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Disclaimer: The views and opinions expressed in this report are those of the author and do not reflect an official ICPDR position.

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Abbreviations

AT	Austria
BA	Bosnia and Herzegovina
BG	Bulgaria
CZ	Czech Republic
DE	Germany
HR	Croatia
HU	Hungary
MD	Moldova
ME	Montenegro
RO	Romania
RS	Republic of Serbia
SI	Slovenia
SK	Slovakia
UA	Ukraine

aFRR	automatic Frequency Restoration Reserve
ANRE	Agenţia Naţională pentru Reglementare în Energetică (Moldovan energy regulator)
BDEW	Bundesverband der Energie- und Wasserwirtschaft (Federal Association of the German Energy and Water Industries)
CCGT	Combined Cycle Gas Turbine
CEC	Citizen Energy Community
CO_2	Carbon Dioxide
CSP	Concentrated Solar Power
DRBD	Danube River Basin District
EBRD	European Bank for Reconstruction and Development
EEX	European Energy Exchange
EIA	Environmental Impact Assessment
ENTSO-E	European Network of Transmission System Operators for Electricity
EPEX	European Power Exchange
ERÚ	Energetický Regulační Úřad (Czech energy regulator)
EU	European Union
FCR	Frequency Containment Reserve
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GLEB	Guideline on Electricity Balancing
GW	Gigawatt
GWh	Gigawatt Hour

HEP	Hrvatska elektroprivreda (HEP Group)
HERA	Croatian Energy Regulatory Agency
HPP	Hydropower Plant
HVDC	High Voltage Direct Current
ICPDR	International Commission for the Protection of the Danube River
IHA	International Hydropower Association
IPCC	Intergovernmental Panel on Climate Change
IPS	Integrated Power System
IRENA	International Renewable Energy Agency
LCOE	Levelized Cost of Electricity
MCP	Market Clearing Price
MEKH	Magyar Energetikai és Közmű-szabályozási Hivatal (Hungarian energy and public utility regulatory authority)
mFRR	manual Frequency Restoration Reserve
MWh	Megawatt Hour
NECP	National Energy and Climate Plan
NREAP	National Renewable Energy Action Plan
PV	Photovoltaic
RE	Renewable Energy
REC	Renewable Energy Community
RES	Renewable Energy Sources
RES-E	Renewable Energy Sources - Electricity
RR	Replacement Reserve
SEA	Strategic Environmental Assessment
SEE	South-Eastern Europe
SERC	State Electricity Regulatory Commission
SOGL	System Operation Guideline
TSO	Transmission System Operator
TW	Terawatt
TWh	Terawatt Hour
UK	United Kingdom
UKRSTAT	State Statistics Committee of Ukraine
UPS	Unified Power System of Russia
USD	US Dollar
VRE	Variable Renewable Energies
WFD	Water Framework Directive

Executive Summary

Hydropower has been the dominant source of renewable electricity generation in the Danube region for decades. Due to the comparatively limited remaining potential, this position is expected to change in most ICPDR countries with non-hydro renewables taking the lead in the transition towards a more sustainable power system. Nevertheless, hydropower still offers economic potential and the expansion of hydropower is on the agenda of energy project developers and national energy policies. But due to new hydropower capacities frequently affecting river stretches with a high ecological value the expansion of hydropower has caused increasing environmental and social concerns. The ICPDR has already addressed ecological aspects of hydropower in its *Guiding Principles on Sustainable Hydropower Development in the Danube Basin; however,* experience has proven that the assessment of conflicting interests between renewable energy and climate targets on the one side and nature conservation on the other side requires an exhaustive understanding of both downsides and upsides of hydropower. For this reason, the ICPDR decided to complement the already existing knowledge base of ecological impacts of hydropower with an evaluation of social and economic drivers for hydropower development in Danube countries. The report at hand closes this gap through a comprehensive analysis of energy-economic and social aspects that affect the further development of hydropower in Danube countries.

One third of the economic hydropower potential in ICPDR countries is not yet developed

ICPDR countries represent an actual hydropower portfolio of 40.2 GW with an average generation of about 126 TWh/a. In 2018, the share of hydropower (excl. pumped storage) was 11% - the same percentage as wind power - of the total electricity generation of ICPDR countries. Biomass contributed 6% and solar PV 4% to the region's electricity mix. Fossil fuels and nuclear still account for 47% and 21%, respectively, of the total electricity generation. However, at national level the composition of the generation portfolios varies greatly. For example, in 2018 the share of hydropower ranged between 57% in Croatia and 1% in Hungary.

The total technical hydropower potential of all ICPDR countries amounts to 261 TWh/a and the total economic potential is estimated at 195 TWh/a. Accordingly, about half of the technical and two thirds of the economic potential are already exploited in the overall region. The figures regarding the realization of the economic potential are extremely varied throughout the individual countries and range between 80% (Austria and Germany) and about 30-40% in Bosnia and Herzegovina and Montenegro.

The energy transition requires a radical transformation of the electricity supply system

Hydropower will only be able to provide a limited quantitative contribution to a decarbonisation of the energy system of most Danube countries. As such, wind power and solar energy will dominate the renewable energy expansion in most ICPDR countries. Existing generation and grid structures are, however, only partly suitable for efficient integration of the increasing proportion of power generated from fluctuating renewable energy sources, which is why the structures of the existing power supply system must be radically adapted alongside the expansion of renewables.

Compared to wind power and solar PV energy economic characteristics of hydropower are more favourable

Even if the importance of hydropower decreases in the light of a massive expansion of wind and solar PV, an overall assessment of renewable technologies based on energy economic aspects shows that especially storage hydropower can provide significant advantages to the electricity supply system. With capacity credits above 90%, storage hydropower is not only at the top of all renewable energies but comparable to conventional thermal generation. The capacity credit of run-of-river hydropower is about 20-45% but still considerable above the capacity credits of wind power and solar PV, which is typically below 10%. Additionally, the balancing demand for the integration of run-of river hydropower is much lower compared to wind power and solar PV.

In contrast to non-dispatchable renewable energies, which increase the flexibility requirements in the residual power plant mix, storage hydropower provides tangible benefits to the power system. Due to their short response time and highly flexible generation characteristic, storage hydropower plants can for example efficiently balance load changes arising from volatile renewables. However, it has to be noted that not all regions and countries are equally suited for storage hydropower and even countries with suitable site conditions may show limited potential for new storage hydropower plants due to e.g. ecological restrictions.

Hydropower shows lowest social costs of all electricity generation technologies

Wind power and solar PV have seen a tremendous cost reduction in the past few years. Hence, their average costs of electricity production could already be in the range of or even below hydropower. In contrast, electricity generation from biomass is significantly more expensive. The system integration costs (i.e. costs for balancing, grid expansion and costs related to the interaction with the overall generation portfolio) of hydropower and biomass usually amount to 20-50% of system integration costs of wind power and solar PV, which can be up to 30 €/MWh. At about 1 €/MWh the external costs of hydropower and wind power are at the lower range of all generation technologies. In contrast, external costs of biomass and solar PV are about 19 and 15 €/MWh, respectively.

By adding up "private" generation costs and external costs of electricity generation, the so-called social costs of electricity generation can be derived. Conventional electricity generation technologies show total social costs between 130 and 190 €/MWh. Hydropower generates only about one fourth to one third of the social costs of conventional technologies and therefore, the lowest social costs of all power generation technologies, since social costs of wind power and solar PV are still 50-130% above hydropower today.

Potential impact of climate change on hydropower needs to be considered in overall portfolio development

Given its dependence on water availability, the impacts of climate change on hydropower are obvious, whereby run-of-river plants are more sensitive to changes in river flows than storage plants. From an ICPDR perspective, Southeast European and Balkan countries will face the highest risks in terms of negative impacts of climate change on hydropower with expected declines in annual hydropower production of more than 15%. The climate change will not only affect hydropower but increasingly the whole electricity sector both on the demand and supply side. For example, thermal power plants are primarily affected by a reduced availability and/or increased temperature of cooling water. By contrast, the overall impact of climate change on wind and solar power is expected to be rather limited on an overall European level but regional variations are very likely.

As a consequence of climate change related risks, a diversification in terms of fuels and energy sources as well as centralized and decentralized technologies will be key for the development of a generation portfolio that is resilient to more variable climatic conditions. This implies a larger contribution of "new" renewable energy sources not depending on water availability and water temperature. Additionally, storage hydropower can have an advantage over run-of river hydropower, since changing water flows can be better balanced and large reservoirs can reduce the impact of seasonal shifts of precipitation and snow melting. However, the potential higher impact of storage hydropower plants on freshwater systems needs to be considered for a holistic assessment of climate change related impacts of hydropower.

Implementation of WFD requirements can have retroactive effects on overall electricity system

The implementation of WFD requirements on existing hydropower plants can not only reduce the generation volume due to e.g. increased ecological flows but can also negatively affect operation characteristics of storage hydropower plants if for example mitigation measures for hydropeaking require restriction of the operating flexibility. Therefore, a "lost" in generation volumes and flexibility would need to be compensated in other – ultimately newly build – generation and storage facilities, which can cause negative ecological effects at other places. The assessment of WFD requirements should therefore not only be focused on ecological improvements at the location of a hydropower plant but also on potential impacts on the overall electricity system.

The socio-economic dimension of hydropower covers different aspects

Even if global warming is one of the major threats of our society today, local social and environmental impacts of hydropower mustn't be underestimated. Therefore, it is essential to include social aspects into a holistic evaluation of the future perspectives of hydropower. Beside social and environmental effects the socio-economic dimension also covers macro-economic effects, distributional effects, energy-system related effects and further effects like impact on geopolitical risks. While energy-system related effects (e.g. grid related impact and balancing demand) as well as social and environmental effects typically show technology-specific differences between hydropower and e.g. wind and solar PV, it is impossible to clearly categorise the other socio-economic aspects with regard to different renewable technologies. For example, macroeconomic effects depend on whether the equipment and required services are imported or sourced locally. However, hydropower can deliver remarkable advantages compared to solar PV and wind power, for example in terms of regional value creation and employment, since the share of locally and regionally sourced civil work is typically noticeable higher in total project costs of hydropower than of wind power and solar PV.

Social and ecological impacts of hydropower can be manifold

All renewable technologies can inevitably have negative ecological and social impacts; however, the environmental and social impact of hydropower can – dependent on plant type, size, mode of operation and location – be considerable. Examples for ICPDR countries are potential adverse effects on the aquatic ecology and natural habitats of river ecosystems and negative impacts on the livelihoods of communities due to e.g. loss of agricultural land. Additionally, a lack of transparency, issues of ownership or limited possibilities for an active participation of the citizens in the planning process can cause negative social effects. In return, hydropower can also have positive social impacts such as the multifunctional use of (large) reservoirs for e.g. irrigation, flood control and tourism, the creation of local jobs or the enhancement of infrastructure and electricity supply. Therefore, the consideration of ecological effects as well as social and socio-economic impacts on local people and communities will be key for public acceptance and hence, the possible further development of hydropower.

Social acceptance of hydropower can be improved by a number of supporting measures

The social acceptance of hydropower is primarily, but not only, linked to the ecological impact of a hydropower project. Additional key aspects for social acceptance are the type of ownership, the degree of local job creation, the level of participation in the planning and decision-making process as well as the amount of financial benefits for communities and cantons from hydropower construction and operation. In order to address these aspects, a number of different measures may be applied – the implementation of a transparent and comprehensive environmental impact assessment should of course play an important role in this matter. In addition, strategic planning processes for hydropower on a country or regional level can be facilitated by criteria catalogues. These should be developed in an extensive discussion with all relevant stakeholders in order to enable a broad acceptance. With regard to ownership structures, local or regional owners are generally preferred over private domestic or foreign investors. Hence, ownership structures and accompanying investment programs that make economic benefits of hydropower accessible to communities can actively support public acceptance. In this context, countries may also adopt the legal and regulatory frameworks to actively support the implementation of citizen and renewable energy communities for financial engagement of local stakeholders through non-commercial energy communities.

Both from an energy economic and ecological perspective small hydropower tends to be less attractive

Large hydropower represents about 85% of the installed hydropower capacities in ICPDR countries but small hydropower is still and frequently considered to have less negative social and environmental impacts. However, from an energy economic and ecological perspective small hydropower has some downsides. On average, small hydropower plants show higher specific investment costs and typically provide less operational flexibility. River flows with small catchment areas are often more variable and more vulnerable to climatic variations. On the one hand, the cumulative ecological impact of small hydropower plants often exceeds the impact of a large hydropower plant that produces the same amount of electricity. On the other hand, small hydropower plants support distributed generation structures and they make it easier to implement financial engagement of local stakeholders. Nevertheless, there is not necessarily a clear linear correlation between size and impact and the discussion should not be about “small or large” but actual impacts of specific hydropower projects and possible mitigation measures.

Hydropower development may supplement wind and solar even in countries with high remaining hydropower potential

A more detailed analysis of the perspective and importance of hydropower for six selected ICPDR countries showed that the hydropower potentials in Bosnia and Herzegovina and Montenegro would theoretically allow a renewable-based autonomy of the national power sector. In contrast, even a full deployment of the remaining technical hydropower potential of Bulgaria, Romania, Serbia and Ukraine would provide only a limited quantitative contribution to the countries' renewable portfolios. However, all six countries have wind and solar potentials, which are significantly above the actual electricity demand. All countries have already started to develop non-hydro renewables, but wind power, solar PV and biomass only provide a noticeable contribution to the national generation mix in Romania and Bulgaria.

Given the general energy-economic requirement of a generation portfolio being robust and low-risk, those countries already having a significant share of hydropower should put a stronger focus on non-hydro renewable technologies to diversify the country's generation portfolio and make it less vulnerable to e.g. seasonal and yearly fluctuations of water runoffs. With a stronger strategic orientation on non-hydro renewables, the remaining hydropower resources could also be developed in a more sustainable way. In this context, storage hydropower as one of several options to provide flexible generation and ancillary services could receive greater emphasis for the integration of volatile renewables. In contrast to Bosnia and Herzegovina and Montenegro, wind power and solar PV in Bulgaria, Romania, Serbia and Ukraine would need to play the most important role anyway, if the generation portfolio should contain a significant higher share of renewable energies. A focus on storage hydropower to support the integration of volatile renewable energies would be also advantageous for these countries, if site and topographical conditions allow. Nevertheless, a glance at the country's long-term strategies for renewables deployment show that either the requirements for a diversified generation portfolio are not sufficiently considered or renewable targets are generally not sufficient to successfully combat climate change.

Conclusions and final recommendations

Undoubtedly, hydropower will remain an important pillar of the Danube region's renewable electricity portfolio but will play a less important role not least due to the expected massive expansion of wind power and solar PV. Generally, the strategic need for additional hydropower development should be defined in an overall power system planning process. An essential objective of such a planning process should be the development of a robust and climate resilient generation portfolio. In this context, site selection and project assessment for hydropower should be based on common frameworks and guidelines in order to identify the "best" available projects from an energy-economic and ecological perspective. High environmental and social standards have to be applied independent of project size and with regard to small hydropower, the assessment of cumulative ecological effects is required. Finally, hydropower projects need to provide tangible benefits to local communities and people to achieve social acceptance for a further hydropower development.

1. Introduction and background

1.1 Danube River Basin District and ICPDR

The Danube and its tributaries, transitional waters, lakes, coastal waters and groundwater form the Danube River Basin District (DRBD), form what is known as the "most international" river basin in the world covering territories of 19 countries. Those 14 countries with territories of more than 2,000 km² in the DRB cooperate in the framework of the International Commission for the Protection of the Danube River (ICPDR[1]). The ICPDR has been established to implement the Danube River Protection Convention and all transboundary aspects of the EU Water Framework Directive (WFD [1]), respectively. Figure 1 illustrates the 14 contracting countries of the ICPDR as well as the geographical area covered by the DRBD[2].

Figure 1: Danube river basin district overview

Source: ICPDR [2]

A major task of the ICPDR is the elaboration of the Danube River Basin District Management Plan (DRBM Plan) according to Article 13 of the WFD. The first DRBM Plan was published by ICPDR in 2009 and includes a basin-wide assessment of the significant pressures, the protected areas, monitoring

1 For more information about ICPDR please refer to https://www.icpdr.org/main/.

2 For the purpose of the Danube River Basin District Management Plan, the DRBD has been defined as covering the Danube River Basin (DRB), the Black Sea coastal catchments in Romanian territory and the Black Sea coastal waters along the Romanian and partly Ukrainian coasts.

networks and ecological/chemical status, environmental objectives and exemptions, economic analysis of water uses, information on flood risk management and climate change as well as of public information and consultation. The Plan also includes a Joint Programme of Measures for achieving the objectives of the WFD. In 2015, the second DRBM Plan [3] was published and ICPDR is currently working on the third DRBM Plan.

The DRBM Plans identified four significant water management issues for the Danube basin: organic pollution, nutrient pollution, hazardous substances pollution and hydromorphological alterations. Besides navigation and flood protection, hydropower utilization is the main cause for hydromorphological alterations. Acknowledging the challenge of sustainable hydropower development within the existing legal and policy frameworks, the ICPDR was asked in the Danube Declaration 2010 "to organise in close cooperation with the hydropower sector and all relevant stakeholders a broad discussion process with the aim of developing guiding principles on integrating environmental aspects in the use of existing hydropower plants, including a possible increase of their efficiency, as well as in the planning and construction of new hydropower plants". (cf. [5]). As a result of the ICPDR-initiated activity "Guiding Principles on Hydropower Development", the *Assessment Report on Hydropower Generation in the Danube Basin* [6] was delivered in 2013 and the *Guiding Principles on Sustainable Hydropower Development in the Danube Basin* [5] were also elaborated in 2013. While the assessment report gives key information and data on hydropower generation in the Danube Basin, the Guiding Principles provide principles as well as ecological and energy management criteria for the elaboration of hydropower projects, including case studies and good practice examples in the context of the Water Framework Directive and the Renewable Energy Directive. However, it needs to be mentioned that both, the assessment report and Guiding Principles are envisaged to facilitate the discussion for future projects but will not replace any legal requirements or technical discussions on national level.

1.2 Aim and structure of the report

So far, the ICPDR Guiding Principles have been proven to be a fine example of good practice for the evaluation of hydropower projects even beyond the Danube River Basin. However, it also became clear that the assessment of conflicting interests between renewable energy and climate targets on the one side and nature conservation on the other side require an exhaustive understanding of both the downside potential (i.e. ecological impact) and upside potential of hydropower (i.e. contribution to climate and energy targets but also e.g. provision of system services). Furthermore, as a follow-up to the ICPDR Hydropower Workshop 2017 [7], it showed that the ICPDR knowledge base on key social and economic drivers for sustainable hydropower development needs to be expanded. During the 15th ICPDR Standing Working Group Meeting in Brussels in June 2017, a resolution was approved "to support the preparation of a knowledge base on key social and economic drivers of hydropower development in the Danube River Basin". Against this background, ICPDR commissioned Mr Jürgen Neubarth (e3 consult) with a study on key social and economic drivers for hydropower development in view of future climate and renewable energy strategies with focus on countries having a high potential for hydropower development. The results and conclusions of the study will be used as a basis for further discussion, e.g. during the ICPDR Hydropower Workshop 2020. The report at hand is structured into the following sections:

- Section 2 provides a view on the overall **European energy policy and energy economic framework** with respect to the future perspectives of hydropower. This includes the energy policy objectives until 2030 and 2050, respectively, the challenges related to the required system and market integration of volatile renewable energy sources, the development of wholesale electricity prices as well as requirements related to water management and biodiversity.
- Section 3 gives an **overview of the existing electricity generation system** in Danube countries. Additionally, key facts of the electricity system with a special focus on hydropower are provided for each of the fourteen ICPDR countries by means of a comprehensive one-page country profile.
- Section 4 highlights the **energy-economic dimension of hydropower** in general and in relation to other renewable energy sources within the context of European climate and energy targets. This includes a comparison of economic and technical parameters, such as electricity generation costs and balancing aspects. Additionally, the potential impact of climate change on hydropower and other generation technologies is discussed.
- Section 5 comprises the **social dimension of hydropower**. This includes the presentation of socio-economic aspects of renewable energy sources in general and hydropower in particular as well as possible measures to improve the social aspects of hydropower. Finally, the question whether small hydropower plants are more favourable than large ones is discussed.
- Section 6 elaborates **perspectives for the further development of hydropower** in the Danube region. Based on an analysis of hydropower potentials in ICPDR countries, a more detailed analysis is provided for six exemplarily selected ICPDR countries, namely Bosnia and Herzegovina, Bulgaria, Montenegro, Romania, Serbia and Ukraine. The analysis relates the potentials of hydropower to the potentials of other renewable energy sources, compares the actual development of hydropower capacities with strategic energy targets and discusses effects of a potential hydropower expansion on the overall national generation portfolio.
- Finally, section 7 provides **key findings and derived recommendations** of the study.

The present study supplements the already available ecological view on hydropower aspects in the *Guiding Principles on Sustainable Hydropower Development in the Danube Basin*. Therefore, it does not include a dedicated section on ecological and nature conservation aspects of hydropower. However, ecological aspects are included in section 5 as one of the social dimensions of hydropower use.

For the genesis of this report, an intensive literature research was carried out to consider the latest scientific and industry findings on economic and social aspects of hydropower. Various thematically related studies have been prepared in recent years – the IRENA study *Cost-Competitive Renewable Power Generation: Potential across South-East Europe* [8], the *Regional Strategy for Sustainable Hydropower in the Western Balkans* [9] and the *Hydropower Sustainability Guidelines* from the International Hydropower Association [10] may be mentioned exemplarily. However, available studies are often focused on detailed aspects of hydropower and renewables, respectively, and were not specifically tailored to the (whole) Danube region. Hence, for this report available information is put into relation to ICPDR countries, additional information is included and consistently prepared to provide a comprehensive overview of social and economic drivers for the further hydropower development in Danube countries.

2. Overall energy policy and energy economic framework

The future role of hydropower in the power systems of Danube countries will, to a large extent, be determined by the energy policy framework at EU level. This is especially true when considering the envisaged extensive decarbonisation of the electricity sector as well as water management and biodiversity. Against this background, the following chapter provides a brief overview of the European energy policy objectives (section 2.1 "European energy policy objectives 2030/2050"). Challenges, which are related to the necessary transformation of the electricity system if the long-term energy policy targets are actually implemented, are presented in section 2.2 "System and market integration of renewable energies". Additionally, an analysis of the development of wholesale electricity prices is provided in section 2.3 "Development of wholesale electricity prices". Finally, section 2.4 "Requirements related to water management and biodiversity" summarizes aspects in relation to EU policies and legislations with respect to water and flood protection as well as environmental and nature protection

2.1 European energy policy objectives 2030/2050

With its *Climate and Energy Package 2020* [7], *Clean Energy for All Europeans Package 2030* [12] and *Roadmap for a competitive low-carbon Europe by 2050* [13], the European Union defined the fundamental framework for the development of the European energy system with regard to climate protection, renewable energies and energy efficiency. The share of renewable energy sources (RES) in total energy consumption should be increased from 9% in 2005 to 20% in 2020 and at least to 27% in 2030. For 2050, no explicit renewables target has been defined so far but a significant further development of renewable energies would be required to meet the EU's agreed objective to reduce greenhouse gas (GHG) emissions by 80-95% in 2050 compared to 1990. The importance of renewable energies for European and national energy policies could increase even further if the EU would agree on a "European Green Deal", i.e. climate neutrality by 2050. So far, legally binding renewable targets for 2020 and 2030 are broken down to individual EU member states and are further detailed in the country's National Renewable Energy Action Plans (NREAP) for the year 2020. Since all five non-EU ICPDR countries are contracting parties to the Energy Community Treaty[3], Bosnia and Herzegovina, Moldova, Montenegro, Serbia and Ukraine also had to adopt NREAPs with national targets for the share of renewable energies.

Besides a significant increase in energy efficiency[4], the expansion of electricity generation from renewable energies is considered to be a major lever not only to comply with overall renewable energy

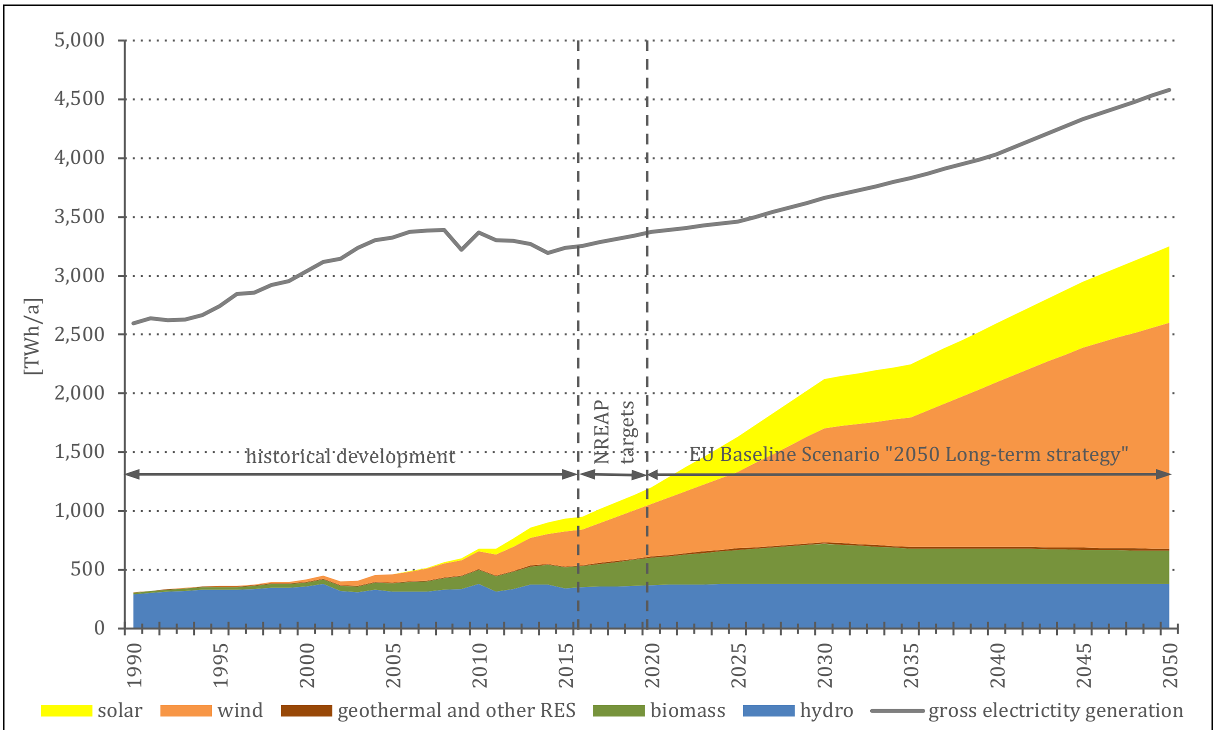
[3] The Energy Community is an international organisation which brings together the European Union and its neighbours to create an integrated pan-European energy market. The key objective of the Energy Community is to extend the EU internal energy market rules and principles to countries in South East Europe, the Black Sea region and beyond on the basis of a legally binding framework (cf. https://www.energy-community.org/).

[4] The Energy Efficiency Directive (2012/27/EU) and the amended Directive (2018/2002) defined an energy efficiency target of 20% for 2020 and 32.5% for 2030, respectively (cf. https://ec.europa.eu/energy/en/topics/energy-efficiency/targets-directive-and-rules/energy-efficiency-directive). However, the implementation and development of energy efficiency policies in ICPDR countries is not taken into consideration in this report. Accordingly, increased energy efficiency as a potential alternative to additional investments in (renewable) electricity generation capacities will not be discussed.

targets but also to reduce GHG emissions. Even if the political framework for the sustainable development of the European energy system does not define sector-specific renewable targets, the share of renewable energies in the total electricity production of the 28 EU member states would need to be increased from 16% in 2005 to about 35% in 2020 and 55-60% in 2030 if overall EU climate and energy objectives are to be met. Until 2050, the share of renewable energies in the EU-28 electricity production could even amount to 80-85% if the Commission's strategic long-term vision for a prosperous, modern, competitive and climate-neutral economy by 2050, *A Clean Planet for All* [14] or the *European Green Deal* [15] was to be achieved. One might argue that the EU 2050 long-term strategy and *European Green Deal* is still vague and a more or less full decarbonisation of the electricity sector in the next 30 years is too ambitious. However, based on already agreed EU policies, or policies that have been proposed by the European Commission but are still under discussion in the European Parliament and Council, renewable energies would even provide more than 70% of the EU-28 electricity production by 2050 [16] within such a so-called baseline scenario.

Wind power and solar energy – mainly photovoltaic (PV) but also concentrated solar power CSP) – have dominated the growth of renewable energies in the last two decades; between 2000 and 2016, almost 75% of the additional electricity generation from RES have been provided from those two renewable energy sources. However, since untapped wind and solar potentials are significantly higher in most European countries than the remaining potentials of hydropower, biomass and geothermal, the further expansion of renewables in the electricity sector will mostly rely on wind power and solar energy. This is shown in Figure 2, which illustrates the development of electricity generation from renewable energies between 1990 and 2016, the projected development by 2020 taken from country specific NREAPs and the renewable growth trajectory by 2050 as given in the baseline scenario of the *EU 2050 long-term strategy*.

Figure 2: Historical and projected electricity generation from renewable energies within the EU-28



Source: European Commission [16] & [17], Beursken, L.W.M [18]

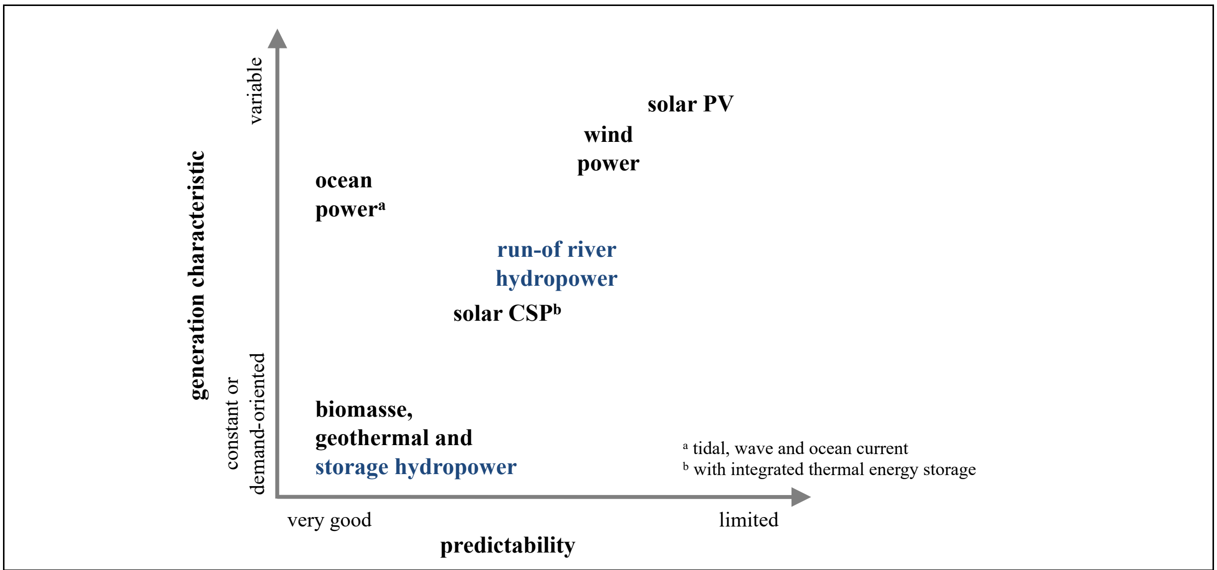
According to the baseline scenario of the *EU 2050 long-term strategy,* the share of wind and solar in the total EU-28 electricity production will increase from today's 15% to 38% in 2030 and 56% in 2050, i.e. wind and solar would provide about 2,700 TWh/a in 2050. However, the more ambitious decarbonisation scenarios of the *EU 2050 long-term strategy,* where fossil energy carriers in the heating, transportation and industrial sector are substituted to a far greater extent by means of a so-called sector coupling with electricity from renewables[5], would require a significantly higher expansion of wind and solar. In contrast to the massive expansion of wind and solar and despite noticeable higher remaining potentials of hydropower in the EU-28[6], the scenario only considers a comparatively small expansion of electricity generation from hydropower of about 50 TWh/a between 2015 and 2050.

2.2 System and market integration of renewable energies[7]

2.2.1 Generation characteristics of variable renewable energies

Wind and solar energy will dominate renewable energy expansion, although it is precisely power generation from these two sources that presents the biggest challenges for integrating renewable energies into the existing electricity supply system. In the past, power grids were not designed for unequal regional distribution as it is the case with power generation from wind and solar energy. Also, conventional power plants up to now have only had to balance fluctuations on the demand side, not on the supply side. Hence, the daily and seasonal variations as well as predictability of RES generation is of particular importance for the electricity supply system, which has to be able to balance fluctuations and forecast errors at every time. Generation characteristics and predictability of RES can behave fundamentally different, which is qualitatively illustrated in Figure 3.

Figure 3: Qualitative generation characteristic and predictability of different RES technologies



Source: Neubarth, J. [20]

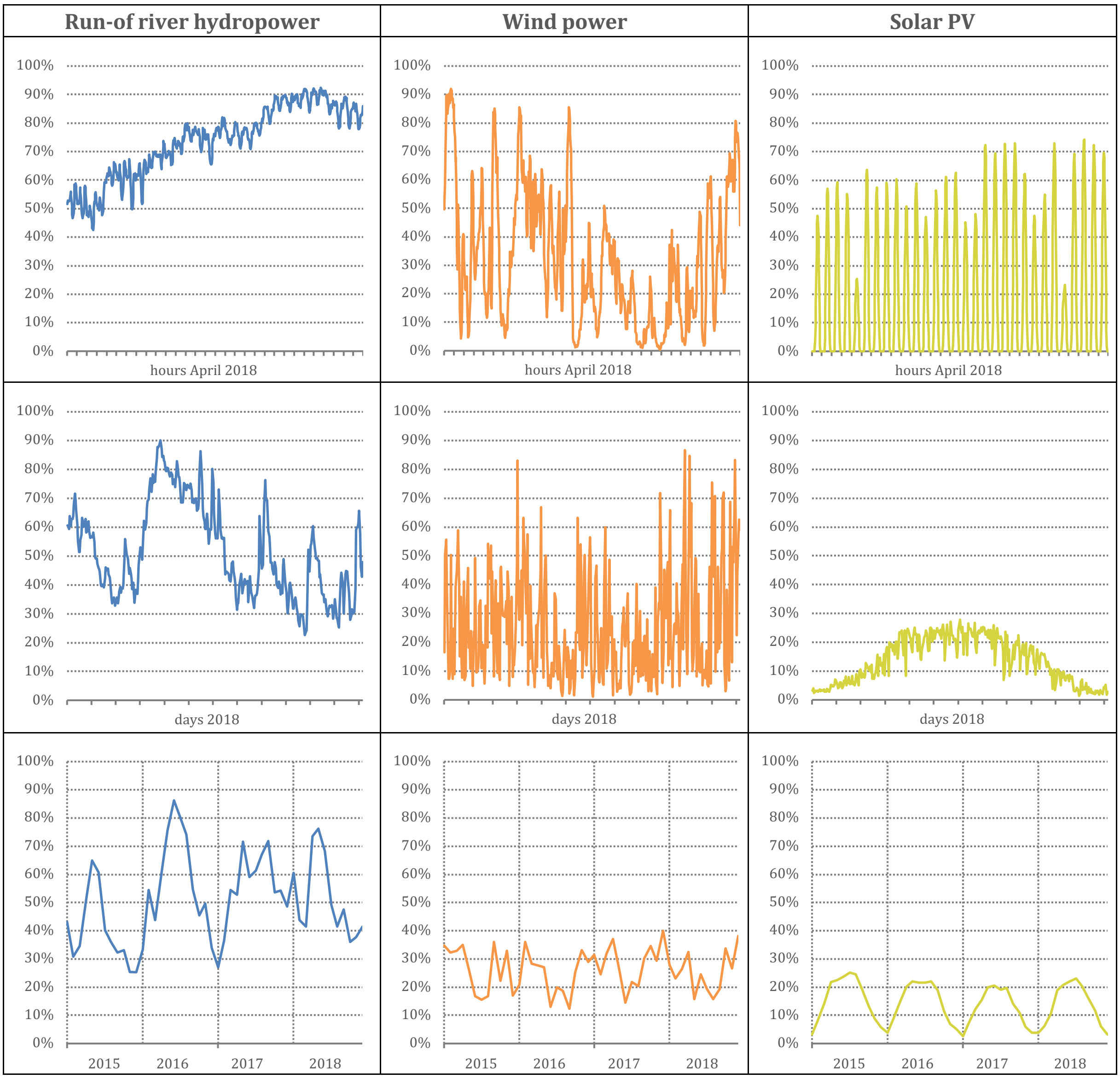
5 Sector coupling refers to linking the electricity sector with other energy sectors (i.e. gas and heat) as well as the transport and industrial sector with the aim to increase the penetration of RES across all sectors and not only the electricity sector. The aim is the full decarbonization of the overall economy.

6 For example, the 2011 Eurelectric report "Hydro in Europe: Powering Renewables" shows a remaining technically feasible hydropower potential for the EU-27 of 276 TWh/a [19].

7 Based on Neubarth, J: Integration of renewable energies into the power supply system[20].

Wind power, solar PV and run-of-river hydropower are non-dispatchable variable renewable energies (VRE) and show – by nature – variable generation characteristics and limitations in terms of predictability of power generation. On the other hand, biomass, geothermal energy and storage hydropower are dispatchable or have a constant generation pattern and hence, a very good predictability. Generation characteristic and predictability of concentrating solar power with integrated thermal energy storage can be compared to run-of-river hydropower, but suitable sites with high direct solar radiation are rare in ICPDR countries. Similar to ocean power, the technology is of minor importance to the Danube region. As qualitatively already indicated in Figure 3, the variability of electricity generation from run-of-river hydropower is typically lower than from wind power and solar PV, respectively. In this context, Figure 4 provides a more detailed analysis based on the example of fluctuations of run-of-river hydropower, wind power and solar PV in Austria for different time intervals. Note that Figure 4 shows the hourly average generation for April 2018, the daily average generation for 2018 and the monthly average generation for the years 2015-2018.

