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OIE HRVATSKA

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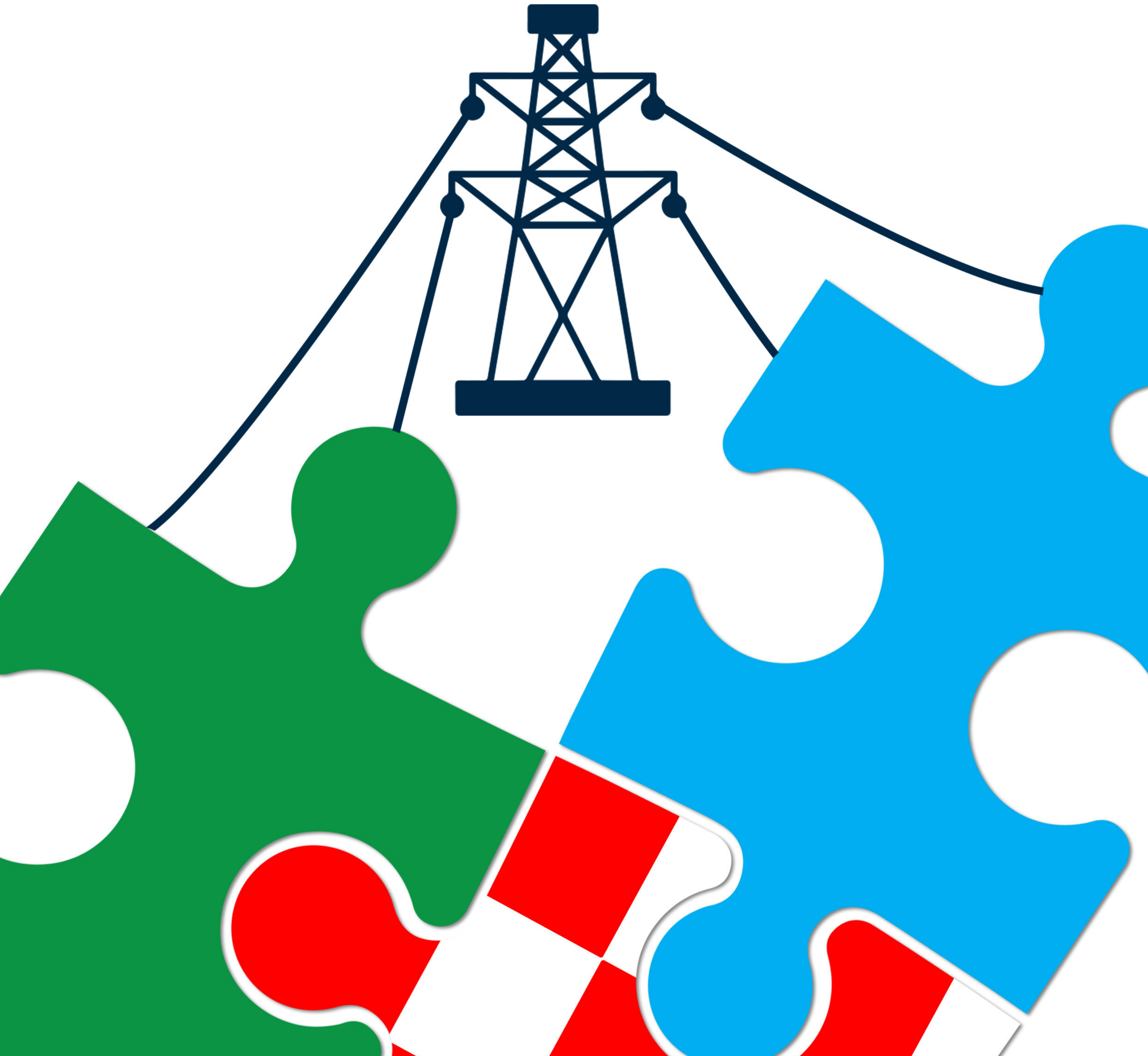
ACTION PLAN FOR POWER GRID STRENGTHENING TO SUPPORT THE INTEGRATION OF RENEWABLE ENERGY SOURCES IN CROATIA



DISCLAIMER

This report was funded by the European Bank for Reconstruction and Development (EBRD) and written jointly by the Faculty of Electrical Engineering and Computing (FER), University of Zagreb and the Energy Institute Hrvoje Požar (EIHP).

This report was written in collaboration with the Croatian Transmission System Operator (HOPS) and the Croatian Distribution System Operator (HEP DSO). Both system operators shared their insights and confidential data with the authors for the purpose of this report.

The report analyses the existing situation of the transmission and distribution networks in Croatia and proposes and an Action Plan that would help the integration of variable renewable energy sources into the power system. Nothing in this report should be taken as legal advice.

Neither the European Bank for Reconstruction and Developments, nor the Renewable Energy Sources of Croatia, nor EIHP and FER shall be responsible for any loss whatsoever sustained by any person who relies on this publication.

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EXECUTIVE SUMMARY

After surpassing its 2020 renewable energy target, the Republic of Croatia has set ambitious targets for 2030. There is a great interest to develop and invest in wind farms and photovoltaic power plants, but their integration will require significant investments in the power network, as well as regulatory and operational changes. The same challenges are occurring all around Europe.

Even without the COVID-19 pandemic, Croatian electricity consumption was declining over the last ten years, while consumption growth rate forecast is limited to 1-2% in the following decade. However, due to the electrification of other sectors (transport and buildings) and an average daily electricity import of more than 30%, there is an increased demand for additional renewable electricity capacity, most notably wind farms and photovoltaic power plants.

Even though both the transmission and distribution system operators have seen declines in network losses, electricity network in Croatia is old (>60% of transmission line length is older than 40 years). Renovation requirements combined with the increasing number of electricity generation grid connection requests is putting a lot of pressure on the system operators to modernise their infrastructure.

As wind farms and photovoltaic power plants are variable renewable energy sources, the transmission and distribution system operators have to find the best way to integrate those power plants into the Croatian power system. Chapter 3 – Variable Renewable Electricity integration in Croatia, presents the main barriers but also the different ancillary services that variable renewable energy sources could provide to the power system.

In the transmission network, the transmission system operator – HOPS, plans to invest HRK 9.1 bn (€1.2bn) by 2030. As defined by the current legal framework, around 35% of investments is expected to be financed by the network users and around 11% is planned from EU funds. The remaining portion of around 54% will be covered through the network tariffs.

According to the existing 10-year transmission network development plan, wind farms with a total capacity of 545 MW are expected to be connected to the grid in the period 2021-2023. Accordingly, at the end of the next three-year timeframe, 1,274 MW of all wind farms (including existing ones) are expected to be connected and operational on the transmission network. In the same three-year period only 12.4 MW of utility scale PV power plants are expected to be connected.

HOPS's analysis prepared for the purpose of the new ten-year transmission network development plan, demonstrated that the existing 220 kV Konjsko – Brinje transmission line is endangered if there is an outage of 400 kV Melina – Velebit transmission line combined with a large production of hydropower and wind power in Dalmatia. In order to enable the connection of a larger number of new production facilities in Dalmatia, it is critical to increase the transmission capacity of the existing 220 kV transmission line to approximately 600 MVA and after that construct a new 400 kV transmission line Konjsko – Lika – Melina.

The 400 kV transmission line Konjsko – Brinje (Lika) is still in the design phase, while the 220 kV transmission line Senj – Melina, where existing lines will be replaced by 2nd generation high-temperature low sag lines, is expected to be tendered soon. To support investments into critical transmission infrastructure, HOPS will receive HRK 1.6 bn (€213mil) from the National Recovery and Resilience Plan for the network development, which is expected to be adequate to strengthen the most critical parts of the transmission network in the next four to five years. Average annual investments level was around HRK 450 mil (€60mil), while in the next decade they are expected to double.

Following the adoption of the new Electricity Market Act (adopted on 1 October 2021), HOPS will need to amend and adapt its Grid Connection Rules. The existing transmission infrastructure allows the connection of around 2.5 GW of new power capacities that will be built in the short-term due to a strong interest by developers. In order to continue investments and better integration of renewable energy sources, new major investments in the transmission network will be necessary. Therefore, changes in spatial plans in some counties should be made as soon as possible. The National Spatial Development Plan is still not finalised and the changes in the county spatial plans can last up to five years. This could be a potential challenge also in the future.

In the distribution network, the distribution system operator – HEP DSO, plans to invest around HRK 12 bn (€1.6bn) by 2030, with a significant amount planned for the 10 (20) kV facilities as it plans to transition to the 20 kV voltage level. The planned infrastructure investments are described in Chapter 4 – Planned infrastructure investments.

Lastly, in Chapter 5 – Action plan, action points, among others, propose legislative changes, proposal of a new connection fee methodology by adjusting the existing “deep” (mixed) model and introducing regulatory solutions for voluntary curtailment.

To the Croatian Government it is suggested to: clarify the infrastructure development policy, ensure full compliance of the new acts, accelerates the spatial planning process, update the Public Procurement Act, introduce realistic scenarios and stricter deadlines for issuing the EOTRP, and introduce higher guarantees.

To the Croatian Energy Regulatory Agency it is suggested to: update the existing grid connection regulations and adjust the grid connection charges and network tariffs.

To the transmission and distribution system operators it is suggested to: reduce the uncertainty of the connection solutions, deadlines and costs, align connection processes between the transmission and distribution system, update the connection rules, and more frequently update grid codes.

The Action Plan also takes a look at the technical, technological, and operational changes that the system operators should implement, such as initiating the public procurement procedures in the earlier stages of project development, increasing the transmission capacity in southern regions, constructing new transformers stations, changing the technical requirements for new renewable energy projects, introducing guarantees for completing renewable energy projects and human resource strengthening and capacity building.

LIST OF ABBREVIATIONS

Abbreviation	Full description
AIT	Average Interruption Time
ACER	The European Union Agency for the Cooperation of Energy Regulators
BiH	Bosnia and Herzegovina
CAIDI	Customer Average Interruption Duration Index
DG	Distributed Generation
DTR	Dynamic Thermal Rating
ENS	Energy Not Supplied
ENTSO-E	European Network of Transmission System Operators for Electricity
EOTRP	Study of optimal technical solution for connection to the grid
EU	European Union
FACTS	Flexible Alternative Current Transmission System
FCR	Frequency Containment Reserve
FRR	Frequency Restoration Reserve
HEP DSO	HEP Distribution System Operator
HERA	Croatian Energy Regulatory Agency
HOPS	Croatian Transmission System Operator
HRK	Croatian Kuna
HROTE	Croatian Energy Market Operator
HTLS	High-Temperature Low Sag
HV	High Voltage
ICT	Information and Communications Technology
KPI	Key Performance Indicator
LV	Low Voltage
MV	Medium Voltage
OHL	Overhead Lines
PCC	Point of Common Coupling
PMU	Phasor Measurement Unit
PST	Phase Shifting Transformer
PV	Photovoltaic
RES	Renewable Energy Sources
RR	Replacement Reserve
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
T&D	Transmission and Distribution
TS	Transformers Stations
TSO	Transmission System Operator
TYNDP	10-year network development plans
VRES	Variable Renewable Energy Sources
VSR	Variable Shunt Reactors

1. INTRODUCTION

In 2019, the Republic of Croatia reached 28.5% of renewable energy share in gross final energy consumption, surpassing its 20% target set for 2020. In the electric power sector, renewable energy sources (hereinafter: RES) covered 49% of the gross electricity consumption (eurostat, 2021).

A large share of the renewable electricity came from hydropower plants (on average 38% between 2010 and 2019), whereas the share of other renewable sources, predominately wind farms has been increasing over the last decade (eurostat, 2021).

The Croatian Government has targeted a significant increase in wind and PV power capacity in the next decade. Wind energy capacity should increase from 803 MW in 2020 to 1,364 MW in 2030 according to the Integrated National Energy and Climate Plan, which will be most likely overachieved as 1,274 MW will be grid connected by 2023. PV capacity should increase from 109 MW to 768 MW in 2030 (Republic of Croatia, 2020).

The Croatian Low Carbon Strategy estimates that variable renewable energy sources (hereinafter: VRES), most notably wind farms and photovoltaic (hereinafter: PV) power plants, will cover 39-43% of electricity generation by 2050, which will together with hydropower plants and other renewable energy sources contribute more than 85% (Republic of Croatia, 2021).

In addition to the defined RES targets, the Croatian Government presented its new support mechanism (feed-in premium for large projects and feed-in tariffs for smaller projects), which triggered a significant number of VRES projects being developed.

Currently, in Croatia there is more than 5 GW of power capacity installed. In mid-2021, there were more than 13 GW of electricity generation projects under development, mostly wind and PV projects, which is several times higher than the target capacities for 2030. Most of the new RES capacity under development is planned to be connected in southern Croatia, in a 200 x 100 km^2 area.

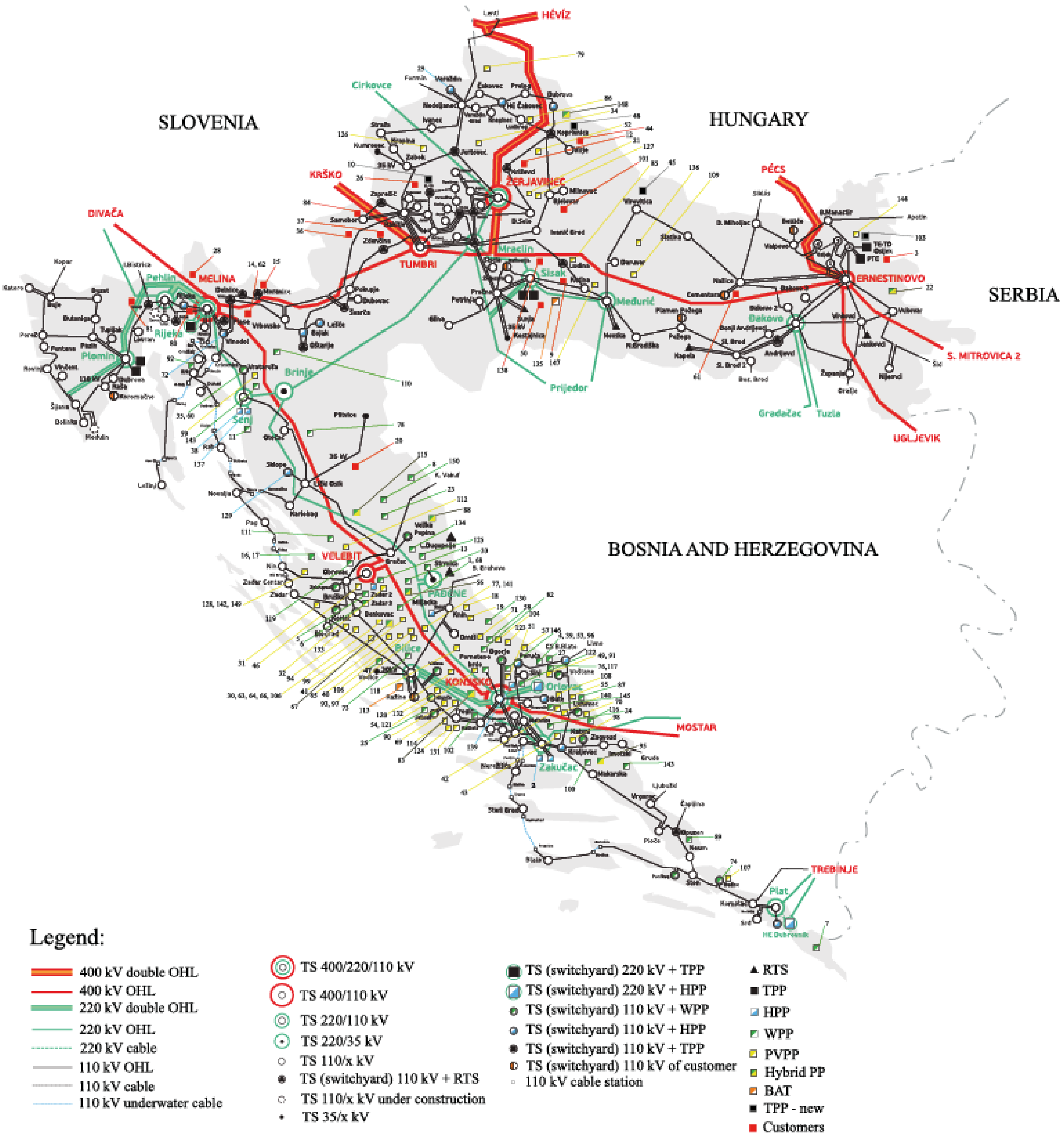
However, majority of electricity consumption centres in Croatia are located in the continental part of the country. Due to the specific shape of the country's territory and a consequently longitudinal network topology, the existing transmission network needs to be upgraded to absorb new VRES and to connect it with main consumption centres, as shown in Figure 1.

The ageing transmission and distribution (hereinafter: T&D) infrastructure, as well as complex permitting procedures for the development of overhead lines, have put T&D system operators under further pressure to deliver network infrastructure investments more quickly than ever before.

The Croatian Transmission System Operator (hereinafter: HOPS) has received a large number of VRES applications for grid-connection. However, the complex spatial permitting and public procurement processes are slowing down grid reinforcement and consequently the permitting process of VRES applications. Currently, this has created a bottleneck of more than 11.3 GW of projects waiting for grid-connection contracts to be signed.

Furthermore, the Croatian Distribution System Operator (hereinafter: HEP DSO) is receiving an increased number of distributed generation (hereinafter: DG) requests, as more than 1.7 GW, mostly small-scale PV power plants, which need to be safely integrated into the power system.

Figure 1. The Croatian transmission system (HOPS, 2021)



2. EXISTING INFRASTRUCTURE FOR TRANSMISSION AND DISTRIBUTION OF ELECTRICITY

2. 1. ELECTRCITY CONSUMPTION

Electricity consumption is an important driver in the power system planning process. Over the last ten years, the total electricity consumption in Croatia has declined sharply. As presented in Figure 2, the total gross consumption on the transmission network (excluding self-consumption) level between 2010 – 2020 dropped from 18 TWh to 15.9 TWh. The significant drop in 2020 can partially be accredited to the COVID-19 pandemic, which reduced electricity consumption across the European Union (hereinafter: EU).

However, there is still demand for new RES projects as Croatia imports on average 30% of its electricity consumption.

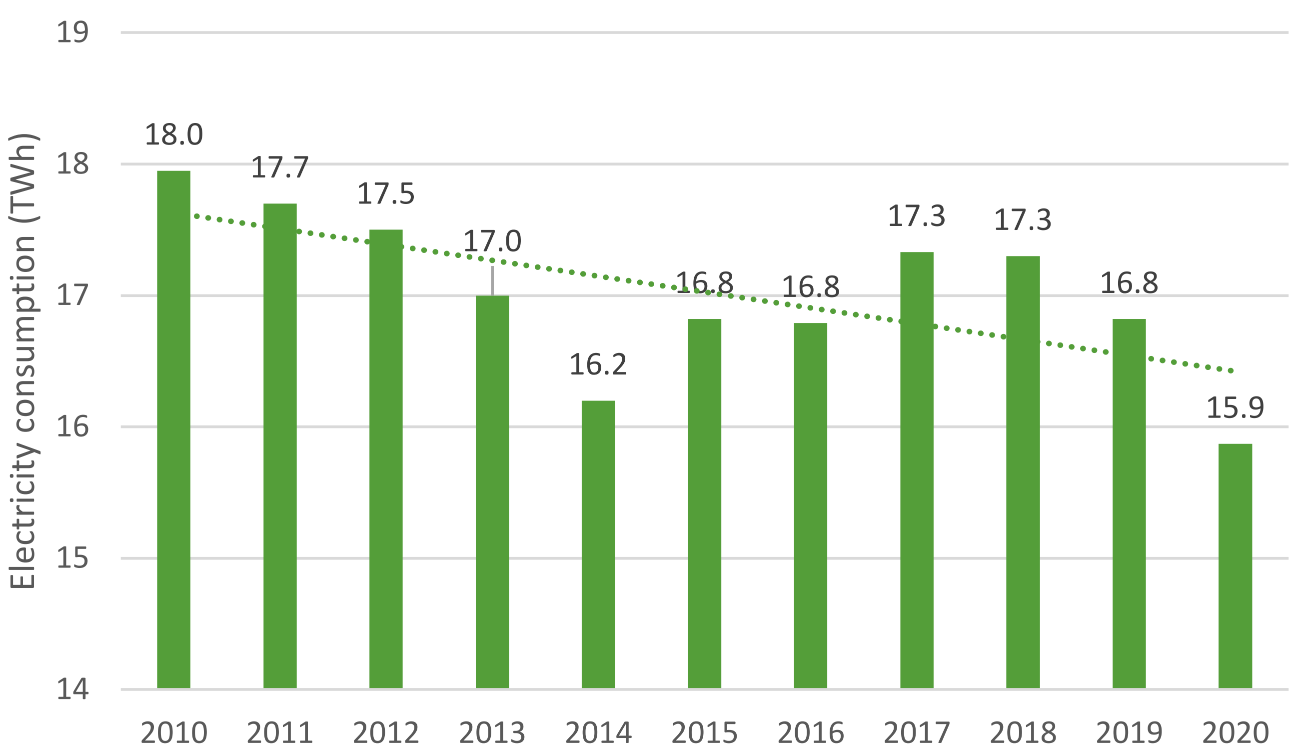
The new Energy Strategy from 2020 forecasts that electricity consumption up to 2030 will grow at an average annual rate of 1.2%. Based on 2019 consumption, in 2030 Croatia will reach 19 TWh of electricity consumption. The strategy also indicates that the share of electricity in gross final consumption is expected to increase in the future from 20.3% in 2017 to 22.1%-23.7% in 2030, and to 35.7%-47% in 2050, also due to the electrification of transport. (Republic of Croatia, 2020).

Table 1 shows RES targets in gross final energy consumption and in the power sector.

Two important factors have significant negative effects on transmission and distribution network development and investments in the future:

1. a low growth rate of electricity demand; and
2. a high integration of distributed generation and prosumers (electricity produced at consumers' sites).

Figure 2. Total electricity consumption in Croatia on the transmission level 2010 – 2020 (HOPS, 2021)



These two factors are important from the network infrastructure perspective – since a larger integration of distributed generation and prosumers will decrease network loading. If part of the consumption is generated on-site, or close to the site, then only the remaining consumption will be delivered through the network. Consequently, this assumes a lower level of electricity delivered through the network and a lower level of income for system operators, which will need different ways of billing (e.g. by introducing a flat fee similar to internet services).

However, the network infrastructure should still be designed on the basis of a full profile, to enable full delivery through the network in cases when local generation is not possible. In the network business, the majority of costs are related to fixed costs (capital expenditures), while only a minor part (usually 1-2%) is related to operation and maintenance (CIGRE WG A3.06).

The level of network costs will increase due to the increased number of RES connections and network reinforcement needs, while network income based on existing volumetric tariffs will drop. **Therefore, it is necessary to update the existing volumetric network tariffs to sustain a larger scale of RES, DG, and prosumer integration in the system and maintain network reliability and security of supply at a high level.**

Peak and minimum system loads

Figure 3 shows the annual peak and minimum system load in the 2010-2020 timeframe. The Croatian power system has a large gap between the minimum and the maximum system load. On average, the minimum load is below 40% of the peak system load.

This is a consequence of the low share of industrial consumption and the dominant share of household consumption, together with a decrease in population. Over the 10-year period, the peak load shows a slight falling trend, with an average decline of 0.63% per annum, while the minimum system load is more constant, with an average annual decline of 0.19%. These peak load and minimum load stagnations were also not favourable for more intensive infrastructure development.
However, due to a strong tourist season in August 2021, Croatia reached its highest peak over the last two years of 3,072 MW and the highest daily consumption over the last two years of 60.791 GWh.

