on coal stations is opposed: the annual capacity utilization is increased by power-controlled heat supply and decreased by electric load shifting. In the combined assessment of both balancing options, the interaction of these effects can be studied. The increase in biomass power generation FLH compared to the step 1 model run is higher than in the heat capacity optimization model run, but lower than the sum of both impacts. In contrast to that, the increase in nuclear and lignite FLH, as well as the decrease in CHP FLH found in the step 2 model runs are almost added up. The annual utilization of coal power plants is found higher, that of CCGT lower than in the step 1 model runs. The corresponding changes are however smaller than in the heat capacity optimization simulations without load shifting. Even though each of them had a decreasing

impact, the combined consideration of load shifting and power-controlled heat supply causes an increase in GT capacity utilization. Exceptions are scenario 50H₂T and 30Base, where minor reductions are found. The resulting FLH range approximately between 7875 h/a and 8300 h/a for biomass, 4475 h/a and 4900 h/a for CHP, 3425 and 4600 h/a for coal, 1125 h/a and 2750 h/a for CCGT, and 30 h/a and 230 h/a for GT. The additional technologies available in the earlier scenario years run 7500 h/a hours in case of nuclear in scenario 20Base, as well as 6850 h/a (30Base) and 7225 h/a (20Base) in case of lignite, respectively. Figure 5.58 shows the FLH by technology and scenario for the step 1 model runs without the additional balancing options (ref.) and for the step 4 model runs with both load shifting and power-controlled heat supply (flex).

The corresponding overall increase in biomass power generation ranges between 0.2% (20Base) and 22% (50PV), the decrease in CHP power output between -0.2% (20Base) and -9% (50Wind), and the change in conventional power generation between +2.7% (30Base) and -9.1% (50PV).

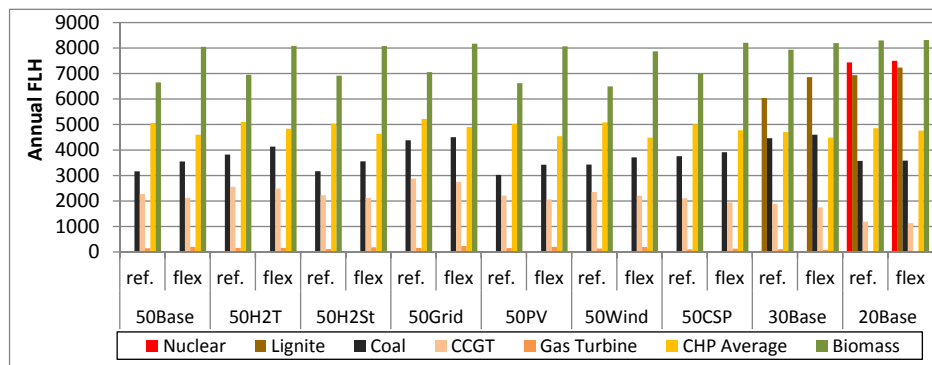


Figure 5.58 Comparison of the power plant FLH in Germany without (ref.) and with (flex) load shifting and power-controlled heat supply.

With the availability of load shifting and power-controlled heat supply as alternative balancing technologies, the electricity-to-electricity storage utilization is reduced approximately by half across all scenarios for the year 2050 (see Figure 5.59). Particularly high decreases of almost 60% are found in scenario 50Grid and 50CSP. In scenario 50H₂St, hydrogen storage are effected to a lower extend than pumped hydro storage – the energy input is reduced by 40% and 57%, respectively. It is striking that the impact on storage utilization of a combined implementation of flexible thermal and electric loads is greater than the sum of the impacts determined in the separate assessments of both technologies. In scenario 50Base, for example, the reduction in storage energy input amounts to 7.4 TWh, which is around 0.4 TWh (6%) higher than the sum of the values found for load shifting (3.4 TWh) and power-controlled heat supply (3.6 TWh) alone. This effect is seen also in the other 2050 scenarios, as well as scenario 20Base. In 30Base, the decrease accounts for 92% of the added values.

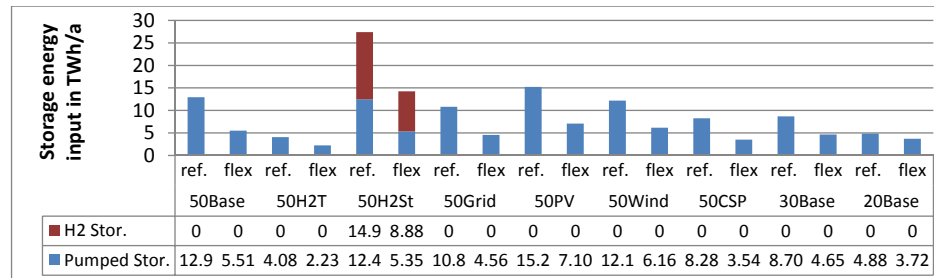


Figure 5.59 Comparison of the electric storage utilization in Germany without (ref.) and with (flex) load shifting and power-controlled heat supply.

Impact on CO₂ Emissions

In the configuration applied in this work, REMix-OptiMo calculates CO₂ emissions arising from fossil fuel consumption in the power sector, as well as the considered part of the heating sector. All further emissions originating from fuel use not related to power and heat supply, is not taken into account. According to the model output displayed in Figure 5.60, increased demand and heat supply flexibility lower the CO₂ emissions across all scenarios for the year 2050. The relative reductions achieved range from 3.3% in 50H₂T to 7.6% in 50Wind, which is equivalent to around 2.5 to 5.3 Mt of CO₂. In contrast to that, an increase in emissions by 2.3% is found for scenario 30Base (3.7 Mt) and 20Base (5.7 Mt), respectively. It arises from the higher utilization of the cheaper but higher emitting lignite and coal power plants, the comparatively low additional integration of VRE power, as well as the increased boiler use in CHP heat supply.

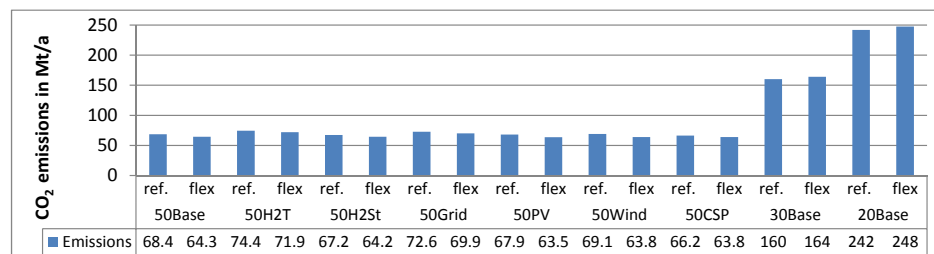


Figure 5.60 Comparison of the annual CO₂ emissions in Germany without (ref.) and with (flex) load shifting and power-controlled heat supply.

Impact on the Heat Supply Structure

In the step 1 model runs, CHP operation was completely heat driven. It was consequently assumed that within the limit set by the thermal capacity all heat is provided by the CHP unit. The conventional boiler could only be used for peak load coverage, but not for a CHP down-regulation. In case of backpressure technologies, the consideration as must-run generation not only determines the heat, but also the power output. With the availability of TES, as well as conventional and electric boilers, CHP operation can be adjusted to the current power system requirements. This implies changes in the heat supply structure in CHP systems. To what

extend different components contribute to heat generation is mostly determined by available capacities and variable operation costs.

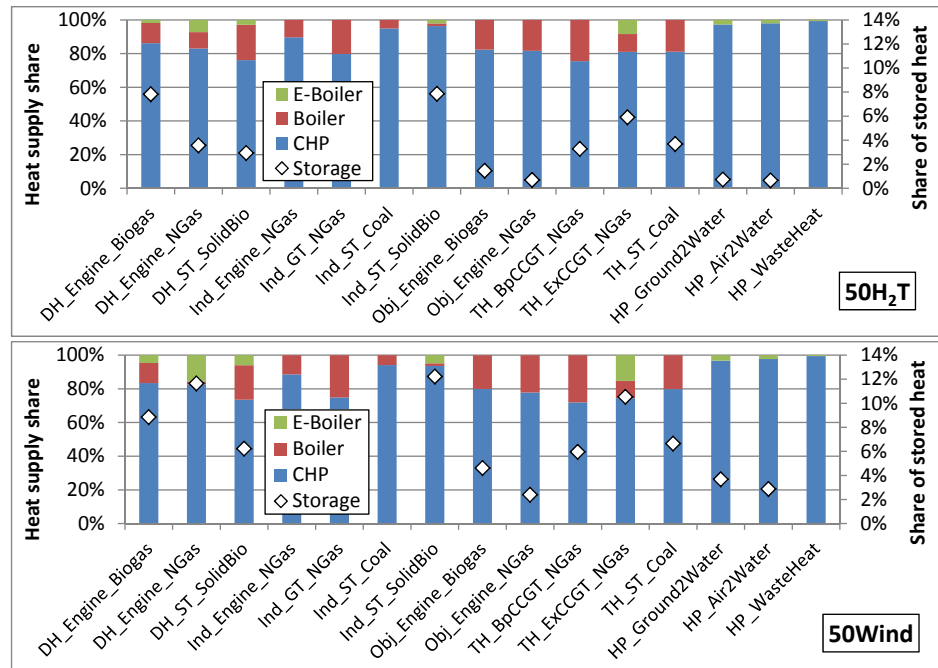


Figure 5.61 Heat supply structure of CHP and HP systems in scenario 50H₂T (upper) and 50Wind (lower) with increased flexibility in the heating sector.

Figure 5.61 compares the resulting heat supply structure of all CHP and HP technologies in scenario 50H₂T and 50Wind. These scenarios represent the extreme cases of a comparatively low (50H₂T) and high (50Wind) implementation of TES and electric boilers. Values for all scenarios are comprised in Table F.44 to F.49 in Appendix F. Taking into account additional components, the supply structure changes significantly. Still, most heat is provided by CHP, its share however decreases to little more than 70% for some technologies. The provision of the remaining heat differs notably both between technologies and scenarios. The electric boiler supply share tends to be higher for gas-fired CHP technologies than for renewable CHP, whereas the contrary situation is found for conventional boilers. The TES utilization is highest in industrial biomass CHP and DH systems, and lowest in building CHP or HP supply. Comparing scenario 50H₂T and 50 Wind, greatest differences in TES input are observed for gas-fired DH systems. This effect is related to the much higher electric boiler heat supply in 50Wind.

In biogas DH systems, electric boilers are used only to a minor extent: except for scenario 50Wind, they do not reach supply shares exceeding 2%. Instead, conventional boilers account for values between 12% in all 2050 scenarios and 14% in 20Base. The amount of heat fed into the TES is similar for all 2050 scenarios and ranges between 8% and 9% of the overall heat demand. In DH systems relying on natural gas engine CHP, electric heat provision plays a more important role. It reaches more than 15% in scenario 50Wind, and goes along with a storage energy input exceeding 12%. The heat supply in solid biomass DH systems is characterized by comparatively low CHP and electric heat production on the one hand, and a

high conventional boiler share on the other. This also affects the TES input, which accounts for only 3% to 6% of the annual heat. Across all scenarios, the biomass CHP technology used in industry achieves shares in total heat supply of more than 95%. They are favored by a generous dimensioning of the CHP unit on the one hand, and an intense TES utilization on the other; over the course of the year up to 14% of the demand is stored. The remaining heat is mostly provided by electric boilers.

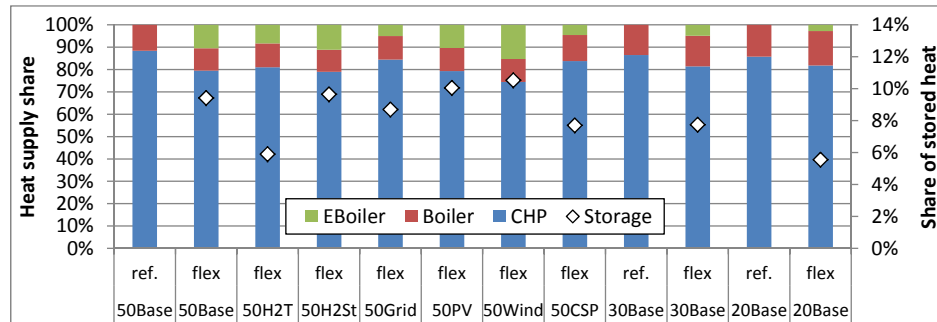


Figure 5.62 Scenario comparison of the heat supply structure of extraction CCGT DH supply systems without (ref.) and with (flex) increased flexibility in the heating sector.

The heat supply structure in DH systems relying on natural gas-fired extraction CCGT is shown for each scenario in Figure 5.62. For each scenario year, the chart includes the supply structure in heat-controlled operation mode, which is clearly dominated by CHP heat. In power-controlled operation, the heat supply combines a high CHP share with a considerable TES and electric boiler utilization. The electric boiler heat production accounts for shares between 3% in scenario 20Base and 15% in 50Wind and is correlated to the VRE power generation surplus. With exception of scenario 50Grid, an increase in electric heat is always accompanied by a higher storage utilization.

In the 2050 scenarios, electric boilers in HP systems are almost exclusively used for peak supply, which accounts for approximately 1.5% of the overall heat in case of ground-source HP and 3.5% in case of air-source HP. Their utilization is affected only to minor degree by TES availability. The supply share of boilers in ground-source HP increases across all scenarios to values between 1.7% in scenario 50CSP and 2.2% in 50Wind. In contrast to that, opposed trends are observed for electric boilers in air-source HP supply: their share ranges from 3% in scenario 50CSP to 3.7% in 50Wind. Both increase and reduction are enabled by the availability of TES, which are used for storing between 0.6% and 3.7% of the annual heat demand. In scenarios with CSP import or hydrogen usage, TES are applied for an increased HP operation, and thus improved efficiency, whereas in scenarios with higher PV and onshore wind share it allows for the conversion of surplus power into heat. This behavior also causes the differences in electric boiler utilization.

A different HP supply structure is found in the earlier scenario years. Due to the smaller HP dimensioning, much higher electric boiler shares are reached. In ground-source HP systems, it amounts to 7.5% in 30Base and 15.5% in 20Base, in air-source HP to 4.7% and 10.7% respectively. The different heat supply structure goes along with a lower TES input

corresponding to 0.9% (ground-source) and 0.6% (air-source) of the annual demand in 30Base, and 0.1% (both) in 20Base, respectively.

5.5.7 Hourly Operation of Power Generation and Load Balancing

In the considered scenarios, the German and European power supply is dominated by VRE. In figure 5.63, hourly VRE power output in Germany and resulting residual load are displayed for the year 2050. Regular and irregular variations of PV and wind power generation are clearly visible. In addition to midday peaks originating from PV, periods with particularly high (e.g. day 80 to 100, 120 to 130 and 300 to 350) and low (e.g. day 25 to 40 and 190 to 210) wind speed can be identified. The overall VRE power output ranges between 4 GW and 113 GW. The residual load reflects both demand and VRE generation fluctuations; it varies between a surplus of 53 GW and a deficit of 80 GW.

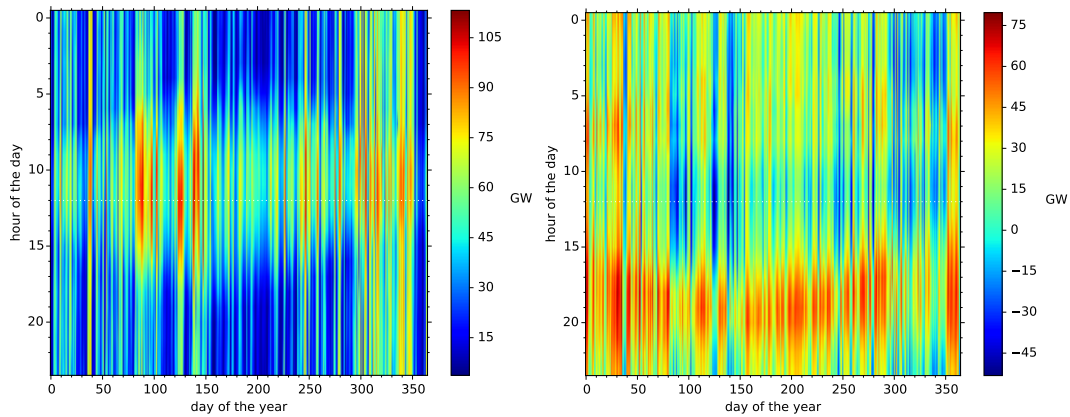


Figure 5.63 Hourly VRE power generation (left) and residual load (right) in Germany, scenario 50Base.

The transmission grid utilization is clearly correlated to the VRE power output: exports are mostly found at midday, as well as windy periods, imports at summer evenings and nights. Hourly net transfers to neighboring countries, as well as the residual load after consideration of power transmission are displayed exemplary in Figure 5.64. Comparison with the right picture in Figure 5.63 shows that both annual peak demand and frequency of surplus generation are significantly reduced by the transmission grid. In contrast, the peak surplus is almost not affected. The resulting residual load exhibits a more even pattern, especially in summer. This implies that PV generation peaks are mostly balanced by the transmission grid. The residual load after consideration of exports and imports must be covered by the further balancing technologies, including conventional power and CHP plants, storage and load flexibility.

In the model runs without load flexibility and with a strictly heat-controlled CHP operation, much of the remaining balancing needs are met by conventional power generation. Its operational pattern reflects the residual load: it is highest in afternoon and evening hours, with highest peaks during winter and times of low wind power output (see Figure 5.71).

The utilization of DR shows a clear correlation with VRE power availability and residual load. This is underlined by the exemplary hourly load reduction (left) and increase (right)

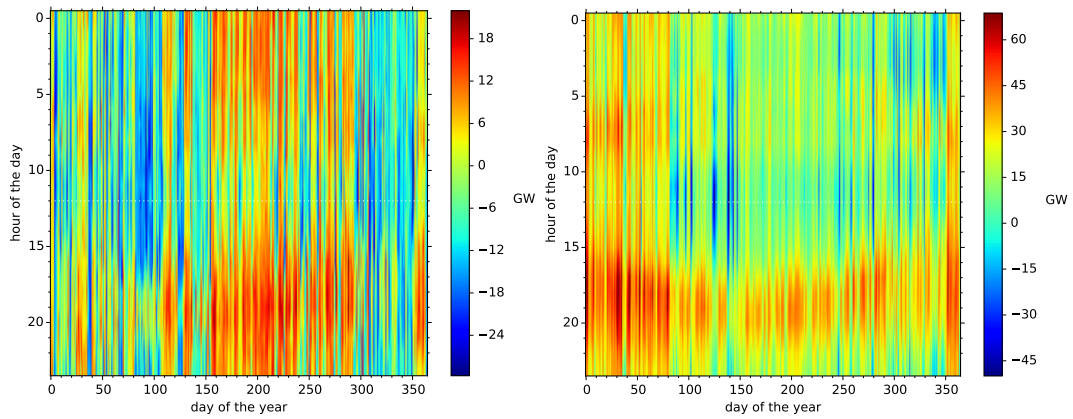


Figure 5.64 Hourly export from (<0) and import to (>0) Germany (left), as well as residual load after grid transfers (right) in scenario 50Base.

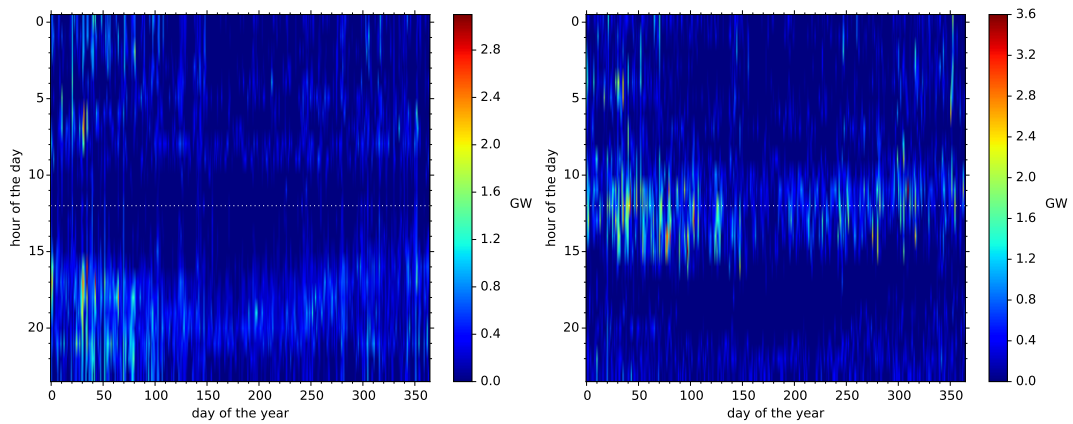


Figure 5.65 Hourly DR load reduction (left) and increase (right) in Germany, scenario 50Base.

through load shifting and shedding displayed in Figure 5.65. Electricity demand is mostly shifted from morning and evening hours to midday and night-time. Due to longer sunshine duration, DR evening load reduction starts later in summer than in winter. Times of particularly high residual load, as for example between day 30 and 40, can be identified in the DR operation pattern. The comparatively low load increase in summer at midday must be seen in relation with the demand profiles and shift times of the considered DR consumers on the one hand, and the balancing function of the power grid, which to a high degree absorbs PV surplus generation in Germany on the other (see Figure 5.64). Most energy shift is provided by heating appliances, which are not available in summer. Figure 5.65 also shows that DR load reductions and increases are mostly in the range of 1 GW, corresponding to approximately one fourth of the maximum values. It also reveals that, even though the load change is typically low, a high number of annual operation hours is achieved.

Figure 5.66 shows that controlled EV charging is mostly used for postponing some of the evening load peak to the night. To a much lesser degree, it is also employed for a concentration of demand to solar PV peak production time. It can also be seen that controlled EV charging is almost not used in periods with very high wind power generation, which are typically characterized by many subsequent hours with surplus generation.

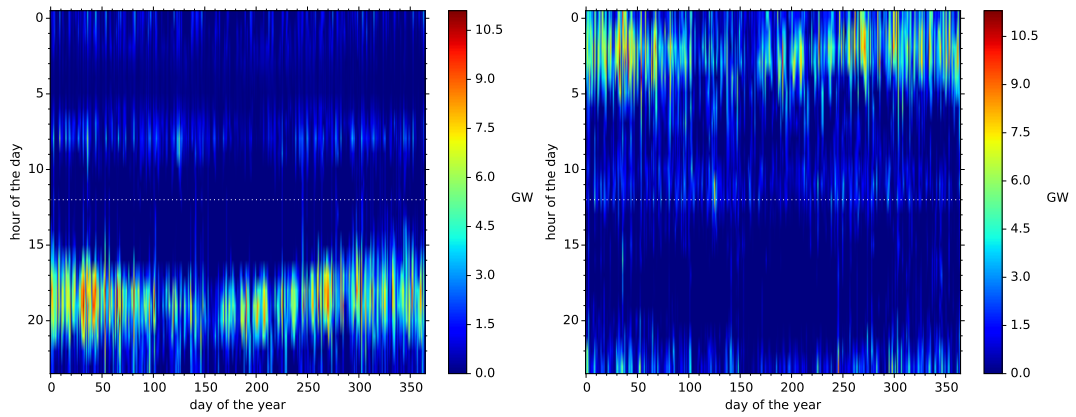


Figure 5.66 Hourly EV load reduction (left) and increase (right) in Germany, scenario 50Base.

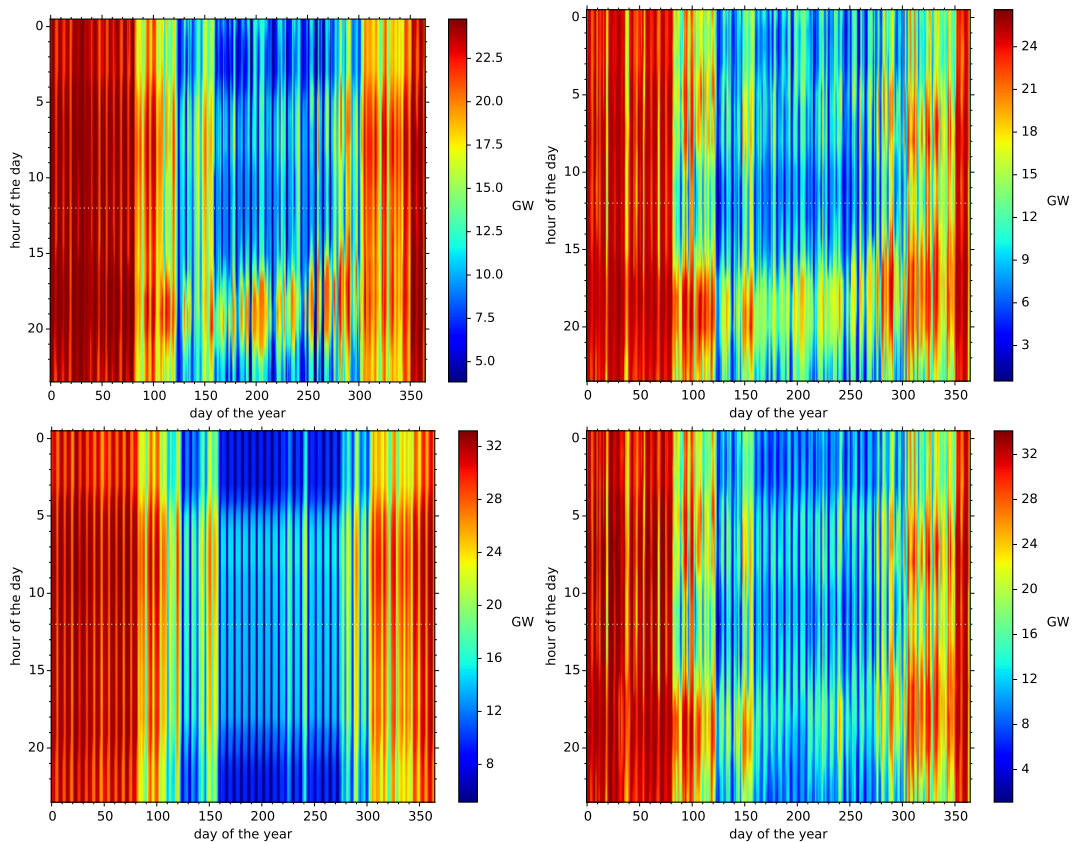


Figure 5.67 CHP power (above) and heat (below) output in Germany in the model runs of scenario 50Base without (left) and with (right) additional supply technologies and TES.

The availability of supplementary heat supply technologies and TES allows for an adjustment of CHP operation to power demand and VRE generation. The hourly power and heat generation in CHP plants is displayed in Figure 5.67 for the model runs without and with enhanced operational flexibility. Seasonal effects triggered by the variation of space heating demand can be clearly identified. The regular weekly down-turns are related to the applied industrial heat demand profile, which declines on weekends. It appears that the additional heat supply components enable a more flexible CHP generation. This includes a down-regulation in times of high VRE power generation, particularly in autumn and winter times on the one

hand, and up-regulation in times of high residual load on the other. CHP generation is shifted preferably to the morning and evening hours, characterized by a high power demand and a comparatively low PV output. In the lower part of Figure 5.67 it can be observed that the strict coupling of process heat demand and production – especially visible during summer – is eliminated by the availability of TES. This explains the particularly high TES installation in the considered industrial CHP units.

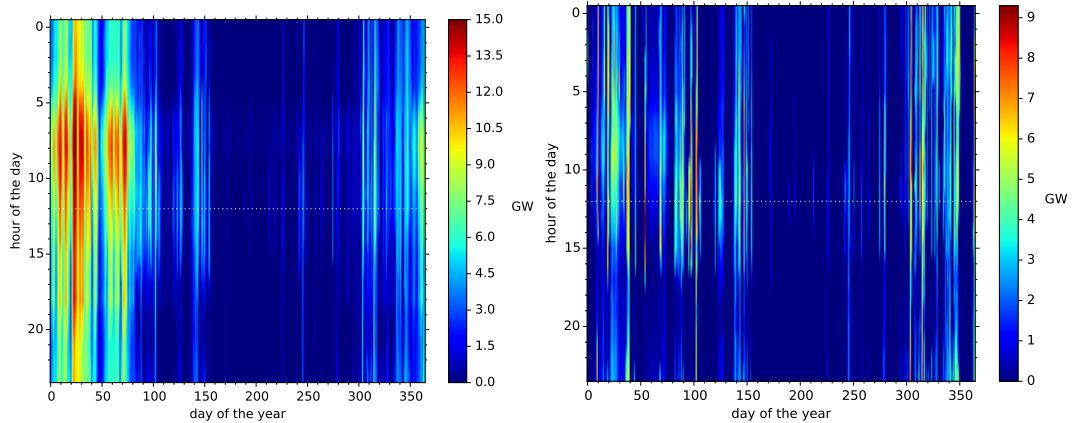


Figure 5.68 Hourly output of conventional (left) and electric boilers (right) in Germany, scenario 50Base.

Figure 5.68 shows the hourly heat production of conventional and electric boilers in CHP supply systems. Conventional boilers are mostly operated during the cold season, and partially substitute CHP heat in times of low residual power and high heat demand. Even though the CHP heat output is not at its maximum, heat is produced in conventional boilers, for example between day 80 and 100 or day 300 and 350. These periods correspond to those most affected by a change in CHP heat production enabled by additional supply components (see Figure 5.67). The electric boiler utilization is clearly correlated to VRE surpluses. A high electric heat output is for example found for the period between day 80 and 90, as well as day 340 and 350, which are characterized by an exceptionally high wind power generation (see Figure 5.63).

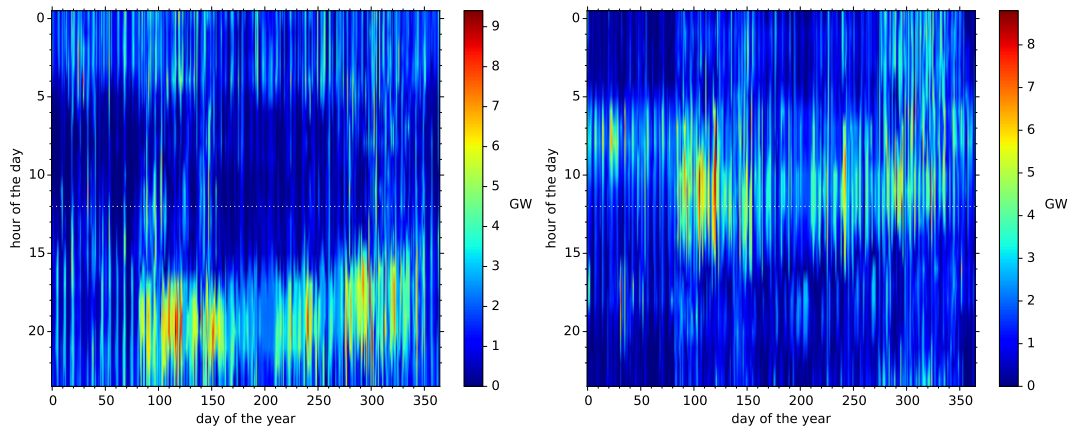


Figure 5.69 Hourly TES input (left) and output (right) in Germany, scenario 50Base.

Figure 5.69 provides the hourly TES energy input and output. It features a superimposition of a broad variety of different effects. TES operation is highest during spring and autumn, when the combined space and water heating demand varies between approximately 40% and 80% of the annual peak. Given that the CHP heat production capacities are in the same range, TES can be used for a more flexible CHP operation. TES utilization is particularly high between day 80 and 120, as well as between day 290 and 310. These periods are characterized by a high VRE power generation, especially during daytime. As it can be seen as well in Figure 5.67, CHP operation is preferably shifted to the evening hours. The surplus heat is then stored, and used during the night or the following day. TES charging is also related to electric heat production. Except for those in the cold season, the electric boiler operation periods seen in Figure 5.68 can also be identified in the left part of Figure 5.69. Given the constantly high demand, TES are generally used to a lower extent during the coldest months. The only exception are TES in industrial CHP systems, which feature a comparatively regular operation cycle. They are charged outside the production time on weekends and during the night, and discharged in the morning peak demand hours, particularly on Mondays.

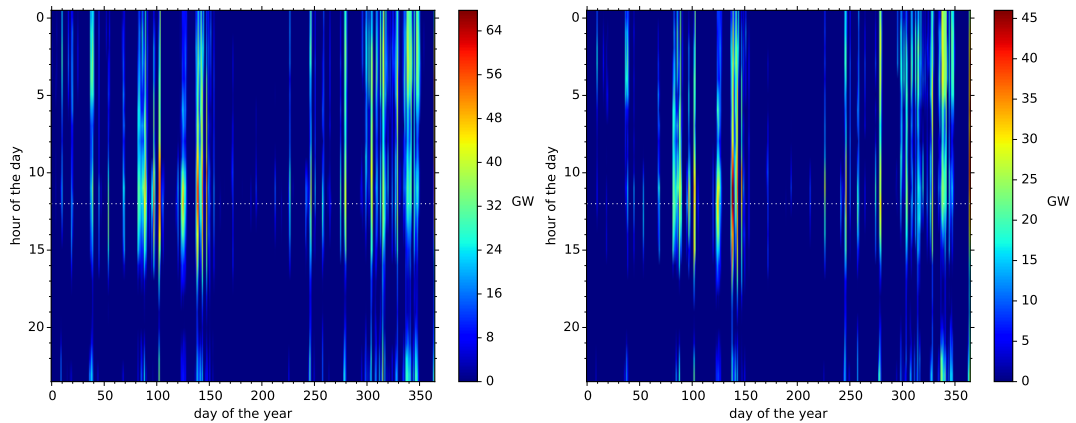


Figure 5.70 Hourly VRE curtailment in Germany in the system without (left) and with (right) electric load shifting and power-controlled heat supply, scenario 50Base.

The hourly impact of load shifting and power-controlled heat supply on VRE curtailment is shown in Figure 5.70. At first glance, the effect of the additional balancing options seems to be rather small. Even though the brighter areas are slightly reduced in number and extent, the color pattern is mostly identical in both images. Taking into account the color scales, it becomes obvious that curtailments are reduced by up to 20 GW whenever they appear. Nonetheless, substantial amounts of VRE power remain unused.

Load shifting and power-controlled heat supply not only influence the demand for, but also the operation of conventional power plants. In Figure 5.71, it is displayed for the system without (left) and with (right) the additional balancing options. Due to the high VRE share, conventional power generation is highly intermittent and mostly determined by the residual load. It is highest in the evening hours and periods with low wind power availability. The effect of additional balancing options can be clearly seen: the conventional peak power is reduced from 34 GW to 21 GW, and the generation profile features a higher regularity. In the

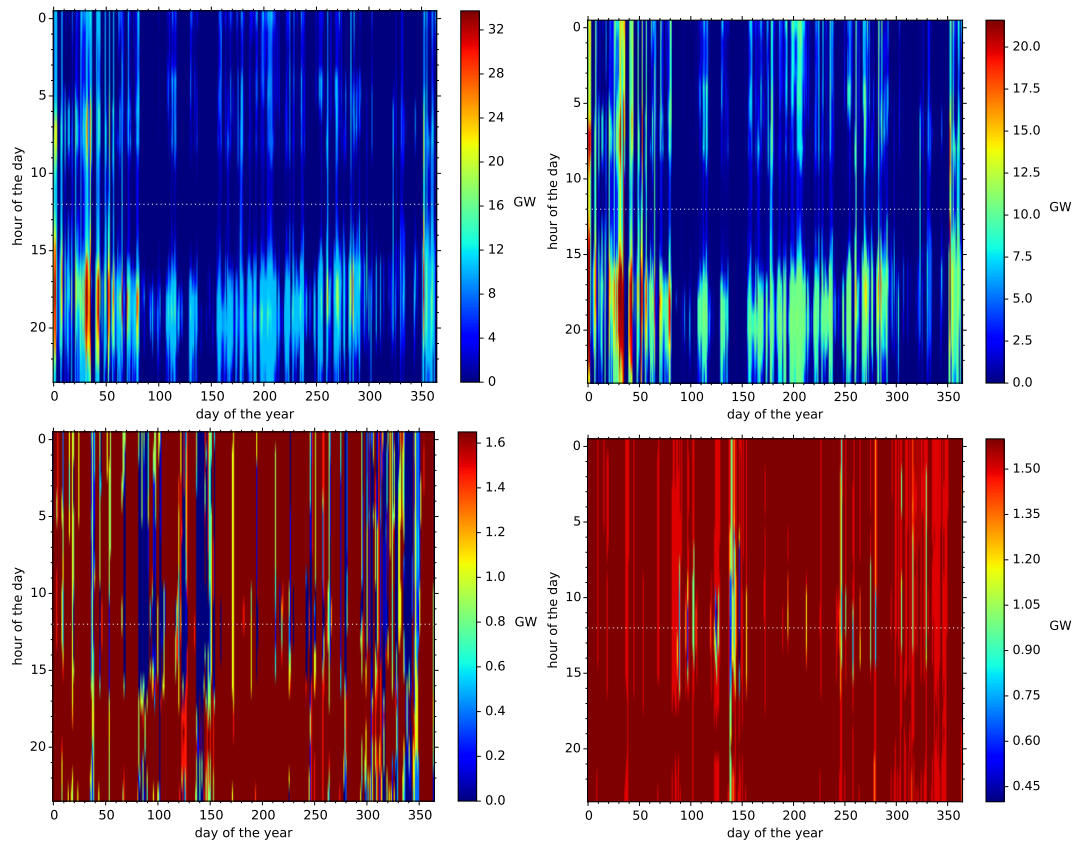


Figure 5.71 Conventional (above) and biomass (below) power generation in Germany in the system without (left) and with (right) electric load shifting and power-controlled heat supply, scenario 50Base.

right Figure, periods of up to 50 days without almost any conventional power generation can be identified. In contrast to conventional power plants, for CHP systems a higher peak generation is found in the more flexible system. It results from the partial substitution of GT capacity by a greater CHP dimensioning (see Figure 5.67). Load shifting and power-controlled heat supply also serve the purpose of a more continuous biomass power plant operation (Figure 5.71). The frequent up and down-regulation are almost completely eliminated.

5.6 Summary and Discussion

The REMix application presented in this chapter provides insight into potential benefits and limitations of electric load shifting and power-controlled heat supply, as well as their impact on other system components, such as power generation and storage. Furthermore, possible system cost reductions and CO₂ emission mitigation measures are derived. The applied model allows for an assessment of the hourly operation of all system components. Like this, interactions between technologies can be studied in detail.

Power Transmission, Back-up Capacity Demand and Curtailment in Europe (Step 1)

The REMix results confirm the high importance of long distance power transmission in supply systems with high VRE share. Generally, electricity exchange is increasing with VRE power

generation share and available grid infrastructure. The grid extension scenario indicates possible efficiency improvements in power plant operation, as well as reductions in curtailment and costs that can be realized by a strengthening of power transmission capacities. Increases in cross-border interconnections compared to the currently available and planned capacity are particularly high for France (+18 GW), Germany (+17 GW) and Switzerland (+11 GW). Within Germany, the grid extension is found comparatively small, which is not surprising given the already very high transmission capacity provided exogenously by the scenario. The importance of inter-regional transmission grids is underlined by the observation that across all scenarios for the year 2050, between 10% and 23% of the annual power production is transferred from one region to another.

Under the scenario assumptions applied in this work, the DC lines within Germany are mostly used for power transport from northern Germany to all other regions, but also from the southern regions to its direct neighbors in the north. This is consistent with the political goal of taking advantage of the comparatively high resource availability for solar PV in southern Germany on the one hand, and for offshore and onshore wind in northern Germany on the other. The high utilization of DC power transmission underlines the vital importance of a grid extension within Germany. It reaches greatest values for power export from southeastern and northern to eastern Germany. Temporal variations in intensity and direction of power flows are clearly correlated to VRE generation.

The exogenously provided scenario capacities of power plants are not sufficient for the coverage of residual peak demands. If no additional flexibility in terms of DR and power-controlled heat supply is available, all over Europe the deficit sums up to more than 110 GW in the 2050 scenarios without CSP import and hydrogen production for the transport sector. Between 21 GW and 24 GW of the demand for additional capacity are located in Germany. A partial substitution of offshore wind power in Germany by PV or onshore wind causes an increase in capacity demand. The model results show that hydrogen storage can provide firm capacity to the same degree as gas turbines, whereas this is not the case for additional transmission grid lines. The net transfer capacity increase to neighboring countries is by approximately factor six higher than the corresponding reduction in capacity demand. The much lower capacity demand found in the earlier scenario years, as well as in the scenarios with hydrogen production for the transport sector and CSP import cannot be directly compared, given that they are based on a completely different power plant structure. It can however be concluded that the corresponding scenarios better reflect the capacity needs identified in this work. Nonetheless, it is confirmed that an import of adjustable renewable power from Northern Africa via CSP-HVDC systems significantly reduces the required power plant capacity. Due to the flexibility and much higher annual FLH of CSP, on European level 81 GW of CSP-HVDC systems can substitute 73 GW of conventional power and 209 GW of VRE capacity.

The high VRE supply share assumed in the scenarios for the year 2050 comes along with substantial amounts of curtailed energy, reaching between 10 TWh and 39 TWh in Germany and between 26 TWh and 104 TWh in the overall assessment area. Curtailments are par-

ticularly high in the scenarios with increased onshore wind generation or additional VRE capacities required for the supply of hydrogen fuel production. On the contrary, a more regionally balanced distribution of power generation in Germany with a higher PV share can reduce surpluses. Much more substantial impacts are found for long-term hydrogen storage application, transmission grid expansion, as well as the substitution of VRE generation by adjustable solar power import. Endogenous installation of hydrogen storage converter capacity is concentrated to regions with high wind power generation. It allows for substantial reductions in curtailments, however at the expense of an increase in overall system losses. In contrast to that, losses are decreased by the installation of additional transmission capacity.

Application of DR and Controlled EV Charging in Germany (Step 2a/3a)

In the considered scenarios, a DR capacity between 10 GW and 33 GW is accessed, equivalent to 11% and 37% of the annual German peak load, respectively. Due to the temporal variability of usage patterns of the corresponding consumers, the load available for reduction or increase in each hour is, however, much lower. The exploitation of DR potentials is strongly dependent on VRE supply share, other available balancing options and applied costs. Comparing the scenarios, highest influence on DR is found for the supply structure on the one hand, and flexible hydrogen production for the transport sector on the other. The DR capacity installation is particularly high in the scenario with additional PV generation, and decreased by the availability of additional storage and grid, as well as lower VRE supply shares.

The development of DR potentials is mostly limited to industrial and commercial loads. The only exception are storage space and water heaters, which combine a comparatively intense utilization in winter with high electric capacities. Even under the consideration of much lower DR investment and operation costs, residential washing and cooling appliances are not used for DR. This arises from their low operation hours, high specific investment costs, as well as the assumed DR participation factors. Nonetheless, variations in DR costs have a high impact on the exploitation of DR potentials. A doubling in investment costs eliminates almost all non-industrial DR application, whereas a halving enables a much broader usage of heating, ventilation and cooling applications for DR. Longer shifting and intervention times have comparatively low impact on the exploitation of DR potentials, and high impact on the overall shifted and shedded energy. The contrary effect is found for additional potentials and less restrictions in temporal availability; both variations especially favor the peak load reduction achieved by industrial DR, which partially substitutes other DR technologies.

DR measures are not applied for advancing or postponing great amounts of energy. In the considered scenarios, the overall shifted and shedded energy does not exceed 2 TWh or 0.4% of the annual demand. By massive cost reductions, this value can be increased to 5 TWh. DR utilization is higher (> 1 TWh) in scenarios with high VRE share and limited availability of alternative balancing options within the regions. In contrast, DR is almost not applied (< 0.2 TWh) when flexible hydrogen production, or adjustable CSP imports are considered. Particularly high load shifting activity is realized in the scenario with increased PV share. DR

is preferably used for reducing the demand in morning and evening hours, at the expense of a higher demand during midday and in the night. Seasonal variations in DR activities indicate a higher utilization of the available DR loads in winter. This is related to seasonal course of the residual load after the consideration of power transmission, which features highest peaks at winter evenings with low wind power availability.

The DR impact on generation capacity requirements and VRE curtailment suggests that it is mostly applied for the purpose of residual load reduction, and not for achieving a higher VRE integration. DR reduces the residual peak load and thus the demand for firm generation capacity by between 1.0 GW and 4.8 GW. In contrast and due to the limited duration between charging and discharging of the functional storage provided by DR, VRE curtailments can be cut only to a very limited extent of less than 0.2 TWh.

The regional distribution of DR development, application and thus impact is highly unbalanced, and clearly correlated to the demand for additional generation capacity. In regions where otherwise an installation of power plant or storage capacity would be needed, DR is employed for peak demand shaving. On the contrary, it is applied much less in regions with sufficient generation capacity. This indicates a strong interrelation between DR utilization and the regional power plant capacities exogenously provided by the scenario. In the considered scenarios, load shifting measures are mostly concentrated to the regions Germany *East*, *West* and *Central*. Exceptions arise from a different allocation of power generation and curtailment caused by additional grid, storage or PV panels. Across all scenarios and variations, the maximum residual load reduction reaches 0.5 GW in Germany *North*, 0.8 GW in *Southwest*, 0.9 GW in *Southeast*, 1.3 GW in *Central*, 1.9 GW in *East* and 4.1 GW in *West*.

Load flexibility is not only provided by DR, but also by electric vehicles. In the REMix case study, the load shifting realized by controlled EV charging exceeds that of other DR consumers by far, and accounts for up to 8 TWh in the year 2050. Taking into account the annual EV electricity demand and the considered charging control availability, around 20% of the theoretical load shifting potential is tapped. The maximum residual peak load reduction realized by controlled EV charging reaches almost 12 GW, which is equivalent to around 60% of the EV charging peak demand. Such as DR, controlled EV charging is used to higher extent in the scenarios with no alternative balancing technologies, and is particularly high if the PV supply share is increased.

Controlled EV charging is favored by the simplified model representation, as well as the negligence of investment costs. Nonetheless, the results underline the importance of an EV charging control mechanism at higher VRE and EV penetration rates. The fact that other load shifting potentials are exploited in spite of the high flexibility of EV charging indicates the need for a broad range of balancing options. The substantial amount of postponed EV energy demand significantly contributes to cost reductions in the operation of adjustable power generation capacities, especially biomass power plants. The sensitivity studies show that other DR cannot substitute EV charging control.

Load shifting activities of DR and EV enable annual supply cost reductions by between 0.02 and 0.68 billion euro in Germany. These reductions result from the substitution of power plant capacity on the one hand, and a higher integration of VRE and thus lower fuel demand on the other. Specific cost reduction accounts for 0.02 to 0.07 €/kWh of shifted or shedded energy. Figure 5.72 summarizes the load shifting impact on curtailment, capacity demand and costs.

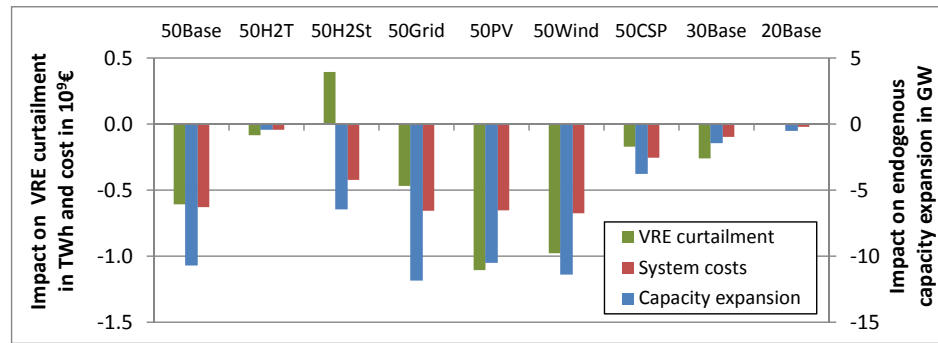


Figure 5.72 Summary of the load shifting impact on curtailment, capacity demand and costs. The increase in curtailment found in scenario *50H₂St* results from a substitution of hydrogen storage capacity by load shifting and gas turbines (see Section 5.5.2).

Application of Power-Controlled Heat Supply in Germany (Step 2b/3b)

The model results show that substantial capacities of TES and electric boilers are installed in HP and CHP supply systems if they are available as investment option. The installation of TES is clearly correlated to the VRE share in Germany. In the scenarios for the year 2050, the overall capacity reaches between 147 and 281 GWh, whereas in the earlier scenario years 2030 and 2020 only 68 GWh and 27 GWh are built, respectively. TES installation is only to a very limited extent affected by the availability of hydrogen fuel production, hydrogen storage, as well as grid extension.

The installation of electric boilers in CHP supply reaches between 5 and 15 GW in the scenarios for the year 2050, 5 GW in 2030 and 2 GW in 2020. Compared to TES, it is to a higher degree influenced by VRE supply structure and availability of alternative balancing options in 2050; it is lowest in the scenarios with CSP import and increased transmission grid capacity, and highest in the scenarios with additional PV and onshore wind power generation. Both TES and electric boiler capacity expansion are correlated to the wind power supply share: they are particularly high in the scenario with increased onshore wind application and always concentrated to the wind power regions of northern and eastern Germany.

Relating the TES capacity to the corresponding thermal peak load, it appears that on average over all scenarios and regions, highest storage installation is found for industrial CHP. It reaches approximately six hours of the annual peak load. For DH-CHP, the TES size does not vary much between different technologies and annual heat demand: it mostly ranges between two and four hours of peak load, with slightly higher values for natural gas-fired engine CHP and extraction CCGT. Much smaller specific capacities are installed in building heat supply. In both building CHP and HP systems, it reaches between 0.5 and 1.5 hours of

the annual peak demand. Differences in specific TES sizes are mostly related to the higher costs assumed for smaller units, as well as the more regular heat demand profile of industrial consumers. To a lower extent, they are furthermore affected by fuel, electricity-to-heat ratio and operational degrees of freedom of the corresponding CHP units. TES tend to be greater in combination with technologies relying on fossil fuels, having a high electricity-to-heat-ratio and flexible heat extraction, and smaller for renewable CHP, low electricity-to-heat ratios and strict backpressure operation. The parameter variations show that the TES capacity is to a much higher degree dependent on the applied investment costs than the annual heat input.

According to the REMix results, between 1% and 12% of the annual heat production is stored, corresponding to an overall TES energy input between 5 TWh and 17 TWh. Except for the scenario with hydrogen storage availability, it is always higher than that of electricity-to-electricity storage technologies. This underlines the contribution of TES and CHP flexibility to the balancing of VRE fluctuations. The ratio of energy input to storage capacity ranges between 40 and 240. In the scenarios for the year 2050, greatest use is made of TES in building CHP supply, smallest of those in large DH systems and industrial heat supply, reaching averages of 150 cycles and 75 cycles, respectively. The electric boiler capacity is used for the production of between 3 TWh and 10 TWh of heat. It is particularly high in the scenario with increased wind power generation, and lowest in the scenarios with additional grid capacity and CSP imports. The annual capacity utilization of TES is not clearly correlated to regional RE supply structures. It is found at a comparable level throughout all regions. In contrast to that, the application of electric boilers is particularly high in the regions dominated by onshore and offshore wind generation.

The availability of supplementary heat supply technologies and TES eliminates the must-run behavior of CHP and allows for an adjustment of operation to power demand and VRE generation. Its down-regulation in times of favorable weather conditions increases the VRE integration. This of course goes along with a lower overall CHP power generation and capacity utilization, as well as a lower CHP share in the corresponding heat supply. Depending on scenario and technology, up to 30% of the heat originate from other sources than CHP. Additional reductions in VRE curtailment can be achieved by the usage of electric heating in CHP supply systems. Increased heat production flexibility proves to be a very effective measure for the reduction of VRE curtailment in Germany. The amount of wasted electricity is cut by up to three quarters or 21 TWh (see Figure 5.73). Furthermore, power-controlled operation of CHP and HP reduces the demand for additional power generation capacity by up to 3.6 GW. This reduction arises from two effects: in heat supply systems relying on extraction CHP units, TES and peak boilers enable a higher CHP power output by substituting the associated decrease in heat production. On the other hand, the availability of TES in HP systems allows for a lowering of the power demand, as far as the heat can be supplied from the storage.

Increased CHP flexibility not only contributes to a better VRE integration, but also to an optimized power plant operation. In the considered scenarios, this mostly applies to biomass

and coal-fired stations, which can significantly increase their annual FLH, and reduce their ramping cycles and shutdowns. Optimized power plant operation, reduced capacity demand and higher VRE integration achieved by power-controlled heat supply enable a reduction in system costs by up to 1.5 billion euro (see Figure 5.73). This is equivalent to specific values of 0.03 to 0.09 €/kWh of stored heat or 0.03 to 0.23 €/kWh of electric boiler heat.

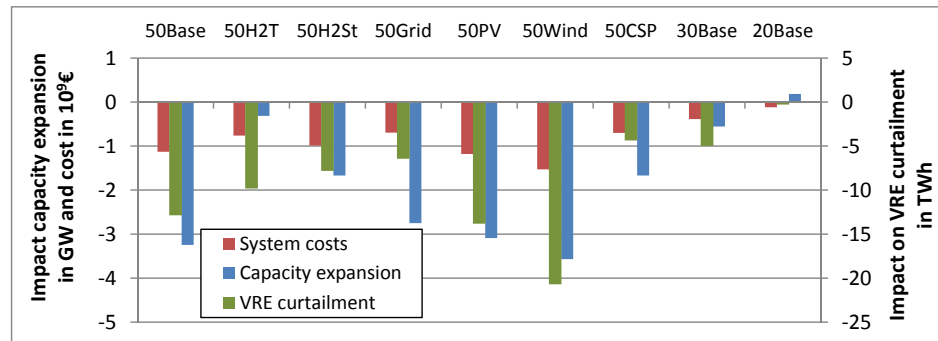


Figure 5.73 Summary of heat supply enhancement impact on curtailment, capacity demand and costs.

Interaction and Impact of Load Shifting and Power-Controlled Heat Supply in Germany (Step 4)

Depending on the scenario and technology, power-controlled heat supply can have either an increasing or decreasing impact on electric load shifting. In most scenarios, the DR utilization is reduced, whereas the application of controlled EV charging is enhanced. Considering both options, changes in overall shifted and shedded energy range between -25% and +17% compared to the model runs with heat-controlled CHP and HP operation. With exception of the scenario for the year 2030, the maximum load reduction achieved by load shifting is enhanced by power-controlled heat supply. The REMix output furthermore reveals that the availability of electric load shifting triggers minor reductions in the utilization of TES and electric boilers. However, the negative impact does not exceed 2.6% of the stored heat and 2.1% of the electric boiler heat obtained in the system without electric load flexibility.

The decreasing effect of both load shifting and additional heat supply flexibility on the demand for firm capacity cannot be added up: the combined impact is by 10% to 45% lower than the sum of the separate impacts. The overall reduction in capacity demand achieved by the additional balancing options accounts for up to 13 GW in the scenarios with high VRE share and limited grid and electricity-to-electricity storage availability. Concerning the integration of VRE generation, electric load shifting and optimized heat supply promote each other. The combined impact is found to be at least as high as the sum of the separate impact, and exceeds it by up to 14%. VRE curtailments in Germany can be reduced by up to 22 TWh, which is equivalent to more than 55% of the value determined in the system without load shifting and power-controlled heat supply. Nonetheless, substantial amounts of VRE power remain unused. This suggests that the demand for load balancing cannot be completely covered by the technologies considered in this work. Both residual peak load reduction and

VRE integration are much lower in the earlier scenario years and the scenario with flexible hydrogen production, accounting for less than 1.5 GW and 0.3 TWh, respectively.

Electric load shifting and TES provide cheaper or more efficient storage function than the considered electricity-to-electricity storage technologies: the annual energy input to pumped hydro storage is reduced by up to 8 TWh or almost 60%, compared to the simulations without the additional balancing technologies. Hydrogen storage is affected to a lower, but still significant extent (-6 TWh, 40%). As for curtailment, load shifting and power-controlled heat supply promote each other in the substitution of electricity-to-electricity storage utilization.

By enhancing VRE integration, additional balancing technologies can have a dampening effect on fuel consumption and thus CO₂ emissions. On the other hand, they may allow for a fuel switch to more carbon-containing fuels in the conventional power sector. Furthermore, an increase in emissions may also result from a higher boiler utilization in CHP supply. Even though an increase in coal power plant output triggered by additional flexibility is determined throughout all scenarios, the overall CO₂ emissions are reduced in most cases. Exceptions are formed by the scenarios for 2020 and 2030. Resulting CO₂ emission reductions account for up to 5.3 million tons in the year 2050, equivalent to 7.6% of the overall emissions in the considered part of the energy system.