Figure 4: Variation of electricity generation from run-of-river hydropower, wind power and solar PV in Austria in relation to installed capacity



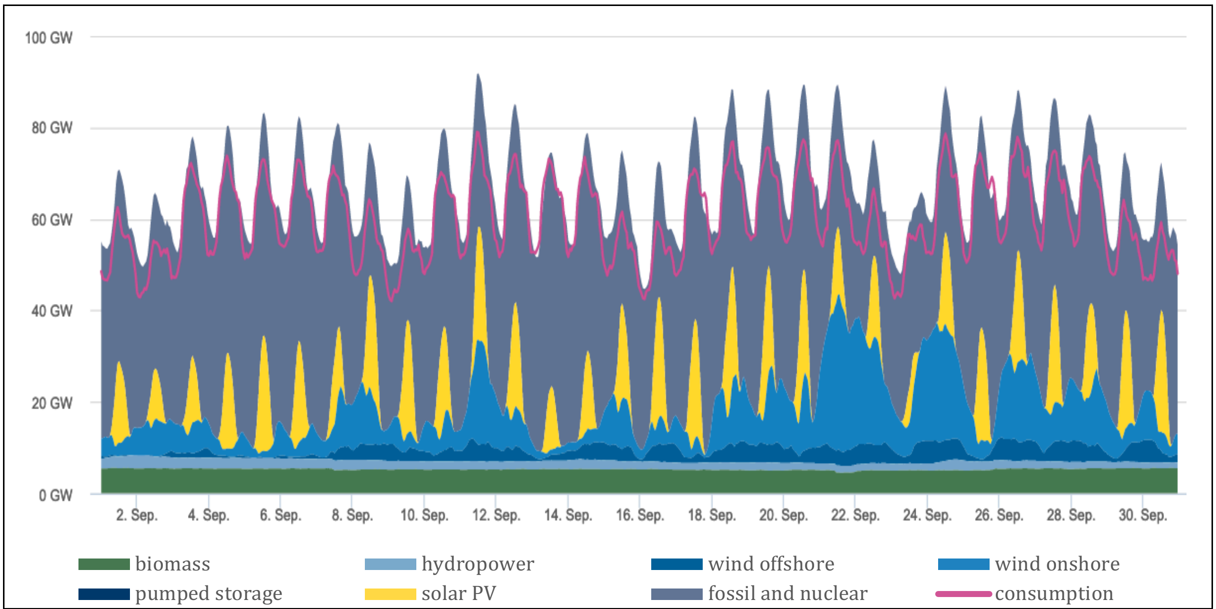
Source: APG [21]

- **Run-of-river hydropower:** Hourly fluctuations of run-of-river hydropower are comparatively low and mainly determined by snow and ice melting during daytime as well as by dispatching storage hydropower within the catchment area of a hydropower plant. Even if the seasonal generation pattern depends on the hydrological regime, it typically shows a peak during summer and a valley during winter in most European countries. Periods with heavy precipitation are directly reflected in overlaid generation peaks. Hence, the generation of a hydropower portfolio can fluctuate between about 20 and 90% of the installed capacity over the course of a year.
- **Wind power:** Over the course of hours and days and depending on prevailing wind and weather conditions, there can be fluctuations in generation within a portfolio of geographically distributed wind parks ranging from practically nothing to nearly 85%. Looking at the monthly pattern, there is a higher wind power generation during the winter months, but within individual months there can be deviations from the relevant long-term monthly averages of up to +90/-50% and in some years deviations from long-term annual averages may reach up to +/-15%.
- **Solar PV:** For electricity generation from PV, the relations are basically similar to wind power, although a much more pronounced generation characteristic depending on time of day or year can be observed, which is directly linked to the fluctuations of the supply pattern of solar radiation.

2.2.2 Interaction of renewables with the existing electricity supply system

It is already evident today that the existing generation and grid structures are only partly for efficient integration of the increasing proportion of power generated from fluctuating renewable energy sources. The fluctuating supply of wind power and solar PV not only reduces the overall amount of electricity to be generated by fossil power plants, but – and more importantly – it also changes the dynamics of the so-called residual load, meaning the electricity demand minus the generation of non-dispatchable electricity generation by wind power, PV, run-of-river power plants and heat-operated cogeneration without thermal storage. Figure 5 exemplifies this by means of electricity generation and the electricity consumption in Germany in September 2018.

Figure 5: Electricity generation and consumption in Germany September 2018



Source: Agora Energiewende [22]

It is evident that periods of high electricity generation by wind power and/or PV with a simultaneous low demand result in a change in the electricity generation by conventional base-load power plants as the remaining residual load, including the exports to neighbouring countries, is then partly below the installed capacity of the nuclear and ignite-fired power plants. Accordingly, renewable energies affect the operational deployment of conventional power plants in the short term but in the long-term they will at least partly supersede conventional generating capacity (known as the capacity effect). It has to be mentioned that the residual peak load (meaning the highest residual electricity demand within one year) cannot be reduced to the same extent by expanding wind power and PV, as high electricity generation by fluctuating renewable energies cannot be guaranteed at high demand periods. Therefore, the expansion of renewable energies leads to a supersession of conventional base-load power plants as well as to a higher demand for medium- and peak-load power plants. Additional demands on conventional power plants result from the maintenance of an operating and balancing reserve to quickly compensate any difference between actual and projected power generation from wind and PV power plants.

These developments mostly affect conventional power plant fleets with their comparatively inflexible base-load power plants. However, these energy-related conditions should also be considered in terms of long-term strategic planning of hydropower expansion. For example, the expansion of PV increasingly causes a "competitive situation" with run-of-river power plants so that additional capacities from run-of-river power plants generally lead to a further increase of production surpluses during summer, which either need to be regulated downward or go into intermediate storages. In contrast, storage power plants are able to flexibly and efficiently balance the load changes arising more frequently and faster in the future and support the balancing of fluctuating renewable energies by means of demand-oriented operation.

Apart from the generation side, the grid itself will be particularly affected by expansion of renewable energy when regional or trans-regional generation surpluses lead to congestion and thus force conventional power plants (and in some cases also RE plants) to reduce their power generation. A number of additional effects in the distribution and transmission network can occur as a result of the fluctuations in power generation, e.g. in terms of voltage quality and network stability, or as a result of specific technical characteristics of the plants, for example, provision of reactive power.

2.2.3 Transformation of the electricity supply system

The potential impacts of increasing the proportion of electricity generated from renewable energy sources on the electricity supply have been discussed extensively, especially since conflicts in the system of existing generation and grid structures could delay the further development of renewable energies. Accordingly, alongside the expansion of renewable energy sources, the structures of the existing power supply system must be adapted to enable the feed-in of the increasing proportion of renewable energies. Figure 6 gives an overview of the possible system optimisations for the integration of renewable energies.

Aside from increasing the grid capacity by optimising existing grids and expanding national and international grids, the generation fleet must be adapted to the changing supply tasks. This may be achieved by optimising the operation of existing conventional power plants or by replacing these with more flexible generation units. Additionally, capacities for short- and medium-term storage of excess electricity from renewable energies are needed. Flexibility and storage capacity may also be provided on the generation side as well as by consumer-driven actions, for example by switching off or on manageable loads. Moreover, the renewables themselves can contribute to the system integration by better adapting their generation to the demand and participating in the provision of grid services. In this context, storage hydropower has a special position amongst renewable technologies. Storage hydropower plants combine electricity generation from renewable energies with dispatchable and highly flexible generation. Additionally, storage hydropower plants typically have a very short start up and shut down speed with high power gradients, i.e. they can e.g. quickly balance sudden changes of wind power and PV production.

Figure 6: System-related options for the integration of renewable energies

System integration of renewable energies

Generation
- Flexible conventional power plants
- System responsibility for renewable energies

Grid
- Network optimisation
- Expansion of existing networks
- New network concepts (supergrids)

Storage
- Central storage systems
- Decentralised storage systems
- Power-to-X (sector coupling)

Consumers
- Demand management
- “New” consumers (e.g. heat pumps, e-mobility)

Source: Neubarth, J. [20]

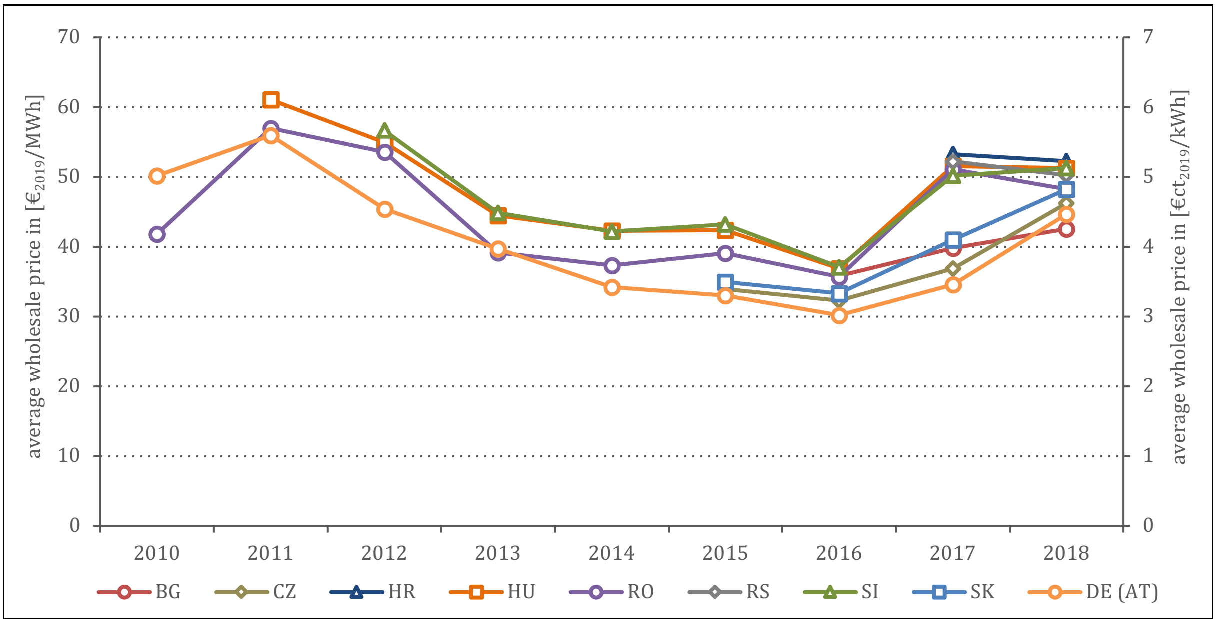
However, the existing potential for flexibility – power plants, storage, networks and consumers – can only be used efficiently if they are actually available to the market. Since existing market design often takes little account of the specific production characteristics of fluctuating power generation from wind and solar energy, further development of the legal and regulatory framework conditions is needed at both national and European level. In particular, the efficient management of grid congestion at the interconnection of national electricity markets as well as liquid intraday markets can contribute to the market integration of renewable energies.

Both the individual system-related features and the options for further development of the market design should never be considered in isolation from one another. Rather, they must be seen as part of an overall portfolio of essential measures for the integration of renewable energies into our power supply system. In this context, it has to be noted that challenges related to system integration of renewables should not be used as an argument to limit or even stop the expansion of wind power and solar PV on a national level. Until now, electricity supply systems in countries with already high penetration of wind and solar proved to be significantly more receptive for fluctuating electricity generation as initially expected (e.g. [23]. For example, in Spain wind power accounted for 43.2% of the total electricity production on 23 January 2019 [24] and in the UK for 32.2% on 28 November 2018 [25]. In Germany renewable energy sources supplied 100% of the demand on 1 January 2018 [26] for the first time and in Portugal RES covered more than 100% (45% from wind power) of the total electricity demand in March 2018 [27].

2.3 Development of wholesale electricity prices

Apart from (small) hydropower plants, which receive guaranteed feed-in tariffs for at least a part of their service life, hydropower plants typically have to take full responsibility for the market risk. Hence, wholesale electricity price development plays a significant role in the overall economic performance of the hydropower sector. Subsequently, the current developments of the electricity market are analysed and an outlook regarding the possible future market environment for hydropower plants is provided. Figure 7 illustrates average wholesale prices from spot markets for those ICPDR countries and years, where market data are commonly and easily accessible.[8] It has to be considered that for reasons of comparability, the prices for the single years are adjusted for inflation and depicted in the monetary value of 2019. Thus, they deviate from prices quoted on a nominal basis (meaning the monetary value of the according year). Additionally, it has to be considered that the previously common German-Austrian power price zone was split on October 1st, 2018. Hence, wholesale prices were the same in both countries until that day. For reasons of simplification, the average Austrian wholesale price 2018, which was about 1.2 €/MWh above the German level, is not displayed in Figure 7.

Figure 7: Annual average wholesale electricity price in exemplarily selected ICPDR countries



Source: ENTSO-E [31], EPEX SPOT [32], Agora Energiewende [33] and others

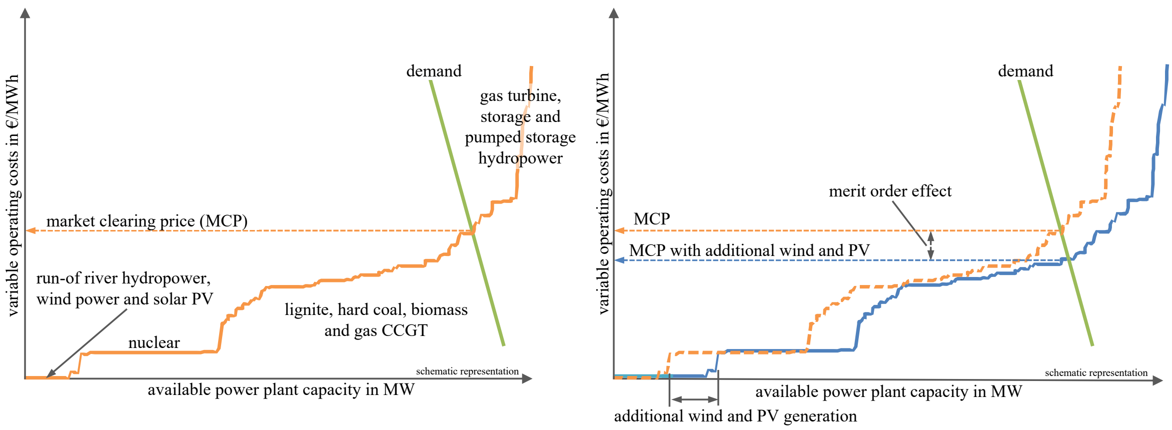
Until 2016/2017, wholesale prices in most European power markets constantly decreased for several reasons. On the one hand, prices for coal, natural gas and CO_2 emission certificates were bearish. On the other hand, the fast expansion of electricity generation from renewable energies compared to a stagnating or significantly decreasing growth in the demand for electricity resulted in a surplus of generation capacity in the market. Additionally, the high degree of feeding-in from PV plants around noon during the summer months especially in the German-Austrian market led to a continued "erosion" of the peaks in electricity prices at these high-load times and thus, to a lower average electricity price for the year (so-called merit order effect, see fact box on price formation at wholesale electricity markets).

8 Wholesale markets in Bosnia and Herzegovina, Moldova, Montenegro and Ukraine have either not or only partially been introduced or still lack the required transparency (cf. e.g. [28]).

Fact box: Price formation in electricity wholesale markets

Price formation in competitively organised markets is based on the approach that power plants are only operated when they are able to at least cover their variable costs via the electricity price. This means that power plant operators will generally offer their available capacities at these (short-term) marginal costs in the market. Thus, the supply curve in the market is determined by ordered available power plant capacities as per rising marginal costs, the so-called Merit Order. The Merit Order basically depicts the variable operating costs of this capacity, essentially costs for CO_2 certificate and fuel, which are plotted against the available power plant capacity. As variable costs for fuel-neutral renewable energies (wind, run-of-river hydropower and solar) are almost nil, these are principally listed at the top of the Merit Order. Storage hydropower power plants are an exception within renewable energies, because their operation is oriented towards the electricity prices in the market (opportunity costs) and therefore, they can be found further on the right side of the Merit Order than for example run-of-river power plants (Figure 8).

Figure 8: Schematically price formation in the electricity wholesale market

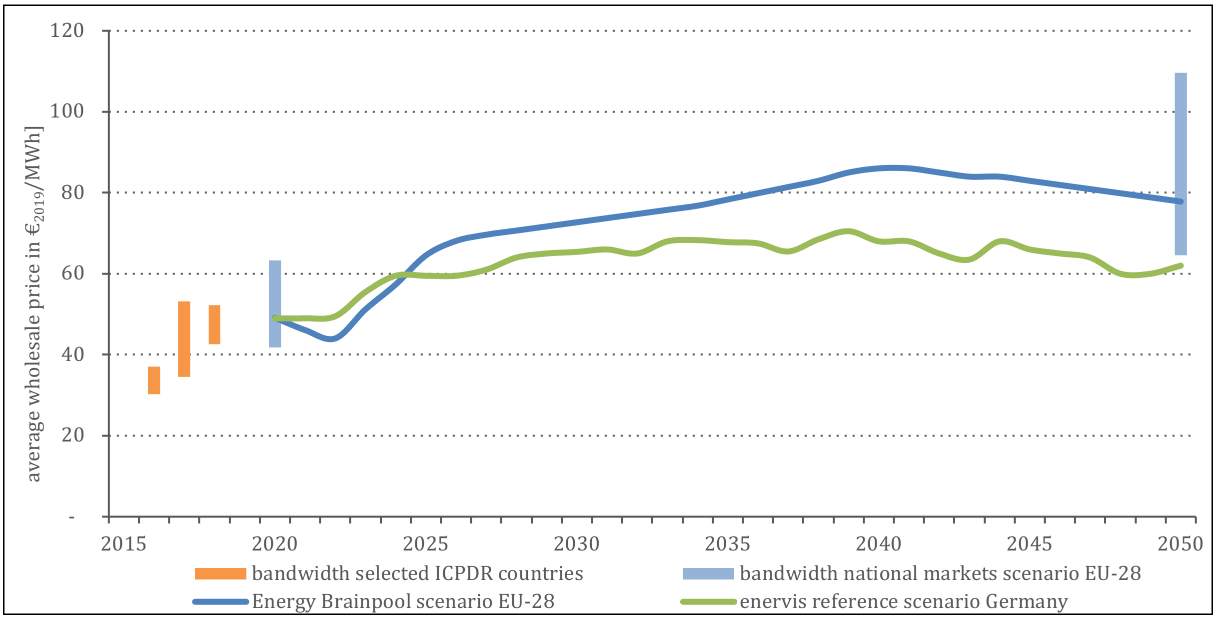


The available generation capacity in e.g. a certain hour is compared with the according demand curve which is affected in the short-term by numerous daily and seasonal factors (e.g. outside temperature, brightness, holidays). The point of intersection of both curves represents the ideal balance between supply and demand from an economical viewpoint and thus, also defines the electricity price established during an auction on the spot market. All suppliers receive and all consumers pay the same price (the so-called market clearing price, MCP), which is the result of the marginal costs of the most expensive power plant needed to just cover the demand.

Whereas in the past the price formation in wholesale markets was mainly defined by an hourly and seasonal fluctuating demand and partly by the seasonally fluctuating supply by run-of-river hydropower, pricing in today's spot market is more and more affected by the fluctuating electricity generation from wind power and PV (the so-called Merit Order effect). Among others, this leads to a reduction of peak prices during midday with high feed of PV power and to very low – partly even negative – electricity prices during off-peak periods on weekends or during the night and simultaneously high electricity generation by wind and/or PV power. Figure 8 displays this fundamental connection in contrast to the left and right diagram. With the same demand, a higher available generation by wind and PV units results in a lower electricity price.

However, after years of unfavourable low prices on the spot as well as forward electricity markets, wholesale prices have shown an upward trend since 2017 in parallel to the increasing prices for coal, natural gas and especially emission allowances for CO_2. Despite all uncertainties, it can be expected that the superordinate energy-related economic and political conditions lead to a further at least moderate increase of electricity prices for the period following 2020. On the one hand, most medium- and long-term forecasts assume an increase in the price for natural gas[9]. On the other hand, it is expected that after 2020 and due to regulatory measures, such as doubling the market stability reserve intake rate and reduced carbon certificate allocation for all sectors, prices for CO_2 certificates on European level will settle in an – from a climate perspective – acceptable range of 25-30 €/t_{CO2}. Such a price is assumed to be required for achieving the long-term climate protection targets (cf. e.g. [30]). Accordingly, most scenarios of long-term electricity price forecasts[10] expect a further increase of wholesale electricity prices in the upcoming decades. As an example, Figure 9 illustrates the average wholesale price development between 2020 and 2050 for the EU-28 countries taken from Energy Brainpool's current *EU Energy Outlook 2050* [34].

Figure 9: Bandwidth of average wholesale electricity price in selected ICPDR countries 2016-2018 and exemplary scenarios of wholesale electricity price development 2020-2050 in the EU-28 and Germany



Source: ENTSO-E [31], EPEX SPOT [32], Agora Energiewende [33], Energy Brainpool [34], enervis [35]

The scenario in Figure 9 is based on the "Sustainable Development" scenario of the *World Energy Outlook 2018* [29], which assumes a significant increase of prices for CO_2 certificates to about 130 €/t_{CO2} until 2050 as one boundary condition. Accordingly, the bandwidth of wholesale prices in single EU-28 markets range from 42 to 63 €$_{2019}$/MWh in 2020 and 65 to 110 €$_{2019}$/MWh in 2050. For comparison, in 2018 the bandwidth of wholesale prices in ICPDR countries was between 40 and 52 €$_{2019}$/MWh.

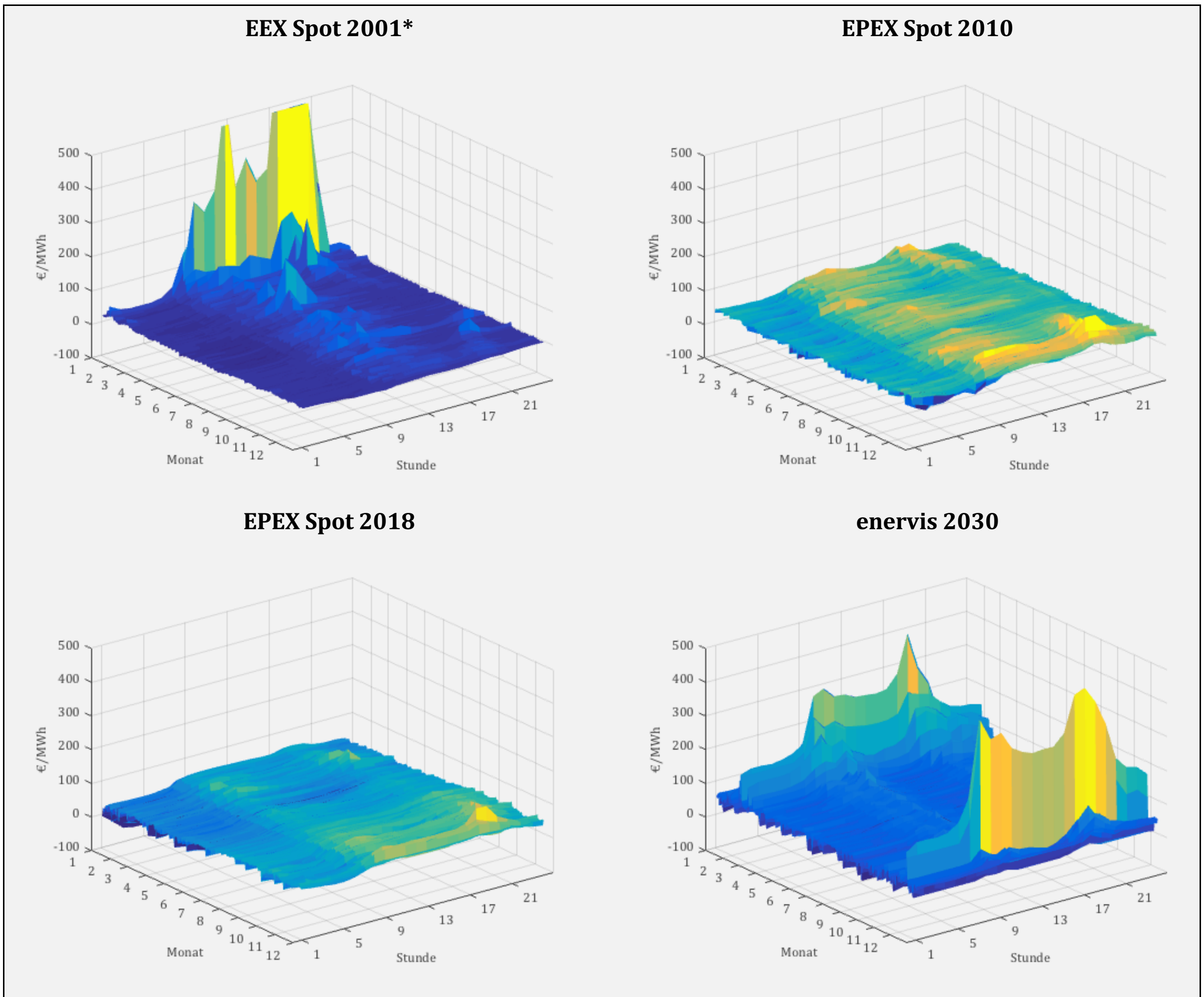
[9] Cf. for example World Energy Outlook 2018 [29]

[10] Long-term electricity price forecasts are typically made with fundamental electricity market models. Essential input variables in market models are the development of fuel and CO2 prices, demand for electricity, supra-regional network expansion and the expansion of renewable energies. However, the results of fundamental electricity market models are only able to forecast long-term developments of electricity prices with a range of uncertainty corresponding to these input values, and results may vary markedly.

However, even scenarios with moderate CO_2 price assumptions result in a robust development of wholesale prices until 2050. For example, the current reference scenario “Best Guess” from enervis energy advisor assumes a growth of CO_2 certificate prices to about 50 €/t_{CO2} until 2050, which would still result in average annual wholesale prices between 60 and 70 €/MWh for the period 2025 [35] for Germany.

Especially when evaluating storage hydropower in energy-economic terms, the development of the absolute level of the average annual wholesale electricity prices alone is not decisive; it is even more important how the characteristics of the hourly spot prices will develop, as their volatility may serve as an indicator for e.g. the need in flexibility in a supply system or market area, respectively. Whereas in the past the price formation in wholesale markets was mainly defined by an hourly and seasonal fluctuating demand and partly by the seasonally fluctuating supply by run-of-river hydropower, price formation in today’s spot markets is primarily affected by the fluctuating electricity generation from wind power and PV. Figure 10 illustrates this with the hourly day-ahead spot prices in the German market for the years 2001, 2010 and 2018 and exemplary with the hourly price structure of the enervis forecast in the scenario Best Guess Q4/2018 for the year 2030.

Figure 10: Hourly spot prices day-ahead in 2001, 2010, 2018 and 2030 market area Austria



Source: EPEX SPOT [32], enervis Best Guess Q4/2018 [36] (real values in EUR_{2019}; *highest hourly spot price 997.98 €/MWh but values only shown up to 500 €/MWh)

It is clearly discernible that the midday peak present in the year 2001 gradually became a less pronounced double peak during the morning and evening hours. This is a direct result of the increased feeding of PV units in the Austrian-German electricity market, which led to a noticeable reduction in spot prices in particular during midday and early afternoon. Aside from that, periods with very low or even negative spot prices occur more and more frequently when for example high feeds of wind power and low demand coincide. The further expansion of wind power and PV gives rise to the expectation that these impacts on market prices will be amplified significantly. For example, also the enervis scenario Best Guess Q4/2018 not only anticipates an increase of the absolute price level until 2030, but also – and in particular – a noticeable increase of the frequency and intensity of price peaks. Such price peaks reflect the lack of supply by wind power and PV units and with that a shortage in the generation capacity within the supply system. However, in parallel with such a development of spot prices also the energy-economic relevance of flexible generation and storage options grows: the importance of storage and pumped-storage power plants increases, as these are able to balance the fluctuating supply from wind and PV power and therefore, to contribute to a significantly more stable electricity supply.

2.4 Requirements related to water management and biodiversity

For decades, hydropower has been in the area of tension between the economic interests on the one hand and nature conservation on the other hand. Climate and energy policy objectives (e.g. Renewable Energy Directive) have put additional pressure on so far untouched river stretches to exploit remaining hydropower potentials. However, hydropower generation in Europe and hence, in the Danube countries may not only be seen in the light of climate and energy targets but also in the context of EU policies related to water management and biodiversity, especially the EU Water Framework Directive (WFD) but also the EU Birds and Habitat Directive [37][11]. Referring to the ICPDR *Assessment Report on Hydropower Generation in the Danube Basin* [6] the main elements of the WFD can be summarised as followed:

- Protection of all waters, surface and ground waters, transitional and coastal waters as well as covering all impacts.
- Achievement of a "good status" for all surface waters and groundwater, as a rule, by 2015.
- Prevention of further deterioration of water bodies, incl. protection of aquatic and terrestrial ecosystems.
- Definition of water quality defined in terms of biology, chemistry and morphology (surface waters) and of chemistry and quantity (groundwater).
- Ensuring coordination and cooperation in shared river basins across administrative and political borders.
- Establishment of monitoring programmes for surface and groundwater.
- Water management based on river basins.
- Integration of economic instruments: economic analysis and pricing reflecting cost recovery to promote prudent use of water.
- Mandatory public participation by citizens, municipalities, NGOs in developing river basin mgmt. plans.

Environmental targets as defined by the WFD for all water bodies are particularly important for hydropower, i.e. "good ecological status" and "good ecological potential", respectively, including requirements for ecological improvement and the deterioration principle. For surface waters, the "good ecological

[11] Other directives on a European level that may need to be taken into account are the Floods Directive, the Eel Directive as well as the Strategic Environmental Assessment (SEA) Directive and the Environmental Impact Assessment (EIA) Directive.

status” is defined in terms of quality of the biological community (e.g. phytobenthos and fish fauna), hydromorphological characteristics (e.g. hydrological regime, river continuity, morphological conditions) as well as chemical and physicochemical characteristics.

However, not all surface water bodies can be enhanced to a “good ecological status”, since they are heavily modified in terms of their physical structure. Hence, it would not be reasonable from a socio-economic perspective to remove physical modifications (e.g. dam of a hydropower plant but also navigation and flood protection measures). Therefore, it is possible to designate a water body as heavily modified if (a) the good ecological status cannot be achieved, (b) changes to the hydromorphological characteristics of a water body would have significant adverse effects on the use and (c) the objectives cannot, for reasons of technical feasibility or disproportionate costs, be reasonably achieved by other more environmentally friendly means. However, for those water bodies designated as heavily modified, the “good ecological potential” must be reached and measures need to be taken to improve the quality of the water body as much as possible (e.g. by building fish passes, setting ecological flows, mitigating negative impacts of hydropeaking). In this context, it has to be noted that the implementation of WFD requirements on existing hydropower plants can reduce the generation volume if less water is available for electricity production due to increased ecological flow and/or water flows for fish passes. Also, the operating characteristic of storage hydropower plants can be negatively affected if mitigation measures for hydropeaking require restriction of the operating flexibility. Therefore, the implementation of WFD requirements should not only be focused on the level of ecological improvements but also on potential negative impacts on existing hydropower generation. If for example ecological measures resulted in a disproportional high reduction of generation volume and/or flexibility of existing hydropower plants, the required “compensation measures” within the overall electricity system could even offset the ecological benefit. In a worst-case scenario, reduced hydropower generation volumes and flexibility would be compensated by fossil and nuclear power plants. However, even if “lost” volumes and flexibility was provided e.g. by wind and solar PV capacities plus battery storage, the additional required generation and storage facilities would entail ecological impacts that would need to be considered in an overall interdisciplinary assessment of the implementation of WFD requirements. In this context the Austrian SuREmMa study may be mentioned as an example for such an interdisciplinary assessment approach [38]. The study, which was conducted by scientists, storage hydropower plant operators and authorities, compares the ecological impacts of hydropeaking mitigation measures, or the ecological potential for improvement, with their impacts on the electricity system, their macroeconomic consequences as well as their impacts on business level.

Additionally, according to Article 4.7 WFD, exemptions from “achieving good ecological status” or “good ecological potential” and the “non-deterioration clause” (i.e. failure to prevent deterioration from high status to good status of a surface water body) can be applied for new modifications and new sustainable human development activities. Exemptions can relate to new projects (e.g. new hydropower plant) or to modifications of existing projects (e.g. additional intakes to existing reservoirs). The requirements of Article 4.7 for new hydropower include, amongst others, that there are no significantly better environmentally friendly options, that the benefits of the new infrastructure outweigh the benefits of achieving the WFD environmental objectives and that all practicable mitigation measures are taken to address the adverse impact of the status of the water body. For example, an overriding public interest or the security of energy supply facilitate the realization of projects despite proven ecological impacts.

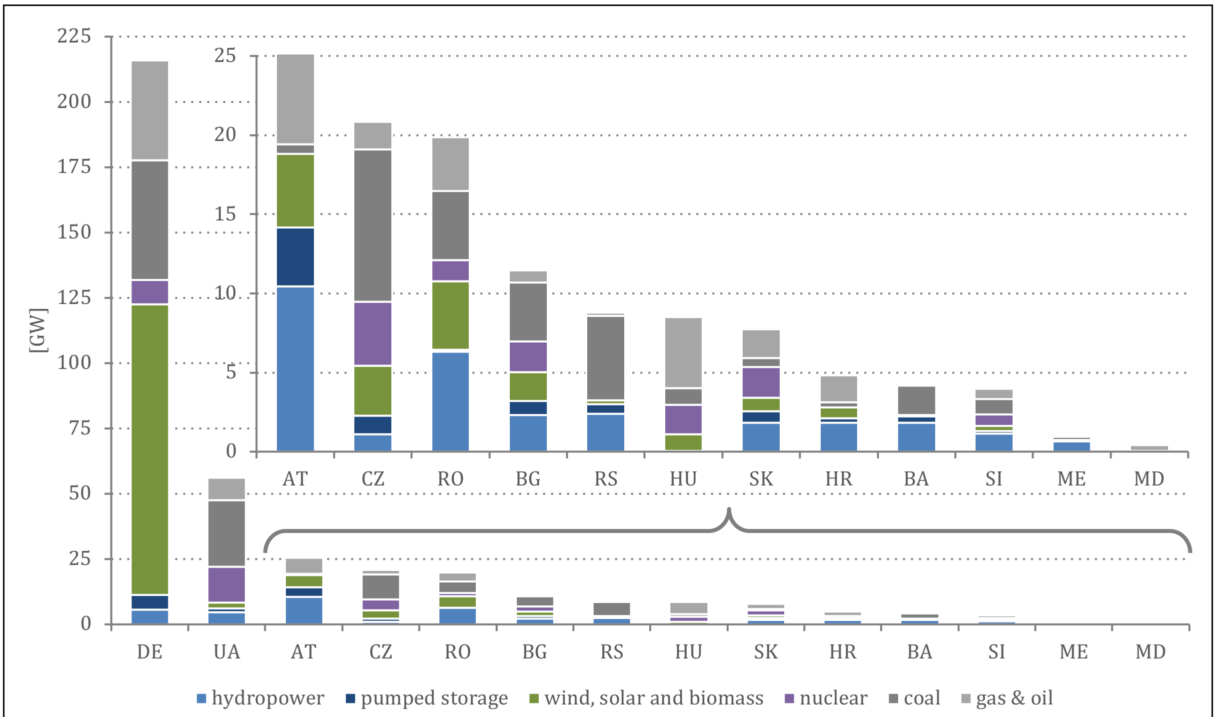
3. Electricity generation system in ICPDR countries

This chapter contains a brief summary of the electricity generation systems of the fourteen ICPDR countries with a particular focus on the role of hydropower. After a detailed overview of the main characteristics of all countries in section 3.1 "Danube region at a glance", section 3.2 "Country profiles" provides a more detailed picture of the country specific generation and demand structure in the years 2011-2018. In order to have a consistent data basis, all presented data are – if available – taken from various ENTSO-E[12] publications [39] and complemented with data from national sources if required. In this context, it has to be noted that ENTSO-E data can differ from other data sources. However, data inconsistency amongst different sources is a general issue and not only related to ICPDR countries. Please note that data are provided for the whole countries and not only the Danube river basin share of a country.

3.1 Danube region at a glance

The fourteen ICPDR countries had an installed generation capacity of about 389 GW at the end of 2018. For comparison, the installed generation capacity in the ENTSO-E system was 1,163 GW. Figure 11 gives the installed net generation capacity by technology groups for each country; a more detailed breakdown and presentation of the installed generation capacity as well as other key figures of the countries' power systems can be found in Annex 1.

Figure 11: Installed net generation capacity by technology groups and country 2018

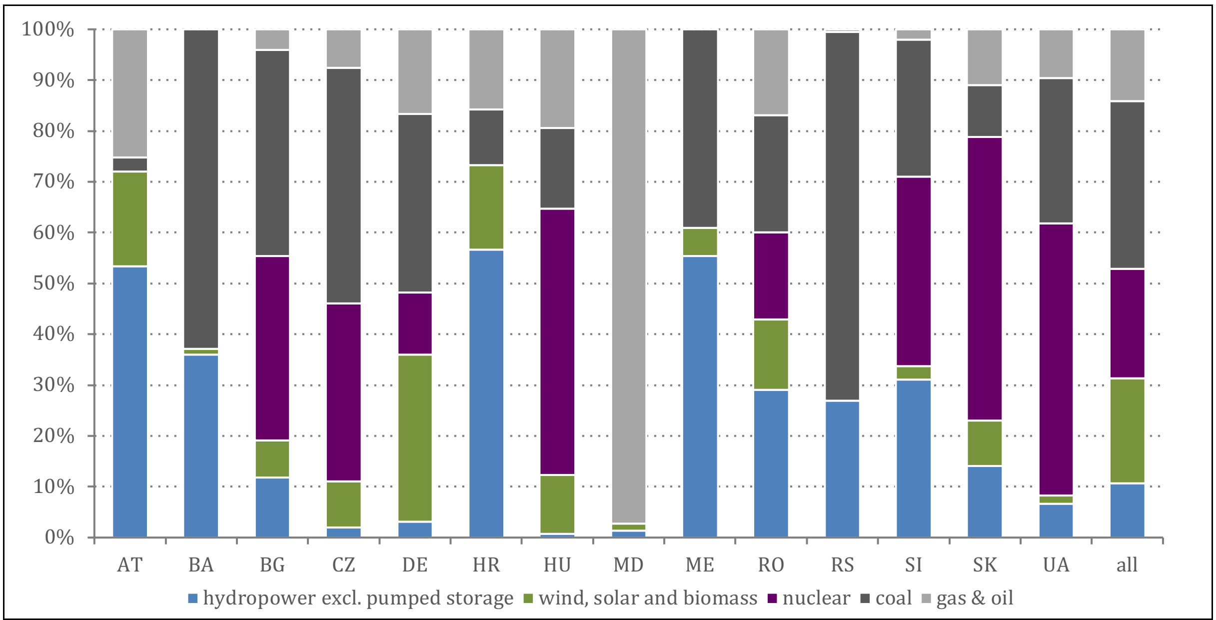


Source: ENTSO-E [39], complemented by country statistics

[12] European Network of Transmission System Operators for Electricity (https://www.entsoe.eu/)

Corresponding to the different sizes of the ICPDR countries, also generation capacities differ widely between 0.4 GW in Moldova and 216 GW in Germany. Hence, more than 55% of the total capacity of ICPDR countries is installed in Germany. This is not only because of Germany's geographical size but also because of the massive expansion of "new" renewable energy sources (i.e. wind power, solar PV and biomass) since the late 1990s, which already account for more than 50% of Germany's generation capacity. Accordingly, with a share of 34% wind power, solar PV and biomass, these renewables already play an important role in ICPDR countries with respect to installed capacity. On the other hand, hydropower (40.2 GW) and pumped storage (15.3 GW) account for 10% and 4%, respectively, of the total generation capacity in ICPDR countries.[13] Lignite and hard coal constitute 26%, natural gas and oil 17% and nuclear energy 9% of the total installed capacity of 389 GW. However, the generation mix can differ widely among individual countries both in terms of installed capacities – as already shown in Figure 11 – and electricity production as depicted in Figure 12.

