THE IMPACT OF HIGH RES ON POSSIBLE GRID CONSTRAINTS IN THE BLACK SEA REGION

Draft Report

Black Sea Transmission Planning Project (BSTP)

Sub-Agreement: USEA/USAID - 2020 - 708 - 01

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Prepared for:

United States Agency for International Development
and United States Energy Association

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CONTENTS

ABBREVIATIONS

General

TSO	- Transmission System Operator
UCTE	- Union for the Coordination of Transmission of Electricity
ENTSO/E	- European Network of Transmission System Operators for Electricity (former UCTE)
ACER	- Agency for the Cooperation of Energy Regulators
REM	- Regional Energy Market
SEE	- South East European
BSTP	- Black Sea Transmission Project
BSRI	- Black Sea Regulatory Initiative
USEA	- United States Energy Association
NARUC	- National Association of Regulatory Utility Commissioners
PSS/E	- Power System Simulator for Engineering
OPF	- Optimal power flow
IPS/UPS	- Interregional Power System/Unified Power System

Transmission

AC	- Alternating Current
DC	- Direct Current
HV	- High Voltage
MV	- Medium Voltage
LV	- Low Voltage
HVAC	- High Voltage AC
HVDC	- High Voltage DC
NTC	- Net Transfer Capacity
TTC	- Total Transfer

Generation

HPP	- Hydro Power Plant
PHPP	- Pumping Hydro Power Plant
TPP	- Thermal Power Plant
NPP	- Nuclear Power Plant
CCGT	- Combined cycle gas turbine
CHP	- Combined Heat and Power Generation
RES	- Renewable Energy Sources
MOR	- Maintenance Outage Rate
FOR	- Forced Outage Rate

Adequacy

ENS	- Energy Not Supplied
LOLE	Loss of Load Expectations, number of hours during the year in which supply is below the load

LOLP - Loss of Load Probability
PC - Primary Control
SoS - Security of Supply

Balancing Market

LFCR - Load-Frequency Control

Countries

	ISO	Country	Car
Bulgaria	BG	BUL	BG
Romania	RO	ROM	ROM
Turkey	TR	TUR	TUR
Ukraine	UA	UKR	UKR
Armenia	AM	ARM	ARM
Georgia	GE	GEO	GEO
Moldova	MD	MLD	MLD
Russia	RU	RUS	RUS
Azerbaijan	AZ	AZB	AZB
Belorussia	BY	BLR	BLR
Poland	PL	PL	PL
Slovakia	SK	SK	SK
Hungary	HU	HU	HU
Serbia	RS	RS	RS
North Macedonia	MK	MK	MK

SEE South Easy Europe
EE East Europe

I. EXECUTIVE SUMMARY

As RES integration is recognized as one of the highest priorities for TSOs in the long-term, the Black Sea Transmission Planning Project (BSTP) conducted analyses that investigate the impact of large-scale RES integration on market and network operations.

The main motivation for conducting this kind of analysis can be found in the sheer size of the envisaged growth of RES capacities until 2030 (see Figure 1) and correlated market and network challenges.

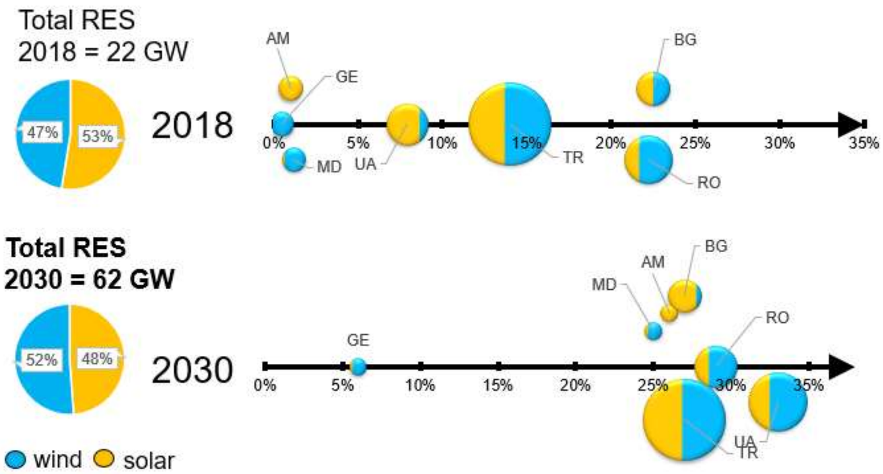

Figure 1: Envisaged growth of installed RES capacities and their share in the BSTP region

Namely, in the entire BSTP region, RES capacities will grow from 22 GW in 2018 to 62 GW in 2030, which is almost triple in just 12 years. RES share in total installed capacities will grow to around 25%-35% for the majority of BSTP countries, except Georgia, which beside wind and solar power plants have ambitious plans for the development of HPPs.

The large-scale exploitation of renewable energy sources will pose challenges for electricity system operations, requiring higher levels of back-up capacity and additional sources of flexibility. Market designs that are primarily based on short-run marginal costs (SRMC) or energy costs, may fail to deliver the necessary level of flexibility in the long term, affecting the availability of back-up capacity and ancillary services. Having this in mind, the objectives of the study were to analyze and quantify the impact of large-scale RES integration in the Black Sea region on both electricity networks and electricity market operations.

