Renewable energy based electricity supply at low costs
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Development of the REMix model and application for Europe

Von der Fakultät für Energie-, Verfahrens- und Biotechnik der Universität Stuttgart
zur Erlangung der Würde eines Doktor-Ingenieurs (Dr.-Ing.)
genehmigte Abhandlung

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Tag der mündlichen Prüfung:	01.06.2012

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2012

Acknowledgement

I am very grateful to all members of the Systems Analysis and Technology Assessment department of the Institute of Technical Thermodynamics at the German Aerospace Centre for their collegiality and the excellent working atmosphere which supportet me in writing this thesis.

In particular I want to thank

- Prof. Dr. Hans Müller-Steinhagen for supervising my work and for creating great research conditions as the director of the Institute of Technical Thermodynamics.
- Prof. Dr. Ulrich Wagner, member of the DLR exectutive board, for agreeing to be the second supervisor and for providing very valuable comments on my work.
- Dr. Wolfram Krewitt, late head of the systems analysis and technology assessment department and my advisor, for bringing this research project into life and for helping me define it and focus on the important questions.
- Carsten Hoyer-Klick and Dr. Christoph Schillings not only for their help with data processing and all questions concerning computer software and hardware but also for their comprehensive work on solar resources and potential assessments which I could build on.
- Dr. Irene Pinedo Pascua for processing the geothermal resource data with me
- Julia Gehrung for her analysis of the influence of the net primary productivity as a proxy parameter for the spatial disaggregation of biomass potentials.

Special thanks go to Dr. Franz Trieb, who agreed to take over the supervision of my work from Wolfram Krewitt, for his critical discussions not only of the parameterization of the developed model but also of the method of energy system modelling using cost minimsation itself.

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Symbols

A	Area
A_{net}	Net area occupied by a power technology
$A_{net,RC}$	Total usable area in a raster cell in km^2
A_{RC}	Area of a raster cell
A_{ap}^{CSP}	Aperture area of CSP troughs
A_{rot}^{WIND}	Area of rotation of a wind turbine rotor
A_{turb}^{WIND}	Ground area for one wind turbine
c_{H2O}	Heat capacity of water
c_{heat}	Monetary credit for heat delivery from CHP technologies in k€/MWh
c_{inv,CSP_PG}	Investment costs for CSP electric power generation units in k€/MW$_{el}$
$c_{inv,CSP\_SF,ap}$	Investment costs for CSP solar fields referred to aperture area in k€/m^2
$c_{inv,CSP\_SF,el}$	Investment costs for CSP solar fields referred to electric CSP capacity in k€/MW$_{el}$
$c_{inv,CSP\_SF,th}$	Investment costs for CSP solar fields referred to thermal capacity in k€/MW$_{th}$
c_{inv,CSP_STOR}	Investment costs for CSP storage units in k€/MWh$_{th}$
$c_{inv,TRANS\_line}$	Investment costs for transmission capacity in k€/(MW*km)
$c_{inv,TRANS\_rect}$	Investment costs for transmission capacity (inverter) in k€/MW
c_{kWh}	Levelised electricity costs
c_p	Coefficient of performance of a wind power plant
c_R	Heat capacity of rock in J/(kg*K)
$c_{\mathrm{var}op,CSP}$	Variable costs for CSP plants in k€/MWh, valid for solar fields (CSP_SF), storage unit (CSP_STOR) and power generating unit (CSP_PG)
$c_{\mathrm{var}op,trans}$	Variable costs of transmission
C_{sys}	Total system costs in Euro in k€
$c_{\mathrm{var}op}^{biomass\_type}$	Variable operation costs (fuel) of biomass types in k€/MWh$_{chem}$
$c_{inv}^{gen\_type}$	Specific investment costs in k€/MW per electric power generator type
$C_{uni}^{gen\_type,node}$	Costs for electric power generation excluding CSP, hydro power, storage and biomass fuel costs in k€
$c_{\mathrm{var}op}^{gen\_type}$	Variable operation costs (fuel) in k€/MWh per electric power generator type
$c_{inv,\mathrm{mod}}^{HYDRO}$	Investment cost for the modernisation of hydro power plants in k€/MWh; 'HYDRO' standing for HYDRO_RR and HYDRO_RES
$C^{HYDRO\_RR,node}$	Costs for old and modernised hydro run-of-river power plants in k€
$C^{HYDRO\_RR\_NEW,node}$	Costs for new hydro run-of-river power plants in k€
$C^{HYDRO\_RES,node}$	Costs for old and modernised hydro reservoir power plants in k€
C_{CSP}^{node}	Costs of CSP plants and electric power generation in k€
C_{TRANS}^{node}	Costs for transmission lines per node (half of the costs of each connection to that node) in k€
$C^{stor\_type,node}$	Costs for electric power storage per storage type and node in k€

$c_{inv,stor\_e}^{stor\_type}$	Investment cost for the storage unit of storage technologies in k€/MWh
$c_{inv,stor\_p}^{stor\_type}$	Investment costs for the power unit of storage technologies in k€/MW
$c_{\mathrm{var}\,op}^{stor\_type}$	Variable operation costs (fuel) of storage technologies in k€/MWh
$D^{nodefull,aliasnodefull}$	Distance between two nodes in km
d_{rot}^{WIND}	Rotor diameter of wind power plants, WIND standing for WIND_ONSHORE or WIND_OFFSHORE
E	Energy
$E^{biomass\_type,bio\_gen\_type,time,node}$	Chemical energy of 'biomass_type' converted in generator 'bio_gen_type' in MWh_{chem} per time step and node
$E_{annual\ ,chem}^{BIO}$	Annual biomass potential of all considered biomass types
$E_{annual,chem}^{biomass\_type}$	Annual biomass potential of a considered biomass type in a region or raster cell
$E_{annual,chem}^{biomass\_type,nodefull}$	Annually available energy from biomass in MWh_{chem} per biomass type and node
$E_{el,annual}^{gen\_type}$	Annual electric power generation potential of a technology
$E_{el,annual}^{bio\_gen\_type}$	Annual electric power generation of a biomass conversion technology in a specific area (raster cell or region)
E_{th}^{GEO}	Heat stored in a rock reservoir in J
E_{u}^{GEO}	Usable geothermal energy in J (heat stored in a rock reservoir)
E_{inst,CSP_STOR}^{node}	Installed thermal storage capacity in CSP plants in MWh_{th}
$E_{annual,biomass\_type}^{nodefull}$	Annually available energy from biomass in MWh per biomass type and node
$E_{inst}^{stor\_type,node}$	Installed storage capacity in MWh (storable energy)
$E_{A\_net}^{t}$	Energy yield referred to the net area occupied by a power technology in MWh/km2/t
$E_{A,RC}^{t}$	Energy yield in a raster cell in a given time span in MWh/t
$f_{annuity,CSP\_PG}$	Annuity factor for CSP power generation unit
$f_{annuity,CSP\_SF}$	Annuity factor for CSP solar fields
$f_{annuity,CSP\_STOR}$	Annuity factor for CSP storage
$f_{annuity,TRANS}$	Annuity factor for transmission technology
$f_{CSP,av}$	Availability factor for CSP power plants
$f_{c\_fixop,CSP}$	Annual fixed operation cost (maintenance a.o.) for CSP plants expressed as a share in the investment cost. Valid for solar fields (CSP_SF), storage unit (CSP_STOR) and power generating unit (CSP_PG)
$f_{c\_fixop,TRANS}$	Annual fixed operation costs (maintenance a.o.) for transmission capacity, expressed as a share in the investment costs
$f_{domestic\_\sup ply}$	User defined ratio of domestic generation to annual electric power demand
$f_{loss,district\_heating}$	Heat losses that occur during heat distribution
$f_{loss,trans}$	Transmission loss factor (loss per km*MW)
$f_{num\_time\_steps}$	Number of time steps in a model run
$f_{pr,CSP}$	Factor for own power requirements of a CSP power plant
f_{reg_share}	User defined ratio of renewable energy to annual electric power demand
f_{SM}	Solar multiple of a CSP plant
$f_{growth}^{BIO,energycrops}$	Biomass potential growth factor

f_{loss}^{BIO}	Biomass loss factor: losses during harvesting, transport and storage expressed as a share in the total biomass potential
$f^{bio\_gen\_type,biomass\_type}$	Allocation of biomass types to electric power generator types for biomass conversion appropriate for the biomass type (1 or 0)
$f_{pchp}^{biomasss\_type}$	Share of a biomass type available for power and CHP generation
$f_{annuity}^{gen\_type}$	Technical availability of generators per generator type, excluding times of outages and maintenance
$f_{rho}^{chp\_gen\_type}$	Heat output per CHP generation technology in MW relative to the electric power generation potential in MW
$f_{a}^{gen\_type}$	Technically usable area share in the total base area for PV
$f_{au}^{gen\_type}$	Share of the base area that is assigned to the installation of PV plants (the product of f_a^{PV} and f_u^{PV})
$f_{av}^{gen\_type}$	Availability factor for power generation technologies
$f_{u}^{gen\_type}$	Actually usable part of the technically usable area for PV considering competing uses
$f_{c\_fixop}^{gen\_type}$	Annual fixed operation cost (maintenance a.o.) per electric power generator type; expressed as share in investment costs
$f_{lc}^{gen\_type}$	Share of base area land cover for technology installation in a raster cell
f_{own}^{GEO}	Factor for own power requirements of a geothermal power or CHP plant
f_{decom}^{HYDRO}	Decommissioning factor: share of old hydro power plants still in operation in the year of investigation; 'HYDRO' standing for HYDRO_RR and HYDRO_RES
f_{mod}^{HYDRO}	Modernisation factor for hydro power plants; 'HYDRO' standing for HYDRO_RR and HYDRO_RES
$f_{storage2power}^{hydro\_res\_gen\_type}$	Size of storage in h, expressed as full load hours of the turbine
$F^{hydro\_res\_gen\_type,time\_inc\_zero,node}$	Fill level of hydro reservoirs in MWh
$f_{TC}^{hydro\_type}(d)$	Time curve factor for hydro power plant operation time curves
$f_{re\_\max}^{nodefull}$	Maximum domestic renewable supply share
$f_{PG2STOR}^{pumped\_storage}$	size of storage in h, expressed as full load hours of the conversion unit
f_{dens}^{PV}	Installation density for open area PV
f_{loss}^{PV}	Factor accounting for losses of effective irradiance due to dirt and shading
f_{ψ}^{PV}	Shares of module azimuths (in the northern hemisphere: deviation from the direction south)
f_{T}^{PV}	PV temperature coefficient
$f_{annuity,e}^{stor\_type}$	Annuity factor for the energy storage unit of storage plants
$f_{annuity,p}^{stor\_type}$	Annuity factor for the power generators of storage technologies
$f_{av}^{stor\_type}$	Availability factor for storage plants
$f_{c\_fixop,e}^{stor\_type}$	Annual fixed operation costs (maintenance a.o.) of storage capacity; expressed as a share in the investment cost
$f_{c\_fixop,p}^{stor\_type}$	Annual fixed operation costs (maintenance a.o.) of storage technology conversion units; expressed as a share in the investment cost
$f_{loss}^{stor\_type}$	Storage losses over time
$F^{stor\_type,time\_inc\_zero,node}$	Fill level of storage units in MWh
$F_{CSP\_STOR}^{time\_inc\_zero,node}$	Fill level of CSP storage units in MWhth
f_{dist}^{WIND}	Distance factor for wind parks: multiple of rotor diameters as minimum distance between two wind turbines, WIND standing for WIND_ONSHORE or WIND_OFFSHORE
f_{loss}^{WIND}	Factor accounting for losses due to turbulence emissions, shading and for losses in cables in a wind park, WIND standing for WIND_ONSHORE or WIND_OFFSHORE
$G_{dif,h}$	Diffuse irradiance on a horizontal surface

$G_{dir,h}$	Direct irradiance on a horizontal surface
$G_{dif,surf}$	Diffuse irradiance on a surface with an arbitrary orientation
$G_{dir,surf}$	Direct irradiance on a surface with an arbitrary orientation
$G_{glob,h}$	Global irradiance on a horizontal surface
$G_{glob,surf}$	Global irradiance on a surface with an arbitrary orientation
$G_{ref,surf}$	Ground reflected irradiance on the module surface
g	Gravitational acceleration
h	Height
h_{fl}	Full load hours
$h_{fl\_el}^{GEO}$	Full load hours of electric power generation in a geothermal power or CHP plant, GEO standing for GEO or GEO_CHP
h_{hub}^{WIND}	Hub height of a wind power plant, WIND standing for WIND_ONSHORE or WIND_OFFSHORE
h_{SR}	Surface roughness
i	Interest rate
k_1, k_2, k_3	Correlation coefficients for PV module temperature calculation
m	Mass
$\dot{m}_{WIND}$	Wind mass flux
$\dot{m}^{GEO}$	Thermal water flow rate in a geothermal power plant
l_t	Length (duration) of a time step
N	Life time of a technical plant
$\mathrm{P}_{\mathrm{hydro}}$	Power of running water
$p_{inst,\max,CSP\_SF}$	Maximum area-specific installable CSP solar field heat generation capacity
$P_{inst,\max,CSP\_SF,RC}$	Maximum installable thermal solar field capacity in a raster cell (CSP)
$P_{Heat}^{chp\_gen\_type,time,node}$	Generation of usable heat per CHP generator, time step and node in MW_{th}
$p_{inst,\max}^{gen\_type}$	Maximum area-specific installable power generation capacity of technology gen_type
$P_{inst}^{gen\_type,node}$	Installed generation capacity per technology ‘gen_type’ (or a subset of ‘gen_type’) in MW
$P_{inst,\max}^{gen\_type,nodefull}$	Maximum installable electric power capacities in MW per technology ‘gen_type’ (or a subset of ‘gen_type’) and node
$P_{inst,\max,RC}^{gen\_type}$	Installable capacity of technology ‘gen_type’ in a raster cell
$P^{gen\_type,time\_inc\_zero,node}$	Electric power generation per technology ‘gen_type’ (or a subset of ‘gen_type’), time step and node in MW
$P_{\max}^{gen\_type,timefull,nodefull}$	Average instantaneous electric power generation potential of maximum installable capacity in MW per technology ‘gen_type’ (or a subset of ‘gen_type’), time step and node
$P_{\max,RC}^{gen\_type,t}$	Power output of maximum installable capacity of technology ‘gen_type’ in a raster cell in time step t
$P_{el,nom}^{GEO}$	Nominal electric capacity of a geothermal power or CHP plant
$p_{inst,\max}^{GEO}$	Volume specific installable electric capacity of a geothermal power or CHP plant, GEO standing for GEO or GEO_CHP
$P_{Well,th}^{GEO}$	Thermal power of a geothermal well
P_{inst,CSP_SF}^{node}	Installed thermal CSP solar fields capacity in MWth
P_{inst,CSP_PG}^{node}	Installed CSP electric power generation capacity in MW
$P_{CSP\_STOR,in}^{node}$	Thermal power flow from the CSP solar field to the storage unit

$P_{CSP\_STOR,out}^{node}$	Thermal power flow from the CSP storage unit to the turbine
$P_{inst,TRANS}^{node,aliasnode}$	Installed electric power transmission capacity in MW
$P_{TRANS}^{node,aliasnode,time}$	Electric power transmission in MW. Here: export (positive) from node to aliasnode.
$P_{inst,\max,CSP\_SF}^{nodefull}$	Maximum installable heat generation capacity of CSP solar fields per node in MW_{th}
$P_{inst,\max,trans}^{nodefull,aliasnodefull}$	Maximum installable transmission capacity in MW (optional transmission line: yes=inf or no=0)
$P_{inst,\max}^{pumped\_stor,nodefull}$	Maximum installable pumped storage electric power capacity per node in MW
$P_{inst}^{stor\_type,node}$	Installed power conversion capacity in storage plants in MW
$P_{PC}^{stor\_type,time.node}$	Electric power consumption per storage type and time step in MW
$P_{PG}^{stor\_type,time,node}$	Electric power generation by storage type and time step in MW
$P_{\max,CSP\_SF,RC}^{time}$	Heat output of maximum CSP solar field capacity in a raster cell per time step
$P_{CSP\_SF}^{time,node}$	Thermal power generation from CSP solar fields per time step and node in MW_{th}
$P_{CSP\_PG}^{time,node}$	Electric power generation in CSP plants per time step and node in MW
$P_{CSP\_Surplus}^{time,node}$	Surplus of thermal power from CSP plants per time step and node in MW_{th} (is discarded if storage units are full)
$P_{Surplus}^{time,node}$	Surplus electric power per time and node in MW
$P_{heat}^{timefull,nodefull}$	Average instantaneous heat demand in MW per time step and node
$P_{hydro\_res\_\inf low}^{timefull,nodefull}$	Water flow into hydro reservoirs per time step and node at maximum installable hydro reservoir capacity, expressed in MWh
$P_{load}^{timefull,nodefull}$	Electric load in MW per time step and node
$P_{load,peak}^{nodefull}$	Maximum electric load (peak load) in MW per node
$P_{\max,CSP\_SF}^{timefull,nodefull}$	CSP average instantaneous heat generation potential of maximum installable solar field capacity in MW_{th} per time step and node
$P_{hydro\_res\_\inf low,used}^{time\_inc\_zero,node}$	Used part of the inflow in MWh (water can be let pass through unused if reservoirs are full)
P_{kin}^{WIND}	Kinetic power of the wind
P_{nom}^{WIND}	Nominal capacity of a wind power plant, WIND standing for WIND_ONSHORE or WIND_OFFSHORE
Q	Discharge of running water
Q_D	Design discharge for run-of-river hydro power plants
q^{PV}	q-factor: efficiency of PV components other than the modules
R^{GEO}	Recovery factor, taking into account incomplete exploitability of geothermal resources
$T_{reinject}$	Temperature of re-injection of the thermal water
T_R^{GEO}	Rock temperature in °C
T_S^{GEO}	Surface temperature at a geothermal power or CHP plant in °C
V	Volume
V_R	Volume of Rock for geothermal use
V_{req}^{GEO}	Rock volume required for a geothermal power or CHP plant
v_{wind}	Wind speed

Greek symbols

γ	Angle between the module surface and the horizontal
η_{CSP_PG}	Efficiency of CSP electric power generation units
η_{CSP_STOR}	Efficiency of CSP storage units
$\eta^{bio\_gen\_type}$	Electric efficiency of electric power generator types for biomass conversion
$\eta_{th}^{bio\_gen\_type}$	Thermal efficiency of electric power generator types for biomass conversion
$\eta^{GEO,T}$	Electric efficiency of a geothermal power or CHP plant with a rock temperature of ϑ
η^{stor_type}	Roundtrip efficiency of storage technologies (charging + discharging)
η^{PV}	PV module efficiency under standard test conditions (25 °C module temperature, 1000 W/m^2 irradiance)
$\eta_{th}^{chp\_gen\_type}$	Thermal efficiency of a CHP generator type
$\Theta_{N,surf}$	Angle between the solar beam and the normal of the module surface
Θ_{Z}	Angle between the solar beam and the zenith
$\vartheta_{ambient}^{t}$	Ambient temperature at a given time
$\vartheta_{m}^{PV,t}$	PV module temperature
ρ_{H2O}	Density of water
ρ_{R}	Density of rock in kg/m^3
$\rho*_{surf}$	Albedo of the ground
ρ_{wind}	Air density

Abbreviations

aaCAES or CAES	Advanced adiabatic compressed air energy storage
AL	Albania
AT	Austria
BA	Bosnia
BE	Belgium
BG	Bulgaria
BIO_ST	Biomass steam turbines
BIO_ST_CHP	Biomass steam turbines for combined heat and power generation
BIO_BIOGAS_CHP	Biogas plants for combined heat and power generation
BY	Belarus
CH	Switzerland
CHP	Combined heat and power
CS	Serbia
CSP	Concentrating solar power
CY	Cyprus
CZ	Czech Republic
DE	Germany
DK	Denmark
DLR	Deutsches Zentrum für Luft- und Raumfahrt (German Aerospace Centre)
DNI	Direct normal irradiance
DWD	Deutscher Wetterdienst (German Meteorological Service)
DZ	Algeria

EE	Estonia
EG	Egypt
EGS	Enhanced geothermal system
ES	Spain
FI	Finland
flh	Full load hours
FR	France
GEO	Geothermal power plants (enhanced geothermal systems)
GEO_CHP	Geothermal power plants (enhanced geothermal systems) for combined heat and power generation
GHI	Global horizontal irradiance
GR	Greece
HR	Croatia
HU	Hungary
HYDRO_ROR	Old and modernised run-of-river hydro power plants
HYDRO_ROR_NEW	New run-of-river-hydro power plants
HYDRO_RES	Old and modernised reservoir hydro power plants
IE	Ireland
IT	Italy
LEC	Levelised electricity costs
LI	Liechtenstein
LT	Lithuania
LU	Luxembourg
LV	Latvia
LY	Libya
MA	Morocco
MD	Moldova
MK	Macedonia
MT	Malta
NL	Netherlands
NO	Norway
PL	Poland
PT	Portugal
PV	Solar photovoltaic plants
REMix	Renewable Energy Mix for sustainable electricity supply
RO	Romania
SE	Sweden
SI	Slovenia
SK	Slovakia
SM	Solar Multiple
TASES	Time And Space resolved Energy Simulation
TN	Tunisia
TR	Turkey
U	Ukraine
UK	United Kingdom
WIND_ONSHORE	Onshore wind power plants
WIND_OFFSHORE	Offshore wind power plants

Zusammenfassung

Mit ihrer Energiepolitik begegnet die Europäische Union dem Klimawandel, der begrenzten Verfügbarkeit fossiler Brennstoffe und der Abhängigkeit von Energieträgerimporten. Dabei setzt sie die folgenden Kriterien für ihre zukünftige Energieversorgung fest: Nachhaltigkeit, Versorgungssicherheit und Wettbewerbsfähigkeit. Angesichts der Kohlendioxidemissionen durch fossile Brennstoffe und der ungelösten Endlagerung radioaktiver Abfälle können derzeit nur sozial- und umweltverträglich genutzte erneuerbare Energieträger als nachhaltig betrachtet werden. Ihr Einsatz kann darüber hinaus die Abhängigkeit von Energieträgerimporten verringern und durch technologisches Lernen die Kosten der Stromversorgung langfristig niedrig halten.

Ein Problem bei der Nutzung mancher erneuerbarer Energieträger ist ihre unregelmäßige Verfügbarkeit. Das Energieversorgungsystem muss angepasst werden, um den Energiebedarf auf Basis des schwankenden Angebots jederzeit zuverlässig decken zu können. **In dieser Arbeit wird das Energiesystemmodell REMix (Renewable Energy Mix for Sustainable Electricity Supply) entwickelt.** Es verwendet Daten über die Verfügbarkeit erneuerbarer Energieträger in Europa und Nordafrika (EUNA), um kostengünstige Stromversorgungssysteme für diese Region oder Teile davon zu dimensionieren. Dabei gelten Randbedingungen wie z.B. benutzerdefinierte Anteile erneuerbarer Energieträger an der Stromversorgung oder nationale Selbstversorgungsgrade. Das Modell berücksichtigt Kosten und technische Randbedingungen von Stromerzeugungs-, Stromtransport- und Speicheranlagen und findet die unter den gegebenen Annahmen kostenminimale Kombination dieser Technologien und ihrer geografischen Standorte.

Für die Analyse der Leistungs- und Stromerzeugungspotenziale charakteristischer Technologien zur Nutzung erneuerbarer Energieträger wird ein geografisches Informationssystem (GIS) verwendet. Die Analyse wird beschrieben und die Potenziale der Stromerzeugung mit PV-, CSP-, Windenergie-, Biomasse-, Wasserkraft- und Geothermieanlagen werden in Tabellen und Karten dargestellt. Die Daten dienen als Input in ein lineares Energiesystemmodell, welches sie als Randbedingungen des zu dimensionierenden Stromversorgungssystems verwendet. Das Modell, eine Sensitivitätsuntersuchung und eine Testanwendung werden beschrieben.

Die Erkenntnisse bekräftigen die Ergebnisse früherer Arbeiten auf diesem Gebiet: Übertragungsleitungen können ein entscheidendes Element einer kostengünstigen, auf erneuerbaren Energieträgern basierenden Stromversorgung sein, da sie Ausgleichseffekte in einem großräumigen Netzwerk und die Nutzung guter Ressourcen auch an verbrauchsfernen Standorten ermöglichen, z.B. auf See oder in der Wüste. Dazu ist jedoch internationale Kooperation erforderlich, die politisch womöglich schwer zu erreichen ist. Daher wurde REMix so aufgebaut, dass einzelne Länder und der Einfluss unterschiedlicher Parameter auf ihre Stromversorgungskosten untersucht werden können. In der Testanwendung werden Versorgungsstrukturen für 36 Regionen in Europa und Nordafrika als unabhängige Inselsysteme einerseits und als Netzwerk andererseits untersucht. Es ergeben sich in manchen Regionen deutlich und in anderen nur geringfügig verschiedene Kosten im Inselsystem und im Netzwerk. Die Sensitivität gegenüber Parametervariationen ist hoch; die Testergebnisse müssen daher als Beispiele technisch machbarer Systeme ohne absoluten Anspruch auf Kostenminimalität betrachtet werden.

Abstract

Climate change, limited fossil fuel availability and the dependency on energy carrier imports lead the European Union to the formulation of an energy policy for Europe. The EU sets the following criteria for its future energy supply: sustainability, security of supply and competitiveness. Considering the carbon dioxide emissions of fossil fuels and the unsolved problem of the ultimate disposal of radioactive waste, only renewable energy can currently be considered sustainable if applied in a socially acceptable way and in accordance with nature conservation. The use of renewable energy can also reduce the dependency on energy carrier imports. Contrary to fossil fuels, renewable energy will become cheaper in the future due to technological learning.

The main disadvantage of some renewable energy resources is their fluctuating availability. Adaptation of the energy supply system must take place especially in the power sector in order to reliably cover fluctuating demand with fluctuating resources at any time. **In this work, the energy system model 'REMix' (Renewable Energy Mix for Sustainable Electricity Supply) is developed**. It uses data on the availability of renewable energy across Europe and North Africa (EUNA) to dimension low-cost power supply structures for the EUNA-region, or parts of it, under specific conditions, such as specified shares of renewable energy in the power supply or specified national self-supply shares. The model takes into account the costs of generation technologies, transmission lines and storage units, and finds a combination of these technologies and their geographic locations that is least-cost under the given assumptions.

A geographic information system was used for the analysis of the installable capacities and power generation potentials of typical technologies for harnessing renewable energy resources. This analysis is described and the potentials of solar PV, solar CSP, wind onshore and wind offshore, biomass, hydro and geothermal power plants are shown in tables and maps. The data are used as input into a linear programming energy system model which uses them as constraints on the power supply system to be dimensioned. The model, its sensitivity to input parameter variations and a test application are described.

The findings confirm the basic findings of other work in this field: transmission lines can be a crucial element of a low-cost, renewable-energy-based electricity supply because they enable balancing effects in a large grid and the use of the highest quality resources even in remote areas, such as deserts or at sea. However, the international cooperation that is necessary to reach the cost-minimum for a given supply task may not be reached by politics or resulting dependencies may be opposed to political goals. Therefore, REMix was built such that countries can be examined individually and the influence of different parameters on their energy supply costs and structure can be investigated. In the test model application, power supply systems for 36 regions in Europe and North Africa, almost all individual countries, are designed with REMix as island grids on the one hand and on the other hand as a network without transmission restrictions (other than the costs of the transmission lines). The model shows that in certain regions the island grid electricity costs can be much higher than, only a little higher than, or even lower than the electricity costs in the network, under the given technological and economic assumptions. The sensitivity to parameter variations is shown to be high; the results of the test application must therefore be considered one example of a technically feasible and efficient supply system but cannot claim to be least-cost in general.

1 Introduction

1.1 Problem outline

In the year 2007, the world's electric power demand amounted to 16,446 TWh[1]. Fossil fuel energy accounted for 68 % of the primary energy used to cover this demand. The electricity and heat sector contributed 41 % to world carbon dioxide emissions in the year 2007 (IEA 2009). The warming of the earth that results from the accumulation of carbon dioxide and other greenhouse gases in the atmosphere endangers the livelihood of many people due to rising sea levels, droughts, extinction of animal and plant species, expansion of deserts, more frequent and more violent storms and possibly other yet unknown effects. The energy sector is the main carbon dioxide emitting economic sector and at the same time it is an essential basis for industrial development and growth. Consequently, the European Commission defines three challenges in its communication 'An energy policy for Europe' (European_Commission 2007): sustainability, security of supply and competitiveness. Security of supply in this communication is predominantly described as secured access to energy resources. Another criterion for the security of supply is reliable load dispatch, a challenge especially concerning the fluctuating availability of renewable energy resources. 'Competitiveness' in the communication has two meanings: firstly, to provide low-cost energy for the European national economies and secondly, to develop technologies for the decarbonisation of the energy supply that are competitive on the world market.

Renewable energy technologies have the potential to fulfil all the criteria that are aimed at: they can provide carbon-emission-free energy from domestic, or at least diversified, sources at decreasing costs. However, especially in the electricity sector, their fluctuating availability requires a transformation of the conventional supply system. The conventional system relies mostly on readily available energy carriers in the form of fossil resources such as coal, oil and natural gas, which make the dispatch of fluctuating load relatively easy. In order to base the electric power supply on high shares of renewable energy, the basic structure of 'power plant – transmission – distribution – end user' must be transformed into a grid that enables decentralised generation in addition to decentralised consumption, and at the same time allows for low-cost balancing of the fluctuations in demand and supply. Such balancing can be performed by dispatchable power plants such as biomass power plants, by storage or by making use of the effect of large-scale levelling of fluctuations in load and generation. According to the aim of the European Commission, this is to be done as cost-efficiently as possible. The questions to be answered here are therefore: what types of electricity generation capacity must be built and where? How much storage and transmission capacity is needed? Where should it be built in order to cover fluctuating demand with fluctuating renewable energy resources at low costs?

1.2 State of knowledge

The total share of renewable energy carriers in the 'New Policy Scenario' of the World Energy Outlook (OECD/IEA 2010) reaches almost a third of the total generation in the year 2035. Many scenarios have been prepared that show a possible development of electric

[1] IEA statistics, August 2010. http://www.iea.org/stats/electricitydata.asp?COUNTRY_CODE=29

power supply systems towards much higher shares for specific regions, e.g. for Germany (BMU 2004) - (BMU 2010), for the EUMENA region (Europe, Middle East and North Africa) (Trieb 2005; Trieb 2006) and for the whole world (Greenpeace 2005) and (Greenpeace 2008). The share of renewable energy carriers in the supply typically reaches between 80 % and 100 % in the year 2050 in these studies. They rely on annual energy figures, i.e. annual power demand and annual generation potentials of renewable energy based technologies. But the load dispatch requires sufficient power to be available at any time, which is not automatically guaranteed if only the annual potentials of technologies that use energy carriers with highly fluctuating availability are considered. In some cases, the energy mix suggested in accord with a scenario generation heuristic was tested for load dispatch reliability by using time series of hourly generation potentials in a specific year (Brischke 2005; Trieb 2005; Trieb 2006). These scenarios were developed using a heuristic that considered several criteria of a sustainable power supply, including ecological as well as economic and social criteria.

While the scenarios mentioned above consider the costs of supply to be one criterion among others that are equally important, many other scenarios are generated using optimisation models such as TIMES, MARKAL or MESSAGE. These models consist of an objective function and constraints. The objective function mostly determines the total system costs to be minimised, i.e. it searches for cost minima for the economies of nations or groups of nations. The technical characteristics of the supply system are modelled as constraints in the form of equations or inequations. These models were designed for long-term scenarios of energy systems that are primarily based on fossil and/or nuclear energy, and thus comprise mostly dispatchable power plants. Renewable energies are often represented in such models by assumptions about degrees of utilization and capacity credits, with little or no respect to the spatial distribution and real-time temporal availability of energy carriers.

An optimisation approach seeks to find low-cost combinations and locations of renewable power technologies for a given supply task, but such coarse-grained approaches to the representation of renewable energy carriers cannot account for the temporal availability and balancing effects of different technologies at a large spatial scale. Some attempts have been made to use the basic principle of energy system models but to design the model explicitly for the use of high-resolution data about renewable power generation potentials. M. Biberacher demonstrates in his work ‘Modelling and optimisation of future energy systems using spatial and temporal methods’ (Biberacher 2004) the feasibility of combining data processing in a geographical information system with a linear programming energy system model. He developed the software tool TASES (Time And Space resolved Energy Simulation) and a database of global solar irradiation and wind speed data, with a temporal resolution of one hour and a spatial resolution of 5° x 5°. The work focuses on the evaluation and application of different optimisation techniques for modelling energy systems with high shares of renewable energy resources.

G. Czisch demonstrated the feasibility of an electric power supply system for Europe, North Africa and Western Asia at costs comparable to today’s electricity supply costs. He developed an energy system model based on the planning instrument ‘PROFAKO’ (Programming system for the optimisation of the operation of combined heat and power plants) in his work ‘Szenarien zur zukünftigen Stromversorgung’ (‘Scenarios of a future electric power supply’). This model uses as input hourly data on solar, wind and hydro power potentials, annual data on biomass and geothermal power generation potentials, and hourly data on electric power demand in Europe, North Africa and Western Asia, divided into 18 regions. It finds the least-cost, 100 % renewable energy mix to cover the electricity demand under given assumptions. Among these assumptions are the costs of each kind of technology. For technologies not yet operational, assumptions about the costs of the mature technology were made and used. For operational technologies, the costs assessed in the period 2000 - 2005 were used. The costs of the years 2000 to 2005 were used because these data are real and not virtual. But since the transition of the electric power system takes time, this is an assumption about the future development of these technologies: that the costs, or at least the relations between the costs, of renewable energy technologies will stay constant in the future.

Since different technologies have undergone very different phases of development and their costs therefore have different potentials for further reduction, this assumption is probably not going to prove true. G. Czisch therefore investigated the influence of the costs of some technologies by varying their cost parameters. The annual electric power demand in the work of G. Czisch was based on the year 1994, and amounts to 3983 TWh. This parameter was changed to 4918 TWh in one scenario, investigating a case in which the demand in regions that presently have relatively low demand might increase with the economic development of such regions. By comparison, the total demand in the EU 27 countries amounted to 2855 TWh in the year 2008[1]. This electric power demand is still growing, and the area investigated by Czisch is more than three times the area of the EU 27-countries. The electric power demand therefore seems underestimated, even in the variation with higher demand. In the base scenario set up by Czisch, wind power covers 71 % of the total electric power demand, complemented by a small amount of solar and mainly balanced with hydro and biomass. Czisch investigated various scenarios e.g. with varying costs, demand or with import restrictions, and comes to the conclusion that a powerful transmission system in a large-scale electric network is a crucial condition for a low-cost, renewable-energy-based electric power supply. No time schedule for how this should be achieved is given by Czisch, nor a point in time when a 100 % renewable energy based supply system should be reached.

1.3 Objective

The various ways to a sustainable electricity supply that Czisch has shown can provide support for policy makers responsible for country clusters in a very large region, such as the European Union. But even in the European Union, the countries have not given up their sovereignty and their own interests and plans. For policy advice, it can therefore be useful to investigate the benefits and effects of different configurations of the supply system for individual countries.

In the scope of this work, an energy system model is to be developed that uses high temporal and spatial resolution data on load and electric power generation potentials as input and designs low-cost power supply structures. Its focus is on Europe, but it is supposed to cover a part of Northern Africa in order to allow for exchange of electric power over greater distances, making use of better resources (especially solar) and allowing less temporal correlation (especially of wind power). A consistent development of the power demand and of technical and economic parameters for the technologies is required as input into the model.

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[1] EUROSTAT 2010: http://epp.eurostat.ec.europa.eu/tgm/table.do?tab=table&plugin=1&language=de&pcode=ten00097

Such a set can be taken from existing scenarios with renewable energy saturations near 100 %, which are typically reached in such scenarios in the year 2050. As can be seen in the communication of the European Commission mentioned above, countries or clusters of countries link the problem of climate change with political goals, such as technology development for enhancing economic growth and reducing the dependency on energy imports through domestic power generation (or at least diversification of foreign energy sources). The economic implications of technology development are not a subject of this investigation, but they are implicitly taken into account via the parameters from scenarios that consider the development of markets and costs for renewable energy technologies under the expected political constraints in the coming decades.

In order to allow for investigations on different spatial scales, a user should be able to choose a model region appropriate to the application. In bigger countries, sub-national investigations should be possible. Such a model and database can be used for investigating diverse questions concerning electricity supply systems in Europe at various scales. The model results are tested for their sensitivity to parameter variations by investigating a test network encompassing Germany, Norway and Algeria. Test applications are performed in order to find a cost and system structure range for the two extreme cases: total national power autarchy (island grids in each country) and a completely liberalised power market (no transmission restrictions).

2 Modelling renewable energy based electricity supply systems

2.1 Modelling approach

Designing technically feasible electricity supply systems substantially based on renewable energy resources with intermittent availability considering technological, economic and political developments requires

- information on the spatial and temporal variation of the availability of the renewable energy resources and their costs considering probable technological and economic developments
- information on the spatial and temporal variation of the electric power demand considering its dependence on population and economy development
- an energy system model that can use the above mentioned information.

An energy system model was developed that can design supply systems with low costs under given constraints: the REMix model (**R**enewable **E**nergy **Mix** for sustainable energy supply in Europe). An inventory with information on the maximum installable capacity of different technologies, on the potential power generation in each hour of a specific year for resources with intermittent availability and on the costs of technologies was built up and provides input into the model. Electricity and heat demand data for each hour of the specific year were also collected and prepared as input into the model.

The basic structure of the model, the inventory and the links with present scenarios are described in this section. The model setup is illustrated in figure 2.1.1. Detailed descriptions of the components of the developed tool follow in the chapters 3 to 6.

2.1.1 Inventory of renewable electricity generation potentials

'Inventory of renewable electricity generation potentials' here means area-wide data on the electric capacities that can be installed and the electricity that can be generated in each hour of a specific year with technologies with certain parameters under sustainable conditions. The case of concentrating solar power is an exception: the electric capacity is variable; only the maximum installable thermal solar field capacity is a fixed value.

In order to asses the installable capacities and, if required because of intermittent availability, hourly generation potentials, three steps were performed for the technologies considered:

- collecting data on the resource in the required spatial and temporal resolution
- analysing the land areas on which the technologies can be used and analysing usable land area shares that might be lower than the total area because of competing energetic and non-energetic land uses
- applying a power plant model with parameters characteristic of a state of the art technology.

Applying a power plant model for all land areas on which a resource can technically be used would result in the technical potential of a technology. These areas were curtailed in some cases considering possible technological impacts. Wind turbines, for example, were considered only to be built in a distance of at least of 1000 m from urban areas in order to eliminate the impact of noise emissions. Competing land uses of non-energetic type were considered and the shares of areas that can actually be used were set conservatively. These constraints were set such that the potentials that were input into the energy system model were considered sustainably usable.

The resulting capacity and electricity generation potentials are then available in a high spatial resolution and can be aggregated on user-defined regions. Such regions can be countries, groups of countries or sub-national regions like federal states or supply areas of utilities. The aggregated capacity and electricity generation potential information can be used as input by the energy system model.

For some technologies, resource information was only available on a national level (biomass, hydro power). In order to enable the user-defined choice of regions nevertheless, national potentials were disaggregated on national territories according to the distribution of a proxy parameter. Forest wood potentials for example were distributed like the land cover category ‘forest’ and industrial old wood was distributed like the land cover category ‘artificial surfaces and associated areas’.

The analysis of installable capacities and electricity generation potentials is described in detail in chapter 4.

2.1.2 Electricity and heat demand

Hourly information on electric power demand is needed as a main input into the energy system model in order to test the adequacy of a supply system structure or to design such a structure. The heat demand is needed as a constraint for the operation and costs of the technologies that generate heat and power. While hourly electric power demand data on national levels are available from European transmission system operators or could be derived from scenarios about a possible sustainable development of the electricity supply in the Middle East and North Africa (Trieb 2005), heat demand information was not readily available for all countries. The heat demand was modelled for all countries in the investigation area based on the German low temperature heat demand using heating degree days for scaling.

Only national level information of electric power demand was available. Therefore, the national power demand was disaggregated on national territories using a proxy parameter. For each raster cell in a country, the share of the proxy parameter value in the raster cell in the country sum of the proxy parameter was multiplied by the national power demand in order to obtain the power demand in each raster cell of a country. For distributing the electric power demand the land cover category ‘artificial surfaces and associated areas’ was used as a proxy parameter. The population density was chosen as a proxy parameter for the distribution of the heat demand.

The analysis of the electricity and heat demand is described in detail in chapter 3.

2.1.3 Energy system model

An energy system model was developed that designs an electricity supply system based on high shares of renewable energy resources under defined constraints, aiming at minimum overall system costs. A linear programming approach was chosen, assuming that because of the high number of renewable power plants of relatively small size it is possible to linearise the problem and obtain sufficiently accurate results (see (Czisch 2005)). The model was built as a deterministic model in order to investigate real-time demand and supply situations.

A linear optimisation model consists of a linear objective function and linear restrictions. Here, the objective function adds up all annual system costs and sets the objective to minimise these. The ‚system' is specified by installed capacities for the generation, transmission and storage of electricity, by the regions and their interconnections, by the time steps regarded and by the availability of power per technology, region and time step. The restrictions formulate the requirements of the system, e.g.:

- the electric power demand must be covered anytime. In each node, import plus generation of electricity must be equal to or bigger than load plus storage consumption plus export and surplus
- the regional limits of installable capacity per technology must not be exceeded
- the limits of regional generation of a given capacity in each time step must not be exceeded
- the transmission capacity limits must be regarded and transmission lines must not be overloaded.

The model varies the variables, i.e. installed capacities, power generation in each hour, storage consumption in each hour and transmission in each hour until the system costs can not be further reduced by further variable variations. A model run results in the structure of a supply system with minimised costs at the given parameters and restrictions. Among others, the following variables are determined for each node / node pair: generation, transmission and storage capacities, generation and transmission in each hour, the overall system costs and the costs per technology and node.

Policy goals can be formulated as restrictions, e.g. a renewable energy share can be set, either for each region or for the whole area. A domestic supply share can be set, i.e. forcing each region to meet a defined part of its electric power demand with regional resources, either in each time step or in the annual energy balance, thus limiting the amount of import and export used for load dispatch in each region. Another possibility of including policy goals in the model can be to preset variables like installed capacities or annual generation by a specific technology in a specific region. If a country wants a diverse power generation infrastructure and sets goals for shares of different technologies in the electricity supply, then such exogenous settings can be included by setting upper and lower limits or by completely fixing the corresponding variables that otherwise would be subject to the cost minimisation process.

Minimising the costs of a future energy system is a common objective in energy system models. Inherent to this approach is the uncertainty of the result due to the uncertainty of the assumptions about the future costs of the considered technologies. Technically feasible systems can be designed with this approach if the underlying assumptions are valid. Such a system can be considered least-cost only under the given uncertain assumptions. The sensitivity of the results to input parameter variations can be huge. In order to obtain more robust results, a stochastic approach that already includes variations of the parameters can be applied instead of a deterministic approach. This was not done in the first version of the REMix model primarily because of the high running times of the model that would be even increased when using a stochastic approach. Depending on the number of regions and time steps regarded, the model running times are several hours up to several weeks on a server with a 64 bit operation system, 2.8 GHz processor and 32 GB main memory.

Other than many energy system models REMix calculates only a system structure for a specific year. It does not calculate a least cost development path for a given time period. This limitation too is due to the already high running times of the model. Like the uncertainty of the future costs this does not affect the technical feasibility of the designed systems as long as the technical assumptions are valid. But it must be considered when evaluating the results that the system can not be called least-cost since the cost parameters considered are the costs expected only for a given year, not for the period in which the system would be built up which can be many years before and/or after the investigated year. With the costs and cost proportions changed in this period, also the model result can change. The model run results must therefore primarily be seen as technically feasible system options but can not be called least-cost without mentioning the limitations to the cost evaluation.

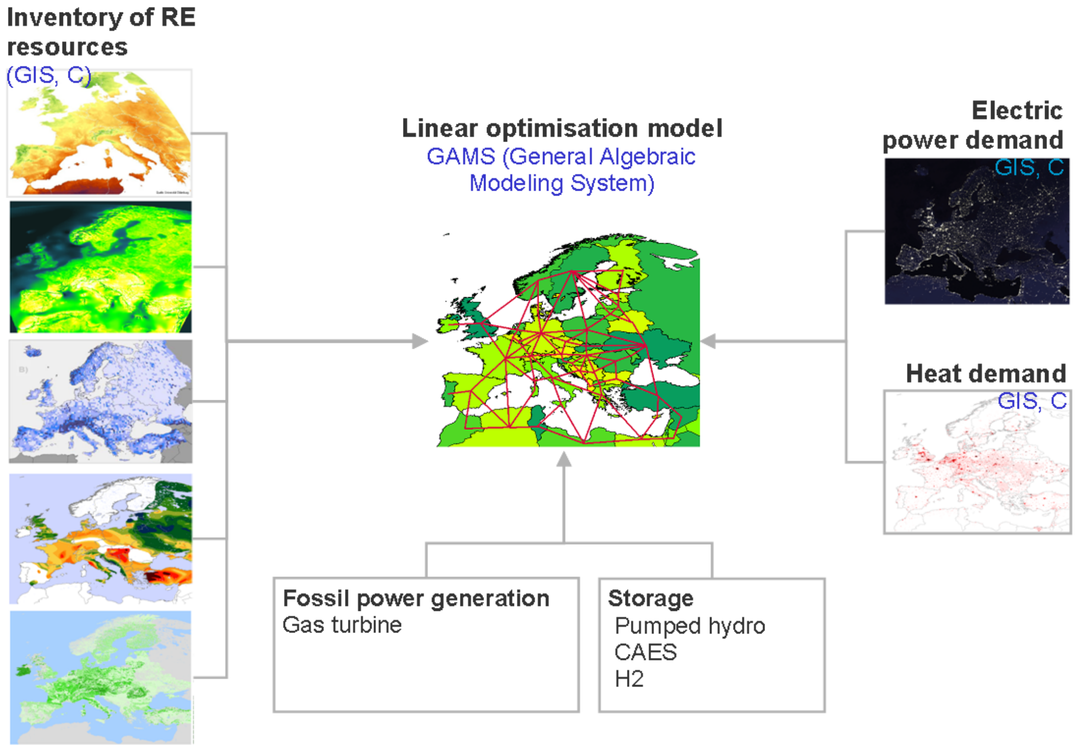

Figure 2.1.1: Setup of the REMix inventory and model.

2.1.4 Interaction with scenarios

A scenario is a description of an event or series of actions and events. Most scenarios of energy systems describe a possible development of the system over a certain period of time, e.g. from 2010 until 2050. They take into account the driving factors of the electricity supply system like population, industry, commerce, and their probable development. An initial system configuration is considered and power capacity replacements are modelled over time, taking into consideration the maximum speed of the expansion of single system components. The development of technical and economic parameters of the system components is extrapolated into the future. Differential costs of different scenarios in the regarded period of time can be calculated. Scenarios that describe a possible development towards a renewable energies based electricity supply are usually developed on the basis of annual electricity generation potentials. In order to take into account the intermittent availability of the solar, wind and hydro resources, they rely on aggregated parameters such as capacity credits as a measure of the reliably available capacity. However, the capacity credit of renewable energy technologies depends on the location, the spatial extent of a system and on the structure of the whole system. Capacity credits for such specific conditions are often unknown. The model REMix does not rely on an aggregated measure of reliably available capacity but takes into account the capacity actually available in each time step. In addition, it takes into account the load that actually has to be covered in each time step.

In a nutshell: conventional scenarios can demonstrate a system development path but are lacking measures of the system reliability that are adjusted to the investigated system; the REMix model can provide suggestions for renewable energy mixes adjusted to a system but it can not yet find for a system the development path with the least differential costs. REMix depends on input from scenarios that provide suggestions for development paths and matching technical and economic parameters. It can, on the other hand, provide suggestions for changes of the final and intermediate supply system structures especially when the shares of renewable energy resources are very high and adequate measures of system reliability are lacking in conventional scenarios.

Scenario adjustment and REMix model runs can alternate in order to obtain a robust final scenario. Scenarios set conditions for a supply system including political goals such as renewable energy shares, national domestic supply shares, minimum shares of single technologies, compulsory, optional or prohibited transmission lines. REMix can either validate the reliability of a supply system suggested in a scenario, or it can, if the supply structure is less predetermined, find a technically feasible supply structure with low costs under the given assumptions for a certain time slice (e.g. a year in a scenario) under the given conditions and thus provide input into scenario modelling.

2.2 Data

2.2.1 Investigation area

The area that was investigated covers Europe and some neighbouring countries as shown in figure 2.2.1. It extends from a minimum latitude of 30 ° and longitude of -12 ° to a maximum latitude of 72 ° and longitude of 40 °. Some countries have been clustered in order to reduce the number of regions and thus the running time of the energy system model. Table 2.2.1 lists the countries and country clusters and the share of their area lying within the investigation area.

Some countries are not lying completely within the area. A small part of Turkey and huge parts of the North African countries are not covered. Nevertheless, the total electricity and heat demand of these countries has been taken into account, assuming that the influence of the mountainous eastern Turkish part on the total demand can be neglected and that the electric power demand of the North African states occurs almost completely near the coast in the regions that are lying within the investigation area. Also in Egypt, where a significant part of the population lives along the Nile in the part of Egypt lying outside the modelling domain, this simplification has been made. The vast solar and wind resources within the modelling domain in Egypt guarantee the feasibility of the power supply of the total population even in the case of an Egyptian island grid with only the resources considered here. Extending the modelling domain to the south would not change the technical feasibility of the designed supply systems, but it might lead to differing optimisation results.

Table 2.2.1: Countries and the share of their area lying within the REMix investigation area.

Nr.	Country / Country Cluster	Short form	Area coverage	Nr.	Country / Country Cluster	Short form	Area coverage
	Albania			17	Slovakia	SK	1
1	Serbia	AL_CS_MK	1	18	Luxembourg	LU	1
	Macedonia			19	Malta	MT	1
	Bosnia			20	Netherlands	NL	1
2	Croatia	BA_HR_SI	1	21	Norway	NO	1
	Slovenia			22	Poland	PL	1
3	Austria	AT	1	23	Portugal	PT	1
4	Belgium	BE	1	24	Romania	RO	1
5	Bulgaria	BG	1	25	Spain	ES	1
6	Cyprus	CY	1	26	Sweden	SE	1
7	Czech Republic	CZ	1	27	Switzerland	CH_LI	1
8	Denmark	DK	1		Liechtenstein		
9	Ireland	IE	1	28	Turkey	TR	0.80
	Estonia			29	United Kingdom	UK	1
10	Lithuania	EE_LT_LV	1	30	Ukraine	U_MD	1
	Latvia				Moldova		
11	Finland	FI	1	31	Belarus	BY	1
12	France	FR	1	32	Algeria	DZ	0.31
13	Germany	DE	1	33	Morocco	MA	0.73
14	Greece	GR	1	34	Tunisia	TN	0.99
15	Hungary	HU	1	35	Libya	LY	0.18
16	Italy	IT	1	36	Egypt	EG	0.13

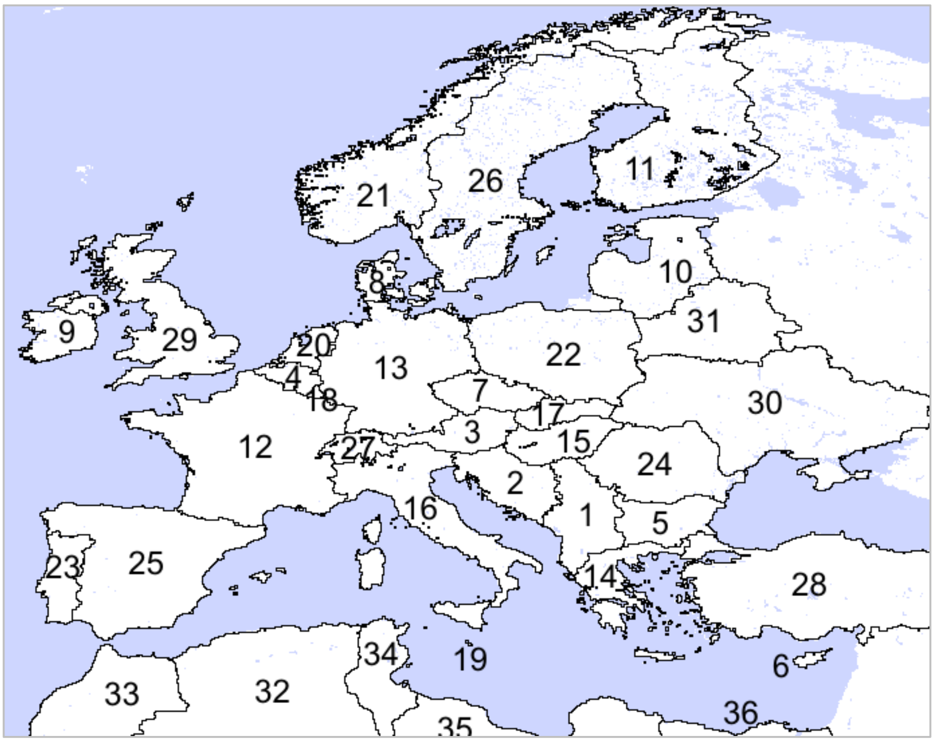

Figure 2.2.1: Countries / country clusters in the REMix investigation area.

2.2.2 Spatial and temporal resolution

The analysis of the power generation potentials was performed on a raster with a resolution of 0.083 ° x 0.083 °, corresponding to around 10 km x 10 km. In some cases, higher resolution data (0.0083 ° edge length) were used. Resource data with a temporal resolution of 1 h were collected for analysing the potentials of solar and wind power technologies. Data from the year 2006 were used because it was the first year for which a complete data set of high resolution wind and load data was available. For hydro power daily discharge data were available that were used for modelling a discharge or reservoir inflow time curve with daily resolution. For biomass and geothermal power technologies, the annual energy potentials were assessed without intra-annual temporal resolution.

2.2.3 Data overview

Data that were only used for a particular potential analysis are described in the respective chapters. Some data sets were used repeatedly. The principal data that have been used are listed in table 2.2.2, followed by a description of the data that have been used in many analyses.

2.2.3.1 Technical and economic parameters

In the German ‘Leitszenario’ - a scenario for the German energy supply until the year 2050 that has been updated annually since 2005 by DLR - a development path of technical and economic parameters of characteristic electricity generation technologies is assumed. The parameters of the ‘Leitszenario 2010’ (BMU 2010) have been adopted in this study after partial aggregation and some adjustments according to personal communications. The parameters have been used here without regional differences for the whole investigation area.

The processing of the data can lead to rounding errors. Small deviations of the values of a variable in different places can therefore occur.

2.2.3.2 Land cover

Land cover data were used for area analyses, i.e. areas were considered appropriate for technology application or they were excluded from the analysis. The Global Land Cover 2000 (GLC 2000) data set from the Joint Research Centre of the European Commission (JRC 2003) covers the whole region, but the spatial resolution is lower and the classification is less diverse than that of the CORINE Land Cover 2000 data set (EEA 2005). Because of its higher spatial resolution, the CORINE data set was considered more accurate. However, it was only prepared for the EU, thus not covering the complete investigation area. A merged data set was generated, complementing the CORINE data with GLC 2000 data. The merged data set has a spatial resolution of 0.0083 ° x 0.0083 °, corresponding to approximately 1 km x 1 km. For area analyses on the coarser raster mostly used in this study with 0.083 ° x 0.083 ° edge length, the shares of the single land cover categories in the coarser raster cells were used. The original categories of the two input data sets and the final classification are listed in table 10.1.1 in the annex. The merged land cover map is shown in figure 2.2.2.

Table 2.2.2: Data for the analysis of the energy demand and power generation potentials.

Chapter	Data / data source	Description	Reference
General parameters			
	'Leitstudie 2010' scenario	Technical and economic parameters of technologies	(BMU 2010)
	CORINE land cover 2000	Land cover data for the EU	(EEA 2005)
	Global land cover 2000	Global land cover data set	(JRC 2003)
	GRUMP urban/rural population grids	Gridded population numbers	(CIESIN 2004)
	World Database on Protected Areas WDPA	Nature reserves and other protected areas	(WDPA 2006)
	MPA global	Global marine protected areas	(Wood 2005)
	USGS GTOPO30 digital elevation model	Elevation (onshore) and slope (derivative of GTOPO30)	(USGS 1996)
	Geomorphology map	Sand dunes for area exclusion	(FAO 2007)
	NUTS Statistical Regions of Europe	Administrative boundaries from country to community level	(GISCO 2006)
Energy demand			
Electric power demand	Load data from transmission system operators (UCTE, NORDEL, UK-National-Grid, EIRGRID, Eesti Energia)		(UCTE 2007); (NORD_POOL_ASA 2007); (UK_Nationalgrid 2007); (EIRGRID 2007); (Eesti_Energia 2007)
	'Med-CSP' and 'Trans-CSP' scenarios		(Trieb 2005), (Trieb 2006)
	IEA country energy statistics		(IEA 2007)
	Technischer Bericht der Liechtensteinischen Kraftwerke		(Liechtensteinische Kraftwerke 2007)
Heat demand	Energie-Info: Endenergieverbrauch in Deutschland 2006	Low-temperature heat demand in Germany	(BDEW 2008)
	EUROSTAT heating degree days	Heating degree days of countries	(EUROSTAT 2008)
	DWD temperature data	Gridded temperature at 2 m above ground	(DWD 2007)
Renewable energy for electric power generation			
Solar (PV)	DLR irradiance data: DNI and GHI	Direct normal and global horizontal irradiance	(DLR 2007)
	DWD temperature data	Temperature 2 m above ground	(DWD 2007)
Solar (CSP)	DLR irradiance data: DNI and GHI	Direct normal and global horizontal irradiance	(DLR 2007)
	Med-CSP scenario	Area exclusion map for CSP	(Trieb 2005)
Wind	DWD wind speed data	Wind speed at 116 m above ground	(DWD 2007)
	General Bathymetric Chart of the Oceans (GEBCO)	Water depth in the oceans	(IOC, IHO et al. 2003)
	Exclusive economic zones	Maritime boundaries	(VLIZ 2006)
Hydro power	Gross hydro power potential	Theoretical hydro power potential	(Lehner, Czisch et al.)
	PLATTS PowerVision database extract	Run-of-river and reservoir hydro power plant sizes and geographic location	(PLATTS 2008)
	WEC 2007 Survey of energy resources	Hydro capacities in operation, annual generation and generation potentials	(WEC 2007)
	GRDC river discharge data	Daily average discharge at 786 measuring stations in Europe	(GRDC 2008)
Biomass	BMU European biomass use scenarios	Land availability, yields and competing use scenarios per country for forestry, agriculture and other sectors	(BMU 2005)
	EUROSTAT statistics	Agricultural statistics: harvest and livestock	(EUROSTAT 2006)
	FAOSTAT statistics	Agricultural statistics: harvest and livestock, forestry statistics: total increment	(FAOSTAT 2006)
	DLR-DFD NPP data	Net primary productivity as a proxy for spatial distribution of agricultural biomass potentials	(Wißkirchen 2004)
Geothermal energy	'Atlas of Geothermal Resources in Europe'	Temperatures in the bedrock	(Hurter 2002)
	'Geothermal Atlas of Europe'	Temperatures in the bedrock	(Hurtig 1992)
Transmission, storage and residual load			
Transmission Storage Residual load	'Leitstudie 2010' scenario	Technical and economic parameters of technologies	(BMU 2010)

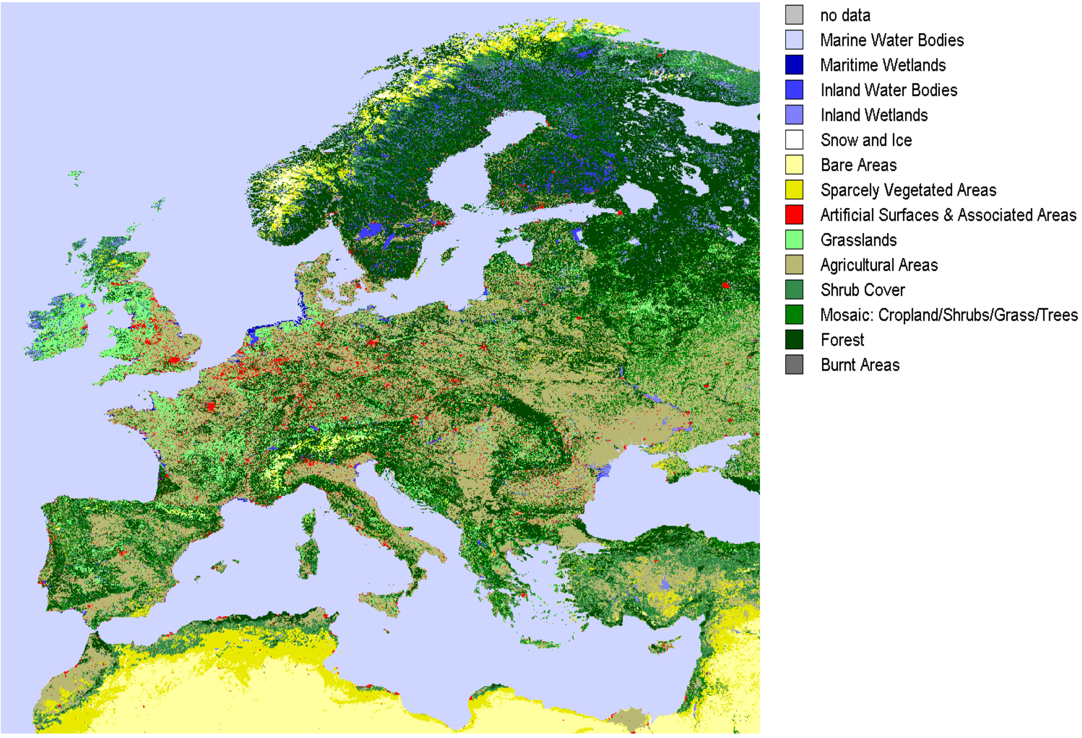

Figure 2.2.2: Land cover data set merged from CORINE Land Cover 2000 (EEA 2005) and Global Land Cover 2000 (JRC 2003).

2.2.3.3 Population

Gridded population numbers from GRUMP (Global Rural-Urban Mapping Project) (CIESIN 2004) were used as a proxy parameter for the spatial distribution of the low-temperature heat demand in each country and for estimating waste wood energy potentials.

2.2.3.4 Elevation, slope and geomorphology

Elevation, slope and sand dunes were used as exclusion criteria for area adequacy for the application of some technologies. The elevation data were taken from a United States Geological Survey data set (USGS 1996). The slope was derived from the elevation data set with a geographical information system. The sand dunes location and shape originates from the Food and Agriculture Organisation 'Digital Soil Map of the World' (FAO 2007).

2.2.3.5 Administrative boundaries

The NUTS (Nomenclature des Unités Territoriales Statistiques) classification and geographical data set were processed and applied for

a) spatial allocation of national potentials in top-down approaches (biomass energy, hydro power)

b) spatial aggregation of gridded potential and load data on regional levels as input into the energy system model.

The data were provided by the Geographic Information System of the European Commission (GISCO 2006).

2.2.3.6 Protected areas

Areas with protection status I – VI in the IUCN (International Union for Conservation of Nature) classification and some areas with other national or international protection status are documented in the World Database on Protected Areas (WDPA 2006). Marine protected areas are registered in (Wood 2005).

Protected areas were excluded from the assessment of some technology potentials or the spatial disaggregation of potentials in top-down approaches. Of some protected areas only the geographic positions and the total areas are documented, not the shape. In such cases, a circle was drawn around the geographic centre of the area to represent it. Figure 2.2.3 shows the regarded protected areas in the investigation area.

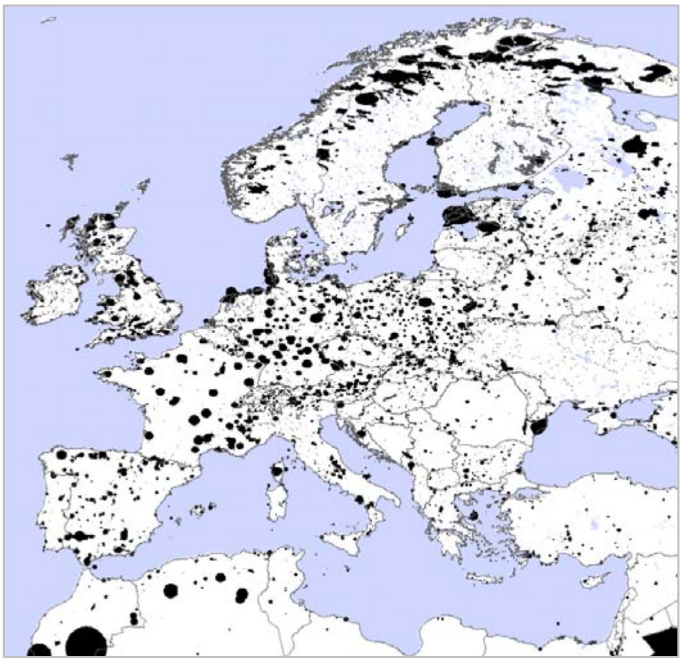

Figure 2.2.3: Protected areas in the investigation area, partly processed (sources: (WDPA 2006) and (Wood 2005)).

2.3 Tools

2.3.1 Data storage

All technical, economic and area-related parameters are stored in a single spreadsheet file. The format was chosen as to provide clear overview for easy adjustments to changing scenario assumptions. The resource data are stored in binary data files, providing quick access by data processing tools. Geographical data for spatial analyses such as land cover, population, elevation, are stored in a database of GIS files. The final results are provided in text files, spreadsheets and diagrams.

2.3.2 Geographic information systems

Geographic information systems are used for data processing and visualisation. Resource and other data with spatial reference often differ in the format and resolution, regional coverage, geographic projection and reference system used. These properties were harmonised for all input data using the geographical information systems ‘IDRISI’ and ‘ARC-

View'. These software tools can cut out a window from a data set covering a bigger area than required or paste together two data sets covering a part of the required area each. Geographical reference systems and projections can be changed. The number of raster cells can be increased or decreased by calculating averages of the original raster cells or choosing the 'nearest original neighbours' values for the new raster cells. Raster cell contents can be reclassified, e.g. country numbers can be replaced with parameter values to be displayed on a country level, such as biomass potentials or annual electric power demand. Mathematical functions can be performed involving one or several data sets. Information can be aggregated and extracted from a data set, e.g. a raster containing country numbers can serve as a model for the extraction of country-level values from a wind electricity generation data set. On the other hand, spatial information can be disaggregated with a proxy parameter by generating a normalised version of the proxy parameter data set and multiplying it with a map containing the parameter to be disaggregated. National potentials of forest wood for energy use, for example, were distributed on the national forest area with land cover data of the category 'forest', normalised on a national level.

Two geographic information systems with different focus and different functions needed for this investigation were used. While IDRISI provides raster data processing tools that can easily be used in combination with C-based data processing programs, ARC-View is a standard in geo-data processing. Many data are provided in ARC formats. Their processing requires the use of Arc-View conversion tools.

2.3.3 C-code

Installable power generation capacities and electricity generation potentials in each grid cell were calculated in C-programs using resource data, technical parameters and GIS-data sets for deciding on area suitability. In principle, these calculations could have been directly executed in a GIS, but using C-programs can strongly reduce the processing times especially for calculations that must be repeated for many time steps.

C-programs were also used for calculating costs in each raster cell and regional cost-potentials curves. The curves were generated by regional sorting of the potential in each raster cell to cost-categories. The regional potential in each cost category was cumulated and plotted versus the levelised electricity costs. These curves are shown in the corresponding sections on the potentials of renewable energy sources (see chapter 4).

The C-programs were also used for transfer of the technical and economic parameters to the energy system model. The model environment needs input with specific formats. The formatting was automated with a C-code module that writes text-files which can be read by the modelling environment GAMS.

2.3.4 GAMS – general algebraic modelling system

The modelling environment GAMS (**G**eneral **A**lgebraic **M**odelling **S**ystem) provides the possibility to build up optimisation models with a clear and dense structure. The terminology adopted in GAMS is as follows: indices are called sets, given data are called parameters, decision variables are called variables, and restrictions and the objective function are called equations. The user defines parameters, variables and equations and declares their domains before they are formulated. A domain is the set over which a parameter, variable, or equation is defined. After defining parameters, their values are read from input files. Then, variables are defined that are varied by GAMS in order to find an optimised solution for the presented problem. The problem itself is formulated in an objective function and restrictions. The objective determined by the objective function is the minimisation or maximisation of the objective variable. While the objective function must be an equation, the restrictions to be regarded can be equations or inequations.

In the presented work, the main sets are regions, technologies and time steps. The main parameters are installable capacities, generation potentials and energy demand, defined for their respective domains. The variables are installed capacities of generation, storage and transmission technologies and generation, storage consumption and transmission in each time step. The objective is to minimise the total system costs. The potentials of and the economic competition between resources, storage capacities and balancing effects enabled by transmission lines is taken into account via the restrictions, leading to the most cost-efficient combination of these options.

A linear programming approach was chosen. As the solution space of a linear optimisation problem is convex, the solution is always a global optimum. However, the model requires large amounts of input data and the running times can be very long. In order to reduce the running times, different solvers offered by GAMS and different algorithms were applied. The CPLEX solver can apply a simplex algorithm, which finds the optimum by changing variables along the ‘outer surface’ of the solution space. The barrier algorithm on the contrary is an interior-point method. In many cases, it proved to be faster than the simplex algorithm, but in some cases the processes could not be finished because of running times of several weeks. Other options for reducing the running times that were applied are the reduction of the number of regions and time steps and keeping the number of technologies low. These simplifications lead to less accurate results but could not be avoided because of the otherwise excessive running times.

3 Energy demand

3.1 Electric power demand

3.1.1 Long term development

In 1980, the world electric power demand registered by the US Energy Information Administration (EIA) reached 7332 TWh/a. In Europe around 2010 TWh/a were consumed in the year 1980. By 2006, the world electric power demand more than doubled and added up to 16378 TWh/a. The European electricity demand in 2006 amounted to 3296 TWh/a[1].

The future development of the electric power demand under different conditions is estimated in many scenarios, but few scenarios provide estimates on a country level. The gross power demand development until the year 2050 for most countries investigated here was taken from the studies 'MED-CSP' (Trieb 2005) and 'Trans-CSP (Trieb 2006)'. It is estimated based on regression analyses of historical power demand and gross domestic product development in different countries. The established correlations were extrapolated until the year 2050.

Some countries in the presently investigated area are not dealt with in the two studies mentioned above: Albania, Belarus, Estonia, Latvia, Liechtenstein, Lithuania, Moldova and the Ukraine. The power demand in these countries was assumed to develop like in neighbouring countries. Year 2004 country statistics (IEA 2007) were used as a basis for scaling the power demand in the investigation period. The development in Poland was used as a proxy for the development in Belarus, Estonia, Latvia, Lithuania, Moldova and the Ukraine. The development in Switzerland was used as a proxy for the development in Liechtenstein and the development of Albania was scaled based on the Macedonian development.

Table 3.1.1: Electric power demand scenarios and statistical data.

Scenario	Temporal coverage	Time steps	Spatial coverage	Spatial resolution
MED-CSP (Trieb 2005)	2000 - 2050	10 years	Middle East, North Africa	National
Trans-CSP (Trieb 2006)	2000 - 2050	10 years	Europe	National
IEA country statistics (IEA 2007)	- 2007	years	global	National

The scenarios and data that served as a source of power demand development assumptions are listed in table 3.1.1 along with their main temporal and spatial properties.