Figure 12: Share of technology in total national electricity production 2018

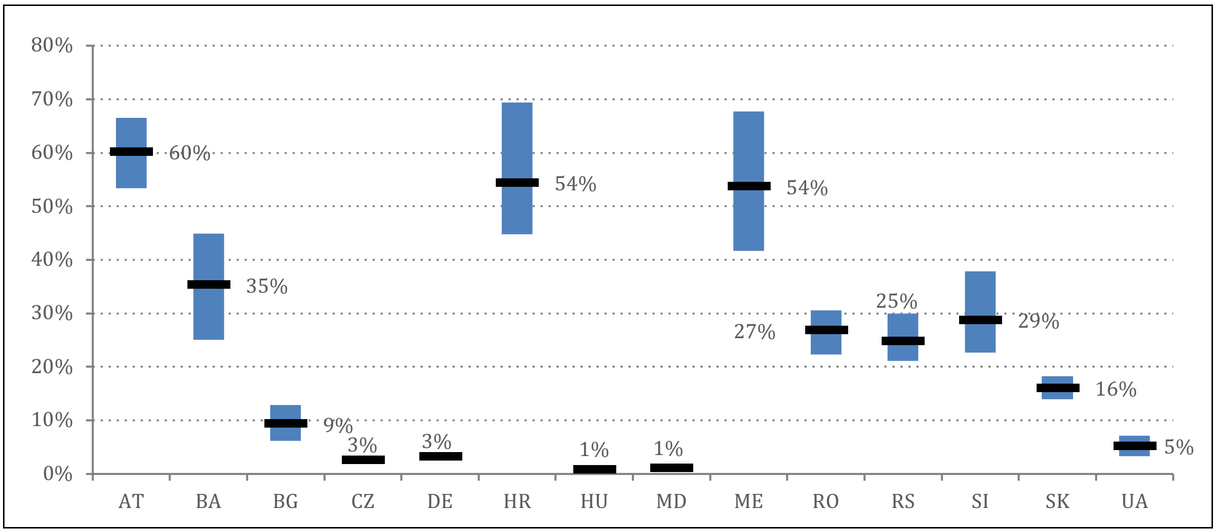


Source: ENTSO-E [39] complemented by country statistics

Fossil fuels amounted to 47% of the total electricity generation in ICPDR countries of about 1139 TWh in 2018. The share of nuclear energy was 21% closely followed by wind power, solar PV and biomass with a combined share of also 21%. Hence, the share of "new" renewable energy sources in total electricity generation was about twice as high as the 11% share of hydropower (excl. pumped storage). However, depending on the country specific conditions, the share of hydropower in the nations' electricity mix differs widely, for example between 57% in Croatia and 1% in Hungary in 2018. Additionally, due to unavoidable yearly fluctuations of the rivers' water supply, the share of hydropower can vary markedly with every year. This is shown in Figure 13 by means of the bandwidth and average share of hydropower (excl. pumped storage) in electricity production of ICPDR countries in the years 2011-2018. Especially Balkan countries have a relatively large annual variability of hydropower production. For example, Montenegro shows a share of hydropower between 42% and 68% and Croatia between 45% and 69%.

[13] The official national and international statistics do not consistently differentiate between storage and pumped storage power plants. Hence, published numbers of storage and pumped storage capacities can significantly differ from each other.

Figure 13: Range and average share of hydropower in total national electricity production 2011-2018



Source: ENTSO-E [39] complemented by country statistics

The total electricity demand in the fourteen ICPDR countries has been relatively stable since 2011 and amounted to about 1,106 TWh/a in 2018. Germany is by far the largest consumer with an electricity demand of about 546 TWh/a followed by Ukraine (158 TWh/a) and Austria (76 TWh/a). The lower boundary of the bandwidth of electricity consumption is marked by Moldova with an annual demand of about 4 TWh/a and Montenegro with 3 TWh/a in 2018. On average, the electricity balance of the whole Danube region has shown a surplus of about 50 TWh/a in the last years. Germany, the Czech Republic, Bulgaria and Romania exported a large proportion of electricity whereas for example Hungary, Austria, Croatia, Slovakia and Montenegro have been depending on electricity imports. However, since all ICPDR countries except most areas of Ukraine and Moldova are part of the synchronously operated ENTSO-E system Continental Europe and as interconnection capacities have been increased in the Danube region in the last years, national import dependency for smaller countries is, at least from the perspective of security of supply, not as critical as it may has been the case in previous years. Accordingly, effects of annual variations of hydropower production may have an impact on a country's electricity exchange balance but not necessarily on security of supply.

In contrast to the synchronously operated ENTSO-E system, the majority of the Moldovan and Ukrainian power system is still integrated in the former Soviet Union's UPS/IPS systems. An interconnection of the Moldovan and Ukrainian power systems has been in discussion for years; however, a synchronization with the ENTSO-E system requires the transmission system operators Ukrenergo and Moldelectrica [40], [41] to first implement a series of technical and organizational measures as defined by ENTSO-E.

3.2 Country profiles

For each ICPDR country a comprehensive one-page summary with key facts of the country's electricity system is presented as shown below.[14] In this context, a special focus is placed on hydropower as well as recent developments of electricity generation from other renewable energies sources.

[14] Country profiles of Bosnia and Herzegovina, Bulgaria, Montenegro and Serbia are based on country profiles as included in the study *"The role of hydropower in selected South-Eastern European countries"* [43], which was prepared by the author on behalf of EuroNatur Foundation ad RiverWatch in October 2018.

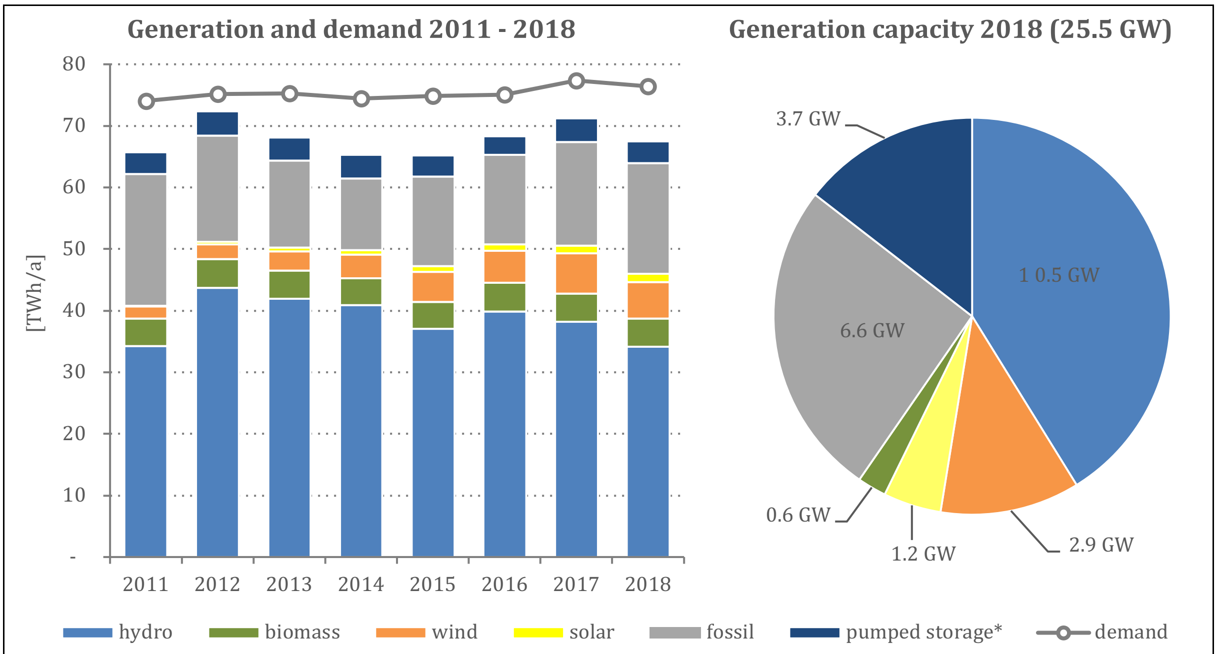
3.2.1 Austria

Thanks to Austria's favourable topography, power generation is traditionally dominated by hydropower. The total installed capacity was 25.5 GW at the end of 2018 with about 14.2 GW of hydropower (incl. pumped storage). In contrast, peak load was 12.1 GW in 2018. Storage and pumped storage power plants accounted for about 8.4 GW, 3.7 GW of which were storage power plants without pumping option and 4.7 GW storage power plants with a pumping capacity of around 3.7 GW. About 2.9 GW of wind power, 1.2 GW of solar PV and 0.6 GW of biomass capacity complete the dominant position of renewables in the Austrian generation system. In addition, about 6.6 GW of non-renewables thermal power plants (mainly gas fired CHP) are installed. Following a public vote in 1978, Austria decided to stop its nuclear programme. Hence, nuclear has never been part of Austria's generation mix.

The development of Austria's generation mix since 2010 has been characterised by a strong build-up of wind power, solar PV and biomass (+3.4 GW) as well as a considerable increase in pumped storage capacities (+0.9 GW). In contrast, renewable hydropower has shown a relatively slow growth rate with a net addition of some 0.3 GW. However, it is expected that additional hydropower capacities between 1.3 and 1.8 GW (6-8 TWh/a) will be required in order to meet the government's target to produce 100% of Austria's electricity demand from domestic renewable energies by 2030 [45].

The annual hydropower production in Austria shows comparatively small variations. For example, the range of the capacity factor (defined as annual generation divided by installed capacity and 8,760 hours) in the years 2011-2018 was between 28% (2018) and 37% (2012), which equals to full load hours of 2,400 h/a and 3,300 h/a, respectively. However, the annual output from hydropower plants still has an effect on the exchange balance with neighbouring countries. Since gross inland consumption has been growing on average by 1.8% p.a. in the last 15 years and utilization rates of thermal power stations have decreased in parallel, Austria has become a net importer of electricity mainly from Germany and the Czech Republic beginning with the early 2000s. In 2018, the net import-export deficit was about 8.9 TWh or 13% of the total electricity consumption of 76.5 TWh/a.

Figure 14: Key figures electricity generation and demand Austria



Source: ENTSO-E [39], E-Control [46]; (*capacity of storage hydropower plants with pumped storage function)

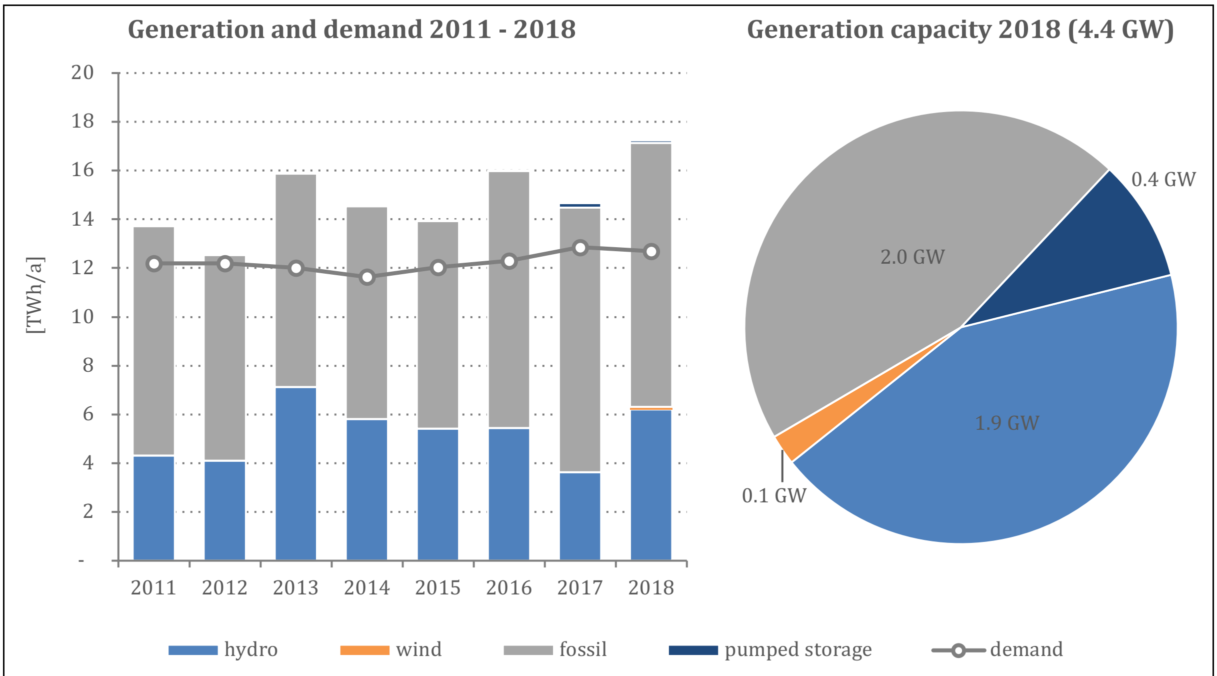
3.2.2 Bosnia and Herzegovina

Bosnia and Herzegovina has a total installed net generation capacity of 4.4 GW (2018) consisting of 1.9 GW lignite, 0.1 GW industrial power plants, 2.3 GW hydropower incl. pumped storage and 0.1 GW wind [47]. In 2018, the country's first wind farm with 22 turbines and an installed capacity of 50.6 MW was commissioned in Mesihovina [42] and the first utility-scale tender for a 65 MW PV plant in Ljubinje was announced [44]. Hydropower capacity has been increased by about 230 MW in last 7 years and in 2016, about 300 MW of lignite were newly commissioned – the latter increased the output from lignite power plants by 2 TWh to 10.5 TWh in 2016 and 10.8 TWh both in 2017 and 2018. Consequently, in 2016 the share of renewables in total electricity generation (excl. pumped storage) dropped on a year-to-year basis from 40% to 34%. Due to an exceptional drought, the share of renewables in total generation further plunged to 25% in 2017 but increased again to 37% in 2018.

Despite the strong dependency on hydropower, Bosnia and Herzegovina is the only power exporter in the Western Balkans. However, hydro conditions have been affecting the actual import-export balance in recent years. Depending on the water supply, hydropower production can vary significantly – in the past 8 years between 3.6 TWh in 2017 (23% capacity factor or 2,000 full load hours) and 7.1 TWh in 2013 (48% capacity factor or 4,200 full load hours). Bosnia and Herzegovina also has substantial hydro pumped storage capacities but according to ENTSO-E and SERC statistics, the pumped storage plants have only been operated for a few hours in the past years.

Power consumption has not changed significantly in last few years and was at 12.7 TWh with a maximum system load of some 2,0 GW in 2018. Generally, the annual demand has mostly been driven by economic and weather events. In 2012 and 2013, power consumption growth was negative due to warm years and weak economic growth. Even if the consumption is expected to increase in the future, the potentially possible closure of Aluminij d.d. Mostar could cause a significant drop in the national power consumption.

Figure 15: Key figures electricity generation and demand Bosnia and Herzegovina



Source: ENTSO-E [39], SERC [47]

3.2.3 Bulgaria

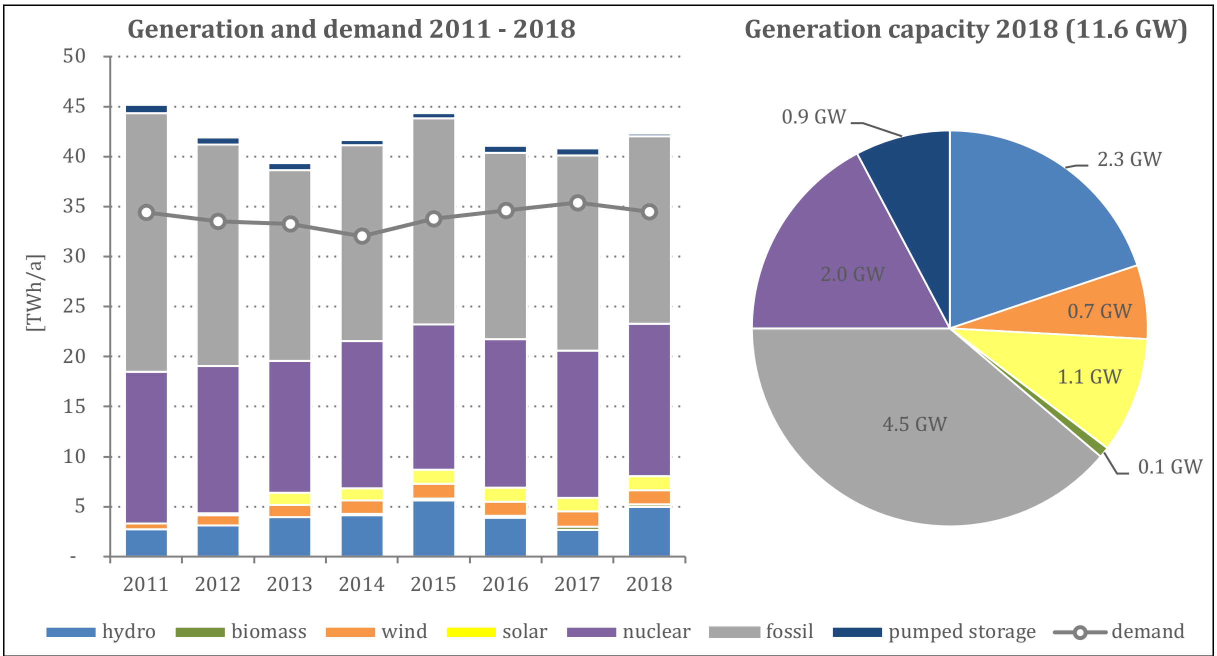
Bulgaria has a total installed generation capacity of 11.6 GW (2018), including 4.5 GW lignite and hard coal, 2.0 GW nuclear, 0.6 GW natural gas, 3.2 GW hydropower incl. pumped storage and 1.8 GW other renewables. Hence, the generation mix primarily depends on domestic coal and nuclear. The country also has substantial hydro (storage) capacities and unlike most other SEE countries, it has already installed considerable wind and solar capacity due to a successful five-year implementation of feed-in tariffs. Nevertheless, the share of renewables in total electricity generation (excl. pumped storage) is still comparatively low and reached about 19% in 2018.

Hydropower has shown a relatively slow growth rate in the past 7 years with a net addition of only about 50 MW. Capacity growth in the upcoming years is expected to be primarily sourced from "new" renewables and gas to substitute old and inefficient fossil fired thermal plants. Even if Bulgaria has pursued plans to build new nuclear plants for years, it is unlikely that these projects will finally be accomplished.

Depending on the available water supply, hydropower production can vary significantly. For example, the range of the capacity factor in the years 2011-2018 was between 13% (2017) and 28% (2015), which equals to full load hours of 1,200 h/a and 2,400 h/a, respectively. However, since the contribution of hydropower to the total annual electricity generation is relatively small – on average 15% in the years 2011-2018 – and the generation portfolio is well diversified, security of supply is generally not affected from the availability of hydropower capacities.

In 2018, Bulgaria's annual electricity consumption was about 35.4 TWh and peak load demand was 6.5 GW. Hence, Bulgaria is well supplied with power compared to the demand and is a strong regional power exporter.

Figure 16: Key figures electricity generation and demand Bulgaria



Source: ENTSO-E [39]

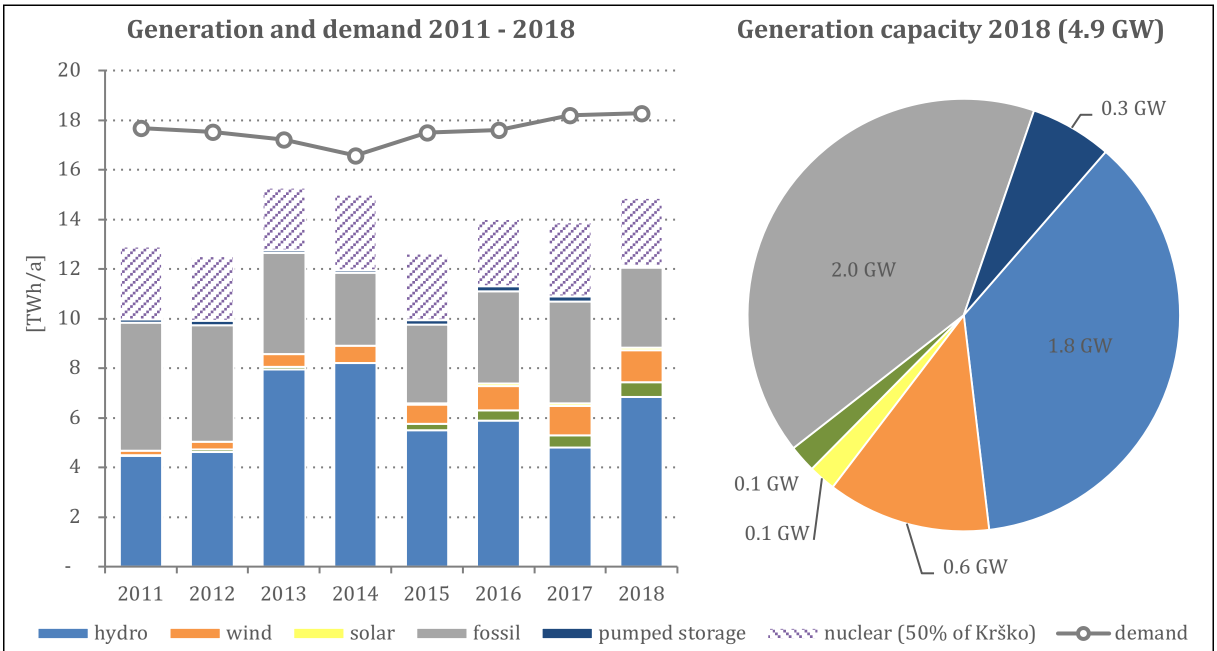
3.2.4 Croatia

Croatia had a total installed capacity of 4.9 GW at the end of 2018 including 0.7 GW natural gas, 0.3 GW hard coal, 1.0 GW oil and mixed fuels, 2.1 GW hydropower incl. pumped storage and 0.8 GW other renewables. Thus, Croatia has already developed a substantial portfolio of "new" renewable energies with an installed capacity of 0.6 GW wind power, 0.1 GW solar PV and 0.1 GW biomass. Additionally, the country's first geothermal power plant (17.5 MW) started its operation at the end of 2018 [55]. In contrast to the relatively strong growth rates of "new" renewables, hydropower has practically seen no capacity additions in the past 8 years. Additionally, the state-owned utility Hrvatska elektroprivreda (HEP) owns 50% (348 MW) of the nuclear power plant Krško. The power plant is located in Slovenia close to the Croatian border but delivers the generated electricity in equal shares to both countries. Hence, Croatia has a virtual share of nuclear energy in its generation mix, which is, however, typically not considered in statistics of the Croatian electricity market.

With an average generation of 6.0 TWh/a in the years 2011-2018, hydropower has been the most important domestic source of electricity production in Croatia. However, as in other Western Balkan countries, the annual hydropower production and therefore, the contribution of hydropower to the national generation mix can vary substantially depending on the available water supply levels. The capacity factor of the years 2011-2018 shows a range between 28% (2011) and 51% (2014), which equals to annual full load hours of 2,400 h/a and 4,500 h/a, respectively. Accordingly, the annual availability of hydropower has had a significant impact on the Croatian exchange balance. In the years 2011-2018, Croatia imported between 26% and 44% of its electricity consumption from neighbouring countries – or between 10% and 29% when considering the Croatian share of the Krško nuclear power plant.

In 2018, the peak demand in the Croatian electricity system was 3.2 GW and the total electricity consumption amounted to 18.3 TWh/a. The share of renewable energies in total consumption was about 48%.

Figure 17: Key figures electricity generation and demand Croatia



Source: ENTSO-E [39], IHA [56], HERA [57]

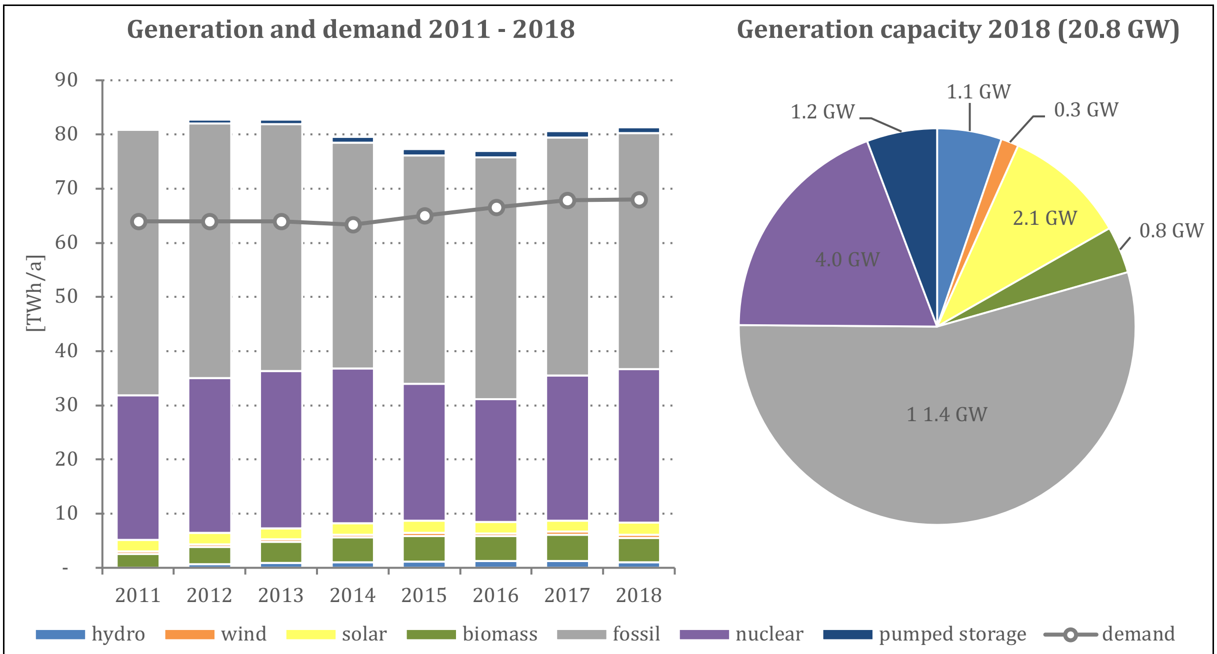
3.2.5 Czech Republic

According to ENTSO-E data, the Czech Republic had a total installed capacity of 20.8 GW at the end of 2018 including 8.5 GW lignite, 4.0 GW nuclear, 1.2 GW hard coal, 1.2 GW natural gas, 2.3 GW hydropower incl. pumped storage and 3.2 GW other renewable energies. With a share of about 53% in total electricity generation, thermal power stations (mainly from domestic lignite) are the largest source of electricity production followed by 35% of nuclear energy. Despite a remarkable extension of capacities from renewable energies in the last few years, the share of renewables in total electricity generation is still comparatively low and reached about 11% in 2018. The considerable high solar PV capacity is the result of very favourable subsidies that were introduced by the Czech government in 2009. However, the triggered solar boom was subject of controversial discussions since profit margins of investments were rather high and therefore, electricity customers excessively burdened. Hence, the government cut incentives and the boom ended in 2011 as quickly as it began two years before that.

In contrast to the strong growth rates of "new" renewables, hydropower capacity additions amount to only around 50 MW in the past 7 years. Hence, hydropower (excl. pumped storage) still provides less than 3% of the Czech Republic's electricity generation. Consequently, annual variations in water supply have only a very limited impact on the balance of the Czech electricity system. For example, the capacity factor was between 17% (2018) and 31% (2011) and of the full load hours of hydropower between 1,500 h/a and 2,700 h/a, respectively. Even if 50% of hydropower potentials are yet not exploited [48], the options for further hydropower development in the Czech Republic are limited, i.e. other renewable energy sources would have to shoulder a potential further expansion of renewable energies in the Czech electricity sector. However, the government has placed a priority on nuclear energy rather than on renewables so far, since the target is a nuclear share in the Czech generation mix of 50% by 2040 [49]

Peak demand in the Czech electricity system was 11.1 GW and the annual electricity consumption was about 68.0 TWh in 2018. Hence, with a total net electricity generation of 81.9 TWh, the Czech Republic is well supplied and has been a strong exporter of electricity since years.

Figure 18: Key figures electricity generation and demand Czech Republic



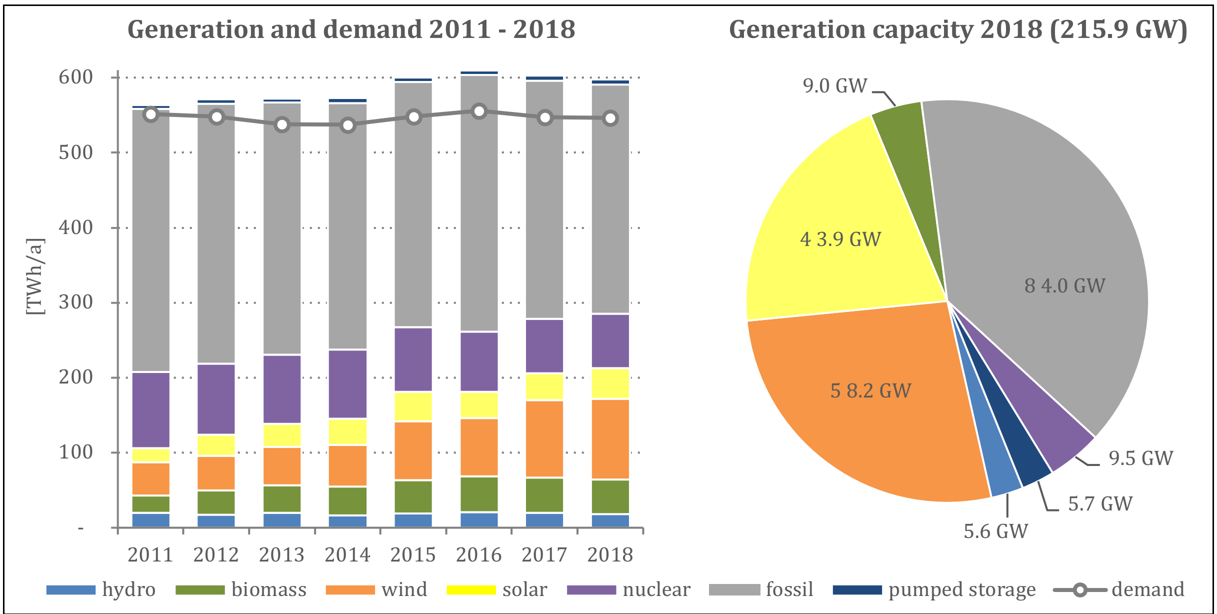
Source: ENTSO-E [39]; ERÚ [50], [51]

3.2.6 Germany

The German electricity system has been facing a tremendous transformation since the beginning of the early 2000s. As a consequence of the German "Energiewende", the total installed generation capacity doubled in the last 20 years although the nuclear phase out, which will be accomplished by 2022, has already halved nuclear capacities compared to 2011. Hence, in 2018, about 216 GW of generation capacity was installed including 21.1 GW lignite, 31.6 GW natural gas, 24.7 GW hard coal, 9.5 GW nuclear, 5.7 GW pumped storage and 117 GW renewable energies. Hydropower was the only renewable energy source in the German generation mix for decades. With 5.6 GW installed generation capacity, hydropower has already been overtaken by wind power (58.2 GW), solar PV (43,9 GW) and even biomass (7.6 GW incl. landfill and sewage gas). The strong growth rate of renewable energies has boosted the share of renewables in total electricity generation from 7% in 2000 to 36% in 2018. However, at about 3%, the contribution of hydropower to total net generation (598 TWh/a in 2018) has been comparatively low. Since 80-90% of Germany's hydropower potentials are already exploited [52], it can also be expected that hydropower will provide only a very limited contribution to the further expansion of renewable energies. for achieving the government's target of 65% for renewable electricity by 2030. Increasing environmental and economic requirements have already restricted hydropower expansion in Germany and therefore, no considerable capacity additions have been made since 2011.

German electricity consumption has been relatively stable in the last few years – peak demand was 79.1 GW and electricity consumption about 546 GWh/a in 2018. However, annual generation increased by about 6% between 2011 and 2018 and hence, Germany has become a strong exporter with a net export of 51 TWh/a in 2018. As a consequence, carbon emissions from the electricity sector have not decreased although electricity generation from renewable energies has significantly increased. As a result of the discussion about a phase out of coal-fired power plants, in 2019 the so-called coal commission agreed on such a phase-out until 2038 at the latest.

Figure 19: Key figures electricity generation and demand Germany



Source: ENTSO-E [39], BDEW [53]

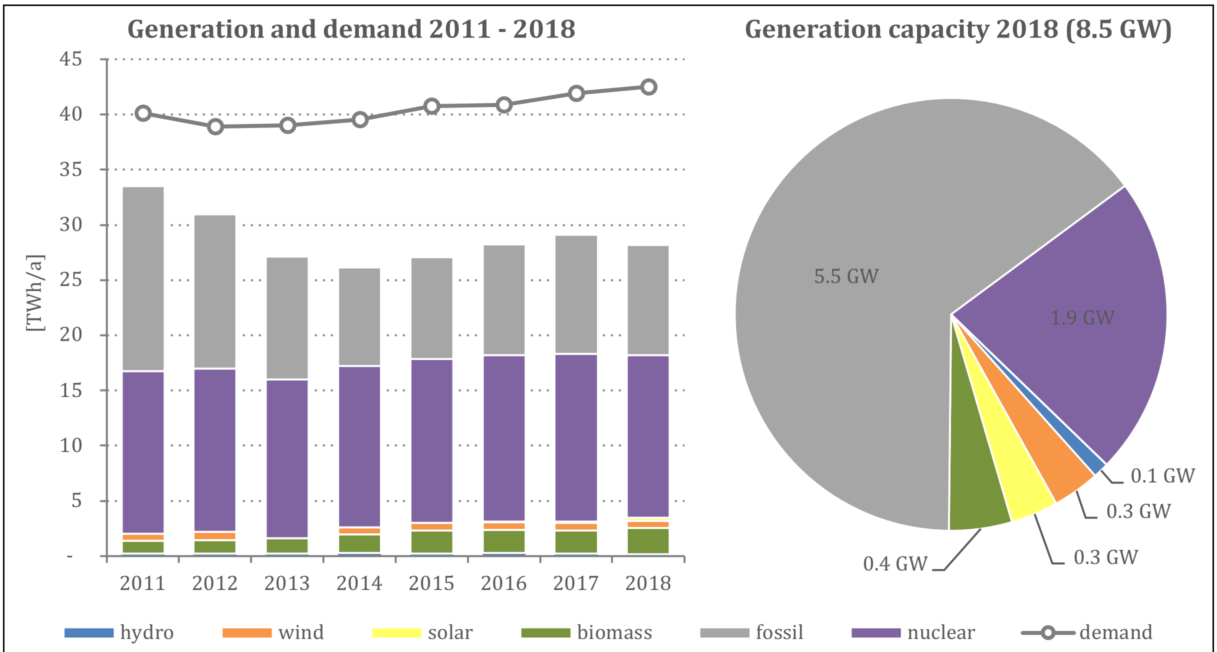
3.2.7 Hungary

Hungary has a total installed generation capacity of 8.5 GW (2018), consisting of 4.0 GW natural gas, 1.9 GW nuclear, 1.0 GW lignite, 0.4 GW oil and 1.1 GW renewable energies. Hydropower has been playing a negligible role in the Hungarian generation mix – about 57 MW of renewable hydropower capacities but no pumped storage power plants are installed – and due to the flat topography, there are hardly any opportunities for additional hydropower plants in Hungary. Accordingly, electricity generation capacities of biomass (0.4 GW) as well as wind power and solar PV (0,3 GW each) have already surpassed hydropower capacities.

In 2018, Hungary's net electricity generation was 28.2 TWh/a with a share of renewable energies of 12%. However, electricity production is still dominated by the country's only nuclear power plant Paks, which accounted for more than 50% of the total domestic production in 2018. In contrast, fossil capacity and generation volumes decreased constantly until 2014 due to the decommissioning of old and inefficient coal-fired power plants. In the past four years, this trend has been reversed, since gas-fired power plants have significantly increased the electricity production. Nevertheless, the government's ambition to expand domestic generation capacities is primarily focused on nuclear energy but secondly also on renewable energies.

According to ENTSO-E numbers, power consumption has slightly increased in the last few years and was at 42.5 TWh/a with a peak load of some 6.6 GW in 2018. Since domestic generation has been considerably lacking behind demand, Hungary has been heavily depending on electricity imports for years. For example, in 2018 the import-export balance was 14.3 TWh/a or 34% of total consumption. The imported electricity mainly came from Slovakia, Austria and Ukraine.

Figure 20: Key figures electricity generation and demand Hungary[15]



Source: ENTSO-E [39]

[15] Note that ENTSO numbers are net electricity generation and consumption, i.e. w/o internal consumption of power plants. In contrast, the Hungarian energy and public utility regulatory authority MEKH has published gross electricity generation and consumption in its yearly reports *Data of the Hungarian Electricity System* (e.g. [54]). Hence, net data from ENTSO-E reports as included in this study differ from gross data in MEKH reports.

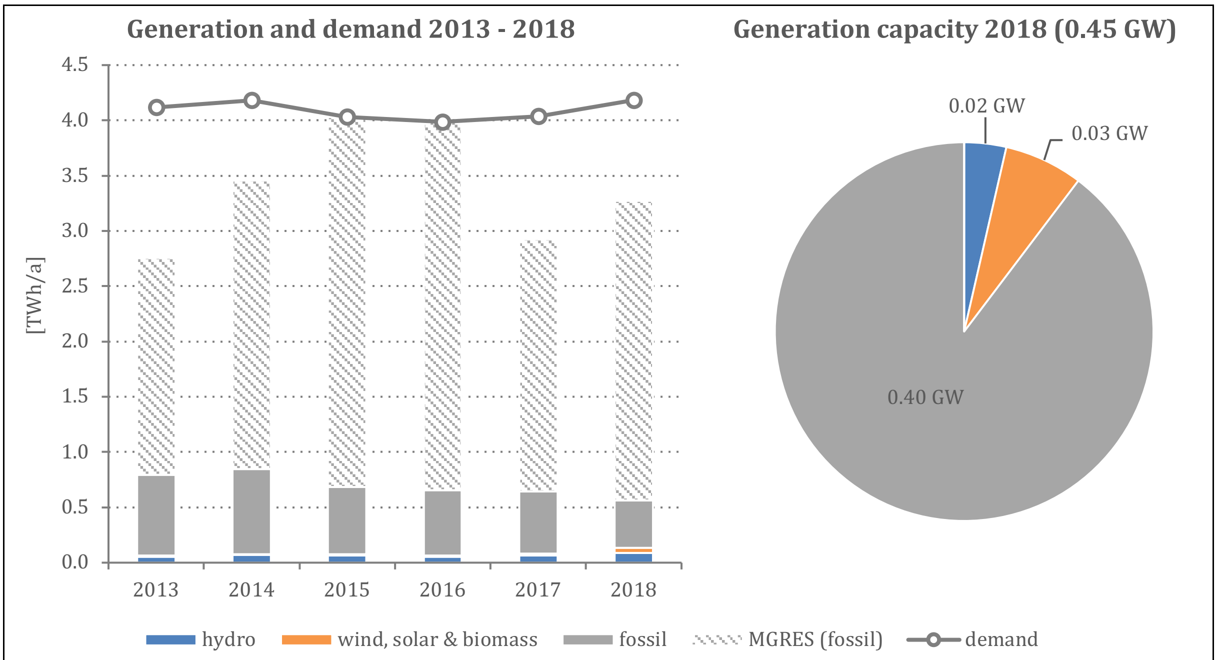
3.2.8 Republic of Moldova

Moldova has an installed generation capacity of about 0.45 GW comprised of 0.40 GW gas and 0,05 GW renewables. Currently, there is only one hydropower station with a capacity of 16 MW (HPP Costesti) in operation and pumped storage has yet not been part of the Moldovan generation portfolio. Despite very favourable wind power and solar PV potentials, also the country's "new" renewable development has been limited so far with installed capacities of 24 MW for wind power and 3 MW for solar PV and biomass, respectively. Hence, renewable energies covered 3% of the national electricity demand in 2018. It is expected that especially wind power will have an increasingly important role in the Moldovan electricity system in the future, while hydropower expansion will still be limited.