Market analysis was conducted by developing a regional Market model in Antares on a plant-by-plant level and running the annual Monte Carlo simulation on the hourly resolution. Network analysis was conducted by developing a regional Network model in PSS/E sw tool and running simulations for most critical regimes regarding the impact of high RES integration. The study was conducted for two scenarios: Referent RES and High RES, where referent RES represents official expected plans for RES integration, provided by BSTP members, and high RES represents sensitivity analysis for even higher RES integration.

The market analysis showed the impact of large-scale RES integration on wholesale market prices, the energy mix and CO2 emissions, country balances and cross-border energy exchanges. The network analysis showed the impact of large-scale RES integration on load flows, voltage profiles and secure grid operations.

Key findings and policy implications that can be taken from these analyses are the following:

- Generation adequacy and security of supply are maintained in each BSTP member state in both – referent and high RES integration scenarios.
- Higher RES generation provokes a reduction of generation from fossil-fired TPPs with equal share between gas and lignite/coal technologies. This is followed by wholesale market prices reduction and issues related to reduced profitability may be expected for both technologies.
- Higher RES generation enables a decrease of CO2 emission, from 139.2 mil.T to 130.7 mil.T (-6%).
- Required balancing reserve can be provided in all hours during the year in all analyzed climatic years and hydrological conditions in almost all BSTP countries except:
    - In the case of Georgia, where required balancing reserve of 390 MW cannot be satisfied in around 60 hours per year but only during flooding season.
    - In the case of Romania, where required balancing reserve of 1400 MW cannot be satisfied in around 240 hours per year, in all seasons except in spring.
- In Armenia and Georgia higher RES generation leads to increased RES curtailment or increased spillages which in Georgia (where drastic HPPs generation increase is expected) reach 3.3 TWh or 14% of total Georgia demand! Having this in mind further investigations related to acceptable levels of RES capacities and the introduction of flexibility levers are advised. Also, a big decrease in wholesale market prices may seriously endanger the business environment for the thermal plants in both countries.
- In the case of Ukraine and Turkey, high RES integration and prices decrease could have a positive impact on the wholesale market and energy trade. However, maybe more interesting are expected changes in these power systems from today till 2030:
    - In the case of Ukraine, large-scale decommissioning of coal TPPs is envisaged till 2030 which will drastically change the generation mix and balance will be changed from +5 TWh (export) in 2017 to -19 TWh and -11 TWh (import) in referent and high RES scenarios, respectively.
    - In the case of Turkey, expected consumption growth (from 300 TWh to 412 TWh) will be hardly compensated with new HPPs, nuclear plants and a rather high level of RES: +48 TWh in referent and + 56 TWh in high RES scenario. So, Turkish import will increase from 2.7 TWh (2018) to 24 TWh.
- Analyses of the wholesale market prices show that in 2030 BSTP countries are grouped in 3 price zones:
    - Armenia and Georgia (around 25-35$/MWh); Armenia and Georgia have lower prices than the central part of the BSTP region due to cheaper gas (and non-CO2 taxes) and excess of HPPs and RES generation
    - Bulgaria, Moldova, Romania and Ukraine (around 55$/MWh-60$/MWh) and

  - Turkey (around 70 $/MWh), since it is a big importing market zone.
- Testing of the network operation in the high RES scenario showed that high RES integration in the Black Sea Region causes some but not significant issues in the transmission network. In several cases, security violations that already exist in the high voltage network in the referent RES scenario are resolved by the integration of more RES capacities at lower voltage levels and by relieving the loading of elements caused by the conventional flow of power from higher towards lower voltage levels.
- In just a few cases, security violations have been observed at internal lines (220 or 400 kV in Romania and Turkey) usually highly loaded, mostly due to the high generation from power plants. When there are problems with the evacuation of the generation, causing issues in the system, it is recommended to direct the generation towards a higher voltage level (400 kV). This improves security conditions and reduces losses in the system. In some cases, the solution could be proper topological changes, or, in other cases, the upgrade of existing substations to higher voltage levels is recommended.
- In order to improve network flexibility and reliability, national Grid Codes should define all relevant requirements that newly connected RES power generating units should fulfill. This includes the provision of ancillary services such as balancing and frequency regulation, as well as voltage and reactive power regulation which improves security and enables flexibility in achieving optimum network operation.

Further, more detailed conclusions can be found in chapter VI.

II. INTRODUCTION

The large-scale exploitation of renewable energy sources poses challenges for electricity system operations, requiring higher levels of back-up capacity and additional sources of flexibility. Currently, market designs are primarily based on short-run marginal costs (SRMC) or energy costs. There is a risk the SRMC may fail to deliver the necessary level of flexibility in the long term, affecting the availability of back-up capacity and ancillary services. Conventional power plants (considered the main resources of flexibility) must run at lower hours, resulting in reduced profitability while they are exposed to more changeable and variable load operating conditions. These situations trigger the need for the implementation of alternate mechanisms (e.g. capacity mechanism) necessary for the provision of the required security of supply.