Technology Comparison of the Annual Balancing Power and Energy

The REMix simulations allow for a comparison of the different balancing options considered in this work. They include adjustable conventional and renewable power plants, electric and thermal energy storage, transmission grids, demand response, controlled EV charging and flexible hydrogen fuel production. The following results are focused on the application of these technologies in Germany and the scenarios for the year 2050, including the variations of the reference scenario. Comparing the overall annual energy provided, it appears that the transmission grid is the dominating balancing option. Electricity transfer over region borders within Germany or to neighboring countries not associated to a net import or export accounts for between 125 TWh and 160 TWh. Due to its annual electricity demand of 100 TWh and assumed flexible operation, hydrogen electrolysis provides comparable quantities of balancing energy. Smaller contributions to load balancing come from adjustable renewable (40 TWh to 80 TWh) and conventional (25 TWh to 50 TWh) power plants. The annual energy input into thermal energy storage amounts to between 8 TWh and 17 TWh. Making use of the technology-specific electricity-to-heat ratios and COP, it can be calculated that this thermal energy is equivalent to up to approximately 11 TWh of electrical energy. Around 95% of it is used for flexible CHP power generation, the remaining 5% for adjusted HP operation. The annual energy input into electricity-to-electricity storages aggregates to between 2 TWh and 7 TWh if only pumped hydro storage is available, and 14 TWh if hydrogen storage can be used as well. Electric boilers in CHP systems have a flexible electricity demand of up to 10 TWh. Finally, the annual load shifting and shedding of controlled EV charging and DR reach 1.3 TWh to 9.5 TWh, and 0.1 TWh to 1.6 TWh, respectively.

Concerning the provision of negative or positive balancing power, a different technology ranking emerges. Hydrogen production for the transport sector turns out to be the most important technology: it offers 36 GW of highly flexible demand. Instead, the balancing power provided by electricity transmission, conventional power plants and CHP accounts for up to 29 GW, 27 GW and 24 GW, respectively. Lower contributions are found for the remaining technologies: peak power generation of adjustable RE adds up to 12 GW in the scenario with CSP imports, and 5 GW in all other scenarios. The converter capacity of electricity-to-electricity storage reaches almost 13 GW in the scenario with endogenous hydrogen storage installation, and amounts to 6.5 GW if only pumped hydro storage is used. Electric load shifting enables load reductions and increases by up to 12 GW for controlled EV charging and 5 GW for other DR. Electric boilers in CHP supply absorb up to 13 GW of surplus power generation, whereas peak charging and discharging of TES sums up to approximately 10 GW.

Reflection on the Scenario Input and Approach

In order to reflect a broad range of possible future supply structures, nine scenarios have been taken into account in this study. They are consistent with the political goal of a mostly renewable supply of power, heat and transport. The scenario input concerning power and heat demand and supply structure, as well as grid and electricity-to-electricity storage capacities significantly affects the utilization of the balancing technologies analyzed in this REMix application. This limits the reliability of the results to the scenario space assessed in this work. The technological and geographical distribution of power generation capacities in the scenario causes the development of structural export and import regions. Net power flows are mostly directed southwards, and run from *Northern Europe*, Germany and the *British Isles* towards its southern neighbors. Only exception is the CSP import scenario, which transforms almost all regions to net importers.

Especially the exogenously defined scenarios for the year 2050 do not provide sufficient firm supply capacity, leading to substantial amounts of additionally installed generation units as endogenous simulation result. This general tendency of an underestimation of power plant capacity in the input scenario parametrization can be related to specific characteristics of the exogenously provided framework scenarios, as well as the approach used in the REMix application. The underlying scenario for Europe does explicitly not account for CHP generation. It is thus presumed that all thermal power plants can provide their maximum power output at any time of the year. In contrast to that, the strictly heat-controlled CHP operation considered in REMix implies that heat must be provided by CHP whenever there is a demand, reducing the available power output of extraction CHP units. On the other hand, in the development of the framework scenario for Germany the availability of additional balancing options – including but not limited to DR and power-controlled operation CHP – has already been taken into account. This implies that the power plant capacity provided by the scenario might be sufficient in a system not disposing of all balancing options, as it is considered in this work.

The approach applied in this work tends to underestimate the application of load shifting and power-controlled heat supply. This is on the one hand related to the considered scenario, and on the other to the stepwise approach, which tends to favor the electricity transmission grid over other balancing options. The stepwise approach already implies a hierarchy of balancing options. Fluctuations in VRE availability are preferably balanced by transmission grids and adjustable conventional or renewable power plants. In contrast, small scale balancing options such as DR and flexible operation of CHP and HP are implicitly assumed to be mainly driven by regional circumstances. From the privileged consideration of power transmission especially arises that the PV peak power generation in Germany is almost completely absorbed by the grid to its neighboring countries, thus decreasing the application of other technologies. In this assessment, the stepwise approach has been chosen in order to facilitate a very high geographical and technological detail. Subsequent works will have to take a closer look on the interaction between grid utilization on the one hand, and load and heat supply flexibility on the other. Additionally, in some German regions the installed power plant capacities provided by the scenario tend to be too high. It follows that the development of DR potentials does not compete with the installation of additional capacities, but with the utilization of available power stations. Given the high investment costs of DR compared to the variable power generation costs, load shifting is not accessed. Due to the deficits arising from the procedure of this case study, it can be expected that the potential contribution of DR to system stability is higher than quantified here.

Major model approximations concerning power balancing include the representation of conventional and CHP power plants on the one hand, and AC power grids on the other. Both the conventional and CHP power plant model take into account neither restrictions in the ramping velocity nor a minimum load. Consequently, the flexibility of power generation is overestimated, which reduces the demand for other balancing technologies. In its current set-up, REMix does also not account for the provision of reserve capacity. This implies that in reality, additional generation capacity might be needed. Furthermore, the simplified EV model representation tends to cause an overestimation of the load shifting potential. It does not take into account different driving cycles and EV technologies, nor a potentially required minimum battery state of charge and weekday variations in charging demand. For a complementary discussion of REMix-OptiMo, see Section 4.7.

The case study is based on numerous assumptions and premises concerning the structural development of the energy system, as well as technical and economic technology characteristics. Nonetheless, the results of the scenario assessment allows for a number of first conclusions concerning the potential load balancing by DR and power-controlled heat supply. They are summarized in the subsequent Chapter 6.

Chapter 6

Key Results, Concluding Remarks and Outlook

In this work, the potential contribution of flexible electric loads and power-controlled operation of combined heat and power (CHP) plants with thermal energy storage (TES) to the balancing of power generation fluctuations of variable renewable energies (VRE) is assessed. It relies on an enhancement and application of the REMix energy system model, which is designed for the preparation and assessment of future energy supply scenarios based on a system representation in high spatial and temporal resolution.

The energy data analysis tool REMix-EnDAT is extended by a calculation method for demand response (DR) potentials, methodologies for the quantification of potentials for district heating (DH) and industrial CHP, as well as an improved representation of heat demand profiles. The evaluation of theoretical DR potentials in Europe reveals substantial amounts of flexible loads throughout all countries and consumer sectors. It is shown that potential load reduction and increase exhibit substantial variations during the year. Even though they rely on numerous assumptions and approximations concerning technological characteristics, spatial allocation and load profiles of flexible consumers, the results offer an indication where high amounts of sheddable and shiftable loads can be accessed. In order to improve the data basis on DR potentials, future research will have to particularly draw upon a more detailed and comprehensive database of country and technology-specific parameters and load profiles.

The results of the spatially explicit approach applied in the assessment of DH suggest that more than half of Europe's residential and commercial space and water heating demand can be supplied by DH. Expansion potentials are particularly high in Germany, France, Italy as well as the UK, and available also under the assumption of substantial heat demand reductions. To which amount the identified potential can be exploited in an economic way, requires further research. Special attention will need to be given to a more detailed assessment of heat distribution costs and a higher spatial resolution in the allocation of heat demands. In this context also the use of DH for cooling purposes needs to be evaluated.

According to the analysis of industrial energy utilization, around half of Europe's industrial heat demand at temperatures below 500°C can be provided by on-site CHP production. Additionally, CHP heat might be provided by the connection of industrial consumers to DH networks. Given that the quantification of CHP potentials relies on influential assumptions concerning the distribution of the final energy consumption to different applications and heat temperatures, follow-up research will have to focus on a more profound evaluation of energy usage in industrial production processes, as well as its characteristic differences between countries. To evaluate the connection of industrial consumers to DH networks, further attention will have to be given to a more detailed spatial allocation of demands.

In order to enable economic assessments of the balancing function of DR and power-controlled heat supply, the linear optimization model REMix-OptiMo has been enhanced by flexible electric loads on the one hand, and the heating sector on the other. The extended model has proven to realistically reflect load shifting and shedding mechanisms of electric load flexibility, as well as the operation of complex heat supply systems. The case study presented in this work demonstrates the model's capability to answer questions regarding the opportunities and restrictions of electric load balancing by DR and power-controlled heat supply. Making use of the survey of potentials, the calculated power and heat demand profiles, as well as the enhanced REMix-OptiMo model, the hourly operation of DR and flexible CHP is assessed for Germany. Based on the model development and data preparation carried out in this work, comparable assessments can be made for any other European country. Due to the strong dependency on generation, storage and grid infrastructure, it can be expected that operation pattern different to those in Germany are present. Additionally, the comprehensive implementation of the heating sector opens up a broad range of new model applications, which are not fully exploited in this work. Future studies may include the development and evaluation of heat supply scenarios, assessments of the competition of different technologies for a specific heat market segment, as well as follow-up examinations of the sector coupling between power, heat and transportation from a macroeconomic perspective.

The scenarios considered in this work reflect an European energy system transformation, in which nuclear power is phased-out, fossil fuel power generation is drastically reduced and variable renewable energies become the major pillar of electricity supply. The corresponding heat supply scenario envisions an increased market penetration of public and industrial CHP relying on renewable energies and natural gas, as well as electric heat pumps (HP).

The model simulations reveal that the application of DR is mostly limited to short time peak shaving of the residual load. This implies that the focus of DR is on the provision of power, not energy, which is also reflected by the comparatively low utilization during the year. Against this background, the development of further potentials particularly in industry, where investment costs are comparatively low and application costs high, appears attractive. This is underlined by the result that the peak load reduction enabled by DR is much less sensitive to changes in the DR cost structure than the amount of shifted or shedded energy. Even at higher

costs, the usage of industrial DR is economically beneficial compared to the installation of additional generation capacity. The model endogenous exploitation of available DR potentials is attributed almost exclusively to industrial and commercial sector loads, whereas those in the residential sector are hardly accessed. The very limited application of residential DR is related to the comparatively high development costs and low utilization of residential appliances. The REMix results suggest that an economic installation of smart meter technologies requires additional revenues than those arising from trans-regional load balancing. They may for example originate from payments for the provision of ancillary services, a reduced need for distribution grid reinforcements or savings in billing costs. Whether and to what extent residential DR is economically competitive does not only depend on economic, but also on social parameters, particularly the participation in DR measures. In industry, the cost of load shifting and shedding is closely connected to external factors such as the wholesale electricity price, as well as the current market situation of the corresponding manufacturing product. These aspects must be considered in detail in future research on DR.

In the REMix assessment, DR utilization is found to reflect fluctuations of the residual peak load. DR measures are preferably taken on winter days with low wind power availability, and applied for reducing morning and evening peak demands, at the expense of a higher demand during midday and in the night. The temporal variations in DR application highlight the particular importance of load profiles in the assessment of DR potentials. Based on the results of this work, requirements concerning the temporal availability of further consumers with load flexibility can be derived.

The functional storage size provided by DR is not only limited by the available potential, but also by the maximum duration of load interventions, as well as the need to balance most of the load change within a given shift time. With estimated intervention and shift times between one and 48 hours, the field of application of the considered DR consumers is restricted to the balancing of short-term fluctuations. The model results show a correlation between DR activity and the regional or scenario-specific PV supply share. This indicates that the temporal availability of DR potentials, as well as their characteristic intervention and shifting times are especially suited for a combination with PV power generation. In an increasingly decentralized power supply system, DR may not only contribute to load balancing on national or regional level, but also to distribution grid stability. By adjusting domestic power demands to PV generation, the peak capacity of distribution grids can in principle be reduced. Given that spatial and temporal resolution of REMix are designed for the assessment of greater areas, such analysis is beyond the model's current capabilities and scope of this work. Nevertheless it needs to be addressed in further research works in order to better understand the potential contribution of DR to energy system transformations.

Power-controlled heat supply is proven to be a powerful measure for a higher VRE integration. It is achieved by a modified operation pattern of CHP and – to a lower extent – HP on the one hand, and an utilization of surplus VRE power generation for heating purposes on the other.

By the provision of thermal energy storage and alternative heat producers, CHP units are down-regulated in times of high VRE availability, and up-regulated in times of high residual load. TES are mostly used in spring and autumn, which are characterized by particularly high fluctuations in wind power generation on the one hand, and a heat demand close to the applied CHP and HP dimensioning on the other. The utilization of electric heating in CHP supply systems is concentrated to regions with high wind power penetration, and goes along with a comparatively great TES dimensioning. It can be concluded that an enhanced coupling between power and heat sector is particularly attractive in combination with the utilization of wind power. This is in line with the approach adopted by the Danish government.

Consideration of TES and electric boilers has significant impact on the heat supply structure in CHP systems. The annual CHP heat output is reduced at the expense of a higher boiler utilization, but still provides the predominant part of the demand. Thermal storages in both CHP and HP supply are mostly used for short-term and medium-term balancing in the range of some hours to a few days. According to the REMix results, an application of TES is particularly attractive in industrial heat supply, where demands typically follow a more regular profile. In this work, the assessment of electric heating and TES utilization has been focused on low-temperature heat demands. Given the available potentials, an extension to high temperature process heat appears attractive. This implies the consideration of different storage technologies, including phase-change materials and thermochemical storage. The implementation of TES in industrial heat supply needs to be assessed further, taking into account specific requirements concerning heat temperature and demand profile, as well as charging and discharging behavior.

Load flexibility across all sectors provides substantial amounts of positive balancing power, which can substitute other firm generation capacity. In the scenarios, highest load reduction is achieved by controlled electric vehicle (EV) charging, with considerably lower contributions from adjusted HP operation and other DR. The maximum load change by DR is found to be much lower than the overall electric capacity of shiftable loads, which again underlines the central importance of the consideration of load profiles in the evaluation of DR. Concerning the impact of DR on power system stability, the shape of load and VRE generation profiles deserves special attention in future research. In order to study the effect of different weather and demand situations, the assessment of load balancing needs to be extended to other profiles, which can include both historical and synthetic data.

The analysis clearly shows that both electric load shifting (including DR and controlled EV charging) and power-controlled heat supply (including CHP and HP) can contribute to the future load balancing. Its application is, however, strongly dependent on the scenario assumptions concerning VRE supply and alternative balancing options. They play a particularly important role in the scenarios with highest VRE share and limited availability of electricity-to-electricity storage, grid, as well as adjustable power generation and demand. Flexible hydrogen fuel production for the transport sector, grid extension and adjustable solar power

import have a decreasing impact of varying degree on the application of load shifting and power-controlled heat supply. It is highest for the flexible hydrogen electrolysis, which substitutes almost all other load shifting activities, and reduces the TES heat input by half. Similar but less pronounced effects are found for solar power imports. The high impact particularly on DR is at least partially caused by the model input data: in the scenarios evaluating hydrogen fuel production and CSP imports comparatively high power plant capacities are present, which tends to limit the exploitation of DR potentials. In contrast to that, power transmission grid expansion within Germany and from Germany to its neighbors cuts DR and EV load shifting only marginally, and even increases their combined maximum peak load reduction. TES utilization is almost not influenced by the availability of additional transmission lines as well. The load balancing options in the focus of this work are used to a much lesser extent in the scenarios with lower VRE share. Even though load shifting and power-controlled heat supply enable a much higher VRE integration, substantial curtailments remain in the scenarios without flexible hydrogen production and CSP import. Their potential utilization deserves further research, which has to include additional energy storage application, extended electric heating, as well as the flexible production of synthetic fuels.

Based on the REMix results it can be concluded that electric load shifting and power-controlled heat supply are not competing but complementary measures in the realization of higher VRE integration and lower back-up capacity demand. Negative interferences between both balancing options are found to be very small. On the contrary, they even promote each other, for example in the reduction in VRE curtailments. This indicates that electric load shifting and power-controlled heat supply are only to limited extent competing for the same market segments.

Electric load shifting and power-controlled heat supply are mostly applied for short-term and medium-term load balancing. This implies that they are particularly competing with peak load power plants and electricity-to-electricity storage technologies. According to the REMix results, the annual utilization of pumped hydro storage capacities is drastically reduced by the alternative balancing options, which operate at lower costs and/or higher efficiency. The function of pumped hydro storage is increasingly restricted to peak shaving of residual load, thus the provision of power, not energy. Hydrogen storage is affected to a lesser degree, as it is mostly used for medium-term or long-term storage, which cannot, or only to a limited extent, be provided by load shifting and TES. Due to its particular focus on flexible electric and thermal loads, the consideration of electricity-to-electricity storage is comparatively limited in this work. Future studies will have to gain insight into the potential application of other storage technologies, as well as their interaction with competing balancing options.

As a consequence of higher VRE integration, load shifting and power-controlled heat supply can contribute substantially to the reduction of CO₂ emissions in Germany. However, this is only the case if the additional balancing potentials are not applied as well for a shift in generation from low-emitting to high-emitting fossil power plants. Furthermore, the additional

balancing options can enable energy supply cost reductions, arising from the substitution of back-up power plant capacity on the one hand, and a more cost-efficient power and heat supply on the other. The latter includes a higher VRE integration into the power and heat sector, as well as a fuel switch to cheaper power generation units.

The scenario study presented in this work provides a first approximate economic assessment of the potential balancing of VRE power generation by load shifting and power-controlled heat supply in Germany. It must be complemented by further and more detailed studies. This includes the development and evaluation of business cases for load flexibility and adjusted CHP operation on the one hand, and potential incentive mechanisms on the other.

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Assessment of Demand Response Potentials: Input and Detailed Results

[illegible]

Table A.2 Hourly load variations of DR consumers, relative to peak – summer.

Day	Consumer / Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Working Days	Res./Com. cool.	80%	80%	80%	80%	80%	80%	89%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	89%	80%
	Washing	0%	0%	0%	0%	0%	0%	12%	56%	78%	88%	100%	84%	78%	56%	50%	56%	56%	66%	34%	66%	62%	22%	0%	0%
	Drying	0%	0%	0%	0%	0%	0%	8%	25%	42%	67%	75%	67%	59%	100%	67%	33%	17%	25%	59%	42%	8%	17%	17%	8%
	Dishwasher	1%	2%	0%	0%	0%	0%	33%	30%	33%	17%	57%	27%	33%	67%	100%	67%	50%	33%	50%	100%	83%	33%	17%	3%
	Cold storage	85%	90%	100%	100%	100%	85%	70%	50%	50%	50%	50%	55%	55%	60%	65%	70%	75%	70%	60%	60%	80%	95%	95%	95%
	Com. vent.	50%	50%	50%	50%	50%	70%	90%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	90%	80%	70%	50%	50%	50%	50%
	Cement	100%	100%	100%	100%	100%	100%	95%	85%	75%	70%	66%	66%	66%	75%	75%	75%	66%	70%	85%	95%	100%	100%	100%	100%
	Ind. cool.	85%	90%	100%	100%	100%	85%	70%	50%	50%	50%	50%	55%	55%	60%	65%	70%	75%	70%	60%	60%	80%	95%	95%	95%
	Ind. vent.	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Water supply	100%	100%	100%	100%	100%	100%	100%	67%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	67%	100%	100%	100%
Saturday	Res./Com. cool.	80%	80%	80%	80%	80%	80%	89%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	89%	80%
	Washing	0%	0%	0%	0%	0%	0%	6%	13%	69%	94%	100%	87%	100%	75%	56%	44%	37%	37%	31%	31%	37%	19%	6%	3%
	Drying	0%	0%	0%	0%	0%	0%	0%	0%	34%	34%	17%	50%	100%	83%	50%	50%	17%	50%	17%	50%	83%	34%	27%	7%
	Dishwasher	0%	0%	0%	0%	0%	0%	0%	3%	10%	36%	70%	66%	34%	66%	100%	60%	34%	34%	27%	34%	43%	40%	23%	7%
	Cold storage	85%	90%	100%	100%	100%	85%	70%	50%	50%	50%	50%	55%	55%	60%	65%	70%	75%	70%	60%	60%	80%	95%	95%	95%
	Com. vent.	50%	50%	50%	50%	50%	70%	90%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	90%	80%	70%	50%	50%	50%	50%
	Cement	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Ind. cool.	85%	90%	100%	100%	100%	85%	70%	50%	50%	50%	50%	55%	55%	60%	65%	70%	75%	70%	60%	60%	80%	95%	95%	95%
	Ind. vent.	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Water supply	100%	100%	100%	100%	100%	100%	100%	67%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	67%	100%	100%	100%
Sunday	Res./Com. cool.	80%	80%	80%	80%	80%	80%	89%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	89%	80%
	Washing	0%	0%	0%	0%	0%	0%	3%	15%	20%	48%	89%	100%	89%	54%	57%	52%	36%	36%	50%	54%	54%	36%	18%	6%
	Drying	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	25%	60%	100%	50%	15%	5%	20%	100%	90%	85%	60%	90%	15%	5%
	Dishwasher	13%	0%	0%	0%	0%	0%	13%	5%	27%	37%	75%	62%	50%	75%	100%	50%	50%	75%	80%	37%	45%	62%	37%	17%
	Cold storage	85%	90%	100%	100%	100%	85%	70%	50%	50%	50%	50%	55%	55%	60%	65%	70%	75%	70%	60%	60%	80%	95%	95%	95%
	Com. vent.	50%	50%	50%	50%	50%	70%	90%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	90%	80%	70%	50%	50%	50%	50%
	Cement	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Ind. cool.	85%	90%	100%	100%	100%	85%	70%	50%	50%	50%	50%	55%	55%	60%	65%	70%	75%	70%	60%	60%	80%	95%	95%	95%
	Ind. vent.	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Water supply	100%	100%	100%	100%	100%	100%	100%	67%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	67%	100%	100%	100%

Table A.3 Hourly load variations of DR consumers, relative to peak – winter.

Day	Consumer / Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Working days	Res./Com. cool.	80%	80%	80%	80%	80%	80%	89%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	89%	80%
	Washing	0%	0%	0%	0%	0%	0%	8%	28%	60%	100%	96%	72%	72%	56%	48%	44%	40%	32%	32%	36%	24%	23%	8%	2%
	Drying	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	17%	13%	27%	43%	100%	33%	3%	3%	10%	13%	20%	50%	43%	33%
	Dishwasher	4%	2%	0%	0%	0%	0%	2%	17%	41%	37%	25%	41%	37%	37%	63%	83%	41%	21%	37%	63%	100%	63%	37%	11%
	Cold storage	85%	90%	100%	100%	100%	85%	70%	50%	50%	50%	50%	55%	55%	60%	65%	70%	75%	70%	60%	60%	80%	95%	95%	95%
	Com. vent.	50%	50%	50%	50%	50%	70%	90%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	90%	80%	70%	50%	50%	50%	50%
	Cement	100%	100%	100%	100%	100%	100%	95%	85%	75%	70%	66%	66%	66%	75%	75%	75%	66%	70%	85%	95%	100%	100%	100%	100%
	Ind. cool.	85%	90%	100%	100%	100%	85%	70%	50%	50%	50%	50%	55%	55%	60%	65%	70%	75%	70%	60%	60%	80%	95%	95%	95%
	Ind. vent.	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Water supply	100%	100%	100%	100%	100%	100%	100%	67%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	67%	100%	100%	100%
Saturday	Res./Com. cool.	80%	80%	80%	80%	80%	80%	89%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	89%	80%
	Washing	0%	0%	0%	0%	0%	0%	8%	20%	38%	69%	100%	100%	69%	62%	62%	58%	38%	34%	34%	34%	30%	16%	8%	3%
	Drying	0%	0%	0%	3%	3%	0%	0%	25%	7%	3%	13%	13%	20%	30%	75%	100%	25%	50%	45%	13%	6%	4%	3%	3%
	Dishwasher	10%	20%	20%	0%	0%	0%	20%	20%	29%	50%	79%	79%	70%	70%	100%	86%	40%	60%	29%	20%	29%	29%	20%	10%
	Cold storage	85%	90%	100%	100%	100%	85%	70%	50%	50%	50%	50%	55%	55%	60%	65%	70%	75%	70%	60%	60%	80%	95%	95%	95%
	Com. vent.	50%	50%	50%	50%	50%	70%	90%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	90%	80%	70%	50%	50%	50%	50%
	Cement	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Ind. cool.	85%	90%	100%	100%	100%	85%	70%	50%	50%	50%	50%	55%	55%	60%	65%	70%	75%	70%	60%	60%	80%	95%	95%	95%
	Ind. vent.	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Water supply	100%	100%	100%	100%	100%	100%	100%	67%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	67%	100%	100%	100%
Sunday	Res./Com. cool.	80%	80%	80%	80%	80%	80%	89%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	89%	80%
	Washing	0%	0%	0%	0%	0%	0%	0%	6%	15%	50%	100%	100%	88%	75%	69%	56%	44%	50%	62%	56%	38%	19%	15%	10%
	Drying	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	25%	20%	88%	88%	100%	50%	45%	45%	30%	25%	18%	30%	75%	45%
	Dishwasher	0%	3%	12%	6%	3%	3%	10%	3%	3%	23%	59%	59%	71%	35%	100%	59%	47%	35%	29%	23%	29%	18%	12%	6%
	Cold storage	85%	90%	100%	100%	100%	85%	70%	50%	50%	50%	50%	55%	55%	60%	65%	70%	75%	70%	60%	60%	80%	95%	95%	95%
	Com. vent.	50%	50%	50%	50%	50%	70%	90%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	90%	80%	70%	50%	50%	50%	50%
	Cement	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Ind. cool.	85%	90%	100%	100%	100%	85%	70%	50%	50%	50%	50%	55%	55%	60%	65%	70%	75%	70%	60%	60%	80%	95%	95%	95%
	Ind. vent.	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	Water supply	100%	100%	100%	100%	100%	100%	100%	67%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	67%	100%	100%	100%

A.2 Country-specific Input and Results

Table A.4 Annual air conditioning and heat circulation pump full load hours.

Country	n_{CDD}	n_{HDD}	n_{FLH}^{AC}				n_{FLH}^{CP}			
			2010	2020	2030	2050	2010	2020	2030	2050
	K/a	K/a	h/a	h/a	h/a	h/a	h/a	h/a	h/a	h/a
Austria	173	3469	237	244	253	276	4970	4965	4960	4904
Belgium	102	2771	232	244	256	282	4944	4943	4941	4899
Bulgaria	430	2648	361	384	400	425	4261	4255	4252	4247
Croatia	418	2561	440	456	472	504	4266	4262	4262	4226
Cyprus	1091	762	991	1009	1027	1063	3773	3767	3728	3492
Czech Republic	108	3517	262	272	282	305	4621	4619	4617	4606
Denmark	40	3438	203	218	233	269	5097	5096	5100	5078
Estonia	38	4393	136	147	158	184	4420	4420	4425	4421
Finland	48	5252	100	100	100	100	4851	4847	4842	4841
France	241	2475	336	347	362	398	4921	4918	4905	4831
Germany	122	3178	275	287	300	329	4873	4877	4873	4842
Greece	923	1531	626	641	658	694	4107	4103	4087	3971
Hungary	256	2888	419	436	453	487	4315	4313	4313	4296
Ireland	19	2876	100	100	100	100	5804	5797	5787	5660
Italy	600	2120	584	604	620	650	4679	4676	4656	4556
Latvia	58	4220	153	163	174	198	4323	4323	4325	4320
Liechtenstein	137	3207	148	158	168	190	5559	5562	5561	5555
Lithuania	68	4048	193	204	215	240	4271	4271	4270	4271
Luxembourg	99	3164	222	233	245	269	5117	5115	5113	5074
Malta	1043	543	928	951	974	1021	3652	3644	3606	3272
Netherlands	68	2851	267	281	296	327	4948	4948	4944	4907
Norway	43	5202	100	100	100	100	5953	5956	5946	5886
Poland	100	3562	304	315	328	354	4234	4233	4230	4228
Portugal	345	1152	467	486	508	556	4401	4396	4372	4180
Romania	290	3040	403	419	433	462	4298	4298	4293	4279
Slovakia	158	3305	319	330	342	367	4596	4595	4596	4574
Slovenia	189	3024	341	352	364	389	4602	4601	4602	4584
Spain	702	1784	614	611	634	706	4478	4470	4446	4328
Sweden	45	4630	186	197	210	240	5308	5314	5312	5288
Switzerland	137	3411	243	253	263	285	5617	5618	5605	5519
UK	66	2954	148	157	168	193	5483	5479	5470	5389

Table A.5 Scenarios of population, household number and tertiary sector electricity demand.

Country	Population				Households				Tertiary demand			
	2010	2020	2030	2050	2010	2020	2030	2050	2010	2020	2030	2050
	Mio.	Mio.	Mio.	Mio.	Mio.	Mio.	Mio.	Mio.	TWh/a	TWh/a	TWh/a	TWh/a
Austria	8.39	8.59	8.85	8.97	3.66	3.88	4.06	4.20	12.13	11.89	12.26	9.57
Belgium	10.90	11.59	12.20	13.13	4.74	5.27	5.81	6.78	22.18	26.10	27.90	21.99
Bulgaria	7.53	7.12	6.61	5.90	2.90	2.85	2.75	2.67	8.10	7.22	8.24	8.67
Croatia	4.42	4.32	4.18	3.83	1.61	1.64	1.66	1.65	5.27	5.21	6.60	7.74
Cyprus	0.80	0.89	0.97	1.09	0.29	0.35	0.42	0.51	2.26	2.13	2.46	2.28
Czech Rep.	10.52	10.82	10.84	10.67	4.38	4.70	4.82	5.05	13.99	12.36	12.99	11.52
Denmark	5.55	5.72	5.89	6.04	2.64	2.72	2.95	3.28	10.77	14.84	16.43	16.56
Estonia	1.34	1.32	1.28	1.21	0.61	0.63	0.61	0.63	2.54	2.79	3.51	3.64
Finland	5.36	5.58	5.70	5.73	2.55	2.79	3.00	3.14	17.83	17.83	18.68	17.22
France	62.96	67.82	70.30	73.18	27.37	30.83	33.48	36.29	145.44	161.97	173.81	143.07
Germany	81.60	80.50	79.10	73.80	39.80	40.66	41.20	39.68	136.17	146.46	150.86	131.83
Greece	11.31	11.53	11.58	11.58	4.19	4.61	4.82	5.23	18.00	19.26	22.10	21.39
Hungary	10.00	9.90	9.70	9.18	4.35	4.50	4.62	4.74	11.36	11.49	13.31	13.83
Ireland	4.47	4.81	5.28	6.21	1.60	1.78	2.11	2.69	9.18	12.45	14.42	13.38
Italy	60.48	62.88	64.49	65.92	27.49	29.94	30.71	34.06	85.62	105.52	115.93	99.57
Latvia	2.24	2.14	2.02	1.80	0.90	0.89	0.88	0.85	2.42	3.72	4.60	4.42
Liechtenstein	0.036	0.038	0.040	0.039	0.015	0.016	0.017	0.018	0.06	0.05	0.06	0.06
Lithuania	3.29	3.18	3.04	2.81	1.26	1.27	1.27	1.27	2.84	3.39	4.36	4.47
Luxembourg	0.51	0.57	0.63	0.70	0.21	0.25	0.28	0.35	1.96	2.58	2.89	2.96
Malta	0.42	0.42	0.42	0.40	0.16	0.17	0.19	0.20	0.63	1.02	1.13	0.92
Netherlands	16.62	17.22	17.58	17.36	7.55	8.20	8.37	8.79	34.96	39.62	42.26	36.62
Norway	4.89	5.38	5.79	6.37	2.17	2.44	2.68	3.06	28.77	32.60	34.23	30.93
Poland	38.18	38.40	37.56	34.54	14.19	14.88	15.27	15.24	43.58	49.32	62.39	73.66
Portugal	10.64	10.73	10.78	10.60	4.09	4.29	4.69	5.00	16.40	16.32	18.97	20.01
Romania	21.44	21.01	20.25	18.48	7.94	8.08	8.10	8.02	7.58	9.21	13.51	20.19
Slovakia	5.43	5.58	5.58	5.33	2.73	3.06	3.19	3.23	8.01	9.09	10.56	10.92
Slovenia	2.05	2.14	2.15	2.11	0.76	0.82	0.83	0.88	3.09	2.97	3.15	2.58
Spain	46.07	47.96	49.96	52.69	17.06	19.18	20.82	23.82	83.89	96.95	115.49	117.56
Sweden	9.38	10.07	10.58	11.23	4.71	5.39	5.84	6.46	32.75	38.83	41.71	40.97
Switzerland	7.83	8.51	8.94	9.31	3.61	4.09	4.43	4.83	17.72	17.00	16.34	10.79
UK	62.23	66.29	70.21	76.41	27.06	30.13	33.43	39.48	97.34	125.93	137.59	126.65

Table A.6 Residential appliance equipment rates: AC – air conditioning, CP – heat circulation pump, RF – refrigerator, FR – freezer, WM – washing machine, TD – tumble dryer, DW – dish washer, WH – storage water heater, SH – storage space heater.

Country	2010									2050								
	f_{eq}^{FR} %	f_{eq}^{RF} %	f_{eq}^{WM} %	f_{eq}^{TD} %	f_{eq}^{DW} %	f_{eq}^{AC} %	f_{eq}^{WH} %	f_{eq}^{CP} %	f_{eq}^{SH} %	f_{eq}^{FR} %	f_{eq}^{RF} %	f_{eq}^{WM} %	f_{eq}^{TD} %	f_{eq}^{DW} %	f_{eq}^{AC} %	f_{eq}^{WH} %	f_{eq}^{CP} %	f_{eq}^{SH} %
Austria	85%	98%	94%	34%	70%	1%	35%	60%	5%	80%	100%	97%	50%	75%	10%	20%	80%	1%
Belgium	62%	114%	89%	60%	55%	2%	26%	60%	5%	80%	100%	97%	50%	75%	10%	15%	80%	1%
Bulgaria	55%	97%	80%	0%	4%	14%	20%	45%	5%	70%	100%	97%	40%	75%	25%	15%	80%	1%
Croatia	67%	98%	92%	6%	20%	28%	20%	35%	3%	70%	100%	97%	30%	75%	60%	15%	75%	1%
Cyprus	40%	100%	95%	10%	30%	60%	25%	35%	5%	80%	100%	97%	25%	75%	60%	10%	70%	1%
Czech Rep.	40%	90%	80%	20%	20%	2%	23%	60%	5%	80%	100%	97%	50%	75%	10%	15%	80%	1%
Denmark	79%	147%	91%	63%	70%	0%	21%	55%	5%	90%	100%	97%	70%	75%	3%	10%	80%	1%
Estonia	40%	99%	89%	20%	10%	2%	25%	60%	5%	80%	100%	97%	50%	75%	10%	15%	80%	1%
Finland	60%	97%	95%	20%	65%	0%	46%	55%	20%	90%	100%	97%	70%	75%	3%	20%	80%	1%
France	86%	100%	94%	31%	49%	5%	44%	60%	5%	80%	100%	97%	50%	75%	10%	25%	80%	1%
Germany	68%	113%	86%	39%	64%	2%	11%	60%	4%	80%	100%	97%	50%	75%	10%	5%	80%	1%
Greece	12%	115%	93%	6%	40%	70%	75%	35%	5%	80%	100%	97%	25%	75%	80%	30%	70%	1%
Hungary	67%	88%	99%	1%	9%	3%	35%	60%	5%	80%	100%	97%	50%	75%	10%	20%	80%	1%
Ireland	35%	100%	95%	62%	50%	0%	9%	60%	8%	70%	100%	97%	70%	75%	3%	10%	60%	1%
Italy	34%	99%	97%	10%	45%	25%	34%	35%	5%	80%	100%	97%	25%	75%	60%	20%	70%	1%
Latvia	7%	96%	83%	2%	5%	1%	40%	60%	5%	80%	100%	97%	50%	75%	10%	25%	80%	1%
Liechtenst.	60%	100%	95%	40%	50%	2%	15%	60%	5%	80%	100%	97%	50%	75%	10%	5%	80%	1%
Lithuania	25%	95%	85%	20%	20%	2%	32%	60%	5%	80%	100%	97%	50%	75%	10%	20%	80%	1%
Luxemb.	60%	100%	95%	40%	50%	2%	15%	60%	5%	80%	100%	97%	50%	75%	10%	7%	80%	1%
Malta	66%	100%	97%	45%	43%	60%	25%	35%	5%	80%	100%	97%	25%	75%	95%	10%	70%	1%
Netherl.	55%	98%	99%	68%	55%	4%	9%	60%	5%	80%	100%	97%	50%	75%	10%	5%	80%	1%
Norway	93%	98%	92%	46%	75%	0%	18%	55%	30%	90%	100%	97%	70%	75%	3%	15%	80%	1%
Poland	40%	90%	80%	20%	20%	2%	29%	60%	5%	80%	100%	97%	50%	75%	10%	15%	80%	1%
Portugal	67%	100%	96%	24%	40%	3%	18%	35%	5%	80%	100%	97%	25%	75%	60%	10%	70%	1%
Romania	30%	95%	80%	2%	5%	1%	20%	45%	5%	70%	100%	97%	40%	75%	25%	15%	80%	1%
Slovakia	38%	102%	69%	20%	20%	1%	23%	60%	5%	80%	100%	97%	50%	75%	10%	15%	80%	1%
Slovenia	81%	98%	98%	45%	51%	15%	50%	60%	5%	80%	100%	97%	50%	75%	60%	25%	80%	1%
Spain	45%	100%	99%	5%	45%	45%	36%	35%	5%	80%	100%	97%	25%	75%	60%	15%	70%	1%
Sweden	98%	100%	76%	50%	68%	0%	14%	55%	20%	90%	100%	97%	70%	75%	3%	10%	80%	1%
Switzerl.	60%	100%	95%	40%	50%	2%	5%	60%	5%	80%	100%	97%	50%	75%	10%	5%	80%	1%
UK	46%	106%	96%	58%	39%	0%	24%	60%	8%	70%	100%	97%	70%	75%	3%	15%	60%	1%

Table A.7 Industrial DR potential – energy demands in GWh/a on country level.

Country	Aluminum				Copper				Zinc				Steel				Chlorine				Pulp			
	2010	2020	2030	2050	2010	2020	2030	2050	2010	2020	2030	2050	2010	2020	2030	2050	2010	2020	2030	2050	2010	2020	2030	2050
	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh
Austria	0	0	0	0	39	38	37	35	0	0	0	0	402	506	625	849	147	137	128	111	735	711	694	660
Belgium	0	0	0	0	190	185	180	172	918	893	871	828	1344	1694	2091	2841	2707	2310	1913	1662	306	296	289	274
Bulgaria	0	0	0	0	76	74	72	68	221	215	210	199	735	927	1143	1554	260	243	226	197	0	0	0	0
Croatia	0	0	0	0	0	0	0	0	0	0	0	0	307	387	478	649	0	0	0	0	88	85	83	79
Cyprus	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Czech Rep.	0	0	0	0	0	0	0	0	0	0	0	0	564	711	878	1193	627	492	358	311	161	156	152	145
Denmark	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Estonia	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	227	220	215	204
Finland	0	0	0	0	54	53	52	49	884	860	839	798	1470	1853	2287	3108	286	248	210	182	8732	8452	8243	7841
France	5614	5028	4548	3722	16	15	15	14	748	728	710	675	3583	4517	5574	7575	4101	3434	2767	2405	10948	10598	10336	9831
Germany	8778	7861	7112	5820	249	242	236	225	510	496	484	460	8152	10277	12681	17233	11889	10622	9356	8131	2730	2643	2577	2451
Greece	2310	2069	1871	1531	0	0	0	0	0	0	0	0	3780	4765	5880	7991	178	148	117	102	0	0	0	0
Hungary	0	0	0	0	0	0	0	0	0	0	0	0	263	331	408	555	755	643	531	462	0	0	0	0
Ireland	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	19	18	16	14	0	0	0	0
Italy	2716	2432	2200	1801	37	36	35	34	748	728	710	675	10343	13039	16088	21864	853	777	701	609	625	605	590	561
Latvia	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Liechtenstein	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2	2	2
Lithuania	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Luxembourg	0	0	0	0	0	0	0	0	0	0	0	0	1502	1893	2336	3174	0	0	0	0	0	0	0	0
Malta	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Netherlands	1400	1254	1134	928	0	0	0	0	884	860	839	798	87	109	135	183	1745	1631	1517	1318	212	205	200	190
Norway	16478	14757	13350	10924	0	0	0	0	510	496	484	460	315	397	490	666	662	618	575	500	2762	2673	2607	2480
Poland	700	627	567	464	189	184	180	171	248	241	235	224	2363	2978	3675	4994	987	869	752	654	123	119	116	110
Portugal	0	0	0	0	0	0	0	0	0	0	0	0	945	1191	1470	1998	206	232	259	225	0	0	0	0
Romania	3780	3385	3062	2506	14	14	13	13	0	0	0	0	2231	2813	3471	4717	1040	883	726	631	58	56	55	52
Slovakia	2310	2069	1871	1531	11	10	10	9	0	0	0	0	315	397	490	666	243	191	139	121	0	0	0	0
Slovenia	1190	1066	964	789	0	0	0	0	0	0	0	0	369	465	573	779	34	31	29	25	94	91	89	84
Spain	5614	5028	4548	3722	141	137	134	127	1326	1290	1258	1197	7665	9663	11923	16203	2304	1831	1358	1180	180	174	170	162
Sweden	1554	1392	1259	1030	84	82	80	76	0	0	0	0	945	1191	1470	1998	384	302	219	190	6885	6665	6500	6182
Switzerland	0	0	0	0	0	0	0	0	0	0	0	0	693	874	1078	1465	86	68	49	43	253	245	239	227
UK	574	514	465	381	0	0	0	0	0	0	0	0	1391	1754	2164	2941	1741	1495	1248	1085	495	479	467	444

Table A.8 Industrial DR potential – energy demands in GWh/a on country level.

Country	Paper				Recyc. paper				Cement				CaC ₂				Air separation				Ind. cooling				Ind. ventil.			
	2010	2020	2030	2050	2010	2020	2030	2050	2010	2020	2030	2050	2010	2020	2030	2050	2010	2020	2030	2050	2010	2020	2030	2050	2010	2020	2030	2050
Austria	481	666	773	1041	2455	2848	3069	3562	619	583	555	502	124	107	94	73	205	209	213	222	477	477	477	477	253	253	253	253
Belgium	717	993	1152	1552	896	1039	1120	1300	1128	1062	1010	913	0	0	0	0	437	446	455	473	1200	1200	1200	1200	278	278	278	278
Bulgaria	25	35	40	54	209	242	261	303	704	663	630	570	0	0	0	0	10	10	11	11	345	345	345	345	90	90	90	90
Croatia	0	0	0	0	257	299	322	373	538	506	482	436	0	0	0	0	21	21	22	23	176	176	176	176	44	44	44	44
Cyprus	7	10	12	16	0	0	0	0	199	187	178	161	0	0	0	0	3	3	3	3	53	53	53	53	7	7	7	7
Czech Rep.	146	202	235	316	483	560	604	701	726	684	650	588	0	0	0	0	76	77	79	82	443	443	443	443	422	422	422	422
Denmark	376	520	604	813	200	232	249	290	297	280	266	241	0	0	0	0	171	175	178	185	612	612	612	612	139	139	139	139
Estonia	17	24	28	37	34	39	42	49	111	105	99	90	0	0	0	0	4	4	4	4	85	85	85	85	28	28	28	28
Finland	230	319	370	498	6769	7853	8461	9820	134	126	120	109	0	0	0	0	95	96	98	102	518	518	518	518	193	193	193	193
France	1858	2572	2985	4020	4661	5408	5826	6762	2984	2810	2672	2417	0	0	0	0	1231	1256	1281	1333	5285	5285	5285	5285	1596	1596	1596	1596
Germany	4921	6811	7905	10647	10942	12696	13677	15874	4620	4350	4138	3743	620	533	470	366	2674	2728	2782	2895	4823	4823	4823	4823	2574	2574	2574	2574
Greece	60	83	96	129	193	224	241	280	2195	2066	1965	1778	0	0	0	0	93	95	97	101	603	603	603	603	163	163	163	163
Hungary	127	176	204	275	261	302	326	378	506	476	453	410	0	0	0	0	44	45	46	48	339	339	339	339	109	109	109	109
Ireland	143	198	230	310	24	27	30	34	220	207	197	178	0	0	0	0	796	812	828	862	430	430	430	430	100	100	100	100
Italy	1744	2414	2801	3773	4775	5540	5969	6927	5917	5571	5299	4793	0	0	0	0	862	879	897	933	3464	3464	3464	3464	1647	1647	1647	1647
Latvia	25	35	40	54	28	33	35	41	43	40	38	35	0	0	0	0	4	4	4	4	94	94	94	94	25	25	25	25
Liechtenstein	0	0	1	1	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lithuania	30	41	48	64	59	68	73	85	151	142	135	123	0	0	0	0	11	12	12	12	0	0	0	0	0	0	0	0
Luxembourg	20	28	32	43	0	0	0	0	160	150	143	129	0	0	0	0	8	8	8	8	38	38	38	38	78	78	78	78
Malta	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	5	6	6	19	19	19	19	9	9	9	9
Netherlands	721	998	1158	1560	1522	1766	1903	2209	684	644	613	554	0	0	0	0	622	635	647	674	1846	1846	1846	1846	328	328	328	328
Norway	144	200	232	312	949	1101	1186	1377	237	223	212	192	0	0	0	0	39	39	40	42	776	776	776	776	151	151	151	151
Poland	484	670	778	1048	1413	1639	1766	2050	2173	2046	1946	1761	0	0	0	0	172	176	179	187	1366	1366	1366	1366	418	418	418	418
Portugal	233	322	374	503	776	901	970	1126	1320	1243	1182	1069	0	0	0	0	58	60	61	63	480	480	480	480	217	217	217	217
Romania	92	128	148	199	264	306	329	382	2438	2295	2183	1975	0	0	0	0	26	26	27	28	455	455	455	455	253	253	253	253
Slovakia	80	111	129	174	432	501	540	627	517	487	463	419	341	293	259	201	21	22	22	23	148	148	148	148	152	152	152	152
Slovenia	47	65	75	101	375	435	469	544	187	176	167	151	0	0	0	0	39	40	40	42	79	79	79	79	63	63	63	63
Spain	1774	2456	2850	3839	3171	3679	3963	4599	5787	5449	5183	4688	124	107	94	73	556	567	579	602	3291	3291	3291	3291	1057	1057	1057	1057
Sweden	499	691	802	1080	5620	6521	7025	8153	374	352	335	303	155	133	118	91	392	400	408	425	675	675	675	675	331	331	331	331
Switzerland	414	573	665	895	726	842	907	1053	550	518	493	446	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UK	2693	3727	4326	5826	2495	2895	3119	3620	1639	1543	1468	1328	0	0	0	0	1265	1290	1316	1369	3146	3146	3146	3146	1342	1342	1342	1342

Table A.9 Average theoretical load reduction potential 2010 in MW.

Country	Aluminum	Copper	Zinc	Chlorine	Pulp	Paper	Recyc. Paper	Steel	Cement	CaC2	Air separation	Ind. cooling	Ind. ventil.	Retail cooling	Cold storage	Gastro. cooling	Com. ventil.	Com. AC	Com. stor. water	Com. stor. heat.	Water supply	Water treatment	Res. refrig.	Res. washing	Res. drying	Dish washer	Res. AC	Res. stor. water	Res. stor. heat	Res. circ. pumps
Austria	0	1	0	7	67	46	44	46	57	2	4	27	14	90	12	18	175	14	21	0	41	8	268	86	44	79	1	73	190	124
Belgium	0	3	22	131	28	17	65	153	103	0	8	68	16	164	22	33	320	25	38	0	76	15	333	105	100	80	4	63	189	160
Bulgaria	0	1	5	13	0	4	2	84	64	0	0	20	5	60	8	12	117	37	14	0	27	5	176	58	0	3	27	30	116	64
Croatia	0	0	0	0	8	5	0	35	49	0	0	10	3	39	5	8	76	24	9	0	18	4	106	37	3	10	37	17	39	28
Cyprus	0	0	0	0	0	0	1	0	18	0	0	3	0	17	2	3	33	31	4	0	8	2	16	7	1	3	32	3	5	4
Czech Rep.	0	0	0	30	15	9	13	64	66	0	1	25	24	104	14	21	202	16	24	0	48	10	228	88	31	27	3	56	228	139
Denmark	0	0	0	0	0	4	34	0	27	0	3	35	8	80	11	16	155	6	18	0	37	7	239	60	58	57	0	32	137	85
Estonia	0	0	0	0	21	1	2	0	10	0	0	5	2	19	3	4	37	1	4	0	9	2	34	14	4	2	0	10	39	18
Finland	0	1	21	14	797	126	21	168	12	0	2	30	11	132	18	26	257	10	31	0	61	12	160	61	18	51	0	74	653	78
France	135	0	18	198	1000	87	170	409	272	0	24	302	91	1078	144	216	2095	332	249	830	498	100	2032	644	293	418	87	619	1094	922
Germany	211	5	12	575	249	204	449	931	422	12	51	275	147	779	104	156	1962	249	113	311	466	93	2885	854	543	791	32	250	1654	1330
Greece	56	0	0	9	0	4	5	432	200	0	2	34	9	133	18	27	259	205	31	0	62	12	213	98	9	52	346	143	117	69
Hungary	0	0	0	37	0	5	12	30	46	0	1	19	6	84	11	17	164	26	19	0	39	8	269	108	2	12	10	78	174	129
Ireland	0	0	0	1	0	0	13	0	20	0	15	25	6	68	9	14	132	5	16	0	32	6	86	38	35	25	0	7	102	64
Italy	65	1	18	41	57	89	159	1181	540	0	17	198	94	635	85	127	1233	684	147	0	293	59	1461	667	96	378	756	473	1098	515
Latvia	0	0	0	0	0	1	2	0	4	0	0	5	1	18	2	4	35	1	4	0	8	2	37	19	0	1	0	22	57	27
Liechtenst.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	1	0	0	0	0	0	1	1
Lithuania	0	0	0	0	0	1	3	0	14	0	0	0	0	21	3	4	41	2	5	0	10	2	61	27	9	8	1	25	81	37
Luxemb.	0	0	0	0	0	0	2	171	15	0	0	2	4	15	2	3	28	1	3	0	7	1	14	5	3	3	0	2	11	7
Malta	0	0	0	0	0	0	0	0	0	0	0	1	1	5	1	1	9	9	1	0	2	0	11	4	3	2	17	2	3	2
Netherl.	34	0	21	84	19	28	66	10	62	0	12	105	19	259	35	52	504	20	60	0	120	24	462	186	180	128	14	35	302	256
Norway	396	0	12	32	252	18	13	36	22	0	1	44	9	213	28	43	414	16	49	0	98	20	166	50	35	50	0	25	833	81
Poland	17	3	6	48	11	26	44	270	198	0	3	78	24	323	43	65	628	50	75	0	150	30	737	284	99	88	12	231	737	412
Portugal	0	0	0	10	0	14	21	108	121	0	1	27	12	122	16	24	236	56	28	0	56	11	272	98	35	50	10	33	114	72
Romania	91	0	0	50	5	5	8	255	223	0	0	26	14	56	7	11	109	17	13	0	26	5	397	159	6	12	6	91	412	175
Slovakia	56	0	0	12	0	8	7	36	47	7	0	8	9	59	8	12	115	9	14	0	27	5	152	47	19	17	1	36	142	86
Slovenia	29	0	0	2	9	7	4	42	17	0	1	4	4	23	3	5	44	4	5	0	10	2	54	19	12	12	7	22	39	24
Spain	135	3	32	111	16	59	162	875	529	2	11	188	60	622	83	124	1209	814	144	0	288	58	989	422	30	237	888	280	477	304
Sweden	37	2	0	19	629	105	46	108	34	3	8	39	19	243	32	49	472	19	56	0	112	22	373	90	82	99	0	41	1205	157
Switzerl.	0	0	0	4	23	14	38	79	50	0	0	0	0	131	18	26	255	20	30	0	61	12	231	86	50	56	3	10	187	139
UK	14	0	0	84	45	46	246	159	150	0	24	180	77	722	96	144	1402	56	167	0	333	67	1645	649	549	326	2	334	1730	1016

Table A.10 Average theoretical load increase potential 2010 in MW.

Country	Pulp	Paper	Recyc. paper	Cement	CaC2	Air separation	Ind. cooling	Ind. ventil.	Retail cooling	Cold storage	Gastro. cooling	Com. ventil.	Com. AC	Com. stor. water	Com. stor. heat.	Water supply	Water treatment	Res. refrig.	Res. washing	Res. drying	Dish washer	Res. AC	Res. stor. water	Res. stor. heat	Res. circ. pumps
Austria	17	28	11	14	3	5	25	7	45	9	13	175	498	707	0	41	11	336	2498	1837	1585	47	2488	2371	96
Belgium	7	10	16	26	0	10	63	8	82	16	25	320	931	1441	0	76	21	417	3050	4171	1604	152	2400	3127	124
Bulgaria	0	2	1	16	0	0	18	3	30	6	9	117	861	526	0	27	7	220	1681	8	68	619	1129	1913	67
Croatia	2	3	0	12	0	0	9	1	20	4	6	76	455	342	0	18	5	133	1077	142	200	696	629	639	29
Cyprus	0	0	0	5	0	0	3	0	8	2	3	33	242	190	0	8	2	20	198	42	53	252	141	196	6
Czech Republic	4	6	3	17	0	2	23	12	52	10	16	202	518	815	0	48	13	285	2542	1284	543	105	1916	2841	124
Denmark	0	2	9	7	0	4	32	4	40	8	12	155	259	628	0	37	10	300	1742	2428	1144	11	1078	1712	61
Estonia	5	0	0	3	0	0	4	1	9	2	3	37	92	134	0	9	2	42	393	178	38	15	295	387	18
Finland	199	77	5	3	0	2	27	6	66	13	20	257	881	942	0	61	16	201	1759	748	1028	10	2276	6498	63
France	250	53	42	68	0	28	280	46	539	108	162	2095	8325	9447	13713	498	134	2545	18689	12252	8376	2172	23470	18068	720
Germany	62	125	112	105	14	61	255	73	389	78	117	1962	7674	3841	3879	466	125	3614	24770	22743	15863	985	8507	20637	1058
Greece	0	2	1	50	0	2	32	5	67	13	20	259	2670	1319	0	62	17	266	2828	362	1046	4491	6139	2814	78
Hungary	0	3	3	12	0	1	18	3	42	8	13	164	516	738	0	39	10	337	3121	64	242	205	2965	2870	132
Ireland	0	0	3	5	0	18	23	3	34	7	10	132	454	596	0	32	9	108	1104	1444	496	7	280	1688	32
Italy	14	55	40	135	0	20	183	47	317	63	95	1233	9578	5561	0	293	79	1830	19354	4028	7574	10585	17947	18146	448
Latvia	0	0	1	1	0	0	5	1	9	2	3	35	78	128	0	8	2	46	539	20	25	19	694	570	27
Liechtenstein	0	0	0	0	0	0	0	0	0	0	0	1	4	3	0	0	0	1	10	9	5	0	4	9	0
Lithuania	0	1	1	3	0	0	0	0	11	2	3	41	72	150	0	10	3	76	779	370	157	31	784	804	39
Luxembourg	0	0	0	4	0	0	2	2	7	1	2	28	43	114	0	7	2	17	145	124	65	7	62	137	5
Malta	0	0	0	0	0	0	1	0	2	0	1	9	72	53	0	2	1	13	112	106	43	142	78	109	3
Netherlands	5	17	16	16	0	14	98	9	130	26	39	504	635	2271	0	120	32	578	5393	7524	2572	453	1325	4985	197
Norway	63	11	3	5	0	1	41	4	107	21	32	414	1422	1520	0	98	26	208	1448	1463	1008	9	757	8285	39
Poland	3	16	11	50	0	4	72	12	162	32	48	628	1384	2540	0	150	40	923	8233	4159	1758	339	7860	9199	440
Portugal	0	9	5	30	0	1	25	6	61	12	18	236	997	1202	0	56	15	341	2848	1464	1006	179	1399	2749	71
Romania	1	3	2	56	0	1	24	7	28	6	8	109	359	442	0	26	7	497	4605	233	246	125	3085	5146	182
Slovakia	0	5	2	12	8	0	8	4	30	6	9	115	242	467	0	27	7	191	1364	800	338	33	1219	1768	78
Slovenia	2	4	1	4	0	1	4	2	11	2	3	44	87	180	0	10	3	68	539	500	238	180	737	492	22
Spain	4	36	41	132	3	13	174	30	311	62	93	1209	10800	6148	0	288	77	1238	12247	1250	4754	11781	12005	11467	293
Sweden	157	64	11	9	4	9	36	9	121	24	36	472	862	1730	0	112	30	467	2597	3452	1984	19	1278	11990	102
Switzerland	6	8	9	13	0	0	0	0	66	13	20	255	709	1033	0	61	16	289	2484	2113	1116	116	350	2337	78
United Kingdom	11	28	61	37	0	29	167	38	361	72	108	1402	3233	6323	0	333	90	2061	18832	22990	6533	110	12654	28574	607

Appendix B

District Heating Assessment: Input and Detailed Results

B.1 Heat Demand Scenario Input

Table B.1 Assignment of OECD and Non-OECD countries

OECD countries	Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Liechtenstein, Luxembourg, Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, UK
Non-OECD countries	Bulgaria, Croatia, Cyprus, Latvia, Lithuania, Malta, Romania

Table B.2 Scenario input building stock model – OECD countries. Within each decade, the values are interpolated linearly. The final energy demands for space heating applied to Germany are scaled with long-term average heating degree days from [59], as to consider climatic conditions.