In 2018, total net electricity consumption was 4.2 TWh/a with a peak load of some 1.0 GW. In contrast, Moldovan net electricity production amounted to 0.6 TWh/a, i.e. domestic supply sources merely covered 15% of consumption. However, an additional 2.7 TWh/a were supplied from the gas-fired Kuchurgan power station (Moldavskaya GRES, MGRES), which is located on the right bank of the River Dniestr. Accordingly, Moldova has been heavily dependent on electricity supply from MGRES and electricity imports from Ukraine for balancing the Moldovan power system.

The Moldovan and Ukrainian power systems are historically integrated in and operated synchronously with the former Soviet Union's UPS/IPS systems – only three isolated 110 kV transmission lines are connected with the Romanian electricity system. In the long-term, the Moldovan and Ukrainian electricity systems might be synchronised with the ENTSO-E system. However, in order to quickly improve the supply situation in Moldova, a back-to-back HVDC (High Voltage Direct Current) connection between the electricity systems of Romania and Moldova in Vulcanesti is planned.

Figure 21: Key figures electricity generation and demand Moldova



Source: Moldelectrica [58], ANRE [59], The World Bank [60]

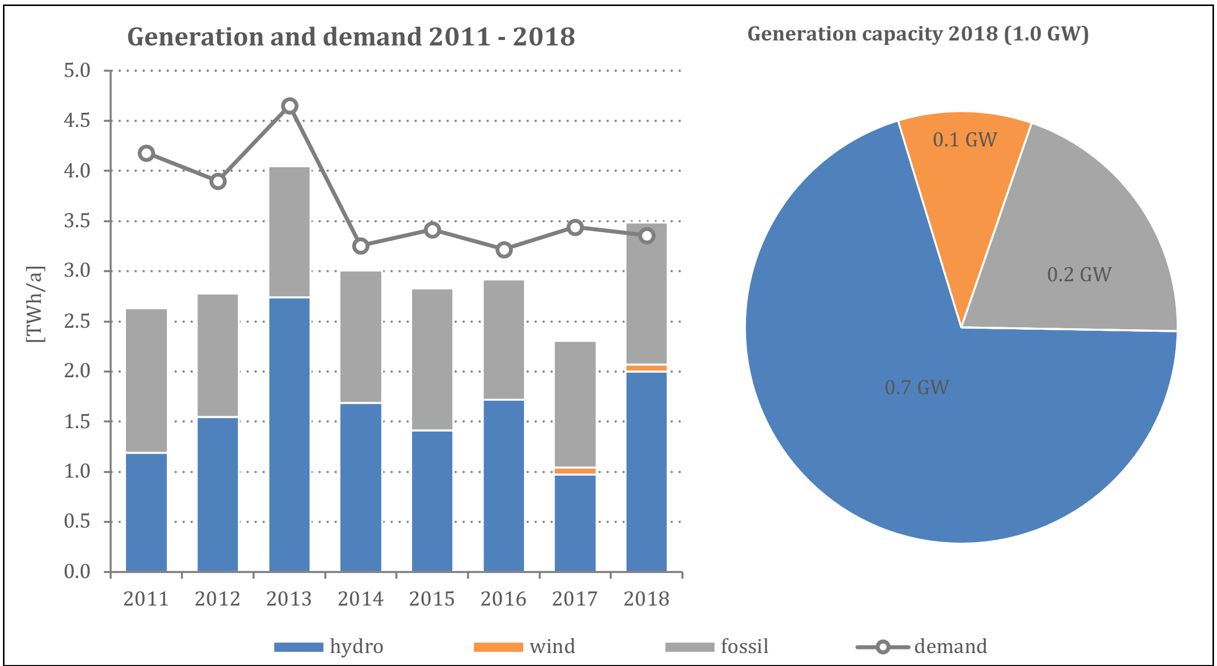
3.2.9 Montenegro

Montenegro has a total installed generation capacity of 1.0 GW (2017) comprised of 0.2 GW lignite, 0.7 GW hydropower and 0.1 GW wind. In the last few years no major fossil and hydropower capacity additions have been developed. However, in 2017, the country's first wind farm with 26 turbines and an installed capacity of 72 MW was commissioned in Krnovo and in 2018, a 1 GW undersea cable between Montenegro and Italy should be completed which will probably affect the utilization of Montenegro's thermal power plants.

Based on ENTSO-E statistics, the total power consumption was at 3.4 TWh with a peak load of about 0.6 GW in 2018. Similar to other Western Balkan countries, the collapse of the energy-intensive industry as well as the reduction of non-technical losses from power thefts and non-collections in the distribution grid have considerably decreased electricity consumption in the last few years. However, it can be expected that this trend will probably be turned into a growing demand in the future. Parallel to the decreasing demand, the share of renewables in total electricity generation has increased during the last years and was at 61% in 2018. However, in 2017, the renewables share was only 43% due to the extraordinary low precipitation in the Balkan region.

Despite the reduction of the national consumption, Montenegro has still been depending on electricity imports in most of the recent years. On average, about 17% of the domestic electricity consumption was imported in the years 2011-2018. Only in 2018 Montenegro was a net exporter of electricity. Generally, in the years 2011-2018, hydropower production had a capacity factor between 17% (2017) and 47% (2013), which corresponds to full load hours of 1,500 and 4,200 h/a, respectively.

Figure 22: Key figures electricity generation and demand Montenegro



Source: ENTSO-E [39]

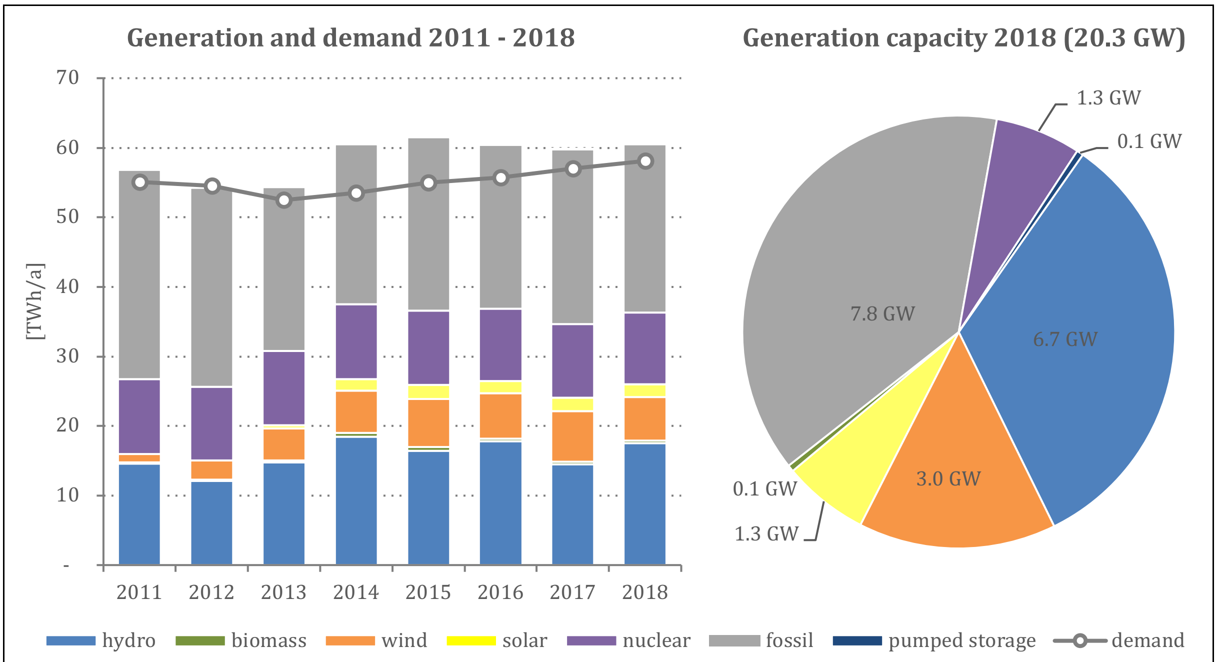
3.2.10 Romania

Romania has a total generation capacity of 20.3 GW (2018), including 3.3 GW lignite and 1.0 GW hard coal, 1.8 GW natural gas, 1.3 GW nuclear, 1.6 GW mixed fuels, 6.8 GW hydropower incl. pumped storage and 4.4 GW other renewables. Romania's generation mix is well diversified with a share of 40% of renewable energies in total electricity generation in 2018. Besides hydropower, Romania has already installed considerable capacities of "new" renewable energies, namely 3.0 GW wind power, 1.3 GW solar PV and 0.1 GW biomass.

In contrast to most other ICPDR countries, Romania still has notable unexploited hydropower potentials. However, compared to wind power and solar PV, hydropower has shown a much slower growth rate in the last 7 years with a net capacity addition of about 300 MW. With an average share of 27% in total generation, hydropower is still the most important energy source in the Romanian electricity system, although hydropower production has varied significantly depending on the available water supply. In the years 2011-2018, the range of the capacity factor was between 22% (2012) and 33% (2014), which equals to full load hours of 2,000 h/a and 2,900 h/a, respectively. Even if thermal fossil capacities have slightly decreased in recent years, Romania's generation portfolio has sufficient capacity margins. In 2018, Romania's annual electricity consumption was about 58.0 TWh and peak load demand was 8.9 GW, i.e. security of supply is generally not affected by the availability of hydropower capacities and actually, Romania has even become a net electricity exporter in the last few years.

According to Romania's *Energy Strategy to 2030 with a 2050 Perspective* [66], the government wants to further strengthen its position as an electricity exporter; however, besides relatively moderate renewable ambitions, the strategy remains committed to the expansion of nuclear capacities with the construction of two additional reactor blocks in Romania's Cernavodă nuclear power plant.

Figure 23: Key figures electricity generation and demand Romania



Source: ENTSO-E [39], IHA [56]; Cîrstea et al. [61], IRENA [62]

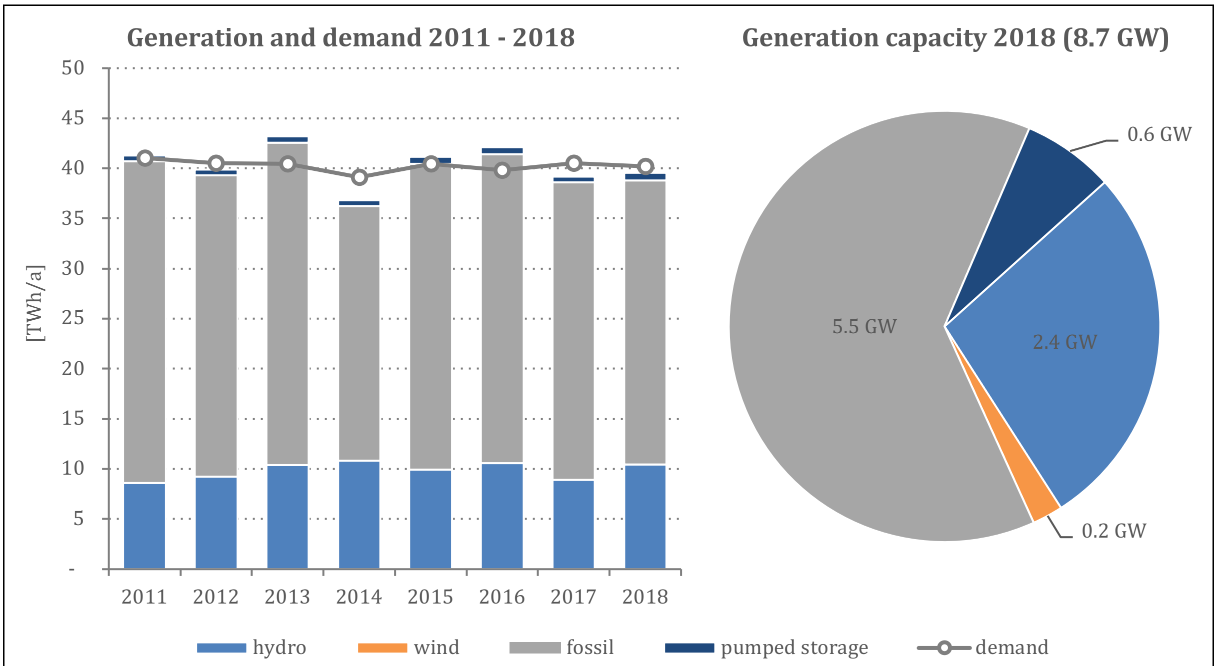
3.2.11 Republic of Serbia

Serbia has a total installed generation capacity of 8.7 GW (2018), including 5.3 GW lignite, 0.2 GW natural gas and 3.0 GW hydropower incl. pumped storage. Until 2018, no notable wind, solar and biomass capacities were installed. Hence, the share of renewables in total electricity generation was solely comprised of hydropower and reached about 23% in 2018. However, in 2018, the construction of a number of wind farms with a total capacity of 266 MW has been announced and started (Alibunar with 42 MW, Čibuk 1 with 158 MW and Kostolac with 66 MW) [63], [64]. Thus, 240 MW of wind power were already put into operation in 2018. Additionally, about 100 MW of wind power capacity are in an advanced development phase and could boost Serbia's renewable portfolio in the upcoming years [65].

Hydropower has shown a relatively slow growth rate in the past 7 years with a net addition of around 130 MW. Despite growing concerns about environmental aspects and climate change, the capacity growth in the upcoming years is expected to be sourced from domestic lignite. However, old and inefficient lignite power plants will be decommissioned in parallel and also the construction of "new" renewables is planned for the next years. Since run-of river plants at large rivers with comparatively smaller annual fluctuations of the water supply (e.g. Danube) dominate Serbia's hydropower production, the contribution of hydropower to the national generation mix shows a significant lower annual variation compared to other SEE countries. In the years 2011 to 2018, the range of the capacity factor was between 42% (2017) and 52% (2014), which equals to full load hours of 3,700 h/a and 4,600 h/a, respectively.

In 2018, Serbia's annual electricity consumption was about 40.2 TWh and peak load was 6.9 GW. Generally, Serbia has had a relatively balanced power exchange with neighbours in the past. Only in 2014, when heavy floods negatively impacted lignite generation, and in 2017, when hydropower generation was very low, Serbia had to import a considerable share of its electricity consumption. However, these years clearly showed the vulnerability of the Serbian electricity system, which depends on just two energy sources up to now.

Figure 24: Key figures electricity generation and demand Serbia



Source: ENTSO-E [39]

3.2.12 Slovenia

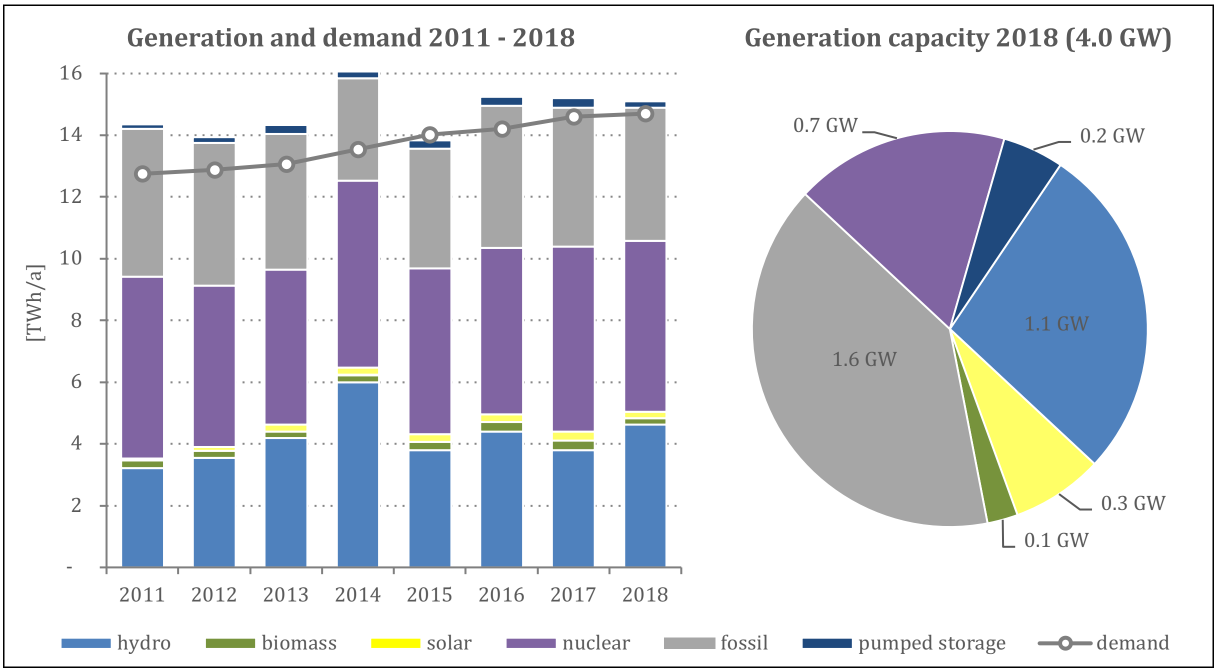
Slovenia had a total installed capacity of 4.0 GW at the end of 2018, including 1.0 GW lignite, 0.7 GW nuclear, 0.6 GW natural gas and other fuels, 1.3 GW hydropower incl. pumped storage and 0.4 GW other renewable energies. With a share of about 40% in total electricity generation, the nuclear power station in Krško was the largest source of electricity production followed by 30% of fossil energy. With an average share of 28%, hydropower plays an important role in the Slovenian generation mix. In contrast, the share of biomass and solar PV is still relatively small and together, they amounted to 3%.

Slovenia still has considerable unexploited hydropower potentials especially at the Sava river. The construction of a chain of five run-of-river hydropower plants at the lower reaches of the Sava river with an installed capacity of 190 MW and an annual output of 720 GWh/a had been begun in 2002 and was completed in 2017 with the exception of the controversially discussed Mokrice project [68].

In 2018, Slovenia's annual electricity consumption was about 14.7 TWh and peak load was 2.4 GW. Hence, Slovenia has generally been a net exporting country in the past years. Only in years with very low water levels (e.g. 2015 with a capacity factor of 36% and average full load hours of 3,200 h/a, respectively), the country's exchange balance was negative. On the other hand, in years with large quantities of precipitation (e.g. 2014 with a capacity factor of 57% and average full load hours of 5,000 h/a, respectively), soaring hydropower production led to a considerable positive exchange balance.

However, the Croatian utility Hrvatska elektroprivreda (HEP) owns 50% of the nuclear power plant Krško, which is located near the Croatian-Slovenian border. Hence, 50% of the generated electricity is directly supplied to Croatia as a virtual share of the nuclear power station. Slovenia has still been depending on electricity imports, although the Croatian share in the Krško power plant is considered in statistics of the Slovenian and not Croatian electricity market.

Figure 25: Key figures electricity generation and demand Slovenia



Source: ENTSO-E [39], Energy Agency [69]

3.2.13 Slovakia

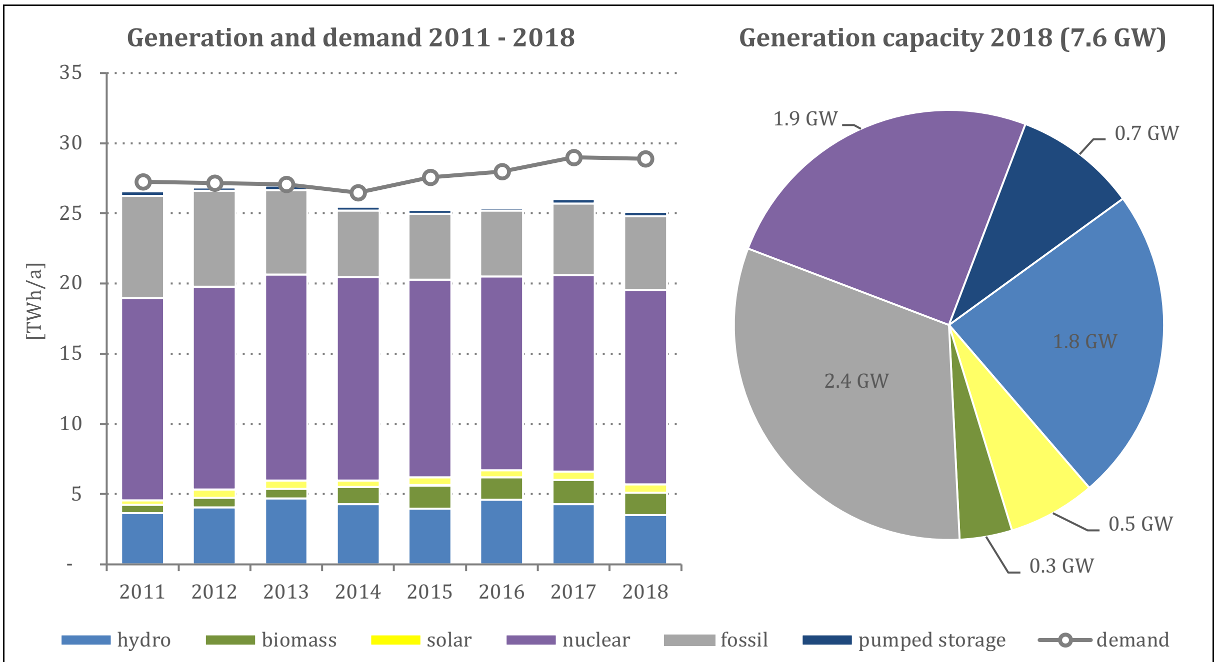
Slovakia has a total installed generation capacity of 7.6 GW (2018), including 1.9 GW nuclear power, 1.1 GW natural gas, 0.6 GW lignite and hard coal, 0.7 GW oil and mixed fuels, 2.5 GW hydropower incl. pumped storage and 0.9 GW other renewable energies. With a share of 56% in total electricity generation, nuclear power stations are the largest source of electricity production followed by 21% fossil energies. Hydropower accounted for 14% and together with solar PV and biomass, renewable energies provided 23% of the Slovakian electricity generation in 2018.

The yearly hydropower production in Slovakia shows comparatively small variations. In the years 2011-2018, for example, the range of the capacity factor was between 22% (2018) and 30% (2013), which equals to full load hours of 1,900 h/a and 2,600 h/a, respectively. Although Slovakia still has some untapped hydropower potentials – 70% of the country's technical potential has already been exploited [70] – basically no capacity additions in hydropower were made in the last few years.

In contrast to hydropower, solar PV and biomass capacities significantly increased in the late 2000s due to the introduction of a favourable renewable promotion scheme. However, incentives for renewables were cut relatively shortly after their introduction and hence, the solar boom ended as quickly as it began. Therefore, biomass has been the only renewable energy source slightly increasing in the last six years.

In 2018, the peak demand in the Slovakian electricity system was 4.5 GW and the annual electricity consumption was about 29.0 TWh. Hence, with a total net electricity generation of 25.1 TWh/a in 2018, Slovakia was – as in previous years – a net importer of electricity. However, the country is expected to become a net exporter after the third and fourth nuclear power plant units at Mochovce are put into operation. According to the actual planning, the disputed reactor blocks should finally be put into operation in 2019 and 2020, respectively.

Figure 26: Key figures electricity generation and demand Slovakia



Source: ENTSO-E [39]

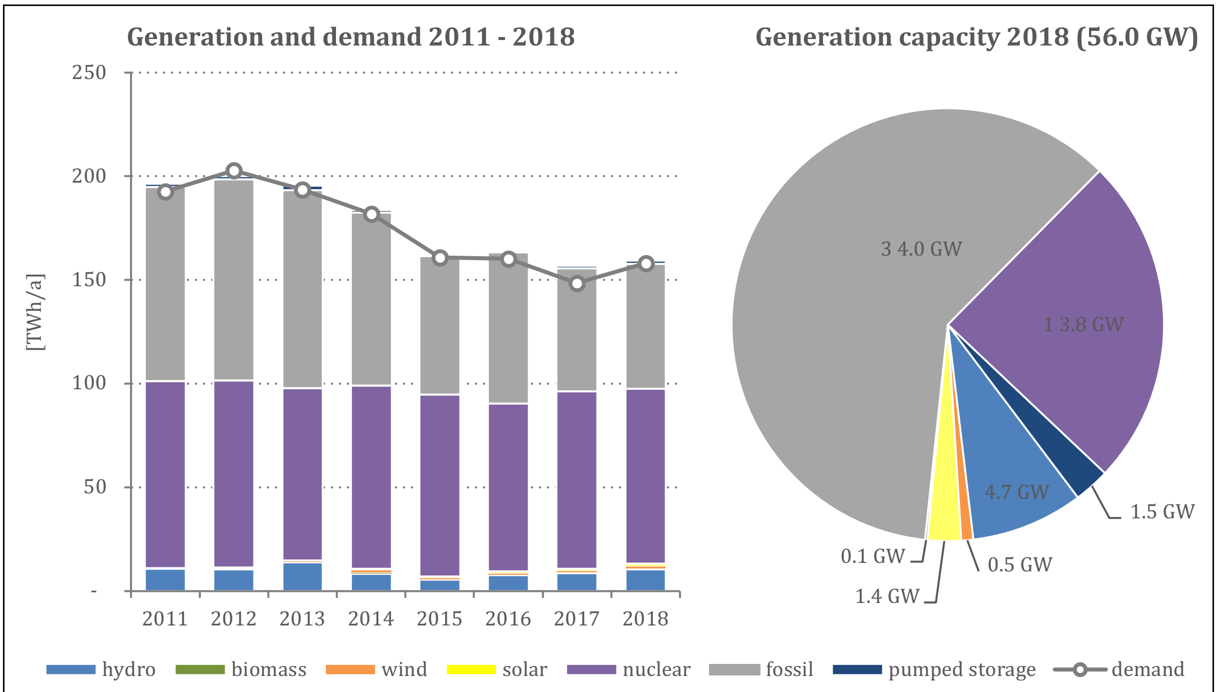
3.2.14 Ukraine

With an installed generation capacity of 56.0 GW[16] (2018), the Ukraine operates the second largest electricity system of ICPDR countries after Germany. The generation portfolio comprises 34.0 GW thermal fossil (of which about 3/4 is hard coal and 1/4 is natural gas), 13.8 GW nuclear, 1.5 GW pumped storage, 4.7 GW hydropower and 2.0 GW "new" renewable energy sources. Although hydropower capacities were increased by about 0.9 GW between 2011 and 2012 and despite an initial important step towards the establishment of wind power and solar PV, the Ukrainian electricity system still relies on nuclear and fossil generation. Hence, the share of renewable energies in total electricity production was about 8% (7% hydropower and 1% "new" renewables) in 2018. With considerable unexploited non-hydropower potentials, in particular a huge wind power potential, the Ukraine could develop a more environmentally friendly generation mix.

However, environmental and climate-related aspects are not the only challenges facing the Ukrainian electricity sector. Due to a rather old generation fleet, security of supply and operational security are major issues and hence, the need for modernization is omnipresent. An additional challenge will be the desired synchronisation of the Ukrainian grid with the ENTSO-E system by 2025 [75]. Currently, the electricity system of the Ukraine is part of the United Power System (UPS), which also includes Moldova, Belarus and the Russian Federation.

Peak demand in the Ukrainian electricity system was 28 GW in 2016 and annual electricity consumption was about 158 TWh/a in 2018. However, due to the sustained economic and political difficulties, electricity consumption and hence, electricity generation has dramatically decreased in the past years.

Figure 27: Key figures electricity generation and demand Ukraine



Source: IHA [56], UKRSTAT [71], BP [72], Flanders Investment & Trade [73], IndexMundi [74]

[16] Statistical data for Ukraine may vary widely amongst different sources. A complete set of data in English is only available for 2016 and was provided by the state statistic service of Ukraine (UKRSTAT). For 2011-2016 as well as 2017 and 2018 other data sources were used and validated with UKRSTAT data, if possible. Please note: UKRSTAT provides data with the comment: "All data excluding the temporarily occupied territories of the Autonomous Republic of Crimea, the city of Sevastopol and part of the anti-terrorist operation zone."

4. Energy economic dimensions of hydropower

Hydropower has been the most important renewable energy source in the European electricity sector for decades. However, considering all EU-28, wind power already outpaced hydropower and at the end of the 2020s at the latest, solar energy will overtake hydropower in the quantitative ranking of electricity generation from renewable energies. Nevertheless, hydropower will maintain its importance especially in those countries which have already developed a high share of hydropower in the national generation mix and still have considerable potentials to further expand the use of hydropower, respectively. Therefore, an overall assessment of renewable technologies should not only be based on quantitative but also on economic and qualitative aspects, which are for example determined by the generation characteristic of a technology. Hence, this chapter provides a qualitative analysis of the importance of hydropower in comparison with other renewable energy sources and conventional generation technologies. In particular, section 4.1 “Contribution to security of supply and system stability” discusses the aspects capacity credit and provision of ancillary services. Section 4.2 “Costs of electricity generation” presents the total social electricity costs, which are comprised by (a) levelized costs of electricity (LCOE), (b) system integration costs and (c) external costs. Additionally, section 4.3 “Impact of climate change on electricity generation” discusses climate change related impacts on hydropower as well as thermal power plants and other renewables and provides a summary of climate change mitigation measures and strategies.

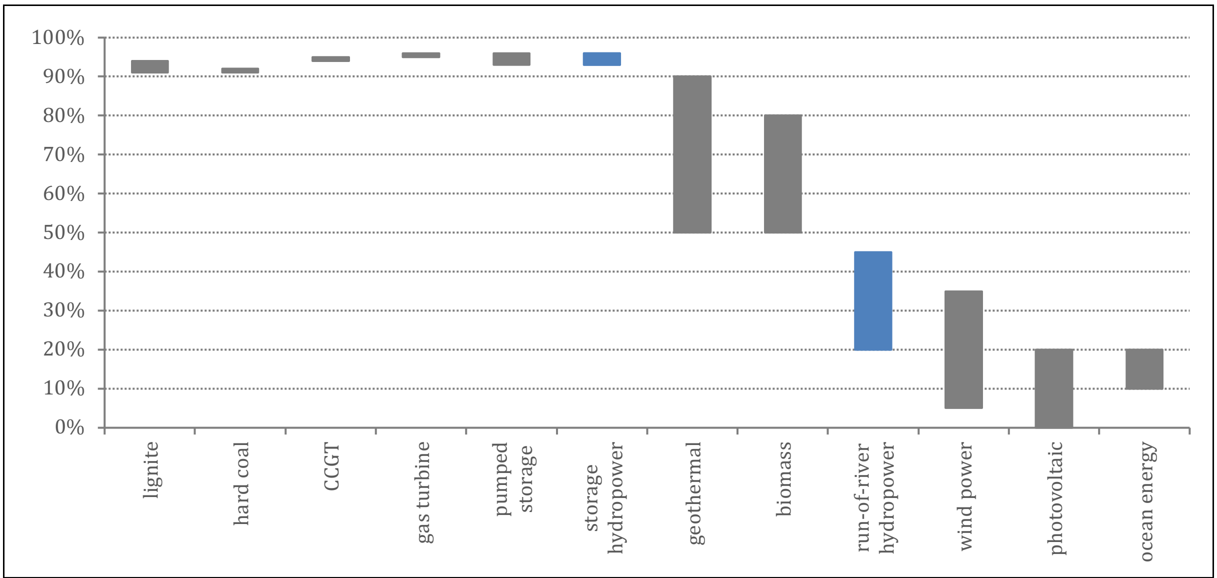
4.1 Contribution to security of supply and system stability

4.1.1 Capacity credit

In fact, the electricity generation from fossil fuels is getting reduced by the increasing share of renewable energy sources. However, the required conventional generation capacity in a power system is only reduced to the extent to which a renewable technology provides firm capacity to cover peak load. Especially wind power and solar PV but also run-of-river hydropower, which are non-dispatchable variable renewable energies (VRE), are not necessarily (fully) available at times with high electricity demand. Hence, can only substitute conventional generation capacity – if at all –to a certain extent. In this context, the term capacity credit or capacity value was introduced. The capacity credit refers to the capacity in a power system that can be replaced by renewable capacity while maintaining the same level of system security. The capacity credit is typically given as a percentage of the installed renewable capacity, i.e. if multiplied with the capacity, the absolute amount of firm capacity of a specific renewable technology can be derived. For example, if the capacity credit of wind was 10%, 1,000 MW of wind capacity would provide a firm system capacity of 100 MW.

Generally, the capacity credit depends on the generation characteristic of a renewable energy resource and the structure of the power system. The capacity credit of a specific renewable technology is higher in systems where peaks in generation and electricity demand coincide and is lower for VREs with increasing share of the technology in the overall electricity system. On the other hand, the capacity credit of VRE increases with the geographical extension, since the generation characteristic is more balanced in a larger area. Accordingly, the quantification of capacity credits depends on the boundary conditions and might have a relatively large range. Hence, the illustrated capacity credit for different generation technologies in Figure 28 may vary between individual ICPDR countries and should, therefore, be seen as an indicative example.

Figure 28: Exemplarily range of capacity credit for different generation technologies



Source: IEA & IRENA [76], r2b [77], IPCC [78], Simoglou, C.K. et al. [79]

In general, conventional thermal technologies are dispatchable, i.e. the capacity credit mainly corresponds with the power plant's overall availability of about 91-96%. With capacity credits above 90%, storage hydropower is not only at the top of all renewable energies but can also have capacity credits comparable to conventional thermal generation. However, such high capacity credits can typically only be achieved with large reservoirs that allow seasonal or at least weekly storage. Depending on the water inflow and dispatch strategy, respectively, capacity credits of storage hydropower with small reservoirs (i.e. hourly storage) can be lower or, under unfavourable conditions, even at the level of run-of-river hydropower, which is about 20-45%. Still, the capacity credit of run-of-river hydropower is still considerably above the capacity credits of wind power and solar PV, which is typically below 10%. Only in countries with low penetration rates and generation of wind power and PV and a high correlation with demand peaks, respectively, capacity credits can be up to 35% for wind power and 20% for PV.

4.1.2 Provision of ancillary services

Grid operators have to constantly take measures to keep frequency, voltage and load of grid equipment within allowed limits in order to maintain quality, reliability and security of power transmission and distribution. The related services, which are required for the full functionality of electricity supply, are called ancillary services. Basically, it can be differentiated between the following ancillary services:

- Load-frequency control by means of active power control (i.e. balancing reserves such as primary control, secondary control and tertiary control, cf. fact box balancing reserve)
- Voltage control by means of reactive power management
- Compensation of grid losses
- Black start and island operation capability
- System coordination and operational management (e.g. congestion management)

Fact box: Balancing reserves

The transmission system operators (TSO) are responsible for the procurement and activation of balancing services or reserves[17]. Balancing reserves are required to guarantee a stable grid frequency of 50Hz in the synchronized Central European electricity system and to meet the planned exchange programmes between control areas, respectively. For this reason, unexpected deviations between generation and consumption have to be balanced at all times by activation of power plant capacities or consumers with controllable loads, i.e. balancing reserves. Activation of balancing reserves must be possible in both directions, i.e. increased generation/reduced load for positive reserves and reduced generation/increased load for negative reserves. According to the EU System Operation Guideline (SOGL) [85], the TSOs procure different types of balancing reserve differing in terms of time for activation and response:

- **Frequency Containment Reserve (FCR) or primary control** is required for the stabilisation of the grid frequency after a disturbance in the time frame of seconds. It is provided simultaneously by all contracted providers in the synchronous Central European grid area, irrespective whether or not the imbalance was caused within the TSO's control area. It is not activated by a centrally sent signal but individually depending on the measured grid frequency. The complete activation of the reserve has to be done within 30 seconds.
- **Automatic Frequency Restoration Reserve (aFRR) or secondary control** is used to balance the energy within each TSO's control area. It should restore the grid frequency to its nominal value, bring back the exchange programs between countries back on track and replace FCR. aFRR is called fully automatically and needs to be completely deployed within five minutes after activation by the TSO.
- **Manual Frequency Restoration Reserve (mFRR) or tertiary control** partially relieves aFRR that it is available for fast responses again. In the case of large deviations within a control area (particularly unplanned outages of power plants), mFRR also complements aFRR.
- **Replacement Reserve (RR)** restores or supports the required level of aFRR and mFRR to be prepared for additional system imbalances. However, RR is not used in every control area.

Balancing of deviations between supply and demand does not represent a new task in power systems. Load showing a volatile behaviour and limited predictability as well as unplanned outages of conventional power plants can reduce generation by more than 1,000 MW within seconds. However, especially the expansion of variable and only to a certain extent predictable electricity generation from wind power and solar PV can lead to additional demands for ancillary services in general and balancing reserves in particular. Hence, it is expected that flexibility in a power system will considerably gain importance in the future, if the share of volatile generation from wind and solar increases as widely as expected. Additionally, conventional generation capacity will most likely significantly decrease and will not be

[17] According to the EU Guideline on Electricity Balancing (GLEB) [86] 'balancing services' means balancing energy or balancing capacity, or both. The terminologies control power, control energy and control reserve are commonly used synonymously. However, in a more specific way, balancing capacity refers to the capacity provided by a power plant or consumer and balancing energy to the energy delivered or withdrawn from the provider of balancing capacity once the capacity is called by the TSO.

available at all times in the next decades if climate and energy targets are implemented. Hence, alternative options for the provision of balancing reserves and other ancillary services may need to be developed. Due to their short response time and high availability (i.e. high capacity credit), storage hydropower plants can not only provide such services efficiently, but also show technology-immanent advantages compared to other flexibility options, as shown in Table 1 for technical parameter of selected flexibility options.

Table 1: Technical parameter of selected flexibility options

	Gradient (% P_N / min)	Min. load (% P_N)	Start-up time until P_N	Min. operating time/downtime	Flexibility range	Capacity range (MW)[a]
Storage hydropower plant	100%	0-30%	0.5-3 min	seconds	sec.-weeks	5-500
Pumped storage power plant	100%	0-30%	0.5-3 min	seconds	sec.-weeks.	30->1,000
Gas turbine	8-15%	20-50%	10-15 min	minutes	min.-days	5-200
Internal combustion engine power plant[b]	25-50%	< 5%	5-15 min	minutes	sec.-days	5-200
CCGT	2-8%	30-50%	30-120 min	hours	hours-weeks	50-600
Biogas (internal combustion engine)	8-20%	40-50%	5-15 min	minutes	sec.-hours	0.1-20
Li-Io battery storage[c]	100%	0%	< 1 min	seconds	sec.-hours	0.1-15
Demand response[d]	100%	0%	< 1 min	seconds	sec.-min.	0.5–50
Power-to-Heat[e]	100%	0%	0.5 min	seconds	sec.-hours	0.5-50
Emergency power system	25-50%	40-50%	0.1-5 min	seconds	min.-hours	0.1–2.5

[a] power plant and single technical device, respectively, [b] multiple engines, [c] large scale battery storage, [d] industry, [e] electric consumer

Source: Neubarth, J. [20], r2b [77], Buttler, A. [80], Bucksteeg, M. et al. [81], VDMA[82], r2b [84]

Overall, storage hydropower plants have the most flexible operation characteristic of all compared flexibility options. Depending on the size of the reservoir, generation can be aligned with demand and requirements of the power system in the range between seconds and weeks. Hence, the expansion of hydropower can not only provide a quantitative contribution to achieve climate and energy targets but, in combination with reservoirs, also a qualitative contribution to efficiently integrate non-dispatchable variable renewables. However, it has to be noted that not all regions and countries are equally suited for storage hydropower and even countries with suitable site conditions may show limited potentials for new storage hydropower plants due to e.g. ecological restrictions.