Share of wind and PV power in Croatia

Figure 4 shows the share of wind and PV in total demand in the South East Europe region in 2018, and 2030 as planned by national Transmission System Operators (hereinafter: TSOs) in 11 countries (Slovenia, Croatia, Bosnia and Herzegovina, Serbia, Kosovo, North Macedonia, Montenegro, Albania, Romania,

Table 1. RES targets in 2030 and 2050 (eurostat, 2021), (Republic of Croatia, 2020)

	Starting value	Target values	
	2019	2030	2050
RES share in the gross final energy consumption	28.5%	36.6% - 36.7%	53.2% - 65.6%
RES share in electricity generation	49.8%	61%	83% - 88%

Figure 3. Peak and minimum system load in Croatia 2010 – 2020 (HOPS, 2021)

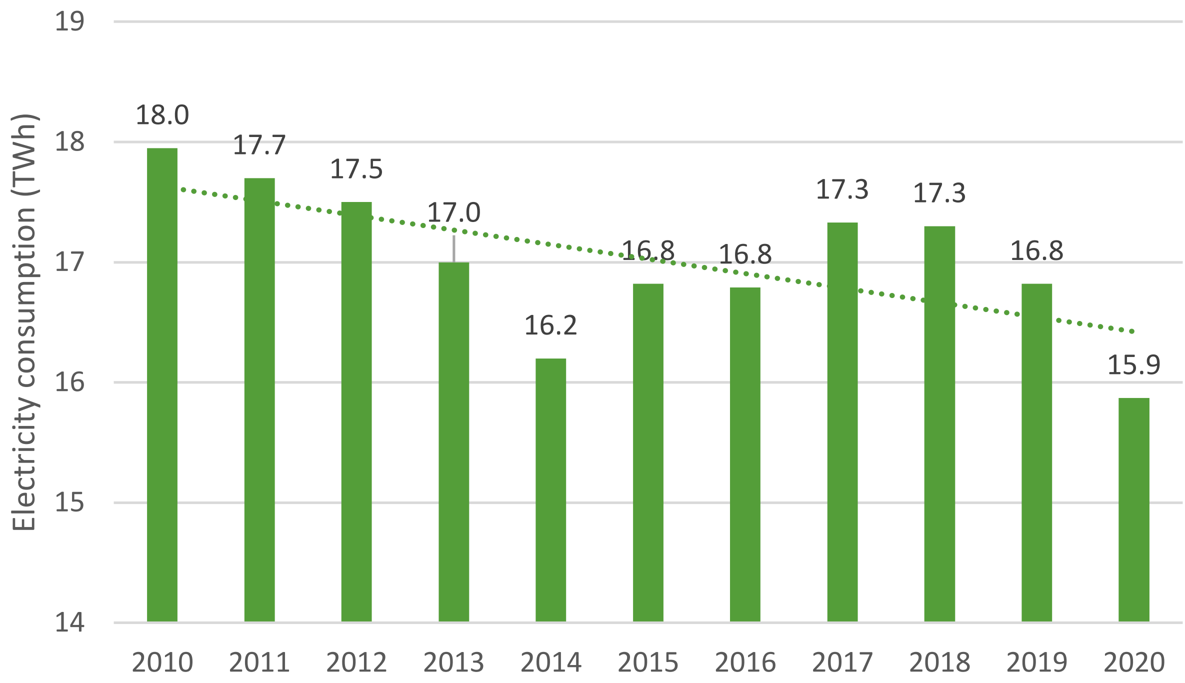
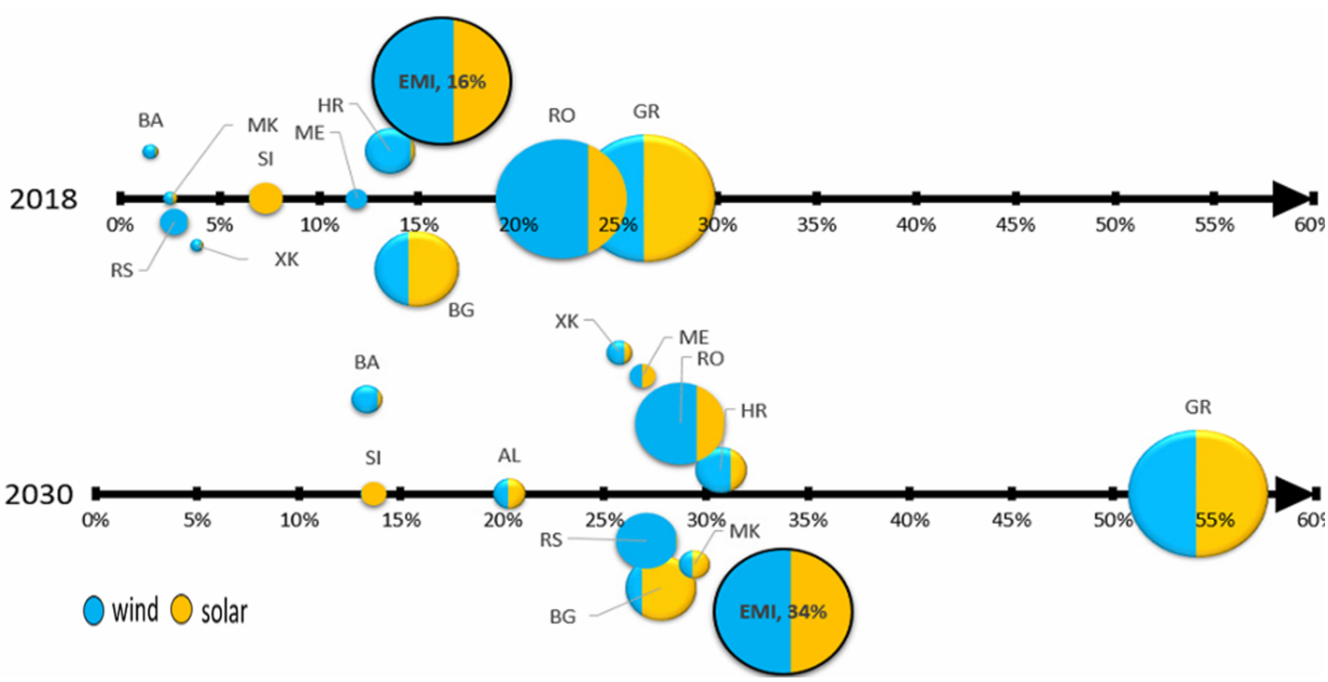


Figure 4. Wind and solar share in total demand in South East Europe in 2018 and 2030 (EIHP, USEA, 2020)



Bulgaria, and Greece). Clearly, Croatia is close to the regional (EMI) average in 2018 and 2030, with a big share of wind energy.

Although Croatia is below the EU average on the uptake of PV in the electricity mix (in 2019 PV was 4.4% of the electricity mix in the EU, compared to 0.4% in Croatia), Croatia has strong PV energy potential, which is expected to be more utilised in the future (eurostat, 2021).

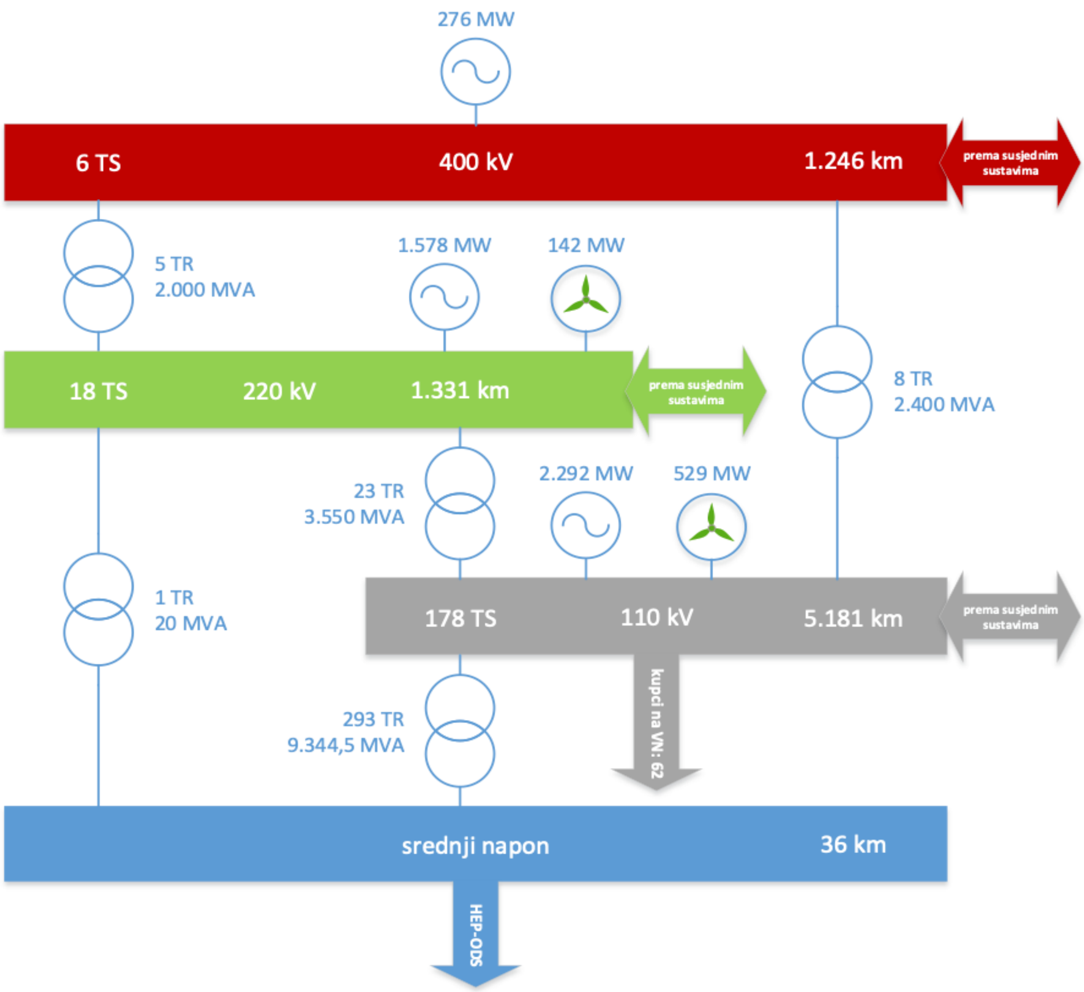
2. 2. MAIN SYSTEMS, EQUIPMENT, AND FACILITIES

The T&D network condition, operation and maintenance, as well as performance practices, are important factors for RES integration. In this subchapter, the review of the T&D system is based on input from HOPS and HEP DSO.

Transmission network

The Croatian power transmission system is shown in Figure 5. There is 7,794 km of high voltage network (400 kV, 220 kV, and 110 kV). The transmission lines designed for the 110 kV voltage level, but currently operating at medium voltage are also included. Total transmission network losses in Croatia in recent years are around 390 – 530 GWh, or about 2% of total electricity transmission, which is the average in most transmission networks in the EU. It is important to emphasize that the losses in 2019 amounted to only 1.75% of transmit-

Figure 5. Croatian power transmission system (HOPS, 2021)



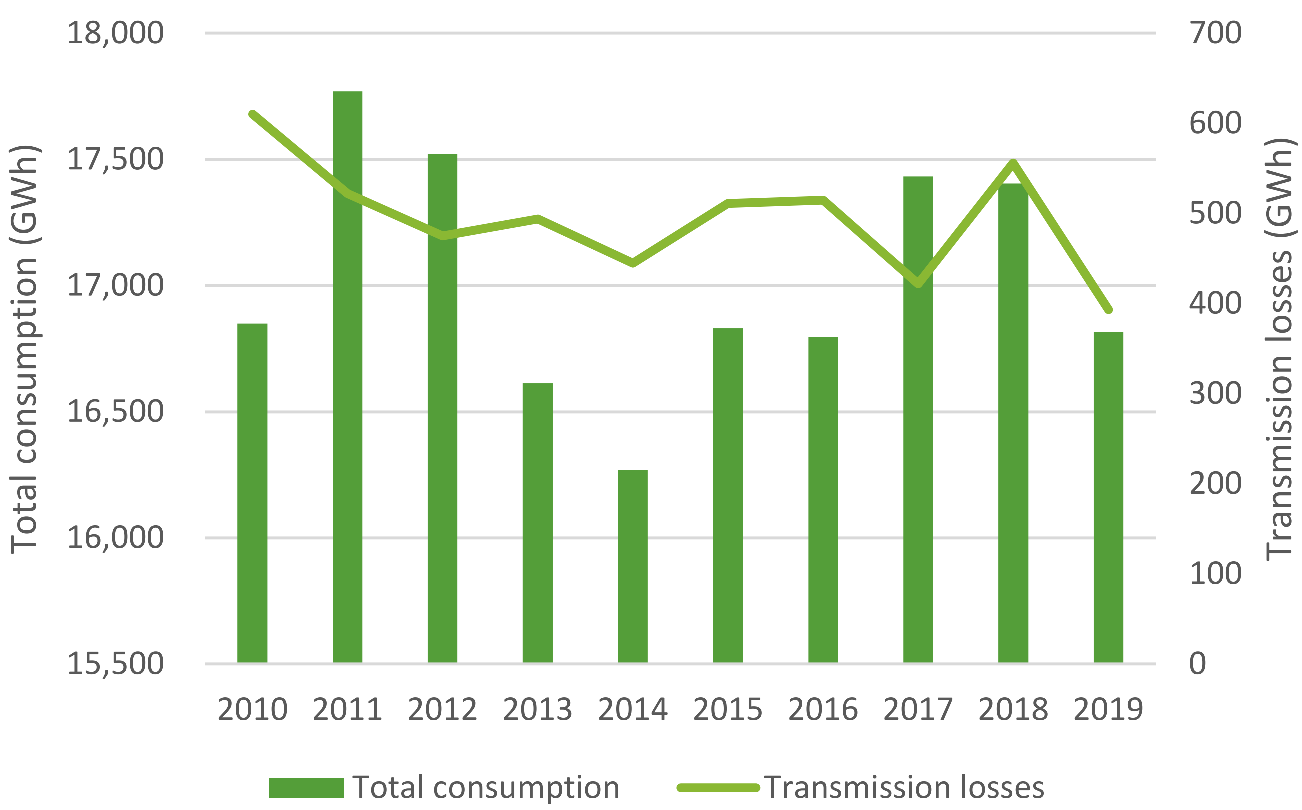
ted energy, or 388 GWh in absolute terms, as presented in Figure 6.

Figure 6 also shows that there is no clear correlation between the absolute amount of network losses and total consumption, i.e. the losses do not necessarily follow fluctuations in transmission consumption. In the period from 2010 to the present, transmission consumption has fluctuated around the average consumption (17,030 GWh) by +4.2% and -4.7%, while losses in the transmission network varied between the average losses (494 GWh) by +19% and -25.8%. The main reason for this is the significant level of transit through the Croatian system (5 – 8 TWh/year) and the low utilisation of lines in continental Croatia, where there is a lack of power generation plants.

Distribution network

The distribution network was initially planned and built according to three voltage levels: 35 (30) kV, 10 kV, and 0.4 kV. The distribution network development concept was updated during the 1970s, in order to save space and reduce the amount of equipment, resulting in an optimal system with just two voltage levels: one on a medium voltage (hereinafter: MV) level (20 kV), and the other on a low voltage (hereinafter: LV) level (0.4 kV). Currently, there are 26,421 transformer stations (hereinafter: TS) under the jurisdiction of HEP DSO,

Figure 6. Losses in the transmission network (HOPS, 2021)



as shown by Figure 7.

In the distribution network, losses have also shown a decreasing trend, reaching 7.7%, as presented in Figure 8, which is, satisfactory compared to other EU countries. In a recent study, the newly calculated ratio between technical and the non-technical losses is approximately 51:49%, which is significantly different from the previous estimates of a 70:30% ratio (EIHP, 2021). Based on the results of this new calculation, which indicate a significantly higher share of non-technical losses than previously estimated, HEP DSO has intensified its activities and investments to reduce non-technical losses such as:

- control of connections and billing metering points and unauthorised electricity consumption;
- testing of technical validations of measurement data in the remote reading system;
- checking the accuracy of measurements;
- replacement of old and oversized transformers with more suitable units from the operating reserve;
- optimising the switching state of the network, switching off the network elements at idle, etc.

2. 3. PERMITTABLE NETWORK LIMITS AND ALLOWANCE OF SHORT-TERM OVERLOADS

Currently, RES projects grid connection is analysed in a ‘Study of the optimal technical solution for the connection to the grid’ (hereinafter: EOTRP). The EOTRP analysis serves as the cornerstone for grid observation and needs to ensure that grid integrity and reliability are maintained. It is the basis for a binding Grid Connection Contract.

Most new grid connection requests are for

Figure 7. Croatian distribution power system (HEP DSO, 2021)

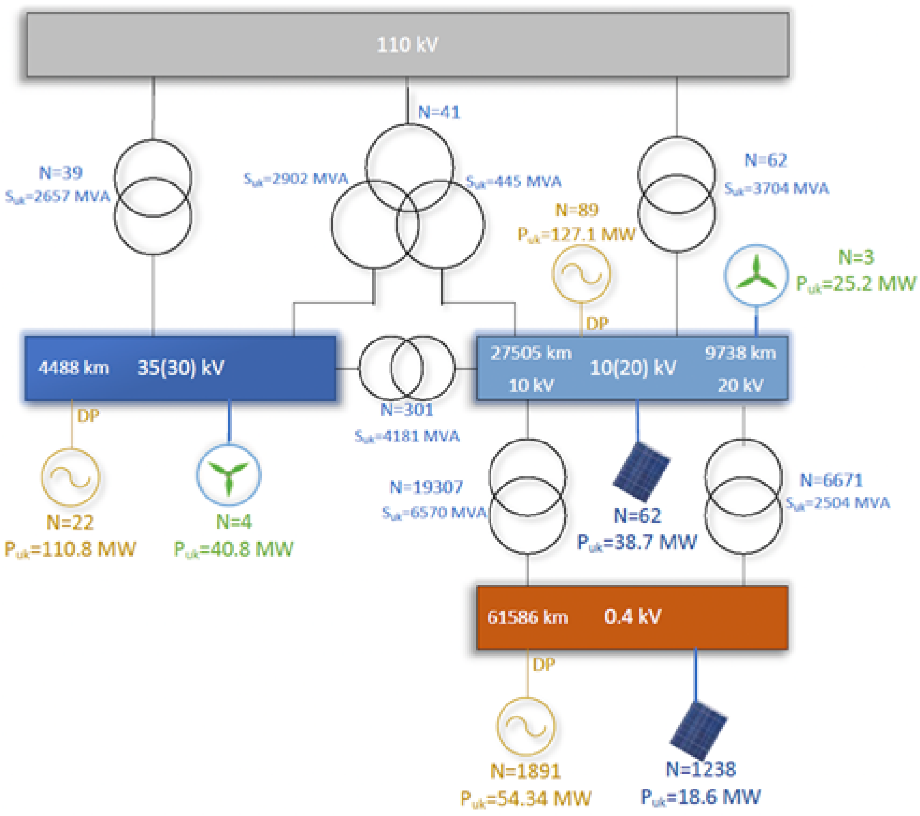
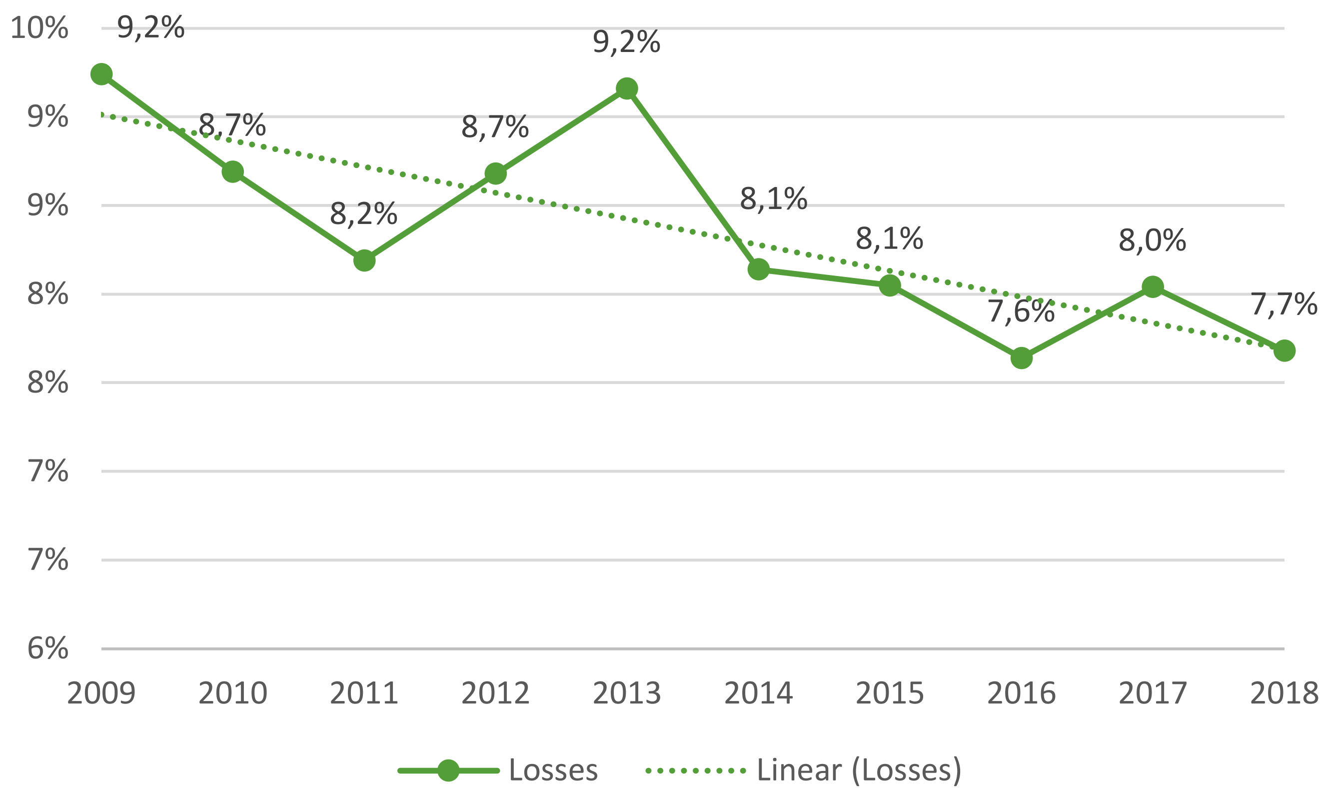


Figure 8. Losses in the distribution network (HEP DSO, 2021)



RES, primarily wind and PV, causing uncertainty of input data and external constraints. Therefore, relevant and location-specific scenarios for the observation of permittable network limits and allowances of short-term overloads play a very important role in establishing transparent and efficient connection procedures.

Both HOPS and HEP DSO have a general approach to selecting subsets of possible scenarios including different network limits. In addition to technical constraints, the network and legislative constraints that result in network reinforcement costs need to find a balance between increasing common welfare and private network investments for new RES capacity.

There are two different grid connection planning and operation tasks:

1. electrical power grid development planning (long-term); and
2. electrical power grid operation planning (short-term).

The former needs to ensure satisfactory long-term security of supply, reliability, and sufficient grid capacity to accommodate:

- new connections for both consumers and electricity generators;
- the alignment of long-term development plans with Croatian strategic policy documents (e.g. Energy Strategy); and
- ensuring the inclusion of new technologies into the power system.

The T&D system operators are obliged to continually develop and annually present their 10-year network development plans (hereinafter: TYNDP), which need the approval of the Croatian Energy Regulatory Agency (hereinafter: HERA).

The latter is a continuous service provided by HOPS which includes planning, control, and analysis of system performance, and the monitoring and control of the power system in real-time. This system operation service is charged through the general transmission network use levy.

Short-term overloads

All grid elements have their physical capacities tied to the maximum current/power they can conduct or to the maximum temperature they can sustain.

Short-term overloads do not pose a threat to the grid elements, because elements such as transformers and overhead lines can sustain smaller overloads for a limited period. Operation planning methodologies allow for a permanent overload of 120% of transformers. However, this is not applied to cable lines and some old overhead lines. These can be changed with the increase of grid observability, which is possible through better monitoring and measurements (e.g. Dynamic Thermal Rating systems).

However, prolonged operation under short-term overloads is not sustainable in the long term as it decreases the expected lifetime of components.

Permittable network limits

Power flows in grid connection procedures usually observe the normal operation state (N state) and contingency analysis under one outage (N-1 state). This is often contrary to the everyday operation of the network, where an N-1 state, or even an n-2 state, can be common. This is more relevant in the transmission network, because in the distribution network most of the grid is radially fed and there are fewer variations of possible grid topologies.

The network limits and allowance of short-term overloads can be technically evaluated through the connection process. New grid connections under the Croatian Grid code require ensuring 100% of connection adequacy, 100% of the time. The aforementioned short-term overloads are not acceptable even in very unlikely or very short events. Such restrictions are very harsh and they should be loosened in the transmission network, in particular for scenarios which are very uncommon or will last very short (e.g. maximum generation of all power plants in a certain area). By using existing tools it is possible to estimate the probability and the length of generation restrictions of RES for various levels of RES integration. It is recommended to implement such analyses as soon as possible in the Croatian power system, as it is the case in other EU power systems and prescribed by ENTSO-E's (European Network of Transmission System Operators for Electricity) and ACER's (the European Union Agency for the Cooperation of Energy Regulators) regulations and recommendations.