Value	Demand sector	2010	2020	2030	2040	2050
Building retrofit rate (relative to stock)	Residential	1%	2%	2%	2%	2%
OECD Countries	Commercial					
Building retrofit rate (relative to stock)	Residential	0.75%	1%	1.25%	1.5%	2%
Non-OECD countries	Commercial					
Relative specific demand of buildings undergoing retrofit (relative to average)	Residential	1.2	1.2	1.2	1.2	1.2
	Commercial					
Demand reduction achieved by retrofit	Residential	35%	50%	50%	50%	50%
OECD countries	Commercial					
Demand reduction achieved by retrofit	Residential	20%	25%	30%	35%	45%
Non-OECD countries	Commercial					
Demolition / Reconstruction rate (relative to stock)	Residential	0.5%	0.5%	0.5%	0.5%	0.5%
	Commercial	1.5%	1.5%	1.5%	1.5%	1.5%
Final space heating energy demand in new buildings (in kWh/m ² , values for Germany)	Residential	60	15	9	7	5
	Commercial					
Relative specific demand of buildings undergoing demolition (relative to average)	Residential	1.3	1.3	1.3	1.3	1.3
	Commercial					

Table B.3 Scenario of residential useful energy demand for space and water heating.

Country	HW useful energy demand								Floor area				Specific SH demand (kWh/m ² /a)							
	kWh/cap/a				Demand share				m ² per capita				Stock				New			
	2008	2020	2030	2050	2008	2020	2030	2050	2008	2020	2030	2050	2008	2020	2030	2050	2008	2020	2030	2050
Austria	0.80	0.77	0.75	0.71	17%	18%	20%	24%	49	54	57	61	115	92	71	47	65	16	10	5
Belgium	0.92	0.90	0.88	0.83	16%	19%	21%	27%	37	41	44	47	160	120	89	55	52	13	8	4
Bulgaria	0.18	0.23	0.30	0.33	10%	12%	15%	18%	32	37	41	46	67	61	56	45	60	45	34	17
Croatia	0.41	0.43	0.44	0.46	18%	18%	18%	21%	29	36	40	45	87	75	66	52	58	44	33	16
Cyprus	0.65	0.64	0.63	0.61	42%	44%	45%	49%	61	65	66	66	25	21	19	14	17	13	10	5
Czech Republic	0.91	0.85	0.83	0.77	21%	22%	24%	29%	32	37	41	46	128	98	75	48	66	17	10	6
Denmark	0.95	0.93	0.91	0.88	14%	16%	18%	23%	59	62	63	65	122	100	80	53	65	16	10	5
Estonia	1.55	1.40	1.30	1.08	30%	30%	31%	32%	29	33	36	42	148	121	97	62	83	21	12	7
Finland	0.98	0.98	0.97	0.92	14%	16%	18%	23%	41	44	46	49	185	150	118	78	99	25	15	8
France	0.69	0.70	0.69	0.66	16%	18%	21%	27%	42	43	45	47	109	87	68	44	47	12	7	4
Germany	0.89	0.86	0.83	0.80	17%	18%	20%	24%	42	45	47	49	125	105	86	61	60	15	9	5
Greece	0.28	0.28	0.31	0.34	10%	12%	15%	21%	33	35	37	41	100	80	63	40	29	7	4	2
Hungary	1.08	1.07	1.03	0.92	26%	28%	30%	33%	32	35	38	43	119	98	77	50	55	14	8	5
Ireland	1.06	1.08	1.05	0.95	21%	25%	29%	37%	42	45	47	51	108	85	63	36	54	14	8	5
Italy	0.40	0.43	0.47	0.46	13%	16%	20%	26%	46	48	50	53	78	63	50	32	40	10	6	3
Latvia	1.10	1.15	1.11	1.00	25%	25%	24%	24%	28	34	38	43	158	136	122	97	96	72	54	27
Liechtenstein	0.79	0.77	0.75	0.71	16%	18%	20%	24%	45	48	51	54	120	94	72	48	61	15	9	5
Lithuania	0.30	0.37	0.42	0.50	11%	13%	14%	17%	25	30	34	42	112	100	89	67	92	69	52	26
Luxembourg	1.00	0.98	0.95	0.90	15%	18%	21%	28%	35	40	44	48	195	133	94	54	60	15	9	5
Malta	0.32	0.37	0.38	0.37	39%	43%	46%	49%	38	41	43	47	15	14	12	10	12	9	7	3
Netherlands	0.87	0.92	0.88	0.84	21%	24%	26%	31%	46	49	51	54	88	72	57	39	54	13	8	4
Norway	0.98	0.97	0.95	0.90	15%	17%	19%	25%	58	60	61	63	125	102	80	50	98	25	15	8
Poland	0.93	0.92	0.91	0.86	27%	28%	30%	33%	24	30	35	43	130	98	73	46	67	17	10	6
Portugal	0.49	0.48	0.49	0.51	43%	44%	47%	54%	50	55	57	60	25	21	17	11	22	5	3	2
Romania	0.46	0.45	0.47	0.47	25%	22%	22%	23%	24	30	34	41	82	72	64	49	69	52	39	19
Slovakia	0.91	0.90	0.88	0.83	28%	30%	32%	37%	30	34	37	42	101	81	63	41	62	16	9	5
Slovenia	0.89	0.88	0.86	0.82	26%	29%	31%	36%	32	34	38	44	105	83	63	39	57	14	9	5
Spain	0.85	0.90	0.87	0.79	43%	47%	50%	56%	49	54	57	60	43	35	27	17	34	8	5	3
Sweden	0.80	0.77	0.75	0.72	13%	14%	17%	22%	49	52	53	55	140	113	89	57	87	22	13	7
Switzerland	0.98	0.90	0.85	0.79	18%	19%	21%	26%	50	54	56	59	110	85	66	43	64	16	10	5
UK	1.06	1.02	0.95	0.87	24%	26%	28%	34%	39	43	45	47	109	83	64	40	56	14	8	5

Table B.4 Scenario of commercial useful energy demand for space and water heating.

Country	HW demand kWh/cap/a				Floor area Specific (m ² /cap				Floor-area specific demand Stock (kWh/m ² /a)			
	2008	2020	2030	2050	2008	2020	2030	2050	2008	2020	2030	2050
Austria	0.18	0.18	0.18	0.18	15	15	15	15	85	63	45	24
Belgium	0.17	0.17	0.17	0.18	15	15	15	16	140	95	65	33
Bulgaria	0.17	0.17	0.18	0.18	10	11	11	12	48	40	34	23
Croatia	0.17	0.17	0.18	0.19	8	9	10	12	63	49	39	25
Cyprus	0.20	0.20	0.20	0.19	11	12	13	14	23	17	13	7
Czech Republic	0.16	0.16	0.17	0.18	11	11	12	13	93	66	46	23
Denmark	0.16	0.17	0.17	0.18	21	22	22	22	100	73	53	28
Estonia	0.16	0.17	0.17	0.18	11	12	13	14	107	76	55	29
Finland	0.17	0.17	0.17	0.18	17	18	18	19	129	92	66	35
France	0.17	0.17	0.17	0.18	14	15	15	16	110	75	52	26
Germany	0.17	0.17	0.17	0.18	19	19	19	19	92	70	53	30
Greece	0.17	0.17	0.17	0.18	10	12	12	14	75	49	34	17
Hungary	0.17	0.17	0.17	0.18	11	12	13	14	85	59	42	23
Ireland	0.17	0.17	0.17	0.18	16	16	16	17	75	53	36	17
Italy	0.17	0.17	0.17	0.18	9	10	11	12	55	38	26	13
Latvia	0.17	0.17	0.18	0.18	10	11	11	13	110	89	73	49
Liechtenstein	0.18	0.18	0.18	0.18	15	15	15	15	85	60	43	23
Lithuania	0.17	0.17	0.18	0.18	10	11	12	13	80	66	56	37
Luxembourg	0.17	0.17	0.17	0.18	15	15	16	16	150	96	65	31
Malta	0.17	0.17	0.18	0.18	8	8	9	10	15	12	9	6
Netherlands	0.17	0.17	0.17	0.18	18	18	18	19	63	46	33	18
Norway	0.17	0.17	0.17	0.18	22	22	22	22	95	69	48	25
Poland	0.17	0.18	0.18	0.18	11	12	12	13	90	62	46	25
Portugal	0.18	0.18	0.18	0.18	9	10	11	13	30	22	14	7
Romania	0.06	0.08	0.10	0.15	6	7	8	10	56	45	37	24
Slovakia	0.16	0.17	0.17	0.18	12	13	13	13	75	53	39	22
Slovenia	0.17	0.17	0.17	0.18	12	13	13	14	80	56	40	22
Spain	0.17	0.17	0.17	0.18	12	12	13	13	45	32	22	11
Sweden	0.16	0.16	0.17	0.18	17	17	17	17	134	95	67	35
Switzerland	0.23	0.22	0.21	0.20	17	18	19	19	137	89	61	31
UK	0.17	0.17	0.17	0.18	14	14	14	15	85	61	42	21

Table B.5 Scenario of residential and commercial useful energy demand for space and water heating in TWh/a.

Country	Space and water heating								Process heat				Considered heat $\vartheta \leq 500^{\circ}\text{C}$			
	Residential sector				Commercial sector				Commercial sector				Industry			
	2008	2020	2030	2050	2008	2020	2030	2050	2008	2020	2030	2050	2008	2020	2030	2050
Austria	47	43	37	28	12	9.4	7.4	4.9	1.4	1.2	1.2	1.0	24	28	27	25
Belgium	70	64	56	42	23	18.2	14.0	8.9	2.3	2.3	2.2	1.9	25	28	28	26
Bulgaria	14	15	14	12	4.8	4.2	3.7	2.8	0.4	0.5	0.5	0.4	5.9	6.6	6.6	6.3
Croatia	12	12	11	9.4	2.9	2.6	2.4	1.8	0.3	0.4	0.4	0.3	4.8	5.3	5.4	5.2
Cyprus	1.5	1.6	1.6	1.5	0.4	0.4	0.3	0.3	0.1	0.1	0.1	0.1	0.2	0.3	0.3	0.3
Czech Republic	49	45	39	29	12	9.6	7.6	5.2	1.7	1.6	1.5	1.3	17	20	20	19
Denmark	41	37	32	24	13	9.7	7.5	4.7	1.0	1.0	1.0	0.8	9.1	10	10	9.4
Estonia	7.7	6.8	5.8	4.3	1.7	1.4	1.1	0.7	0.2	0.2	0.2	0.2	1.9	2.1	2.1	1.9
Finland	42	38	33	25	12	9.9	7.7	4.8	1.4	1.5	1.4	1.1	41	48	47	45
France	313	286	249	188	108	84.7	66.2	42.9	12.0	12.6	12.0	10.0	79	91	90	84
Germany	483	425	363	265	156	120.2	92.1	56.2	14.3	14.0	13.4	11.3	129	147	144	132
Greece	35	31	27	20	10	8.3	6.7	4.6	1.0	1.0	1.0	0.9	7.9	9.1	9.0	8.5
Hungary	47	42	36	27	11	8.5	6.8	4.5	1.4	1.4	1.4	1.2	6.5	7.4	7.3	6.7
Ireland	24	23	21	17	6.0	4.9	3.9	2.8	0.9	0.8	0.7	0.6	5.9	6.8	6.7	6.3
Italy	203	185	164	124	40	34.3	28.8	21.7	9.6	10.1	9.7	8.1	75	86	84	78
Latvia	11	11	10	8.3	2.8	2.3	2.0	1.4	0.3	0.3	0.3	0.3	2.2	2.4	2.4	2.4
Liechtenstein	0.2	0.2	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Lithuania	10	11	10	9.1	3.3	2.9	2.5	1.9	0.3	0.3	0.3	0.3	2.9	3.1	3.1	2.9
Luxembourg	3.7	3.4	3.0	2.3	1.2	0.9	0.7	0.5	0.2	0.2	0.2	0.2	0.8	0.9	0.9	0.8
Malta	0.4	0.4	0.4	0.3	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2
Netherlands	79	74	65	49	21	16.8	13.4	8.9	4.1	4.2	4.0	3.3	37	41	40	36
Norway	36	35	31	24	11	8.8	7.0	4.6	1.2	1.3	1.2	1.0	13	15	15	13
Poland	155	145	127	96	42	34.5	27.1	17.6	3.4	3.6	3.5	2.9	37	42	42	39
Portugal	14	13	12	10	4.8	4.2	3.6	2.8	0.9	1.0	1.0	0.8	18	21	20	18
Romania	48	49	48	41	8.8	8.5	8.1	7.1	1.0	1.1	1.0	1.0	14	16	16	16
Slovakia	20	18	16	12	5.5	4.5	3.6	2.4	1.0	1.0	1.0	0.8	7.0	8.1	8.0	7.6
Slovenia	8.0	7.4	6.6	5.1	2.3	1.9	1.5	1.0	0.2	0.3	0.3	0.2	3.7	4.2	4.0	3.6
Spain	103	103	94	78	31	26.4	22.2	17.0	4.2	4.3	4.1	3.5	54	61	60	55
Sweden	61	57	50	38	22	17.2	13.3	8.4	2.1	2.1	2.0	1.6	46	53	52	49
Switzerland	48	45	39	30	19	15.1	11.7	7.4	0.4	0.4	0.4	0.3	14	16	15	14
UK	318	297	261	204	83	66.7	53.4	36.7	8.3	7.9	7.6	6.3	75	86	84	78

Table B.6 Assumed future development of sectoral final energy consumption based on scenario $E[R]$ in [183]. All values relative to the reference year, which is 2009 in industry and 2008 in residential and commercial sector.

	2010	2020	2030	2050
OECD countries				
Industry	3%	11%	5%	-10%
Other Sectors	3%	1%	-5%	-24%
Non-OECD countries				
Industry	3%	9%	8%	0%
Other Sectors	3%	4%	1%	-8%

B.2 Additional Results on DH Potentials

Regional DH Potentials in Germany

Within Germany, potentials are assessed for 16 regions equivalent to grid regions defined by the German transmission grid operators [182], see Figure 5.2 and Table E.1 in Appendix E. Figure B.1 shows the regional DH potential and supply share for each of the 18 regions in Germany. Highest absolute potentials are found in the regions AMP2, AMP5, TNBW1 and 50Hz1. Achievable DH shares range between 45% and 81%.

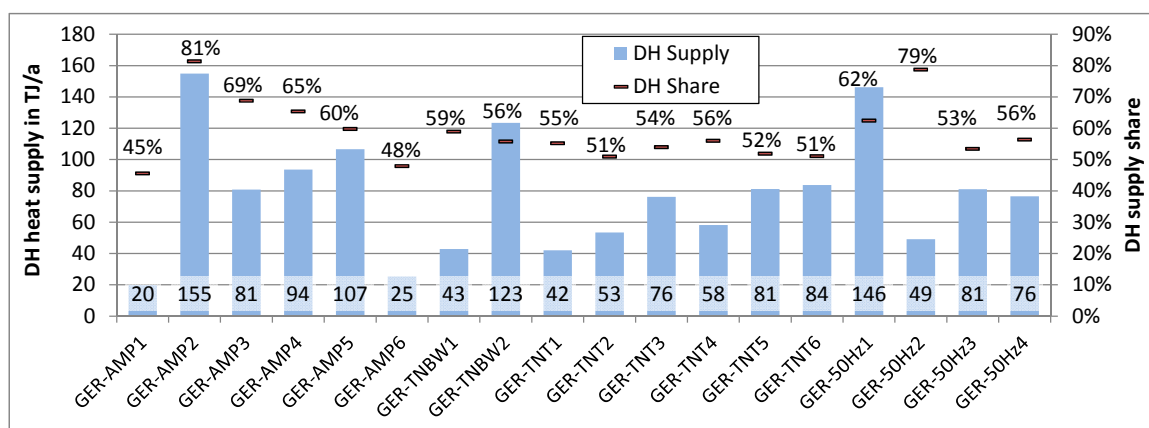


Figure B.1 District heating potential in Germany: supplied energy and supply share for 2008 values

Impact of a higher Minimum Demand Density on the DH Potential

The impact of higher threshold values on the DH potential is different in the assessed countries and regions, as can be learned from Figure B.2 for European countries and B.3 for German regions. It is particularly pronounced in regions with comparatively low population density and/or a dominance of smaller DH communities. Amongst other, in Finland, Norway, Portugal, Slovakia and Sweden, DH heat supply potentials are reduced to less than 25% if the threshold is increased from 4 GWh/km²/a to 15 GWh/km²/a. Also in Germany, regions with lower population density are affected most.

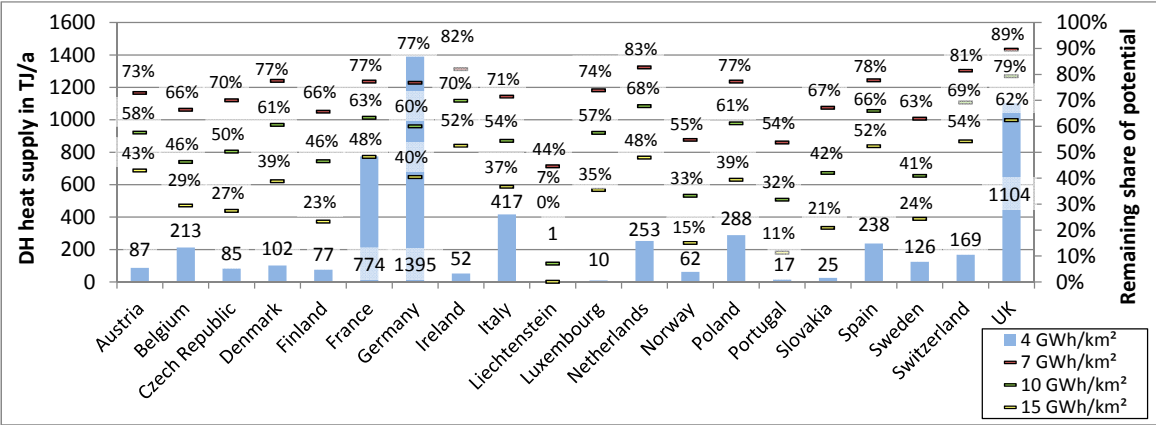


Figure B.2 District heating potential in Europe: demand density threshold dependency for 2008 values

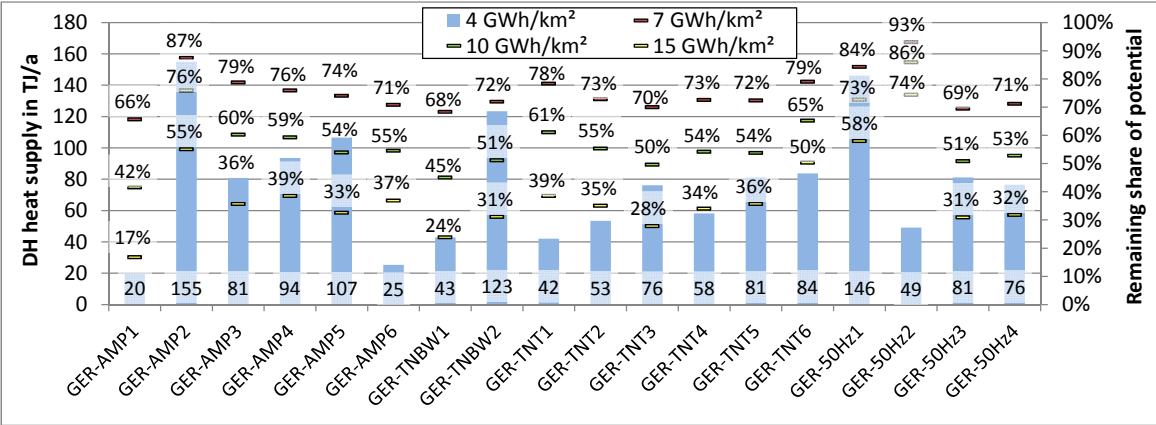


Figure B.3 District heating potential in Germany: demand density threshold dependency for 2008 values

B.3 District Heating Potential by Region, Technology Class and Demand Density Threshold

See Table B.7 to B.10 on the following pages.

Table B.7 DH potential by region, technology class and demand density threshold, 2008 values in PJ.

Region	DH-S				DH-M				DH-L				DH-XL			
	4 GWh/km ² /a	7 GWh/km ² /a	10 GWh/km ² /a	15 GWh/km ² /a	4 GWh/km ² /a	7 GWh/km ² /a	10 GWh/km ² /a	15 GWh/km ² /a	4 GWh/km ² /a	7 GWh/km ² /a	10 GWh/km ² /a	15 GWh/km ² /a	4 GWh/km ² /a	7 GWh/km ² /a	10 GWh/km ² /a	15 GWh/km ² /a
Austria	2.79	0.66	0.02	0	10.3	5.9	3.1	1.0	13.0	7.6	4.9	3.2	61.4	49.5	42.2	33.3
Belgium	4.26	1.57	0.88	0	13.9	12.4	6.5	2.1	14.8	15.7	9.2	7.5	179.7	111.4	81.8	52.8
Bulgaria	0.21	0.16	0	0	2.5	1.1	0.4	0.2	3.4	1.0	1.0	0.3	9.6	8.1	5.5	1.8
Croatia	0.31	0.05	0	0	1.4	0.4	0.6	0.1	1.7	0.6	0	0.8	8.8	6.6	3.9	1.0
Cyprus	0	0.02	0	0	0	0	0	0	1.0	0	0	0	0	0	0	0
Czech Rep.	1.99	0.72	0.24	0	12.3	6.5	4.9	2.4	20.9	14.0	10.8	4.7	49.4	38.0	26.6	16.1
DK-East	1.03	0.40	0.25	0	3.8	2.2	1.7	1.3	7.5	6.8	6.2	3.7	42.8	38.2	33.0	26.3
DK-West	2.60	0.70	0.31	0	10.7	5.7	2.3	1.5	8.2	6.5	6.2	5.2	25.4	18.4	11.7	1.5
Estonia	0.16	0.07	0.05	0	1.9	1.5	0.8	0.4	2.8	2.2	1.6	1.3	11.6	9.6	8.7	6.8
Finland	2.36	0.59	0.23	0.12	7.9	3.4	1.6	1.2	10.6	5.5	4.7	3.3	56.5	41.2	29.4	13.3
France	19.49	5.93	0.61	0	77.6	38.3	25.0	14.9	91.0	69.2	54.6	36.2	586	484	409	322
GER-AMP1	0.90	0.30	0.14	0	4.2	3.1	2.1	0.5	6.9	4.5	3.2	0.8	7.8	5.0	2.8	1.9
GER-AMP2	0.67	0.59	0.22	0	4.4	5.1	4.3	3.4	8.0	11.0	8.1	6.7	141.9	118.8	104.9	75.1
GER-AMP3	1.34	0.91	0.42	0	6.9	6.3	3.4	3.0	10.3	7.4	7.4	6.9	62.3	49.1	37.5	18.8
GER-AMP4	2.22	1.36	0.55	0	9.2	6.6	4.4	2.0	10.8	6.6	6.9	4.9	71.4	56.5	43.6	29.2
GER-AMP5	2.68	1.15	0.51	0	11.6	10.7	7.4	4.0	14.3	12.6	12.0	8.7	77.9	54.5	37.5	21.9
GER-AMP6	1.52	0.41	0.04	0	3.8	2.8	2.3	0.2	5.6	2.9	1.8	1.5	14.3	11.9	9.7	7.6
GER-TNBW1	1.34	0.73	0.19	0	8.3	6.4	4.2	1.9	7.5	7.8	3.6	1.2	25.7	14.3	11.3	7.2
GER-TNBW2	4.44	2.35	0.25	0	18.4	12.9	8.5	4.2	23.0	20.6	14.1	9.4	77.5	53.0	40.3	24.8
GER-TNT1	1.23	0.46	0.23	0	4.9	3.9	2.7	1.9	12.5	8.7	6.2	3.2	23.5	20.0	16.6	11.2
GER-TNT2	1.65	0.67	0.31	0	8.8	4.7	2.3	1.0	9.0	6.8	6.1	3.4	33.9	26.8	20.8	14.4
GER-TNT3	3.18	1.25	0.47	0	13.7	6.1	3.7	2.3	15.6	14.7	9.1	4.6	43.7	31.2	24.5	14.2
GER-TNT4	2.62	1.01	0.40	0	10.2	5.9	2.8	1.1	8.2	3.6	3.1	2.9	37.3	31.7	25.3	15.8
GER-TNT5	3.74	1.18	0.23	0	13.3	7.0	4.4	2.0	13.5	8.1	5.7	4.7	50.6	42.5	33.4	22.2
GER-TNT6	2.69	0.94	0.17	0	10.8	6.1	3.5	2.7	17.1	11.9	11.1	5.2	53.0	47.2	39.9	34.2
GER-50Hz1	4.55	1.02	0.47	0	11.9	6.4	3.7	2.2	15.1	12.0	9.6	5.4	114.6	103.8	92.4	77.1
GER-50Hz2	0.15	0.06	0.02	0	0.4	0.5	0.7	0.4	1.7	1.7	0.7	1.7	46.8	43.5	40.8	34.4
GER-50Hz3	4.89	1.28	0.32	0	15.3	6.7	3.9	2.0	15.8	15.2	13.0	6.6	45.1	33.2	24.1	16.5
GER-50Hz4	3.43	1.08	0.42	0	10.2	6.4	3.7	2.3	15.9	12.6	9.7	5.4	46.9	34.4	26.6	16.7
Greece	2.70	0.53	0	0	6.3	2.6	1.7	1.4	9.3	6.5	4.1	3.6	51.9	48.7	47.0	41.1
Hungary	2.14	0.45	0.02	0	11.6	6.5	3.2	1.5	16.8	9.1	8.8	5.9	55.1	45.3	35.2	24.3
Ireland	1.31	0.21	0.22	0	6.7	4.0	2.4	1.6	10.7	7.8	5.4	2.1	33.1	30.5	28.2	23.5
Italy	9.83	4.15	0	0	53.6	34.2	23.2	13.1	66.2	49.3	38.6	27.2	287.2	209.9	164.6	112.3
Latvia	0.32	0.10	0.11	0	2.7	2.0	1.4	0.7	5.9	3.7	2.5	1.3	16.7	15.1	12.8	9.8
Liechtenstein	0	0.04	0	0	0.1	0.2	0.0	0	0.5	0	0	0	0	0	0	0
Lithuania	0.05	0.04	0.07	0	0.4	0.7	0.8	0.3	1.0	1.0	1.2	0.6	10.1	6.7	3.2	0
Luxembourg	0.40	0.09	0.04	0	1.4	0.8	0.5	0.3	0.4	0.7	0.3	0.5	7.9	5.8	4.9	2.7
Malta	0.01	0	0	0	0	0.3	0.1	0	0	0	0	0	0.8	0	0	0
Netherlands	3.71	1.80	0.82	0	22.6	15.1	9.6	6.3	33.9	29.5	29.5	21.4	193.3	163.1	131.7	93.7
Norway	3.99	1.09	0.22	0	9.3	4.4	1.1	0.5	8.4	4.0	1.0	0	40.0	24.3	18.2	8.7
Poland	5.44	1.38	0.78	0	20.6	12.4	9.1	6.6	53.3	51.1	44.5	24.0	209.0	157.9	121.7	83.0
Portugal	0.45	0.14	0	0	2.7	1.5	1.1	0.5	3.4	2.0	1.3	0	10.2	5.4	3.0	1.4
Romania	0.44	0.12	0.02	0	4.3	2.8	1.4	1.0	10.1	5.9	6.7	6.2	33.5	28.4	21.3	11.3
Slovakia	0.70	0.16	0.06	0	5.1	3.6	1.6	0.9	9.2	6.0	4.7	1.8	10.3	7.2	4.3	2.6
Slovenia	0.66	0.16	0	0	2.1	0.7	0.7	0.2	2.0	0.8	1.0	0.2	5.1	4.0	1.9	0.8
Spain	5.38	1.99	0	0	29.1	13.7	9.1	5.3	38.4	28.7	26.6	19.1	164.6	140.1	120.8	99.7
Sweden	6.36	1.86	0.55	0.02	27.2	10.8	4.9	1.8	20.0	13.7	7.6	1.8	72.1	52.6	38.3	26.9
Switzerland	1.39	0.70	0.04	0	12.3	8.8	7.2	4.8	23.5	25.5	20.5	16.9	132.3	103.0	89.5	70.2
UK	9.03	4.25	1.98	0	46.6	37.6	35.3	28.6	106.5	102.8	93.6	83.5	942	844	744	576

Table B.8 DH potential by region, technology class and demand density threshold, 2020 values in PJ.

Region	DH-S				DH-M				DH-L				DH-XL			
	4 GWh/km ² /a	7 GWh/km ² /a	10 GWh/km ² /a	15 GWh/km ² /a	4 GWh/km ² /a	7 GWh/km ² /a	10 GWh/km ² /a	15 GWh/km ² /a	4 GWh/km ² /a	7 GWh/km ² /a	10 GWh/km ² /a	15 GWh/km ² /a	4 GWh/km ² /a	7 GWh/km ² /a	10 GWh/km ² /a	15 GWh/km ² /a
Austria	2.00	0.46	0	0	9.2	5.1	2.1	1.0	10.3	6.3	5.0	1.9	53.6	43.0	36.3	29.2
Belgium	3.38	1.29	0.60	0	12.3	9.5	4.1	2.0	14.9	11.8	7.9	5.0	143.8	89.6	65.4	43.1
Bulgaria	0.20	0.14	0	0	2.3	1.1	0.5	0.4	3.5	1.1	1.1	0.3	10.3	8.8	6.2	2.1
Croatia	0.27	0.05	0	0	1.5	0.5	0.6	0.1	1.5	0.4	0	0.7	8.7	6.5	3.8	0.9
Cyprus	0	0.02	0	0	0	0	0	0	1.1	0	0	0	0	0	0	0
Czech Rep.	1.65	0.69	0.18	0	9.9	6.2	3.9	2.0	19.0	12.2	8.7	3.4	43.1	31.7	22.4	12.7
DK-East	0.82	0.26	0.18	0	3.0	2.4	0.9	1.1	5.8	4.9	5.3	2.2	37.6	32.8	27.8	21.7
DK-West	1.98	0.48	0.17	0	7.8	3.2	1.4	1.3	7.8	6.5	6.0	2.8	19.4	12.8	6.7	0.0
Estonia	0.23	0.07	0.05	0	1.6	1.1	0.8	0.4	2.8	2.0	0.9	1.4	9.5	8.1	7.6	5.0
Finland	1.57	0.34	0.17	0.04	5.6	2.6	1.9	0.6	8.4	5.5	2.9	1.9	49.6	33.9	24.9	12.1
France	13.90	4.42	0.51	0	61.3	31.2	20.8	11.3	80.8	58.8	46.7	31.7	504.9	415.5	349.1	272.6
GER-AMP1	0.68	0.29	0.12	0	3.6	2.4	1.0	0.4	5.5	4.0	2.0	0.0	6.1	2.9	2.4	1.5
GER-AMP2	0.75	0.42	0.33	0	4.0	4.6	3.9	4.1	9.2	8.1	7.9	4.2	116.6	98.5	81.5	51.0
GER-AMP3	1.04	0.53	0.28	0	6.4	4.8	3.1	3.3	8.4	8.1	7.2	3.4	48.0	34.5	23.7	10.1
GER-AMP4	1.82	0.78	0.20	0	8.2	5.2	3.1	1.9	7.8	5.6	5.2	3.0	59.1	45.4	34.4	21.3
GER-AMP5	1.97	1.01	0.28	0	11.1	8.7	5.9	3.3	13.0	11.0	8.8	6.6	61.1	41.1	28.0	15.2
GER-AMP6	0.87	0.19	0	0	3.8	2.5	1.5	0.1	4.0	2.2	2.0	1.8	11.2	8.9	7.4	5.3
GER-TNBW1	1.32	0.62	0.14	0	7.1	5.3	3.0	1.4	8.6	4.6	2.5	1.4	18.0	12.0	8.7	4.4
GER-TNBW2	3.18	1.93	0.08	0	15.6	9.9	7.0	3.6	21.0	16.0	9.1	4.6	58.7	39.4	30.2	17.8
GER-TNT1	0.69	0.17	0.15	0	5.0	3.0	2.1	1.4	8.8	7.6	4.4	2.7	20.0	15.6	12.6	6.8
GER-TNT2	1.62	0.44	0.19	0	6.6	3.5	1.8	0.5	7.8	5.3	4.6	3.1	27.9	22.2	16.7	10.5
GER-TNT3	2.65	0.73	0.28	0	9.9	5.0	3.3	1.1	14.1	10.5	7.0	2.6	33.0	23.3	15.8	9.5
GER-TNT4	1.84	0.79	0.20	0	7.9	3.4	1.7	0.5	5.0	3.2	3.3	3.0	31.0	24.6	18.0	9.9
GER-TNT5	2.72	0.85	0.16	0	9.9	4.8	3.5	0.8	8.6	6.5	4.4	3.4	42.3	32.9	24.5	16.5
GER-TNT6	2.15	0.76	0.02	0	9.7	5.1	3.4	2.8	13.6	10.6	8.5	3.3	49.5	43.3	38.0	32.5
GER-50Hz1	2.29	0.60	0.21	0	9.5	5.0	2.8	1.3	10.4	9.0	6.5	4.0	97.4	85.7	76.3	63.9
GER-50Hz2	0.15	0.01	0.02	0	0.3	0.8	0.6	0.3	1.5	0.9	0.9	1.1	45.2	42.2	39.2	33.7
GER-50Hz3	3.05	0.71	0.18	0	9.6	4.4	2.5	2.0	16.3	11.9	6.2	2.1	28.9	21.0	17.3	9.1
GER-50Hz4	1.86	0.36	0.24	0	8.0	3.9	3.0	1.2	14.1	11.2	5.8	2.8	30.8	21.8	16.4	7.5
Greece	1.67	0.24	0	0	4.7	2.1	1.5	1.2	7.3	5.3	3.3	2.6	45.3	42.5	40.5	34.7
Hungary	1.41	0.18	0	0	10.0	5.2	2.7	1.6	14.5	10.6	6.8	4.0	47.4	37.0	31.0	21.5
Ireland	0.84	0.22	0.24	0	6.6	3.4	2.5	1.7	8.1	6.8	3.4	2.0	30.5	27.3	25.6	20.1
Italy	8.21	3.60	0	0	47.8	30.3	21.0	11.5	57.7	44.7	29.9	21.9	254.0	180.7	144.1	95.0
Latvia	0.26	0.11	0.07	0	2.5	2.1	1.5	0.7	5.3	3.1	2.0	2.0	16.1	14.5	12.4	8.4
Liechtenstein	0	0.05	0	0	0.1	0.1	0	0	0.4	0	0	0	0	0	0	0
Lithuania	0.05	0.03	0.04	0	0.4	0.8	0.8	0.6	1.0	1.1	0.9	0.6	10.5	7.1	4.0	0
Luxembourg	0.22	0.06	0.04	0	1.3	0.6	0.3	0.3	0	0.5	0.3	0.4	7.2	5.2	4.3	2.5
Malta	0.01	0	0	0	0	0.1	0.1	0	0	0	0	0	0.8	0	0	0
Netherlands	3.42	1.51	0.95	0	20.0	13.3	8.4	6.0	30.6	26.3	25.5	17.4	173.8	144.2	114.8	80.2
Norway	3.54	0.68	0.04	0	7.5	2.3	0.6	0.4	7.6	3.5	0	0	33.2	22.7	18.3	8.8
Poland	3.96	1.00	0.72	0	18.2	11.6	8.8	6.1	52.3	46.4	35.1	21.0	181.4	137.1	107.7	66.9
Portugal	0.33	0.11	0	0	2.5	1.4	1.2	0.2	2.9	2.6	0.9	0	9.5	4.2	2.7	1.2
Romania	0.50	0.20	0	0	3.7	3.0	1.8	0.8	10.0	6.4	7.3	6.1	36.9	30.1	22.8	14.0
Slovakia	0.63	0.18	0.08	0	4.5	3.4	1.4	0.7	8.6	4.6	3.5	1.2	8.9	6.8	4.0	2.5
Slovenia	0.59	0.10	0	0	1.8	0.6	0.6	0.2	1.4	0.5	0.8	0.6	4.5	3.5	1.3	0
Spain	4.71	1.89	0	0	26.6	13.8	9.2	5.6	35.6	27.7	26.1	17.4	161.9	137.2	119.1	99.9
Sweden	4.85	1.24	0.28	0.02	20.7	8.2	3.3	1.0	16.9	9.7	8.0	1.5	63.2	46.2	32.2	25.1
Switzerland	1.53	0.81	0.00	0	11.3	8.8	6.0	4.7	21.5	21.0	19.5	12.9	114.7	89.6	74.7	60.0
UK	7.67	3.27	1.84	0	41.1	36.3	32.6	26.6	101.2	96.5	88.9	75.4	845.2	744.0	645.7	478.4

Table B.9 DH potential by region, technology class and demand density threshold, 2030 values in PJ.

Region	DH-S				DH-M				DH-L				DH-XL			
	4 GWh/km ² /a	7 GWh/km ² /a	10 GWh/km ² /a	15 GWh/km ² /a	4 GWh/km ² /a	7 GWh/km ² /a	10 GWh/km ² /a	15 GWh/km ² /a	4 GWh/km ² /a	7 GWh/km ² /a	10 GWh/km ² /a	15 GWh/km ² /a	4 GWh/km ² /a	7 GWh/km ² /a	10 GWh/km ² /a	15 GWh/km ² /a
Austria	1.47	0.51	0.04	0	7.6	3.4	1.2	0.7	7.2	5.5	3.3	0.8	44.6	34.3	30.7	23.4
Belgium	2.85	0.77	0.34	0	11.1	6.9	3.0	1.8	13.8	10.3	6.2	1.9	107.8	66.0	48.1	33.9
Bulgaria	0.18	0.16	0	0	2.5	1.2	0.6	0.3	3.2	0.8	0.9	0.5	10.2	8.8	6.3	2.1
Croatia	0.33	0.05	0	0	1.1	0.6	0.3	0.2	1.4	0.2	0	0.5	8.2	6.0	3.4	0.9
Cyprus	0	0	0	0	0	0	0	0	1.1	0	0	0	0	0	0	0
Czech Rep.	1.37	0.55	0.26	0	9.1	5.2	3.1	1.5	15.3	11.4	5.9	2.4	34.0	22.5	16.3	8.0
DK-East	0.61	0.17	0.09	0	2.4	1.6	1.7	0.9	5.1	5.3	3.5	0.7	31.0	25.4	21.6	16.5
DK-West	1.41	0.29	0.13	0	5.9	2.0	1.9	1.2	6.5	6.1	3.7	0.8	13.8	7.9	2.9	0.0
Estonia	0.21	0.07	0.04	0	1.5	1.1	0.3	0.4	1.8	1.1	2.0	1.0	8.0	6.8	4.9	3.2
Finland	1.08	0.16	0.18	0.10	4.0	1.8	1.8	0.5	8.3	3.8	2.7	0.8	37.6	26.8	16.1	9.2
France	9.63	3.42	0.37	0	46.0	24.3	15.0	9.3	67.3	53.4	40.0	25.6	414.2	328.8	277.2	212.5
GER-AMP1	0.51	0.16	0.18	0	3.5	1.8	0.5	0.0	4.8	2.6	1.1	0.0	3.5	2.4	1.9	1.1
GER-AMP2	0.77	0.37	0.16	0	4.1	4.1	2.5	2.9	6.8	6.8	5.5	7.9	95.2	77.1	61.5	23.8
GER-AMP3	0.98	0.48	0.24	0	6.4	3.7	3.0	1.4	6.4	4.9	4.7	2.9	35.4	25.0	14.2	3.3
GER-AMP4	1.54	0.71	0.22	0	6.9	3.9	2.5	1.4	5.2	4.4	4.4	3.0	47.4	34.6	24.4	13.1
GER-AMP5	1.59	0.66	0.20	0	9.5	6.2	5.0	1.9	10.4	9.0	5.4	5.0	46.9	30.2	20.2	8.9
GER-AMP6	0.71	0.11	0.04	0	3.5	1.9	0.6	0.2	2.5	2.0	1.5	1.5	8.7	6.6	6.0	3.3
GER-TNBW1	1.18	0.61	0.17	0	6.1	4.3	1.8	0.8	6.7	2.3	1.1	1.2	13.1	8.9	6.6	2.5
GER-TNBW2	2.56	1.01	0.21	0	12.7	8.2	4.7	2.2	17.1	9.7	8.4	4.5	43.0	28.8	18.3	8.4
GER-TNT1	0.64	0.23	0.17	0	4.1	2.6	2.1	0.8	7.3	6.1	2.7	1.6	15.6	11.5	9.5	4.5
GER-TNT2	1.06	0.23	0.12	0	4.7	2.5	1.4	0.9	6.9	3.8	3.5	2.3	22.5	18.1	12.5	6.3
GER-TNT3	1.64	0.41	0.10	0	7.7	3.9	2.2	1.4	11.7	8.8	3.5	1.3	23.9	14.8	11.5	4.9
GER-TNT4	1.37	0.38	0.18	0	5.8	2.3	1.4	0.7	3.0	1.8	3.6	0.9	24.5	18.6	11.1	6.6
GER-TNT5	1.91	0.50	0.16	0	6.8	3.9	1.7	0.9	7.2	4.9	3.9	4.0	32.5	23.3	17.5	8.8
GER-TNT6	1.49	0.55	0.17	0	7.9	3.9	2.9	1.8	11.2	9.7	6.6	3.2	43.8	36.9	33.1	27.4
GER-50Hz1	1.44	0.34	0.37	0	6.4	3.5	1.8	0.9	8.7	8.4	4.7	2.6	78.9	66.2	59.8	51.6
GER-50Hz2	0.09	0.01	0.08	0	0.5	0.6	0.3	0.4	0.8	0.7	1.2	0.5	41.5	38.5	35.0	30.2
GER-50Hz3	1.81	0.43	0.14	0	6.3	3.2	2.2	0.5	11.9	7.1	3.2	1.8	19.7	13.5	9.9	3.7
GER-50Hz4	1.24	0.31	0.22	0	5.6	3.2	2.2	0.4	11.8	5.7	2.3	1.2	19.0	14.0	9.3	1.9
Greece	1.04	0.14	0	0	3.2	1.8	1.5	1.0	5.7	3.6	3.7	2.8	38.6	36.5	32.4	27.6
Hungary	0.92	0.29	0	0	8.5	3.8	1.9	0.9	10.9	7.6	6.8	2.9	39.6	30.8	23.5	17.5
Ireland	0.49	0.25	0.13	0	5.3	3.7	2.7	1.3	6.7	4.2	2.6	1.9	27.0	24.0	21.3	15.9
Italy	6.91	2.62	0	0	41.9	24.4	17.9	8.7	49.3	37.1	24.9	16.1	208.7	148.5	113.7	75.5
Latvia	0.23	0.08	0.13	0	2.7	1.8	0.9	0.5	4.4	3.3	1.6	1.6	14.6	12.6	11.3	7.4
Liechtenstein	0	0.03	0	0	0.4	0.0	0	0	0.0	0	0	0	0	0	0	0
Lithuania	0.05	0.03	0.09	0	0.3	0.7	0.8	0.5	1.0	1.0	1.2	0.6	10.2	6.8	3.3	0
Luxembourg	0.22	0.05	0	0	0.9	0.5	0.2	0.4	0.6	0.3	0.4	0.5	5.5	4.3	3.1	1.4
Malta	0.01	0	0	0	0	0.2	0.1	0	0	0	0	0	0.8	0	0	0
Netherlands	2.99	1.41	0.69	0	16.9	10.2	8.3	4.9	29.9	25.5	22.6	14.9	140.1	113.3	85.5	54.3
Norway	2.45	0.37	0.04	0	5.3	1.4	0.3	0.2	5.2	2.2	0	0	27.3	18.1	16.5	5.8
Poland	2.85	0.71	0.71	0	15.8	11.6	8.1	5.0	49.8	41.2	26.7	13.2	142.9	104.6	82.3	48.1
Portugal	0.29	0.14	0	0	2.2	1.9	0.8	0.1	2.1	1.2	0.7	1	8.2	3.2	2.2	0
Romania	0.50	0.21	0.02	0	4.0	2.9	1.7	1.1	9.4	6.1	7.1	6.1	36.4	29.7	22.4	13.0
Slovakia	0.43	0.14	0.04	0	4.5	2.4	1.5	0.2	6.7	3.3	1.7	0.8	7.0	5.6	3.3	1.9
Slovenia	0.36	0.07	0	0	1.1	0.4	0.4	0.1	1.0	0.9	0.4	0.3	3.8	2.0	1.0	0
Spain	3.77	1.42	0	0	22.7	12.3	7.8	4.1	33.7	25.8	23.2	19.4	140.8	119.6	105.1	83.8
Sweden	3.12	0.73	0.25	0	14.2	4.7	2.4	0.9	15.3	9.6	3.4	1.8	47.8	33.4	27.5	18.5
Switzerland	1.31	0.70	0.06	0	10.0	6.8	5.9	3.7	21.7	18.1	14.1	10.5	87.6	70.5	58.6	44.3
UK	6.17	2.62	1.78	0	39.1	35.0	31.1	24.6	98.7	90.8	82.6	65.1	705.0	608.1	510.0	345.7

Table B.10 DH potential by region, technology class and demand density threshold, 2050 values in PJ.

Region	DH-S				DH-M				DH-L				DH-XL			
	4 GWh/km ² /a	7 GWh/km ² /a	10 GWh/km ² /a	15 GWh/km ² /a	4 GWh/km ² /a	7 GWh/km ² /a	10 GWh/km ² /a	15 GWh/km ² /a	4 GWh/km ² /a	7 GWh/km ² /a	10 GWh/km ² /a	15 GWh/km ² /a	4 GWh/km ² /a	7 GWh/km ² /a	10 GWh/km ² /a	15 GWh/km ² /a
Austria	0.61	0.16	0	0	4.8	1.1	1.1	1.0	4.5	2.5	0.8	0.8	29.2	24.0	19.9	11.9
Belgium	1.72	0.34	0.16	0	8.1	2.8	1.8	0.5	7.6	5.6	3.0	1.2	63.8	38.7	28.0	20.6
Bulgaria	0.19	0.12	0	0	1.9	0.7	0.4	0.1	1.7	0.8	1.2	0	8.3	6.1	3.1	1.6
Croatia	0.13	0.05	0	0	0.6	0.4	0	0.1	1.0	0	1	0.8	6.4	3.9	0.9	0
Cyprus	0	0.02	0	0	0	0	0	0	1.0	0	0	0	0	0	0	0
Czech Rep.	0.96	0.39	0.04	0	5.8	3.2	1.7	0.3	11.7	7.0	2.2	0.9	18.8	11.1	8.1	2.3
DK-East	0.29	0.08	0.11	0	2.4	1.7	1.3	0.4	3.7	2.1	0.7	0	20.3	16.8	13.4	9.3
DK-West	0.67	0.14	0.02	0	2.3	1.7	1.1	0.5	6.1	2.8	1.0	0.2	6.0	2.3	0	0
Estonia	0.14	0.07	0.02	0	1.3	0.6	0.5	0.3	1.2	1.5	1.1	0	4.8	3.4	2.6	1.3
Finland	0.62	0.17	0.08	0	2.8	1.4	1.2	0.3	3.6	3.7	0.5	0.4	22.7	11.8	7.5	4.5
France	5.20	1.34	0.21	0	29.8	16.9	10.5	6.8	54.8	33.3	27.1	16.0	265.0	212.6	170.4	121.5
GER-AMP1	0.27	0.16	0.04	0	1.9	0.6	0	0	2.2	0.5	0	0.2	2.0	1.4	0.9	0
GER-AMP2	0.42	0.28	0.22	0	4.4	2.2	2.9	1.1	4.5	4.4	6.6	4.1	60.6	44.6	21.2	1.1
GER-AMP3	0.66	0.29	0.12	0	4.2	3.0	1.9	0.4	4.6	3.7	3.0	1.0	19.7	9.5	2.3	0
GER-AMP4	0.87	0.30	0.02	0	3.9	2.3	1.2	1.0	4.0	4.3	2.2	1.9	27.7	16.7	11.0	2.3
GER-AMP5	1.19	0.38	0.20	0	6.7	4.8	2.1	1.1	7.1	4.8	3.6	2.0	25.1	13.0	7.6	1.3
GER-AMP6	0.37	0.11	0	0	1.7	0.5	0.3	0.3	2.3	1.5	1.2	0	4.4	3.9	2.6	1.3
GER-TNBW1	0.82	0.31	0.04	0	3.9	1.4	0.9	0.3	2.3	1.3	1.7	1.3	7.7	4.4	1.4	0
GER-TNBW2	1.79	0.57	0.10	0	9.5	4.6	2.3	1.1	9.4	5.9	4.6	0.5	21.8	12.8	6.2	2.6
GER-TNT1	0.28	0.12	0.07	0	2.8	1.9	0.9	0.2	4.8	3.1	1.1	1.3	8.7	5.5	3.8	0.8
GER-TNT2	0.47	0.11	0.08	0	3.3	1.4	0.7	0.4	3.3	2.2	1.9	1.0	13.4	9.1	5.2	0.8
GER-TNT3	0.91	0.12	0.02	0	4.7	1.9	1.0	0.3	6.5	3.0	1.3	1.2	12.4	7.8	4.4	0
GER-TNT4	0.80	0.18	0.06	0	2.9	1.1	0.7	0.2	1.9	2.6	1.6	0.8	14.2	8.3	4.5	2.2
GER-TNT5	0.94	0.26	0.10	0	4.1	1.3	1.0	0.5	4.8	4.1	2.7	1.7	18.1	11.5	7.5	3.1
GER-TNT6	0.83	0.26	0.08	0	5.0	3.4	1.9	0.5	8.1	4.3	2.7	1.1	27.0	23.5	20.5	16.0
GER-50Hz1	0.65	0.27	0.08	0	3.9	1.8	1.0	0.7	6.3	3.0	2.0	1.1	50.6	43.7	38.1	29.8
GER-50Hz2	0.08	0.07	0.02	0	0.5	0.3	0.5	0.3	0.6	0.7	1.6	1.7	28.7	25.6	21.3	16.3
GER-50Hz3	0.74	0.13	0.04	0	4.2	2.5	0.5	0.1	5.6	1.9	1.0	1.7	10.7	6.7	3.8	0
GER-50Hz4	0.58	0.23	0.08	0	3.4	1.8	0.5	0.5	4.8	2.8	1.1	0	11.7	5.4	1.9	0
Greece	0.22	0.08	0	0	2.3	1.4	1.0	0.3	4.6	4.2	2.4	1.8	27.0	23.7	21.9	18.8
Hungary	0.43	0.23	0.02	0	4.9	1.9	1.5	0.8	7.5	5.8	1.7	0.7	24.5	17.1	14.6	9.9
Ireland	0.29	0.18	0.12	0	4.2	2.9	1.6	1.0	4.2	2.4	2.3	2.2	21.0	18.3	14.8	7.8
Italy	4.86	1.98	0	0	30.7	17.5	11.1	5.1	32.2	23.1	17.6	9.0	133.2	89.4	62.7	40.9
Latvia	0.25	0.08	0.07	0	1.8	1.3	0.6	0.5	3.4	2.2	2.0	0	10.7	8.6	6.6	5.0
Liechtenstein	0	0	0	0	0.1	0	0	0	0	0	0	0	0	0	0	0
Lithuania	0.02	0.04	0.04	0	0.3	0.6	0.5	0.1	0.8	1.2	2.1	0.2	8.6	4.8	1.0	0
Luxembourg	0.06	0.03	0.02	0	0.7	0.2	0.4	0.1	0.4	0.2	0.5	0.3	3.7	2.9	1.2	0.9
Malta	0	0	0	0	0	0.3	0.1	0	1	0	0	0	0	0	0	0
Netherlands	2.22	0.56	0.39	0	12.4	9.1	6.3	1.8	24.6	22.0	15.9	8.9	89.3	61.6	44.6	22.3
Norway	0.82	0.02	0.03	0	1.7	0.3	0.2	0.1	2.2	0	0	0	16.9	13.1	7.1	0
Poland	1.32	0.73	0.63	0	14.6	8.8	5.2	2.4	35.1	23.1	14.9	9.3	86.3	61.4	39.7	15.2
Portugal	0.15	0.13	0	0	1.6	1.0	0.6	0.1	1.1	0.9	0	0	6.4	2.4	1.4	0
Romania	0.39	0.20	0	0	3.6	2.1	1.2	0.9	9.4	7.4	7.1	4.4	27.7	20.9	15.5	8.9
Slovakia	0.18	0.12	0.04	0	3.2	1.4	0.7	0.3	4.2	1.7	0.8	0.9	4.3	2.8	1.8	0
Slovenia	0.16	0.08	0	0	0.5	0.4	0.2	0.1	1.1	0.3	0.4	0	1.9	0.9	0	0
Spain	2.45	1.07	0	0	17.3	8.7	6.4	3.5	25.8	21.6	18.8	21.0	108.2	90.5	77.3	55.3
Sweden	1.66	0.30	0.19	0	5.8	2.5	0.7	0.6	10.1	2.6	1.2	2.3	28.4	21.6	16.8	8.6
Switzerland	0.96	0.48	0	0	8.0	5.5	4.6	2.3	14.3	11.9	8.7	4.5	55.8	42.0	33.5	25.1
UK	4.35	2.26	1.98	0	36.4	32.2	24.9	18.9	82.0	72.6	65.2	36.5	500.4	407.0	310.3	163.6

Appendix C

Assessment of Industrial CHP Potentials: Input and Detailed Results

C.1 Heat Demand Input

Table C.1 Final energy use and process heat temperatures in the different industrial sectors of Germany in 2007.

Industries	PH < 100°C	PH 100-500°C	PH 500-1000°C	PH > 1000°C	All PH	SH and HW	Process cooling	Cooling	Lighting	ICT	Mechanical
Metals	0.4%	1.4%	15.9%	62.6%	80.3%	3.6%	0.0%	0.3%	0.8%	0.4%	14.6%
Chemical	10.1%	15.7%	33.5%	8.2%	67.5%	2.7%	1.4%	0.6%	0.4%	0.5%	27.0%
Minerals	1.1%	1.7%	25.6%	53.0%	81.4%	2.3%	0.0%	0.2%	0.4%	0.3%	15.3%
Mining	60.0%	0.0%	0.0%	0.0%	60.0%	4.8%	0.0%	0.4%	0.9%	0.4%	33.5%
Food	27.4%	33.6%	0.0%	0.0%	61.0%	10.9%	5.2%	1.4%	1.8%	1.5%	18.1%
Textile	34.7%	0.0%	0.0%	0.0%	34.7%	25.6%	0.0%	1.2%	4.8%	4.7%	29.1%
Paper/Print	11.2%	53.9%	0.0%	0.0%	65.1%	2.2%	0.1%	0.5%	0.4%	0.3%	31.4%
Transport Eq.	7.7%	5.8%	2.8%	8.0%	24.3%	27.7%	0.0%	1.4%	4.8%	3.5%	38.2%
Machinery	8.2%	6.3%	3.3%	8.5%	26.3%	32.0%	0.0%	1.7%	6.5%	6.4%	27.2%
Wood	27.6%	7.0%	0.0%	0.0%	34.7%	25.6%	0.0%	1.2%	4.8%	4.7%	29.1%
Construction	34.7%	0.0%	0.0%	0.0%	34.7%	25.6%	0.0%	1.2%	4.8%	4.7%	29.1%
Other	3.8%	12.7%	8.2%	17.0%	41.7%	17.0%	0.0%	1.3%	3.2%	2.7%	34.1%

Table C.2 Industrial heat demand subdivision to annual full load hour classes.