4.2 Costs of electricity generation

4.2.1 Levelised costs of electricity

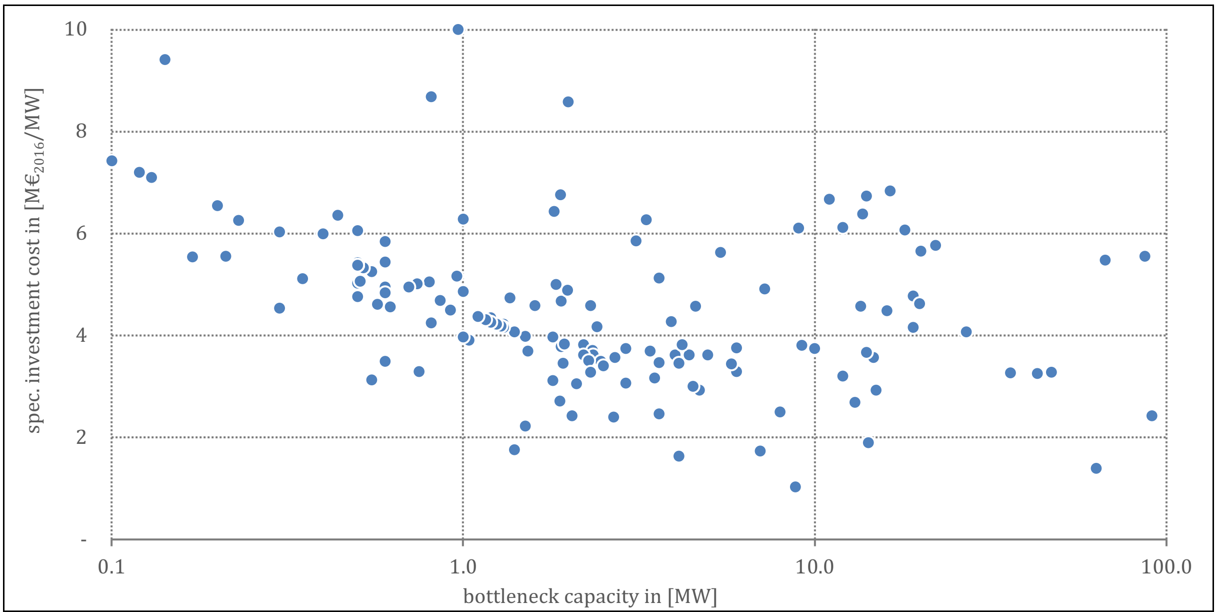
Differing variants of an investment project or differing technologies are commonly compared by means of levelized costs of electricity (LCOE). The LCOE represent the average electricity generation costs throughout the entire operating life of a facility and are calculated by discounting all expenses (investment costs and annual operating expenses) and generated amount of electricity at the same reference point[18]. Hence, LCOE are a purely comparative calculation on a cost basis and do not allow any statements regarding the profitability of an investment without additional consideration of revenues. The range of LCOE of a renewable technology is typically very wide, since input parameters may also have a wide range. For example, capital costs depend on the country and financing structure and the annual electricity output depends on site specific aspects such as wind speed and solar radiation. Additionally, specific investment and operation costs typically decrease with the size of a project. This is also the case for hydropower: specific investment costs of small hydropower plants are generally higher than specific

[18] For background information about LCOE calculation please refer e.g. to Kost, C. et al. [83].

investment costs of large(r) hydropower plants. Figure 29 shows the exemplary investment costs of an analysis that was conducted for 159 Austrian run-of river power plants in the year 2016 [87].[19]

The study showed that the average investment costs weighted by capacity was EUR 4.0 million per MW. Although the results did not show a clear correlation between installed capacity and specific investment costs, the study concluded that small hydropower plants below 2 MW typically incur the highest specific investment costs, whereas the most attractive hydropower plants in Austria were in the range between about 5 and 10 MW. Although these results cannot be transferred directly to ICPDR countries, they at least provide an indication that very small hydropower plants are the least favourable hydropower option from an economic perspective.

Figure 29: Specific investment costs of run-of river power plants in Austria

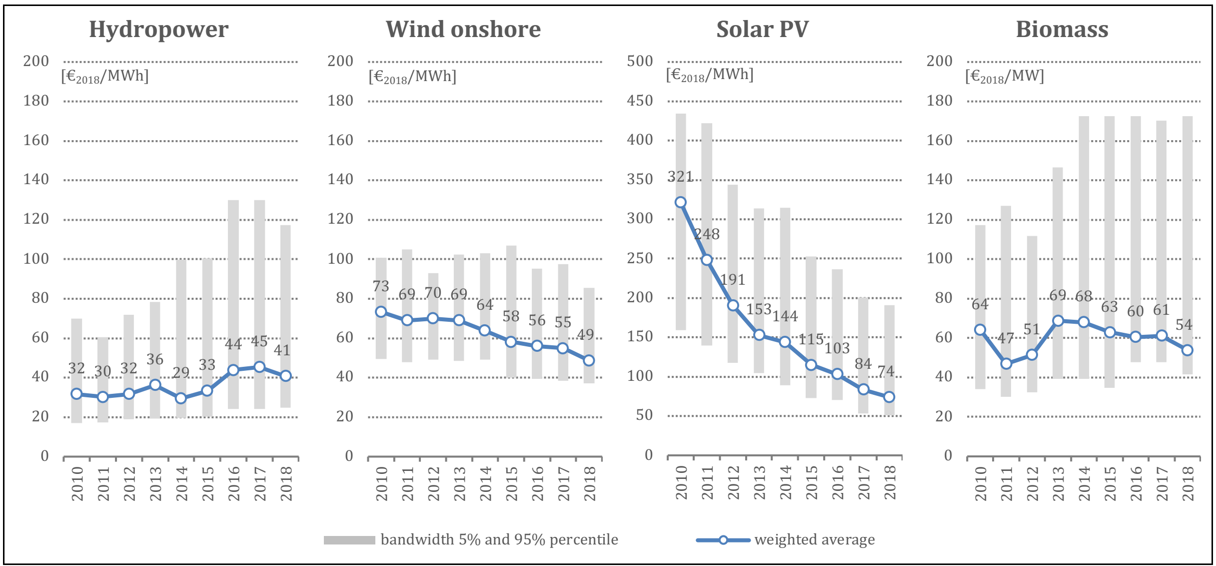


Source: Neubarth, J. [87]

A global perspective on the cost development and LCOE of different renewable energy technologies for the years 2011-2018 is provided for example by the International Renewable Energy Agency IRENA in its report *Renewable Power Generation Costs in 2018* [88]. Figure 30 depicts the LCOE for hydropower, wind onshore, solar PV and biomass. Please note that the y-axis of solar PV has a different scaling. The IRENA report shows that hydropower is still the most economically viable renewable energy technology on a global level with average LCOEs of about 41 €/MWh. However, non-hydro technologies, namely wind power and solar PV, have seen tremendous and partly even unexpected cost reductions in the past few years with average LCOE of 49 €/MWh for wind onshore and 74 €/MWh for PV. Still, under very favourable site conditions, the LCOE of wind and solar PV are already in the range or even below hydropower. Accordingly, tenders for PV in 2018 resulted in an average auction price of 43.3 €/MWh in Germany [91] and 58.2 €/MWh in France [92], respectively.

[19] Due to additional expenses for a reservoir specific investment costs of storage hydropower plants are generally above specific investment costs of run-of-river hydropower plants. However, the dispatchability of storage hydropower plants allows higher earnings in spot and balancing markets to cover higher investment costs. Accordingly, investment costs and LCOE, respectively, of storage hydropower plants may not be directly compared with run-of-river hydropower plants and other RES technologies, respectively.

Figure 30: Global development of levelized cost of electricity for different RES technologies



Source: IRENA [88] (published figures converted to EUR using an exchange rate of USD1,15 for EUR1.00)

It has to be noted that in the IRENA report, LCOEs for biomass are extremely low from a European perspective, which is mainly because of significantly lower investment and feedstock costs in developing and emerging countries. For comparison, the Ecofys report *Subsidies and costs of EU energy* shows average LCOEs for dedicated biomass plants in EU-28 countries between about 100 and 150 €/MWh [89]. The same range is given for biogas plants in the Fraunhofer ISE publication *Levelized cost of electricity -renewable energy technologies* [83].

As a consequence, renewable energies have already achieved or will probably soon achieve cost competitiveness with regard to fossil and nuclear generation. The LCOE of conventional technologies do not only depend on the assumption about the discount rate (i.e. cost of capital), fuel prices and costs for carbon emissions. Hence, published numbers for LCOE of conventional power technologies can significantly differ from each other and/or show a wide range. For example, in the above-mentioned Ecofys report *Subsidies and costs of EU energy* the LCOE in EU-28 countries for hard coal range between about 60 and 80 €/MWh, for natural gas between about 60 and 100 €/MWh and for nuclear energy between about 90 and 100 €/MWh [89][20]. A more recently published analysis from Lazard calculates a global LCOE range of 52-124 €/MWh for coal, 37-64 €/MWh for gas combined cycle gas turbine (CCGT) and 97-164 €/MWh for nuclear [90][21]. Additionally, in the Fraunhofer ISE publication *Levelized cost of electricity -renewable energy technologies* the LCOE for newly constructed power plants amount to 46-80 €/MWh for lignite, 63-99 €/MWh for hard coal and 78-100 €/MWh for gas-fired CCGT [83].[22]

[20] €$_{2012}$ values are adjusted for inflation to €$_{2018}$ values with Eurostat Harmonised Index of Consumer Prices (HICP) (https://ec.europa.eu/eurostat/web/hicp/data/main-tables). Results are based on an assumed CO_2 certificate price of 6.67 €/t.

[21] Published figures in Lazard report converted to Euro by using an exchange rate of USD 1.15 for EUR 1.00. No costs for carbon emissions considered in LCOE calculation.

[22] Results for 2018 are based on an assumed CO_2 certificate price of €5.3/t.

4.2.2 System integration costs

The LCOE approach only covers costs directly related to the generation unit and usually do not consider costs related to the supply of electricity to the consumer at a specific time and place, i.e. costs for the expansion of the transmission and distribution grid[23], costs for balancing of forecast errors[24] as well as costs related to the interaction with the overall generation portfolio. These additional costs are often referred to as “integration costs” and “system integration costs”, respectively (cf. e.g. [76], [93], [94]). In this context, it has to be noted that every generation technology involves integration costs but for thermal power and hydropower these are, in general, noticeably below wind power and solar PV. Therefore, studies on integration costs typically focus on wind power and solar PV and hence, there are only few references for integration costs for hydropower and thermal electricity generation.

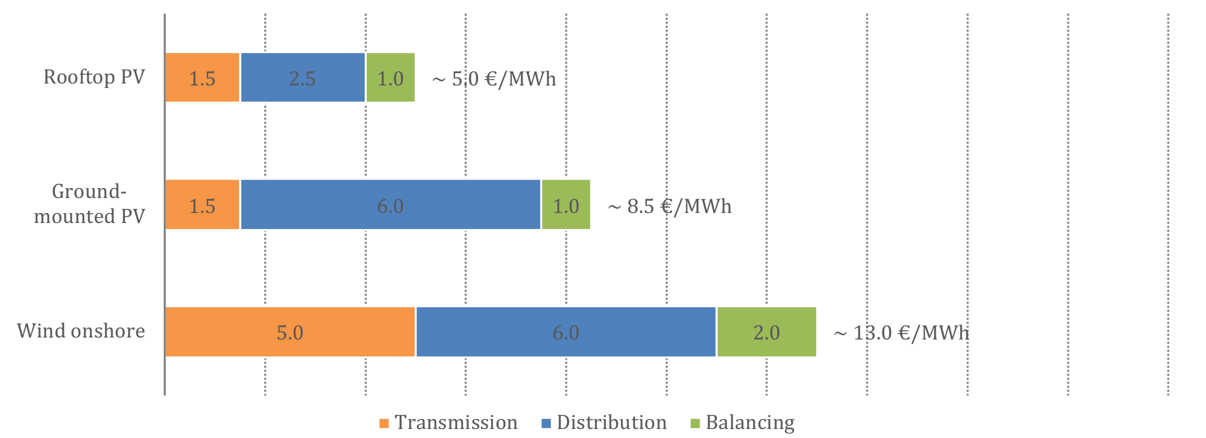
Specific integration costs of VRE generally increase with the share of wind power and solar PV in an electricity system and also depend on the structure of the residual power plant fleet of the electricity system. Accordingly, published numbers for system integration costs of wind and solar may range widely. For example, UKERK conducted an extensive analysis of international publications and concluded in its report *The costs and impacts of intermittency* that grid-related integration costs range between 6-23 €/MWh for VRE penetration levels up to 30% [95]. Balancing costs for wind and solar PV are usually below grid costs and range between about 1 and 6 €/MWh with hydro-dominated systems being at the lower and thermal-dominated systems at the upper boundary of the range [96], [97]. The above-mentioned numbers are also confirmed in an analysis of the Wuppertal Institute for Climate, Environment and Energy about the social costs of electricity generation. Grid-related integration costs for both wind on- and offshore as well as utility-scale solar PV are indicated with 10 €/MWh and balancing costs with 2 €/MWh for wind and 3 €/MWh for PV, respectively. Contrary to other publications, the Wuppertal Institute analysis also states system integration costs for fossil and nuclear generation amounting to 5 €/MWh for grid-related integration costs. In a good approximation, these may also be applied to biomass and hydropower [98].

In most cases, distributed generation in close proximity to consumers, as e.g. rooftop PV, show lower grid and balancing costs compared to large wind parks or multi-MW utility scale PV installations. As an example, Figure 31 depicts grid and balancing costs for wind onshore and solar PV in the German power system taken from the Agora Energiewende publication *The Integration Costs of Wind and Solar Power* [94]. However, depending on the local and regional situation, the distributed generation may not always show lower grid costs compared to large scale generation. For example, the final report of the study *Regional Strategy for Sustainable Hydropower in the Western Balkans* [99] states, “[…] the capacity of the distribution networks in the region is insufficient to facilitate growing demand for connection of new small HPPs and distributed generation in general”. On the other hand, the study also concluded, “The capacity of the transmission grid, if observed from the regional level, seems to be sufficient to facilitate any additional major planned HPP development projects.”

[23] Grid costs relate to the reinforcement of the public transmission and distribution grid. Grid expansion costs are typically covered by grid users via the grid usage fee. In contrast, grid connection costs (i.e. costs for the connection of a power plant and the public grid) are covered by the generation unit in most cases and hence, considered in the LCOE calculation.

[24] Balancing costs are related to differences inherent in the system between forecasts and actual production and consumption of electricity, respectively. Balancing costs have to be paid by the parties responsible for balancing and reflect the imbalance of a balance group within an imbalance settlement period in relation to the overall net position of a control area.

Figure 31: Representative grid and balancing costs for wind and solar power in Germany



Source: Agora Energiewende [94]

Besides grid-related and balancing costs, a third cost component being part of the integration costs are costs for the interaction with other power plants in the overall electricity system. As already discussed in section 4.1.1 "Capacity credit", variable renewable energies are only partially available at times of peak demand and hence, other power plants in the system are required to compensate the limited availability of VREs. However, the average utilisation (i.e. full load hours) of those "backup" power plants decreases and therefore, specific costs of electricity production increase since fixed costs have to be allocated to hours with decreased operation. Additionally, operation and maintenance costs of conventional power plants, e.g. for increased ramping, cycling and operation at partial load, increase. In the literature, the cost effects related to the interaction of VREs with other power plants are summarised under the terms backup cost, adequacy cost, profile cost, utilisation effect and capacity-factor effect [94]). However, the quantification of costs related to the interaction between new (renewable) capacities and other (existing) power plants is subject to a controversial discussion since they do not only depend on the electricity system and period under review (i.e. existing vs. future electricity system) but also on the perspective (i.e. cost effect for consumer and producer, respectively). Hence, costs related to the interaction of VREs with other power plants can even be negative if e.g. lower wholesale electricity prices are considered as a positive effect from a consumer's perspective. As an example, the above-mentioned Agora Energiewende report exemplarily quantified backup costs and utilisation effect in a range between -6 and +13 €/MWh [94].

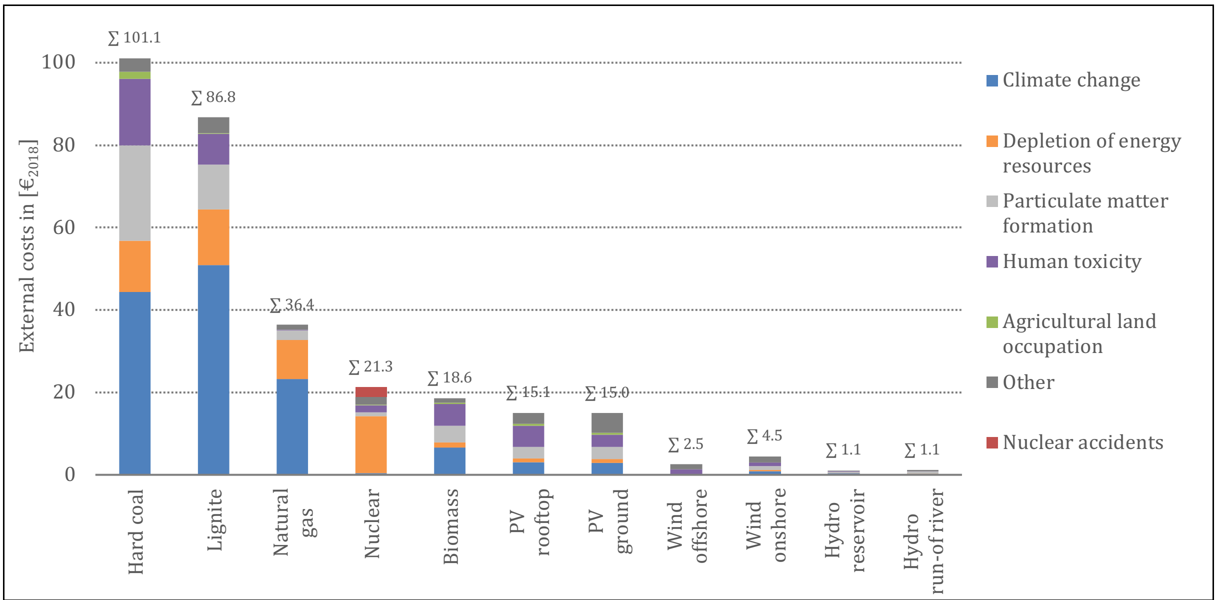
The total integration costs for wind power and solar PV can range between about close to zero for power systems with very low penetration rates and up to 30 €/MWh for inflexible thermal dominated systems with a penetration rate of wind and solar PV above 30-40%. Power systems with a considerable share of flexible storage hydropower typically show considerably lower integration costs even at higher wind and solar PV penetration rates.

4.2.3 External costs

External costs are costs related to impacts on e.g. human health, ecosystems and biodiversity or resources depletion. These are not or only partially taken into account by markets and hence, not borne by the polluter. Examples for so-called externalities are costs of GHG emissions and health-related costs caused by carbon and pollutant emissions of e.g. coal-fired power plants, which are borne by the society. However, specific externalities can be internalised through policy interventions such as taxes, regulations, subsidies and other measures. One of the best-known examples is the European Emission Trading System (ETS) that attributes costs to the climate change externality and hence, represents a level of (partial) internalisation [89].

External costs are often used to quantify the "true" or social cost of energy. Especially in the context of existing LCOE-related disadvantages of renewable energies, the consideration of external costs could provide a level playing field for renewables in a cost comparison with conventional energy sources. Hence, in the last 20 years, a number of studies has been conducted to quantify external costs of different electricity generation technologies; *ExternE – External Costs of Energy* [100] is only one but a very prominent example. However, published numbers for external costs of specific generation technologies can differ significantly since the calculation is broadly determined by assumptions and the definition of boundary conditions. As a consequence, external costs can vary between geographical regions and countries since the economic damage of a certain emission can depend on regional parameters and the economic strength of a country. This is for example shown in the Ecofys report *Subsidies and costs of EU energy* which provides external costs of electricity generation technologies for each EU-28 country [89]. The report differentiates 18 environmental impact categories[25] and quantifies the damage on human health, ecosystems and biodiversity as well as resources and depletion. Figure 32 depicts the average external costs of electricity generation in EU-28 member states.

Figure 32: Average external costs for electricity generation technologies in EU-28 member states



Source: Ecofys [89] (adjusted for inflation with Eurostat HICP)[26]

[25] Climate change, ozone depletion, terrestrial acidification, freshwater eutrophication, marine eutrophication, human toxicity, photochemical oxidant formation, particulate matter formation, terrestrial ecotoxicity, freshwater ecotoxicity, marine ecotoxicity, ionising radiation, agricultural land occupation, urban land occupation, natural land transformation, water depletion, metal depletion and depletion of energy resources.

[26] In order to avoid double counting of carbon emission costs, which are already internalised by means of the EU ETS, the assumed value of climate change of $€_{2012}$ 50 t_{CO2e} is included in the average EU-ETS price of $€_{2012}$ 6.67 t_{CO2} in 2012. Hence, the value of climate change included in external cost calculation is reduced to $€_{2012}$ 43.33 t_{CO2e} for technologies under the EU ETS [89].

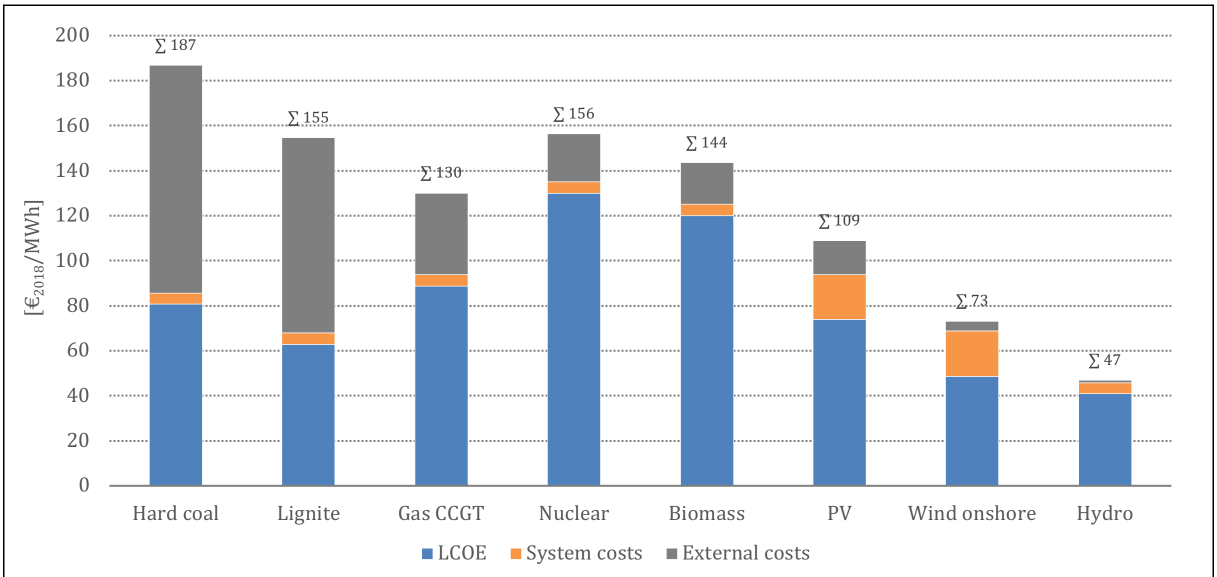
Hard coal and lignite cause the highest external costs with about 101 and 87 €/MWh, respectively. External costs of natural gas (36 €/MWh) and nuclear (21 €/MWh) are noticeably below coal. Renewable energy technologies generally show lower external costs with hydropower (about 1 €/MWh) at the lower end of the range. While external costs of wind power are in the range of hydropower, external costs of biomass (19 €/MWh) and PV (15 €/MWh) are considerably higher due to biomass production and combustion and resource intensive production of PV modules, respectively. The results of the Ecofys report correspond well with the results of other studies (e.g. [98], [100], [101]). Only external cost due to a nuclear accident are estimated significantly higher in some other studies (e.g. in [102] between 107 and 343 €/MWh). However, it has to be noted that the range of 0.5-4.0 $€_{2012}$/MWh for external costs of nuclear accidents as shown in the Ecofys report was derived from an intensive literature research, i.e. the quantification of external effects from nuclear accidents is still subject of a controversial scientific discussion.

4.2.4 Social costs of electricity generation

The concept of social costs of electricity generation by adding up "private" generation costs and external costs of electricity generation has been introduced by Krupnick and Burtraw way back in 1996 [103]. In this context, "private" generation costs can be further differentiated into costs at plant level (i.e. LCOE) and system-related costs (i.e. system integration costs). In a wider sense, macro-economic (e.g. employment effects) and geopolitical costs (e.g. dependency on fuel imports) could also be considered as social costs. However, it is difficult to quantify these costs for a specific generation technology and hence, they are typically not included in social cost calculations [98].

Based on the discussed LCOEs, system integration costs and external costs of different generation technologies in the previous subsections, Figure 33 exemplarily depicts social cost of electricity generation. For reasons of simplification, the range of the respective costs is not depicted but it has to be noted that LCOEs, system integration costs, external costs and hence, social costs can vary significantly depending on e.g. site and country specific conditions. Nevertheless, Figure 33 provides a clear picture of the dimensions as well as relations of social costs of different electricity generation technologies.

Figure 33: Exemplarily social electricity generation costs



Source: IRENA [88], Ecofys [89], Fraunhofer ISE [83], Lazard [90], Samadi [98], UKERK [95]

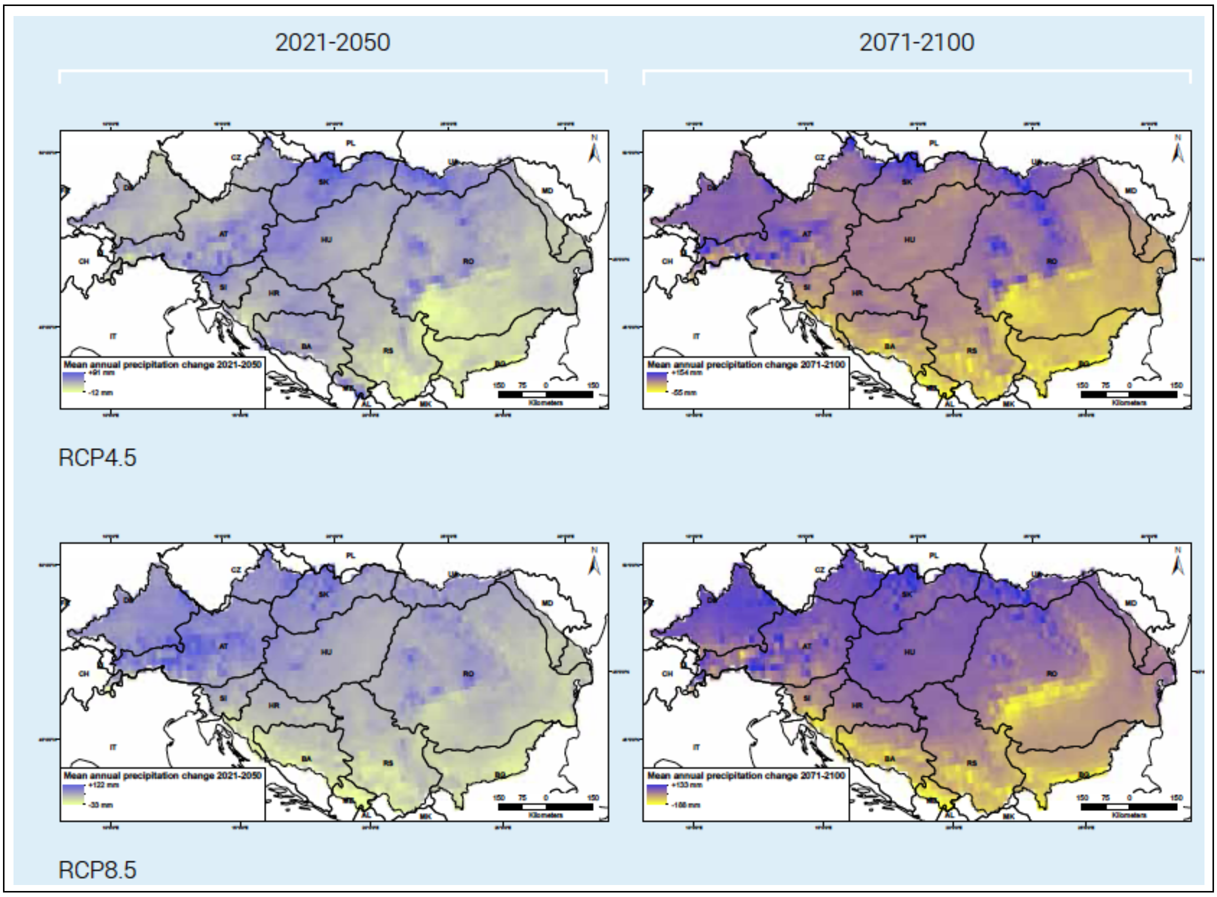
Conventional electricity generation technologies show total social costs between €130 and €187/MWh. Hydropower amounts to just one fourth to one third of the social cost of conventional technologies and therefore, these show the lowest social costs of all considered electricity generation technologies. Today's social costs of wind power and solar PV are still 50-130% above hydropower. However, it can be expected that the gap between hydropower and wind power and solar PV, respectively, will decrease in the future due to still existing cost reduction potentials and potentials to increase production efficiency of wind and solar PV.

4.3 Impact of climate change on electricity generation

4.3.1 Vulnerability of hydropower

Given its dependence on water availability, climate change related impacts on hydropower are obvious since changes in precipitation and temperature and thus, also river flows will directly impact hydropower generation in terms of annual production and seasonal distribution. In this context, a global survey of 50 companies already found in 2015 that 40% of hydropower operators see evidence of climate change related-effects on engineering and design measures [105]. However, spatial patterns of changes in hydropower generation can show big differences between regions and sometimes even within countries. Against this background, ICPDR prepared its first *Strategy on Adaptation to Climate Change* [106] in 2012 to provide guidance on the integration of adaptations in connection with climate change into ICPDR planning processes.

Figure 34: Change of mean annual precipitation in the Danube River Basin for the periods 2021-2050 and 2071-2100

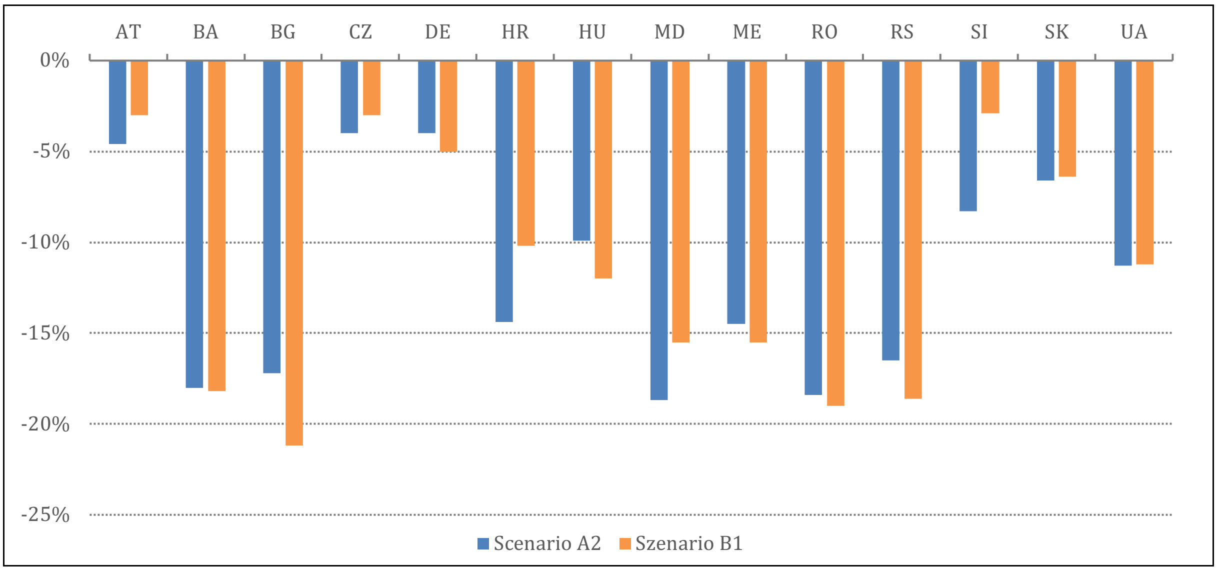


Source: ICPDR [107] (according to RCP4.5 and RCP8.5 of the EURO-CORDEX ensemble runs; status: September 2018)

The strategy was updated and revised in 2018 [107] taking into account new scientific results and implementation steps in the Danube countries. The updated strategy concluded that wet regions will become even wetter and dry regions even drier with a strong precipitation gradient from northwest (high) to southeast (low). Additionally, significant changes in the seasonality of precipitations with wetter winters and drier summers are very certain although mean annual precipitation rates show insignificant trends. This can be seen in Figure 34 that shows the changes of mean annual precipitation in the Danube River Basin for the periods 2021-2050 and 2071-2100 for two exemplarily climate scenarios.

Even if projected changes in the seasonal distribution and amount of precipitation of different climate scenarios show some uncertainties, effects of climate change will most likely result in proportional changes in hydropower generation. Generally, mean annual and mean summer electricity generation from hydropower is likely to decrease in the DRB – especially pronounced in the South-Eastern parts. In contrast, in mountain areas, a possible seasonal shift of hydropower production from summer to winter months due to changes in precipitation and snow cover is expected. Consequently, Southeast European ICPDR countries face the highest risks in terms of negative impacts of climate change on hydropower production. Van Vliet et al. [108] quantified these risks for two exemplarily climate scenarios and showed large declines in annual hydropower production (>15%) for SEE and Balkan countries like Bulgaria, Romania, Serbia and Macedonia but less noticeable effects on Central and Eastern European countries like Austria, Germany, Czech Republic and Slovakia (cf. Figure 35).

Figure 35: Change in mean annual hydropower production for two climate scenarios (2031-2060) relative to current climate (1971-2000)



Source: Van Vliet et al. [108]

It has to be noted that climate change-induced effects on precipitation and hence, on hydropower vary in different climate scenarios reflecting the uncertainties of input parameter of climate models (c.f. [109], [110], [111]). However, a decline of annual hydropower production is very likely for ICPDR countries at least in the long-term with highest risks in Southeast European and especially Western Balkan countries[27].

[27] See also Globevnik, L. et al. (2018): Outlook on Water and Climate Change Vulnerability in the Western Balkans. [112]

Besides considerable regional differences, the sensitivity of hydropower to climate change can also vary by the type and design of a hydropower plant. Run-of-river plants are more sensitive to changes in river flows than storage plants, particularly with regard to minimum flows (i.e. river flows below minimum requirements of turbines) but also high flows (river flows above nominal discharge of turbines). Storage power plants are generally less vulnerable to climate change since they can balance variations in river flows with their reservoirs. Additionally, large seasonal reservoirs can provide flood protection, which will become more important if extreme weather conditions with high precipitations in very short timeframes occur more frequently in the future.

Climate change-related impacts on hydropower generation do not necessarily entail an economic disadvantage for the hydropower sector. Restrictions in connection with cooling water for thermal power plants as well as reduced river flows for hydropower will result in higher wholesale prices and hence, higher specific revenues for the remaining hydropower production. Additionally, storage power plants can disproportionally benefit from price spikes. These are caused by supply restrictions coinciding with demand peaks. As an example, van Vliet et al. [108] quantified climate change-related effects on wholesale prices for two climate scenarios and concluded that higher wholesale prices can be projected for most European countries (except for Sweden and Norway). In this context, the largest increases are projected for Slovenia (12-15%), Bulgaria (21-23%) and Romania (31-32%) in the period 2031-2060.

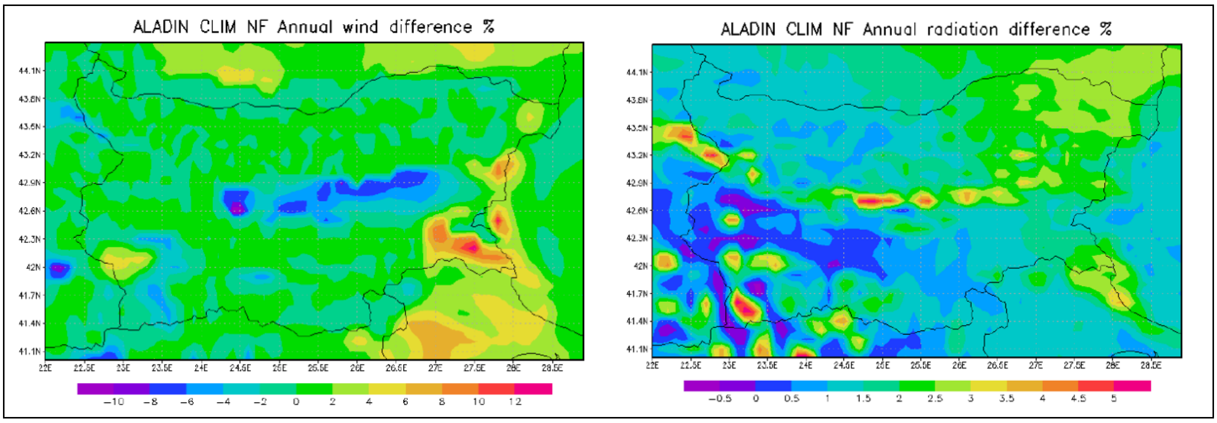
4.3.2 Vulnerability of thermal power plants and other renewables

Climate change will not only affect hydropower but increasingly the whole electricity sector, both on the demand and supply side. Thermal power plants are mainly affected by a reduced availability and increased temperature of cooling water. Rising temperatures of rivers will reduce the cooling efficiency and therefore the overall efficiency of thermal power plants [113]. Hence, thermal power plants with closed-circuit cooling systems are less vulnerable to changes in the temperature of water supplies than once-through systems. Also, the fuel supply of coal-fired power plants can be jeopardized by climate change. Low and high river flows affect the navigability on rivers and the loading of vessels. Mining can also be affected by extreme weather events like the flooding in Serbia in 2014. As a result of the 2014 flooding damages at the open pit mines in Tamnava West, Viliki Crljeni and Kolubara, the state-owned power utility EPS had to contract the import of coal and electricity to avoid electricity shortfalls in the winter period 2014/2015 [114], [115].

In contrast to (run-of-river) hydropower and thermal power generation, the climate change-related impact on wind and solar power is expected to be rather limited on an overall European level, but regional variations are very likely [113]. Wind power generation will tend towards a decrease in the potentials in Mediterranean areas and an increase across northern Europe throughout the 21st century. Additionally, stronger seasonal fluctuations and more frequent phases with low wind speeds (i.e. below 3 m/s) are expected for all countries. Nevertheless, annual wind potentials are expected to remain within the range of +/-5% and therefore in most countries noticeable below expected climate change related variation of hydropower, but still in some regions changes of +/-20% are possible [116]. An example for such regional differences can be derived from Spiridonov and Valcheva, who quantified the impact of climate change on the wind energy potentials for Bulgaria [117] (Figure 36, left). Whereas Eastern and South-Eastern Bulgaria can expect an increase of annual wind energy potentials between 8 and 14%, Central Bulgaria will see a decrease of wind energy potentials of 8-12% and South-Western Bulgaria of 4-6%. Additionally, a strong seasonal shift of wind potentials from winter to summer months is expected.