Adding large-scale RES to transmission networks may increase the possibility of overloading network elements and forming bottlenecks in the High Voltage (HV) transmission networks. These conditions present difficulties, as they may require Transmission System Operators (TSO) to increase system operation costs.

As RES integration is recognized as one of the highest priorities for TSOs in the long-term, the Black Sea Transmission Planning Project (BSTP) conducted analyses that investigates the impact of large scale RES integration on market and network operations.

The objectives of the study are to analyze and quantify the impact of large-scale RES integration in the Black Sea region on both electricity networks and electricity market operations.

The results of this Study provides the following benefits for the BSTP members:

1. Optimizing regional generation
2. Improving utilization of the internal and cross-border grids
3. Anticipating needed network and interconnection investments
4. Recognition of the RES impact on the wholesale power prices and conventional generation
5. Showcasing the potential for considerably lower emissions
6. Eliminating seams and increasing resilience

The Study analyzed the impact of high RES development on electricity markets and prices and how the transmission grid will need to adapt – both internally within the BSTP member countries and between them - to successfully integrate these resources with a two phased approach:

1) An assessment of the changes in the regional electricity market, as they add a rapidly growing share of RES; and
2) An assessment of the network impacts of RES development, including where congestion may arise and where new transmission network elements may be required.

The market analysis carried out hourly simulations of the power system and provides results for each hour of the year. The network forecast focuses on snapshots of the grid operations at moments when the networks could be under stress. The analyses were conducted for the forecasted target year 2030.

The market analysis enables the BSTP members to assess and understand the impact of large-scale RES integration on wholesale market prices, the energy mix, country balances, cross-border energy exchanges, CO_2 emissions and congestion costs.

The network analysis enables the BSTP members to better understand the effects of large-scale RES integration impact on load flows, voltage profiles, secure grid operations and congestion in the regional transmission network.

Upon completion of the Study, the network and market models (in Antares and PSS/E forms) will be transferred to the BSTP members.

II.1 Organization of the Report

This Final Report (FR) consists of five chapters:

Chapter 2: Introduction

Chapter 3: Proposed methodological approach and scenarios

Chapter 4: Market: Modeling, Analyses and Results

Chapter 5: Network: Modeling. Analyses and Results

Chapter 6: Conclusions

Chapter 7: List of References

Review of the market input data sets and review of the initial network models are given in Appendices.

III. PROPOSED METHODOLOGICAL APPROACH AND SCENARIOS

This Chapter presents the summary of the applied methodology and description of the analysed Scenarios. More information can be found in Interim Report.

This study methodology builds upon previous BSTP Studies and the agreed scope related to the impact of large scale RES.

III.1 Methodological Approach

The methodology is divided into two sections:

1. Market Analysis
2. Network Simulations

The electricity market simulations for the future time horizon include seven main drivers:

1. Electricity demand level
2. Hydrological conditions
3. **RES generation capacities**
4. Non-RES (conventional generation) generation capacities
5. Fuel prices (gas, coal)
6. CO_2 emission prices
7. Available transmission interconnection capacities

These drivers are not fully independent, but rather mutually related.

The primary focus of this Study is the analysis of the integration of large-scale RES and its impact on the electricity markets and network operations in the Black Sea region. Therefore, the Study focuses on RES generation capacities while other influential drivers are kept at a constant in all analyzed scenarios (when applying the expected, referent values).

For each BSTP member country, two levels of large-scale RES are modelled and analyzed:

- referent RES capacities
- high RES capacities

The referent level of RES integration value is sourced from BSTP member documents, such as the transmission network development plans or national energy strategy of national energy and climate plans (NCEP). Furthermore, the RES projects are formally verified by the BSTP members through grid connection agreements, connection consents, or connection requests.

The High-RES scenario is defined as large-scale RES integration, including RES projects that are under development or under potential evaluation but are not yet formally approved or registered by the TSO. As each BSTP member approaches actual and planned RES projects differently, the Consultant added variant RES inputs based on location, size and total installed capacity for the ten year timeframe analyzed in this study.

A breakdown of the methodology is shown in the following figure:

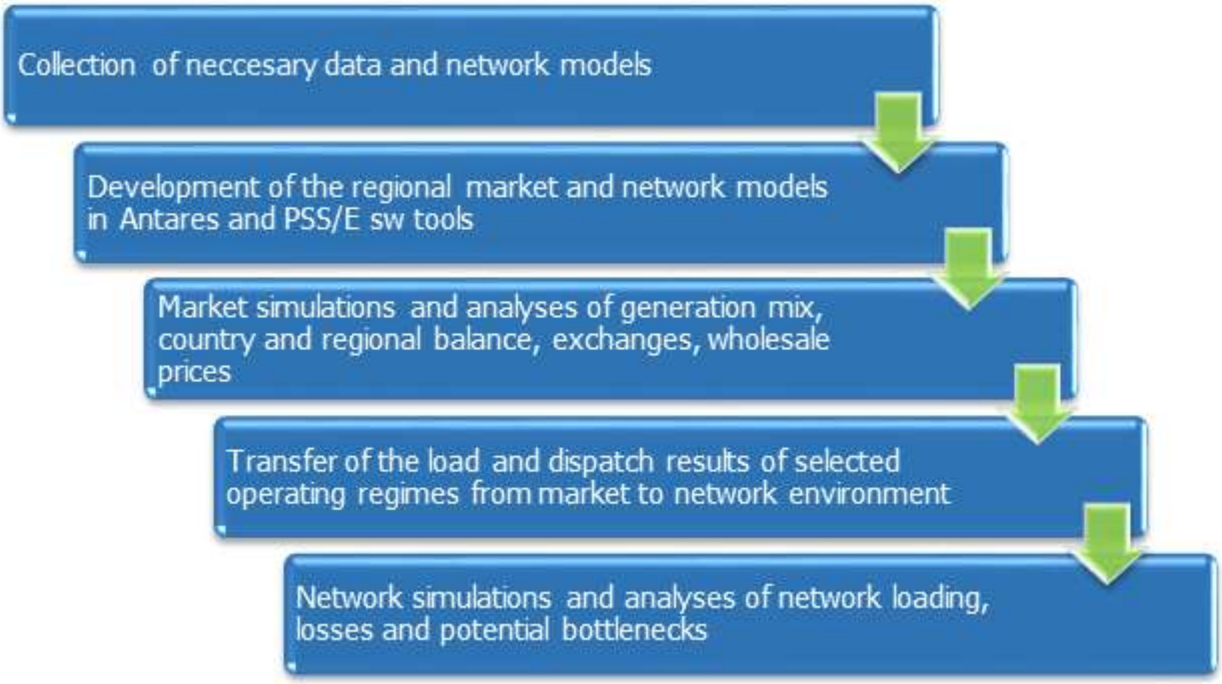

Figure 2: Study methodology approach

The modeling included two phases for the 2030 planning horizon:

- Creation of the regional BSTP market model in the Antares Software Tool, encompassing relevant parts of the "outside" markets (Europe, Central Asia, IPS/UPS);
- Merging of the individual network models into a regional network model, including expected system generation patterns, load changes and network topology.

The market simulations ran on an hourly basis, providing 8760 hourly results and the impact of variant RES levels on the the following indicators:

- Impact on market prices: wholesale day-ahead market prices for the region as well as on the country level
- Impact on the generation mix: changes in the electricity generation mix by country and the region for time horizon 2030
- Impact on carbon emissions: changes in thermal generation and total carbon emissions

- Impact on commercial exchanges: level of imports and exports at the country and regional level

After the market simulations were complete, the Consultant selected characteristic market results and transited them to the network model (step 4). Among a series of 8760 market simulation results, several of the most indicative snapshots from the network operation perspective (network element loading, voltage profiles or system security) were selected and transferred to the network simulation software PSS/E. The characteristic market results were selected based on the scenarios as described in the following subchapter.

In the network analyses, the following four outputs have been obtained:

1. Load flows in the transmission networks;
2. Voltage profiles on all transmission network nodes;
3. Transmission network losses per country and on the regional level;
4. Security analyses (N-1) and detection of the network bottlenecks.

After completion of the five step approach, the developed market and network models will be transferred to the BSTP members and an advanced training course on the Antares software application will be conducted by the Consultant.

III.2 Proposed Scenarios

To analyze and quantify the impact of large-scale RES integration on regional electricity markets, the Consultant analysed the target level of RES penetration (referent RES case) and the higher RES integration scenario (e.g. 25% higher than the referent one) for each member country. Utilizing the Monte Carlo approach in the Antares Software Platform, the system operations were simulated in several Monte Carlo years by combining different climatic conditions, hydrology and random distribution of thermal power plant unavailability. Monte Carlo "years" (30) were developed as a combination of 10 climatic years (related to climatic years 2006-2015), 3 hydrological conditions (average, dry, wet) and random availability of thermal units.

The analysed market scenarios are presented in Figure 3:

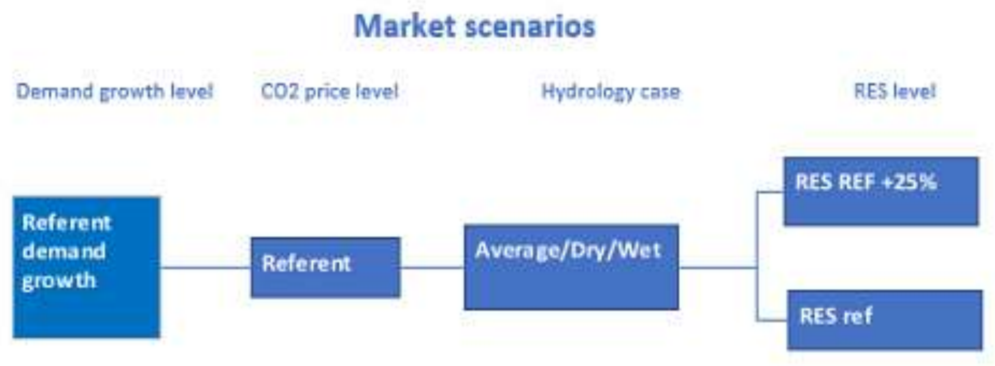

Figure 3: Market scenarios analysed in the Study

The Antares Model tested the changes in market prices, cross-border flows, generation mix, CO2 emissions and other factors associated with substantial growth in RES deployment by target year 2030. The hourly dispatch results obtained as market model simulations (Figure 4) served as input for network simulations of operational regimes of interest.