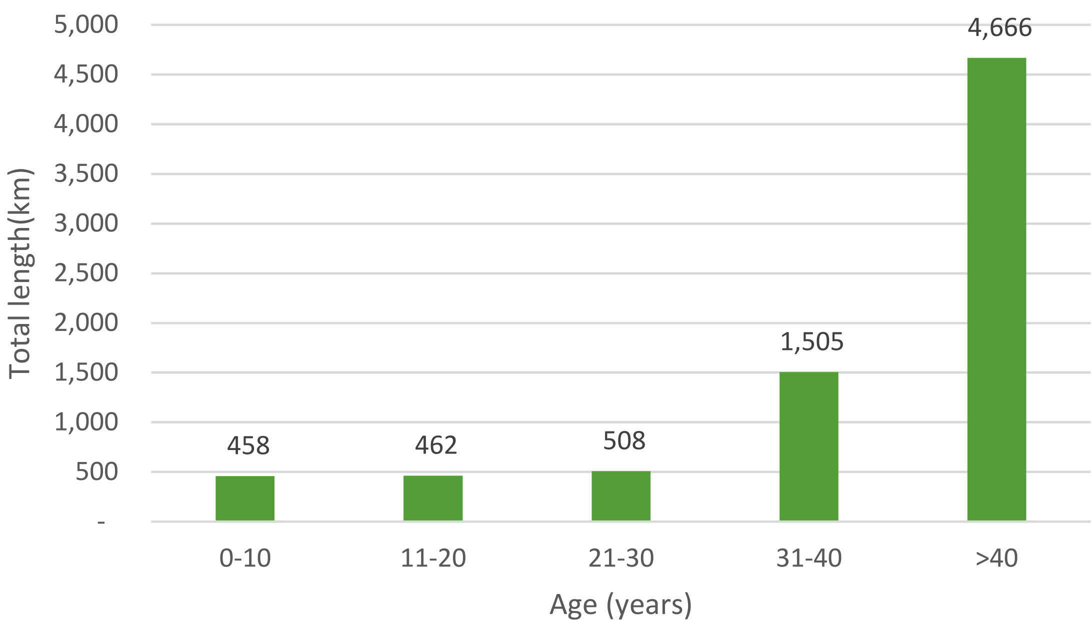
This is the goal in the distribution system, where every new generation unit connection is localised, and where grid capacity is used for much smaller segments of radially fed networks under the feeding point of a 110/MV kV substation.

However, on the transmission network level,

Table 2. Average life expectancy for high-voltage equipment in Croatia (HOPS, 2021)

Elements	Expected lifetime (years)
Energy transformers	40
Constructions (foundations)	40
Conductors, groundings, metal constructions	40
Energy cables	40
Secondary systems	15

Figure 9. Transmission lines' age in Croatia (HOPS, 2021)



the boundary or the most stringent scenarios are chosen to ensure that, in all the other cases, the grid limits will be satisfied. Such an approach often leads to high grid-strengthening costs, which are not based the frequency of extreme scenarios, nor analysis of the exact grid events that lead to such scenarios.

If operators would base their analysis on detailed historical data and forecasts, it would provide a measure that could identify critical grid outages/events, and create a list of operational events that would require actions on the generation side, such as the reduction of power or disconnection. There are additional technical aspects that would need to be included in the connection procedure in these cases, especially for units of larger power connected to 400 kV or 220 kV, such as a dynamic response analysis. Under current procedures, 10 MW projects are evaluated the same way as projects of above 100 MW, whose impact on the system reliability is much higher.

The recent legislative changes to the Electricity Market Act enable the possibility of a redefinition of connection procedures, which would set new network limits and allowances of short-term overloads.

2. 4. REHABILITATION AND MODERNISATION

Power network elements have a relatively long life expectancy of several decades, depending on the component type. Even though life expectancy depends on operational conditions, the average lifetime of the high voltage (hereinafter: HV) equipment in Croatia is given in Table 2.

Furthermore, Croatia's transmission network is obsolete in that more than 61% of the lines are older than their life expectancy (40 years), as shown in Figure 9 .

In its latest annual report, HOPS announced that 38% of its total investments is to be spent on renovations and reconstruction, in the following split (HOPS, 2020):

- renovations: HRK 608 mil (€82mil) (30%);
- replacements and reconstructions: HRK 160 mil (€21mil) (8%).

In addition, HOPS plans to utilise EU funds to replace submarine 110 kV cables in the amount of HRK 335 mil (€45mil). The rehabilitation of the obsolete network is a very challenging task in Croatia.

Besides powering urban areas, the transmission network was designed for large industrial consumers and large generating units, while today network users' structure is quite different. There are more and more small-scale power generation units in remote areas, far from urban areas, while large consumers have significantly reduced their consumption as industrial activity decreased in Croatia. The aforementioned changes impact the different topology needs on top of needed renovations.

Criteria for rehabilitation and modernisation

In 2020, HOPS updated its internal document: *Criteria and methodology for replacement and reconstruction of transmission network elements* in which it assumes large investments in network rehabilitation and renovation. It includes transmission lines, transformer stations, bays (switching devices), and busbars. This document is an update of a similar internal act prepared ten years ago, which covered transmission lines only.

When defining criteria for the inclusion of individual network elements on the list of elements targeted for renovation and the method of scoring individual criteria, the main focus was to simplify the procedure and to use data that were fully available within HOPS. Part of the criteria is related to various network calculations that can be performed using modern software tools, which are already regularly implemented in the preparation of the 10-year transmission network development plans.

These criteria are related to two or three main categories of renovation needs:

1. the actual condition of the observed network element;
2. the importance of the observed element within the transmission network and the electricity system as a whole;
3. an economic analysis of the justification for initiating the renovation project.

Individual criteria for assessing the actual situation and significance of the observed element that was previously included in the list of elements targeted for renovation within a given timeframe are evaluated in two basic ways:

1. by assigning a certain number of points equal to 0, 0.5 or 1, depending on the satisfaction of pre-set conditions;
2. by assigning a certain number of points between 0 and 1 depending on the relative ratios of individual indicators in relation to the reference indicator from the observed group of elements targeted for renovation.

The individual criteria, as well as the scoring methods, in relation to individual units of the transmission network (lines, transformers, switches) are described in detail within the above-mentioned HOPS' document (HOPS, 2020).

The methodology for drafting the list of priority elements targeted for renovation within the observed groups of network elements is based on:

- the determination of the element status index and element significance index within the transmission network and the power system as a whole, and additionally for individual groups of elements (overhead lines and large network transformers); and
- the economic justification for launching the renovation project in question.

When determining individual status indices and the index of significance for the observed targeted element, weighting factors are defined by HOPS, which gives higher or lower importance to each criterion.

It is envisaged that additional weighting factors in determining the final priority list regarding the overall status index, the importance index, and the economic criterion, will be used. A much higher weighting factor is attached to the economic criterion compared to the remaining two indices.

The procedure for creating a list of priorities for the renovation of individual units of the network is conceived as iterative, i.e. an element targeted for renovation evaluated with the highest total number of points is included in the final list of priorities and deleted from the list of targeted elements for renovation. An iterative procedure is necessary for the relative relationships of individual indicators used in scoring some criteria, which means that the mutual relationships in scoring depend on all targeted elements observed, and therefore the inclusion of one element on the final list affects the number of points of all the remaining elements. HEP DSO uses the analytical hierarchy process (AHP) for the same procedure.

Finally, it should be emphasised that these criteria in the transmission network do not consider the justification for launching an individual renovation project. This is done by an individual cost-benefit analysis (for projects with a CAPEX of above HRK 40 mil (€5.3mil)), whereas with these criteria the priority list for renovation is defined.

However, planned renovation activities need to be aligned with the total amount of funding available to HOPS for these purposes, which will then be invested on the basis of compiled and updated priority lists. More financially demanding renovation projects are subject to more detailed economic analyses, in order to determine the justification for starting a project with pre-conceived dynamics, or to determine the optimal dynamics of a project's implementation if the imagined dynamics prove to be economically unjustified.

Clear and applicable criteria for transmission network rehabilitation and modernisation are defined and implemented in Croatia. All targeted elements are treated with the same set of criteria and procedures with no discrimination between them.

Decommissioning and best practice

In Croatia, there are no specific environmental, health or safety rules or guidelines for decommissioning of components in transmission and distribution networks. Such rules are determined in the general environmental, health and safety legal framework.

Therefore, best international industry practice could be used, such as the *World Bank's Environmental, Health, and Safety Guidelines for Electric Power Transmission and Distribution (EHS Guidelines)*.

The guidelines include recommendations for the management of different non-technical impacts during the construction and decommissioning phases of power transmission and distribution systems. Examples of the impacts addressed in the EHS Guidelines include:

- construction site waste generation;
- soil erosion and sediment control from materials sourcing areas and site preparation activities;
- fugitive dust and other emissions (e.g. from vehicle traffic, land clearing activities, and materials stockpiles);
- noise from heavy equipment and truck traffic; and
- potential for hazardous materials and oil spills associated with heavy equipment operation and fuelling activities.

Environmental issues during the construction and decommissioning phase of network projects include:

- terrestrial habitat alteration;
- aquatic habitat alteration;
- electric and magnetic fields; and
- hazardous materials.

For example, the recommended measures to prevent and control impacts on terrestrial habitats during the construction of a right-of-way include:

- site transmission and distribution rights-of-way, access roads, lines, towers, and substations to avoid critical habitat through the use of existing utility and transport corridors for transmission and distribution, and existing roads and tracks for access roads, whenever possible;
- the installation of transmission lines above existing vegetation to avoid land clearing;
- the avoidance of construction activities during the breeding season and other sensitive seasons or times of day;
- the revegetation of disturbed areas with native plant species;
- the removal of invasive plant species during routine vegetation maintenance.

In addition, community health and safety impacts during the construction and decommissioning of transmission and distribution power lines are common to those of most large industrial facilities and are discussed in the EHS Guidelines. These impacts include, among others, dust, noise, and vibration from construction vehicle transit and communicable diseases associated with the influx of temporary construction labour.

3. VARIABLE RENEWABLE ELECTRICITY INTEGRATION IN CROATIA

3. 1. KEY PERFORMANCE INDICATORS IN INTEGRATING VRES

In addition to the losses mentioned in Chapter 2 – Existing infrastructure for transmission and distribution of electricity, there are several Key Performance Indicators (hereinafter: KPIs) that are used by T&D system operators to assess the achievement of their objectives by means of monitoring several performance indicators. System operators use many different KPIs, most of which can be classified into the following two groups:

1. System and Supply Availability and Reliability KPIs; and
2. System Performance and Stability KPIs.

Some of the most commonly used KPIs are listed below, but it is important to note that operators often use many internal performance indicators for specific internal purposes.

Availability and Reliability KPIs

System Availability is calculated as the total sum of availability of individual circuits of the grid, expressed as a percentage of the total number of circuits. A circuit is defined as an overhead line, cable, transformer, substation bus or any combination of these components controlled by one or more circuit breakers.

Total System Unavailability includes planned and unplanned outages.

Supply availability KPIs provide a measure for indicating the level of readiness of the system to deliver electrical energy to customers:

- Energy Not Supplied (hereinafter: ENS) – the sum total of all energy not supplied due to supply interruptions over a one-year period;
- Average Interruption Time (hereinafter: AIT) – general indicator of the duration of long-term power outages in the transmission network.

Most used **System Reliability** KPIs are defined as follows:

- System Average Interruption Frequency Index (hereinafter: SAIFI) – measures the average number of interruptions (all planned and unplanned) experienced by each customer. SAIFI can be calculated for each voltage level.
- System Average Interruption Duration Index (hereinafter: SAIDI) - measures the yearly average interruptions duration per customer.
- Customer Average Interruption Duration Index (hereinafter: CAIDI) - this index can be directly calculated provided SAIFI and SAIDI are available.

System performance and stability KPIs

Voltage Deviation Index
HOPS has defined the allowable system voltage ranges during normal operating conditions for each transmission voltage levels, as follows:

- 400 kV: 400 – 10% +5% = 360-420 kV;
- 220 kV: 220 ±10% = 198-242 kV;
- 110 kV: 110 ±10% = 99-121(123) kV;
- 35(30) kV: 35(30) ±10% = 31.5(27)-38.5(33) kV.

In a disturbed operation, the system voltage can be in the following ranges:

- 400 kV: 400 kV ±15% = 340-460 kV;
- 220 kV: 220 kV ±15% = 187-253 kV;
- 110 kV: 110 kV ±15% = 94-127 kV;
- 35(30) kV: 35(30) ±15% = 29.8(25.5)-40.2(34.5) kV.

Frequency Deviation Index

HOPS has defined allowable system frequency ranges during the following operating conditions:

- maximum frequency deviation from the setpoint (50 Hz), in a temporary steady-state and interconnection operation, shall not exceed ± 200 mHz;
- the current frequency deviation from the nominal value must not exceed ± 800 mHz;
- frequency deviations from the setpoint by more than ± 20 mHz are corrected by the action of primary regulation (allowed "dead band of the primary governor").

KPIs from Croatian T&D operators

HOPS and HEP DSO are obliged to publish once a year (on their website) the following KPIs:

HOPS (TSO):

- quality of services - share of requests resolved in a reasonable time for the issuance of an prior electricity consent for the connection of a electricity generator to the transmission grid in the observed year;
- supply reliability – general power supply reliability indicators, ENS and AIT, expressed at the level of the transmission system operator and the level of transmission areas, according to the type of long-term power outages (planned/unplanned) and the cause of long-term power outages.

HEP DSO (DSO):

- quality of services;
- supply reliability – general power supply reliability indicators such as SAIFI, SAIDI and CAIDI; and
- voltage Quality.

The following figures and tables show the available T&D power supply reliability KPIs :

Transmission System

Power supply reliability KPIs for transmission system areas and overall (ENS and AIT) in Croatia are shown for 2020 in Table 3. The overall reliability was lower than the required standard in Table 4.

Figure 10 shows the total AIT (with forced and planned interruptions) of the transmission grid by voltage levels from 2015 to 2019. For all the observed years (2015-2019), the total transmission grid AIT is higher than the required standard (17 min). It should be noted that the largest unavailability of the transmission network was at the PrP Split area, where most of the existing and planned RES projects are located. The reason for the large unavailability is that the grid in this area is

Table 3. Annual Croatian transmission system supply reliability (2020) (HOPS, 2021)

Transmission area	Annually transferred energy (GWh)	ENS (MWh)	AIT (min)
PrP Zagreb	11,017.40	291.50	13.94
PrP Split	5,771.06	505.80	46.19
PrP Rijeka	6,139.98	67.84	5.82
PrP Osijek	3,766.74	8.58	1.20
HOPS	26,695.18	873.72	21.49

*AIT=(8760*60*ENS)/Annually Transferred Energy

Table 4. Comparison with general KPI standards (transmission system) (2020) (HOPS, 2021) (HERA, 2017)

Power supply reliability KPI	General power supply reliability standard
ENS	873.72 MWh > 700 MWh
AIT	21.49 min > 17 min

Table 5. Annual Croatian transmission system supply reliability (2019) (HOPS, 2021)

Transmission area	Annually transferred energy (GWh)	ENS (MWh)	AIT (min)
PrP Zagreb	10,565.10	67.00	3.33
PrP Split	5,936.86	213.00	18.86
PrP Rijeka	7,012.20	29.43	2.26
PrP Osijek	3,971.70	15.60	2.06
HOPS	27,485.86	325.03	7.70

*AIT=(8760*60*ENS)/Godišnje prenesena energija

very old, poorly maintained in recent history (because they are in rural areas, which have a low usage of the lines, and a tough terrain) and weather conditions with many extremes (high temperature, cyclic salt, strong winds with alternative directions, frequent storms, etc.).

The research conducted by the Council of European Energy Regulators has shown that there are different rules for calculating power supply reliability KPIs across Europe, which make benchmarking of these indicators more challenging (Council of European Energy Regulators, 2019).

Most countries exclude short interruptions when calculating values of SAIDI and SAIFI, while others do not distinguish between long and short interruptions. Therefore, the lack of harmonisation might result in the misleading interpretation of KPI data in benchmarking reports.

The most common indicators for evaluating power supply reliability in transmission net-

Table 6. Comparison with general KPI standards (transmission system) (2019) (HOPS, 2021)

Power supply reliability KPI	General power supply reliability standard
ENS	325.03 MWh < 700 MWh
AIT	6.22 min < 17 min

Figure 10. Average interruption time by transmission grid voltage levels (2015 – 2019) (HOPS, 2021)

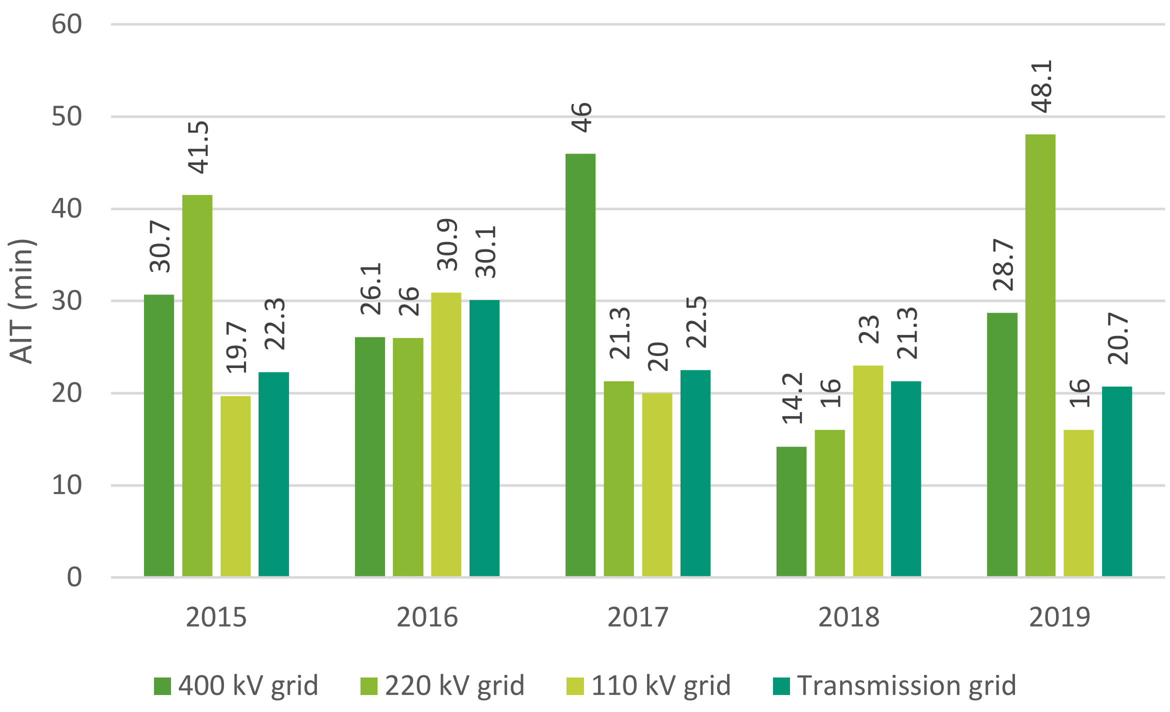


Table 7. Unplanned AIT (transmission), without exceptional events (minutes) (Council of European Energy Regulators, 2018)

Country	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Belgium									2,18	1,76	3,45	1,25	1,90
Czech Re-public						5,50	5,00	15,40	4,00	18,38	15,83	17,50	16,00
Estonia									1.756,00	2.719,00	410,30	552,00	1.404,66
Finland									0,44	1,24	4,40	1,54	1,22
France	3,77	2,44	1,89	2,52	4,35	6,35	2,89	1,73	2,28	3,02	2,77	7,02	2,90
Greece									13,61	23,78	19,65	30,61	20,93
Hungary												0,03	0,03
Croatia								32,9	20,6	20,5	36,8	22,3	30,1
Italy			5,28	12,80	3,68	3,82	3,41	4,88	6,17	4,65	2,68	5,29	2,69
Lithuania						0,06	0,49	0,35	0,34	0,31	0,25	0,22	0,04
Norway									19,15	4.370,77	102,65	11,00	5,97
Poland				0,00	468,45	0,00	4,57	252,33	161,89	0,00	1.249,78	86,77	84,44
Portugal	6,68	0,52	0,78	0,81	1,35	0,44	1,16	0,28	0,00	0,09	0,02	0,00	0,12
Romania					1,80	0,81	3,10	1,06	1,19	0,35	0,82	0,36	2,11
Slovakia									0,26	3,85	1,45	1,02	11,09
Slovenia	4,03	0,11	6,33	1,35	0,06	0,36	2,95	0,40	0,37	1,08	0,04	2,67	0,27
Spain									0,24	0,24	0,44	0,11	0,14
Sweden									0,03	0,00	0,05	0,04	0,01

Table 8. Unplanned ENS (transmission), without exceptional events (MWh) (Council of European Energy Regulators, 2018)

Country	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Belgium									293,81	237,48	453,79	161,09	242,33
Czech Republic						41,00	7,00	161,30	4,50	167,50	231,00	64,00	16,00
Estonia									148,21	58,41	27,56	11,93	67,54
Finland									60,00	150,00	490,00	170,00	139,67
France	2.950,00	1.937,00	1.512,00	2.002,00	3.563,00	5.089,00	2.429,00	1.374,00	1.865,00	2.499,00	2.150,00	5.540,00	2.320,00
Greece									1.275,00	2.050,63	1.672,13	2.645,03	1.806,75
Hungary												2,45	2,73
Italy			3.477,00	8.465,00	2.430,00	2.372,00	2.175,00	3.131,00	3.886,00	2.839,00	1.593,00	3.209,00	1.623,00
Lithuania						2,24	11,63	7,53	7,36	6,70	5,36	4,54	1,03
Norway									106,25	8.608,00	188,55	14,49	18,92
Poland				0,00	1.925,14	0,00	18,98	1.134,28	755,13	0,00	5.375,17	388,99	425,10
Portugal	496,00	40,20	262,59	75,90	130,16	42,09	116,20	27,00	0,00	8,60	1,80	0,40	11,00
Romania					167,00	69,30	267,90	98,80	107,12	30,89	82,51	38,36	224,69
Slovenia	94,54	2,54	156,76	34,02	1,34	7,69	67,94	9,71	8,85	26,69	0,82	64,47	6,42
Spain									113,00	1.126,00	204,00	232,00	524,30
Sweden									6,90	0,20	10,60	9,30	1,10

works are ENS and AIT, shown in Table 7 and Table 8.

However, transmission networks, and the correct indicator evaluation methods are not equally defined across Europe and these differences can significantly affect the compared data.

Distribution System

Figure 11, Figure 12 and Figure 13 show that since 2009, the values of all the main reliability indicators in Croatia had a downward trend, which is in line with the set business goals of increasing the quality of electricity supply and increasing business efficiency.

A major exception occurred in 2014 in the distribution network when the duration of forced interruptions caused by force majeure (SAIDI) was significantly increased due to extreme weather conditions in the Gorski Kotar area (where hail demolished a section of the distribution line).

KPI values in Figures 11-13 are not well represented because it is missing the total value of the actual KPI (shown in Tables 10-11) which could then be compared to planned values.

Power supply reliability KPIs for the distribution system (SAIDI, SAIFI, CAIDI) show that for the 10-year period (2009 -2018), supply reliability increased, and meets regulatory requirements, as presented in Table 9.

In European distribution networks, SAIFI and SAIDI are commonly used, but some countries do not use distribution network data to calculate these parameters (e.g. France since 2016) or use data of the entire distribution and transmission network (e.g. Netherlands).