The adopted electric power demand values in the investigation area in the years 2010, 2020 and 2050 are shown in table 3.1.2. The development path is displayed in figure 3.1.1.

The electric power demand in countries with little developed industry today is assumed in the source scenarios to grow at higher rates than in more developed countries due to a higher growth of the population and the economy. The assumed higher increase in electric power demand in the countries in North Africa and in Eastern Europe is visible in figure 3.1.1 in the group of countries displayed in green.

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[1] Historic electric power demand data from EIA (2010). World Electricity Data, EIA (US Energy Informatoon Administration). http://www.eia.doe.gov/iea/elec.html

Table 3.1.2: National electric power demand development in the investigation area in TWh/a.

	2010	2020	2050		2010	2020	2050
Albania	4.6	4.7	7.3	Slovakia	28	28	29
Bosnia	10	11	18	Liechtenstein	0.4	0.4	0.2
Serbia	37	37	49	Luxembourg	8.8	10	11
Macedonia	7.2	7.5	11	Malta	2.7	2.9	2.3
Moldova	6.5	7.1	9	Netherlands	120	131	116
Austria	64	66	49	Norway	130	133	112
Belgium	91	93	67	Poland	142	153	191
Bulgaria	32	28	27	Portugal	47	54	62
Cyprus	4.0	4.7	4.9	Romania	53	58	96
Czech Rep.	62	60	52	Slovenia	12	12	9
Denmark	44	49	51	Spain	258	299	320
Ireland	30	35	34	Sweden	155	161	154
Estonia	8.4	9.0	11.2	Switzerland	63	64	39
Finland	83	84	76	Turkey	149	206	494
France	507	542	426	UK	431	477	451
Germany	605	640	549	Ukraine	170	184	229
Greece	56	62	62	Belarus	39	42	52
Croatia	15	16	20	Algeria	41	81	249
Hungary	39	40	44	Morocco	27	57	235
Italy	344	373	311	Tunisia	15	24	66
Lithuania	11	12	15	Libya	23	27	44
Latvia	7.7	8.3	10	Egypt	103	172	631
				Total Area	***4085***	***4568***	***5497***

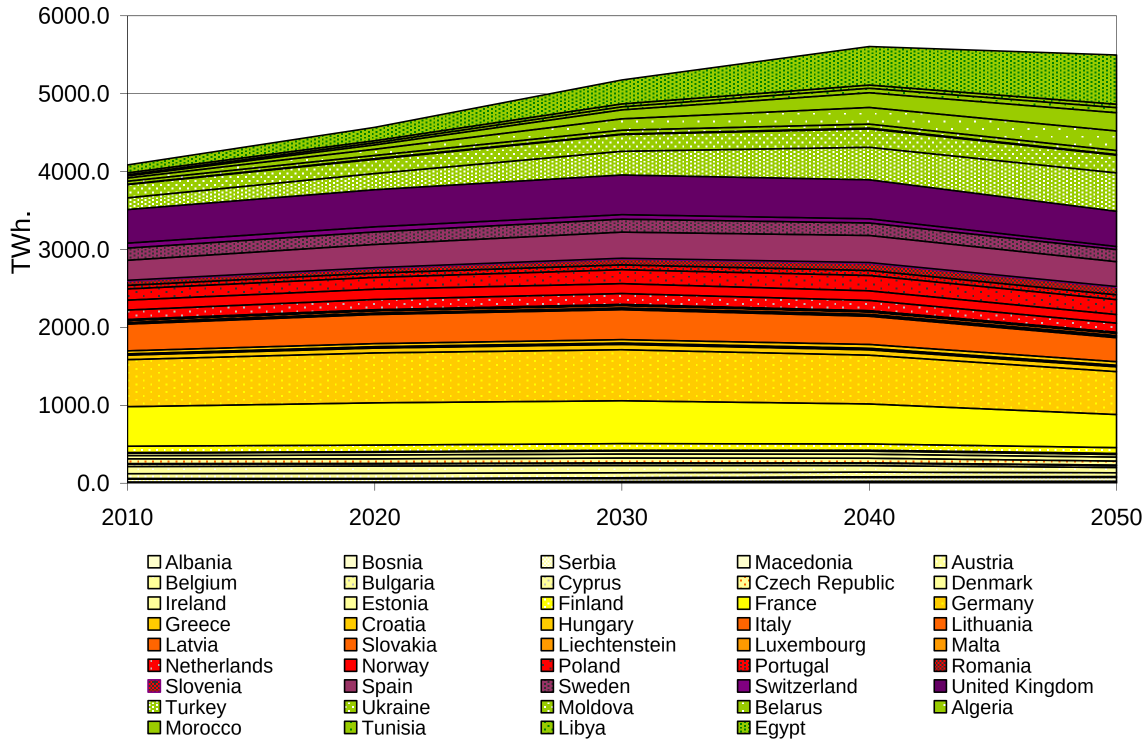

Figure 3.1.1: Electric power demand development in the investigation area in TWh/a.

3.1.2 Temporal resolution

The annual electric power demand given for each country was temporally disaggregated with time curves generated by normalising year 2006 load data. 'Load' is referred to by the European Network of Transmission System Operators for Electricity (ENTSO-E) as the ‘hourly average active power absorbed by all installations connected to the transmission network or to the distribution network’ (ENTSO-E 2010). It includes transmission losses and it excludes the consumption for pumped storage and the consumption of power generating auxiliaries.

Table 3.1.3: Sources of load data for the generation of normalised time curves.

	Load data source	Backup time curve		Load data source	Backup time curve
Albania		Macedonia	Slovakia	UCTE (ENTSO-E)[1)]	
Bosnia	UCTE (ENTSO-E)[1)]		Liechtenstein		Switzerland
Serbia	UCTE (ENTSO-E)[1)]		Luxembourg	UCTE (ENTSO-E)[1)]	
Macedonia	UCTE (ENTSO-E)[1)]		Malta		Greece
Moldova		Poland	Netherlands	UCTE (ENTSO-E)[1)]	
Austria	UCTE (ENTSO-E)[1)]		Norway	NORD POOL (NORD_POOL_ASA 2007)	
Belgium	UCTE (ENTSO-E)[1)]		Poland	UCTE (ENTSO-E)[1)]	
Bulgaria	UCTE (ENTSO-E)[1)]		Portugal	UCTE (ENTSO-E)[1)]	
Cyprus		Greece	Romania	UCTE (ENTSO-E)[1)]	
Czech Rep.	UCTE (ENTSO-E)[1)]		Slovenia	UCTE (ENTSO-E)[1)]	
Denmark	NORD POOL (NORD_POOL_ASA 2007)		Spain	UCTE (ENTSO-E)[1)]	
Ireland	EIRGRID (EIRGRID 2007)		Sweden	NORD POOL (NORD_POOL_ASA 2007)	
Estonia	Eesti Energia (Eesti_Energia 2007)		Switzerland	UCTE (ENTSO-E)[1)]	
Finland	NORD POOL (NORD_POOL_ASA 2007)		Turkey		Greece
France	UCTE (ENTSO-E)[1)]		UK	UCTE (ENTSO-E)[1)]	
Germany	UCTE (ENTSO-E)[1)]		Ukraine[2)]		Poland
Greece	UCTE (ENTSO-E)[1)]		Belarus		Poland
Croatia	UCTE (ENTSO-E)[1)]		Algeria	MEM Algeria (MEM 2007)	
Hungary	UCTE (ENTSO-E)[1)]		Morocco	World Bank (Eichhammer, Ragwitz et al. 2005)	
Italy	UCTE (ENTSO-E)[1)]		Tunisia	STEG (STEG 2007)	
Lithuania		Estonia	Libya	GEC (GEC 2007)	
Latvia		Estonia	Egypt	EEHC (EEHC 2005)	

1) ‘Union for the Coordination of the Transmission of Electricity’ (UCTE), now called ‘European Network of Transmission System Operators for Electricity’ (ENTSO-E), (UCTE 2007)
2) Load data available from UCTE only for Burshtyn Island

2006 is the first year for which comprehensive hourly load data were published by most of the European transmission system operators. Before 2006, hourly load data were provided for every 3rd Wednesday and for the following Saturday and Sunday in a month. These data were used as representatives for all working days and weekend days in a month in many studies that needed high temporal resolution load data. Here, the continuous real-time load data available for 2006 were used. This improved data base enables the automatic consideration of correlations between load and weather-dependent renewable energy availability which were not directly taken into account when using the previous representative load data.

For the North African countries only some load patterns for single days were available. In the context of the Trans-CSP study (Trieb 2006), load curves for the Arabian and North African countries were generated by interpolating between the few load curves available. Additional information was taken from a temporally comprehensive load curve from Jordan: on Fridays - the official holidays in the Arabian world – the electric power demand is 10 % lower than on a working day. On Saturdays, the demand is 4 % lower and on Sundays it is 2 % lower than on a normal working day. This information was taken into account in the load curve generation for the islamic states in North Africa.

For some countries no hourly load data were available. In those cases the load patters of neighbouring countries were used as a proxy for the temporal disaggregation. The sources of base data for the load curve generation are listed in table 3.1.3.

Among other factors the temporal course of the electric load during a year depends on the weather and on the income situation of the inhabitants of a region. In countries in hot climates the electric load tends to be significantly higher in summer when air conditioning systems are used most, if people can afford them. In countries in cold regions more electric power is needed in the winter for cooking and for room and water heating.

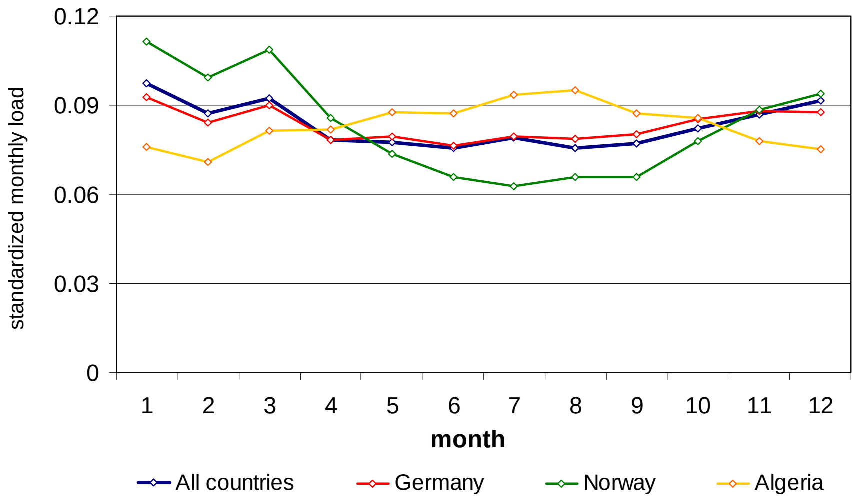

Figure 3.1.2: Standardised monthly average load for Germany, Norway, Algeria and for the total area investigated (all countries aggregated).

Figure 3.1.2 shows the standardised monthly average load for Germany, Norway, Algeria and of all countries in the investigated area. In Norway the load is clearly higher in winter and in Algeria the opposite is the case. The load pattern of all countries together is clearly smoother than is the load in Norway or Algeria, whereas Germany's annual load pattern almost equals the load pattern of the total investigation area (red and dark blue lines).

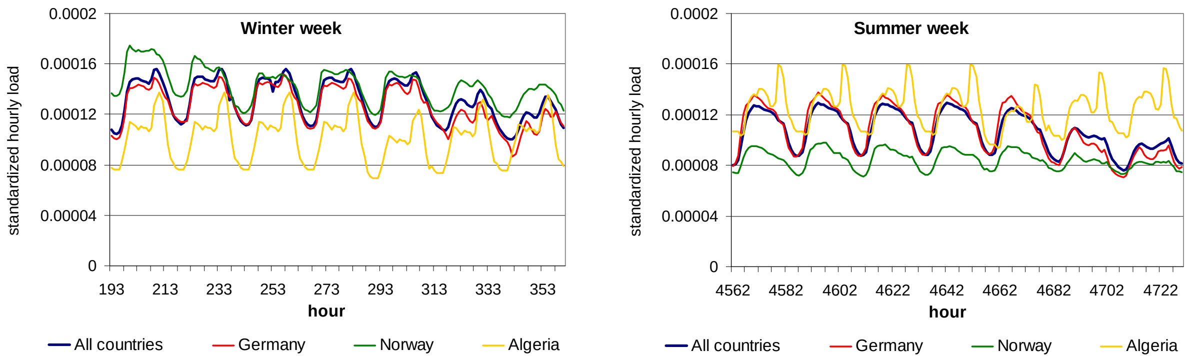

Figure 3.1.3: Standardised hourly average load for Germany, Norway, Algeria and for the total area investigated (average of all countries).

Figure 3.1.3 shows the standardised hourly load pattern in the same countries and in all investigated countries together in one winter and one summer week. Again, the German load pattern almost equals the load pattern of the total area. While the two European countries show a clear reduction of the electric load on the weekend, the day with the lowest load in Algeria is the Friday.

3.1.3 Spatial resolution

The national load values were disaggregated spatially in order to allow for arbitrary choice of regions to be investigated. Since electricity consumption takes place mostly in urban areas, the land cover category ‘artificial surfaces and associated areas’ was chosen as the proxy parameter for the spatial disaggregation. The artificial surfaces in each raster cell of the investigation area were summed up nationally; then for each raster cell the share of artificial surfaces in the total national artificial surface was calculated. In each raster cell, this percentage was then multiplied by the national load. Figure 3.1.4 shows the distribution of the load in the year 2010 in dense urban centres (Paris, London and other English, Belgian, Dutch and German city regions), and in areas with sparse occurrence of artificial surfaces (e.g. in Northern and Eastern UK).

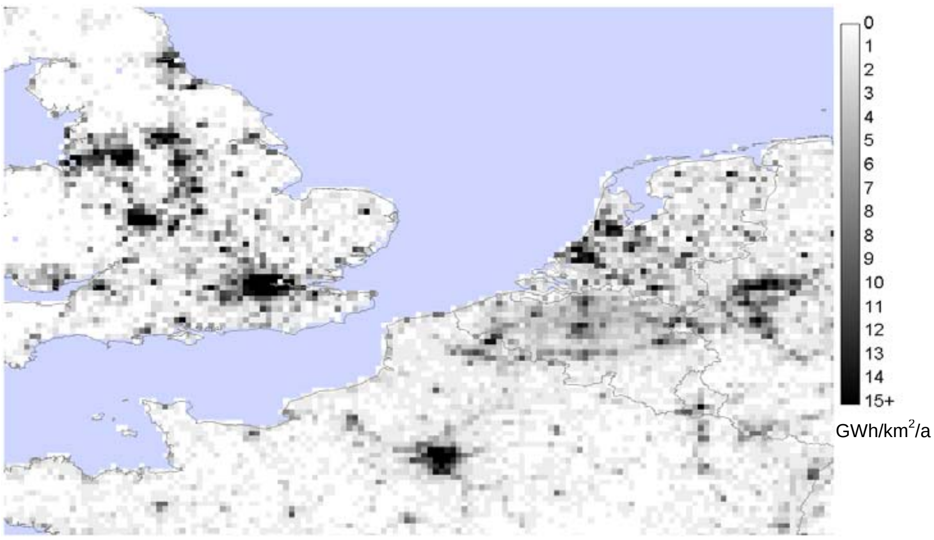

Figure 3.1.4: Annual electricity demand in GWh/km^2/a disaggregated with the proxy parameter ‘artificial surfaces and associated areas’. Extract: South-East UK, Northern France, Belgium and the Netherlands.

3.2 Heat demand and heat demand density

The heat demand in the investigation area must be taken into account in order to assess the potentials and benefits of combined heat and power generation (CHP). Only low temperature heat demand was taken into account because the waste heat of thermal power plants typically supplies heat demands at temperatures below 130 °C such as heating and domestic and commercial hot water supply.

The following electricity generation technologies considered here were assumed to be adaptable for cogeneration of heat and power: solid biomass steam turbines, biogas and geothermal power plants. The ‘residual’ backup capacities were given the properties of gas turbines, allowing for the dispatch of quickly changing residual load. The probable intermittent characteristics of generation and the consequently low full load hours make the additional delivery of heat unlikely; therefore, an additional technology ‘residual (CHP)’ was not considered.

3.2.1 National per-capita heat demands

Readily available statistical data on final heat consumption (EUROSTAT, IEA) only take heat sold as such into account – no fuels converted in households and in the commercial sector are regarded. However, some national studies deal with the actual heat demand, regarding all fuels used for space heating and domestic water warming.

From a German report (BDEW 2008), a value of 11.2 MWh_{th}/(capita*a) of the annual low-temperature heat demand per capita in Germany can be derived. In Austria, 10 MWh_{th}/(capita*a) were calculated in a bottom-up method, but according to the author of the study this value is slightly below the demand as compared with official statistics available in Austria (Schmidt 2008).

Both heat demand values were transferred to other countries by scaling them up or down according to heating degree days that were obtained from the EUROSTAT statistical database (EUROSTAT 2008). Heating degree days are a relative measure of heat demand. In order to calculate heating degree days, the daily differences between average outside temperatures and a desired room temperature of 20 °C (if outside temperatures are lower than 15 °C) are summed up for a certain period of time. Heating degree days are frequently used as an index for heating demand changes in time.

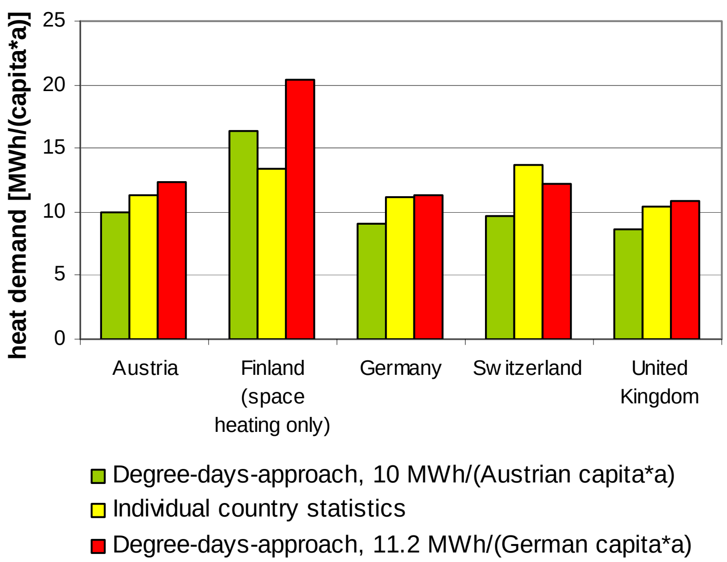

Figure 3.2.1: Scaled low temperature heat demand in MWh_{th}/(capita*a) compared to individual country study results.

The scaling results were compared to low temperature heat demand values from other individual country studies or appropriate statistics where available (BERR 2008), (Statistics_Finland 2008), (Statistik_Austria 2008), (Bundesamt_fuer_Energie 2008)). Calculating the national per-capita heat demands on the basis of the German per-capita heat demand results in values closer to those values given in national studies in most cases, as can be seen in figure 3.2.1. The German value was chosen as a basis for scaling: national per-capita heat demand values for all countries considered were obtained by scaling of the German per-capita heat demand with country specific heating degree days.

For some countries, no heating degree days were available from EUROSTAT. The degree days of neighbouring countries were used as a proxy. These countries and the respective proxy countries are listed in table 3.2.1.

Table 3.2.1: Proxy data sources for countries without heating degree day information.

Proxy country	**Bulgaria**	**Croatia**	**Greece**	**Lithuania**	**Malta**	**Slovakia**	**Switzerland**
Countries without heating degree day information	Serbia	Bosnia	Albania, Macedonia	Belarus	Cyprus, Algeria, Morocco, Tunisia, Libya, Egypt	Ukraine, Moldova	Liechtenstein

3.2.2 Spatial resolution

The low temperature heat demand that is not to be exceeded by the cumulated heat delivery of all CHP technologies must fulfil the criterion that the heat demand density is high enough for economic district heating systems.

Assuming a strong correlation with the population distribution, a heat demand density map was created by multiplying the per-capita heat demand values with population numbers in each raster cell and dividing the result by the raster cell areas. Figure 3.2.2 shows the heat demand density in Europe and neighbouring countries.

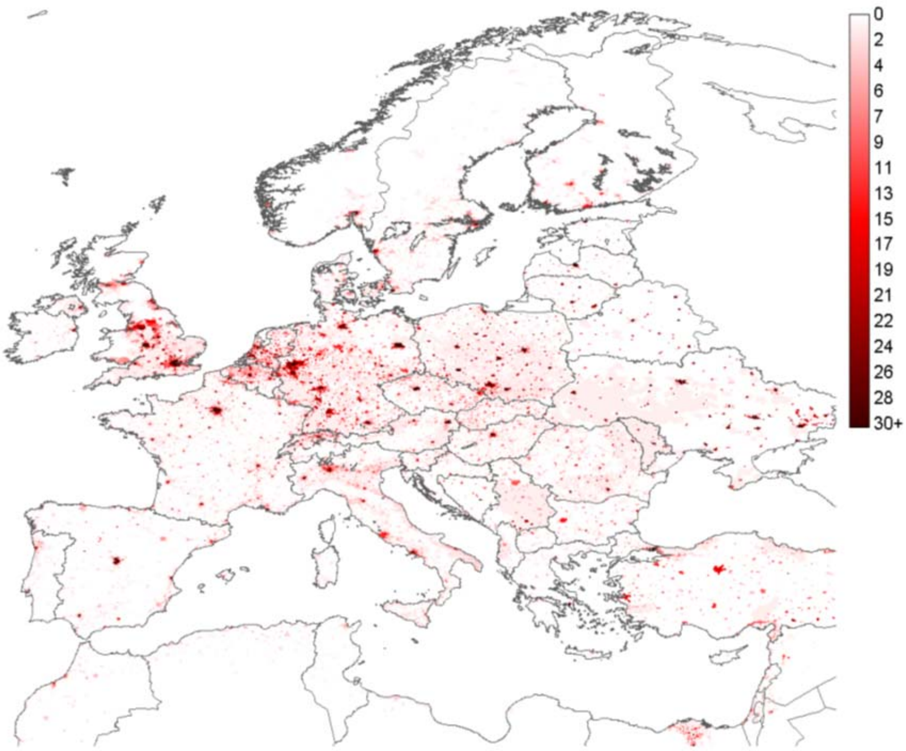

Figure 3.2.2: Heat demand density in Europe and neighbouring countries in $GWh_{th}/(km^2*a)$.

For economic district heating applicability, the heat demand density must be higher than a certain threshold. Different values for this threshold can be found in literature. They are mostly given as minimum heat delivery per meter of district heating: (Reidhav and Werner 2008) indicates 556 $kWh_{th}/(m*a)$, whereas in (UBA 2007), a value of 1000 $kWh_{th}/(m*a)$ was assumed. The average district heat delivery in Denmark currently is 500 $kWh_{th}/(m*a)$; the Danish district heating system operator Dansk Fjernvarme aims at pushing the limit of economic district heating system operability down to 140 $kWh_{th}/(m*a)$ (Nast 2008). As a lower boundary, a value of 200 $kWh_{th}/(m*a)$ was assumed here. The relation between the length of a district heating grid and the area it covers varies as well: for urban areas excluding industrial areas it ranges between 190 m/ha and 320 m/ha (UBA 2007). The resulting threshold for the heat demand density lies between 4 $GWh_{th}/(km^2*a)$ and 32 $GWh_{th}/(km^2*a)$. Here, the more optimistic value of 4 $GWh_{th}/(km^2*a)$ was chosen as the threshold of heat demand density below which the heat demand was not considered.

3.2.3 Temporal resolution

The heat demand for heating was temporally disaggregated with normalized daily heating degree day values that were derived from 2-m-above-ground temperature data from the German Weather Service DWD (DWD 2007). Based on (BDEW 2008), the share of the heat demand for heating in the total low-temperature heat demand was calculated. In Germany, it amounted to around 85 % in 2006. This fraction of the total low-temperature heat demand was temporally disaggregated with heating degree days for all countries.

Around 15 % of the German low temperature heat demand is for hot water. This fraction of the heat demand was evenly distributed over the year.

Due to the lack of comprehensive information for the fractions of hot water and heating demand in the total low-temperature heat demand in other countries, the German shares were used for all countries in the investigation area as a best guess. The resulting temporal distribution of the total heat demand in the investigation area is shown in figure 3.2.3.

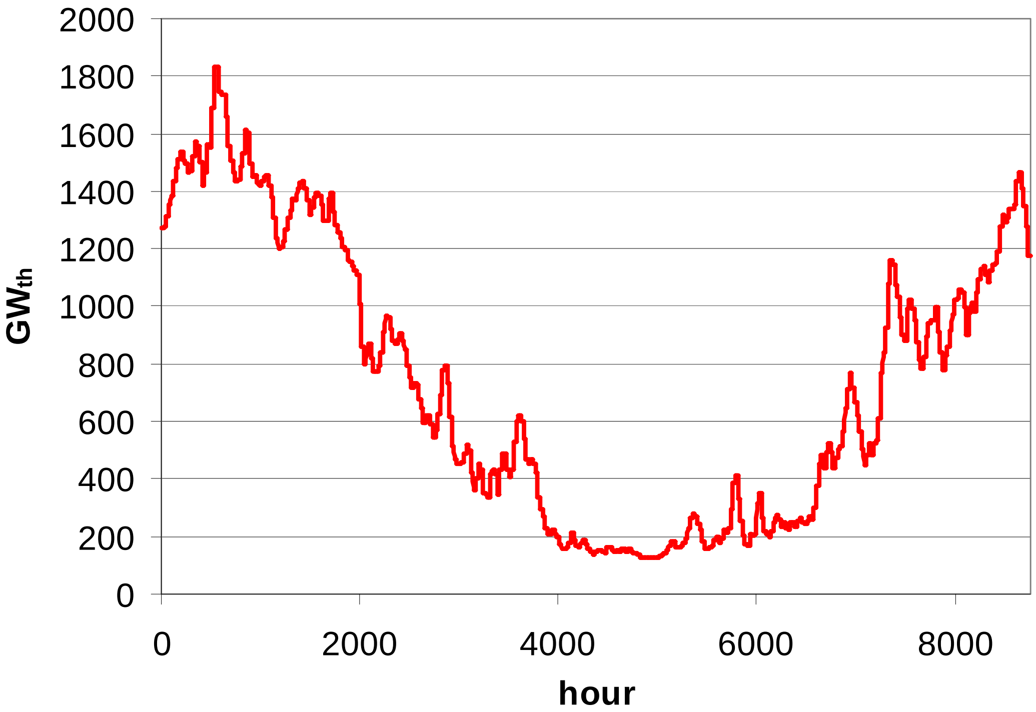

Figure 3.2.3: Mean hourly heat load in the total investigation area in GW_{th}, course over the year.

4 Renewable energy for electric power generation

Three energy sources deliver energy which is available on earth: the sun, the planetary movement and geothermal energy (Kaltschmitt, Wiese et al. 2003). All continuous energy fluxes on earth, the so called ‘renewable energy’, and all fossil energy carriers originate from one of these energy sources. The continuous energy fluxes normally have a lower energy density than the fossil energy carriers and thus need to be used on larger areas.

The technologies for the conversion of renewable energies into electricity listed in table 3.2.1 were regarded in this investigation:

Table 3.2.1: Technologies for electric power generation from renewable energy.

Technology	**Abbreviation**
Solar photovoltaic plants	PV
Concentrating solar power plants	CSP
Onshore wind power plants	WIND_ONSHORE
Offshore wind power plants	WIND_OFFSHORE
Biomass steam turbines	BIO_ST
Biomass steam turbines for combined heat and power generation	BIO_ST_CHP
Biogas plants for combined heat and power generation	BIO_BIOGAS_CHP
Geothermal power plants (enhanced geothermal systems)	GEO
Geothermal power plants (enhanced geothermal systems) for combined heat and power generation	GEO_CHP
Old and modernised run-of-river hydro power plants	HYDRO_ROR
New run-of-river-hydro power plants	HYDRO_ROR_NEW
Old and modernised reservoir hydro power plants	HYDRO_RES

The installable capacities and the electricity generation potentials were analysed in bottom-up approaches for solar PV and CSP, for wind power and for the geothermal technologies, i.e. the total potential was calculated from the potentials analysed in each raster cell in the investigation area. For biomass and hydro power this was not possible in the scope of this study. Top-down approaches were chosen instead, i.e. national potentials were taken from literature and disaggregated according to a proxy parameter.

The distribution of the potentials is displayed in maps in this chapter. Because the area of the single raster cells in the chosen projection varies and because the raster cells can not be clearly distinguished from one another visually, the potentials were not given in absolute numbers but were referred to the area of the raster cell. The results are maps of the average energy densities in the raster cells of 0.083° edge length. The potentials contain assumptions about the share of the base area not usable for a technology or reserved for competing area use, e.g. the share of area usable for PV in the total urban area contains assumptions about the share of the roof, facade and other urban area in the total urban area and about the share of such areas required for chimneys, windows and solar heating systems. The energy density maps give an overview over the distribution of the total sustainably usable potential. The energy density values can not serve directly for the development of individual projects. A project developer needs to know the energy yield in a given time span per net-area, i.e. per base area completely used for the installation of the respective power plant type:

$$E^t_{A\_net} = \frac{E^t}{A_{net}} \qquad \text{eq. 1}$$

where	E^t	Energy yield in a power plant in a given time span in MWh/t
	A_{net}	Total area which the power plant occupies in km^2
	$E^t_{A\_net}$	Net-area specific energy yield in $MWh/km^2/t$
	t	Time span

In the maps displayed here, the energy density in each raster cell equals the net energy yield multiplied with an area use factor and the share of usable land cover in the raster cell area:

$$E^t_{A,RC} = E^t_{A\_net} \cdot f_{au} \cdot f_{lc} = E^t_{A\_net} \cdot \frac{A_{net,RC}}{A_{gross,RC}} \qquad \text{eq. 2}$$

where	$E^t_{A,RC}$	Energy yield in a raster cell in a given time span in MWh/t
	$A_{net,RC}$	Total usable area in a raster cell in km^2
	$A_{gross,RC}$	Total area in a raster cell in km^2
	f_{au}	Area use factor
	f_{lc}	Share of technically usable land cover in a raster cell

4.1 Solar energy - photovoltaic

4.1.1 Resource assessment

The sun mainly consists of hydrogen and helium. Helium is generated by nuclear fusion of hydrogen, which leads to a loss of around 0.7 % of mass which is released as energy. At the core of the sun, this leads to temperatures of around 13,600,000 Kelvin, at its surface the temperature is around 5,800 Kelvin. The irradiance at the surface of the sun is $2*10^7$ W/m^2 on average. At the outer surface of the earth's atmosphere the irradiance is approximately $1.368*10^3$ W/m^2. Only a part of the sunlight reaches the surface of the earth because in the atmosphere, it is absorbed and scattered by molecules, aerosols and clouds. It reaches the ground partly as undisturbed direct beam and partly as scattered, diffuse radiation.

The passage of the sunlight through the atmosphere is modelled at DLR with the HELIOSAT method (Hammer, Heinemann et al. 2003), using satellite data (cloud density and frequency), meteorological data (water content) and global aerosol data sets. Global horizontal irradiance (GHI) and direct normal irradiance (DNI) (irradiance on a plane normal to the beam) are calculated. Hourly irradiance data generated at DLR were used for the analysis of photovoltaic and concentrating solar thermal electricity generation potentials.

Figure 4.1.1 shows the annual integral of the global horizontal irradiance in the investigation area. On average, the global horizontal irradiance is around 1500 $kWh/m^2/a$. The data are not complete because of the limited field of view of the METEOSAT satellite: the GHI and DNI data were not available for the northern parts of the countries Norway, Sweden and Finland. This lack was considered insignificant because of the generally low irradiance in these countries and the unlikely application of grid connected PV plants especially in their northern parts. The maximum country average is found in Egypt, amounting to 2255 kWh/m^2. The country averages for all countries can be found in table 10.1.2 in the annex. The direct normal irradiance is discussed in chapter 4.2.1.

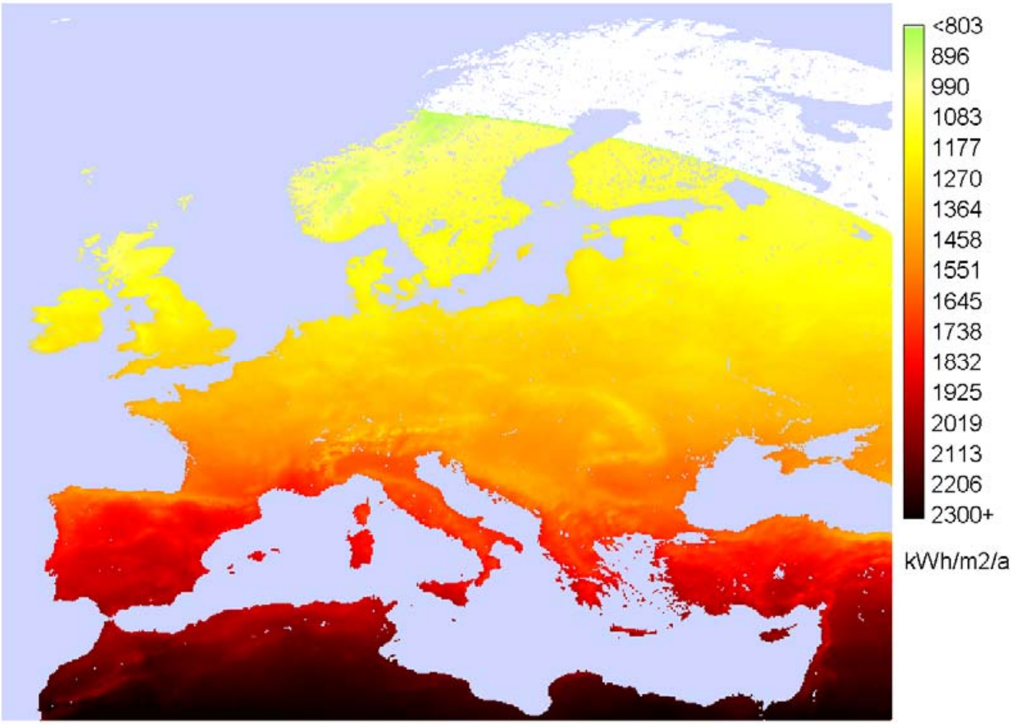

Figure 4.1.1: Global horizontal irradiance in the investigation area (annual integral) in kWh/m^2/a.

The total irradiance on a PV module with an arbitrary orientation can be calculated from the global horizontal irradiance $G_{glob,h}$ and the direct normal irradiance. This ‘global irradiance’ $G_{glob,surf}$ is composed of the direct, the diffuse and the ground-reflected irradiance on the module surface:

$$G_{glob,surf} = G_{dir,surf} + G_{dif,surf} + G_{ref,surf} \quad \text{eq. 3}$$

where $G_{dir,surf}$ Direct irradiance on the module surface
$G_{dif,surf}$ Diffuse irradiance on the module surface
$G_{ref,surf}$ Irradiance on the module surface reflected from the ground

Direct, diffuse and ground-reflected irradiance on the module surface were calculated according to (Iqbal 1983) from eq. 4 to eq. 6.

$$G_{dir,surf} = G_{dir,h} \cdot \frac{\cos\Theta_{N,surf}}{\cos\Theta_Z} \quad \text{eq. 4}$$

$$G_{dif,surf} = G_{dif,h} \cdot \frac{(1+\cos\gamma)}{2} \quad \text{eq. 5}$$

$$G_{ref,surf} = G_{glob,h} \cdot \frac{(1-\cos\gamma)\cdot\rho*_{surf}}{2} \quad \text{eq. 6}$$

where $G_{dir,h}$ Direct irradiance on the horizontal
$G_{dif,h}$ Diffuse irradiance on the horizontal
$G_{glob,h}$ Global irradiance on the horizontal
Θ_Z Angle between the solar beam and the zenith
$\Theta_{N,surf}$ Angle between the solar beam and the normal of the module surface
γ Angle between the module surface and the horizontal
$\rho*_{surf}$ Albedo of the ground

The direct horizontal irradiance $G_{dir,h}$ is the result of the multiplication of the direct normal irradiance and the cosine of the angle between the beam and the horizontal. The diffuse horizontal irradiance $G_{dif,h}$ is the difference between the global horizontal irradiance $G_{glob,h}$ and the direct horizontal irradiance $G_{dir,h}$. The angles Θ_Z , $\Theta_{N,surf}$ and γ are shown in figure 4.1.2 which has been taken from (Quaschning 2000) and adapted. As a simplification, the albedo (the rate of reflexion) ρ^*_{surf} of the ground has been set to a constant value of 0.2. More detailed information on the calculation of irradiance on arbitrarily oriented surfaces at different times of the year can be found in (Iqbal 1983).

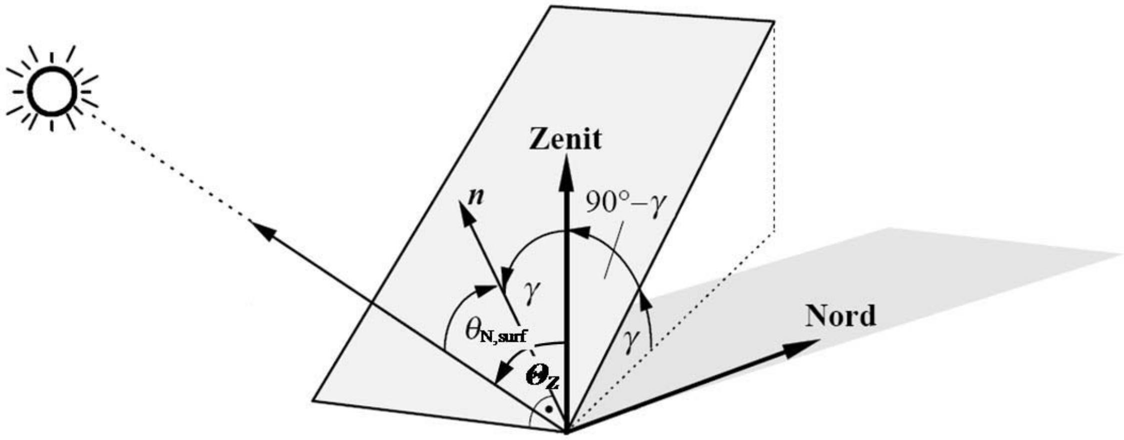

Figure 4.1.2: Angles for calculating the irradiance on arbitrarily oriented surfaces from the irradiance on horizontal surfaces (adapted from (Quaschning 2000)).

4.1.2 Area analysis

PV plants can be installed on roof tops, facades and on other urban areas such as noise barriers or as shadings for car-parks. Installation on open areas is also possible and mostly more cost-efficient because of the bigger size of the plants installed. The land cover categories used as base areas - defining the areas on which PV plants can be built - are ‘artificial surfaces and associated areas’ for roof tops, facades and other urban areas and ‘agricultural areas’, ‘grasslands’, ‘bare areas’ and ‘sparsely vegetated areas’ for open area PV. Protected areas and sand dunes are generally excluded.

There can be competition with other technologies for the surfaces on which PV plants can be installed: thermal collectors can be built on roofs and facades, food and fodder production may be prior to electricity generation on agricultural areas and on grasslands and there might be competition with wind farms or concentrating solar power plants on bare and sparsely vegetated areas.

In order to calculate the PV module area that can be installed on a base area with known size, a relation between the two parameters is established considering the share of the technically usable surface type (roof, façade, other urban and open area) area (excluding e.g. chimneys, windows, doors, north oriented surfaces, …) in the total base area, and considering to which extent it is available and not reserved for competing uses.

Estimates of technically usable surface types were taken from (BMU 2004), estimates of the areas to be provided for competing uses were taken from (Quaschning 2000) and (BMU 2004), and total base areas were extracted from CORINE Land Cover 2000 (EEA 2005). The area shares derived from studies made for Germany were applied to the whole investigation area assuming that even though roof shapes, building density and other characteristics may vary, the overall area shares that can be used for PV are probably rather similar: the less houses, the more other urban areas can be used and vice versa.

In Germany, about 800 km^2 of roof tops, 150 km^2 of facades and 670 km^2 of other urban areas are apt for PV plant installations (BMU 2004). About 26139 km^2 is artificial surface in Germany (EEA 2005). Thus, the ratio 'technically usable surface in base area' is 3.1 % for roofs, 0.6 % for facades and 2.6 % for other urban areas. On the basis of (Quaschning 2000) and (BMU 2004), the share of the technically usable areas reserved for PV plants was set to 25 % for roofs, 80 % for facades and 45 % for other urban areas.

About 1300 km^2 of agricultural areas and grasslands are not used for food or material production in Germany and could be used for installing PV plants. This amounts to 0.3 % of the total agricultural and grassland area of 383100 km^2. Only a small fraction of 1 % out of the 0.3 % currently available is allowed here for PV installations, because the potential on artificial areas is already huge, because additional changes of the landscape with artificial constructions have low acceptance in the population and because future competing uses of agricultural land and grassland for biomass production are likely and must be considered.

For bare and sparsely vegetated areas it is assumed that these areas are hardly used for other purposes where they occur in the southern Mediterranean region (desert and desert-adjacent areas) and that artificial constructions would not be objected by the population. Therefore, the only restriction to using the area for PV installations is competition with CSP plants and wind energy use. Consequently, a third of the bare and sparsely vegetated areas was assigned for potential application of these three technologies each. Bare and sparsely vegetated areas occur in middle and northern Europe, too, but less frequently. Like for agricultural land and grassland, 0.003 % of these areas have been allotted for use for PV installations. In order to decide where the border between the areas to be treated with one or the other of the two area share values should be, the competition with CSP was taken as a simplified criterion. CSP is considered only to be built where the annual sum of direct normal irradiance (DNI) exceeds 1800 kWh/m^2. A third of such areas was assumed to be available for PV and a third for wind turbines, of all bare and sparsely vegetated areas with less DNI only 0.03 % is allotted for PV installation. Protected areas were completely excluded from the analysis.

No change of the area shares is assumed for the period between 2010 and 2050. The area shares are summed up in table 4.1.1: f_a^{PV} being the technically usable area share in the total base area, f_u^{PV} being the actually usable part of the technically usable area considering competing uses and the product of the two, f_{au}^{PV}, being the final share of the base area that is assigned to the installation of PV plants.

Table 4.1.1: Area utilisation factors for PV.

Area type	Base / distribution land cover	Area availability f_a^{PV}	Utilisation of available area f_u^{PV}	Total area utilisation f_{au}^{PV}
Roof-tops	Artificial surfaces	0.031	0.25	0.00775
Facades	Artificial surfaces	0.006	0.8	0.0048
Other urban areas	Artificial surfaces	0.026	0.45	0.0117
Agricultural areas	Agricultural areas	1	0.0003	0.0003
Grassland	Grassland	1	0.0003	0.0003
Bare areas	Bare areas	1	0.33 or 0.0003	0.33 or 0.0003
Sparsely vegetated areas	Sparsely vegetated areas	1	0.33 or 0.0003	0.33 or 0.0003

The actually usable radiation on a module varies with the deviation from the optimal module orientation and is lowered by shading and dirt deposition. The variation due to the orientation is taken into account by calculating the irradiance on the oriented surface. Losses due to shading and dirt deposition depend on the surface type. A distribution of surface orientations and corresponding loss factors was assumed on the basis of (Quaschning 2000). The shares f_{ψ}^{PV} of module azimuths (in the northern hemisphere: deviation from the direction south), the angles between the module and the horizontal, γ, as well as the assumed loss factors f_{loss}^{PV} are given in table 4.1.2.

Table 4.1.2: Module orientation and loss factors for PV plants (based on (Quaschning 2000)).

	Symbol	Roof-tops	Facades	Other urban areas	Open area
Angle between module and the horizontal	γ	35 °	90 °	60 °	latitude - 10 °
Share of module azimuth East	f_{ψ}^{PV}	25 %	25 %	25 %	0 %
Share of module azimuth South		50 %	50 %	50 %	100 %
Share of module azimuth West		25 %	25 %	25 %	0 %
Losses (shading and dirt)	f_{loss}^{PV}	15 %	10 %	10 %	10 %

4.1.3 Energy conversion

4.1.3.1 Technology

PV modules convert direct and diffuse radiation to direct current electricity, making use of the photovoltaic effect. For detailed descriptions of the physical principle of the photovoltaic effect see (Kaltschmitt, Wiese et al. 2003). The cells mostly consist of mono- or polycrystalline or of amorphous silicon, but they can also be built of cadmium telluride, gallium arsenide or copper indium selenide. The non-silicon materials enable the production of thin layer cells which can be produced at lower costs and with more diverse shapes of cells (e.g. foils) which can easily be adapted to the requirements of individual projects.

However, silicon cells are most widespread as they have the highest efficiencies and longevity. Therefore, technical and economical parameters of silicon cell PV plants were used here as the basis for the analysis of PV electricity generation potentials. The values of technical parameters in the year 2010 and assumptions for their development until 2050 were set based on (BMU 2010). The parameters are listed in table 4.1.3.

Table 4.1.3: Technical parameters of PV plants, based on (BMU 2010).

	Symbol	Unit	2010	2020	2050
Temperature coefficient	f_{T}^{PV}	1/°C	-0.005	-0.0045	-0.004
Availability factor	f_{av}^{PV}	-	0.98	0.98	0.98
Module efficiency[1)]	η^{PV}	-	0.161	0.173	0.18
q-factor (efficiency of other components)	q^{PV}	-	0.811	0.82	0.847
System efficiency, annual average	-	-	0.128	0.139	0.149
Installation density (for open space PV)[2)]	f_{dens}^{PV}	-	0.33	0.33	0.33

[1)] Under standard test conditions: 25 °C module temperature, 1000 W/m^2 irradiance

[2)] For urban PV installations this factor is set to 1.

The parameters are valid under standard test conditions, i.e. at an irradiance of 1000 W/m^2 and at a module temperature of 25 °C. While the power output of a PV module is proportional to the irradiance, it is inversely proportional to the cell temperature. The deviation of the power output from the power output at 25 °C conditions is specified by the temperature coefficient f_T^{PV}. In order to take into account the influence of the module temperature $\vartheta_M^{PV,time}$ at a given time on the power output of PV modules, $\vartheta_M^{PV,time}$ is calculated according to the following correlation with the ambient temperature $\vartheta_{ambient}^{time}$ and the irradiance on the module with the correlation coefficients k_1 = -2 °C, k_2 = 1.02 and k_3 = 0.03 °C*m^2/W (Zahir 1994):

$$\vartheta_M^{PV,time} = k_1 + k_2 \cdot \vartheta_{ambient}^{time} + k_3 \cdot G_{glob,surf}^{time} \qquad \text{eq. 7}$$

The area-specific installable PV capacity $p_{inst,\max}^{PV}$ is calculated according to eq. 8:

$$p_{inst,\max}^{PV} = \eta^{PV} \cdot q^{PV} \cdot 1000[W/m^2] \qquad \text{eq. 8}$$

where $p_{inst,\max}^{PV}$ Maximum area-specific installable PV capacity
η^{PV} Efficiency of PV modules
q^{PV} Efficiency of the other system components

For each raster cell, the installable PV capacity $P_{inst,\max,RC}^{PV}$ is calculated with the area-specific installable capacity $p_{inst,\max}^{PV}$, the area of the raster cell, the share of usable base area in the raster cell, the area share and the installation density:

$$P_{inst,\max,RC}^{PV} = A_{RC} \cdot f_{lc}^{PV} \cdot f_{au}^{PV} \cdot f_{dens}^{PV} \cdot p_{inst,\max}^{PV} \qquad \text{eq. 9}$$

where $P_{inst,\max,RC}^{PV}$ Maximum PV capacity installable in a raster cell
A_{RC} Area of the raster cell
f_{lc}^{PV} Share of base-area landcover in the raster cell
f_{au}^{PV} Usable area share
f_{dens}^{PV} Installation density

For each raster cell, the power output $P_{\max,RC}^{PV,time}$ at a given time step is calculated from the maximum installable capacity, the global irradiance on the module surface in the regarded time step, the loss factor, the module temperature, the temperature coefficient and the availability factor:

$$P_{\max,RC}^{PV,time} = P_{inst,\max}^{PV} \cdot \frac{G_{glob,surf}^{time}}{1000[W/m^2]} \cdot (1 - f_{loss}^{PV}) \cdot \left(1 + f_T^{PV} \cdot \left(\vartheta_M^{PV,time} - \vartheta_{M,STC}^{PV}\right)\right) \cdot f_{av}^{PV} \qquad \text{eq. 10}$$

where $time$ Time step index
$P_{\max,RC}^{PV,time}$ Power output of maximum installable capacity in the regarded time step
$G_{glob,surf}^{time}$ Global irradiance on the module surface
f_{loss}^{PV} Loss factor
f_T^{PV} Temperature coefficient
$\vartheta_M^{PV,time}$ Module temperature in the regarded time step
$\vartheta_{M,STC}^{PV}$ Module temperature under standard test conditions
f_{av}^{PV} Availability factor, accounting for maintenance times and blackouts

The power output is calculated for each module orientation. The sum of power outputs of all module orientations is the total potential power output in the raster cell in a time step. The integral of $P_{\max,RC}^{PV,time}$ over a whole year is the annual electricity generation potential in the raster cell.

4.1.3.2 Costs

Economic parameters assumed for urban area and for open area PV plants for the year 2010 and anticipated values for the years 2020 and 2050 were taken from (BMU 2010). The parameters are listed in table 4.1.4.

Table 4.1.4: Economic parameters of urban and open area PV power plants, based on (BMU 2010). All costs in €$_{2009}$.

	Symbol	Unit	2010		2020		2050	
			Urban	Open area	Urban	Open area	Urban	Open area
Investment costs	c_{inv}^{PV}	€/kW	2978	2470	1229	940	921	690
Relative fixed op. costs[1)]	$f_{c\_fixop}^{PV}$	-	0.01	0.01	0.01	0.01	0.01	0.01
Absolute fixed op. costs	-	€/kW/a	30	25	12	9	9	7
Variable operation costs	$c_{\mathrm{var}\,op}^{PV}$	€/kWh	0	0	0	0	0	0
Life-time	N^{PV}	a	20	20	20	20	20	20

1) Annual share in investment costs

The levelised electricity costs in each raster cell were calculated from annuities plus operation costs and annual electricity generation according to eq. 11. The annuity factor was calculated according to eq. 12 with an interest rate i of 6 %. The equations are valid not only for PV; they were applied for all technologies and therefore have been formulated neutrally here.

$$c_{kWh} = \frac{c_{inv} \cdot P_{inst,\max} \cdot \left(f_{annuity} + f_{fixop}^{c}\right) + c_{\mathrm{var}\,op} \cdot E_{el,annual}}{E_{el,annual}} \qquad \text{eq. 11}$$

where
c_{kWh} Levelised electricity cost in €/kWh
c_{inv} Investment costs
$P_{inst,\max}$ Maximum installable capacity
$f_{annuity}$ Annuity factor
f_{fixop}^{c} Fixed operation costs given as percentage of the investment costs
$c_{\mathrm{var}op}$ Variable operation costs in €/kWh
$E_{el,annual}$ Annual electricity generation

$$f_{annuity} = \frac{i \cdot (1+i)^N}{(1+i)^N - 1} \qquad \text{eq. 12}$$

where
i Interest rate = 6 %
N Life-time

A cost potential curve can be generated by ordering and accumulating the potentials in the raster cells according to their levelised electricity costs which vary with the local resource quality. The cumulative curve shows the marginal costs of the development of the potential.

4.1.4 Potentials

In the investigation area the total PV electricity generation potential calculated with the given parameters and restrictions is 26443 (29065; 31671) TWh/a in the year 2010 (2020; 2050). This is ca. 6.5 (6.4; 5.8) times as much as the annual electric power demand of around 4084 (4567; 5497) TWh/a in the year 2010 (2020; 2050). The maximum ratio of the regional PV potential to the regional electric power demand occurs in Libya with 338 (316; 213). For the year 2050, the maximum installable capacities and the annual electricity generation potentials of the single regions are listed in table 4.1.5. The respective values for all years can be found in tables 10.1.5 - 10.1.10 in annex 10.1. The distribution of the potential in the year 2050 in $MWh/km^2/a$ is shown in figure 4.1.3.

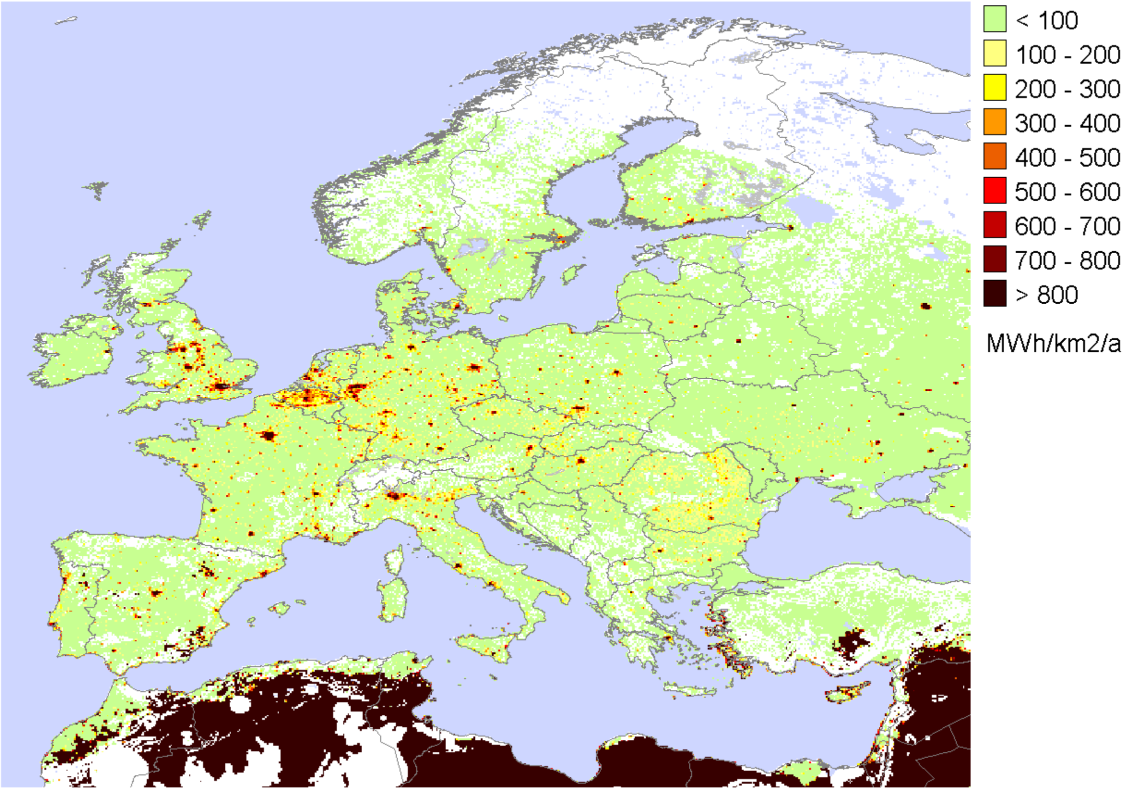

Figure 4.1.3: PV electricity generation potential in $MWh/km^2/a$ (annual integral, year 2050). Unusable areas are excluded and competing area use is taken into account, i.e. the energy density in each raster cell equals the maximum net energy yield multiplied with an area use factor and the share of usable land cover in the raster cell area.

Table 4.1.5: Maximum installable PV capacities and annual electricity generation potentials in the investigation area, year 2050.

	1)	Max. installable Capacity $P_{inst,max}$ in GW	Annual electricity generation potential in TWh/a		1)	Max. installable Capacity $P_{inst,max}$ in GW	Annual electricity generation potential in TWh/a
AL_CS_MK 2)	1	7.0	8.4	Malta	1	0.4	0.5
BA_HR_SI 3)	1	10	12	Netherlands	1	16	15
Austria	1	13	14	Norway	1	3.0	2.6
Belgium	1	23	23	Poland	1	41	41
Bulgaria	1	21	24	Portugal	1	13	20
Cyprus	1	7.0	12	Romania	1	56	62
Czech Republic	1	18	19	Spain	1	76	121
Denmark	1	9.5	8.6	Sweden	1	19	17
Ireland	1	4.7	4.5	CH, LI 5)	1	2.6	2.8
EE_LT_LV 4)	1	15	14	Turkey	0.80	355	627
Finland	1	13	12	UK	1	63	60
France	1	99	111	U_MD 6)	1	31	32
Germany	1	108	107	Belarus	1	4.2	4.2
Greece	1	14	20	Algeria	0.31	6605	12588
Hungary	1	20	22	Morocco	0.73	1551	2990
Italy	1	51	66	Tunisia	0.99	1480	2771
Slovakia	1	10.2	11	Libya	0.18	4845	9341
Luxembourg	1	0.7	0.7	Egypt	0.13	1275	2489
				Total Area		***16883***	***31671***

1) Share of the region lying within the modelling domain
2) Albania, Serbia-Montenegro, Macedonia
3) Bosnia-Herzegovina, Croatia, Slovenia
4) Estonia, Lithuania, Latvia
5) Switzerland, Liechtenstein
6) Ukraine, Moldova

Figure 4.1.4 shows the annual course of the total hourly mean power output of photovoltaic power plants in the investigated area and the daily average in GW. The daily average curve clearly shows that the power output is higher in the summer than in the winter. The potential hourly mean power output of the installable photovoltaic plants with a total capacity of 16883 GW ranges between 0 and 14114 GW.

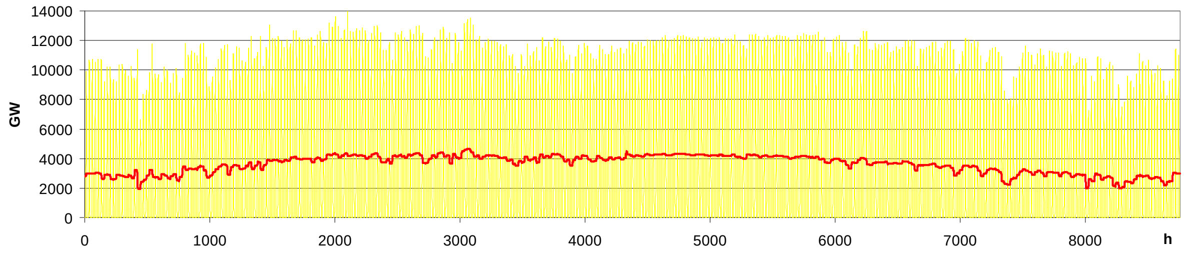

Figure 4.1.4: Annual course of the total hourly mean power output of photovoltaic power plants in the investigated area (yellow) and daily average (red) in GW.

Figure 4.1.5 shows the potentials of the total area of investigation ordered according to the specific costs for their development and cumulated in a cost-potential-curve. The x-axis gives the potential that can be developed and the y-axis shows the marginal levelised electricity costs at a specific point of development of the potential. Technical progress such as increased conversion efficiency leads the curve to stretch parallel to the x-axis. Lower costs, e.g. due to economisation of the converter production, lead to shifting of the curve parallel to the y-axis.

In the case of photovoltaic power, the curves show two sections: one for the open area potential and one for the potential on urban areas. In the first section the huge open area potentials on the bare areas of the Sahara occur, with low costs and with small slope. In the second section, the costs are much higher and show a higher variability, i.e. a higher increase of the costs with further potential development.

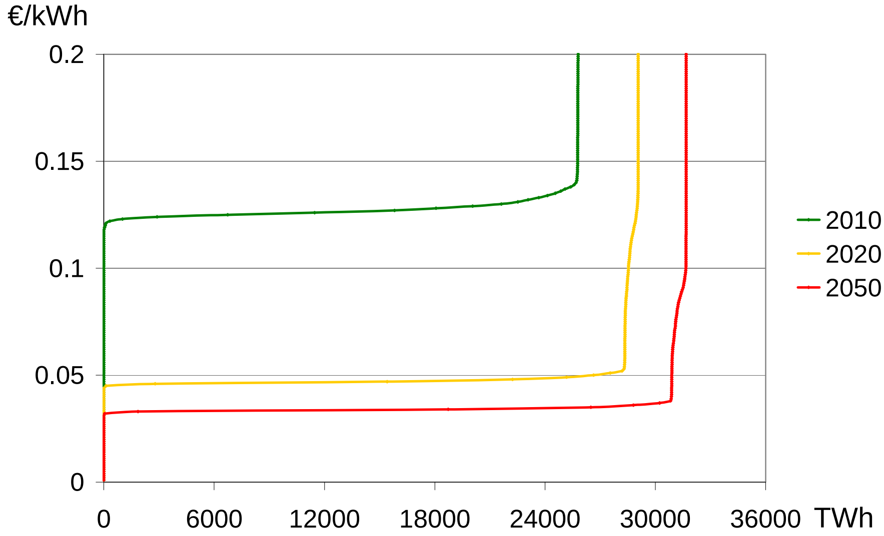

Figure 4.1.5: PV cost-potential-curves for the investigation area from 2010 to 2050.

4.2 Solar energy – concentrating solar thermal power

Electricity can be generated in concentrating solar power (CSP) plants by concentrating the sunlight, converting it into heat in absorber pipes and operating a thermal power generation unit with a heat transfer medium. The intermediate step of generating heat enables storing the energy in salt or concrete storage units. Electricity generation can thus be decoupled from irradiation, enabling control functions in the electricity grid.

4.2.1 Resource assessment

As CSP plants concentrate the sunlight, the resource they can use is direct radiation only. Diffuse radiation can not be concentrated and is no usable resource for CSP plants. The same DNI data for direct solar irradiance were used here as for the PV potential analysis, and the same methods were used for calculating the irradiance on the surfaces of the units concentrating the sunlight (see chapter 4.1.1).

Figure 4.2.1 shows the annual integral of the direct normal irradiance (DNI) in the investigation area. The highest values in the investigation area occur in Algeria and Morocco: more than 2600 kWh/km^2/a of DNI can be harvested there at the best locations. Country averages for all countries can be found in table 10.1.2 in the annex.

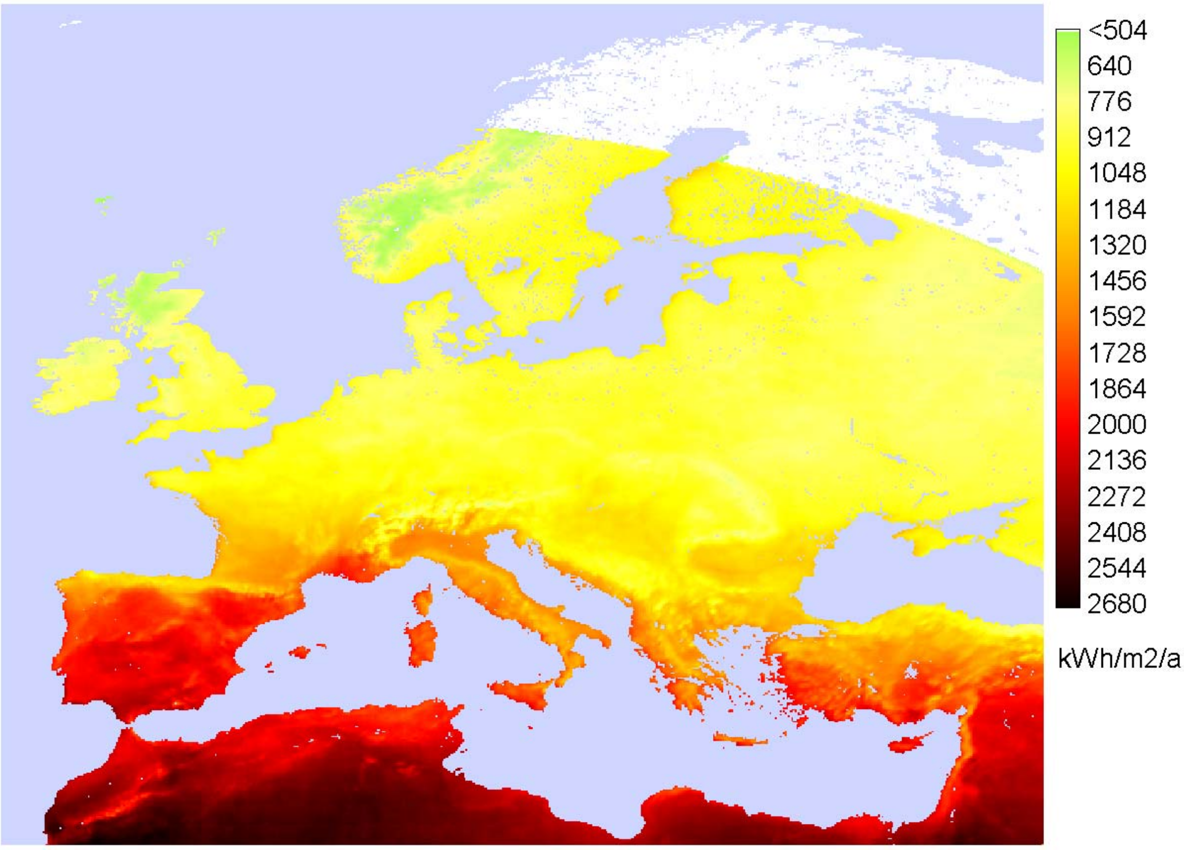

Figure 4.2.1: Direct normal irradiance in the investigation area (annual integral) in kWh/m^2/a.

4.2.2 Area availability

The area exclusion was based on an exclusion map developed in the MED-CSP project (Trieb 2005). Excluded are all land areas that are unsuitable for the construction of solar fields due to ground structure (sand dunes), water bodies, slope, protected or restricted areas, forests, agriculture etc.. It was assumed that 100 % of the remaining area can technically be used for CSP ($f_a^{CSP} = 1$). No competing non-energetic use is assumed to occur on these areas. Energy technologies competing for land can be wind turbines and PV plants. The area utilisation f_u^{CSP} was thus set to 33 % for each of these technologies.

4.2.3 Energy conversion

4.2.3.1 Technology

In concentrating solar thermal power plants, direct sunlight is concentrated with mirrors or prisms to a focal point or line where it is absorbed and converted into heat. The heat is then transported to a power generation unit (gas and/or steam turbine and power generator) when power is needed. The intermediate step of generating heat enables the use of heat storage units: containers with salt, concrete or phase change materials. The heat can be stored when the sun is shining but no electricity is needed and it can be released when electric power demand is high but no or little solar energy is available. A CSP plant can be designed and operated to satisfy base load or to provide dispatchable power for balancing intermittent load and intermittent electricity generation from other renewable energy sources. Different types of operation require different proportions between the heat generation unit, the storage unit and the power generation unit.

Heat generation units consist either of a field of parabolic troughs or Fresnel mirrors concentrating the sunlight to an absorber tube in a focal line, of heliostats concentrating the sunlight to a focal point on a tower or of a paraboloid. The paraboloids are tracking the sun along two axes. They are complete generation modules as they already contain a power generation unit (mostly a Stirling engine). The so-called ‘solar dish Stirling engines’ have very high concentration factors of 1000 – 3000, high heat to electricity efficiencies but also relatively high costs. Therefore, their prevalent field of application are small-scale supply tasks in remote areas. In a solar tower CSP plant, a field of heliostats that track the sun along two axes, too, concentrates the sunlight to one focus in the tower with concentration factors of 300 - 1000. Very high temperatures can be reached which enables applying a more efficient gas- and steam cycle instead of a steam cycle only. However, higher temperatures lead to higher losses, and therefore the efficiencies and electricity costs at the current state of development can not compete with those of parabolic trough CSP plants.

In most existing CSP plants, parabolic troughs that track the sun along one axis are used. They concentrate the sunlight to an absorber tube in a focal line with concentration factors between 70 and 80. The maximum temperatures of heat mediums are lower than in solar dish Stirling or solar tower CSP plants. The heat is transported from the troughs to the storage or power generation unit with a thermo-oil; or steam is generated directly in the absorber tube. If a thermo-oil is used, its temperature tolerance limits the total process temperature to around 400 °C. Direct steam generation makes it possible to work with higher temperatures and thus higher efficiencies. This is especially valuable if the concentration factor can be increased. Fresnel collectors for example have concentration factors of up to 100. They consist of lighter constructions and less land is required than for parabolic troughs. However, parabolic troughs are the technology that has been proven to work in the past and that has been built and gained experience with in the last years. Therefore, technical parameters of parabolic troughs were chosen for the analysis of CSP electricity generation potentials. They have been set based on (Trieb, Quaschning et al. 2004) and (Trieb, Schillings et al. 2009). The technical parameters are listed in table 4.2.1.

Table 4.2.1: Technical parameters of parabolic trough CSP plants, based on (Trieb, Quaschning et al. 2004), (Trieb, Schillings et al. 2009).

	Symbol	Unit	2010 - 2050
Area-specific installable solar field capacity	$p_{inst,\max,CSP\_SF}$	$kW_{th}/km^2_{base\_area}$	176190
Aperture area per kW (thermal)	A_{ap}^{CSP}	m^2/kW_{th}	2.10
Efficiency of the power generation unit	η_{CSP_PG}	-	0.37
Storage efficiency	η_{CSP_STOR}	-	0.95
Availability factor	f_{av}^{CSP}	-	0.95

The area-specific installable thermal capacity of the solar field is given for the reference irradiance (direct normal irradiance DNI) of 800 W/m^2. The area-specific installable thermal capacity takes into account the head space between the troughs as well as losses due to dirt deposition and shading. The storage efficiency was estimated including charging, discharging and temperature losses over time. It also accounts for lower efficiency of the power generation unit due to lower temperature of the heat transfer medium coming from the storage unit instead of coming directly from the solar field. The maximum installable thermal capacity in a raster cell can be calculated from the area-specific capacity, the area of the raster cell, the share of the base area in the raster cell and the usable area share:

$$P_{inst,\max,CSP\_SF,RC} = A_{RC} \cdot f_{lc}^{CSP} \cdot f_{au}^{CSP} \cdot p_{inst,\max,CSP\_SF} \qquad \text{eq. 13}$$

where $P_{inst,\max,CSP\_SF,RC}$ Maximum installable thermal solar field capacity in a raster cell
A_{RC} Area of the raster cell
f_{lc}^{CSP} Share of base-area landcover in the raster cell
f_{au}^{CSP} Usable area share

For each raster cell, the maximum thermal output $P_{\max,CSP\_SF,RC}^{time}$ at a given time step is calculated from the maximum installable thermal capacity, the direct irradiance on the trough surface in the time step and the availability factor according to eq. 14. The direct irradiance on the trough surface is calculated assuming a north-to-south orientation and one-axis tracking. The availability factor accounts for maintenance times and technical blackouts.

$$P_{\max,CSP\_SF,RC}^{time} = P_{inst,\max CSP\_SF,RC} \cdot \frac{G_{glob,surf}^{time}}{800[W/m^2]} \cdot f_{av,CSP} \qquad \text{eq. 14}$$

where $time$ Time step index
$P_{\max,CSP\_SF,RC}^{time}$ Heat output of maximum solar field capacity
$G_{glob,surf}^{time}$ Direct irradiance on the trough surface in the regarded time step
f_{av}^{CSP} CSP availability factor

Because of the possibility of storing the heat and using it at other times, the electric power output of a CSP plant does not have to correspond directly to the thermal power output of the solar field. The dimensioning of the solar field, the storage unit and the power generation unit is an optimisation problem that depends on the task of the plant. The ratio between the thermal output of the solar field at the reference irradiance of 800 W/m^2 and the nominal thermal capacity of the turbine is described by the term ‘solar multiple’ (SM). A solar multiple of 1 (SM1) means that the solar field delivers the heat needed to run the turbine at nominal power when the irradiance is 800 W/m^2. SM 4 would mean that at reference irradiance, four times the nominal heat input of the turbine is delivered, three fourths of which could be sent to a storage unit if available. This stored heat could provide for around 18 hours of full load operation of the power block. In addition to the heat used directly, this would enable base load operation in most situations.