FLH min. FLH max.	Process heat								SH/HW
	8000	7000	6000	5000	4250	3750	3250	1	-
	8760	7999	6999	5999	4999	4249	3749	3249	-
Austria	0%	8%	1%	20%	7%	23%	11%	10%	20%
Belgium	0%	21%	6%	6%	9%	13%	14%	12%	19%
Czech Republic	0%	17%	8%	6%	8%	15%	14%	6%	25%
Denmark	0%	7%	8%	3%	24%	11%	10%	13%	24%
Finland	0%	4%	43%	2%	4%	19%	15%	3%	10%
France	0%	16%	7%	5%	12%	10%	12%	16%	22%
Germany	0%	18%	12%	5%	9%	18%	11%	5%	23%
Ireland	0%	12%	4%	5%	21%	16%	12%	6%	24%
Italy	0%	10%	6%	9%	6%	15%	18%	14%	21%
Luxembourg	0%	9%	10%	4%	8%	13%	14%	8%	34%
Netherlands	0%	23%	5%	10%	10%	12%	17%	8%	16%
Norway	0%	13%	10%	8%	8%	16%	16%	8%	20%
Poland	0%	16%	7%	7%	13%	14%	16%	8%	19%
Portugal	0%	3%	8%	5%	11%	25%	31%	7%	11%
Slovakia	0%	11%	23%	3%	5%	16%	18%	3%	19%
Spain	0%	9%	5%	6%	9%	20%	19%	12%	20%
Sweden	0%	3%	34%	2%	4%	24%	20%	2%	11%
United Kingdom	0%	11%	8%	4%	13%	23%	11%	3%	27%

C.2 Detailed Result Tables of Industrial Cogeneration Potentials

Table C.3 Industrial CHP potential in the year 2009 in TWh/a (useful heat).

Country	High temperature 100-500°C				Low temperature <100°C			
	Demand	CHP	Boiler	Residual	Demand	CHP	Boiler	Residual
Austria	12.99	9.35	3.12	0.52	17.98	10.04	3.35	4.60
Belgium	14.09	8.88	2.96	2.25	17.76	10.36	3.45	3.95
Czech Republic	9.24	4.83	1.61	2.80	14.48	7.55	2.52	4.42
Denmark	3.96	2.74	0.91	0.30	7.11	4.28	1.43	1.40
Finland	32.96	24.22	8.07	0.66	17.65	10.66	3.55	3.44
France	42.08	20.97	6.99	14.11	59.93	27.55	9.18	23.19
Germany	76.34	46.90	15.63	13.81	91.10	50.44	16.81	23.85
Ireland	2.50	1.71	0.57	0.22	5.19	3.55	1.18	0.46
Italy	37.92	12.93	4.31	20.68	59.65	19.06	6.35	34.24
Luxembourg	0.36	0.22	0.07	0.07	0.84	0.52	0.17	0.15
Netherlands	21.03	13.94	4.65	2.45	24.51	15.24	5.08	4.20
Norway	7.93	5.49	1.83	0.60	9.16	4.82	1.61	2.73
Poland	20.70	10.73	3.58	6.40	27.51	13.08	4.36	10.07
Portugal	10.14	6.90	2.30	0.94	11.72	5.33	1.78	4.61
Slovakia	4.96	3.53	1.18	0.25	4.68	2.77	0.92	0.99
Spain	28.21	11.44	3.81	12.95	41.29	15.05	5.02	21.23
Sweden	35.80	25.94	8.65	1.21	20.09	12.29	4.10	3.70
United Kingdom	40.11	21.65	7.22	11.24	56.65	28.93	9.64	18.07

Table C.4 Industrial CHP potential in the year 2020 in TWh/a (useful heat).

Country	High temperature 100-500°C				Low temperature <100°C			
	Demand	CHP	Boiler	Residual	Demand	CHP	Boiler	Residual
Austria	14.64	10.54	3.51	0.59	20.27	11.32	3.77	5.18
Belgium	15.89	10.06	3.35	2.47	20.03	11.83	3.94	4.25
Czech Republic	10.45	5.50	1.83	3.11	16.38	8.63	2.88	4.88
Denmark	4.46	3.09	1.03	0.34	8.01	4.82	1.61	1.58
Finland	37.42	27.82	9.27	0.32	20.04	12.85	4.28	2.90
France	47.50	23.68	7.89	15.93	67.65	31.10	10.37	26.18
Germany	85.89	52.77	17.59	15.54	102.50	56.75	18.92	26.83
Ireland	2.82	1.96	0.65	0.21	5.86	4.05	1.35	0.46
Italy	42.73	14.57	4.86	23.30	67.21	21.47	7.16	38.58
Luxembourg	0.40	0.24	0.08	0.08	0.95	0.58	0.19	0.17
Netherlands	23.55	15.61	5.20	2.74	27.45	17.35	5.78	4.32
Norway	8.85	6.43	2.14	0.28	10.22	5.71	1.90	2.61
Poland	23.36	12.71	4.24	6.41	31.04	15.39	5.13	10.52
Portugal	11.40	7.76	2.59	1.06	13.17	6.50	2.17	4.50
Slovakia	5.62	4.01	1.34	0.28	5.30	3.18	1.06	1.07
Spain	31.74	13.85	4.62	13.28	46.46	17.72	5.91	22.83
Sweden	40.50	29.35	9.78	1.37	22.73	13.91	4.64	4.19
United Kingdom	45.22	25.43	8.48	11.31	63.87	33.79	11.26	18.82

Table C.5 Industrial CHP potential in the year 2030 in TWh/a (useful heat).

Country	High temperature 100-500°C				Low temperature <100°C			
	Demand	CHP	Boiler	Residual	Demand	CHP	Boiler	Residual
Austria	14.12	10.16	3.39	0.57	19.54	10.91	3.64	5.00
Belgium	15.31	9.65	3.22	2.44	19.30	11.26	3.75	4.29
Czech Republic	10.10	5.32	1.77	3.01	15.85	8.34	2.78	4.72
Denmark	4.30	2.98	0.99	0.33	7.71	4.64	1.55	1.52
Finland	36.32	27.00	9.00	0.31	19.45	12.18	4.06	3.21
France	45.84	22.85	7.62	15.37	65.28	30.01	10.00	25.26
Germany	82.59	50.74	16.91	14.94	98.56	54.57	18.19	25.80
Ireland	2.73	1.87	0.62	0.24	5.66	3.89	1.30	0.48
Italy	41.14	14.03	4.68	22.44	64.72	20.68	6.89	37.15
Luxembourg	0.39	0.23	0.08	0.08	0.91	0.56	0.19	0.16
Netherlands	22.53	14.93	4.98	2.62	26.25	16.59	5.53	4.13
Norway	8.44	6.13	2.04	0.27	9.75	5.45	1.82	2.49
Poland	22.52	12.26	4.09	6.18	29.93	14.84	4.95	10.14
Portugal	10.94	7.45	2.48	1.01	12.64	6.24	2.08	4.32
Slovakia	5.44	3.88	1.29	0.27	5.14	3.08	1.03	1.03
Spain	30.52	13.32	4.44	12.77	44.67	17.04	5.68	21.95
Sweden	39.18	28.39	9.46	1.32	21.99	13.45	4.48	4.05
United Kingdom	43.57	24.51	8.17	10.90	61.54	32.56	10.85	18.13

Table C.6 Industrial CHP potential in the year 2050 in TWh/a (useful heat).

Country	High temperature 100-500°C				Low temperature <100°C			
	Demand	CHP	Boiler	Residual	Demand	CHP	Boiler	Residual
Austria	12.62	9.08	3.03	0.51	17.47	9.75	3.25	4.47
Belgium	13.67	8.62	2.87	2.18	17.24	10.05	3.35	3.83
Czech Republic	9.09	4.75	1.58	2.76	14.25	7.43	2.48	4.35
Denmark	3.83	2.66	0.89	0.29	6.88	4.14	1.38	1.36
Finland	32.88	24.17	8.06	0.66	17.61	10.63	3.54	3.43
France	41.06	20.46	6.82	13.77	58.47	26.31	8.77	23.39
Germany	73.48	45.14	15.05	13.29	87.69	48.55	16.18	22.95
Ireland	2.45	1.67	0.56	0.22	5.09	3.48	1.16	0.45
Italy	36.71	12.52	4.17	20.02	57.75	18.45	6.15	33.15
Luxembourg	0.34	0.20	0.07	0.07	0.80	0.48	0.16	0.16
Netherlands	19.84	13.08	4.36	2.41	23.12	14.15	4.72	4.26
Norway	7.39	5.12	1.71	0.56	8.54	4.49	1.50	2.55
Poland	20.15	10.44	3.48	6.23	26.77	12.73	4.24	9.80
Portugal	9.71	6.58	2.19	0.93	11.22	4.94	1.65	4.63
Slovakia	4.91	3.50	1.17	0.25	4.64	2.74	0.91	0.99
Spain	27.15	11.01	3.67	12.47	39.74	14.48	4.83	20.43
Sweden	35.25	25.53	8.51	1.21	19.79	12.04	4.01	3.74
United Kingdom	38.92	21.01	7.00	10.91	54.97	28.08	9.36	17.54

Appendix D

Heating and Cooling Demand Profiles: Input

Table D.1 Assumed relative hourly heating and cooling demand.

Demand Day θ in °C	Space heating Working day					HW	Space heating Weekend day					HW	AC
	<0	0-5	5-10	10-15	>15	all	<0°C	0-5	5-10	10-15	>15	all	all
1	0.73	0.69	0.68	0.65	0.76	0.76	0.84	0.83	0.82	0.82	0.88	0.88	0.12
2	0.72	0.68	0.66	0.63	0.76	0.76	0.82	0.80	0.80	0.81	0.88	0.88	0.10
3	0.71	0.69	0.68	0.64	0.75	0.75	0.84	0.82	0.80	0.82	0.88	0.88	0.07
4	0.73	0.69	0.69	0.66	0.76	0.76	0.84	0.83	0.82	0.83	0.90	0.90	0.05
5	0.75	0.72	0.71	0.68	0.77	0.77	0.85	0.85	0.83	0.83	0.92	0.92	0.04
6	0.80	0.77	0.76	0.74	0.81	0.81	0.87	0.87	0.84	0.86	0.92	0.92	0.03
7	0.88	0.87	0.87	0.86	0.89	0.89	0.91	0.92	0.90	0.93	0.95	0.95	0.07
8	0.96	0.97	0.96	0.97	0.96	0.96	0.95	0.96	0.95	0.97	0.98	0.98	0.09
9	1.00	1.00	1.00	1.00	1.00	1.00	0.97	0.98	0.98	0.99	1.00	1.00	0.11
10	1.00	0.99	0.97	0.94	0.95	0.95	1.00	1.00	1.00	1.00	0.99	0.99	0.15
11	0.99	0.96	0.90	0.85	0.90	0.90	0.99	0.99	0.99	0.96	0.97	0.97	0.24
12	0.96	0.93	0.83	0.80	0.86	0.86	0.96	0.95	0.96	0.90	0.93	0.93	0.33
13	0.93	0.89	0.77	0.76	0.85	0.85	0.92	0.92	0.90	0.86	0.91	0.91	0.46
14	0.91	0.86	0.73	0.72	0.83	0.83	0.90	0.90	0.85	0.84	0.89	0.89	0.64
15	0.88	0.86	0.73	0.71	0.80	0.80	0.89	0.90	0.81	0.81	0.88	0.88	0.82
16	0.89	0.86	0.73	0.68	0.79	0.79	0.90	0.89	0.81	0.78	0.85	0.85	0.95
17	0.90	0.86	0.74	0.66	0.77	0.77	0.91	0.90	0.85	0.78	0.84	0.84	1.00
18	0.90	0.85	0.74	0.64	0.76	0.76	0.93	0.93	0.88	0.77	0.83	0.83	0.98
19	0.90	0.86	0.75	0.64	0.75	0.75	0.97	0.98	0.89	0.78	0.84	0.84	0.84
20	0.88	0.85	0.74	0.65	0.74	0.74	0.99	1.00	0.90	0.80	0.83	0.83	0.59
21	0.84	0.85	0.75	0.66	0.75	0.75	0.97	0.98	0.92	0.83	0.84	0.84	0.48
22	0.82	0.83	0.75	0.68	0.76	0.76	0.94	0.96	0.93	0.85	0.85	0.85	0.32
23	0.81	0.80	0.75	0.68	0.77	0.77	0.93	0.95	0.91	0.85	0.87	0.87	0.24
24	0.76	0.75	0.72	0.66	0.77	0.77	0.89	0.91	0.89	0.86	0.88	0.88	0.17

Table D.2 Hourly process heat demand, relative to installed capacity, subdivided by FLH class and weekday (Mon = Monday, T-T = Tuesday-Thursday, Fri = Friday, Sat = Saturday, Sun = Sunday).

7000-7999 FLH						6000-6999 FLH					5000-5999 FLH					4250-4999 FLH					3750-4249 FLH					3250-3749 FLH					<3250 FLH				
h	Mon	T-T	Fri	Sat	Sun	Mon	T-T	Fri	Sat	Sun	Mon	T-T	Fri	Sat	Sun	Mon	T-T	Fri	Sat	Sun	Mon	T-T	Fri	Sat	Sun	Mon	T-T	Fri	Sat	Sun	Mon	T-T	Fri	Sat	Sun
1	0.8	0.9	0.9	0.8	0.8	0.65	0.79	0.79	0.65	0.65	0	0.77	0.77	0.77	0	0	0.77	0.77	0	0	0	0.5	0.5	0	0	0	0	0	0	0	0	0	0	0	0
2	0.8	0.9	0.9	0.8	0.8	0.65	0.79	0.79	0.65	0.65	0	0.77	0.77	0.77	0	0	0.77	0.77	0	0	0	0.5	0.5	0	0	0	0	0	0	0	0	0	0	0	0
3	0.8	0.9	0.9	0.8	0.8	0.65	0.79	0.79	0.65	0.65	0	0.77	0.77	0.77	0	0	0.77	0.77	0	0	0	0.5	0.5	0	0	0	0	0	0	0	0	0	0	0	0
4	0.8	0.9	0.9	0.8	0.8	0.65	0.79	0.79	0.65	0.65	0	0.77	0.77	0.77	0	0	0.77	0.77	0	0	0	0.5	0.5	0	0	0	0	0	0	0	0	0	0	0	0
5	0.8	0.9	0.9	0.8	0.8	0.65	0.79	0.79	0.65	0.65	0.5	0.77	0.77	0.77	0	0.3	0.77	0.77	0	0	0.3	0.5	0.5	0	0	0.3	0.3	0.3	0	0	0.3	0.3	0.3	0	0
6	0.8	0.9	0.9	0.8	0.8	0.8	0.79	0.79	0.65	0.65	0.8	0.77	0.77	0.77	0	0.7	0.77	0.77	0	0	0.7	0.7	0.7	0	0	0.7	0.7	0.7	0	0	0.7	0.7	0.7	0	0
7	0.9	0.9	0.9	0.8	0.8	0.9	0.79	0.79	0.65	0.65	0.9	0.77	0.77	0.77	0	0.9	0.77	0.77	0	0	0.9	0.8	0.8	0	0	0.9	0.9	0.9	0	0	0.9	0.9	0.9	0	0
8	0.95	0.9	0.9	0.8	0.8	0.9	0.79	0.79	0.65	0.65	0.95	0.77	0.77	0.77	0	0.95	0.77	0.77	0	0	0.95	0.8	0.8	0	0	0.95	0.95	0.95	0	0	0.95	0.95	0.95	0	0
9	0.95	0.9	0.9	0.8	0.8	0.85	0.79	0.79	0.65	0.65	0.95	0.77	0.77	0.77	0	0.95	0.77	0.77	0	0	0.95	0.8	0.8	0	0	0.95	0.95	0.95	0	0	0.95	0.95	0.95	0	0
10	0.9	0.9	0.9	0.8	0.8	0.79	0.79	0.79	0.65	0.65	0.85	0.77	0.77	0.77	0	0.8	0.77	0.77	0	0	0.8	0.8	0.8	0	0	0.8	0.8	0.8	0	0	0.8	0.8	0.8	0	0
11	0.9	0.9	0.9	0.8	0.8	0.79	0.79	0.79	0.65	0.65	0.8	0.77	0.77	0.77	0	0.77	0.77	0.77	0	0	0.8	0.8	0.8	0	0	0.8	0.8	0.8	0	0	0.8	0.8	0.8	0	0
12	0.9	0.9	0.9	0.8	0.8	0.79	0.79	0.79	0.65	0.65	0.77	0.77	0.77	0.77	0	0.77	0.77	0.77	0	0	0.8	0.8	0.8	0	0	0.8	0.8	0.8	0	0	0.8	0.8	0.8	0	0
13	0.9	0.9	0.9	0.8	0.8	0.79	0.79	0.79	0.65	0.65	0.77	0.77	0.77	0.77	0	0.77	0.77	0.77	0	0	0.8	0.8	0.8	0	0	0.8	0.8	0.8	0	0	0.8	0.8	0.8	0	0
14	0.9	0.9	0.9	0.8	0.8	0.79	0.79	0.79	0.65	0.65	0.77	0.77	0.77	0.77	0	0.77	0.77	0.77	0	0	0.8	0.8	0.8	0	0	0.8	0.8	0.8	0	0	0.8	0.8	0.8	0	0
15	0.9	0.9	0.9	0.8	0.8	0.79	0.79	0.79	0.65	0.65	0.77	0.77	0.77	0.77	0	0.77	0.77	0.77	0	0	0.8	0.8	0.8	0	0	0.8	0.8	0.8	0	0	0.8	0.8	0.8	0	0
16	0.9	0.9	0.8	0.8	0.8	0.79	0.79	0.79	0.65	0.65	0.77	0.77	0.77	0.77	0	0.77	0.77	0.77	0	0	0.8	0.8	0.8	0	0	0.8	0.8	0.8	0	0	0.8	0.8	0.8	0	0
17	0.9	0.9	0.8	0.8	0.8	0.79	0.79	0.79	0.65	0.65	0.77	0.77	0.77	0.77	0	0.77	0.77	0.77	0	0	0.8	0.8	0.8	0	0	0.8	0.8	0.8	0	0	0.8	0.8	0.8	0	0
18	0.9	0.9	0.8	0.8	0.8	0.79	0.79	0.65	0.65	0.65	0.77	0.77	0.77	0.77	0	0.77	0.77	0.77	0	0	0.8	0.8	0.8	0	0	0.8	0.8	0.8	0	0	0.7	0.7	0.6	0	0
19	0.9	0.9	0.8	0.8	0.8	0.79	0.79	0.65	0.65	0.65	0.77	0.77	0.77	0.77	0	0.77	0.77	0.77	0	0	0.8	0.8	0.8	0	0	0.8	0.8	0.8	0	0	0.5	0.5	0.3	0	0
20	0.9	0.9	0.8	0.8	0.8	0.79	0.79	0.65	0.65	0.65	0.77	0.77	0.77	0.6	0	0.77	0.77	0.6	0	0	0.5	0.5	0.5	0	0	0.8	0.8	0.8	0	0	0.2	0.2	0	0	0
21	0.9	0.9	0.8	0.8	0.8	0.79	0.79	0.65	0.65	0.65	0.77	0.77	0.77	0.4	0	0.77	0.77	0.2	0	0	0.5	0.5	0	0	0	0.7	0.7	0.5	0	0	0	0	0	0	0
22	0.9	0.9	0.8	0.8	0.8	0.79	0.79	0.65	0.65	0.65	0.77	0.77	0.77	0.1	0	0.77	0.77	0	0	0	0.5	0.5	0	0	0	0.2	0.2	0	0	0	0	0	0	0	0
23	0.9	0.9	0.8	0.8	0.8	0.79	0.79	0.65	0.65	0.65	0.77	0.77	0.77	0	0	0.77	0.77	0	0	0	0.5	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0
24	0.9	0.9	0.8	0.8	0.8	0.79	0.79	0.65	0.65	0.65	0.77	0.77	0.77	0	0	0.77	0.77	0	0	0	0.5	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0

Appendix E

REMix-OptiMo Input

E.1 Assessment Area

Table E.1 REMix-OptiMo model regions used in this work.

Model Node	Countries and regions included
Austria	Austria
BeNeLux	Belgium, Luxemburg, Netherlands
Denmark-West	Western Denmark (Jutland)
France	France
Ger-Central	Ger-TNT3, Ger-TNT4
Ger-East	Ger-50Hz0, Ger-50Hz1, Ger-50Hz3, Ger-50Hz4 (50Hertz)
Ger-North	Ger-TNT0, Ger-TNT1, Ger-TNT2, Ger-50Hz2 (Tennet, 50Hertz)
Ger-SouthEast	Ger-AMP6, Ger-TNT5, Ger-TNT6 (Amprion, Tennet)
Ger-SouthWest	Ger-TNBW1, Ger-TNBW2 (TransNet BW)
Ger-West	Ger-AMP1, Ger-AMP2, Ger-AMP3, Ger-AMP4, Ger-AMP5 (Amprion)
Iberia	Portugal, Spain
Italy	Italy
Northern Africa	Algeria, Morocco, Tunisia
Northern Europe	Eastern Denmark (Danish Archipelago), Finland, Norway, Sweden
Eastern Europe	Czech Republic, Poland, Slovak Republic
Switzerland	Liechtenstein, Switzerland
British Isles	Ireland, United Kingdom

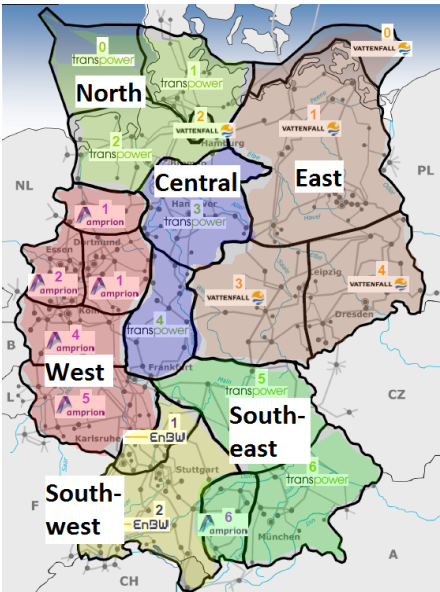


Figure E.1 Map of the subregions in Germany.

E.2 Heat Supply Scenario

Residential and Commercial Heat Supply

The future European DH supply is estimated based on the current diffusion and the potentials assessed in Chapter 3. In the Nordic countries Denmark, Sweden and Finland, the calculated potential has been found to be lower than today's market shares above 40%. For this reason, in these countries only a minor increase in market share of 5% until the year 2050 is assumed. As a consequence of overall demand reductions, the DH heat supply will be decreasing in those countries. In Poland, Austria, as well as the Czech and Slovak Republic, the identified potentials are in the range of the current supply share of around 30%. Nonetheless, it is assumed that the market shares can be augmented by 10% until 2050. All other countries in the study area feature a potential considerably exceeding the current DH utilization. According to the climatic conditions, different DH development paths are applied here. In the Mediterranean countries Spain, Italy and Portugal, where to date DH is almost not present at all, a DH share of 7.5% in the year 2050 is assumed. To the remaining countries (Belgium, Germany, France, Ireland, Liechtenstein, Luxembourg, the Netherlands, Norway, Switzerland and the UK), a market share gain of 15% is applied. Today, it reaches values between 0% in Ireland and 12% in Germany. For all countries it is assumed that half of the DH extension takes place before the year 2030, and the other half until 2050. The assumed development of national heat markets result in an increase of the overall assessment area DH supply share in the residential and commercial sector from 11.9% in 2008 to 23.6% in the year 2050. Due to the significant demand reductions, the amount of heat supplied by DH grows only to minor extent. It augments from 1223 PJ in 2008 to 1475 PJ in 2020, then decreasing to 1466 PJ in 2030 and 1414 PJ in 2050. According to the subdivision of the potential introduced in Section 3.1.3, the overall scenario DH supply is distributed to four technology size classes. Due to the much higher thermal loads, the predominant share of the heat sales are realized in DH networks with electric capacities exceeding 10 MW. As a result of the decreasing demand and the assumed extension of smaller DH networks, this share is however decreasing in the future. Figure E.2 shows the resulting DH heat supply for each country and scenario year.

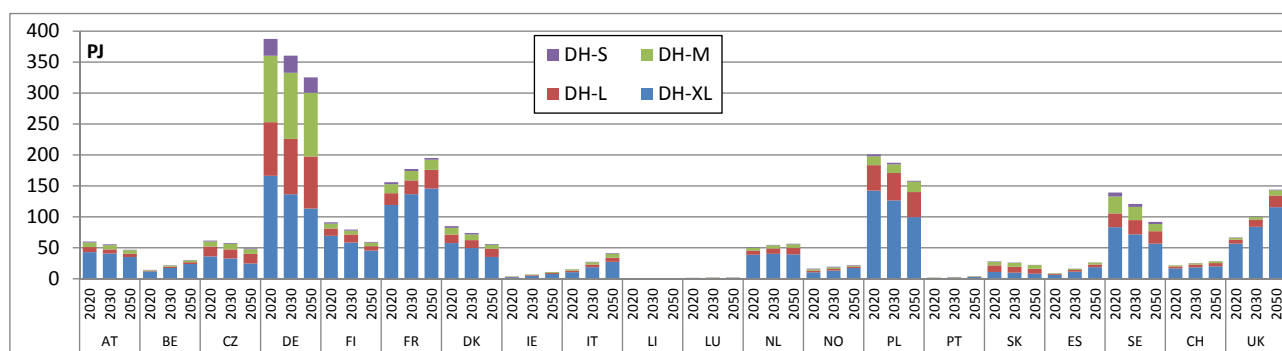


Figure E.2 District heating supply scenario.

Complementary to the DH supply, the future market shares of electric heat pumps are assessed. For residential and commercial buildings, air-to-water and ground-to-water HP are taken into account. A scenario of future HP technology diffusion in each country is derived based on market data [46–48, 75, 112, 145], the DH supply share and climatic conditions. The assumed supply shares in each

country are shown in Figure E.3. On European average, in the year 2050 air-to-water HP cover around 12%, ground-to-water around 8% of residential and commercial demand.

Table E.2 Assessment criteria and classification for the building CHP potential.

Classification	Not using DH/HP % of demand	Residential demand MWh/a/capita	Multi-family houses % of dwellings	Gas market share % of final energy
Very favorable (1)	>80%	>0.85	>60%	>55%
Favorable (2)	>70%	>0.7	>45%	>40%
Neutral (3)	>55%	>0.55	>35%	>25%
Unfavorable (4)	>40%	>0.4	>25%	>10%
Very unfavorable (5)	<40%	<0.4	<25%	<10%
Weighting	2	2	1	2

Analogous to the HP scenario, a development trajectory of building CHP systems with electric capacities below 50 kW is defined. It is assumed, that its contribution to the heat supply will be increasing in the future. National market potentials are estimated in accordance with the scenario for Germany presented in [135]. For each country, four parameters are considered: the share of buildings neither supplied by DH, nor by a HP, the inhabitant specific residential heat demand, the availability of natural gas distribution infrastructure and the share of multi-family buildings. These parameters are derived from statistical data [51] or premises of future developments. It is assumed that a low DH/HP share, a high specific heat demand, a high gas market share and a high share of multi-family buildings have positive impact on the building CHP dissemination. For each parameter, a numerical assessment is made (see Table E.2). It includes a weighting reflecting the assumption that the number of dwellings in multi-family buildings has a lower impact on the potential than the other parameters. The rating of all parameters are summed up for each country and used as reference for the assignment of a building CHP market share in the year 2050. Assumed values reach between 3% and 8%, with an European average of 5.4%.

Industrial Heat Supply

The industrial heat supply scenario relies on the analysis of demand and CHP potential introduced in Section 3.2. In addition to on-site CHP production, connection to a heat network and heat recovery discussed there, also the usage of industrial heat pumps is taken into account. For each country and scenario year, four values are regarded:

1. Exhaustion of the on-site CHP potential for the provision of process heat with temperatures between 100°C and 500°C
2. Exhaustion of the CHP potential for the provision of heat with temperatures below 100°C, subdivided into on-site production and heat networks. This subdivision is assessed separately for each country according to the DH market share
3. Network-based supply with heat at temperatures below 100°C to enterprises with demands below the threshold value applied for on-site production
4. Network-based supply with heat at temperatures between 100°C and 500°C to enterprises with demands below the threshold value applied for on-site production

According to the scenario, in 2050 the CHP potential for temperatures exceeding 100°C is exhausted to 80% in all countries. A complete exhaustion is not reached, given that a economic operation of CHP with heat extraction at temperatures higher than 350°C can not be realized in all cases [135]. To what extent the potential is used in earlier scenario years depends on the current industrial CHP dissemination in each country. For temperatures below 100°C, it is assumed that by the year 2050 all heat demand of enterprises with demand exceeding the on-site production threshold is either provided by on-site CHP or a heat network. The country-specific shares of on-site production are estimated from the current DH usage. Whether and to what extent also enterprises with lower demands are connected to a heat network is also derived from the current state of DH dissemination. Due to limitations in the methodology, in some countries the on-site CHP potential quantified in Section 3.2 is lower than the 2007 industrial CHP heat supply. In order to achieve an agreement with the statistical data, in those countries comparatively high shares of industrial heat network are applied.

Beyond the residential and commercial sector, HP can also be used for industrial heat supply. Given that the HP efficiency is mainly determined by the temperature spread between heat source and heat sink, its economic application is however mostly limited to space heat and hot water at temperatures below 70°C [119, 132]. Nonetheless, waste heat recovery using HP can be expedient in a number of industrial branches. In the scenario, it is assumed that electric HP have a significant contribution to future industrial heat generation. Depending on climate and DH diffusion, country-specific supply shares ranging from 1% to 5% of the industrial heat demand are applied. Higher values are found in countries with relatively low DH share. The HP shares assumed for the earlier scenario years 2020 and 2030 take into account the increasing efforts for a broader RE adoption in the heating sector. Figure E.3 shows the supply shares of DH, HP, industrial and building CHP. The detailed consideration of the remaining supply structure not related to the power market lies beyond the scope of this work.

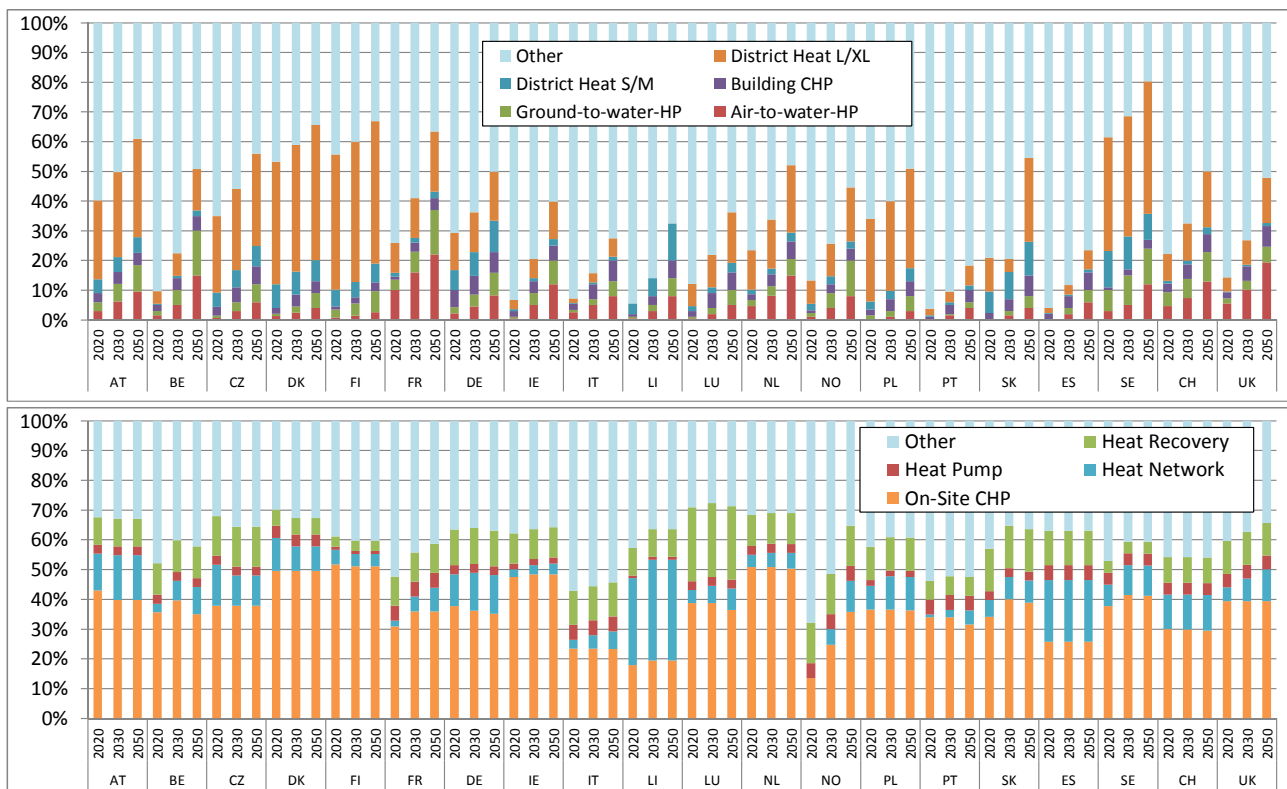


Figure E.3 Heat supply scenario for the residential/commercial sector (above), and industry (below).

Table E.3 Market shares of district heating, building CHP and heat pumps in the residential and commercial heat supply scenario, and of industrial CHP in the industrial heat supply scenario.

Country	District heating			Building CHP			Heat pump			Industrial CHP		
	2020	2030	2050	2020	2030	2050	2020	2030	2050	2020	2030	2050
Austria	31%	34%	39%	3.0%	4.0%	4.0%	6%	12%	19%	62%	64%	68%
Belgium	5%	8%	16%	2.0%	4.0%	5.0%	3%	10%	30%	44%	51%	54%
Czech Rep.	31%	33%	38%	3.0%	5.0%	6.0%	1%	6%	12%	57%	62%	66%
Denmark-E	66%	71%	80%	2.0%	4.0%	4.0%	2%	5%	9%	64%	66%	70%
Denmark-West	37%	36%	33%	2.0%	4.0%	4.0%	2%	5%	9%	64%	66%	70%
Finland	51%	52%	54%	1.0%	2.0%	3.0%	4%	6%	10%	59%	60%	64%
France	11%	15%	22%	1.0%	3.0%	4.0%	14%	23%	37%	38%	46%	54%
GER-AMP1	21%	27%	38%	5.7%	6.3%	6.5%	4%	9%	16%	58%	60%	65%
GER-AMP2	19%	23%	42%	6.0%	6.6%	6.9%	4%	9%	16%	58%	60%	65%
GER-AMP3	21%	26%	44%	6.2%	6.8%	7.1%	4%	9%	16%	58%	60%	65%
GER-AMP4	22%	28%	45%	6.3%	7.0%	7.3%	4%	9%	16%	58%	60%	65%
GER-AMP5	20%	26%	44%	6.2%	6.9%	7.2%	4%	9%	16%	58%	60%	65%
GER-AMP6	24%	30%	47%	6.2%	6.9%	7.2%	4%	9%	16%	58%	60%	65%
GER-TNBW1	24%	31%	49%	5.9%	6.5%	6.8%	4%	9%	16%	58%	60%	65%
GER-TNBW2	25%	31%	49%	6.7%	7.4%	7.7%	4%	9%	16%	58%	60%	65%
GER-TNT1	22%	27%	42%	5.4%	6.0%	6.3%	4%	9%	16%	58%	60%	65%
GER-TNT2	20%	26%	39%	5.4%	5.9%	6.2%	4%	9%	16%	58%	60%	65%
GER-TNT3	21%	27%	40%	5.3%	5.9%	6.2%	4%	9%	16%	58%	60%	65%
GER-TNT4	21%	27%	42%	6.0%	6.7%	7.0%	4%	9%	16%	58%	60%	65%
GER-TNT5	21%	28%	41%	5.9%	6.5%	6.8%	4%	9%	16%	58%	60%	65%
GER-TNT6	25%	31%	51%	6.3%	7.0%	7.3%	4%	9%	16%	58%	60%	65%
GER-50Hz1	16%	21%	36%	4.6%	5.1%	5.4%	4%	9%	16%	58%	60%	65%
GER-50Hz2	21%	26%	51%	5.9%	6.5%	6.8%	4%	9%	16%	58%	60%	65%
GER-50Hz3	21%	28%	36%	5.3%	5.9%	6.3%	4%	9%	16%	58%	60%	65%
GER-50Hz4	18%	23%	33%	4.5%	5.1%	5.4%	4%	9%	16%	58%	60%	65%
Ireland	4%	8%	15%	2.0%	4.0%	5.0%	1%	9%	20%	57%	60%	62%
Italy	2%	4%	7%	2.0%	5.0%	7.0%	3%	7%	13%	34%	39%	50%
Liechtenstein	4%	6%	12%	1.0%	3.0%	6.0%	1%	5%	14%	0%	0%	0%
Luxemburg	9%	13%	20%	2.0%	5.0%	6.0%	1%	4%	10%	58%	61%	62%
Netherlands	15%	19%	26%	2.0%	4.0%	6.0%	7%	11%	20%	62%	65%	68%
Norway	10%	14%	21%	1.0%	3.0%	4.0%	2%	9%	20%	17%	36%	57%
Poland	30%	33%	38%	2.0%	4.0%	5.0%	2%	3%	8%	56%	60%	64%
Portugal	3%	5%	8%	1.0%	3.0%	4.0%	0%	2%	6%	38%	44%	49%
Slovakia	19%	14%	40%	2.0%	4.0%	7.0%	0%	3%	8%	49%	60%	63%
Spain	2%	4%	7%	2.0%	4.0%	6.0%	0%	4%	10%	53%	56%	59%
Sweden	51%	52%	53%	1.0%	2.0%	3.0%	10%	15%	24%	51%	59%	63%
Switzerland	10%	14%	21%	3.0%	5.0%	6.0%	9%	14%	23%	43%	46%	50%
UK	5%	9%	16%	2.0%	5.0%	7.0%	7%	13%	25%	52%	58%	66%

E.3 Electricity and Heat Demand

Table E.4 Conventional, electric vehicle, hydrogen electrolysis and heat pump electricity demand, as well as residential/commercial (RC) and industrial heat demand by region, all values in TWh/a.

Region	20Basis					30Basis					50H ₂ T						2050 all other				
	Electricity		Heat			Electricity		Heat			Electricity		Heat				Electricity		Heat		
	Conv.	EV	HP	RC	Ind.	Conv.	EV	HP	RC	Ind.	Conv.	EV	HP	H ₂	RC	Ind.	Conv.	EV	HP	RC	Ind.
	TWh _{el} /a					TWh _{th} /a					TWh _{el} /a						TWh _{el} /a				
Austria	68	1.9	1.2	54	28	64	5.0	2.0	46	27	60	3.7	2.1	11.2	34	25	60	6.8	2.1	34	25
BeNeLux	224	6.1	3.1	184	71	210	17.0	5.5	158	69	199	14.0	8.7	46.2	117	63	199	25.7	8.7	117	63
Denmark-West	25	0.6	0.2	28	5.5	24	1.8	0.4	24	5.4	22	0.8	0.5	2.3	17	5.0	22	1.5	0.5	17	5.0
France	536	14.5	17.5	383	91	499	40.7	24.3	327	90	474	33.9	27.1	81.9	241	84	474	62.0	27.1	241	84
GER-Central	62	2.4	0.9	58	15	52	6.5	1.4	49	14	45	5.1	1.7	13.1	34	13	46	9.3	1.7	34	13
GER-East	162	3.5	1.8	124	21	143	9.6	2.8	100	20	136	7.5	3.3	20.2	70	19	130	13.7	3.3	70	19
GER-North	54	2.1	0.9	58	12	45	5.7	1.4	50	12	39	4.4	1.7	11.7	36	11	40	8.1	1.7	36	11
GER-SouthEast	75	3.3	1.4	89	27	62	8.9	2.2	76	26	51	6.9	2.7	18.3	54	24	53	12.7	2.7	54	24
GER-SouthWest	68	2.9	1.1	70	26	56	7.8	1.8	59	25	47	6.1	2.2	15.8	42	23	48	11.1	2.2	42	23
GER-West	154	6.6	2.4	160	48	126	18.0	3.9	135	47	107	14.1	4.8	36.4	96	43	109	25.7	4.8	96	43
Iberia	352	10.3	0.2	152	82	359	30.5	2.1	138	80	341	30.5	4.0	82.4	112	74	341	50.0	4.0	112	74
Italy	342	14.3	2.6	230	86	349	37.7	4.8	202	84	332	30.5	6.7	62.5	154	78	332	50.0	6.7	154	78
Northern Europe	386	4.7	4.2	191	120	361	12.9	6.2	164	119	343	12.4	7.4	37.4	120	112	343	20.4	7.4	120	112
Eastern Europe	251	8.3	1.4	263	71	263	22.2	3.0	227	70	258	16.8	4.8	95.0	168	65	258	30.6	4.8	168	65
Switzerland	67	1.9	2.1	61	16	64	5.0	2.5	52	15	61	3.9	2.8	6.7	38	14	61	7.1	2.8	38	14
British Isles	414	14.3	9.2	401	92	393	40.6	14.5	347	91	374	39.4	19.5	67.2	267	84	374	64.5	19.5	267	84

E.4 Power Generation Capacities

Table E.5 Installed electric capacity of conventional power generation technologies in MW_{el} by region.

Region	20Basis					30Basis					50H ₂ T			2050 all other		
	CCGT	GT	Coal	Lign.	Nucl.	CCGT	GT	Coal	Lign.	Nucl.	CCGT	GT	Coal	CCGT	GT	Coal
	MW _{el}					MW _{el}					MW _{el}			MW _{el}		
Austria	488	1642	923	0	0	163	788	0	0	0	171	239	0	171	239	0
BeNeLux	13911	8071	4674	0	3998	12126	6863	1708	0	2999	7924	4202	267	7924	4202	267
Denmark-West	325	2821	152	0	0	352	2267	175	0	0	460	1822	0	460	1822	0
France	719	13181	4363	0	45012	3398	13805	2980	0	20600	4485	13258	1600	4485	13258	1600
GER-Central	2583	448	1289	213	856	2665	462	848	96	0	2344	414	64	1432	248	64
GER-East	2953	512	1199	5694	0	3048	528	788	2575	0	2680	473	59	1638	284	59
GER-North	832	144	4194	0	1761	859	149	2758	0	0	755	133	208	461	80	208
GER-SouthEast	3814	661	187	0	3511	3936	682	123	0	0	3461	611	9	2115	367	9
GER-SouthWest	957	166	2369	0	1595	987	171	1557	0	0	868	153	117	531	92	117
GER-West	7767	1346	6918	6532	877	8016	1389	4549	2954	0	7049	1244	343	4307	747	343
Iberia	14785	4697	7662	135	5533	16004	2740	5536	413	2019	11762	1145	1419	11762	1145	1419
Italy	23031	19667	5668	0	0	22922	18185	3556	0	0	15198	8279	1167	15198	8279	1167
Northern Europe	5043	3160	1375	125	7707	5624	2896	1293	0	2044	6417	2567	0	6417	2567	0
Eastern Europe	2321	3110	9543	9643	5248	2877	4530	6991	4916	3001	4793	4215	2491	4793	4215	2491
Switzerland	432	315	300	0	2230	134	125	300	0	1150	150	46	0	150	46	0
British Isles	28172	13489	25641	159	4924	28513	13825	18808	0	2453	29609	10535	7555	29609	10535	7555

Table E.6 Installed electric capacity of fluctuating renewable power plants (PV = photovoltaic, On = onshore wind, Off = offshore wind) in MW_{el} by region.

Region	20Basis			30Basis			50H ₂ T			50CSP			2050 all other		
	PV	On	Off	PV	On	Off	PV	On	Off	PV	On	Off	PV	On	Off
	MW _{el}			MW _{el}			MW _{el}			MW _{el}			MW _{el}		
Austria	1910	4103	0	3022	6475	0	9956	11217	0	5271	7022	0	7714	8691	0
BeNeLux	10529	12444	5041	18791	14421	12721	34167	18719	22367	19343	14158	18021	26846	18719	17574
Denmark-West	178	0	1229	509	3264	1635	1477	3894	2477	849	3397	2371	1406	3705	2356
France	16718	31284	5378	42022	48828	16276	65654	63177	40260	19096	38713	41250	59734	57480	36629
GER-Central	4273	5013	0	5374	6219	0	6409	7595	0	5365	6265	0	6079	6834	0
GER-East	13043	14584	1612	16404	18093	4012	19563	22095	6059	16375	18227	5019	18557	19881	5621
GER-North	5247	9165	8346	6599	11370	20767	7869	13885	31363	6587	11454	25981	7465	12494	29098
GER-SouthEast	14279	1922	0	17959	2384	0	21418	2912	0	17928	2402	0	20316	2620	0
GER-SouthWest	6536	1858	0	8221	2305	0	9804	2815	0	8206	2322	0	9300	2533	0
GER-West	10122	8065	0	12731	10005	0	15183	12218	0	12709	10079	0	14402	10994	0
Iberia	11111	50308	408	17780	69425	1480	50435	108949	4874	16969	68743	4301	38332	82803	3704
Italy	31839	16611	941	46551	25066	4798	47729	62138	16325	45155	23048	10498	47729	43874	9477
Northern Europe	2228	8463	3722	5139	17917	10091	18048	27221	18100	11389	21009	15403	15076	22738	15120
Eastern Europe	10491	9559	1418	20982	27721	5558	50583	68820	14107	21422	26018	10747	33283	45283	9282
Switzerland	2068	2690	0	2663	7100	0	8563	7100	0	3015	7100	0	8563	7100	0
British Isles	3469	31289	7927	8607	40929	12653	24733	50411	26426	9864	37168	22396	20054	50411	21427

Table E.7 Installed electric capacity of adjustable renewable power and pumped hydro storage plants. Maximum storage capacity of hydrogen underground reservoirs.

Region	Hydro run-of-river			Solar CSP			Reservoir hydro						Pumped hydro		H ₂ Res.
	Turbine capacity			Turbine capacity			Turbine capacity			Storage capacity			Turbine	Stor.	Stor.
	2020	2030	2050	2020	2030	2050	2020	2030	2050	2020	2030	2050	all	all	all
	MW _{el}			MW _{el}			MW _{el}			GWh _{el}			MW _{el}	GWh _{el}	TWh _{el}
Austria	3870	4050	4200	0	0	0	5127	5500	5500	3038	3259	3259	1941	15.5	12.9
BeNeLux	387	725	1300	0	0	0	0	0	0	0	0	0	2305	18.4	40.3
Denmark-West	10	10	10	0	0	0	0	0	0	0	0	0	0	0.0	21.8
France	15983	15983	15983	178	540	700	12317	12317	12317	10406	10406	10406	4734	37.9	80.6
GER-Central	143	151	160	0	0	0	2	2	2	0	2	2	597	4.8	24.2
GER-East	150	158	168	0	0	0	0	0	0	0	0	0	2051	16.4	67.7
GER-North	7	8	8	0	0	0	0	0	0	0	0	0	0	0.0	54.8
GER-SouthEast	2329	2464	2615	0	0	0	148	148	148	32	165	165	0	0.0	0.0
GER-SouthWest	1236	1307	1387	0	0	0	133	133	133	28	149	149	2493	19.9	8.1
GER-West	456	482	512	0	0	0	67	67	67	14	75	75	1346	10.8	6.4
Iberia	13871	13871	13871	2665	5579	7879	15539	15539	15539	34339	34339	34339	4896	39.2	180.6
Italy	15450	15450	19814	198	600	1000	2350	2350	3350	2509	2509	3576	5936	47.5	16.1
Northern Europe	38565	39315	39315	0	0	0	10385	10385	10385	103651	103651	103651	1457	11.7	2.4
Eastern Europe	3106	3156	3509	0	0	0	983	983	983	1099	1099	1099	3472	27.8	209.6
Switzerland	15528	16210	16210	0	0	0	832	832	832	930	930	930	430	3.4	0.0
British Isles	2217	2347	2347	0	0	0	147	147	147	164	164	164	2542	20.3	61.3

Table E.8 Installed electric capacity and resource availability of geothermal and biomass power plants by region.

Region	Installed capacity						Annual resource availability								
	Geothermal			Solid biomass			Geoth. all TWh/a	Solid biomass			Biogas				
	2020	2030	2050	2020	2030	2050		2020	2030	2050	2020	2030	2050		
	MW _{el}			MW _{el}				TWh/a			TWh/a				
Austria	1	80	200	0	0	0	13	28	30	33	9	11	12		
BeNeLux	4	100	300	2666	1780	761	34	16	17	17	17	17	17		
Denmark-West	0	25	100	93	57	104	4	6	6	6	16	21	23		
France	80	500	2700	0	0	0	359	104	108	113	220	293	339		
GER-Central	34	114	337	301	272	187	26	11	12	12	10	13	15		
GER-East	83	279	823	821	742	509	62	29	30	32	28	36	41		
GER-North	30	100	295	326	295	202	22	8	8	8	10	12	14		
GER-SouthEast	55	184	545	381	344	236	41	15	16	18	13	17	19		
GER-SouthWest	43	142	420	276	250	171	32	11	11	12	8	10	11		
GER-West	54	179	530	695	629	431	40	21	21	22	15	20	22		
Iberia	125	600	3500	833	1504	2312	94	54	55	57	22	25	27		
Italy	920	1920	3738	1727	1432	6483	107	48	50	53	12	12	12		
Northern Europe	50	275	900	386	171	1201	12	169	174	182	19	24	27		
Eastern Europe	29	290	1950	222	309	324	176	76	80	86	50	62	70		
Switzerland	30	120	700	0	0	376	19	5	5	5	4	4	4		
British Isles	3	83	170	1537	620	0	46	43	44	46	31	31	31		

Table E.9 Installed electric capacity of large DH-CHP in MW_{el} by region.

Region	DH-ST-Coal			DH-ST-Lignite			DH-ExCCGT-NGas			DH-ST-Waste			DH-BpCCGT-NGas		
	2020	2030	2050	2020	2030	2050	2020	2030	2050	2020	2030	2050	2020	2030	2050
	MW _{el}			MW _{el}			MW _{el}			MW _{el}			MW _{el}		
Austria	93	0	0	0	0	0	3032	1951	1288	227	227	202	0	0	0
BeNeLux	420	177	0	0	0	0	1942	1962	1537	309	452	588	0	0	0
Denmark-West	599	146	0	0	0	0	112	66	0	234	216	204	0	0	0
France	469	304	0	0	0	0	7744	7632	8782	744	908	1355	0	0	0
GER-Central	318	252	145	0	0	0	367	423	480	236	231	210	183	124	66
GER-East	479	380	360	307	244	0	903	1040	1344	504	493	417	391	263	131
GER-North	461	366	277	0	0	0	535	616	919	223	218	216	173	117	68
GER-SouthEast	534	424	388	0	0	0	592	682	717	324	317	378	251	169	119
GER-SouthWest	430	342	282	0	0	0	441	508	307	366	358	292	284	191	92
GER-West	800	536	531	676	641	0	1672	1926	2817	543	531	557	422	284	175
Iberia	0	0	0	0	0	0	378	400	8	82	170	293	0	0	0
Italy	124	105	0	0	0	0	288	411	127	100	191	331	0	0	0
Northern Europe	2167	582	0	445	0	0	2550	2176	123	1347	1384	1411	0	0	0
Eastern Europe	6944	5861	2552	4027	2473	0	721	760	1786	1547	1929	2321	0	0	0
Switzerland	0	0	0	0	0	0	627	705	0	137	219	265	0	0	0
British Isles	0	0	0	0	0	0	2348	2422	4042	286	509	885	0	0	0

Table E.10 Installed electric capacity of small DH-CHP and building CHP in MW_{el} by region.

Region	DH-ST-SolidBio			DH-Eng-NGas			DH-Eng-Biogas			Bld-Eng-NGas			Bld-Eng-Biogas		
	2020	2030	2050	2020	2030	2050	2020	2030	2050	2020	2030	2050	2020	2030	2050
	MW _{el}			MW _{el}			MW _{el}			MW _{el}			MW _{el}		
Austria	255	636	703	100	10	0	144	149	131	85	86	46	40	63	75
BeNeLux	646	1057	1625	42	27	12	94	133	186	211	341	225	78	181	368
Denmark-West	570	915	956	30	4	0	170	142	97	32	49	0	15	36	71
France	548	1263	1420	121	51	47	424	460	497	234	548	594	65	259	278
GER-Central	191	173	122	290	318	272	213	310	408	208	140	24	60	130	209
GER-East	289	262	184	455	501	335	340	496	480	418	282	47	120	261	418
GER-North	126	114	106	172	186	155	118	173	207	196	132	22	57	123	196
GER-SouthEast	251	227	172	375	411	349	273	398	514	292	197	33	84	182	292
GER-SouthWest	243	220	216	323	346	430	218	317	629	260	175	29	75	162	260
GER-West	357	323	337	461	492	588	304	444	834	645	434	73	186	403	645
Iberia	156	393	918	27	10	6	22	50	81	222	316	419	61	243	319
Italy	184	447	1004	23	13	3	29	75	98	298	515	400	82	378	654
Northern Europe	4286	4922	4785	165	92	0	730	687	641	64	76	15	122	305	404
Eastern Europe	504	1113	4402	864	847	577	438	452	612	400	551	437	167	440	652
Switzerland	356	386	749	10	13	1	36	52	73	78	114	0	86	125	234
British Isles	904	1802	2398	35	31	46	50	84	145	258	549	626	378	860	1001

Table E.11 Installed electric capacity of industrial CHP in MW_{el} by region.

Region	Ind-ST-Coal			Ind-ST-Lignite			Ind-GT-NGas			Ind-ST-SolidBio			Ind-Engine-NGas		
	2020	2030	2050	2020	2030	2050	2020	2030	2050	2020	2030	2050	2020	2030	2050
	MW _{el}			MW _{el}			MW _{el}			MW _{el}			MW _{el}		
Austria	158	0	0	0	0	0	342	342	236	912	1253	1525	417	254	84
BeNeLux	28	28	0	0	0	0	1119	1041	851	2004	2547	3143	910	672	225
Denmark-West	0	0	0	0	0	0	47	53	57	279	303	329	39	20	0
France	283	188	0	0	0	0	685	755	865	1905	2551	3314	286	362	203
GER-Central	115	117	0	0	0	0	541	471	341	279	365	414	71	115	115
GER-East	0	0	0	0	0	0	935	840	479	392	514	581	99	162	162
GER-North	43	44	0	0	0	0	510	452	286	234	306	346	59	96	96
GER-SouthEast	0	0	0	0	0	0	1213	1089	622	509	666	754	129	210	210
GER-SouthWest	201	205	102	0	0	0	947	825	487	489	640	725	124	201	201
GER-West	372	381	190	0	0	0	1759	1531	905	908	1189	1346	230	374	374
Iberia	34	0	0	0	0	0	822	698	487	1746	3162	3989	2189	853	191
Italy	110	63	0	0	0	0	412	466	449	772	1609	3349	2047	1451	222
Northern Europe	0	0	0	80	0	0	1273	1267	1014	4631	5685	6596	35	18	0
Eastern Europe	884	884	319	187	181	0	92	84	413	1963	2603	3594	1515	1211	589
Switzerland	0	0	0	0	0	0	149	149	102	499	550	638	0	0	0
British Isles	387	301	279	18	0	0	770	896	1099	1697	2385	2757	2448	2134	2019

E.5 Demand Response Potentials

See Table E.12 next page.

Table E.12 Installable DR capacity, average load reduction and increase in MW_{el} by region.