Studies on climate change-related impacts on solar power generation show very limited or neutral effects [113]. However, changing atmospheric water vapour content and cloud characteristics as well as higher temperatures, which reduces the overall efficiency of PV modules, can cause regional disparities. Spiridonov and Valcheva also quantified climate change related impacts on annual solar radiation (Figure 36, right) for Bulgaria, which will increase in South-Eastern Bulgaria between 2 and 3.5% and in parts of the Balkan and Pirin Mountains up to 6%. On the other hand, solar radiation is expected to decrease up to 1% in some parts of South-Western Bulgaria.

Figure 36: Expected changes in annual wind energy potential (left) and solar radiation (right) for Bulgaria between 2021 and 2050



Source: Spiridonov and Valcheva [117]

4.3.3 Mitigation measures and strategies

Despite a certain degree of uncertainty about the extent of climate change in general and its impact on the power sector in particular, the implementation of mitigation measures and strategies for the future development of the power plant infrastructure is highly recommended. This is particularly relevant given the long design life of thermal and hydropower plants, the high shares of these power plants in most ICPDR countries and the projected largest impact of climate change on thermal and hydropower capacities in the Southern and South-Eastern part of Europe. However, neither hydropower investors and operators always consider future climate conditions so far, nor do energy planners always adequately assess climate change risks in overall electricity system planning [118]. As a consequence, the vulnerability of power systems increases if the required 24/7 balancing of production and consumption is negatively affected by climate change-related impacts. Hence, to maintain security of supply, the primary objective of adaptation strategies should focus on building resilience with regard to current and uncertain future climate risks in the overall power sector [119].[28]

[28] Climate resilience from the perspective of the electricity system is the capacity of an individual generation facility and electricity supply system, respectively, to absorb the stresses imposed by climate change. A resilient power system can withstand shocks such as extreme weather events or outages of generation capacity and rebuild itself. When a power system loses resilience, it becomes vulnerable to changes that could have been absorbed previously. (c.f. [107], [10])

Besides technology specific adaptation measures (e.g. closed-circuit cooling systems for thermal power plants, increased flood protection for hydropower plants), the diversification of an energy system in terms of fuels and energy sources as well as centralised and decentralised technologies will increase the flexibility of the system and hence, its resilience against more variable climatic conditions [113]. An increased (sustainable) diversification in the electricity sector typically requires a larger contribution of "new" renewable energy sources that are independent from water availability and water temperature (i.e. solar PV and wind power), even if those resources can also be negatively affected by climate change. Climate adaptation strategies for hydro-dominated power systems may also require a diversification moving away from hydropower to develop a robust and climate-resilient generation portfolio. In this context, storage hydropower can have an advantage over run-of-river hydropower from the perspective of a power system since storage power plants can balance changing water flows and, with large reservoirs, even reduce the impact on electricity generation from seasonal shifts of precipitation and snow melting.

Aside from the consideration of climate change-imposed risks to hydropower, an overall strategic power system planning process should include a climate risk assessment for concrete hydropower projects, which also needs to be included obligatorily in approval processes. For example, the International Hydropower Association published its *Hydropower Sector Climate Resilience Guide* [120] in 2019, which intends to provide an approach for "[…] identifying, assessing and managing climate risks to enhance the climate change resilience of new and existing hydropower projects". Also, the U.S. Agency for International Development provided an approach for how to address climate change risks for hydropower at project as well as sector level and how to integrate these into the overall project planning process [118].

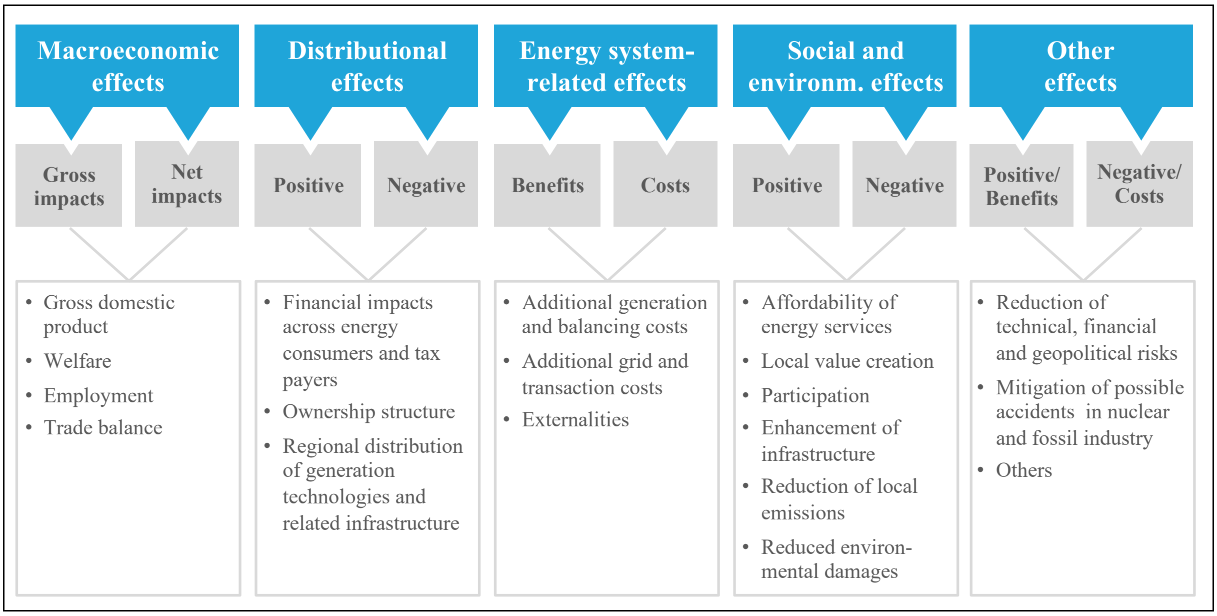
5. Social dimension of hydropower

Not least because of its well-known technical characteristic and risks, low generation and system integration costs as well as reliable generation patterns, hydropower can play an important role in the sustainable and climate-friendly transition of our power system. Hence, efforts to further exploit hydropower potentials have been strengthened in most ICPDR countries, since the expansion of hydropower is considered to deliver a substantial contribution for the implementation of renewable energy and climate targets. Although global warming is one of the major threats of our society today, local and social as well as environmental impacts of hydropower (and other renewable energy technologies) still exist and therefore, the social dimension of energy transition has been becoming increasingly important. Due to the distributed character of renewable energies, renewable power plants are being deployed in many locations and therefore, more and more communities are directly affected by the energy transition and the social costs of the power systems' decarbonisation. With regard to hydropower, it has to be considered that a considerable part of technical potentials has already been exploited and new hydropower capacities frequently affect river stretches with a high ecological value. Additionally, hydropower plants with large reservoirs or large upstream impoundments could negatively affect residential or recreation areas. Therefore, it is essential to include social aspects into a holistic evaluation of the future perspectives of hydropower besides the afore-mentioned favourable energy-economic characteristics. Hence, this chapter provides the social perspectives of hydropower as a counterpart to the energy-economic perspectives. In particular, section 5.1 "Socio-economic aspects " gives an overview of relevant socio-economic aspects of renewable energies and hydropower, respectively. On this basis, section 5.2 "Improving social acceptance of hydropower" provides recommendations to improve social acceptance of hydropower development. Finally, section 5.3 "Is small hydropower more beautiful than large hydropower?" discusses the question, whether small hydropower is more favourable than large hydropower or vice versa.

5.1 Socio-economic aspects

Numerous studies have already been conducted to assess the socio-economic value of renewable energies. However, depending on the various interests and research questions, different methodological approaches, system boundaries and assumptions have been applied. For this reason, it is difficult to compare or even merge results [121]. Against this background, in 2016 the International Renewable Energy Agency IRENA suggested an analytical framework for a country-specific assessment of socio-economic benefits of renewable energies [122]. In its corresponding report *Renewable Energy Benefits: Measuring the Economics*, IRENA differentiated between macroeconomic effects, distributional effects, energy system-related effects and other effects. However, only macroeconomic effects were analysed and quantified, but aspects like for example social, environmental and health-related effects were not explicitly considered (cf. [121]). Therefore, the IRENA concept is slightly extended by explicitly including social and environmental effects as depicted in Figure 37 and discussed in the following.

Figure 37: Potential socio-economic aspects of renewable energy deployment



Source: Adapted from IRENA [122] (indicators exemplarily and not exhaustive)

The IRENA report and also most other publications on socio-economic aspects of renewable energies do not consider specific technologies, i.e. a different view on socio-economic aspects of hydropower and other renewable energy sources, respectively. Nevertheless, a qualitative and quantitative discussion of socio-economic aspects of hydropower is included in the following whenever possible.

5.1.1 Macroeconomic effects

Macroeconomic effects include economic growth (gross domestic product, GDP), welfare, employment and international trade. These effects can either be assessed within the renewable energy and related sectors (gross impacts) or within the economy as a whole (net impacts).

- **Gross domestic product:** Given the capital-intensive nature of renewable energy technologies, the impact of renewables expansion on GDP growth is mostly determined by the additionally required investments. The above-mentioned IRENA report estimated that a doubling of the share of renewables in the final global energy mix would increase the global GDP by 0.6% to 1.1% in 2030 compared to a business-as-usual case [122][29]. However, depending on the economic structure of a country, the costs of conventional energy sources and whether the equipment and required services are imported or sourced locally, the country-specific GDP effects of renewables expansion can vary significantly. For example, countries with a high share of domestic fossil fuels in the electricity mix can even see a negative impact on GDP if renewable equipment (e.g. PV panels, wind turbines) is mainly imported and not sourced locally. In this context, hydropower can be more advantageous than solar PV and wind power in terms of local and regional value creation since the share of civil work in total project costs averages at about 55% [123]. For comparison, wind turbines amount to 70-80% of total wind

[29] The reference case is a business-as-usual case that reflects the most up-to date official plans of a country under existing legislation and the New Policies Scenario of the 2014 World Energy Outlook, respectively. In the REmap case, the global share of renewables doubles by 2030 compared to 2010, accounting for 36% in total final energy consumption. In the REmap Electrification case (REmapE), the global share of renewables also doubles by 2030, but greater emphasis is placed on electrification of heating and transport, requiring a greater deployment of renewables for power generation. [122]

power project costs [124] and modules and inverters to about 50% of total PV project costs [88], i.e. the share of civil work of wind power and solar PV projects is significantly below hydropower.

- **Welfare:** The welfare index is an alternative to the solely economic performance index GDP since it takes into account additional dimensions in which renewables can make a positive contribution. For example, a welfare indicator proposed by IRENA includes the dimensions health and employment as well as climate change and material consumption. According to IRENA, doubling the share of renewables would increase global welfare by 2.7 to 3.7% [122]. Due to the significant reduction of GHG emissions, the positive impact of the deployment of renewables on welfare is considerably higher compared to the impact on economic growth.
- **Employment:** Due to its economic and social significance, job creation is a key element in the discussion about renewable policies and targets. Since the industries involved in the renewables supply chain are generally widely distributed and labour intensive than the conventional energy sector, new jobs in the renewable sectors are likely to offset job losses in fossil fuels industries on a global level. Employment effects differ between countries and especially those countries with a strong fossil, but a weak renewables manufacturing industry might see negative net job effects from the expansion of renewable energies. For example, solar PV creates at least twice the number of jobs per MWh of electricity compared to coal or natural gas [122]. Although a significant share of solar PV jobs is created in the manufacturing industry – specifically China's PV manufacturing industry, which produced nearly 70% of the world's PV panel demand in 2018 – this share accounted for almost 45% of the 3.6 million global PV jobs [125]. In contrast, Europe's PV industry employed only about 0.1 million people in 2018, which is noticeably below wind power (0.31 million [125]) and even below the hydropower sector with about 120,000 people being employed across Europe [126]. However, it has to be considered that on average 72% of the total jobs in the hydropower sector are in operations and maintenance (23% in construction and installation and 5% in manufacturing) [125] and therefore, on a local/regional and not global level. Accordingly, specific operations and maintenance employment of hydropower is about 0.4 jobs/MW and therefore, in same order of magnitude as for wind power and solar PV, which is estimated to account for between 0.1 and 0.6 jobs/MW for wind power and 0.1 and 0.7 jobs/MW for solar PV [127].
- **Trade balance:** The analysis in the IRENA report *Renewable Energy Benefits: Measuring the Economics* shows that the impact of a significant increase in global renewables deployment on overall trade is relatively low [122]. However, depending on the reliance on domestic fossil fuels, a greater share of renewables will slightly shift global trade flows and hence, can have different effects on individual countries. In general, countries with a reduced utilisation of domestic fossil fuels for export and domestic consumption, respectively, will see a reduction of exports, whereas countries with a strong renewables manufacturing industry will see an increase of net exports. Hence, the IRENA analysis shows a negative impact of an increased renewables deployment on trade balance for all ICPDR countries except Germany and Austria and therefore, effects comparable to GDP and employment.

5.1.2 Distributional effects

Distributional effects refer to the allocation of effects of the energy transition to different stakeholders primarily within the energy sector but also within the overall society. Usually, distributional effects are related to fiscal aspects, i.e. the distribution of costs and benefits of renewable and climate policies amongst energy consumers and taxpayers. However, in a broader sense, distributional effects also cover the type of ownership structure of renewable assets as well as the regional geographical distribution of renewable generators incl. grid and storage infrastructure ([121], [128], [129]). Distributional effects of the energy transition can be positive or negative – positive for the beneficiaries and negative for those who have to bear the corresponding burden. Hence, it is crucial for the acceptance of the energy transition and further deployment of renewable energies to adequately address distributional effects since the public has been becoming increasingly sensitive to social imbalances caused by e.g. rising power prices and uneven regional distribution of renewable assets.

The discussion and analysis of distributional effects in academic literature is mostly focused on fiscal impacts of the design of climate policies and renewable support schemes, respectively, and the related question of which actors are financially engaged in the deployment of renewable energies (e.g. [129]). Although the literature does not distinguish between financial distributional effects of different renewable technologies, it can be expected that technologies with lower generation and systems costs (cf. section 4.2 “Costs of electricity generation”) will have less impact on the electricity bill of consumers and therefore, less potentially negative social effects.

Besides financial impacts on different parts of the society, distributional effects also include the regional distribution of renewable deployment and hence, the visual and subjectively noticeable impact of renewable energies. Generally, for an evenly distributed renewables generation close to final consumers, it would be important to illustrate the required structural changes and changes in the landscape for all parts of society. Renewables deployment will physically affect different parts of the population differently. Wind potentials are typically not evenly distributed in a country, large solar PV plants require large fallow or agricultural land, hydropower plants are located on a few rivers and the expansion of the distribution and transmission grid affects a limited geographical corridor. Hence, economic and social benefits beyond the construction phase of renewable energy plants should be provided to those regions which are affected most by the energy transition. Rural regions are generally more affected by the energy transition than urban areas, since heavily populated areas do not have the required areas to supply their energy demands from renewables in close proximity. Therefore, renewable deployment should be used actively for the development of rural regions and local value creation by means of e.g. financial compensations beyond concessions and one-time fees, ownership structures that allow a financial participation of individual persons, communities and local entities as well as a balanced portfolio of large centralised and smaller distributed generation.

Although distributional effects – with the exception of geographical distribution – cannot be attributed to a specific technology, the further development of hydropower represents a particular challenge for social acceptance due to the perceived large environmental impacts. Hence, efforts to achieve social acceptance for hydropower are of particular importance and are further discussed in section 5.2 “Improving social acceptance of hydropower”.

5.1.3 Energy system-related effects

Energy system-related effects refer to additional costs or benefits of renewable energies compared to a "conventional" power or energy system without an increased share of renewables. The associated costs are also often referred to as "integration costs" and "system integration costs", respectively, and typically comprise (a) costs for the interaction of renewables with other power plants in the electricity system (e.g. costs for backup capacities, increased ramping, cycling and operation at partial load), (b) balancing costs to compensate differences between forecasted and actual production of renewables and (c) grid costs for the expansion of the distribution and transmission networks. For a more detailed discussion of this energy-system related effects of renewable energies in general and hydropower in particular, please refer to section 4.2.2 "System integration costs" of the report at hand. Additionally, the benefits of reduced negative environmental externalities of renewable energies can also be considered as energy system-related effects and are discussed in more detail in section 4.2.3 "External costs".

With regard to hydropower, it can be summarised that both in terms of system-related effects and externalities, hydropower does not only offer advantages compared to conventional fossil and nuclear electricity generation but also compared to other renewable energies.

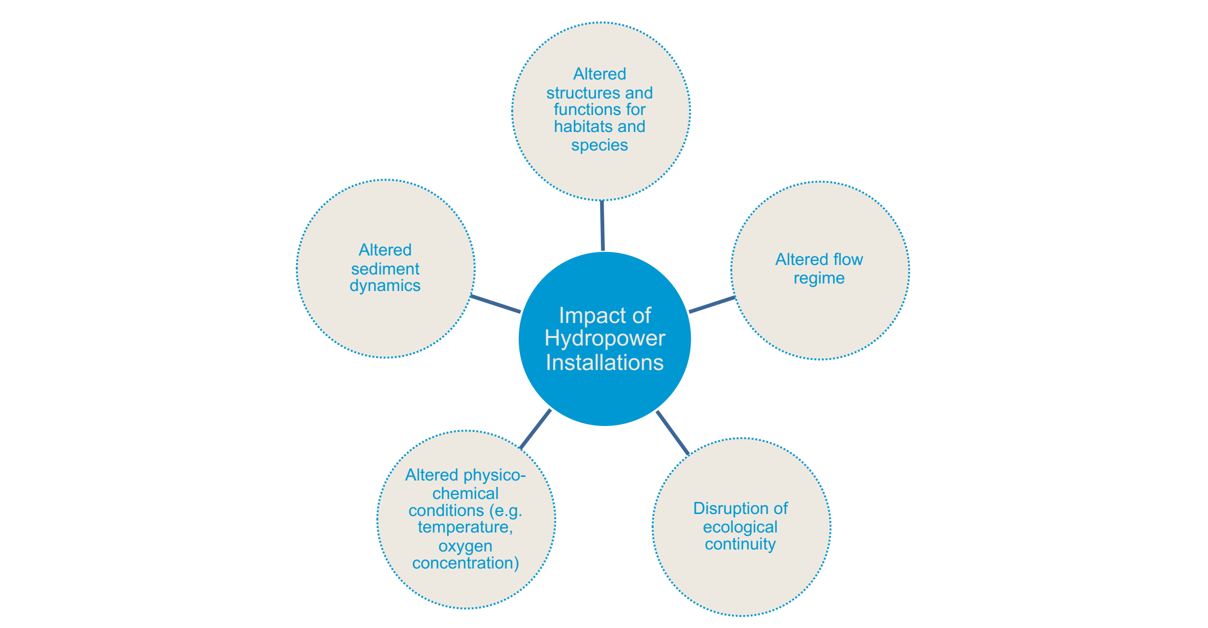
5.1.4 Social and environmental effects

The deployment of renewable energies can offer manifold advantages far beyond their contribution to climate change mitigation. Besides positive macroeconomic effects and low environmental externalities, renewable energies may also be considered for its social and economic benefits. Among these benefits are opportunities for local value creation, access to affordable energy services, active participation in the energy value chain or enhancement of local infrastructure [121], [122]. Additionally, renewable energies can have favourable effects on health by eliminating local emissions from fossil power plants and can reduce environmental damages of the production and mining of fossil fuels (cf. [130]). Inevitably, renewable energies can also have negative ecological and social impacts on e.g. natural resources, agriculture and forest land use, settlements and cultural heritages. Hence, renewable energy deployment not only needs to be assessed from the climate and energy-economic perspectives but also from the perspective of social responsibility.

Although social and environmental issues have been discussed for all kinds of renewable energy sources, it is especially hydropower that is in the focus of the discussion around environmental and social impacts of renewables. Dependent on plant type, size, mode of operation and location, hydropower can have various impacts on the aquatic ecology, natural scenery and ecosystems. In its *Guiding Principles on Sustainable Hydropower Development in the Danube Basin* [5] ICPDR depicted possible key ecological impacts in connection with hydropower (cf. Figure 38) and provided in the following.

- Dams and weirs used for hydropower generation cause an interruption of the longitudinal river continuity resulting in significant adverse effects on the river's aquatic communities. Migrating species like fish in particular are affected by the fragmentation of their habitats.
- Furthermore, hydropower plants can change the hydromorphology. Morphological degradation affects not only the composition of natural structural elements and the loss of dynamic hydrological processes and sediment transport but can also cause fundamental changes to the river type or surface water category.

Figure 38: Possible key ecological impacts of hydropower installations – Illustrative range of possible alterations typically associated with hydropower dams



Source: ICPDR [5]

- In case of impounded rivers, the reduction of flow velocity can impact fish due to the loss of orientation. Changed width-depth variations and reduced riverine habitats can shift the species composition from a riverine type (lotic) to a standing type (lentic). Reduction of flow velocity also results in other negative impacts like increase of water temperature and decrease of oxygen concentration, decrease of self-purification capacity, increased deposition of fine sediment in the impoundment as well as disturbed bed load discharges and sediment transport, leading to erosion and deepening processes downstream of the impounded section. A series of impoundments (chain of hydropower plants) have strong cumulative effects on the aquatic ecosystem of the whole (sub-)basin.
- In case of hydropower generation by diversion plants, nonsufficient ecological flow in the affected stretches cause a number of impacts on the river ecology, notably: homogenisation of the flow character and degradation of habitat, continuity disruptions for migrating fish and changes of the natural temperature conditions.
- Another impact stemming from hydropower can be hydropeaking, which is mainly caused by large hydropower plants in combination with reservoirs. Hydropeaking can have severe ecological effects on a river. Depending on the rate of discharge acceleration, benthic invertebrates and also juvenile and small fish can get washed away with the flush, which results in decimation of benthic fauna, reduction of fish biomass and also changes to the structure of fish populations. During the down-surge, benthic invertebrates and fish can get trapped in pools that might dry out later on so the animals either die or become easy prey for predators.
- In reservoirs and impounded river stretches the reduced flow velocity leads to an increased deposition of fine sediment that requires periodical flushing of the reservoirs. This can cause a number of negative effects on freshwater ecology.

Besides potential adverse effects on the aquatic ecology and natural habitats of river ecosystems, hydropower potentially has negative impacts on the livelihoods of (indigenous) communities due to the flooding of settlements and forced relocation, loss of agricultural land and cultural heritage, to name a few. In return, hydropower can also have positive social impacts such as the multifunctional use of (large) reservoirs for e.g. irrigation, flood control and tourism, the creation of local jobs or the enhancement of infrastructure and electricity supply. Table 2 provides a summary of potential positive and negative social and environmental impacts of new hydropower stations.[30]

Table 2: Potential positive and negative social and environmental impacts of new hydropower stations

Positive impacts	Negative impacts
Flood protection/prevention	Forced population displacement and resettlement[a]
Water supply for irrigation, cooling water, drinking water, etc.	Boomtown formation around major construction sites[a]
Job creation and local employment	Displacement of indigenous people[a]
New tourism and recreation opportunities	Loss of cultural heritage assets[a]
Enhancement of infrastructure (road access)	Degradation/loss of ecosystem services and natural resources
Financial benefits for local communities	GHG emissions from reservoirs[a]
Support of secure electricity supply	Loss of agricultural and forestry land
Support of climate and renewable policies	Deterioration of water quality
Provision of ancillary services (storage hydropower)	Loss/decline of fishery
	Decline of tourism (e.g. wild water rafting)

Source: Fichtner [123], IHA [131], Moran et al. [132], EBRD [133] and others; [a] developing and emerging countries

It is, however, worth to mention that severe social issues from new hydropower plants today mainly occur in developing and emerging countries, where potentials for very large hydropower plants with up to several 1,000 MW are still available. Hence, social issues such as displacement of (indigenous) population, boomtown formation, vast losses of agricultural and forestry land or loss of cultural heritages are, from a European perspective, rather negligible. In contrast, ecological impacts, lack of transparency, issues of ownership or missing possibilities for an active citizen participation in the planning process can also lead to social issues in European countries. Therefore, a careful consideration and assessment of social aspects is also crucial for hydropower projects in European countries (c.f. section 5.2 “Improving social acceptance of hydropower”).

5.1.5 Other effects

In its report *Renewable Energy Benefits: Measuring the Economics*, IRENA subsumed socioeconomic effects, which cannot be clearly assigned to one of the defined categories, under other effects [122]. Besides the mitigation of possible accidents in the fossil and nuclear industry, other effects mainly refer to reduced financial, technical and geopolitical risks by deploying renewable energies. Financial risks refer to risks that are related to the uncertain development of future fuel prices. Since the LCOE of renewable electricity technologies are mostly determined by investment and not fuel costs, renewable energy sources have more predictable and less volatile costs and hence, can reduce financial risks within an energy system. Geopolitical risks are related to the dependency of an economy on energy imports, whereas technical risks refer to the possible risk of supply disruptions caused by technical issues in e.g. electricity transmission and distribution networks and power plants, respectively. Since renewable energies are generally more distributed than conventional power plants, the impact of a single technical failure on the overall supply system is smaller in systems characterised by renewables. Volatile renewable energies may be more distributed but, on the other hand, they can imply a reliability risk due to their intermittency and hence, can result in adverse energy system related effects. Therefore, it is

[30] For a detailed discussion of potential ecological effects of hydropower, please refer to the ICPDR document *Guiding Principles for a Sustainable Hydropower Development in the Danube Basin* [5].

reasonable to develop a well-diversified energy mix in general and electricity generation portfolio in particular to provide the required robustness against technical and geopolitical risks.

In this context, hydropower can offer technology-immanent risk reduction to the electricity system. Especially if hydropower plants are combined with a reservoir, they can provide flexible generation and ancillary services, which will considerably gain importance in a power system with a high share of volatile generation from wind and solar PV. However, hydropower alone will not necessarily help a generation portfolio to be more robust. A greater consideration of wind, solar PV and biomass in a hydro-dominated renewable and generation portfolio, respectively, would provide for a better diversification of the portfolio and make it less vulnerable to unavoidable seasonal and yearly fluctuations of electricity generation from hydropower as well as potential impacts of climate change on the availability of hydropower plants.

5.2 Improving social acceptance of hydropower

The German Development Institute put the controversial discussions about hydropower development in a nutshell pretty well: "Is hydropower desirable because of its ability to provide low-carbon energy, or undesirable because of its local environmental and social impacts?" [134]. Although the benefit of hydropower goes beyond simply contributing to climate change mitigation, the consideration of social and socio-economic impacts on local people and communities will be key for public acceptance and hence, the possible further development of hydropower – also in ICPDR countries. In this context, it is worth to mention that social acceptance of hydropower may not only be linked to new hydropower installations but also to the way how adverse social and ecological impacts of existing hydropower plants are mitigated and minimised. For example, an exemplary implementation of WFD requirements or revitalisation of degraded river stretches at existing hydropower plants could positively impact the overall acceptance of hydropower. Nevertheless, new hydropower projects will always remain challenging with regard to acceptance and hence, adequate measures to improve social acceptance should be considered. The elements that can decisively influence public acceptance of the expansion of renewable energies are for example categorised by POLIMP in its Policy Brief *Acceleration of clean technology deployment within the EU: The role of social acceptance* [135]:

- Awareness of climate change and knowledge of the technology (i.e. hydropower) as such and its role in the electricity system.
- Fairness of the planning and decision-making processes, which includes openness (sharing all relevant information), inclusiveness (interacting with all stakeholders), responsiveness (listening to the community and stakeholder concerns), accountability (ongoing process of monitoring, evaluation and participation), and flexibility (preparing for local requests and being open to amendments) [136].
- Assessment of costs, risks and benefits, taking specific needs and fears of (local) stakeholders into account.
- Local context to facilitate discussion about rational and emotional objections to a project. The local context also includes benefit sharing through e.g. financial compensations, local (co-)ownership and direct investments in local infrastructure, cultural, social and sports facilities, etc.
- Public trust in decision-makers and other stakeholders, which reflects the public perception of the stakeholder's organisational competence and integrity.

Whereas POLIMP and most other literature does not quantify the effect of different elements of public acceptance of renewable energy deployment, Tabi and Wüstenhagen investigated in an empirical survey the influence of different parameter on the social acceptance of hydropower in Switzerland [137]. The study concluded that a fair and participatory planning and decision-making process (9.8%) and a fair allocation of costs and benefits through local job creation (10.6%) as well as financial benefits for communities and cantons through water tax (7.5%) are necessary prerequisites for social acceptance. However, successfully addressing people's concerns about potential ecological impacts (41.5%) and the type of ownership (30.6%) are – at least for Switzerland – the most important elements of social acceptance by far. Hence, Tabi and Wüstenhagen summarised their results as "keeping a hydropower project local and fish-friendly", i.e. social acceptance of further expansion of hydropower requires a low ecological impact and local or regional owners are strongly preferred over private domestic or foreign investors. With regard to the comparatively low importance of a participatory decision-making process, the authors noted that Switzerland already offers sufficient legal provision for participation through its direct democracy and hence, the importance of this element for social acceptance of hydropower might be smaller compared to other countries. Generally speaking, country-specific economic and social conditions play an important role in the prioritisation of adverse effects and benefits of hydropower projects; i.e. the exemplarily shown relations for Switzerland may not be directly applied to other countries.

Public participation is also an essential part of the environmental impact assessment (EIA) procedures and strategic environmental assessment (SEA)[31], which must be implemented not only by EU member states but also by Contracting Parties of the Energy Community (EnC, cf. [138]). Hydropower projects are also subject to EIA legislation and a so-called screening obligation. If significant negative effects on the environment are identified at the screening stage, a full EIA must be carried out. The scope of the EIA is defined by the competent authority based on the legal requirements of the directive. Besides public participation, an EIA typically considers impacts on human beings, fauna and flora, soil, water, air, climate, landscape, material assets, cultural heritage, etc. With regard to hydropower, various guidelines are available to support an EIA, for example the *Hydropower Sustainability Assessment Protocol* from the International Hydropower Association (IHA) [131] or the *Environmental and Social Guidance Note for Hydropower Projects* from the European Bank for Reconstruction and Development (EBRD) [133]. Project developer, investors and authorities should consider an EIA not only as a formal prerequisite but as a chance to identify, manage and actively engage stakeholders to understand why communities accept or reject hydropower projects. Additionally, the basic principles of an EIA should also be applied if an EIA is not legally required, since local communities are an important factor for the successful implementation of hydropower projects. For example, a lack of public participation has already become an incalculable risk for hydropower companies in several Western Balkan countries, where the Energy Community stated to challenge any permit granted for small hydropower plants that does not comply with EIA requirements with regard to public participation [138], [139].

Besides the implementation of EIA principles, the development of sustainable and socially accepted hydropower projects can also be facilitated by commonly accepted criteria catalogues. Criteria

[31] Directive 2011/92/EU on the assessment of the effects of certain public and private projects on the environment (Environmental Impact Assessment (EIA) Directive) and amending Directive 2014/52/EU. Directive 2001/42/EC on the assessment of the effects of certain plans and programmes on the environment (Strategic Environmental Assessment (SEA) Directive).

catalogues for the assessment of hydropower projects should cover both energy and water management as well as ecological and social aspects and should be developed in a broad integrative process that includes all relevant stakeholder. Several criteria catalogues and approaches for strategic hydropower planning and/or project evaluation have been developed in the recent years, e.g. ICPDR *Guidelines on Sustainable Hydropower Development in the Danube Basin* [5], *Austrian Catalogue for Water: Protecting Rivers – Using Rivers* [140], *Common Guidelines for the Use of Small Hydropower in the Alpine Region* [141] or the Tyrolean criteria catalogue *Hydropower in Tyrol* [142] (cf. fact box below). The Tyrolean criteria catalogue also served as a best practice example in Bosnia and Herzegovina, where the *Criteria Catalogue for sustainable small hydropower plants (SHPP) in Bosnia and Herzegovina (BIH)* was developed in the course of a project funded by GIZ[32] [144].

Fact box: Tyrolean criteria catalogue "Hydropower in Tyrol"

The Tyrolean criteria catalogue should support the reasonable and for all involved and affected stakeholders, respectively, acceptable (i.e. "integrative") utilisation of the remaining hydropower potential in the Austrian province of Tyrol. The criteria catalogue as well as an accompanying study on hydropower potentials was elaborated between 2009 and 2011. The catalogue was prepared by internal experts of the Regional Government of Tyrol and independent external experts. Additionally, an intensive interaction with the public and relevant stakeholders took place, e.g. almost 400 persons and institutions provided feedback to the first draft of the criteria catalogue.

The catalogue considers five different subject areas: (a) energy management, (b) water management, (c) regional planning, (d) aquatic ecology and (e) nature conservation. Criteria to assess social aspects do not constitute a separate subject area but are included in other subject areas. These are, for example, the criteria financial participation of local stakeholder, contribution to regional and national economy, impact on infrastructure and contribution to distributed generation.

However, the catalogue is not legally binding but should provide an orientation for the evaluation of concrete hydropower projects during the planning phase. Additionally, the criteria should support the identification of the most suitable areas and river stretches, respectively, for e.g. regional master plans and regional programmes. To facilitate the implementation of the criteria catalogue, a comprehensive application manual as well as an Excel spreadsheet are provided to support the assessment.

Participation of individual persons and local communities in the planning and decision-making process of hydropower projects is one thing; it is another to set up ownership structures and accompanying investment programmes, respectively, that enable a community to participate in economic benefits of a hydropower plant. Sharing of financial benefits has already become increasingly important, since local stakeholders a more and more unwilling to accept the uneven distribution of benefits and negative impacts of hydropower (e.g. [145]). Benefit sharing can, for example, be implemented through financial compensations, (co-)ownership of communities and direct investments in local infrastructure, cultural, social and sports facilities, etc. Today, financial compensations such as concession fees and water taxes are, in many cases, insufficient to give due consideration to the society's demand for financial benefit sharing. Local

[32] Deutsche Gesellschaft für Internationale Zusammenarbeit (German Federal Enterprise for International Cooperation)

stakeholders and communities should have participatory rights via financing or other contractual mechanisms to establish long-term revenue- and non-revenue-based benefit sharing for the region bearing the negative social and environmental effects of a hydropower plant. However, actual financing of hydropower projects in the Danube region does not reflect the growing need for local and regional financial participation. For example, the 2018 update of the CEE Bankwatch Network study *Financing for hydropower in protected areas in Southeast Europe* [143] showed that most hydropower projects in SEE with available data are financed by foreign commercial banks and multilateral development banks (e.g. European Bank for Reconstruction and Development and European Investment Bank). Due to the comparatively high investment demands of hydropower plants, local stakeholders will, in most cases, not be able to completely finance a hydropower project. Hence, at least co-ownership should always be offered to local stakeholders and communities as well as local and regional utilities by private investors and supra-regional utilities.

Examples for the implementation of local and regional sharing of economic benefits from hydropower are the hydropower plant Stanzertal [146] in the Austrian province of Tyrol and the so-called environmental plans of the South Tyrolian utility Alperia [147]:

- The diversion hydropower plant Stanzertal with an installed capacity of 13.5 MW and an average annual production of 53 GWh/a was commissioned in 2014. Total investment costs were €58 million and financed by a consortium of five communities (30%), three community-owned regional utilities (60%) and a regional project developer (10%).
- In 2011, Alperia received concessions for several large hydroelectric power plants for a thirty-year period. For the first time in Italy, the concessions are mandatorily linked to significant environmental investments. In total, Alperia will invest €400 million in environmental measures such as energy-saving street lightning, refurbishment of public buildings, cabling of overhead lines and new walking trails and other recreational facilities. Besides direct investments in those communities, where the hydropower plants are located, investments are also made for the restoration of rivers in the entire South Tyrolean province of Bolzano.

Financial engagement of local stakeholders can also be realised via non-commercial energy communities, which is especially true for (very) small hydropower plants. The legal status of energy communities was significantly improved by the EU's *Clean Energy for All Europeans* package in late 2018. Member states have to incorporate the requirements into national law before mid-2021. Energy communities can either be implemented as "Citizen Energy Communities" (CEC; acc. Article 2(11) Electricity Directive[33]) or "Renewable Energy Communities" (REC; acc. Article 2(16) Renewables Directive[34]). Although the basic principles and ideas of CECs and RECs are rather similar, they can differ significantly in its details. CECs can be used by citizens, small businesses and local authorities to participate in activities across the entire energy sector. In contrast, RECs are technology-specific, centred on renewable energy sources and more rooted in local communities (cf. [148]). Energy communities should not be considered as a necessary evil of European legislation but as a chance to increase public and social acceptance of the energy transition and hydropower projects, respectively. Hence, countries should adopt the legal and regulatory frameworks not only to allow, but to actively support, the implementation of CECs and RECs.

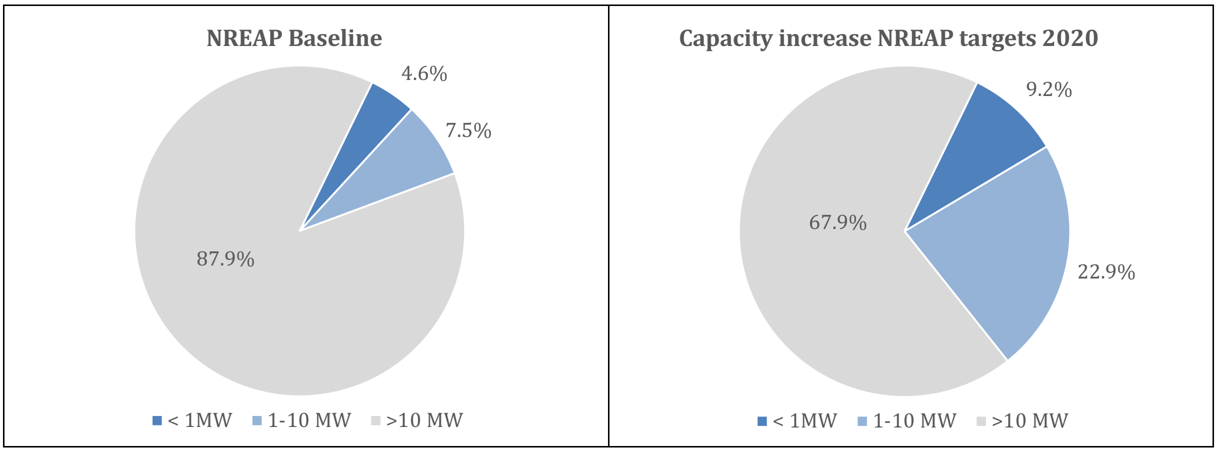
[33] Directive (EU) 2019/944 on common rules for the internal market for electricity and amending Directive 2012/27/EU.
[34] Directive (EU) 2018/2001 on the promotion of the use of energy from renewable sources (Renewable Energy Directive).

5.3 Is small hydropower more beautiful than large hydropower?

Small hydropower (i.e. up to 10 MW) is often considered to have less negative social and environmental impacts than large hydropower and should, therefore, be developed preferably. However, in recent years more and more critical voices argued that “small is not always beautiful”, since cumulative ecological impacts of small hydropower plants can even exceed the impact of a large hydropower plant that produces the same amount of electricity (e.g. [134], [149], [150], [151], [153], [154], [152]). Additionally, lack of participation in planning and decision-making processes as well as missing financial benefits for the local community and region, respectively, have already reduced public acceptance for small hydropower in many ICPDR countries such as Montenegro, Serbia and Bosnia and Herzegovina ([139], [145], [155]).