The annual electricity generation potential can be calculated with eq. 15.

$$E_{el,annual}^{CSP} = \int_{t=0}^{8760} P_{\max,CS\_SF}^{time} dt \cdot (1 - \frac{f_{SM} - 1}{f_{SM}} \cdot (1 - \eta_{CSP\_STOR})) \cdot \eta_{CSP\_PG} \quad \text{eq. 15}$$

where $E_{el,annual}^{CSP}$ Annual electricity generation potential of a CSP plant with SM3

f_{SM} Solar multiple

η_{CSP_STOR} Efficiency of the storage unit

η_{CSP_PG} Efficiency of the power generation unit

As the overall task here is to minimise the costs of the total electricity supply system under specified conditions, the proportions between solar field, storage and power block depend on the availability of electricity from other components of the electricity supply system and their costs. The dimensioning was thus not predefined but left as a question for the optimisation model to solve. For the potential electricity generation displayed in figure 4.2.2, the solar multiple was set to 1 and no storage was assumed.

4.2.3.2 Costs

The economic parameters have been set based on (Trieb, Schillings et al. 2009) and (Trieb 2010). The parameters given there can be considered realistic. The long term cost development assumed here for PV and wind power plants is considered optimistic. Therefore an equally optimistic cost data set was chosen for CSP by lowering the costs for all components of a CSP plant by 20 % in the year 2050. The economic parameters assumed for CSP plants are displayed in table 4.2.2.

Table 4.2.2: Economic parameters of parabolic trough CSP plants, based on (Trieb, Schillings et al. 2009) and (Trieb 2010). All costs in $€_{2009}$.

	Symbol	Unit	2010	2020	2050
Solar field					
Investment costs referring to the aperture area	$c_{Inv,CSP\_SF,ap}$	€/m²	330	182	96
Investment costs referring to the thermal capacity	$c_{Inv,CSP\_SF,th}$	$€/kW_{th}$	693	383	202
Investment costs referring to the electric capacity	$c_{Inv,CSP\_SF,el}$	$€/kW_{el}$	1873	1035	545
Fixed operation costs [1)]	f_{c_fixop,CSP_SF}	-	0.025	0.025	0.025
Fixed operation costs (absolute)	-	$€/kW_{th}/a$	17	10	5
Variable operation costs	c_{varop,CSP_SF}	$€/kWh_{th}$	0	0	0
Life-time	N_{CSP_SF}	a	40	40	40
Power generation					
Investment costs	c_{inv,CSP_PG}	$€/kW_{el}$	1150	1018	777
Fixed operation costs [1)]	f_{c_fixop,CSP_PG}	-	0.025	0.025	0.025
Fixed operation costs (absolute)	-	$€/kW_{el}/a$	29	25	19
Variable operation costs	c_{varop,CSP_PG}	$€/kWh_{el}$	0	0	0
Life-time	N_{CSP_PG}	a	40	40	40
Storage					
Investment costs	c_{inv,CSP_STOR}	$€/kWh_{th}$	52	36	20
Fixed operation costs [1)]	f_{c_fixop,CSP_STOR}	-	0.025	0.025	0.025
Fixed operation costs (absolute)	-	$€/kWh_{th}/a$	1.3	0.9	0.5
Variable operation costs	c_{varop,CSP_STOR}	$€/kWh_{th}$	0	0	0
Life-time	N_{CSP_STOR}	a	40	40	40

1) Annual share in investment costs

The overall costs of a CSP plant depend on its configuration. With a solar multiple of 1 (3) and a storage capacity of 0 (12) h, they amount to around 3020 (8450) €/kW$_{el}$ in the year 2010 and are expected to fall to around 1320 (3060) €/kW$_{el}$ in the year 2050. Levelised electricity costs and cost potential curves were calculated as described in chapter 4.1.3.2.

4.2.4 Potentials

In table 4.2.3 the regional values for installable electric power generation capacities and annual power generation potentials for a concentrating solar power plant with a solar multiple of 1 and no storage are listed. The distribution of the electric power generation potential in the investigation area is shown in figure 4.2.2. The total potential amounts to just below 43100 TWh/a. This is 10.6 (9.4; 7.8) times as much as the respective annual electric power demand in the investigation area in the year 2010 (2020; 2050).

The highest regional potential is found in Algeria: 17543 TWh/a of electricity could be generated with CSP plants in the part of the country which lies within the area of investigation. The maximum ratio of the CSP electricity generation potential to the electric power demand in the year 2010 (2020; 2050) occurs in Libya, where around 518 (440; 272) times the annual electric power demand could be covered with CSP alone. The potential of the total country is even higher given the fact that only 18 % of the country's area was considered in the investigation and that the parts that were not considered are further south where higher irradiances occur but the population density is very low.

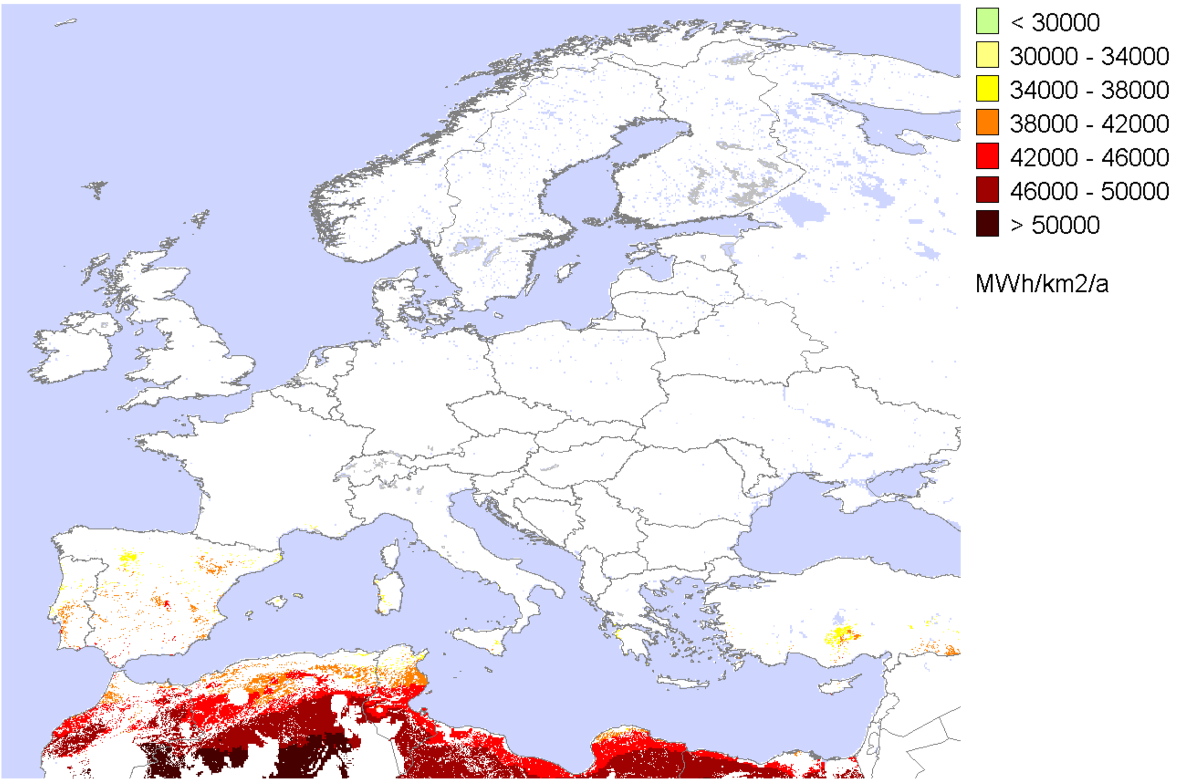

Figure 4.2.2: CSP power generation potential (solar multiple: 1) in MWh/km^2/a (annual integral). Unusable areas are excluded and competing area use is taken into account, i.e. the energy density in each raster cell equals the maximum net energy yield multiplied with an area use factor and the share of usable land cover in the raster cell area.

Table 4.2.3: Maximum installable power generation capacities and annual electricity generation potentials (solar multiple: 1, no storage) of CSP plants in the investigation area. While the generation potential changes little with the configuration of the plant, the maximum installable electric power generation capacity is in inversely proportional to the solar multiple.

	1)	Max. installable capacity P_{inst,max,CSP_PB} in GW	Annual electricity generation potential in TWh/a		1)	Max. installable capacity P_{inst,max,CSP_PB} in GW	Annual electricity generation potential in TWh/a
AL_CS_MK [2)]	1	0	0	Malta	1	0.6	1.0
BA_HR_SI [3)]	1	0	0	Netherlands	1	0	0
Austria	1	0	0	Norway	1	0	0
Belgium	1	0	0	Poland	1	0	0
Bulgaria	1	0	0	Portugal	1	120	216
Cyprus	1	5.1	9.8	Romania	1	0	0
Czech Republic	1	0	0	Spain	1	459	839
Denmark	1	0	0	Sweden	1	0	0
Ireland	1	0	0	CH, LI [5)]	1	0	0
EE_LT_LV [4)]	1	0	0	Turkey	0.8	276	486
Finland	1	0	0	UK	1	0	0
France	1	6.9	12	U_MD [6)]	1	0	0
Germany	1	0	0	Belarus	1	0	0
Greece	1	15	27	Algeria	0.31	7934	17543
Hungary	1	0	0	Morocco	0.73	2035	4385
Italy	1	38	65	Tunisia	0.99	1876	3907
Slovakia	1	0	0	Libya	0.18	5524	11931
Luxembourg	1	0	0	Egypt	0.13	1682	3670
				Total Area		***19972***	***43093***

1) Share of the region lying within the modelling domain
2) Albania, Serbia-Montenegro, Macedonia
3) Bosnia-Herzegovina, Croatia, Slovenia
4) Estonia, Lithuania, Latvia
5) Switzerland, Liechtenstein
6) Ukraine, Moldova

Cost-potential-curves for CSP in the total area of investigation are given in figure 4.2.3. A solar multiple of 3 was assumed for these curves. Other power plant configurations lead to different costs and different cost curves. No change in the technology was assumed for CSP; the potential stays the same until the year 2050.

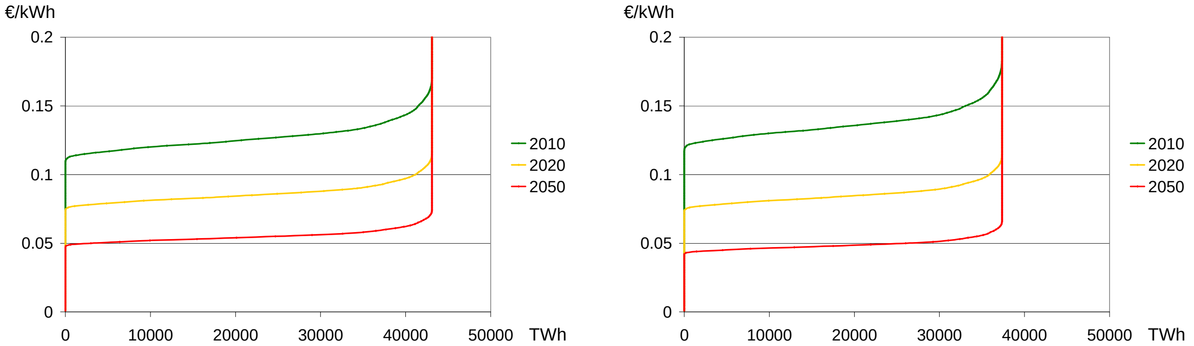

Figure 4.2.3: CSP cost-potential-curves for the area of investigation from 2010 to 2050. On the left: configuration with solar multiple 1 and no storage, on the right: configuration with solar multiple 3 and a storage capacity sufficient for 12 h of full load operation of the turbine. The configuration with solar multiple 3 enables medium load operation. It results in a lower overall potential because of storage losses and increased heat surplus.

4.3 Wind energy

4.3.1 Resource assessment

Wind is directional air movement in the atmosphere. It is caused by pressure differences that occur when air masses are warmed up unequally over the earth's surface. The kinetic power of the wind P_{kin}^{WIND} flowing through an area A normal to the wind direction can be calculated with the following equation:

$$P_{kin}^{WIND} = \frac{1}{2} \cdot \dot{m}_{wind} \cdot v_{wind}^2 = \frac{1}{2} \cdot \rho_{wind} \cdot A \cdot v_{wind}^3$$ eq. 16

where P_{kin}^{WIND} Kinetic power of the wind
$\dot{m}_{wind}$ Mass flux of the wind
v_{wind} Wind speed
ρ_{wind} Density of the air
A Area normal to the wind direction with mass $\dot{m}_{wind}$ flowing through it

Not all of the wind power can be extracted from the wind because the air mass must have kinetic energy left after passing a converter - it must keep flowing in order not to block the incoming air masses and thus reduce the extractable power. The share of the wind energy that can be extracted from the wind is called 'coefficient of performance' c_p. The theoretical maximum of c_p is at 59.3 % of the kinetic wind power (Betz' Law).

Wind is slowed down by friction when it has contact with the earth's surface. The shearing of the wind is the higher the more frequent and the higher the obstacles on the surface are. A known roughness of the surface can be used for calculating a wind speed profile from a wind speed measured at a known height. Given these parameters, the wind speed at an arbitrary height can be calculated with eq. 17.

$$v_{wind} = v_{wind,ref} \cdot \frac{\ln \frac{h}{h_{SR}}}{\ln \frac{h_{ref}}{h_{SR}}}$$ eq. 17

where $v_{wind,ref}$ Wind speed at reference height
h_{ref} Reference height
h Height for which the wind speed v_{wind} is calculated
h_{SR} Surface roughness

This relation is valid if no temperature or pressure anomalies are present. Because such anomalies can be present in reality, it is the more accurate the nearer the reference height is to the height for which the wind speed is to be calculated. Here, wind speed and surface roughness data from the German Weather Service (DWD 2007) at a height of 116 m were used for calculating wind speeds at different hub heights. A map with the averages of the wind speed in the investigation area is shown in figure 4.3.1. The average **onshore wind speed** in the total area is 6 m/s. The maximum country average occurs in Ireland with 8.5 m/s, the minimum country average occurs in Switzerland / Liechtenstein with 4.6 m/s. For **offshore wind speed**, the total area average is 7.9 m/s. Ireland has the maximum country average with 10.3 m/s and Bosnia-Herzegovina has the lowest country average with 5.9 m/s. Information for all countries in the investigation area are listed in table 10.1.2 in the annex.

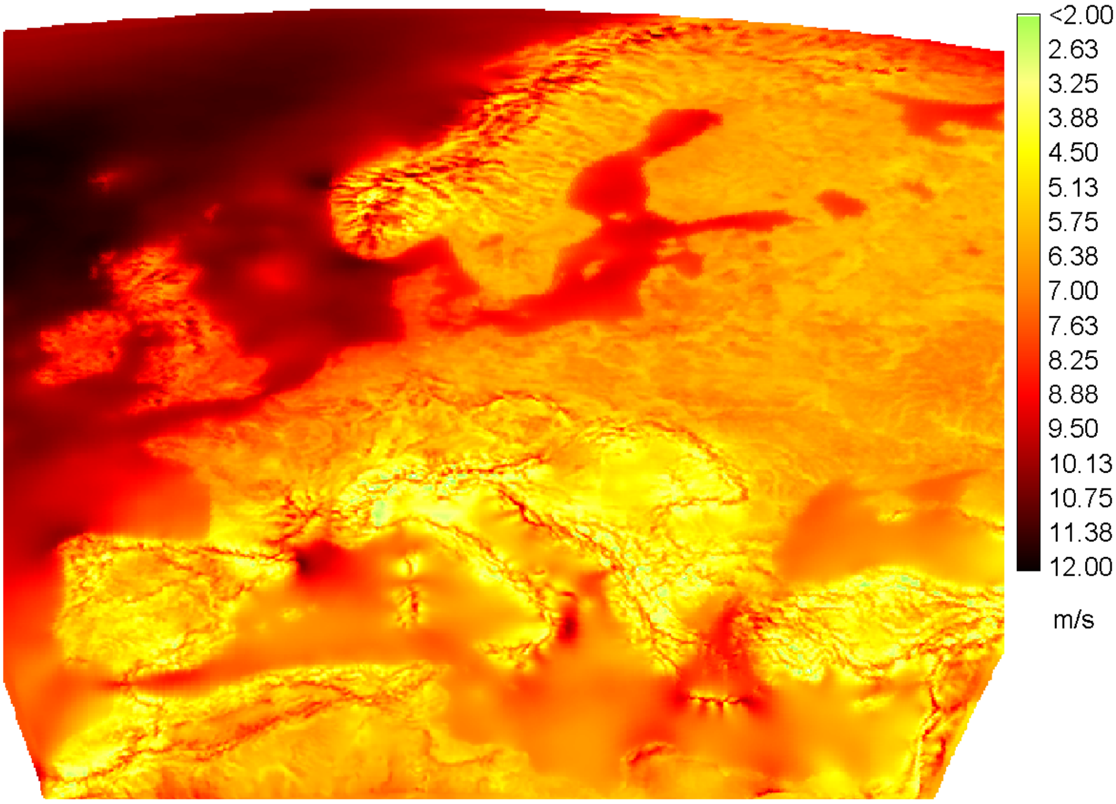

Figure 4.3.1: Average wind speed in the investigation area at a hub height of 116 m (annual integral), data from (DWD 2007).

4.3.2 Area availability

4.3.2.1 Onshore areas for wind energy use

In principle, wind energy can be used wherever wind is blowing and a wind turbine can be constructed. Apart from the adequacy of the building-ground, possible noise emissions and irritation of humans and animals are to be considered when defining areas adequate for using wind energy. Thus, sand dunes, protected areas, urban areas with a clearance of 1000 m and streets with a clearance of 500 m have been excluded from the analysis as well as the land cover categories 'inland water bodies and wetlands', 'snow and ice' and 'burnt areas'. This leaves the land cover categories 'bare areas', 'sparsely vegetated areas', 'grasslands', 'agricultural land', 'shrub cover', 'mosaic' and 'forest' for the erection of wind energy conversion plants. Considering competing uses such as agriculture and recreation, only a share of the technically usable area can actually be used. The area share f_{au}^{WIND} of actually usable area in the total base land cover area was set to 3 % for agricultural areas, grasslands, shrub cover, forests and mosaic based on (BMU 2004). For bare areas and sparsely vegetated areas, it was set to 33 % considering possible competition between wind energy use and solar energy use with PV or CSP plants in North Africa.

4.3.2.2 Offshore areas for wind energy use

At sea the surface roughness is smaller than on shore and wind speed at a given height consequently is higher. As given in eq. 16, the wind power is proportional to the cubed wind speed, making it economically interesting to make this offshore resource accessible. The main restriction for technical feasibility of offshore wind energy use is the water depth. Offshore wind parks have already been built on concrete or steel basements at water depths below 50 m, but this gets much more expensive with increasing depth. Similar to oil and gas platforms, floating foundations are possible for wind turbines. They offer the opportunity to install wind turbines in water depths between 100 and 300 m without significant cost differences between the two water depths (Tong 1998). At Karmøy in Norway a floating 2.3 MW wind turbine was installed at a water depth of about 220 meters (SIEMENS 2009). The operators announced the concept to be applicable at water depths of up to 700 m.

For the analysis of wind power electricity generation potentials the water depth at which wind turbines can be installed was limited to 300 m. Of the remaining areas, an area share f_{au}^{WIND} of 16 % was set in agreement with (BMU 2010). The maximum distance from shore was set to 200 nautical miles according to the outer border of the exclusive economic zones of countries (VLIZ 2006). A clearance from the shore of 5000 m, maritime wetlands and protected areas were excluded from the analysis.

4.3.3 Energy conversion

4.3.3.1 Technology

The energy of the wind can be captured using drag and/or lift. The drag principle has a lower theoretical efficiency. Most wind power plants today deploy the lift principle. They convert the kinetic energy of the wind into mechanical energy of rotor blades rotating around a horizontal axis. The mechanical energy is then converted into electricity with a generator.

Most wind turbines start rotating from a start-up wind speed of 2 - 3 m/s with a low coefficient of performance c_p that increases with wind speed. At nominal output capacity of the electricity generator, the power extracted from the wind is limited so that even at higher wind speeds, the generator would not be overloaded. At a specific cut-off wind speed, the mechanic stress of the whole plant becomes so big that power extraction is regulated down and the rotor is turned out of the main wind direction in order to protect it from damages. The power extraction from the wind can be regulated by either the stall (rotor blade design makes the wind stall above a specific wind speed) or the pitch approach (rotor blades are rotated along their centrelines in order to control the lift forces). Modern wind power plants are regulated down over a certain interval of wind speeds until the rotor is completely turned out of the wind and the electricity generation is stopped.

The power curve of a wind power plant is its power output plotted against the wind speed. As a basis for calculating the potential power output at given wind speeds, the power curve of the ENERCON E82 (ENERCON 2007) wind turbine with a rotor diameter of 82 m was used. The start-up wind speed is 2 m/s, nominal power output is reached at 12 m/s. Cut-off was set to start at 25 m/s and to end at 35 m/s, with a linear decrease in between these two wind speeds. The resulting power curve is shown in figure 4.3.2.

The technical development until the year 2050 was assumed to result in higher nominal power output. The same coefficients of performance and the same wind speeds for start-up, reaching nominal capacity, start and end of cut-off were used for the higher power outputs. The rotor diameters d_{rot}^{WIND} were chosen so as to match the respective nominal power output at the wind speed of 12 m/s. Hub heights h_{hub}^{WIND} were assumed to increase as well. The values for d_{rot}^{WIND} and h_{hub}^{WIND} are listed in table 4.3.1.

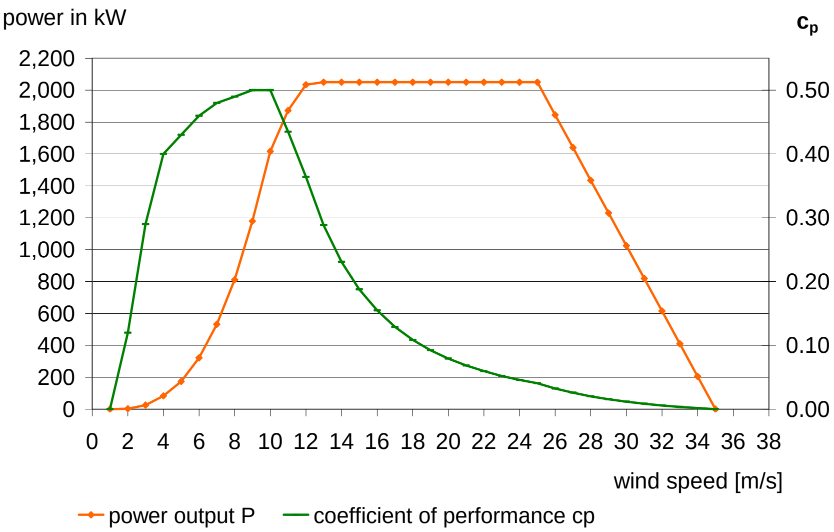

Figure 4.3.2: Power curve for analysing the wind power electricity generation potential, based on (ENERCON 2007).

When wind turbines are grouped in wind parks, losses due to shading and losses in the cables linking the wind turbines to the grid occur. Technical blackout times and time for maintenance were taken into account by an overall availability factor f_{av}^{WIND} (Kuehn 2008). The values for the loss factor f_{loss}^{WIND} and the availability factor f_{av}^{WIND} are also given in table 4.3.1.

Table 4.3.1: Technical parameters of wind power plants. Based on (Kaltschmitt, Wiese et al. 2003), (Kuehn 2008).

	Symbol	Unit	2010	2020	2050
Onshore wind turbines					
Nominal capacity	$P_{nom}^{WIND\_ON}$	kW	1950	3400	5500
Hub height	$h_{hub}^{WIND\_ON}$	m	112	122	132
Rotor diameter	$d_{rot}^{WIND\_ON}$	m	77.47	102.29	130.1
Distance factor	$f_{dist}^{WIND\_ON}$	-	6	6	6
Area-specific installable capacity	$p_{inst,max}^{WIND\_ON}$	kW/km2	10422	10423	10423
Losses: shading, cables	$f_{loss}^{WIND\_ON}$	-	0.15	0.15	0.15
Availability factor	$f_{av}^{WIND\_ON}$	-	0.95	0.95	0.95
Offshore wind turbines					
Nominal capacity	$P_{nom}^{WIND\_OFF}$	kW	3000	6000	12000
Hub height	$h_{hub}^{WIND\_OFF}$	m	80	102	140
Rotor diameter	$d_{rot}^{WIND\_OFF}$	m	96.09	135.89	192.17
Distance factor	$f_{dist}^{WIND\_OFF}$	-	6	6	6
Area-specific installable capacity	$p_{inst,max}^{WIND\_OFF}$	kW/km2	10422	10422	10423
Losses: shading, cables	$f_{loss}^{WIND\_OFF}$	-	0.15	0.15	0.15
Availability factor	$f_{av}^{WIND\_OFF}$	-	0.95	0.95	0.95

In order to calculate the nominal output capacity that can be installed on a usable base area of known size, the distance between the wind turbines must be defined. The bigger the distance is, the lower the losses through turbulence emissions and the higher the yield per wind turbine are. On the other hand higher distances mean lower absolute numbers of turbines, lowering the potential wind energy yield from a defined area. The distance between the turbines is given as a multiple of the rotor diameter, the so called distance factor f_{dist}^{WIND}. According to (Kaltschmitt, Wiese et al. 2003), values for f_{dist}^{WIND} lie between 6 and 15 when no wind direction is prevalent and with a prevalent wind direction, f_{dist}^{WIND} is chosen between 8 and 10 in the prevalent wind direction and between 4 and 5 normal to it, resulting in a much denser formation. When areas are rare, smaller distance factors are sometimes chosen. Here, f_{dist}^{WIND} was set to 6 without distinguishing between different wind directions. The area that one wind turbine occupies can be calculated from eq. 18 (Kaltschmitt, Wiese et al. 2003).

$$A_{turb}^{WIND} = \sqrt{\frac{3}{4}}\left(f_{dist}^{WIND} \cdot d_{rot}^{WIND}\right)^2 \qquad \text{eq. 18}$$

where A_{turb}^{WIND} Area occupied by one wind turbine
f_{dist}^{WIND} Distance factor
d_{rot}^{WIND} Rotor diameter

The area-specific installable output capacity $p_{inst,\max}^{WIND}$ is calculated by dividing the nominal output capacity of one turbine P_{nom}^{WIND} by the area it occupies.

$$p_{inst,\max}^{WIND} = \frac{P_{nom}^{WIND}}{A_{turb}^{WIND}} \qquad \text{eq. 19}$$

The maximum installable capacity in a raster cell can be calculated from the area-specific capacity, the area of the raster cell, the share of the base area in the raster cell and the usable area share:

$$P_{inst,\max,RC}^{WIND} = A_{RC} \cdot f_{lc}^{WIND} \cdot f_{au}^{WIND} \cdot p_{inst,\max}^{WIND} \qquad \text{eq. 20}$$

where $P_{inst,\max,RC}^{WIND}$ Maximum installable wind turbine capacity in a raster cell
A_{RC} Area of the raster cell
f_{lc}^{WIND} Share of base-area landcover in the raster cell
f_{au}^{WIND} Usable area share

For each raster cell the power output $P_{\max,RC}^{WIND,time}$ is calculated according to eq. 21.

$$P_{\max,RC}^{WIND,time} = \frac{1}{2} \cdot \rho_{wind} \cdot A_{rot}^{WIND} \cdot v_{wind}^3 \cdot c_p\left(v_{wind}\right) \cdot (1 - f_{loss}^{WIND}) \cdot f_{av} \cdot \frac{P_{inst,\max}^{WIND}}{P_{nom}^{WIND}} \qquad \text{eq. 21}$$

where $time$ Time step index
$P_{\max,RC}^{WIND,time}$ Power output of the maximum installable capacity in a raster cell
ρ_{wind} Density of the air
v_{wind} Wind speed
$c_p(v_{wind})$ Coefficient of performance, depending on wind speed
A_{rot}^{WIND} Area swept over by the rotor blades
f_{loss}^{WIND} Loss factor
f_{av}^{WIND} Availability factor (accounting for maintenance times and technical blackouts)

The annual integral of the power output of the maximum installable wind power capacity $P_{\max,RC}^{WIND,time}$ over a whole year is the annual electricity generation potential in the raster cell.

4.3.3.2 Costs

Economic parameters for wind power plants for the year 2010 and anticipated values for the years 2020 and 2050 were taken from (BMU 2010). They are listed in table 4.3.2. Levelised electricity costs and cost potential curves were calculated as described in chapter 4.1.3.2.

Table 4.3.2: Economic parameters of on- and offshore wind power plants, based on (BMU 2010). All costs in $€_{2009}$.

	Symbol	Unit	2010	2020	2050
Onshore wind turbines					
Investment costs	$c_{inv}^{WIND\_ON}$	€/kW	1160	1030	900
Fixed operation costs[1)]	$f_{c\_fixop}^{WIND\_ON}$	-	0.04	0.04	0.04
Fixed operation costs (absolute)	-	€/kW	46	41	36
Variable operation costs	$c_{\mathrm{var}op}^{WIND\_ON}$	€/kWh	0	0	0
Life-time	N^{WIND_ON}	a	18	18	18
Offshore wind turbines					
Investment costs	$c_{inv}^{WIND\_OFF}$	€/kW	3300	2100	1300
Fixed operation costs[1)]	$f_{c\_fixop}^{WIND\_OFF}$	-	0.055	0.055	0.055
Fixed operation costs (absolute)	-	€/kW/a	182	116	72
Variable operation costs	$c_{\mathrm{var}op}^{WIND\_OFF}$	€/kWh	0	0	0
Life-time	N^{WIND_OFF}	a	18	18	18

1) Annual share in investment costs

4.3.4 Potentials

4.3.4.1 Onshore wind potentials

In the investigation area, the total onshore wind electricity generation potential calculated with the given parameters and restrictions is 8819 (9068; 9298) TWh/a in the year 2010 (2020; 2050). This is ca. 2.2 (2.0; 1.7) times as much as the respective annual electric power demand in the investigation area.

Table 4.3.3: Installable onshore wind turbine capacities and annual electricity generation potentials in the investigation area.

	1)	Max. Installable Capacity $P_{inst,max}$ in GW	Annual electricity generation potential in TWh/a		1)	Max. Installable Capacity $P_{inst,max}$ in GW	Annual electricity generation potential in TWh/a
AL_CS_MK [2)]	1	40	51	Malta	1	0	0
BA_HR_SI [3)]	1	30	45	Netherlands	1	5.1	15
Austria	1	15	24	Norway	1	68	173
Belgium	1	3.5	9.8	Poland	1	59	122
Bulgaria	1	24	33	Portugal	1	22	35
Cyprus	1	2.2	2.8	Romania	1	48	64
Czech Republic	1	14	26	Spain	1	131	217
Denmark	1	7.5	24	Sweden	1	90	180
Ireland	1	13	47	CH, LI [5)]	1	7	9
EE_LT_LV [4)]	1	35	82	Turkey	0.80	244	372
Finland	1	69	137	UK	1	36	121
France	1	109	237	U_MD [6)]	1	160	316
Germany	1	55	123	Belarus	1	52	103
Greece	1	29	45	Algeria	0.31	1427	2911
Hungary	1	19	24	Morocco	0.73	435	721
Italy	1	61	88	Tunisia	0.99	308	542
Slovakia	1	8.4	12	Libya	0.18	979	1893
Luxembourg	1	0.3	0.8	Egypt	0.13	262	493
				Total Area		***4869***	***9298***

1) Share of the region lying within the modelling domain
2) Albania, Serbia-Montenegro, Macedonia
3) Bosnia-Herzegovina, Croatia, Slovenia
4) Estonia, Lithuania, Latvia
5) Switzerland, Liechtenstein
6) Ukraine, Moldova

The maximum ratio of the onshore wind electricity generation potential to the electric power demand occurs in Libya. It amounts 78 (68; 43) in the year 2010 (2020; 2050). For the year 2050, the maximum installable capacities and the annual electricity generation potentials of the single regions are listed in table 4.3.3. The respective values for all years can be found in tables 10.1.5 - 10.1.10 in annex 10.1. The distribution of the year 2050 wind power generation potential in MWh/km^2/a is shown in figure 4.3.3.

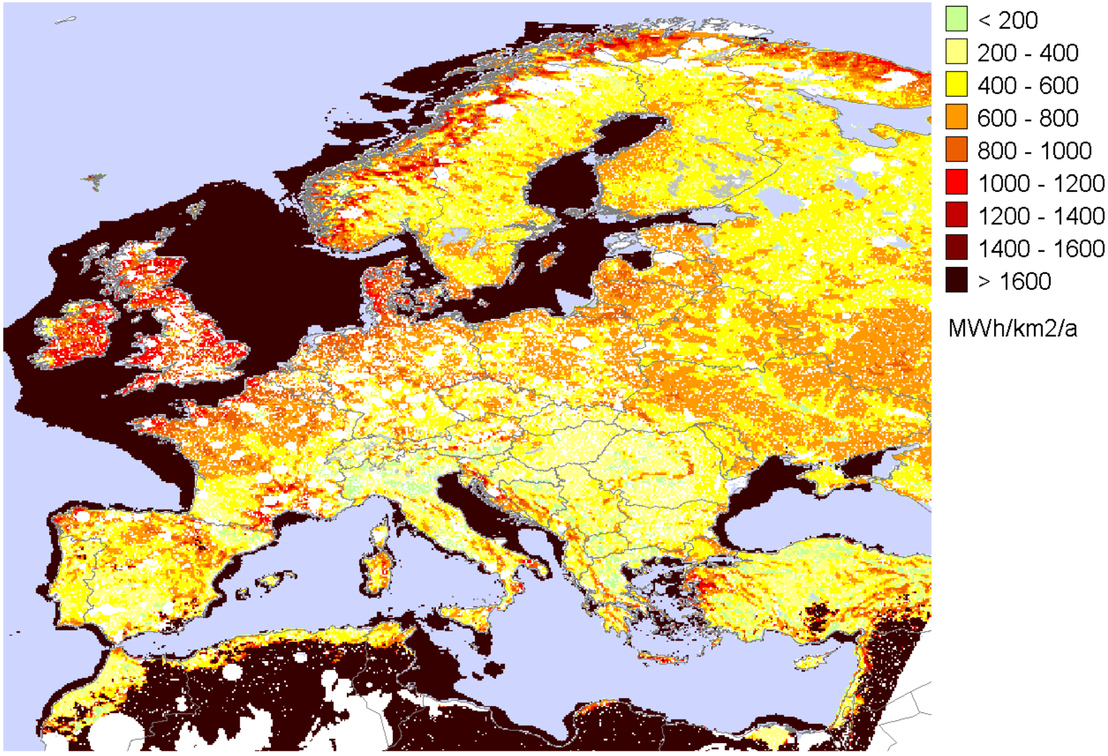

Figure 4.3.3: Wind onshore electricity generation potential in MWh/km^2/a (annual integral, year 2050). Unusable areas are excluded and competing area use is taken into account, i.e. the energy density in each raster cell equals the maximum net energy yield multiplied with an area use factor and the share of usable land cover in the raster cell area.

4.3.4.2 Offshore wind potentials

The total offshore wind electricity generation potential in the investigation area calculated with the given parameters and restrictions is 12046 (12336; 12662) TWh/a in the year 2010 (2020; 2050). This is ca. 3 (2.7; 2.3) times as much as the respective annual electric power demand in the investigation area. The maximum ratio of the offshore wind electricity generation potential to the electric power demand occurs in Ireland with 32 (28; 30). For the year 2050, the maximum installable capacities and the annual electricity generation potentials of the single regions are listed in table 4.3.4. The respective values for all years can be found in tables 10.1.5 - 10.1.10 in annex 10.1. The distribution of the year 2050 offshore wind power generation potential in MWh/km^2/a is shown in figure 4.3.4.

Table 4.3.4: Installable offshore wind turbine capacities and annual electricity generation potentials in the investigation area.

	1)	Max. Installable Capacity $P_{inst,max}$ in GW	Annual electricity generation potential in TWh/a		1)	Max. Installable Capacity $P_{inst,max}$ in GW	Annual electricity generation potential in TWh/a
AL_CS_MK [2)]	1	15	37	Malta	1	21	62
BA_HR_SI [3)]	1	60	112	Netherlands	1	92	400
Austria	1	0	0	Norway	1	386	1640
Belgium	1	5.6	24	Poland	1	50	168
Bulgaria	1	19	46	Portugal	1	38	103
Cyprus	1	1.8	3.1	Romania	1	25	68
Czech Republic	1	0	0	Spain	1	104	263
Denmark	1	125	535	Sweden	1	223	811
Ireland	1	224	1017	CH, LI [5)]	1	0	0
EE_LT_LV [4)]	1	94	350	Turkey	0.80	55	104
Finland	1	97	377	UK	1	831	3691
France	1	253	918	U_MD [6)]	1	119	312
Germany	1	72	310	Belarus	1	0	0
Greece	1	93	245	Algeria	0.31	10	18
Hungary	1	0	0	Morocco	0.73	49	100
Italy	1	165	320	Tunisia	0.99	116	271
Slovakia	1	0	0	Libya	0.18	125	287
Luxembourg	1	0	0	Egypt	0.13	42	68
				Total Area		***3511***	***12662***

1) Share of the region lying within the modelling domain
2) Albania, Serbia-Montenegro, Macedonia
3) Bosnia-Herzegovina, Croatia, Slovenia
4) Estonia, Lithuania, Latvia
5) Switzerland, Liechtenstein
6) Ukraine, Moldova

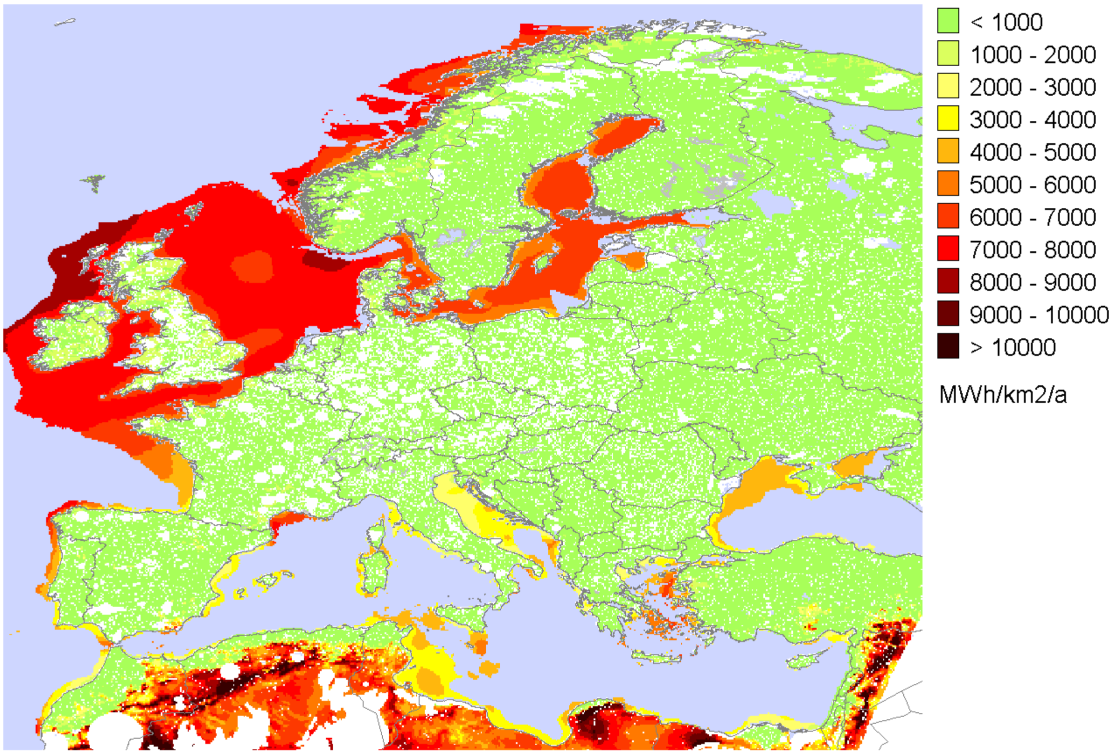

Figure 4.3.4: Offshore wind electricity generation potential in MWh/km^2/a (annual integral, year 2050). Unusable areas (offshore protected areas) are excluded and competing area use is taken into account, i.e. the energy density in each raster cell equals the maximum net energy yield multiplied with an area use factor.

Figure 4.3.5 shows the annual course of the total hourly mean power output of onshore and offshore wind turbines in the investigated area in GW. Onshore as well as offshore, more wind energy is available in the winter than in the summer. The potential hourly mean power output of the installable onshore wind turbines with a total capacity of 4869 GW ranges between 304 and 2754 GW. The potential hourly mean power output of the installable offshore wind turbines with a total capacity of 3511 GW ranges between 366 and 2576 GW. The minimum power that is available onshore equals 6.2 % of the installable capacity. Offshore, the minimum power available equals 10.4 % of the installable capacity.

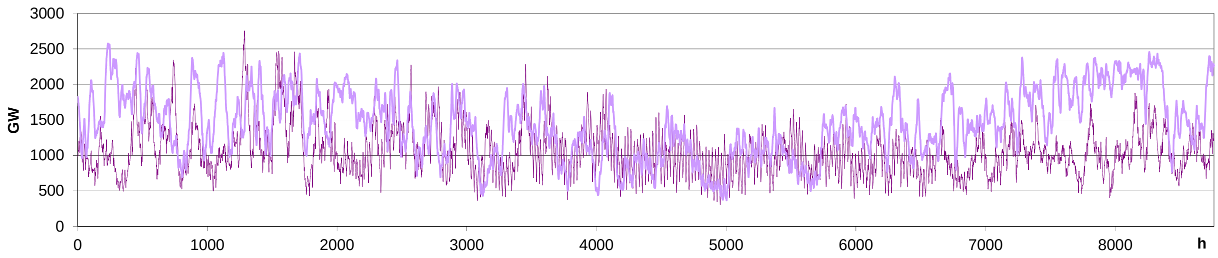

Figure 4.3.5: Annual course of the total hourly mean power output of onshore (dark purple) and offshore (light purple) wind turbines in the investigated area in GW.

Figure 4.3.6 shows the cost-potential-curves for wind onshore and wind offshore power in the total area of investigation. The cost reduction until the year 2050 is bigger for wind offshore power, for this technology is not yet as far developed as the wind onshore power generation technology and the remaining cost reduction potentials are thus bigger.

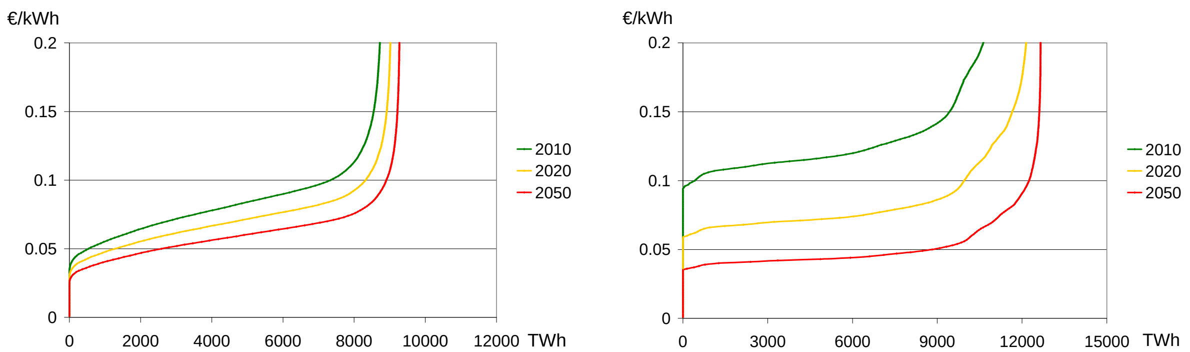

Figure 4.3.6: Wind cost-potential-curves for the area of investigation from 2010 to 2050. On the left: wind onshore potentials, on the right: wind offshore potentials.

4.4 Hydro power

4.4.1 Resource assessment

The earth's water is present in oceans (97 %), as ground water (1.7 %), glaciers (1.74 %) and surface water (0.0132 %). 0.001 % of the earth's water is present in the atmosphere. The water changes between different aggregate states continuously and it can be moved by wind, currents and gravity. The cycle of precipitation and evaporation is called the hydrological cycle. When water is moved in the atmosphere and the precipitation takes place over land, some of the water infiltrates the soil and forms groundwater, some of it is evaporated and some of it forms surface runoff. When surface runoff and groundwater resurfacing in springs accumulate in channels, they form so-called channel runoff in rivers, streams and other channels. About 0.0002 % of the water is present in such channels. Its potential energy can be used for electricity generation in run-of-river or in reservoir hydro power plants. The power of water P_{hydro} can be calculated from

$$P_{hydro} = \rho_{H2O} \cdot Q \cdot g \cdot \Delta h \qquad \text{eq. 22}$$

where
ρ_{H2O} Density of the water
Q Discharge in m^3/s
g Acceleration due to gravity
Δh Drop height

Drop height and discharge information are needed in order to calculate the amount of hydro power available at a specific site. The drop height can be assumed to be the difference in geodetic height if pressure and velocity differences are neglected. The discharge of the channel runoff can be measured or it can be modelled. It depends on the surface runoff, precipitation, soil structure, slope of the surfaces, temperature, vegetation and other parameters. Information on the spatial distribution of discharge were taken from (Lehner, Czisch et al. 2005), where the gross hydro power potential on a global scale grid was calculated for grid cells with the drop height assumed to be the average height difference between a grid cell and the surrounding grid cells to which water is discharged.

4.4.1.1 Installable capacities and electricity generation potentials

In order to assess the technical hydro power potential, the degree to which the theoretical potential can be utilized would have to be analysed. This degree depends on local geographical and political conditions and on competing uses of waterways. The analysis of these local conditions would be too substantial for this study. Furthermore, in many countries in the investigation area, hydro power potentials are already developed to a high degree. Thus, instead of deriving technical potentials from the gross hydro power potential, information on existing power plants and on maximum installable capacities were used for the analysis of hydro power potentials. Some information were available from a database with geographical coordinates, type (run-of-river or reservoir) and the electric nameplate capacity (PowerVision, (PLATTS 2008)) of individual power plants. These data are incomplete: they only cover hydro power plants with a capacity of more than 5 MW and probably some of the bigger power plants might be missing. In some countries the total capacity of the plants listed in the PowerVision database differs by a multiple from the capacities listed in the ‘2007 Survey of Energy Resources’ by the World Energy Council (WEC 2007). The PowerVision data were complemented with total country values for installed capacities at the end of the year 2005, taken from (WEC 2007). This study also contains information about the annual electricity generation in 2007 and maximum installable capacities in each country in the investigation area, but no information about the number of power plants and no distinction between run-of-river and reservoir power plants. In order to keep the assumptions conservative, the installed capacities for which no type information was available were all considered to be run-of-river type plants, since these are not dispatchable and thus no function in the supply system is allowed for in the optimisation model that can not be met.

Country averages of the full load hours of a power plant were derived from the installed capacities and the annual generation values in (WEC 2007). The country aggregates of run-of-river and reservoir power plants taken from the PowerVision database, the total installed capacities, the maximum installable capacities and the full load hours derived from the WEC data are listed in table 4.4.1.

Table 4.4.1: Installable hydro power capacities and annual full load operating hours in the investigation area (sources: PLATTS (PLATTS 2008) and WEC (WEC 2007))

	Run-of-river capacity in MW (PLATTS)	Reservoir capacity in MW (PLATTS)	Total (run-of-river + reservoir) capacity in MW (PLATTS)	Total capacities in operation in MW (WEC)	Maximum installable capacities in MW (WEC)	Full load hours (derived from WEC)
AL_CS_MK [1)]	286	0	286	4857	11385	3426
BA_HR_SI [2)]	320	665	985	5446	14802	2837
Austria	6076	2604	8680	11811	22702	3304
Belgium	101	0	101	95	95	2537
Bulgaria	1926	0	1926	2874	12728	1178
Cyprus[6)]	0	0	0	1	12000 / 1 [6)]	2000
Czech Republic	201	638	839	1019	1698	2356
Denmark	6	0	6	11	11	2091
Ireland	93	118	211	249	389	2570
EE_LT_LV [3)]	1588	0	1588	1670	2673	3321
Finland	2393	573	2966	3000	5074	4533
France	7022	11906	18928	25526	45384	2203
Germany	3719	332	4051	4525	4084	6122
Greece	2958	0	2958	3060	9329	1608
Hungary	64	0	64	55	2146	3727
Italy	7101	2272	9373	17326	50440	2082
Slovakia	1553	161	1714	2547	3851	3812
Luxembourg	20	0	20	39	39	2462
Malta	0	0	0	0	0	0
Netherlands	35	0	35	38	38	2316
Norway	19421	8661	28082	27698	40613	4925
Poland	1634	151	1785	850	6093	2298
Portugal	971	2345	3316	4818	23535	1062
Romania	5571	0	5571	6346	11049	3168
Spain	2206	12676	14882	18674	53090	1243
Sweden	15389	804	16193	16100	22330	4478
CH, LI [4)]	4359	6345	10704	13356	19062	2256
Turkey	0	672	672	12788	78774	2742
UK	1370	24	1394	1513	915	3279
U_MD [5)]	0	0	0	4796	9415	2655
Belarus	0	0	0	12	1500	2000
Algeria	0	0	0	275	2477	2018
Morocco	0	0	0	1498	4690	1066
Tunisia	0	0	0	62	62	2339
Libya	0	0	0	0	0	0
Egypt	0	0	0	2850	11270	4436
Total Area	86383	50947	137330	195785	483742 / 363743 [6)]	

1) Albania, Serbia-Montenegro, Macedonia
2) Bosnia-Herzegovina, Croatia, Slovenia
3) Estonia, Lithuania, Latvia
4) Switzerland, Liechtenstein
5) Ukraine, Moldova
6) WEC indicates an installable capacity of 12000 MW in Cyprus. This value seemed too high and could not be validated by other studies. The maximum installable capacity was set to the capacity in operation.

Capacities can be increased not only by building new hydro power plants but also by modernisation. Replacing old turbines with new, more efficient ones is a cost-efficient way of increasing the hydro power potential. It was assumed that the installed capacity can be increased by 15 % through modernisation, that power plants must be modernised latest after their lifetime of 60 years and that the first generation of power plant reaches the age of 60 in the year 2007. In the year 2010, 4/60 of the power plants would have been modernised and 56/60 would still be in operation in their original state. According to this assumption, all power plants will have been modernised in the year 2066, reaching the potential given in (WEC 2007).

Distinguishing between two types of power plants – run-of-river and reservoir – and between the three categories 'old' (capacity in operation in 2007 without modernised plants), modernised (fraction of old capacity modernised) and new power plants would result in six technology categories to be considered in the energy system model, increasing the already high running times. In order to lower the model running times, some technologies were aggregated. As a conservative assumption, new plants were all considered to be run-of-river plants. Furthermore, the categories 'old' and 'modernised' plants were aggregated for both power plant types each in order to reduce the number of technologies to be considered in the energy system model and thus the running times. This leaves three hydro power technology categories as input into the energy system model: old plus modernised run-of-river power plants, new run-of-river power plants and old plus modernised reservoir power plants.

The shares of old and modernised power plants in the total capacity changes with time because of the modernisation of old plants. The decommissioning factor f_{decom}^{HYDRO} and the modernisation factor f_{mod}^{HYDRO} are given for the different power plant categories and investigation years in table 4.4.2.

The total annual electricity generation potential was calculated from the installed capacities and the country-specific full load hours derived from (WEC 2007). The total installable capacities and electricity generation potentials for all years are listed in tables 10.1.5 - 10.1.10 in the annex.

4.4.1.2 Temporal disaggregation

The temporal characteristic of the river discharge depends on meteorological and geological conditions in the catchment area of a river. No model of the river discharge could be developed in the scope of this study; measured daily average discharge data were used instead for generating a time-curve for the temporal disaggregation of the hydro power potentials. Such data are provided by the Global Runoff Data Centre (GRDC) for 7362 measurement stations worldwide (GRDC 2008). The data sets of 786 stations in the investigation area were available for the assessment of the temporal characteristics of the hydro power electricity generation potential. The distribution of the measurement stations is shown in figure 4.4.1.

Figure 4.4.1: Discharge measurement stations. Source: (GRDC 2008).

The time span for which measurements exist varies from station to station. For the available data, it lies between 1812 and 2007. Sometimes measurements are lacking. For the generation of discharge time-curves for the temporal disaggregation of the hydro power potentials, only discharge measurements from after 1980 were chosen in order to obtain a time-curve as up to date as possible. For each day of the year and each station, the average daily discharge was calculated from all valid measurements available from that station.

A standardization of all daily averages results in a time curve that can represent the temporal generation characteristics of a power plant that is designed to use even the highest discharge that occurs in a river. This was considered appropriate for reservoir hydro power plants that collect the inflow and use it when needed, assuming that the reservoirs are dimensioned big enough to fulfil that task. The time curve for the inflow into hydro reservoirs was thus calculated by standardizing all daily average discharge values.

However, in a run-of-river hydro power plant the inflow can only be converted into electricity immediately or it can be discharged unused. The dimensioning of the turbine is an economic optimisation task that takes into account the discharge available and the costs of the turbine. Therefore, run-of-river hydro power stations are dimensioned such as to use only a part of the discharge. Their full load hours can be used as a measure for how much of it they use. A standardized time curve was derived from the daily discharge data and a design discharge by performing the following iteration, i.e. searching for the design discharge with which the country specific full load hours are reached and generating the daily time curve factors at the same time:

$$while(\sum_{d=1}^{365}\left(f_{TC}^{HYDRO\_RR}(d)\right)>1)\{Q_D+=0.1;\}$$
$$f_{TC}^{HYDRO\_RR}(d)=\frac{(MIN(Q(d);Q_D)\cdot 24}{Q_D\cdot h_{fl}} \quad \text{eq. 23}$$

where $f_{TC}^{HYDRO\_RR}(d)$ Time curve factor of day d
$Q(d)$ Day-average discharge at day d in m^3/s
Q_D Design-discharge in m^3/s
h_{fl} Full load hours

To each grid cell in the investigation area the time curve of the nearest GRDC measurement station was assigned. Due to this, streams might be assigned non-fitting discharge regimes where the nearest measurement station is that of a side arm coming in. At the same time, side arms of large rivers are assigned the stream's discharge regime instead of a local regime if the measurement station of the large river is nearer to the side arm than its own measurement station or if there is none at all. A solution to this problem would be to use gridded discharge data for the generation of the time curve, but such data were not available when this analysis was conducted. Gridded (monthly) runoff regimes were available, but these would only have turned the problem around: then a stream would be assigned a local (surface) runoff regime that does not necessarily coincide with the course of the discharge of the river. Gridded discharge information will hopefully be available soon and will be used for improving the database.

4.4.2 Spatial distribution

The data taken from (PLATTS 2008) include capacities and geographical coordinates of the power plants. All categories without given coordinates were distributed using the gross hydro power potential as a proxy parameter. No areas were explicitly excluded.

4.4.3 Energy conversion

4.4.3.1 Technology

The two hydro power plant types ‘run-of-river’ and ‘reservoir’ differ in that the reservoir plants consist of a power conversion unit and a reservoir while the run-of-river plants are lacking a reservoir. The reservoir enables temporal separation of the discharge of a river and the generation of electricity, making a reservoir power plant dispatchable.

Since no bottom-up analysis of the hydro power electricity generation potentials based on the gross theoretical hydro power potentials was done, no power plant model was applied. The only technical parameters used are the full load hours and the storage size in relation to the turbine size, $f_{storage2power}^{hydro\_res\_gen\_type}$. The full load hours were derived from the installed capacities and generation potentials in (WEC 2007). They are given for each country in table 4.4.1. The reservoir size was derived from (Lehner, Czisch et al. 2005), where storage capacity and turbine capacities were evaluated for different countries. The ratio of the storage size to the turbine capacity varies between 214 h and 2390 h in the different countries evaluated in (Lehner, Czisch et al. 2005), the average is at 1034 h. No comprehensive data could be found for all countries in the area investigated here. The ratio was set to 1000 h for all countries in the present study.

4.4.3.2 Costs

Table 4.4.2 shows the economic parameters for the three hydro power categories: old, modernised and new plants. The values were chosen based on (BMU 2010). The costs of new plants are increasing because it was assumed in (BMU 2010) that locations for large hydro power plants become rare and more smaller pants with higher costs are built.

Table 4.4.2: Economic parameters of hydro power plants, based on (BMU 2010). All costs in $€_{2009}$.

	Symbol	Unit	2010	2020	2050
Old hydro power plants (run-of-river and reservoir)					
Decommissioning factor (share of capacity still in original state)	f_{decom}^{HYDRO}		0.93	0.77	0.27
Investment costs	$c_{inv}^{HYDRO,old}$	€/kW	4000	4000	4000
Fixed operation costs (percentage of investment costs)	$f_{c\_fixop}^{HYDRO,old}$	-	0.05	0.05	0.05
Fixed operation costs (absolute)	-	€/kW/a	200	200	200
Variable operation costs	$c_{\mathrm{var}op}^{HYDRO,old}$	€/kWh	0	0	0
Life-time	$N^{HYDRO,old}$	a	60	60	60
Modernised hydro power plants (run-of-river and reservoir)					
Power increment through modernisation	f_{mod}^{HYDRO}	-	0.15	0.15	0.15
Investment costs	$c_{inv}^{HYDRO,\mathrm{mod}}$	€/kW	1386	1452	1540
Fixed operation costs (percentage of investment costs)	$f_{c\_fixop}^{HYDRO,\mathrm{mod}}$	-	0.1	0.1	0.1
Fixed operation costs (absolute)	-	€/kW/a	139	145	154
Variable operation costs	$c_{\mathrm{var}op}^{HYDRO,\mathrm{mod}}$	€/kWh	0	0	0
Life-time	$N^{HYDRO,\mathrm{mod}}$	a	60	60	60
New hydro power plants (run-of-river)					
Investment costs	$c_{inv}^{HYDRO,new}$	€/kW	4662	4778	4820
Fixed operation costs[1)]	$f_{c\_fixop}^{HYDRO,new}$	-	0.05	0.05	0.05
Fixed operation costs (absolute)	-	€/kW/a	233	239	241
Variable operation costs	$c_{\mathrm{var}op}^{HYDRO,new}$	€/kWh	0	0	0
Life-time	$N^{HYDRO,new}$	a	60	60	60

1) Annual share in investment costs

For the category ‘old and modernised hydro power plants’ in the linear optimisation model, the costs were calculated from the investment costs of old and modernised plants weighted with the shares of old and modernised power plants in the investigated year. Levelised electricity costs and cost potential curves were calculated as described in chapter 4.1.3.2.

4.4.4 Potentials

The installable capacities and the electricity generation potentials of the total hydro power potential in the investigation area are listed in tables 10.1.5 - 10.1.10 in the annex.

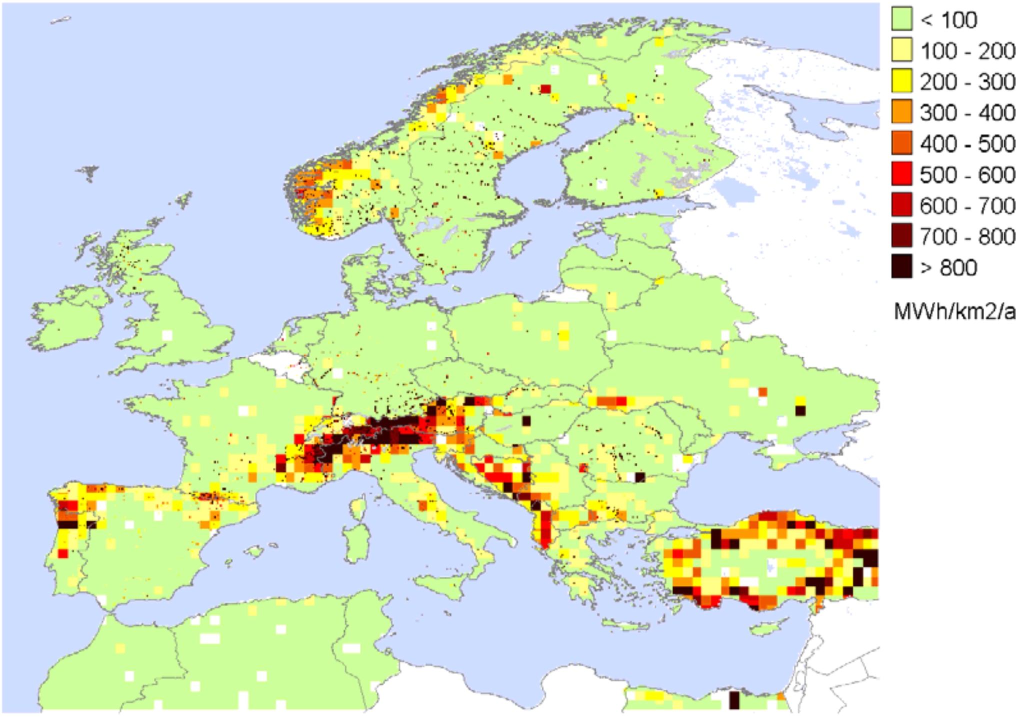

Figure 4.4.2: Run-of-river hydro power generation potential in the investigation area in MWh/km^2/a.

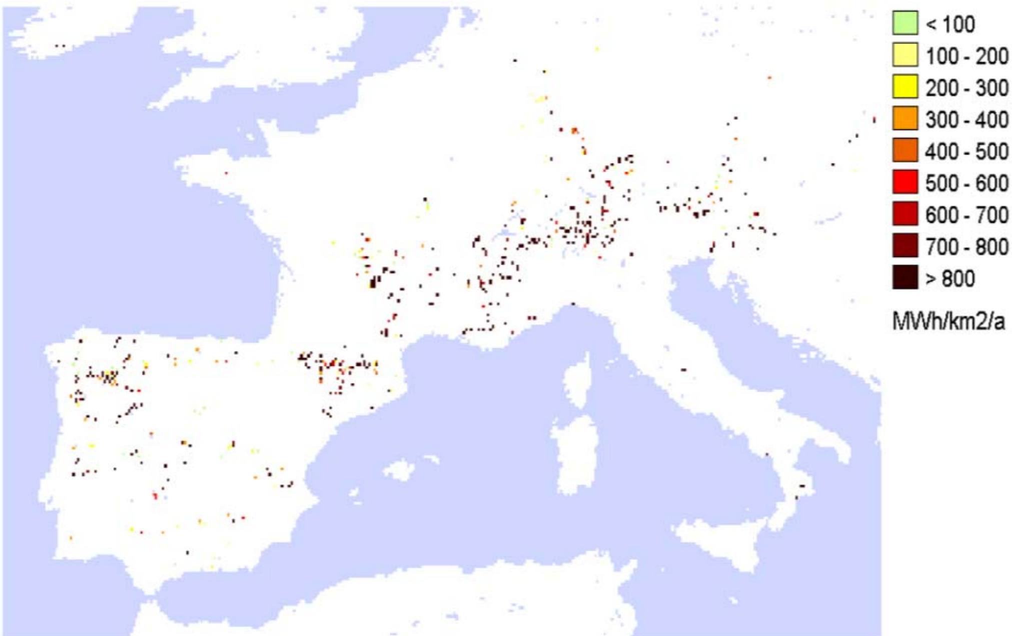

Figure 4.4.3: Reservoir hydro power generation potential in south-west Europe in MWh/km^2/a.

Figure 4.4.2 is a map of the total run-of-river electricity generation potential and figure 4.4.3 shows the reservoir hydro power generation potential in the year 2050. For better visibility, only the south-west of Europe is shown where much of the reservoir hydro potential is located.

Figure 4.4.4 shows cost-potential-curves for all run-of-river hydro power plants and for reservoir hydro power plants. In both cases, the total potential gets bigger through modernisation.

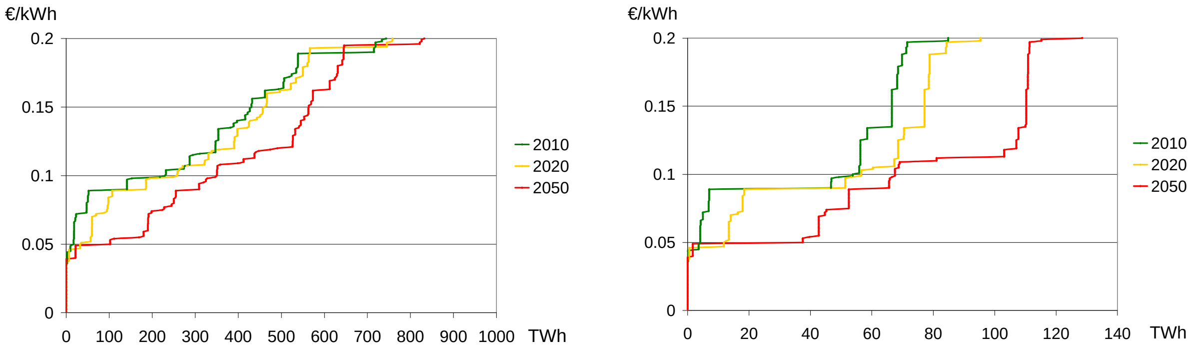

Figure 4.4.4: Hydro power cost-potential-curves for the area of investigation from 2010 to 2050. On the left: Run-of-river hydro, on the right: reservoir hydro.

Norway's reservoir hydro power was treated as a special case: as pumped hydro power with natural inflow, described in section 5.2.1.

4.5 Biomass

4.5.1 Resource assessment

Biomass is any kind of organic matter apart from fossil organic matter. It is primarily formed by autotrophic organisms (plants and some algae and bacteria) through photosynthesis. In the process of photosynthesis, carbon dioxide and water are converted into organic compounds using energy in the form of light. Oxygen is released during this process. The gross efficiency of photosynthesis depends on temperature, humidity and availability of nutrients. It can be as high as 15 %. Only a part of the generated organic substances is used for growth. The rest is used for respiration. This energy metabolism of the organism reverses the process of photosynthesis: the energy-rich organic molecules are broken down into carbon dioxide and water, releasing binding energy when and where it is needed and consuming oxygen. The net photosynthetic efficiency excludes respiratory substance losses. It can be as high as 9 % for single organisms, but on average it is only around 1 % in European vegetation (Kaltschmitt and Hartmann 2001).

The mass of the organic matter generated is called 'net primary production' (NPP). Apart from the growth factors irradiance and light spectrum (photosynthetically active radiation), humidity, temperature, availability of nutrients and soil structure, the NPP depends on the species. Models exist that calculate the amount of grown biomass using meteorological and remote sensing data. By remote sensing, one can obtain information about the type of land cover and in case of plants about the leaf area at a given time. In combination with temporally highly resolved meteorological data, photosynthesis and respiration can be calculated and integrated, resulting in the net primary production in a specified period of time.

A bottom up analysis of biomass energy potentials would have to assess net primary production, subtract biomass used up for secondary production (animal biomass) and subtract biomass used for food and as material in high spatial resolution. Such an investigation would be too substantial for this study. In other studies, biomass energy potentials have been assessed on national or global levels based on statistical data on production and competing uses (food, fodder, materials) ((BMU 2005), (EEA 2006), (Hoogwijk 2004)).

Because a bottom-up analysis of biomass potentials was not feasible in the scope of this study, a top-down approach was chosen: national biomass potentials calculated or taken from studies were disaggregated spatially in order to enable regional aggregation independently from national boundaries.

Biomass potentials were calculated with the methods applied in (BMU 2005) with averages of statistical harvest and livestock data for the years 1998 - 2002 from EUROSTAT (EUROSTAT 2006), FAOSTAT (FAOSTAT 2006) and from UNECE/FAO (UNECE/FAO 2005) if available. No information could be found for the countries in North Africa. The biomass potential in these countries was considered negligible for this study since the population there is growing and the fertile earth is likely to be needed for food production. As a conservative assumption for the energy system modelling, only waste wood potentials were considered in North African states while the potential of other biomass fractions was assumed to be zero. The potentials of forest wood, waste wood, agricultural residues (straw), energy crops and other biomass in the investigation area in the year 2000 are shown in table 4.5.1. For the individual country values, see table 10.1.2 in annex 10.

Table 4.5.1: Biomass potentials in the investigation area in the year 2000 in PJ.

	Potential in PJ	**Source**	**Land cover for disaggregation / additional disaggregation parameters**
Forest wood	2639	UNECE/FAO 2005, FAOSTAT 2006	Forest
Waste wood	1749	BMU 2005	Artificial surfaces and associated areas
Agricultural residues	996	FAOSTAT 2006, EUROSTAT 2006	Agricultural land / NPP
Energy crops	1197	FAOSTAT 2006, EUROSTAT 2006	Agricultural land / NPP
Other biomass	979	FAOSTAT 2005, BMU 2005	Agricultural land, grassland
Total	***7560***		

The **forest wood** potential consists of unused increment, fuel wood and residual forest wood (the leftovers of round wood felling). **Waste wood** comprises industrial waste wood, domestic waste wood and black liquor, a lignin-rich by-product of cellulose production. The **agricultural residues** here are calculated as a fraction of 20 % of straw which is calculated from harvest statistics and straw-to-grain-ratios given in (Hartmann 2002). The following plant species have been chosen as representatives for all crops: cereals (wheat, barley, rye, oat), corn and rape. These plant species have been chosen as representatives because they have been used for modelling the net primary productivity at the German Remote sensing Data Centre at DLR (Wißkirchen 2004) (see below in section 4.5.2). The amount of **Energy crops** has been calculated from harvest statistics and straw-to-grain-ratios, too, considering the whole plant as the energy crop. The share of the agricultural area that can be used for energy crop cultivation was taken from the CP-scenario in (BMU 2005). '**Other biomass**' comprises biogas from manure and grass. Following the methods developed in (BMU 2005), the amounts of biogas from manure were calculated from livestock numbers and typical gas production per livestock unit in different forms of animal breeding. The amounts of biogas from grass were calculated from the available area of grassland, country average yields of grass and biogas yield from grass fermentation. For detailed information on the methods for the biomass potential assessment see (BMU 2005) and (Gehrung 2009).

The given potentials are valid for the year 2000. They include biomass that is already used for energy supply today, such as fuel wood and black liquor. Some minor biomass sources have not been considered: agricultural residues from viticulture and other permanent crops, waste from beer breweries, slaughterhouses, dairies and other food processing industries. Therefore, the potential considered here is around 12 % lower than the potential reported in the CP-scenario in (BMU 2005) and 5 % lower than the potential reported in the E+-scenario in the same study. The distribution of the total biomass resource is shown in figure 4.5.1. The distributions of the single biomass fractions are shown in figure 10.2.1 - 10.2.5 in the annex. The resources of each biomass type are listed in table 10.1.3 in the annex.

The yields in agriculture are continuously increased and more land is assumed to become available for energy crop cultivation. The energy crop potential was assumed to grow until 2020 as given in the CP-scenario in (BMU 2005). For the later years, no information is given in (BMU 2005). As a conservative assumption, no further growth was assumed. The growth factors for the energy crops $f_{growth}^{BIO,energycrops}$ are given in table 4.5.2.