Bulgaria, Croatia, Germany, Greece, and Latvia only include low and medium voltage interruptions in their SAIDI and SAIFI values. Planned and unplanned SAIFI and SAIDI with included exceptional events are presented in

Figure 11. Average duration of long power outages of each network user (SAIDI) (HOPS, 2021)

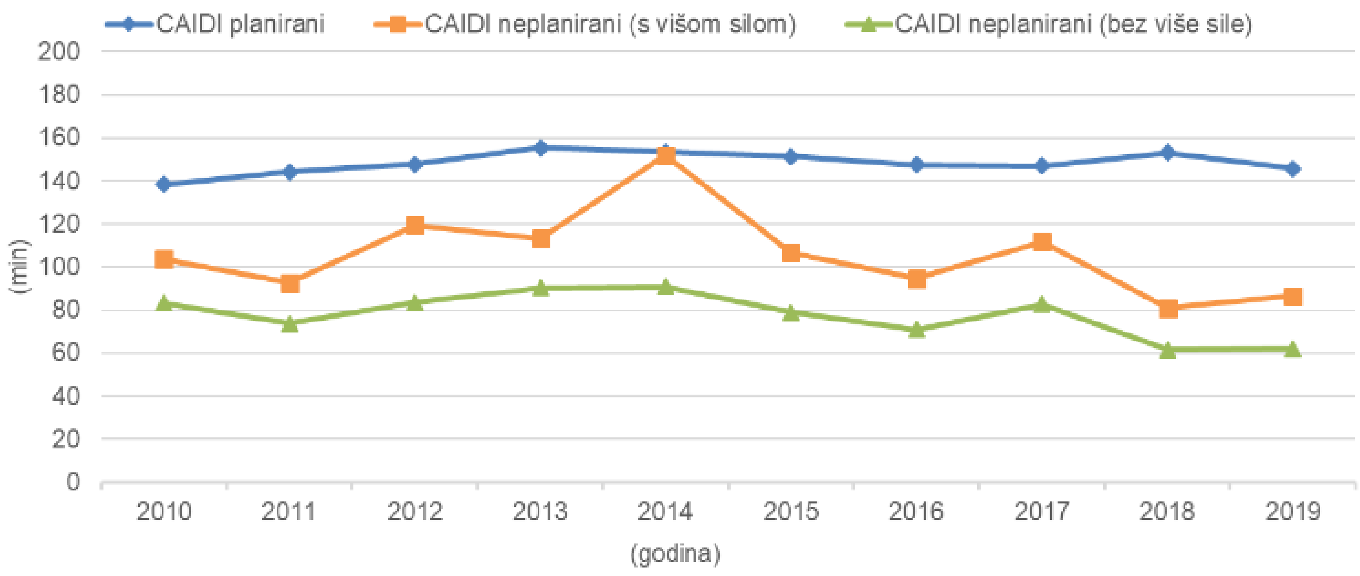


Figure 12. Average number of long-term power outages of each network user (SAIFI) (HOPS, 2021)

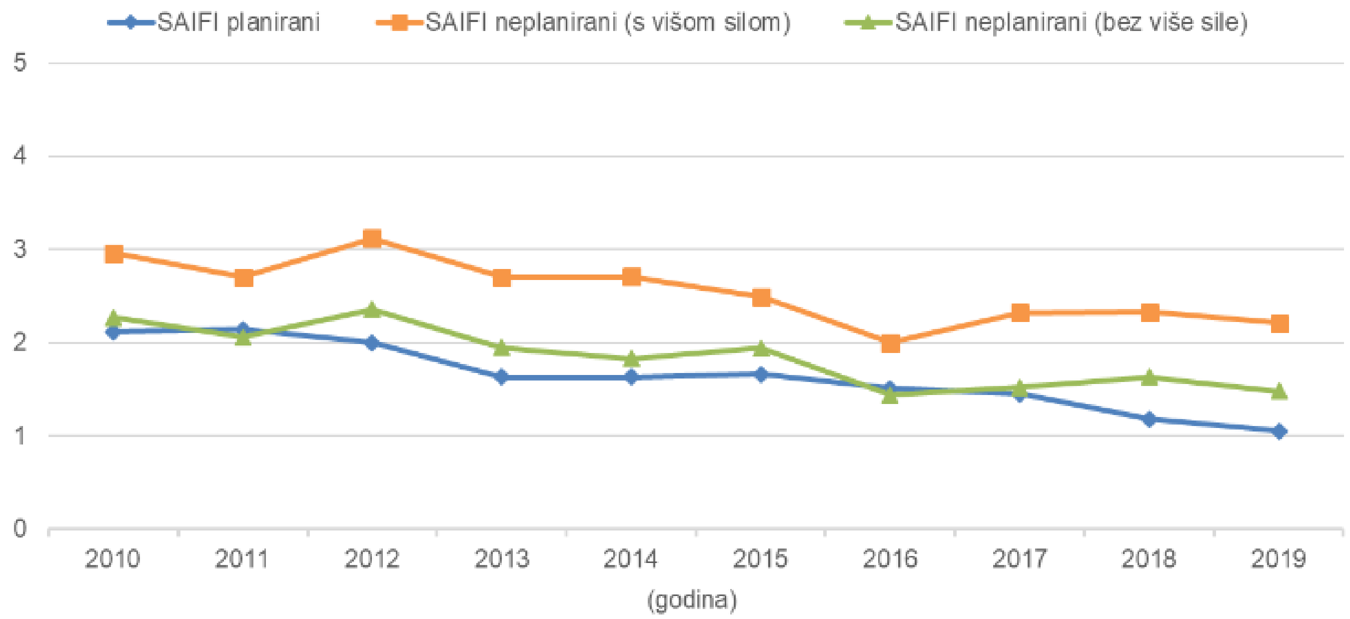


Figure 13. Average duration of long power outages per network user (CAIDI) (HOPS, 2021)

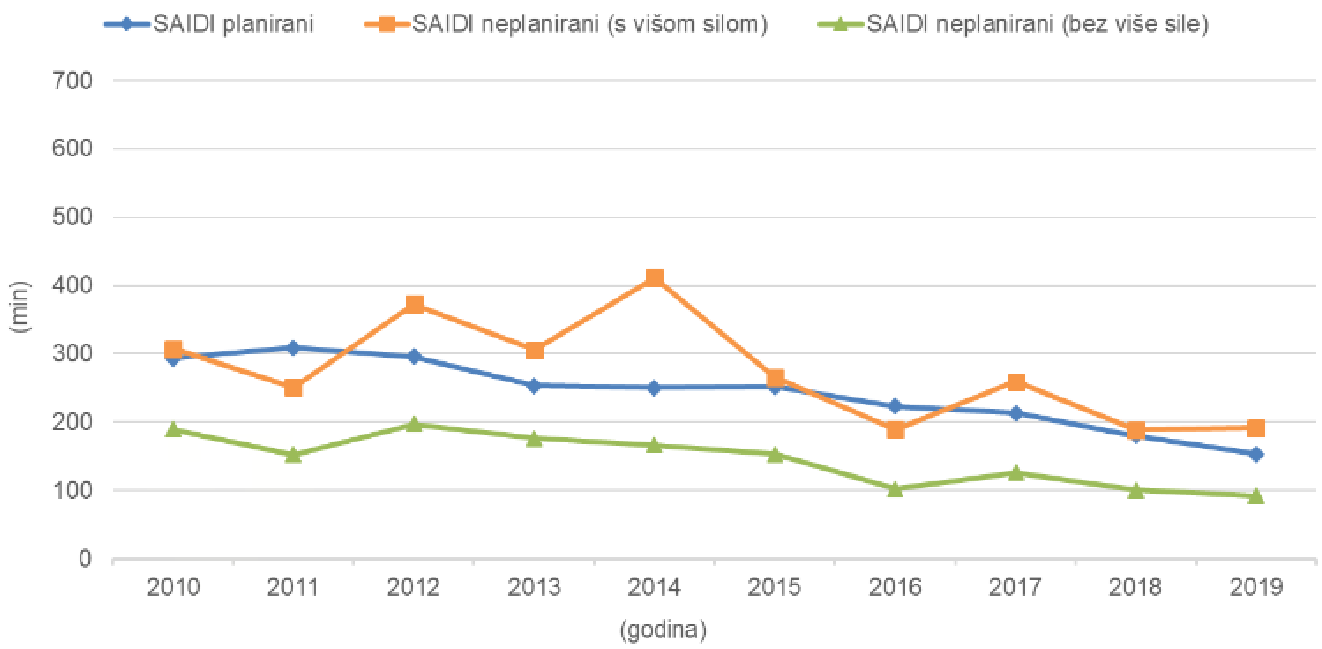


Table 10 and Table 11. It can be seen that SAIDI and SAIFI indicators for the Croatian distribution network are amongst the worst in Europe, only superseded by Romania.

New KPIs to consider

As the share of VRES continuously increases in power systems, it is necessary to understand the impact of new sources on the system dynamic, and to establish new stability indicators that will enable the reliable management of systems with a high share of generation units connected via power electronics. Therefore, new KPIs have been defined and suggested for the stability of systems with a high share of renewable sources:

- Effective Area System Inertia - important for defining the speed at which the frequency reserve must be deployed, i.e. it will define how much of the response must be in the rapid response category;
- Short Circuit Capacity (System Strength) - describes the strength of the system to maintain voltage at near-nominal level, as opposed to the measure of current supplied in a short circuit fault; and
- Sub-Synchronous Oscillations - can include frequency components up to the grid nominal frequency.

The above-mentioned KPIs (Effective Area System Inertia, Short Circuit Capacity and Sub-Synchronous Oscillations) capture the dynamic performance of modern power systems and must be derived from fast measurements (i.e. Wide Area Monitoring Systems) using Phasor Measurement Units (hereinafter: PMUs). Currently, the assessment of the dynamic performance of the Croatian power system using these KPIs is not available, but there is potential for achieving this, in order to better monitor system stability since the majority of the high-voltage transmission system is covered by PMU measurements.

Table 9. Standards for the quality of electricity supply (HERA, 2017)

Standard	Type of grid	SAIDI	SAIFI
1	urban area with predominantly cable network	120	2
2	suburban areas and larger settlements	240	4
3	overhead lines in suburban area	360	8

Table 10. Planned and unplanned SAIFI, including exceptional events (interruptions per customer) (Council of European Energy Regulators, 2018)

Country	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Austria									0,83	0,81	0,96	0,80	0,86
Croatia									5,09	4,32	4,34	4,15	3,51
Czech Republic					2,84	2,54	2,37	2,36	2,39	2,65	2,37	2,65	2,21
Denmark							0,44	0,44	0,44	0,41	0,35	0,42	0,42
Estonia									2,32	3,06	1,13	1,73	1,96
Finland									1,96	2,35	1,76	2,78	1,58
France	0,16	0,13	0,15	0,19	0,32	0,34	0,28	0,19	0,19	0,23	0,20	0,22	0,22
Germany				0,55	0,44	0,40	0,40	0,44	0,41	0,58	0,45	0,91	0,59
Great Britain			0,76	0,90	0,79	0,75	0,74	0,72	0,68	0,63	0,74	0,58	0,54
Greece									3,30	3,20	2,80	2,90	2,80
Hungary												1,55	1,43
Ireland												1,50	1,30
Italy	2,88	2,79	2,58	2,46	2,73	2,66	2,65	2,46	2,74	2,57	2,35	2,81	2,17
Latvia				3,01	2,95	1,80	5,00	5,59	4,78	4,48	3,77	3,18	3,13
Lithuania		1,57	1,73	2,44	1,89	1,89	2,45	2,67	2,36	1,97	1,85	1,72	1,83
Luxembourg										0,40	0,38	0,43	0,28
Malta									5,05	4,76	5,34	3,13	2,60
The Netherlands									0,33	0,33	0,31	0,47	0,32
Norway									1,63	2,22	2,44	2,17	1,89
Poland				3,50	4,88	4,60	4,45	5,04	4,14	3,94	3,52	4,11	3,46
Portugal	3,89	3,73	3,90	2,66	2,82	3,64	4,33	2,42	1,89	3,10	1,90	1,55	1,65
Romania										6,23	5,86	5,49	5,00
Slovakia										2,58	2,24	2,14	2,26
Slovenia					3,81	3,46	2,67	2,79	3,87	3,09	5,17	2,66	2,49
Spain									7,03	1,19	1,29	1,30	1,18
Sweden									1,47	1,48	1,46	1,36	1,34
Switzerland							0,40	0,40	0,45	0,37	0,30	0,32	0,30

Table 11. Planned and unplanned SAIDI, including exceptional events (minutes per customer) (Council of European Energy Regulators, 2018)

Country	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Austria									50,41	53,64	68,31	62,76	54,86
Bulgaria							485,20	470,10	455,10	435,20	350,80	346,90	291,30
Croatia									664,00	559,46	661,72	516,32	412,24
Czech Republic					351,36	351,59	295,28	268,82	272,65	354,76	283,22	316,07	258,29
Denmark							20,42	21,98	19,49	20,56	16,64	20,51	19,38
Estonia									255,79	465,32	182,82	237,74	222,23
Finland									94,36	186,72	79,79	169,13	80,56
France	63,70	13,90	94,20	72,40	93,50	197,00	119,10	72,80	78,50	99,50	67,30	73,80	70,50
Germany			38,35	49,52	30,13	26,82	29,67	27,37	29,20	39,98	21,06	22,19	23,55
Great Britain			73,22	108,44	87,64	82,17	88,14	76,70	74,75	66,70	98,23	55,74	50,43
Greece									299,00	289,00	258,00	248,00	244,00
Hungary												228,00	216,00
Ireland												183,30	152,40
Italy	153,15	138,63	114,34	104,05	138,99	122,25	144,55	169,81	198,70	160,68	153,40	195,65	143,74
Latvia				506,00	497,00	678,00	1.292,00	944,00	636,00	621,00	466,00	350,00	286,00
Lithuania		280,26	290,29	326,36	231,50	256,63	421,64	460,50	467,33	366,69	361,49	300,71	345,96
Luxembourg										33,64	25,09	28,81	21,84
Malta	556,11	520,15	405,52	490,40	262,18	763,74	693,00	260,00	366,60	421,08	777,60	227,59	163,82
The Netherlands									31,50	29,42	25,89	37,66	27,28
Norway									106,76	181,41	161,12	172,82	128,83
Poland				531,00	589,69	518,66	515,88	478,81	410,51	420,94	324,81	363,32	272,00
Portugal	266,95	237,89	261,89	143,31	164,74	282,03	277,61	133,48	95,83	260,26	97,34	77,47	77,65
Romania										761,00	710,00	582,00	555,00
Slovakia										298,06	254,36	257,52	258,82
Slovenia					253,35	264,65	186,12	202,39	286,04	224,41	1027,19	199,95	191,92
Spain									69,18	108,36	63,36	69,12	65,82
Sweden									105,11	170,81	101,89	134,81	94,42
Switzerland							28,00	29,00	34,00	25,00	22,00	21,00	19,00

3. 2. PLANNED MEDIUM- AND LARGE- SCALE VRES PROJECTS

According to data from the 10-Year Transmission Network Development Plan 2021-2030, there was more than 7 GW of grid connection requests, mostly from production plants using renewable energy sources. The connection costs for the transmission network are estimated at HRK 3.2 bn (€400 mil), out of which 80% should be provided by the developers whose generation facilities are connected to the transmission network, and the remaining 20% by HOPS.

HOPS submitted these costs to the EU Recovery and Resilience fund in for them to cover a part of these costs.

Furthermore, by 1 September 2021, there were more than 11.3 GW of projects waiting for a transmission grid connection, as well as 883 MW of installed consumer capacity. Out of the 11 GW, the majority of applications were for PV projects (4.7 GW), wind farms (3.3 GW) and hybrid power plants (1.8 GW) (HOPS, 2021).

In addition, there were 1.7 GW on the HEP DSO candidate list, making a total of 13 GW of new generation capacities that want to be grid-connected.

Necessary balancing reserve capacities

Ancillary services related to system balancing can be divided as:

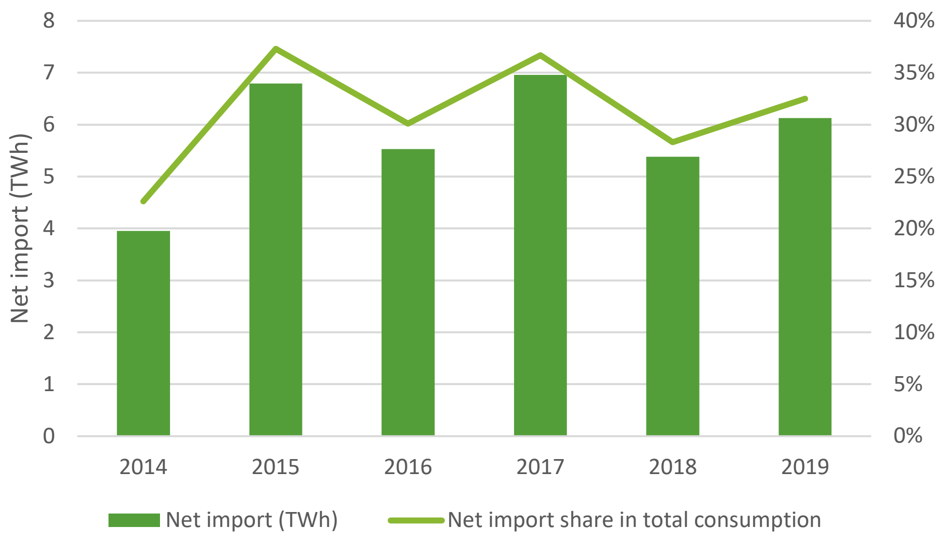
- **Frequency Containment Reserve** (hereinafter: FCR) - serves to stabilise the frequency after a disturbance by automatically responding all synchronous units to frequency deviations;
- **Frequency Restoration Reserve** (hereinafter: FRR) - is used to return the frequency to the nominal value and maintain the power flows of the interconnection lines;
- **Replacement Reserve** (hereinafter: RR) - is used to release the secondary reserve capacity for new imbalances and is usually activated manually when a major disturbance occurs.

The Croatian system load is in the range 1.1 GW – 3.2 GW, while the existing power generation capacity is around 5.6 GW (hydropower plants – 2.1 GW, thermal power plants – 2 GW, industrial power plants – 212 MW, wind power plants – 801.3 MW, distributed sources – 431.6 MW) (HOPS, 2021), (EIHP, 2021).

Currently, in Croatia, there are 1.63 times more installed generation capacities than the system peak load. However, Croatia is still an electricity net importer. It imports between 22% and 37% of its total gross consumption, as shown in Figure 14. The main reason behind the relatively high level of electricity import is the fact that electricity market prices abroad are lower than local generation costs from thermal power plants and a seasonal dependence on generation from hydropower plants.

Renewable electricity producers who are entitled to a support mechanism (e.g. feed-in premium or feed-in tariff) are a part of the ECO balance group, which is managed by the Croatian Energy Market Operator (hereinafter: HROTE). HROTE is required to settle the costs of balancing energy with HOPS, due to the difference of the planned hourly electricity generation and the actual electricity delivery of the ECO balance group.

Figure 14. Total electricity net import and its share in total consumption in Croatia 2014 – 2019 (EIHP, 2021)



As of 1 January 2020, the balancing methodology was changed in and transferred the balancing related calculation obligation to HOPS in line with the New Balancing Rules issued by HOPS. The new Balancing Rules are harmonised with the electricity billing mechanism in the country and with the EU Balancing Guidelines (HOPS, 2019).

The New Balancing Rules introduced a new principle whereby balancing costs consists only of the balancing of energy costs, while balancing (reserve) capacity costs are no longer born by balancing responsible parties but are dispersed through the transmission network tariff (the old Methodology envisaged that 20% of the reserve cost would also be covered by the balancing groups). This legislative change relaxed the balancing costs in 2020 for the ECO balance group by a significant amount, as presented in Table 12.

It is important to note that the New Balancing Rules defined balancing unit costs based on the Croatian Power Exchange (CROPEX) day-ahead prices. However, it is expected that in the future these prices will be fully based on the balancing market, which assumes significantly higher prices, as it is the case in other countries with balancing market in place (ACER/CEER, 2020).

Croatia is trying to follow European experience, which has shown that greater co-operation amongst system operators of neigh-

Table 12. ECO balance group (BG) balancing costs in 2019 and 2020 (HROTE, 2021)

Year	Installed capacity (MW)	Delivered electricity (TWh)	Imbalance costs (HRK mil)	Imbalance cost per generated MWh (HRK/MWh)
2017	321	2,2		
2018				
2019	877	2,9	41,7*	14,2
2020	1035	3,2	11,9**	5,6

*until 2019 ECO BG imbalance costs were paid through the transmission network tariff

** since 2020 ECO BG are not paying for the reserve capacity (20%) and unit prices are decreased due to EBGL requirements

Table 13. System positive and negative balancing energy and ECO BG positive and negative imbalance energy 2015-

Year	ECO BG Positive imbalance energy (GWh)	ECO BG Negative imbalance energy (GWh)	Positive system balancing energy (GWh)	Negative system balancing energy (GWh)
2017	116	125	189	172
2018	147	147	209	156
2019	111	117	189	106
2020	1035	3,2	11,9**	5,6

bouring countries that operate in the same control area reduces reserve requirements. Previously, reserves were procured separately by individual TSOs, which sometimes resulted in reserves simultaneously being activated in opposite directions (positive/negative) within the same control block. New grid protocols regarding co-operation helped in solving the issue, leading to a common market for the reserves, where bidders can offer their products to all TSO areas. Together with shorter market intervals (down to 15 minutes on the spot market), reserve requirements and prices have decreased, while the total VRES capacity increased in the same period.

3. 3. CONNECTION AND OPERATION RULES FOR VRES

The technical requirements for the integration of RES depend on several factors, such as the design, type, and capability of the electrical equipment of the power plant. Therefore, some technical requirements cannot be applied in the same manner to all RES types.

The technical requirements imposed on RES may differ from power system to power system, as the requirements depend on the share of RES, interconnection capacity with other power systems, the readiness of the conventional power fleet, and other characteristics of the power system itself.

Listed here are those technical requirements that are expected to be applied in the near future or are already being applied in power systems with a high share of RES, which the Croatian power system is forecast to become in the short to midterm period.

Frequency control capacities

Traditionally, this function was performed by synchronous generators equipped with governor control to increase or reduce power generation when frequency deviates from its nominal value. By replacing conventional generators with RES, it becomes very important to require this type of control from these new sources as well. There are two main types of this regulation that can be expected from inverter connected RES:

α) **Upward frequency control**: this function requires the production unit to reduce its output power as the frequency increases above the nominal value.

β) **Downward frequency control**: this function requires the production unit to increase its output power as the frequency decreases below the nominal value.

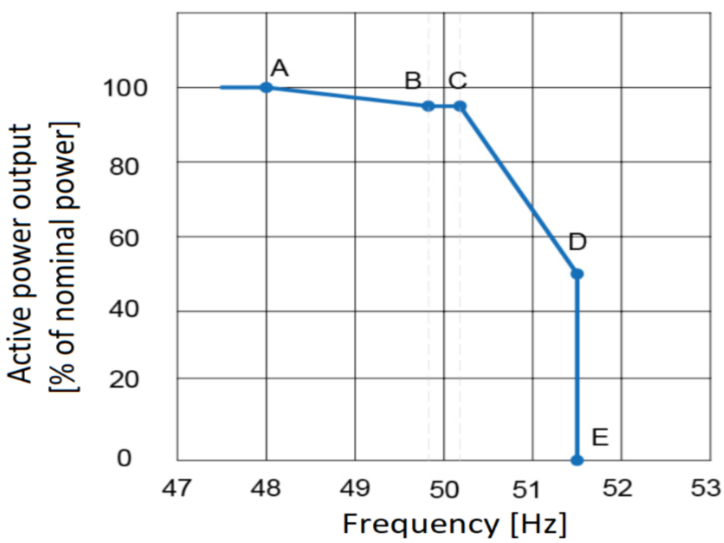
While many countries have already obligated RES (mostly wind farms) to provide the upward frequency control function, the downward frequency control function is only required by some countries (e.g. Ireland and Germany). The reason for this is that, for the upward frequency function, RES can continuously operate at the maximum power point and reduce their output power when needed, whereas for the downward frequency function, RES should maintain a certain reserve power, i.e., operate at a non-optimal point below the maximum power point (or operate with a battery storage system, which would increase the price of RES). However, it has not yet been agreed between TSOs and electricity generators how much reserve power these RES generators should maintain and how to compensate for the incurred cost that occurred due to the reduction of generation for frequency control.

Similarly, in Croatia, the current grid code does not require RES to participate in frequency control, but RES must have a built-in control system that allows the potential frequency response for the purpose of the primary frequency regulation, according to Figure 15.

In the event of a disturbance, the RES control system must be able to accept in real-time and execute, within 1 minute at the latest, which includes HOPS' order to include setting a reference value of generation power. This could be generation reduction in the steps of 10%, until it reaches 0% of the current generation power, with a tolerance of 1%-5% of the total nominal power.

In most countries, RES generators are required to stay connected to the grid for a certain period of time within the frequency interval (47.5 Hz - 51.5 Hz) to support and maintain the stability of the system and provide both, voltage and frequency support. The specifics of the exact time and frequency interval vary from system to system.

Figure 15. Required RES response characteristic to the frequency change (HOPS, 2020)



In the Croatian power system, the RES generators have permission to disconnect from the grid in the event of a frequency increase above 51.5 Hz, while in the case of a frequency decrease, RES generators should have a rate of change of frequency withstand capability of 2 Hz/s, measured within a time frame of 500 ms. All further details can be found in the Croatian grid code.

With increasing share of RES capacities in a power system, it will be necessary to establish better communication and connection between each RES with HOPS, but also with HEP DSO.