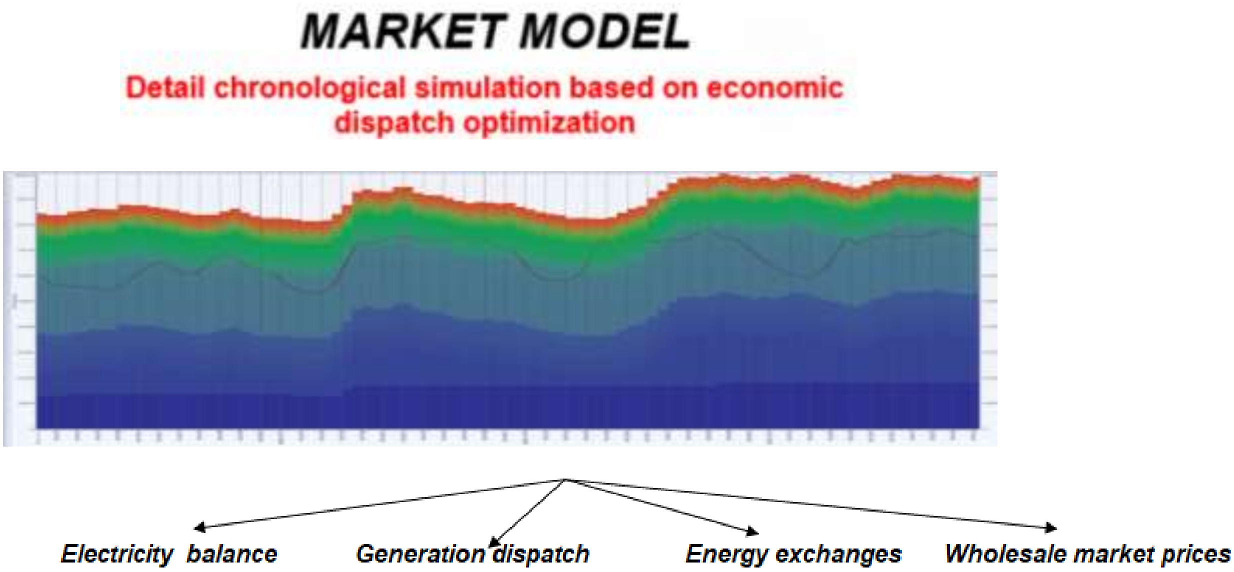

Figure 4: Market simulations results

In addition to the market scenarios, the network analysis scenarios were developed to assess the impact of large-scale RES on the transmission network operations in different regimes. The network scenarios were developed using three main criteria: 1) Base cases; 2) Load/RES level; and 3) Network availability (all (n) elements available and n-1 elements available).

As shown in the following chart, two groups of network scenarios have been analyzed: 1) Referent level of RES integration; 2) High RES integration scenario that is 25% higher than the referent or determined by the BSTP members.