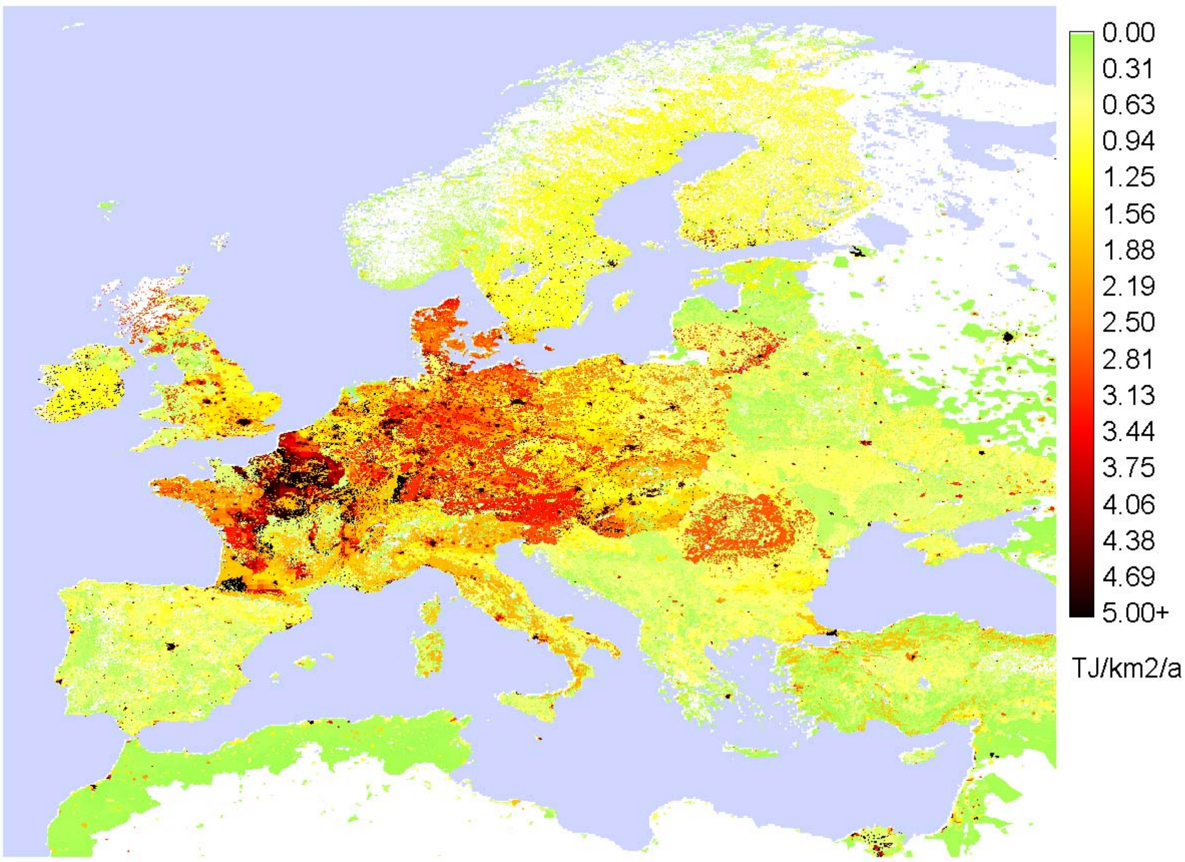

Figure 4.5.1: Total biomass energy resource available in TJ/km^2/a (annual integral, year 2000).

Because of its energy density and storability, biomass can also be used as a fuel (plant oil, plant oil methyl ester, ethanol, methane, …), enabling the continued use of existing mobility infrastructure with relatively low effort for technical and behavioural adaption. It can also be used for heating. In (BMU 2010), assumptions about the development of the share of the biomass that is used in Germany for the generation of power and combined heat and power

(CHP), of heat and of fuels are made. These assumptions have been adopted here by only using the share for electricity and combined heat and power as input into the energy system model. The shares of the single biomass fractions regarded here were not given in (BMU 2010). They have been chosen such that the total amounts of biomass for power and combined power, for heat and for fuel equal the total amounts assigned to these categories in (BMU 2010).

It was not possible in the scope of this study to find similar studies for all countries. Therefore the factors given for Germany were applied to all countries in the investigation area. The shares f_{pchp}^{BIO} of the total biomass potentials that can be used for power and CHP generation are given in table 4.5.2.

Table 4.5.2: Shares for power and combined heat and power generation and energy crop growth factors.

		Symbol	Unit	2000	2010	2020	2050
Energy crop potential growth factor		$f_{growth}^{BIO,energycrops}$	-	1	2.9	6.6	6.6
Total annual biomass potential		$E_{annual,chem}^{BIO}$	PJ	7560	9866	14265	14265
Share for power and combined heat and power	Forest wood	$f_{pchp}^{forestwood}$	-		0.34	0.28	0.40
	Waste wood	$f_{pchp}^{wastewood}$	-		1.00	1.00	1.00
	Straw	f_{pchp}^{straw}	-		0.72	1.00	1.00
	Energy crops	$f_{pchp}^{energycrops}$	-		0.00	0.20	0.32
	Other biomass	$f_{pchp}^{otherbiomass}$	-		1.00	1.00	1.00

In the scenario in (BMU 2010), the electricity generation from biomass without cogeneration of heat is decreasing while the biomass use in combined heat and power plants is strongly increasing. In the optimisation model runs, other results can occur when biomass plants are used for balancing load and generation fluctuations such that the overall operating hours are low. High shares of combined heat and power generation are likely when the operating hours can be high because balancing can be performed more cost-efficiently by other system components such as storage plants.

In (EEA 2006), the biomass resource available for energy use in EU-25 in the years 2010 (2020; 2050) was assessed to be around 189 (235; 283) MTOE, equalling 7892 (9826; 11865) PJ. The potential calculated or adopted in the present study for EU-28 is 8037 (11889; 11889) for the year 2010 (2020; 2050).

4.5.2 Spatial distribution

The biomass potentials were distributed like the land cover type they were assigned to (see table 4.5.1) by multiplying the share of each raster cell area of the land cover type in the total area of this land cover type in a region with the regional biomass potential. Protected areas of the IUCN categories I – IV and areas with a slope higher than 60 % were excluded from the forest potential disaggregation.

In case of straw and energy crops, the resource distribution was additionally weighed with net primary production data modelled at DLR (Wißkirchen 2004). Thus not only the distribution of areas from which the straw and energy crops resource originates was taken into account, but also the quality of each site with respect to precipitation, irradiation and temperature.

The benefit of the NPP data as a proxy parameter for the disaggregation of agricultural products and of forest wood has been investigated in (Gehrung 2009). Using the NPP data in addition to the land cover as a basis for the disaggregation resulted in better agreement in comparison with local statistics for the regarded agricultural products, but not for forest wood. The reason for this might be that the age distribution which has a big influence on the growth rates of trees is not yet included in the NPP model. The disaggregation of forest wood was thus only done based on the forest areas.

4.5.3 Energy conversion

4.5.3.1 Technology

Biomass is chemically stored energy; it thus enables controllable power generation and can play an important role in an electricity supply system based on large shares of resources with intermittent availability. Biomass is very diverse and such are the conversion technologies. For electric power generation in gas and/or steam cycles or cogeneration units different processes for converting the chemical biomass energy into heat are used, depending on the chemical composition of the biomass. Mostly direct combustion, fermentation followed by combustion of the methane or gasification followed by combustion of the gas is applied. Fermentation is especially apt for biomass with high water and low lignin content such as whole corn or rape plants, grass and manure. Drying these materials requires more space, effort and energy than fermentation. Furthermore, fermentation residues can be used as fertilizer on the fields, closing the cycle of the nutrients and improving the soil structure.

Three electricity generation technologies have been chosen from (BMU 2010) as representatives for the many technologies that exist: steam turbines for power generation, steam turbines for combined heat and power generation and biogas plants with cogeneration units. The characteristic technical parameters of the conversion technologies are listed in table 4.5.3.

Table 4.5.3: Technical parameters of biomass power plants (source: (BMU 2010)).

	Symbol	**Unit**	**2010**	**2020**	**2050**
Steam turbine					
Electric efficiency	η^{BIO_ST}	-	0.28	0.29	0.305
Steam turbine, combined heat and power					
Electric efficiency	$\eta^{BIO\_ST\_CHP}$	-	0.20	0.212	0.228
Thermal efficiency	$\eta_{th}^{BIO\_ST\_CHP}$	-	0.645	0.648	0.654
Relative heat output	$f_{rho}^{BIO\_ST\_CHP}$	-	3.2	3.1	2.9
Biogas combined heat and power					
Loss factor: gas leakage	f_{gas}^{BIOGAS}	-	0.02	0.02	0.02
Electric efficiency	η_{th}^{BIOGAS}	-	0.375	0.393	0.405
Thermal efficiency	f_{rho}^{BIOGAS}	-	0.489	0.489	0.495
Relative heat output	f_{rho}^{BIOGAS}	-	1.30	1.24	1.22

The conversion technologies can only be operated with biomass with appropriate characteristics (humidity, chemical composition, …). Table 4.5.4 shows the assignment of biomass types to conversion technologies $f^{bio\_gen\_type,biomass\_type}$ made here.

Table 4.5.4: Biomass conversion technologies and assignment of biomass types they can be operated with.

	Forest wood	Waste wood	Straw	Energy crops	Other biomass
Steam turbine	1	1	1	0	0
Steam turbine, CHP	1	1	1	0	0
Biogas, CHP	0	0	0	1	1

The biomass electricity generation potentials of the biomass technologies ‘bio_gen_type’ depend on the amount of biomass converted by this technology. It is calculated according to eq. 20.

$$E_{annual,el}^{bio\_gen\_type} = \frac{\sum_{\substack{biomass\\type}} E_{annual,chem}^{biomass\_type}}{3600} \cdot f^{bio\_gen\_type,biomass\_typ} \cdot \eta^{bio\_gen\_type} \cdot f_{growth}^{BIO} \cdot \left(1 - f_{loss}^{BIO}\right) \qquad \text{eq.24}$$

where $E_{annual,el}^{bio\_gen\_type}$ Annual biomass electricity generation potential of a ‘bio_gen_type’ in TWh/a

$E_{annual,chem}^{biomass\_type}$ Annual resource of a biomass type available for power and combined heat and power generation in TJ/a

$f^{bio\_gen\_type,biomass\_type}$ Share of a biomass type converted to electricity by ‘bio_gen_type’

$\eta^{bio\_gen\_type}$ Electric efficiency of biomass conversion technology ‘bio_gen_type’

f_{growth}^{BIO} Biomass potential growth factor

f_{loss}^{BIO} Loss factor accounting for losses during harvesting, transport and storage

Losses that occur during harvesting, transport and storage have been set to 15 % generally. The shares $f^{bio\_gen\_type,biomass\_type}$ depend on the energy system characteristics and are set individually in the different energy system model runs.

4.5.3.2 Costs

The economical parameters used for the cost assessment were set according to (BMU 2010). They are listed in table 4.5.5.

Table 4.5.5: Economic parameters of biomass power plants (source: (BMU 2010)). All costs in $€_{2009}$.

	Symbol	**Unit**	**2010**	**2020**	**2050**
Steam turbine					
Investment costs	$c_{inv}^{BIO\_ST}$	€/kW	2500	2241	2131
Fixed operation costs[1)]	$f_{c\_fixop}^{BIO\_ST}$	-	0.05	0.05	0.05
Fixed operation costs (absolute)	-	€/kW/a	125	112	107
Life-time	N^{BIO_ST}	a	20	20	20
Steam turbine, combined heat and power					
Investment costs	$c_{inv}^{BIO\_ST\_CHP}$	€/kW	3880	3633	3499
Fixed operation costs[1)]	$f_{c\_fixop}^{BIO\_ST\_CHP}$	-	0.07	0.07	0.071
Fixed operation costs (absolute)	-	€/kW/a	272	254	248
Life-time	$N^{BIO\_ST\_CHP}$	a	20	20	20
Biogas combined heat and power					
Investment costs	c_{inv}^{BIOGAS}	€/kW	3584	3211	2858
Fixed operation costs[1)]	$f_{c\_fixop}^{BIOGAS}$	-	0.065	0.065	0.065
Fixed operation costs (absolute)	-	€/kW/a	233	209	186
Life-time	N^{BIOGAS}	a	20	20	20

Table 4.5.5 (continued): Economic parameters of biomass power plants (source: (BMU 2010)). All costs in €$_{2009}$.

Variable operation costs (fuel costs)					
Forest_wood	$c_{\text{varop}}^{forestwood}$	€/kWh$_{chem}$	0.025	0.0295	0.035
Waste_wood	$c_{\text{varop}}^{wastewood}$	€/kWh$_{chem}$	0.01	0.0118	0.014
Straw	c_{varop}^{straw}	€/kWh$_{chem}$	0.01	0.0118	0.014
Energy_crops	$c_{\text{varop}}^{energycrops}$	€/kWh$_{chem}$	0.04	0.0472	0.056
Other_biomass	$c_{\text{varop}}^{otherbiomass}$	€/kWh$_{chem}$	0.01	0.0118	0.014

1) Annual share in investment costs

4.5.4 Potentials

The total annual biomass electricity generation potential depends on the efficiency of the conversion technology used. An estimation of the potential with a conversion efficiency of 30 % results in a total electric power generation potential of 326 (451; 548) TWh/a in the year 2010 (2020; 2050). The optimisation model runs can lead to electric power generation potentials that significantly differ from the values given here depending on the allocation of biomass amounts to the conversion technologies with different conversion efficiencies.

4.5.5 Biomass - combined heat and power generation

The technology for combined heat and power generation from biomass has already been discussed together with the power generation. The factor ‘relative heat output’ $f_{rho}^{chp\_gen\_type}$ is the amount of heat that can be delivered to heat consumers per unit of electricity generated. The investment costs of CHP plants and their operation costs are higher than the costs of power plants (see table 4.5.5). CHP plants can become cost-efficient by selling the heat. The cogeneration steam turbines compete with the biogas cogeneration units and with geothermal CHP plants for the heat credit. The total amount of heat that can be delivered is limited by the total low temperature heat demand (see chapter 3.2).

4.6 Geothermal energy

4.6.1 Resource assessment

The geothermal resource is the heat stored in the earth’s crust. About a third originates from the formation process of the earth. Around two thirds originate from radioactive decay processes. The temperature difference between the inside of the earth and the atmosphere results in a heat flux from the earth. On average, the heat flux amounts to 65 mW/m^2 at the earth’s surface. This is by far too little for technical and economic use: in order to power one water boiler with 1500 W, geothermal energy from two to three football fields would have to be harnessed. In (Paschen, Oertel et al. 2003) the depletion of the extractable fraction of the heat stored in a rock reservoir within a time period of 1000 years is assumed to be sustainable.

The following criteria for upper and lower limits of the geothermal heat potential were chosen:

- minimum rock temperature: 80 °C
- maximum drilling depth: 5000 m

Temperatures in 2000, 3000 and 5000 m depth were taken from maps in the ‘Atlas of geothermal resources in Europe’ (Hurter 2002) and in the ‘Geothermal Atlas of Europe’ (Hurtig 1992). Temperatures at 4000 m depth were assumed to be the average between the temperatures in 3000 and 5000 m depth. The resource was analysed separately for each raster cell and each average depth of 2000, 3000, 4000 and 5000 m, assuming layers of 1 km thickness for each average depth. The temperature maps are shown in figures 4.6.1 - 4.6.4. Only sites were taken into account for which temperature data were available.

The geothermal heat that can be technically exploited is called the ‘usable heat’ here. It has been assessed following a method described in (Paschen, Oertel et al. 2003), but other temperature categories and another depth range have been chosen. The temperature threshold set in this study is at 80 °C instead of 100 °C in (Paschen, Oertel et al. 2003) as temperatures of 80 °C have already been demonstrated to be usable for electricity generation. The depth range differs because the resource information available for Europe is given for 2000 - 5000 m instead of 3000 - 7000 m in (Paschen, Oertel et al. 2003). An overview of the method applied is given in the following section.

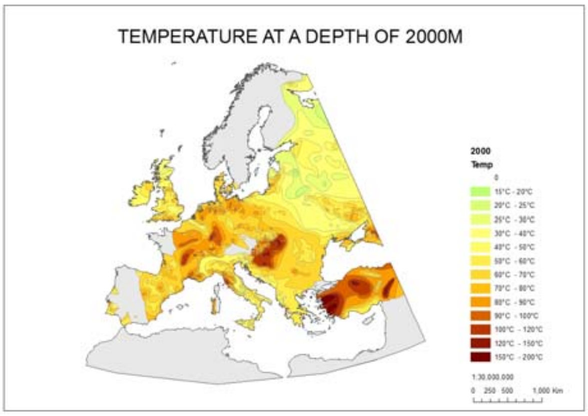

Figure 4.6.1: Temperature in °C at 2000 m depth. Source: (Hurter 2002) and (Hurtig 1992).

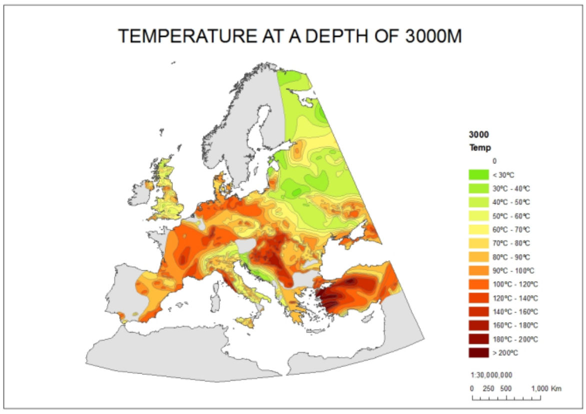

Figure 4.6.2: Temperature in °C at 3000 m depth. Source: (Hurter 2002) and (Hurtig 1992).

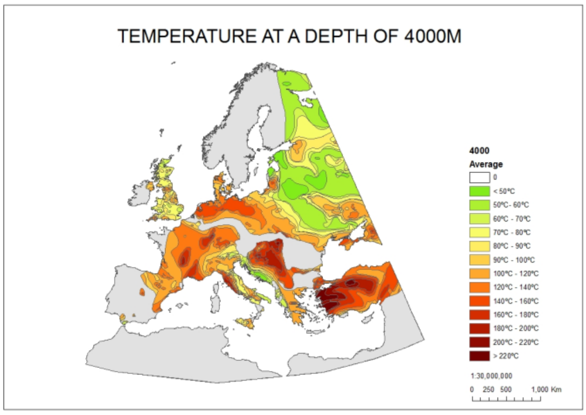

Figure 4.6.3: Temperature in °C at 4000 m depth, derived from (Hurter 2002) and (Hurtig 1992).

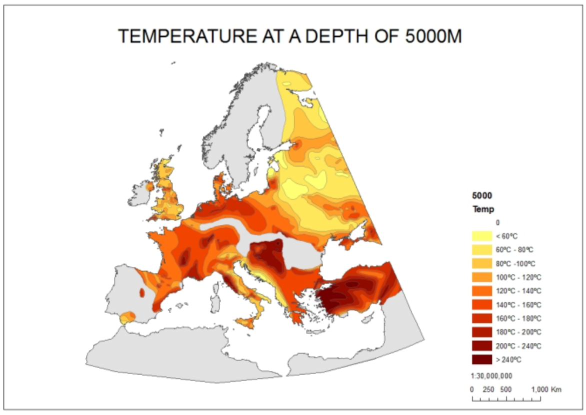

Figure 4.6.4: Temperature in °C at 5000 m depth. Source: (Hurter 2002) and (Hurtig 1992).

The annually usable heat E_u^{GEO} is the geothermal energy that can be recovered from the hot rock. It can be calculated according to eq. 25.

$$E_u^{GEO} = \frac{R^{GEO} \cdot E_{th}^{GEO}}{1000} \qquad \text{eq. 25}$$

where E_{th}^{GEO} Heat stored in a rock reservoir in J
R^{GEO} Recovery factor (taking into account incomplete heat extraction)
1000 Number of years for sustainable use of the stored heat

The assumption that the extraction of the usable heat in 1000 years can be considered sustainable was taken from (Paschen, Oertel et al. 2003). This period may seem short, but it must be considered that only 2.8 - 5.4 % of the heat stored in the rock is extracted. However, it should be noticed that the assumption is not based on long term studies and may change in the future.

The heat stored in a rock reservoir E_{th}^{GEO} can be calculated according to eq. 26.

$$E_{th}^{GEO} = c_R \cdot d_R \cdot V_R \cdot \left(T_R^{GEO} - T_S^{GEO}\right) \qquad \text{eq. 26}$$

where c_R Specific heat capacity of the rock in J/(kg*K)
ρ_R Density of the rock in kg/m³
V_R Rock volume regarded in m³
T_R^{GEO} Temperature of the rock in °C
T_S^{GEO} Temperature at the surface in °C

The following parameter values were assumed:

c_R = 840 J/(kg*K)
ρ_R = 2600 kg/m³
T_S^{GEO} = 10 °C

The rock temperature categories and the corresponding values for efficiency and recovery factors as well as the calculated volume-specific values for the usable heat are shown in table 4.6.1. They were chosen based on (Paschen, Oertel et al. 2003).

Table 4.6.1: Recovery factors and volume-specific usable heat for rock temperature categories based on (Paschen, Oertel et al. 2003) and own calculations.

Rock temperature range in °C	Mean rock temperature T_R^{GEO} in °C	Recovery factor R^{GEO}	Total annually usable heat E_u^{GEO} in kWh/km³/a
80 – 100 °C	90	0.028	1,358,933
100 – 120 °C	110	0.032	1,941,333
120 – 140 °C	130	0.036	2,620,800
140 – 160 °C	150	0.04	3,397,333
200 – 220 °C	170	0.044	4,270,933
160 – 180 °C	190	0.048	5,241,600
220 – 240 °C	210	0.05	6,066,667
180 – 200 °C	230	0.052	6,940,267
> 240 °C	260	0.054	8,190,000

In table 10.1.4 in the annex, the resulting areas of the different temperature category and depth combinations are listed for each of the 36 investigated regions.

4.6.2 Area availability

According to (Kristmannsdottir and Armannsson 2003), geothermal power plants can cause impacts such as

- Surface disturbances
- Physical effects of fluid withdrawal
- Noise
- Thermal effects
- Chemical pollution
- Biological effects

These effects can generally be reduced to negligible levels by modern technical means. Therefore, it was assumed that geothermal resources can in principle be used anywhere.

In addition to the effects mentioned above, earthquakes may be triggered by drilling, stimulating or cooling of reservoirs. This could be a major drawback for geothermal electricity generation technologies, especially for enhanced geothermal systems.

4.6.3 Energy conversion

4.6.3.1 Technology

Geothermal power plants can make use of hot aquifers, faults or be operated as enhanced geothermal systems (EGS). Because most of the heat is stored in 'dry rock' (e.g. 95% of the total potential in Germany (Paschen, Oertel et al. 2003)), an EGS power plant has been chosen as a characteristic power plant. The principle is to stimulate a reservoir of hot rock by cracking it and thus generating a huge surface for the transfer of heat between the rock and a heat transfer medium. This medium - mostly water - is pumped down a borehole and flows through the cracks in the rock that transfers its heat to it. The water comes up through another borehole or several other boreholes. The temperature difference between the injected and the extracted medium can be used for electricity generation. The temperature difference is low compared to the temperature differences that can be achieved with combustion processes. Power cycles for electricity generation from geothermal heat often use a working medium with an evaporating temperature lower than that of water, e.g. NH_3, which increases the efficiency of the process.

An important technical parameter of a geothermal power plant is the flow rate. In combination with the temperature in the rock and the re-injection temperature, it determines the thermal capacity of the well $P_{Well,th}^{GEO}$ as indicated in eq. 27.

$$P_{Well,th}^{GEO} = \dot{m}^{GEO} \cdot c_{H2O} \cdot \left(T_R^{GEO} - T_{reinject}\right) \qquad \text{eq. 27}$$

where $\dot{m}^{GEO}$ Flow rate in the geothermal power plant

c_{H2O} Heat capacity of water

$T_{reinject}$ Temperature of re-injection of the thermal water

The nominal electric output capacity $P_{el,nom}^{GEO}$ of a geothermal power plant can be calculated from the thermal capacity of the well, an efficiency factor and parasitic power requirements of the plant according to eq. 28:

$$P_{el,nom}^{GEO} = P_{Well,th}^{GEO} \cdot \eta^{GEO,T} \cdot \left(1 - f_{own}^{GEO}\right) \qquad \text{eq. 28}$$

where $\eta^{GEO,T}$ Efficiency factor at temperature T
f_{own}^{GEO} Parasitic power requirements of the power plant

In order to assess the sustainable electric output capacity in each raster cell, a relation between rock volumes and the output capacity of the characteristic geothermal power plant was established. This volume-specific installable capacity $p_{inst,\max}^{GEO}$ was calculated by dividing the output capacity of the power plant by the required rock volume V_{req}^{GEO}.

$$p_{inst,\max}^{GEO} = \frac{P_{el,nom}^{GEO}}{V_{req}^{GEO}} \quad \text{eq. 29}$$

where V_{req}^{GEO} Required rock volume

The required rock volume was calculated from the usable heat in a specific rock volume V_r and the annual heat requirement of the power plant, which equals the thermal capacity of the well multiplied by the electric full load hours. It was calculated as given in eq. 30.

$$V_{req}^{GEO} = \frac{P_{well}^{GEO} \cdot h_{fl\_el}^{GEO}}{\frac{E_u^{GEO}}{V_r}} \quad \text{eq. 30}$$

where $h_{fl\_el}^{GEO}$ Electric full load hours of the power plant

Technical and economic parameters mainly based on (Frick 2007) were scaled to a 1115 kW (nominal capacity), 150 °C power plant. They were assumed to stay constant in the whole investigation period of time. The parameters are shown in table 4.6.2.

Table 4.6.2: Technical parameters of a characteristic EGS plant based on (Frick 2007).

	Symbol	Unit	2010 - 2050
Number of boreholes	-	-	2
Flow rate	$\dot{m}^{GEO}$	m³/h	100
Re-injection temperature	$T_{reinject}$	°C	70
Full load hours (electric)	$h_{flh\_el}^{GEO}$	h/a	7500
Mean rock temperature	T_R^{GEO}	°C	150
Parasitic power requirements of the plant[1]	f_{own}^{GEO}	%	25
Thermal capacity of the well	$P_{Well,th}^{GEO}$	kW	9296
Annual heat extraction[2]	-	kWh	69716667
Efficiency factor	$\eta^{GEO,150°C}$	-	0.12
Electric output capacity	$P_{el,nom}^{GEO}$	kW	837
Required rock volume[3]	V_{req}^{GEO}	km³	20.5
Electric output capacity installable per rock volume	$p_{inst,\max}^{GEO}$	kW/km³	41

[1] Pumping and other
[2] Annual heat extraction = thermal capacity of the well * full load hours (electric) = $P_{well}^{GEO} \cdot h_{fl\_el}^{GEO}$
[3] Required rock volume = annual heat extraction by a power plant / usable heat in one km³ of rock

The specific electric output capacity changes significantly with the rock temperature. The electric output capacities installable per rock volume for all temperature categories regarded are shown in table 4.6.3.

Table 4.6.3: Efficiency factors based on (Frick 2007) and own assumptions; Electric output capacity installable per rock volume (2010 – 2050), own calculations.

Mean rock temperature T_R^{GEO}	Electric efficiency $\eta^{GEO,T}$	Volume-specific installable electric output capacity $p_{inst,\max}^{GEO}$ in kW/km3
90 °C	0.1	14
110 °C	0.11	21
130 °C	0.115	30
150 °C	0.12	41
170 °C	0.125	53
190 °C	0.128	67
210 °C	0.132	80
230 °C	0.135	94
260 °C	0.138	113

4.6.3.2 Costs

Literature values for investment costs for geothermal EGS power plants vary greatly. In addition, it is difficult to compare them, because they normally refer to different plant settings (flow rates, temperatures and drilling depths). In table 4.6.4, cost information from different sources have been compiled and made comparable in order to show their variance.

Table 4.6.4: Different cost assumptions for geothermal EGS power plants, in € 2006. Derived from (MIT 2006), (Sanyal, Morrow et al. 2007) and (Frick 2007).

	Drilling Cost (doublet) in M€			**Plant cost, incl. stimulation in M€/MW**			**Total Investment Cost in M€/MW**		
	low	medium	high	low	medium	high	low	medium	high
2000 - 3000 m drilling depth									
(MIT 2006)	4.1	5.4	6.4	1.2	1.5	1.8	5.3	6.9	8.2
(Sanyal, Morrow et al. 2007)	8.0	8.8	9.6	1.8	2.2	2.5	9.8	11.0	12.1
(Frick 2007)	n.a.	9.5	n.a.	n.a.	4.1	n.a.	n.a.	13.6	n.a.
4000 - 5000 m drilling depth									
(MIT 2006)	8.3	10.8	13.2	1.2	1.5	1.8	9.5	12.3	15.1
(Frick 2007)	n.a.	19.9	n.a.	n.a.	6.7	n.a.	n.a.	26.6	n.a.

Table 4.6.5 shows the mean economic parameters that were estimated based on the values found in literature.

Table 4.6.5: Economic parameters of a characteristic geothermal power plant. All costs in $€_{2009}$.

	Symbol	**Unit**	**2010**	**2020**	**2050**
Investment costs at 2000 m drilling depth	$c_{inv}^{GEO,2000}$	€/kW	8906	7397	4025
Investment costs at 3000 m drilling depth	$c_{inv}^{GEO,3000}$	€/kW	12197	10130	5513
Investment costs at 4000 m drilling depth	$c_{inv}^{GEO,4000}$	€/kW	15674	13018	7084
Investment costs at 5000 m drilling depth	$c_{inv}^{GEO,5000}$	€/kW	20921	17375	9456
Representative investment costs for optimisation	c_{inv}^{GEO}	€/kW	17700	14700	8000
Fixed operation costs[1)]	$f_{c\_fixop}^{GEO}$	-	0.027	0.027	0.027
Fixed operation costs (absolute)	-	€/kW/a	478	397	216
Variable operation costs	$c_{\text{var}op}^{GEO}$	€/kWh	0	0	0
Life-time	N^{GEO}	a	20	20	20

1) Annual share in investment costs

The development of the costs until 2050 was estimated according to (BMU 2010). Levelised electricity costs and cost potential curves were calculated from the depth-specific investment costs as described in chapter 4.1.3.2. The representative investment costs that were used in the optimisation model were taken from (BMU 2010). They lie between the costs for plants with a 4000 m deep well and a 5000 m deep well.

4.6.4 Potentials

The annual electricity generation potential in each raster cell can be calculated from the volume-specific installable electric output capacity in kW/km^3 multiplied with the area of the raster cell, the thickness of the layer and the full load hours. The annual full load hours are a result of the energy system model runs. The annual generation potential of geothermal power plants with assumed 7500 full load hours of operation is shown in figure 4.6.5. No change in technology efficiency has been assumed; thus the potential is the same in the years 2010, 2020 and 2050.

Table 4.6.6: Total installable geothermal power generation capacities and annual electricity generation potentials in the investigation area, 7500 full load hours of operation assumed.

	1)	Max. Installable Capacity $P_{inst,max}$ in GW	Annual electricity generation potential in TWh/a		1)	Max. Installable Capacity $P_{inst,max}$ in GW	Annual electricity generation potential in TWh/a
AL_CS_MK [2)]	1	16	119	Malta	1	0	0
BA_HR_SI [3)]	1	9.0	67	Netherlands	1	3.5	26
Austria	1	1.7	13	Norway	1	0	0
Belgium	1	1.0	7.3	Poland	1	19	139
Bulgaria	1	5.3	40	Portugal	1	0.02	0.2
Cyprus	1	0	0	Romania	1	6.4	48
Czech Republic	1	2.8	21	Spain	1	13	94
Denmark	1	2.2	16	Sweden	1	0	0
Ireland	1	0.1	0.5	CH, LI [5)]	1	2.6	19
EE_LT_LV [4)]	1	1.8	13	Turkey	0.80	96	717
Finland	1	0	0	UK	1	6.0	45
France	1	48	359	U_MD [6)]	1	20	148
Germany	1	30	223	Belarus	1	0.8	5.7
Greece	1	6.8	51	Algeria	0.31	0	0
Hungary	1	15	114	Morocco	0.73	0	0
Italy	1	14	107	Tunisia	0.99	0	0
Slovakia	1	2.2	17	Libya	0.18	0	0
Luxembourg	1	0.1	0.4	Egypt	0.13	0	0
				Total Area		***321***	***2409***

1) Share of the region lying within the modelling domain
2) Albania, Serbia-Montenegro, Macedonia
3) Bosnia-Herzegovina, Croatia, Slovenia
4) Estonia, Lithuania, Latvia
5) Switzerland, Liechtenstein
6) Ukraine, Moldova

In table 4.6.6, the regional values for installable capacities and annual electricity generation potentials under the same assumption for the annual full load hours are listed. The values include the potentials for CHP plants which are separately analysed in the next section. The total potential in the investigation area amounts to 2409 TWh/a. This is ca. 59 % (53 %; 44 %) of the respective annual electric power demand in the investigation area in the year 2010 (2020; 2050). Only regions were regarded for which data were available, resulting in a conservative estimate of the total potential. The highest regional potential is found in Turkey: 717 TWh/a of electricity could be generated here. The maximum ratio of the geothermal electricity generation potential to the electric power demand occurs in Turkey and in Hungary. In Turkey the geothermal electricity generation potential is 4.8 (3.5; 1.5) times as high as the electric power demand in the year 2010 (2020; 2050). In Hungary, it amounts to the 2.9 (2.8; 2.6) fold of the electric power demand in the year 2010 (2020; 2050). To the following regions, no potential could be assigned due to lack of data: Cyprus, Malta, Norway, Sweden, Algeria, Morocco, Tunisia, Libya, Egypt. For the optimisation, the potentials in these regions were set to 0.

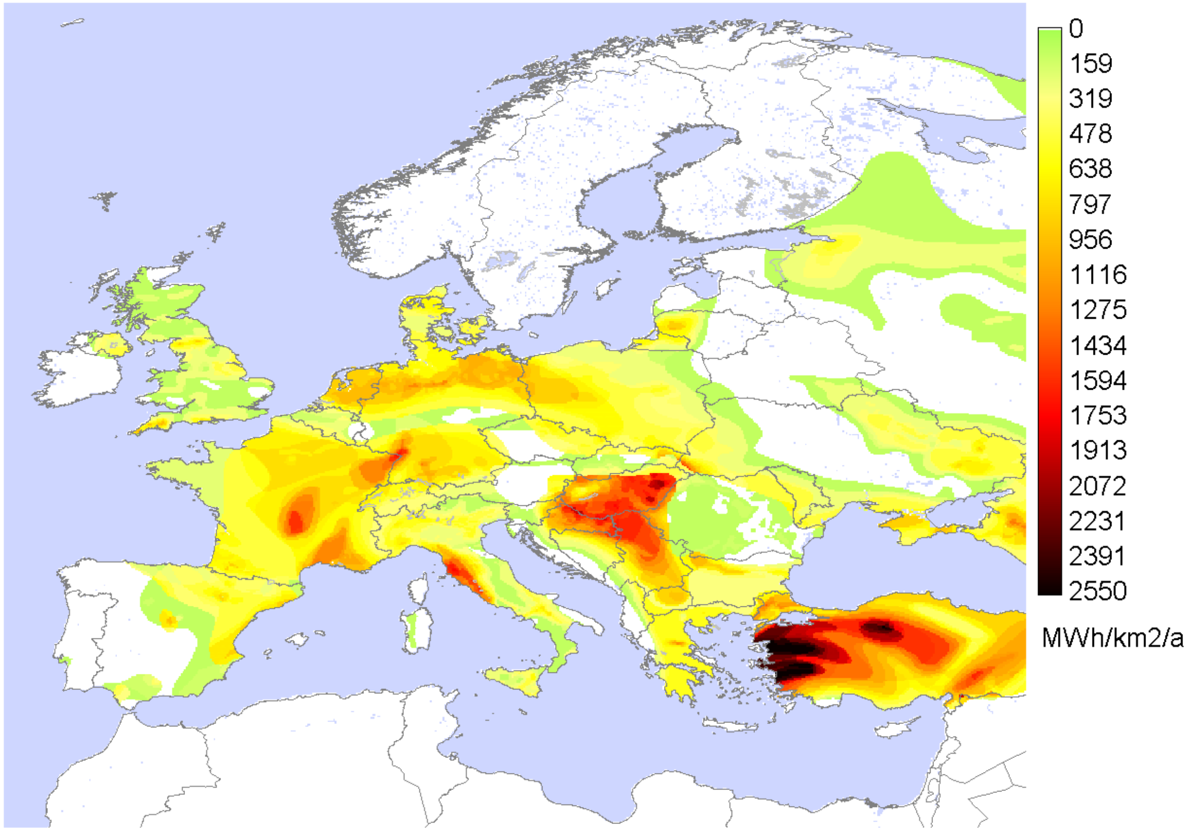

Figure 4.6.5: Total geothermal electricity generation potential in MWh/km^2/a (annual integral), 7500 full load hours of operation assumed. All areas considered usable.

4.6.5 Geothermal energy – combined heat and power

If geothermal energy is to be exploited for combined heat and power delivery, the total heat demand at a site limits the amount of heat from a geothermal plant that can be sold. In addition, the heat demand density in the environment must be sufficient to enable economic operation of a district heating system. The total heat demand and the heat demand density have been estimated translating the German low-temperature per-capita heat demand to other countries by scaling with heating degree days (see chapter 3.2). The resulting heat demand map has been used for calculating the geothermal CHP generation potential under the condition that the heat generated in the plant must not exceed the total heat demand in a raster cell plus average distribution losses of 25 %. 4000 full load hours were assumed for the heat delivery for the potential given here while the actual number of full load hours is a result of the energy system model runs. It depends strongly on the function of geothermal power or CHP plants. If they have to balance intermittent generation from wind and solar power plants, the full load hours are low. If the intermittent generation is balanced by other system components, the full load hours are likely to be very high in order to reduce the overall generation costs through the heat credit.

The technical parameters of a geothermal CHP plant equal those of a power plant without heat delivery, except that heat can be delivered to a district heating system. The amount of heat that can be delivered is given as a relation to the electricity output. For each electric kWh generated, 2 kWh of heat can be delivered. It is assumed in agreement with (Paschen, Oertel et al. 2003) that no losses in electricity generation occur. The temperature of the working medium after condensation is 70°C in the power generation cycle. When heat is used in addition, the condensation temperature is not increased but only the remaining heat is used at the temperature level of 70°C. The economic parameters of a characteristic EGS CHP plant are given in table 4.6.7. In order to account for the connection to a district heating system 500 €/kW$_{el}$ were added to the costs of geothermal power plants based on (BMU 2010).

Table 4.6.7: Economic parameters of a characteristic EGS CHP plant. All costs in €$_{2009}$.

	Symbol	**Unit**	**2010**	**2020**	**2050**
Investment costs at 2000 m drilling depth	$c_{inv}^{GEO\_CHP,2000}$	€/kW	9406	7897	4525
Investment costs at 3000 m drilling depth	$c_{inv}^{GEO\_CHP,3000}$	€/kW	12697	10630	6013
Investment costs at 4000 m drilling depth	$c_{inv}^{GEO\_CHP,4000}$	€/kW	16174	13518	7584
Investment costs at 5000 m drilling depth	$c_{inv}^{GEO\_CHP,5000}$	€/kW	21421	17875	9956
Representative investment costs for optimisation	$c_{inv}^{GEO\_CHP}$	€/kW	18200	15200	8500
Fixed operation costs[1)]	$f_{c\_fixop}^{GEO\_CHP}$	-	0.037	0.037	0.037
Fixed operation costs (absolute)	-	€/kW/a	673	562	315
Variable operation costs	$c_{\mathrm{var}op}^{GEO\_CHP}$	€/kWh	0	0	0
Life-time	N^{GEO_CHP}	a	20	20	20

1) Annual share in investment costs

In table 4.6.8 the regional values for installable capacities and annual electricity generation potentials of geothermal combined heat and power plants are listed.

Table 4.6.8: Installable geothermal CHP electricity generation capacities and annual electricity generation potentials in the investigation area.

	1)	Max. Installable Capacity $P_{inst,max}$ in GW	Annual electricity generation potential in TWh/a		1)	Max. Installable Capacity $P_{inst,max}$ in GW	Annual electricity generation potential in TWh/a
AL_CS_MK [2)]	1	6.3	47.6	Malta	1	0	0
BA_HR_SI [3)]	1	3.3	25	Netherlands	1	2.9	22
Austria	1	1.4	11	Norway	1	0	0.0
Belgium	1	0.9	6.7	Poland	1	14.6	109
Bulgaria	1	2.7	20	Portugal	1	0	0.1
Cyprus	1	0	0	Romania	1	4.3	32
Czech Republic	1	2.4	18	Spain	1	4.1	31
Denmark	1	1.6	11.9	Sweden	1	0	0
Ireland	1	0.1	0.4	CH, LI [5)]	1	2.0	14.8
EE_LT_LV [4)]	1	0.9	7.0	Turkey	0.80	24	178
Finland	1	0.002	0.02	UK	1	4.7	35
France	1	18	139	U_MD [6)]	1	13	94
Germany	1	20	153	Belarus	1	0.5	3.5
Greece	1	1.7	12	Algeria	0.31	0	0
Hungary	1	5.4	41	Morocco	0.73	0	0
Italy	1	9.2	69	Tunisia	0.99	0	0
Slovakia	1	1.6	12	Libya	0.18	0	0
Luxembourg	1	0.1	0.4	Egypt	0.13	0	0
				Total Area		146	1093

1) Share of the region lying within the modelling domain
2) Albania, Serbia-Montenegro, Macedonia
3) Bosnia-Herzegovina, Croatia, Slovenia
4) Estonia, Lithuania, Latvia
5) Switzerland, Liechtenstein
6) Ukraine, Moldova

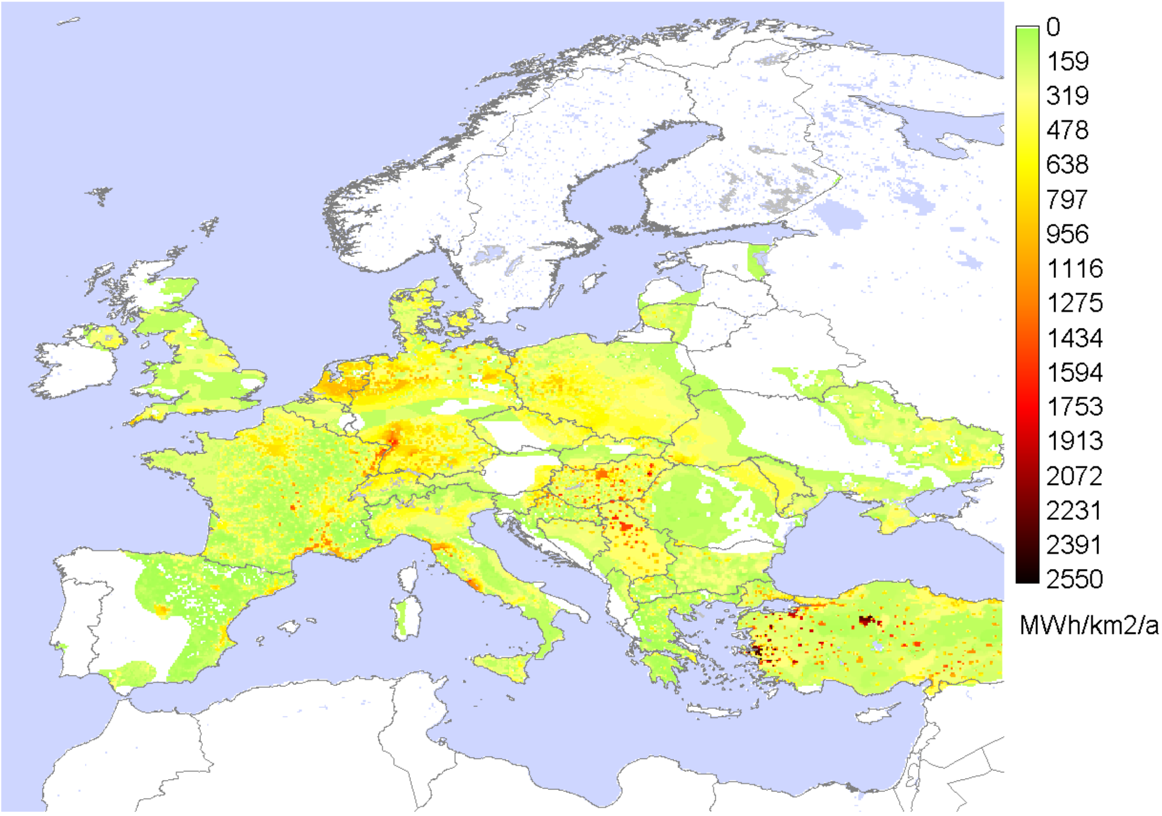

Figure 4.6.6: Geothermal CHP electricity generation potential in MWh/km^2/a (annual integral), 7500 full load hours of operation assumed. All areas considered usable.

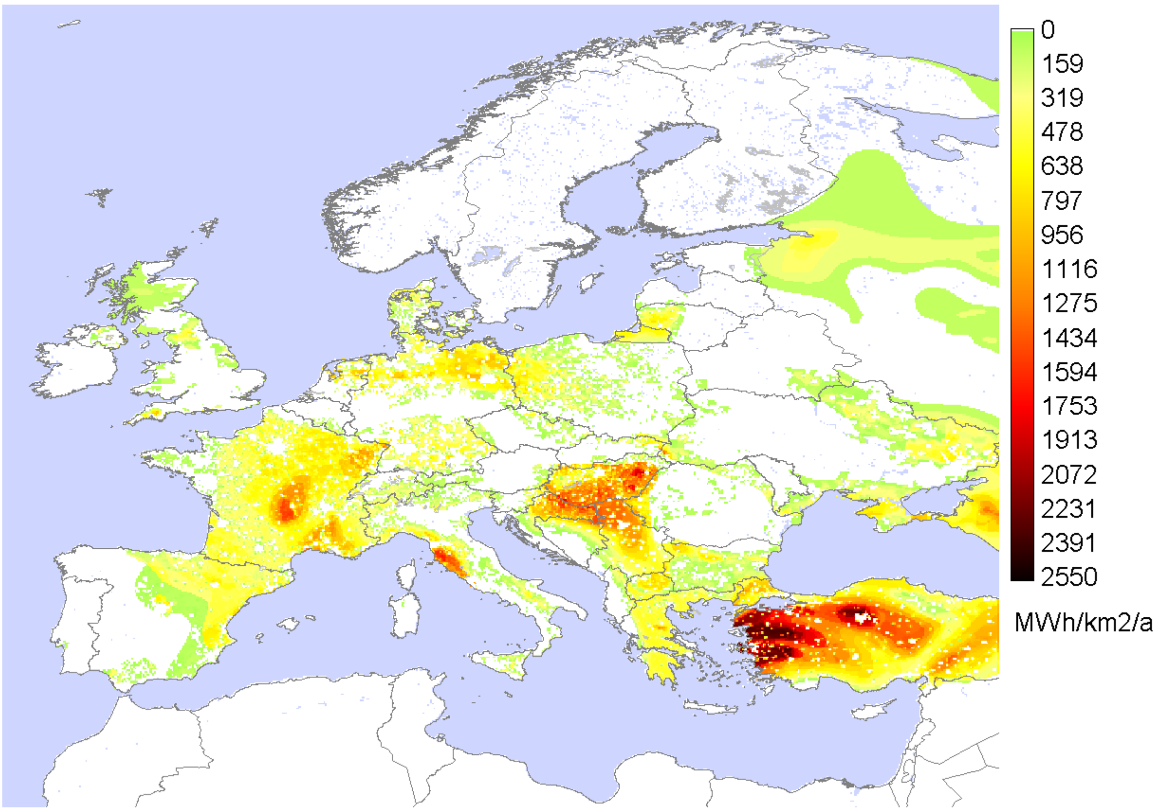

Figure 4.6.7: Geothermal electricity generation potential excluding CHP plants in MWh/km^2/a (annual integral), 7500 full load hours of operation assumed. All areas considered usable.

The total potential in the investigation area amounts to 1093 TWh/a. This is ca. 27 (24; 20) percent of the respective annual electric power demand in the investigation area in the year 2010 (2020; 2050). The highest regional geothermal CHP potential is found in Turkey: 178 TWh/a of electricity could be generated here in geothermal CHP plants. The maximum ratio of the geothermal CHP electricity generation potential to electric power demand occurs in Turkey and in Hungary. In the year 2010 (2020; 2050), the Turkish geothermal CHP potential power generation is 1.2 (0.86; 0.36) times as high as the electric power demand in Turkey. In Hungary, the ratio is 1.04 (1.01; 0.93) in the respective years.

Figure 4.6.6 shows the geothermal CHP electricity generation potential in the investigation area, limited by the total heat demand in a raster cell and by the local heat demand density. Figure 4.6.7 shows the remaining geothermal non-CHP electricity generation potential.

Figure 4.6.8 shows cost-potential-curves for power generation in EGS plants and in EGS-CHP plants in the total area of investigation.

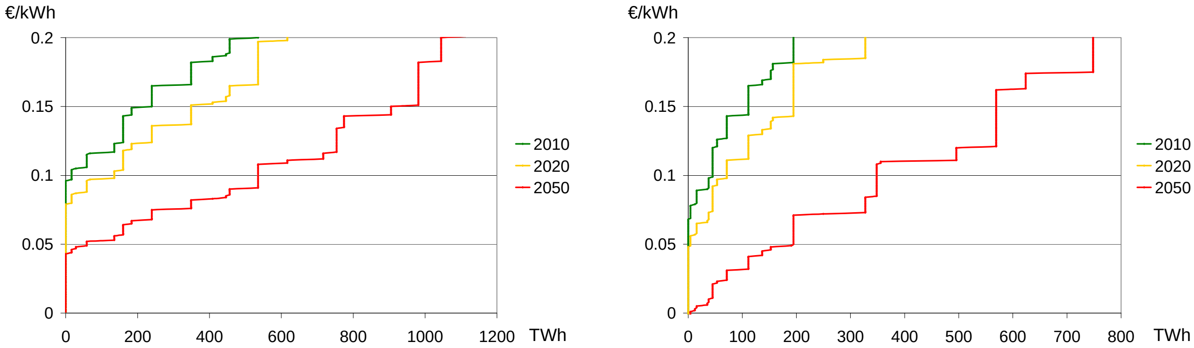

Figure 4.6.8: Geothermal power cost-potential-curves for the area of investigation from 2010 to 2050, on the left: Geothermal power plants, on the right: geothermal CHP plants. A heat credit of 0.05 €/kWh$_{th}$ was considered.

4.7 Overview over all potentials

The total annual potential of electric power generation from renewable energy resources in the investigation area amounts to 94320 (97620; 100923) TWh/a in the year 2010 (2020; 2050), corresponding to the 23.1 (21.4; 18.4)-fold of the total annual power demand of 4084 (4567; 5497) TWh/a. The annual power generation potentials in the single regions are listed in tables 10.1.8 - 10.1.10 in the annex. The year 2050 potentials in each country are displayed in figure 4.7.1 and listed in table 4.7.1 along with the year 2050 power demand in each region. In 2050 the annual power demand only exceeds the annual renewable power generation potential in Belgium and Luxembourg. In most countries the annual renewable power generation potential exceeds the annual power demand by a multiple.

Table 4.7.1: Electricity generation potentials in TWh/a, year 2050, The potentials are given for the area assumptions described including competition with non-energetic area use and between the different technologies. The area assumptions have been made such that the potentials given here can be cumulated.

	1)	BIO[7)]	PV	CSP[8)]	GEO	GEO-CHP	HYDRO[9)]	WIND ON-SHORE	WIND OFF-SHORE	POWER DEMAND
AL_CS_MK [2)]	1	4.1	8.4	0	71	47.6	38	51	37	68
BA_HR_SI [3)]	1	6.0	12	0	42	25	41	45	112	47
Austria	1	13	14	0	2.2	11	74	24	0	49
Belgium	1	4.4	23	0	0.6	6.7	0.3	9.8	24	67
Bulgaria	1	7.2	24	0	19	20	15	33	46	26
Cyprus	1	0.2	12	9.8	0	0	0.002	2.8	3.1	4.9
Czech Republic	1	11	19	0	3.1	18	3.9	26	0	52
Denmark	1	11	8.6	0	4.2	11.9	0.03	24	535	51
Ireland	1	6.3	4.5	0	0.1	0.4	1.0	47	1017	34
EE_LT_LV [4)]	1	9.9	14	0	6.1	7.0	6.9	82	350	36
Finland	1	25	12	0	0.02	0.02	22	137	377	76
France	1	135	111	12	220	139	98	237	918	426
Germany	1	68	107	0	70	153	31	123	310	549
Greece	1	3.1	20	27	38	12	15	45	245	62
Hungary	1	16	22	0	73	41	8.0	24	0	44
Italy	1	20	66	65	37	69	104	88	320	311
Slovakia	1	4.4	11	0	4.4	12	6.8	12	0	29
Luxembourg	1	0.7	0.7	0	0	0.4	0.1	0.8	0	11
Malta	1	0.0	0.5	1.0	0	0	0	0	62	3
Netherlands	1	5.2	15	0	4.1	22	0.1	15	400	116
Norway	1	1.9	2.6	0	0	0.0	195	173	1640	112
Poland	1	31	41	0	30	109	14	122	168	191
Portugal	1	4.6	20	216	0.1	0.1	25	35	103	62
Romania	1	16	62	0	16	32	34	64	68	96
Spain	1	21	121	839	63	31	65	217	263	320
Sweden	1	33	17	0	0	0	97	180	811	154
CH, LI [5)]	1	2.9	2.8	0	4.5	14.8	42	9	0	40
Turkey	0.80	21	627	486	539	178	215	372	104	494
UK	1	17	60	0	9.9	35	5.5	121	3691	451
U_MD [6)]	1	32	32	0	54	94	25	316	312	237
Belarus	1	7.3	4.2	0	2.2	3.5	3.0	103	0	52
Algeria	0.31	2.2	12588	17543	0	0	5.0	2911	18	249
Morocco	0.73	2.4	2990	4385	0	0	4.9	721	100	235
Tunisia	0.99	0.8	2771	3907	0	0	0.2	542	271	66
Libya	0.18	0.4	9341	11931	0	0	0	1893	287	44
Egypt	0.13	3.5	2489	3670	0	0	50	493	68	631
Total Area		548	31671	43093	1316	1093	1243	9298	12662	5497

1) Share of the region lying within the modelling domain
2) Albania, Serbia-Montenegro, Macedonia
3) Bosnia-Herzegovina, Croatia, Slovenia
4) Estonia, Lithuania, Latvia
5) Switzerland, Liechtenstein
6) Ukraine, Moldova
7) Potential under the assumption of an average conversion efficiency of 30 %
8) Electric power generation potential when solar multiple = 1
9) Sum of hydro run-of-river, hydro run-of-river, new and hydro reservoir potentials

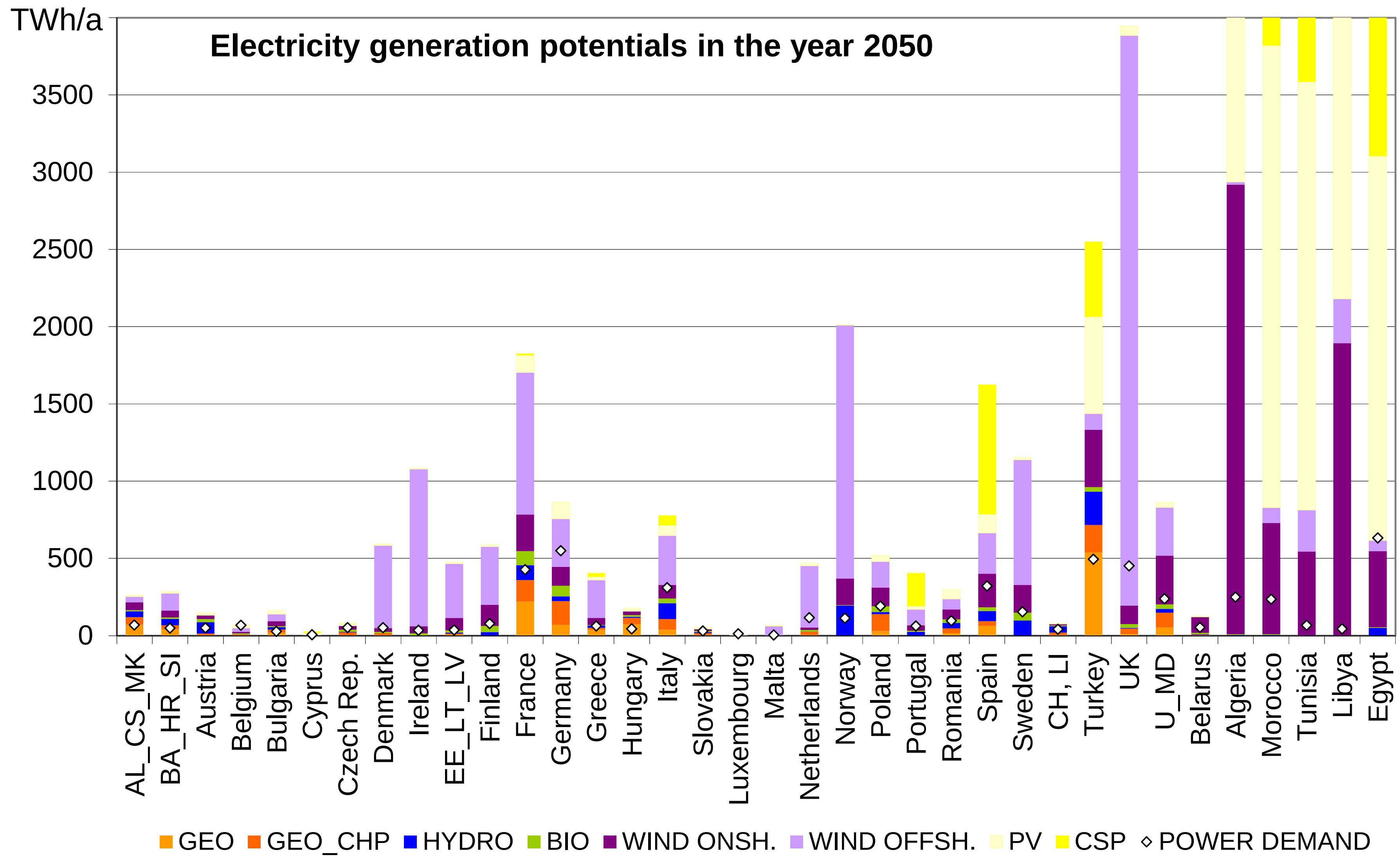

Figure 4.7.1: Renewable electric power generation potentials per region in TWh/a, year 2050. CSP and PV potentials not completely displayed for Algeria, Morocco, Tunisia, Libya and Egypt. The potentials are given for the area assumptions described including competition with non-energetic area use and between the different technologies. The area assumptions have been made such that the potentials given here can be cumulated.

5 Transmission, storage and residual load dispatch

5.1 HVDC electricity transmission

Electricity can be transported with direct or with alternating current. Alternating current (AC) can be transformed, thus enabling the transmission and distribution of electricity with different currents in one synchronised grid.

However, for long distance electric power transmission of more than 500 km, high-voltage direct current (HVDC) transmission lines normally are economically superior to high-voltage AC transmission lines, in some cases also below 500 km distance transmission (Bahrman and Johnson 2007). They have lower losses of 3 % to 5 % per 1000 km (Trieb, O'Sullivan et al. 2009) and can be built with smaller transmission towers and narrower routes for the transmission of the same amount of electric power. Furthermore, HVDC transmission lines do not need reactive power compensation stations, making them favourable for bridging distances where such stations can not be erected (e.g. middle to long distance sea cables).

Figure 5.1.1: Transmission route options set for the energy system model.

The present study focuses on large-scale balancing effects of electric load and renewable electric power generation with different technologies and different local resource characteristics. In order to allow for efficient large-scale balancing, transmission lines with low losses are needed. Therefore, the potential transmission system was given the technical and economic properties of HVDC transmission lines. The transmission routes shown in figure 5.1.1 and listed in table 10.1.12 in the annex were predefined as possible. The following simplifications are implicated in the representation of the transmission lines: 1) the lines connect the centres of regions with coordinates calculated as the mean latitude and longitude coordinates of the power plants installed today. In reality, more connections than only one can exist and the starting and ending points can be distributed over a region. 2) The distance between the nodes (centres of regions) was calculated as their direct linear connection. In order to account for the sagging of the lines and for route deviations from the direct connection, the distance was multiplied with factor of 1.5 in general, which can be considered very conservative. 3) No distinction was made between land and sea cables. Sea cables are more expensive than overhead lines or earth cables. Not distinguishing between land and sea cables erases the relative advantage of land cables compared to sea cables. This simplification was made because the process of calculating the distance between nodes was automated for arbitrary choice of regions, but automatically distinguishing between sea cables and land cables would have been too complex in the scope of this study. The allowed connections were chosen such that the sea cable length is short in order to keep the error small.

Technical and economic properties were chosen based on the description of transmission lines in (Trieb, O'Sullivan et al. 2009). The parameters used here are shown in table 5.1.1. They were assumed to be constant in the investigation period.

Table 5.1.1: Technological and economic parameters of HVDC overhead, underground and sea cable transmission lines (derived from (Trieb, O'Sullivan et al. 2009)). All costs in $€_{2009}$.

	Symbol	Unit	2010 - 2050
Technological parameters			
Voltage	-	kV	600
Station losses	-	-	0.007
Transmission losses (overhead lines)	-	1/1000 km	0.045
Transmission losses (underground cables)	-	1/1000 km	0.035
Transmission losses (sea cables)	-	1/1000 km	0.027
Overall transmission losses (default in model runs)	$f_{loss,trans}$	1/1000 km	0.04
Economic parameters			
Investment costs inverter or rectifier (one station)	$c_{inv,TRANS\_rect}$	€/kW	120
Investment costs transmission line (overhead lines)	-	€/(kW*km)	0.068
Investment costs transmission line (underground cables)	-	€/(kW*km)	0.45
Investment costs transmission line (sea cables)	-	€/(kW*km)	0.6
Investment costs transmission line (default in model runs)	$c_{inv,TRANS\_line}$	€/(kW*km)	0.068
Fixed operation costs [1)]	$f_{c\_fixop,TRANS}$	-	0.01
Variable operation costs	$c_{varop,trans}$	$€/kWh_{el}$	0
Life-time	N_{trans}	a	40

1) Share in original investment costs

The costs for the technical implementation of overhead lines are only 11 % of the costs of sea cables and 15 % of the costs of underground cables. However, the costs for the planning processes might be considerably higher due to citizens' initiatives' oppositions especially concerning overhead lines.

The impact of the simplifications on the system structure and costs were considered small because of the small overall share of the transmission costs in the total system costs that has been shown by (Czisch 2005). Here, the share of the transmission costs in the total system costs is a single-digit percentage in most cases as is shown in the results chapter.

The decision about whether a line should be built and how it should be dimensioned is a result of the energy system model runs. Regional distribution grids were not an object of this study. In evaluating the results of the electric power system model, it must be regarded that their costs were not considered.

5.2 Electricity storage technologies

5.2.1 Pumped-storage hydro power

Pumped-storage hydro power plants consist of two water reservoirs at different geodetic elevation levels and of a conversion unit. Water is pumped from the lower elevation reservoir to the higher elevation reservoir when excess or cheap energy is available and is directed back through a turbine when the electric load is high and the generation of other power plants can not cover the demand or could only do so at higher costs. The pump(s) and the turbine(s) can be separate machines or one or several bi-directional units. Most pumped storage power plants are used for daily load balancing, i.e. their reservoirs allow for about eight hours of pump or turbine full load operation. Reservoir hydro power with natural inflow can be combined with pumped-storage hydro power if the water is released not to a river but to a lower reservoir. These plants often have bigger reservoirs and are used for seasonal load balancing.

Table 5.2.1: Pumped-storage hydro power capacities in operation in the countries in the investigation area (source: (PLATTS 2008)).

Country / region	Pumped-storage capacity in MW	Country / region	Pumped storage capacity in MW	Country / region	Pumped storage capacity in MW
AL_CS_MK [1)]	0	Germany	5931	Spain	3443
BA_HR_SI [2)]	0	Greece	0	Sweden	36
Austria	3284	Hungary	0	CH, LI [4)]	2913
Belgium	1304	Italy	8062	Turkey	790
Bulgaria	840	Slovakia	735	UK	2794
Cyprus	0	Luxembourg	0	U_MD [5)]	0
Czech Republic	450	Malta	0	Belarus	0
Denmark	0	Netherlands	0	Algeria	0
Ireland	292	Norway	765	Morocco	0
EE_LT_LV [3)]	900	Poland	243	Tunisia	0
Finland	0	Portugal	1085	Libya	0
France	4922	Romania	30	Egypt	0
				Total Area	***38819***

1) Albania, Serbia-Montenegro, Macedonia 2) Bosnia-Herzegovina, Croatia, Slovenia
3) Estonia, Lithuania, Latvia 4) Switzerland, Liechtenstein 5) Ukraine, Moldova

In the PowerVision data base by PLATTS (PLATTS 2008), nameplate capacities of the turbines of pumped-storage hydro power plants and the geographic coordinates of the plants in Europe are registered. Like for new reservoir hydro power plants, the potential locations for pumped-storage reservoirs are already exhausted in many countries. An exception from this is Norway: many of the hydro reservoir power plants there are connected to a higher and a lower reservoir and could be used as pumped hydro power plants by replacing the turbine by a combined turbine/pump unit. The potential locations for pumped-storage reservoirs in all countries but Norway were limited in the present study to the currently existing stations registered in (PLATTS 2008), listed in table 5.2.1. The total pumped hydro turbine capacity in the investigation area is given as 38.8 GW.

The pumped hydro capacities in operation given in (PLATTS 2008) are incomplete and should be completed. However, a comprehensive compilation of pumped-storage power stations in the investigation area would have been too substantial for this study. The inaccuracy was considered tolerable because it leads to conservative results. It is likely that higher capacities would further reduce the overall costs of the energy mixes suggested by the model runs.

Reservoir hydro power in Norway was treated as pumped hydro power with natural inflow. The hydro plants in Norway have a storage capacity of around 82 TWh (Haaheim 2010). Not all of them lie between two reservoirs and in many cases the upper reservoir and the lower reservoir are of different size. In some cases nature conservation could prevent the use for load levelling (frequent water level changes, salt water from a lower reservoir that must not enter a fresh water reservoir, ...). However, the Norwegian state utility Statkraft has already announced that they are planning to enhance the capacities and are promoting the development of pumped storage capacity as a ‘battery’ for Europe. Here, it was assumed that a reservoir capacity of 70 TWh maximum could be used for load balancing. No investment costs were considered for these reservoirs by default; some model runs were performed with investment costs of 10 €/kWh for the reservoirs. The energy conversion capacity that can be installed and used is limited because the water level change speed must be limited in order to prevent landslides. In publications of Statkraft, the biggest Norwegian energy provider, different values of the potentially installable capacity can be found: according to a presentation held in Oslo in December 2010 (Haaheim 2010), the installable capacity lies between 3.2 GW and 85 GW when the water level change speed lies between 0.01 and 0.5 m/day. In another presentation held at the ‘German Norwegian Offshore Wind Energy Conference’ in Bergen in May 2010 (Alne 2010), a capacity of 60 GW is considered possible, but it is not clear whether this refers to reservoir hydro or to pumped hydro power. In a personal communication (Fodstad 2011) the capacity that could be built in southern Norway was estimated to be between 15 and 20 GW. Here, the installable pumped hydro power conversion capacity in Norway was limited to 30 GW.

The technical and economic properties of pumped-storage hydro power plants considered here were set according to (BMU 2010). The parameters are listed in table 5.2.2.

Table 5.2.2: Technical and economic parameters of pumped hydro storage plants (based on: (BMU 2010)). All costs in $€_{2009}$.

	Symbol	Unit	2010 - 2050
Technical parameters			
Roundtrip efficiency	$\eta^{pumped\_storage}$	kW	0.8
Losses per hour	$f_{loss}^{pumped\_storage}$	1/h	0
Storage capacity in relation to power generation unit size	$f_{PG2STOR}^{pumped\_storage}$	kWh/kW	8
Availability factor	$f_{av}^{pumped\_storage}$	-	0.98
Economic parameters			
Investment costs converter	$c_{inv,p}^{pumped\_stor}$	€/kW	640
Fixed operation costs converter [1)]	$f_{c\_fixop,p}^{pumped\_storage}$	-	0.03
Fixed operation costs converter (absolute)	-	€/kW/a	19.2
Life-time converter	$N_{p}^{pumped\_storage}$	a	20
Investment costs reservoir (storage)	$c_{inv,e}^{pumped\_stor}$	€/kWh	10
Fixed operation costs reservoir [1)]	$f_{c\_fixop,e}^{pumped\_storage}$	€/kWh	0.03
Fixed operation costs reservoir (absolute)	-	€/kWh/a	0.3
Life-time reservoir	$N_{e}^{pumped\_storage}$	a	60
Variable operation costs	$c_{\mathrm{var}op}^{pumped\_stor}$	€/kWh	0

1) Annual share in investment costs

The pumped hydro power technology has already been developed for a long time and may be considered mature; hence no further changes in the technology or costs were assumed to occur. A ratio of the present storage capacity given in kWh to the turbine capacity given in kW of 8 h of turbine full load operation was assumed that corresponds to the daily load levelling tasks performed by most pumped-storage plants today. This storage capacity was set as fixed installed capacity in the optimisation runs. It was not subject to the optimisation. The energy conversion capacity of the pumped hydro storage plants on the other hand was left variable.

5.2.2 Adiabatic compressed air energy storage

Compressed air energy storage (CAES) plants consist of a pressure reservoir, mostly a cavern in a salt deposit, and a compression/turbine unit that charges or discharges the reservoir when electric power is available or required. During compression, heat is released and during decompression, the same amount of heat needs to be supplied. In the past this heat was supplied by burning gas. Currently adiabatic CAES plants are developed that store the heat released during compression and supply it to the turbine when needed. Therefore, adiabatic CAES plants have higher round-trip efficiencies than non-adiabatic CAES plants. The technical and economic parameters applied for adiabatic CAES plants are based on (BMU 2010), (Zafirakis and Kaldellis 2009) and own assumptions. They are listed in table 5.2.3.

Table 5.2.3: Technical and economic parameters of adiabatic CAES plants (sources: (BMU 2010), (Zafirakis and Kaldellis 2009) and own assumptions). All costs in €$_{2009}$.