Voltage control capacities

Voltage control capacities are the ability of an electricity generator to respond to voltage fluctuations at the point of common coupling (hereinafter: PCC). It is expected that all generators connected to the power system are able to operate in the nominal value range, usually ± 10% to ± 15% of the nominal voltage value, depending on the grid code of the particular power system. Croatian voltage limits are within the 10% range, with the 400 kV voltage level having a more stringent satisfactory voltage range of -10% to +5%. Typically, there are two ways in which an RES generating unit can contribute to voltage regulation:

a) **reactive current injection – dynamic voltage support:** this function requires RES generators to support voltage by injecting reactive current during a fault. The amount of injected reactive current specified in the grid code is usually determined by the depth of the allowable voltage sag. Although this function is not yet required from RES generators in the Croatian power system, it is already defined in some international power systems. In the German power system, reactive current injections of 2% of the rated current value are expected from the RES generator for every 1% voltage drop between 10% to 50% of the nominal voltage value. The Austrian grid code is even stricter, by requiring a reactive current injection of 4% of the nominal current value within a 1% drop of the voltage at PCC.

b) **reactive power injection – static voltage support:** this function refers to the production or absorption of reactive power at the PCC. The grid codes of most power systems generally do not differ too much on this issue. As in most of these grid codes, the Croatian grid code also specify that RES generators are required to have certain reactive power control capabilities.

Fault ride-through

This function means remaining connected for a certain length of time during a voltage disturbance. The two types of this function are as follows:

a) **high-voltage ride-through:** this refers to the RES capability remaining connected when an overvoltage occurs. This function is still not widely requested in the grid codes of power systems around the world. Only a few power systems require RES to have this capability. Such systems are active in Germany (V = 120% for t = 0.1s), Italy (V = 125% for t = 0.1s), and Spain (V = 130% for t = 0.25s). The Croatian power system does not yet require this capability from RES.

b) **low-voltage ride-through:** similar to the high-voltage ride-through function, this function refers to the RES capability remaining connected in the event of low voltage. This requirement is defined very similarly in the grid codes of various power systems. In general, RES are required to withstand voltage dips for a period of time. Furthermore, during voltage recovery, RES must continue to operate without disconnection, and restore active and reactive power to the default values sufficiently quickly. This requirement is defined in the same way in the Croatian power system.

Power quality

Due to the variety of consumers that require voltage of a certain quality, it is extremely important to maintain the sinusoidal voltage shape. Due to the inverter technology in RES, voltage distortions in the grid can take place. The requirements for power quality are the following:

a) **voltage flickers:** PV power plants and wind farms generate different amounts of voltage flickers in the grid due to the variation in solar irradiance and wind speed. The Croatian grid code specifies this requirement such that, in normal operation, for any period of one week, the intensity of long-term voltage flickers in 95% of 120-minute intervals must not exceed the value of a probability flicker severity of Plt = 1.0.

b) **harmonic distortion**: this parameter defines the voltage and current waveform distortion from the sinusoidal shape. The grid code of the Croatian power system stipulates that, in normal operating conditions at PCC, the total harmonic voltage distortion is allowable in the amount of:

- 1.5% for the 400 kV and 220 kV voltage levels; and
- 3% for the 110 kV voltage level.

c) **voltage unbalance:** this parameter describes voltage amplitudes or phase angles differences. The high share of RES (particularly PV) can cause voltages with higher magnitudes than allowed in LV and MV networks and in that way increase the voltage unbalance in each node of the LV network. The voltage unbalance factor should not exceed the value of 3%. The Croatian grid code allows voltage unbalance in the transmission network of 1.4%. The prescribed value of voltage unbalance refers to 95% of the 10-minute averages of the root mean square value of the inverse voltage component for a period of one week.

A review of grid codes and technical requirements for RES shows that, with the increased integration of RES, some requirements have recently been revised and adopted. On the other hand, there are some requirements (mostly related to frequency and active power control) that are still under consideration and will have to be specified with the further growth of RES in the system.

3. 4. MAIN BARRIERS FOR LARGER INTEGRATION OF VRES

The main barriers for the larger integration of RES can be grouped into several categories, such as technological barriers, economic barriers, regulatory barriers, social barriers etc. This subchapter focuses on technological barriers, because inadequate solutions to these issues can endanger the safe and stable operation of the electric power system. Concerns arising from the large integration of RES are mainly related to voltage and frequency conditions, but there are also concerns regarding the needs for balancing power, advanced RES generation forecasting, communication systems, civil engineering barriers, etc.

Voltage and reactive power

High wind power and photovoltaic power penetration can cause overvoltage in power networks, primarily in the distribution networks as these power plants tend to raise the voltage at the PCC. Maintaining the voltage within the allowable limits becomes more challenging, mostly due to the variable and unpredictable nature of energy sources i.e., wind speed and solar irradiation. This problem is especially pronounced during the afternoon, when the power consumption of the power system is reduced but PV power plants are operating at their maximum power (and in early evenings when there is an increased demand but a significant drop in PV generation).

Furthermore, most power systems require a disconnection of most RES from the grid in the event of a failure, which can lead to an even greater problem in the situations of high-power production from RES. If we look at the Croatian power system and specifics of electricity consumption and power production from RES, the following specific stands out:

- the northern part of Croatia consists of electricity-intensive industry and most of electricity consumption is happening in this area, while;
- the coastal part of Croatia is less industrialised but is the area where majority of the RES production capacities are installed (and are expected to be installed).

Therefore, because of the relatively small loads and considerable RES generation, especially during the night (and seasonally during the winter), long overhead lines, together with a lack of voltage regulation nodes, mean that voltage levels in southern part of Croatia vary a lot, and even exceed the upper voltage limits.

Frequency and active power

The large share of RES integration into the transmission network greatly affects frequency stability, especially if they are intended to replace thermal power plants. In Croatia, the vast majority of RES are integrated into the transmission network installed at the 110 kV voltage level. In the coming years, a large share of RES capacity (power plants with a nameplate capacity above 100 MW) is expected to be integrated into the 400 kV voltage level.

The large share of RES integration into the transmission network can have the following effects:

- reduction of the total kinetic energy of the power system due to the replacement of conventional synchronous generators by RES;.
- the RES are connected to the grid via the power electronics interface, making them inherently insensitive to changes in grid frequency and resulting with no inertial response, which is not good for the power system. Sensitivity can be built into the grid interface and this will be the object of further research.

- some types of RES (e.g., PV power plants) do not have rotating parts that could reduce or increase their kinetic energy, so they cannot inherently contribute to the inertial response. This can be compensated by the governed behaviour at the grid connection, and a wider integration of battery storage capacities (i.e. by introducing the virtual inertial response).
- VRES usually operate in maximum power point tracking mode, which means that they do not maintain a reserve of power, so the total reserve power of the system required to regulate frequency and active power decreases.

All this shows why replacing synchronous generation with RES can cause frequency instability if not accompanied by proper countermeasures and additional investment in new and fast response capabilities such as battery energy storage or supercapacitors.

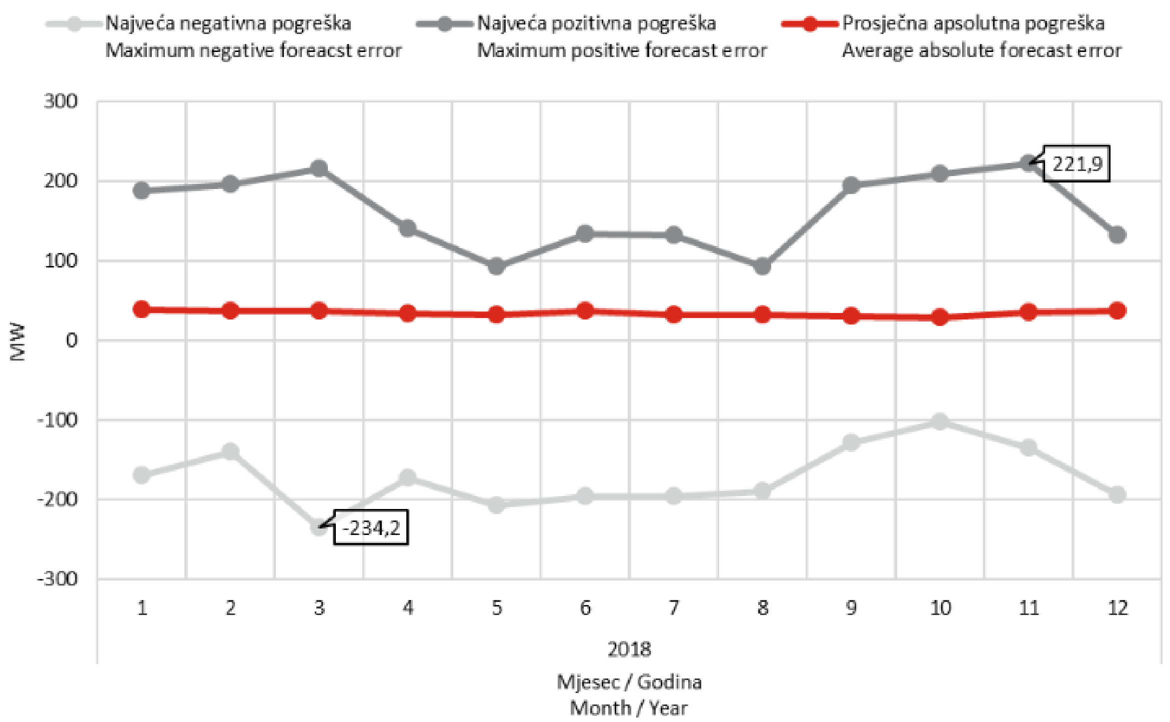
Power system balancing

Power system balancing refers to matching supply and demand in the power system in a scheduled manner. In addition to thermal power plants, Croatia has a vast hydropower infrastructure, which is being used to balance the power system and to improve system flexibility and capacity for acceptance of additional RES.

In addition to the lack of PV generation during the night, wind farms in Croatia have a narrow geographical dispersion. The maximum distance between two wind farms is about 300 km, while 19 out of 22 wind farms are located in a similar wind-climate regime (110 x 70 km^2). Therefore, the variability of wind speed and direction significantly affects total wind energy generation in Croatia.

Another obstacle to additional RES integration is the forecasting of wind energy generation. In 2018, HOPS planned wind energy generation with an average absolute hourly

Figure 16. Forecast of wind farms' production errors in 2018 performed by HOPS (HOPS, 2018)



forecast error of 5.89% of installed wind energy capacity. As presented in Figure 16, the maximum positive hourly forecast error of wind energy generation was 221.9 MW, and the maximum negative hourly forecast error was -234.2 MW. It should be noted that the total installed capacity of wind farms in 2018 was 584 MW. Forecasting was taken over by HROTE and forecasting accuracy was improved but remained in a similar percentage range.

The data shows that forecasting techniques need to be improved to allow for a further increase in RES integration because it results in lower reserve requirements and lower system operational costs.

Grid code – ancillary services

One of the potential barriers to increasing RES integration is the grid code, which needs to be revised (in power systems with a high RES share the grid codes are often revised, every few years, following the latest technology trends), especially the part related to ancillary services.

First of all, one of the most important requirements for RES (especially for wind farms and PV) is the low voltage ride through function. When it comes to a fault and a dip in voltage, the power plants should stay connected and if possible, inject reactive power to help the system to recover. Currently, the low voltage ride through function in the Croatian power system is defined for wind farms, but with a large increase in solar integration, it should be defined for PV as well, especially with regard to reactive power capability.

In future, permitting a simple “ON/OFF” operation for RES would not be possible because the massive tripping of these sources under severe grid disturbances could result, at worst, in a blackout.

As more RES are being integrated, new projects will need to participate in frequency and voltage regulation. However, some barriers will still exist (e.g. the distribution network grid code does not recognise RES on the distribution level to participate in ancillary services.

One of the problems is the inverters’ low overcurrent capacity, resulting in limited dynamic voltage support during faults.

Participation in frequency regulation will require that RES operate below the maximum power point to maintain a certain amount of power reserve or be coupled with some type of energy storage. However, cost increases would be inevitable in both cases.

Furthermore, most RES have the grid-following type of inverters, so they cannot establish voltage and frequency in the system and support the grid during islanding. Islanding is the condition in which a distributed generator continues to power a location even though the external electrical grid power is no longer present and the segment of the grid is separated from the main synchronous zone. To be able to support the system during islanded operation, the inverters of RES should be of a grid-forming type with a possibility of frequency forming, not only its tracking, and these requirements need to meet the specific development needs of the Croatian power system.

Grid development planning

The development of grid infrastructure limits the amount of RES that can connect to the grid. As most of the new RES additions will be integrated in the southern counties, there will be enormous stress on the existing infrastructure. Therefore, significant investments will have to be made in new and existing transmission capacities, to ensure system adequacy, and evacuation paths for all the electricity generated by RES. Which transmission lines should have priority in terms of investment needs to be addressed on a wider European level, and on the ENTSO-E level due to a large number electricity transmission to neighboring power systems.

With additional investments in pumped storage capacity where possible, the stress on the grid could be reduced.

As grid development planning is a very long process, T&D system operators need a long-term view of planned RES capacity in the country. Over the past few years, the climate targets in the EU have been increasing significantly.

The European Green Deal has set a target of climate neutrality by 2050, which will result in significantly larger shares of renewables over the next three decades. In the short-term, changes to the EU's 2030 RES target over the last three years has put T&D operators under more pressure. In 2018, the RES target was increased from 27% to 32%, and currently the EU is proposing an increase to 40%.

As EU targets are distributed amongst Member States, Croatia must follow the same trend of increasing its 2030 RES targets. This sudden increase in RES capacity, as well as the increase of electrification rates, impacts the development plans of HOPS and HEP DSO, ultimately resulting in a limited uptake of renewables in the short term.

Furthermore, the recent record prices of EU's emissions trading system certificates have made RES investments even more interesting to developers.

3. 5. VRES AND ANCILLARY SERVICES

Wind farms, PV power plants, and battery systems can provide ancillary services and inertial response in the following ways:

Photovoltaic power plants

a) Inertial response
Since PV power plants do not have rotating parts, they can provide only a virtual or a synthetic inertial response. One possible solution is to enable the PV participation in the inertial response by using a capacitor at the DC link, however, at a higher system cost.

b) Primary frequency regulation
PV power plants could participate in the primary frequency regulation if they would operate at a non-optimal point (below the maximum power point) to provide additional (reserve) power that could be injected into the grid during a frequency drop. The main question is how much of the reserve power should be maintained. The larger the reserve power, the greater the contribution of PV power plants to frequency regulation but results in a lower amount of generated electricity and a lower profit for the owner.

Therefore, it is necessary to find the optimum in order to achieve the greatest possible contribution to the system with the least possible financial losses. However, some recent studies show that less than 5% of the nominal power of PV power plants is sufficient to maintain satisfactory frequency stability (Baškard, Kuzle, & Holjevac, 2021.).

Wind power plants

a) Inertial response
Out of the four main types of wind turbine generators (hereinafter: WTG), two types can provide inertial response. The WTG type IV is completely disconnected from the grid via a power converter and has no inertial response, while in the case of WTG type III the stator is still connected to the grid directly and therefore there will be some active power injection into the grid immediately after the disturbance, but this amount of power is negligible. However, by adding additional control circuits sensitive to the frequency deviations and rate of change of frequency, the flexible control of WTG with variable speed is achieved and thus a virtual inertial response can be achieved.

b) Primary frequency regulation
Wind farms have already operated in the primary frequency regulation only with the possibility of reducing the output power, which is also a requirement in the Croatian power system. To ensure a rotating reserve, wind farms must operate at a power that is less than the available power. WTG types I and II (old models whose market share is marginal in Croatia) can achieve reserve power via the blade pitch control system by increasing the blade pitch angle. For the WTG types III and IV, the power converters in these WTG types allow flexible rotor speed control for wind speeds below the rated speed.

Battery energy storage

Battery energy storage consists of new technologies that are able to react faster and provide services in shorter time intervals, which is especially important in power systems with a large share of VRES. Battery energy storage can help to maintain the stability of the power system on the following levels:

- at the power system level (independent of the battery location), by providing balancing services and virtual inertial response services;
- at the network level (with a specific network location of the battery), by providing voltage and reactive power control and congestion management.

a) Inertial response
Using advanced control algorithms, power electronics in battery energy storage can be transformed into the so-called virtual synchronous generators. The ability to provide an inertial response using a large battery energy storage is more often analysed in hybrid systems (e.g. batteries in combination with wind farms or PV power plants) than with stand-alone battery systems. Battery energy storage in such hybrid systems can have the following roles:

- providing the active power required for wind turbine speed recovery to prevent the second frequency drop;
- as a backup system for the provision of power during low renewable electricity generation (due to low wind speed or solar irradiation);
- absorbing the output power from the wind farm or PV power plant and excess power from the grid.

b) Balancing service
The provisions of ancillary services with battery energy storage have not yet been defined in the Croatian power system. In 2015, the German TSOs published rules for the participation of battery energy storage in the FCR market, which must be able to deliver FCR for 30 minutes and must be within the

allowable state of charge range.

The 15-minute criterion, which would increase the ability to provide this service for batteries, or their range of operation, is proposed in the EU system operating guidelines. This 15-minute criterion is currently under revision and the introduction of a 30-minute criterion is being considered.

After deactivating the FCR service from the batteries, the battery energy storage system must return the state of charge to the allowable range within two hours. Out of about 600 MW of German FCR requirements, about 200 MW or 31% is provided from battery energy storage (Rancilio, et al., 2020). On the other hand, in the provision of FRR, this share is significantly lower due to the unsuitability of tenders for battery energy storage.

c) Voltage and reactive power

Battery energy storage is a DC source or consumer of energy, which means that it cannot produce or consume reactive power. They are connected to the AC network via an AC/DC bidirectional inverter.

Battery energy storage cannot directly participate in maintaining voltage stability in the Croatian power system (i.e. provide voltage reactive power regulation and be paid for it). Currently, there is no valorisation system for the provision of voltage regulation from private energy storage. Battery energy storage can participate in voltage regulation only if they are considered part of the transmission/distribution network (owned by TSO/DSO).

4. PLANNED INFRASTRUCTURE INVESTMENTS

4. 1. TRANSMISSION INFRASTRUCTURE SYSTEMS

Investments for new RES capacity

As more and more RES are being developed, there is a large discrepancy in the maturity of project development, while the existing regulatory framework envisages that projects receive equal treatment in terms of the grid connection process.

Figure 17 shows that 709 MW of utility-scale RES projects are being developed in the geographical area between the cities of Rijeka and Split.

Starting from project No.56, according to the order list of projects, HOPS identified that there is a need to reinforce the 400 kV line Velebit – Melina. As expected, the impact of each grid connection candidate on the overall grid reinforcement need is proportional to its installed capacity.

However, with the growing number of grid connection applications, the reinforcement of the 400 kV line Velebit – Melina has been expanded to a whole route Konjsko – Melina, as shown in Figure 18.

Figure 17. 400 kV and 220 kV transmission grid topology and selected grid connection applicants' locations (HOPS,

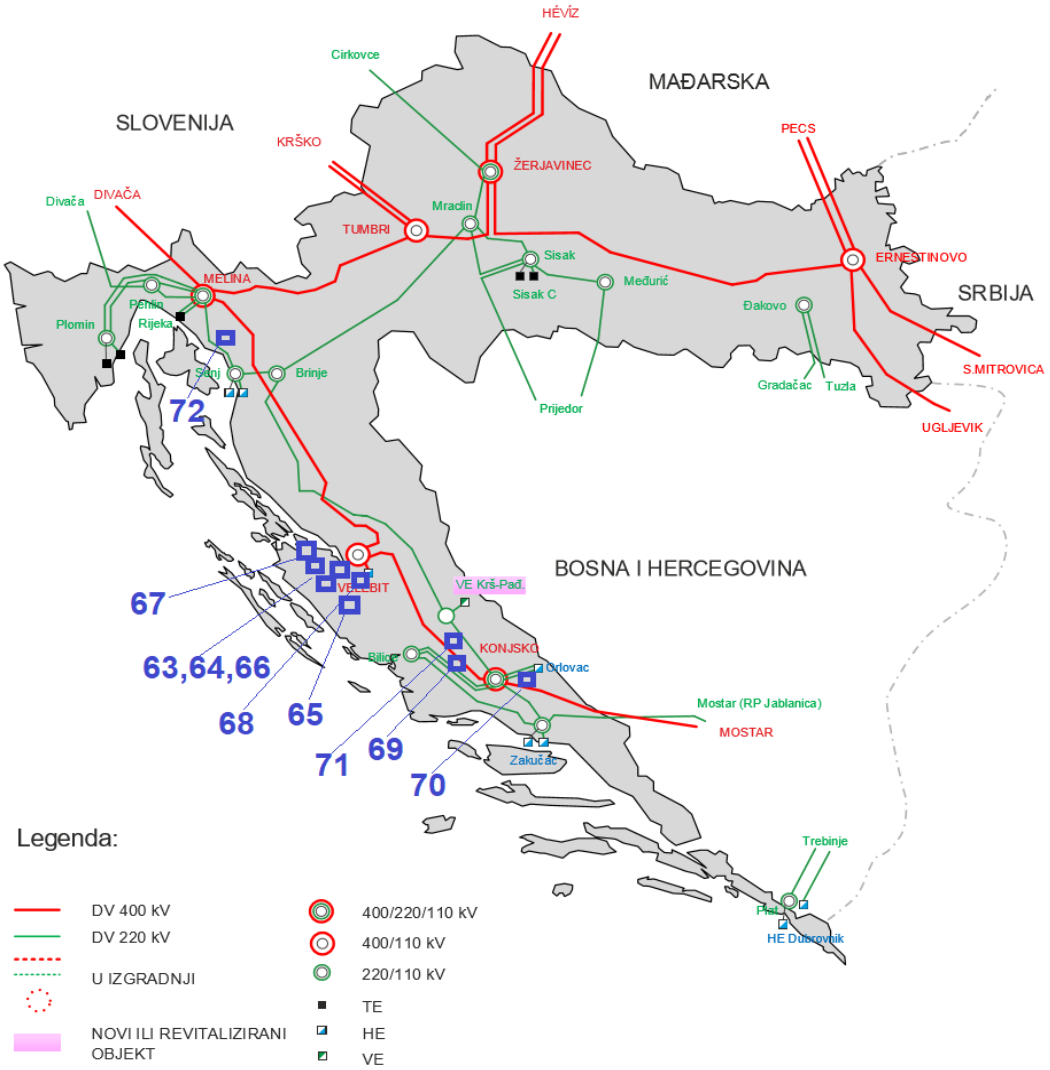


Figure 18. 400 kV and 220 kV transmission grid topology and necessary reinforcement Konjsko – Melina 400 kV due to new grid connection applications (HOPS, 2021)