Region	HeatingAC-Res			HVAC-ComInd			CoolingWater-ComI			ProcessShift-Ind			WashingEq-Res			StorHeat-ResCom			ProcessShed-Ind		
	2020	2030	2050	2020	2030	2050	2020	2030	2050	2020	2030	2050	2020	2030	2050	2020	2030	2050	2020	2030	2050
	MW _{el}			MW _{el}			MW _{el}			MW _{el}			MW _{el}			MW _{el}			MW _{el}		
Installable capacity																					
GER-Central	1133	1202	1180	1730	1916	1909	348	359	329	266	282	322	5645	4729	3548	4092	3411	1964	264	267	285
GER-East	2271	2410	2366	4285	4745	4729	862	890	815	603	639	729	11315	9481	7113	8202	6838	3936	598	605	646
GER-North	1066	1131	1110	1648	1824	1818	331	342	313	366	388	442	5311	4450	3338	3850	3209	1847	363	367	392
GER-Southeast	1586	1683	1652	2029	2246	2238	408	421	386	396	419	478	7902	6621	4968	5728	4776	2749	392	397	424
GER-Southwest	1411	1497	1470	1652	1830	1823	332	343	314	441	468	534	7029	5890	4419	5095	4248	2445	438	443	473
GER-West	3504	3718	3650	4173	4620	4604	839	866	793	1504	1594	1818	17458	14627	10974	12655	10551	6073	1491	1509	1611
Average load reduction																					
GER-Central	276	211	106	121	139	151	104	108	101	116	123	141	38	39	39	220	171	82	141	155	188
GER-East	554	422	212	300	344	375	257	268	251	263	279	320	77	77	78	441	342	165	319	351	424
GER-North	260	198	100	115	132	144	99	103	96	160	169	194	36	36	37	207	161	77	193	213	257
GER-Southeast	387	295	148	142	163	178	122	126	119	173	183	210	54	54	54	308	239	115	210	231	279
GER-Southwest	344	262	132	116	133	145	99	103	97	193	204	234	48	48	48	274	213	102	233	257	311
GER-West	854	651	327	292	335	365	251	260	244	656	695	798	119	119	120	680	528	254	796	878	1058
Average load increase																					
GER-Central	787	939	1045	1329	1492	1519	116	120	110	50	53	60	437	457	515	3484	2916	1693	0	0	0
GER-East	1578	1882	2095	3292	3696	3761	287	297	272	77	81	91	875	917	1032	6985	5846	3394	0	0	0
GER-North	741	883	983	1266	1421	1446	110	114	104	46	48	55	411	430	484	3278	2744	1593	0	0	0
GER-Southeast	1102	1314	1463	1558	1750	1780	136	141	129	97	103	116	611	641	721	4878	4083	2370	0	0	0
GER-Southwest	980	1169	1302	1270	1425	1450	111	114	105	79	84	95	544	570	641	4339	3632	2109	0	0	0
GER-West	2435	2904	3233	3206	3599	3662	279	289	264	186	196	223	1350	1415	1592	10777	9020	5237	0	0	0

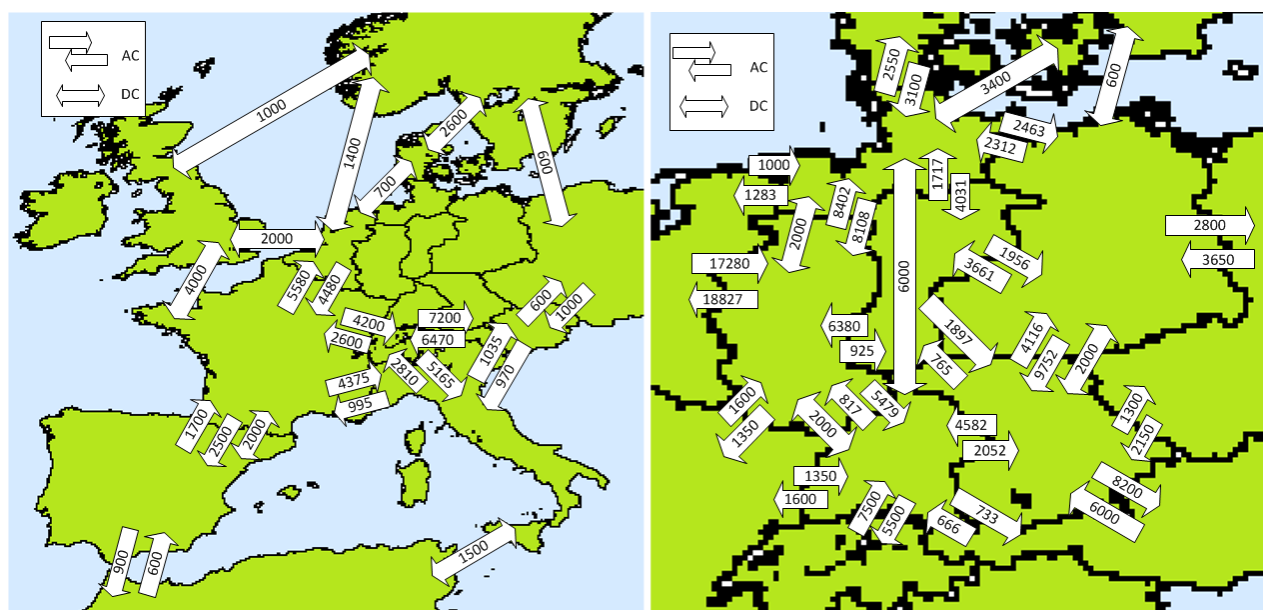
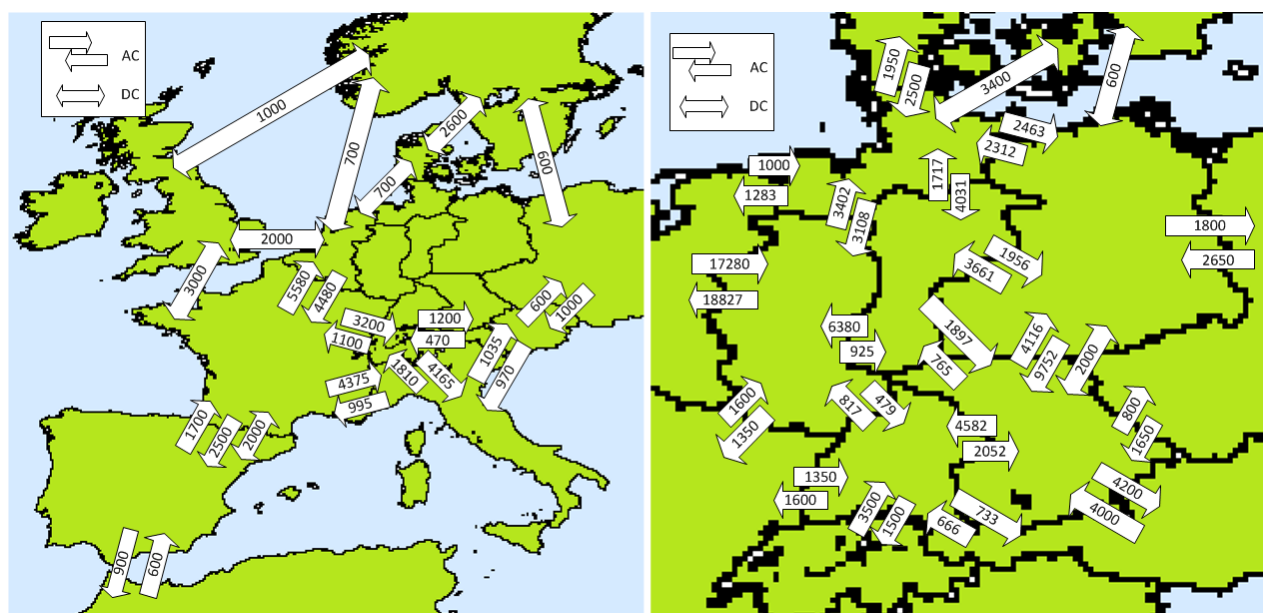


Figure E.5 Transmission grid net transfer capacities in the scenario year 2030 in Europe (left) and Germany (right).

E.7 Technology Parameter

Power Supply

Table E.13 Techno-economic parameter of CSP plants in REMix-OptiMo, including TES η_{TES} and power block η_{PB} efficiency, dimensioning of solar field f_{SF2PB} , TES f_{TES2PB} and back-up system relative to the power block, availability f_{Avail} and variable generation c_{OMVar} costs. All values extracted or derived from [135].

Techn.	η_{TES}	η_{PB}	f_{SF2PB}	f_{TES2PB}	f_{BUS}	f_{Avail}	c_{OMVar}
	%	%	–	–	%	%	€/MWh
CSP	95%	37%	3	6	100%	95%	0

Table E.14 Techno-economic parameter of reservoir hydro power plants in REMix-OptiMo, including power block η_{PB} and pump η_{Pump} efficiency, availability f_{Avail} and specific variable operational costs c_{OMVar} . All values extracted or derived from [168].

Techn.	η_{PB}	η_{Pump}	f_{Avail}	c_{OMVar}
	%	%	%	€/MWh
Reservoir hydro	90%	89%	98%	0

Table E.15 Techno-economic parameter of biomass and geothermal power plants in REMix-OptiMo, including efficiency η_{el} , availability f_{Avail} , variable generation c_{OMVar} and power change c_{WaT} costs. All values extracted or derived from [32, 117, 135].

Technology	η_{el}			f_{Avail}	c_{OMVar}	c_{WaT}
	2020	2030	2050			
		%		%	€/MWh	€/MW
Geothermal power	9.5%	10%	11%	95%	0	–
Biomass power	29%	29.5%	30.5%	95%	2	1

Table E.16 Techno-economic parameter of conventional power plants in REMix-OptiMo, including gross η_{gross} and net η_{net} efficiency, availability f_{Avail} , life time t_{life} , as well as variable generation c_{OMVar} and power change c_{WaT} costs. All values extracted or derived from [32, 117, 135].

Technology	Constr. Year	η_{gross} %	η_{net} %	f_{Avail} %	t_{life} years	c_{OMVar} €/MWh	c_{WaT} €/MW
ST-Lignite	1990	39.5%	37.0%	90.2%	40	0.1	1.5
ST-Lignite	2000	42.5%	40.0%	90.2%	40	0.1	1.5
ST-Lignite	2010	45.5%	43.0%	90.2%	40	0.1	1.5
ST-Lignite	2020	49.5%	46.8%	90.2%	40	0.1	1.5
ST-Lignite	2030	52.0%	49.1%	90.2%	40	0.1	1.5
ST-Lignite	2050	52.0%	49.1%	90.2%	40	0.1	1.5
ST-Coal	1990	41.7%	38.0%	89.6%	40	0.1	1.5
ST-Coal	2000	46.7%	43.0%	89.6%	40	0.1	1.5
ST-Coal	2010	49.5%	45.8%	89.6%	40	0.1	1.5
ST-Coal	2020	54.0%	50.0%	89.6%	40	0.1	1.5
ST-Coal	2030	55.0%	50.9%	89.6%	40	0.1	1.5
ST-Coal	2050	55.0%	50.9%	89.6%	40	0.1	1.5
CCGT	2000	55.9%	55.0%	96.0%	30	0.3	0.5
CCGT	2010	59.0%	58.1%	96.0%	30	0.3	0.5
CCGT	2020	61.0%	60.1%	96.0%	30	0.3	0.5
CCGT	2030	63.0%	62.1%	96.0%	30	0.3	0.5
CCGT	2050	63.0%	62.1%	96.0%	30	0.3	0.5
Gas turbine	2000	37.4%	37.0%	94.8%	30	0.3	0.5
Gas turbine	2010	40.0%	39.6%	94.8%	30	0.3	0.5
Gas turbine	2020	44.0%	43.6%	94.8%	30	0.3	0.5
Gas turbine	2030	46.0%	45.5%	94.8%	30	0.3	0.5
Gas turbine	2050	47.0%	46.5%	94.8%	30	0.3	0.5
ST-Nuclear	All	32.4%	30.9%	90.0%	60	0.1	1.5

Table E.17 Techno-economic parameter electricity-to-electricity storage, including charging η_{charge} , discharging $\eta_{discharge}$ and self-discharging η_{self} efficiency, availability f_{Avail} , as well specific investment costs $c_{specInv}$, amortization time t_{amort} , fixed c_{OMFix} and variable c_{OMVar} operational costs. All values extracted or derived from [1, 27, 35, 36, 74, 122, 173].

Technology	Storage						Converter			
	η_{charge} %	$\eta_{discharge}$ %	η_{self} %	f_{Avail} %	$c_{specInv}$ k€/MWh	t_{amort} a	$c_{specInv}$ k€/MW	t_{amort} a	c_{OMFix} %Invest/a	c_{OMVar} €/MWh
Hydrogen storage	70.0%	57.0%	0%	95%	0.2	30	1500	15	3%	0
Pumped storage	89.0%	90.0%	0%	98%			Not considered			0

Table E.18 Techno-economic parameter DC transmission lines, including nominal power P_{nom} , amortization time t_{amort} , fixed operational costs c_{OMFix} , as well as losses f_{Losses} and specific investment costs $c_{specInv}$ of land cables, sea cables and converters. All values derived from [188].

Technology	P_{nom} MW_{el}	f_{Losses}			$c_{specInv}$			t_{amort} years	c_{OMFix} %Invest/a
		Land	Sea	Conv.	Land	Sea	Conv.		
		%/100 km			M€/km		M€		
HVDC-1500	1500	0.45%	0.27%	0.70%	0.415	0.825	165	40	1%

Table E.19 Techno-economic parameter of CHP plants in REMix-OptiMo, including cooling share $s_{cooling}$, capacity-to-peak ratio $f_{Cap2Peak}$, overall efficiency η_{CHP} , electricity-to-heat ratio σ_W , power loss coefficient β , availability f_{Avail} , as well as specific investment costs $c_{specInv}$, amortization time t_{amort} , fixed c_{OMFix} and variable c_{OMVar} operational costs, and specific power change costs c_{WaT} . All values extracted or derived from [2, 32, 49, 50, 54, 117, 135].

Technology	Year	$s_{cooling}$ %	$f_{Cap2Peak}$ –	f_{Avail} –	σ_W –	β –	η_{CHP} %	$c_{specInv}$ k€/MW	t_{amort} a	c_{OMFix} % $_{Invest}/a$	c_{OMVar} €/MWh	c_{WaT} €/MW
DH-ST-Lignite-XL	2020	0%	0.6	90%	0.575	0.15	81.3%	1600	40	4%	0.3	2
DH-ST-Lignite-XL	2030	0%	0.6	90%	0.6	0.15	82.5%	1600	40	4%	0.3	2
DH-ST-Lignite-XL	2050	0%	0.6	90%	0.65	0.15	85.0%	1600	40	4%	0.3	2
DH-ST-Coal-XL	2020	0%	0.6	90%	0.575	0.15	81.3%	1600	40	4%	0.3	2
DH-ST-Coal-XL	2030	0%	0.6	90%	0.6	0.15	82.5%	1600	40	4%	0.3	2
DH-ST-Coal-XL	2050	0%	0.6	90%	0.65	0.15	85.0%	1600	40	4%	0.3	2
DH-ExCCGT-NGas-XL	2020	0%	0.6	95%	1.175	0.15	84.3%	850	25	5%	0.5	0.5
DH-ExCCGT-NGas-XL	2030	0%	0.6	95%	1.2	0.15	85.5%	850	25	5%	0.5	0.5
DH-ExCCGT-NGas-XL	2050	0%	0.6	95%	1.25	0.15	88.0%	850	25	5%	0.5	0.5
DH-ST-Waste-L	2020	0%	1.15	90%	0.275	0.1	61.3%	7000	20	4%	22	2
DH-ST-Waste-L	2030	0%	1.15	90%	0.3	0.1	62.5%	7000	20	4%	22	2
DH-ST-Waste-L	2050	0%	1.15	90%	0.35	0.1	65.0%	7000	20	4%	22	2
DH-BpCCGT-NGas-L	2020	50%	0.5	95%	1.025	0	84.3%	1100	20	5%	1	0.5
DH-BpCCGT-NGas-L	2030	50%	0.5	95%	1.05	0	85.5%	1100	20	5%	1	0.5
DH-BpCCGT-NGas-L	2050	50%	0.5	95%	1.1	0	88.0%	1100	20	5%	1	0.5
DH-ST-SolidBio-M	2020	0%	0.5	95%	0.425	0.15	81.3%	1900	25	5%	2	1.5
DH-ST-SolidBio-M	2030	0%	0.5	95%	0.45	0.15	82.5%	1900	25	5%	2	1.5
DH-ST-SolidBio-M	2050	0%	0.5	95%	0.5	0.15	85.0%	1900	25	5%	2	1.5
DH-Engine-NGas-M	2020	50%	0.6	98%	0.775	0	86.3%	850	20	2%	5	1
DH-Engine-NGas-M	2030	50%	0.6	98%	0.8	0	87.5%	850	20	2%	5	1
DH-Engine-NGas-M	2050	50%	0.6	98%	0.85	0	90.0%	850	20	2%	5	1
DH-Engine-Biogas-M	2020	50%	0.6	98%	0.775	0	83.3%	1100	20	2%	5	1
DH-Engine-Biogas-M	2030	50%	0.6	98%	0.8	0	84.5%	1100	20	2%	5	1
DH-Engine-Biogas-M	2050	50%	0.6	98%	0.85	0	87.0%	1100	20	2%	5	1
Bld-Engine-NGas-XS	2020	0%	0.5	99%	0.475	0	86.3%	2500	20	2%	15	1
Bld-Engine-NGas-XS	2030	0%	0.5	99%	0.5	0	87.5%	2500	20	2%	15	1
Bld-Engine-NGas-XS	2050	0%	0.5	99%	0.55	0	90.0%	2500	20	2%	15	1
Bld-Engine-Biogas-XS	2020	0%	0.5	99%	0.525	0	76.3%	3000	20	2%	15	1
Bld-Engine-Biogas-XS	2030	0%	0.5	99%	0.55	0	77.5%	3000	20	2%	15	1
Bld-Engine-Biogas-XS	2050	0%	0.5	99%	0.6	0	80.0%	3000	20	2%	15	1
Ind-ST-Lignite-XL	2020	0%	0.7	95%	0.425	0.15	78.3%	1600	40	4%	0.3	2
Ind-ST-Lignite-XL	2030	0%	0.7	95%	0.45	0.15	79.5%	1600	40	4%	0.3	2
Ind-ST-Lignite-XL	2050	0%	0.7	95%	0.5	0.15	82.0%	1600	40	4%	0.3	2
Ind-ST-Coal-XL	2020	0%	0.7	95%	0.425	0.15	78.3%	1600	40	4%	0.3	2
Ind-ST-Coal-XL	2030	0%	0.7	95%	0.45	0.15	79.5%	1600	40	4%	0.3	2
Ind-ST-Coal-XL	2050	0%	0.7	95%	0.5	0.15	82.0%	1600	40	4%	0.3	2
Ind-GT-NGas-L	2020	0%	0.6	95%	0.625	0	76.3%	800	20	4%	0.5	0.5
Ind-GT-NGas-L	2030	0%	0.6	95%	0.65	0	77.5%	800	20	4%	0.5	0.5
Ind-GT-NGas-L	2050	0%	0.6	95%	0.7	0	80.0%	800	20	4%	0.5	0.5
Ind-ST-SolidBio-M	2020	0%	0.7	95%	0.375	0.15	79.3%	1950	25	4%	2	2
Ind-ST-SolidBio-M	2030	0%	0.7	95%	0.4	0.15	80.5%	1950	25	4%	2	2
Ind-ST-SolidBio-M	2050	0%	0.7	95%	0.45	0.15	83.0%	1950	25	4%	2	2
Ind-Engine-NGas-M	2020	50%	0.6	98%	0.875	0	86.3%	850	20	2%	5	1
Ind-Engine-NGas-M	2030	50%	0.6	98%	0.9	0	87.5%	850	20	2%	5	1
Ind-Engine-NGas-M	2050	50%	0.6	98%	0.95	0	90.0%	850	20	2%	5	1

Heat Supply

Table E.20 Composition of flexible heat supply systems.

Technology name	CHP	Conventional Boiler	Thermal storage	Electric boiler
DH-ST-Lignite-XL	DH-ST-Lignite-XL	Lignite-fired Boiler-XL	TES-DH-CHP-XL	
DH-ST-Coal-XL	DH-ST-Coal-XL	Coal-fired Boiler-XL	TES-DH-CHP-XL	
DH-ExCCGT-NGas-XL	DH-ExCCGT-NGas-XL	Gas-fired Boiler-XL	TES-DH-CHP-XL	Boiler-Electric-XL-L
DH-ST-Waste-L	DH-ST-Waste-L			
DH-BpCCGT-NGas-L	DH-BpCCGT-NGas-L	Gas-fired Boiler-L	TES-DH-CHP-L	
DH-ST-SolidBio-M	DH-ST-SolidBio-M	Biomass-fired Boiler-M	TES-DH-CHP-M	Boiler-Electric-M-S
DH-Engine-NGas-M	DH-Engine-NGas-M	Gas-fired Boiler-M	TES-DH-CHP-M	Boiler-Electric-M-S
DH-Engine-Biogas-M	DH-Engine-Biogas-M	Gas-fired Boiler-M	TES-DH-CHP-M	Boiler-Electric-M-S
Bld-Engine-NGas-XS	Bld-Engine-NGas-XS	Gas-fired Boiler-XS	TES-Bld-CHP	
Bld-Engine-Biogas-XS	Bld-Engine-Biogas-XS	Gas-fired Boiler-XS	TES-Bld-CHP	
Ind-ST-Lignite-XL	Ind-ST-Lignite-XL	Lignite-fired Boiler-XL		
Ind-ST-Coal-XL	Ind-ST-Coal-XL	Coal-fired Boiler-XL		
Ind-GT-NGas-L	Ind-GT-NGas-L	Gas-fired Boiler-L		
Ind-ST-SolidBio-M	Ind-ST-SolidBio-M	Biomass-fired Boiler-M	TES-Ind-CHP	Boiler-Electric-M-S
Ind-Engine-NGas-M	Ind-Engine-NGas-M	Gas-fired Boiler-M		
HP-Ground2Water-XS	HP-Ground2Water-XS		TES-Bld-HP	Boiler-Electric-XS-HP
HP-Air2Water-XS	HP-Air2Water-XS		TES-Bld-HP	Boiler-Electric-XS-HP
HP-WasteHeat2Water-S	HP-WasteHeat2Water-S		TES-Ind-HP	Boiler-Electric-S-HP

Table E.21 Techno-economic parameter of electric heat pumps in REMix-OptiMo, including maximum COP $\eta_{HP,max}$, specific investment costs $c_{specInv}$, amortization time t_{amort} , fixed c_{OMFix} and variable c_{OMVar} operational costs, as well as COP coefficients a_1/a_2 and inlet temperature $\vartheta_{inletHP}$ of air-source HP. All values extracted or derived from [135, 145, 158, 159].

Technology	Year	$\varepsilon_{HP,max}$ %	$c_{specInv}$ k€/MW	t_{amort} years	c_{OMFix} % $_{Invest}/year$	c_{OMVar} €/MWh	a_1 –	a_2 –	$\vartheta_{inletHP}$ °C
HP-Ground2Water-XS	2020	3.6	1414	20	1.25%	0	–	–	–
HP-Ground2Water-XS	2030	3.8	1279	20	1.00%	0	–	–	–
HP-Ground2Water-XS	2050	4.2	1008	20	1.00%	0	–	–	–
HP-Air2Water-XS	2020	4.4	1004	20	1.25%	0	6.59	-0.02	46
HP-Air2Water-XS	2030	4.6	908	20	1.00%	0	6.89	-0.02	44
HP-Air2Water-XS	2050	4.9	715	20	1.00%	0	7.34	-0.02	41
HP-WasteHeat2Water-S	2020	3.4	700	20	3.00%	0	–	–	–
HP-WasteHeat2Water-S	2030	3.6	600	20	2.50%	0	–	–	–
HP-WasteHeat2Water-S	2050	3.9	500	20	2.00%	0	–	–	–

Table E.22 Techno-economic parameter thermal energy storage in REMix-OptiMo, including charging η_{charge} , discharging $\eta_{discharge}$ and self-discharging η_{self} efficiency, specific investment costs $c_{specInv}$, amortization time t_{amort} , maximum capacity-to-peak demand ratio $f_{Cap2Peak}$ and fixed operational costs c_{OMFix} . All values extracted or derived from [29, 32, 135, 175, 197].

Technology	η_{charge} %	$\eta_{discharge}$ %	η_{self} %/h	$c_{specInv}$ k€/MWh			$f_{Cap2Peak}$	t_{amort} a	c_{OMFix} %/Invest/a
				2020	2030	2050			
TES-DH-CHP-XL	98%	98%	0.1%	9.6	5.5	3.3	12	30	0.7%
TES-DH-CHP-L	98%	98%	0.2%	11.2	6.4	3.9	12	30	0.7%
TES-DH-CHP-M	98%	98%	0.3%	17.7	10.0	6.1	12	30	0.7%
TES-Bld-CHP	98%	98%	0.4%	23.8	13.3	8.0	7	20	0.7%
TES-Bld-HP	80%	98%	0.4%	40.0	22.2	13.8	5	20	0.7%
TES-Ind-HP	80%	98%	0.3%	33.3	18.5	11.5	4	20	0.7%
TES-Ind-CHP	98%	98%	0.2%	11.2	6.4	3.9	6	30	0.7%

Table E.23 Techno-economic parameter of electric boilers in REMix-OptiMo, including efficiency η_{th} , specific investment costs $c_{specInv}$, amortization time t_{amort} , fixed c_{OMFix} and variable c_{OMVar} operational costs. All values extracted or derived from [29, 32].

Technology	η_{th}	$c_{specInv}$	t_{amort}	c_{OMFix}	c_{OMVar}
	%	k€/MW	years	%Invest/year	€/MWh
Boiler-Electric-XL-L	99%	60	20	2%	0.5
Boiler-Electric-M-S	99%	90	20	1%	0.5
Boiler-Electric-S-HP	99%	120	20	1%	0
Boiler-Electric-XS-HP	99%	150	20	1%	0

Table E.24 Techno-economic parameter of conventional boilers in REMix-OptiMo, including efficiency η_{th} , specific investment costs $c_{specInv}$, amortization time t_{amort} , fixed c_{OMFix} and variable c_{OMVar} operational costs. All values extracted or derived from [32, 49, 50].

Technology	η_{th}	$c_{specInv}$	t_{amort}	c_{OMFix}	c_{OMVar}
	%	k€/MW	years	%Invest/year	€/MWh
Coal-fired Boiler-XL	80%	60	20	1%	10
Lignite-fired Boiler-XL	80%	60	20	1%	10
Gas-fired Boiler-XL	90%	60	20	1%	2
Gas-fired Boiler-L	90%	65	20	1%	2
Gas-fired Boiler-M	90%	75	20	2%	2
Biomass-fired Boiler-M	85%	75	20	2%	5
Gas-fired Boiler-XS	90%	100	20	2%	2

Fuel and CO₂ Prices

Table E.25 Fuel and CO₂ price scenarios according to [169].

	Coal	Lignite	Natural Gas	Uranium	Biogas	Solid Biom.	Waste	CO ₂
Year	€/MWh _{chem}	€/MWh _{chem}	€/MWh _{chem}	€/MWh _{chem}	€/MWh _{chem}	€/MWh _{chem}	€/MWh _{chem}	€/ton
2020	17.05	6.39	37.31	2.85	31.13	33.3	0	27
2030	19.31	6.88	42.80	2.85	33.33	33.3	0	45
2050	22.23	9.18	47.86	2.85	36.36	33.3	0	75

Appendix F

REMix-OptiMo Results

F.1 Step 1: Assessment of European Generation, Storage and Transmission Grid Operation

Table F.1 REMix-OptiMo output: power and heat generation and storage utilization in Germany Central.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Power generation in GWh/a									
Nuclear	0	0	0	0	0	0	0	0	6419
Lignite	0	0	0	0	0	0	0	558	1433
Coal	227	278	228	279	218	229	249	4021	5430
CCGT	4233	8337	4219	4855	4077	4373	4004	5603	5047
Gas turbine	835	178	435	782	927	854	278	25	146
DH-Engine-Biogas-M	2458	2563	2459	2599	2421	2483	2485	1548	1052
DH-Engine-NGas-M	1305	1305	1305	1305	1305	1305	1305	1555	1432
DH-ST-SolidBio-M	643	690	644	684	627	654	637	682	747
Ind-Engine-NGas-M	746	746	746	746	746	746	746	615	376
Ind-GT-NGas-L	2182	2182	2182	2182	2182	2182	2182	2504	2860
Ind-ST-Coal-M	0	0	0	0	0	0	0	412	396
Ind-ST-SolidBio-M	2212	2304	2212	2317	2200	2231	2208	1245	914
Bld-Engine-Biogas-XS	1059	1059	1059	1059	1059	1059	1059	665	308
Bld-Engine-NGas-XS	119	119	119	119	119	119	119	718	1070
DH-BpCCGT-NGas-L	340	340	340	340	340	340	340	647	968
DH-ExCCGT-NGas-XL	2221	2060	2175	2208	2203	2226	2067	1839	1596
DH-ST-Coal-XL	597	548	581	592	590	598	550	1035	1644
DH-ST-Waste-L	918	1002	918	1033	888	937	922	1229	1448
Run-of-river hydro	825	825	825	825	825	825	825	775	735
Photovoltaic	5886	6206	5887	5891	8793	5890	5201	5203	4142
Wind onshore	14466	16726	14509	14621	14167	20272	13572	13483	11330
Reservoir hydro	7	7	7	7	7	7	7	7	7
Biomass power	1293	1367	1320	1320	1274	1205	1308	2209	2505
Geothermal power	2800	2800	2800	2800	2800	2800	2800	947	283
CSP Import	0	0	0	0	0	0	7087	0	0
Import, export and RE curtailment in GWh/a									
AC import	13007	13523	13421	5798	10822	8737	7826	13979	14483
AC export	719	671	737	1023	974	2608	858	298	137
DC import	0	0	0	6332	0	0	1508	0	0
DC export	0	0	0	276	0	0	124	0	0
VRE curtailment	986	445	942	826	1325	3944	587	581	0
Installed capacity in MW									
Gas turbine	5693	1156	5140	4502	6165	5751	3005	462	1865
Electric storage input in GWh/a									
Pumped hydro storage	1237	428	1164	1075	1394	1149	808	890	702
Electric storage losses in GWh/a									
Pumped hydro storage	246	85	232	214	277	229	161	177	140
Heat production in GWh/a									
DH-Engine-Biogas	2306	2306	2306	2306	2306	2306	2306	1895	1357
DH-Engine-NGas	1535	1535	1535	1535	1535	1535	1535	1943	1848
DH-ST-SolidBio	965	965	965	965	965	965	965	1514	1758
Ind-Engine-NGas	785	785	785	785	785	785	785	683	430
Ind-GT-NGas	3117	3117	3117	3117	3117	3117	3117	3853	4577
Ind-ST-Coal	0	0	0	0	0	0	0	901	913
Ind-ST-SolidBio	4012	4012	4012	4012	4012	4012	4012	3069	2437
Bld-Engine-Biogas	1764	1764	1764	1764	1764	1764	1764	1210	587
Bld-Engine-NGas	217	217	217	217	217	217	217	1435	2252
DH-BpCCGT-NGas	309	309	309	309	309	309	309	617	945
DH-ExCCGT-NGas	1626	1626	1626	1626	1626	1626	1626	1512	1352
DH-ST-Coal	834	834	834	834	834	834	834	1578	2083
DH-ST-Waste	1290	1290	1290	1290	1290	1290	1290	1651	1840
HP-Ground2Water-XS	2833	2833	2833	2833	2833	2833	2833	2161	1274
HP-Air2Water-XS	2598	2598	2598	2598	2598	2598	2597	1949	1233
HP-WasteHeat2Water-S	452	452	452	452	452	452	452	262	86
EBoiler-HP-Air2Water-XS	38	38	38	38	38	38	39	33	17
EBoiler-HP-Ground2Water-XS	84	84	84	84	84	84	85	69	36
EBoiler-HP-WasteHeat2Water-S	5	5	5	5	5	5	5	3	1

Table F.2 REMix-OptiMo output: power and heat generation and storage utilization in Germany East.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Power generation in GWh/a									
Lignite	0	0	0	0	0	0	0	16081	40084
Coal	219	272	219	259	198	211	235	4031	4836
CCGT	4909	10226	4865	5312	4486	4502	4373	9684	6351
Gas turbine	2207	882	1506	1898	2328	1936	529	755	4
DH-Engine-Biogas-M	2785	2941	2783	2910	2684	2768	2781	2400	1597
DH-Engine-NGas-M	1493	1493	1493	1493	1493	1493	1493	2278	2132
DH-ST-SolidBio-M	927	1043	925	970	893	917	912	978	1082
Ind-Engine-NGas-M	1033	1033	1033	1033	1033	1033	1033	847	518
Ind-GT-NGas-L	3013	3013	3013	3013	3013	3013	3013	4377	4843
Ind-ST-SolidBio-M	3073	3265	3071	3163	3040	3043	3028	1738	1261
Bld-Engine-Biogas-XS	1970	1970	1970	1970	1970	1970	1970	1232	581
Bld-Engine-NGas-XS	222	222	222	222	222	222	222	1329	2015
DH-BpCCGT-NGas-L	636	637	636	636	636	636	635	1303	1988
DH-ExCCGT-NGas-XL	5885	5529	5780	5745	5778	5795	5341	4243	3627
DH-ST-Coal-XL	1400	1315	1372	1358	1369	1376	1246	1665	2313
DH-ST-Lignite-XL	0	0	0	0	0	0	0	1550	2060
DH-ST-Waste-L	1779	2054	1770	1924	1663	1734	1745	2737	3181
Run-of-river hydro	865	865	865	865	865	865	865	815	771
Photovoltaic	18048	19028	17368	18049	27044	18049	15926	15956	12686
Wind onshore	40642	46571	41382	41013	40192	67361	38376	39088	31643
Wind offshore	18793	20266	18804	18792	13533	10222	16790	13420	5393
Biomass power	3488	3675	3574	3586	3447	3234	3585	6139	6834
Geothermal power	6842	6842	6842	6842	6842	6842	6842	2319	691
Import, export and RE curtailment in GWh/a									
AC import	8486	10012	9043	4009	7418	5751	5480	16873	26583
AC export	7911	7876	7472	7072	8632	12538	6379	2539	206
DC import	30341	31924	30390	33576	29694	23694	37676	11982	10611
DC export	1633	1531	1914	2526	1649	5161	2158	3122	3523
VRE curtailment	2506	1371	2435	2134	3028	11782	1171	168	0
Installed capacity in MW									
Gas turbine	10632	3745	10640	7863	11052	10404	4113	4807	512
Electric storage input in GWh/a									
Hydrogen storage	0	0	79	0	0	0	0	0	0
Pumped hydro storage	4337	1462	4189	3593	5137	3908	2891	2951	2158
Electric storage losses in GWh/a									
Hydrogen storage	0	0	48	0	0	0	0	0	0
Pumped hydro storage	863	291	834	715	1022	778	575	587	429
Heat production in GWh/a									
DH-Engine-Biogas	2519	2519	2519	2519	2519	2519	2519	2818	2060
DH-Engine-NGas	1757	1757	1757	1757	1757	1757	1757	2848	2751
DH-ST-SolidBio	1379	1379	1379	1379	1379	1379	1379	2155	2546
Ind-Engine-NGas	1087	1087	1087	1087	1087	1087	1087	941	592
Ind-GT-NGas	4305	4305	4305	4305	4305	4305	4305	6733	7749
Ind-ST-SolidBio	5580	5580	5580	5580	5580	5580	5580	4237	3363
Bld-Engine-Biogas	3284	3284	3284	3284	3284	3284	3284	2240	1107
Bld-Engine-NGas	404	404	404	404	404	404	404	2658	4242
DH-BpCCGT-NGas	578	578	578	578	578	578	578	1241	1939
DH-ExCCGT-NGas	4178	4178	4178	4178	4178	4178	4178	3395	3078
DH-ST-Coal	1884	1884	1884	1884	1884	1884	1884	2150	2842
DH-ST-Lignite	0	0	0	0	0	0	0	1433	1933
DH-ST-Waste	2293	2293	2293	2293	2293	2293	2293	3176	3687
HP-Ground2Water-XS	5869	5869	5869	5869	5869	5869	5869	4518	2748
HP-Air2Water-XS	5344	5344	5344	5344	5344	5344	5344	4045	2642
HP-WasteHeat2Water-S	635	635	635	635	635	635	635	369	121
EBoiler-HP-Air2Water-XS	42	42	42	42	42	42	42	31	20
EBoiler-HP-Ground2Water-XS	91	91	91	91	91	91	91	67	41
EBoiler-HP-WasteHeat2Water-S	8	8	8	8	8	8	8	5	1

Table F.3 REMix-OptiMo output: power and heat generation and storage utilization in Germany North.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Power generation in GWh/a									
Nuclear	0	0	0	0	0	0	0	0	12702
Coal	569	703	571	788	554	637	651	10527	9439
CCGT	722	1092	698	888	747	803	649	769	597
Gas turbine	5	7	1	2	63	61	4	3	0
DH-Engine-Biogas-M	1189	1236	1188	1267	1175	1216	1204	879	600
DH-Engine-NGas-M	771	771	771	771	771	771	771	944	873
DH-ST-SolidBio-M	493	485	491	509	488	499	480	465	505
Ind-Engine-NGas-M	611	611	611	611	611	611	611	508	31
Ind-GT-NGas-L	1779	1779	1779	1779	1779	1779	1779	2372	2659
Ind-ST-Coal-M	0	0	0	0	0	0	0	154	149
Ind-ST-SolidBio-M	1663	1700	1659	1767	1670	1684	1662	1022	757
Bld-Engine-Biogas-XS	1042	1042	1042	1042	1042	1042	1042	656	298
Bld-Engine-NGas-XS	117	117	117	117	117	117	117	707	1034
DH-BpCCGT-NGas-L	363	363	363	363	363	363	363	636	942
DH-ExCCGT-NGas-XL	4270	4122	4177	4290	4265	4281	4116	2791	2379
DH-ST-Coal-XL	1138	1096	1111	1143	1137	1142	1096	1472	1819
DH-ST-Waste-L	751	828	742	889	745	788	767	1028	1280
Run-of-river hydro	42	42	42	42	42	42	42	40	37
Photovoltaic	6534	6887	6534	6533	9783	6532	5765	5775	4593
Wind onshore	20895	25017	26223	28107	25586	38209	27619	25807	26327
Wind offshore	114799	128106	121057	120794	85232	66173	109537	87881	35972
Biomass power	1219	1243	1325	1352	1272	1254	1352	2013	2691
Geothermal power	2459	2459	2459	2459	2459	2459	2459	834	248
Import, export and RE curtailment in GWh/a									
AC import	2195	1790	2095	2364	3373	3783	2429	65	318
AC export	30110	31959	30803	17895	25031	20431	20341	51632	44204
DC import	1150	959	773	483	1425	1360	958	2994	7023
DC export	83819	93693	85216	109849	68628	64109	93961	45540	11497
VRE curtailment	25803	22156	14216	12596	15902	17282	7906	8658	138
Installed capacity in MW									
Gas turbine	121	133	80	80	1039	823	80	149	144
Electric storage input in GWh/a									
Hydrogen storage	0	0	14850	0	0	0	0	0	0
Electric storage losses in GWh/a									
Hydrogen storage	0	0	8925	0	0	0	0	0	0
Heat production in GWh/a									
DH-Engine-Biogas	1217	1217	1217	1217	1217	1217	1217	1097	774
DH-Engine-NGas	907	907	907	907	907	907	907	1179	1126
DH-ST-SolidBio	875	875	875	875	875	875	875	1034	1189
Ind-Engine-NGas	643	643	643	643	643	643	643	565	355
Ind-GT-NGas	2541	2541	2541	2541	2541	2541	2541	3649	4254
Ind-ST-Coal	0	0	0	0	0	0	0	341	345
Ind-ST-SolidBio	3314	3314	3314	3314	3314	3314	3314	2544	2020
Bld-Engine-Biogas	1736	1736	1736	1736	1736	1736	1736	1192	568
Bld-Engine-NGas	214	214	214	214	214	214	214	1414	2178
DH-BpCCGT-NGas	330	330	330	330	330	330	330	606	919
DH-ExCCGT-NGas	3292	3292	3292	3292	3292	3292	3292	2324	2024
DH-ST-Coal	1685	1685	1685	1685	1685	1685	1685	2415	3103
DH-ST-Waste	1431	1431	1431	1431	1431	1431	1431	1684	1828
HP-Ground2Water-XS	2954	2954	2954	2954	2954	2954	2954	2257	1270
HP-Air2Water-XS	2705	2705	2705	2705	2705	2705	2705	2032	1228
HP-WasteHeat2Water-S	378	378	378	378	378	378	378	219	72
EBoiler-HP-Air2Water-XS	33	33	33	33	33	33	33	23	14
EBoiler-HP-Ground2Water-XS	76	76	76	76	76	76	76	55	31
EBoiler-HP-WasteHeat2Water-S	5	5	5	5	5	5	5	3	1

Table F.4 REMix-OptiMo output: power and heat generation and storage utilization in Germany Southeast.

[illegible]

Table F.5 REMix-OptiMo output: power and heat generation and storage utilization in Germany Southwest.

[illegible]

Table F.6 REMix-OptiMo output: power and heat generation and storage utilization in Germany West.

[illegible]

Table F.7 REMix-OptiMo output: power and heat generation and storage utilization in the assessment area.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Power generation in GWh/a									
Nuclear	0	0	0	0	0	0	0	248721	621539
Lignite	0	0	0	0	0	0	0	70205	160585
Coal	75507	77881	75458	75388	75319	75812	67881	290257	420655
CCGT	300547	330977	298898	283851	299177	302873	203614	403608	322298
Gas turbine	39929	28415	35654	21693	40370	39896	5666	20267	8937
DH-Engine-Biogas-M	33501	34597	33463	35195	33132	33772	33436	22380	17571
DH-Engine-NGas-M	12703	12705	12703	12705	12703	12703	12702	15152	16019
DH-ST-SolidBio-M	103325	106416	102979	100609	102751	103399	93363	57876	39237
Ind-Engine-NGas-M	27768	27769	27768	27768	27768	27768	27768	44827	58383
Ind-GT-NGas-L	52056	52056	52056	52056	52056	52056	52056	60262	63301
Ind-ST-Coal-M	4013	4020	4005	3955	4014	4012	3932	8617	10048
Ind-ST-SolidBio-M	179217	182662	178832	178890	179012	179567	170216	104165	72898
Bld-Engine-Biogas-XS	32171	32171	32171	32171	32171	32171	32171	22106	8907
Bld-Engine-NGas-XS	15735	15735	15735	15735	15735	15735	15735	23533	20163
DH-BpCCGT-NGas-L	3423	3424	3423	3423	3423	3423	3423	6131	9162
DH-ExCCGT-NGas-XL	117920	114384	116898	110317	117842	117861	104953	104382	104736
DH-ST-Coal-XL	18813	19155	18609	17735	18760	18776	16579	37398	53237
DH-ST-Lignite-XL	0	0	0	0	0	0	0	21667	36964
DH-ST-Waste-L	44455	46285	44205	45337	44047	44786	39931	42568	41876
Run-of-river hydro	352529	352538	352534	352538	352521	352521	352538	337266	327364
Photovoltaic	350565	411026	348120	352045	384697	350451	228774	245394	151930
Wind onshore	742265	883703	742976	768336	746165	794923	593610	630814	436188
Wind offshore	524725	636282	545292	535342	490034	467657	561157	336756	140233
Reservoir hydro	173737	171985	173411	169843	174182	173511	171522	164242	158790
Biomass power	101524	101549	103137	101984	101598	101373	101074	69225	85957
Geothermal power	94532	94532	94531	94532	94531	94531	94532	35193	12815
CSP Import	0	0	0	0	0	0	449995	0	0
Import, export and RE curtailment in GWh/a									
AC import/export	172018	165690	171583	84384	174980	166781	95468	139444	126894
DC import/export	195048	201236	196666	298424	183685	179479	267314	139428	89566
VRE curtailment	97682	98629	78844	59505	91647	103684	26015	15837	435
Installed capacity in MW									
Gas turbine	158049	105190	148763	150431	159208	158718	84836	103207	81681
Electric storage input in GWh/a									
Hydrogen storage	0	0	21960	0	0	0	0	0	0
Pumped hydro storage	57045	18384	55972	50037	61300	55948	36915	41267	30699
Electric storage losses in GWh/a									
Hydrogen storage	0	0	13198	0	0	0	0	0	0
Pumped hydro storage	11352	3658	11139	9957	12199	11134	7346	8212	6109
Heat production in GWh/a									
DH-Engine-Biogas	32124	32124	32124	32124	32124	32124	32124	26979	22645
DH-Engine-NGas	14942	14942	14942	14942	14942	14942	14942	18938	20670
DH-ST-SolidBio	160839	160839	160839	160839	160839	160839	160839	127691	92322
Ind-Engine-NGas	29229	29229	29229	29229	29229	29229	29229	49808	66724
Ind-GT-NGas	74366	74366	74366	74366	74366	74366	74366	92711	101282
Ind-ST-Coal	7858	7858	7858	7858	7858	7858	7858	18864	23513
Ind-ST-SolidBio	310224	310224	310224	310224	310224	310224	310224	255607	194391
Bld-Engine-Biogas	53618	53618	53618	53618	53618	53618	53618	40192	16965
Bld-Engine-NGas	28609	28609	28609	28609	28609	28609	28609	47067	42447
DH-BpCCGT-NGas	3112	3112	3112	3112	3112	3112	3112	5839	8939
DH-ExCCGT-NGas	83763	83763	83763	83763	83763	83763	83763	85520	88882
DH-ST-Coal	25352	25352	25352	25352	25352	25352	25352	55850	84798
DH-ST-Lignite	0	0	0	0	0	0	0	19482	32052
DH-ST-Waste	59145	59145	59145	59145	59145	59145	59145	56378	52404
HP-Ground2Water-XS	187844	187846	187844	187846	187841	187843	187846	144352	90295
HP-Air2Water-XS	127493	127498	127495	127498	127493	127492	127497	86983	52368
HP-WasteHeat2Water-S	30980	30980	30980	30980	30980	30980	30980	17106	5055
EBoiler-HP-Air2Water-XS	2452	2447	2450	2447	2452	2453	2448	1592	973
EBoiler-HP-Ground2Water-XS	7585	7583	7585	7583	7588	7586	7583	5705	3674
EBoiler-HP-WasteHeat2Water-S	410	409	410	409	410	410	410	228	68

F.2 Step 2a: DR Capacity Expansion

Table F.8 REMix-OptiMo output: DR capacity expansion results Germany Central.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Power generation and curtailment in GWh/a									
Nuclear	0	0	0	0	0	0	0	0	6427
Lignite	0	0	0	0	0	0	0	604	1477
Coal	237	275	233	273	228	234	241	4053	5406
CCGT	4235	8334	4149	4893	4061	4329	3927	5527	5046
Gas turbine	622	160	346	550	671	638	207	7	109
DH-Engine-Biogas-M	2467	2555	2467	2581	2430	2481	2469	1537	1051
DH-Engine-NGas-M	1305	1305	1305	1305	1305	1305	1305	1555	1432
DH-ST-SolidBio-M	646	690	644	682	624	654	631	681	747
Ind-Engine-NGas-M	746	746	746	746	746	746	746	615	376
Ind-GT-NGas-L	2182	2182	2182	2182	2182	2182	2182	2504	2860
Ind-ST-Coal-M	0	0	0	0	0	0	0	408	394
Ind-ST-SolidBio-M	2220	2304	2213	2310	2207	2233	2208	1234	915
Bld-Engine-Biogas-XS	1059	1059	1059	1059	1059	1059	1059	665	308
Bld-Engine-NGas-XS	119	119	119	119	119	119	119	718	1070
DH-BpCCGT-NGas-L	340	340	340	340	340	340	340	647	968
DH-ExCCGT-NGas-XL	2161	2054	2102	2171	2139	2169	2042	1818	1594
DH-ST-Coal-XL	579	548	558	582	572	582	543	1032	1640
DH-ST-Waste-L	924	1001	921	1029	900	940	920	1226	1454
Run-of-river hydro	825	825	825	825	825	825	825	776	735
Photovoltaic	5892	6210	5699	5893	8806	5892	5201	5203	4142
Wind onshore	14544	16731	14780	14727	14300	20472	13616	13506	11330
Reservoir hydro	7	7	7	7	7	7	7	7	7
Biomass power	1380	1386	1393	1410	1362	1264	1354	2211	2505
Geothermal power	2800	2800	2800	2800	2800	2800	2800	948	283
VRE curtailment	902	436	858	718	1179	3742	543	557	0
Installed electric capacities in MW									
Gas turbine	3670	980	3117	2677	4143	3739	1292	462	1348
HVAC-ComInd	1909	0	1909	0	1909	1909	0	0	0
CoolingWater-ComInd	329	329	329	329	329	329	329	359	348
ProcessShift-Ind	322	322	322	322	322	322	322	282	266
StorHeat-ResCom	1964	0	1964	1964	1964	1964	1964	0	3111
ProcessShed-Ind	285	285	285	285	285	285	285	267	264
Electric storage and load shifting in GWh/a									
Pumped hydro storage	784	386	726	655	919	784	582	668	617
E-Mobility-2h	30	4	22	38	35	27	18	13	1
E-Mobility-4h	203	19	161	236	253	202	112	78	18
E-Mobility-8h	761	125	661	804	836	766	492	357	59
HVAC-ComInd	65	0	57	0	78	64	0	0	0
CoolingWater-ComInd	32	11	26	35	47	38	24	18	14
ProcessShift-Ind	0.3	0.7	0.6	0.7	0.7	0.8	0	0.4	0
StorHeat-ResCom	0	1.3	1.3	1.2	1.3	1.3	0	2.6	0
ProcessShed-Ind	1.1	1.9	1.2	1.5	1.2	1.2	1.3	0	0.6
Demand Response Max. Reduction in MW									
HVAC-ComInd	151	0	151	0	151	151	0	0	0
CoolingWater-ComInd	218	152	244	194	218	222	176	202	200
ProcessShift-Ind	268	70	268	268	268	268	274	0	134
StorHeat-ResCom	319	0	319	326	337	323	294	0	643
ProcessShed-Ind	188	188	188	188	188	188	188	0	141
Demand Response Max. Increase in MW									
HVAC-ComInd	156	0	156	0	156	156	0	0	0
CoolingWater-ComInd	171	157	160	224	288	224	216	310	255
ProcessShift-Ind	71	71	71	71	71	71	120	0	59
StorHeat-ResCom	1040	0	1222	1036	1012	1035	1042	0	1133
Electricity Losses in GWh/a									
Pumped hydro storage	156	77	145	130	183	156	116	133	123
Demand response	7	0	6	5	10	9	5	1	5

Table F.9 REMix-OptiMo output: DR capacity expansion results Germany East.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Power generation and curtailment in TWh/a									
Lignite	0	0	0	0	0	0	0	16403	40108
Coal	229	274	227	249	209	209	228	4020	4839
CCGT	4984	10172	4893	5404	4575	4528	4274	9543	6321
Gas turbine	1784	839	1195	1516	1854	1599	436	573	2
DH-Engine-Biogas-M	2788	2939	2791	2871	2697	2754	2768	2373	1597
DH-Engine-NGas-M	1493	1494	1493	1494	1494	1493	1493	2278	2132
DH-ST-SolidBio-M	934	1042	930	973	893	925	897	973	1082
Ind-Engine-NGas-M	1033	1034	1033	1033	1033	1033	1033	848	518
Ind-GT-NGas-L	3013	3013	3013	3013	3013	3013	3013	4377	4843
Ind-ST-SolidBio-M	3110	3268	3102	3178	3073	3073	3018	1739	1261
Bld-Engine-Biogas-XS	1970	1970	1970	1970	1970	1970	1970	1232	581
Bld-Engine-NGas-XS	222	222	222	222	222	222	222	1329	2015
DH-BpCCGT-NGas-L	636	637	635	636	636	636	635	1303	1988
DH-ExCCGT-NGas-XL	5620	5512	5525	5618	5492	5541	5272	4167	3625
DH-ST-Coal-XL	1320	1316	1294	1321	1298	1302	1234	1652	2309
DH-ST-Lignite-XL	0	0	0	0	0	0	0	1557	2062
DH-ST-Waste-L	1818	2060	1813	1941	1704	1761	1733	2729	3181
Run-of-river hydro	865	865	865	865	865	865	865	815	771
Photovoltaic	17627	18846	17622	17693	26048	16362	15748	15927	12686
Wind onshore	42698	47674	42688	42722	42611	72046	39316	39227	31643
Wind offshore	17298	19357	17346	17543	12296	7508	16070	13341	5393
Biomass power	3730	3743	3740	3788	3697	3377	3776	6147	6834
Geothermal power	6842	6842	6842	6842	6842	6842	6842	2319	691
VRE curtailment	2365	1358	2333	2031	2842	11497	1130	137	0
Installed electric capacities in GW									
Gas turbine	7843	3491	7729	5722	8277	7744	2732	3362	512
HVAC-ComInd	4729	0	618	0	4729	0	0	0	0
CoolingWater-ComInd	815	815	815	815	815	815	815	890	0
ProcessShift-Ind	729	729	729	729	729	729	729	639	603
StorHeat-ResCom	3936	0	3936	3936	3936	3936	0	6838	0
ProcessShed-Ind	646	646	646	646	646	646	646	605	598
Electric storage and load shifting in GWh/a									
Pumped hydro storage	3150	1349	3082	2707	3965	3023	2410	2387	2105
E-Mobility-2h	54	11	65	88	67	79	49	25	1
E-Mobility-4h	400	44	373	393	437	397	212	168	23
E-Mobility-8h	1737	246	1607	1429	1787	1530	920	637	85
HVAC-ComInd	171	0	26	0	189	0	0	0	0
CoolingWater-ComInd	107	40	98	104	152	115	63	88	0
ProcessShift-Ind	0.7	1.4	1.1	1.4	1.3	0.9	0.9	0	0
StorHeat-ResCom	0	2.7	2.5	2.7	2.6	0	5.9	0	0
ProcessShed-Ind	1.7	3.8	1.7	1.9	1.7	1.7	3.0	1.4	0
Demand Response Max. Reduction in MW									
HVAC-ComInd	375	0	49	0	375	0	0	0	0
CoolingWater-ComInd	581	628	652	596	581	482	460	543	0
ProcessShift-Ind	563	197	576	584	563	472	198	259	0
StorHeat-ResCom	654	0	646	648	685	648	0	1510	0
ProcessShed-Ind	424	424	424	424	424	424	424	351	0
Demand Response Max. Increase in MW									
HVAC-ComInd	387	0	51	0	387	0	0	0	0
CoolingWater-ComInd	511	396	510	746	746	545	599	594	0
ProcessShift-Ind	108	108	132	108	108	108	108	100	0
StorHeat-ResCom	1668	0	1794	1927	2054	1702	0	2788	0
Electricity Losses in GWh/a									
Pumped hydro storage	627	268	613	539	789	602	480	475	419
Demand response	21	2	16	15	27	17	2	24	0

Table F.10 REMix-OptiMo output: DR capacity expansion results Germany North.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Power generation and curtailment in TWh/a									
Nuclear	0	0	0	0	0	0	0	0	12709
Coal	539	681	558	739	529	598	617	10480	9439
CCGT	722	1081	820	932	765	832	631	735	593
Gas turbine	1	5	6	1	36	36	2	0	0
DH-Engine-Biogas-M	1190	1231	1196	1260	1173	1212	1193	878	600
DH-Engine-NGas-M	771	771	771	771	771	771	771	944	873
DH-ST-SolidBio-M	500	485	507	521	497	511	479	465	505
Ind-Engine-NGas-M	611	611	611	611	611	611	611	508	311
Ind-GT-NGas-L	1779	1779	1779	1779	1779	1779	1779	2372	2659
Ind-ST-Coal-M	0	0	0	0	0	0	0	153	147
Ind-ST-SolidBio-M	1691	1700	1715	1777	1695	1711	1659	1019	757
Bld-Engine-Biogas-XS	1042	1042	1042	1042	1042	1042	1042	656	298
Bld-Engine-NGas-XS	117	117	117	117	117	117	117	707	1034
DH-BpCCGT-NGas-L	363	363	363	363	363	363	363	636	942
DH-ExCCGT-NGas-XL	4153	4120	4146	4186	4144	4159	4115	2789	2379
DH-ST-Coal-XL	1105	1096	1096	1109	1099	1105	1095	1467	1818
DH-ST-Waste-L	763	823	786	889	757	797	759	1021	1279
Run-of-river hydro	42	42	42	42	42	42	42	40	37
Photovoltaic	6424	6844	6493	6460	9464	6223	5738	5737	4593
Wind onshore	33575	37989	34933	35051	34389	49947	32554	32112	26457
Wind offshore	102344	115215	111615	114013	76865	54860	104676	81704	35843
Biomass power	1239	1254	1284	1392	1304	1286	1387	2026	2691
Geothermal power	2459	2459	2459	2459	2459	2459	2459	834	248
VRE curtailment	25688	22119	14990	12506	15785	17166	7859	8568	137
Installed electric capacities in GW									
Gas turbine	80	133	80	80	292	247	80	149	144
Hydrogen storage	0	0	1577	0	0	0	0	0	0
Hydrogen converter	0	0	5585	0	0	0	0	0	0
CoolingWater-ComInd	313	313	313	313	313	313	313	342	33
ProcessShift-Ind	442	442	442	442	442	442	442	388	366
StorHeat-ResCom	0	0	1847	0	397	0	0	0	0
ProcessShed-Ind	392	392	392	392	392	392	392	367	363
Electric storage and load shifting in GWh/a									
Hydrogen storage	0	0	13799	0	0	0	0	0	0
E-Mobility-2h	17	3	103	14	25	21	9	8	1
E-Mobility-4h	88	14	279	87	118	109	31	37	4
E-Mobility-8h	327	79	901	305	369	403	187	176	19
CoolingWater-ComInd	20.7	13.2	63.6	19.5	25.4	22.7	12.0	26.3	1.1
ProcessShift-Ind	0	0.6	0	0.6	0.4	0	0	0	0
StorHeat-ResCom	0	1.3	0	0.3	0	0	0	0	0
ProcessShed-Ind	0	0.0	0.6	0	1.1	2.4	0	0	0
Demand Response Max. Reduction in MW									
CoolingWater-ComInd	171	148	252	193	232	235	148	211	25
ProcessShift-Ind	0	0	172	0	225	165	0	0	0
StorHeat-ResCom	0	0	301	0	65	0	0	0	0
ProcessShed-Ind	0	0	236	0	234	257	0	0	0
Demand Response Max. Increase in MW									
CoolingWater-ComInd	225	150	282	196	264	288	152	290	27
ProcessShift-Ind	0	0	64	0	64	64	0	0	0
StorHeat-ResCom	0	0	1102	0	251	0	0	0	0
Electricity Losses in GWh/a									
Hydrogen storage	0	0	8293	0	0	0	0	0	0
Demand response	0.8	0.5	7.5	0.8	0.8	1.0	0.5	1.1	0