	Symbol	Unit	2010	2020	2050
Technical parameters					
Roundtrip efficiency	η^{CAES}	-	0.67	0.7	0.75
Losses of pressure and heat per hour	f_{loss}^{CAES}	1/h	0.0002	0.0002	0.0002
Availability factor	f_{av}^{CAES}	-	0.95	0.95	0.95
Economic parameters					
Investment costs converter	$c_{inv,p}^{CAES}$	€/kW	650	650	650
Fixed operation costs converter 1)	$f_{c\_fixop,p}^{CAES}$	-	0.03	0.03	0.03
Fixed operation costs converter (absolute)	-	€/kW/a	19.5	19.5	19.5
Life-time converter	N_p^{CAES}	a	20	20	20
Invest. costs cavern / pressure tank (storage)	$c_{inv,e}^{CAES}$	€/kWh	30 / 196	30 / 170	30 / 150
Fixed operation costs cavern or pressure tank 1)	$f_{c\_fixop,e}^{CAES}$	-	0.03	0.03	0.03
Fixed op. costs cavern / pressure tank (absolute)	-	€/kWh/a	0.9 / 5.9	0.9 / 5.1	0.9 / 4.5
Life-time cavern / pressure tank	N_e^{CAES}	a	40 / 20	40 / 20	40 / 20
Variable operation costs	$c_{\mathrm{var}\,op}^{CAES}$	€/kWh	0	0	0

1) Annual share in investment costs

Hardly any information is available about the potentials of compressed air energy storage in salt caverns. Germany is the only region for which a study about the potential of CAES storage in salt caverns was available. This study (Ehlers 2000) states a storage capacity of 2.5 TWh in Germany which was set as the upper limit in this region in the energy system model, corresponding to 0.86 km^3 assuming an energy storage density of 2.9 kWh/m^3 as given in (VDE 2008). An overview over existing natural gas storage projects and a map of salt deposits usable for cavern mining in Europe is given in (GILLHAUS 2007). The map is displayed in figure 5.2.1. In order to limit the installable cavern capacities and thus avoid significant overestimation of the storage potential, this map was used for estimating the salt cavern potentials in other countries relative to the German potential of 0.86 km^3.

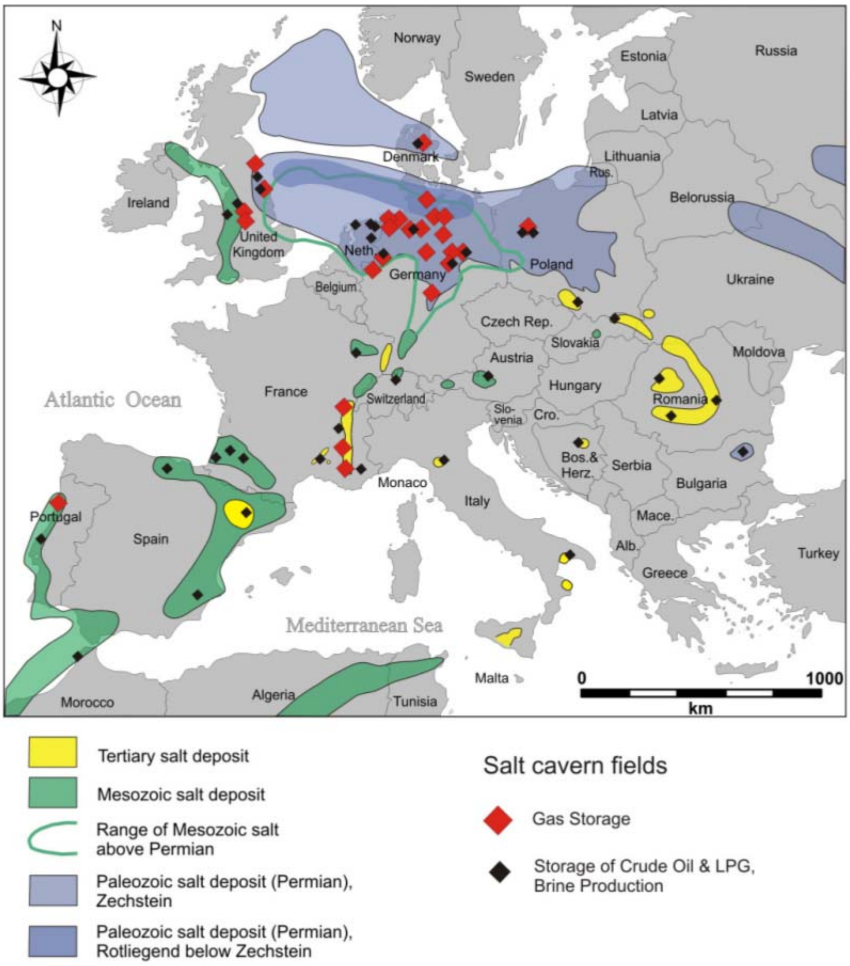

Figure 5.2.1: Underground salt deposits and cavern fields in Europe. Source: (GILLHAUS 2007).

In order to account for possible competition between CAES and hydrogen storage, the salt cavern volumes estimated for each country were used as a limit for the sum of CAES and hydrogen storage capacity in the optimisation model, thus making sure that the volume is only used once. The salt cavern volumes estimated for each country are given in table 5.2.4.

Table 5.2.4: Salt cavern volumes assumed available for storage of compressed air or for storage of hydrogen in km^3. Own calculation based on (GILLHAUS 2007) and (VDE 2008).

Country / region	Salt cavern storage volume in km^3	Country / region	Salt cavern storage volume in km^3	Country / region	Salt cavern storage volume in km^3
AL_CS_MK 1)	0.0000	Germany	0.8621	Spain	0.8621
BA_HR_SI 2)	0.0172	Greece	0.0000	Sweden	0.0000
Austria	0.0690	Hungary	0.0000	CH, LI 4)	0.0259
Belgium	0.0000	Italy	0.0862	Turkey	0.0000
Bulgaria	0.0517	Slovakia	0.0431	UK	0.2586
Cyprus	0.0000	Luxembourg	0.0000	U_MD 5)	0.6897
Czech Republic	0.0000	Malta	0.0000	Belarus	0.1293
Denmark	0.1293	Netherlands	0.2155	Algeria	0.5172
Ireland	0.0690	Norway	0.0000	Morocco	0.0862
EE_LT_LV 3)	0.0000	Poland	1.0776	Tunisia	0.1379
Finland	0.0000	Portugal	0.1034	Libya	0.0000
France	0.4310	Romania	0.2586	Egypt	0.0000
				Total Area	***6.1207***

1) Albania, Serbia-Montenegro, Macedonia
2) Bosnia-Herzegovina, Croatia, Slovenia
3) Estonia, Lithuania, Latvia
4) Switzerland, Liechtenstein
5) Ukraine, Moldova

No fixed limits for the installable pressure tank capacities were set, i.e. the optimisation model dimensions the capacities only considering their costs. Because storage technologies tend to strongly increase the running times of the optimisation model, only one of the two storage options – salt caverns or pressure tanks - is set at a time. As the default the cheaper capacity with limited potential is set. Some model runs were performed with the unlimited but higher cost pressure tanks.

No fixed ratio of storage capacity (energy) to turbine capacity (power) was set; the dimensioning of the CAES plant components was a result of the energy system model runs.

5.2.3 Hydrogen energy storage

Water can be split into oxygen and hydrogen (H_2) by electrolysis which uses electricity as energy source. The hydrogen can be stored and used for electricity generation in the reverse process performed in fuel cells or in gas turbines. Hydrogen as a chemical energy carrier additionally offers a possible link with the mobility sector (passenger and goods street and air traffic). With relatively high costs for the conversion unit and very low costs for storage, the application area would most likely be long-term energy storage for weekly up to seasonal load balancing.

Electrolysis plus hydrogen storage and fuel cells was chosen as the hydrogen based electric power storage technology. The efficiency of the electrolysis process is specified in (Nitsch 2002) as 73 % in the year 2000 and expected to be increased up to 77 % in the year 2020. In the same publication, fuel cell efficiencies are specified: the average efficiency in the year 2000 is around 45 % and in the year 2020 it is expected to be around 55 %. These figures were used as a basis for the assumptions about the round-trip efficiency of electric power storage plants using hydrogen for chemical energy storage, assuming 5 % of own power requirements for compressors. It was assumed that the plant is available 95 % of time and that a slight further increase in the efficiency occurs until the year 2050.

Shaw and Peteves (Shaw and Peteves 2008) state the cost for electrolysers to be 1000 €/kW in the year 2005, excluding costs for compression of the hydrogen. The investment costs of a complete electrolysis unit are given by (Taljan, Fowler et al. 2008) as 1370 €/kW in the year 2008, the investment costs for fuel cells are specified as 1000 €/kW in (Taljan, Fowler et al. 2008). (Nitsch 2002) gives a figure of 1000 €/kW for electrolysers in the year 2002 and expects the costs to fall to 670 €/kW after 2020. Based on these figures, the cumulative costs of the electrolyser unit and fuel cell were set to 2300 €/kW in the year 2010; they were assumed to drop to 1500 €/kW until the year 2050.

The costs for storing the hydrogen are relatively low compared to the costs for the energy conversion unit. Kottenstette and Cotrell (Kottenstette and Cotrell 2003) investigated the costs of storing hydrogen in wind turbine towers and compared them to surface pressure vessels with pressures of 150 bars. The costs they calculate with are 83000 $ for a 'hydrogen tower' with a storage capacity of 940 kg of Hydrogen, added to the costs of a conventional wind turbine tower (Kottenstette and Cotrell 2003). For the reference pressure tank system with the same storage capacity, they calculate with investment costs of 224000 $. With an exchange rate of 1 $ = 0.73 € and a calorific value of hydrogen of 33.3 kWh/kg, this results in specific storage costs of 1.9 €/kWh_{H2} (hydrogen tower) and 5.2 €/kWh_{H2} (pressure vessel). The costs for underground storage in salt caverns are considerably lower. In (BMU 2010) a value of 0.2 €/kWh is given for salt cavern storage and a value of 10 €/kWh for decentralised hydrogen storage pressure vessels. These values were used for the optimisation runs here. All technical and economic parameters used are listed in table 5.2.5.

Table 5.2.5: Technical and economic parameters of hydrogen energy storage plants (sources: (Nitsch 2002), (Shaw and Peteves 2008), (Taljan, Fowler et al. 2008), (BMU 2010)). All costs in $€_{2009}$.

	Symbol	Unit	2010	2020	2050
Technical parameters					
Roundtrip efficiency including losses during compression	η^{CAES}	-	0.31	0.32	0.35
Losses per hour	$f_{loss}^{hydrogen}$	1/h	0	0	0
Availability factor	$f_{av}^{hydrogen}$	-	0.95	0.95	0.95
Economic parameters					
Investment costs converter	$c_{inv,p}^{hydrogen}$	€/kW	2300	1750	1500
Fixed operation costs converter [1)]	$f_{c\_fixop,p}^{hydrogen}$	-	0.03	0.03	0.03
Fixed operation costs converter (absolute)	-	€/kW/a	69	53	45
Life-time converter	$N_p^{hydrogen}$	a	15	15	15
Investment costs cavern / pressure tank (storage)	$c_{inv,e}^{hydrogen}$	€/kWh	0.2 / 10	0.2 / 10	0.2 / 10
Fixed operation costs cavern / pressure tank [1)]	$f_{c\_fixop,e}^{hydrogen}$	-	0.03	0.03	0.03
Fixed op. costs cavern / pressure tank (absolute)	-	€/kW/a	0.006 / 0.3	0.006 / 0.3	0.006 / 0.3
Life-time cavern / pressure tank	$N_e^{hydrogen}$	a	30 / 15	30 / 15	30 / 15
Variable operation costs	$c_{\mathrm{var}op}^{hydrogen}$	€/kWh	0	0	0

1) Annual share in investment costs

The cheaper hydrogen storage potential in salt caverns is limited by the available salt cavern volume. Hydrogen storage plants compete for this volume with compressed air energy storage plants. This was modelled directly in the optimisation model, ensuring that the total volume is not used twice. For hydrogen, (VDE 2008) gives a storage density of 187 kWh/m^3 which is about the 64 fold of the energy storage density of hydrogen of 2.9 kWh/m^3 given in the same publication. The use of salt caverns with limited volume for the storage is used as the default setting in the optimisation model runs. Some runs were performed with the higher costs for pressure tanks and without a volume limit instead of the default setting.

5.3 Residual load dispatch

For renewable energy shares in the electricity supply below 100 %, a technology was introduced that covers the residual load. Such shares can be set by the model user or they can be set in the model when a high degree of regional domestic supply is set by the user that a region can not conform to without additional energy carriers because of the lack of sufficient renewable resources.

Only one technology was introduced because a detailed representation of all conventional power plants was not feasible within the scope of this investigation. This single technology must be dispatchable and it must allow for fast ramping up and down in order to guarantee the electricity supply at any time and at any share of intermittent renewable energy sources in the supply structure. Therefore, it was given the characteristics of a gas turbine power plant. The parameters were taken from (BMU 2010). They are listed in table 5.3.1.

Table 5.3.1: Technical and economic parameters of residual load dispatch. Source: (BMU 2010). All costs in €$_{2009}$.

	Symbol	Unit	2010	2020	2050
Technical parameters					
Availability factor	$f_{availability}^{residual}$	-	0.98	0.98	0.98
Economic parameters					
Investment costs	$c_{inv}^{residual}$	€/kW	400	400	400
Fixed operation costs 1)	$f_{c\_fixop}^{residual}$	-	0.02	0.02	0.02
Fixed operation costs (absolute)	-	€/kW/a	8	8	8
Variable operation costs including costs for CO_2 emissions	$c_{\mathrm{var}\,op}^{residual}$	€/kWh$_{el}$	0.096	0.123	0.198
Life-time	$N^{residual}$	a	25	25	25

1) Share in original investment costs

A technology 'residual (CHP)' was not regarded because of the probable intermittent characteristics of generation and the consequently low full load hours that make the additional delivery of heat unlikely.

6 The REMix model

A model was developed to answer the following question: what mixture of renewable-energy-based electric power generators and of transmission lines, storage and possibly fossil backup capacities can cover the electric power demand reliably at the lowest costs under specific conditions? Specific conditions means for example: with different shares of renewable energies, different claims for national supply security and thus different levels of integration in an overlying system and with different dimensions of overlying systems.

6.1 Optimisation approach

Mathematical methods exist for solving optimisation problems: linear programming (LP), mixed-integer linear programming (MILP), quadratic programming (QP), and non-linear programming (NLP). The basic formulation of an optimisation problem is an objective function to be minimised (or maximised), complemented with restrictions of the solution space. When the objective and the restrictions can be expressed in linear terms, linear programming is used predominantly because, it offers the following advantages (Krey 2006):

- LP can efficiently solve very big systems of equations,
- the uniqueness of the solution is guaranteed,
- the solutions are mostly well comprehensible.

Many established energy system models are based on linear programming but apply non-linear modules for representing facts like economies of scale or efficiencies of power plants in partial load operation. Mixed-integer modules are applied e.g. for representing the state of operation of power plants that are large in relation to the total system so that their output can not be aggregated and treated as a linear function (Krey 2006).

The REMix model was built as a linear model in order to keep the running times as low as possible. The optimisation problem can be linearised because all of the power plants regarded are small in relation to the total system. The objective is to minimise the total system costs under given restrictions. It is thus a ‘social planner’ model which solves a problem for the total system regarded, such as a national economy, a utility’s power plant fleet operation, a European electric power supply system. A market model on the other hand tries to represent the choices made by single market actors who optimise their benefit. The REMix model focuses on designing energy supply structures in the long term at minimum costs for the total area investigated. It provides results for the total area investigated as a whole, implying international cooperation for achieving the corresponding development if the area of investigation is bigger than one country and if interaction is allowed.

The model is a deterministic model. Its inputs are fixed parameters for costs and fixed hourly data of electric power demand and generation potentials. The output is a specific result valid for the fixed input parameters. The results can be very sensitive to changes in the parameters. Stochastic models take into account the uncertainties in the parameters by using probability distributions of parameters instead of determined parameter values. The results of stochastic models are more robust to input parameter variations, i.e. their sensitivity to parameter variations of the uncertain parameters is small. However, the aim of the REMix model is to make use of the benefits of spatial and temporal balancing effects of electric power demand and of generation potentials in networks. It was thus designed as a deterministic model because it has to consider correlations between fixed values of the electric power demand and the generation potential in order to capture correlations such as seasonal concurrence of power demand and wind power output in northern Europe or daily concurrences of solar power and demand peaks as well as anti-correlations between wind speed profiles or power demand in Europe and North Africa.

Different algorithms exist for solving optimisation problems. The most widespread is the simplex algorithm. It searches for the minimum or maximum value of the convex solution space of a linear optimisation problem along its borders. The barrier 'inner-point-method' on the contrary finds the solution through the interior of the solution space. It is usually faster than the simplex algorithm but the number of iterations can as well become unbounded and the running times thus infinite. The barrier algorithm was used for all model runs performed in the scope of this work.

Measures to reduce model running times are the reduction of the number of variables, e.g. time step reduction or reduction of the number of regions regarded. Such reductions of the number of variables regarded also reduce the accuracy of the results but can be inevitable when the running times are very long. All model runs performed for this study with less than 10 regions could be solved with the input data for a complete year. For model runs with the complete investigation area with 36 regions, two methods of variable reduction with subsequent model runs that use the previous results as input data were tested:

1) Time step reduction:

   a) 5 runs with each second hour of each fifth day, each starting at another day.
   b) Average of the installed power generation capacities as preset fixed input into a run with the total number of time steps. Biomass conversion technologies were left unset in order to avoid capacity shortage due to the averaging.

2) Spatial decomposition and recombination

   a) Spatial aggregation of the 36 regions to 9 super-regions, model run with all time steps for the 9 super-regions. The transmission distance between two super-regions was set such that in a network of the 36 regions no longer distance could occur for transmission between two regions: it was set to the shortest distance between the two regions in the super-regions to be connected that are the farthest away from each other.
   b) Model run for the regions within a super-region with the import and export between the super-regions from the previous run as boundary conditions.
   c) Model run with the total number of regions and time steps with preset fixed generation and storage capacities for finding the required transmission capacities between the regions.

Method 2 proved to be the faster method and was applied for the model run with 36 regions.

As explained in chapter 2.1.3, the model is set up in the modelling environment GAMS as a unit of sets (indices), parameters, variables and equations. Below, the setup and the basic functions are briefly outlined. A detailed description of the model is given in the next section.

The model REMix dimensions power supply systems with the following power generation and power storage technologies:

Power generation technologies

- Photovoltaic
- Concentrating Solar Power
- Wind onshore
- Wind offshore
- Run-of-river hydro (old + modernised)
- Run-of-river hydro (new)
- Reservoir hydro
- Biomass steam turbines
- Biomass steam turbines, CHP
- Biogas plants, CHP
- Geothermal power plants
- Geothermal CHP plants
- Residual (natural gas turbines)

Storage technologies

- Pumped hydro power storage
- Advanced adiabatic compressed air energy storage (CAES)
- Hydrogen storage

From the inventory, the model is supplied with parameters about maximum installable capacities and maximum hourly power generation in each time step and each of the up to 36 regions regarded. The objective function of the model defines that the total system costs, calculated as the sum of the investments and fixed and variable operation costs of all system components, are to be minimised. The main restriction defines that the load must always be covered, i.e. that in each time step and in each region, the power generation plus imports must be equal to or higher than the load plus exports, storage consumption and surplus. Other restrictions define

- capacity limits
- power generation limits
- system reliability requirements
- the share of renewable energy in the annual generation in each region
- the share of the annual domestic generation in the annual power demand in each region
- the transmission line connection options of each region
- the heat demand limiting the heat credit paid for heat delivery from CHP plants.

The capacities to be installed and the operation of each power generation and storage technology as well as of HVDC transmission capacities are varied by GAMS until the costs of the supply system can not be further reduced.

6.2 REMix optimisation model formulation

6.2.1 Sets

Sets are the indices that specify the domains of parameters, variables or equations. Subsets can be established that contain only a part of the members of a set or of another subset; they can be used to specify the domains of parameters, variables or equations that are valid for only a part of a set. An alias is a copy of a set. Dynamic sets are not predefined before a model run but assigned a value in a model run.

The set ‘gen_type’ contains all electric power generation technology types considered: photovoltaic power plants (‘pv’), wind turbines (‘wind_onshore’ and ‘wind_offshore’), a combination of old and modernised run-of-river hydro plants (‘hydro_ror’), new run-of-river hydro plants (‘hydro_ror_new’), reservoir hydro power (‘hydro_res’), geothermal power plants (‘geo’), geothermal plants with combined heat and power generation (‘geo_chp’), steam turbines for biomass combustion (‘bio_st’), steam turbines for biomass combustion with combined heat and power generation (‘bio_st_chp’), biogas plants with combined heat and power generation (‘bio_gas_chp’), natural gas turbines (‘residual’).

The sets ‘re_gen_type’, ‘bio_gen_type’, ‘chp_gen_type’, ‘hydro_type’, ‘hydro_res_type’, ‘variable_type’ and ‘dispatch_type’ are subsets of ‘gen_type’. The ‘gen_type’-subset ‘re_gen_type’ contains only the renewable-energy-based generator technology types. In ‘bio_gen_type’, all technologies for the generation of electric power from biomass are contained. ‘CHP_gen_type’ covers all technologies that can provide electric power and heat. ‘Hydro_gen_type’ covers all hydro power technologies, ‘Hydro_res_gen_type’ covers only the hydro reservoir technology. The ‘gen_type’-subset ‘var_gen_type’ contains only the generators that depend on renewable sources with intermittent availability; ‘dispatch_gen_type’ contains the dispatchable electric power generation technologies. Table 6.2.1 shows the subsets of ‘gen_type’ and the technologies they cover.

Table 6.2.1: Definitions of the set ‚gen_type’ and its subsets

	gen type	re_ gen_type	bio_ gen_type	chp_ gen_type	hydro_ gen_type	hydro_res_ gen_type	var_ gen_type	dispatch_ gen_type
pv	+	+					+	
wind_onshore	+	+					+	
wind_offshore	+	+					+	
hydro_ror	+	+			+		+	
hydro_ror_new	+	+			+		+	
hydro_res	+	+			+	+		
geo	+	+						+
geo_chp	+	+		+				+
bio_st	+	+	+					+
bio_st_chp	+	+	+	+				+
bio_gas_chp	+	+	+	+				+
residual	+							+

The set ‘biomass_type’ is defined in table 6.2.2. It contains the types of biomass that can be converted in biomass conversion plants:

Table 6.2.2: Definition of the set ‘biomass_type’

biomass_type	forestwood, wastewood, straw, energycrops, otherbiomass

The set ‘stor_type’ contains the different storage types. It is defined in table 6.2.3. Its member ‘pumped_storage’ was assigned to a subset because equations were formulated for setting the power-to-storage ratio for pumped storage only; the respective ratios of the other storage technologies were results of the model runs.

Table 6.2.3: Definition of the set ‚stor_type’ and its subset ‘pumped_stor_type’

stor_type	pumped_storage, caes, hydrogen
pumped_stor(stor_type)	pumped_storage

The set ‘timefull’ and its subsets are defined in table 6.2.4. ‘Timefull’ covers all time steps that input data are available for plus a time step zero which is relevant for the storage balance formulation. Its subset ‘time_inc_zero’ contains all time steps that are actually regarded in one model run plus time step zero. The time steps regarded can be e.g. every second hour or every second hour of every second day. Reduction and distribution of time steps can be valuable for reducing running time of the model during application and especially during development. The set ‘time’ is a subset of ‘time_inc_zero’; it covers all time steps actually regarded in one model run but it excludes time step zero. In this example, the model run would cover only the first half of the year until time step 4380:

Table 6.2.4: Definition of the set ‚timefull’ and its subsets

timefull	0 * 8760
time_inc_zero(timefull)	0 * 4380
time(time_inc_zero)	1 * 4380
first_hour(time_inc_zero); last_hour(time).	

The dynamic ‘time_inc_zero’-subset ‘first_hour’ and the dynamic ‘time’-subset ‘last_hour’ are the number (position) of the first element and the last element in the time vector regarded; these sets are needed for storage balance equations formulation.

Region-specific input data are aggregated in the C-programs and are assigned to a node in the optimisation model. A node represents a region. It was calculated as the centre of the power plant infrastructure in a country in operation today. The set ‘nodefull’ is defined in table 6.2.5. It covers all 36 nodes that input data are available for. Its subset ‘node’ contains only the nodes regarded in the current model run, enabling single-node investigation or investigation of different clusters of nodes. The sets ‘aliasnodefull’ and ‘aliasnode’ are identical with ‘nodefull’ and ‘node’. These aliases are needed for the definitions of parameters, variables and equations referring to transmission between two nodes.

Table 6.2.5: Definitions of the set ‚nodefull’, its subset node and aliases

nodefull	1 * 36
node(nodefull)	for example: 13, 21, 32 (= Germany, Norway, Algeria)
ALIAS (nodefull,aliasnodefull)	
ALIAS (node,aliasnode).	

6.2.2 Parameters

All input data are called parameters in GAMS. They are read from text files generated by the C-programs. The sets that specify the domains for which non-scalar parameters are defined are written as superscripts. Subscript indices further specify the parameters. The following parameters are used:

c_{heat}	Monetary credit for heat delivery from CHP technologies in k€/MWh
c_{inv,CSP_SF}	Investment costs for CSP solar fields in k€/MW_{th}, referred to the thermal capacity
c_{inv,CSP_PG}	Investment costs for CSP electric power generation units in k€/MW_{el}
c_{inv,CSP_STOR}	Investment costs for CSP storage units in k€/MWh_{th}
$c_{inv,TRANS\_line}$	Investment costs for transmission capacity in k€/(MW*km)
$c_{inv,TRANS\_rect}$	Investment costs for transmission capacity (inverter) in k€/MW
$c_{\mathrm{var}op,CSP}$	Variable costs for CSP plants in k€/MWh
$c_{\mathrm{var}op}^{biomass\_type}$	Variable operation costs for biomass power plants: fuel costs of the biomass types in k€/MWh_{chem}
$c_{inv}^{gen\_type}$	Specific investment costs in k€/MW per electric power generator type

$c_{\mathrm{var}op}^{gen\_type}$	Variable operation costs (fuel) in k€/MWh per electric power generator type
$c_{inv,\mathrm{mod}}^{HYDRO}$	Investment cost for the modernisation of hydro power plants in k€/MWh; 'HYDRO' standing for HYDRO_ROR and HYDRO_RES
$c_{inv,stor\_e}^{stor\_type}$	Investment cost for the storage unit of storage technologies in k€/MWh
$c_{inv,stor\_p}^{stor\_type}$	Investment costs for the power unit of storage technologies in k€/MW
$c_{\mathrm{var}op}^{stor\_type}$	Variable operation costs (fuel) of storage technologies in k€/MWh
$D^{nodefull,aliasnodefull}$	Distance between two nodes in km
$E_{annual,chem}^{biomass\_type,nodefull}$	Annually available energy from biomass in MWh per biomass type and node
η_{CSP_PG}	Efficiency of CSP electric power generation units
η_{CSP_STOR}	Efficiency of CSP storage units
$\eta^{bio\_gen\_type}$	Efficiency of electric power generator types for biomass conversion
η^{stor_type}	Roundtrip efficiency of storage technologies (charging + discharging)
$f_{annuity,CSP\_PG}$	Annuity factor for CSP power generation unit
$f_{annuity,CSP\_SF}$	Annuity factor for CSP solar fields
$f_{annuity,CSP\_STOR}$	Annuity factor for CSP storage
$f_{annuity,TRANS}$	Annuity factor for transmission technology
$f_{CSP,av}$	Availability factor for CSP power plants
$f_{c\_fixop,CSP}$	Annual fixed operation cost (maintenance a.o.) for CSP plants; expressed as percentage of investment cost. Valid for solar fields (CSP_SF), storage unit (CSP_STOR) and power generating unit (CSP_PG)
$f_{c\_fixop,TRANS}$	Annual fixed operation costs (maintenance a.o.) for transmission capacity, expressed as share in investment costs
$f_{depr,HYDRO}$	Depreciation factors: share of old hydro power plants still in operation in the year of investigation, 'HYDRO' standing for HYDRO_ROR and HYDRO_RES
$f_{domestic\_\mathrm{sup}ply}$	User defined ratio of domestic generation to annual electric power demand
$f_{loss,district\_heating}$	Heat losses that occur during heat distribution
$f_{loss,trans}$	Transmission loss factor (loss per km*MW)
f_{reg_share}	User defined ratio of the share of the annual electric power demand not covered by fossil fuels to annual electric power demand (not covered by fossil fuels here means: covered either by renewable electric power or by imports)
$f_{pr,CSP}$	Factor for own power requirements of a CSP power plant
$f^{bio\_gen\_type,biomass\_type}$	Allocation of biomass types to electric power generator types for biomass conversion appropriate for the biomass type (1 or 0)
$f_{annuity}^{gen\_type}$	Annuity factor of electric power generator types
$f_{av}^{gen\_type}$	Technical availability of generators per generator type, excluding times of outages and maintenance
$f_{c\_fixop}^{gen\_type}$	Annual fixed operation cost (maintenance a.o.) per electric power generator type; expressed as share in investment costs
$f_{rho}^{chp\_gen\_type}$	Heat output per CHP generation technology in MW relative to the electric power generation potential in MW
$f_{storage2power}^{hydro\_res\_gen\_type}$	Size of hydro reservoir storage in h (full load hours of the turbine)
$f_{PG2STOR}^{pumped\_storage}$	Size of the reservoir of a pumped storage hydro power plant in h, expressed as full load hours of the conversion unit
$f_{annuity,e}^{stor\_type}$	Annuity factor for the storage unit of storage technologies
$f_{annuity,p}^{stor\_type}$	Annuity factor for the power generators of storage technologies

$f_{c\_fixop,e}^{stor\_type}$	Annual fixed operation costs (maintenance a.o.) of storage units; expressed as share in the investment costs
$f_{c\_fixop,p}^{stor\_type}$	Annual fixed operation costs (maintenance a.o.) of storage technology conversion units; expressed as share in investment costs
$f_{loss}^{stor\_type}$	Storage losses per time step
$f_{num\_time\_steps}$	Number of time steps regarded
i	Interest rate; percentage
l_t	Length (duration) of a time step
$P_{inst,\max}^{gen\_type,nodefull}$	Maximum installable electric power capacities in MW per technology 'gen_type' (or a subset of 'gen_type') and node
$P_{\max}^{gen\_type,timefull,nodefull}$	Average electric power generation potential of maximum installable capacity in MW per technology 'gen_type' (or a subset of 'gen_type'), time step and node
$P_{inst,\max,CSP\_SF}^{nodefull}$	Maximum installable heat generation capacity of CSP solar fields per node in MW_{th}
$P_{inst,\max,trans}^{nodefull,aliasnodefull}$	Maximum installable transmission capacity in MW (optional transmission line: yes=inf or no=0)
$P_{inst,\max}^{pumped\_stor,nodefull}$	Maximum installable pumped storage electric power capacity per node in MW
$P_{heat}^{timefull,nodefull}$	Average heat load in MW per time step and node
$P_{hydro\_res\_\inf low}^{timefull,nodefull}$	Average water flow into hydro reservoirs per time step and node at maximum installable hydro reservoir capacity, expressed in MW
$P_{load}^{timefull,nodefull}$	Electric load in MW per time step and node
$P_{load,peak}^{nodefull}$	Maximum electric load (peak load) in MW per node
$P_{\max,CSP\_SF}^{timefull,nodefull}$	CSP average heat generation potential of maximum installable solar field capacity in MW_{th} per time step and node

6.2.3 Variables

In GAMS, variables are given a name and a domain if appropriate. At least on variable must be a scalar without a domain: the variable to be minimised or maximised. Here, the total system costs are to be minimised. For non-scalar variables, the sets that specify the domains for which the variables are defined are written as superscripts. Subscript indices further specify the variables. The following variables are used:

C_{sys}	Total system cost in Euro in k€
$C_{uni}^{gen\_type,node}$	Universal costs for electric power generation excluding CSP, hydro power, storage and biomass fuel costs in k€
C_{CSP}^{node}	Cost of CSP plants and electric power generation in k€
$C^{stor\_type,node}$	Costs for electric power storage in k€
$C^{HYDRO\_RR,node}$	Costs for old and modernised hydro run-of-river power plants in k€
$C^{HYDRO\_RR\_NEW,node}$	Costs for new hydro run-of-river power plants in k€
$C^{HYDRO\_RES,node}$	Costs for old and modernised hydro reservoir plants in k€
C_{trans}^{node}	Costs for transmission lines per node (half of the costs of each line connected to that node) in k€

Some variables must not have negative values. **Positive variables** are:

$E^{biomass\_type,bio\_gen\_type,time,node}$	Chemical energy of 'biomass_type' converted in generator 'bio_gen_type' per time step and node in MWh_{chem}
E_{inst,CSP_STOR}^{node}	Installed thermal storage capacity in CSP plants in MWh_{th}
$E_{inst}^{stor\_type,node}$	Installed storage capacity in MWh (storable energy)

$F^{hydro\_res\_gen\_type,time\_inc\_zero,node}$	Fill level of hydro reservoirs in MWh
$f_{re\_\max}^{nodefull}$	Maximum domestic renewable supply share
$F^{stor\_type,time\_inc\_zero,node}$	Fill level of storage units in MWh
$F_{CSP\_STOR}^{time\_inc\_zero,node}$	Fill level of CSP storage units in MWh_{th}
$P_{Heat}^{chp\_gen\_type,time,node}$	Generation of usable heat per CHP generator, time step and node in MW_{th}
$P_{inst}^{gen\_type,node}$	Installed generation capacity per technology ‘gen_type’ (or a subset of ‘gen_type’) in MW
$P^{gen\_type,time\_inc\_zero,node}$	Electric power generation per technology ‘gen_type’ (or a subset of ‘gen_type’), time step and node in MW
P_{inst,CSP_SF}^{node}	Installed thermal CSP solar field capacity in MW_{th}
P_{inst,CSP_PG}^{node}	Installed CSP electric power generation capacity in MW
$P_{CSP\_STOR,in}^{node}$	Thermal power flow from the CSP solar field to the storage unit
$P_{CSP\_STOR,out}^{node}$	Thermal power flow from the CSP storage unit to the turbine
$P_{inst,TRANS}^{node,aliasnode}$	Installed electric power transmission capacity in MW
$P_{TRANS}^{node,aliasnode,time}$	Electric power transmission in MW. Here: export (positive) from node to aliasnode.
$P_{inst}^{stor\_type,node}$	Installed energy conversion capacity in storage plants in MW
$P_{PC}^{stor\_type,time,node}$	Electric power consumption per storage type and time step in MW
$P_{PG}^{stor\_type,time,node}$	Electric power generation by storage type and time step in MW
$P_{CSP\_SF}^{time,node}$	Thermal power generation from CSP solar fields per time step and node in MW_{th}
$P_{CSP\_PG}^{time,node}$	Electric power generation in CSP plants per time step and node in MW
$P_{CSP\_Surplus}^{time,node}$	Surplus of thermal power from CSP plants per time step and node in MW_{th} (is discarded if storage units are full)
$P_{Surplus}^{time,node}$	Surplus electric power per time and node in MW
$P_{hydro\_res\_\inf low,used}^{time\_inc\_zero,node}$	Used share of the inflow to a hydro reservoir plant expressed in MW (water can be let pass through unused if reservoirs are full)

6.2.4 Equations

There are two different types of equations in an optimisation model: an objective function and restrictions. Here, the **objective** function assigns the total annual system costs to the variable C_{sys} and determines this variable to be minimised (eq. 31). The total annual system costs include all costs for generation capacity $C_{uni}^{gen\_type,node}$ and C_{CSP}^{node}, storage plants $C^{stor\_type,node}$, transmission capacity C_{TRANS}^{node} and for biomass consumption lowered by the heat credit paid for heat from CHP plants in all nodes.

$$
\begin{aligned}
&C_{sys} = \\
&\sum_{\substack{gen\\type}}\sum_{node} C_{uni}^{gen\_type,node} + \sum_{node} C_{CSP}^{node} + \sum_{\substack{stor\\type}}\sum_{node} C^{stor\_type,node} + \sum_{node} C_{TRANS}^{node} \\
&+ \sum_{\substack{biomass\\type}} \sum_{\substack{bio\\gen\\type}} \sum_{time} \sum_{node} E^{biomass\_type,bio\_gen\_type,time,node} \cdot c_{\mathrm{var}\,op}^{biomass\_type} \cdot \frac{8760\,h}{l_t \cdot f_{num\_time\_steps}} \\
&- \sum_{\substack{chp\\gen\\type}} \sum_{time} \sum_{node} \frac{P_{Heat}^{chp\_gen\_type,time,node}}{1+f_{loss,district\_heating}} \cdot c_{Heat} \cdot \frac{8760\,h}{f_{num\_time\_steps}} \\
&\Rightarrow \min .
\end{aligned}
\qquad \text{eq. 31}
$$

The costs for electric power generators apart from CSP plants are calculated like shown in eq. 32 as the sum of the annuities of all investments, the fixed operation costs such as personnel, maintenance and other services and the variable operation costs, i.e. costs for fuel. Biomass fuel costs are included in the system costs separately, for they do not only depend on the generator type but on the biomass type as well.

$$
\begin{aligned}
&C_{uni}^{gen\_type,node} = \\
&c_{inv}^{gen\_type} \cdot P_{inst}^{gen\_type,node} \cdot \left(f_{annuity}^{gen\_type} + f_{c\_fixop}^{gen\_type}\right) + \sum_{time} P^{gen\_type,time,node} \cdot c_{\mathrm{var}op}^{gen\_type} \cdot \frac{8760h}{f_{num\_time\_steps}}
\end{aligned}
\qquad \text{eq. 32}
$$

The costs for CSP are composed of the investment costs and the fixed and variable operation costs for the solar fields, the power generation units and the storage units (eq. 33):

$$
\begin{aligned}
&C_{CSP}^{node} = \\
&c_{inv,CSP\_SF} \cdot P_{inst,CSP\_SF}^{node} \cdot \left(f_{annuity,CSP\_SF} + f_{c\_fixop,CSP}\right) \\
&+ c_{inv,CSP\_PG} \cdot P_{inst,CSP\_PG}^{node} \cdot \left(f_{annuity,CSP\_PG} + f_{c\_fixop,CSP}\right) \\
&+ c_{inv,CSP\_STOR} \cdot E_{inst,CSP\_STOR}^{node} \cdot \left(f_{annuity,CSP\_STOR} + f_{c\_fixop,CSP}\right) \\
&+ \sum_{time} c_{\mathrm{var}\,op,CSP} \cdot P_{CSP\_PG}^{time,node} \cdot \frac{8760\,h}{f_{num\_time\_steps}}
\end{aligned}
\qquad \text{eq. 33}
$$

The storage costs per node are calculated according to eq. 34 from the investment costs and the fixed and variable operations costs for the electric power conversion unit and the storage unit separately.

$$
\begin{aligned}
&C^{stor\_type,node} = c_{inv,p}^{stor\_type} \cdot P_{inst}^{stor\_type,node} \cdot \left(f_{annuity,p}^{stor\_type} + f_{c\_fixop,p}^{stor\_type}\right) \\
&+ c_{inv,e}^{stor\_type} \cdot E_{inst}^{stor\_type,node} \cdot \left(f_{annuity,e}^{stor\_type} + f_{c\_fixop,e}^{stor\_type}\right) \\
&+ c_{\mathrm{var}op}^{stor\_type} \cdot \sum_{time} P_{PG}^{stor\_type,time,node} \cdot \frac{8760}{f_{num\_time\_steps}}
\end{aligned}
\qquad \text{eq. 34}
$$

To each node the costs of one converter and half of the costs of a transmission line between the node and the aliasnode the line connects it with are assigned (eq. 35); Summing up those costs over all lines (aliasnodes) results in the total transmission costs per node.

$$C_{TRANS}^{node} = \sum_{\substack{alias\\node}} P_{inst,TRANS}^{node,aliasnode} \cdot \left(c_{inv,TRANS\_rect} + c_{inv,TRANS\_line} \cdot D^{node,aliasnode} \cdot 0.5\right) \cdot \left(f_{annuity,TRANS} + f_{c\_fixop,TRANS}\right) \quad \text{eq. 35}$$

The **restrictions** limit the solution space. Because the model consists of only linear restrictions, the solution space is convex and therefore there are no local minima or maxima. The global optimum is the unique solution of a model run. While the objective function must be an equation, the restrictions can be inequations.

The node balance restriction (eq. 36) defines that in each node and time step, the electric load $P_{load}^{time,node}$ in that node must be covered. It can either be covered by generation $P^{gen\_type,time,node}$, $P_{CSP\_PG}^{time,node}$ and $P_{PG}^{stor\_type,time,node}$ in the node itself or by import from other nodes. Export to other nodes and storage consumption $P_{PC}^{stor\_type,time,node}$ must be regarded. The restriction formulated in words says: ‘In each node and in each time step, the sum of average electric power generation of all generator types and storage types and of import must be equal to or bigger than the sum of load, storage consumption, export and surplus’.

$$\begin{aligned}&\sum_{\substack{gen\\type}} P^{gen\_type,time,node} + P_{CSP\_PG}^{time,node} + \sum_{\substack{stor\\type}} P_{PG}^{stor\_type,time,node}\\ &+ \sum_{\substack{alias\\node}} P_{TRANS}^{aliasnode,node,time} \cdot (1 - f_{loss,trans} \cdot D^{nodefull,aliasnodefull} \cdot 1.5)\\ &\geq\\ &P_{load}^{time,node} + \sum_{\substack{stor\\type}} P_{PC}^{stor\_type,time,node} + \sum_{\substack{alias\\node}} P_{TRANS}^{node,aliasnode,time} + P_{Surplus}^{time,node}\end{aligned} \quad \text{eq. 36}$$

The share of renewable energy in the supply system f_{reg_share} is set indirectly in eq. 37 by limiting the share of the sum of fossil energy use $P^{residual,time,node}$ over time in the coverage of the total power demand.

$$\sum_{time} P^{residual,time,node} \cdot l_t \leq \left(1 - f_{reg\_share}\right) \cdot \sum_{time} P_{load}^{time,node} \cdot l_t \quad \text{eq. 37}$$

A ‘domestic supply share restriction’ was introduced in order to investigate supply structures with different shares of supply from renewable sources on the territory of nations or other regions interconnected in a network. The user-defined domestic supply share may exceed the energy that can be provided regionally. The maximum renewable energy supply on a regional territory was calculated with a conservative approach for each region (eq. 38.a), assuming that 20 % of the total generation must be stored. The minimum of this value and the user defined domestic supply share (eq. 38) was set as the lower limit of renewable generation in a node in eq. 39. The domestic supply share restriction is formulated as an annual energy balance.

$$f_{re\_\max}^{nodefull} = \min\left(f_{\substack{domestic \\ supply}}, \frac{x}{\sum_{time} P_{load}^{time,node} \cdot l_t} \right)$$ eq. 38

where

$$x = \left(\begin{array}{l} \sum_{\substack{reg \\ gen \\ type}} \sum_{time} P_{\max}^{reg\_gen\_type,time,node} \cdot l_t \\ + \sum_{time} P_{\max,CSP\_SF}^{time,node} \cdot \eta_{CSP\_PG} \cdot (1 - f_{pr,CSP}) \cdot l_t \\ + \sum_{time} P_{hydro\_res\_\inf low}^{time,node} \cdot l_t \\ + \sum_{\substack{biomass \\ type}} E_{annual,chem}^{biomass\_type,node} \cdot \frac{f_{num\_time\_steps} \cdot l_t}{8760h} \cdot \min\left(\begin{array}{c} \eta^{bio\_st} \\ \eta^{bio\_st\_chp} \\ \eta^{bio\_biogas\_chp} \end{array} \right) \\ + P_{inst,\max}^{geo,node} \cdot f_{num\_time\_steps} \cdot l_t \cdot f_{av}^{geo} \\ + P_{inst,\max}^{geo\_chp,node} \cdot f_{num\_time\_steps} \cdot l_t \cdot f_{av}^{geo\_chp} \end{array} \right) \cdot \left(1 - \left(1 - \min\left(\begin{array}{c} \eta^{caes} \\ \eta^{\substack{pumped \\ storage}} \\ \eta^{hydrogen} \end{array} \right) \right) \cdot 0.2 \right)$$ eq. 38.a

$$\begin{aligned} & \sum_{\substack{gen \\ type}} \sum_{time} P^{gen\_type,time,node} \cdot l_t + \sum_{time} P_{CSP\_PG}^{time,node} \cdot l_t \\ & + \sum_{\substack{stor \\ type}} \sum_{time} P_{PG}^{stor\_type,time,node} \cdot l_t - \sum_{\substack{stor \\ type}} \sum_{time} P_{PC}^{stor\_type,time,node} \cdot l_t \\ & \geq \\ & f_{re\_\max}^{nodefull} \cdot \sum_{time} P_{load}^{time,node} \cdot l_t \end{aligned}$$ eq. 39

Enough reliably available capacity is planned in each node to cover the peak load in any time step (eq. 40). This can be done with backup capacity such as natural gas turbines which are never operated in the investigated time period but might be necessary to use in another year, resulting in marginal consumption of natural gas or additionally provided renewable fuels. The reliably available capacity is calculated for each time step and node in eq. 41, assuming an average availability of 95 % of the storage capacity.

$$P_{av}^{time,node} \geq P_{load,peak}^{node}$$ eq. 40

$$\begin{aligned} P_{av}^{time,node} = & \sum_{\substack{\mathrm{var} \\ gen \\ type}} P^{\mathrm{var}\_gen\_type,time,node} + \sum_{\substack{dispatch \\ gen \\ type}} P_{inst}^{dispatch\_gen\_type,node} \cdot f_{av}^{dispatch\_gen\_type} \\ & + P_{CSP\_PG,inst}^{node} \cdot f_{CSP,av} + \sum_{\substack{hydro \\ res \\ type}} P_{inst}^{hydro\_res\_type,node} \cdot f_{av}^{hydro\_res\_type} + \sum_{\substack{stor \\ type}} P_{inst}^{stor\_type,node} \cdot 0.95 \end{aligned}$$ eq. 41

Of each generator type for the conversion of renewable energy, only a limited amount of electric power generation capacity $P_{inst}^{gen\_type,node}$ can be installed: $P_{inst,\max}^{gen\_type,node}$. This restriction was formulated in eq. 42. It is valid for all generator types but biomass conversion technologies. The capacity of biomass conversion plants is only limited by their costs. For the generator type 'residual', it was assumed that as much capacity as needed can be built; the limit was set to 'infinite'.

$$P_{inst}^{gen\_type,node} \le P_{inst,\max}^{gen\_type,node} \qquad \text{eq. 42}$$

In each time step the electric power generation of variable generator types $P^{\mathrm{var}\_gen\_type,time,node}$ is limited by the installed capacities $P_{inst}^{\mathrm{var}\_gen\_type,node}$ and by the resource availability. The restriction formulated in words is: 'the generation potential of the installed capacity is proportional to the potential generation $P_{\max}^{\mathrm{var}\_gen\_type,time,node}$ of the maximum installable capacity $P_{inst,\max}^{\mathrm{var}\_gen\_type,node}$ multiplied by the ratio of the installed capacity to the maximum installable capacity'. The restriction was set up without divisions as given in eq. 43. For all generator types with maximum installable capacities of zero, the potential generation in each time step was set to zero.

$$P^{\mathrm{var}\_gen\_type,time,node} \cdot P_{inst,\max}^{\mathrm{var}\_gen\_type,node} \le P_{\max}^{\mathrm{var}\_gen\_type,time,node} \cdot P_{inst}^{\mathrm{var}\_gen\_type,node} \qquad \text{eq. 43}$$

The power generation $P^{dispatch\_gen\_type,time,node}$ of dispatchable generator types in each time step is limited by the installed capacity $P_{inst}^{dispatch\_gen\_type,time,node}$ and the availability of the plant, taken into account with the availability factors $f_{av}^{dispatch\_gen\_type}$ in eq. 44.

$$P^{dispatch\_gen\_type,time,node} \le P_{inst}^{dispatch\_gen\_type,time,node} \cdot f_{av}^{dispatch\_gen\_type} \qquad \text{eq. 44}$$

Like for the dispatchable generator types, the electric power generation $P^{hydro\_res\_gen\_type,time,node}$ in hydro reservoir power plants is limited by the installed capacity $P_{inst}^{hydro\_res\_gen\_type,time,node}$ and the availability of the plant $f_{av}^{hydro\_res\_gen\_type}$ (eq. 45).

$$P^{hydro\_res\_gen\_type,time,node} \le P_{inst}^{hydro\_res\_gen\_type,time,node} \cdot f_{av}^{hydro\_res\_gen\_type} \qquad \text{eq. 45}$$

The used inflow per time step and node, $P_{hydro\_res\_\inf low,used}^{time,node}$, is equal to or smaller than the actual inflow in the time step and node, $P_{hydro\_res\_\inf low}^{time,node}$. That means that a part of the inflow can be left unused if e.g. the reservoirs are full and the turbine is operated at full capacity or there are surpluses in the network already (eq. 46).

$$P_{hydro\_res\_\inf low,used}^{time,node} \le P_{hydro\_res\_\inf low}^{time,node} \qquad \text{eq. 46}$$

The fill level $F^{hydro\_res\_gen\_type,time\_inc\_zero,node}$ of hydro reservoirs is calculated according to eq. 47, the storage balance, from the fill level in the previous time step, from the used inflow $P_{hydro\_res\_\inf low,used}^{time\_inc\_zero,node}$ and from the electric power generation $P^{hydro\_res\_gen\_type,time\_inc\_zero,node}$ in the time step. It is calculated for all time steps apart from time step zero.

$$F^{hydro\_res\_gen\_type,time\_inc\_zero,node} = F^{hydro\_res\_gen\_type,time\_inc\_zero-1,node} + \left(P^{time\_inc\_zero,node}_{hydro\_res\_\inf low,used} - P^{hydro\_res\_gen\_type,time\_inc\_zero,node}\right) \cdot l_t \qquad \text{eq. 47}$$

The upper limit of the reservoir fill level is the reservoir size which is specified by a number of full load hours of turbine operation $f^{hydro\_res\_gen\_type}_{power2storage}$ multiplied with the installed turbine capacity $P^{hydro\_res\_gen\_type,node}_{inst}$ as given in eq. 48.

$$F^{hydro\_res\_gen\_type,time\_inc\_zero,node} \leq P^{hydro\_res\_gen\_type,node}_{inst} \cdot f^{hydro\_res\_gen\_type}_{storage2\,power} \qquad \text{eq. 48}$$

In order to avoid initial fill levels that contribute to electric power supply but are not based on generation in the regarded time steps, an annual cycle was simulated by defining the fill level in the last time step regarded and in the first time step - time step zero - to be equal (eq. 49).

$$F^{hydro\_res\_gen\_type,first\_hour,node} = F^{hydro\_res\_gen\_type,last\_hour,node} \qquad \text{eq. 49}$$

The installed capacity of CSP solar fields, P^{node}_{inst,CSP_SF}, is limited by the maximum installable solar field capacity $P^{node}_{inst,\max,CSP\_SF}$ (eq. 50).

$$P^{node}_{inst,CSP\_SF} \leq P^{node}_{inst,\max,CSP\_SF} \qquad \text{eq. 50}$$

The heat generation $P^{time,node}_{CSP\_SF}$ of CSP solar fields is limited by the installed solar field capacity and the irradiation in a time step. The heat generation of the installed capacity is proportional to the heat generation $P^{time,node}_{\max,CSP\_SF}$ of the maximum installed capacity multiplied with the ratio of the installed capacity to the maximum installed capacity $P^{node}_{inst,\max,CSP\_SF}$. The restriction was formulated without division as given in eq. 51. For all regions without CSP potential, the potential heat generation in each time step was set to zero.

$$P^{time,node}_{CSP\_SF} \cdot P^{node}_{inst,\max,CSP\_SF} = P^{time,node}_{\max,CSP\_SF} \cdot P^{node}_{inst,CSP\_SF} \qquad \text{eq. 51}$$

The heat generation $P^{time,node}_{CSP\_SF}$ from the solar field feeds the power generation unit and the storage unit. In time steps without irradiation, the power generation unit can be fed by the storage unit. In case that neither the storage unit nor the turbine can use any further energy flow, surplus heat can occur (eq. 52).

$$P^{time,node}_{CSP\_SF} = \frac{P^{time,node}_{CSP\_PG}}{\left(\eta_{CSP\_PG} \cdot \left(1 - f_{pr,CSP}\right)\right)} + \frac{P^{node}_{CSP\_STOR,in}}{1 - \left(\dfrac{1-\eta_{CSP\_STOR}}{2}\right)} - P^{node}_{CSP\_STOR,out} \cdot \left(1 - \left(\frac{1-\eta_{CSP\_STOR}}{2}\right)\right) + P^{time,node}_{CSP\_SURPLUS} \qquad \text{eq. 52}$$

In each node, the CSP power generation capacity P^{node}_{inst,CSP_PG} must be sufficient to deliver the highest power generation $P^{time,node}_{CSP\_PG}$ that occurs in any time step (eq. 53). It has no upper limit, i.e. it is only limited by its costs.

$$P_{inst,CSP\_PG}^{node} \geq P_{CSP\_PG}^{time,node} \qquad \text{eq. 53}$$

The installed CSP storage capacity E_{inst,CSP_STOR}^{node} must be bigger than or equal to the highest fill level $F_{CSP\_STOR}^{time,node}$ that occurs in any time step (eq. 54). It has no upper limit, i.e. it is only limited by its costs.

$$E_{inst,CSP\_STOR}^{node} \geq F_{CSP\_STOR}^{time,node} \qquad \text{eq. 54}$$

The fill level $F_{CSP\_STOR}^{time,node}$ of CSP storage units is calculated according to the storage balance (eq. 55) from the fill level in the previous time step and the heat flows $P_{CSP\_STOR,in}^{node}$ and $P_{CSP\_STOR,out}^{node}$ to or from the storage unit. It is calculated for all time steps apart from time step zero.

$$F_{CSP\_STOR}^{time,node} = F_{CSP\_STOR}^{time-1,node} + P_{CSP\_STOR,in}^{node} \cdot l_t - P_{CSP\_STOR,out}^{node} \cdot l_t \qquad \text{eq. 55}$$

Like for hydro reservoirs, an annual cycle was simulated by defining the fill level in the last time step regarded and in the first time step - time step zero - to be equal (eq. 56).

$$F_{CSP\_STOR}^{first\_hour,node} = F_{CSP\_STOR}^{last\_hour,node} \qquad \text{eq. 56}$$

In each node and for each biomass type, the sum of biomass consumed by electric power generators $E^{biomass\_type,bio\_gen\_type,time,node}$ in all time steps must not exceed the total biomass available in the time steps regarded which is calculated as a fraction of the annually available biomass $E_{annual,chem}^{biomass\_type,node}$ (eq. 57).

$$\sum_{\substack{bio\\gen\\type}} \sum_{time} E^{biomass\_type,bio\_gen\_type,time,node} \leq E_{annual,chem}^{biomass\_type,node} \cdot \frac{f_{num\_time\_steps}}{8760h} \cdot l_t \qquad \text{eq. 57}$$

In each node and in each time step, the electric power generation of each (biomass) generator type $P^{bio\_gen\_type,time,node}$ is the sum of the consumption of the different biomass types $E^{biomass\_type,bio\_gen\_type,time,node}$ that can be converted by the generator type as specified by the factor $f^{bio\_gen\_type,biomass\_type}$, multiplied by its efficiency and divided by the duration of the time step in h (eq. 58).

$$P^{bio\_gen\_type,time,node} = \frac{\sum_{\substack{biomass\\type}} E^{biomass\_type,bio\_gen\_type,time,node} \cdot f^{bio\_gen\_type,biomass\_type} \cdot \eta^{bio\_gen\_type}}{l_t} \qquad \text{eq. 58}$$

The electric power generation capacities of pumped hydro storage plants, $P_{inst}^{pumped\_stor\_type,node}$, were considered not to be extended in the future, thus they were limited by the capacities in operation $P_{inst,\max}^{pumped\_stor\_type,node}$ (eq. 59).

$$P_{inst}^{pumped\_stor\_type,node} \leq P_{inst,\max}^{pumped\_stor\_type,node} \qquad \text{eq. 59}$$

The typical application of pumped storage power today is daily peak shaving; thus the storage capacities of pumped hydro storage plants in operation were assumed to allow for a fixed number of full load hours of electric power generation ($f_{PG2STOR}^{pumped\_storage}$ =8). The energy storage capacity in operation served as a preset value for the energy storage capacity $E_{inst}^{pumped\_storage,node}$ as given in eq. 60.

$$E_{inst}^{pumped\_storage,node} = P_{inst,\max}^{pumped\_storage,node} \cdot f_{PG2STOR}^{pumped\_storage} \qquad \text{eq. 60}$$

The electric power generation in storage plants $P_{PG}^{stor\_type,time,node}$ is limited by the installed power generation capacity $P_{inst}^{stor\_type,node}$ in the plant (eq. 61). The same applies to the electric load of storage plants, $P_{PC}^{stor\_type,time,node}$ (eq. 62).

$$P_{PG}^{stor\_type,time,node} \le P_{inst}^{stor\_type,node} \qquad \text{eq. 61}$$

$$P_{PC}^{stor\_type,time,node} \le P_{inst}^{stor\_type,node} \qquad \text{eq. 62}$$

The fill level of the storage units $F^{stor\_type,time,node}$ is calculated according to the storage balance (eq. 63) from the fill level in the previous time step $F^{stor\_type,time-1,node}$ and from storage consumption $P_{PC}^{stor\_type,time,node}$ and generation $P_{PG}^{stor\_type,time,node}$. The round-trip efficiency is divided into two parts which are taken into account during charging and discharging of the storage unit. The storage fill level is calculated for all time steps apart from time step zero, for which it is set in eq. 65 to the same value as it has in the last time step in order to level the balance.

$$\begin{aligned} F^{stor\_type,time,node} &= F^{stor\_type,time-1,node} \cdot \left(1 - f_{loss}^{stor\_type}\right) \\ &+ P_{PC}^{stor\_type,time,node} \cdot \left(1 - \left(\frac{1-\eta^{stor\_type}}{2}\right)\right) \cdot l_t \\ &- \frac{P_{PG}^{stor\_type,time,node}}{\left(1 - \left(\frac{1-\eta^{stor\_type}}{2}\right)\right)} \cdot l_t \end{aligned} \qquad \text{eq. 63}$$

The fill level of pumped storage units with natural inflow in Norway, $F^{stor\_type,time,node=NO}$, is calculated according to the general storage balance but additionally takes into account the natural inflow into hydro reservoirs in Norway (eq. 64).

$$\begin{aligned} F^{stor\_type,time,node=NO} &= F^{stor\_type,time-1,node=NO} \cdot \left(1 - f_{loss}^{stor\_type}\right) + P_{hydro\_res\_\inf low,used}^{time,node=NO} \\ &+ P_{PC}^{stor\_type,time,node=NO} \cdot \left(1 - \left(\frac{1-\eta^{stor\_type}}{2}\right)\right) \cdot l_t \\ &- \frac{P_{PG}^{stor\_type,time,node=NO}}{\left(1 - \left(\frac{1-\eta^{stor\_type}}{2}\right)\right)} \cdot l_t \end{aligned} \qquad \text{eq. 64}$$

$$F^{stor\_type,\,first\_hour,node} = F^{stor\_type,last\_hour,node}$$ eq. 65

The fill level of the storage unit $F^{stor\_type,time,node}$ has an upper limit for each storage type, time step and node: the installed storage capacity $E_{inst}^{stor\_type,node}$ (eq. 66).

$$F^{stor\_type,time,node} \leq E_{inst}^{stor\_type,node}$$ eq. 66

For each node-aliasnode couple, a limit, $P_{inst,\max,TRANS}^{node,aliasnode}$, was set for the installed transmission capacity $P_{inst,TRANS}^{node,aliasnode}$ (eq. 67). It was set either to zero (no line allowed) or to infinite (line allowed); the capacity of allowed lines is a result of the optimisation, limited only by their costs.

$$P_{inst,TRANS}^{node,aliasnode} \leq P_{inst,\max,TRANS}^{node,aliasnode}$$ eq. 67

The transmission of electric power between two nodes, $P_{TRANS}^{node,aliasnode,time}$, must not exceed the installed transmission capacity between the two nodes, $P_{inst,TRANS}^{node,aliasnode}$ (eq. 68).

$$P_{TRANS}^{node,aliasnode,time} \leq P_{inst,TRANS}^{node,aliasnode}$$ eq. 68

The transmission capacities between ‘node and aliasnode’, $P_{inst,TRANS}^{node,aliasnode}$, are equal to the transmission capacity between ‘aliasnode and node’, $P_{inst,TRANS}^{aliasnode,node}$ (eq. 69).

$$P_{inst,TRANS}^{node,aliasnode} = P_{inst,TRANS}^{aliasnode,node}$$ eq. 69

The maximum heat output of each CHP generator type $P_{HEAT}^{chp\_gen\_type,time,node}$ in each node and time step has a fixed ratio to the electric power output , $f_{rho}^{chp\_gen\_type}$ (eq. 70).

$$P_{HEAT}^{chp\_gen\_type,time,node} \leq P^{chp\_gen\_type,time,node} \cdot f_{rho}^{chp\_gen\_type}$$ eq. 70

The total heat output $P_{HEAT}^{chp\_gen\_type,time,node}$ of all CHP generators in each node and time step a heat credit can be paid for is limited by the total heat load $P_{heat}^{time,node}$ (eq. 71).

$$\sum_{\substack{chp\\gen\\type}} P_{HEAT}^{chp\_gen\_type,time,node} \leq P_{heat}^{time,node} \cdot \left(1 + f_{loss,district\_heating}\right)$$ eq. 71

Different solvers and different solution methods were tested. The CPLEX solver and the barrier solution method showed the shortest solution times and were used for the model runs in chapter 7. While the simplex method searches for the minimum or maximum along the edges of the of the solution space, the barrier method is a so-called interior points method which tries to find the optimum through the inside of the solution space.

7 Model sensitivity and example of application

In this chapter the sensitivity of the model REMix to parameter changes is investigated and discussed. The parameter variations were performed with a relatively small network of Germany, Norway and Algeria. The combination of these countries was chosen because it covers all possible resources and storage options but it keeps the model running times in acceptable limits.

Secondly, the model is applied to the regions in the EUNA network in order to estimate costs and system structures that result from the cost minimisation under the given assumptions. Two cases are investigated in order to estimate the influence of interregional power transmission on the costs and system structures: 1) no transmission is allowed, all regions are treated as island grids; 2) the transmission capacities are limited only by the costs.

All model runs were performed with scenario parameters for the year 2050 and in all cases, the renewable energy share in the supply was set to 100 %.

The description of the steps required to reach a certain system structure and the modelling of the temporally intermediate system structures is referred to as a ‘scenario’ here. Since REMix designs a system structure for only one specific year in the future, the system structures that are described here are referred to as ‘cases’, not ‘scenarios’.

7.1 Model sensitivity

Model runs with the parameter variations listed in table 7.1.1 were performed for a network of Germany, Norway and Algeria (DE-NO-DZ). Transmission lines were allowed between Norway and Germany and between Germany and Algeria. The resulting annual power generation of the different technologies is listed in table 7.1.2, its structure is displayed in figure 7.1.1. While the table gives the absolute numbers, the values in the diagram are all referred to the total annual power generation = 100 % in order to make the structures visually comparable. The installed capacities, the costs and the data for the individual countries are listed in tables 10.1.13 - 10.1.23 in the annex.

The power demand amounts to 910 TWh/a. In the base case 966 TWh/a of electric power are generated including the natural inflow into pumped hydro power plants in Norway, equivalent to 47 TWh/a. The losses – transmission losses, storage losses and surplus - amount to around 6 % of the total generation: 22 TWh/a of transmission losses and 35 TWh/a of storage losses. No surplus occurs. 40 % of the power generation comes from offshore wind parks, 31 % from CSP plants, just beyond 11 % from geothermal combined heat and power generation, 8 % from hydro power plants (including natural inflow into pumped storage reservoirs in Norway), 6.7 % from onshore wind parks, 3 % from biomass combined heat and power and below 1 % from PV plants.

The parameter variations were chosen such that the costs of generation technologies with high shares in the base case were increased and the costs of generation technologies with low shares were decreased in order to see whether they lose their dominance or gain importance in system within the tested cost range. Because of the questionable social acceptance of additional transmission lines some model runs with limited transmission capacity were performed. Since no comprehensive information about the storage potential for compressed air energy and hydrogen storage in salt caverns was available, the storage costs were set to the costs of storage tanks instead of caverns in some cases. In these ‘conservative storage assumptions’ cases, investment costs were taken into account for reservoirs of pumped hydro power in Norway which were else assumed only to have operation costs but not to require extra investment. Transmission limitations and conservative storage assumptions were combined in two cases to form a ‘worst case’ for these infrastructures for power balancing.

Table 7.1.1: Network Germany – Norway – Algeria: parameter variations.

Case denomination	**Explanation**
Base	All base parameters have the default values given in the technology description sections
windcost120	Wind onshore and wind offshore investment costs at 120 % of base value; all other parameters like base case
windcost150	Wind onshore and wind offshore investment costs at 150 % of base value; all other parameters like base case
windoffshcost120	Wind offshore investment costs at 120 % of base value; all other parameters like base case
windoffshcost150	Wind offshore investment costs at 150 % of base value; all other parameters like base case
windonshcost120	Wind onshore investment costs at 120 % of base value; all other parameters like base case
pvcost80	PV investment costs at 80 % of base value; all other parameters like base case
pvcost50	PV investment costs at 50 % of base value; all other parameters like base case
cspcost120	Investment costs of all CSP components at 120 % of base value; all other parameters like base case
biocost80	Biomass investment costs and biomass fuel costs at 80 % of base value; all other parameters like base case
hydrocost50	All hydro power investment costs at 50 % of base value; all other parameters like base case
geocost120	Geothermal power and geothermal CHP investment costs at 120 % of base value; all other parameters like base case
geocost80	Geothermal power and geothermal CHP investment costs at 80 % of base value; all other parameters like base case
geocost50	Geothermal power and geothermal CHP investment costs at 50 % of base value; all other parameters like base case
load200	Hourly load in all regions at 200 % of base value; all other parameters like base case
load150	Hourly load in all regions at 150 % of base value; all other parameters like base case
load120	Hourly load in all regions at 120 % of base value; all other parameters like base case
load80	Hourly load in all regions at 80 % of base value; all other parameters like base case
load50	Hourly load in all regions at 50 % of base value; all other parameters like base case
translim2500	All transmission capacities restricted to 2500 MW; all other parameters like base case
translim1600	All transmission capacities restricted to 16000 MW; all other parameters like base case
storcons	Conservative storage parameters: In Norway the investment costs for pumped storage reservoirs were set to 10 €/kWh instead of 0 €/kWh; in all regions the costs for the storage capacities of compressed air and hydrogen were set to the costs of tanks instead of salt caverns, i.e. 150 €/kWh for CAES and 10 €/kWh for hydrogen; all other parameters like base case
storcons translim2500	All transmission capacities restricted to 2500 MW; all other parameters like ‘storcons’
storcons translim16000	All transmission capacities restricted to 16000 MW; all other parameters like ‘storcons’

Table 7.1.2: Total annual energy sums in TWh/a; storage capacities in TWh in the network DE-NO-DZ; different parameter variations.

	base	windcost120	windcost150	windoffsh cost120	windoffsh cost150	windonsh cost120	pvcost80	pvcost50	cspcost120	biocost80	hydrocost50	geocost120	geocost80	geocost50	load200	load150	load120	load80	load50	translim 2500	translim 16000	storcons	storcons t.lim2500	storcons t.lim16000
Annual power demand	910	910	910	910	910	910	910	910	910	910	910	910	910	910	1820	1365	1092	728	455	910	910	910	910	910
Annual power demand / generation	94	94	93	94	94	94	94	93	94	94	94	93	95	95	93	93	94	94	94	90	94	96	90	96
Annual generation (without n. i.[1] in NO)	919	917	930	917	922	920	918	936	921	918	924	933	912	906	1917	1420	1119	723	434	965	926	901	959	897
Annual gen. (inc. n. i.[1] in NO)	966	965	978	964	969	968	966	983	968	965	972	981	960	953	1965	1468	1167	771	482	1012	973	948	1006	944
Geothermal power	0	0	0	0	0	0	0	0	0	0	0	0	0	78	0	0	0	0	0	0	0	0	0	0
Geothermal CHP	103	118	154	118	123	104	105	103	103	111	102	0	170	170	113	111	108	103	96	169	118	119	168	170
N.i.[1] in NO	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
Run-of-river hydro (old+mod.)	28	28	28	28	28	28	28	28	28	28	135	28	28	28	28	28	28	28	28	28	28	28	28	28
Run-of-river hydro (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reservoir hydro	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.2	2.3
Biomass (steam turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	17	35	21
Biomass (steam turb., CHP)	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	5.0	0.0	2.2
Biomass (biogas CHP)	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Wind onshore	65	60	70	257	308	0	60	93	86	69	138	49	87	95	88	37	54	76	59	60	97	195	114	175
Wind offshore	390	325	132	108	0	455	384	276	435	379	228	495	308	238	916	702	514	257	99	408	373	229	384	251
Photovoltaic	1.6	11	11	5.5	1.9	5.0	35	268	16	1.1	7.2	12	3.6	4.7	7.4	9.3	5.0	1.5	0.4	66	10	9.0	57	2.7
CSP	299	343	503	370	430	297	275	136	222	298	284	318	284	261	732	502	378	226	120	203	268	285	159	233
Residual (gas turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission losses	-22	-23	-33	-26	-30	-22	-21	-28	-21	-21	-25	-27	-18	-14	-64	-40	-28	-15	-7.7	-3.5	-15	-26	-3.4	-16
Storage losses	-35	-31	-35	-28	-30	-35	-35	-41	-38	-34	-36	-44	-32	-30	-80	-63	-47	-27	-17	-80	-48	-11	-53	-16
Surplus	0	0	0	0	0	0	0	-4.5	0	0	-0.9	0	0	0	-0.4	0	0	0	-1.6	-19	-0.3	-0.7	-41	-2.4
Storage capacity in TWh	20	20	34	17	20	20	19	20	19	19	28	20	19	18	36	29	23	16	11	32	20	2.2	2.6	1.8
Pumped storage	3.3	3.0	2.0	2.5	2.6	3.6	3.0	2.4	3.2	3.3	2.2	2.7	2.5	1.8	2.9	2.5	2.7	2.1	1.0	1.6	1.5	2.2	0.8	1.5
CAES	0	0	0	0	0	0	0	0.1	0	0	0	0	0	0	0.5	0.1	0	0	0	0.6	0.1	0	0	0
Hydrogen	16	17	32	14	17	17	16	17	16	16	26	17	16	16	33	26	21	14	10	30	19	0	1.8	0.4
Annual district heat from CHP	272	301	355	299	307	273	275	271	271	286	269	65	374	374	291	287	282	271	258	363	299	263	320	327
Storage input in % of an. Gen.	8.0	6.9	6.6	6.6	6.7	8.1	7.9	11	8.9	7.8	7.2	9.7	7.0	6.2	9.2	9.3	8.7	7.1	5.6	15	10	3.6	7.6	3.8

1) Annual natural inflow into pumped hydro power plants in Norway

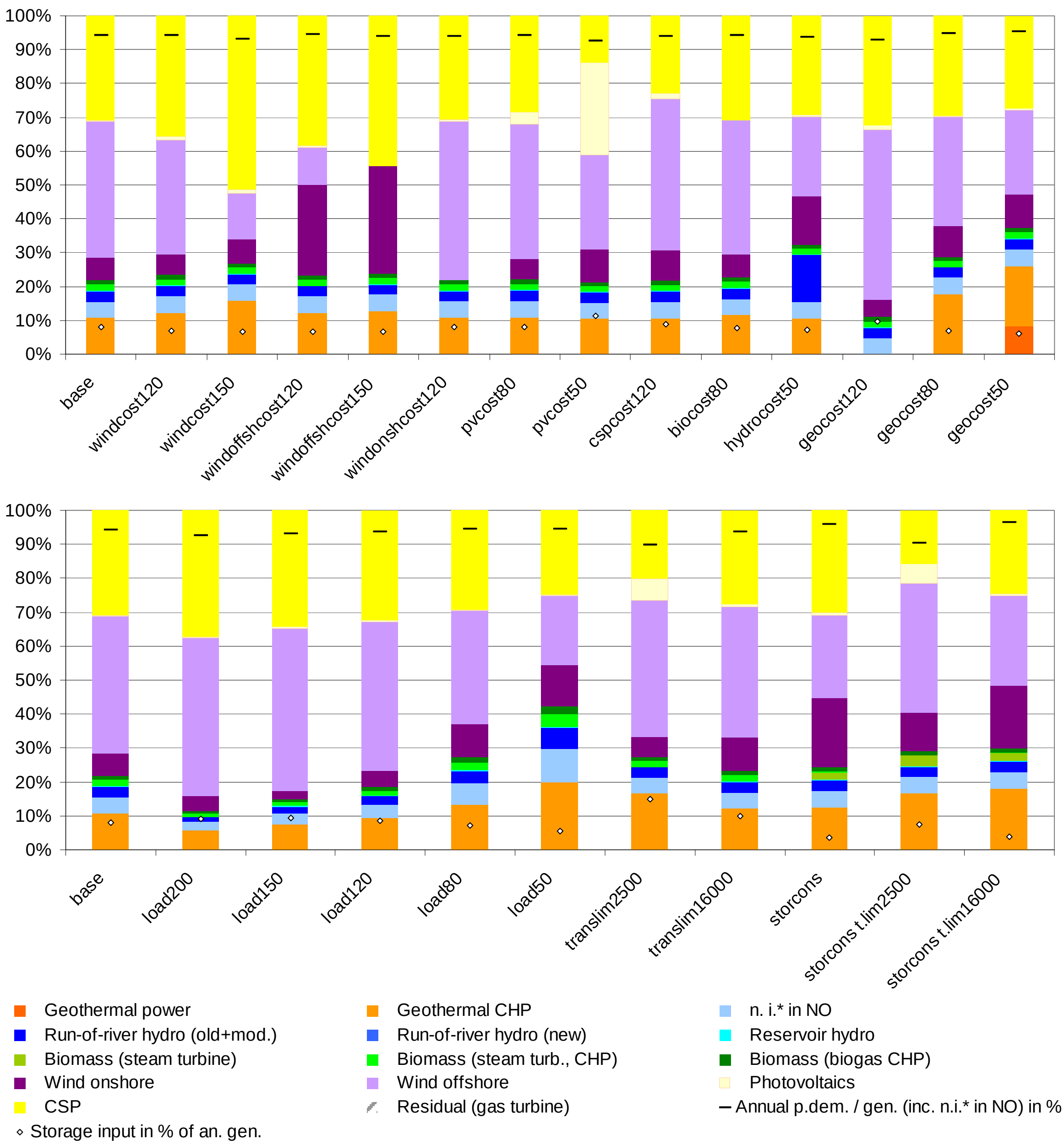

Figure 7.1.1: Normalised total annual electric power generation in the network DE-NO-DZ; different parameter variations (see Table 7.1.1). On top: base case and variations of generation costs. At the bottom: base case and variation of annual load, transmission restrictions, storage restrictions and costs. * 'n.i. in NO': Annual natural inflow into pumped hydro power plants in Norway.