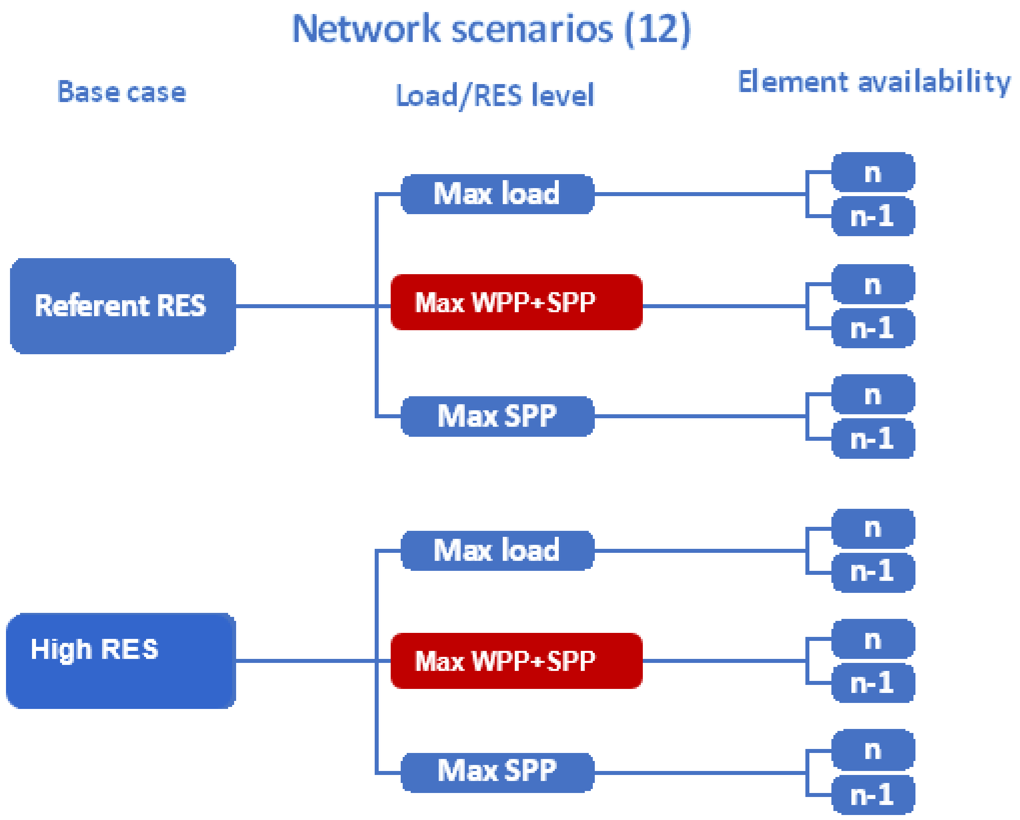

Figure 5: Network regimes analysed in the Study

For each scenario, three regimes were analyzed:

1) **Max load regime:** Winter maximum load regime model + load and generation dispatch taken from market simulation results for third Wednesday in January 2030 at 18:00 CET
2) **Max WPP+SPP regime:** Summer maximum load regime model + load and generation dispatch taken from market simulation results for the hour in which maximum of the sum of wind and solar generation is realized
3) **Max SPP regime:** Summer maximum load regime model + load and generation dispatch taken from market simulation results for the hour in which maximum of the solar generation is realized

The Consultant ran contingency analyses, with: 1) all network elements available (n), (2) one key element out of operation (n-1).

The number of scenarios is higher for the network analyses than for the market analyses as the network analyses includes an additional set of scenarios related to network element availability. One set of network scenarios is made under the assumption of full availability of all network elements, while the other one is analyzed with one-by-one network elements unavailable (so called n-1 security criterion). These scenarios are based on all network codes the transmission network must employ to operate without any limitation in case one element is unavailable. In other words, an outage or the maintenance of any single network element should not cause any problem in transmission network operations.

These scenarios provided a wide range of network conditions based on RES and load levels, generation output and network availability. As the inputs are uncertain, this approach identifies many if not all potential bottlenecks in the network for target year 2030, regardless of their probability.

In all analyzed scenarios with referent and high RES penetration, certain assumptions are the same, including: existing and planned conventional generation capacities in the region with detailed technical and economic inputs, CO_2 taxes and fuel prices, cross-border transmission capacities and prices on external electricity markets. The impact of variable climatic conditions that refer to load and RES generation, impact of variable hydrological conditions as well as availability of thermal units are analyzed through the Monte Carlo market simulation approach. For detailed network simulations, the selection of the relevant regimes also encompassed the selection of the climatic year.

IV. MARKET: MODELING, ANALYSES AND RESULTS

IV.1 Input data and modeling approach

The development of the BSTP market modeling database has been comprised of the following:

- ✓ Definition of the relevant input data needed for the market analyses on the regional level in the selected software tool – Antares[1]
- ✓ Collection of input data for target year 2030 from the BSTP member TSOs through a comprehensive spreadsheet
- ✓ Clarification of any missing input data and suggestions for solutions, including sources such as TYNDP, MAF and other publicly available sources, as well as the Consultants' databases

The Study employed the following approach to model the BSTP power systems and neighboring areas:

- The Armenian, Bulgarian, Georgian, Moldovan, Romanian and Ukrainian power systems have been represented on a plant-by-plant level, with demand and non-dispatchable generation modeled on an hourly level.

- The Turkish power system has been modeled by technology clusters (hydro by type, thermal by fuel type, nuclear, RES), with demand and non-dispatchable generation modeled at an hourly level. The Turkish data has been provided by Turkish TSO after Interim Report was finalized and they are presented in the Appendix of this Report.

- The neighboring power systems in EE and SEE have been modeled with different levels of detail (per plant or per technology), while distant zones (CE – Germany & Austria) modeled as spot markets (in which the market price is insensitive to fluctuations of prices in the Black Sea region) and constrained by cross-border transmission capacity (see chapter 1.5).

- Commercial exchanges with the IPS/UPS and Belarussian systems have not been simulated.

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[1] Antares – probabilistic software tool for simulation of power system operation based on day-ahead market principles, developed by RTE (French TSO).

- Central Asia has been included in the model, as envisaged export under the "gas-for-electricity" agreement (1,218 GWh at annual level).