Table F.11 REMix-OptiMo output: DR capacity expansion results Germany Southeast.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Power generation and curtailment in TWh/a									
Nuclear	0	0	0	0	0	0	0	0	26382
Coal	28	38	28	41	26	28	32	652	614
CCGT	4334	6983	4195	5019	3905	4270	3607	8314	4262
Gas turbine	36	3	19	93	1	39	5	4	1
DH-Engine-Biogas-M	3178	3329	3176	3373	3109	3186	3207	2192	1478
DH-Engine-NGas-M	1876	1876	1876	1876	1876	1876	1876	2241	2034
DH-ST-SolidBio-M	860	851	856	893	834	860	832	987	1066
Ind-Engine-NGas-M	1345	1345	1345	1345	1345	1345	1345	1100	672
Ind-GT-NGas-L	3930	3930	3930	3930	3930	3930	3930	5683	6287
Ind-ST-SolidBio-M	3801	3894	3788	4039	3729	3797	3782	2204	1636
Bld-Engine-Biogas-XS	1649	1649	1649	1649	1649	1649	1649	1036	472
Bld-Engine-NGas-XS	186	186	186	186	186	186	186	1118	1638
DH-BpCCGT-NGas-L	680	680	680	680	680	680	680	985	1449
DH-ExCCGT-NGas-XL	3424	3420	3422	3424	3424	3424	3418	3266	2801
DH-ST-Coal-XL	1621	1620	1620	1622	1619	1621	1619	1895	2467
DH-ST-Waste-L	1514	1606	1504	1716	1448	1515	1497	1782	2067
Run-of-river hydro	13495	13495	13495	13495	13495	13495	13495	12716	12020
Photovoltaic	20247	21982	20346	20648	28388	20189	18302	18468	14683
Wind onshore	4232	4977	4260	4368	4017	2675	4053	4091	3298
Reservoir hydro	751	753	752	754	747	750	752	757	757
Biomass power	1775	1788	1798	1842	1680	1752	1785	2861	3169
Geothermal power	4539	4539	4538	4539	4539	4539	4539	1539	458
VRE curtailment	909	62	782	372	3429	870	202	2	0
Installed electric capacities in GW									
Gas turbine	367	611	367	438	367	367	367	682	661
CoolingWater-ComInd	386	386	386	386	386	386	386	0	0
ProcessShift-Ind	478	478	478	478	478	478	478	419	396
StorHeat-ResCom	0	0	0	2089	2749	0	0	0	0
ProcessShed-Ind	424	424	424	424	424	424	424	397	392
Electric storage and load shifting in GWh/a									
E-Mobility-2h	45	3	35	41	94	41	12	6	0
E-Mobility-4h	180	17	139	196	303	192	60	37	2
E-Mobility-8h	518	76	421	541	591	548	196	150	14
CoolingWater-ComInd	29.8	11.6	23.6	26.2	59.0	27.6	11.6	0.01	0
ProcessShift-Ind	0	0	1.1	0	0.1	0	0	0	0
StorHeat-ResCom	0	0	1.4	1.4	0	0	0	0	0
ProcessShed-Ind	0	0	0	0.9	0	0	0	0	0
Demand Response Max. Reduction in MW									
CoolingWater-ComInd	328	167	328	302	308	236	174	0	0
ProcessShift-Ind	83	0	0	408	0	116	0	0	0
StorHeat-ResCom	0	0	0	326	396	0	0	0	0
ProcessShed-Ind	0	0	0	279	0	0	0	0	0
Demand Response Max. Increase in MW									
CoolingWater-ComInd	338	189	348	340	354	348	200	0	0
ProcessShift-Ind	84	0	0	153	0	117	0	0	0
StorHeat-ResCom	0	0	0	1222	1557	0	0	0	0
Electricity Losses in GWh/a									
Demand response	1.2	0.4	1.0	5.0	10.1	1.1	0.5	0	0

Table F.12 REMix-OptiMo output: DR capacity expansion results Germany Southwest.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Power generation and curtailment in TWh/a									
Nuclear	0	0	0	0	0	0	0	0	11965
Coal	292	432	290	469	291	347	396	7263	11287
CCGT	758	1297	724	1040	765	876	572	1343	1580
Gas turbine	6	1	0	0	9	8	0	0	0
DH-Engine-Biogas-M	3641	3932	3631	4060	3594	3736	3827	1658	1142
DH-Engine-NGas-M	2200	2200	2200	2200	2200	2200	2200	1806	1692
DH-ST-SolidBio-M	1004	989	1000	1053	988	1024	957	918	1001
Ind-Engine-NGas-M	1315	1314	1314	1314	1315	1315	1314	1075	657
Ind-GT-NGas-L	3137	3137	3137	3137	3137	3137	3137	4375	4997
Ind-ST-Coal-M	461	461	461	461	461	461	461	711	680
Ind-ST-SolidBio-M	3526	3735	3515	3896	3503	3599	3659	2152	1601
Bld-Engine-Biogas-XS	1406	1406	1406	1406	1406	1406	1406	884	408
Bld-Engine-NGas-XS	159	159	159	159	159	159	159	954	1415
DH-BpCCGT-NGas-L	504	504	504	504	504	504	504	1066	1588
DH-ExCCGT-NGas-XL	1368	1368	1368	1377	1367	1368	1367	2328	2026
DH-ST-Coal-XL	1133	1134	1133	1134	1133	1133	1133	1408	2049
DH-ST-Waste-L	1002	1181	996	1320	996	1065	1139	1878	2490
Run-of-river hydro	7151	7151	7151	7151	7151	7151	7151	6738	6370
Photovoltaic	9473	9993	9464	9479	14189	9472	8365	8251	6662
Wind onshore	4262	4747	4270	4271	4255	2090	3914	3757	3133
Reservoir hydro	676	672	677	681	677	678	669	681	685
Biomass power	1251	1241	1278	1342	1263	1274	1262	1992	2297
Geothermal power	3493	3493	3493	3493	3493	3493	3493	1184	353
VRE curtailment	16	0	17	0	46	13	2	259	0
Installed electric capacities in GW									
Gas turbine	92	153	92	92	92	92	92	171	166
CoolingWater-ComInd	314	314	314	314	314	314	314	343	0
ProcessShift-Ind	534	534	534	534	534	534	534	468	441
ProcessShed-Ind	473	473	473	473	473	473	473	443	438
Electric storage and load shifting in GWh/a									
Pumped hydro storage	3996	1320	3857	3014	4881	3929	2451	2770	677
E-Mobility-2h	62	5	51	52	53	65	19	12	0
E-Mobility-4h	249	18	206	231	259	235	101	86	5
E-Mobility-8h	879	114	812	854	898	869	597	356	20
CoolingWater-ComInd	24.0	7.7	22.3	17.5	33.6	22.6	12.8	14.1	0
ProcessShift-Ind	0	0	0	0.2	0.3	0	0	0	0
ProcessShed-Ind	0	0	0	0	0	0	0	0	0
Demand Response Max. Reduction in MW									
HVAC-ComInd	0	0	0	0	0	0	0	0	0
CoolingWater-ComInd	152	135	135	168	135	132	135	235	0
ProcessShift-Ind	192	0	0	0	159	192	0	0	0
ProcessShed-Ind	0	0	0	0	0	0	0	0	0
Demand Response Max. Increase in MW									
CoolingWater-ComInd	150	150	153	182	278	153	149	164	0
ProcessShift-Ind	98	0	0	0	96	109	0	0	0
Electricity Losses in GWh/a									
Pumped hydro storage	795	263	768	600	971	782	488	551	135
Demand response	1.0	0.3	0.9	0.7	1.4	0.9	0.5	0.6	0

Table F.13 REMix-OptiMo output: DR capacity expansion results Germany West.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Power generation and curtailment in TWh/a									
Nuclear	0	0	0	0	0	0	0	0	6503
Lignite	0	0	0	0	0	0	0	17564	44816
Coal	1055	1280	1028	1441	1035	1141	1216	20739	26088
CCGT	8895	15793	8445	13308	8937	9955	8606	10533	4596
Gas turbine	253	46	2	567	304	374	45	0	0
DH-Engine-Biogas-M	4868	5055	4847	5224	4769	4959	4926	2190	1509
DH-Engine-NGas-M	2825	2825	2825	2825	2825	2825	2825	2424	2283
DH-ST-SolidBio-M	1642	1758	1615	1816	1596	1686	1615	1282	1400
Ind-Engine-NGas-M	2455	2455	2455	2456	2455	2455	2455	2005	1226
Ind-GT-NGas-L	5854	5854	5854	5854	5854	5854	5854	8168	9328
Ind-ST-Coal-M	863	861	861	867	865	866	863	1319	1262
Ind-ST-SolidBio-M	6947	7206	6897	7384	6924	7069	6931	3996	2973
Bld-Engine-Biogas-XS	3242	3242	3242	3242	3242	3242	3242	2046	944
Bld-Engine-NGas-XS	366	366	366	366	366	366	366	2206	3276
DH-BpCCGT-NGas-L	901	901	901	901	901	901	901	1493	2226
DH-ExCCGT-NGas-XL	11751	11606	11676	12060	11710	11792	11591	8125	7101
DH-ST-Coal-XL	2004	1980	1994	2056	1988	2006	1978	2059	3700
DH-ST-Lignite-XL	0	0	0	0	0	0	0	4027	4487
DH-ST-Waste-L	2164	2364	2123	2606	2111	2282	2200	2738	3288
Run-of-river hydro	2637	2637	2637	2637	2637	2637	2637	2484	2346
Photovoltaic	13502	14256	13264	13771	20069	13461	12135	12137	9668
Wind onshore	21729	24820	22278	24171	21629	28511	22238	21517	17734
Reservoir hydro	334	336	336	340	335	334	336	340	341
Biomass power	2979	2922	3052	3306	3027	2985	3092	5034	5734
Geothermal power	4417	4417	4417	4417	4417	4417	4417	1497	446
VRE curtailment	3012	2637	2701	301	3431	5210	213	791	230
Installed electric capacities in GW									
Gas turbine	1935	1244	747	2890	1914	2192	747	1389	1346
CoolingWater-ComInd	793	793	793	793	793	793	793	866	0
ProcessShift-Ind	1818	1818	1818	1818	1818	1818	1818	1594	1504
StorHeat-ResCom	6073	0	0	6073	6073	6073	0	0	0
ProcessShed-Ind	1611	1611	1611	1611	1611	1611	1611	1509	1491
Electric storage and load shifting in GWh/a									
Pumped hydro storage	1632	744	1732	1301	1928	1570	1172	1379	1265
E-Mobility-2h	85	9	43	92	84	81	24	24	4
E-Mobility-4h	505	39	332	421	590	515	190	212	55
E-Mobility-8h	1896	308	1455	1750	2069	1996	984	979	151
CoolingWater-ComInd	63	32	51	54	80	64	35	61	0
ProcessShift-Ind	0	0	3.2	2.4	2.2	0	0	0	0
StorHeat-ResCom	0	0	4.3	3.7	3.5	0	0	0	0
ProcessShed-Ind	4.2	0	0	12.4	4.2	4.2	0	0	0
Demand Response Max. Reduction in MW									
CoolingWater-ComInd	468	341	356	468	450	462	356	682	0
ProcessShift-Ind	867	0	0	1362	694	675	0	0	0
StorHeat-ResCom	989	0	0	989	972	918	0	0	0
ProcessShed-Ind	1058	0	0	1058	1058	1058	0	0	0
Demand Response Max. Increase in MW									
CoolingWater-ComInd	384	381	384	474	384	384	613	778	0
ProcessShift-Ind	264	0	0	528	264	264	0	0	0
StorHeat-ResCom	3242	0	0	2799	3242	3267	0	0	0
Electricity Losses in GWh/a									
Pumped hydro storage	325	148	345	259	384	312	233	275	252
Demand response	14	1	2	5	17	17	1	3	0

F.3 Step 2b: Heat Supply Capacity Expansion

Table F.14 REMix-OptiMo output: heat supply capacity expansion results Germany Central, part I.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Power generation and curtailment in TWh/a									
Nuclear	0	0	0	0	0	0	0	0	6438
Lignite	0	0	0	0	0	0	0	699	1580
Coal	261	287	262	295	257	268	267	4264	5552
CCGT	4079	8179	4063	4675	3890	4255	3795	5544	4906
Gas turbine	748	152	397	680	826	778	246	35	132
DH-Engine-Biogas-M	2459	2566	2462	2584	2418	2332	2497	1514	1056
DH-Engine-NGas-M	1291	1350	1298	1309	1279	1132	1235	1448	1431
DH-ST-SolidBio-M	624	678	623	667	599	590	609	670	751
Ind-Engine-NGas-M	766	781	764	775	750	688	751	609	374
Ind-GT-NGas-L	1903	1974	1930	1993	1852	1770	1887	2355	2786
Ind-ST-Coal-M	0	0	0	0	0	0	0	412	394
Ind-ST-SolidBio-M	2169	2291	2165	2266	2118	2055	2160	1236	919
Bld-Engine-Biogas-XS	1038	1047	1039	1041	1035	960	1028	656	309
Bld-Engine-NGas-XS	115	117	115	115	114	105	112	703	1069
DH-BpCCGT-NGas-L	328	336	328	329	325	297	317	639	965
DH-ExCCGT-NGas-XL	2101	1993	2030	2118	2067	1886	1886	1779	1590
DH-ST-Coal-XL	563	545	551	562	558	533	533	989	1625
DH-ST-Waste-L	915	1000	916	1026	888	916	916	1253	1534
Run-of-river hydro	825	825	825	825	825	825	825	778	735
Photovoltaic	5893	6213	5815	5893	8838	5893	5201	5210	4142
Wind onshore	15289	17073	15365	15346	15221	23338	14120	13826	11330
Reservoir hydro	7	7	7	7	7	7	7	7	7
Biomass power	1527	1539	1527	1533	1522	1462	1529	2232	2505
Geothermal power	2800	2800	2800	2800	2800	2800	2800	949	283
VRE curtailment	155	91	158	99	225	875	39	229	0
Installed electric capacity in MW									
Gas turbine	5185	944	4683	3976	5652	5272	2566	462	1532
DH-Engine-NGas-M	364	343	359	368	368	364	350	318	357
Ind-Engine-NGas-M	135	136	133	138	136	135	132	115	71
Ind-GT-NGas-L	344	341	341	352	344	347	341	471	541
Ind-ST-Coal-XL	0	0	0	0	0	0	0	117	115
Bld-Engine-NGas-XS	24	24	24	24	24	24	24	140	208
DH-BpCCGT-NGas-L	66	66	66	66	66	66	66	124	183
DH-ExCCGT-NGas-XL	519	480	496	525	524	495	499	423	367
DH-ST-Coal-XL	145	145	145	145	145	145	145	252	318
Electric storage energy input in GWh/a									
Pumped hydro storage	783	238	725	706	923	878	515	510	488
Thermal storage energy input in GWh/a									
Storage-DH-Engine-Biogas-M	257	221	257	258	263	260	270	157	71
Storage-DH-Engine-NGas-M	213	85	198	200	236	267	160	99	83
Storage-DH-ST-SolidBio-M	66	38	63	65	72	84	58	47	49
Storage-Ind-ST-SolidBio-M	523	328	514	493	581	564	452	273	143
Storage-Bld-Engine-Biogas-XS	106	34	100	100	115	121	75	40	10
Storage-Bld-Engine-NGas-XS	9	3	8	8	10	10	6	24	25
Storage-DH-BpCCGT-NGas-L	23	13	22	23	25	27	21	38	44
Storage-DH-ExCCGT-NGas-XL	167	79	151	156	185	220	140	117	99
Storage-DH-ST-Coal-XL	66	37	64	64	74	77	60	102	99
Storage-HP-Air2Water-XS	121	28	112	127	145	146	107	12	18
Storage-HP-Ground2Water-XS	83	15	63	87	100	118	55	6	12

Table F.15 REMix-OptiMo output: heat supply capacity expansion results Germany Central, part II.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Heat production in GWh/a									
DH-Engine-Biogas-M	2304	2320	2306	2302	2297	2112	2303	1882	1363
DH-Engine-NGas-M	1519	1588	1527	1540	1505	1332	1453	1809	1847
DH-ST-SolidBio-M	951	954	951	954	946	859	946	1488	1763
Ind-Engine-NGas-M	806	821	804	816	789	724	791	677	427
Ind-GT-NGas-L	2718	2820	2756	2847	2646	2529	2696	3623	4457
Ind-ST-Coal-XL	0	0	0	0	0	0	0	898	910
Ind-ST-SolidBio-M	4137	4162	4142	4149	4113	3834	4137	3071	2446
Bld-Engine-Biogas-XS	1731	1745	1732	1735	1725	1601	1714	1192	589
Bld-Engine-NGas-XS	208	213	209	209	207	191	203	1407	2251
DH-BpCCGT-NGas-L	298	306	298	299	295	270	288	608	941
DH-ExCCGT-NGas-XL	1584	1576	1554	1601	1565	1338	1490	1478	1351
DH-ST-Coal-XL	825	828	825	823	824	779	816	1568	2091
DH-ST-Waste-L	1290	1290	1290	1290	1290	1290	1290	1651	1840
EBoiler-DH-Engine-Biogas-M	17	0	15	13	28	229	13	15	0
EBoiler-DH-Engine-NGas-M	205	103	195	183	221	402	256	161	50
EBoiler-DH-ST-SolidBio-M	18	0	16	4.5	22	129	15	20	0
EBoiler-Ind-ST-SolidBio-M	32	0	30	19	67	364	35	16	0
EBoiler-DH-ExCCGT-NGas-XL	113	48	107	100	141	352	174	49	0
HP-Ground2Water-XS	2846	2850	2839	2851	2850	2846	2844	2088	1176
HP-Air2Water-XS	2609	2599	2607	2616	2615	2611	2613	1899	1174
HP-WasteHeat2Water-S	455	455	455	455	455	455	455	262	86
EBoiler-HP-Air2Water-XS	60	45	60	55	59	64	54	86	81
EBoiler-HP-Ground2Water-XS	93	71	94	89	93	101	88	144	137
EBoiler-HP-WasteHeat2Water-S	2.1	2.2	2.6	2.1	2.1	2.1	2.5	3.7	0.9
Installed thermal capacities in MW / GWh									
EBoiler-DH-Engine-Biogas-M	61	0	54	57	89	381	39	85	0
EBoiler-DH-Engine-NGas-M	361	208	349	345	379	462	327	283	33
EBoiler-DH-ST-SolidBio-M	65	0	59	19	72	202	48	94	0
EBoiler-Ind-ST-SolidBio-M	146	0	142	99	266	618	137	103	0
EBoiler-DH-ExCCGT-NGas-XL	362	215	362	329	389	491	328	254	0
Storage-DH-Engine-Biogas-M	2250	2469	2252	2227	2338	2480	3121	906	296
Storage-DH-Engine-NGas-M	1768	1363	1563	1517	1906	4769	1557	572	403
Storage-DH-ST-SolidBio-M	413	692	405	496	449	931	499	236	554
Storage-Ind-ST-SolidBio-M	5164	5787	5517	5517	5263	5787	5633	1109	715
Storage-Bld-Engine-Biogas-XS	491	382	473	502	525	604	440	251	56
Storage-Bld-Engine-NGas-XS	47	47	47	47	47	44	47	228	175
Storage-DH-BpCCGT-NGas-L	266	281	266	281	266	356	261	344	229
Storage-DH-ExCCGT-NGas-XL	1893	1525	1736	1517	1969	5362	1565	895	724
Storage-DH-ST-Coal-XL	706	739	706	627	715	1045	680	831	940
HP-Ground2Water-XS	649	663	647	653	651	646	652	449	240
HP-Air2Water-XS	608	618	607	612	610	607	614	424	253
HP-WasteHeat2Water-S	87	86	86	87	87	87	86	47	16
EBoiler-HP-Air2Water-XS	847	847	847	847	847	847	847	641	407
EBoiler-HP-Ground2Water-XS	937	937	937	937	937	937	937	721	426
EBoiler-HP-WasteHeat2Water-S	103	103	103	103	103	103	103	59	19
Storage-HP-Air2Water-XS	939	277	939	1250	939	916	1224	57	177
Storage-HP-Ground2Water-XS	683	239	525	965	683	771	703	43	248

Table F.16 REMix-OptiMo output: heat supply capacity expansion results Germany East, part I.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Power generation and curtailment in TWh/a									
Lignite	0	0	0	0	0	0	0	17725	41279
Coal	260	300	257	281	237	260	258	3978	4692
CCGT	4684	9922	4645	5077	4306	4414	4014	8648	5713
Gas turbine	2037	828	1406	1772	2160	1843	509	640	20
DH-Engine-Biogas-M	2781	2976	2782	2913	2686	2554	2844	2306	1606
DH-Engine-NGas-M	1384	1431	1392	1404	1377	1181	1417	1992	1806
DH-ST-SolidBio-M	885	1014	882	931	840	786	850	978	1081
Ind-Engine-NGas-M	1070	1098	1068	1089	1059	946	1100	814	499
Ind-GT-NGas-L	2632	2753	2657	2759	2594	2480	2745	3943	4616
Ind-ST-SolidBio-M	2990	3235	2988	3107	2895	2697	2992	1736	1265
Bld-Engine-Biogas-XS	1931	1928	1927	1928	1928	1745	1943	1234	562
Bld-Engine-NGas-XS	213	215	213	214	213	190	217	1299	1888
DH-BpCCGT-NGas-L	615	618	615	617	614	544	624	1225	1835
DH-ExCCGT-NGas-XL	5462	5289	5328	5354	5319	5114	5114	4008	3410
DH-ST-Coal-XL	1300	1268	1286	1293	1275	1223	1223	1497	2230
DH-ST-Lignite-XL	0	0	0	0	0	0	0	3152	3559
DH-ST-Waste-L	1806	2066	1803	1939	1687	1765	1765	2623	3240
Run-of-river hydro	865	865	865	865	865	865	865	815	771
Photovoltaic	17893	18973	17898	17916	26609	16946	15869	15951	12686
Wind onshore	43045	47847	43050	43046	43016	76452	39497	39254	31643
Wind offshore	18214	19946	18212	18294	12987	8528	16518	13370	5393
Biomass power	4120	4174	4117	4133	4091	3786	4167	6162	6834
Geothermal power	6842	6842	6842	6842	6842	6842	6842	2319	691
VRE curtailment	836	469	828	732	1184	5487	380	58	0
Installed electric capacity in MW									
Gas turbine	9710	3401	9792	7001	10153	9568	3311	3861	512
DH-Engine-NGas-M	417	399	416	412	416	412	405	588	455
Ind-Engine-NGas-M	201	201	200	201	201	201	201	162	99
Ind-GT-NGas-L	517	492	515	510	509	515	505	840	935
Bld-Engine-NGas-XS	47	47	47	47	47	47	47	282	418
DH-BpCCGT-NGas-L	131	131	131	131	131	131	131	263	391
DH-ExCCGT-NGas-XL	1421	1380	1386	1395	1409	1344	1349	1040	903
DH-ST-Coal-XL	360	360	360	360	360	360	360	380	479
DH-ST-Lignite-XL	0	0	0	0	0	0	0	496	508
Electric storage energy input in GWh/a									
Pumped hydro storage	3456	1054	3325	2899	4115	3597	2187	2139	1866
Thermal storage energy input in GWh/a									
Storage-DH-Engine-Biogas-M	330	322	331	335	322	298	320	334	158
Storage-DH-Engine-NGas-M	274	137	268	243	280	322	189	267	108
Storage-DH-ST-SolidBio-M	127	70	122	123	139	155	108	152	88
Storage-Ind-ST-SolidBio-M	829	517	811	747	892	868	662	553	131
Storage-Bld-Engine-Biogas-XS	277	100	269	234	299	295	176	113	24
Storage-Bld-Engine-NGas-XS	24	9	23	21	27	24	15	87	72
Storage-DH-BpCCGT-NGas-L	55	33	54	48	59	57	43	101	116
Storage-DH-ExCCGT-NGas-XL	523	354	498	475	546	647	418	382	274
Storage-DH-ST-Coal-XL	203	138	198	190	217	230	165	228	152
Storage-HP-Air2Water-XS	333	93	299	300	401	420	234	161	0
Storage-HP-Ground2Water-XS	254	64	224	222	294	317	152	98	0

Table F.17 REMix-OptiMo output: heat supply capacity expansion results Germany East, part II.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Heat production in GWh/a									
DH-Engine-Biogas-M	2507	2546	2506	2521	2492	2219	2541	2841	2073
DH-Engine-NGas-M	1628	1682	1637	1652	1620	1390	1667	2490	2330
DH-ST-SolidBio-M	1340	1352	1340	1332	1331	1142	1353	2146	2543
Ind-Engine-NGas-M	1126	1153	1124	1144	1114	996	1156	903	570
Ind-GT-NGas-L	3760	3932	3795	3942	3705	3543	3922	6066	7385
Ind-ST-SolidBio-M	5718	5777	5720	5718	5692	4997	5789	4277	3372
Bld-Engine-Biogas-XS	3218	3214	3211	3213	3213	2909	3239	2244	1070
Bld-Engine-NGas-XS	388	391	388	390	388	345	395	2598	3974
DH-BpCCGT-NGas-L	559	562	559	561	558	494	567	1167	1791
DH-ExCCGT-NGas-XL	3973	4028	3943	3949	3937	3190	4001	3297	2901
DH-ST-Coal-XL	1854	1851	1857	1838	1848	1713	1851	2139	2852
DH-ST-Lignite-XL	0	0	0	0	0	0	0	1626	2273
DH-ST-Waste-L	2293	2293	2293	2293	2293	2293	2293	3176	3687
EBoiler-DH-Engine-Biogas-M	47	18	50	40	57	337	11	0	0
EBoiler-DH-Engine-NGas-M	270	189	261	244	279	522	211	525	325
EBoiler-DH-ST-SolidBio-M	38	10	40	33.3	46	260	11	0	14
EBoiler-Ind-ST-SolidBio-M	130	33	130	103	159	873	26	0	0
EBoiler-DH-ExCCGT-NGas-XL	327	197	317	290	345	1081	174	0	55
HP-Ground2Water-XS	5856	5848	5844	5862	5853	5853	5843	4255	2321
HP-Air2Water-XS	5353	5314	5340	5344	5359	5359	5325	3928	2351
HP-WasteHeat2Water-S	639	639	639	639	639	639	639	370	119
EBoiler-HP-Air2Water-XS	124	96	127	126	135	144	127	195	311
EBoiler-HP-Ground2Water-XS	173	130	176	159	185	193	159	357	468
EBoiler-HP-WasteHeat2Water-S	3.3	3.4	3.4	3.3	3.3	3.8	3.2	3.2	3.7
Installed thermal capacities in MW / GWh									
EBoiler-DH-Engine-Biogas-M	150	79	162	140	166	436	51	0	0
EBoiler-DH-Engine-NGas-M	406	313	407	401	411	509	296	382	235
EBoiler-DH-ST-SolidBio-M	120	46	128	122	126	323	51	0	36
EBoiler-Ind-ST-SolidBio-M	435	159	438	402	454	1037	149	0	0
EBoiler-DH-ExCCGT-NGas-XL	903	690	897	885	919	1231	671	0	67
Storage-DH-Engine-Biogas-M	3588	5233	3506	4265	3028	2970	4265	2082	699
Storage-DH-Engine-NGas-M	2554	2279	2455	2402	2270	7309	1773	1412	422
Storage-DH-ST-SolidBio-M	1080	1157	905	1079	1090	1814	1079	1404	559
Storage-Ind-ST-SolidBio-M	8218	8354	8146	8354	8354	8354	8354	2390	381
Storage-Bld-Engine-Biogas-XS	1427	909	1413	1272	1442	1796	1066	587	113
Storage-Bld-Engine-NGas-XS	107	104	104	104	115	109	104	577	433
Storage-DH-BpCCGT-NGas-L	722	804	722	626	678	857	512	797	576
Storage-DH-ExCCGT-NGas-XL	5064	9337	4923	5051	4949	17317	4399	3251	1371
Storage-DH-ST-Coal-XL	1988	3497	2058	2057	1866	4117	1593	1761	760
HP-Ground2Water-XS	1371	1395	1366	1389	1368	1365	1388	919	448
HP-Air2Water-XS	1276	1286	1271	1285	1276	1270	1285	898	485
HP-WasteHeat2Water-S	125	125	125	126	125	125	126	70	20
EBoiler-HP-Air2Water-XS	1901	1901	1901	1901	1901	1901	1901	1457	958
EBoiler-HP-Ground2Water-XS	2104	2104	2104	2104	2104	2104	2104	1639	1004
EBoiler-HP-WasteHeat2Water-S	149	149	149	149	149	149	149	86	28
Storage-HP-Air2Water-XS	4014	1338	3325	3832	4014	4014	3855	2635	0
Storage-HP-Ground2Water-XS	2905	1171	2501	2818	2897	2808	2547	1217	0

Table F.18 REMix-OptiMo output: heat supply capacity expansion results Germany North, part I.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Power generation and curtailment in TWh/a									
Nuclear	0	0	0	0	0	0	0	0	13114
Coal	906	956	774	1035	900	901	827	10900	9706
CCGT	630	1000	698	783	604	667	530	717	642
Gas turbine	6	11	1385	6	41	36	9	13	30
DH-Engine-Biogas-M	994	1035	978	1188	1024	1057	1118	754	590
DH-Engine-NGas-M	500	522	517	601	619	602	642	711	696
DH-ST-SolidBio-M	339	352	376	420	368	372	398	385	492
Ind-Engine-NGas-M	481	490	469	549	549	540	567	438	306
Ind-GT-NGas-L	1371	1405	1256	1560	1482	1459	1603	1997	2580
Ind-ST-Coal-M	0	0	0	0	0	0	0	147	149
Ind-ST-SolidBio-M	1334	1414	1381	1598	1394	1415	1542	892	751
Bld-Engine-Biogas-XS	816	817	778	927	891	860	958	575	290
Bld-Engine-NGas-XS	91	91	82	103	99	96	107	609	1001
DH-BpCCGT-NGas-L	280	283	252	319	305	295	331	548	916
DH-ExCCGT-NGas-XL	2819	2842	2938	3391	3097	3489	3489	2162	2299
DH-ST-Coal-XL	880	877	957	994	957	1016	1016	1312	1785
DH-ST-Waste-L	776	819	751	907	731	732	732	1044	1398
Run-of-river hydro	42	42	42	42	42	42	42	40	37
Photovoltaic	6467	6868	6518	6489	9625	6355	5755	5770	4593
Wind onshore	34663	39003	35380	35541	35256	51830	32870	32592	26461
Wind offshore	107694	120061	114102	117058	80709	58182	106964	84592	35935
Biomass power	1344	1379	1393	1514	1444	1422	1557	2194	2707
Geothermal power	2459	2459	2459	2459	2459	2459	2459	834	248
VRE curtailment	19206	16234	12031	8943	10914	11828	5238	5166	42
Installed electric capacity in MW									
Gas turbine	80	133	1947	80	602	387	80	149	144
DH-Engine-NGas-M	155	155	208	155	199	198	155	186	172
Hydrogen storage	0	0	1105.5	0	0	0	0	0	0
Hydrogen Converter	0	0	4118.5	0	0	0	0	0	0
Ind-Engine-NGas-M	96	96	114	98	113	114	98	96	59
Ind-GT-NGas-L	286	286	295	286	295	296	286	452	510
Ind-ST-Coal-XL	0	0	0	0	0	0	0	44	43
Bld-Engine-NGas-XS	22	22	22	22	22	22	22	132	196
DH-BpCCGT-NGas-L	68	68	68	68	68	68	68	117	173
DH-ExCCGT-NGas-XL	919	919	964	919	919	919	919	616	535
DH-ST-Coal-XL	277	277	277	277	277	277	277	366	461
Electric storage energy input in GWh/a									
Hydrogen storage input	0	0	9560	0	0	0	0	0	0
Thermal storage energy input in GWh/a									
Storage-DH-Engine-Biogas-M	103	104	143	100	98	101	93	90	24
Storage-DH-Engine-NGas-M	152	113	192	117	155	149	89	164	30
Storage-DH-ST-SolidBio-M	127	93	136	83	113	113	63	102	16
Storage-Ind-ST-SolidBio-M	404	334	518	374	435	417	334	271	46
Storage-Bld-Engine-Biogas-XS	79	27	109	75	99	84	56	34	4
Storage-Bld-Engine-NGas-XS	5.5	1.1	10.0	5.6	6.9	6.0	3.9	18.8	6.4
Storage-DH-BpCCGT-NGas-L	23	17	23	21	24	24	18	31	24
Storage-DH-ExCCGT-NGas-XL	585	463	632	475	566	557	385	342	69
Storage-DH-ST-Coal-XL	135	100	137	116	141	142	94	143	96
Storage-HP-Air2Water-XS	202	70	311	147	231	228	92	51	0.0
Storage-HP-Ground2Water-XS	206	61	304	142	224	212	80	50	0.7

Table F.19 REMix-OptiMo output: heat supply capacity expansion results Germany North, part II.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Heat production in GWh/a									
DH-Engine-Biogas-M	935	950	934	1065	1011	987	1099	943	761
DH-Engine-NGas-M	588	614	608	708	728	708	755	888	898
DH-ST-SolidBio-M	598	633	607	728	662	643	772	855	1159
Ind-Engine-NGas-M	506	515	491	578	578	568	597	487	349
Ind-GT-NGas-L	1959	2008	1794	2229	2118	2085	2289	3072	4128
Ind-ST-Coal-XL	0	0	0	0	0	0	0	322	343
Ind-ST-SolidBio-M	2612	2740	2630	3023	2805	2766	3183	2221	1997
Bld-Engine-Biogas-XS	1360	1362	1297	1545	1485	1433	1597	1046	553
Bld-Engine-NGas-XS	165	166	150	188	180	174	195	1218	2108
DH-BpCCGT-NGas-L	255	257	227	290	277	269	301	522	894
DH-ExCCGT-NGas-XL	2168	2271	2083	2616	2370	2316	2791	1802	1956
DH-ST-Coal-XL	1335	1349	1335	1508	1434	1388	1563	2180	3063
DH-ST-Waste-L	1431	1431	1431	1431	1431	1431	1431	1684	1828
EBoiler-DH-Engine-Biogas-M	314	299	321	167	222	255	132	171	10
EBoiler-DH-Engine-NGas-M	385	345	452	237	313	332	184	349	191
EBoiler-DH-ST-SolidBio-M	347	304	315	183.9	250	276	130	232	28
EBoiler-Ind-ST-SolidBio-M	898	765	869	480	688	728	316	344	26
EBoiler-DH-ExCCGT-NGas-XL	1372	1239	1553	813	1078	1153	614	637	71
HP-Ground2Water-XS	2943	2953	2940	2957	2959	2956	2959	2088	1108
HP-Air2Water-XS	2706	2696	2727	2704	2698	2692	2704	1967	1122
HP-WasteHeat2Water-S	380	380	381	380	380	380	380	218	71
EBoiler-HP-Air2Water-XS	87	61	97	74	102	110	58	102	120
EBoiler-HP-Ground2Water-XS	141	93	173	109	130	131	92	237	194
EBoiler-HP-WasteHeat2Water-S	2.8	2.7	2.2	2.6	2.5	2.4	2.5	3.8	1.9
Installed thermal capacities in MW / GWh									
EBoiler-DH-Engine-Biogas-M	300	295	315	235	242	276	223	230	32
EBoiler-DH-Engine-NGas-M	401	362	353	315	338	354	295	388	113
EBoiler-DH-ST-SolidBio-M	294	268	300	249	275	277	225	325	81
EBoiler-Ind-ST-SolidBio-M	633	582	697	625	663	640	519	468	94
EBoiler-DH-ExCCGT-NGas-XL	1547	1426	1404	1180	1352	1396	1098	788	202
Storage-DH-Engine-Biogas-M	1018	1344	2212	760	692	936	839	737	168
Storage-DH-Engine-NGas-M	3726	3726	3726	3726	3726	3726	3726	3676	248
Storage-DH-ST-SolidBio-M	3041	3252	2972	1745	1948	2383	1420	1752	141
Storage-Ind-ST-SolidBio-M	4939	4939	4939	4939	4939	4939	4939	1775	226
Storage-Bld-Engine-Biogas-XS	733	398	960	724	805	749	638	223	36
Storage-Bld-Engine-NGas-XS	46	14	60	46	54	46	54	196	138
Storage-DH-BpCCGT-NGas-L	483	499	430	372	470	418	372	368	274
Storage-DH-ExCCGT-NGas-XL	14002	14002	14002	14002	14002	14002	14002	8025	570
Storage-DH-ST-Coal-XL	3130	2939	2493	2037	2009	2387	1705	1544	1034
HP-Ground2Water-XS	663	677	651	675	677	675	676	423	211
HP-Air2Water-XS	628	633	637	632	632	628	634	433	230
HP-WasteHeat2Water-S	73	73	74	73	73	74	73	39	12
EBoiler-HP-Air2Water-XS	893	893	893	893	893	893	893	673	408
EBoiler-HP-Ground2Water-XS	988	988	988	988	988	988	988	757	427
EBoiler-HP-WasteHeat2Water-S	88	88	88	88	88	88	88	51	17
Storage-HP-Air2Water-XS	1841	707	2114	1274	1921	2273	847	281	0
Storage-HP-Ground2Water-XS	1917	608	1932	1223	1846	2096	691	273	4

Table F.20 REMix-OptiMo output: heat supply capacity expansion results Germany Southeast, part I.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Power generation and curtailment in TWh/a									
Nuclear	0	0	0	0	0	0	0	0	26397
Coal	43	46	43	46	43	41	47	747	781
CCGT	3908	6829	3788	4306	3923	3866	3426	8252	4272
Gas turbine	54	11	26	175	28	64	21	34	26
DH-Engine-Biogas-M	3392	3494	3409	3655	3249	3384	3428	2188	1483
DH-Engine-NGas-M	2118	1871	2117	2182	1671	2105	1799	2247	1930
DH-ST-SolidBio-M	814	829	805	839	769	814	770	991	1067
Ind-Engine-NGas-M	1396	1342	1399	1430	1252	1394	1331	1100	672
Ind-GT-NGas-L	3532	3709	3570	3680	3435	3518	3688	5674	6284
Ind-ST-SolidBio-M	3718	3861	3713	3951	3577	3730	3732	2222	1638
Bld-Engine-Biogas-XS	1627	1649	1630	1641	1594	1630	1645	1039	472
Bld-Engine-NGas-XS	182	186	183	184	178	182	184	1119	1637
DH-BpCCGT-NGas-L	670	682	672	677	653	670	672	990	1453
DH-ExCCGT-NGas-XL	3429	3433	3402	3596	3188	3391	3391	3284	2809
DH-ST-Coal-XL	1612	1626	1613	1634	1583	1622	1622	1818	2451
DH-ST-Waste-L	1467	1612	1465	1694	1423	1503	1503	1882	2236
Run-of-river hydro	13495	13495	13495	13495	13495	13495	13495	12716	12020
Photovoltaic	20723	22019	20734	20793	30194	20716	18392	18468	14683
Wind onshore	4401	4993	4409	4419	4281	2789	4079	4092	3298
Reservoir hydro	756	757	756	756	753	756	757	757	757
Biomass power	1937	1962	1941	1951	1873	1938	1954	2866	3169
Geothermal power	4539	4539	4539	4539	4539	4539	4539	1539	458
VRE curtailment	263	9	244	176	1358	229	87	0	0
Installed electric capacity in MW									
Gas turbine	832	611	512	1463	367	920	367	682	661
DH-Engine-NGas-M	504	349	493	509	349	496	349	411	375
Ind-Engine-NGas-M	240	210	240	253	210	239	210	210	129
Ind-GT-NGas-L	622	622	622	645	622	622	622	1089	1213
Ind-ST-Coal-XL	0	0	0	0	0	0	0	0	0
Bld-Engine-NGas-XS	33	33	33	33	33	33	33	197	292
DH-BpCCGT-NGas-L	119	119	119	119	119	119	119	169	251
DH-ExCCGT-NGas-XL	729	717	719	758	717	721	717	682	592
DH-ST-Coal-XL	388	388	388	388	388	388	388	424	534
Thermal storage energy input in GWh/a									
Storage-DH-Engine-Biogas-M	224	202	217	226	239	227	245	167	57
Storage-DH-Engine-NGas-M	156	27	145	147	181	147	64	79	34
Storage-DH-ST-SolidBio-M	84	42	81	86	91	82	76	57	15
Storage-Ind-ST-SolidBio-M	650	507	624	692	825	654	737	270	33
Storage-Bld-Engine-Biogas-XS	91	26	84	69	122	88	65	31	2.2
Storage-Bld-Engine-NGas-XS	4.7	0.9	3.9	4.7	8.1	4.7	1.5	17.2	6.1
Storage-DH-BpCCGT-NGas-L	33	19	32	33	36	33	34	38	38
Storage-DH-ExCCGT-NGas-XL	185	94	176	185	248	178	175	142	83
Storage-DH-ST-Coal-XL	153	72	145	146	161	150	131	116	69
Storage-HP-Air2Water-XS	115	14	102	109	156	120	23	8.0	0
Storage-HP-Ground2Water-XS	82	15	82	90	145	78	23	2.9	0

Table F.21 REMix-OptiMo output: heat supply capacity expansion results Germany Southeast, part II.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Heat production in GWh/a									
DH-Engine-Biogas-M	3244	3279	3246	3257	3179	3246	3268	2732	1913
DH-Engine-NGas-M	2492	2201	2491	2567	1966	2476	2117	2808	2490
DH-ST-SolidBio-M	1488	1510	1490	1488	1424	1486	1508	2202	2511
Ind-Engine-NGas-M	1469	1413	1472	1505	1318	1467	1401	1222	768
Ind-GT-NGas-L	5045	5298	5100	5258	4908	5025	5269	8730	10055
Ind-ST-SolidBio-M	7501	7569	7507	7532	7293	7495	7579	5518	4367
Bld-Engine-Biogas-XS	2712	2749	2717	2735	2657	2717	2742	1889	899
Bld-Engine-NGas-XS	331	338	332	335	323	331	335	2238	3447
DH-BpCCGT-NGas-L	609	620	611	615	594	609	611	943	1417
DH-ExCCGT-NGas-XL	2677	2746	2671	2796	2504	2663	2713	2736	2390
DH-ST-Coal-XL	2461	2501	2465	2471	2435	2462	2496	2966	3818
DH-ST-Waste-L	2897	2897	2897	2897	2897	2897	2897	2810	3024
EBoiler-DH-Engine-Biogas-M	13	0	6	0	87	12	0	0	0
EBoiler-DH-Engine-NGas-M	131	17	114	59	302	136	77	0	28
EBoiler-DH-ST-SolidBio-M	6	0	3	0.5	91	6	1	0	0
EBoiler-Ind-ST-SolidBio-M	23	0	0	0	306	25	0	0	0
EBoiler-DH-ExCCGT-NGas-XL	92	0	79	10	277	90	9	0	0
HP-Ground2Water-XS	4454	4471	4455	4456	4492	4448	4470	3282	1710
HP-Air2Water-XS	4062	4071	4060	4060	4101	4061	4071	2970	1710
HP-WasteHeat2Water-S	828	827	828	828	828	828	827	477	154
EBoiler-HP-Air2Water-XS	124	87	122	123	94	126	90	146	194
EBoiler-HP-Ground2Water-XS	165	130	164	166	142	169	133	223	284
EBoiler-HP-WasteHeat2Water-S	5.6	6.3	5.9	5.7	6.0	5.5	6.3	7.4	5.0
Installed thermal capacities in MW / GWh									
EBoiler-DH-Engine-Biogas-M	50	0	23	0	212	50	0	0	0
EBoiler-DH-Engine-NGas-M	324	22	314	140	608	316	129	0	30
EBoiler-DH-ST-SolidBio-M	27	0	15	5	214	28	5	0	7
EBoiler-Ind-ST-SolidBio-M	131	0	0	0	662	147	0	0	0
EBoiler-DH-ExCCGT-NGas-XL	421	0	391	51	764	404	35	0	0
Storage-DH-Engine-Biogas-M	2034	2429	2034	1986	2400	2035	2104	1125	406
Storage-DH-Engine-NGas-M	1234	459	1222	1113	2022	1151	350	599	493
Storage-DH-ST-SolidBio-M	762	673	709	693	669	720	673	533	535
Storage-Ind-ST-SolidBio-M	10132	10735	9636	10735	10735	10132	10735	1023	221
Storage-Bld-Engine-Biogas-XS	601	601	601	601	751	601	601	366	58
Storage-Bld-Engine-NGas-XS	74	74	74	74	74	74	74	423	221
Storage-DH-BpCCGT-NGas-L	352	322	352	344	322	352	352	320	344
Storage-DH-ExCCGT-NGas-XL	1967	1415	1626	1266	2756	1563	1348	1200	518
Storage-DH-ST-Coal-XL	1633	1303	1455	1303	1632	1474	1341	768	812
HP-Ground2Water-XS	985	1009	985	988	1001	981	1007	691	326
HP-Air2Water-XS	920	941	920	923	939	921	938	645	343
HP-WasteHeat2Water-S	160	159	160	160	159	160	159	87	26
EBoiler-HP-Air2Water-XS	1278	1278	1278	1278	1278	1278	1278	963	594
EBoiler-HP-Ground2Water-XS	1414	1414	1414	1414	1414	1414	1414	1083	622
EBoiler-HP-WasteHeat2Water-S	191	191	191	191	191	191	191	110	36
Storage-HP-Air2Water-XS	1331	181	1249	1443	857	1393	208	46	0
Storage-HP-Ground2Water-XS	795	246	1070	1459	856	728	261	24	0

Table F.22 REMix-OptiMo output: heat supply capacity expansion results Germany Southwest, part I.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Power generation and curtailment in TWh/a									
Nuclear	0	0	0	0	0	0	0	0	11993
Coal	378	493	416	546	368	416	507	7745	11458
CCGT	626	1262	727	958	652	709	542	1278	1616
Gas turbine	6	0	0	0	5	4	0	6	0
DH-Engine-Biogas-M	3716	3986	3739	4183	3621	3830	3966	1656	1147
DH-Engine-NGas-M	2424	2199	2190	2205	2434	2457	2030	1624	1640
DH-ST-SolidBio-M	980	976	968	1009	970	994	926	913	1004
Ind-Engine-NGas-M	1380	1314	1314	1314	1379	1381	1284	1059	657
Ind-GT-NGas-L	2615	2780	2684	2884	2631	2650	2792	4094	4976
Ind-ST-Coal-M	461	461	461	462	461	461	461	713	686
Ind-ST-SolidBio-M	3485	3707	3486	3873	3457	3538	3605	2165	1603
Bld-Engine-Biogas-XS	1413	1410	1413	1413	1413	1414	1410	879	408
Bld-Engine-NGas-XS	159	159	159	159	159	159	155	943	1415
DH-BpCCGT-NGas-L	506	506	507	507	506	506	492	1054	1590
DH-ExCCGT-NGas-XL	1393	1375	1387	1401	1395	1346	1346	2285	2030
DH-ST-Coal-XL	1148	1138	1143	1159	1141	1140	1140	1376	2000
DH-ST-Waste-L	987	1164	994	1339	978	1114	1114	1955	2527
Run-of-river hydro	7151	7151	7151	7151	7151	7151	7151	6738	6370
Photovoltaic	9479	9993	9476	9479	14207	9478	8365	8356	6662
Wind onshore	4269	4747	4272	4272	4262	2095	3916	3838	3133
Reservoir hydro	685	685	685	685	685	685	685	684	685
Biomass power	1424	1425	1424	1425	1424	1424	1423	2064	2297
Geothermal power	3493	3493	3493	3493	3493	3493	3493	1184	353
VRE curtailment	2	0	3	0	21	1	0	73	0
Installed electric capacity in MW									
Gas turbine	330	153	92	92	265	216	92	171	166
DH-Engine-NGas-M	566	430	430	430	574	572	430	346	323
Ind-Engine-NGas-M	232	201	201	201	232	235	201	201	124
Ind-GT-NGas-L	487	487	487	487	487	487	487	825	947
Ind-ST-Coal-XL	102	102	102	102	102	102	102	205	201
Bld-Engine-NGas-XS	29	29	29	29	29	29	29	175	260
DH-BpCCGT-NGas-L	92	92	92	92	92	92	92	191	284
DH-ExCCGT-NGas-XL	307	307	307	307	307	307	307	508	441
DH-ST-Coal-XL	282	282	282	282	282	282	282	342	430
Electric storage energy input in GWh/a									
Pumped hydro storage	3728	1045	3685	3252	4445	3709	2347	2179	593
Thermal storage energy input in GWh/a									
Storage-DH-Engine-Biogas-M	349	287	349	405	376	357	396	169	70
Storage-DH-Engine-NGas-M	298	59	179	149	324	304	112	96	54
Storage-DH-ST-SolidBio-M	124	54	123	108	129	125	106	75	38
Storage-Ind-ST-SolidBio-M	851	536	881	781	950	858	795	469	60
Storage-Bld-Engine-Biogas-XS	124	40	119	99	145	124	77	52	5.6
Storage-Bld-Engine-NGas-XS	11.9	3.5	11.3	10.3	13.9	12.0	7.3	35.6	14.6
Storage-DH-BpCCGT-NGas-L	33	15	32	28	34	33	29	60	65
Storage-DH-ExCCGT-NGas-XL	99	50	95	85	102	99	92	145	93
Storage-DH-ST-Coal-XL	128	49	124	105	136	132	102	143	99
Storage-HP-Air2Water-XS	105	14	40	35	126	114	30	1.4	0
Storage-HP-Ground2Water-XS	37	7	15	13	45	30	14	0.3	0

Table F.23 REMix-OptiMo output: heat supply capacity expansion results Germany Southwest, part II.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Heat production in GWh/a									
DH-Engine-Biogas-M	3825	3828	3826	3830	3825	3826	3832	2070	1479
DH-Engine-NGas-M	2852	2588	2577	2594	2863	2890	2388	2030	2116
DH-ST-SolidBio-M	1825	1827	1830	1829	1823	1825	1829	2029	2363
Ind-Engine-NGas-M	1452	1384	1383	1384	1451	1454	1351	1176	750
Ind-GT-NGas-L	3736	3972	3834	4120	3759	3786	3989	6299	7962
Ind-ST-Coal-XL	919	921	921	921	918	919	921	1575	1600
Ind-ST-SolidBio-M	7310	7336	7355	7347	7312	7315	7351	5409	4274
Bld-Engine-Biogas-XS	2355	2350	2354	2355	2356	2356	2350	1598	778
Bld-Engine-NGas-XS	289	289	289	289	289	289	282	1886	2979
DH-BpCCGT-NGas-L	460	460	461	461	460	460	447	1004	1552
DH-ExCCGT-NGas-XL	1098	1100	1101	1101	1098	1098	1077	1904	1728
DH-ST-Coal-XL	1751	1751	1754	1753	1749	1751	1753	2290	3000
DH-ST-Waste-L	2040	2040	2040	2040	2040	2040	2040	2877	3192
EBoiler-DH-Engine-Biogas-M	0	0	0	0	0	0	0	0	0
EBoiler-DH-Engine-NGas-M	67	6.0	18	0	76	40	186	183	2.2
EBoiler-DH-ST-SolidBio-M	0	0	0	0.0	0	0	0	1.2	0.1
EBoiler-Ind-ST-SolidBio-M	0	0	0	0	0	0	0	0	0
EBoiler-DH-ExCCGT-NGas-XL	0	0	0	0	0	0	0	36.1	0
HP-Ground2Water-XS	3442	3441	3442	3449	3444	3437	3448	2503	1347
HP-Air2Water-XS	3158	3143	3147	3151	3162	3160	3150	2284	1340
HP-WasteHeat2Water-S	794	794	794	795	795	795	794	457	147
EBoiler-HP-Air2Water-XS	74	66	68	63	74	74	63	116	160
EBoiler-HP-Ground2Water-XS	114	107	109	100	114	117	102	197	225
EBoiler-HP-WasteHeat2Water-S	6.8	7.3	7.2	6.7	6.7	5.8	6.9	8.4	5.4
Installed thermal capacities in MW / GWh									
EBoiler-DH-Engine-Biogas-M	0	0	0	0	0	0	0	0	0
EBoiler-DH-Engine-NGas-M	44	5.0	11	0	52	28	196	191	6.1
EBoiler-DH-ST-SolidBio-M	0	0	0	0	0	0	0	7.5	4.2
EBoiler-DH-ExCCGT-NGas-XL	0	0	0	0	0	0	0	92	0
Storage-DH-Engine-Biogas-M	2293	2917	2380	2394	2396	2228	2763	946	324
Storage-DH-Engine-NGas-M	1862	930	1133	1107	1922	1950	865	508	420
Storage-DH-ST-SolidBio-M	802	874	874	874	773	817	874	492	510
Storage-Ind-ST-SolidBio-M	8018	10299	10299	10299	7979	8410	10299	1786	250
Storage-Bld-Engine-Biogas-XS	563	516	522	516	655	545	516	316	50
Storage-Bld-Engine-NGas-XS	63	63	63	63	63	63	63	313	174
Storage-DH-BpCCGT-NGas-L	268	234	251	241	256	259	288	486	384
Storage-DH-ExCCGT-NGas-XL	766	889	748	701	722	736	843	980	387
Storage-DH-ST-Coal-XL	951	787	884	787	916	1008	878	1055	693
HP-Ground2Water-XS	771	777	776	782	771	770	781	523	257
HP-Air2Water-XS	721	728	726	731	721	722	731	498	269
HP-WasteHeat2Water-S	150	149	149	150	150	151	150	81	24
EBoiler-HP-Air2Water-XS	947	947	947	947	947	947	947	713	449
EBoiler-HP-Ground2Water-XS	1049	1049	1049	1049	1049	1049	1049	802	470
EBoiler-HP-WasteHeat2Water-S	181	181	181	181	181	181	181	104	34
Storage-HP-Air2Water-XS	636	117	137	133	636	788	134	6.0	0
Storage-HP-Ground2Water-XS	678	146	163	149	678	361	156	3.3	0

Table F.24 REMix-OptiMo output: heat supply capacity expansion results Germany West, part I.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Power generation and curtailment in TWh/a									
Nuclear	0	0	0	0	0	0	0	0	6572
Lignite	0	0	0	0	0	0	0	19988	47078
Coal	1195	1368	1248	1516	1168	1284	1329	21202	25789
CCGT	8300	15595	8184	12673	8410	9298	8356	10237	4229
Gas turbine	400	52	15	763	451	503	63	21	0
DH-Engine-Biogas-M	4884	5065	4909	5297	4763	4920	5057	2184	1508
DH-Engine-NGas-M	2685	2567	2491	2990	2704	2567	2480	1818	1828
DH-ST-SolidBio-M	1567	1700	1551	1778	1527	1580	1560	1269	1383
Ind-Engine-NGas-M	2483	2395	2391	2606	2465	2412	2389	1953	1179
Ind-GT-NGas-L	4889	5035	5099	5428	4928	4814	5155	6905	8807
Ind-ST-Coal-M	848	855	856	861	847	844	859	1327	1263
Ind-ST-SolidBio-M	6829	7153	6809	7306	6690	6886	6921	4019	2975
Bld-Engine-Biogas-XS	3179	3169	3178	3241	3169	3131	3237	2027	911
Bld-Engine-NGas-XS	354	356	354	364	352	346	362	2154	3055
DH-BpCCGT-NGas-L	867	869	871	897	865	844	879	1447	2042
DH-ExCCGT-NGas-XL	11324	10926	11156	12094	11239	11343	11343	7719	6523
DH-ST-Coal-XL	2010	1950	1963	2047	1991	1982	1982	2005	3507
DH-ST-Lignite-XL	0	0	0	0	0	0	0	4334	6322
DH-ST-Waste-L	2130	2385	2143	2614	2047	2225	2225	2768	3367
Run-of-river hydro	2637	2637	2637	2637	2637	2637	2637	2485	2349
Photovoltaic	13762	14517	13670	13773	20617	13765	12154	12175	9680
Wind onshore	24304	27129	24373	24462	24209	33070	22421	22199	17902
Reservoir hydro	341	341	341	342	341	341	342	342	342
Biomass power	3551	3544	3550	3584	3547	3528	3571	5198	5766
Geothermal power	4417	4417	4417	4417	4417	4417	4417	1497	446
VRE curtailment	176	68	200	6	303	348	12	70	48
Installed electric capacity in MW									
Gas turbine	4361	1244	747	7442	4627	4925	747	1389	1346
DH-Engine-NGas-M	745	588	588	746	756	751	588	492	461
Ind-Engine-NGas-M	418	374	374	457	421	421	374	374	230
Ind-GT-NGas-L	905	905	905	944	905	905	905	1531	1759
Ind-ST-Coal-XL	190	190	190	190	190	190	190	381	372
Bld-Engine-NGas-XS	73	73	73	73	73	73	73	434	645
DH-BpCCGT-NGas-L	175	175	175	175	175	175	175	284	422
DH-ExCCGT-NGas-XL	2817	2817	2817	2846	2817	2817	2817	1926	1672
DH-ST-Coal-XL	531	531	531	531	531	531	531	536	800
DH-ST-Lignite-XL	0	0	0	0	0	0	0	693	924
Electric storage energy input in GWh/a									
Pumped hydro storage	1339	363	1227	1113	1583	1424	763	959	1019
Thermal storage energy input in GWh/a									
Storage-DH-Engine-Biogas-M	485	427	495	504	504	520	500	258	125
Storage-DH-Engine-NGas-M	302	67	177	277	361	394	114	144	81
Storage-DH-ST-SolidBio-M	176	44	141	151	188	183	139	108	77
Storage-Ind-ST-SolidBio-M	1581	967	1503	1333	1792	1641	1259	893	75
Storage-Bld-Engine-Biogas-XS	226	64	208	199	278	269	141	118	30.4
Storage-Bld-Engine-NGas-XS	21.5	4.2	19.4	17.7	24.1	23.3	9.5	71.4	78.4
Storage-DH-BpCCGT-NGas-L	59	30	58	47	66	65	44	90	107
Storage-DH-ExCCGT-NGas-XL	777	410	791	747	852	913	741	547	457
Storage-DH-ST-Coal-XL	207	102	195	170	228	222	164	223	249
Storage-HP-Air2Water-XS	247	32	99	209	305	296	81	18.5	0
Storage-HP-Ground2Water-XS	164	23	69	121	184	173	45	2.1	0

Table F.25 REMix-OptiMo output: heat supply capacity expansion results Germany West, part II.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Heat production in GWh/a									
DH-Engine-Biogas-M	4693	4692	4703	4762	4689	4611	4765	2730	1946
DH-Engine-NGas-M	3159	3020	2931	3517	3182	3020	2918	2273	2358
DH-ST-SolidBio-M	2629	2610	2639	2664	2619	2575	2658	2820	3254
Ind-Engine-NGas-M	2614	2521	2517	2743	2595	2539	2514	2170	1348
Ind-GT-NGas-L	6985	7193	7284	7754	7040	6878	7364	10623	14091
Ind-ST-Coal-XL	1684	1703	1706	1710	1680	1675	1713	2926	2969
Ind-ST-SolidBio-M	13645	13587	13686	13674	13615	13463	13741	10042	7933
Bld-Engine-Biogas-XS	5299	5282	5296	5402	5282	5219	5396	3685	1736
Bld-Engine-NGas-XS	644	647	645	662	641	629	658	4308	6431
DH-BpCCGT-NGas-L	788	790	792	815	786	768	799	1378	1993
DH-ExCCGT-NGas-XL	8625	8734	8729	9269	8585	8282	9039	6433	5552
DH-ST-Coal-XL	2990	2999	3000	3040	2982	2960	3034	3339	5179
DH-ST-Lignite-XL	0	0	0	0	0	0	0	4055	4912
DH-ST-Waste-L	3413	3413	3413	3413	3413	3413	3413	3797	4204
EBoiler-DH-Engine-Biogas-M	31	38	25	0	38	132	0	3.1	2.2
EBoiler-DH-Engine-NGas-M	520	346	454	125	518	681	366	767	532.9
EBoiler-DH-ST-SolidBio-M	12	23	21	0.0	24	87	0	9.0	45.8
EBoiler-Ind-ST-SolidBio-M	47	133	60	0	111	266	0	0	0
EBoiler-DH-ExCCGT-NGas-XL	691	605	636	0	733	1105	142	354.0	412
HP-Ground2Water-XS	7907	7913	7907	7926	7921	7911	7939	5733	2958
HP-Air2Water-XS	7251	7216	7227	7262	7260	7262	7239	5239	3022
HP-WasteHeat2Water-S	1480	1477	1477	1482	1480	1480	1479	850	274
EBoiler-HP-Air2Water-XS	171	147	152	150	176	174	136	269	412
EBoiler-HP-Ground2Water-XS	277	232	249	247	267	274	212	460	639
EBoiler-HP-WasteHeat2Water-S	7.2	10.4	10.4	6.1	7.5	7.7	8.3	13.6	9.5
Installed thermal capacities in MW / GWh									
EBoiler-DH-Engine-Biogas-M	138	194	112	0	143	414	0	19	19
EBoiler-DH-Engine-NGas-M	706	614.9	655	164	738	874	329	523	348.8
EBoiler-DH-ST-SolidBio-M	53	103	81	0	85	256	0	55.8	91.9
EBoiler-Ind-ST-SolidBio-M	244	709	315	0	510	947	0	0	0
EBoiler-DH-ExCCGT-NGas-XL	1928	1758	1899	0	1930	2443	298	673	484
Storage-DH-Engine-Biogas-M	4356	6209	4876	3948	4596	5040	4411	1541	532
Storage-DH-Engine-NGas-M	2665	1694	1499	2191	3000	3661	845	648	309
Storage-DH-ST-SolidBio-M	2372	590	882	1358	1432	1456	1379	627	510
Storage-Ind-ST-SolidBio-M	17968	18621	18621	14939	18621	17968	18621	3367	257
Storage-Bld-Engine-Biogas-XS	1113	1066	1066	1066	1293	1285	1066	744	161
Storage-Bld-Engine-NGas-XS	131	119	131	131	131	131	131	664	523
Storage-DH-BpCCGT-NGas-L	877	729	722	548	785	828	512	755	558
Storage-DH-ExCCGT-NGas-XL	7515	6533	6779	7138	7570	10794	7080	3889	2001
Storage-DH-ST-Coal-XL	2579	2300	2190	1636	2165	2291	1713	1536	1206
HP-Ground2Water-XS	1785	1811	1797	1799	1792	1785	1826	1205	549
HP-Air2Water-XS	1689	1692	1687	1696	1692	1688	1701	1147	600
HP-WasteHeat2Water-S	276	271	271	278	276	275	274	147	45
EBoiler-HP-Air2Water-XS	2293	2293	2293	2293	2293	2293	2293	1717	1077
EBoiler-HP-Ground2Water-XS	2537	2537	2537	2537	2537	2537	2537	1932	1128
EBoiler-HP-WasteHeat2Water-S	328	328	328	328	328	328	328	188	62
Storage-HP-Air2Water-XS	3502	381	469	3219	3053	3458	594	87.9	0
Storage-HP-Ground2Water-XS	2327	392	574	2576	1948	1771	588	14.7	0

F.4 Step 3a: DR Capacity Expansion Sensitivities

Table F.26 REMix-OptiMo output: DR capacity expansion sensitivities results Germany Central.