7.1.1 Cost parameter variations

In this section the structure of the power generation in the cases with varied cost parameters, marked by the word 'cost' in the denomination, is described.

Germany is the only country in the three country network with a geothermal power and CHP potential. Geothermal power without district heating is only applied when the investment costs are at 50 % of the base case costs. The share of geothermal CHP in the total power generation is almost constant in all cases with varied cost parameters. It is hardly affected by changes of the costs of PV, concentrating solar, hydro and biomass power plants. Its share in the total power generation increases from 11 % to 16 % when the investment costs for wind power are at 150 % of the base case costs. However, this cost development in the period of the coming 40 years is unlikely. In the case of onshore wind power, this would even mean an increase of the investment costs from 1160 €/kW in the year 2010 to 1350 €/kW in the year 2050. The share of geothermal CHP is strongly influenced by costs for the geothermal power plants themselves: geothermal power generation disappears completely through the cost minimisation if the costs are only 20 % higher. On the other hand, it is increased from 12 % in base case to almost 18 % when the investment costs are 80 % or 50 % of the base case costs. In these cases the potential is completely exploited. In the case 'geocost50' geothermal power plants without heat delivery contribute 8 % of the total power generation. The potential is then completely exploited. A relatively small variation of the investment costs, which is well in the possible range of cost developments especially of the young technology of enhanced geothermal systems, can result in it being one major contributor to the power supply or of it playing no role at all in the energy mix.

The share of biomass is almost constant and even unaffected by the reduction of biomass power plant investment costs and fuel costs to 80 % of the base case values.

The share of hydro power is rather stable in all cases apart from the hydro power investment cost variations: hydro power investment costs of 50 % of the base case costs lead to the increase of the hydro power share in the total generation from 8 % to 19 %, the additional hydro power coming from the technology category 'old and modernised plants' in Norway. In all other cases the Norwegian power plant mix does not contain any run-of-river hydro power. The cost minimisation eliminates this option at the given costs assumption. In Libya there is also a small hydro power potential. This is not exploited in any of the model runs.

The wind power share is quite variable: it is highest when wind power generation replaces geothermal CHP generation because of elevated investment costs for geothermal CHP in the case 'geocost120'. The share of onshore wind power varies strongly only when wind onshore or wind offshore costs are varied. Onshore wind power is completely replaced by offshore wind power in the case 'windonsh_cost120' in which the investment costs for onshore wind turbines are only 20 % higher than in the base case. In the cases with only offshore wind investment costs increased, the reduced offshore wind power generation is compensated by onshore wind power in combination with CSP, completely replacing it when the offshore wind investment costs are at 150 % of the base case investment costs.

In all cases apart from the cases with a transmission limit set to 2500 MW per transmission line, photovoltaic power plants are only built in Algeria. With the transmission limit, some PV is also built in Germany. PV only plays a major role of 27 % in the total generation if its investment costs are at 50 % of base case costs. In that case, it reduces the wind share to less than 40 % and the CSP share to around 14 %. At 80 % of the investment costs, the share amounts to 3.6 %. In all other cases, the PV share in the total generation is even lower.

Algeria is the only region in the network with a concentrating power potential. The share of CSP in the total power generation is very variable: the highest share of 51 % occurs when the investment costs for wind power are at 150 % of the base case costs. The resulting lower wind share is almost completely compensated by CSP and by some more geothermal power. The lowest CSP share in the total power generation of 14 % occurs when the costs for PV are at 50 % of the base case costs. The increase of the CSP costs themselves to 120 % of the base case costs has little influence on the CSP share in the generation. The configuration of the CSP plants changes in the cost variation cases as well, as can be seen in table 7.1.3: the solar multiple is between 2.6 (case ‘pvcost50’) and 3.9 (case ‘windcost150’). On average it amounts to 3.2. The storage capacity suffices for between 9.7 h (case ‘cspcosts120’) and 13.7 h (case ‘windcost150’) of turbine full load operation. On average it amounts to 12.5.

Table 7.1.3: CSP characteristics: solar multiple and relation between storage capacity and thermal turbine power input given in full load hours (flh) of turbine operation. Different parameter variations.

	base	windcost120	windcost150	windoffsh cost120	windoffsh cost150	windonsh cost120	pvcost80	pvcost50	cspcost120	biocost80	hydrocost50	geocost120	geocost80	geocost50
Solar multiple	3.2	3.4	3.9	3.3	3.4	3.3	3.2	2.6	2.7	3.2	3.2	3.2	3.2	3.2
Storage cap. in flh of turbine operation	12.5	12.9	13.7	12.8	12.6	12.7	12.8	13.4	9.7	12.6	11.9	12.6	12.7	12.7

	load200	load150	load120	load80	load50	translim 2500	translim 16000	storcons	storcons t.lim2500	storcons t.lim16000
Solar multiple	3.2	3.2	3.2	3.2	3.3	3.5	3.3	3.3	3.8	3.2
Storage cap. in flh of turbine operation	12.6	12.8	12.6	12.7	12.3	14.9	13.0	12.7	20.2	12.2

The losses due to storage, transmission and surplus vary between 4.6 % and 7.5 %, on average they amount to 6.1 % in the cost variation cases. The annual power demands are marked in the diagrams in figure 7.1.1 by black bars. The white dot with the black border in the same diagrams indicates the share of the total annual power generation that is stored before it is consumed. This share varies between 6.2 % (case ‘geocost50’) and 11.3 % (case ‘pvcost50’), and it amounts to 7.9 % on average in the cost variation cases.

Table 7.1.4: Transmission capacities in the network of Germany, Norway and Algeria (DE-NO-DZ) in GW, transmission grid length in TWkm. Different parameter variations.

	base	windcost120	windcost150	windoffsh cost120	windoffsh cost150	windonsh cost120	pvcost80	pvcost50	cspcost120	biocost80	hydrocost50	geocost120	geocost80	geocost50
Norway - Germany	37	35	21	35	27	38	37	36	39	37	38	44	30	22
Germany - Algeria	19	24	44	28	36	19	20	51	18	19	20	22	18	17
Transmission grid length in TWkm	117	126	151	137	143	119	119	197	117	117	121	138	102	83

	load200	load150	load120	load80	load50	translim 2500	translim 16000	storcons	storcons t.lim2500	storcons t.lim16000
Norway - Germany	88	55	42	26	14	2.5	16	42	2.5	16
Germany - Algeria	57	37	26	14	8.6	2.5	16	22	2.5	16
Transmission grid length in TWkm	308	196	143	84	47	11	70	133	11	70

The capacity of the transmission lines, listed in table 7.1.4, varies strongly with the assumptions about the costs of the generation technologies. The capacity of the line between Norway and Germany is 37 GW in the base case and ranges between 21 GW and 44 GW as a result of the cost parameter variations. Germany and Algeria are connected by a 19 GW line in the base case and the capacity ranges between 17 GW and 51 GW due to the cost variations. The length of the grid, i.e. the sum of the lengths of each line multiplied by its capacity, ranges between 11 TWkm and 308 TWkm considering all parameter variations. It ranges between 83 TWkm and 197 TWkm, only considering the generation cost variations. The share of the transmission costs in the total system costs is below 5.1 % in all regarded cases. The transmission lines are limited primarily by their function for the exchange and little by their costs. This leads to the strong variability with the energy mix in the system.

7.1.2 Load, transmission and storage parameter variations

No geothermal power without district heating occurs in any of the load, transmission and storage parameter variations. In most cases the absolute amount of geothermal CHP generation is very stable; therefore the relative share varies with the power demand. In some cases the geothermal CHP generation is increased compared to its share of near 11 % in the power generation in the base case. It amounts to 16.7 % in both cases with transmission limits of 2500 MW per line (‘translim2500’ and ‘storcons_translim2500’) and to 18 % in the case with transmission limits of 16000 MW per line and conservative storage assumptions (‘storcons_translim16000’). The increase in these cases results from the higher need for domestic power generation in Germany. It replaces imports of power from Norway and Algeria and it can also reduce the need for storage because it is continuously available.

The hydro power amounts are constant in all cases. The hydro power share in the total generation thus varies only with the power demand. Hydro power occurs only in Germany in all variations of the load, transmission and storage parameters. This is due to the high degree of capacity utilisation of more than 6000 full load hours in Germany assumed for hydro power based on (WEC 2007).

The biomass amounts used are quite constant and their relative share in the generation thus varies with the power demand. As long as balancing of load and demand fluctuations can be performed primarily by storage and CSP plants, all biomass is used in combination with heat delivery to a district heating grid in CHP plants. The full load hours of the biomass CHP plants in the cases with load variations or transmission limits but with realistic-optimistic storage assumptions are 7011 h on average in the total network, 6900 h in Germany, 8200 h in Norway and 8322 h in Algeria. Only in the cases with conservative storage assumptions, power plants without heat delivery to a district heating grid are built and operated. The overall biomass full load hours (total network generation divided by total network capacity) fall to between 1671 h and 1894 h in these cases. The reduction of the overall full load hours is strongest in Germany. While in Norway the pumped hydro power can cover the balancing requirements and in Algeria the CSP plants can do so, in Germany the only options that can replace storage for balancing are biomass and geothermal power, and both of them are increasingly applied when the storage parameters are set conservatively and/or the transmission is limited.

The absolute wind power amounts are rather variable. Contrary to hydro power and biomass, its share decreases and increases with the power demand. The highest share amounts to 51 % (case ‘load200’); the lowest share amounts to 33 % (case ‘load50’). Offshore wind is dominant. In the cases with conservative storage assumptions and little or no transmission restriction the onshore wind power share is elevated in Norway. The reason for this is not clear, since in Norway onshore wind power is generated at levelised electricity costs of 0.047 €/kWh and offshore wind power at costs of 0.044 €/kWh on average in all runs and the temporal fluctuations of onshore wind are generally higher than offshore. Maybe the temporal onshore wind characteristics complement the temporal resource availability in Germany or Algeria better than the offshore wind characteristics: when the transmission is limited to 2500 MW per line, the onshore wind power share in the total generation is even reduced compared to the base case, it is elevated only when conservative storage parameters are set in addition.

The CSP share like the wind share grows and shrinks with the power demand. The highest CSP share of 37 % occurs when the power demand is highest (case 'load200'). The lowest CSP share of 16 % occurs in the case 'storcons_translim2500'. Power from concentrating solar power plants is replaced by power from wind, PV, and geothermal power plants in this case. In the base case the solar multiple is 3.2 and the storage to turbine heat input ratio is 12.5 h. The configuration of the CSP plants is significantly different only in the cases with the stricter transmission and with conservative storage assumptions ('translim2500', 'storcons'). The transmission restriction to 2500 MW per line leads to the increase of the solar multiple to 3.5. The storage to turbine heat input ratio increases to 14.9. The full load hours of turbine operation increase from 6497 h (base case) to 6787 h. The Algerian CSP plants are used less for export and are now dimensioned more as a base load plant. At the same time the wind and PV shares are higher and some CAES and hydrogen storage is installed in Algeria for supporting the peak load dispatch.

When the storage assumptions are set conservatively, storage is installed in Algeria only when the transmission is limited to 2500 MW per line. Then less CSP and PV occurs but more wind turbines are installed. The CSP plants are then used to balance the fluctuations of the wind power. This is possible with an increased solar multiple of 3.8 and an increased storage to turbine heat input ratio of 20.2. The full load hours of the turbine fall to 5559 h.

The losses due to storage, transmission and surplus in only the load, transmission and storage parameter variation cases vary between 3.6 % (case 'storconstranslim16000') and 10.1 % (case 'translim2500'); on average they amount to 6.6 %. The transmission limit has the biggest influence on the surplus which reaches almost 19 TWh/a = 1.8 % of the total generation in the case 'translim2500'. The annual power demands are marked in the diagram with black bars.

The share of the total annual power generation that is stored before it is consumed, indicated by the white dots with black border in figure 7.1.1, varies between 3.6 % (case 'storcons') and 14.8 % (case 'translim2500') and is 8 % on average in the regarded cases.

The transmission capacities of the transmission lines change more with the load, transmission and storage parameter variations than with the generation costs assumptions. Both transmission connections have their lowest capacity when it is limited to 2500 MW. The highest capacity of both connections in the network DE-NO-DZ occurs when the load is doubled (case 'load200'). It amounts to 88 GW between Norway and Germany and to 57 GW between Germany and Algeria in that case. The transmission grid length ranges between 11 TWkm (case 'translim2500') and 308 TWkm (case 'load200').

7.1.3 General parameter variation results and discussion

Figure 7.1.2 shows a diagram with the **levelised electricity costs**, calculated by dividing the total annual system costs by the total annual power demand. The variation of the costs with the varied parameters is rather small: the smallest value is 0.046 €/kWh and the highest value 0.075 €/kWh. Only 0.029 €/kWh separate the least cost variation from the most expensive one, which is the option with conservative storage assumptions and with the transmission capacity limited to 2500 MW per line which is in the range of the capacity of today's alternating current transmission system in Europe. The deviation of the highest and lowest levelised electricity costs from the base case LEC is about 30 % and -20 %.

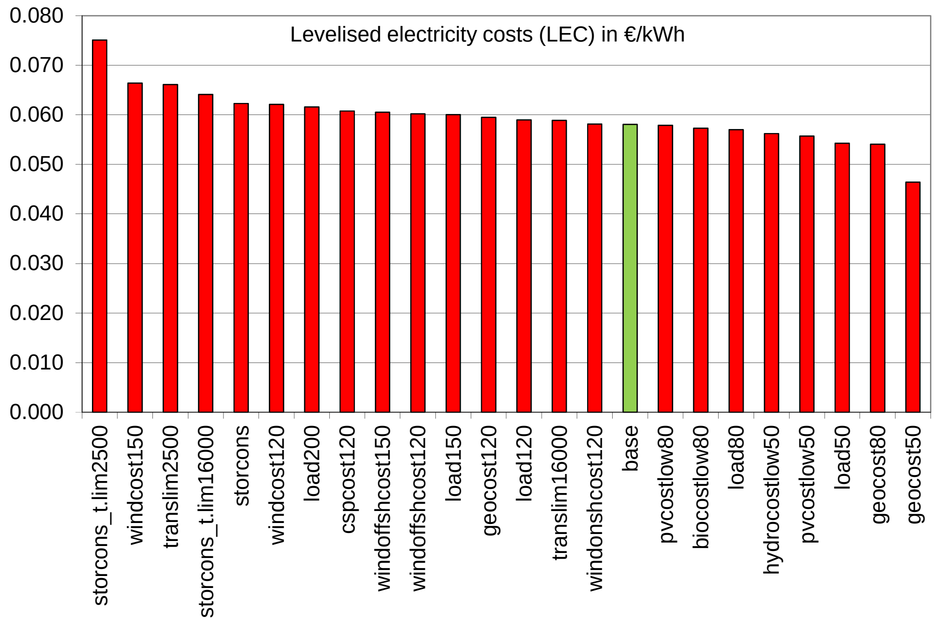

Figure 7.1.2: Levelised electricity costs in the network DE-NO-DZ; different parameter variations (see Table 7.1.1 for explanations of the cases).

All investigated **generation, storage and transmission** options occur in at least single cases in at least one of the nodes of the network. The bulk of the power in most cases is provided by wind and CSP power plants. The only cases in which the cumulated sum of wind and CSP power is lower than 60 % is when the overall power demand amounts to only 50 % of the base case power demand and when the investment costs for PV amount to only 50 % of the base case costs.

Hydro power is present in Germany in all cases. The German hydro power plants have the highest number of full load hours of operation in the investigated regions of more than 6100 flh/a. Algeria does have a hydro power potential, but it is not exploited in any of the investigated cases. The reservoir hydro potential in Norway occurs as natural inflow in the pumped storage plants in all cases. The Norwegian run-of-river hydro power potential on the other hand is only used in the case with the hydro power investment costs at 50 % of the base case costs. It is not a part of the least cost energy mix under the given assumptions – the electricity can be provided cheaper with other technologies. However, it is unlikely that the existing hydro power plant locations will be given up. The fact that they are costlier than other options under the given assumptions but that they are widely used today and will probably be in the future, may be due to the difference between their technical life time and the period in which they are written off financially. In the REMix model, the technical life time is inserted in the annuity factor calculation in order to calculate the annual costs for a national economy. In that case, the annuity of system components with very long life times like hydro power (60 a) converges towards the interest rate, not towards zero. In reality, the plants are probably paid after 20 or 30 years and generate electricity at only the operation costs afterwards.

Storage occurs in all cases, even if the costs for the reservoirs are much more expensive than expected, i.e. if the reservoirs in Norway need investments of 10 €/kWh in order to be usable as pumped hydro reservoirs and if storage tanks must be built instead of using salt caverns for CAES and hydrogen storage. Pumped hydro power is the only storage technology with a preset reservoir capacity and the only storage technology that occurs in all cases. With conservative storage assumptions and unrestricted transmission capacities, it is the only storage technology applied and only 3.6 % of the total power generation is stored before it is consumed. With conservative storage assumptions plus restricted transmission capacities, hydrogen storage is applied in addition. CAES only occurs in some cases: when the load is very high (cases 'load150' and 'load 200'), to complement PV when the PV costs are at 50 % of the base case costs, to support regional load balancing when the transmission capacities are limited but the storage assumptions are optimistic-realistic. The highest value of the power generation that is stored before it is consumed amounts to 14.8 % and occurs in the case with the transmission capacities limited to 2500 MW per line.

Storage and transmission losses and surplus add up to between 3.6 % (case 'storcons_translim1600') and 10.1 % (case 'translim2500').

The system structure shows high variability with the assumed parameters. A switch between a significant role of a technology in the system and the total absence of this technology due to a change of the costs of 20 % or less can occur. This is the case for geothermal combined heat and power generation (case 'geo120'). Especially in that case the variation of the costs lies well in a possible range since the technology is very young and the uncertainties about its cost development are very high.

The results are strongly influenced by the uncertain assumptions made about the future technology and cost development. This must be considered when evaluating the model run results. The designed systems are cost-efficient in terms of the choice of locations with high resource quality considering at the same time the temporal availability and the distance from demand centres. But they can be called 'least-cost' only referring to the chosen set of uncertain parameters. The model designs technically feasible systems by minimising the system costs under the given assumptions. It can not generate a scenario of the development of a power supply system and it can not claim that the designed systems are least cost systems in general. But it can support scenario modellers who want to find a structure for a power supply system under certain conditions that can be set as equations in the model.

7.2 Test application: power supply in Europe and North Africa

REMix is applied for two supply cases for Europe and North Africa: the domestic supply in separate island grids in each region on the one hand and on the other hand an electricity exchange network in which power transmission is only limited by its costs. The network includes all 36 countries / country-clusters in the whole region. These two polar transmission options provide information for each region about the range of structures and costs of their electric power supply under the given cost assumptions. The results are given for each region in the area of investigation. For the overall network and for selected regions the results are described and compared.

7.2.1 No transmission: island grids in each region

The annual power generation of all regions in TWh/a is displayed in figure 7.2.1; all numbers are given in table 7.2.1. The capacities and costs are listed in table 10.1.24 and table 10.1.25 in the annex.

The total power demand in all regions amounts to 5497 TWh/a. The total power generation including natural inflow into pumped hydro plants in Norway is 5960 TWh/a. 109 TWh/a of surplus occur and 354 TWh/a are lost in storage plants. The single technologies have the following shares in the overall mix: wind offshore 27.2 %, CSP 22.5 %, wind onshore 14.2 %, GEO_CHP 18.9 %, PV 6.9 %, Biomass overall 5.0 %, hydro overall 4.2 %, Geothermal power 0.9 % and residual load covered by gas turbines 0.3 % (in Luxembourg and Belgium). The storage input is 716 TWh, which is equal to 12 % of the total power generation. In the single regions, this share varies between 0 % and almost 30 %. Some biomass is used for load balancing in steam turbines without heat delivery; some biomass is used in CHP plants.

Wind power and biomass energy are used in all regions. Geothermal power is generated in all regions with a geothermal potential; almost all of it is CHP. The geothermal CHP potential is completely exploited in many regions. PV is also frequently used. While the reservoir hydro potential is exploited to some extent in all regions that have a hydro reservoir potential, only some regions with a run-of-river hydro potentials do make use of it. No new hydro power capacity is built at all. CSP plants are built in all regions with CSP potential; the potential is fully exploited in France, Greece, Italy and Malta. Of these countries only Italy also fully exploits its PV and wind onshore potential, thus making use of all bare and sparsely vegetated areas that can be used by either one of these technologies. In the analysis of the potentials only one third of the total usable area was assigned to CSP and one third each to wind turbines and PV plants. In France, Greece and Malta it can be expected that even more CSP would be used if the areas had not been reserved for the competing technologies.

Apart from Algeria, Morocco and Tunisia, all regions install some gas turbines ('residual') to fulfil the system reliability restriction. This restriction requires that the available capacity must exceed the peak load at any time, i.e. the sum of the momentary power output of technologies using fluctuating sources and the capacities of the dispatchable technologies multiplied by the respective availability factors must be higher than peak load any time. This restriction leads to a high level of system reliability. It was introduced in order to guarantee the load dispatch also in other years that where not subject of this investigation. The operation of the gas turbines would require the use of a fuel such as methane which can be natural gas or generated from additional renewable energy resources. Overall, 5.5 % of the total installed capacity is 'residual'. In the single island grids this share varies between 0 % and 55 %. The 'residual' gas turbines generate power only in Luxembourg and Belgium. In all other regions the capacity stays unused in the considered time period.

Each region with pumped hydro potential uses pumped hydro and each region with salt caverns uses hydrogen storage. Most regions with salt caverns also use compressed air energy storage. Apart from Morocco no region uses its assumed salt cavern volume completely.

Figure 7.2.2 shows the levelised costs of electricity in each region, calculated by dividing the annual system costs by the annual power demand.

Table 7.2.1: Total annual energy sums in TWh/a and storage capacities in TWh in Europe and North Africa, no transmission (island grids, '100ds').

	AL_CS_MK	BA_HR_SI	AT	BE[2]	BG	CY	CZ	DN	IE	EE_LT_LV	FI	FR	DE	GR	HU	IT	SK	LU[2]
Annual power demand	68	47	49	67	26	4.9	52	51	34	36	76	426	549	62	44	311	29	11
Annual power demand / generation (inc. n. i.[1] in NO) in %	96	96	95	86	96	99	96	85	88	92	94	90	90	100	99	94	95	100
Annual gen. (without n. i.[1] in NO)	71	49	51	78	28	5.0	54	60	39	39	82	473	612	62	44	329	31	11
Annual gen. (inc. n. i.[1] in NO)	71	49	51	78	28	5.0	54	60	39	39	82	473	612	62	44	329	31	11
Geothermal power	0	0	0	0.4	0	0	2.7	0	0	0.5	0	0	0	7.5	0	20	4.8	0
Geothermal CHP	48	28	12	7.4	23	0	20	7.2	0.5	7.8	0	85	169	14	38	77	13	0.4
N. i.[1] in NO																		
Run-of-river hydro (old+mod.)	15	0	0	0.3	0	0	0	0	0	0	12	0	28	0	0	0	0	0.1
Run-of-river hydro (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reservoir hydro	0	2.6	9.6	0	0	0	1.7	0	0.3	0	2.9	29	2.3	0	0	5.3	0.3	0
Biomass (steam turbine)	2.5	0	0	2.9	0	0.1	5.7	0	0	4.0	11	0	0	2.7	3.9	2.9	0.2	0.2
Biomass (steam turb., CHP)	0	1.7	3.9	0	1.4	0	0.4	1.7	0.7	1.0	9.0	19	16	0	0.2	5.8	1.5	0
Biomass (biogas CHP)	2.2	1.2	1.8	2.0	0.6	0.1	3.4	2.3	6.3	3.3	0.6	13	11	0.6	1.3	4.9	0.7	0.6
Wind onshore	0.2	8.6	19	9.8	0.1	1.2	16	15	11	3.5	13	0	43	11	0.4	88	5.9	0.8
Wind offshore	3.4	0	0	24	2.4	0	0	34	20	17	33	314	310	0	0	0	0	0
Photovoltaic	0	7.4	5.8	22	0.3	0.7	4.4	0	0	1.7	0.2	1.8	33	10	0	66	4.0	0.7
CSP	0	0	0	0	0	2.9	0	0	0	0	0	11	0	16	0	60	0	0
Residual (gas turbine)	0	0	0	8.7	0	0	0	0	0	0	0	0	0	0	0	0	0	8.0
Import (+) / export (-)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Storage losses	0	-1.7	-2	-0.5	-1.1	0	-0.1	-7.5	-4.7	-0.2	0	-46	-52	0	0	-17	-1.4	0
Surplus	-2.8	0	-0.3	-10	0	0	-2.1	-1.7	0	-3.1	-5.3	-1.1	-11	-0.2	-0.3	-1.2	0	0
Storage capacity in TWh	0	1.1	1.9	0	1.1	0	0	3.3	1.8	0	0	23	19	0	0	12	1.1	0
Pumped storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.1	0	0
CAES	0	0	0	0	0	0	0	0.1	0	0	0	0.1	0.4	0	0	0	0	0
Hydrogen	0	1.1	1.8	0	1.1	0	0	3.2	1.8	0	0	23	19	0	0	12	1.1	0
Annual district heat from CHP	82	52	37	17	41	0.1	43	20	11	23	27	229	355	23	55	166	29	1.4
Storage input in % of an. Gen.	0	9.5	10	3.5	8.8	0	1.0	27	27	2.4	0	19	19	0	0	11	11	0

1) Annual natural inflow into pumped hydro power plants in Norway

2) Belgium and Luxembourg: no 100 % domestic renewable supply, domestic renewable energy carriers complemented with other fuels used in gas turbines.

Table 7.2.1 (continued): Total annual energy sums in TWh/a and storage capacities in TWh in Europe and North Africa, no transmission (island grids, '100ds').

	MT	NE	NO	PL	PT	RO	ES	SE	CH_LI	TR	UK	U_MD	BY	DZ	MA	TN	LY	EG	Total
Annual power demand	2.9	116	112	191	62	96	320	154	40	494	451	237	52	249	235	66	44	631	5497
Annual power demand / generation (inc. n. i.[1] in NO) in %	53	83	71	94	92	93	94	90	96	99	87	91	81	93	91	93	100	100	92
Annual gen. (without n. i.[1] in NO)	5.5	139	111	204	68	103	341	170	41	498	519	260	64	266	258	71	44	631	5912
Annual gen. (inc. n. i.[1] in NO)	5.5	139	158	204	68	103	341	170	41	498	519	260	64	266	258	71	44	631	5960
Geothermal power	0	0	0	0	0	17.1	0	0	0	0	0	0	1.9	0	0	0	0	0	55
Geothermal CHP	0	24	0	121	0.1	35	34	0	16	197	39	104	3.9	0	0	0	0	0	1124
N. i.[1] in NO			47																47
Run-of-river hydro (old + mod.)	0	0	0	0	0	0	0	51	0	0	0	0	0	0	0	0	0	0	107
Run-of-river hydro (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reservoir hydro	0	0	0	0.4	2.8	0	17	3.9	16	2.0	0.1	0	0	0	0	0	0	0	97
Biomass (steam turbine)	0.03	0	0.6	0	0	0	0	21	0	16	0	0	0	0	2.4	0	0.4	3.6	80
Biomass (steam turb., CHP)	0	1.3	0	7.5	2.7	4.7	7.8	6.8	0.6	0	7.6	8.0	1.7	1.7	0	0.6	0	0	113
Biomass (biogas CHP)	0.02	4.2	0.5	5.7	1.1	2.6	4.9	1.0	1.1	7.3	6.3	9.2	3.8	0	0	0	0	0	103
Wind onshore	0	0	0	28	5.8	0	26	22	6.8	55	103	120	48	21	6.3	5.2	8.7	145	848
Wind offshore	4.4	110	109	40	12	27	55	64	0	42	364	5.4	0	0	0	1.2	0	26	1618
Photovoltaic	0.5	0	0	1.8	6.8	16	31	0	0.5	71	0	13	4.2	53	44	9.3	0.1	0	409
CSP	0.5	0	0	0	36	0	164	0	0	109	0	0	0	190	206	55	35	457	1341
Residual (gas turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	17
Import (+) / export (-) or 'total': transmission losses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Storage losses	0	-20	-14	-12	-5.6	-6.9	-20	0	-1.8	-0.2	-68	-18	-6.5	-17	-23	-5.2	0	0	-354
Surplus	-2.6	-3.3	-32	-1.6	0	-0.1	0	-16	0	-3.3	-0.5	-4.6	-5.7	0	0	0	0	-0.1	-109
Storage capacity in TWh	0	9.2	2.2	5.1	5.4	3.1	21	0	2.1	0	29	4.3	1.9	16	16	4.9	0	0	186
Pumped storage	0	0	2.2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2.5
CAES	0	0.1	0	0.1	0	0.1	0	0	0	0	0.1	0.2	0.1	0.2	0	0	0	0	1.6
Hydrogen	0	9.1	0	4.9	5.4	3.1	21	0	2.1	0	29	4.1	1.8	15	16	4.9	0	0	182
Annual district heat from CHP	0	52	0.6	225	9.5	85	93	21	36	305	107	223	18	4.9	0	1.7	0	0	2391
Storage input in % of an. Gen.	0	30	4.8	13	16	16	11	0	8.6	0.3	26	15	24	14	16	13	0	0	12

1) Annual natural inflow into pumped hydro power plants in Norway

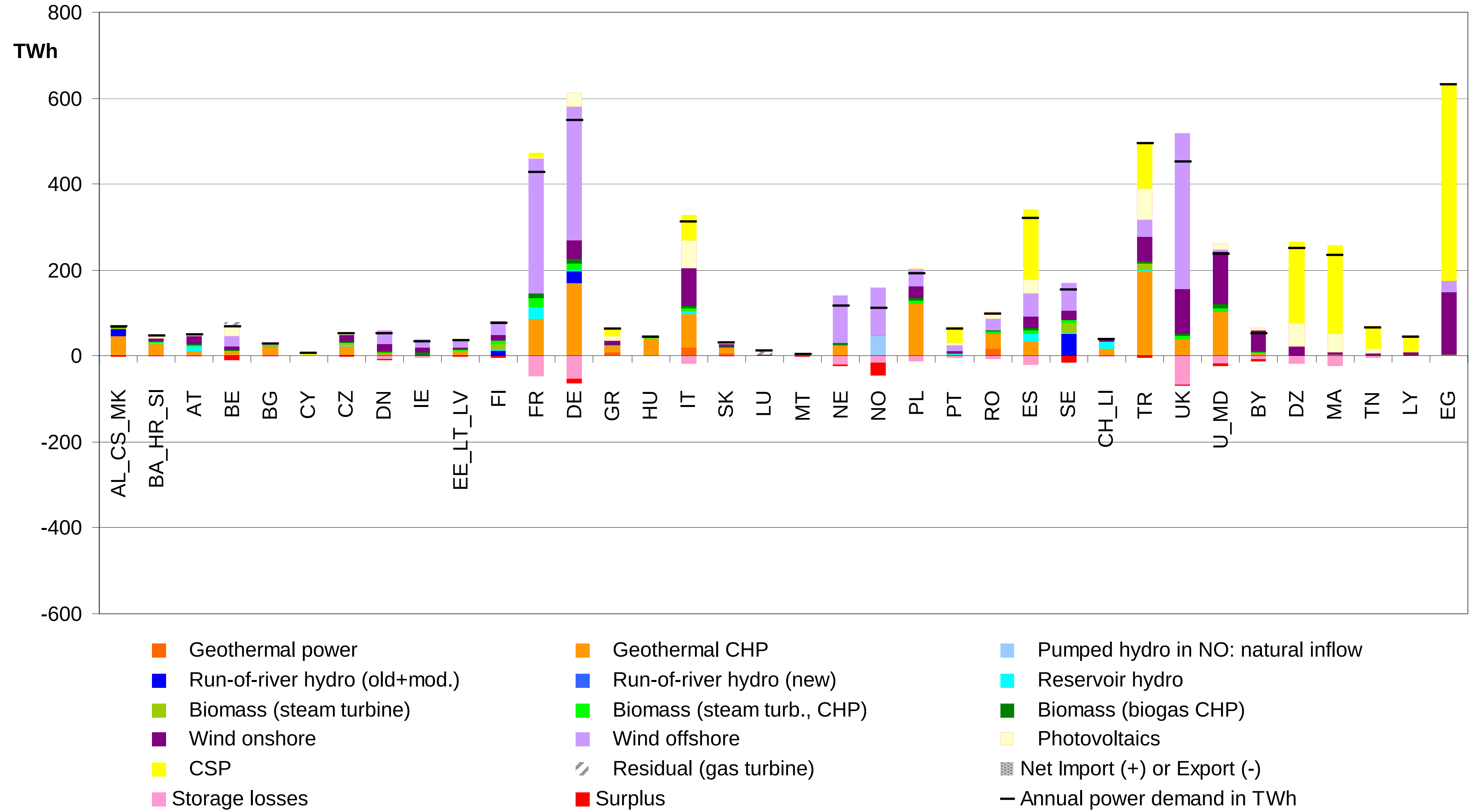

Figure 7.2.1: Power demand and generation in TWh/a; storage capacity in TWh in the regions in Europe and North Africa; no transmission (‘100ds’).

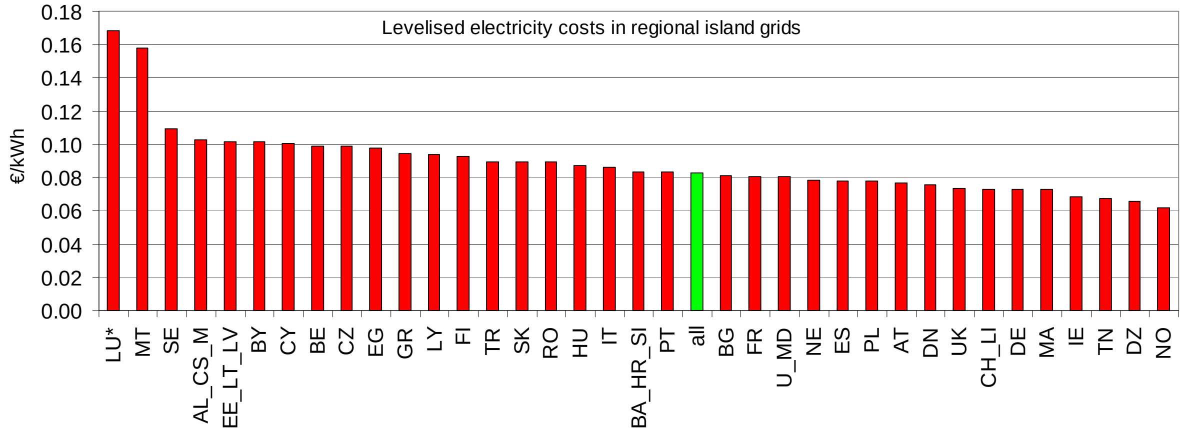

Figure 7.2.2: Levelised electricity costs in the island power supply systems in Europe and North Africa, calculated by dividing the annual system costs by the annual power demand.

In Norway the electric power is supplied at the lowest costs of 0.062 €/kWh with a mixture of wind and hydro power and some biomass. The highest costs of 0.169 €/kWh occur in Luxemburg, where 8 TWh/a out of 10.9 TWh/a are generated in gas turbines with e.g. natural gas because the domestic renewable resources can not cover the power demand. The LEC for the power from the gas turbines in Luxembourg are 0.206 €/kWh, 0.198 €/kWh$_{el}$ for the gas and only 0.08 €/kWh for the turbine which is operated for 5062 full load hours. In Malta the LEC of 0.158 €/kWh are only slightly lower than in Luxembourg. In Malta no pumped hydro and no salt caverns for CAES or hydrogen storage are available. The energy mix here is 80 % offshore wind at costs of 0.063 €/kWh, 9.4 % PV power at costs of 0.062 €/kWh. 9.6 % are provided by CSP plants and the remaining 1 % is provided by biomass steam turbines and by biogas plants with combined heat and power generation. The balancing of the fluctuations of the load, wind and PV generation is performed by the CSP and biomass power plants, which have very low full load hours of operation of 1456 h (CSP), 468 h (biomass, steam turbine) and 880 h (biogas plant with CHP). The levelised electricity costs of all regions lie between 0.062 €/kWh and 0.169 €/kWh, without Malta and Luxembourg they lie between 0.062 €/kWh and 0.109 €/kWh (Sweden). The average LEC calculated by dividing the cumulated annual system costs of all regions by the cumulated annual power demand of all regions are 0.083 €/kWh (category 'all' in figure 7.2.2).

7.2.2 No transmission restriction

The annual power generation of all regions in TWh/a is displayed in figure 7.2.3; all numbers are given in table 7.2.2. The generation and transmission capacities and the costs are listed in tables 10.1.26 - 10.1.28 in the annex.

The total annual power demand of 5497 TWh/a in the EUNA region is covered with a total generation capacity of 1603 GW. Overall, 5919 TWh/a of electric power are generated including natural inflow into pumped hydro power plants in Norway.

4 TWh/a of surplus occur, 236 TWh/a of storage losses and 182 TWh/a of transmission losses. The shares of the power from the single generation technologies in the total power generation are: CSP 38.8 %, wind offshore 30.1 %, wind onshore 12.9 %, geothermal CHP 10.1 %, all biomass power plants 4.4 %, all hydro power plants 2.9 % and PV 0.8 %. No geothermal power plants without heat delivery are built.

Table 7.2.2: Total annual energy sums in TWh/a, storage capacities in TWh in a European-North African network; no transmission restriction (‘0ds’).

	AL_CS_MK	BA_HR_SI	AT	BE	BG	CY	CZ	DN	IE	EE_LT_LV	FI	FR	DE	GR	HU	IT	SK	LU
Annual power demand	68	47	49	67	26	4.9	52	51	34	36	76	426	549	62	44	311	29	11
Annual power demand / generation (inc. n. i.[1] in NO) in %	157	220	181	404	198	81	225	115	16	63	101	191	149	124	326	265	297	1096
Annual gen. (without n. i.[1] in NO)	43	22	27	17	13	6	23	44	212	57	76	223	367	50	13	117	10	1
Annual gen. (inc. n. i.[1] in NO)	43	22	27	17	13	6	23	44	212	57	76	223	367	50	13	117	10	1
Geothermal power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal CHP	33	16	12	7.4	11	0	16	0	0	7.8	0	66	0	9.6	9.1	53	7.3	0.1
N. i.[1] in NO																		
Run-of-river hydro (old+mod.)	0	0	0	0	0	0	0	0	0	0	0	0	28	0	0	0	0	0
Run-of-river hydro (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reservoir hydro	0	2.6	9.6	0	0	0	1.7	0	0.3	0	2.9	29	2.3	0	0	5.3	0.3	0
Biomass (steam turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	0.04	0	0	0	0
Biomass (steam turb., CHP)	1.2	1.7	3.9	1.8	1.4	0.1	2.9	1.7	0.7	2.6	14	19	16	1.5	3.1	8.0	1.6	0.2
Biomass (biogas CHP)	1.9	1.2	1.8	2.0	0.6	0.1	1.4	2.3	6.3	1.8	0.6	13	11	0.6	1.3	4.9	0.7	0.6
Wind onshore	0	0	0	5.3	0	0	0.6	24	47	3.9	0	0	0	0	0	0	0	0.1
Wind offshore	7.0	0	0	0	0	0	0	16	158	41	58	85	310	12	0	0	0	0
Photovoltaic	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CSP	0	0	0	0	0	5.9	0	0	0	0	0	12	0	26	0	46	0	0
Residual (gas turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Import (+) / export (-)	25	29	27	51	23	-1.16	29	25	-174	-21	0.9	234	203	12	30	209	25	10
Storage losses	0	-2.9	-4.7	-0.1	-9	0	-0.1	-18	0	-0.1	0	-32	-22	0	0	-15	-5.2	0
Surplus	0	0	0	0	0	0	0	0	-3.7	0	0	0	0	0	0	0	0	0
Storage capacity in TWh	0	3.2	5.5	0	9.7	0	0	21	0	0	0	35	19	0	0	16	6.0	0
Pumped storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.1	0	0
CAES	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydrogen	0	3.2	5.5	0	9.7	0	0	21	0	0	0	35	19	0	0	16	6.0	0
Annual district heat from CHP	62	37	37	23	27	0.3	43	7.7	9.7	25	41	200	58	23	29	134	20	1.5
Storage input in % of an. Gen.	0	25	35	4.5	130	0	1.5	76	0.1	1.3	0	27	11	0	0	25	98	0

1) Annual natural inflow into pumped hydro power plants in Norway

Table 7.2.2 (continued): Total annual energy sums in TWh/a, storage capacities in TWh in a European-North African network; no transmission restriction (‘0ds’).

	MT	NE	NO	PL	PT	RO	ES	SE	CH_LI	TR	UK	U_MD	BY	DZ	MA	TN	LY	EG	Total
Annual power demand	3	116	112	191	62	96	320	154	40	494	451	237	52	249	235	66	44	631	5497
Annual power demand / generation (inc. n. i.[1] in NO) in %	451	118	21	132	113	248	87	202	130	143	62	100	119	57	102	72	8	109	93
Annual gen. (without n. i.[1] in NO)	1	98	489	144	55	39	370	76	30	346	729	237	44	436	231	91	552	581	5872
Annual gen. (inc. n. i.[1] in NO)	1	98	537	144	55	39	370	76	30	346	729	237	44	436	231	91	552	581	5919
Geothermal power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal CHP	0	16	0	49	0.1	31	17	0	13	114	39	65	3.9	0	0	0	0	0	596
N. i.[1] in NO			47																47
Run-of-river hydro (old + mod.)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28
Run-of-river hydro (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reservoir hydro	0	0	0	0.4	2.8	0	17	3.8	16	2.0	0.1	0	0	0	0	0	0	0	96
Biomass (steam turbine)	0	0	0	0	0	0	0	0	0	5.4	0	0	0	0	0	0	0	3.6	9
Biomass (steam turb., CHP)	0	1.3	0.5	7.5	2.7	4.7	7.8	16.7	0.6	5.0	7.6	8.0	1.4	1.7	1.8	0.6	0.3	0	150
Biomass (biogas CHP)	0	4.2	0.5	5.7	1.1	2.6	4.9	1.0	1.1	7.3	6.3	9.2	3.8	0	0	0	0	0	99
Wind onshore	0	15	92	56	0	0	0	0	0	0	119	155	35	7.2	0	0	149	54	763
Wind offshore	0.4	62	397	25	0	0.7	0	55	0	0	557	0	0	0	0	0	0	0	1784
Photovoltaic	0	0	0	0	0	0	0	0	0	50	0	0	0	0	0	0	0	0	50
CSP	0.2	0	0	0	48	0	323	0	0	163	0	0	0	427	229	91	403	524	2297
Residual (gas turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Import (+) / export (-) or ‘total’: transmission losses	2.3	26	-413	62	7.6	69	-50	78	13	148	-224	13	8.7	-187	11	-25	-508	50	-182
Storage losses	0	-8.9	-12	-15	-0.4	-12	-0.2	0.0	-4.3	-0.1	-53	-13	-0.5	0.0	-6.9	0.0	0.0	0.0	-236
Surplus	0	0	-0.2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-4.0
Storage capacity in TWh	0	6.4	3.9	16	0.3	14	0	0	4.9	0	26	14	0.1	0	6.6	0	0	0	207
Pumped storage	0	0	3.9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4.2
CAES	0	0	0	0.1	0	0	0	0	0	0	0	0.1	0	0	0	0	0	0	0.2
Hydrogen	0	6.4	0	16	0.3	14	0	0	4.8	0	26	14	0.1	0	6.6	0	0	0	203
Annual district heat from CHP	0.1	41	2.0	127	9.5	78	62	49	29	223	107	165	17	4.9	5.2	1.7	0.8	0	1700
Storage input in % of an. Gen.	0	17	7.0	21	1.8	56	0.2	0	28	0.1	14	11	4.5	0	5.5	0	0	0	7.9

1) Annual natural inflow into pumped hydro power plants in Norway

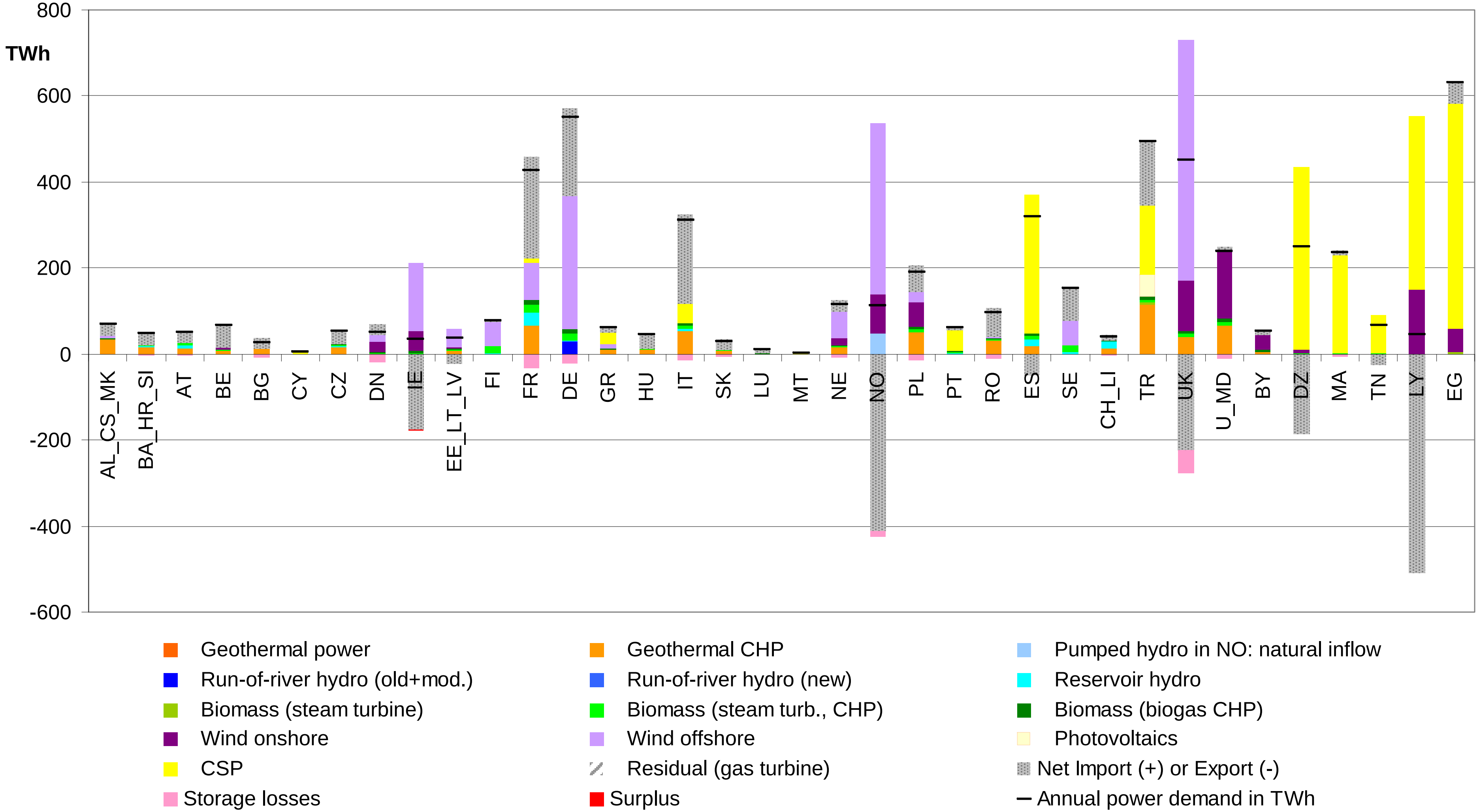

Figure 7.2.3: Power demand, generation and storage capacity in the regions of the EUNA network without transmission restriction (‘0ds’) in TWh.

No residual load must be covered with gas turbines. Luxembourg and Belgium, the two regions that cover a part of their load with gas turbines in the island grid case now cover most of their demand with imports. The input to storage amounts to 465 TWh/a. This is 7.9 % of the total power generation. A transmission system with a capacity-length of 941 TWkm is built.

CSP dominates the power generation in the network; it is applied in all regions that have a CSP potential. France and Greece use all of their CSP potential. Wind power is widely used, but not in all regions. Geothermal energy is used in many regions. Only combined heat and power geothermal plants are built. Biomass is the only energy resource that is used in all regions. Almost everywhere it is used only in CHP plants; only in Greece, Turkey and Egypt biomass steam turbines without heat delivery to a district heating system are used. All regions that have a reservoir hydro potential use it but only Turkey and Finland exploit all of it. No new hydro power plants are built. Run-of-river hydro power plants are used only in Germany where the operating hours are the highest in the total network. PV occurs only in Turkey. 18.7 % of the total generation capacity is 'residual', i.e. gas turbines that are never operated in the regarded time period but guarantee the availability of enough capacity to cover peak load at any time. No power is generated in the 'residual' gas turbines plants.

Libya, Norway, UK, Algeria, Ireland, Spain, Tunisia and the Baltic region are net power exporters. The annual import and export in Cyprus and Finland is almost balanced. All other regions cover parts of their power demand by imports. The bulk of the import goes to France, Italy, Germany and Turkey. The highest share of imports in the annual power demand occurs in Luxembourg, where 91 % of the annual power demand is covered with imports.

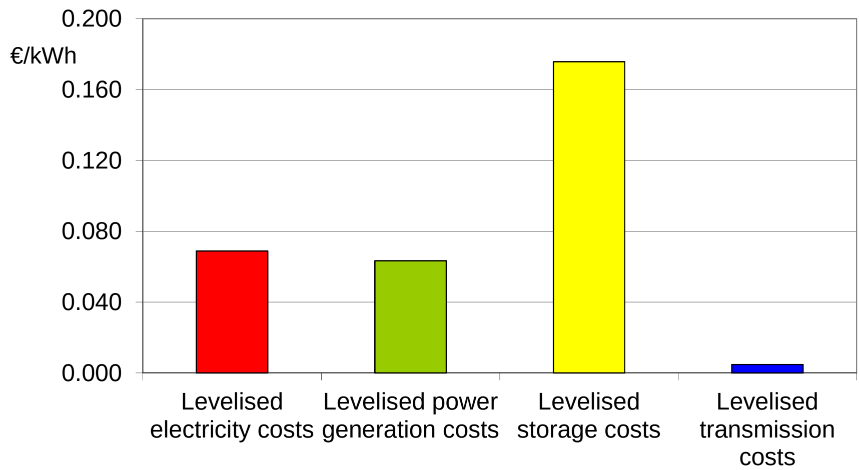

Figure 7.2.4: Average levelised costs in the power supply network EUNA.

The levelised costs for the power generation in the total network were calculated by dividing the total costs for the power generation by the total power generation. They amount to 0.063 €/kWh. The levelised costs for storage, calculated by dividing the total annual costs for storage by the storage output, amount to 0.176 €/kWh. The levelised costs for transmission are 0.005 €/kWh. They were calculated by dividing the total annual costs for transmission by half of the sum of all imports and exports. The overall levelised electricity costs of the total network, calculated by dividing the total annual system costs by the total annual power demand, amount to 0.069 €/kWh. The costs cannot be separated for each region because the system components in each region can use, provide, store or transport power for or from other regions and these functions cannot clearly be assigned to one region. The levelised power generation, storage, transmission and total electricity costs are shown in figure 7.2.4.

7.2.3 Comparison of the EUNA supply system characteristics

Figure 7.2.5 shows the structure of the total power generation in the regions of Europe and North Africa in the island grid and in the network case. In the European-North African network less power is generated in PV, geothermal, hydro and biomass power plants than in the island grids. PV only occurs in Turkey. Germany is the only region in which run-of-river hydro power is used. Less biomass is converted in steam turbines that only generate power and are preferably used for load balancing if necessary; almost all biomass is converted in CHP plants. Like in the island grids, all regions use some of their biomass potential. The wind power share is almost equal in both cases, but the distribution is different. While in the island grids all regions use some wind power, less than two thirds of all countries do so in the network case.

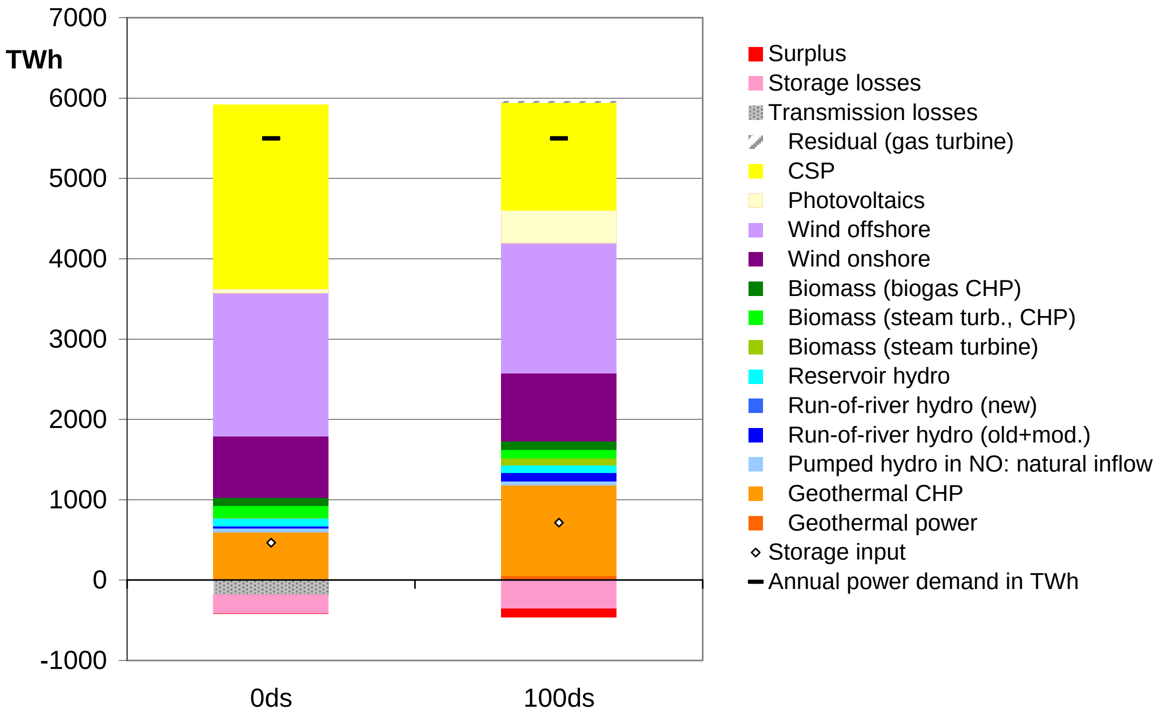

Figure 7.2.5: Total annual electric power generation in Europe and North Africa in TWh/a without transmission restriction (‘0ds’) and in island power supply systems (‘100ds’).

The reduced power generation from PV, biomass, hydro and geothermal power in the network case is replaced by power from CSP plants. The CSP share in the total generation is 38.8 % in the network and 22.5 % in the island grids. In the island grids the CSP plants have a solar multiple of 4.2 on average, i.e. at nominal capacity the solar field delivers 4.2 times the heat that the turbine can use at nominal capacity. The storage size to turbine heat input ratio is 18.5 h. This is a typical base load configuration for a CSP power plant. But the full load hours of operation are only 5151 h. The ability of the CSP plants to balance load and generation fluctuations by storing heat and generating power when it is needed is widely applied here. In the network case this function is needed less: the CSP plants have a solar multiple of 3.4 on average here, the storage size to turbine heat input is 12.3 h on average and the plants are operated for 6060 h. Even though the dimensioning now rather conforms to a medium load CSP plant, the full load hours of operation are higher than those of the prevailing ‘base load’ configuration plants of the island grids.

The overall losses due to storage, transmission and surplus are 463 TWh/a in the island grids and 422 TWh/a in the network case, corresponding to 7.8 % of the total generation in the island grids and 7.1 % of the total generation in the network. This is well in the range of the surplus that occurs in the parameter variation cases of the German-Norwegian-Algerian network of between 3.6 % and 10.1 %.

In addition to the stronger use of the balancing potential of CSP plants, more power is stored before consumption in the island grids than in the network: 12.0 % of the total power generation compared to 7.9 % in the network. These results lie within the range that occurs in the German-Norwegian-Algerian network cases: the lowest storage input related to the total power generation there is 3.6 % and the highest value that occurs is 14.8 %. The results of the island grids in individual regions, however, vary between 0 % and 30 %.

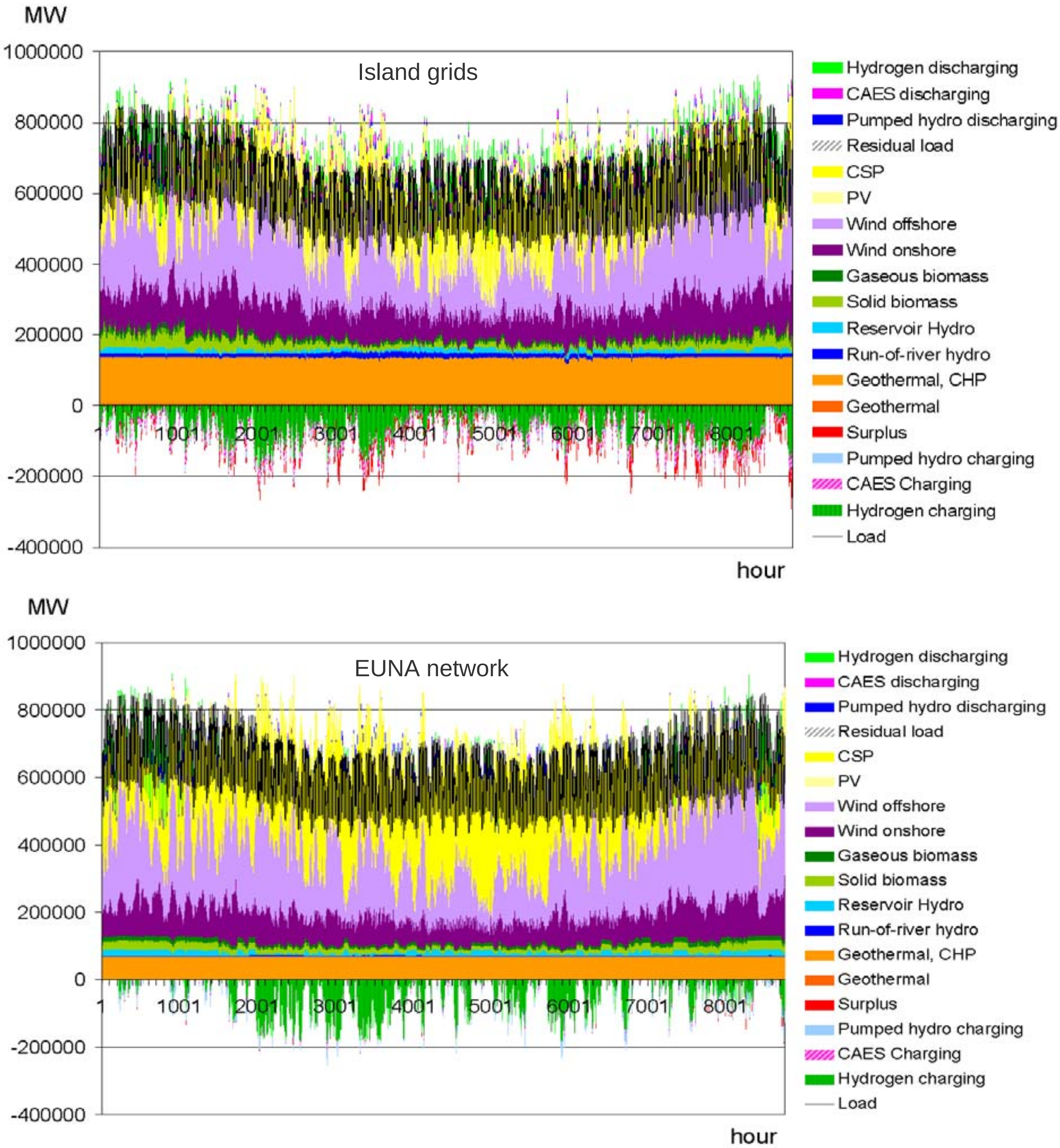

Figure 7.2.6: Total annual electric power generation in Europe and North Africa. On top: island power supply systems ('100ds'). at the bottom: network without transmission restriction ('0ds').

Less storage capacity but a little more conversion capacity is installed in the island grids than in the network: 186 TWh of storage capacity, 182 TWh of which are hydrogen storage, and 324 GW of storage conversion capacity of which 203 GW are hydrogen storage conversion capacity are installed in the island grids. In the network, the storage capacity amounts to 207 TWh, 203 of which are hydrogen storage and the conversion capacity is 261 GW, 182 GW of which are hydrogen storage conversion capacity. The conversion capacity in storage plants in the island grids is used with higher full load hours on average, calculated by dividing the total storage output by the installed conversion capacity: 1266 h on average in the island grids and 1058 h on average in the network. In single regions the full load hours of the storage conversion capacity are higher in the network case than in the island grid. The reasons for the increase or decrease of the storage full load hours can not easily be determined. Figure 7.2.6 shows the cumulated annual load dispatch in the European-North African island grids (on top) and in the network (at the bottom). Concluding from the temporal course of the hydrogen storage output one reason for lower operating hours in the network case could be that the storage capacity is mainly used for covering the load in the times of little wind power generation but high load in the time around the end of January and in the middle of December. In the island grid case, more geothermal base load power narrows the gap between load and generation in these periods. Storage in the island grids is more constantly needed because there is no large scale grid that can distribute fluctuations of load or generation in the short term.

Overall, the diversity of the power generation is reduced in the network: the shares of the power generation technologies with already relatively small share in the total generation in the island grids is further decreased and replaced by more CSP power. The overall costs are lower in the network: they amount to 378 G€, while in the island grids they amount to 457 G€. This leads to a reduction of the averaged levelised electricity costs from 0.083 €/kWh on average in the island grids to 0.069 €/kWh on average in the network. Only four regions have lower or equal levelised costs of electricity in the island grid case than in the network: Norway (0.062 €/kWh), Algeria (0.066 €/kWh), Tunisia (0.067 €/kWh) and Ireland (0.069 €/kWh). The levelised electricity costs in Germany are 0.073 €/kWh. In the base case of the network of Germany, Norway and Algeria, the levelised electricity costs are only 0.058 €/kWh, which is lower than in any of the network member’s island grids.

8 Summary and conclusions

Established energy system models were originally designed for dimensioning energy systems that are based on conventional power generation. They lack the spatial-temporal information and information processing ability required for adequately representing electricity generation from renewable energy sources with fluctuating availability. Resource data with high temporal and spatial resolution have been integrated into energy system models by M. Biberacher and by G. Czisch. The latter has identified various low-cost 100 % renewable energy-based electric power supply systems for a large-scale European-North African-West Asian network. The present work partly builds on the findings of these works, but its goal is to provide an **instrument for policy advice on different spatial scales** - from international stakeholders to national and even subnational policy makers. It **takes into account the spatial distribution and the temporally intermittent availability** of renewable energy resources and it uses a **consistent set of assumptions** about the development of load and the technical and economic characteristics of energy technologies.

The **instrument** was **set up** in the following steps:

1) **Energy demand assessment**: The total electric power demand in the investigated area was assumed to amount to 4084 TWh/a in the year 2010 and to 5497 TWh/a in the year 2050, corresponding to an increase of 35 % in 40 years. It was temporally disaggregated using hourly load data from transmission system operators. A spatial disaggregation was performed using the land cover category ‘artificial and associated areas’ as a proxy parameter. The low temperature heat demand and the local heat demand density were taken into account with a simple approach in order to provide limits to the application of combined heat and power technologies.

2) **Renewable electricity generation potentials**: an inventory of electric power generation potentials with high spatial and temporal resolution was built up. The potentials were analysed in three steps: resource assessment, area analysis and power plant model application. National potentials were spatially disaggregated in a top-down approach in order to allow for region classification according to the investigation purpose. The total renewable electric power generation potential in the investigated area amounts to 101 PWh/a in the year 2050, which is about 18 times the total electric power demand in the area.

3) A **linear programming model** for dimensioning renewable energy-based electric power supply systems that consist of electric power generation, storage and transmission units was set up. The objective function determines the total costs of the supply system to be minimised. Characteristics of the system, such as hourly load, generation potentials and storage and transmission restrictions, are expressed as conditions. The input data for the conditions are the rasterised results of the demand assessment and the renewable generation potential inventory which have been regionally aggregated.

The running times of the model depend on the number of variables investigated. The high temporal resolution applied can lead to high running times of up to several weeks. For one focus of the model - the interaction of single countries with a large-scale grid and with their direct neighbours - the number of regions was kept at the number of countries regarded, with few exceptions. Reducing the number of time steps however provides less reliable results. A method of spatial decomposition and subsequent recombination was developed in order to enable the investigation of all countries and all time steps within one year. The long running times did not allow minimising the costs of a system development path. Only one year can be investigated at a time, which leads to the inherent inconsistency that a system is dimensioned based on the investment costs of a specific year, but must be built up in a time span of many years before and/or after the year of investigation. This must be considered when evaluating the model results. The designed systems are technically feasible as long as the input assumptions are feasible; however, even though the objective function of the model is the minimisation of the system costs, the system can not be called ‘least-cost’, because the cost relations of the regarded technologies may change during the transformation period of the system and such changes can not be taken into account in the model.

Many model input parameters are uncertain since they refer to a future point in time. In order to estimate the influence of these uncertainties on the model results, **sensitivities of the model results to parameter variations** were investigated using a test subset of regions: a network of Germany, Norway and Algeria. The costs of all power generation and storage technologies, transmission restrictions and annual power demand were varied, and the influence on system structure and costs was evaluated. While parameter variations caused system costs to differ from base case costs by a modest -20 % to +30 %, the shares of the power generation from single technologies in the total power generation could change drastically - increasing by a multiple (e.g. photovoltaic power generation when the investment costs for PV are 50 % of the base case costs, which is well possible), disappearing completely (e.g. geothermal combined heat and power generation when the investment costs are 120 % of the base case costs) or emerging (e.g. geothermal power generation without heat delivery to a district heating grid when the investment cost are 50 % of the base case costs). The number of parameter variations that could be performed was limited due to long model running times, but the results reveal a basic weakness of the model: relatively small changes of the input parameters lead to small changes of the system costs but can, at the same time, lead to huge changes of the system structure. The contribution of photovoltaic power generation to a low-cost electricity supply system for example can be much higher if the costs are decreased stronger than assumed here, i.e. if the cost relation with other renewable technologies decreases further. However, the model uses only the system costs as a decision criterion for the system dimensioning. Since the cost changes with the parameter variations are relatively small, other criteria may play a bigger role for the planning of power supply systems than previously assumed.

The model designs a system based on the (uncertain) cost assumptions. It leads to system designs that are cost-efficient with respect to the avoidance of overcapacities and surplus, and the distribution of technology capacities in response to resource quality and transmission distances. The resulting systems cannot be called least-cost because of the uncertainties of the cost parameters and because the planning and construction times are much longer than the one year that is modelled. This does not conflict with the technical feasibility of the designed systems as long as all technical assumptions are valid. But it must be considered when evaluating and using the model results.