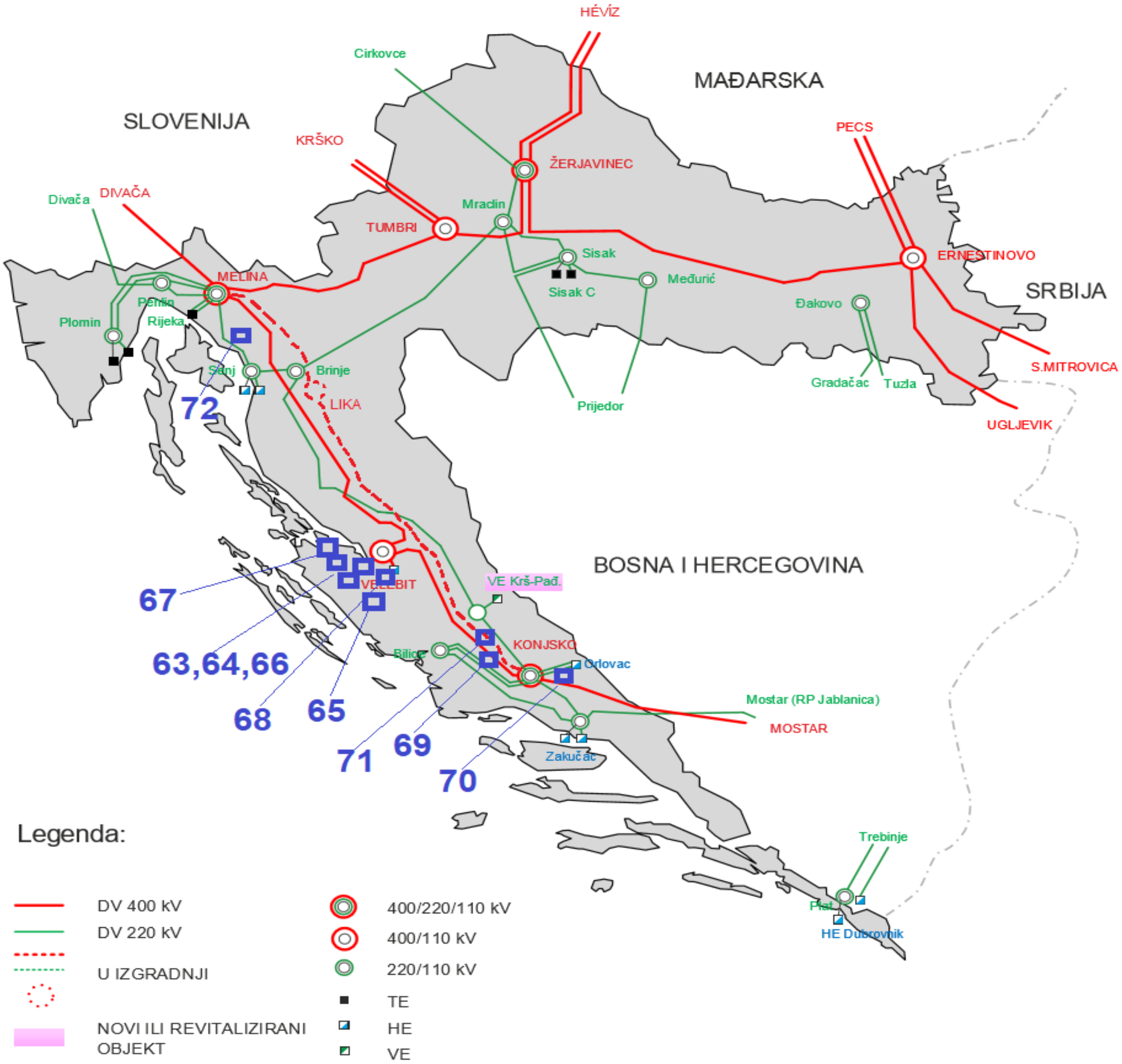
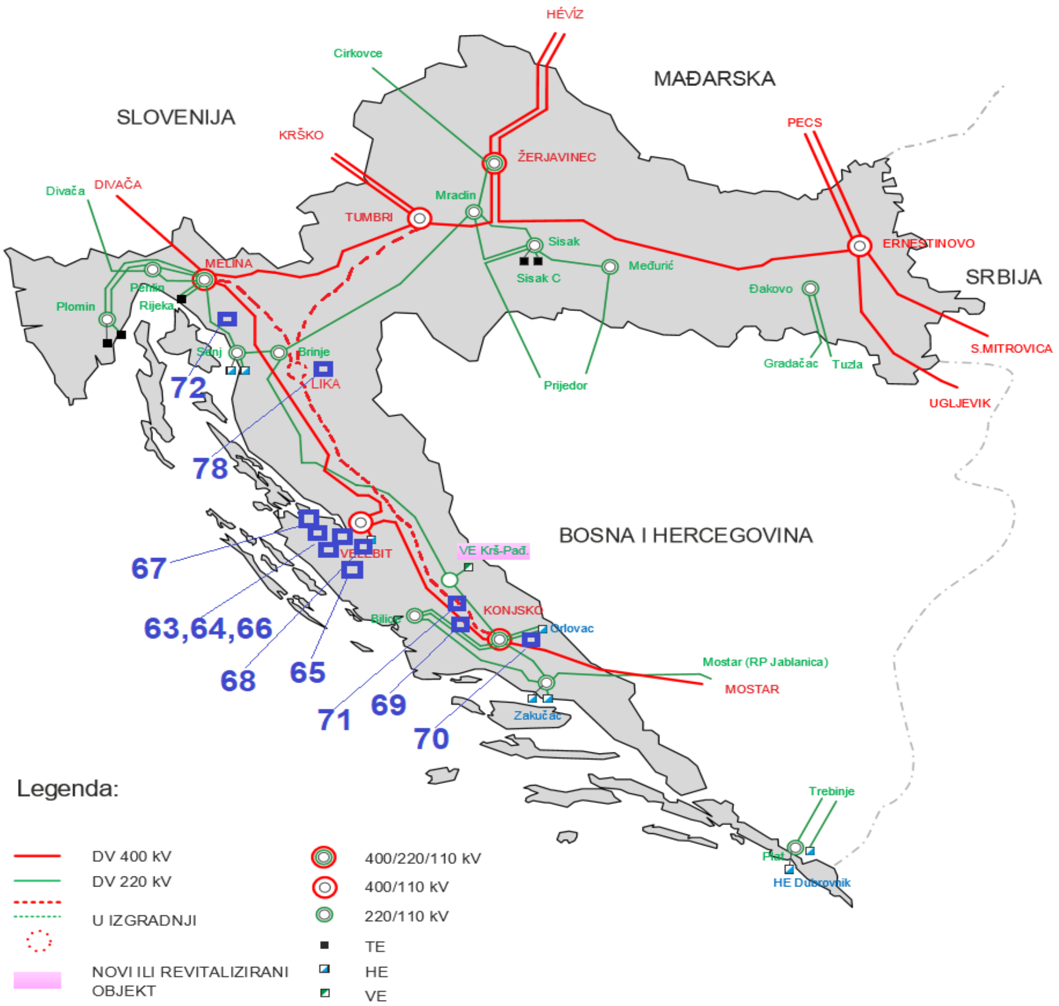


Figure 19. 400 kV and 220 kV transmission grid topology and necessary reinforcement between Lika and Zagreb areas due to new grid connection applications (HOPS, 2021)



HOPS estimates that after reaching 3 GW of total RES installed capacity, there will be a need to also reinforce the interconnection overhead line (hereinafter: OHL) 400 kV Melina - Divača (SLO), and/or to significantly reinforce the internal 400 kV network. It certainly strongly depends on the individual realised projects pattern.

This interconnection line overload can be resolved with an internal network reinforcement between the Lika and Zagreb areas, as presented in Figure 19. One potential option is the construction of a new OHL 2x400 kV Lika-Tumbri (Veleševec).

According to the existing regulation, the priority is given to the project that applied the earliest for a grid connection, rather than the planned commissioning date.

Impact related to new RES capacity in Bosnia and Herzegovina

There is another very important aspect to be taken into account when analysing the grid connection of utility-scale RES in Croatia, which is the mutual impact with Bosnia and Herzegovina.

Bosnia and Herzegovina (hereinafter: BiH), with a system slightly smaller than the Croatian, is a net exporter of electricity. On average, more than half of its electricity generation is made up of hydropower plants (depending on the hydrology), while the remainder is made up of large domestic lignite-fired power plants.

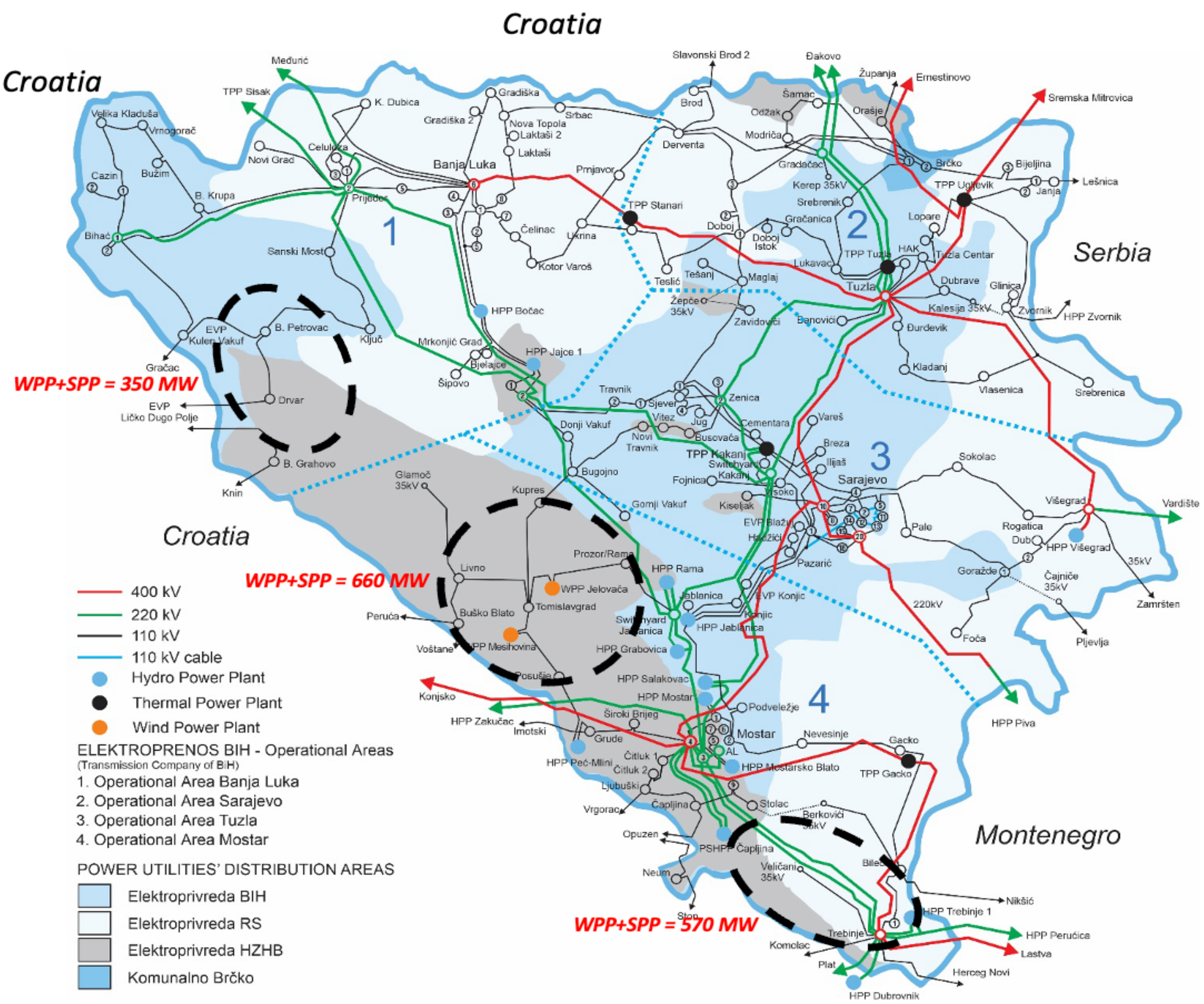
BiH has around 4.2 GW of total installed generation capacity: approximately 2.1 GW of net installed capacity in 16 hydropower plants larger than 10 MW, and approximately 1.9 GW of net capacity in five lignite-fired thermal power plants, all connected to the transmission network. The remaining capacity comes from wind farms (86 MW) and distributed generation units (NOS BiH, 2021).

Although it seems that RES integration is still in its early stage of development, the BiH system operator (NOS BiH) plans for approximately 600 MW of wind power plants to be connected by 2030, while currently in 2021 there are already more than 1.5 GW of wind energy projects under development, as shown in Figure 20.

Roughly 2/3 of the total BiH border length is with Croatia. Consequently, the BiH power system is extremely well connected to the power system of neighbouring Croatia. There are 24 interconnection lines between these two systems on 400, 220 and 110 kV voltage levels, especially concentrated in the southern part.

Clearly, the mutual impact of these two sys-

Figure 20. Transmission grid connection candidates in BiH, April 2021 (NOS BiH, 2021)



tems is extremely high, and therefore there is a need to coordinate transmission network development related to RES development in the region.

Thus, a coordinated analysis using a regionally verified model, could be instrumental and time saving for both sides in the long and challenging process of network reinforcement.

Financial structure of investments

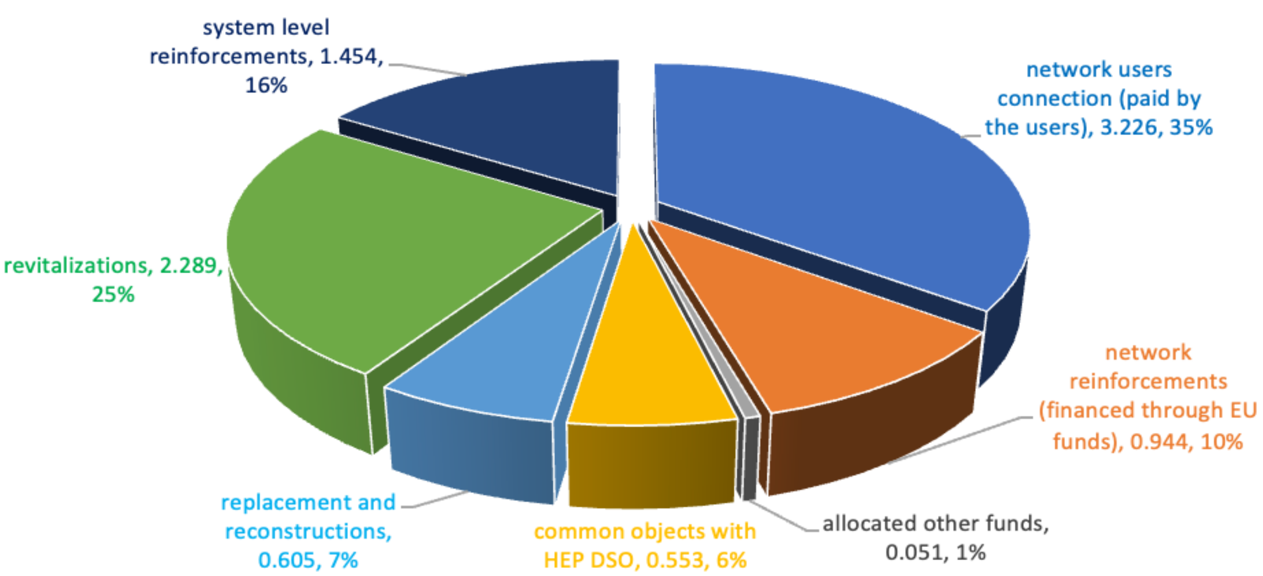
When drafting its development plan, HOPS was guided by the planning criteria defined in the Transmission Grid Code, as well as the planning criteria defined by ENTSO-E in the TYNDP 2018, as follows:

- technical evaluation of the project – flexibility and elasticity of proposed solutions;
- minimum project implementation costs;
- minimum environmental and social impact aspects;
- security of supply in accordance with the conditions of quality of supply;
- high standards of public welfare;
- integration of the EU electricity market;
- project sustainability - reduction of transmission network losses, minimisation of CO_2 emissions, and (the biggest challenge) support for large-scale RES integration.

In defining optimal transmission network development over the coming 10 years, HOPS has followed these basic principles:

- achieving satisfactory security of supply for customers in the territory of Croatia;
- achieving satisfactory availability and sufficiency in the Croatian transmission network for the smooth operation of activities of all participants in the electricity market (electricity generators, traders, suppliers, and other entities);
- enabling the connection of new users to the transmission network under equal, transparent and non-discriminatory conditions;
- the integration of RES into the transmission system in order to meet the obligations undertaken by Croatia when joining the EU;
- defining the reconfiguration of the

Figure 21. Transmission network investment categories in Croatia in the period 2021 – 2030 (HOPS, 2021)



transmission network in future, in a flexible and resilient manner;
- fulfilment of the goals of the Croatian Energy Strategy.

These principles, or strategic determinants, will be fulfilled by carrying out the following activities:

- continuous investments in renovation, i.e. the replacement and reconstruction of outdated transmission network units;
- investments in the construction of new network elements (lines, transformers, information and communications infrastructure, reactive power compensation devices, active power control devices, etc.) based on the criteria prescribed in the Grid Code, taking into account economic criteria;
- the application of modern technologies in electricity transmission, such as High-Temperature Low Sag (hereinafter: HTLS) conductors of the 2nd generation in the renovation and an increase in the transmission power of existing transmission lines, as well as the installation of power electronics devices such as Flexible Alternative Current transmission systems (hereinafter: FACTS), or conventional control devices as Variable Shunt Reactors (hereinafter: VSR), to solve the problem of high voltages in the transmission network, and the installation of phase shift transformers (power flow control), etc.;
- continuous capacity building of the TSO staff through active participation in European processes under the framework of ENTSO-E, and participation in other international organisations (CIGRE, IEEE, etc.).

Total transmission network investments in 2021-2030 are planned to be at the level of HRK 9.1 bn (€1.2bn), as presented in Figure 21. Approximately 35% of this is expected to be paid by network users, and approximately 11% is planned to be from EU funds. The remaining portion, of approximately 54%, will be covered by network tariffs. This assumes average annual investments of approximately HRK 910 mil/year (€120mil/year), which is twice higher than in the previous 10-year timeframe, which was approximately HRK 450 mil/year (€60mil/year).

This sharp increase in network investment is based on the expected large scale of RES integration and is similar to other EU countries. A significant portion of network investments is financed through the grid connection process by network users, while part of the funding is expected from EU funding mechanisms, primarily the Recovery and Resilience Facility.

4. 2. DISTRIBUTION INFRASTRUCTURE SYSTEMS

In the 10-Year Plan for The Development of the Distribution Grid, HEP DSO aims to increase business efficiency, power supply reliability and overall readiness to integrate new technologies (e.g. advanced measurements, sensors, and providers of ancillary services). The business goals are divided into three main categories and several subcategories:

1. **Increasing the Network Capacity**

- construction of new facilities and grid components;
- reconstruction and extension of existing ones; and
- transition to the 20 kV voltage level and gradual abandonment of the 10 kV and the 35 (30) kV voltage levels.

2. **Increasing the Quality of Power Supply**

- the renovation of obsolete equipment;
- remote control system;
- MV grid automation;
- construction of additional power facilities to ensure double power supply (N-1 criterion);
- MV network grounding systems; and
- increasing service quality and voltage quality.

3. **Increasing Business Efficiency**

- arrangement of billing metering points and customer connections (without metering devices);
- arrangement of billing metering points;
- increasing energy efficiency;
- improving technological level of grid elements and maintenance;
- informatisation of business processes;
- investments in business infrastructure;
- specialist education and training.

Increasing Network Capacity

The basic incentive for replacing the 10 kV voltage level with a 20 kV voltage level in the distribution area, is the lack of transmission capacity of the existing 10 kV network. The replacement of the 10 kV voltage level with 20 kV enables smaller technical losses in the network, with voltage drops reduced by half. The gradual abolition of the 35 (30) kV level and the introduction of direct 110/20 (10) kV transformation enables easier control and cheaper maintenance of the network.

Increasing Quality of Power Supply

The renovation of obsolete equipment with the aim of increasing power reliability is defined according to the end-of-life criterion of the equipment (related to a large number of failures) and the difficulty of maintenance due to non-existing spare parts.

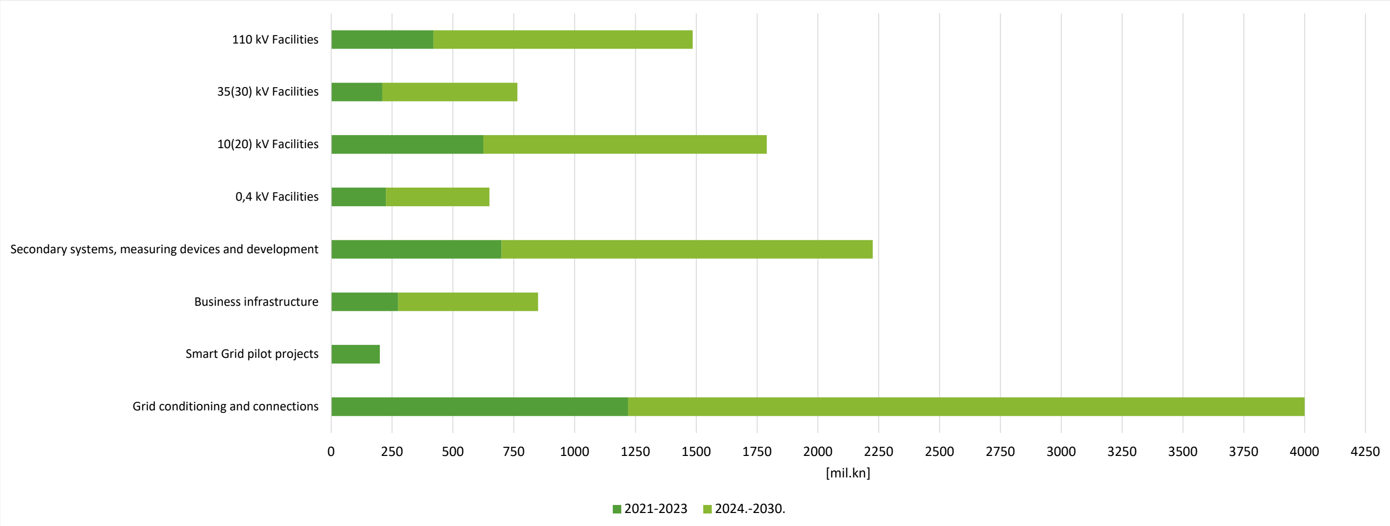
The adverse effect of unplanned power outages can be reduced by using remotely controlled switchgear, in a way to reduce the number of customers without power supply, the time required for fault location, and the amount of undelivered energy. Also, there is a potential for building self-healing MV network especially in urban areas. Single fault in a distribution grid often results in an outage, which can last for hours and incur significant losses to both customers and utilities. By replacing a full range breaker switchgear with the traditional Ring Main Unit MV switchgear along with fault indicators and communication devices we can get a smart, self-healing network which can restore the power after any earth fault within less than 0.2 seconds. Faults that are lasting below 200 ms is not felt by consumers and electronic devices.

Increasing Business Efficiency

Measures to reduce technical losses, which are also measures to increase energy efficiency, include:

- increasing the cross-section of conductors in the initial sections of MV and LV feeders where the largest amount of losses is generated;
- switching part of the LV feeder to the adjacent and/or unloaded LV lead or MV/LV substation;
- the replacement of HV/MV and MV/MV power transformers due to overload and the replacement of old MV/LV power transformers, with a reduction in oversized transformers;
- the introduction of new HV/MV, MV/MV and MV/ LV substations (applied

Figure 22. Transmission network investment categories in Croatia in the period 2021 – 2030 (HOPS, 2021)



primarily in cases of overloaded existing substations, or in cases of the connection of new customers and manufacturers with larger connection powers);
- transition to 20 kV network level and the gradual introduction of direct transformation 110/10 (20) kV.

One important goal is the integration of existing business applications, interface development, and other functionalities that would allow easy and fast data sharing between important business applications (DISPO, GIS, SCADA, Billing, Development Planning, Slap, etc.). This step would allow greater efficiency in planning and the speedier adoption of important business decisions.

Impact of Distributed Generation (DG) on development planning

The emergence of DG has put additional pressure on HEP DSO in terms of the network development planning process. However, by reducing the stress on some network components, DGs usually help to reduce losses in the distribution network.

In many cases, DGs are grouped in a certain area (e.g. around one 110/x kV substation), and due to their cumulative connection power, there is a need to create conditions in the distribution network, in order to take over the total electricity produced from local DGs. The most common interventions aimed at creating appropriate conditions in the network are the cross-section increase of existing lines, the replacement of existing transformers with new 110/10(20) kV or 35(30)/10 (20) kV transformers of appropriate rated power with automatic voltage regulation, the upgrading of parts of the network to the 20 kV voltage level, etc.

Financial structure of investments

For the 2021 – 2030 period, HEP DSO plans total investments of approximately HRK 12 bn (€1.6bn) as follows:

- 2021 – 2023: HRK 3.8 bn (€506mil), which is on average HRK 1.27 bn (€169mil) per year;
- 2024 – 2030: HRK 8.2 bn (€1.09mil), which is on average HRK 1.17 bn (€156mil) per year.

Figure 22 shows planned investments for various facilities and infrastructure.