The following are the technical and economic parameters included in the 2030 market model:

1. Thermal Power Plants (TPPs)

- General data (plant name, number of units, fuel type)
- Operational status for each unit for target year 2030
- Maximum net output power per unit
- Minimum net output power per unit
- Heat rates at maximum net output power per unit
- Fuel costs per unit
- Variable O&M costs per unit
- Outage rates (FOR, MOR) and maintenance periods per unit
- CO_2 emission factors per unit
- Operational constraints (minimum up/down time) per unit
- Must-run constraints per unit

2. Hydro Power Plants (HPPs)

- General data (plant name, number of units)
- Operational status for each unit for target year 2030
- Plant type (run of river, storage or pumped storage plant)
- Maximum net output power per unit
- Minimum net output power per unit
- Biological minimum production
- Maximum net output power per unit in the case of pumped storage plants
- Minimum net output power per unit in case of pumped storage plants
- The efficiency of pumped storage plants
- Monthly generations for 3 hydrological conditions: average, dry and wet

3. Renewable Energy Sources (RES) for Referent and High Scenario

- Installed capacities (solar)
- Installed capacities (wind)
- The hourly capacity factor for 10 characteristic climatic years: 2006-2015 (solar)
- The hourly capacity factor for 10 characteristic climatic years: 2006-2015 (wind)

4. Demand in Referent Scenario

- Annual consumption expected in 2030 (TWh)
- Hourly load profiles for 10 characteristic climatic years: 2006-2015

5. Network Capacity

- NTC values applied as cross-border limits for energy exchange

For any unavailable data, the Consultant applied other verified and publicly available official data, data from previous BSTP studies in addition to the consultants' documents and estimates. The data inputs primarily originate from the TYNDP and MAF datasets available at ENTSO-E platform.

The nine subsections below describe the data-gathering approach and modeling inputs in support of the analysis. They include the following: load, wind and solar profiles, hydro power plant generation, thermal power plants, fuel and CO_2 prices and the impact of neighboring power systems.

IV.1.1 Load, Wind and Solar Hourly Profiles

The expected annual demands were provided by the member TSOs. If the TSOs could not provide hourly load profiles for 10 climatic years, the Consultant utilized hourly load profiles from previous BSTP studies.

For the referent RES scenarios, the Consultant applied the expected installed RES capacities, provided by the TSOs. In case if TSO did not provide installed capacities in wind and solar power plants for high RES scenario, consultant applied capacities that are 25% higher than referent ones.

For all zones outside BSTP regiona and in cases when TSO did not provide wind and/or solar hourly capacity factors, the Consultant applied data from previous BSTP studies, which are based on publicly available databases from ETH Zurich[2].

IV.1.2 Generation from Hydro Power Plants (HPPs)

Each BSTP TSO provided generation input at least for the average hydrological conditions on an annual level.

If monthly generation in different hydrological conditions were not provided, the Consultant estimated generation based on the generation of similar HPPs. If the only data available is for average hydrology, dry and wet generations are estimated based on previous BSTP studies.

IV.1.3 Technical and Economic Parameters – Thermal Power Plants

Unless otherwise specified in the data gathering spreadsheet, the Consultant applied general technical and economic parameters for all TPPs, as shown in the following tables (Table 1 and Table 2).

[2] https://www.renewables.ninja/

Table 1: General technical and economic parameters for TPPs from TYNDP 2018 common base

Category #	Fuel	Type	Efficiency range in NCV terms	Standard efficiency in NCV terms	CO_2 emission factor	Variable O&M cost	Min Time on	Min Time off	Heat Rate (GJ/MWh)
			%	%	kg / Net GJ	Euro/MWh	hours	hours	%
1	Nuclear	-	30% - 35%	33%	0	9	12	12	10.9
2	Hard coal	old 1	30% - 37%	35%	94	3.3	8	8	10.3
3		old 2	38% - 43%	40%		3.3	6	6	9.0
4		New	44% - 46%	46%		3.3	5	5	7.8
5		CCS	30% - 40%	38%	9.4	6.6	7	7	9.5
6	Lignite	old 1	30% - 37%	35%	101	3.3	11	11	10.3
7		old 2	38% - 43%	40%		3.3	9	9	9.0
8		New	44% - 46%	46%		3.3	8	8	7.8
9		CCS	30% - 40%	38%	10.1	6.6	10	10	9.5
10	Gas	conventional old 1	25% - 38%	36%	57	1.1	5	5	10.0
11		conventional old 2	39% - 42%	41%		1.1	5	5	8.8
12		CCGT old 1	33% - 44%	40%		1.6	3	3	9.0
13		CCGT old 2	45% - 52%	48%		1.6	3	3	7.5
14		CCGT new	53% - 60%	58%		1.6	2	2	6.2
15		CCGT CCS	43% - 52%	51%	5.70	3.2	4	4	7.1
16		OCGT old	35% - 38%	35%	57	1.6	1	1	10.3
17		OCGT new	39% - 44%	42%		1.6	1	1	8.6
18	Light oil	-	32% - 38%	35%	78	1.1	1	1	10.3
19	Heavy oil	old 1	25% - 37%	35%	78	3.3	3	3	10.3
20		old 2	38% - 43%	40%		3.3	3	3	9.0
21	Oil shale	old	28% - 33%	29%	100	3.3	11	11	12.4
22		new	34% - 39%	39%		3.3	8	8	9.2