While large hydropower is a well-established technology in Danube countries, small hydropower has emerged in most countries only in the last few years. Accordingly, large hydropower still represents about 85% of the installed hydropower capacities in ICPDR countries. In contrast, the countries’ National Renewable Energy Action Plans (NREAP)[35] have put a strong focus on small hydropower. 32% or 5.4 GW of the combined hydropower targets of 16.9 GW (excl. pumped storage) for 2020 is allocated to small hydropower. Figure 39 gives an overview of the share of small and large hydropower of all ICPDR countries for the NREAP baseline and the capacity increase as defined in the 2020 objectives.

Figure 39: Share of small and large hydropower capacity of ICPDR countries for NREAP baseline and 2020 targets



Source: NREAPs of ICPDR countries

The relatively strong focus of the countries’ hydropower strategies on small hydropower is, to some extent, contrary to the energy-economic and environmental characteristics of small hydropower. As already shown in section 4.2.1 “Levelised costs of electricity”, specific investment costs of small hydropower plants are generally higher than specific investment costs of large(r) hydropower plants. Hence, (very) small hydropower plants typically require higher subsidies per MW and MWh, respectively, to provide potential investors a viable business case. From the perspective of security of supply, large hydropower plants typically provide greater operational flexibility, as they can be implemented easier and more cost-effective in combination with reservoirs (i.e. storage hydropower) and/or hydropeaking operation. Additionally, flows of rivers with small catchment areas are often more variable and more

[35] As part of the ratification of the Treaty on establishing the Energy Community (EnC) also the non-EU member states from the ICPDR adopted the EU Renewable Energy Directive with binding renewable energy targets for 2020 and the obligation to submit a NREAP to further detail renewable energy targets.

vulnerable to climatic variations [118]. On the other hand, small hydropower can support distributed generation structures, which can be more resilient against a failure of a single power plant. Also, it is easier to implement community ownership and financial engagement of local stakeholders for small hydropower plants with manageable investment needs. From a grid perspective, distributed small hydropower plants may also be advantageous if located close to consumers and hence, reduce grid losses and grid expansion requirements, respectively. Such a positive contribution might be especially visible in regions with strong and highly meshed distribution grids, as for example in Germany [156]. However, distributed generation and hence, small hydropower plants may also have disadvantages compared to large hydropower in terms of grid connection. For example, the final report of the study *Regional Strategy for Sustainable Hydropower in the Western Balkans* [99] stated, "[…] the capacity of the distribution networks in the region is insufficient to facilitate growing demand for connection of new small HPPs and distributed generation in general". However, the study also concluded, "the capacity of the transmission grid, if observed from the regional level, seems to be sufficient to facilitate any additional major planned HPP development projects."

Despite having some downsides from energy-economic perspective, investment in small hydropower plants are often favoured by climate and energy policies due to the general perception of "small is beautiful" or simply as a counter-reaction to the growing resistance against large hydropower plants and their social and environmental impacts. Of course, the social and environmental impact of a small hydropower plant is generally a magnitude smaller than of a large project. But a small hydropower plant also produces far less electricity, i.e. many small hydropower plants need to be built to provide the same amount of electricity as a large hydropower plant. Hence, it is important to consider the cumulative impacts of small hydropower plants on e.g. a single river or within a catchment area and not only impacts of an individual project. Recent studies have concluded that the specific impact (i.e. per MW or MWh) of small hydropower plants is bigger than of large hydropower plants [149]. For example, in the Duero River Basin in Spain, small hydropower projects caused nearly one-third of the total hydropower impacts but provided only 7% of the total electricity generation. Additionally, electricity generation by small hydropower was 15% more expensive and less flexible in terms of meeting grid demands [157]. Also, a Norwegian study comparing the environmental impacts of small and large hydropower concluded, "[…] it is reasonable to assume that a few large hydropower projects will produce electricity to a lower environmental cost compared to many small projects" [158].

In summary, large hydropower tends to be the better option both from an energy-economic as well as environmental and social view. However, there is generally not a linear relationship between size and impact and hence, the discussion should not focus on "small or large" but about on benefits and impacts of concrete hydropower projects and possible mitigation measures. Therefore, small hydropower plants should be subject to the same environmental regulations as large hydropower plants and need to be included into long-term coordinated planning and assessment at basin-scale. Additionally, renewable strategies and promotion schemes should consider the true environmental and social costs and benefits of small hydropower.[36]

[36] Adapted from Lange, K. et al. *Small hydropower goes unchecked* [153].

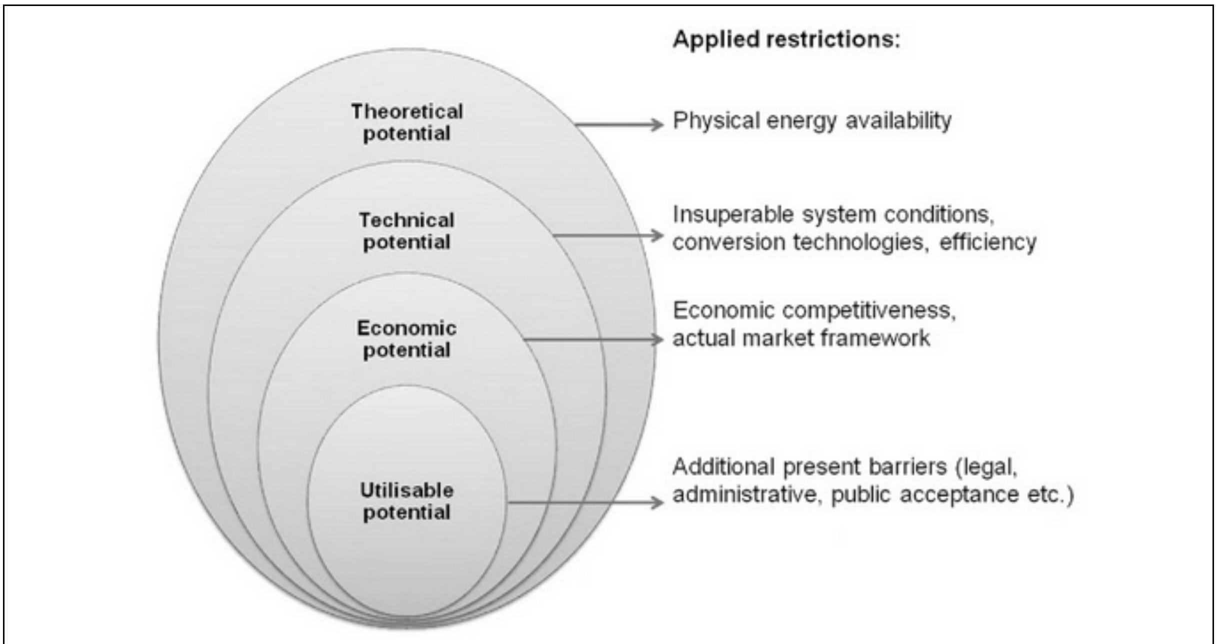
6. Perspectives for further development of hydropower

With an installed capacity of about 40.2 GW and an average generation of about 122 TWh/a, hydropower (excl. pumped storage) today represents about 10% of the capacity and generation mix of the fourteen ICPDR countries. Although the development of hydropower potentials is already in an advanced stage, the Danube countries still have considerable potentials for major hydropower capacity additions – about half of the technical hydropower potential in ICPDR countries has not been exploited yet. However, depending on the country-specific conditions both the share of hydropower in the nations' electricity mix and the remaining hydropower potential range widely. Accordingly, the importance of hydropower for the development of the individual country's electricity system can differ markedly. Against this background, this chapter provides a summary of the hydropower potentials in the Danube countries in section 6.1 "Technical and economic hydropower potentials of Danube countries" and a more detailed analysis of the perspectives for a further development of hydropower in six selected ICPDR countries in section 6.2 "A more detailed view on selected ICPDR countries".

6.1 Technical and economic hydropower potentials of Danube countries at a glance

It is estimated that only about half of the technical hydropower potential of the Danube countries has already been exploited so far. However, due to e.g. economic and environmental restrictions, only a certain share of the technical hydropower potential can finally be realised, i.e. the technical potential is only a first indication with regard to the remaining hydropower potentials. Generally, besides the technical potential it can additionally be differentiated between the theoretical, economic and utilisable potential of renewable energies as shown in Figure 40 (cf. e.g. [159], [160]).

Figure 40: Definition of different renewable potentials and applied restrictions



Source: Hermann [160]

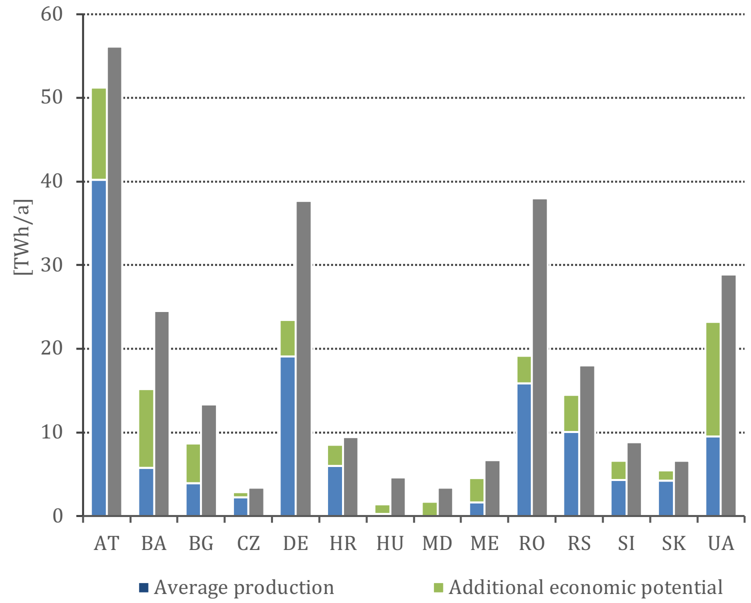
- **Theoretical potential:** from a physical perspective theoretically useable amount of energy within a limited region and over a specific time period (e.g. potential energy of drainage in river stretches in a certain country). The theoretical potential has no practical relevance but is typically used to calculate other potentials.
- **Technical potential:** defined as the part of the theoretical potential that is available if technical restrictions are taken into account, such as efficiencies and conversion losses. Other restrictions can be the availability of a grid connection as well as distribution and transmission grid capacities, the accessibility of locations for the construction of power plants or the daily/seasonal demand for energy.
- **Economic potential:** the part of the technical potential that can be economically utilised under the current or the expected future market framework. The economic potential of renewable technologies is primarily determined by the cost structure of conventional technologies that are used for comparison with the cost structure of renewables. Hence, the economic potential is a function of the underlying assumptions of e.g. fuel and carbon emission costs, investment and maintenance costs and costs of financing.
- **Utilisable potential:** the share of the economic potential that is accessible if not only technical and economic but also other restrictions are taken into account (e.g. legal and regulatory barriers, nature conservation and other environmental restrictions). The utilisable potential is usually smaller than the economic potential but subsidies for renewable energies can boost the utilisable potential even beyond the economic potential.

For its report *Cost-Competitive Renewable Power Generation: Potential across South-East Europe* [8], the International Renewable Energy Agency (IRENA) collected and published the latest publicly available information on hydropower potentials in SEE at country level. Aside from the technical potential, the IRENA report also includes the so-called cost-competitive (i.e. economic) potential considering the fact that only a portion of the technical potential can – from an economic point of view –be implemented effectively. IRENA defines the cost-competitive renewable energy potential as the potential that is cost-competitive with new hard coal, natural gas and lignite fired power plants. The IRENA report explicitly mentions that environmental aspects were not taken into account to derive the cost-competitive hydropower potentials and stated, “the real implementable renewable potentials might be lower due to increasing environmental protection requirements”.

The IRENA report includes nine of the fourteen ICPDR countries, i.e. Bosnia and Herzegovina, Bulgaria, Croatia, Moldova, Montenegro, Romania, Serbia, Slovenia and Ukraine. Hence, for Austria, the Czech Republic, Germany, Hungary, and Slovakia the technical and economic hydropower potential is derived from other sources. Additionally, the hydropower potentials as included in the IRENA report are verified with other publications and – if justifiable – adopted.[37] Figure 41 depicts the technical and additional (remaining) economic potentials of hydropower in ICPDR countries as well as the already utilised potentials, which are expressed as the average hydropower production in a regular year based on the installed capacities of the year 2018.

[37] Note that hydropower potentials as included in publications of the EU-funded project *Regional Strategy for Sustainable Hydropower in the Western* Balkans (cf. [9]) only consider potentials of large hydropower (except for FYROM and partially Montenegro). For this reason, besides possible general difference in the definition of the technical hydropower potential the published numbers cannot directly be compared.

Figure 41: Annual hydropower production, technical and additional economic hydropower potential



	Average annual production	Additional economic potential	Total technical potential
AT	40.2	11.0	56.1
BA	5.8	9.4	24.5
BG	3.9	4.8	13.4
CZ	2.2	0.6	3.4
DE	19.0	4.4	37.7
HR	6.0	2.5	9.4
HU	0.3	1.1	4.6
MD	0.0	1.7	3.4
ME	1.7	3.2	6.6
RO	16.6	10.5	38.0
RS	10.0	4.5	19.5
SI	4.3	2.3	8.8
SK	4.3	1.2	6.6
UA	1.8	5.8	28.9
Total	**126.0**	**62.9**	**260.8**

Source: IRENA [8], [161], Eurelectric [19], Mot MacDonald [9], Pöyry [162], WEC [163], Anderer, P. et al, [52]

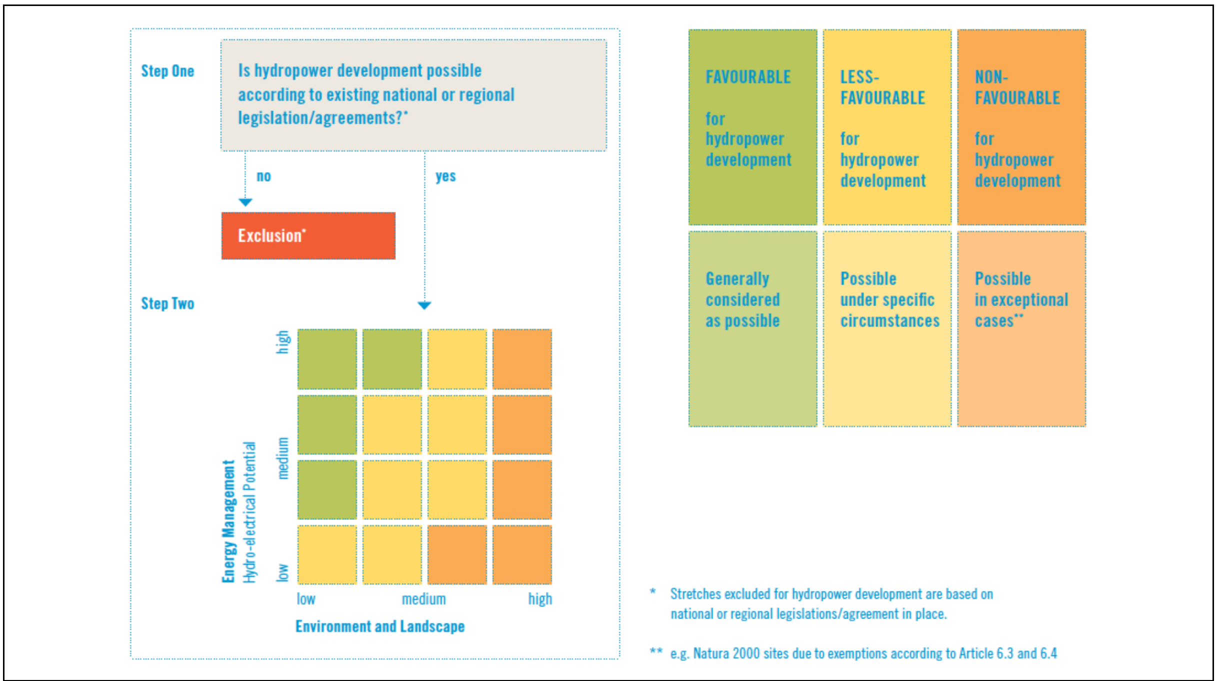
The ICPDR countries represent a hydropower portfolio of 40.2 GW with an average annual generation of about 126 TWh/a[38]. In total, the technical potential amounts to 261 TWh/a, i.e. about two times the actual usage. In contrast, the total economic potential is estimated to be 195 TWh/a, i.e. about one third less than the technical potential. Hence, the additional cost-competitive or economic potential is about 63 TWh/a or 50% of the already used potential. The individual countries achieved different deployment rates concerning their economic potentials ranging between about 80% in Austria and Germany and about 30-40% in Bosnia and Herzegovina and Montenegro.

It should be noted again that the economic potential generally does not consider environmental and social restrictions with the exception of exclusions zones such as national parks or other strictly protected areas. Hence, the economic potential may only be considered as the hydropower potential solely from an energy-economic perspective. In contrast, the actually utilisable potential reflects a socio-political consensus in which the energy-economic perspective is only one aspect of the overall decision-making process. Therefore, the utilisable potential could even be close to zero if perceived negative social and ecological impacts of new hydropower projects are rated higher than a contribution to climate and renewable energy targets as well as potentially positive energy-economic characteristics. However, this process has not yet been implemented in most countries and therefore, the utilisable hydropower potentials for Danube countries are not available. In this context, ICPDR proposed in its *Guiding principles on sustainable hydropower development* [5] a criteria-based assessment to identify those river stretches which should either be kept free from hydropower development and or which are suitable for new hydropower plants. The approach consists of two steps: in step 1 the suitability of the regional hydropower potential for actual hydropower use is classified to support a strategical planning process (i.e. “where”; cf. Figure 42) and in step 2 the technical design of a concrete hydropower plant with the

[38] Calculated on the basis of installed capacities 2017 and average full load hours of the years 2011 to 2017, i.e. numbers differ from actual generation in the year 2017.

least ecological and social impact is identified (i.e. "how").[39] However, the ICPDR Guiding Principles do not provide a quantitative classification of "ecologically harmless" hydropower potentials.

Figure 42: ICPDR assessment matrix and classification scheme to establish the utilisable hydropower potential



Source: ICPDR [5]

6.2 A more detailed view on selected ICPDR countries

6.2.1 Scope and general considerations

Whether or not the remaining hydropower potentials can actually be utilised, it is obvious that hydropower alone cannot facilitate a transition towards a decarbonised electricity system. About 47% of today's electricity production in the fourteen ICPDR countries is from coal and gas – the remaining economic hydropower potentials correspond to about 6% of annual electricity production in Danube countries. Hence, at ICPDR level wind power and solar PV would need to play the most important role if the generation portfolio was developed towards a significantly higher share of renewable energies. Nevertheless, this may differ from country to country if, for example, the remaining hydropower potentials are high in relation to the demand and/or the potentials of alternative RES are comparatively low. Against this background, a more detailed analysis of the perspective and importance of hydropower for a selected number of ICPDR countries, namely Bosnia and Herzegovina, Bulgaria, Montenegro, Romania, Serbia and Ukraine, is conducted in this section[40]. The scope of the analysis includes a discussion of (a)

[39] For more information on criteria-based assessment of hydropower please refer to section 5.2 "Improving social acceptance of hydropower".

[40] The selection of the countries is based on (a) the overall scope of the study on new EU member states, candidate and associated countries, (b) today's importance of hydropower in the national generation mix and (c) the remaining (economic) hydropower potential. In this context, it is worth to mention that Croatia and Slovenia, in principle, also have a considerable remaining hydropower potential. However, the two countries are not considered in the analysis because the remaining hydropower potentials are smaller compared to the selected six countries. Please note that the analysis for Bosnia and Herzegovina, Bulgaria, Montenegro and Serbia are based on the study *The role of hydropower in selected South-Eastern European countries*[43], which was prepared by the author on behalf of EuroNatur Foundation ad RiverWatch in October 2018.

hydropower potentials in relation to overall RES expansion requirements, (b) the role of hydropower in strategic renewable energy targets and (c) aspects related to diversification effects of RES technologies in a generation portfolio. The boundary conditions considered in this analysis are the following:

- **Potential of hydropower in comparison with potential of other renewable energy sources:** Besides technical and economic hydropower potentials, the afore-mentioned IRENA report on cost-competitive renewables potential across South-East Europe also includes the potential of solar PV, wind power, biomass and geothermal [8]. Naturally, the potential of renewables changes over time and depends, to some extent, on the quantification methodology. As a result, potentials can vary in different publications and the numbers provided by the IRENA report may differ from other sources. However, the IRENA report provides at least a consistent set of economic and technical potentials of hydropower, wind, solar PV, biomass and geothermal for all of the six selected ICPDR countries.[41] Furthermore, the IRENA report defines different scenarios to assess the cost-competitive or economic potentials to include uncertainties with regard to today's and future capital costs as well as expected investment cost reductions of renewables. Except for hydropower, the report provides a range of economic potentials for the years 2016, 2030 and 2050. For reasons of simplification, a conservative approach is applied in this report, i.e. only the average of the range of the cost-competitive potentials for the year 2030 is taken into account. Hence, it can be expected that in a long-term perspective (>2030) the economic potential of especially wind and solar PV will be higher than shown in the country-specific analysis.
- **Role of hydropower in strategic renewable energy targets:** All of the exemplarily selected six ICPDR countries still have a considerable hydropower potential, which is also reflected in the individual country's strategic renewable energy targets. However, with the exception of the renewable energy targets for 2020 as included in the countries' National Renewable Energy Action Plans (NREAP)[42], there are not any consistent official long-term targets for the expansion of different renewable energy technologies so far, since national RES objectives for 2030 are still under discussion. Hence, the analysis of the status of the implementation of NREAP targets will be included and complemented with long-term strategic objectives for the expansion of hydropower– if available.
- **Portfolio effects of hydropower expansion:** Due to unavoidable seasonal and year-to-year fluctuations of the rivers' runoff, electricity generation from hydropower can vary considerably over the years. Especially South-Eastern European countries can have a relatively high annual variability of hydropower production. For example, Montenegro shows a share of hydropower between 42% and 68% in the years 2011-2018 and Bosnia and Herzegovina between 25% and 45%.[43] Hence, security of supply can become a major issue in an electricity system dominated by hydropower if seasonal fluctuations of hydropower and the quite considerable year-to-year differences in the capacity factor of hydropower pose a risk for a continuous and secure electricity supply. Additionally, new hydropower capacities without storage options (i.e. reservoirs) may only deliver a limited contribution to

[41] Due to its negligible potential for electricity generation, geothermal energy is not considered in this report's analysis.

[42] As part of the ratification of the Treaty on establishing the Energy Community (EnC), also the non-EU member states from the ICPDR adopted the EU Renewable Energy Directive with binding renewable energy targets for 2020 and the obligation to submit a NREAP to further detail renewable energy targets.

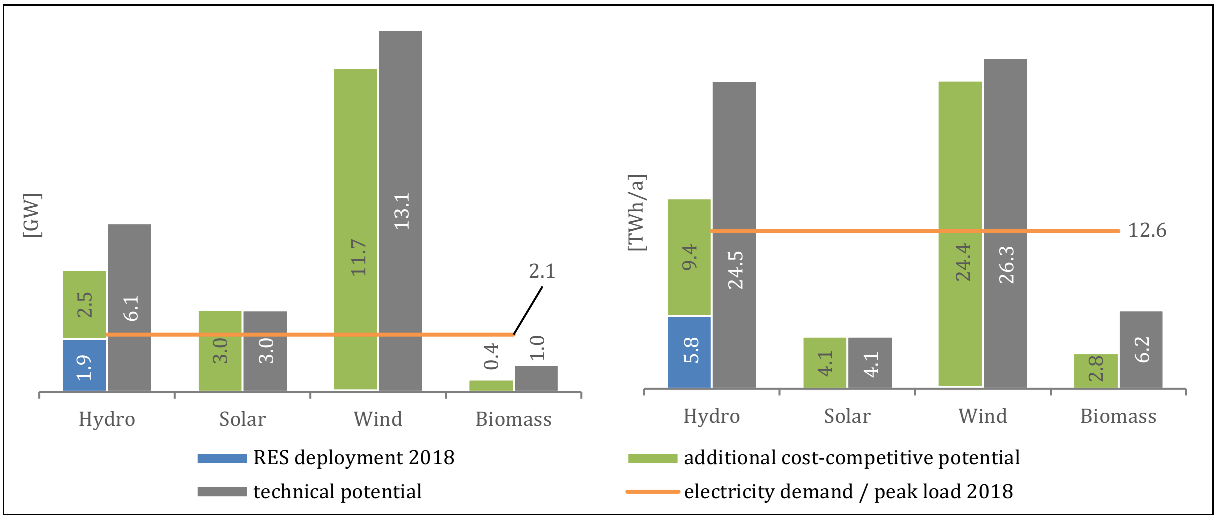
[43] cf. Figure 13: Range and average share of hydropower in total national electricity production 2011-2018; section 3.1 "Danube region at a glance".

the country's security of supply if the generation pattern does not significantly differ from existing hydropower power plants – which is generally not the case. A stronger focus on hydropower with storage options and non-hydro renewable technologies could diversify a country's generation portfolio and hence, make it less vulnerable to e.g. seasonal and yearly fluctuations of water runoffs. However, it is necessary to bear in mind that an expansion of volatile electricity generation from wind and solar PV would require additional capacities for balancing and storage, respectively. Portfolio effects will also be highly important in the context of climate change adaption strategies, since climate change may have a severe effect on the runoffs and therefore, the electricity generation from hydropower in some regions (cf. section 4.3 "Impact of climate change on electricity generation"). A portfolio diversification by means of a mix of RES and storage technologies can not only increase the security of supply of a power system but can also reduce overall system costs and risks related to technological, political, environmental and social aspects (incl. lack of public acceptance).

6.2.2 Bosnia and Herzegovina

Bosnia and Herzegovina has a technical hydropower potential of 6.1 GW (24.5 TWh/a) and an economic potential of 4.2 GW (14.6 TWh/a). Based on the installed hydropower capacity of 1.9 GW (5.8 TWh/a) in 2018, an additional cost-competitive potential of 2.5 GW (9.4 TWh/a) can be derived. Hence, Bosnia and Herzegovina has exploited about 24% of its technical and 38% of its economic potential to this date. Hydropower covers already about 40% of the country's electricity demand of 12.6 TWh/a, i.e. the economic hydropower potential of 9.4 TWh/a would, in principle, suffice to cover the remaining actual electricity demand plus an additional demand growth of about 15% (cf. Figure 43).

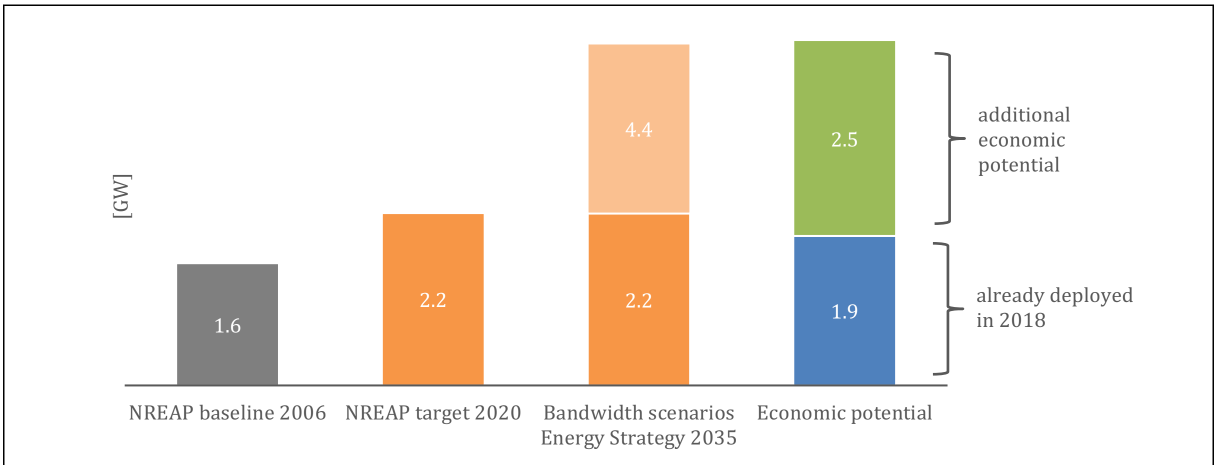
Figure 43: RES potential in relation to RES deployment and electricity demand in Bosnia and Herzegovina2018



Source: IRENA [8], Mot MacDonald [9], ENTSO-E [39] (hydro generation calculated with average utilisation 2011-2018)

Bosnia and Herzegovina does not only have a considerable remaining hydropower potential but in particular substantial solar PV, wind power and biomass potentials, which are about three times higher than the hydropower potential in terms of electricity generation. The combined economic potentials of solar PV, wind power and biomass amount to about 30 TWh/a, i.e. about 20% of these potentials would need to be deployed for a full decarbonisation of the country's power sector. Although the attractive potentials of non-hydro renewable energy sources are included in the country's NREAP targets to some extent, the expansion of renewable energies in the electricity sector is still very much focused on hydropower. Only a small portion of non-hydro renewables has been developed so far and/or is included in the country's strategic energy targets. For example, Bosnia and Herzegovina has a 2020 NREAP target of about 2.2 GW for hydropower excl. pumped storage, i.e. an increase of 640 MW compared to the NREAP baseline in 2006. In contrast, NREAP 2020 targets for wind power, solar PV and biomass amount to 380 MW. With an actual net capacity addition of 350 MW for hydropower and 70 MW for non-hydro renewables, Bosnia and Herzegovina will most likely fail to meet its RES-E target in 2020. Figure 44 depicts the installed hydropower capacities for the NREAP baseline year 2006, the NREAP target 2020 and the already deployed hydropower capacities in 2018. Additionally, Figure 44 also shows the range of the installed hydropower capacity of the four 2035 scenarios from the *Framework Energy Strategy of Bosnia and Herzegovina until 2035* [164] and the remaining economic potential.[44]

Figure 44: Strategic targets, actual deployment and economic potential of hydropower in Bosnia and Herzegovina



Source: IRENA [8], ENTSO-E [39], NREAP BiH, Framework Energy Strategy BiH [164] (numbers adopted by excluding existing pumped storage capacity of 420 MW; according to *Framework Energy Strategy*, in all scenarios 16% of the total RES contribution in the electricity sector is from wind power, solar PV and biomass, cf. footnote 44)

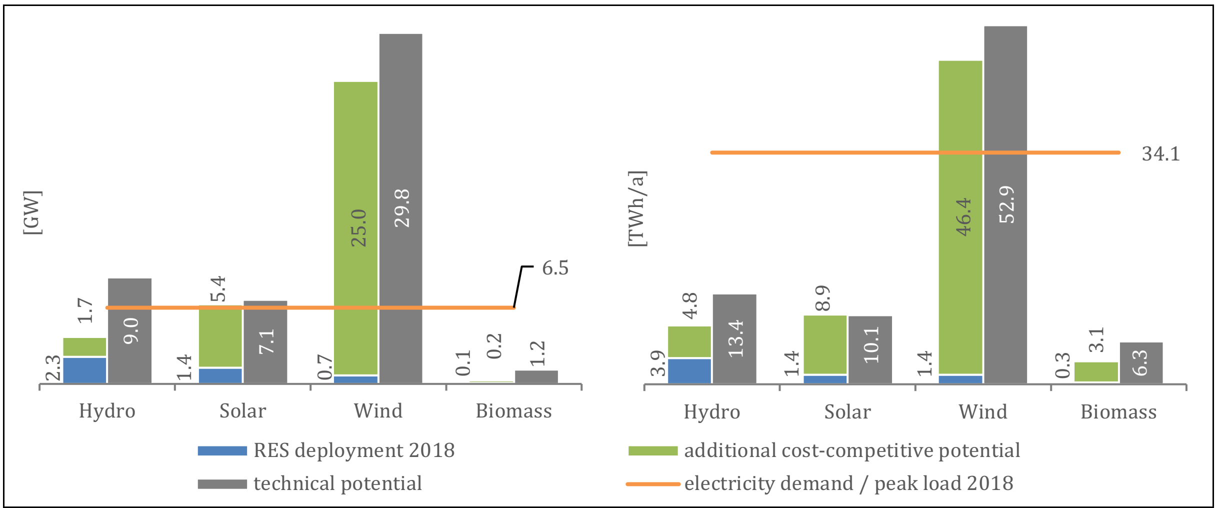
The scenarios of the *Framework Energy Strategy of Bosnia and Herzegovina until 2035* show a range of hydropower capacity (excl. pumped storage) between 2.2 GW (cost-optimised IP scenario) and 4.4 GW (entity scenario). The latter would imply a full deployment of the economic potential until 2035. In contrast, the assumed expansion of wind power, solar PV and biomass is relatively low in all scenarios and hence, independent of the scenario hydropower would remain with a RES-E share of 84% in 2035 the dominant renewables technology in Bosnia and Herzegovina. However, from a portfolio perspective, a more diversified RES development would be worth to consider, since additional hydropower capacities without storage may only deliver a limited contribution to the country's security of supply. A stronger focus on non-hydro renewables would also reduce the ecological and social pressure on the remaining undeveloped river stretches, could increase public acceptance of the energy transition and could make the country less vulnerable to impacts of climate change on water runoffs.

[44] Pumped storage capacities are included in hydropower capacities within the *Framework Energy Strategy of Bosnia and Herzegovina until 2035*[164]. Since the analysis is focused on renewable hydropower, pumped storage capacities are excluded. Additionally, the *Framework Energy Strategy of Bosnia and Herzegovina until 2035* subsumed under "RES in the incentive system" small hydropower, wind power, solar PV and biomass without further specifying individual capacities. However, the *Framework Energy Strategy* states that it assumes a hydropower share of 84% in total RES in the electricity sector for all scenarios in the year 2035. Based on this information the total hydropower capacity (large and small hydropower excl. pumped storage) can be derived. Accordingly, the numbers as shown in Figure 44 cannot be directly derived from the *Framework Energy Strategy of Bosnia and Herzegovina until 2035*.

6.2.3 Bulgaria

Bulgaria has a technical hydropower potential of 9.0 GW (13.4 TWh/a) and an economic hydropower potential of 4.0 GW (8.7 TWh/a). Based on the installed hydropower capacity of 2.3 GW (3.9 TWh/a) in 2018, an additional cost-competitive potential of 1.7 GW (4.8 TWh/a) can be derived. In terms of electricity production, Bulgaria has already exploited about 29% of its technical and 45% of its economic potential, respectively, i.e. hydropower provides about 10% of the country's electricity demand of 34 TWh/a today. Accordingly, even a full deployment of the remaining technical hydropower potential would only provide a small contribution to accomplish a renewable-based decarbonisation of the power sector in Bulgaria (cf. Figure 45).

Figure 45: RES potentials in relation to RES deployment and electricity demand 2018 in Bulgaria

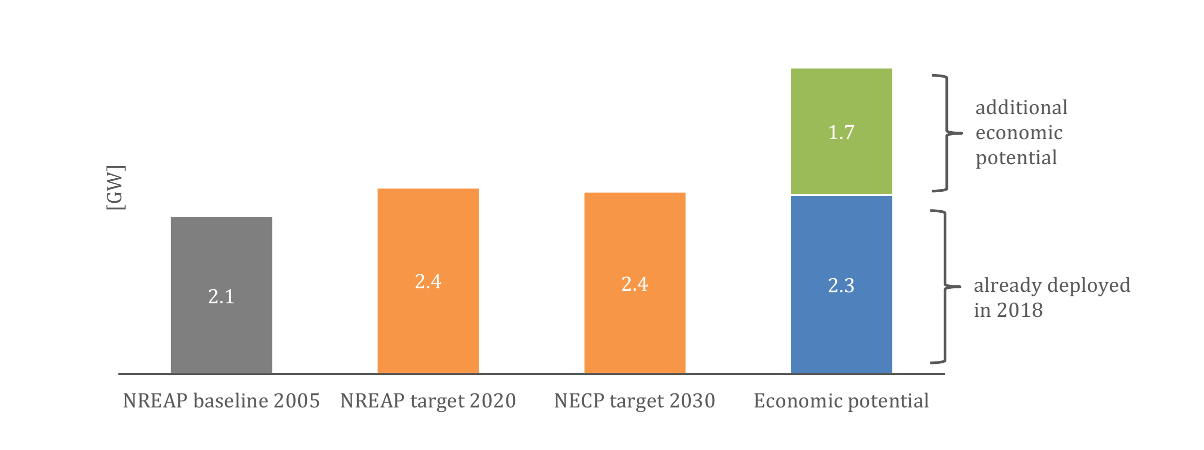


Source: IRENA [8], ENTSO-E [39] (hydro generation calculated with average utilisation 2011-2018)

Potentials of wind power, solar PV and biomass are much more promising options compared to hydropower additions – the combined remaining economic potential amounts to about 58 TWh/a. Bulgaria has already started to develop this potential and with a share of about 7%, solar PV, wind power and biomass provide a noticeable contribution to the national generation mix. However, the country has seen only very limited capacity additions of both hydropower and non-hydropower renewables in the last few years.

Although actual numbers for hydropower are slightly below Bulgaria's 2020 NREAP target of 2.42 GW, the country has already met its total RES-E target, since combined hydropower, solar PV, wind power and biomass capacities and generation volumes, respectively, exceed the 2020 NREAP targets. 2030 targets as included in the 2018 draft of the National Energy and Climate Plan (NECP) are, however, far less ambitious. For hydropower, the 2030 targets (2.4 GW) are only about 40 MW above actually installed capacities and therefore, even below 2020 NREAP targets. Since projected growth rates of solar PV, wind power and biomass are also very modest (570 MW until 2030 in total), electricity generation from renewables would only increase by about 10% between 2020 and 2030. Figure 46 depicts the installed hydropower capacities for the NREAP baseline year 2005, the NREAP target 2020 and the already deployed hydropower capacities in 2018. Additionally, Figure 46 also shows the NECP target for 2030 and the remaining economic potential.

Figure 46: Strategic targets, actual deployment and economic potential of hydropower in Bulgaria



Source: IRENA [8], ENTSO-E [39], NREAP and NECP Bulgaria (NECP number adopted by excluding pumped storage capacity of 864 MW)

The status of hydropower in the overall Bulgarian generation portfolio will not significantly change in the upcoming years – not least because of the expected slow expansion of renewable energies in total. Based on the draft NECP, coal and especially nuclear will maintain their dominant position and no major RES-E capacity additions are planned. The combat against climate change needs more ambitious targets in order to be successful and such weak RES-E targets would not be sufficient. Therefore, the European Commission has already called on Bulgaria to step up its renewable energy ambitions and align its NECP with EU legislation and the Paris Agreement [45]. Hence, an adaption of the NECP could result in higher final RES-E targets compared to the targets included in the 2018 draft NECP. Although remaining hydropower potentials are limited, a further expansion could have a positive effect on the overall renewable portfolio in this context, especially if a focus was put on hydropower with storage options that could provide additional flexibility to the power system.