As an **example of application,** the 36 regions in Europe and North Africa that belong to the investigation area were modelled with two extreme transmission assumptions: as island grids, and as a network without transmission capacity restrictions other than the costs. These two cases were chosen because, on the one hand, the transmission capacities were identified as one of the most important factors for the system structure and costs in the sensitivity analysis and because, on the other hand, the feasibility of a European-North African HVDC transmission system is rather uncertain, especially with respect to its social acceptance. The basic findings and conclusions are that

- Most regions can supply 100 % of their power demand with renewable energy.
- The two countries Luxembourg and Belgium cannot cover 100 % of their power demand with domestic resources. Building international infrastructures is indispensible for these countries if they aim at very high shares of renewable energies.
- Naturally, the costs of power supply in the unrestricted network are lower than the total costs in the island grids. With the given parameters, the levelised electricity costs (LEC) amount to 0.069 €/kWh in the network and to 0.083 €/kWh on average in the island grids. They differ thus by 0.014 €/kWh. For single regions, the costs can be as high as 0.169 €/kWh in an island grid (Luxembourg), where fuel imports must complement the renewable energy resources available on the national territory.
- A few countries can supply themselves with power in an island grid at lower costs than in the unrestricted network: Norway, Algeria, Tunisia, and Ireland. For these countries a power transmission network can be beneficial by offering export opportunities if the power can be distributed to other regions.
- The countries with island grid electricity costs lower than in the EUNA network all become exporters in the network. But also countries with higher island grid supply costs can become exporters: Libya, for example, supplies its island grid at levelised costs of 0.093 €/kWh, which is 0.024 €/kWh more than the LEC in the EUNA network. In the network however, it is the main power exporter. In the network, its solar resource can be exploited in CSP plants at costs of 0.049 €/kWh, compared with 0.094 €/kWh in the island grid. The connection to the network enables the country to specialise its CSP plants and thus exploit its solar resource at much lower costs.
- In the base case of the smaller network of Germany, Norway and Algeria, the average levelised electricity costs are 0.058 €/kWh; they are lower than the costs of any of the island grids. They are also lower than the LEC in the EUNA network, which are 0.011 €/kWh higher. The costs are obviously significantly influenced by the size and members of a network, and can be lower in a smaller network if their resource quality is high.
- Under the given assumptions, the total annual storage input is 7.2 % of total annual power generation in the network. In the island grids, it can be as high as 30 %.
- The backup gas turbine capacity (‘residual’) that guarantees coverage of peak load at any time of the investigated period and thus a high level of system reliability in other years has a share of just below 19 % of total power generation capacity in the EUNA network, and a share of 5.5 % on average in the island grids. This capacity does not generate any power during the investigation period in the network, or in any other country’s island grid except Luxembourg and Belgium, which cannot cover their demand completely with domestic renewable resources. In all other regions this capacity is purely backup capacity for the system reliability. In the network, countries have the opportunity to replace relatively expensive domestic power generation with cheaper imports from other network members. The replaced domestic capacity does not contribute to the

national system reliability - which is compensated for by installing more ‘residual’ backup capacity. This shows that it can be favourable for a country to cover a part of its power demand with imports and keep its reliability of supply high by simply installing reserve capacity to cover the demand, should the import not suffice in some periods of time.

- Transmission enables countries to avoid power generation at high costs by using cheaper but more remote resources instead. This is advantageous in terms of the costs, but it also leads to a reduction of the diversity of supply in single regions, on the one hand, and to a regional concentration of capacities of single technologies on the other. This can be seen as a disadvantage in terms of the diversity, and thus inherent security, of supply.

The main **shortcomings of the model REMix and the resulting need for further research and development** are:

– The results are valid only for the used set of parameters. The parameter variations that were performed show that relatively small variations of the assumptions can lead to significant changes in the structure of the energy mix. One possibility to improve the robustness of the results in the future is to develop the deterministic model into a stochastic model with probability functions instead of fixed parameters concerning the costs and possibly other input parameters of the model. Until this problem is solved, the results must be regarded as technical solutions that efficiently consider the quality, location and temporal availability of the used resources under the given conditions, but which cannot be considered least-cost in general.

– The model suggests technically feasible systems based on parameters assumed for one scenario year; it does not suggest a sustainable development trajectory. It can thus be used as a supporting tool for scenario development by iteratively setting boundary conditions and interpreting the suggested model results. It cannot be used as a stand-alone tool for scenario development yet.

– As of yet, the use as a scenario supporting tool is adequate only for scenario periods with high shares of renewable energy carriers of about 80 % or more, since in the model the only conventional power plant type to cover a residual load are gas turbines. Other power plant types are not yet included and the current power plant fleet is not represented in detail. The validation of scenarios starting from today requires the knowledge of the current power plant structure. Building up this database and representing it in the model is one of the next steps of development.

– REMix concentrates on the power sector: it has only a simplified representation of the heat demand in order to limit the use of combined heat and power plants for the actual heat demand. How the residual heat demand is covered is not determined by the model, but it could influence the results and it could even open up new options of load balancing because heat can be stored more easily, and thus normally cheaper, than electric energy.

– The mobility sector is not represented in REMix, but electric mobility as well as hydrogen production in electrolysers at gas stations might also be competitive options for load balancing. The mobility sector’s influence can be ambiguous: the possibility of using demand side management potentials could reduce costs, though a higher overall electric power demand would have the tendency to increase costs because of the required use of lower quality resources. The costs increasing effect would probably be small in a large-scale network but it could be big in small island grids.

– Distribution grids, and the impact of distributed and intermittent power generation on them, are not evaluated and considered in the model.

– The model is a 'retrospect' model, dimensioning an energy system for a year with perfect information available, i.e. no forecasting uncertainties like in a real power system. In order to operate a power system near its perfect operation mode, the forecasts of load and of the power available in the next hours and days must be further improved.

Given the abundant renewable energy potentials, the technical feasibility of a European-North African power supply based on renewable energy can hardly be questioned. The economic feasibility depends on the development of the technology costs. What was not considered here is the social acceptance of the required infrastructure. It can be introduced into the model by further limiting the potentials or by estimating costs for the social acceptance and introducing these into the objective function. Furthermore, the diversity of the applied resources might be a more important factor for the long-term security of supply than considered here. The same is true for cooperation in a network: the more partners are cooperating, the higher the reliability of the total resource availability. Further model developments might include a diversity measure in addition to the costs, in order to better conform to all goals declared by the European Commission in 'An energy policy for Europe': 'sustainability, security of supply and competitiveness'.

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10 Annex

10.1 Tables

10.1.1 Land cover categories

Table 10.1.1: Land cover categories of CORINE 2000 (EEA 2005), GLC 2000 (JRC 2003) and the land cover data set merged for REMix.

Merged Land Cover		CORINE LC 2000 equivalent		GLC 2000 equivalent	
ID	Label	ID	Label	ID	Label
1	Marine Water Bodies	255	Marine water bodies	20	Water Bodies (natural & artificial)
2	Maritime wetlands	37	Salt marshes	8	Tree Cover, regularly flooded, saline water, (daily variation of water level)
		38	Salines		
		39	Intertidal flats		
3	Inland Water Bodies	40	Water courses	20	Water Bodies (natural & artificial)
		41	Water bodies		
		42	Coastal lagoons		
		43	Estuaries		
		44	Sea and ocean		
4	Inland wetlands	35	Inland marshes	7	Tree Cover, regularly flooded, fresh water (& brackish)
		36	Peat bogs	15	Regularly flooded Shrub and/or Herbaceous Cover
5	Snow and Ice	34	Glaciers and perpetual snow	21	Snow and Ice (natural & artificial)
6	Bare Areas	31	Bare rocks	19	Bare Areas
		30	Beaches, dunes, sands		
7	Sparsely vegetated areas	32	Sparsely vegetated areas	14	Sparse Herbaceous or sparse Shrub Cover
8	Artificial surfaces and associated areas	1	Continuous urban fabric	22	Artificial surfaces and associated areas
		2	Discontinuous urban fabric		
		3	Industrial or commercial units		
		4	Road and rail networks and associated land		
		5	Port areas		
		6	Airports		
		7	Mineral extraction sites		
		8	Dump sites		
		9	Construction sites		
		10	Green urban areas		
		11	Sport and leisure facilities		
9	Grasslands	18	Pastures	13	Herbaceous Cover, closed-open
		26	Natural grasslands		
10	Agricultural areas	12	Non-irrigated arable land	16	Cultivated and managed areas
		13	Permanently irrigated land		
		14	Rice fields		
		15	Vineyards		
		16	Fruit trees and berry plantations		
		17	Olive groves		
		19	Annual crops associated with permanent crops		
		20	Complex cultivation patterns		
11	Shrub Cover	27	Moors and heathland	11	Shrub Cover, closed-open, evergreen
		28	Sclerophyllous vegetation	12	Shrub Cover, closed-open, deciduous
12	Mosaic: Cropland/ Shrub/ Tree Cover	21	Land principally occupied by agriculture, with significant areas of natural vegetation	9	Mosaic: Tree cover / Other natural vegetation
		29	Transitional woodland-shrub	17	Mosaic: Cropland / Tree Cover / Other natural vegetation
				18	Mosaic: Cropland / Shrub or Grass Cover
13	Forest	22	Agro-forestry areas	1	Tree Cover, broadleaved, evergreen
		23	Broad-leaved forest	2	Tree Cover, broadleaved, deciduous, closed
		24	Coniferous forest	3	Tree Cover, broadleaved, deciduous, open
		25	Mixed forest	4	Tree Cover, needle-leaved, evergreen
				5	Tree Cover, needle-leaved, deciduous
				6	Tree Cover, mixed leaf type
14	Burnt areas	33	Burnt areas	10	Tree Cover, burnt

10.1.2 Resource indicators

Table 10.1.2: Total annual potential or average resource quality for biomass, solar and wind energy.

	1)	Biomass in PJ/a, year 2000	GHI in kWh/(m^2*a)	DNI in kWh/(m^2*a)	Wind speed onshore in m/s	Wind speed offshore in m/s
AL_CS_MK [2)]	1	71	1571	1205	4.84	6.94
BA_HR_SI [3)]	1	111	1498	1140	5.15	5.87
Austria	1	260	1394	996	5.44	-
Belgium	1	68	1313	922	7.30	9.54
Bulgaria	1	85	1597	1205	4.99	6.96
Cyprus	1	2.9	2048	1972	5.01	6.04
Czech Republic	1	165	1357	949	5.87	-
Denmark	1	106	1185	924	8.00	9.40
Ireland	1	98	1217	818	8.49	10.32
EE_LT_LV [4)]	1	147	1195	928	6.69	8.49
Finland	1	430	470	437	6.37	8.73
France	1	1334	1504	1225	6.36	8.46
Germany	1	904	1314	935	6.48	9.42
Greece	1	53	1793	1535	5.23	7.09
Hungary	1	175	1454	1086	5.01	-
Italy	1	373	1682	1472	4.94	6.50
Slovakia	1	80	1375	957	5.37	-
Luxembourg	1	10	1334	934	6.76	-
Malta	1	0.6	2025	2012	7.18	7.36
Netherlands	1	76	1280	907	7.67	9.73
Norway	1	32	619	471	7.18	10.13
Poland	1	463	1303	929	6.36	8.13
Portugal	1	64	1845	1912	5.57	7.77
Romania	1	329	1468	1036	4.92	7.17
Spain	1	308	1834	1858	5.54	7.96
Sweden	1	570	735	636	6.24	8.32
CH, LI [5)]	1	49	1435	1041	4.61	-
Turkey	0.80	354	1810	1534	5.08	6.08
UK	1	266	1200	831	8.16	10.29
U_MD [6)]	1	361	1362	902	6.21	6.94
Belarus	1	91	1247	884	6.22	-
Algeria	0.31	30	2169	2321	6.14	6.86
Morocco	0.73	32	2159	2290	5.24	8.08
Tunisia	0.99	11	2112	2189	5.83	6.79
Libya	0.18	5.2	2227	2273	6.17	6.88
Egypt	0.13	47	2255	2266	5.81	6.64

1) Share of the region lying within the modelling domain
2) Albania, Serbia-Montenegro, Macedonia
3) Bosnia-Herzegovina, Croatia, Slovenia
4) Estonia, Lithuania, Latvia
5) Switzerland, Liechtenstein
6) Ukraine, Moldova

Table 10.1.3: Biomass energy resource: year 2000 potentials per biomass category in TJ/a.

Country	1)	**Forest wood**	**Waste wood**	**Straw**	**Energy crops**	**Other biomass**
Albania	1	3064	3504	38	36	4620
Bosnia	1	12553	4472	359	266	3433
Serbia	1	17812	11936	3487	1474	12528
Macedonia	1	8074	2298	36	36	1681
Moldova	1	318	4810	433	243	3813
Austria	1	160790	52661	15106	14247	17507
Belgium	1	16047	25617	6592	0	19958
Bulgaria	1	29071	11091	13598	25262	5902
Cyprus	1	868	855	259	0	929
Czech Republic	1	75661	30976	20659	24215	13732
Denmark	1	8636	6967	23237	45120	22283
Ireland	1	23623	7697	4689	0	62084
Estonia	1	21497	5548	1357	0	2063
Finland	1	169140	238952	6034	9326	6264
France	1	291593	136994	197391	582285	125882
Germany	1	340754	147415	130542	181224	103695
Greece	1	20462	12844	14397	0	5792
Croatia	1	12034	5161	11750	6259	4401
Hungary	1	45258	12436	41485	63307	12792
Italy	1	184337	75869	64167	0	48245
Lithuania	1	40228	9834	6287	13009	13005
Latvia	1	446	21078	2148	6944	3123
Slovakia	1	41081	19539	9273	3345	6862
Liechtenstein	1	69	37	1	0	3
Luxembourg	1	1223	2379	372	0	5918
Malta	1	0	413	0	0	206
Netherlands	1	11604	18311	4146	0	41665
Norway	1	15121	4774	3515	2927	5260
Poland	1	207528	73371	58292	67946	56068
Portugal	1	4688	43238	4744	0	11183
Romania	1	211344	34358	48859	8556	26125
Slovenia	1	37833	6245	1859	0	4168
Spain	1	99355	81624	56072	22648	48154
Sweden	1	250660	282700	10416	16582	9606
Switzerland	1	23790	8015	3256	2872	11213
Turkey	0.80	124044	80261	77959	0	72227
United Kingdom	1	70479	73432	60255	0	62114
Ukraine	1	43479	55771	79967	84754	86977
Belarus	1	14713	11463	13344	13748	37604
Algeria	0.31	0	29740	0	0	0
Morocco	0.73	0	31673	0	0	0
Tunisia	0.99	0	10572	0	0	0
Libya	0.18	0	5258	0	0	0
Egypt	0.13	0	46599	0	0	0

1) Share of the region lying within the modelling domain

Table 10.1.4: Geothermal energy resource derived from (Hurter 2002) and (Hurtig 1992): areas in km^2 per temperature and depth category in each country in the area of investigation.

		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
AL_CS_MK[1]	2000 m	15748	3356	0	0	0	0	0	0	0
	3000 m	22328	11140	26788	26702	21124	0	0	0	0
	4000 m	8503	14237	13169	32808	16689	30842	0	0	0
	5000 m	8170	6494	7048	53145	14250	12936	32782	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
BA_HR_SI[2]	2000 m	11197	24039	2898	0	0	0	0	0	0
	3000 m	15310	10526	14178	10977	2697	299	0	0	0
	4000 m	16179	12841	9158	16825	11940	7989	953	0	0
	5000 m	16723	15247	11197	10926	22580	8521	10635	0	595
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Austria	2000 m	1925	233	0	0	0	0	0	0	0
	3000 m	8109	634	58	0	0	0	0	0	0
	4000 m	14268	2679	1277	526	116	0	0	0	0
	5000 m	765	15396	3719	4046	1166	4534	3110	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Belgium	2000 m	484	0	0	0	0	0	0	0	0
	3000 m	5762	0	0	0	0	0	0	0	0
	4000 m	10332	2349	0	0	0	0	0	0	0
	5000 m	0	17063	7371	2790	0	0	0	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Bulgaria	2000 m	3045	0	0	0	0	0	0	0	0
	3000 m	19440	8415	1519	0	0	0	0	0	0
	4000 m	5613	5754	11894	8061	0	0	0	0	0
	5000 m	0	6114	3001	67951	15831	496	0	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Cyprus	2000 m	0	0	0	0	0	0	0	0	0
	3000 m	0	0	0	0	0	0	0	0	0
	4000 m	0	0	0	0	0	0	0	0	0
	5000 m	0	0	0	0	0	0	0	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Czech Republic	2000 m	2141	0	0	0	0	0	0	0	0
	3000 m	25750	2567	0	0	0	0	0	0	0
	4000 m	5460	32787	3669	0	0	0	0	0	0
	5000 m	0	0	24036	17880	0	0	0	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Denmark	2000 m	0	0	0	0	0	0	0	0	0
	3000 m	21996	0	0	0	0	0	0	0	0
	4000 m	11709	18431	6581	0	0	0	0	0	0
	5000 m	0	11758	16905	8304	0	0	0	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Ireland	2000 m	0	0	0	0	0	0	0	0	0
	3000 m	1486	0	0	0	0	0	0	0	0
	4000 m	651	101	0	0	0	0	0	0	0
	5000 m	1158	501	252	0	0	0	0	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
EE_LT_LV[3]	2000 m	1314	0	0	0	0	0	0	0	0
	3000 m	10931	2862	0	0	0	0	0	0	0
	4000 m	8243	5221	6847	1940	0	0	0	0	0
	5000 m	19773	7079	5083	7244	2519	0	0	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Finland	2000 m	0	0	0	0	0	0	0	0	0
	3000 m	0	0	0	0	0	0	0	0	0
	4000 m	0	0	0	0	0	0	0	0	0
	5000 m	356	0	0	0	0	0	0	0	0

Table 10.1.4: Geothermal energy resource derived from (Hurter 2002) and (Hurtig 1992): areas in km^2 per temperature and depth category in each country in the area of investigation.

		90 °C	110 °C	130 °C	150 °C	170 °C	190 °C	210 °C	230 °C	260 °C
France	2000 m	169886	12244	564	0	0	0	0	0	0
	3000 m	190875	208413	54823	8222	169	0	0	0	0
	4000 m	9340	149859	216495	51191	43913	6249	0	0	0
	5000 m	0	9608	196403	222900	41113	50874	9166	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Germany	2000 m	105109	5382	113	0	0	0	0	0	0
	3000 m	148951	137161	25823	4010	1118	0	0	0	0
	4000 m	3579	77653	123116	90048	4012	1067	0	0	0
	5000 m	0	1848	68152	132991	88326	8715	1013	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Greece	2000 m	0	0	0	0	0	0	0	0	0
	3000 m	77373	2366	1057	133	0	0	0	0	0
	4000 m	7055	71217	4002	1637	729	0	0	0	0
	5000 m	1254	7007	5042	79916	1391	1044	331	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Hungary	2000 m	28714	39341	13742	0	517	0	0	0	0
	3000 m	6620	9502	27375	41575	5292	0	0	0	0
	4000 m	0	1283	4539	8092	28011	32182	3791	0	0
	5000 m	0	0	0	2980	5659	12691	53879	0	3791
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Italy	2000 m	22957	1376	438	0	0	0	0	0	0
	3000 m	59619	10809	5097	7070	4348	0	0	0	0
	4000 m	86860	77786	15587	7472	7241	7864	0	0	0
	5000 m	64768	61456	63922	39912	6619	9158	10800	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Slovakia	2000 m	9658	1758	0	0	0	0	0	0	0
	3000 m	17229	11521	8722	342	0	0	0	0	0
	4000 m	562	11045	2745	2779	1207	0	0	0	0
	5000 m	0	0	8576	5213	2194	169	2243	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Luxembourg	2000 m	0	0	0	0	0	0	0	0	0
	3000 m	612	0	0	0	0	0	0	0	0
	4000 m	0	612	0	0	0	0	0	0	0
	5000 m	0	0	945	0	0	0	0	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Malta	2000 m	0	0	0	0	0	0	0	0	0
	3000 m	0	0	0	0	0	0	0	0	0
	4000 m	0	0	0	0	0	0	0	0	0
	5000 m	0	0	0	0	0	0	0	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Netherlands	2000 m	14414	0	0	0	0	0	0	0	0
	3000 m	4894	23503	0	0	0	0	0	0	0
	4000 m	0	1552	3393	23452	0	0	0	0	0
	5000 m	0	0	810	4864	26415	0	0	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Norway	2000 m	0	0	0	0	0	0	0	0	0
	3000 m	0	0	0	0	0	0	0	0	0
	4000 m	0	0	0	0	0	0	0	0	0
	5000 m	0	0	0	0	0	0	0	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Poland	2000 m	7713	0	0	0	0	0	0	0	0
	3000 m	101704	47607	2260	0	0	0	0	0	0
	4000 m	85029	116740	48592	28790	0	0	0	0	0
	5000 m	18811	71444	112059	68656	31828	0	0	0	0

Table 10.1.4: Geothermal energy resource derived from (Hurter 2002) and (Hurtig 1992): areas in km^2 per temperature and depth category in each country in the area of investigation.

		90 °C	110 °C	130 °C	150 °C	170 °C	190 °C	210 °C	230 °C	260 °C
Portugal	2000 m	1677	0	0	0	0	0	0	0	0
	3000 m	0	0	0	0	0	0	0	0	0
	4000 m	0	0	0	0	0	0	0	0	0
	5000 m	0	0	0	0	0	0	0	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Romania	2000 m	9506	2560	0	0	0	0	0	0	0
	3000 m	142593	21657	7105	2013	178	0	0	0	0
	4000 m	3814	21004	5084	7143	7118	468	0	0	0
	5000 m	0	1490	21884	3415	1165	11748	4930	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Spain	2000 m	5178	0	0	0	0	0	0	0	0
	3000 m	174921	39297	1216	0	0	0	0	0	0
	4000 m	31181	86958	35104	2754	0	0	0	0	0
	5000 m	8245	47329	80330	25222	21525	0	0	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Sweden	2000 m	0	0	0	0	0	0	0	0	0
	3000 m	0	0	0	0	0	0	0	0	0
	4000 m	0	0	0	0	0	0	0	0	0
	5000 m	0	0	0	0	0	0	0	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
CH, LI [4)]	2000 m	13046	0	0	0	0	0	0	0	0
	3000 m	18173	1273	58	0	0	0	0	0	0
	4000 m	13999	18795	7062	116	0	0	0	0	0
	5000 m	532	2709	26129	10899	116	0	0	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Turkey	2000 m	273250	88583	45783	0	37582	0	0	0	0
	3000 m	129286	170949	78998	70200	44699	22949	34243	0	0
	4000 m	4135	66300	118505	147923	92006	60825	48829	54118	0
	5000 m	2134	2826	36054	81021	147846	109080	118530	0	98522
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
UK	2000 m	3416	0	0	0	0	0	0	0	0
	3000 m	29905	743	0	0	0	0	0	0	0
	4000 m	73257	19202	4841	1116	0	0	0	0	0
	5000 m	115140	65437	17314	4816	2565	819	0	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
U_MD [5)]	2000 m	2902	911	0	0	0	0	0	0	0
	3000 m	146545	26332	3172	1881	0	0	0	0	0
	4000 m	141283	147479	24287	12217	1308	285	0	0	0
	5000 m	105757	136447	140437	24360	13160	1899	1137	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Belarus	2000 m	0	0	0	0	0	0	0	0	0
	3000 m	0	0	0	0	0	0	0	0	0
	4000 m	11762	0	0	0	0	0	0	0	0
	5000 m	25246	11710	0	0	0	0	0	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Algeria	2000 m	0	0	0	0	0	0	0	0	0
	3000 m	0	0	0	0	0	0	0	0	0
	4000 m	0	0	0	0	0	0	0	0	0
	5000 m	0	0	0	0	0	0	0	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Morocco	2000 m	0	0	0	0	0	0	0	0	0
	3000 m	0	0	0	0	0	0	0	0	0
	4000 m	0	0	0	0	0	0	0	0	0
	5000 m	0	0	0	0	0	0	0	0	0

Table 10.1.4: Geothermal energy resource derived from (Hurter 2002) and (Hurtig 1992): areas in km^2 per temperature and depth category in each country in the area of investigation.

		90 °C	110 °C	130 °C	150 °C	170 °C	190 °C	210 °C	230 °C	260 °C
Tunisia	2000 m	0	0	0	0	0	0	0	0	0
	3000 m	0	0	0	0	0	0	0	0	0
	4000 m	0	0	0	0	0	0	0	0	0
	5000 m	0	0	0	0	0	0	0	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Libya	2000 m	0	0	0	0	0	0	0	0	0
	3000 m	0	0	0	0	0	0	0	0	0
	4000 m	0	0	0	0	0	0	0	0	0
	5000 m	0	0	0	0	0	0	0	0	0
		90 °C	**110 °C**	**130 °C**	**150 °C**	**170 °C**	**190 °C**	**210 °C**	**230 °C**	**260 °C**
Egypt	2000 m	0	0	0	0	0	0	0	0	0
	3000 m	0	0	0	0	0	0	0	0	0
	4000 m	0	0	0	0	0	0	0	0	0
	5000 m	0	0	0	0	0	0	0	0	0

1) Albania, Serbia-Montenegro, Macedonia
2) Bosnia-Herzegovina, Croatia, Slovenia
3) Estonia, Lithuania, Latvia
4) Switzerland, Liechtenstein
5) Ukraine, Moldova

10.1.3 Capacity and power generation potentials

Table 10.1.5: Maximum installable capacities in GW, year 2010.

	1)	PV	CSP[7)]	GEO	GEO CHP	HYDRO[8)]	WIND ON-SHORE	WIND OFF-SHORE
AL_CS_MK [2)]	1	6.0	0	9.5	6.3	11	40	15
BA_HR_SI [3)]	1	9	0	5.6	3.3	14	30	60
Austria	1	11	0	0.3	1.4	21	15	0
Belgium	1	20	0	0.1	0.9	0.1	3.5	5.6
Bulgaria	1	18	0	2.6	2.7	12.3	24	19
Cyprus	1	5.9	5.1	0	0	0.001	2.2	1.8
Czech Republic	1	16	0	0.4	2.4	1.6	14	0
Denmark	1	8.1	0	0.6	1.6	0	7.5	125
Ireland	1	4.0	0	0	0.1	0.4	13	223
EE_LT_LV [4)]	1	13	0	0.8	0.9	2.4	35	94
Finland	1	11	0	0.003	0.002	4.7	69	97
France	1	85	6.9	29.4	18	42	109	253
Germany	1	92	0	9.4	20	4.6	55	72
Greece	1	12	15	5.1	1.7	8.9	29	93
Hungary	1	17	0	9.8	5.4	2.1	19	0
Italy	1	44	38	5.0	9.2	48	61	165
Slovakia	1	8.7	0	0.6	1.6	3.5	8.4	0
Luxembourg	1	0.6	0	0	0.1	0.04	0.3	0
Malta	1	0.3	0.6	0	0	0	0	21
Netherlands	1	14	0	0.6	2.9	0.04	5.1	92
Norway	1	2.6	0	0	0	37	68	386
Poland	1	35	0	3.9	14.6	5.8	59	50
Portugal	1	11	120	0	0	23	22	38
Romania	1	48	0	2.1	4.3	10	48	25
Spain	1	64	459	8.4	4.1	50	131	104
Sweden	1	16	0	0	0	20	90	223
CH, LI [5)]	1	2.2	0	0.6	2.0	17	7	0
Turkey	0.80	303	276	71.9	24	77	244	55
UK	1	54	0	1.3	4.7	1.5	36	831
U_MD [6)]	1	26	0	7.2	13	8.7	160	119
Belarus	1	3.6	0	0.3	0.5	1.5	52	0
Algeria	0.31	5630	7934	0	0	2.4	1426	10
Morocco	0.73	1322	2035	0	0	4.5	435	49
Tunisia	0.99	1261	1876	0	0	0.1	308	116
Libya	0.18	4130	5524	0	0	0	979	125
Egypt	0.13	1087	1682	0	0	11	262	42
Total Area		14390	19972	175	146	446	4868	3510

1) Share of the region lying within the modelling domain
2) Albania, Serbia-Montenegro, Macedonia
3) Bosnia-Herzegovina, Croatia, Slovenia
4) Estonia, Lithuania, Latvia
5) Switzerland, Liechtenstein
6) Ukraine, Moldova
7) Electric power capacity when solar multiple = 1
8) Sum of hydro run-of-river, hydro run-of-river, new and hydro reservoir capacities

Table 10.1.6: Maximum installable capacities in GW, year 2020.

	1)	PV	CSP[7)]	GEO	GEO CHP	HYDRO[8)]	WIND ON-SHORE	WIND OFF-SHORE
AL_CS_MK [2)]	1	6.5	0	9.5	6.3	11	40	15
BA_HR_SI [3)]	1	10	0	5.6	3.3	14	30	60
Austria	1	12	0	0.3	1.4	21	15	0
Belgium	1	21	0	0.1	0.9	0.1	3.5	5.6
Bulgaria	1	19	0	2.6	2.7	12.4	24	19
Cyprus	1	6.5	5.1	0	0	0.001	2.2	1.8
Czech Republic	1	17	0	0.4	2.4	1.6	14	0
Denmark	1	8.8	0	0.6	1.6	0	7.5	125
Ireland	1	4.4	0	0	0.1	0.4	13	223
EE_LT_LV [4)]	1	14	0	0.8	0.9	2.5	35	94
Finland	1	12	0	0.003	0.002	4.7	69	97
France	1	92	6.9	29.4	18	42	109	253
Germany	1	100	0	9.4	20	4.7	55	72
Greece	1	13	15	5.1	1.7	9.0	29	93
Hungary	1	19	0	9.8	5.4	2.1	19	0
Italy	1	48	38	5.0	9.2	48	61	165
Slovakia	1	9.4	0	0.6	1.6	3.5	8.4	0
Luxembourg	1	0.7	0	0	0.1	0.04	0.3	0
Malta	1	0.3	0.6	0	0	0	0	21
Netherlands	1	15	0	0.6	2.9	0.04	5.1	92
Norway	1	2.8	0	0	0	37	68	386
Poland	1	38	0	3.9	14.6	5.9	59	50
Portugal	1	12	120	0	0	23	22	38
Romania	1	52	0	2.1	4.3	10	48	25
Spain	1	70	459	8.4	4.1	51	131	104
Sweden	1	18	0	0	0	20	90	223
CH, LI [5)]	1	2.4	0	0.6	2.0	18	7	0
Turkey	0.80	329	276	71.9	24	77	244	55
UK	1	58	0	1.3	4.7	1.6	36	831
U_MD [6)]	1	29	0	7.2	13	8.9	160	119
Belarus	1	3.9	0	0.3	0.5	1.5	52	0
Algeria	0.31	6124	7934	0	0	2.4	1427	10
Morocco	0.73	1438	2035	0	0	4.5	435	49
Tunisia	0.99	1372	1876	0	0	0.1	308	116
Libya	0.18	4492	5524	0	0	0	979	125
Egypt	0.13	1182	1682	0	0	11	262	42
Total Area		15654	19972	175	146	451	4869	3510

1) Share of the region lying within the modelling domain
2) Albania, Serbia-Montenegro, Macedonia
3) Bosnia-Herzegovina, Croatia, Slovenia
4) Estonia, Lithuania, Latvia
5) Switzerland, Liechtenstein
6) Ukraine, Moldova
7) Electric power capacity when solar multiple = 1
8) Sum of hydro run-of-river, hydro run-of-river, new and hydro reservoir capacities

Table 10.1.7: Maximum installable capacities in GW, year 2050.

	1)	PV	CSP[7)]	GEO	GEO CHP	HYDRO[8)]	WIND ON-SHORE	WIND OFF-SHORE
AL_CS_MK [2)]	1	7.0	0	9.5	6.3	11	40	15
BA_HR_SI [3)]	1	10	0	5.6	3.3	15	30	60
Austria	1	13	0	0.3	1.4	22	15	0
Belgium	1	23	0	0.1	0.9	0.1	3.5	5.6
Bulgaria	1	21	0	2.6	2.7	12.6	24	19
Cyprus	1	7.0	5.1	0	0	0.001	2.2	1.8
Czech Republic	1	18	0	0.4	2.4	1.7	14	0
Denmark	1	9.5	0	0.6	1.6	0	7.5	125
Ireland	1	4.7	0	0	0.1	0.4	13	224
EE_LT_LV [4)]	1	15	0	0.8	0.9	2.6	35	94
Finland	1	13	0	0.003	0.002	5.0	69	97
France	1	99	6.9	29.4	18	44	109	253
Germany	1	108	0	9.4	20	5.0	55	72
Greece	1	14	15	5.1	1.7	9.2	29	93
Hungary	1	20	0	9.8	5.4	2.1	19	0
Italy	1	51	38	5.0	9.2	50	61	165
Slovakia	1	10.2	0	0.6	1.6	3.7	8.4	0
Luxembourg	1	0.7	0	0	0.1	0.04	0.3	0
Malta	1	0.4	0.6	0	0	0	0	21
Netherlands	1	16	0	0.6	2.9	0.04	5.1	92
Norway	1	3.0	0	0	0	39	68	386
Poland	1	41	0	3.9	14.6	6.0	59	50
Portugal	1	13	120	0	0	23	22	38
Romania	1	56	0	2.1	4.3	11	48	25
Spain	1	76	459	8.4	4.1	52	131	104
Sweden	1	19	0	0	0	22	90	223
CH, LI [5)]	1	2.6	0	0.6	2.0	19	7	0
Turkey	0.80	355	276	71.9	24	78	244	55
UK	1	63	0	1.3	4.7	1.7	36	831
U_MD [6)]	1	31	0	7.2	13	9.2	160	119
Belarus	1	4.2	0	0.3	0.5	1.5	52	0
Algeria	0.31	6605	7934	0	0	2.5	1427	10
Morocco	0.73	1551	2035	0	0	4.6	435	49
Tunisia	0.99	1480	1876	0	0	0.1	308	116
Libya	0.18	4845	5524	0	0	0	979	125
Egypt	0.13	1275	1682	0	0	11	262	42
Total Area		16883	19972	175	146	466	4869	3511

1) Share of the region lying within the modelling domain
2) Albania, Serbia-Montenegro, Macedonia
3) Bosnia-Herzegovina, Croatia, Slovenia
4) Estonia, Lithuania, Latvia
5) Switzerland, Liechtenstein
6) Ukraine, Moldova
7) Electric power capacity when solar multiple = 1
8) Sum of hydro run-of-river, hydro run-of-river, new and hydro reservoir capacities

Table 10.1.8: Electricity generation potentials in TWh/a, year 2010.

	1)	BIO[7)]	PV	CSP[8)]	GEO	GEO CHP	HYDRO[9)]	WIND ON-SHORE	WIND OFF-SHORE
AL_CS_MK [2)]	1	3.7	7.1	0	71	47.6	37	48	35
BA_HR_SI [3)]	1	4.4	10	0	42	25	40	42	105
Austria	1	10	12	0	2.2	11	70	23	0
Belgium	1	4.2	19	0	0.6	6.7	0.3	9.3	23
Bulgaria	1	2.7	21	0	19	20	15	31	44
Cyprus	1	0.2	10	9.8	0	0	0.002	2.6	2.9
Czech Republic	1	6.4	16	0	3.1	18	3.7	25	0
Denmark	1	3.7	7.4	0	4.2	11.9	0.02	23	511
Ireland	1	6.1	3.9	0	0.1	0.4	0.9	45	964
EE_LT_LV [4)]	1	6.2	12	0	6.1	7.0	6.5	77	328
Finland	1	23	10	0	0.02	0.02	21	127	358
France	1	38	94	12	220	139	92	225	863
Germany	1	35	91	0	70	153	28	117	297
Greece	1	2.7	17	27	38	12	14	43	234
Hungary	1	5.3	19	0	73	41	8.0	23	0
Italy	1	17	55	65	37	69	100	83	299
Slovakia	1	3.5	9	0	4.4	12	6.3	11	0
Luxembourg	1	0.7	0.6	0	0	0.4	0.1	0.8	0
Malta	1	0.0	0.4	1.0	0	0	0	0	59
Netherlands	1	5.0	13	0	4.1	22	0.1	14	385
Norway	1	1.3	2.3	0	0	0.0	181	163	1572
Poland	1	18	35	0	30	109	13	115	160
Portugal	1	4.5	17	216	0.1	0.1	24	32	96
Romania	1	13	52	0	16	32	32	59	65
Spain	1	15	102	839	63	31	63	205	247
Sweden	1	29	15	0	0	0	90	167	772
CH, LI [5)]	1	2.2	2.4	0	4.5	14.8	39	9	0
Turkey	0.80	19	526	486	539	178	211	350	98
UK	1	15	51	0	9.9	35	5.0	116	3537
U_MD [6)]	1	17	27	0	54	94	23	298	294
Belarus	1	4.8	3.6	0	2.2	3.5	3.0	96	0
Algeria	0.31	2.2	10500	17543	0	0	4.9	2774	16
Morocco	0.73	2.4	2503	4385	0	0	4.8	684	94
Tunisia	0.99	0.8	2312	3907	0	0	0.1	515	255
Libya	0.18	0.4	7791	11931	0	0	0	1801	271
Egypt	0.13	3.5	2076	3670	0	0	48	467	63
Total Area		326	26443	43093	1316	1093	1185	8819	12046

1) Share of the region lying within the modelling domain
2) Albania, Serbia-Montenegro, Macedonia
3) Bosnia-Herzegovina, Croatia, Slovenia
4) Estonia, Lithuania, Latvia
5) Switzerland, Liechtenstein
6) Ukraine, Moldova
7) Biomass power generation potential under the assumption of an average conversion efficiency of 30 %
8) Electric power generation potential when solar multiple = 1
9) Sum of hydro run-of-river, hydro run-of-river, new and hydro reservoir potentials

Table 10.1.9: Electricity generation potentials in TWh/a, year 2020.

	1)	BIO 7)	PV	CSP 8)	GEO	GEO CHP	HYDRO 9)	WIND ON-SHORE	WIND OFF-SHORE
AL_CS_MK 2)	1	3.8	7.7	0	71	47.6	37	50	36
BA_HR_SI 3)	1	5.1	11	0	42	25	40	43	108
Austria	1	11	13	0	2.2	11	71	23	0
Belgium	1	4.2	21	0	0.6	6.7	0.3	9.5	23
Bulgaria	1	5.4	22	0	19	20	15	32	45
Cyprus	1	0.2	11	9.8	0	0	0.002	2.7	3.0
Czech Republic	1	8.8	17	0	3.1	18	3.7	25	0
Denmark	1	8.5	8.0	0	4.2	11.9	0.02	24	522
Ireland	1	6.1	4.2	0	0.1	0.4	0.9	46	989
EE_LT_LV 4)	1	8.1	13	0	6.1	7.0	6.6	80	338
Finland	1	23	11	0	0.02	0.02	21	132	367
France	1	97	103	12	220	139	93	231	889
Germany	1	53	99	0	70	153	29	120	303
Greece	1	2.9	18	27	38	12	14	44	239
Hungary	1	12	20	0	73	41	8.0	24	0
Italy	1	18	61	65	37	69	101	85	309
Slovakia	1	3.9	10	0	4.4	12	6.4	12	0
Luxembourg	1	0.7	0.7	0	0	0.4	0.1	0.8	0
Malta	1	0.0	0.5	1.0	0	0	0	0	60
Netherlands	1	5.1	14	0	4.1	22	0.1	15	392
Norway	1	1.6	2.5	0	0	0.0	184	168	1604
Poland	1	25	38	0	30	109	14	119	163
Portugal	1	4.5	18	216	0.1	0.1	24	34	100
Romania	1	13	57	0	16	32	33	62	66
Spain	1	18	112	839	63	31	63	211	254
Sweden	1	30	16	0	0	0	92	173	790
CH, LI 5)	1	2.5	2.6	0	4.5	14.8	40	9	0
Turkey	0.80	20	577	486	539	178	212	361	101
UK	1	16	56	0	9.9	35	5.1	119	3610
U_MD 6)	1	27	30	0	54	94	24	307	302
Belarus	1	6.3	3.9	0	2.2	3.5	3.0	99	0
Algeria	0.31	2.2	11547	17543	0	0	4.9	2845	17
Morocco	0.73	2.4	2748	4385	0	0	4.8	703	97
Tunisia	0.99	0.8	2542	3907	0	0	0.1	529	262
Libya	0.18	0.4	8568	11931	0	0	0	1849	278
Egypt	0.13	3.5	2283	3670	0	0	49	480	66
Total Area		451	29065	43093	1316	1093	1199	9068	12336

1) Share of the region lying within the modelling domain
2) Albania, Serbia-Montenegro, Macedonia
3) Bosnia-Herzegovina, Croatia, Slovenia
4) Estonia, Lithuania, Latvia
5) Switzerland, Liechtenstein
6) Ukraine, Moldova
7) Potential under the assumption of an average conversion efficiency of 30 %
8) Electric power generation potential when solar multiple = 1
9) Sum of hydro run-of-river, hydro run-of-river, new and hydro reservoir potentials

Table 10.1.10: Electricity generation potentials in TWh/a, year 2050.

	1)	BIO[7)]	PV	CSP[8)]	GEO	GEO CHP	HYDRO[9)]	WIND ON-SHORE	WIND OFF-SHORE
AL_CS_MK [2)]	1	4.1	8.4	0	71	47.6	38	51	37
BA_HR_SI [3)]	1	6.0	12	0	42	25	41	45	112
Austria	1	13	14	0	2.2	11	74	24	0
Belgium	1	4.4	23	0	0.6	6.7	0.3	9.8	24
Bulgaria	1	7.2	24	0	19	20	15	33	46
Cyprus	1	0.2	12	9.8	0	0	0.002	2.8	3.1
Czech Republic	1	11	19	0	3.1	18	3.9	26	0
Denmark	1	11	8.6	0	4.2	11.9	0.03	24	535
Ireland	1	6.3	4.5	0	0.1	0.4	1.0	47	1017
EE_LT_LV [4)]	1	9.9	14	0	6.1	7.0	6.9	82	350
Finland	1	25	12	0	0.02	0.02	22	137	377
France	1	135	111	12	220	139	98	237	918
Germany	1	68	107	0	70	153	31	123	310
Greece	1	3.1	20	27	38	12	15	45	245
Hungary	1	16	22	0	73	41	8.0	24	0
Italy	1	20	66	65	37	69	104	88	320
Slovakia	1	4.4	11	0	4.4	12	6.8	12	0
Luxembourg	1	0.7	0.7	0	0	0.4	0.1	0.8	0
Malta	1	0.0	0.5	1.0	0	0	0	0	62
Netherlands	1	5.2	15	0	4.1	22	0.1	15	400
Norway	1	1.9	2.6	0	0	0.0	195	173	1640
Poland	1	31	41	0	30	109	14	122	168
Portugal	1	4.6	20	216	0.1	0.1	25	35	103
Romania	1	16	62	0	16	32	34	64	68
Spain	1	21	121	839	63	31	65	217	263
Sweden	1	33	17	0	0	0	97	180	811
CH, LI [5)]	1	2.9	2.8	0	4.5	14.8	42	9	0
Turkey	0.80	21	627	486	539	178	215	372	104
UK	1	17	60	0	9.9	35	5.5	121	3691
U_MD [6)]	1	32	32	0	54	94	25	316	312
Belarus	1	7.3	4.2	0	2.2	3.5	3.0	103	0
Algeria	0.31	2.2	12588	17543	0	0	5.0	2911	18
Morocco	0.73	2.4	2990	4385	0	0	4.9	721	100
Tunisia	0.99	0.8	2771	3907	0	0	0.2	542	271
Libya	0.18	0.4	9341	11931	0	0	0	1893	287
Egypt	0.13	3.5	2489	3670	0	0	50	493	68
Total Area		548	31671	43093	1316	1093	1243	9298	12662

1) Share of the region lying within the modelling domain
2) Albania, Serbia-Montenegro, Macedonia
3) Bosnia-Herzegovina, Croatia, Slovenia
4) Estonia, Lithuania, Latvia
5) Switzerland, Liechtenstein
6) Ukraine, Moldova
7) Potential under the assumption of an average conversion efficiency of 30 %
8) Electric power generation potential when solar multiple = 1
9) Sum of hydro run-of-river, hydro run-of-river, new and hydro reservoir potentials

10.1.4 Transmission line characteristics of the EUNA network

Table 10.1.11: Direct distances between the nodes in Europe and North Africa in km.

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
AL_CS_MK [1)]	**1**	0	382	729	1452	355	1418	856	1613	2333	1503	2308	1401	1183	478	481	712	621	1317
BA_HR_SI [2)]	**2**	382	0	359	1073	716	1800	553	1304	1951	1388	2151	1029	822	832	366	420	452	936
Austria	**3**	729	359	0	725	1035	2141	289	974	1611	1241	1937	769	464	1191	462	479	434	595
Belgium	**4**	1452	1073	725	0	1759	2867	737	684	887	1445	1880	443	343	1901	1140	962	1053	143
Bulgaria	**5**	355	716	1035	1759	0	1116	1094	1822	2646	1529	2343	1745	1463	411	665	1067	797	1630
Cyprus	**6**	1418	1800	2141	2867	1116	0	2209	2919	3751	2462	3235	2804	2579	1026	1777	2067	1903	2734
Czech Republic	**7**	856	553	289	737	1094	2209	0	759	1605	957	1649	930	399	1334	432	768	322	644
Denmark	**8**	1613	1304	974	684	1822	2919	759	0	1190	899	1197	1119	573	2092	1160	1406	1024	745
Ireland	**9**	2333	1951	1611	887	2646	3751	1605	1190	0	2089	2226	1035	1206	2769	2022	1768	1927	1016
EE_LT_LV [3)]	**10**	1503	1388	1241	1445	1529	2462	957	899	2089	0	814	1797	1155	1912	1052	1708	937	1431
Finland	**11**	2308	2151	1937	1880	2343	3235	1649	1197	2226	814	0	2306	1696	2727	1842	2416	1716	1924
France	**12**	1401	1029	769	443	1745	2804	930	1119	1035	1797	2306	0	642	1789	1231	752	1191	382
Germany	**13**	1183	822	464	343	1463	2579	399	573	1206	1155	1696	642	0	1652	819	841	720	281
Greece	**14**	478	832	1191	1901	411	1026	1334	2092	2769	1912	2727	1789	1652	0	947	1044	1088	1761
Hungary	**15**	481	366	462	1140	665	1777	432	1160	2022	1052	1842	1231	819	947	0	767	140	1026
Italy	**16**	712	420	479	962	1067	2067	768	1406	1768	1708	2416	752	841	1044	767	0	817	819
Slovakia	**17**	621	452	434	1053	797	1903	322	1024	1927	937	1716	1191	720	1088	140	817	0	950
Luxembourg	**18**	1317	936	595	143	1630	2734	644	745	1016	1431	1924	382	281	1761	1026	819	950	0
Malta	**19**	952	1022	1291	1815	1159	1699	1554	2258	2554	2400	3174	1520	1703	828	1349	865	1464	1675
Netherlands	**20**	1502	1132	774	168	1788	2904	720	522	887	1323	1720	611	326	1964	1145	1077	1042	273
Norway	**21**	2180	1907	1595	1265	2337	3387	1353	635	1434	1022	805	1708	1208	2652	1704	2040	1564	1354
Poland	**22**	937	750	599	1000	1074	2150	332	777	1817	650	1402	1252	659	1397	456	1059	319	934
Portugal	**23**	2374	2061	1896	1527	2728	3643	2096	2190	1402	2959	3383	1171	1805	2631	2344	1664	2331	1527
Romania	**24**	444	661	893	1587	327	1367	871	1552	2470	1201	2015	1653	1264	725	447	1073	551	1472
Spain	**25**	1997	1690	1546	1268	2350	3268	1764	1951	1366	2662	3148	865	1508	2253	1984	1288	1980	1241
Sweden	**26**	2126	1898	1626	1436	2235	3237	1354	755	1728	796	497	1874	1304	2582	1644	2095	1506	1500
CH, LI [4)]	**27**	1029	651	395	512	1368	2442	607	1036	1332	1542	2150	382	466	1440	855	451	828	371
Turkey	**28**	997	1371	1690	2412	657	515	1725	2416	3300	1949	2730	2398	2108	728	1293	1695	1411	2285
UK	**29**	2006	1628	1277	555	2304	3417	1243	828	376	1724	1928	826	848	2457	1667	1497	1565	696
U_MD [5)]	**30**	1080	1250	1379	1965	868	1507	1235	1700	2796	1004	1734	2141	1621	1270	929	1670	949	1879
Belarus	**31**	1268	1252	1213	1609	1217	2078	969	1189	2355	401	1161	1891	1279	1620	887	1632	815	1560
Algeria	**32**	1640	1472	1520	1642	1954	2665	1804	2281	2079	2761	3412	1208	1725	1727	1833	1073	1890	1544
Morocco	**33**	2630	2402	2348	2175	2960	3685	2600	2859	2193	3532	4055	1755	2391	2753	2741	1982	2767	2137
Tunisia	**34**	1206	1167	1353	1740	1467	2069	1638	2272	2385	2551	3287	1379	1700	1176	1525	878	1619	1611
Libya	**35**	1280	1410	1694	2216	1413	1677	1952	2663	2931	2767	3555	1904	2110	1022	1716	1271	1839	2078
Egypt	**36**	1667	2033	2391	3102	1441	534	2513	3258	3964	2905	3699	2963	2850	1201	2098	2211	2234	2962

1) Albania, Serbia-Montenegro, Macedonia; 2) Bosnia-Herzegovina, Croatia, Slovenia; 3) Estonia, Lithuania, Latvia; 4) Switzerland, Liechtenstein; 5) Ukraine, Moldova

Table 10.1.11 (continued): Direct distances between the nodes in Europe and North Africa in km.

		19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36
AL_CS_MK [1]	1	952	1502	2180	937	2374	444	1997	2126	1029	997	2006	1080	1268	1640	2630	1206	1280	1667
BA_HR_SI [2]	2	1022	1132	1907	750	2061	661	1690	1898	651	1371	1628	1250	1252	1472	2402	1167	1410	2033
Austria	3	1291	774	1595	599	1896	893	1546	1626	395	1690	1277	1379	1213	1520	2348	1353	1694	2391
Belgium	4	1815	168	1265	1000	1527	1587	1268	1436	512	2412	555	1965	1609	1642	2175	1740	2216	3102
Bulgaria	5	1159	1788	2337	1074	2728	327	2350	2235	1368	657	2304	868	1217	1954	2960	1467	1413	1441
Cyprus	6	1699	2904	3387	2150	3643	1367	3268	3237	2442	515	3417	1507	2078	2665	3685	2069	1677	534
Czech Republic	7	1554	720	1353	332	2096	871	1764	1354	607	1725	1243	1235	969	1804	2600	1638	1952	2513
Denmark	8	2258	522	635	777	2190	1552	1951	755	1036	2416	828	1700	1189	2281	2859	2272	2663	3258
Ireland	9	2554	887	1434	1817	1402	2470	1366	1728	1332	3300	376	2796	2355	2079	2193	2385	2931	3964
EE_LT_LV [3]	10	2400	1323	1022	650	2959	1201	2662	796	1542	1949	1724	1004	401	2761	3532	2551	2767	2905
Finland	11	3174	1720	805	1402	3383	2015	3148	497	2150	2730	1928	1734	1161	3412	4055	3287	3555	3699
France	12	1520	611	1708	1252	1171	1653	865	1874	382	2398	826	2141	1891	1208	1755	1379	1904	2963
Germany	13	1703	326	1208	659	1805	1264	1508	1304	466	2108	848	1621	1279	1725	2391	1700	2110	2850
Greece	14	828	1964	2652	1397	2631	725	2253	2582	1440	728	2457	1270	1620	1727	2753	1176	1022	1201
Hungary	15	1349	1145	1704	456	2344	447	1984	1644	855	1293	1667	929	887	1833	2741	1525	1716	2098
Italy	16	865	1077	2040	1059	1664	1073	1288	2095	451	1695	1497	1670	1632	1073	1982	878	1271	2211
Slovakia	17	1464	1042	1564	319	2331	551	1980	1506	828	1411	1565	949	815	1890	2767	1619	1839	2234
Luxembourg	18	1675	273	1354	934	1527	1472	1241	1500	371	2285	696	1879	1560	1544	2137	1611	2078	2962
Malta	19	0	1939	2886	1772	2018	1385	1664	2909	1303	1535	2327	2010	2209	968	1986	369	406	1636
Netherlands	20	1939	0	1097	939	1674	1590	1428	1270	638	2434	522	1916	1519	1807	2337	1884	2343	3165
Norway	21	2886	1097	0	1263	2676	2035	2488	320	1668	2872	1166	2008	1415	2899	3399	2908	3290	3775
Poland	22	1772	939	1263	0	2422	783	2095	1188	939	1643	1443	979	639	2118	2932	1903	2153	2515
Portugal	23	2018	1674	2676	2422	0	2722	378	2911	1504	3335	1527	3272	3061	1129	794	1692	2263	3652
Romania	24	1385	1590	2035	783	2722	0	2352	1918	1272	865	2112	636	894	2071	3042	1650	1684	1742
Spain	25	1664	1428	2488	2095	378	2352	0	2694	1161	2956	1394	2913	2734	839	911	1355	1935	3291
Sweden	26	2909	1270	320	1188	2911	1918	2694	0	1771	2722	1434	1800	1197	3028	3605	2973	3306	3656
CH, LI [4]	27	1303	638	1668	939	1504	1272	1161	1771	0	2023	1048	1775	1575	1262	1995	1253	1707	2632
Turkey	28	1535	2434	2872	1643	3335	865	2956	2722	2023	0	2954	1017	1569	2455	3482	1895	1639	978
UK	29	2327	522	1166	1443	1527	2112	1394	1434	1048	2954	0	2421	1980	1989	2283	2205	2720	3658
U_MD [5]	30	2010	1916	2008	979	3272	636	2913	1800	1775	1017	2421	0	602	2700	3652	2286	2281	1995
Belarus	31	2209	1519	1415	639	3061	894	2734	1197	1575	1569	1980	602	0	2705	3561	2411	2547	2537
Algeria	32	968	1807	2899	2118	1129	2071	839	3028	1262	2455	1989	2700	2705	0	1027	605	1145	2589
Morocco	33	1986	2337	3399	2932	794	3042	911	3605	1995	3482	2283	3652	3561	1027	0	1616	2090	3572
Tunisia	34	369	1884	2908	1903	1692	1650	1355	2973	1253	1895	2205	2286	2411	605	1616	0	582	1985
Libya	35	406	2343	3290	2153	2263	1684	1935	3306	1707	1639	2720	2281	2547	1145	2090	582	0	1485
Egypt	36	1636	3165	3775	2515	3652	1742	3291	3656	2632	978	3658	1995	2537	2589	3572	1985	1485	0

1) Albania, Serbia-Montenegro, Macedonia; 2) Bosnia-Herzegovina, Croatia, Slovenia; 3) Estonia, Lithuania, Latvia; 4) Switzerland, Liechtenstein; 5) Ukraine, Moldova

Table 10.1.12: Transmission lines allowed in the EUNA network: 0 = no line allowed; inf = line allowed, capacity to be set according to cost minimisation.

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36
AL_CS_MK [1)]	1	0	inf	0	0	inf	0	0	0	0	0	0	0	0	0	inf	0	0	0	inf	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BA_HR_SI [2)]	2	inf	0	inf	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Austria	3	0	inf	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	0	0
Belgium	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	inf	0	inf	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	0
Bulgaria	5	inf	0	0	0	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	0	0	inf	0	0	0	inf	0	0	0	0	0	0	0	0
Cyprus	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	inf
Czech Republic	7	0	0	0	0	0	0	0	0	0	0	0	0	inf	0	0	0	inf	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Denmark	8	0	0	0	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	inf	inf	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ireland	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	0
EE_LT_LV [3)]	10	0	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	0	inf	0	0	0	0	0
Finland	11	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	0	0	0
France	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	inf	0	inf	0	0	0	0	0	0	0	0	0
Germany	13	0	0	0	0	0	0	inf	inf	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	0	0
Greece	14	0	0	0	0	inf	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hungary	15	inf	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Italy	16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	0	0
Slovakia	17	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	inf	0	0	0	0	0	0
Luxembourg	18	0	0	0	inf	0	0	0	0	0	0	0	inf	inf	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Malta	19	inf	0	0	0	0	0	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	inf	inf	0
Netherlands	20	0	0	0	inf	0	0	0	inf	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Norway	21	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	0	0	0
Poland	22	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Portugal	23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	0	0	0	0
Romania	24	0	0	0	0	inf	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0
Spain	25	0	0	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	0	0	inf	0	0	0
Sweden	26	0	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CH, LI [4)]	27	0	0	inf	0	0	0	0	0	0	0	0	inf	inf	0	0	inf	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Turkey	28	0	0	0	0	inf	inf	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UK	29	0	0	0	inf	0	0	0	0	inf	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
U_MD [5)]	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	inf	0	0	0	0	0	0	inf	0	0	0	0	0
Belarus	31	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0
Algeria	32	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	inf	inf	0	0
Morocco	33	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	inf	0	0	0	0
Tunisia	34	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	0	0	0	0	0	inf	0	0	inf	0
Libya	35	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	inf	0	0	0	0	0	0	0	0	0	0	0	0	0	0	inf	0	inf
Egypt	36	0	0	0	0	0	inf	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	inf	0

1) Albania, Serbia-Montenegro, Macedonia; 2) Bosnia-Herzegovina, Croatia, Slovenia; 3) Estonia, Lithuania, Latvia; 4) Switzerland, Liechtenstein; 5) Ukraine, Moldova

10.1.5 Energy sums, capacities and costs in the network DE-NO-DZ

10.1.5.1 Network results DE-NO-DZ, total network

Table 10.1.13: Power gen. and storage conversion capacities in the network DE-NO-DZ in GW; transmission grid length in TWkm; different parameter variations.

	base	windcost120	windcost150	windoffsh cost120	windoffsh cost150	windonsh cost120	pvcost80	pvcost50	cspcost120	biocost80	hydrocost50	geocost120	geocost80	geocost50	load200	load150	load120	load80	load50	translim 2500	translim 16000	storcons	storcons t.lim2500	storcons t.lim16000
Peak load	134	134	134	134	134	134	134	134	134	134	134	134	134	134	269	202	161	108	67	134	134	134	134	134
Peak load / total gen. cap.	56	58	65	51	50	59	55	40	51	57	55	52	59	63	54	56	56	58	64	53	57	49	46	52
Total generation capacity	238	231	207	265	270	227	245	340	262	238	246	258	228	213	499	358	286	186	105	252	237	273	294	259
Geothermal power	0	0	0	0	0	0	0	0	0	0	0	0	0	9	0	0	0	0	0	0	0	0	0	0
Geothermal CHP	12	14	19	14	15	12	13	12	12	13	12	0	20	20	14	13	13	12	12	20	14	14	20	20
Run-of-river hydro (old+mod.)	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	26.2	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Run-of-river hydro (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reservoir hydro	0.3	0.3	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.3	0.4	0.4	0.4
Biomass (steam turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	14	21	17
Biomass (steam turb., CHP)	2.5	2.8	3.1	2.8	2.9	2.5	2.6	2.5	2.5	2.7	2.5	2.2	3.2	3.2	2.8	2.7	2.6	2.5	2.3	2.6	2.9	0.7	0.0	0.3
Biomass (biogas CHP)	1.5	1.6	2.0	1.7	1.8	1.5	1.4	1.5	1.4	1.5	1.4	1.4	1.6	1.7	1.5	1.4	1.4	1.5	1.4	1.9	1.6	2.6	3.3	3.2
Wind onshore	27	23	28	106	128	0	23	37	37	28	54	19	35	39	37	15	22	31	23	27	41	79	52	74
Wind offshore	91	76	31	25	0	107	90	65	102	89	53	116	72	56	215	164	121	60	23	95	87	54	90	59
Photovoltaic	0.8	5.7	5.9	2.9	1.0	2.6	18	141	8	0.6	3.8	6.5	1.9	2.5	3.9	4.9	2.6	0.8	0.2	42	5.4	4.7	45	1.4
CSP	46	51	70	55	64	45	43	26	40	46	45	49	44	40	113	77	58	35	19	30	41	47	25	42
Residual (gas turbine)	52	51	44	52	52	51	49	51	53	52	48	59	45	36	107	74	61	39	20	27	39	53	33	37
Storage (conversion) capacity	48	46	41	42	40	50	51	66	50	48	45	55	44	40	90	71	58	38	22	67	51	32.7	46.4	29.7
Pumped storage	32	29	22	27	26	32	34	35	35	32	27	33	28	24	32	32	32	24	14	17	23	33	17	25
CAES	0	0	0	0	0	0	0	15	0	0	0	0	0	0	11	2.8	0	0	0	22	4.8	0	5.1	0
Hydrogen	17	17	19	14	14	18	17	16	15	16	18	22	16	16	47	36	26	14	8	29	23	0	24	4.6
Transm. grid length in TWkm	117	126	151	137	143	119	119	197	117	117	121	138	102	83	308	196	143	84	47	11	70	133	11	70

Table 10.1.14: Annual costs in the network DE-NO-DZ in M€/a; different parameter variations.

	base	windcost120	windcost150	windoffsh cost120	windoffsh cost150	windonsh cost120	pvcost80	pvcost50	cspcost120	biocost80	hydrocost50	geocost120	geocost80	geocost50	load200	load150	load120	load80	load50	translim 2500	translim 16000	storcons	storcons t.lim2500	storcons t.lim16000
Total system costs	52835	56498	60416	54769	55039	52892	52666	50682	55282	52118	51124	54119	49172	42224	112058	81924	64375	41484	24676	60156	53541	56659	68307	58321
Total gen. capacity costs	55033	59966	65939	58867	59442	54733	54722	50554	57462	55049	53287	46779	56340	50124	103925	79285	64884	45695	31194	63191	56628	60800	71799	65931
Geothermal power	0	0	0	0	0	0	0	0	0	0	0	0	0	4405	0	0	0	0	0	0	0	0	0	0
Geothermal CHP	13426	15364	20010	15280	15954	13494	13649	13347	13362	14384	13228	0	17635	11022	14706	14413	14063	13357	12526	22044	15280	15418	22044	22044
Run-of-river hydro (old+mod.)	1557	1557	1557	1557	1557	1557	1557	1557	1557	1557	4386	1557	1557	1557	1557	1557	1557	1557	1557	1557	1557	1557	1557	1557
Run-of-river hydro (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reservoir hydro	104	103	123	123	123	103	104	103	112	104	62	105	103	103	103	103	102	103	106	123	113	123	123	123
Biomass (steam turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5014	8527	5980
Biomass (steam turb., CHP)	2481	2682	2823	2675	2698	2484	2526	2466	2477	2095	2472	2304	2877	2876	2646	2621	2569	2467	2391	2524	2689	689	0	278
Biomass (biogas CHP)	1014	1093	1248	1106	1156	1012	985	1034	1008	828	1002	983	1093	1104	1024	1004	1007	1026	1008	1205	1061	1493	1802	1772
Wind onshore	3165	3357	4930	12582	15300	0	2793	4352	4443	3331	6415	2272	4207	4636	4439	1748	2602	3648	2765	3263	4833	9357	6203	8828
Wind offshore	16896	16920	8561	5600	0	19731	16653	11972	18844	16434	9854	21467	13361	10280	39812	30447	22307	11135	4266	17631	16108	9918	16605	10835
Photovoltaic	76	509	527	257	91	236	1300	6308	739	51	339	584	170	219	349	438	233	72	17	3750	480	425	4001	127
CSP	14252	16393	24434	17625	20520	14098	13212	7431	12853	14218	13653	15205	13574	12501	35103	24057	18064	10809	5765	10021	12979	14731	9652	12922
Residual (gas turbine)	2061	1988	1725	2061	2043	2016	1943	1984	2067	2045	1876	2303	1763	1420	4185	2895	2379	1521	792	1072	1527	2075	1284	1465
Storage costs	7042	6823	6701	5994	6001	7413	7294	8351	7005	6899	6900	8023	6397	5941	15536	11429	8776	5448	3150	11344	7928	4514	9165	4526
Pumped storage	3395	3085	2253	2824	2767	3531	3486	3373	3604	3397	2680	3300	2867	2369	3273	3174	3222	2469	1411	1764	2237	4514	2033	3228
CAES	0	0	0	0	0	0	0	1435	0	0	0	0	0	0	2168	469	0	0	0	3281	700	0	526	0
Hydrogen	3647	3738	4448	3171	3234	3883	3808	3542	3401	3502	4220	4723	3530	3571	10095	7785	5554	2979	1739	6299	4991	0	6606	1298
Transmission costs	1631	1729	1963	1862	1895	1660	1660	2601	1646	1628	1687	1923	1404	1134	4240	2691	1980	1169	650	148	947	1847	148	947

10.1.5.2 Network results of Germany in the network DE-NO-DZ

Table 10.1.15: Total annual energy sums in TWh/a, storage capacities in TWh in Germany as a member of the network DE-NO-DZ; different parameter variations.

	base	windcost120	windcost150	windoffsh cost120	windoffsh cost150	windonsh cost120	pvcost80	pvcost50	cspcost120	biocost80	hydrocost50	geocost120	geocost80	geocost50	load200	load150	load120	load80	load50	translim 2500	translim 16000	storcons	storcons t.lim2500	storcons t.lim16000
Annual power demand	549	549	549	549	549	549	549	549	549	549	549	549	549	549	1098	823	659	439	274	549	549	549	549	549
Annual p. dem. / gen. in %	149	159	186	171	181	154	148	178	143	148	166	179	134	119	222	172	155	139	124	93	113	183	92	121
Annual power generation	369	345	296	321	303	356	372	308	383	371	331	307	409	462	494	478	426	316	222	591	485	301	594	454
Geothermal power	0	0	0	0	0	0	0	0	0	0	0	0	0	78	0	0	0	0	0	0	0	0	0	0
Geothermal CHP	103	118	154	118	123	104	105	103	103	111	102	0	170	170	113	111	108	103	96	169	118	119	168	170
Run-of-river hydro (old+mod.)	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
Run-of-river hydro (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reservoir hydro	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.2	2.3
Biomass (steam turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	17	32	21
Biomass (steam turb., CHP)	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	3	0	0
Biomass (biogas CHP)	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Wind onshore	0	0	0	74	123	0	0	0	0	0	0	0	0	0	14	0	0	0	0	40	0	0	13	0
Wind offshore	209	169	85	72	0	195	210	149	223	203	172	250	182	157	310	310	261	156	69	310	310	120	310	222
Photovoltaic	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	15	0	0	30	0
CSP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residual (gas turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Import (+) / export (-)	204	226	282	246	266	217	201	261	189	201	245	275	161	106	669	396	268	141	60	14	102	249	7.6	102
Storage losses	-24	-22	-29	-18	-20	-24	-24	-20	-24	-23	-27	-33	-21	-19	-66	-51	-36	-18	-7.6	-50	-38	-0.6	-32	-7
Surplus	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-6.6	0	0	-21	0
Storage capacity in TWh	16	17	32	15	17	16	16	16	14	16	25	17	15	14	33	26	21	13	6.4	18	18	0	1.5	0
Pumped storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAES	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.5	0.1	0	0	0	0.3	0.1	0	0	0
Hydrogen	16	17	32	14	17	16	16	15	14	16	25	17	15	14	33	26	21	13	6.4	18	18	0	1.4	0
Annual district heat from CHP	265	294	348	292	301	266	268	264	264	280	262	58	367	367	284	280	275	264	251	356	292	256	319	320
Storage input in % of an. Gen.	12	12	18	11	13	13	13	14	12	12	16	20	10	8.2	26	21	16	11	7.2	19	16	1.0	10	3.7

Table 10.1.16: Power gen. and storage conversion capacities in Germany as a member of the network DE-NO-DZ in GW; different parameter variations.

	base	windcost120	windcost150	windoffsh cost120	windoffsh cost150	windonsh cost120	pvcost80	pvcost50	cspcost120	biocost80	hydrocost50	geocost120	geocost80	geocost50	load200	load150	load120	load80	load50	translim 2500	translim 16000	storcons	storcons t.lim2500	storcons t.lim16000
Peak load	87	87	87	87	87	87	87	87	87	87	87	87	87	87	175	131	105	70	44	87	87	87	87	87
Peak load / total gen. cap.	72	77	95	70	67	74	73	82	70	72	80	70	75	78	87	78	73	73	78	57	65	74	51	65
Total generation capacity	122	113	92	126	131	118	119	106	126	122	109	125	117	112	201	168	143	96	56	155	134	117	172	135
Geothermal power	0	0	0	0	0	0	0	0	0	0	0	0	0	9	0	0	0	0	0	0	0	0	0	0
Geothermal CHP	12	14	19	14	15	12	13	12	12	13	12	0	20	20	14	13	13	12	12	20	14	14	20	20
Run-of-river hydro (old+mod.)	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Run-of-river hydro (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reservoir hydro	0.3	0.3	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.3	0.4	0.4	0.4
Biomass (steam turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	14	17	17
Biomass (steam turb., CHP)	2.2	2.6	2.8	2.6	2.6	2.2	2.3	2.2	2.2	2.5	2.2	1.9	2.9	2.9	2.5	2.5	2.4	2.2	2.1	2.3	2.6	0.4	0.0	0.0
Biomass (biogas CHP)	1.4	1.6	1.9	1.6	1.7	1.4	1.3	1.4	1.4	1.4	1.4	1.3	1.6	1.6	1.4	1.4	1.4	1.4	1.4	1.8	1.5	2.4	2.9	3.0
Wind onshore	0	0	0	33	55	0	0	0	0	0	0	0	0	0	6	0	0	0	0	18	0	0	6	0
Wind offshore	49	39	20	17	0	45	49	35	52	47	40	58	42	37	72	72	61	36	16	72	72	28	72	52
Photovoltaic	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	16	0	0	31	0
CSP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residual (gas turbine)	52	51	44	52	52	51	49	51	53	52	48	59	45	36	100	74	61	39	20	19	39	53	18	37
Storage (conversion) capacity	18	18	20	16	16	20	21	21	18	18	24	25	17	17	60	41	28	14	7.0	42	30	2.7	29.2	9
Pumped storage	1.8	1.1	1.2	1.3	1.7	2.1	4.0	5.9	4.8	1.8	5.7	2.9	2.3	3.5	1.7	2.0	1.9	2.0	2.0	4.4	3.2	2.7	5.9	4.8
CAES	0	0	0	0	0	0	0	0.5	0	0	0	0	0	0	11	2.8	0	0	0	16.7	4.8	0	5.1	0
Hydrogen	17	17	19	14	14	17	17	14	14	16	18	22	15	14	47	36	26	12	5.0	21	22	0	18.2	4.6

Table 10.1.17: Annual costs in Germany as a member of the network DE-NO-DZ in M€/a; different parameter variations.

	base	windcost120	windcost150	windoffsh cost120	Windoffsh cost150	Windonsh cost120	pvcost80	pvcost50	cspcost120	biocost80	hydrocost50	geocost120	geocost80	geocost50	load200	load150	load120	load80	load50	translim 2500	translim 16000	storcons	storcons t.lim2500	storcons t.lim16000
Total system costs	23361	24197	24282	22704	22105	22965	23689	21006	23529	22815	21419	21313	22098	18112	40919	34226	28341	19368	12624	37832	29794	22157	43350	31784
Total gen. capacity costs	29317	31212	32635	30142	29779	28760	29477	26575	29883	29505	26515	17700	32553	28946	37735	35635	32600	26420	21017	44781	35271	31216	49935	42417
Geothermal power	0	0	0	0	0	0	0	0	0	0	0	0	0	4405	0	0	0	0	0	0	0	0	0	0
Geothermal CHP	13426	15364	20010	15280	15954	13494	13649	13347	13362	14384	13228	0	17635	11022	14706	14413	14063	13357	12526	22044	15280	15418	22044	22044
Run-of-river hydro (old+mod.)	1557	1557	1557	1557	1557	1557	1557	1557	1557	1557	779	1557	1557	1557	1557	1557	1557	1557	1557	1557	1557	1557	1557	1557
Run-of-river hydro (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reservoir hydro	104	103	123	123	123	103	104	103	112	104	62	105	103	103	103	103	102	103	106	123	113	123	123	123
Biomass (steam turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5014	7059	5980
Biomass (steam turb., CHP)	2203	2405	2545	2397	2421	2206	2248	2188	2200	1864	2195	2026	2599	2598	2368	2343	2292	2189	2114	2247	2412	412	0	0
Biomass (biogas CHP)	968	1046	1201	1057	1107	966	939	988	960	790	956	936	1047	1058	974	956	961	979	962	1159	1015	1426	1646	1686
Wind onshore	0	0	0	3934	6574	0	0	0	0	0	0	0	0	0	748	0	0	0	0	2135	0	0	685	0
Wind offshore	8997	8749	5472	3733	0	8416	9037	6406	9624	8760	7420	10773	7848	6781	13366	13366	11246	6713	2960	13366	13366	5191	13366	9561
Photovoltaic	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1390	0	0	2749	0
CSP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residual (gas turbine)	2061	1988	1725	2061	2043	2016	1943	1984	2067	2045	1876	2303	1763	1420	3913	2895	2379	1521	792	760	1527	2075	706	1465
Storage costs	3826	3867	4578	3310	3403	4015	4117	3680	3380	3680	4535	4983	3538	3299	12432	8451	5741	2917	1325	7228	5737	244	6119	1702
Pumped storage	178	129	130	139	170	203	347	488	402	178	473	260	219	303	169	196	187	195	196	373	285	244	488	403
CAES	0	0	0	0	0	0	0	43	0	0	0	0	0	0	2168	469	0	0	0	2250	700	0	526	0
Hydrogen	3647	3738	4448	3171	3234	3812	3770	3149	2978	3502	4061	4723	3318	2996	10095	7785	5554	2722	1129	4606	4752	0	5104	1298