Technology	DR Cost++	DR Cost+	DR Cost–	DR Cost––	Frequ- ency+	Poten- tial+	Shift- Time+	No EV- Flex	Red. Cap.
Power generation and curtailment in GWh/a									
Coal	231	231	240	247	237	236	239	233	0
CCGT	4236	4235	4219	4218	4234	4234	4219	4220	4431
Gas turbine	655	649	614	604	622	613	593	793	623
DH-Engine-Biogas-M	2465	2464	2473	2476	2467	2467	2467	2456	2479
DH-Engine-NGas-M	1305	1305	1305	1305	1305	1305	1305	1305	1305
DH-ST-SolidBio-M	646	646	645	645	646	646	645	640	650
Ind-Engine-NGas-M	746	746	746	746	746	746	746	746	746
Ind-GT-NGas-L	2182	2182	2182	2182	2182	2182	2182	2182	2182
Ind-ST-SolidBio-M	2221	2222	2221	2224	2220	2220	2222	2208	2228
Obj-Engine-Biogas-XS	1059	1059	1059	1059	1059	1059	1059	1059	1059
Obj-Engine-NGas-XS	119	119	119	119	119	119	119	119	119
TH-BpCCGT-NGas-L	340	340	340	340	340	340	340	340	340
TH-ExCCGT-NGas-XL	2165	2164	2156	2152	2161	2160	2157	2213	2162
TH-ST-Coal-XL	582	582	577	577	579	578	577	592	579
TH-ST-Waste-L	925	925	925	932	924	924	926	916	936
Run-of-river hydro	825	825	825	825	825	825	825	825	825
Photovoltaic	5892	5892	5892	5892	5614	5892	5892	5892	5892
Wind onshore	14524	14528	14554	14586	14822	14550	14572	14481	14544
Reservoir hydro	7	7	7	7	7	7	7	7	7
Biomass power	1366	1369	1384	1350	1380	1382	1392	1330	1380
Geothermal power	2800	2800	2800	2800	2800	2800	2800	2800	2800
VRE curtailment	921	917	891	860	901	895	873	965	902
Installed electric capacities in MW									
Coal	61	61	61	61	61	61	61	61	0
CCGT	1432	1432	1432	1432	1432	1432	1432	1432	1486
Gas turbine	3875	3753	3670	3670	3643	3147	3619	5010	3670
HVAC-ComInd	0	1447	1909	1909	1909	867	1909	1909	1909
CoolingWater-ComInd	329	329	329	329	329	658	329	329	329
ProcessShift-Ind	322	322	322	322	322	643	322	322	322
StorHeat-ResCom	0	0	1964	1964	1964	1964	1964	1964	1964
ProcessShed-Ind	285	285	285	285	285	570	285	285	285
Electric storage and load shifting in GWh/a									
Pumped hydro storage	840	832	740	685	782	775	747	1117	780
E-Mobility-2h	56	57	27	16	29	39	28	0	32
E-Mobility-4h	224	223	180	149	198	205	203	0	201
E-Mobility-8h	763	783	735	707	762	781	784	0	757
HVAC-ComInd	0	13	85	124	73	34	94	59	65
CoolingWater-ComInd	10	16	79	148	33	64	61	61	31
ProcessShift-Ind	0.4	0.5	0.7	0.7	0.4	1.0	0.5	0.5	0.5
StorHeat-ResCom	0	0	1.6	1.9	1.4	1.4	1.8	1.6	1.4
ProcessShed-Ind	0.5	1.2	1.1	1.1	1.2	3.0	0.6	1.3	1.1
Demand Response Max. Reduction in MW									
HVAC-ComInd	0	115	151	151	151	69	278	151	151
CoolingWater-ComInd	190	190	256	262	228	437	262	262	218
ProcessShift-Ind	268	268	268	282	268	548	276	274	268
StorHeat-ResCom	0	0	319	319	319	319	342	319	319
ProcessShed-Ind	188	188	188	188	188	376	188	188	188
Demand Response Max. Increase in MW									
HVAC-ComInd	0	118	156	156	156	71	312	156	156
CoolingWater-ComInd	224	155	288	300	189	378	288	288	171
ProcessShift-Ind	71	71	142	142	71	142	130	71	71
StorHeat-ResCom	0	0	1137	1297	1033	1187	1003	958	1033
Electricity Losses in GWh/a									
Pumped hydro storage	167	166	147	136	156	154	149	222	155
Demand response	0	1	13	22	9	6	13	9	7

Table F.27 REMix-OptiMo output: DR capacity expansion sensitivities results Germany East.

Technology	DR Cost++	DR Cost+	DR Cost–	DR Cost––	Frequ- ency+	Poten- tial+	Shift- Time+	No EV- Flex	Red. Cap.
Power generation and curtailment in GWh/a									
Coal	226	225	232	236	228	228	231	229	0
CCGT	4973	4970	4964	4966	4984	4985	4983	4883	5485
Gas turbine	1881	1876	1767	1751	1790	1769	1704	2099	1633
DH-Engine-Biogas-M	2782	2781	2795	2800	2789	2788	2785	2792	2787
DH-Engine-NGas-M	1494	1494	1493	1493	1494	1494	1494	1493	1493
DH-ST-SolidBio-M	935	935	933	934	934	934	932	921	931
Ind-Engine-NGas-M	1033	1033	1033	1033	1033	1033	1033	1033	1033
Ind-GT-NGas-L	3013	3013	3013	3013	3013	3013	3013	3013	3013
Ind-ST-SolidBio-M	3110	3110	3107	3110	3110	3109	3113	3067	3107
Obj-Engine-Biogas-XS	1970	1970	1970	1970	1970	1970	1970	1970	1970
Obj-Engine-NGas-XS	222	222	222	222	222	222	222	222	222
TH-BpCCGT-NGas-L	636	636	636	636	636	636	636	636	636
TH-ExCCGT-NGas-XL	5627	5627	5603	5592	5618	5613	5605	5857	5526
TH-ST-Coal-XL	1332	1332	1313	1310	1321	1321	1313	1388	1295
TH-ST-Waste-L	1814	1814	1821	1831	1819	1817	1817	1787	1819
Run-of-river hydro	865	865	865	865	865	865	865	865	865
Photovoltaic	17623	17623	17624	17629	17058	17615	17625	17618	17617
Wind onshore	42683	42691	42698	42715	41781	42702	42718	42681	42696
Wind offshore	17292	17287	17318	17360	18781	17318	17341	17215	17310
Biomass power	3691	3694	3744	3676	3726	3736	3758	3586	3730
Geothermal power	6842	6842	6842	6842	6842	6842	6842	6842	6842
VRE curtailment	2390	2388	2348	2285	2369	2354	2305	2475	2365
Installed electric capacities in MW									
Coal	57	57	57	57	57	57	57	57	0
CCGT	1638	1638	1638	1638	1638	1638	1638	1638	1866
Gas turbine	8171	8171	7843	7843	7655	7336	7318	9694	7664
HVAC-ComInd	0	0	4729	4729	1019	0	4729	1093	4729
CoolingWater-ComInd	815	815	815	815	815	1629	815	815	815
ProcessShift-Ind	729	729	729	729	729	1458	729	729	729
StorHeat-ResCom	0	0	3936	3936	3936	3936	3936	3936	3936
ProcessShed-Ind	646	646	646	646	646	1292	646	646	646
Electric storage and load shifting in GWh/a									
Pumped hydro storage	3411	3393	2991	2849	3181	3149	3034	4078	3133
E-Mobility-2h	94	86	41	29	72	81	50	0	58
E-Mobility-4h	427	435	366	300	411	419	382	0	398
E-Mobility-8h	1725	1732	1730	1703	1726	1736	1792	0	1755
HVAC-ComInd	0	0	217	298	51	0	258	39	186
CoolingWater-ComInd	38	56	250	414	118	220	218	174	107
ProcessShift-Ind	0.7	0.7	1.3	1.2	1.0	1.6	1.3	1.0	0.9
StorHeat-ResCom	0	0	3.4	3.5	3.0	3.1	3.7	3.1	3.0
ProcessShed-Ind	1.7	1.7	1.7	1.7	3.7	3.4	3.1	1.7	1.7
Demand Response Max. Reduction in MW									
HVAC-ComInd	0	0	375	375	81	0	657	87	375
CoolingWater-ComInd	696	696	646	688	624	922	696	581	581
ProcessShift-Ind	465	465	597	597	576	831	604	425	563
StorHeat-ResCom	0	0	654	654	654	654	748	615	654
ProcessShed-Ind	424	424	424	424	424	848	424	424	424
Demand Response Max. Increase in MW									
HVAC-ComInd	0	0	387	387	83	0	774	89	387
CoolingWater-ComInd	385	385	662	746	575	951	746	599	674
ProcessShift-Ind	108	108	216	216	216	368	184	108	108
StorHeat-ResCom	0	0	1807	1871	1668	1628	2085	1628	1799
Electricity Losses in GWh/a									
Pumped hydro storage	679	675	595	567	633	627	604	812	624
Demand response	0	2	34	52	20	19	34	20	21

Table F.28 REMix-OptiMo output: DR capacity expansion sensitivities results Germany North.

Technology	DR Cost++	DR Cost+	DR Cost–	DR Cost—	Frequ- ency+	Poten- tial+	Shift- Time+	No EV- Flex	Red. Cap.
Power generation and curtailment in GWh/a									
Coal	543	539	551	594	538	535	524	562	0
CCGT	728	723	679	645	722	717	681	719	763
Gas turbine	1	1	0	0	1	1	0	3	119
DH-Engine-Biogas-M	1191	1190	1194	1195	1190	1189	1188	1187	1245
DH-Engine-NGas-M	771	771	771	771	771	771	771	771	771
DH-ST-SolidBio-M	502	501	495	493	500	500	498	492	529
Ind-Engine-NGas-M	611	611	611	611	611	611	611	611	612
Ind-GT-NGas-L	1779	1779	1779	1779	1779	1779	1779	1779	1779
Ind-ST-SolidBio-M	1691	1691	1688	1686	1691	1691	1687	1662	1762
Obj-Engine-Biogas-XS	1042	1042	1042	1042	1042	1042	1042	1042	1042
Obj-Engine-NGas-XS	117	117	117	117	117	117	117	117	117
TH-BpCCGT-NGas-L	363	363	363	363	363	363	363	363	363
TH-ExCCGT-NGas-XL	4153	4153	4151	4149	4153	4153	4152	4270	4234
TH-ST-Coal-XL	1105	1105	1098	1097	1105	1105	1101	1137	1127
TH-ST-Waste-L	765	764	760	760	763	761	757	749	882
Run-of-river hydro	42	42	42	42	42	42	42	42	42
Photovoltaic	6424	6424	6424	6424	5238	6424	6424	6424	6424
Wind onshore	33571	33575	33591	33598	22744	33577	33601	33554	33577
Wind offshore	102337	102343	102376	102405	114362	102352	102394	102261	102347
Biomass power	1235	1238	1245	1212	1239	1242	1244	1226	1239
Geothermal power	2459	2459	2459	2459	2459	2459	2459	2459	2459
VRE curtailment	25698	25688	25640	25603	25687	25678	25611	25791	25683
Installed electric capacities in MW									
Coal	200	200	200	200	200	200	200	200	0
CCGT	461	461	461	461	461	461	461	461	340
Gas turbine	80	80	80	80	80	80	80	80	262
CoolingWater-ComInd	0	313	313	313	313	626	313	313	313
ProcessShift-Ind	442	442	442	442	442	885	442	442	442
StorHeat-ResCom	0	0	1847	1847	0	0	1847	0	184
ProcessShed-Ind	392	392	392	392	392	784	392	392	392
Electric storage and load shifting in GWh/a									
E-Mobility-2h	19	17	14	10	17	15	19	0	33
E-Mobility-4h	87	88	77	64	87	90	87	0	125
E-Mobility-8h	321	332	303	287	327	336	316	0	496
CoolingWater-ComInd	0	14	37	82	24	39	38	32	28
ProcessShift-Ind	0	0	0.6	0.6	0	0	0	0.1	0.2
StorHeat-ResCom	0	0	1.5	1.7	0	0	1.9	0	0.2
Demand Response Max. Reduction in MW									
CoolingWater-ComInd	0	171	236	252	236	356	180	175	223
ProcessShift-Ind	0	0	331	306	0	0	0	39	63
StorHeat-ResCom	0	0	301	301	0	0	351	0	35
Demand Response Max. Increase in MW									
CoolingWater-ComInd	0	225	256	210	225	404	274	214	197
ProcessShift-Ind	0	0	127	120	0	0	0	39	64
StorHeat-ResCom	0	0	994	1155	0	0	1184	0	122
Electricity Losses in GWh/a									
Demand response	0	0.6	5.6	11.3	1.0	1.6	6.6	1.4	1.6

Table F.29 REMix-OptiMo output: DR capacity expansion sensitivities results Germany Southeast.

Technology	DR Cost++	DR Cost+	DR Cost–	DR Cost––	Frequ- ency+	Poten- tial+	Shift- Time+	No EV- Flex	Red. Cap.
Power generation and curtailment in GWh/a									
Coal	28	28	34	42	28	28	29	29	0
CCGT	4343	4333	4292	4245	4333	4323	4314	4326	3599
Gas turbine	39	38	24	21	36	34	25	62	305
DH-Engine-Biogas-M	3178	3178	3190	3228	3178	3177	3177	3163	3297
DH-Engine-NGas-M	1876	1876	1876	1876	1876	1876	1876	1876	1876
DH-ST-SolidBio-M	861	860	854	853	860	859	858	855	881
Ind-Engine-NGas-M	1345	1345	1345	1345	1345	1345	1345	1345	1346
Ind-GT-NGas-L	3930	3930	3930	3930	3930	3930	3930	3930	3930
Ind-ST-SolidBio-M	3801	3800	3784	3786	3801	3799	3795	3767	3937
Obj-Engine-Biogas-XS	1649	1649	1649	1649	1649	1649	1649	1649	1649
Obj-Engine-NGas-XS	186	186	186	186	186	186	186	186	186
TH-BpCCGT-NGas-L	680	680	680	680	680	680	680	680	680
TH-ExCCGT-NGas-XL	3425	3424	3423	3422	3424	3424	3424	3547	3481
TH-ST-Coal-XL	1622	1622	1619	1619	1621	1621	1620	1665	1641
TH-ST-Waste-L	1514	1514	1508	1516	1514	1514	1512	1484	1627
Run-of-river hydro	13495	13495	13495	13495	13495	13495	13495	13493	13495
Photovoltaic	20237	20247	20293	20310	20013	20257	20274	20203	20265
Wind onshore	4229	4231	4241	4249	4467	4234	4235	4221	4237
Reservoir hydro	751	751	752	752	751	751	752	750	752
Biomass power	1770	1774	1795	1772	1775	1780	1789	1734	1783
Geothermal power	4539	4539	4539	4539	4539	4539	4539	4539	4539
VRE curtailment	921	910	853	829	908	897	879	965	885
Installed electric capacities in MW									
Coal	9	9	9	9	9	9	9	9	0
CCGT	2115	2115	2115	2115	2115	2115	2115	2115	1455
Gas turbine	367	367	367	367	367	367	367	810	829
HVAC-ComInd	0	0	0	0	0	0	0	1922	0
CoolingWater-ComInd	90	386	386	386	386	771	386	386	386
ProcessShift-Ind	478	478	478	478	478	956	478	478	478
StorHeat-ResCom	0	0	2749	2749	0	0	944	2749	2029
ProcessShed-Ind	424	424	424	424	424	847	424	424	424
Electric storage and load shifting in GWh/a									
E-Mobility-2h	48	47	34	25	46	43	44	0	108
E-Mobility-4h	183	185	142	117	183	181	172	0	340
E-Mobility-8h	510	519	425	381	513	522	496	0	1038
HVAC-ComInd	0	0	0	0	0	0	0	44	0
CoolingWater-ComInd	4	22	61	107	32	55	54	53	45
ProcessShift-Ind	0.0	0	1.2	1.3	0	0.1	0	1.3	0.4
StorHeat-ResCom	0	0	2.2	2.4	0	0	0.8	1.6	1.8
ProcessShed-Ind	0	0	0	0	0	0	0	4.3	1.1
Demand Response Max. Reduction in MW									
HVAC-ComInd	0	0	0	0	0	0	0	152	0
CoolingWater-ComInd	76	328	328	328	328	656	328	328	328
ProcessShift-Ind	8	0	438	438	83	83	0	408	252
StorHeat-ResCom	0	0	429	457	0	0	171	408	352
ProcessShed-Ind	0	0	0	0	0	0	0	279	279
Demand Response Max. Increase in MW									
HVAC-ComInd	0	0	0	0	0	0	0	157	0
CoolingWater-ComInd	81	338	348	364	344	680	350	364	341
ProcessShift-Ind	8	0	276	276	84	84	0	138	138
StorHeat-ResCom	0	0	1328	1405	0	0	528	1218	1202
Electricity Losses in GWh/a									
Demand response	0.2	0.9	10.0	17.0	1.3	2.3	5.1	5.8	7.2

Table F.30 REMix-OptiMo output: DR capacity expansion sensitivities results Germany Southwest.

Technology	DR Cost++	DR Cost+	DR Cost–	DR Cost––	Frequ- ency+	Poten- tial+	Shift- Time+	No EV- Flex	Red. Cap.
Power generation and curtailment in GWh/a									
Coal	293	293	296	302	292	290	292	314	0
CCGT	761	761	727	712	758	755	754	840	567
Gas turbine	7	7	4	3	6	6	5	10	134
DH-Engine-Biogas-M	3642	3642	3634	3632	3641	3639	3639	3651	3757
DH-Engine-NGas-M	2200	2200	2200	2200	2200	2200	2200	2200	2200
DH-ST-SolidBio-M	1006	1006	1000	999	1004	1003	1003	1005	1037
Ind-Engine-NGas-M	1315	1315	1314	1314	1315	1314	1314	1315	1316
Ind-GT-NGas-L	3137	3137	3137	3137	3137	3137	3137	3137	3137
Ind-ST-SolidBio-M	3527	3527	3516	3517	3526	3526	3524	3531	3617
Obj-Engine-Biogas-XS	1406	1406	1406	1406	1406	1406	1406	1406	1406
Obj-Engine-NGas-XS	159	159	159	159	159	159	159	159	159
TH-BpCCGT-NGas-L	504	504	504	504	504	504	504	504	504
TH-ExCCGT-NGas-XL	1368	1368	1367	1367	1368	1368	1368	1404	1384
TH-ST-Coal-XL	1133	1133	1133	1133	1133	1133	1133	1158	1149
TH-ST-Waste-L	1004	1004	996	996	1002	1000	1001	1019	1084
Run-of-river hydro	7151	7151	7151	7151	7151	7151	7151	7151	7151
Photovoltaic	9473	9473	9473	9475	9465	9473	9473	9473	9473
Wind onshore	4262	4262	4263	4264	4270	4262	4262	4263	4262
Reservoir hydro	675	675	680	685	676	677	677	670	677
Biomass power	1245	1245	1277	1267	1252	1257	1257	1187	1252
Geothermal power	3493	3493	3493	3493	3493	3493	3493	3493	3493
VRE curtailment	16	16	15	12	16	16	15	15	16
Installed electric capacities in MW									
Coal	113	113	113	113	113	113	113	113	0
CCGT	531	531	531	531	531	531	531	531	273
Gas turbine	92	92	92	92	92	92	92	137	375
CoolingWater-ComInd	0	0	314	314	314	628	314	314	314
ProcessShift-Ind	534	534	534	534	534	1067	534	534	534
StorHeat-ResCom	0	0	2104	2445	0	0	0	2445	0
ProcessShed-Ind	473	473	473	473	473	945	473	473	473
Electric storage and load shifting in GWh/a									
Pumped hydro storage	4019	4019	3803	3678	3995	3973	3970	4641	4026
E-Mobility-2h	55	57	47	36	58	59	56	0	75
E-Mobility-4h	252	247	239	220	246	252	255	0	312
E-Mobility-8h	882	884	870	873	886	886	876	0	1097
CoolingWater-ComInd	0	0	81	151	25	46	51	44	38
ProcessShift-Ind	0	0	0.6	0.7	0.2	0.3	0	1.0	0.4
StorHeat-ResCom	0	0	2.1	2.5	0	0	0	1.9	0
ProcessShed-Ind	0	0	0	0	0	0	0	3.8	0
Demand Response Max. Reduction in MW									
CoolingWater-ComInd	0	0	256	270	152	270	200	186	190
ProcessShift-Ind	0	0	466	446	192	327	196	414	205
StorHeat-ResCom	0	0	349	430	0	0	0	398	0
ProcessShed-Ind	0	0	0	0	0	0	0	311	0
Demand Response Max. Increase in MW									
CoolingWater-ComInd	0	0	288	292	153	300	182	219	288
ProcessShift-Ind	0	0	191	198	98	192	101	206	113
StorHeat-ResCom	0	0	1198	1487	0	0	0	1033	0
Electricity Losses in GWh/a									
Pumped hydro storage	800	800	757	732	795	791	790	924	801
Demand response	0	0	12.1	20.8	1.0	1.9	1.8	5.4	1.5

Table F.31 REMix-OptiMo output: DR capacity expansion sensitivities results Germany West.

Technology	DR Cost++	DR Cost+	DR Cost–	DR Cost––	Frequ- ency+	Poten- tial+	Shift- Time+	No EV- Flex	Red. Cap.
Power generation and curtailment in GWh/a									
Coal	1049	1047	1068	1098	1055	1053	1059	1049	0
CCGT	8950	8944	8815	8771	8924	8879	8824	8702	8512
Gas turbine	298	293	249	239	242	234	207	412	738
DH-Engine-Biogas-M	4859	4858	4868	4883	4865	4866	4860	4849	4971
DH-Engine-NGas-M	2825	2825	2825	2825	2825	2825	2825	2825	2825
DH-ST-SolidBio-M	1644	1644	1639	1639	1642	1641	1640	1610	1711
Ind-Engine-NGas-M	2455	2455	2455	2455	2456	2455	2456	2455	2455
Ind-GT-NGas-L	5854	5854	5854	5854	5854	5854	5854	5854	5854
Ind-ST-SolidBio-M	6952	6952	6945	6944	6951	6947	6943	6857	7136
Obj-Engine-Biogas-XS	3242	3242	3242	3242	3242	3242	3242	3242	3242
Obj-Engine-NGas-XS	366	366	366	366	366	366	366	366	366
TH-BpCCGT-NGas-L	901	901	901	901	901	901	901	901	901
TH-ExCCGT-NGas-XL	11760	11759	11741	11739	11755	11750	11751	12287	12065
TH-ST-Coal-XL	2011	2011	1997	1992	2008	2004	1999	2078	2081
TH-ST-Waste-L	2163	2162	2169	2182	2164	2164	2163	2127	2362
Run-of-river hydro	2637	2637	2637	2637	2637	2637	2637	2637	2637
Photovoltaic	13494	13495	13506	13521	13207	13502	13513	13488	13505
Wind onshore	21680	21683	21775	21818	21995	21747	21802	21639	21726
Reservoir hydro	333	334	336	335	334	334	335	333	334
Biomass power	2947	2952	3004	2943	2964	2990	3017	2838	2979
Geothermal power	4417	4417	4417	4417	4417	4417	4417	4417	4417
VRE curtailment	3069	3064	2962	2903	3040	2993	2927	3115	3011
Installed electric capacities in MW									
Coal	329	329	329	329	329	329	329	329	0
CCGT	4307	4307	4307	4307	4307	4307	4307	4307	3528
Gas turbine	2581	2316	1935	1926	1376	1456	1353	3900	3012
HVAC-ComInd	0	0	0	1962	0	0	0	1572	0
CoolingWater-ComInd	793	793	793	793	793	1587	793	793	793
ProcessShift-Ind	1818	1818	1818	1818	1818	3636	1818	1818	1818
StorHeat-ResCom	0	0	6073	6073	2386	6073	6073	6073	6073
ProcessShed-Ind	1611	1611	1611	1611	1611	3221	1611	1611	1611
Electric storage and load shifting in GWh/a									
Pumped hydro storage	1793	1773	1520	1364	1699	1607	1578	2354	1648
E-Mobility-2h	92	99	76	37	90	84	83	0	147
E-Mobility-4h	540	534	470	379	523	513	496	0	704
E-Mobility-8h	1912	1951	1810	1737	1962	1927	1920	0	2467
HVAC-ComInd	0	0	0	120	0	0	0	48	0
CoolingWater-ComInd	19	39	169	348	75	124	114	128	73
ProcessShift-Ind	1.0	0.9	1.9	2.4	2.2	1.9	1.9	2.4	0.9
StorHeat-ResCom	0	0	5.0	5.7	1.9	4.1	5.0	4.3	5.2
ProcessShed-Ind	0	4.2	4.2	4.2	23.4	12.5	12.3	8.2	4.2
Demand Response Max. Reduction in MW									
HVAC-ComInd	0	0	0	156	0	0	0	125	0
CoolingWater-ComInd	341	468	636	644	468	776	468	540	468
ProcessShift-Ind	668	668	1175	1175	919	1636	1176	1053	668
StorHeat-ResCom	0	0	997	997	392	953	997	989	1097
ProcessShed-Ind	0	1058	1058	1058	1058	1712	1058	1058	1058
Demand Response Max. Increase in MW									
HVAC-ComInd	0	0	0	161	0	0	0	129	0
CoolingWater-ComInd	384	384	645	633	498	760	684	376	384
ProcessShift-Ind	225	225	506	506	506	528	528	450	264
StorHeat-ResCom	0	0	3242	2564	1171	3242	3264	3242	3242
Electricity Losses in GWh/a									
Pumped hydro storage	357	353	302	271	338	320	314	468	328
Demand response	0.8	1.6	26.5	50.6	9.9	8.8	27.8	17.4	15.9

F.5 Step 3b: Heat Supply Capacity Expansion Sensitivities

Table F.32 REMix-OptiMo output: heat supply capacity expansion sensitivities results Germany Central, part I.

	TES Cost+	TES Cost–	TES Cost––	TES Loss+	EB Cost+	Solar DH	El. Heat+	Red. Cap.
Power generation and curtailment in GWh/a								
Coal	263	262	261	252	260	270	265	0
CCGT	4098	4051	4023	4106	4084	4128	4115	4033
Gas turbine	752	745	743	768	750	753	760	795
DH-Engine-Biogas-M	2449	2471	2489	2471	2447	2483	2444	2500
DH-Engine-NGas-M	1298	1291	1288	1275	1308	1110	1319	1294
DH-ST-SolidBio-M	625	621	618	625	621	616	552	642
Ind-Engine-NGas-M	764	766	767	765	760	766	771	768
Ind-GT-NGas-L	1900	1904	1913	1871	1863	1929	1970	1914
Ind-ST-SolidBio-M	2166	2171	2171	2186	2168	2184	2170	2196
Bld-Engine-Biogas-XS	1034	1041	1044	1036	1034	1038	1044	1039
Bld-Engine-NGas-XS	114	115	115	114	115	115	115	115
DH-BpCCGT-NGas-L	326	329	330	328	327	327	319	328
DH-ExCCGT-NGas-XL	2092	2109	2116	2117	2116	2125	2131	2221
DH-ST-Coal-XL	563	563	564	567	560	567	557	582
DH-ST-Waste-L	915	916	911	912	915	923	918	928
Run-of-river hydro	825	825	825	825	825	825	825	825
Photovoltaic	5893	5893	5841	5893	5893	5893	5893	5893
Wind onshore	15289	15287	15346	15288	15219	15280	15292	15289
Reservoir hydro	7	7	7	7	7	7	7	7
Biomass power	1527	1527	1528	1527	1519	1526	1528	1527
Geothermal power	2800	2800	2800	2800	2800	2800	2800	2800
VRE curtailment	155	157	151	156	226	164	152	155
Installed electric capacity in MW								
Coal	61	61	61	61	61	61	61	0
CCGT	1432	1432	1432	1432	1432	1432	1432	1363
Gas turbine	5188	5180	5179	5215	5172	5192	5182	5266
DH-Engine-NGas-M	364	366	365	338	365	352	365	368
Ind-Engine-NGas-M	135	135	135	135	135	136	136	136
Ind-GT-NGas-L	346	344	344	345	344	347	347	349
Bld-Engine-NGas-XS	24	24	24	24	24	24	24	24
DH-BpCCGT-NGas-L	66	66	66	66	66	66	66	66
DH-ExCCGT-NGas-XL	512	523	525	510	514	522	523	551
DH-ST-Coal-XL	145	145	145	145	145	145	145	145
DH-ST-Waste-L	210	210	210	210	210	210	210	210
Electric storage energy input in GWh/a								
Pumped hydro storage	790	782	791	886	785	780	759	802
Thermal storage energy input in GWh/a								
Storage-DH-Engine-Biogas-M	240	273	290	265	258	257	272	256
Storage-DH-Engine-NGas-M	198	219	219	89	194	219	209	224
Storage-DH-ST-SolidBio-M	63	72	77	42	70	64	93	63
Storage-Ind-ST-SolidBio-M	458	532	533	349	521	515	525	504
Storage-Bld-Engine-Biogas-XS	95	116	124	61	108	107	109	109
Storage-Bld-Engine-NGas-XS	8	10	10	1	9	9	9	9
Storage-DH-BpCCGT-NGas-L	21	25	26	17	23	24	27	25
Storage-DH-ExCCGT-NGas-XL	152	170	172	132	148	169	165	189
Storage-DH-ST-Coal-XL	60	70	73	54	67	67	62	70
Storage-HP-Air2Water-XS	124	119	136	96	124	120	117	120
Storage-HP-Ground2Water-XS	81	90	111	67	89	79	77	78

Table F.33 REMix-OptiMo output: heat supply capacity expansion sensitivities results Germany Central, part II.

	TES Cost+	TES Cost–	TES Cost– –	TES Loss+	EB Cost+	Solar DH	El. Heat+	Red. Cap.
Heat production in GWh/a								
DH-Engine-Biogas-M	2294	2321	2342	2346	2291	2304	2283	2308
DH-Engine-NGas-M	1527	1518	1515	1500	1538	1306	1551	1522
DH-ST-SolidBio-M	950	956	960	953	948	874	808	951
Ind-Engine-NGas-M	804	807	808	805	800	806	812	808
Ind-GT-NGas-L	2714	2720	2734	2673	2661	2756	2815	2734
Ind-ST-SolidBio-M	4085	4145	4145	4139	4137	4133	4136	4131
Bld-Engine-Biogas-XS	1723	1735	1740	1727	1724	1730	1739	1731
Bld-Engine-NGas-XS	208	209	209	207	208	208	210	209
DH-BpCCGT-NGas-L	297	299	300	298	298	298	290	298
DH-ExCCGT-NGas-XL	1575	1591	1596	1591	1596	1588	1608	1632
DH-ST-Coal-XL	822	827	828	830	820	824	815	826
DH-ST-Waste-L	1290	1290	1290	1290	1290	1290	1290	1290
EBoiler-DH-Engine-Biogas-M	19	14	12	26	0	18	0	16
EBoiler-DH-Engine-NGas-M	196	207	210	205	185	172	173	204
EBoiler-DH-ST-SolidBio-M	17	13	11	18	2	12	0	17
EBoiler-Ind-ST-SolidBio-M	41	31	31	40	0	35	29	32
EBoiler-DH-BpCCGT-NGas-L	0	0	0	0	0	0	25	0
EBoiler-DH-ExCCGT-NGas-XL	110	112	111	108	86	114	95	111
EBoiler-DH-ST-Coal-XL	0	0	0	0	0	0	24	0
HP-Ground2Water-XS	2846	2847	2853	2846	2845	2846	2849	2848
HP-Air2Water-XS	2611	2608	2613	2609	2609	2609	2609	2611
HP-WasteHeat2Water-S	455	455	455	455	455	455	455	455
EBoiler-HP-Air2Water-XS	59	60	61	59	61	59	58	58
EBoiler-HP-Ground2Water-XS	92	94	96	93	95	92	89	90
EBoiler-HP-WasteHeat2Water-S	2	2	2	2	2	2	2	2
Installed thermal capacities in MW / GWh								
EBoiler-DH-Engine-Biogas-M	62	54	49	89	0	63	0	57
EBoiler-DH-Engine-NGas-M	335	360	358	289	228	331	326	367
EBoiler-DH-ST-SolidBio-M	62	47	41	68	6	43	0	63
EBoiler-Ind-ST-SolidBio-M	184	144	142	176	0	153	143	146
EBoiler-DH-BpCCGT-NGas-L	0	0	0	0	0	0	77	0
EBoiler-DH-ExCCGT-NGas-XL	342	362	361	309	216	363	322	354
EBoiler-DH-ST-Coal-XL	0	0	0	0	0	0	102	0
Storage-DH-Engine-Biogas-M	1455	4168	6916	2110	2303	2303	2071	2689
Storage-DH-Engine-NGas-M	1168	2327	2671	791	1633	1974	1684	1989
Storage-DH-ST-SolidBio-M	370	815	1690	409	547	401	462	386
Storage-Ind-ST-SolidBio-M	2455	5787	5787	3310	5508	5188	4916	4891
Storage-Bld-Engine-Biogas-XS	382	689	1042	385	523	494	490	523
Storage-Bld-Engine-NGas-XS	34	65	82	36	47	47	47	47
Storage-DH-BpCCGT-NGas-L	169	430	674	155	266	275	319	302
Storage-DH-ExCCGT-NGas-XL	1219	2279	2515	1285	1452	1887	1921	2279
Storage-DH-ST-Coal-XL	463	1045	1547	481	725	715	466	734
HP-Ground2Water-XS	649	648	649	649	648	649	652	651
HP-Air2Water-XS	608	607	607	609	608	608	609	609
HP-WasteHeat2Water-S	87	87	87	87	87	87	87	87
EBoiler-HP-Air2Water-XS	847	847	847	847	847	847	847	847
EBoiler-HP-Ground2Water-XS	937	937	937	937	937	937	937	937
EBoiler-HP-WasteHeat2Water-S	103	103	103	103	103	103	103	103
Storage-HP-Air2Water-XS	939	874	1464	974	923	939	939	939
Storage-HP-Ground2Water-XS	676	829	1680	702	706	683	705	684

Table F.34 REMix-OptiMo output: heat supply capacity expansion sensitivities results Germany East, part I.

	TES Cost+	TES Cost–	TES Cost–	TES Loss+	EB Cost+	Solar DH	El. Heat+	Red. Cap.
Power generation and curtailment in GWh/a								
Coal	261	261	263	244	256	264	264	0
CCGT	4719	4616	4595	4719	4671	4741	4717	4717
Gas turbine	2051	2022	2016	2088	2033	2037	2045	2076
DH-Engine-Biogas-M	2764	2804	2812	2781	2787	2804	2776	2812
DH-Engine-NGas-M	1389	1392	1397	1365	1386	1191	1403	1389
DH-ST-SolidBio-M	889	879	878	888	888	874	811	898
Ind-Engine-NGas-M	1068	1072	1073	1068	1064	1069	1076	1071
Ind-GT-NGas-L	2630	2657	2670	2614	2608	2654	2677	2643
Ind-ST-SolidBio-M	2981	2993	2993	3019	3004	3000	2995	3006
Bld-Engine-Biogas-XS	1921	1937	1947	1930	1927	1930	1936	1930
Bld-Engine-NGas-XS	213	214	214	211	213	213	214	213
DH-BpCCGT-NGas-L	611	617	618	614	613	615	584	615
DH-ExCCGT-NGas-XL	5472	5469	5460	5480	5511	5500	5533	5539
DH-ST-Coal-XL	1297	1301	1301	1321	1298	1307	1275	1310
DH-ST-Waste-L	1804	1801	1788	1787	1806	1819	1808	1825
Run-of-river hydro	865	865	865	865	865	865	865	865
Photovoltaic	17896	17896	17895	17894	17856	17889	17899	17889
Wind onshore	43039	43048	43050	43044	43005	43037	43047	43042
Wind offshore	18201	18218	18229	18213	18115	18210	18253	18221
Biomass power	4119	4120	4122	4120	4102	4120	4121	4120
Geothermal power	6842	6842	6842	6842	6842	6842	6842	6842
VRE curtailment	854	827	815	838	1013	852	789	837
Installed electric capacity in MW								
Coal	57	57	57	57	57	57	57	0
CCGT	1638	1638	1638	1638	1638	1638	1638	1609
Gas turbine	9792	9701	9700	9750	9694	9710	9698	9756
DH-Engine-NGas-M	413	421	425	390	416	404	416	419
Ind-Engine-NGas-M	201	201	201	202	201	202	202	202
Ind-GT-NGas-L	517	517	517	516	516	519	519	520
Bld-Engine-NGas-XS	47	47	47	47	47	47	47	47
DH-BpCCGT-NGas-L	131	131	131	131	131	131	131	131
DH-ExCCGT-NGas-XL	1426	1426	1423	1397	1430	1432	1435	1448
DH-ST-Coal-XL	360	360	360	360	360	360	360	360
DH-ST-Waste-L	417	417	417	417	417	417	417	417
Electric storage energy input in GWh/a								
Pumped hydro storage	3482	3476	3482	3684	3448	3448	3423	3466
Thermal storage energy input in GWh/a								
Storage-DH-Engine-Biogas-M	300	358	389	339	342	330	337	331
Storage-DH-Engine-NGas-M	255	294	304	141	255	280	271	279
Storage-DH-ST-SolidBio-M	127	132	140	86	130	126	160	127
Storage-Ind-ST-SolidBio-M	755	834	837	525	820	827	829	819
Storage-Bld-Engine-Biogas-XS	224	303	332	150	277	278	278	279
Storage-Bld-Engine-NGas-XS	22	29	31	2	24	24	25	24
Storage-DH-BpCCGT-NGas-L	49	59	62	41	54	55	59	55
Storage-DH-ExCCGT-NGas-XL	503	565	581	451	492	527	526	538
Storage-DH-ST-Coal-XL	194	217	223	169	203	203	191	204
Storage-HP-Air2Water-XS	324	329	331	251	337	335	327	335
Storage-HP-Ground2Water-XS	158	256	274	196	260	254	245	253

Table F.35 REMix-OptiMo output: heat supply capacity expansion sensitivities results Germany East, part II.

	TES Cost+	TES Cost–	TES Cost– –	TES Loss+	EB Cost+	Solar DH	El. Heat+	Red. Cap.
Heat production in GWh/a								
DH-Engine-Biogas-M	2482	2542	2570	2560	2524	2507	2498	2509
DH-Engine-NGas-M	1634	1638	1644	1606	1630	1402	1651	1634
DH-ST-SolidBio-M	1339	1342	1347	1347	1349	1285	1192	1339
Ind-Engine-NGas-M	1125	1128	1130	1124	1120	1125	1132	1127
Ind-GT-NGas-L	3757	3795	3815	3735	3726	3792	3824	3776
Ind-ST-SolidBio-M	5649	5722	5725	5727	5760	5715	5724	5717
Bld-Engine-Biogas-XS	3201	3228	3244	3217	3212	3217	3226	3217
Bld-Engine-NGas-XS	387	389	390	384	387	388	389	388
DH-BpCCGT-NGas-L	555	561	562	558	557	559	531	559
DH-ExCCGT-NGas-XL	3974	3985	3984	3998	4010	3984	4025	4005
DH-ST-Coal-XL	1849	1860	1862	1874	1852	1854	1816	1854
DH-ST-Waste-L	2293	2293	2293	2293	2293	2293	2293	2293
EBoiler-DH-Engine-Biogas-M	55	34	32	56	15	48	28	45
EBoiler-DH-Engine-NGas-M	261	265	261	281	266	223	247	265
EBoiler-DH-ST-SolidBio-M	39	39	35	40	10	35	6	39
EBoiler-Ind-ST-SolidBio-M	137	128	126	135	55	133	121	131
EBoiler-DH-BpCCGT-NGas-L	0	0	0	0	0	0	56	0
EBoiler-DH-ExCCGT-NGas-XL	326	334	338	335	289	328	289	326
EBoiler-DH-ST-Coal-XL	0	0	0	0	0	0	72	0
HP-Ground2Water-XS	5830	5853	5850	5854	5858	5856	5855	5857
HP-Air2Water-XS	5351	5352	5353	5347	5354	5354	5354	5355
HP-WasteHeat2Water-S	640	639	638	640	639	639	639	639
EBoiler-HP-Air2Water-XS	123	124	124	125	125	124	122	123
EBoiler-HP-Ground2Water-XS	169	177	187	173	172	173	172	172
EBoiler-HP-WasteHeat2Water-S	3	4	4	3	3	3	3	3
Installed thermal capacities in MW / GWh								
EBoiler-DH-Engine-Biogas-M	172	117	107	171	40	155	101	145
EBoiler-DH-Engine-NGas-M	366	428	438	350	292	377	394	410
EBoiler-DH-ST-SolidBio-M	121	123	112	126	26	109	21	120
EBoiler-Ind-ST-SolidBio-M	471	431	429	459	164	437	424	436
EBoiler-DH-BpCCGT-NGas-L	0	0	0	0	0	0	142	0
EBoiler-DH-ExCCGT-NGas-XL	876	963	991	846	622	901	907	903
EBoiler-DH-ST-Coal-XL	0	0	0	0	0	0	266	0
Storage-DH-Engine-Biogas-M	1850	7016	10478	3074	4429	3612	3288	3704
Storage-DH-Engine-NGas-M	1710	4392	5500	1479	2270	2837	2299	2620
Storage-DH-ST-SolidBio-M	1079	1271	2432	1167	1079	1113	1200	1080
Storage-Ind-ST-SolidBio-M	4364	8354	8354	5514	8354	8186	8056	8200
Storage-Bld-Engine-Biogas-XS	849	2006	3859	851	1413	1427	1427	1427
Storage-Bld-Engine-NGas-XS	86	176	245	72	106	106	111	107
Storage-DH-BpCCGT-NGas-L	399	1278	2139	374	784	759	636	722
Storage-DH-ExCCGT-NGas-XL	3877	9486	13739	3844	4489	5134	4971	5204
Storage-DH-ST-Coal-XL	1508	3553	5243	1651	1992	1988	1512	1988
HP-Ground2Water-XS	1365	1370	1365	1373	1371	1372	1373	1372
HP-Air2Water-XS	1275	1275	1276	1280	1276	1276	1277	1277
HP-WasteHeat2Water-S	127	124	124	126	125	125	125	125
EBoiler-HP-Air2Water-XS	1901	1901	1901	1901	1901	1901	1901	1901
EBoiler-HP-Ground2Water-XS	2104	2104	2104	2104	2104	2104	2104	2104
EBoiler-HP-WasteHeat2Water-S	149	149	149	149	149	149	149	149
Storage-HP-Air2Water-XS	3584	3886	4014	4191	4014	4014	4014	4014
Storage-HP-Ground2Water-XS	880	3128	4181	2913	2906	2905	3006	2905

Table F.36 REMix-OptiMo output: heat supply capacity expansion sensitivities results Germany North, part I.

	TES Cost+	TES Cost–	TES Cost– –	TES Loss+	EB Cost+	Solar DH	El. Heat+	Red. Cap.
Power generation and curtailment in GWh/a								
Coal	910	899	896	800	887	927	933	0
CCGT	643	617	617	703	631	644	664	714
Gas turbine	7	6	6	9	6	6	13	59
DH-Engine-Biogas-M	998	985	979	973	992	1005	1021	1145
DH-Engine-NGas-M	500	499	499	507	504	427	501	577
DH-ST-SolidBio-M	349	335	334	352	343	340	343	375
Ind-Engine-NGas-M	482	481	481	481	480	481	487	529
Ind-GT-NGas-L	1373	1369	1370	1368	1370	1372	1378	1385
Ind-ST-SolidBio-M	1347	1327	1326	1348	1341	1340	1377	1458
Bld-Engine-Biogas-XS	811	822	826	810	817	816	822	816
Bld-Engine-NGas-XS	90	91	91	89	91	91	91	91
DH-BpCCGT-NGas-L	278	282	283	278	280	280	237	280
DH-ExCCGT-NGas-XL	2824	2818	2819	2860	2834	2819	2832	2934
DH-ST-Coal-XL	872	884	886	879	879	885	746	899
DH-ST-Waste-L	784	767	765	778	772	789	819	968
Run-of-river hydro	42	42	42	42	42	42	42	42
Photovoltaic	6466	6468	6468	6467	6467	6467	6471	6467
Wind onshore	34616	34713	34720	34661	34590	34659	34796	34666
Wind offshore	107569	107785	107794	107740	107593	107666	108220	107680
Biomass power	1343	1344	1344	1345	1345	1343	1349	1344
Geothermal power	2459	2459	2459	2459	2459	2459	2459	2459
VRE curtailment	19380	19065	19049	19162	19382	19238	18544	19217
Installed electric capacity in MW								
Coal	200	200	200	200	200	200	200	0
CCGT	461	461	461	461	461	461	461	394
Gas turbine	80	80	80	80	80	80	80	80
DH-Engine-NGas-M	155	155	155	155	155	155	155	216
Ind-Engine-NGas-M	97	96	96	96	96	96	98	119
Ind-GT-NGas-L	286	286	286	286	286	286	286	300
Bld-Engine-NGas-XS	22	22	22	22	22	22	22	22
DH-BpCCGT-NGas-L	68	68	68	68	68	68	68	68
DH-ExCCGT-NGas-XL	919	919	919	919	919	919	919	977
DH-ST-Coal-XL	277	277	277	277	277	277	277	277
DH-ST-Waste-L	216	216	216	216	216	216	216	216
Thermal storage energy input in GWh/a								
Storage-DH-Engine-Biogas-M	79	123	142	102	92	102	99	104
Storage-DH-Engine-NGas-M	151	152	152	142	133	164	149	171
Storage-DH-ST-SolidBio-M	84	143	143	97	102	126	111	123
Storage-Ind-ST-SolidBio-M	374	404	406	345	392	400	407	390
Storage-Bld-Engine-Biogas-XS	58	104	125	39	81	78	82	85
Storage-Bld-Engine-NGas-XS	3	8	9	0	5	5	6	6
Storage-DH-BpCCGT-NGas-L	20	27	31	13	23	23	62	23
Storage-DH-ExCCGT-NGas-XL	585	585	585	571	531	585	584	592
Storage-DH-ST-Coal-XL	109	152	170	84	136	135	292	134
Storage-HP-Air2Water-XS	101	303	303	188	201	202	206	240
Storage-HP-Ground2Water-XS	76	326	326	178	200	206	212	251

Table F.37 REMix-OptiMo output: heat supply capacity expansion sensitivities results Germany North, part II.

	TES Cost+	TES Cost–	TES Cost– –	TES Loss+	EB Cost+	Solar DH	El. Heat+	Red. Cap.
Heat production in GWh/a								
DH-Engine-Biogas-M	925	940	942	944	932	935	946	955
DH-Engine-NGas-M	588	587	587	596	593	502	590	678
DH-ST-SolidBio-M	621	591	590	612	610	598	601	589
Ind-Engine-NGas-M	507	506	506	506	505	506	512	549
Ind-GT-NGas-L	1961	1956	1957	1955	1958	1960	1968	1978
Ind-ST-SolidBio-M	2617	2613	2613	2644	2648	2611	2621	2600
Bld-Engine-Biogas-XS	1351	1371	1377	1349	1362	1360	1370	1361
Bld-Engine-NGas-XS	163	165	166	162	165	165	166	165
DH-BpCCGT-NGas-L	253	256	257	253	254	255	215	255
DH-ExCCGT-NGas-XL	2169	2168	2168	2200	2181	2167	2177	2242
DH-ST-Coal-XL	1323	1341	1344	1324	1333	1335	1127	1330
DH-ST-Waste-L	1431	1431	1431	1431	1431	1431	1431	1431
EBoiler-DH-Engine-Biogas-M	317	321	331	319	301	314	245	294
EBoiler-DH-Engine-NGas-M	384	387	387	392	367	350	380	378
EBoiler-DH-ST-SolidBio-M	305	361	361	336	319	347	211	346
EBoiler-Ind-ST-SolidBio-M	876	896	896	916	857	898	889	898
EBoiler-DH-BpCCGT-NGas-L	0	0	0	0	0	0	150	0
EBoiler-DH-ExCCGT-NGas-XL	1370	1371	1371	1419	1302	1373	1361	1373
EBoiler-DH-ST-Coal-XL	0	0	0	0	0	0	694	0
HP-Ground2Water-XS	2950	2944	2945	2957	2943	2943	2950	2937
HP-Air2Water-XS	2699	2708	2708	2713	2706	2706	2707	2715
HP-WasteHeat2Water-S	380	380	380	380	380	380	380	381
EBoiler-HP-Air2Water-XS	64	124	123	85	88	87	87	89
EBoiler-HP-Ground2Water-XS	98	184	184	128	140	142	137	161
EBoiler-HP-WasteHeat2Water-S	3	3	3	3	3	3	3	2
Installed thermal capacities in MW / GWh								
EBoiler-DH-Engine-Biogas-M	298	318	343	303	245	300	268	300
EBoiler-DH-Engine-NGas-M	401	400	401	362	281	385	401	394
EBoiler-DH-ST-SolidBio-M	264	302	302	280	237	294	212	294
EBoiler-Ind-ST-SolidBio-M	618	631	631	640	559	631	632	631
EBoiler-DH-BpCCGT-NGas-L	0	0	0	0	0	0	168	0
EBoiler-DH-ExCCGT-NGas-XL	1536	1541	1541	1540	1058	1546	1547	1536
EBoiler-DH-ST-Coal-XL	0	0	0	0	0	0	793	0
Storage-DH-Engine-Biogas-M	352	2392	4022	825	772	1018	940	1068
Storage-DH-Engine-NGas-M	3714	3726	3726	3726	3726	3726	3726	3726
Storage-DH-ST-SolidBio-M	984	4027	4027	2076	2278	3038	2105	2974
Storage-Ind-ST-SolidBio-M	3907	4939	4939	4939	4939	4939	4939	4939
Storage-Bld-Engine-Biogas-XS	350	1431	2389	257	749	743	780	759
Storage-Bld-Engine-NGas-XS	14	100	185	0	45	46	49	50
Storage-DH-BpCCGT-NGas-L	264	881	1325	284	483	483	1520	500
Storage-DH-ExCCGT-NGas-XL	14002	14002	14002	14002	14002	14002	14002	14002
Storage-DH-ST-Coal-XL	1478	4274	7109	1473	3112	3130	7373	3130
HP-Ground2Water-XS	672	656	656	667	663	663	667	656
HP-Air2Water-XS	630	620	620	629	628	628	630	634
HP-WasteHeat2Water-S	73	73	73	73	73	73	73	74
EBoiler-HP-Air2Water-XS	893	893	893	893	893	893	893	893
EBoiler-HP-Ground2Water-XS	988	988	988	988	988	988	988	988
EBoiler-HP-WasteHeat2Water-S	88	88	88	88	88	88	88	88
Storage-HP-Air2Water-XS	548	4464	4464	1600	1841	1841	1841	2098
Storage-HP-Ground2Water-XS	397	4940	4940	1446	1843	1917	1902	2140

Table F.38 REMix-OptiMo output: heat supply capacity expansion sensitivities results Germany Southeast, part I.