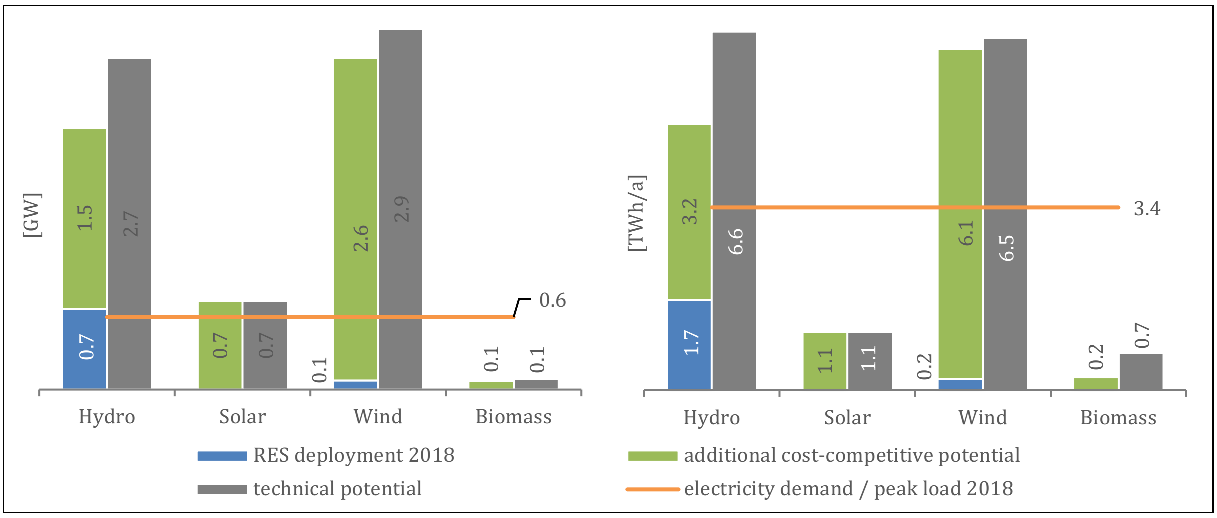
6.2.4 Montenegro

According to the IRENA report *Cost-Competitive Renewable Power Generation: Potential across South-East Europe* [8], Montenegro has a technical hydropower potential of 2.04 GW (5.0 TWh/a) and an economic potential of 1.96 GW (4.5 TWh/a). Even without considering small hydropower to a full extend, the *Regional Strategy for Sustainable Hydropower in the Western Balkans* [9] showed a considerably higher technical potential of about 6.6 TWh/a. Hence, in the following a technical potential of 6.6 TWh/a (2.7 GW) is considered for Montenegro. With regard to the economic potential, the Montenegrin *Energy Development Strategy of Montenegro by 2030* estimates the total technically and economically usable potential of large hydropower between 3.7 and 4.6 TWh/year, which could be increased to 5.3 TWh/year if water is partially diverted from River Tara to River Moraca. Additionally, the usable small hydropower potential is estimated to be about 0.4 TWh/a (cf. [165]). Accordingly, the total economic hydropower potential considered in the Energy Development Strategy is slightly above the cost-competitive potential of 4.5 TWh/a as included in the IRENA report. In the following, the average range from the *Energy Development Strategy of Montenegro by 2030* (i.e. 4.9 TWh/a) will be considered. Hence, an

[45] Cf. Commission recommendation of 18/06/2019 on the draft integrated National Energy and Climate Plan of Bulgaria covering the period 2021-2030.

additional cost-competitive potential of 1.5 GW (2.9 TWh/a) can be derived based on the installed hydropower capacity of 0.7 GW (1.7 TWh/a) in 2018. Montenegro has already exploited about 25% of its technical and 34% of its economic potential. Since Montenegro has a remaining economic hydropower potential of 3.2 TWh/a, hydropower would in principle allow coverage of about 145% of the actual demand of 3.4 TWh/a (cf. Figure 47).

Figure 47: RES potentials in relation to RES deployment and electricity demand 2018 in Montenegro



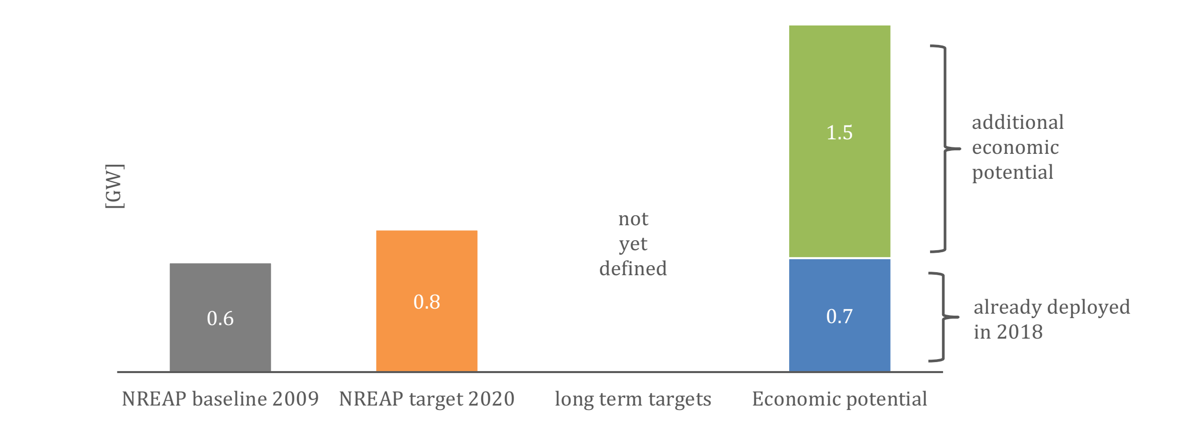
Source: IRENA [8], ENTSO-E [39], *Energy Development Strategy of Montenegro by 2030* [157] (hydro generation calculated with average utilisation 2011-2018)

Montenegro does not only have a considerable remaining hydropower potential but also substantial wind power and to some extent solar PV potentials, which, taken together, account for more than two times the actual electricity demand. In total, economic potentials of hydropower, solar PV, wind power and biomass amount to about 12 TWh/a, i.e. about 30% of these potentials would need to be deployed for a full decarbonisation of the country's power sector. A debate on such a 100% RES-E target was already opened by Montenegro's Economy Minister Mrs. Dragica Sekulić, who is in charge of the subject area energy[166]. However, there have not been communicated any long-term targets for the development of RES-E in general and individual technologies in particular so far and therefore, Montenegro's NREAPs remain to be the only sources with regard to official hydropower targets for the moment.[46]

Montenegro has a 2020 NREAP hydropower target of 0.83 GW. This represents an increase of 30% (190 MW) compared to the baseline in 2009. However, between 2010 and 2018 only about 25 MW of new hydropower capacity was commissioned. Besides hydropower, Montenegro also defined considerable NREAP 2020 targets for non-hydro renewables, namely wind power (150 MW), solar PV (10 MW) and biomass (29 MW). Thereof, about 120 MW of wind power are already installed (wind parks Mozura and Krnovo) and a tender for a wind park in Brajići with a minimum capacity of 70 MW was published in August 2019. Hence, Montenegro could meet its NREAP target for wind power but will most likely fail to achieve its 2020 target for hydropower, solar PV and biomass. Figure 48 depicts the installed hydropower capacities for the NREAP baseline year 2009, the NREAP target 2020 and the already deployed hydropower capacities in 2018.

[46] Discussions about the design of the country's National Energy and Climate Plan has already started (. The final NECP shall be submitted to the Secretariat of the Energy Community by October 2020. [167]

Figure 48: Strategic targets, actual deployment and economic potential of hydropower in Montenegro



Source: IRENA [8], ENTSO-E [39], NREAP Montenegro

Given the dominant share of hydropower generation and the promising potentials of mainly wind power but also solar PV, a further diversification of the Montenegrin generation portfolio would be worth considering for future RES-E strategies. Wind power and solar PV could, in principle, close the gap between actual power production from renewables and demand. Additional hydropower could supplement this development, though a focus should be put on storage hydropower to provide flexibility for the integration of volatile electricity generation from wind power and solar PV. In contrast, new hydropower plants without storage options may only deliver a limited contribution to the country's security of supply, especially against the background of the expected decrease of available water runoffs due to climate change.

6.2.5 Romania

The IRENA report *Cost-Competitive Renewable Power Generation: Potential across South-East Europe* [8], showed a technical hydropower potential of 15.4 GW (38.0 TWh/a) and an economic potential of 8.2 GW (19.9 TWh/a) for Romania. In contrast, the *Energy Strategy Romania 2019-2030*, which is also basis for the Romanian NECP, considered a techno-economic hydropower potential of 27.1 TWh/a [66][47]. Based on this most current economic potential and the installed hydropower capacity of 6.7 GW (16.0 TWh/a, of which 6.8 TWh/a is contributed from the Romanian sector of the Danube River) in 2018, an additional cost-competitive potential of 4.1 GW (11.1 TWh/a[48]) can be derived. Romania has already exploited about 42% of its technical and 59% of its economic potential. Accordingly, even a full deployment of the remaining hydropower potential would not even in theory allow full supply of the country's electricity demand from hydropower (cf. Figure 49).

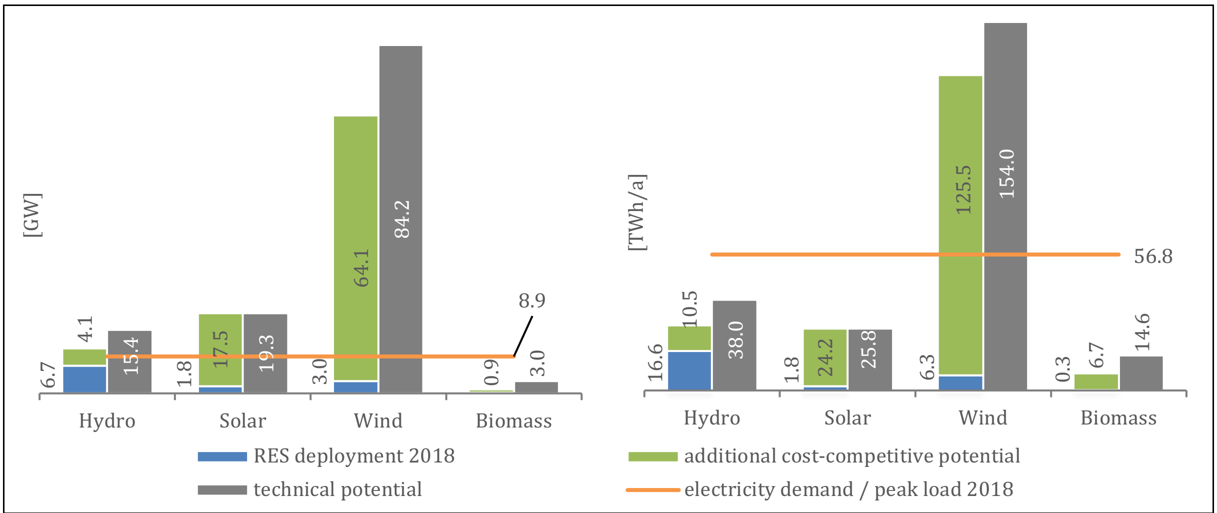
The economic potentials of wind power, solar PV and biomass are noticeably higher and amount to about 160 TWh/a in total, i.e. about three times of the actual electricity demand. Hence, about 30% of the total economic potential of hydropower and non-hydro renewables would need to be deployed for a full decarbonisation of the country's power sector. In the early 2000s, Romania has already started to

[47] The techno-economic potential is given in annual average electricity generation. However, no corresponding installed generation capacity is provided. For the further analysis, the corresponding techno-economic hydropower capacity is derived from the average capacity factor of 29.2% (2,560 h/a) as considered for Romania's NREAP hydropower targets 2020.

[48] The total technical potential of the Danube River in Romania is about 11.8 TWh/a and the additional economic potential of the Danube River in Romania about 3.5 TWh/a (Islaz-Somovit hydropower plant). [66]

develop non-hydro RES and with a share of about 14%, solar PV, wind power and biomass provide a significant contribution to the national generation mix. However, in the last 4-5 years renewables expansion has slowed down and the RES-E share remained at a level similar to previous years.

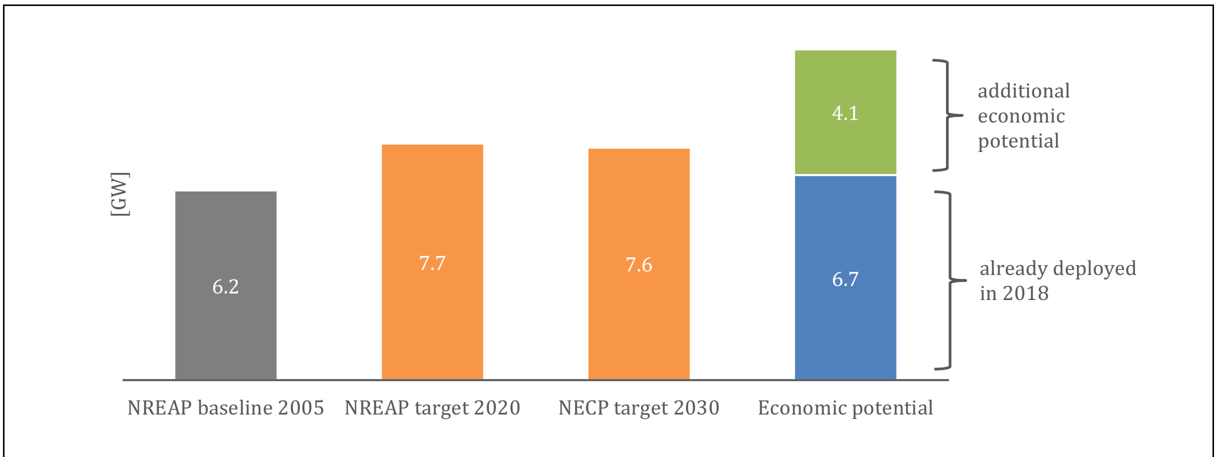
Figure 49: RES potentials in relation to RES deployment and electricity demand 2018 in Romania



Source: IRENA [8], Romania, Energy Strategy Romania 2019-2030 [66] (hydropower generation calculated based on average utilisation 2008-2018)

The limited expansion of renewables in recent years is also reflected in the degree to which NREAP targets are achieved in terms of technology specific capacity and production. For example, despite an increase of about 400 MW of hydropower capacity between 2005 (NREAP baseline) and 2018, the current installations are still 15% below the NREAP target of 7.7 GW and 19.8 TWh/a, respectively. 2030 hydropower targets as included in the 2018 draft of the National Energy and Climate Plan (7.6 GW and 17.6 TWh/a) are even less ambitious and below 2020 NREAP targets. This is shown in Figure 50 which depicts the installed hydropower capacities for the NREAP baseline year 2005, the NREAP target 2020 and the already deployed hydropower capacities in 2018. Additionally, the draft NECP target for 2030 and the remaining economic potential are included.

Figure 50: Strategic targets, actual deployment and economic potential of hydropower in Romania



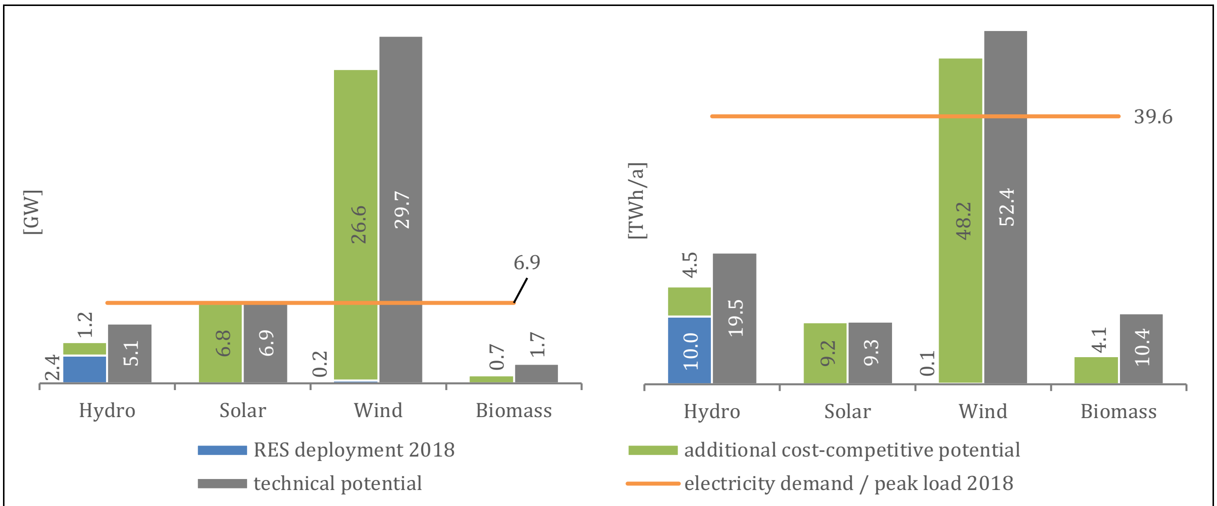
Source: IRENA [8], ENTSO-E [39], NREAP Romania, Energy Strategy Romania 2019-2030 [66]

Since NECP 2030 targets for solar PV, wind power and biomass are also modest (in total 2,900 MW between 2020 and 2030), the overall importance of hydropower in the Romanian generation portfolio is not expected to change significantly in the upcoming years. Based on the draft NECP, coal, gas/oil and nuclear will maintain their dominant position in the Romanian generation mix until 2030 with a share of more than 60%. However, the European Commission has already called on Romania to step up its renewable energy ambitions and align its NECP with EU legislation and the Paris Agreement [49]. An adaption of the NECP could result in higher final RES-E targets compared to the targets included in the 2018 draft NECP. Although remaining hydropower potentials are limited, a further expansion could have a positive effect on the overall renewable portfolio, especially if a focus was put on hydropower with storage to provide additional flexibility to the power system.

6.2.6 Serbia

The IRENA report *Cost-Competitive Renewable Power Generation: Potential across South-East Europe* [8] shows a technical hydropower potential of 4.7 GW (18.0 TWh/a) and an economic potential of 3.6 GW (14.5 TWh/a) for Serbia. In contrast, the *Energy Sector Development Strategy of the Republic of Serbia for the period by 2025 with projections by 2030* includes a slightly higher technical hydropower potential of 19.5 TWh/a (17.7 TWh/a large hydropower and 1.8 TWh/a small hydropower), which is considered in the following [168][50]. Based on the installed hydropower capacity of 2.4 GW (10.0 TWh/a) in 2018, Serbia has already exploited about 51% of its technical and 69% of its economic potential, i.e. the additional cost-competitive potential amounts to 1.2 GW (4.5 TWh/a), i.e. hydropower alone will not even in theory be able to meet the country's electricity demand (cf. Figure 51).

Figure 51: RES potentials in relation to RES deployment and electricity demand 2018 in Serbia



Source: IRENA [8], [161], ENTSO-E [39] (hydropower generation calculated based on average utilisation 2011-2018)

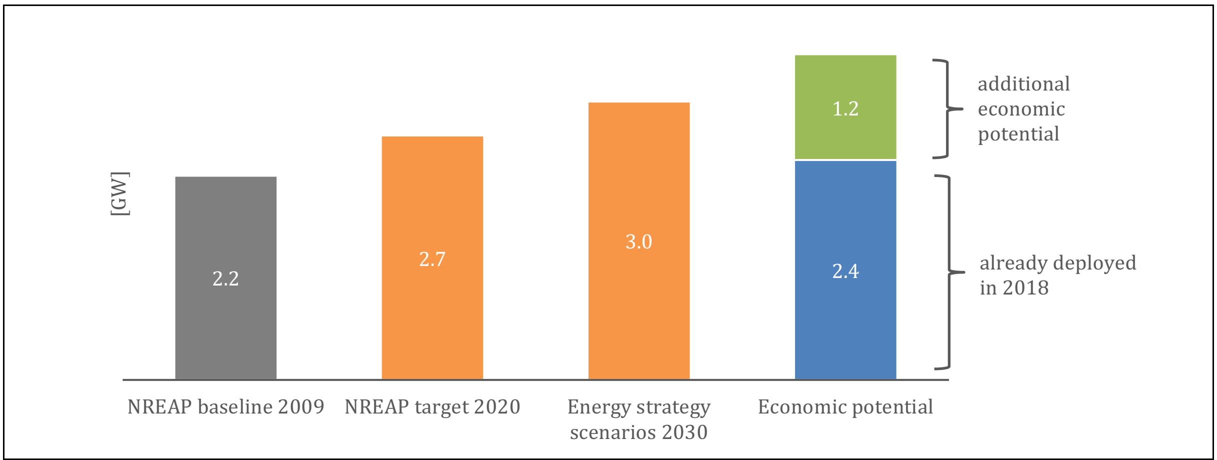
On the other hand, the potentials of wind power, solar PV and biomass are promising – the combined economic potential amounts to about 62 TWh/a, which would, in principle, allow a full decarbonisation of the country's power sector with domestic renewable energy sources. The development of non-hydro renewables has been tackled in Serbia relatively late and hence, non-hydro renewables are still a niche technology in the country. Nevertheless, it can be expected that NREAP 2020 targets could be met at

[49] Cf. Commission recommendation of 18/06/2019 on the draft integrated National Energy and Climate Plan of Romania covering the period 2021-2030.

[50] The techno-economic potential is given in annual average electricity generation. However, no corresponding installed generation capacity is provided. For the further analysis, the corresponding techno-economic hydropower capacity is derived from the average capacity factor of 49.0% (4,300 h/a) as considered for Serbia's NREAP hydropower targets 2020.

least for wind power, since 240 MW of wind power are connected to the grid and another 240 MW are already in the construction phase. Hydropower, however, presents a different picture: Serbia defined a hydropower target of 2.66 GW (11.4 TWh/a) in its NREAP for 2020, which corresponds to an increase of 20% or 0.44 GW compared to the NREAP baseline in 2009. Until 2018, only about 170 MW of new hydropower capacities have been put into operation, i.e. Serbia's NREAP targets for hydropower will most likely not be met. Against this background, the indicative hydropower targets for 2030 are challenging, since both scenarios of the *Energy Sector Development Strategy of the Republic of Serbia for the period by 2025 with projections by 2030* considered a target of about 13.0 TWh/a [168][51] for hydropower. This is shown in Figure 52 that depicts the installed hydropower capacities for the NREAP baseline year 2009, the NREAP target 2020 and the already deployed hydropower capacities in 2018. Additionally, the development of hydropower until 2030 according to the scenarios of the Energy Sector Development Strategy and the remaining economic potential are shown.

Figure 52: Strategic targets, actual deployment and economic potential of hydropower in Serbia



Source: IRENA [8], ENTSO-E [39], *Energy Sector Development Strategy of the Republic of Serbia* [168]

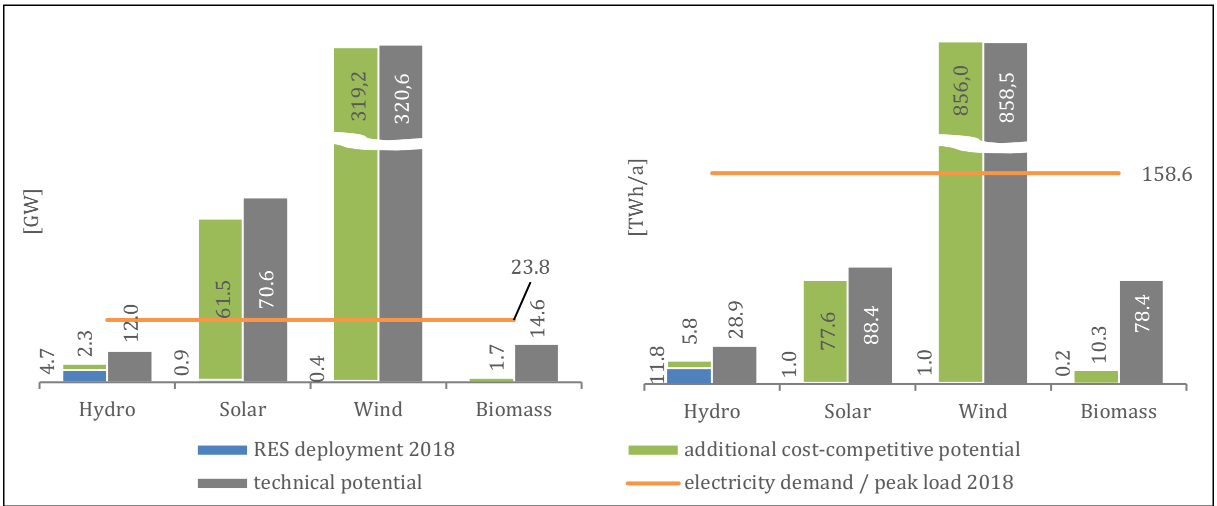
The implementation of the 2030 hydropower scenarios would not per se conflict with the principles of a robust and diversified generation portfolio, since hydropower has a relatively modest share in the country's electricity demand of about 25% toady. However, the scenarios of the *Energy Sector Development Strategy* only consider a relatively modest trajectory for the expansion of wind power and solar PV by about 1.9 TWh/a until 2030. Additionally, the European Commission urged Serbia in its 2019 report that "Any further development of hydropower should be in line with EU environmental legislation including environmental impact assessments with proper public consultations, nature protection and water management legislation." [169]. Hence, a stronger strategical focus on non-hydro renewables could not only provide advantages from a RES-E portfolio perspective but could also contribute to a more sustainable development of the remaining hydropower resources.

[51] Hydropower targets are given as annual average electricity generation. In order to calculate a corresponding hydropower capacity, an average capacity factor of 49.0% (4,300 h/a) as considered for Serbia's NREAP hydropower targets 2020 is taken into account. Hence, the 2030 hydropower target of 13.0 TWh/a corresponds to a generation capacity of 3.0 GW.

6.2.7 Ukraine

According to the IRENA report *REmap 2030 Renewable Energy Prospects for Ukraine*, the country has a technical hydropower potential of 28.9 TWh/a [161]. Other sources mention a technical hydropower potential of 21.5 TWh/a [8], [163]. With regard to the economic hydropower potential, the *Ukrainian hydropower program until 2026* estimates the so-called "total economically efficient hydropower potential" with 17.5 TWh/a [170].[52] Both the technical and economic potential are only given as annual average electricity generation and not in terms of installed capacity. Taking a capacity factor of 28.5% or 2,500 h/a into account (considered in Ukraine's NREAP for 2020 hydropower targets), a corresponding installed capacity of 12.0 GW for the technical and 7.0 GW for the economic potential can be derived. Based on the actually installed hydropower capacity of 4.7 GW (excl. pumped storage) and average annual generation of 11.8 TWh/a, an additional cost-competitive potential of 2.3 GW (5.8 TWh/a) can be estimated. Although Ukraine has already exploited only about 41% of its technical and 67% of its economic potential, a further expansion of hydropower could only provide a limited quantitative contribution to a substantial increase of the country's renewable portfolio (cf. Figure 53).

Figure 53: RES potentials in relation to RES deployment and electricity demand 2018 in Ukraine



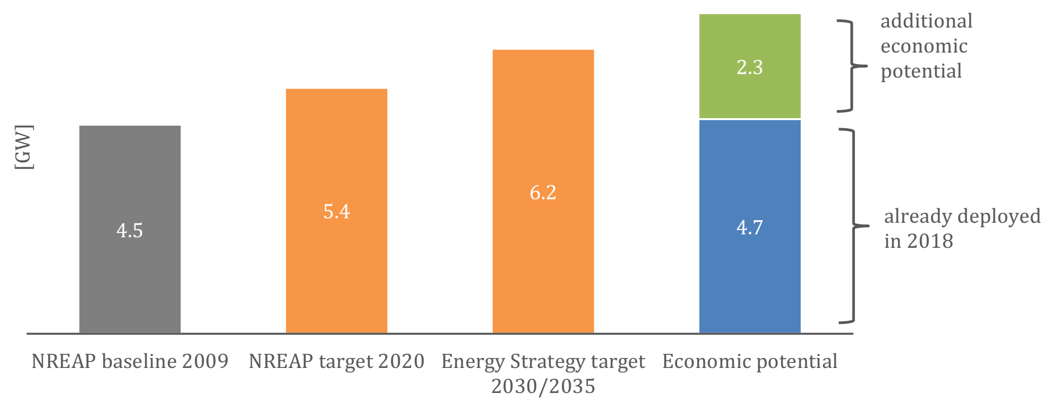
Source: IRENA [8], [161], ENTSO-E [39], Ukrainian hydropower programme until 2026 [170] (hydropower generation in 2018 calculated based on average utilisation of 2,500 full load hours p.a.)

In contrast to hydropower potentials, potentials of solar PV, biomass and especially wind power are noticeably higher. The IRENA study *Cost-Competitive Renewable Power Generation: Potential across South-East Europe* [8] estimates an economic potential of about 850 TWh/a. Economic potentials of solar PV and biomass are much smaller (about 80 TWh/a and 10 TWh/a, respectively) but still considerable. Hence, about one fifth of the total economic potential of hydropower and non-hydro renewables would need to be deployed for a full decarbonisation of the country's power sector. Ukraine has already started to develop non-hydro RES, but with a share of 1.5% in total generation the actual contribution is relatively small and therefore, NREAP 2020 targets of 2.3 GW each will most likely not be achieved. This is also the case for hydropower, since today's installed capacity of 4.7 GW lacks behind the NREAP target of 5.4 GW. However, within the *Energy Strategy of Ukraine through 2035* [171], the

[52] The IRENA report *Cost-Competitive Renewable Power Generation: Potential across South-East Europe* [8] showed inconsistent hydropower potentials for Ukraine. Economic potentials (10.3 GW) are higher than technical potentials (9.0 GW), which cannot be by definition. Hence, different sources for Ukrainian hydropower potentials are used in this report.

hydropower targets for 2020 (excl. pumped storage) were already adapted to 5.0 GW for 2020 and defined for 2025 (5.4 GW) and 2030 (6.2 GW)[53]. For 2035, the strategy does not include any further expansion (cf. Figure 54).

Figure 54: Strategic targets, actual deployment and economic potential of hydropower in Ukraine



Source: IRENA [8], ENTSO-E [39], *Energy Strategy of Ukraine* until 2035 [171] (excl. pumped storage)

The planned expansion of hydropower does not represent a restriction from a portfolio perspective, since the overall share of hydropower in the Ukrainian power system would remain comparatively low and only a moderate increase of wind power and solar PV of in total 6.1 GW is planned in the *Energy Strategy of Ukraine through 2035* at the same time. The emphasis of the energy strategy is rather on an increased production from coal and especially nuclear, which would maintain their dominant position in the country's electricity mix.

[53] For pumped storage, the *Energy Strategy of Ukraine through 2035* considers an additional expansion target of 3.8 GW until 2030.

7. Conclusions and recommendations

The expansion of electricity generation from renewable energies is considered to be a major lever for the transition to a more sustainable power system. While hydropower has been the dominant source of renewable generation in the Danube region for decades, this position is expected to change in the future. On the one hand, the already achieved high degree of hydropower utilisation in most ICPDR countries only allows for comparably limited capacity additions. Also, the expansion of hydropower has caused increasing environmental and social concerns because new hydropower capacities frequently affect river stretches of high ecological value. On the other hand, European climate targets require a massive growth of electricity production from renewable energies, which will result in a significant increase in the proportion of wind and solar in the European and national electricity systems, since not only hydropower but also biomass has only limited additional potentials in most countries. However, the expansion of wind and solar PV will increase the need for flexible generation, which for example can be provided from storage and pumped storage hydropower, to balance unavoidable fluctuations of electricity generation from wind and solar PV. Nevertheless, hydropower will remain an important pillar of the region's renewable electricity portfolios but the role of hydropower would need to be redefined or at least adjusted in this context. Based on the results of the present study, the following key conclusions and recommendations for the further development of hydropower in Danube countries can be drawn:

- **Strategic need for hydropower development to be defined in an overall system planning process**
  The development of hydropower requires interaction with the overall power system planning at country level but also at a broader regional electricity market level in order to verify the actual need and value of any additional hydropower capacity. Besides energy economic aspects (e.g. security of supply, reliable operation of the power system, minimized costs, etc.), a strategic planning process should also consider ecological and social aspects of hydropower and other renewable technologies to arrive at a socially accepted trajectory for RES-E expansion.
- **A robust and climate-resilient generation mix calls for portfolio diversification**
  A strategic power system planning entails the requirement to develop a robust, well diversified generation portfolio. Especially for countries with electricity systems dominated by run-of-river hydropower, seasonal and yearly fluctuations of hydropower production can negatively impact security of supply. In contrast, a stronger focus on non-hydro renewable technologies and storage hydropower, respectively, could diversify a country's generation portfolio and make it less vulnerable to fluctuations of water runoffs. Such a diversification away from (run-of-river) hydropower will become even more important for those countries, which are expected to suffer most from negative climate change-related effects on water runoffs.
- **Establishing a coherent framework for site selection and project assessment**
  Strategic planning approaches should not only be considered on a system level but also for the evaluation of potential sites for hydropower expansion. In this context, planning tools and criteria catalogues, developed in a broad stakeholder process could not only support the selection of

socially accepted sites but could also provide project developers with a framework for a more sustainable design of hydropower plants. As an example, for such a commonly agreed and coherent framework the ICPDR *Guiding Principles on Sustainable Hydropower Development in the Danube Basin* may be mentioned.

- **Considering energy economic strengths and advantages of hydropower**
  Although there are undoubtedly potential negative effects of hydropower on river ecology, hydropower offers a number of advantages from an energy-economic perspective compared to other renewable technologies. Amongst others, hydropower has a higher capacity credit and lower balancing requirements or – in case of storage hydropower – can even provide flexibility and ancillary services. And despite a tremendous cost reduction of non-hydro renewables in the past few years, hydropower still has the lowest total costs in terms of combined levelized cost of electricity, balancing and external costs. However, those advantages are often not commonly known and/or accepted. Hence, in the discussion of pros and cons of different renewable technologies the energy-economic characteristics of hydropower should be appreciated without any prejudice.
- **Recognising the potential value of storage hydropower for the electricity system**
  The role of storage hydropower in energy transition will differ from the role of run-of-river hydropower. In contrast to run-of river-hydropower, storage hydropower – as one option for ensuring grid stability – can provide flexible generation which will be increasingly required to integrate variable electricity production from wind power and solar PV. Additionally, storage power plants are generally less vulnerable to climate change-related impacts on water runoffs, since they can balance variations in river flows and shift production in hours with high residual loads.
- **Application of high environmental and social standards independent of project size**
  Generally, it should be a matter of course that the further development of hydropower is in line with EU and national environmental legislation (i.e. environmental impact assessment and WFD procedure), respectively. In this context, project developer, investors and authorities should consider appropriate environmental impact assessments and WFD procedures not only as a formal prerequisite but as a chance to identify, manage and actively engage stakeholders in hydropower projects. Additionally, the basic principles of an environmental impact assessment with proper public consultations should not only be applied for large hydropower but also small hydropower projects for which an environmental impact assessment is not legally required.
- **Assessment of cumulative impacts of small hydropower required**
  Small hydropower is still often considered to have less negative social and environmental impacts than large hydropower. However, there is generally no linear relationship between size and impact and large hydropower tends to be the better option both from an energy economic as well as cumulative environmental and social view. Therefore, small hydropower plants should be subject to the same environmental regulations as large hydropower plants, not be granted any small hydropower specific subsidies or other economic incentives and be included in long-term coordinated planning and assessment at a basin scale. Also, renewable strategies should consider the actual environmental and social costs and benefits of small hydropower to a full extent.

- **Hydropower projects need to provide tangible benefits to local communities and people**
  Local stakeholders are more and more unwilling to accept the uneven distribution of benefits and negative impacts of hydropower. Hence, the social acceptance of hydropower projects is increasingly conditional on the ecological impact but also the ownership structure. Projects that allow co-ownership for local communities and people can increase social acceptance and should, therefore, be considered by project developers and investors. If not yet done so, countries should adopt the legal and regulatory frameworks to actively support the implementation of citizen and renewable energy communities.

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9. Annex 1: Key figures of national power systems 2018

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	AT	BA	BG	CZ	DE	HR	HU	MD	ME	RO	RS	SI	SK	UA
Generation (TWh/a)	**67.52**	**17.34**	**42.31**	**81.89**	**597.57**	**12.12**	**28.17**	**3.18**	**3.61**	**60.64**	**39.67**	**15.09**	**25.10**	**99.04**
nuclear	0.00	0.00	15.27	28.33	71.90	0.00	14.76	0.00	0.00	10.36	0.00	5.54	13.84	84.40
lignite	0.00	10.84	16.76	34.23	134.80	0.00	4.47	0.00	1.41	12.98	28.13	4.02	1.33	60.31
hard coal	1.79	0.00	0.30	3.21	72.90	1.32	0.00	0.00	0.00	1.00	0.00	0.00	1.20	
natural gas	9.86	0.00	1.68	4.43	87.30	1.90	5.37	3.14	0.00	5.00	0.21	0.00	1.82	
oil and other fossil	6.24	0.10	0.00	1.70	11.00	0.00	0.10	0.00	0.00	5.20	0.00	0.30	0.90	
hydropower	34.10	6.20	4.96	1.60	18.40	6.83	0.20	0.04	2.00	17.56	10.43	4.63	3.50	10.51
pumped storage	3.60	0.10	0.28	1.06	6.67	0.07	0.00	0.00	0.00	0.14	0.80	0.20	0.30	1.50
wind power	5.90	0.10	1.38	0.63	107.20	1.30	0.60	0.00	0.20	6.30	0.10	0.01	0.01	1.10
solar PV	1.44	0.00	1.38	2.30	41.20	0.10	0.30	0.00	0.00	1.80	0.00	0.20	0.60	1.23
biomass and other RES	4.60	0.00	0.30	4.40	46.20	0.60	2.37	0.00	0.00	0.30	0.00	0.20	1.60	0.30
Consumption (TWh/a)[a]	**76.47**	**12.74**	**34.50**	**68.00**	**546.44**	**18.28**	**42.52**	**4.18**	**3.36**	**58.10**	**40.27**	**14.70**	**28.90**	**158.00**
Exchange balance (TWh/a)[b]	**8.95**	**-4.61**	**-7.81**	**-13.89**	**-51.13**	**6.16**	**14.35**	**0.96**	**-0.25**	**-2.54**	**0.60**	**-0.39**	**3.80**	**-1.35**
Net capacity (GW)	**25.39**	**4.37**	**11.46**	**20.82**	**215.97**	**4.83**	**8.48**	**0.43**	**0.95**	**20.23**	**8.77**	**3.96**	**7.73**	**22.06**
nuclear	0.00	0.00	1.95	4.04	9.52	0.00	1.90	0.00	0.00	1.30	0.00	0.70	1.94	13.84
lignite	0.00	1.87	3.56	8.45	21.10	0.00	1.05	0.00	0.22	3.34	5.31	0.98	0.35	34.00
hard coal	0.60	0.00	0.18	1.20	24.65	0.33	0.00	0.00	0.00	1.03	0.00	0.00	0.22	
natural gas	4.85	0.00	0.76	1.23	31.61	0.74	4.04	0.38	0.00	1.83	0.21	0.52	1.11	
oil and other fossil	1.12	0.09	0.00	0.48	6.65	0.95	0.41	0.00	0.00	1.58	0.00	0.12	0.70	
hydropower	10.45	1.92	2.32	1.09	5.61	1.81	0.06	0.02	0.66	6.70	2.40	1.12	1.81	4.67
pumped storage	3.70	0.42	0.86	1.17	5.71	0.28	0.00	0.00	0.00	0.09	0.61	0.18	0.73	1.50
wind power	2.89	0.05	0.70	0.32	58.23	0.56	0.33	0.02	0.07	2.98	0.24	0.00	0.00	0.53
solar PV	1.19	0.02	1.05	2.05	43.92	0.05	0.34	0.00	0.00	1.26	0.00	0.29	0.53	1.42
biomass and other RES	0.59	0.00	0.08	0.80	8.98	0.11	0.36	0.00	0.00	0.12	0.00	0.05	0.34	0.10
Peak load (GW)	**12.07**	**2.08**	**6.47**	**11.14**	**79.07**	**3.17**	**6.57**	**0.97**	**0.59**	**8.92**	**6.87**	**2.38**	**4.52**	**0.00**

[a] incl. consumption of pumped storage, [b] import – export