110 kV Facilities

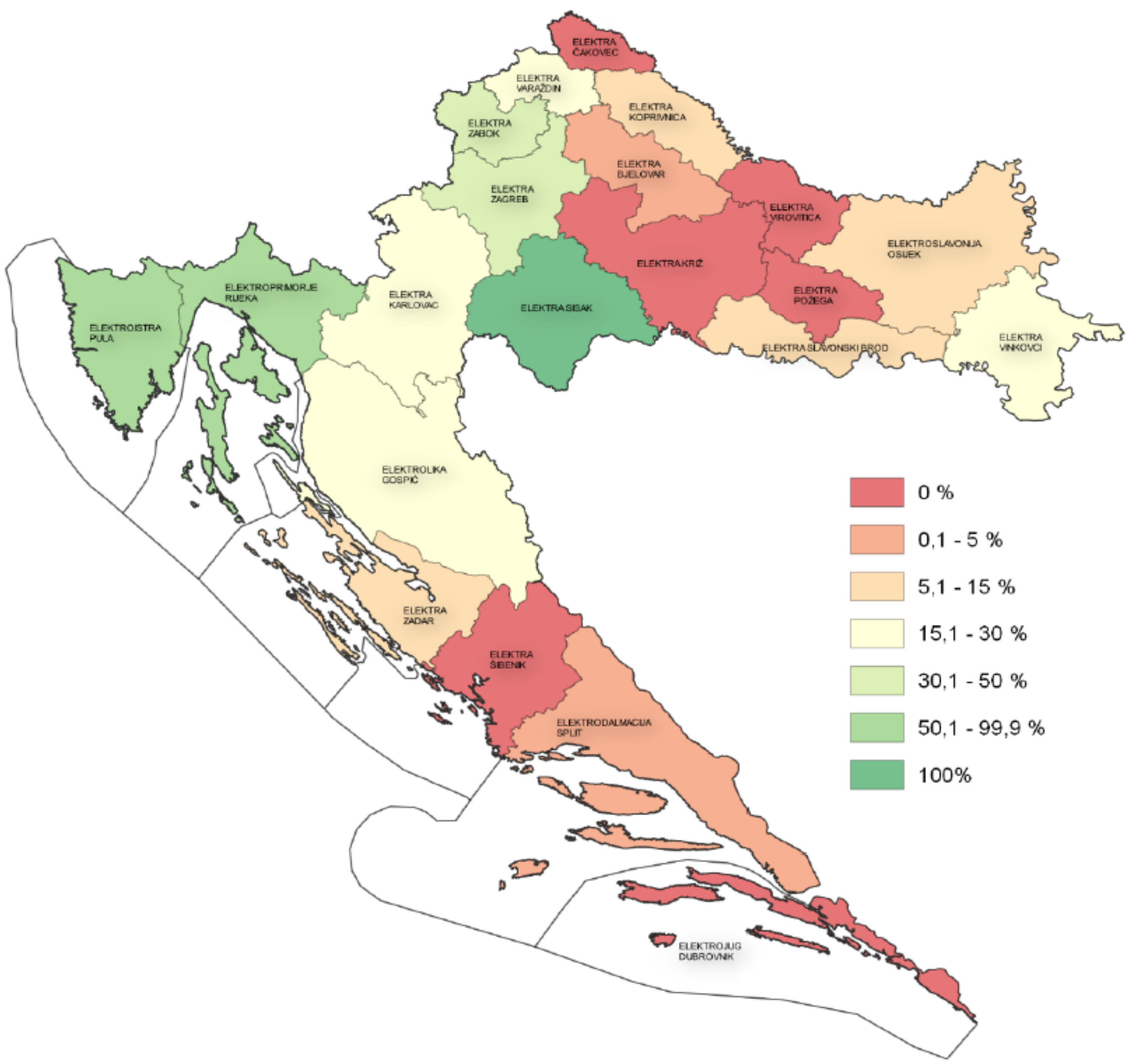
Because the 110/x kV investments require the joint work of both HOPS and HEP DSO, as well as complying with various regulator frameworks, investments are complex and require more time to finalise. Such projects can have development times of up to five years.

Planned investments for the 110/35 kV plants are: the renovation of the subsystem, the reconstruction of 35 kV plants and more complex reconstruction with the installation of direct transformation (replacement of 110/35 kV transformers with 110/20 (10) kV transformers). By investing in 110/x kV connection points, the preconditions for the transition of the MV network to 20 kV can be realised.

35(30) kV Facilities

35(30)/10 kV and 35(30)/10(20) kV substations make up the largest part of HEP DSO connection points (almost 75% of all x/10 (20) kV connection points).

Figure 23. Overview of the share of MV/LV substations operation at 20 kV by distribution areas (HEP DSO, 2021)



One of the most significant investments in the 2021 – 2024 period is the construction of five 35 kV underground cable sections and one section of 35 kV OHL with a total length of about 31.3 km, at an investment value of HRK 16.1 mil (€2.15mil).

In the 2024 – 2030 period, it is planned to build 35 kV OHL and underground cables worth roughly HRK 44.9 mil (€5.9mil). Due to the development of direct transformation 110/20 (10) kV and the transition to the 20 kV level, large investments in the 35 kV are being avoided.

10(20) kV Facilities

Investments in the construction of new 10(20) kV MV lines, which represent a key component of the distribution network, are extremely important because of power supply security and reliability. The connection of the growing number of DG to these lines further increases their importance.

In areas where the density of consumption is low, low nominal power substations should be built, and it is necessary to optimise the length of low voltage lines. The increase in load must be accompanied by introducing new 10 (20) /0.4 kV substations into the existing low voltage network.

In the short term, the transition of parts of the 10 kV distribution network to 20 kV operating voltage leads to more favourable voltage conditions in the medium voltage network, which doubles transmission capacities and quadruples reductions in energy losses and improves the voltage condition on long lines, without major construction works.

The condition of the MV network operation at 20 kV by distribution areas is shown in Figure 22. The distribution area Sisak (Elektra Sisak) became the first distribution area to completely switch to 20 kV operating voltage in 2019.

By 2030, HEP DSO plans to invest in 7,000 additional MV/LV kV substations and approximately 8,500 km of MV lines in the transition to 20 kV.

These investments primarily include:

- the replacement of MV/LV transformers with switchable ones;
- the reconstruction of substations with 24 kV insulation level equipment;
- the reconstruction of 10 kV overhead lines with 24 kV insulation level equipment;
- the replacement of 10 kV cables with 24 kV insulation level ones; and
- other investments of smaller scope for switching to the 20 kV level network.

0.4 kV Facilities

The construction of the low-voltage network is planned in accordance with the expansion of settlements and the introduction of new substations. As a significant part of investment in the network, the rehabilitation of voltage conditions will be carried out, and the replacement of unreliable uninsulated conductors, wooden poles with self-supporting cable bundle and concrete poles. The main reasons for the reconstruction and renovation of LV networks are the age and poor condition of the equipment and the quality of voltage.

Secondary systems, measuring devices and their development

Investments in management systems should be continued and appropriate development activities should be envisaged in order to create technologically modern systems that will be able to respond to the challenges that will arise with a higher RES integration. Investments in distribution network secondary systems include:

- investment in management systems of distribution control centres and distribution dispatch centres;
- the integration of distribution control centres;
- the modernisation of remote control systems in electrical power facilities; and
- investing in Distribution Management System functions and other advanced functions.

Business infrastructure

Investments in this area relate to:

- cars, trucks, work, and testing vehicles;
- business buildings and other workspaces;
- communication infrastructure, business informatics and business support; and
- testing and measuring equipment, protective technical means, tools, and machines.

Smart Grids and the Smart Grid pilot projects

A Smart grid can be defined by its main feature: an intelligent network, which can be seen as the modernised version of the traditional grid that implements the advanced functions of grid monitoring, controlling, protection and communications systems, which is an all-around integration of information and communication technologies in the power system.

Contrary to a traditional network that is characterised by large, centralised power plants, a Smart grid is characterised by numerous small, dispersed producers, where the power flow in the distribution network is no longer exclusively in one direction but in two directions as consumers are no longer just passive participants in the power system.

There are many advantages to operating the power system as a smart grid:

- the reliability and stability of the power system is greatly improved;
- the overall system operation efficiency is increased;
- system security is raised to a new level;
- better conditions for RES integration;
- provision of participants in power system with greater data and information;
- higher economics and environmental benefits.

HEP DSO’s Smart Grid pilot project has a goal to increase the efficiency of electricity distribution, increase power reliability, and increase the number of users with access to an advanced network, in order to integrate more DGs, especially renewable sources.

Grid conditioning and connections

Investments in grid conditioning and connection mostly depend on economic and demographic changes. Therefore, it is extremely difficult to plan the amount, and especially the structure, of necessary investments in the future. However, based on current trends, HRK 3.8 bn (€500 mil) are earmarked for investment over a period of 10 years, as follows:

- CABLE 10 (20) kV

- construction of new cables – 210 km;
- reconstruction and renovation of existing cables – 10 km;

- (10/20)/0.4 kV substations

- new substations – 165;
- reconstruction and renovation of existing substations – 30;

- OHL 0.4 kV

- construction of new lines – 250 km;
- reconstruction and renovation of lines – 70 km;

- CABLE 0.4 kV

- construction of new lines – 600 km;
- reconstruction and renovation of existing lines – 15 km.

4. 3.OTHER INVESTMENTS

In addition to the expected investments for the transmission and distribution network described above, other investments would improve the overall stability and reliability of the electricity system:

- the modernisation of auxiliary services of transmission and distribution systems;
- the modernisation of SCADA and the Energy Management System;
- the modernisation of metering systems, possible energy storage and demand response;
- the procurement of modern communication and information technology hardware and software for the integrated and efficient operation of the network with full capacity integration of renewable sources.

Modernisation of ancillary services of transmission and distribution systems

Incorporating new technologies into the system can increase its flexibility. HOPS is in the investment phase of the SINCRO.GRID project, which focuses on using advanced technology systems and algorithms with the aim of improving the quality of voltage in the power system and increasing the transmission power of existing lines. The ultimate goal of this project is to ensure the integration of RES and increase the security of supply to customers.

Voltage support can be greatly improved by installing FACTS devices into the power grid. HOPS plans to invest in the installation of three reactive power compensation devices in the existing transformer stations Konjsko, Melina, and Mraclin. The types of FACTS devices that should be installed are:

- SVC (static var compensator) with a total power of 250 MVAr in TS 400/220/110 kV Konjsko;
- VSR (variable shunt reactor) with a total power of 200 MVAr in TS 400/220/110 kV Melina;
- VSR with a total power of 100 MVAr in TS 220/110/10 kV Mraclin.

These compensation devices are installed at 220 kV voltage level because, in that case, the overall losses in the transmission network are least.

When the expansion of the power network is delayed, a partial solution can be found in Dynamic Thermal Rating (hereinafter: DTR) systems that have a function to increase the capacity of existing transmission lines and do not require large capital investment.

The DTR approach is based on actual operating conditions using real-time measurements and/or calculations, load currents and ambient conditions, as well as the actual physical quantities associated with the transmission line. There is a great potential for using the DTR system to increase the stability and reliability of power systems. Transmission lines targeted for the implementation of the DTR system in the Croatian power system are:

- 400 kV and 220 kV Konjsko – Brinje;
- 220 kV Senj – Melina;
- 220 kV Konjsko – Zakučac;
- 110 kV network – most important lines.

Power flows control can be improved using a Phase Shifting Transformer (hereinafter: PST). The use of PST increases overall system efficiency by solving problems with uncontrollable energy transit. In the Croatian power system, a PST was installed in TS 400/220/110 kV Žerjavinec and TS 220/110 kV Senj, where the operation of a phase angle regulation showed how the power flows transition from LV to higher levels, which reduces transmission losses, congestion, and improves the overall system efficiency.

The main function of this PST is to control and redirect power flows at 400, 220 and 110 kV voltage levels. Plans for additional installations of these transformers have not yet been defined but investing in this equipment would certainly help regulate power flows on account of large VRES integrations.

Investments at the distribution system level can also be made to improve reliability. Investments can be made in advanced automation schemes, such as fault location, isolation, and service restoration systems, increasing the real-time monitoring of distribution systems and DGs, advanced dynamic protection systems etc.

Modernization of SCADA and Energy Management System

HOPS, in cooperation with the Slovenian system operator – ELES, is investing in the development of a Virtual Cross-Border Control Centre. This enables centralised coordination, voltage control and optimization of power losses in the power systems of Croatia and Slovenia, as well as the ability to monitor, forecast and control RES in order to maintain the stable operation of the entire management area.

The Virtual Cross-Border Control Centre represents the implementation of modern information and communication technologies (hereinafter: ICT) in connecting national dispatch centres of HOPS and ELES and their Supervisory Control and Data Acquisition (hereinafter: SCADA) systems with the corresponding centres and SCADA systems of distribution system operators (HEP DSO and SODO).

Modernisation of Metering and Protection Systems

The application of advanced metering infrastructure is especially important for increasing the efficiency of the distribution grid, because it will enable the calculation of losses and the locating of areas with increased losses at low and medium voltage levels. In addition, the application of advanced metering infrastructure will provide the collection of data on the number of customers affected by the interruption and the actual duration of the interruption, on the basis of which power reliability indicators can be more accurately calculated, and thus contribute to increasing power reliability.

Investments in advanced measurements provide the preconditions for many functionalities of the smart grid, primarily to support the development of many new market services, and certainly in terms of the increased availability of reliable data for planning the development of the distribution network. Therefore, the largest investments in this point should be in measuring devices and infrastructure.

Most of these investments relate to the purchase and installation of meters with the possibility of remote reading (primarily power-line communication), as well as other functionalities of advanced meters, supporting equipment and systems for reading and using metering data.

One of the solutions for the adequate monitoring of RES integration into the system is the use of PMU devices. PMU devices are the basis of the monitoring system of a large part of the power system in Wide Area Monitoring Systems. They combine the functions of traditional secondary equipment with a new real-time data collection function.

In Croatia, a total of 20 PMU devices are installed in all 400 kV and 200 kV nodes and in a part of the 110 kV network that is in proximity of large power plants. The Wide Area Monitoring System software (phasor data concentrator) was installed in the National Dispatch Centre in Zagreb. In this way, a complete monitoring of the angular, voltage, and stability of the 400 kV and 220 kV networks were achieved, as well as and monitoring of thermal ratings of some lines.

Possible investments in this area can be oriented towards the installation of new synchronised measurement devices, and work on improving algorithms for better data processing and alarming function.

Modern communication and information technology

The power system communication infrastructure is a key component in the performance of electricity transmission and distribution activities. The communication systems must enable the secure exchange of information among all stakeholders in the electricity sector.

With respect to smart grids, the priorities of communication and information technology are to provide reliable and real-time data collection from a large number of various data sources, and to support the various communication services whose function is to distribute commands and configuration instructions in the power system.

Some of the basic requirements for smart grid communication infrastructures are:

- latency – smart grids require communications with low and stable latencies for proper RES control and protection functions;
- reliability – the transmission of data must be very reliable to ensure proper RES operation, especially in the event of failures in the grid;
- scalability – it is extremely important for a communication system to be able to easily process an increasing amount of data traffic or service requests coming from the numerous RES;
- flexibility – a smart grid communication system should have the ability to process requests coming from different services and subjects; and
- security – implies the ability to ensure that the smart grid is robust against failure and cyber attacks.

In this part, investments can be done in two categories, in wired or wireless communication infrastructure with the aim of improving some of the above-listed requirements that have to be met by the chosen communication system.

5. ACTION PLAN

This action plan proposes a series of measures to improve the connection process and improve the integration of renewable energy sources. The measures are based on the analysis of the existing infrastructure, development plans and regulatory framework in cooperation with the most important stakeholders (HOPS, HEP DSO, Ministry of Economy and Sustainable Development, Renewable Energy Sources of Croatia and Croatian Chamber of Commerce) and 11 key questions to improve the integration of RES in Croatia have been identified.

Namely, based on the analysis of the existing infrastructure and a series of individual connection studies carried out according to the current connection order of HOPS, it is estimated that without the construction of a new 400 kV in the Croatian power system it is possible to integrate 1,600 to 1,800 MW of new wind and photovoltaic capacities, on top of the existing installed capacity of 5,590 MW, and a peak load of about 3,000 MW.

By applying a probabilistic approach, it would be possible to integrate a significantly higher capacity of new RES, estimated at around 2,000 to 3,000 MW. However, it is important to note that these amounts largely depend on the order of connections of individual candidates and their rated power capacity, so it is possible that the legislative changes to the Electricity Market Act and the connection procedure will change the estimated amounts.

In the next medium and the long term, no significant increase in the system load is expected, while at the same time there is a very high interest in the construction of production facilities. This could ultimately result in Croatia becoming an electricity exporter instead of an importer. However, such a scenario requires a significant upgrade of the transmission network, including interconnections to neighbouring countries.

These questions are addressed in the Action Plan in the following format:

1. **Action Plan for policies and regulations**
   - 1.1. How to accelerate the grid connection process for RES in Croatia?
   - 1.2. What should be the connection fee methodology for new power generation projects?
   - 1.3. Which grid connection procedures need to be harmonised between HOPS and HEP DSO?
   - 1.4. What should be the legal and technical framework for the non-delivery of electricity?
   - 1.5. What are the main public procurement challenges in the grid connection process and how to resolve it?
   - 1.6. Which other regulatory changes need to be addressed?

2. **Action Plan for technical, technological, and operational measures.**
   - 2.1. How to accelerate the grid reinforcement of the T&D network infrastructure?
   - 2.2. Which T&D infrastructure projects should be prioritised in the short and medium terms to support larger-scale RES integration?
   - 2.3. Which new technologies should the T&D system operators implement?
   - 2.4. What should be the technical requirements for the connection and operation of VRES?

Which additional challenges impact the T&D system operators?

5. 1. ACTION PLAN FOR POLICIES AND REGULATIONS

1. How to accelerate the grid connection process for RES in Croatia?

In the last 15 years around 1 GW of new RES projects have been connected to the power network with minimal grid reinforcements and connection costs. However, on top of that there is a large number of new connection requests (more than 13 GW), which will require significant power network reinforcements, as the current capacities are almost saturated. Under the existing rules, developers are responsible to pay 80% of the grid reinforcement costs (STUM), while the T&D system operators cover remaining 20%.

In order to accelerate up the grid connection process, it is suggested to the Croatian Government to:

- **improve the infrastructure development policy** and clearly define which parts (or voltage levels) of the network are expected to be financed by the network users and which parts by the T&D system operators (and individual network users through the unit connection fee (HRK / kW)). Currently, developers have to contribute to the grid strengthening costs depending on their impact on the grid, which is not sustainable when there is a large number of applicants that plan to use the same infrastructure but are in a different development stage.
- **ensure full legal compliance** of the Electricity Market Act and the Renewable Energy and High-Efficiency Cogeneration Act with the relevant legislative frameworks in other areas (construction, spatial planning, environment, public procurement etc.) to avoid conflicting provisions and possible disputes due to legal discrepancy;
- **accelerate the spatial planning process**: the procedure for inclusion of new network elements in spatial planning is sometimes time consuming (several years) and it slows down the whole network construction process (especially in some counties and municipalities). Moreover, the new Electricity Market Act requires the system operators to include all network elements in the relevant county spatial plans that are submitted in their ten-year network development plans, which could slow down the network development process. A quick process of updating spatial plans is crucial for the grid build-out as well as new RES facilities. The process can be accelerated by a national plan.
- **adapt the Public Procurement Act** to accelerate up the construction of electricity network facilities, especially network infrastructure projects of strategic interest. With the planned

increase of the budget level for a simplified public procurement it is expected to accelerate and simplify the network development.

- **impose stricter deadline for the advance grid connection payment** of 5% (or a similar approach), because delays of one developer slow down all other projects in the pipeline;
- **introduce higher** guarantees for developers, such as in the energy approval payment.

It is suggested to the Croatian Energy Regulatory Agency (HERA) to:

- **update the existing grid connection regulations** (primarily the Methodology for determination of the grid connection fee (*OG, No. 51/17*)), in order to more accurately define the responsibility of financing the grid reinforcement costs. The existing grid connection cost sharing principle is not applicable with large number of applicants.
- **adjust the level of grid connection charges and network tariffs** to reflect the required large investments in the power network.

It is suggested to the T&D system operators to:

- **introduce more realistic scenarios when analysing current and voltage conditions in the network (in accordance with operating conditions and not only theoretical conditions) and stricter deadlines for issuing EOTRP** (currently there is a deadline of 360 days for HOPS to issue an EOTRP), as well as for the additional time of 270 days for signing the Grid Connection Agreement. Scenarios must be realistic and take into account the probabilities of occurrence of individual events and should not plan for expensive investments in the network in order to save a rare-occurring small amount of cheap energy.
- **reduce the uncertainty of the connection solution, deadlines, and costs**, since the development of a single power plant currently depends on other projects and mutual reimbursement of the grid reinforcement costs;
- **align practices and coordination between HOPS and HEP DSO**, in order to reduce uncertainty, misunderstanding, and inefficiency;
- **update** the Rules on connection to the distribution network;
- **update** the Rules on connection to the transmission network;
- **frequently** (at least every five years) **update the Grid Codes** in order to match technological advancements and the possibility for network users to participate in services, which is in line with other EU countries.

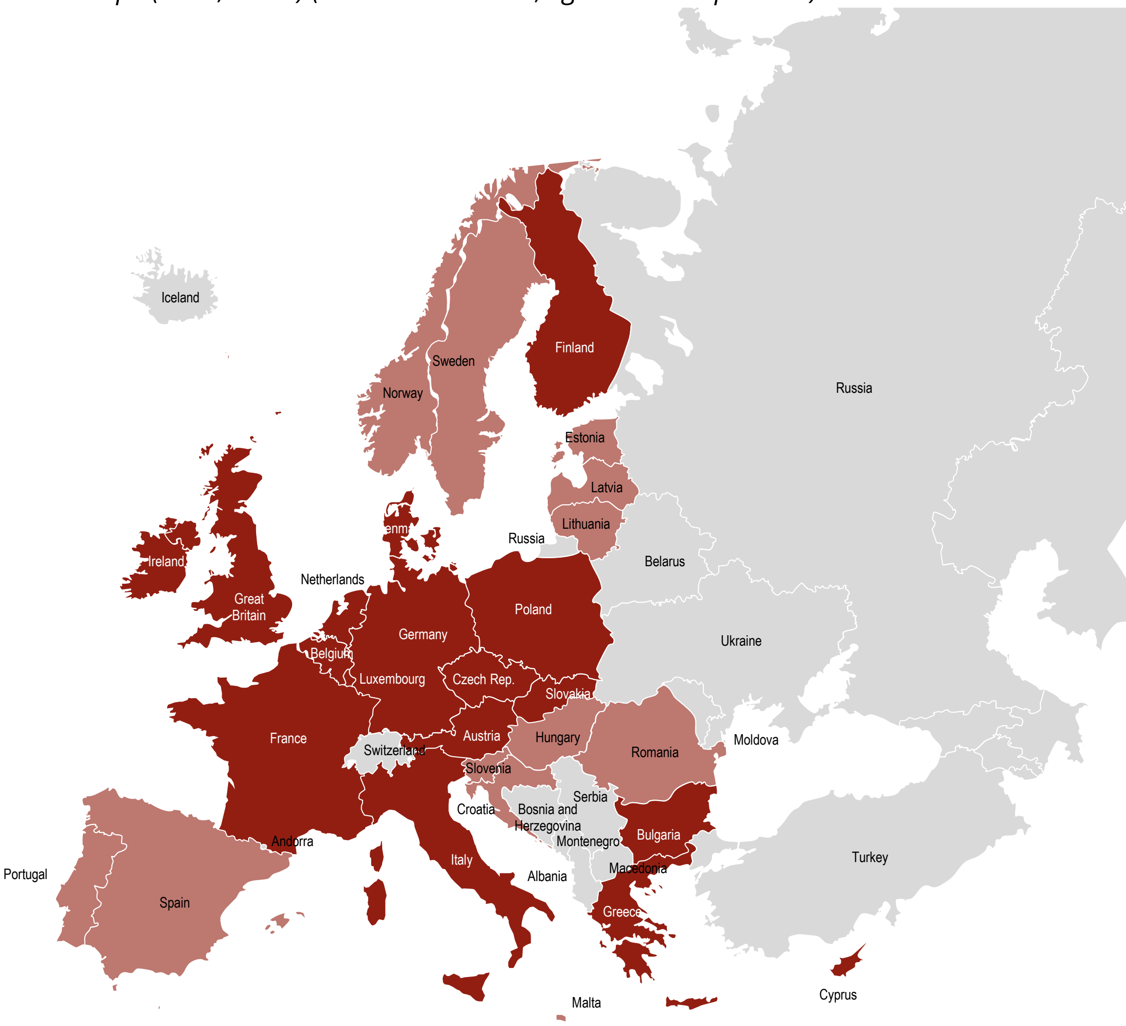
2. What should be the connection fee methodology for new power generation projects?

One of the most significant barriers in the development of RES projects in Croatia is the grid connection procedure and the connection fee. The existing framework does not have clear connection timelines and costs, as they are interlinked with other projects.

There are different models of connection fees across Europe and they are often tailored for a specific country. Each connection cost-sharing model has its advantages and disadvantages. The main differences between the "shallow" and the "deep" model are shown Table 14 but both have their pros and cons.

Figure 24 shows the experience of other EU countries. In 2018, 17 countries had a (dominantly) shallow approach for the connection fee in the transmission network, while the remaining 11 had a deep approach. It should be taken into account that each country has its own specifics, heritage, structure of network users and tariff system, which also

Figure 24. Overview of shallow and deep connection fees in the transmission network in Europe (ACER, 2019.) (dark red – shallow, light red – deep model)



affects the approach to determining the connection fee. A shallow approach is usually complemented by a G-component (network usage fee per MWh produced).

Overall, a shallow approach is the most favourable for RES developers because they do not bear the costs of network reinforcement, nor do they pay the network fee, instead all these costs are borne by customers. On the other hand, a deep approach is the most favourable for end users, because then there is no need to increase the network fee.