10.1.5.3 Network results of Norway in the network DE-NO-DZ

Table 10.1.18: Total annual energy sums in TWh/a, storage capacities in TWh in Norway as a member of the network DE-NO-DZ; different parameter variations.

	base	windcost120	windcost150	windoffsh cost120	windoffsh cost150	windonsh cost120	pvcost80	pvcost50	cspcost120	biocost80	hydrocost50	geocost120	geocost80	geocost50	load200	load150	load120	load80	load50	translim 2500	translim 16000	storcons	storcons t.lim2500	storcons t.lim16000
Annual power demand	112	112	112	112	112	112	112	112	112	112	112	112	112	112	224	168	134	90	56	112	112	112	112	112
Annual power demand / generation	40	42	67	44	51	36	40	42	36	40	32	33	45	54	32	35	38	42	42	75	61	34	72	57
Annual generation (without n. i.[1] in NO)	236	217	119	210	174	260	235	222	261	235	301	295	200	158	661	427	303	168	87	102	136	282	109	148
Annual gen. (inc. n. i.[1] in NO)	283	264	166	257	221	308	283	269	309	282	348	342	248	206	709	475	350	216	134	150	184	330	156	195
Geothermal power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal CHP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N. i.[1] in NO	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
Run-of-river hydro (old+mod.)	0	0	0	0	0	0	0	0	0	0	106	0	0	0	0	0	0	0	0	0	0	0	0	0
Run-of-river hydro (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reservoir hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass (steam turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.9	0
Biomass (steam turb., CHP)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0	0.5
Biomass (biogas CHP)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Wind onshore	54	60	70	173	173	0	60	93	49	58	138	49	73	77	54	35	48	66	56	4	72	173	33	118
Wind offshore	181	156	47	36	0	259	175	128	211	176	56	245	126	80	606	391	254	101	30	98	63	108	74	29
Photovoltaic	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CSP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residual (gas turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Import (+) / export (-)	-161	-143	-47	-135	-100	-185	-160	-146	-185	-159	-227	-219	-126	-86	-470	-295	-205	-118	-71	-10	-63	-206	-10	-72
Storage losses	-11	-10	-7	-10	-10	-11	-10	-11	-11	-11	-8	-11	-9	-8	-14	-12	-11	-8	-6	-15	-8	-11	-16	-9
Surplus	0	0	0	0	0	0	0	-0.5	0	0	-0.9	0	0	0	-0.4	0	0	0	-1.5	-12	-0.3	-0.7	-19	-2.2
Storage capacity in TWh	3.2	2.9	2.0	2.4	2.6	3.6	3.0	2.3	3.2	3.2	2.1	2.6	2.4	1.8	2.8	2.4	2.6	2.0	1.0	1.6	1.5	2.2	0.8	1.4
Pumped storage	3.2	2.9	2.0	2.4	2.6	3.6	3.0	2.3	3.2	3.2	2.1	2.6	2.4	1.8	2.8	2.4	2.6	2.0	1.0	1.6	1.5	2.2	0.8	1.4
CAES	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydrogen	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Annual district heat from CHP	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	0.6	2.0
Storage input in % of an. Gen.	11	9.7	6.3	11	12	11	10	12	11	11	4.7	9.5	9.9	7.8	7.1	8.1	9.5	8.1	3.2	4	10	9.5	2.9	9.9

1) Natural inflow into pumped hydro power plants in Norway

Table 10.1.19: Power gen. and storage conversion capacities in Norway as a member of the network DE-NO-DZ in GW; different parameter variations.

	base	windcost120	windcost150	windoffsh cost120	windoffsh cost150	windonsh cost120	pvcost80	pvcost50	cspcost120	biocost80	hydrocost50	geocost120	geocost80	geocost50	load200	load150	load120	load80	load50	translim 2500	translim 16000	storcons	storcons t.lim2500	storcons t.lim16000
Peak load	20	20	20	20	20	20	20	20	20	20	20	20	20	20	40	30	24	16	10	20	20	20	20	20
Peak load / total gen. cap.	32	33	52	26	30	33	31	30	29	31	23	26	35	41	24	29	31	32	35	62	47	22	51	38
Total generation capacity	64	60	39	76	68	61	65	67	69	64	89	77	58	49	171	106	79	50	29	33	43	93	39	53
Geothermal power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal CHP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Run-of-river hydro (old+mod.)	0	0	0	0	0	0	0	0	0	0	22	0	0	0	0	0	0	0	0	0	0	0	0	0
Run-of-river hydro (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reservoir hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass (steam turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.8	0
Biomass (steam turb., CHP)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0	0.1
Biomass (biogas CHP)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.3	0.2
Wind onshore	21	23	28	68	68	0	23	37	19	23	54	19	29	30	21	14	19	26	22	1	28	68	13	46
Wind offshore	43	37	11	8	0	61	41	30	50	41	13	58	30	19	143	92	60	24	7	23	15	26	17	7
Photovoltaic	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CSP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residual (gas turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6.9	0	0	0	0	8	0	0	8	0
Storage (conversion) capacity	30	28	20	26	24	30	30	29	30	30	21	30	26	20	30	30	30	22	12	12	20	30	11	20
Pumped storage	30	28	20	26	24	30	30	29	30	30	21	30	26	20	30	30	30	22	12	12	20	30	11	20
CAES	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydrogen	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 10.1.20: Annual costs in Norway as a member of the network DE-NO-DZ in M€/a; different parameter variations.

	base	windcost120	windcost150	windoffsh cost120	Windoffsh cost150	Windonsh cost120	pvcost80	pvcost50	cspcost120	biocost80	hydrocost50	geocost120	geocost80	geocost50	load200	load150	load120	load80	load50	translim 2500	translim 16000	storcons	storcons t.lim2500	storcons t.lim16000
Total system costs	14172	14996	10460	13135	11069	15193	14082	13329	15278	14097	15213	16645	11994	9483	33589	22474	16961	10157	5338	6203	8319	17687	7089	9868
Total gen. capacity costs	10524	11635	8126	10046	8179	11422	10517	10024	11614	10449	12563	13074	9016	7200	29353	18817	13424	7606	4015	4857	6226	12923	5536	6903
Geothermal power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal CHP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Run-of-river hydro (old+mod.)	0	0	0	0	0	0	0	0	0	0	3607	0	0	0	0	0	0	0	0	0	0	0	0	0
Run-of-river hydro (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reservoir hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass (steam turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	285	0
Biomass (steam turb., CHP)	61	61	61	61	61	61	61	61	61	48	61	61	61	61	61	61	61	61	61	61	61	61	0	61
Biomass (biogas CHP)	46	47	47	49	49	46	46	46	48	38	46	47	46	46	50	48	46	46	46	46	46	67	156	86
Wind onshore	2518	3357	4930	8069	8069	0	2793	4352	2287	2688	6415	2272	3396	3595	2523	1628	2257	3077	2602	174	3377	8069	1553	5483
Wind offshore	7899	8171	3089	1867	0	11315	7617	5565	9220	7674	2434	10694	5513	3498	26446	17081	11061	4422	1306	4265	2742	4727	3239	1274
Photovoltaic	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CSP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residual (gas turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	273	0	0	0	0	312	0	0	302	0
Storage costs	3217	2956	2123	2684	2597	3328	3139	2885	3203	3219	2206	3040	2648	2066	3104	2978	3035	2274	1215	1391	1953	4270	1544	2824
Pumped storage	3217	2956	2123	2684	2597	3328	3139	2885	3203	3219	2206	3040	2648	2066	3104	2978	3035	2274	1215	1391	1953	4270	1544	2824
CAES	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydrogen	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

10.1.5.4 Network results of Algeria in the network DE-NO-DZ

Table 10.1.21: Total annual energy sums in TWh/a, storage capacities in TWh in Algeria as a member of the network DE-NO-DZ; different parameter variations.

	base	windcost120	windcost150	windoffsh cost120	windoffsh cost150	windonsh cost120	pvcost80	pvcost50	cspcost120	biocost80	hydrocost50	geocost120	geocost80	geocost50	load200	load150	load120	load80	load50	translim 2500	translim 16000	storcons	storcons t.lim2500	storcons t.lim16000
Annual power demand	249	249	249	249	249	249	249	249	249	249	249	249	249	249	498	373	299	199	124	249	249	249	249	249
Annual p. dem. / gen. in %	79	70	48	64	56	82	80	61	90	80	85	75	82	87	65	73	77	83	99	92	82	78	97	84
Annual power generation	313	356	516	387	445	304	311	406	276	312	293	332	303	286	762	515	390	239	125	271	304	318	256	295
Geothermal power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal CHP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Run-of-river hydro (old+mod.)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Run-of-river hydro (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reservoir hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass (steam turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2.3	0
Biomass (steam turb., CHP)	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	0.0	1.7
Biomass (biogas CHP)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind onshore	11	0	0	9.9	11	0	0	0	37	11	0	0	14	18	20	2.1	5.9	9.8	2.8	16	25	22	68	57
Wind offshore	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Photovoltaic	1.6	11	11	5.5	1.9	5.0	35	268	16	1.1	7.2	12	3.6	4.7	7.4	9.3	5.0	1.5	0.4	50	10	9.0	27	2.7
CSP	299	343	503	370	430	297	275	136	222	298	284	318	284	261	732	502	378	226	120	203	268	285	159	233
Residual (gas turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Import (+) / export (-)	-64	-107	-267	-138	-196	-54	-62	-143	-25	-63	-42	-83	-53	-34	-264	-141	-91	-39	3	-7	-54	-69	-1	-46
Storage losses	0	0	0	0	0	-0.4	-0.2	-9.6	-2.6	0	-1.1	0	-1.1	-2.9	0	0	0	-1.4	-3.7	-15	-1.6	0	-5.5	0
Surplus	0	0	0	0	0	0	0	-4.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0
Storage capacity in TWh	0	0	0	0	0	0.4	0.2	1.8	2.0	0	1.2	0	0.9	2.5	0	0	0	1.2	3.7	12.1	0.9	0	0.3	0
Pumped storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAES	0	0	0	0	0	0	0	0.1	0	0	0	0	0	0	0	0	0	0	0	0.2	0	0	0	0
Hydrogen	0	0	0	0	0	0.4	0.2	1.7	2.0	0	1.2	0	0.9	2.5	0	0	0	1.2	3.7	11.9	0.9	0	0.3	0
Annual district heat from CHP	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	0	4.9
Storage input in % of an. Gen.	0	0	0	0	0	0.3	0.1	9	1.7	0	0.7	0	0.7	1.8	0	0	0	1.1	5.4	12	1	0	3.9	0

Table 10.1.22: Power gen. and storage conversion capacities in Algeria as a member of the network DE-NO-DZ in GW; different parameter variations.

	base	windcost120	windcost150	windoffsh cost120	windoffsh cost150	windonsh cost120	pvcost80	pvcost50	cspcost120	biocost80	hydrocost50	geocost120	geocost80	geocost50	load200	load150	load120	load80	load50	translim 2500	translim 16000	storcons	storcons t.lim2500	storcons t.lim16000
Peak load	41	41	41	41	41	41	41	41	41	41	41	41	41	41	82	61	49	33	20	41	41	41	41	41
Peak load / total gen. cap.	78	72	54	64	57	85	67	24	61	78	83	73	78	79	64	73	77	80	100	63	69	65	49	57
Total generation capacity	52	57	76	63	71	48	61	167	67	52	49	56	53	52	127	84	64	41	20	64	59	62	83	72
Geothermal power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal CHP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Run-of-river hydro (old+mod.)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Run-of-river hydro (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reservoir hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass (steam turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	0
Biomass (steam turb., CHP)	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.0	0.2
Biomass (biogas CHP)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind onshore	5.4	0	0	4.9	5.5	0	0	0	18.1	5.4	0	0	6.8	8.7	9.8	1.0	2.9	4.8	1.4	8.0	12	11	33	28
Wind offshore	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Photovoltaic	0.8	5.7	5.9	2.9	1.0	2.6	18	141	8.3	0.6	3.8	6.5	1.9	2.5	3.9	4.9	2.6	0.8	0.2	26.4	5.4	4.7	14.0	1.4
CSP	46	51	70	55	64	45	43	26	40	46	45	49	44	40	113	77	58	35	19	30	41	47	25	42
Residual (gas turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7.0	0
Storage (conversion) capacity	0	0	0	0	0	0.3	0.2	16	1.9	0	0.7	0	1.0	2.6	0	0	0	1.2	2.7	13	1.1	0	5.8	0
Pumped storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAES	0	0	0	0	0	0	0	15	0	0	0	0	0	0	0	0	0	0	0	5.4	0	0	0	0
Hydrogen	0	0	0	0	0	0.3	0.2	1.8	1.9	0	0.7	0	1.0	2.6	0	0	0	1.2	2.7	7.3	1.1	0	5.8	0

Table 10.1.23: Annual costs in Algeria as a member of the network DE-NO-DZ in M€/a; different parameter variations.

	base	windcost120	windcost150	windoffsh cost120	windoffsh cost150	windonsh cost120	pvcost80	pvcost50	cspcost120	biocost80	hydrocost50	geocost120	geocost80	geocost50	load200	load150	load120	load80	load50	translim 2500	translim 16000	storcons	storcons t.lim2500	storcons t.lim16000
Total system costs	15301	17304	25674	18930	21864	14734	14894	16347	16474	15206	14493	16161	15080	14628	37550	25224	19073	11960	6714	16122	15428	16815	17868	16670
Total gen. capacity costs	15192	17119	25177	18678	21485	14551	14728	13956	15965	15095	14209	16006	14772	13978	36837	24833	18860	11669	6162	13552	15131	16660	16327	16611
Geothermal power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal CHP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Run-of-river hydro (old+mod.)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Run-of-river hydro (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reservoir hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass (steam turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1182	0
Biomass (steam turb., CHP)	217	217	217	217	217	217	217	217	217	182	217	217	217	217	217	217	217	217	217	217	217	217	0	217
Biomass (biogas CHP)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind onshore	647	0	0	579	656	0	0	0	2156	643	0	0	810	1041	1168	121	346	571	163	954	1455	1287	3965	3346
Wind offshore	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Photovoltaic	76	509	527	257	91	236	1300	6308	739	51	339	584	170	219	349	438	233	72	17	2360	480	425	1252	127
CSP	14252	16393	24434	17625	20520	14098	13212	7431	12853	14218	13653	15205	13574	12501	35103	24057	18064	10809	5765	10021	12979	14731	9652	12922
Residual (gas turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	276	0
Storage costs	0	0	0	0	0	71	38	1786	423	0	159	0	211	575	0	0	0	258	610	2725	238	0	1502	0
Pumped storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAES	0	0	0	0	0	0	0	1393	0	0	0	0	0	0	0	0	0	0	0	1032	0	0	0	0
Hydrogen	0	0	0	0	0	71	38	393	423	0	159	0	211	575	0	0	0	258	610	1693	238	0	1502	0

10.1.6 Capacities and costs in the network EUNA

10.1.6.1 Capacities and costs in the EUNA regions; no transmission: island grids in each region (case 'EUNA_100ds')

Table 10.1.24: Peak load and power generation capacities in the regions in Europe and North Africa in GW; transmission grid length in TWkm; no transmission (island grids, 'EUNA_100ds').

	AL_CS_M[1)]	BA_HR_SI[2)]	AT	BE	BG	CY	CZ	DN	IE	EE_LT_LV[3)]	FI	FR	DE	GR	HU	IT	SK	LU
Peak load	12	8.1	8.0	10	4.9	0.9	8.5	9.1	6.1	7.2	13	77	87	11	6.6	52	4.5	1.7
Total generation capacity	17	18	21	41	4.8	2.3	21	15	9.4	15	29	123	170	26	7.2	148	11	2.9
Geothermal power	0	0	0	0.1	0	0	0.4	0	0	0.1	0	0	0	1.0	0	2.4	0.6	0
Geothermal CHP	6.3	3.3	1.4	0.9	2.7	0	2.4	0.9	0.1	0.9	0	10.3	20.4	1.7	4.7	9.2	1.6	0.1
Run-of-river hydro (old + mod.)	4.1	0	0	0.1	0	0	0	0	0	0	2.7	0	4.7	0	0	0	0	0
Run-of-river hydro (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reservoir hydro	0	0.6	1.8	0	0	0	0.4	0	0.1	0	0.6	6.6	0.4	0	0	1.4	0.1	0
Biomass (steam turbine)	3.7	0	0	0.8	0	0.1	3.9	0	0	3.7	7.3	0	0	2.6	1.9	0.8	0.1	0
Biomass (steam turb., CHP)	0	0.4	0.5	0	0.3	0	0.1	0.2	0.1	0.2	1.8	3.7	2.3	0	0	1.0	0.3	0
Biomass (biogas CHP)	0.9	0.2	0.2	0.5	0.1	0.1	0.8	0.4	0.8	0.7	0.1	2.0	1.8	0.2	0.2	0.9	0.1	0.1
Wind onshore	0.2	5.9	11	3.5	0.1	0.9	8.6	4.7	3.0	1.5	6.4	0	19	7.1	0.3	61	4.0	0.3
Wind offshore	1.4	0	0	5.6	1.0	0	0	7.9	4.4	4.7	8.4	86	72	0	0	0	0	0
Photovoltaic	0	6.7	5.4	22	0.3	0.4	4.3	0	0	1.9	0.2	1.6	34	7.2	0	51	3.8	0.7
CSP	0	0	0	0	0	0.6	0	0	0	0	0	4.6	0	4.9	0	14	0	0
Residual (gas turbine)	0.9	0.8	0.6	7.0	0.3	0.1	0.5	1.2	0.9	1.0	1.8	7.9	15	1.6	0.1	5.4	0.1	1.6
Storage conversion capacity	0	3.2	3.6	1.3	1.7	0	0.5	6.8	4.5	0.9	0	43	47	0	0	17	1.8	0
Pumped storage	0	0	1.9	1.3	0.7	0	0.5	0	0.3	0.9	0	2.6	4.6	0	0	6.3	0.6	0
CAES	0	2.1	0	0	0.1	0	0	3.1	2.0	0	0	5.8	19	0	0	0.8	0.3	0
Hydrogen	0	1.2	1.7	0	0.8	0	0	3.7	2.2	0	0	35	23	0	0	9.4	0.8	0
Transmission grid length in TWkm																		

1) Albania, Serbia-Montenegro, Macedonia; 2) Bosnia-Herzegovina, Croatia, Slovenia; 3) Estonia, Lithuania, Latvia; 4) Switzerland, Liechtenstein; 5) Ukraine, Moldova

Table 10.1.24 (continued): Peak load and power generation capacities in the regions in Europe and North Africa in GW; transmission grid length in TWkm; no transmission (island grids, 'EUNA_100ds').

	MT	NE	NO	PL	PT	RO	ES	SE	CH_LI[4]	TR	UK	U_MD[5]	BY	DZ	MA	TN	LY	EG	Total
Peak load	0.5	19	20	32	11	15	53	28	8.9	91	78	39	8.6	41	39	10	8	109	
Total generation capacity	2.4	32	33	46	21	33	97	65	12	192	126	96	32	66	56	17	12	206	1826
Geothermal power	0	0	0	0	0	2.1	0	0	0	0	0	0	0.3	0	0	0	0	0	7.0
Geothermal CHP	0	2.9	0	14.6	0	4.3	4.1	0	2.0	24	4.7	13	0.5	0	0	0	0	0	136
Run-of-river hydro (old + mod.)	0	0	0	0	0	0	0	11.4	0	0	0	0	0	0	0	0	0	0	23
Run-of-river hydro (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reservoir hydro	0	0	0	0.1	0.7	0	4.5	0.9	2.1	0.7	0	0	0	0	0	0	0	0	21
Biomass (steam turbine)	0.1	0	0.4	0	0	0	0	20	0	15	0	0	0	0	1.4	0	1.0	11	73
Biomass (steam turb., CHP)	0	0.2	0	1.2	0.4	0.8	1.5	1.6	0.1	0.0	0.9	1.2	0.3	0.2	0	0.1	0	0	19
Biomass (biogas CHP)	0	0.7	0.3	0.9	0.2	0.4	0.9	0.3	0.3	2.9	0.8	1.4	0.7	0	0	0	0	0	20
Wind onshore	0	0	0	13	3.6	0	16	11	5.4	36	31	61	25	11	3.8	3.0	4.5	77	439
Wind offshore	1.5	25	26	12	4.5	10	22	18	0	22	82	2.0	0	0	0	0.5	0	16	433
Photovoltaic	0.4	0	0	1.8	4.6	15	19	0	0.5	40	0	12	4.2	28	23	5.0	0	0	294
CSP	0.4	0	0	0	6.9	0	29	0	0	35	0	0	0	28	28	8.1	6.6	95	260
Residual (gas turbine)	0.1	2.9	6.3	2.2	0	1.0	0	1.3	1.7	17	6.7	5.2	1.0	0	0	0	0.3	8.0	101
Storage conversion capacity	0	13	13	14	3.4	7.2	15	0	3.1	0.8	64	20	6.1	15	16	3.3	0	0	324
Pumped storage	0	0	13	0.2	0.2	0	0.5	0	1.7	0.8	2.8	0	0	0	0	0	0	0	39
CAES	0	4.0	0	7.1	0	3.4	0	0	0	0	15	8.9	3.4	6.0	0	0	0	0	81
Hydrogen	0	9.0	0	6.7	3.2	3.7	14	0	1.3	0	46	11	2.7	8.7	16	3.3	0	0	203
Transmission grid length in TWkm																			0

1) Albania, Serbia-Montenegro, Macedonia; 2) Bosnia-Herzegovina, Croatia, Slovenia; 3) Estonia, Lithuania, Latvia; 4) Switzerland, Liechtenstein; 5) Ukraine, Moldova

Table 10.1.25: Annual costs in the regions in Europe and North Africa in M€/a; no transmission (island grids, 'EUNA_100ds').

	AL_CS_M[1]	BA_HR_SI[2]	AT	BE	BG	CY	CZ	DN	IE	EE_LT_LV[3]	FI	FR	DE	GR	HU	IT	SK	LU
Total system costs	6998	3955	3761	6629	2152	494	5115	3872	2330	3662	7089	34422	40086	5862	3828	26817	2635	1842
Total gen. capacity costs	10265	5559	4688	7215	3523	499	6810	3480	1976	4489	8158	35102	46373	6787	6027	30672	3521	1899
Geothermal power	0	0	0	78	0	0	382	0	0	84	0	0	0	891	0	2279	555	0
Geothermal CHP	6859	3589	1536	966	2955	0	2558	934	62	1010	2	11110	22044	1793	5072	9984	1748	54
Run-of-river hydro (old+mod.)	1362	0	0	37	0	0	0	0	0	0	902	0	1557	0	0	0	0	14
Run-of-river hydro (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reservoir hydro	0	204	608	0	0	0	117	0	22	0	213	2221	123	0	0	481	30	0
Biomass (steam turbine)	1244	0	0	404	0	46	1539	0	0	1363	2801	0	0	923	742	368	28	23
Biomass (steam turb., CHP)	0	298	518	0	257	0	89	242	97	203	1753	3215	2224	0	34	922	254	0
Biomass (biogas CHP)	486	138	165	277	78	27	693	239	581	577	79	1329	1154	110	144	546	78	52
Wind onshore	19	703	1350	416	9	111	1029	559	359	180	760	0	2286	848	33	7304	480	40
Wind offshore	260	0	0	1039	190	0	0	1459	822	866	1558	16000	13366	0	0	0	0	0
Photovoltaic	0	597	485	2003	24	35	383	0	0	167	22	142	3029	647	0	4604	341	67
CSP	0	0	0	0	0	273	0	0	0	0	0	774	0	1513	0	3974	0	0
Residual (gas turbine)	35	31	25	1996	11	6	21	46	33	39	69	311	590	61	2	211	5	1649
Storage costs	0	470	549	107	274	0	37	1194	776	74	0	8481	7931	0	0	2769	289	0
Pumped storage	0	0	165	107	60	0	37	0	24	74	0	228	389	0	0	535	51	0
CAES	0	213	0	0	22	0	0	399	283	0	0	843	2551	0	0	100	46	0
Hydrogen	0	257	384	0	192	0	0	796	469	0	0	7411	4991	0	0	2134	192	0
Transmission costs																		
Heat Credit	-3267	-2074	-1476	-693	-1645	-4	-1732	-802	-422	-901	-1069	-9161	-14217	-924	-2200	-6625	-1175	-57

1) Albania, Serbia-Montenegro, Macedonia; 2) Bosnia-Herzegovina, Croatia, Slovenia; 3) Estonia, Lithuania, Latvia; 4) Switzerland, Liechtenstein; 5) Ukraine, Moldova

Table 10.1.25 (continued): Annual costs in the regions in Europe and North Africa in M€/a; no transmission (island grids, 'EUNA_100ds').

	MT	NE	NO	PL	PT	RO	ES	SE	CH_LI[4]	TR	UK	U_MD[5]	BY	DZ	MA	TN	LY	EG	Total
Total system costs	459	9113	6952	14854	5166	8588	24960	16825	2894	44315	33021	19095	5266	16376	17074	4431	4127	61628	456693
Total gen. capacity costs	459	8598	5307	21513	4777	10764	25359	17647	3860	56439	25698	24576	4848	13351	13592	3738	4127	61628	493323
Geothermal power	0	0	0	0	0	1977	0	0	0	0	0	0	275	0	0	0	0	0	6521
Geothermal CHP	0	3170	0	15741	16	4599	4446	0	2132	25661	5052	13519	509	0	0	0	0	0	147123
Run-of-river hydro (old+mod.)	0	0	0	0	0	0	0	3824	0	0	0	0	0	0	0	0	0	0	7697
Run-of-river hydro (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reservoir hydro	0	0	0	28	243	0	1496	299	708	250	4	0	0	0	0	0	0	0	7048
Biomass (steam turbine)	21	0	150	0	0	0	0	7173	0	5271	0	0	0	0	524	0	315	3266	26202
Biomass (steam turb., CHP)	0	180	0	1107	386	724	1291	1554	87	0	986	1168	287	217	0	79	0	0	18174
Biomass (biogas CHP)	11	472	135	592	126	268	579	147	175	1508	554	925	417	0	0	0	0	0	12661
Wind onshore	0	0	0	1584	431	0	1883	1345	647	4265	3672	7263	2944	1253	457	354	535	9182	52300
Wind offshore	279	4661	4775	2210	829	1845	4024	3253	0	4087	15164	378	0	0	0	99	0	2994	80158
Photovoltaic	32	0	0	164	415	1311	1729	0	45	3581	0	1117	375	2507	2028	444	3	0	26293
CSP	111	0	0	0	2330	0	9911	0	0	11143	0	0	0	9374	10584	2763	3262	45874	101887
Residual (gas turbine)	4	114	246	87	0	39	0	52	66	673	265	205	41	0	0	0	12	312	7259
Storage costs	0	2585	1672	2323	767	1239	3318	3	462	65	11617	3433	1118	3220	3482	762	0	0	59016
Pumped storage	0	0	1672	20	23	2	62	3	152	65	230	0	0	0	0	0	0	0	3899
CAES	0	597	0	873	0	429	0	0	0	0	1572	1194	547	1158	0	0	0	0	10825
Hydrogen	0	1989	0	1430	744	808	3256	0	310	0	9814	2238	571	2062	3482	762	0	0	44292
Transmission costs																			0
Heat Credit	-1	-2070	-26	-8982	-378	-3415	-3717	-825	-1427	-12189	-4294	-8914	-700	-195	0	-69	0	0	-95646

1) Albania, Serbia-Montenegro, Macedonia; 2) Bosnia-Herzegovina, Croatia, Slovenia; 3) Estonia, Lithuania, Latvia; 4) Switzerland, Liechtenstein; 5) Ukraine, Moldova

10.1.6.2 Capacities and cost in the network EUNA without transmission restriction ('EUNA_0DS')

Table 10.1.26: Peak load and power generation capacities in the regions in the EUNA network in GW; transmission grid length in TWkm; no transmission restriction ('EUNA_0DS').

	AL_CS_M[1]	BA_HR_SI[2]	AT	BE	BG	CY	CZ	DN	IE	EE_LT_LV[3]	FI	FR	DE	GR	HU	IT	SK	LU
Peak load	12	8.1	8.0	10	4.9	0.9	8.5	9.1	6.1	7.2	13	77	87	11	6.6	52	4.5	1.7
Total generation capacity	16	3.2	3.6	12	1.8	1.0	8.7	12	54	19	28	65	142	17	6.8	35	1.2	1.8
Geothermal power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal CHP	4.0	1.9	1.4	0.9	1.4	0	2.0	0	0	0.9	0	7.9	0	1.2	1.1	6.3	0.9	0
Run-of-river hydro (old + mod.)	0	0	0	0	0	0	0	0	0	0	0	0	4.7	0	0	0	0	0
Run-of-river hydro (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reservoir hydro	0	0.6	1.4	0	0	0	0.3	0	0	0	0.6	7.6	0.3	0	0	1.4	0	0
Biomass (steam turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass (steam turb., CHP)	0.3	0.3	0.5	0.2	0.2	0	0.5	0.2	0.1	0.3	1.8	3.4	3.1	0.4	0.4	1.1	0.2	0
Biomass (biogas CHP)	0.5	0.3	0.2	0.3	0.1	0	0.3	0.3	0.8	0.3	0.1	1.7	1.4	0.2	0.2	1.3	0.1	0.1
Wind onshore	0	0	0	1.9	0	0	0.3	7.5	13	1.7	0	0	0	0	0	0	0	0
Wind offshore	2.9	0	0	0	0	0	0	3.7	35	11	15	24	72	4.6	0	0	0	0
Photovoltaic	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CSP	0	0	0	0	0	0.9	0	0	0	0	0	4.3	0	7.0	0	13	0	0
Residual (gas turbine)	7.9	0	0	8.4	0	0	5.4	0	5.0	4.9	10	16	60	3.2	5.0	11	0	1.6
Storage conversion capacity	0	5.4	4.8	0.8	12	0	0.5	11	0.1	0.9	0	39	21	0	0	19	3.5	0
Pumped storage	0	0	2.1	0.8	0.2	0	0.5	0	0.1	0.9	0	4.9	1.6	0	0	5.2	0.4	0
CAES	0	0	0	0	0	0	0	0.1	0	0	0	4.1	0	0	0	0	0	0
Hydrogen	0	5.4	2.8	0	12	0	0	11	0	0	0	30	20	0	0	14	3.1	0
Transmission grid length in TWkm																		

1) Albania, Serbia-Montenegro, Macedonia; 2) Bosnia-Herzegovina, Croatia, Slovenia; 3) Estonia, Lithuania, Latvia; 4) Switzerland, Liechtenstein; 5) Ukraine, Moldova

Table 10.1.26 (continued): Peak load and power generation capacities in the regions in the EUNA network in GW; transmission grid length in TWkm; no transmission restriction ('EUNA_0DS').

	MT	NE	NO	PL	PT	RO	ES	SE	CH_LI[4]	TR	UK	U_MD[5]	BY	DZ	MA	TN	LY	EG	Total
Peak load	0.5	19	20	32	11	15	53	28	8.9	91	78	39	8.6	41	39	10	7.6	109	852
Total generation capacity	0.7	29	129	50	11	5.7	67	43	5.6	122	192	103	21	67	35	14.1	139	142	1603
Geothermal power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal CHP	0	1.9	0	5.9	0	3.7	2.0	0	1.5	13.7	4.7	7.8	0.5	0	0	0	0	0	72
Run-of-river hydro (old + mod.)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4.7
Run-of-river hydro (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reservoir hydro	0	0	0	0.1	0.4	0	2.5	0.5	2.5	0.7	0	0	0	0	0	0	0	0	19
Biomass (steam turbine)	0	0	0	0	0	0	0	0	0	2.3	0	0	0	0	0	0	0	3.4	5.7
Biomass (steam turb., CHP)	0	0.2	0.1	0.9	0.3	0.7	1.0	2.0	0.1	1.2	0.9	1.0	0.2	0.2	0.2	0.1	0	0	22
Biomass (biogas CHP)	0	0.5	0.1	0.8	0.2	0.4	0.6	0.1	0.1	2.0	0.8	1.1	0.5	0	0	0	0	0	16
Wind onshore	0	5.1	36	27	0	0	0	0	0	0	36	78	18	3.5	0	0	77	29	333
Wind offshore	0.2	14	93	7.3	0	0.3	0	15	0	0	125	0	0	0	0	0	0	0	424
Photovoltaic	0	0	0	0	0	0	0	0	0	28	0	0	0	0	0	0	0	0	28
CSP	0.3	0	0	0	10	0	61	0	0	38	0	0	0	63	35	14	62	69	379
Residual (gas turbine)	0.2	7.2	0	7.7	0	0.7	0	25	1.4	36	24	15	2.3	0	0	0	0	40	300
Storage conversion capacity	0	9.8	30	17	0.4	10	0.5	0	3.7	0.8	44	15	5.5	0	5.9	0	0	0	261
Pumped storage	0	0	30	0.2	0.2	0	0.5	0	1.3	0.8	1.1	0	0	0	0	0	0	0	51
CAES	0	1.4	0	7.4	0	1.9	0	0	0	0	0	7.8	5.4	0	0	0	0	0	28
Hydrogen	0	8.3	0	9.6	0.2	8.3	0	0	2.4	0	43	7.4	0	0	5.9	0	0	0	182
Transmission grid length in TWkm																			941

1) Albania, Serbia-Montenegro, Macedonia; 2) Bosnia-Herzegovina, Croatia, Slovenia; 3) Estonia, Lithuania, Latvia; 4) Switzerland, Liechtenstein; 5) Ukraine, Moldova

Table 10.1.27: Annual costs in the regions in the EUNA network in M€/a; no transmission restriction (‘EUNA_0DS’).

	AL_CS_M[1]	BA_HR_SI[2]	AT	BE	BG	CY	CZ	DN	IE	EE_LT_LV[3]	FI	FR	DE	GR	HU	IT	SK	LU
Total system costs	3874	2481	2167	2903	4067	894	1747	5585	8883	3450	3991	21582	24832	3360	1081	11702	1696	1748
Total gen. capacity costs	5703	2747	2681	1943	1788	365	3060	1994	8845	3978	5312	21059	21049	4210	1948	12388	1251	166
Geothermal power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal CHP	4316	2089	1536	966	1482	0	2120	0	0	1010	2	8523	0	1246	1183	6848	944	19
Run-of-river hydro (old+mod.)	0	0	0	0	0	0	0	0	0	0	0	0	1557	0	0	0	0	0
Run-of-river hydro (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reservoir hydro	0	216	470	0	0	0	86	0	16	0	213	2548	110	0	0	466	16	0
Biomass (steam turbine)	0	0	0	0	0	0	0	0	0	0	0	0	0	6	0	0	0	0
Biomass (steam turb., CHP)	256	270	507	235	221	9	439	220	93	337	1846	3046	2672	319	416	1091	227	24
Biomass (biogas CHP)	289	173	167	187	85	14	163	196	546	190	67	1194	970	88	151	752	65	55
Wind onshore	0	0	0	226	0	0	40	890	1573	200	0	0	0	0	0	0	0	5
Wind offshore	532	0	0	0	0	0	0	688	6422	2048	2776	4351	13366	853	0	0	0	0
Photovoltaic	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CSP	0	0	0	0	0	342	0	0	0	0	0	757	0	1572	0	2780	0	0
Residual (gas turbine)	310	0	0	329	0	0	212	0	195	192	408	640	2374	125	198	452	0	64
Storage costs	0	1141	843	66	2584	0	37	2614	8	74	0	7376	4525	0	0	3534	780	0
Pumped storage	0	0	179	66	23	0	37	0	8	74	0	405	167	0	0	452	32	0
CAES	0	0	0	0	0	0	0	5	0	0	0	369	0	0	0	0	0	0
Hydrogen	0	1141	664	0	2561	0	0	2609	0	0	0	6602	4358	0	0	3082	748	0
Transmission costs																		
Heat Credit	-2496	-1485	-1476	-904	-1074	-12	-1711	-308	-388	-1015	-1628	-8007	-2331	-901	-1144	-5367	-804	-59

1) Albania, Serbia-Montenegro, Macedonia; 2) Bosnia-Herzegovina, Croatia, Slovenia; 3) Estonia, Lithuania, Latvia; 4) Switzerland, Liechtenstein; 5) Ukraine, Moldova

Table 10.1.27 (continued): Annual costs in the regions in the EUNA network in M€/a; no transmission restriction (‘EUNA_0DS’).

	MT	NE	NO	PL	PT	RO	ES	SE	CH_LI[4]	TR	UK	U_MD[5]	BY	DZ	MA	TN	LY	EG	Total
Total system costs	2087	6599	25904	10979	3336	4442	21771	4629	3295	23574	41316	16695	3397	21588	13019	5108	30123	34524	378430
Total gen. capacity costs	86	6160	21688	12816	3576	4999	23459	6192	2713	31799	35046	20223	3243	21343	11574	4600	28741	33527	372271
Geothermal power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal CHP	0	2079	0	6397	16	3988	2196	0	1654	14783	5052	8477	509	0	0	0	0	0	77436
Run-of-river hydro (old+mod.)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1557
Run-of-river hydro (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reservoir hydro	0	0	0	20	138	0	832	180	821	250	4	0	0	0	0	0	0	0	6385
Biomass (steam turbine)	0	0	0	0	0	0	0	0	0	918	0	0	0	0	0	0	0	1156	2080
Biomass (steam turb., CHP)	3	186	61	980	350	673	1050	2145	83	986	976	1036	181	217	231	77	38	0	21499
Biomass (biogas CHP)	3	378	46	524	108	261	449	86	101	1133	585	801	366	0	0	0	0	0	10192
Wind onshore	0	603	4280	3235	0	0	0	0	0	0	4256	9330	2099	419	0	0	9159	3407	39721
Wind offshore	29	2630	17301	1359	0	50	0	2781	0	0	23222	0	0	0	0	0	0	0	78408
Photovoltaic	0	0	0	0	0	0	0	0	0	2539	0	0	0	0	0	0	0	0	2539
CSP	43	0	0	0	2964	0	18931	0	0	9782	0	0	0	20707	11343	4523	19545	27377	120665
Residual (gas turbine)	9	284	0	302	0	26	0	1000	54	1408	951	579	89	0	0	0	0	1587	11788
Storage costs	0	1965	3413	3059	77	2123	66	3	703	65	9153	2559	507	0	1307	0	0	0	48582
Pumped storage	0	0	3413	20	24	2	66	3	116	65	106	0	0	0	0	0	0	0	5260
CAES	0	170	0	794	0	181	0	0	0	0	0	794	500	0	0	0	0	0	2813
Hydrogen	0	1795	0	2245	52	1939	0	0	587	0	9047	1765	7	0	1307	0	0	0	40509
Transmission costs																			25565
Heat Credit	-4	-1633	-80	-5077	-379	-3129	-2491	-1960	-1148	-8928	-4294	-6590	-662	-195	-207	-69	-34	0	-67989

1) Albania, Serbia-Montenegro, Macedonia; 2) Bosnia-Herzegovina, Croatia, Slovenia; 3) Estonia, Lithuania, Latvia; 4) Switzerland, Liechtenstein; 5) Ukraine, Moldova

Table 10.1.28: Transmission line capacities between regions in the EUNA network in MW; no transmission restriction (‘EUNA_0DS’).

		1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**
AL_CS_MK [1]	**1**	0	3314	0	0	15748	0	0	0	0	0	0	0	0	0	12079	0	0	0
BA_HR_SI [2]	**2**	3314	0	4090	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Austria	**3**	0	4090	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Belgium	**4**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	77683
Bulgaria	**5**	15748	0	0	0	0	0	0	0	0	0	0	0	0	4737	0	0	0	0
Cyprus	**6**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Czech Republic	**7**	0	0	0	0	0	0	0	0	0	0	0	0	19304	0	0	0	14975	0
Denmark	**8**	0	0	0	0	0	0	0	0	0	0	0	0	54064	0	0	0	0	0
Ireland	**9**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EE_LT_LV [3]	**10**	0	0	0	0	0	0	0	0	0	0	14532	0	0	0	0	0	0	0
Finland	**11**	0	0	0	0	0	0	0	0	0	14532	0	0	0	0	0	0	0	0
France	**12**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	58572
Germany	**13**	0	0	0	0	0	0	19304	54064	0	0	0	0	0	0	0	0	0	26300
Greece	**14**	0	0	0	0	4737	0	0	0	0	0	0	0	0	0	0	0	0	0
Hungary	**15**	12079	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	14987	0
Italy	**16**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Slovakia	**17**	0	0	0	0	0	0	14975	0	0	0	0	0	0	0	14987	0	0	0
Luxembourg	**18**	0	0	0	77683	0	0	0	0	0	0	0	58572	26300	0	0	0	0	0
Malta	**19**	26107	0	0	0	0	0	0	0	0	0	0	0	0	0	0	59083	0	0
Netherlands	**20**	0	0	0	5418	0	0	0	4822	0	0	0	0	0	0	0	0	0	0
Norway	**21**	0	0	0	0	0	0	0	53346	0	0	0	0	0	0	0	0	0	0
Poland	**22**	0	0	0	0	0	0	0	0	0	7443	0	0	0	0	0	0	9111	0
Portugal	**23**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Romania	**24**	0	0	0	0	17509	0	0	0	0	0	0	0	0	0	0	0	0	0
Spain	**25**	0	0	0	0	0	0	0	0	0	0	0	39677	0	0	0	0	0	0
Sweden	**26**	0	0	0	0	0	0	0	0	0	0	11645	0	0	0	0	0	0	0
CH, LI [4]	**27**	0	0	7182	0	0	0	0	0	0	0	0	3557	45884	0	0	37783	0	0
Turkey	**28**	0	0	0	0	31799	24003	0	0	0	0	0	0	0	0	0	0	0	0
UK	**29**	0	0	0	88092	0	0	0	0	39510	0	0	0	0	0	0	0	0	0
U_MD [5]	**30**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5825	0
Belarus	**31**	0	0	0	0	0	0	0	0	0	13787	0	0	0	0	0	0	0	0
Algeria	**32**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Morocco	**33**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tunisia	**34**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Libya	**35**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Egypt	**36**	0	0	0	0	0	24490	0	0	0	0	0	0	0	0	0	0	0	0

1) Albania, Serbia-Montenegro, Macedonia; 2) Bosnia-Herzegovina, Croatia, Slovenia; 3) Estonia, Lithuania, Latvia; 4) Switzerland, Liechtenstein; 5) Ukraine, Moldova

Table 10.1.28 (continued): Transmission line capacities between regions in Europe and North Africa in MW; no transmission restriction (case 'EUNA_0DS').

		19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36
AL_CS_MK [1)]	**1**	26107	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BA_HR_SI [2)]	**2**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Austria	**3**	0	0	0	0	0	0	0	0	7182	0	0	0	0	0	0	0	0	0
Belgium	**4**	0	5418	0	0	0	0	0	0	0	0	88092	0	0	0	0	0	0	0
Bulgaria	**5**	0	0	0	0	0	17509	0	0	0	31799	0	0	0	0	0	0	0	0
Cyprus	**6**	0	0	0	0	0	0	0	0	0	24003	0	0	0	0	0	0	0	24490
Czech Republic	**7**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Denmark	**8**	0	4822	53346	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ireland	**9**	0	0	0	0	0	0	0	0	0	0	39510	0	0	0	0	0	0	0
EE_LT_LV [3)]	**10**	0	0	0	7443	0	0	0	0	0	0	0	0	13787	0	0	0	0	0
Finland	**11**	0	0	0	0	0	0	0	11645	0	0	0	0	0	0	0	0	0	0
France	**12**	0	0	0	0	0	0	39677	0	3557	0	0	0	0	0	0	0	0	0
Germany	**13**	0	0	0	0	0	0	0	0	45884	0	0	0	0	0	0	0	0	0
Greece	**14**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hungary	**15**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Italy	**16**	59083	0	0	0	0	0	0	0	37783	0	0	0	0	0	0	0	0	0
Slovakia	**17**	0	0	0	9111	0	0	0	0	0	0	0	5825	0	0	0	0	0	0
Luxembourg	**18**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Malta	**19**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25766	61789	0
Netherlands	**20**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Norway	**21**	0	0	0	0	0	0	0	25632	0	0	0	0	0	0	0	0	0	0
Poland	**22**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Portugal	**23**	0	0	0	0	0	0	5886	0	0	0	0	0	0	0	0	0	0	0
Romania	**24**	0	0	0	0	0	0	0	0	0	0	0	23064	0	0	0	0	0	0
Spain	**25**	0	0	0	0	5886	0	0	0	0	0	0	0	0	0	14247	0	0	0
Sweden	**26**	0	0	25632	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CH, LI [4)]	**27**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Turkey	**28**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UK	**29**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
U_MD [5)]	**30**	0	0	0	0	0	23064	0	0	0	0	0	0	14127	0	0	0	0	0
Belarus	**31**	0	0	0	0	0	0	0	0	0	0	0	14127	0	0	0	0	0	0
Algeria	**32**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12686	23892	0	0
Morocco	**33**	0	0	0	0	0	0	14247	0	0	0	0	0	0	12686	0	0	0	0
Tunisia	**34**	25766	0	0	0	0	0	0	0	0	0	0	0	0	23892	0	0	2801	0
Libya	**35**	61789	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2801	0	48582
Egypt	**36**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	48582	0

1) Albania, Serbia-Montenegro, Macedonia; 2) Bosnia-Herzegovina, Croatia, Slovenia; 3) Estonia, Lithuania, Latvia; 4) Switzerland, Liechtenstein; 5) Ukraine, Moldova

10.2 Figures

10.2.1 Maps of the biomass potential distribution

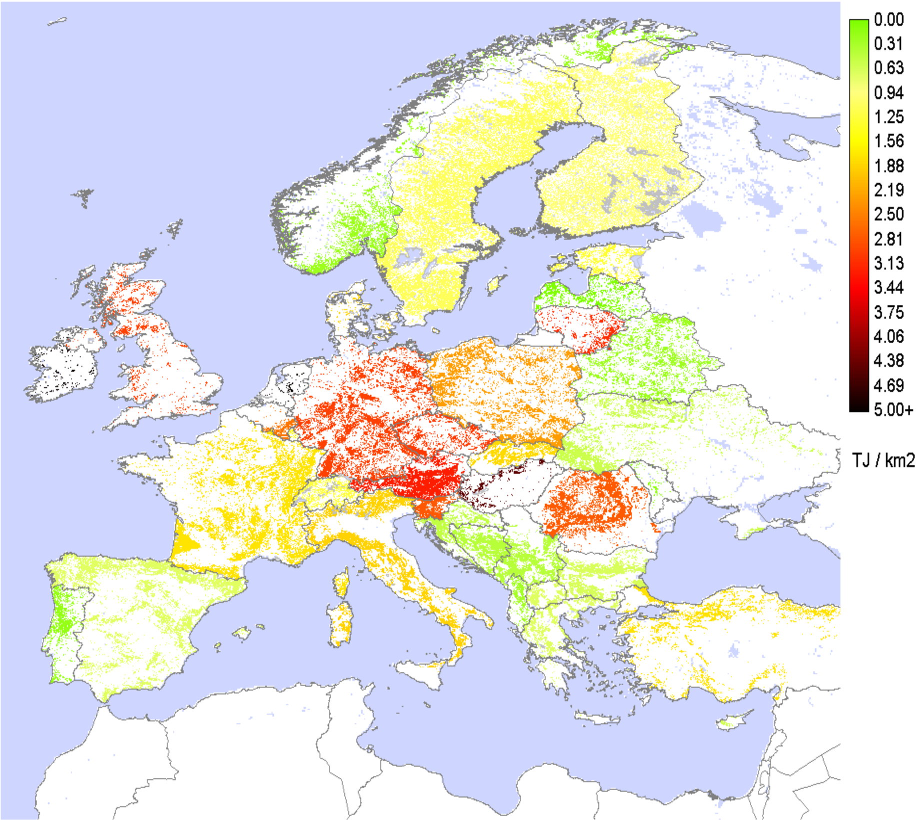

Figure 10.2.1: Forest wood available for energy use in TJ/km^2 (annual integral, year 2000)

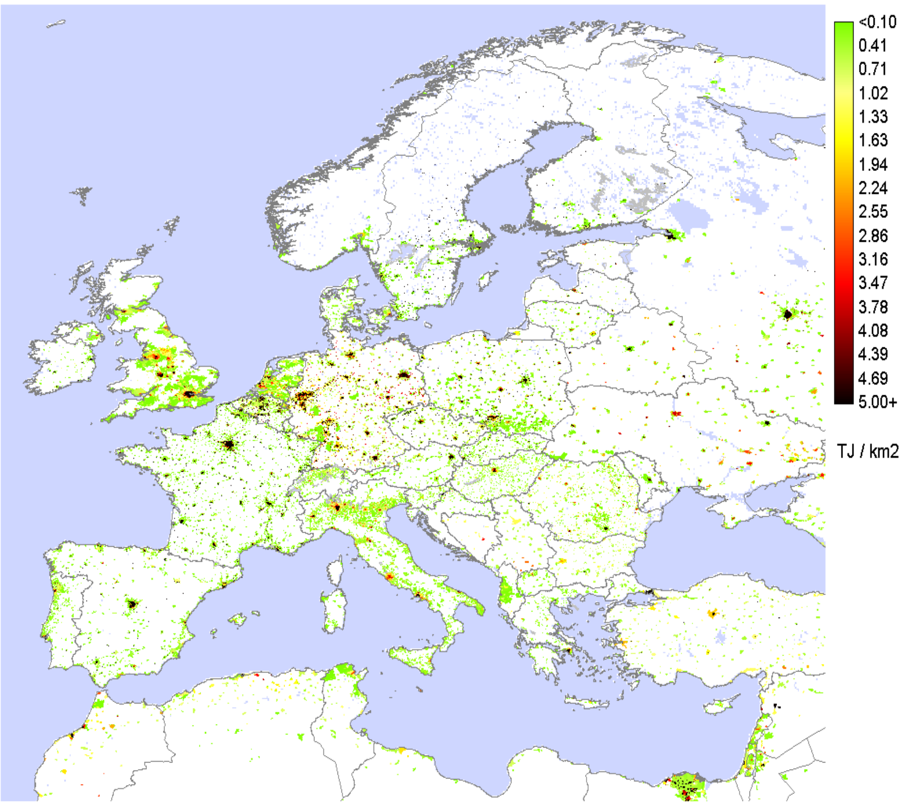

Figure 10.2.2: Waste wood available for energy use in TJ/km^2 (annual integral, year 2000)

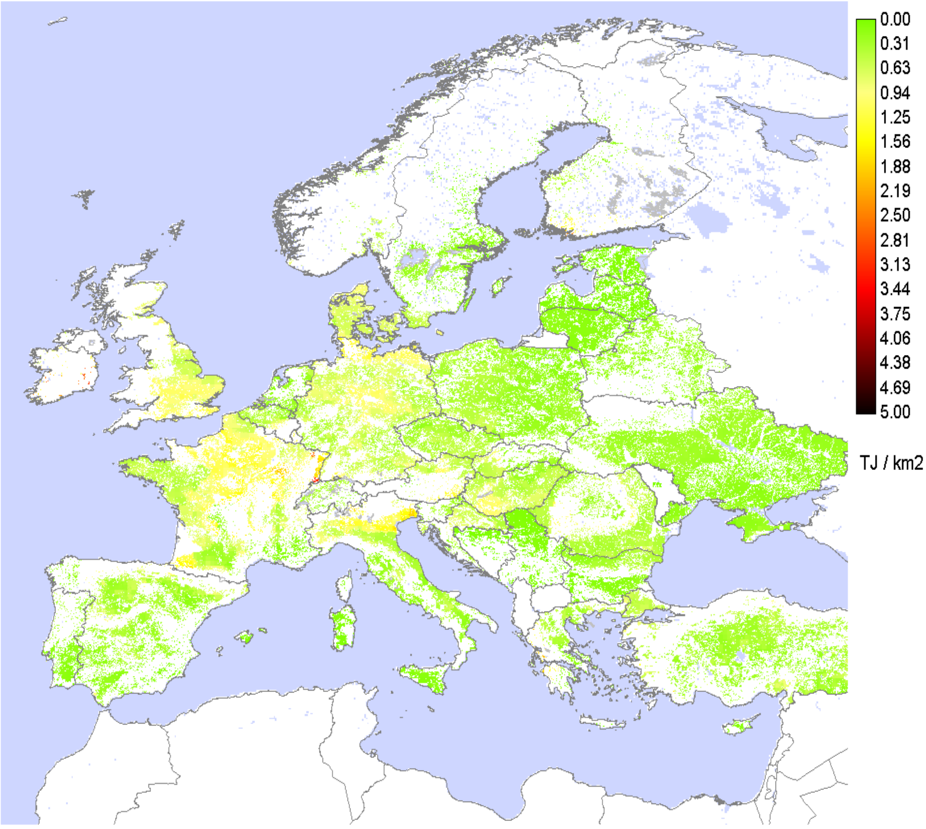

Figure 10.2.3: Straw available for energy use in TJ/km^2 (annual integral, year 2000)

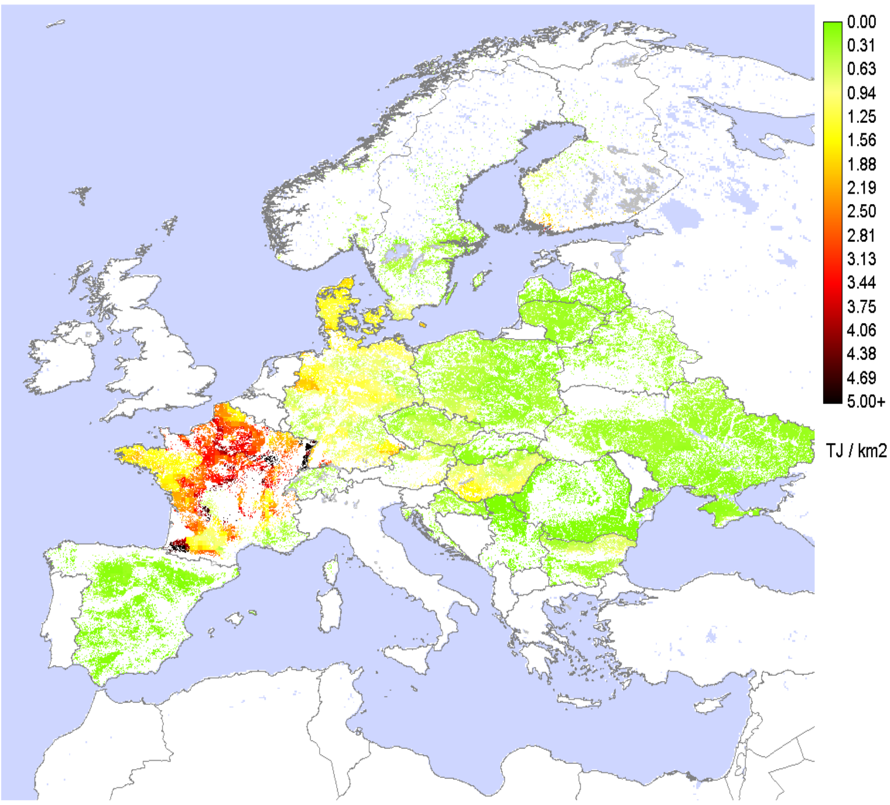

Figure 10.2.4: Energy crops available for energy use in TJ/km^2 (annual integral, year 2000)

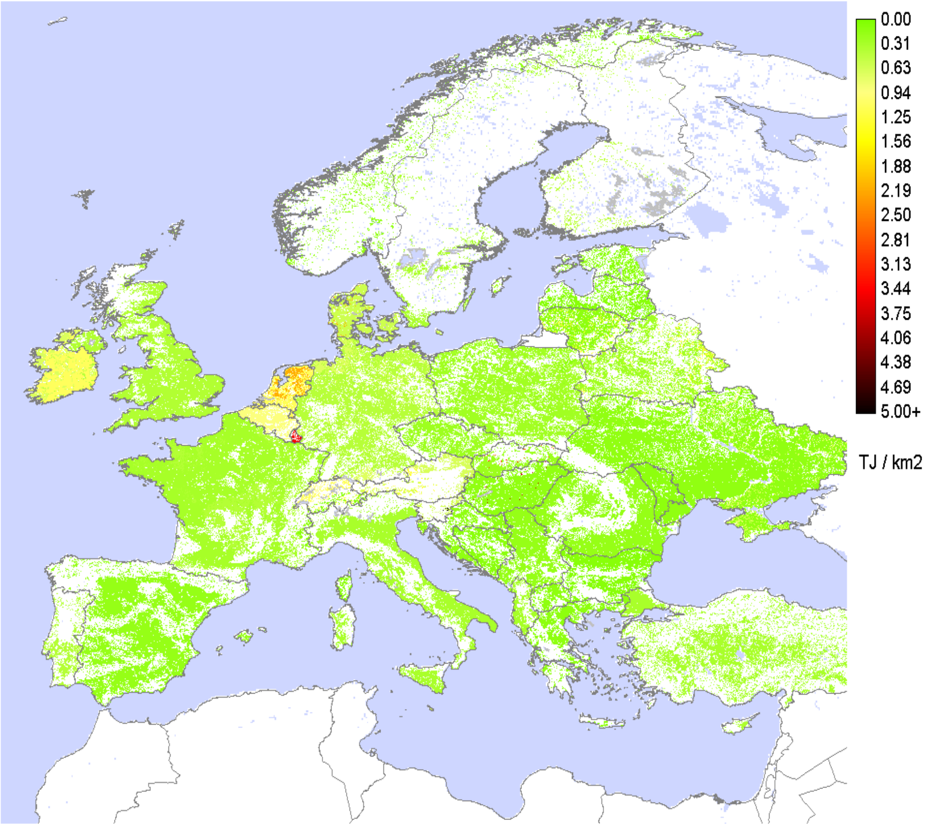

Figure 10.2.5: Other biomass (manure and grass) available for energy use in TJ/km^2 (annual integral, year 2000)

10.2.2 Annual energy sums in the member regions of the network DE-NO-DZ

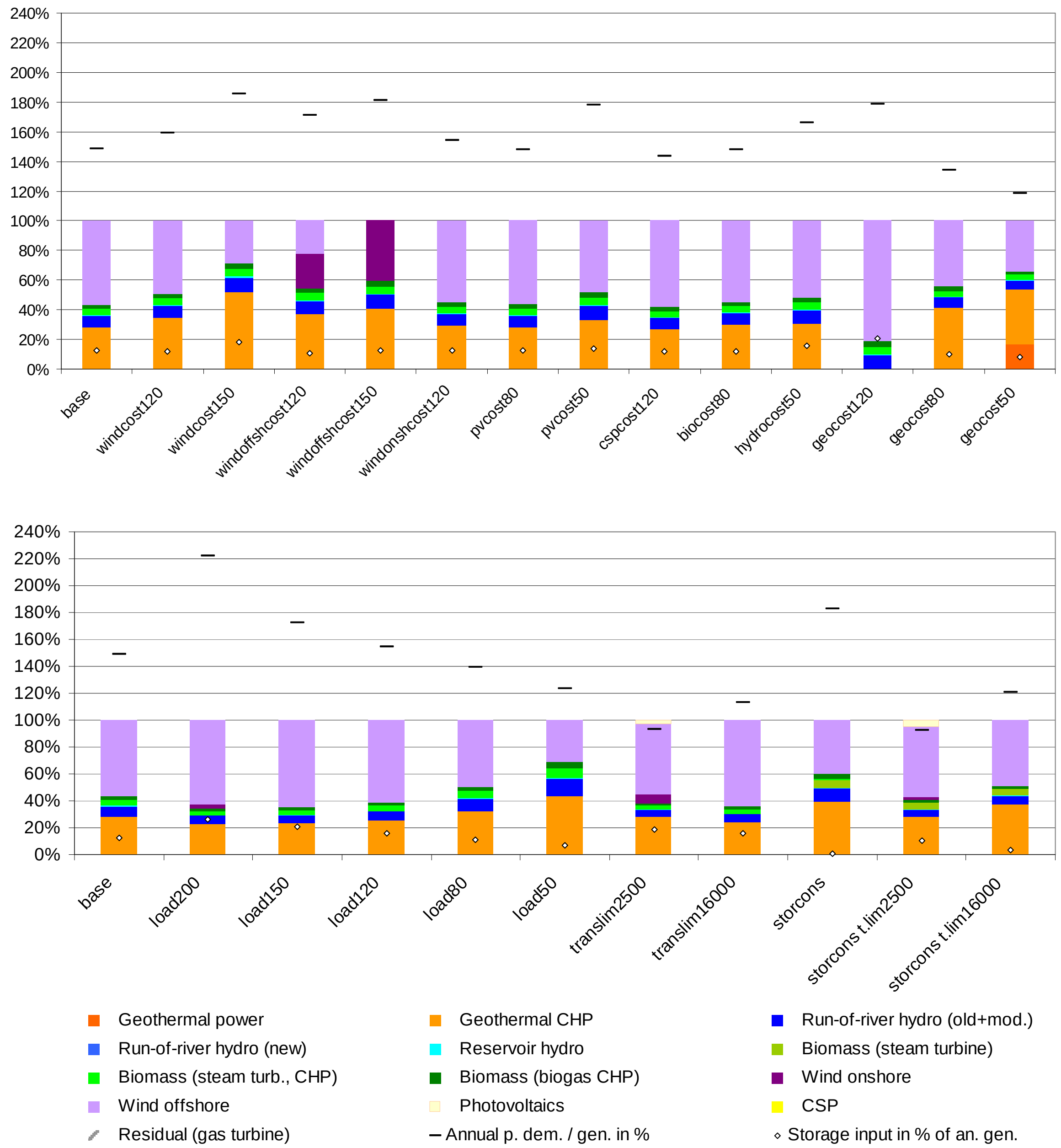

Figure 10.2.6: Normalised annual electric power generation in Germany as a member of the network DE-NO-DZ; different parameter variations (see chapter 7.1). On top: variations of generation costs. At the bottom: variation of annual load, transmission restrictions, storage restrictions and costs.

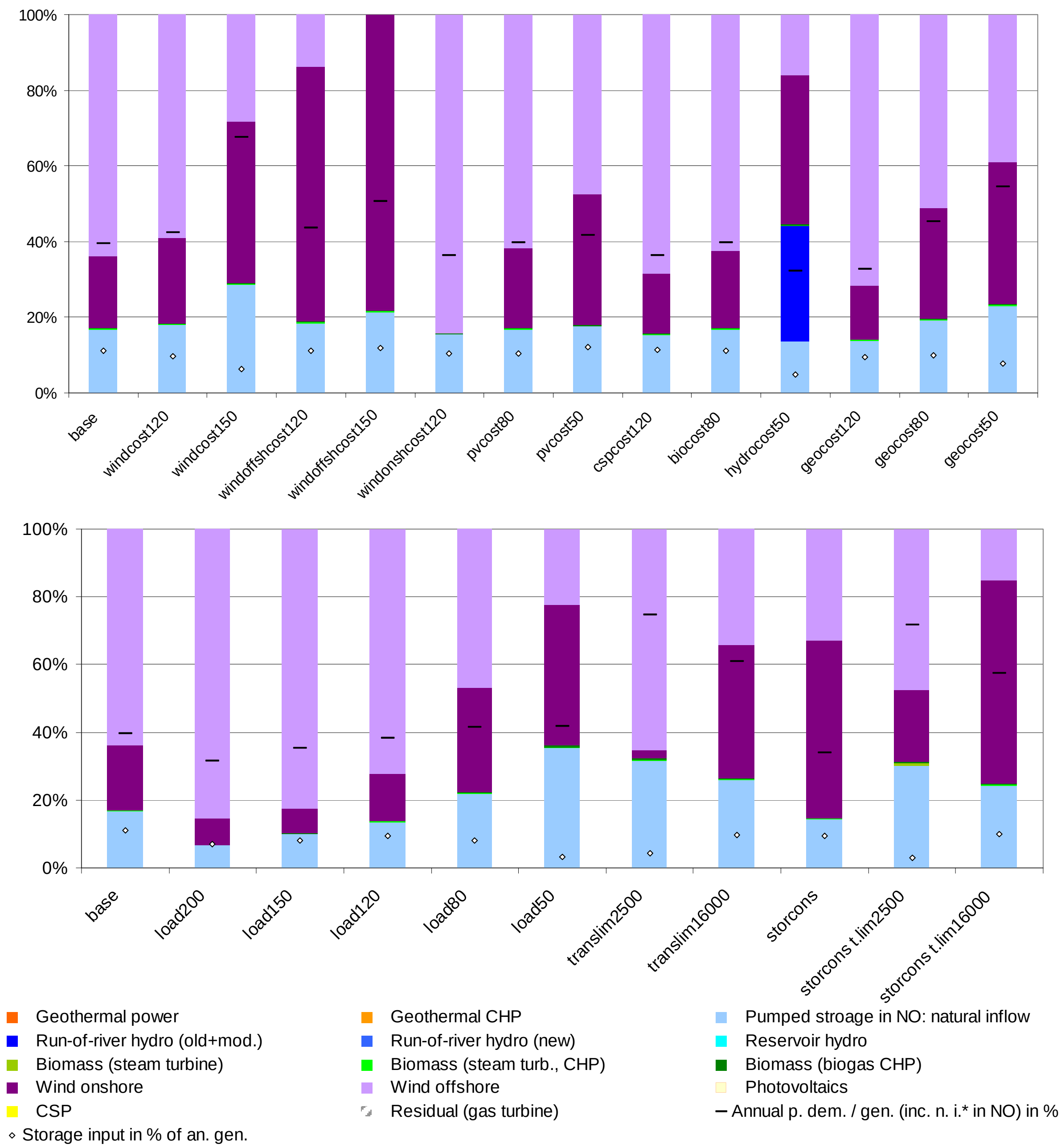

Figure 10.2.7: Normalised annual electric power generation in Norway as a member of the network DE-NO-DZ; different parameter variations (see chapter 7.1). On top: variations of generation costs. At the bottom: variation of annual load, transmission restrictions, storage restrictions and costs.

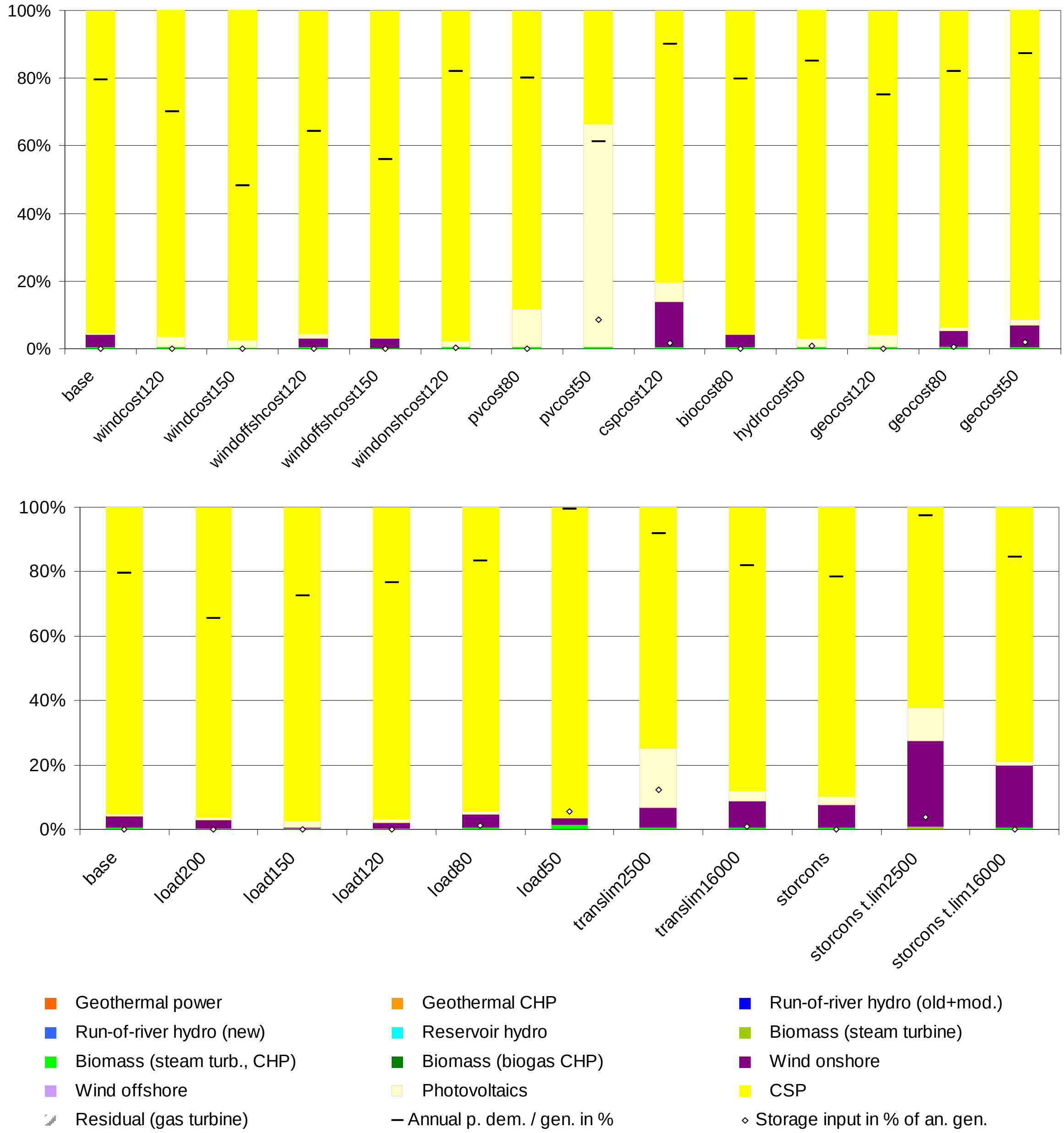

Figure 10.2.8: Normalised annual electric power generation in Algeria as a member of the network DE-NO-DZ; different parameter variations (see chapter 7.1). On top: variations of generation costs. At the bottom: variation of annual load, transmission restrictions, storage restrictions and costs.

10.3 List of tables

10.4 List of figures

Eidesstattliche Erklärung

Hiermit erkläre ich, diese Arbeit selbständig angefertigt, alle benutzten Hilfsmittel vollständig und genau angegeben sowie alles kenntlich gemacht zu haben, was aus Arbeiten anderer unverändert oder mit Abänderungen entnommen wurde.

Stuttgart, den 26.06.2012

Ort, Datum Unterschrift