	TES Cost+	TES Cost–	TES Cost– –	TES Loss+	EB Cost+	Solar DH	El. Heat+	Red. Cap.
Power generation and curtailment in GWh/a								
Coal	43	43	42	33	42	44	44	0
CCGT	3922	3886	3854	4108	3922	3972	3957	3139
Gas turbine	53	53	52	58	55	55	53	113
DH-Engine-Biogas-M	3386	3416	3415	3186	3382	3522	3389	3363
DH-Engine-NGas-M	2117	2113	2120	2091	2111	1817	2148	2136
DH-ST-SolidBio-M	815	811	810	830	811	750	705	844
Ind-Engine-NGas-M	1395	1396	1395	1394	1390	1398	1411	1421
Ind-GT-NGas-L	3545	3537	3540	3538	3513	3582	3684	3440
Ind-ST-SolidBio-M	3698	3715	3708	3752	3717	3751	3724	3785
Bld-Engine-Biogas-XS	1625	1631	1634	1626	1624	1626	1635	1629
Bld-Engine-NGas-XS	182	182	182	181	182	182	183	182
DH-BpCCGT-NGas-L	667	670	672	666	668	669	662	670
DH-ExCCGT-NGas-XL	3426	3430	3449	3406	3449	3453	3540	4071
DH-ST-Coal-XL	1612	1615	1621	1624	1608	1617	1615	1741
DH-ST-Waste-L	1469	1463	1459	1470	1466	1496	1469	1471
Run-of-river hydro	13495	13495	13495	13495	13495	13495	13495	13495
Photovoltaic	20723	20726	20727	20726	20670	20707	20745	20725
Wind onshore	4401	4402	4402	4402	4382	4397	4409	4402
Reservoir hydro	756	756	756	756	756	756	756	756
Biomass power	1937	1937	1938	1937	1931	1936	1939	1937
Geothermal power	4539	4539	4539	4539	4539	4539	4539	4539
VRE curtailment	263	259	259	260	335	284	233	261
Installed electric capacity in MW								
Coal	9	9	9	9	9	9	9	0
CCGT	2115	2115	2115	2115	2115	2115	2115	1553
Gas turbine	820	833	822	848	845	840	781	1015
DH-Engine-NGas-M	502	503	509	483	494	487	514	578
Ind-Engine-NGas-M	240	240	240	240	239	242	247	255
Ind-GT-NGas-L	622	622	622	622	622	622	622	639
Bld-Engine-NGas-XS	33	33	33	33	33	33	33	33
DH-BpCCGT-NGas-L	119	119	119	119	119	119	119	119
DH-ExCCGT-NGas-XL	729	729	734	718	726	736	765	983
DH-ST-Coal-XL	388	388	388	388	388	388	390	414
DH-ST-Waste-L	378	378	378	378	378	378	378	378
Thermal storage energy input in GWh/a								
Storage-DH-Engine-Biogas-M	195	246	270	226	227	236	249	224
Storage-DH-Engine-NGas-M	142	165	176	63	141	169	151	241
Storage-DH-ST-SolidBio-M	84	86	87	37	84	89	116	72
Storage-Ind-ST-SolidBio-M	547	662	665	413	656	626	646	670
Storage-Bld-Engine-Biogas-XS	86	105	115	50	93	84	90	109
Storage-Bld-Engine-NGas-XS	4	5	6	1	5	5	5	9
Storage-DH-BpCCGT-NGas-L	27	34	37	13	33	32	33	34
Storage-DH-ExCCGT-NGas-XL	184	189	196	113	181	187	196	237
Storage-DH-ST-Coal-XL	155	159	173	91	155	151	151	170
Storage-HP-Air2Water-XS	113	122	139	112	117	111	104	165
Storage-HP-Ground2Water-XS	79	90	106	76	88	81	77	127

Table F.39 REMix-OptiMo output: heat supply capacity expansion sensitivities results Germany Southeast, part II.

	TES Cost+	TES Cost–	TES Cost––	TES Loss+	EB Cost+	Solar DH	El. Heat+	Red. Cap.
Heat production in GWh/a								
DH-Engine-Biogas-M	3231	3276	3304	3281	3237	3243	3221	3246
DH-Engine-NGas-M	2491	2486	2494	2460	2483	2138	2527	2513
DH-ST-SolidBio-M	1487	1489	1489	1488	1482	1322	1275	1487
Ind-Engine-NGas-M	1468	1469	1468	1467	1463	1471	1485	1496
Ind-GT-NGas-L	5064	5052	5058	5054	5019	5117	5263	4914
Ind-ST-SolidBio-M	7396	7510	7509	7456	7502	7493	7506	7464
Bld-Engine-Biogas-XS	2708	2719	2724	2711	2706	2709	2725	2714
Bld-Engine-NGas-XS	331	331	331	329	330	331	332	331
DH-BpCCGT-NGas-L	606	609	611	606	607	608	602	609
DH-ExCCGT-NGas-XL	2674	2681	2699	2654	2694	2690	2765	3105
DH-ST-Coal-XL	2460	2465	2478	2471	2455	2460	2465	2554
DH-ST-Waste-L	2897	2897	2897	2897	2897	2897	2897	2897
EBoiler-DH-Engine-Biogas-M	12	9	0	12	0	14	0	13
EBoiler-DH-Engine-NGas-M	129	137	139	133	111	82	104	179
EBoiler-DH-ST-SolidBio-M	6	6	6	6	0	1	0	6
EBoiler-Ind-ST-SolidBio-M	24	22	23	26	0	27	19	23
EBoiler-DH-BpCCGT-NGas-L	0	0	0	0	0	0	22	0
EBoiler-DH-ExCCGT-NGas-XL	93	94	94	97	54	95	77	88
EBoiler-DH-ST-Coal-XL	0	0	0	0	0	0	31	0
HP-Ground2Water-XS	4456	4456	4464	4457	4453	4455	4456	4464
HP-Air2Water-XS	4062	4065	4072	4072	4062	4061	4067	4080
HP-WasteHeat2Water-S	829	828	828	829	828	828	828	829
EBoiler-HP-Air2Water-XS	124	124	122	119	125	124	116	119
EBoiler-HP-Ground2Water-XS	162	165	162	163	167	163	161	165
EBoiler-HP-WasteHeat2Water-S	5	6	6	5	6	6	5	5
Installed thermal capacities in MW / GWh								
EBoiler-DH-Engine-Biogas-M	50	45	0	53	0	53	0	54
EBoiler-DH-Engine-NGas-M	329	346	349	315	197	195	304	363
EBoiler-DH-ST-SolidBio-M	27	26	26	29	0	4	0	27
EBoiler-Ind-ST-SolidBio-M	131	130	130	143	0	148	125	130
EBoiler-DH-BpCCGT-NGas-L	0	0	0	0	0	0	95	0
EBoiler-DH-ExCCGT-NGas-XL	421	428	431	415	194	428	382	414
EBoiler-DH-ST-Coal-XL	0	0	0	0	0	0	175	0
Storage-DH-Engine-Biogas-M	1097	6120	9231	1980	2293	2034	1936	2220
Storage-DH-Engine-NGas-M	852	1755	2464	763	1035	1443	1093	2501
Storage-DH-ST-SolidBio-M	829	993	1197	884	875	944	1047	940
Storage-Ind-ST-SolidBio-M	4270	10735	10735	5606	10132	10132	10210	7711
Storage-Bld-Engine-Biogas-XS	531	993	1486	622	601	601	601	622
Storage-Bld-Engine-NGas-XS	51	74	183	70	74	74	74	74
Storage-DH-BpCCGT-NGas-L	167	464	1118	181	352	352	311	359
Storage-DH-ExCCGT-NGas-XL	1919	2141	3627	1758	1738	1884	2022	2082
Storage-DH-ST-Coal-XL	1633	2343	5269	1756	1633	1632	1674	1789
HP-Ground2Water-XS	986	985	988	987	984	986	987	987
HP-Air2Water-XS	920	921	924	927	920	920	927	929
HP-WasteHeat2Water-S	162	159	159	161	160	160	160	161
EBoiler-HP-Air2Water-XS	1278	1278	1278	1278	1278	1278	1278	1278
EBoiler-HP-Ground2Water-XS	1414	1414	1414	1414	1414	1414	1414	1414
EBoiler-HP-WasteHeat2Water-S	191	191	191	191	191	191	191	191
Storage-HP-Air2Water-XS	1307	1538	2255	1460	1321	1321	1467	1538
Storage-HP-Ground2Water-XS	756	1025	1561	783	836	796	845	873

Table F.40 REMix-OptiMo output: heat supply capacity expansion sensitivities results Germany Southwest, part I.

	TES Cost+	TES Cost–	TES Cost– –	TES Loss+	EB Cost+	Solar DH	El. Heat+	Red. Cap.
Power generation and curtailment in GWh/a								
Coal	379	378	377	356	361	424	415	0
CCGT	640	611	604	729	629	680	695	251
Gas turbine	6	6	6	8	7	7	7	94
DH-Engine-Biogas-M	3727	3715	3716	3695	3715	3805	3724	3809
DH-Engine-NGas-M	2413	2429	2434	2319	2419	2084	2492	2499
DH-ST-SolidBio-M	981	980	980	997	980	906	802	1017
Ind-Engine-NGas-M	1380	1379	1379	1384	1373	1382	1390	1408
Ind-GT-NGas-L	2609	2615	2622	2617	2584	2699	2783	2665
Ind-ST-Coal-M	461	461	461	461	461	461	461	468
Ind-ST-SolidBio-M	3472	3496	3493	3532	3483	3525	3495	3611
Bld-Engine-Biogas-XS	1412	1415	1415	1412	1413	1413	1414	1414
Bld-Engine-NGas-XS	159	159	159	158	159	159	159	159
DH-BpCCGT-NGas-L	506	507	507	509	505	506	507	505
DH-ExCCGT-NGas-XL	1393	1394	1394	1408	1393	1404	1398	1583
DH-ST-Coal-XL	1147	1149	1152	1152	1148	1156	1149	1202
DH-ST-Waste-L	989	984	980	1003	987	1015	998	1019
Run-of-river hydro	7151	7151	7151	7151	7151	7151	7151	7151
Photovoltaic	9479	9479	9478	9479	9479	9479	9479	9479
Wind onshore	4269	4269	4270	4270	4269	4269	4269	4269
Reservoir hydro	685	685	685	685	685	685	685	685
Biomass power	1424	1424	1424	1424	1424	1424	1424	1424
Geothermal power	3493	3493	3493	3493	3493	3493	3493	3493
VRE curtailment	2	2	2	2	2	2	2	2
Installed electric capacity in MW								
Coal	113	113	113	113	113	113	113	0
CCGT	531	531	531	531	531	531	531	151
Gas turbine	333	329	326	365	339	346	327	601
DH-Engine-NGas-M	555	570	574	517	559	549	577	651
Ind-Engine-NGas-M	233	232	232	235	231	235	239	257
Ind-GT-NGas-L	487	487	487	487	487	487	487	506
Ind-ST-Coal-XL	102	102	102	102	102	102	102	102
Bld-Engine-NGas-XS	29	29	29	29	29	29	29	29
DH-BpCCGT-NGas-L	92	92	92	92	92	92	92	92
DH-ExCCGT-NGas-XL	307	307	307	307	307	307	307	379
DH-ST-Coal-XL	282	282	282	282	282	282	282	286
DH-ST-Waste-L	292	292	292	292	292	292	292	292
Electric storage energy input in GWh/a								
Pumped hydro storage	3772	3709	3699	3993	3757	3712	3682	3780
Thermal storage energy input in GWh/a								
Storage-DH-Engine-Biogas-M	327	366	382	344	350	351	364	342
Storage-DH-Engine-NGas-M	266	308	315	49	293	297	305	404
Storage-DH-ST-SolidBio-M	117	131	137	89	125	124	179	115
Storage-Ind-ST-SolidBio-M	746	888	889	569	854	837	877	826
Storage-Bld-Engine-Biogas-XS	116	147	156	41	125	126	127	139
Storage-Bld-Engine-NGas-XS	10	13	14	1	12	12	12	14
Storage-DH-BpCCGT-NGas-L	32	35	37	24	33	33	33	35
Storage-DH-ExCCGT-NGas-XL	94	101	102	78	101	98	99	135
Storage-DH-ST-Coal-XL	124	136	145	102	130	129	133	136
Storage-HP-Air2Water-XS	105	104	121	33	105	104	103	122
Storage-HP-Ground2Water-XS	36	37	37	22	39	36	33	55

Table F.41 REMix-OptiMo output: heat supply capacity expansion sensitivities results Germany Southwest, part II.

	TES Cost+	TES Cost–	TES Cost–	TES Loss+	EB Cost+	Solar DH	El. Heat+	Red. Cap.
Heat production in GWh/a								
DH-Engine-Biogas-M	3820	3832	3841	3880	3826	3826	3824	3826
DH-Engine-NGas-M	2839	2858	2864	2728	2846	2452	2932	2940
DH-ST-SolidBio-M	1824	1828	1831	1836	1825	1624	1470	1824
Ind-Engine-NGas-M	1453	1452	1452	1457	1446	1455	1464	1482
Ind-GT-NGas-L	3728	3736	3745	3739	3692	3855	3976	3807
Ind-ST-Coal-XL	920	919	919	919	919	919	920	919
Ind-ST-SolidBio-M	7237	7344	7344	7313	7307	7308	7317	7294
Bld-Engine-Biogas-XS	2354	2358	2359	2353	2355	2355	2356	2356
Bld-Engine-NGas-XS	289	289	289	288	289	289	289	289
DH-BpCCGT-NGas-L	460	461	461	463	459	460	460	459
DH-ExCCGT-NGas-XL	1097	1098	1099	1108	1097	1098	1099	1198
DH-ST-Coal-XL	1750	1754	1760	1764	1751	1751	1752	1766
DH-ST-Waste-L	2040	2040	2040	2040	2040	2040	2040	2040
EBoiler-DH-Engine-Biogas-M	0	0	0	0	0	0	0	0
EBoiler-DH-Engine-NGas-M	60	71	72	86	0	21	2	91
EBoiler-DH-ST-SolidBio-M	0	0	0	0	0	0	0	0
EBoiler-Ind-ST-SolidBio-M	0	0	0	0	0	0	0	0
EBoiler-DH-BpCCGT-NGas-L	0	0	0	0	0	0	0	0
EBoiler-DH-ExCCGT-NGas-XL	0	0	0	0	0	0	0	0
EBoiler-DH-ST-Coal-XL	0	0	0	0	0	0	0	0
HP-Ground2Water-XS	3444	3441	3442	3444	3442	3443	3445	3453
HP-Air2Water-XS	3158	3157	3160	3143	3157	3158	3158	3169
HP-WasteHeat2Water-S	795	794	794	795	794	794	795	795
EBoiler-HP-Air2Water-XS	74	75	77	73	75	74	73	68
EBoiler-HP-Ground2Water-XS	112	115	114	111	115	113	111	108
EBoiler-HP-WasteHeat2Water-S	6	7	7	6	7	7	7	6
Installed thermal capacities in MW / GWh								
EBoiler-DH-Engine-Biogas-M	0	0	0	0	0	0	0	0
EBoiler-DH-Engine-NGas-M	38	47	49	56	0	17	2	70
EBoiler-DH-ST-SolidBio-M	0	0	0	0	0	0	0	0
EBoiler-Ind-ST-SolidBio-M	0	0	0	0	0	0	0	0
EBoiler-DH-BpCCGT-NGas-L	0	0	0	0	0	0	0	0
EBoiler-DH-ExCCGT-NGas-XL	0	0	0	0	0	0	0	0
EBoiler-DH-ST-Coal-XL	0	0	0	0	0	0	0	0
Storage-DH-Engine-Biogas-M	1698	3209	4839	2092	2302	2259	2293	2398
Storage-DH-Engine-NGas-M	1376	2204	2479	382	1864	1875	1906	3214
Storage-DH-ST-SolidBio-M	680	1117	1530	735	802	786	835	802
Storage-Ind-ST-SolidBio-M	3859	10299	10299	4176	7799	7985	8318	7182
Storage-Bld-Engine-Biogas-XS	516	872	1059	496	563	569	566	661
Storage-Bld-Engine-NGas-XS	51	71	119	53	63	63	63	63
Storage-DH-BpCCGT-NGas-L	222	370	593	182	263	259	259	307
Storage-DH-ExCCGT-NGas-XL	603	980	1221	658	766	766	744	1139
Storage-DH-ST-Coal-XL	830	1404	2771	879	951	951	997	1009
HP-Ground2Water-XS	772	770	770	773	770	771	773	776
HP-Air2Water-XS	721	720	718	722	721	721	722	728
HP-WasteHeat2Water-S	150	150	150	151	150	150	150	151
EBoiler-HP-Air2Water-XS	947	947	947	947	947	947	947	947
EBoiler-HP-Ground2Water-XS	1049	1049	1049	1049	1049	1049	1049	1049
EBoiler-HP-WasteHeat2Water-S	181	181	181	181	181	181	181	181
Storage-HP-Air2Water-XS	636	636	1142	658	636	636	636	636
Storage-HP-Ground2Water-XS	676	678	710	700	678	678	682	678

Table F.42 REMix-OptiMo output: heat supply capacity expansion sensitivities results Germany West, part I.

	TES Cost+	TES Cost–	TES Cost– –	TES Loss+	EB Cost+	Solar DH	El. Heat+	Red. Cap.
Power generation and curtailment in GWh/a								
Coal	1200	1205	1218	1138	1198	1241	1223	0
CCGT	8341	8257	8219	8472	8291	8421	8388	8153
Gas turbine	406	399	391	416	401	405	417	550
DH-Engine-Biogas-M	4867	4911	4921	4860	4883	4928	4870	5051
DH-Engine-NGas-M	2675	2685	2688	2637	2707	2286	2751	2704
DH-ST-SolidBio-M	1571	1560	1557	1578	1557	1503	1282	1627
Ind-Engine-NGas-M	2483	2487	2491	2486	2466	2489	2506	2527
Ind-GT-NGas-L	4879	4910	4948	4795	4784	4975	5169	4904
Ind-ST-Coal-M	848	847	847	847	844	848	849	857
Ind-ST-SolidBio-M	6805	6832	6839	6846	6818	6867	6862	6974
Bld-Engine-Biogas-XS	3173	3188	3193	3182	3170	3179	3201	3184
Bld-Engine-NGas-XS	353	354	354	352	353	354	355	354
DH-BpCCGT-NGas-L	866	869	871	868	864	867	837	868
DH-ExCCGT-NGas-XL	11324	11320	11309	11400	11362	11339	11399	11891
DH-ST-Coal-XL	2009	2013	2016	2028	1997	2022	1995	2064
DH-ST-Waste-L	2138	2117	2106	2105	2127	2173	2135	2255
Run-of-river hydro	2637	2637	2637	2637	2637	2637	2637	2637
Photovoltaic	13763	13762	13669	13762	13760	13761	13761	13761
Wind onshore	24293	24300	24388	24300	24219	24300	24301	24302
Reservoir hydro	341	341	341	341	341	341	341	341
Biomass power	3550	3553	3556	3551	3532	3551	3552	3552
Geothermal power	4417	4417	4417	4417	4417	4417	4417	4417
VRE curtailment	187	181	185	180	262	181	180	178
Installed electric capacity in MW								
Coal	329	329	329	329	329	329	329	0
CCGT	4307	4307	4307	4307	4307	4307	4307	3949
Gas turbine	4435	4349	4335	4388	4345	4384	4368	4689
DH-Engine-Biogas-M	834	834	834	834	834	834	834	834
DH-Engine-NGas-M	726	755	766	697	738	721	752	800
Ind-Engine-NGas-M	418	418	419	420	417	421	423	443
Ind-GT-NGas-L	905	905	905	905	905	905	905	921
Ind-ST-Coal-XL	190	190	190	190	190	190	190	190
Bld-Engine-NGas-XS	73	73	73	73	73	73	73	73
DH-BpCCGT-NGas-L	175	175	175	175	175	175	175	175
DH-ExCCGT-NGas-XL	2817	2817	2817	2817	2817	2817	2817	3039
DH-ST-Coal-XL	531	531	531	531	531	531	531	531
DH-ST-Waste-L	557	557	557	557	557	557	557	557
Electric storage energy input in GWh/a								
Pumped hydro storage	1345	1334	1321	1516	1356	1339	1300	1459
Thermal storage energy input in GWh/a								
Storage-DH-Engine-Biogas-M	428	532	560	489	506	484	545	484
Storage-DH-Engine-NGas-M	261	330	357	114	277	338	303	367
Storage-DH-ST-SolidBio-M	180	177	190	117	181	171	279	175
Storage-Ind-ST-SolidBio-M	1385	1592	1588	1011	1577	1570	1600	1557
Storage-Bld-Engine-Biogas-XS	219	258	294	124	231	229	229	237
Storage-Bld-Engine-NGas-XS	17	24	27	1	22	21	22	22
Storage-DH-BpCCGT-NGas-L	54	65	69	37	60	59	55	62
Storage-DH-ExCCGT-NGas-XL	784	800	831	666	763	777	794	877
Storage-DH-ST-Coal-XL	208	222	240	157	210	207	210	211
Storage-HP-Air2Water-XS	232	244	268	192	255	243	227	271
Storage-HP-Ground2Water-XS	133	166	201	143	170	160	142	190

Table F.43 REMix-OptiMo output: heat supply capacity expansion sensitivities results Germany West, part II.

	TES Cost+	TES Cost–	TES Cost– –	TES Loss+	EB Cost+	Solar DH	El. Heat+	Red. Cap.
Heat production in GWh/a								
DH-Engine-Biogas-M	4673	4730	4765	4764	4690	4691	4673	4697
DH-Engine-NGas-M	3147	3159	3163	3102	3185	2689	3237	3182
DH-ST-SolidBio-M	2628	2629	2637	2641	2615	2408	2064	2628
Ind-Engine-NGas-M	2614	2617	2622	2617	2596	2620	2637	2660
Ind-GT-NGas-L	6970	7015	7068	6850	6834	7107	7384	7006
Ind-ST-Coal-XL	1685	1682	1681	1683	1677	1684	1684	1684
Ind-ST-SolidBio-M	13465	13663	13691	13641	13618	13636	13687	13648
Bld-Engine-Biogas-XS	5288	5313	5321	5304	5283	5298	5336	5307
Bld-Engine-NGas-XS	642	644	644	640	642	644	646	644
DH-BpCCGT-NGas-L	788	790	792	789	785	788	761	789
DH-ExCCGT-NGas-XL	8628	8626	8620	8685	8656	8624	8685	8934
DH-ST-Coal-XL	2986	2998	3005	3008	2968	2989	2967	2993
DH-ST-Waste-L	3413	3413	3413	3413	3413	3413	3413	3413
EBoiler-DH-Engine-Biogas-M	42	21	15	34	0	32	0	28
EBoiler-DH-Engine-NGas-M	500	538	555	506	471	465	441	537
EBoiler-DH-ST-SolidBio-M	12	10	0	13	0	2	0	12
EBoiler-Ind-ST-SolidBio-M	50	35	10	46	0	53	0	36
EBoiler-DH-BpCCGT-NGas-L	0	0	0	0	0	0	74	0
EBoiler-DH-ExCCGT-NGas-XL	691	697	723	722	595	693	627	693
EBoiler-DH-ST-Coal-XL	0	0	0	0	0	0	76	0
HP-Ground2Water-XS	7907	7905	7923	7912	7910	7905	7907	7928
HP-Air2Water-XS	7251	7250	7248	7246	7247	7251	7254	7268
HP-WasteHeat2Water-S	1482	1479	1478	1481	1480	1480	1481	1481
EBoiler-HP-Air2Water-XS	166	171	184	175	178	170	164	162
EBoiler-HP-Ground2Water-XS	267	279	277	275	275	277	271	262
EBoiler-HP-WasteHeat2Water-S	6	9	10	7	7	7	7	7
Installed thermal capacities in MW / GWh								
EBoiler-DH-Engine-Biogas-M	176	99	73	150	0	145	0	127
EBoiler-DH-Engine-NGas-M	692	744	783	654	597	685	692	766
EBoiler-DH-ST-SolidBio-M	51	46	0	59	0	7	0	53
EBoiler-Ind-ST-SolidBio-M	250	183	49	222	0	270	0	191
EBoiler-DH-BpCCGT-NGas-L	0	0	0	0	0	0	180	0
EBoiler-DH-ExCCGT-NGas-XL	1928	1971	2098	1931	1476	1928	1855	1969
EBoiler-DH-ST-Coal-XL	0	0	0	0	0	0	359	0
Storage-DH-Engine-Biogas-M	2027	9427	13524	3375	5635	4323	5388	4848
Storage-DH-Engine-NGas-M	1568	3951	5332	1266	2284	3273	2513	4567
Storage-DH-ST-SolidBio-M	2354	2371	3522	2491	2372	2421	2425	2372
Storage-Ind-ST-SolidBio-M	8376	18621	18621	11536	18085	17968	17968	17910
Storage-Bld-Engine-Biogas-XS	1004	1725	3371	1082	1175	1113	1100	1200
Storage-Bld-Engine-NGas-XS	82	185	334	91	131	131	131	131
Storage-DH-BpCCGT-NGas-L	463	1431	2303	448	909	807	452	891
Storage-DH-ExCCGT-NGas-XL	7515	8846	13000	8207	7515	7515	7515	8726
Storage-DH-ST-Coal-XL	2579	3981	6667	2816	2579	2579	2579	2579
HP-Ground2Water-XS	1788	1782	1780	1788	1785	1785	1787	1798
HP-Air2Water-XS	1690	1689	1680	1690	1686	1690	1696	1700
HP-WasteHeat2Water-S	279	273	272	277	276	276	276	277
EBoiler-HP-Air2Water-XS	2293	2293	2293	2293	2293	2293	2293	2293
EBoiler-HP-Ground2Water-XS	2537	2537	2537	2537	2537	2537	2537	2537
EBoiler-HP-WasteHeat2Water-S	328	328	328	328	328	328	328	328
Storage-HP-Air2Water-XS	2696	3476	5604	3559	3481	3530	3736	3507
Storage-HP-Ground2Water-XS	1431	2498	5526	2412	2327	2327	2336	2327

F.6 Step 4: Operation Optimization with all Flexibility Options

Table F.44 REMix-OptiMo output: operation optimization results Germany Central.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Power generation and curtailment in GWh/a									
Nuclear	0	0	0	0	0	0	0	0	6438
Lignite	0	0	0	0	0	0	0	699	1580
Coal	245	283	245	281	235	246	252	4290	5545
CCGT	4095	8169	4017	4718	3900	4234	3728	5486	4907
Gas turbine	530	132	302	444	567	551	162	12	98
DH-Engine-Biogas-M	2474	2565	2471	2581	2424	2320	2493	1514	1056
DH-Engine-NGas-M	1283	1348	1287	1305	1273	1117	1229	1445	1439
DH-ST-SolidBio-M	633	680	629	675	609	598	614	671	750
Ind-Engine-NGas-M	762	781	760	773	748	683	752	609	374
Ind-GT-NGas-L	1948	1998	1963	2022	1892	1741	1911	2359	2790
Ind-ST-Coal-M	0	0	0	0	0	0	0	408	394
Ind-ST-SolidBio-M	2180	2291	2170	2271	2128	2068	2163	1233	918
Bld-Engine-Biogas-XS	1044	1049	1043	1049	1041	970	1033	656	309
Bld-Engine-NGas-XS	114	117	114	115	114	104	112	703	1069
DH-BpCCGT-NGas-L	327	336	327	328	324	294	318	638	965
DH-ExCCGT-NGas-XL	2048	1977	1961	2105	2023	1736	1872	1774	1590
DH-ST-Coal-XL	560	544	545	565	556	532	536	990	1624
DH-ST-Waste-L	923	998	920	1026	899	940	915	1257	1544
Run-of-river hydro	825	825	825	825	825	825	825	778	735
Photovoltaic	5893	6213	5893	5893	8840	5893	5201	5210	4142
Wind onshore	15387	17091	15387	15417	15333	23559	14151	13858	11330
Reservoir hydro	7	7	7	7	7	7	7	7	7
Biomass power	1538	1539	1538	1542	1537	1480	1541	2236	2505
Geothermal power	2800	2800	2800	2800	2800	2800	2800	949	283
VRE curtailment	57	73	57	27	112	654	8	198	0
Installed electric capacity in MW									
Gas turbine	2911	397	2403	1934	3403	3035	776	0	778
Electric storage energy input and load shifting in GWh/a									
Pumped hydro storage input	381	190	340	337	478	514	267	385	404
E-Mobility-2h	47	7	44	60	56	58	25	13	1
E-Mobility-4h	218	23	189	221	260	251	112	52	12
E-Mobility-8h	737	142	618	751	832	873	468	253	48
HVAC-ComInd	84	0	76	0	93	90	0	0	0
CoolingWater-ComInd	26	8	20	27	40	44	16	10	8
ProcessShift-Ind	2	1	3	5	3	2	3	0	1
StorHeat-ResCom	122	0	111	120	158	158	88	0	89
ProcessShed-Ind	1	2	1	2	1	1	1	0	1
Thermal storage energy input in GWh/a									
Storage-DH-Engine-Biogas-M	253	221	256	258	258	260	263	156	71
Storage-DH-Engine-NGas-M	221	87	203	207	240	275	162	98	84
Storage-DH-ST-SolidBio-M	63	36	60	65	70	83	56	47	48
Storage-Ind-ST-SolidBio-M	523	340	526	511	590	564	459	265	142
Storage-Bld-Engine-Biogas-XS	103	35	95	100	114	111	70	39	9
Storage-Bld-Engine-NGas-XS	6	2	5	6	7	7	4	20	24
Storage-DH-BpCCGT-NGas-L	23	13	21	23	25	27	20	38	44
Storage-DH-ExCCGT-NGas-XL	173	83	156	162	190	230	141	117	99
Storage-DH-ST-Coal-XL	67	37	64	64	73	76	60	102	99
Storage-HP-Air2Water-XS	74	20	70	80	98	107	68	10	16
Storage-HP-Ground2Water-XS	46	13	35	50	62	83	34	4	10
Heat production in GWh/a									
EBoiler-DH-Engine-Biogas-M	14	0	13	9	22	217	11	15	0
EBoiler-DH-Engine-NGas-M	217	105	209	189	231	423	265	163	46
EBoiler-DH-ST-SolidBio-M	14	0	13	2.9	17	113	12	20	0
EBoiler-Ind-ST-SolidBio-M	23	0	22	11	47	322	26	15	0
EBoiler-DH-ExCCGT-NGas-XL	116	52	113	94	137	359	172	49	0
HP-Ground2Water-XS	2841	2850	2835	2847	2847	2844	2845	2088	1176
HP-Air2Water-XS	2603	2598	2600	2608	2610	2607	2610	1899	1174
HP-WasteHeat2Water-S	455	455	455	455	455	455	455	262	86
EBoiler-HP-Air2Water-XS	55	44	56	52	53	59	47	86	80
EBoiler-HP-Ground2Water-XS	89	71	92	85	87	96	83	144	137
EBoiler-HP-WasteHeat2Water-S	2.1	2.2	2.6	2.1	2.1	2.1	2.5	3.7	0.9

Table F.45 REMix-OptiMo output: operation optimization results Germany East.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Power generation and curtailment in GWh/a									
Lignite	0	0	0	0	0	0	0	17814	41292
Coal	235	291	233	255	216	228	241	4014	4697
CCGT	4842	9939	4744	5241	4425	4497	3960	8480	5684
Gas turbine	1635	780	1098	1403	1733	1523	406	471	13
DH-Engine-Biogas-M	2759	2968	2755	2853	2669	2478	2810	2302	1606
DH-Engine-NGas-M	1374	1429	1376	1390	1363	1168	1416	2003	1808
DH-ST-SolidBio-M	904	1017	899	949	855	801	847	976	1081
Ind-Engine-NGas-M	1063	1095	1060	1083	1048	929	1095	816	499
Ind-GT-NGas-L	2690	2789	2698	2788	2643	2414	2792	3958	4615
Ind-ST-SolidBio-M	2992	3237	2982	3099	2894	2678	2982	1732	1264
Bld-Engine-Biogas-XS	1928	1931	1926	1933	1934	1739	1941	1234	562
Bld-Engine-NGas-XS	212	214	212	213	212	186	216	1301	1888
DH-BpCCGT-NGas-L	610	617	611	613	609	535	621	1229	1836
DH-ExCCGT-NGas-XL	5208	5235	5096	5214	5071	4142	5039	3993	3411
DH-ST-Coal-XL	1265	1265	1249	1269	1252	1159	1217	1494	2228
DH-ST-Lignite-XL	0	0	0	0	0	0	0	3166	3561
DH-ST-Waste-L	1822	2061	1816	1943	1709	1788	1747	2675	3242
Run-of-river hydro	865	865	865	865	865	865	865	815	771
Photovoltaic	17920	18976	17917	17941	26679	17023	15871	15954	12686
Wind onshore	43054	47842	43070	43062	43042	76724	39508	39255	31643
Wind offshore	18380	19972	18374	18414	13142	8706	16586	13393	5393
Biomass power	4146	4175	4143	4155	4121	3830	4181	6166	6834
Geothermal power	6842	6842	6842	6842	6842	6842	6842	2319	691
VRE curtailment	636	445	627	572	934	4961	299	31	0
Installed electric capacity in MW									
Gas turbine	7011	3222	6844	5034	7323	7114	2324	2874	512
Electric storage energy input and load shifting in GWh/a									
Pumped hydro storage input	1962	842	1888	1711	2609	2409	1341	1655	1795
E-Mobility-2h	75	21	115	133	102	160	87	23	2
E-Mobility-4h	476	71	477	469	499	536	301	116	24
E-Mobility-8h	1946	378	1812	1618	1979	1853	1052	515	94
HVAC-ComInd	225	0	32	0	228	0	0	0	0
CoolingWater-ComInd	99	26	90	98	138	137	44	61	0
ProcessShift-Ind	8	2	9	8	13	8	1	3	0
StorHeat-ResCom	337	0	321	296	420	370	0	396	0
ProcessShed-Ind	2	0	2	2	2	2	3	1	0
Thermal storage energy input in GWh/a									
Storage-DH-Engine-Biogas-M	330	322	335	334	324	304	325	326	158
Storage-DH-Engine-NGas-M	277	140	272	251	284	332	200	257	108
Storage-DH-ST-SolidBio-M	129	71	124	118	138	154	105	148	89
Storage-Ind-ST-SolidBio-M	832	537	830	766	924	871	703	549	130
Storage-Bld-Engine-Biogas-XS	275	104	268	245	299	282	192	112	24
Storage-Bld-Engine-NGas-XS	19	8	18	16	22	18	11	74	70
Storage-DH-BpCCGT-NGas-L	56	36	55	51	59	56	44	101	116
Storage-DH-ExCCGT-NGas-XL	536	372	510	494	558	673	411	378	274
Storage-DH-ST-Coal-XL	208	147	205	190	222	230	162	217	152
Storage-HP-Air2Water-XS	243	73	224	220	312	357	177	124	0
Storage-HP-Ground2Water-XS	166	57	153	159	207	270	101	72	0
Heat production in GWh/a									
EBoiler-DH-Engine-Biogas-M	45	16	48	37	55	357	11	0	0
EBoiler-DH-Engine-NGas-M	284	192	281	263	296	541	215	515	324
EBoiler-DH-ST-SolidBio-M	34	9	37	31.4	42	250	11	0	13
EBoiler-Ind-ST-SolidBio-M	119	27	121	90	145	851	27	0	0
EBoiler-DH-ExCCGT-NGas-XL	341	202	329	304	371	1114	188	0	55
HP-Ground2Water-XS	5845	5847	5831	5867	5846	5860	5851	4252	2321
HP-Air2Water-XS	5338	5311	5326	5349	5348	5358	5334	3940	2351
HP-WasteHeat2Water-S	639	639	639	639	639	639	639	370	119
EBoiler-HP-Air2Water-XS	118	94	123	100	125	132	103	174	311
EBoiler-HP-Ground2Water-XS	163	128	172	138	172	176	139	354	468
EBoiler-HP-WasteHeat2Water-S	3.4	3.4	3.4	3.3	3.3	3.8	3.2	3.2	3.7

Table F.46 REMix-OptiMo output: operation optimization results Germany North.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Power generation and curtailment in GWh/a									
Nuclear	0	0	0	0	0	0	0	0	13122
Coal	762	881	719	901	729	764	749	10823	9706
CCGT	622	991	1011	819	605	672	516	695	648
Gas turbine	2	8	826	1	12	11	3	2	15
DH-Engine-Biogas-M	958	1019	987	1160	994	1031	1112	756	590
DH-Engine-NGas-M	479	518	499	577	594	581	609	703	698
DH-ST-SolidBio-M	347	353	404	433	377	383	400	386	493
Ind-Engine-NGas-M	472	488	460	542	541	533	560	435	306
Ind-GT-NGas-L	1289	1384	1175	1479	1388	1382	1502	1951	2577
Ind-ST-Coal-M	0	0	0	0	0	0	0	146	148
Ind-ST-SolidBio-M	1322	1405	1424	1595	1397	1416	1540	891	749
Bld-Engine-Biogas-XS	810	817	761	924	884	857	957	573	290
Bld-Engine-NGas-XS	89	91	80	102	97	94	106	605	1001
DH-BpCCGT-NGas-L	275	282	245	315	299	291	327	545	916
DH-ExCCGT-NGas-XL	2670	2836	2818	3244	2938	2891	3442	2158	2298
DH-ST-Coal-XL	865	876	941	979	940	914	1016	1310	1786
DH-ST-Waste-L	768	805	868	895	729	793	726	1040	1397
Run-of-river hydro	42	42	42	42	42	42	42	40	37
Photovoltaic	6468	6870	6516	6490	9633	6358	5754	5771	4593
Wind onshore	34746	39036	35426	35598	35323	51927	32906	32615	26461
Wind offshore	108189	120196	114229	117479	81216	58602	107284	84754	35935
Biomass power	1351	1382	1407	1522	1461	1430	1567	2201	2708
Geothermal power	2459	2459	2459	2459	2459	2459	2459	834	248
VRE curtailment	18628	16065	11860	8464	10331	11309	4881	4981	41
Installed electric capacity in MW									
Gas turbine	80	133	1436	80	95	80	80	149	144
Hydrogen storage	0	0	1080	0	0	0	0	0	0
Hydrogen converter	0	0	3880	0	0	0	0	0	0
Electric storage energy input and load shifting in GWh/a									
Hydrogen storage input	0	0	8884	0	0	0	0	0	0
E-Mobility-2h	106	17	149	96	110	104	63	33	2
E-Mobility-4h	188	42	426	190	221	207	127	59	8
E-Mobility-8h	559	163	1259	462	618	562	318	211	29
CoolingWater-ComInd	46	27	105	41	57	46	30	41	3
ProcessShift-Ind	0	0	6	0	3	3	0	0	0
StorHeat-ResCom	0	0	213	0	30	0	0	0	0
ProcessShed-Ind	0	0	0	0	0	0	0	0	0
Thermal storage energy input in GWh/a									
Storage-DH-Engine-Biogas-M	115	109	158	109	112	113	97	90	24
Storage-DH-Engine-NGas-M	153	114	199	120	159	151	94	165	30
Storage-DH-ST-SolidBio-M	128	94	145	85	115	114	66	101	16
Storage-Ind-ST-SolidBio-M	438	349	538	408	472	447	362	269	46
Storage-Bld-Engine-Biogas-XS	78	26	106	74	94	81	54	32	4
Storage-Bld-Engine-NGas-XS	4	1	8	4	5	4	2	14	6
Storage-DH-BpCCGT-NGas-L	23	17	23	20	23	23	17	30	24
Storage-DH-ExCCGT-NGas-XL	592	465	684	484	569	559	389	343	69
Storage-DH-ST-Coal-XL	135	102	148	117	135	135	91	140	95
Storage-HP-Air2Water-XS	193	68	288	137	210	204	84	44	0
Storage-HP-Ground2Water-XS	197	58	277	134	209	198	72	42	1
Heat production in GWh/a									
EBoiler-DH-Engine-Biogas-M	345	310	346	179	236	276	131	170	10
EBoiler-DH-Engine-NGas-M	411	351	474	265	343	358	222	360	187
EBoiler-DH-ST-SolidBio-M	344	302	330	180.3	244	273	125	229	28
EBoiler-Ind-ST-SolidBio-M	897	755	908	477	676	731	304	341	26
EBoiler-DH-ExCCGT-NGas-XL	1414	1244	1662	854	1128	1199	658	640	71
HP-Ground2Water-XS	2946	2954	2938	2959	2964	2962	2959	2087	1108
HP-Air2Water-XS	2708	2697	2731	2705	2706	2704	2704	1966	1122
HP-WasteHeat2Water-S	380	380	381	380	380	380	380	218	71
EBoiler-HP-Air2Water-XS	84	59	89	70	89	92	56	101	120
EBoiler-HP-Ground2Water-XS	137	92	170	105	121	122	90	236	194
EBoiler-HP-WasteHeat2Water-S	2.8	2.7	2.2	2.6	2.5	2.4	2.5	3.8	1.9

Table F.47 REMix-OptiMo output: operation optimization results Germany Southeast.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Power generation and curtailment in GWh/a									
Nuclear	0	0	0	0	0	0	0	0	26398
Coal	41	46	43	45	36	40	48	759	782
CCGT	3820	6809	3696	4341	3753	3795	3400	8238	4284
Gas turbine	6	5	1	30	0	10	5	7	8
DH-Engine-Biogas-M	3383	3492	3401	3651	3130	3380	3428	2188	1483
DH-Engine-NGas-M	2113	1871	2109	2178	1664	2100	1799	2247	1933
DH-ST-SolidBio-M	818	829	809	847	772	818	771	991	1067
Ind-Engine-NGas-M	1396	1342	1399	1429	1254	1394	1331	1100	672
Ind-GT-NGas-L	3606	3730	3632	3768	3408	3574	3706	5675	6284
Ind-ST-SolidBio-M	3719	3862	3713	3965	3533	3727	3722	2213	1638
Bld-Engine-Biogas-XS	1635	1650	1636	1643	1601	1635	1645	1039	472
Bld-Engine-NGas-XS	182	186	183	184	177	182	184	1119	1637
DH-BpCCGT-NGas-L	669	682	671	676	651	670	672	990	1453
DH-ExCCGT-NGas-XL	3362	3432	3354	3511	3143	3347	3389	3284	2809
DH-ST-Coal-XL	1615	1626	1615	1620	1590	1615	1623	1817	2450
DH-ST-Waste-L	1469	1611	1467	1698	1408	1477	1500	1917	2237
Run-of-river hydro	13495	13495	13495	13495	13495	13495	13495	12716	12020
Photovoltaic	20780	22020	20784	20834	30490	20785	18408	18468	14683
Wind onshore	4435	4995	4440	4444	4337	2812	4087	4092	3298
Reservoir hydro	756	757	756	757	754	756	757	757	757
Biomass power	1945	1962	1948	1956	1895	1948	1955	2866	3169
Geothermal power	4539	4539	4539	4539	4539	4539	4539	1539	458
VRE curtailment	173	6	164	110	1007	137	62	0	0
Installed electric capacity in MW									
Gas turbine	367	611	367	367	367	367	367	682	661
Electric storage energy input and load shifting in GWh/a									
E-Mobility-2h	79	2	58	55	150	71	13	4	1
E-Mobility-4h	139	8	121	146	247	148	39	21	4
E-Mobility-8h	315	39	251	348	363	316	98	73	22
CoolingWater-ComInd	24	3	20	15	54	25	7	0	0
ProcessShift-Ind	0	0	0	0.04	0	0	0	0	0.01
StorHeat-ResCom	0	0	0	87	181	0	0	0	0
Thermal storage energy input in GWh/a									
Storage-DH-Engine-Biogas-M	233	203	225	233	254	236	245	168	58
Storage-DH-Engine-NGas-M	165	27	152	154	188	156	64	79	34
Storage-DH-ST-SolidBio-M	79	42	77	80	95	79	75	57	16
Storage-Ind-ST-SolidBio-M	696	518	648	709	916	699	748	266	33
Storage-Bld-Engine-Biogas-XS	92	27	84	70	131	89	64	31	2
Storage-Bld-Engine-NGas-XS	4	1	3	4	8	4	1	13	6
Storage-DH-BpCCGT-NGas-L	33	19	33	33	36	33	34	38	39
Storage-DH-ExCCGT-NGas-XL	182	94	171	180	253	176	175	142	83
Storage-DH-ST-Coal-XL	145	72	139	135	168	142	131	117	68
Storage-HP-Air2Water-XS	86	11	76	62	126	86	15	5	0
Storage-HP-Ground2Water-XS	61	12	59	50	119	56	16	2	0
Heat production in GWh/a									
EBoiler-DH-Engine-Biogas-M	10	0	5	0	83	10	0	0	0
EBoiler-DH-Engine-NGas-M	132	13	117	53	295	135	71	0	27
EBoiler-DH-ST-SolidBio-M	5	0	3	0.5	80	5	1	0	0
EBoiler-Ind-ST-SolidBio-M	18	0	0	0	265	20	0	0	0
EBoiler-DH-ExCCGT-NGas-XL	92	0	77	11	268	89	9	0	0
HP-Ground2Water-XS	4454	4470	4457	4460	4489	4448	4469	3282	1710
HP-Air2Water-XS	4072	4070	4070	4069	4099	4073	4069	2970	1710
HP-WasteHeat2Water-S	828	827	828	828	828	828	827	477	154
EBoiler-HP-Air2Water-XS	106	87	106	103	88	106	89	146	194
EBoiler-HP-Ground2Water-XS	159	130	156	152	139	163	132	222	284
EBoiler-HP-WasteHeat2Water-S	5.6	6.3	5.9	5.7	6.0	5.5	6.3	7.4	5.0

Table F.48 REMix-OptiMo output: operation optimization results Germany Southwest.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Power generation and curtailment in GWh/a									
Nuclear	0	0	0	0	0	0	0	0	11993
Coal	315	468	340	503	302	360	455	7748	11455
CCGT	510	1253	638	923	520	590	511	1231	1618
DH-Engine-Biogas-M	3699	3979	3704	4117	3629	3806	3919	1657	1147
DH-Engine-NGas-M	2391	2195	2101	2176	2413	2422	2014	1613	1642
DH-ST-SolidBio-M	981	978	977	1040	963	998	936	914	1004
Ind-Engine-NGas-M	1376	1314	1310	1314	1377	1380	1288	1057	657
Ind-GT-NGas-L	2664	2800	2756	2877	2673	2701	2785	4093	4972
Ind-ST-Coal-M	461	461	461	461	460	461	461	710	682
Ind-ST-SolidBio-M	3463	3702	3472	3848	3429	3519	3589	2164	1603
Bld-Engine-Biogas-XS	1414	1410	1414	1414	1414	1414	1412	879	408
Bld-Engine-NGas-XS	159	159	159	159	159	159	155	942	1415
DH-BpCCGT-NGas-L	505	506	507	507	506	506	494	1054	1590
DH-ExCCGT-NGas-XL	1374	1376	1376	1377	1374	1374	1350	2287	2031
DH-ST-Coal-XL	1141	1138	1141	1140	1140	1141	1140	1378	1999
DH-ST-Waste-L	972	1161	985	1311	957	1028	1098	1954	2529
Run-of-river hydro	7151	7151	7151	7151	7151	7151	7151	6738	6370
Photovoltaic	9479	9993	9479	9479	14216	9479	8365	8360	6662
Wind onshore	4272	4747	4272	4272	4265	2096	3916	3842	3133
Reservoir hydro	685	685	685	685	685	685	685	684	685
Biomass power	1425	1425	1425	1425	1424	1425	1425	2065	2297
Geothermal power	3493	3493	3493	3493	3493	3493	3493	1184	353
VRE curtailment	0	0	0	0	9	0	0	65	0
Installed electric capacity in MW									
Gas turbine	92	153	92	92	92	92	92	171	166
Electric storage energy input and load shifting in GWh/a									
Pumped hydro storage input	2504	884	2468	2027	3271	2494	1504	1869	565
E-Mobility-2h	91	10	85	79	86	94	33	15	1
E-Mobility-4h	306	36	274	257	291	285	135	73	5
E-Mobility-8h	1059	144	994	965	1090	1078	736	319	29
CoolingWater-ComInd	6	1	4	5	11	6	3	4	0
Thermal storage energy input in GWh/a									
Storage-DH-Engine-Biogas-M	365	301	364	416	390	364	400	168	71
Storage-DH-Engine-NGas-M	312	63	185	161	343	315	124	97	55
Storage-DH-ST-SolidBio-M	129	56	130	117	133	128	107	74	38
Storage-Ind-ST-SolidBio-M	931	600	961	885	1034	939	843	466	60
Storage-Bld-Engine-Biogas-XS	132	42	125	108	153	129	85	52	6
Storage-Bld-Engine-NGas-XS	10	3	10	9	12	10	6	33	14
Storage-DH-BpCCGT-NGas-L	34	15	33	30	36	34	29	60	65
Storage-DH-ExCCGT-NGas-XL	103	54	102	92	105	101	93	146	94
Storage-DH-ST-Coal-XL	135	52	130	114	141	135	105	143	100
Storage-HP-Air2Water-XS	80	11	35	30	105	89	26	1	0
Storage-HP-Ground2Water-XS	25	7	12	9	30	20	11	0	0
Heat production in GWh/a									
EBoiler-DH-Engine-NGas-M	68	6	17	0	75	39	191	191	2
EBoiler-DH-ST-SolidBio-M	0	0	0	0.0	0	0	0	1	0
EBoiler-DH-ExCCGT-NGas-XL	0	0	0	0	0	0	0	36	0
HP-Ground2Water-XS	3441	3441	3441	3449	3444	3437	3448	2503	1347
HP-Air2Water-XS	3156	3142	3146	3150	3162	3159	3149	2284	1340
HP-WasteHeat2Water-S	794	794	794	795	795	795	794	457	147
EBoiler-HP-Air2Water-XS	70	66	68	62	70	69	63	116	160
EBoiler-HP-Ground2Water-XS	112	107	108	100	111	115	102	197	225
EBoiler-HP-WasteHeat2Water-S	6.8	7.3	7.2	6.7	6.7	5.8	6.9	8.4	5.4

Table F.49 REMix-OptiMo output: operation optimization results Germany West.

Technology	50Base	50H ₂ T	50H ₂ St	50Grid	50PV	50Wind	50CSP	30Base	20Base
Power generation and curtailment in GWh/a									
Nuclear	0	0	0	0	0	0	0	0	6572
Lignite	0	0	0	0	0	0	0	20079	47117
Coal	1134	1337	1157	1478	1116	1217	1265	21217	25734
CCGT	8384	15554	8110	12811	8420	9362	8243	9996	4201
Gas turbine	185	46	2	435	219	288	42	1	0
DH-Engine-Biogas-M	4921	5070	4922	5301	4816	4970	5029	2186	1508
DH-Engine-NGas-M	2680	2555	2463	3017	2686	2544	2494	1819	1832
DH-ST-SolidBio-M	1609	1709	1577	1815	1557	1639	1563	1272	1383
Ind-Engine-NGas-M	2487	2395	2390	2611	2472	2406	2397	1958	1180
Ind-GT-NGas-L	5011	5051	5142	5571	4992	4849	5217	6915	8806
Ind-ST-Coal-M	857	856	856	868	857	856	862	1320	1262
Ind-ST-SolidBio-M	6863	7160	6820	7325	6720	6943	6909	4017	2975
Bld-Engine-Biogas-XS	3217	3184	3218	3255	3210	3163	3240	2026	913
Bld-Engine-NGas-XS	354	356	355	364	353	346	362	2153	3059
DH-BpCCGT-NGas-L	869	869	872	897	868	845	881	1447	2045
DH-ExCCGT-NGas-XL	10906	10914	10949	11890	10853	10475	11371	7729	6528
DH-ST-Coal-XL	1973	1953	1971	2028	1970	1957	1982	2014	3505
DH-ST-Lignite-XL	0	0	0	0	0	0	0	4352	6324
DH-ST-Waste-L	2169	2379	2145	2622	2081	2297	2208	2756	3369
Run-of-river hydro	2637	2637	2637	2637	2637	2637	2637	2485	2349
Photovoltaic	13773	14520	13772	13773	20634	13773	12154	12175	9680
Wind onshore	24404	27148	24376	24469	24341	33241	22424	22239	17905
Reservoir hydro	342	341	342	342	342	341	342	342	342
Biomass power	3573	3556	3566	3586	3568	3553	3584	5221	5766
Geothermal power	4417	4417	4417	4417	4417	4417	4417	1497	446
VRE curtailment	65	45	94	0	154	170	9	29	45
Installed electric capacity in MW									
Gas turbine	1107	1244	747	2029	1163	1415	747	1389	1346
Electric storage energy input and load shifting in GWh/a									
Pumped hydro storage input	662	318	656	487	744	745	424	741	958
E-Mobility-2h	102	5	86	103	114	120	23	13	3
E-Mobility-4h	422	16	309	361	497	522	113	110	38
E-Mobility-8h	1674	261	1226	1330	1874	1995	641	633	138
CoolingWater-ComInd	33	11	24	31	54	55	7	22	0
ProcessShift-Ind	5	0	0	23	7	7	0	0	0
StorHeat-ResCom	311	0	0	250	408	347	0	0	0
ProcessShed-Ind	8	0	0	10	9	10	0	0	0
Thermal storage energy input in GWh/a									
Storage-DH-Engine-Biogas-M	475	429	490	494	499	515	498	255	126
Storage-DH-Engine-NGas-M	310	70	184	281	373	403	113	138	81
Storage-DH-ST-SolidBio-M	169	44	135	147	179	169	130	105	77
Storage-Ind-ST-SolidBio-M	1617	996	1571	1377	1846	1670	1294	878	75
Storage-Bld-Engine-Biogas-XS	215	65	201	196	260	248	138	116	31
Storage-Bld-Engine-NGas-XS	14	3	12	12	17	16	5	53	77
Storage-DH-BpCCGT-NGas-L	59	31	58	47	65	63	44	89	106
Storage-DH-ExCCGT-NGas-XL	780	416	798	773	850	906	723	545	456
Storage-DH-ST-Coal-XL	200	103	191	169	218	206	157	217	249
Storage-HP-Air2Water-XS	145	27	59	118	180	192	47	15	0
Storage-HP-Ground2Water-XS	93	22	47	74	103	105	32	2	0
Heat production in GWh/a									
EBoiler-DH-Engine-Biogas-M	18	36	13	0	22	95	0	3	2
EBoiler-DH-Engine-NGas-M	523	351	468	94	539	708	336	766	527
EBoiler-DH-ST-SolidBio-M	8	21	12	0.0	14	62	0	9	45
EBoiler-Ind-ST-SolidBio-M	32	121	38	0	74	170	0	0	0
EBoiler-DH-ExCCGT-NGas-XL	696	608	632	0	719	1112	132	341	410
HP-Ground2Water-XS	7909	7913	7903	7922	7914	7908	7937	5733	2958
HP-Air2Water-XS	7251	7215	7219	7254	7259	7261	7233	5239	3022
HP-WasteHeat2Water-S	1480	1477	1477	1482	1480	1480	1479	850	274
EBoiler-HP-Air2Water-XS	147	147	151	137	147	150	134	269	412
EBoiler-HP-Ground2Water-XS	259	232	248	240	254	260	211	460	639
EBoiler-HP-WasteHeat2Water-S	7.2	10.4	10.4	6.0	7.5	7.7	8.3	13.6	9.5

Curriculum Vitae

Hans Christian Gils

born on September 15, 1983

in Karlsruhe Germany

2014-2015	Researcher	German Aerospace Centre (DLR)
2010-2013	PhD Candidate	University of Stuttgart and German Aerospace Centre (DLR) Visiting Scientist at the International Institute for Applied Systems Analysis (IIASA)
2009-2010	Researcher	Institute for Peace Research and Security Policy at the University of Hamburg (IFSH)
2009	Master of Science in Physics	Graduation from the University of Hamburg (Germany) Specialization: Astronomy, Particle Physics Secondary subjects: Philosophy, Economy, Chemistry Academic exchange with the University of Padua (Italy)
2002	Baccalaureat	Helmholtz-Gymnasium Karlsruhe