Table 14. Comparison of the different cost-sharing grid connection models

Connection type	Advantages	Disadvantages
Shallow model	•Easy to apply and requires simple regulations; •lowest costs for the developer; •clear connection costs for the developer are defined in advance; •the grid reinforcement costs are covered from the network tariff and the connection assets value is a part of the regulated asset base;	•There is no location signal for the developers from the standpoint of network connections; •the system operator does not immediately receive funding for grid reinforcements but is reimbursed through a tariff only after the completion of the grid reinforcement; •the grid reinforcement is realised according to the plan and dynamics of the system operator, which determines the connection time of the power plant; •increased network tariffs or introduction of a G-component; •increased risk of unnecessary grid reinforcement if the power plant does not end up being built.
Deep model	•In general, no G-component (the network tariff that generators pay for each kWh) is introduced for electricity generators; •strong location signal to the developers; •the network tariff for other network users is not increased; •other network users benefit from the grid reinforcements.	•The connection fee can be very high; •the costs of the grid reinforcements are unpredictable due to the lack of clarity; •the first developer pays the grid reinforcements, which can be used by other developers; •it is necessary to initially introduce a connection cost-sharing mechanism; •the additional costs to developers are likely transferred to the customers; •The grid reinforcement costs are not covered from the network tariff and the connection assets value is not a part of the regulated asset base.

Therefore, other models cannot be simply copied, especially due to the specifics of the Croatian power system (unusual geographical shape, lots of islands, seasonal and geographic demand fluctuations, network age, etc.).

This study analysed six possible models and recommends adjusting the existing "deep" grid connection cost model (i.e. "mixed" model).
One possibility is to introduce a "mixed" model in which the 400 and 220 kV network is financed from the network fee, and the lower voltage levels are financed by the developers. This would result in higher costs for the system operators.

A second option would be introducing a connection fee (HRK/kW) as other network users have. Therefore, before defining the "depth" of the connection financing model, it is necessary to determine what is the maximum network fee that can be borne by the consumers (households, industry, etc.). The maximum network fee should assess how to achieve the greatest social benefit while balancing the responsibility and costs between different network users (RES developers and other power producers on one side and other users (consumers) on the other side).

The existing grid reinforcement costs-sharing principle can be redefined in the following six ways:

1. **leave the existing deep model** but rearrange the corresponding methodology by excluding the grid reinforcements at the 400 kV and the 220 kV network level. These network levels would be fully financed by the system operator. With this model, the existing network tariff in Croatia should be increased by approximately 15%. The advantage of this model is a clear location signal to the developers in which parts of the existing network there is a redundancy for connections (and thus lower connection costs according to the current methodology). The disadvantage of this model is the necessary increase in the network tariff, which transfers the cost of network development to existing network users. Likewise, new RES projects are often of higher power (above 100 MW) and will be expected to be connected to the 400 kV or 220 kV network. In such conditions, abandoning a deep approach and at the same time introducing a new methodology according to which developer do not bear the costs of network reinforcement, creates the need for a significant increase in network fees.

2. **leave the existing deep model but introduce an unit connection fee** (in HRK/kW) for electricity generation units, as existing for the consumers. In this way, the total connection cost is divided into two components: the first component is the cost of building the connection itself, while the second component is the mentioned unit connection fee that serves the system operator for maintaining and operating the grid. The advantage of this model is that the connection costs are the same for all developers and known in advance. In addition, it will require a lower increase of the network tariff. Also, this approach would not pass the entire cost of grid reinforcements to consumers but would still be paid partly by the network users in their connection process. Therefore, the unit connection fee would need to be determined by HERA (as regulated by the existing Energy Act) based on of non-discriminatory and transparent principles and respecting the proposal of the system operators. The unit connection fee could be further developed on a geographical basis and define different unit connection fees in different areas.

3. **introduce a mixed model**, whereby the flat connection fee would cover a part of the grid reinforcement costs and the rest would be covered from the network tariff. This ratio should be defined by HERA based on the maximum level of the network tariff that the Croatian economy and society can bear. The financing of the connection is borne by the developer, while the cost of network reinforcement is co-financed through a fee from mixed sources (connection fee and network fee).

4. **introduce a mixed model and a G-component**, whereby the connection fee would cover part of grid reinforcement costs, a part would be covered from the G-component, and the rest from the network tariff. The advantage of this model is that HOPS could generate additional revenue to finance parts of grid reinforcements. However, the disadvantage of this model is that the introduction of the G-component has (currently) a very limited range. In accordance with Annex B of Regulation 2010/838 and the decision of ACER, it is possible to introduce a G-component in Croatia at the level of a maximum of HRK 3.75/MWh (€0.5/MWh), which would today provide an additional revenue to HOPS of approximately HRK 50 mil/year (€6.7mil/year), which could increase to HRK 90 mil/year (€12mil/year) by 2030. Moreover, in accordance with the Regulation 2019/943, the same G-component needs to be paid for by users connected to both the transmission and distribution network, which would require significant changes in the existing regulation and operational practice, which could affect the

investment climate in the power sector. Furthermore, in when a minimal increase or stagnation of electricity consumption is paired with an increase in electricity production within the Republic of Croatia, the introduction of the G-component is a justified procedure. However, as already mentioned, the total annual revenues of the system operator on this basis will not be sufficient to finance the necessary network reinforcements, and the G-component needs to be combined with a unit connection fee to avoid significant increases in network charges.

5. **introduce a shallow model**, which would completely exclude developers from financing grid reinforcements. The advantage of this model is that all investments in grid reinforcements go into regulated assets of the system operator, and the disadvantage is the additional costs to all consumers (an estimated increase of at least 25% of the transmission network tariff), there is no location signal, with a high investment risk for the system operator.

The estimate of the 25% increase of the transmission network tariff is based on the following assumptions for the transmission network in 2030:

- the Regulated Asset Base (RAB) is HRK 8.5 bn (€1.1bn) (an increase of HRK 3 bn (€400mil) compared to the current situation);
- annual yield from RAB is HRK 343 mil (€45mil) (55% increase);
- annual depreciation is HRK 517 mil (€68mil) (55% increase);
- annual CAPEX is HRK 860 mil (€113mil) (55% increase);
- required tariffs income is HRK 1.795 bn (€237mil) (33% increase);
- electricity sales are 17.5 TWh (compared to 16.5 TWh in 2019);
- furthermore, an increase in network charges for distribution has to be added, which due to lack of input data could not be simulated, but is estimated as lower than the above-mentioned increase for transmission due to: 1) lower costs of creating technical conditions in the network and 2) an initially higher network charges for the distribution network (e.g. for households, tariff model white: HRK 0.24/kWh (higher tariff), HRK 0.12/kWh (lower tariff)) in relation to the transmission network (HRK 0.11/kWh (higher tariff), HRK 0.05/kWh (lower tariff)).

It should be noted that already in 2019 there were conditions for increasing the network fee by about 5% for the transmission network and 5% for the distribution network, because the total operating costs of both system operators were already higher than the realised tariff revenues.

6. **financing of all grid reinforcements through EU funding**. The biggest challenge with this model is that due to the large number of grid reinforcements, this model implies a large, unforeseeable risk and change of the existing practice. The total value of the transmission infrastructure in Croatia is around HRK 5 bn (€666mil), so it does not seem realistic to finance such large amounts in the next few years only through EU funding.

From the point of view of the system operator, the last two models (5 and 6) represent by far the greatest risk to business and technical viability. Namely, due to the large number of candidates and the various required network reinforcements, the operator would have to start a large number of individual network reinforcements (STUM) at the same time in the case of a shallow model, without financial responsibility or guarantee of network users for its project. In addition to the questionable operational feasibility of such simultaneous interventions, this would certainly pose a major business risk for the system operator. Furthermore, in order to change the existing "deep" model to the "shallow" model, it is necessary to amend of the Energy Act (*OG, No. 120/12*). Any changes in the regulatory model that affect the acquired rights of already started projects calls into question the legitimate expectations of investors who are protected by international law, either through general agreements or specialised international energy agreements that Croatia has ratified. Namely, if the changed regulatory framework would treat different investments differently so as to change their business model, the state would be exposed to potential arbitration requirements that could result in high compensations for the affected projects.

An example of such vaguely defined transitional provisions can be found in the Electricity Market Act (*OG, No. 111/21*), which vaguely establishes the obligation to obtain the energy approval for already started projects in a very short time (90 days) under the threat of losing the connection right (Article 133), without being adequately regulated by a transitional provision (Article 139).

Therefore, it is recommended to:

- **instead of the existing model for grid reinforcements to introduce a unit connection fee based on the planned power rating (HRK/kW)**. With this approach the grid connection process would be faster, more transparent, and cheaper for developers. The

flat fee would cover part of the grid reinforcement costs (STUM) and the rest of STUM would be covered from the network tariff. The exact value of the fees should be carefully developed and in line with the operation of other sectors of the Croatian economy.
- analyse and simulate the introduction of a G-component. However, it is not expected to cover a significant part of the grid reinforcement cost.

3. Which grid connection procedures need to be harmonised between HOPS and HEP DSO?

- HEP DSO doesn't require payment before issuing electricity consent according to the Grid Connection Agreement, while HOPS requires payment before issuing the electrical energy consent. This could result in a potential problem in which a distributed generation project can obtain the location permit and energy consent without any deposit for the grid connection payment.
- HEP DSO and HOPS should harmonise procedures and authorize RES developers to undertake certain activities on behalf of the system operator where applicable (e.g. issuing of location permit, construction permit, resolving of property right issues, etc.) and initiate adequate legal framework (primarily Construction Act) update. This could significantly shorten the grid connection procedure.
- HOPS and HEP DSO should harmonise grid connection study deadlines in the cases where transmission network analysis is required for the distribution network connection application.

4. What should be the legal and technical framework for the non-delivery of electricity?

Clearly, due to expected large scale RES integration in Croatia, it is expected to have large scale grid reinforcement needs. However, grid reinforcements are usually very time consuming and waiting for its full completion before RES connection could cause significant delay of RES integration process. Therefore, in the case unavailability of the power network, a power plant operator might have to accept the risk of occasional and temporary non-delivery of electricity for its facility. This point is referring to analysing and proposing an option that's different compared to the current N-1 criterion in the Croatian power system.

The legal framework governing the non-delivery of electricity is the Commission Regulation (EU) 2017/1485 on establishing a guideline on electricity transmission system operation.

A TSO is not required to comply with the (N-1) criterion in the following situations:

- during switching sequences;
- during the period required to prepare and activate corrective maintenance actions.

Furthermore, the regulation states an exemption that the TSO is not required to comply with the (N-1) criterion as long as there are only local consequences within the TSO's control area.

However, in order to implement those exception, further technical analysis must be provided. A legal practice can be established by stipulating exceptions in the connection agreements, with recourse to the abovementioned rules. Therefore, it is possible to allow the possibility for the network users to accept the risks of non-delivery of electricity from its power plants on a solely contractual basis, subject to technical pre-analysis, which would not require further legislative activity.

Another important aspect relevant for this topic is regulated in the Regulation (EU) 2019/943 on the internal market for electricity, which defines the limit for T&D system operators in resolution of the grid connection issues using RES dispatching/curtailment of maximum 5% of the annual generated electricity from RES. In other words, the operator requesting the redispatch of RES is subject to the payment of a financial fee to the operator of the production plant. Namely, the system operator is obliged to take all possible measures of system flexibility and to rely on RES redispatching only as a last resort. That is, the system operator is tasked with optimally developing the network and its flexibility, and only in rare cases, if it is determined by a cost-benefit analysis, relies on redispatching. One of the most effective options for removing the grid connection barrier is the introduction of regulatory solutions for voluntary reduction of RES production (and more than 5% of annual production, which needs to be regulated very precisely by contracts) until the electricity grid is not properly strengthened and the deterministic approach (N-1) is replaced by a probabilistic approach for power grid planning.

With this approach, it would be possible to integrate a significant amount of RES planned in the Energy Development Strategy for 2030. In general, it can be said that investments in network construction and reinforcement are justified if their cost is lower than the cost of network constraints (production deliveries, i.e. consumption constraints). This approach further justifies the introduction of a probabilistic approach to planning, which certainly represents a major change in relation to the current state and specifics of the Croatian transmission network (longitudinal structure, island connections, large seasonal variations, age of the network, etc.) so it is necessary to approach such regulatory change with extreme caution.

The recent changes in the Electricity Market Act have paved the way for abandoning the current deterministic approach for the (N-1) criterion in network planning. Future rules on congestion management of the transmission and distribution system now have a legal basis for abandoning the deterministic approach in network planning.

5. What are the main public procurement challenges in the grid connection process and how to resolve it?

There are three key problems in the implementation of the Public Procurement Act in the construction of electricity network facilities:

- unclear provisions of the Public Procurement Act (e.g. definition of "similar products and services"), which usually requires the interpretation by the National Commission for Public Procurement or even the Administrative Court. This significantly slows down the network reinforcement process.
- the appealing procedure can be initiated without major cost and detailed argumentation, which often results in slowing down the process of contracting and project implementation of the power network;
- due to the aforementioned issues, the internal procedures of the T&D system operators for the implementation of the Public Procurement Act are extremely complex and time-consuming, which further slows down the whole process.

6. Which other regulatory changes need to be addressed?

There are two additional regulatory aspects to be separately addressed and improved. The first one relates to the same process that is currently used to connect rooftop PV projects or e.g. a nuclear power plant, even though the impact of large-scale power plants on the dynamic support to the power system during faults is crucial. One possible solution is to introduce the afore-mentioned unit connection fee (HRK/kW), as well as the obligation to prepare dynamic response studies of the system for all types of power plants (including conventional power plants and RES).

The second issue relates to the high number of grid connection applications. A possible solution is to collect the applications on a seasonal level and then to analyse and systematically process them (once a

Table 15. Other regulatory changes for accelerating the integration of RES in the distribution network

Fact	Recommendation
1. Electricity distribution network in Croatia was not originally designed to accommodate the scope and quantity of two-way electricity flows. Investment in the distribution network in order to integrate new production capacities must include solutions of smart grid initiatives, smart meter deployment and investment to improve security and quality of supply.	A predictable, stable, and transparent regulatory framework must be established, enabling full cost recovery and access to credit and capital markets needed to fund distribution system operator investment priorities.
2. The electricity network tariff is primarily based on the volume of electricity that is passed through the network. With the rise of new production capacities and prosumers TSO and DSO revenues will decline, jeopardizing the security and reliability of service.	Network tariffs should be redesigned with a gradual transition toward capacity tariffs or two-part tariffs that will decouple TSO and DSO revenues from the volume of electricity passed through its network. These tariffs, which are used in other parts of the world, are better suited to account for the impact of the VRES, generation installed for self-consumption purposes, and energy efficiency measures.
3. Net-metering, in which the prosumer pays only for the difference between what they self-produce and receive from the network, is detrimental to utility revenue in the current volumetric tariff formulation. It reduces the amount of funds available for operation and capital expenditures on the grid.	The regulator should avoid net-metering schemes for prosumers in the current volumetric tariff design. If necessary, net metering may be used in a transitional phase and limited to very small scale residential and commercial installations, with yearly system quotas.
4. Widespread deployment of new production capacities will lead to operational challenges (voltage control, protection settings etc.) and higher network losses, particularly at peak hours when two-way flows of energy will be at their greatest levels.	The distribution network tariff should be reformed to encourage network users (consumers, producers, prosumers) to shift their peak energy use to non-peak hours. The change in tariffs to encourage network users to shift their loads can reduce the amount of investment required to accommodate the widespread deployment of DG.
5. Under the current regulatory framework and market design, new production capacities connecting to the distribution network do not pay system usage charges. These charges cover ancillary services, network losses, operations and maintenance, administrative, metering costs or other related costs.	Understanding that it is difficult to allocate the additional operating costs to each generator, the use of system costs should be: 1) socialised to all network users or 2) (partly) allocated to the electricity generation units. In general, clear price signals to the electricity generation units (2nd approach) always results with more efficient system use.

6. Prosumers remain connected to the network for back-up service in case their generation unit fails. They are also not charged for their use of the system and the provision of back-up service, instead they are subsidised by other network users.	Prosumers should pay adequate share of the network costs and other system costs and not rely on the subsidies provided by other network customers (those that are not generating electricity).
7. New production capacities and prosumers that oversize their production capacity to export electricity via the distribution network create network congestion and contribute to network losses, particularly if that excess electricity produced is not consumed in the neighbourhood (locally).	Network tariffs should be designed to encourage the most technically and economically efficient use of the existing infrastructure to avoid excessive investment in the network. For example, tariff should encourage solar rooftop generation to follow consumption pattern or installing energy storage systems.
8. 8. New production capacities integration requires the provision of new network services and a more active management strategy to compensate for greater uncertainty on the distribution grid. Adoption of active network management strategies will help mitigate network costs caused by widespread deployment of new production capacities.	DSO should embrace an active role in the implementation of these new network management strategies but require confidence and incentives to deploy new technologies and services (e.g. smart grids, active role of network users, widespread SCADA systems, etc.), which would help in managing a more complex distribution network.
9. 9. New production capacities do not pay for their use of the network (system charges). The connection charge is a one-time payment primarily based on the situation in the existing network.	Understanding that connection costs can easily be allocated to each user, socialisation of these costs is not recommended. Adequately designed „deep" connection charging provides appropriate and harmonised locational signals for efficient investments in generation.
10. 10.To maintain system safety, security, and reliability, prior to connecting to their networks, TSO and DSO must conduct/approve a grid connection study to determine the optimal connection point and to determine necessary reinforcements/additions to the network. The study process can be cumbersome and time consuming, driving up the connection costs.	Grid connection study process and procedure must be simplified and less time consuming. One option may be to cluster grid connection requests to reduce the overall number of studies required (area approach). DSO can also consider simplified methodologies for smaller DGs and transparency and public notice practices.

year), as it is the case in some other EU countries (i.e. Ireland).

Finally, it is of utmost importance to keep the network infrastructure both operationally and financially stable, while at the same time enabling a higher integration of RES in the system. Therefore, in addition to the two regulatory changes, Table 15 shows ten additional recommendations for other regulatory changes related to the network tariffs and system use fees. These findings and recommendations are not only Croatian specifics, but a result of a SEE regional analysis and discussion with 11 system operators based on an exhaustive assessment of the technical, legal, regulatory, economic, and commercial policies and practices in order to support larger scale RES integration (EIHP, USEA, 2020).

5. 2. ACTION PLAN FOR TECHNICAL, TECHNOLOGICAL, AND OPERATIONAL MEASURES

1. How to accelerate the grid reinforcement of the T&D network infrastructure?

It is necessary to accelerate and advance in the preparation of the network reinforcements, therefore, HOPS and HEP DSO should:

- initiate the public procurement procedures for the necessary documentation (preliminary and main design, environmental protection, geodetic surveys, resolving property rights, etc.) in earlier stage. These steps are prerequisites for EU recovery and resilience fund absorption or other potential sources of funding.
- urgently accelerate the renovation of the existing network elements, including implementation of new technologies (e.g. high-temperature conductors, dynamic thermal rating, smart grids, etc.). Such investments do not require building permits nor resolving property rights, so it is much less time consuming than investments in new infrastructure.

2. Which T&D infrastructure projects should be prioritised in the short and medium terms to support larger-scale RES integration?

The Croatian power system is extremely well connected to its neighbouring systems. The total installed interconnection capacity is five times higher than its system peak load. Therefore, there is no need for a further significant strengthening of the interconnections with neighbouring countries. However, there is a need to reinforce internal regional connections, primarily between Dalmatia and the rest of the country, both to the west and the north.

An additional 500 – 1,000 MW on top of the projects already constructed and in the testing phase (exact value depends on the specific locations of RES projects) can be integrated just with 110 kV network reinforcements. For a larger-scale RES integration it is necessary to strengthen the main 400 kV network backbone Konjsko - Lika – Melina and from Lika to northern Croatia (Tumbri or Veleševec). There is a large uncertainty in the determination of additional 400 kV network reinforcements due the uncertainty of power plants' sites, the rated power of individual projects, and commissioning years. Until recently, the legal framework allowed investors to initiate a connection request (development of EOTRP) before previously resolving spatial planning, environmental or other important conditions. Due to that, a large number of candidates for connections appeared. Also, there are several very large projects in the development process, such as the PV power plant Promina (950 MW), wind farm Lički Medvjed (420 MW), hydropower plant Senj 2 (350 MW), pumped storage power plant Blaca (500 MW), etc. The grid connection solution (for example, radial connection to TS Lika and TS Tumbri or TS Meline) can strongly impact the required necessary network topology, also the future network development and the manner and costs of connecting all other candidates. Therefore, it is recommended to introduce guarantees for completing a RES project in order to reduce the risk of non-completion.

Both HOPS and HEP DSO should:

- prioritise all crucial infrastructure projects that acquired a building permit and projects that are the most advanced in terms of permitting. This is because the development of new grid infrastructure projects lasts several years due it's complexity and size. Therefore, in the 10-year network development plan it is strongly recommended to introduce proactive network development principle (grid connection candidates are grouped and directed to the strong network nodes defined in the system operators' plan) rather than existing reactive principle (network nodes are defined for individual connection needs).

In the transmission network, HOPS should create the conditions to connect new VRES by:

- uprating of the transmission line capacities in the Southern region (replacing existing conductors with HTLS, expansion of DTR system, poles etc.);
- introducing PST or FACTS devices in several crucial TS;
- upgrade of secondary equipment and advanced protection.

In the distribution network, HEP DSO should create the conditions to connect new VRES by:

- replacing the existing MV/LV transformers and lines (OHL and cables) with elements with higher capacities;
- construct new substations and connection lines to increase power supply reliability (criterion N-1) and a gradual transition to 20 kV voltage level.

3. Which grid investments are needed on the transmission and distribution network?

Based on the experience from the previous pilot projects, it is recommended to continue using dynamic thermal rating (DTR) systems that are already established at several transmission lines in Croatia and the implementation of demand response technologies. The following technology applications in the network would enable a larger RES integration:

- implement Power Control Systems on several locations (modular mobile units that can be switched between locations are also considered as an useful option);
- replace existing conductors with HTLS conductors on internal and cross border lines, primarily with Slovenia;
- expand the existing DTR system on internal and cross-border lines, primarily with Slovenia;
- installation of the phase shift transformers wherever there is demand for them;
- establish an information connection and standardised data exchange between the transmission and distribution dispatch centres;
- upgrade the existing ICT infrastructure both communication and power control wise, to suit the advanced needs of the systems implemented;
- upgrade to fully automated substations (to the so called “digital” TS);

- upgrade of secondary equipment and advanced protection;
- implement FACTS devices for voltage control and power flow;
- fast inverter-based resources, especially storage, to respond autonomously to the rate of change of frequency;
- analyse the demand and possibility of introducing the High Voltage Direct Current (HVDC) technology for a completely controlled energy flow from RES.

In the distribution network, HEP DSO should also explore the following technologies:

- advanced automation schemes, such as fault location, isolation, and service restoration to cost-effectively improve the power system's reliability;
- high-speed communications and synchrophasors to enhance the stability of the power system;
- microgrids can provide efficient energy supply to isolated or remote areas and help the integration of DG, especially small and medium-scale VRES.

The Internet of Things solutions promises low-cost supervision and communications to DG, which would help in aggregating them to a grid service provider. However, in order to maintain a high level of reliability, security, and availability, cybersecurity should remain a high priority along with privacy and data ownership.

In addition to the investments in increasing the transmission capacity, upgrading the secondary equipment, and implementing new technologies, the T&D system operators should also:

- implement advanced short-term (intraday) and long-term forecasting systems, for accurate generation forecasts of wind farms and PV power plants. The control system for the power system should be equipped with an early warning system for major disturbances caused by weather disasters and a quantitative assessment of the probability of such events.
- implement forecasting systems for other dynamic stability KPIs (Area inertia, Power Angle Monitoring, Short Circuit Capacity, etc.), which will be necessary for reliable management of systems with a high share of VRE;
- upgrade the existing ICT infrastructure which will enable the processing and utilisation of data from an increasing number of smart metering points.

4. Which new technologies should the T&D system operators implement?

New VRES projects and battery storage projects could help in the operation of the power network through new technical requirements. The implementation of the technical requirements should be under the supervision of HOPS or HEP DSO (depending on the connection to the transmission or distribution network). However, T&D system operators will need to upgrade and adapt their own infrastructure and control systems to implement the additional technical requirements.

The following technical requirements for VRES, battery storage projects, or hybrid systems could be implemented:

- participation in dynamic voltage support in which RES generators would support voltage by injecting reactive current during a fault;
- participation in ancillary services, particularly frequency control through upward frequency control (in which the output power is being reduced), downward frequency control (by increasing the output power, which requires operation below a maximum power point or installed an energy storage system) and maintaining a reserve to provide a function of virtual inertia response.

5. What should be the technical requirements for the connection and operation of VRES?

In addition to the aforementioned challenges, the transmission and distribution system operators' also need to address one additional issue:

- **human resource strengthening** and capacity building: one of the challenging tasks for the T&D system operators in Europe, including Croatia, is in its human resource capacities during the energy transition. Large-scale RES integration requires an intensive investment cycle and higher technical, economic, and regulatory skills. Therefore, it is strongly recommended to system operators to implement training programs and continuous education for: power system control, network development under large uncertainties, implementation of new technologies in power system operation, special protection schemes, following the relevant EU legal framework and exchange of best practices, etc. Which additional challenges impact the T&D system operators?

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