Table 2: Additional technical parameters for TPPs from TYNDP 2018 common base

Category #	Fuel	Type	Unavailability				Minimum stable generation
			Forced outage		Planned outage		
			annual rate	Mean time to repair	annual rate	winter	
			%	Days	number of days	% of annual number of days	(% of max power)
1	Nuclear	-	5%	7	54	15%	50%
2	Hard coal	old 1	10%	1	27	15%	43%
3		old 2	10%	1	27	15%	43%
4		new	7.50%	1	27	15%	43%
5		Lignite CCS	7.50%	1	27	15%	43%
6	Lignite	old 1	10%	1	27	15%	43%
7		old 2	10%	1	27	15%	43%
8		new	7.50%	1	27	15%	43%
9		Hard coal CCS	7.50%	1	27	15%	43%
10	Gas	conventional old 1	8%	1	27	15%	35%
11		conventional old 2	8%	1	27	15%	35%
12		CCGT old 1	8%	1	27	15%	35%
13		CCGT old 2	8%	1	27	15%	35%
14		CCGT new	5%	1	27	15%	35%
15		CCGT CCS	5%	1	27	15%	35%
16		OCGT old	8%	1	13	15%	30%
17		OCGT new	5%	1	13	15%	30%
18	Light oil	-	8%	1	13	15%	35%
19	Heavy oil	old 1	10%	1	27	15%	35%
20		old 2	10%	1	27	15%	35%
21	Oil shale	old	10%	1	27	15%	40%
22		new	7.50%	1	27	15%	40%

IV.1.4 Fuel and CO_2 Prices

As most member TSOs were unable to provide exact numbers for fuel and CO_2 prices, the Consultant applied consistent and comparable values for the analyzed countries and market areas. The Consultant applied the 2030 fuel prices from the TYNDP 2020 database (Table 3), with the exception of Georgia and Armenia, where fuel prices were taken from the BSTP Armenia-Georgia sub-regional Study.

Table 3: Fuel and CO_2 prices in 2030 from TYNDP 2020

		2020	2021	2023	2025		2030			2040		
					BE	G2C	NT	DE	GA	NT	DE	GA
€/GJ	Nuclear	0.47	0.47	0.47	0.47		0.47			0.47		
	Lignite	1.1	1.1	1.1	1.1		1.1			1.1		
	Oil shale	2.3	2.3	2.3	2.3		2.3			2.3		
	Hard Coal	3.0	3.12	3.4	3.79		4.3			6.91		
	Natural Gas	5.6	5.8	6.1	6.46		6.91			7.31		
	Light Oil	12.9	14.1	16.4	18.8		20.5			22.2		
	Heavy Oil	10.6	11.1	12.2	13.3		14.6			17.2		
€/tCO_2	CO_2 price	19.7	20.4	21.7	23	56	27	53	35	75	100	80

Table 5: Fuel prices in TYNDP 2020 scenarios

To input the CO_2 price, the Consultant used 27 €/t$C0_2$, the same amount as described in the TYNDP 2020 National Trends (NT)[3] scenario analyzed in the TYNDP 2020.

The CO_2 price must be applied for all EU member states. Concerning non-EU countries, the Consultant applied the same CO_2 tax in the Turkey, Ukraine and Moldova. This is applied with the expectation that by 2030, Ukraine and Moldova will be fully synchronized into the ENTSO-E and that there will be key requirements from the EC or EnC related to the CO_2 emission reductions, which will refer to Turkey as well. However, implementation of CO_2 tax in Georgia and Armenia is not expected.

[3] The central policy scenario of TYNDP 2020, recognizing national and EU climate targets, notably the draft National Energy and Climate Plans (NECPs)

IV.1.5 Neighboring Power Systems

This Study considers seven power systems in the Black Sea Region. These power systems are modeled on a plant-by-plant level of detail[4], with a simplified representation of the transmission network.

In order to achieve better modeling accuracy and to adequately model the exchange of electricity between the Black Sea region and neighboring power systems, it was important to include them in the wider regional market model.

The Study considered three approaches to model the neighboring systems:

- "Plant by plant" or technology cluster level of modeling for the SEE and EE countries
- Distant market zone (Central Europe) modeled as a power exchange
- Forecasted electricity exchange, in the case of Central Asia

The following is a detailed explanation of each approach:

IV.1.6 Technology Clusters or "Plant by Plant" Level of Modeling

The BSTP model includes neighboring market zones in Eastern and South Eastern Europe (Poland, Slovakia, Hungary, Serbia, Montenegro, Croatia, Slovenia, Bosnia & Herzegovina, North Macedonia, Albania, Greece) that are modeled with varying levels of detail:

- Demand: total demand is defined at the hourly level and modeled with one demand center per country;
- Conventional generating units (TPP, NPP, HPP, PSHPP): per power plant or technological clusters, with corresponding technical and economic parameters (min and max capacity, operating costs, availability, available weekly generation for hydro power plants, other operating constraints, etc.);
- Renewable sources (wind, solar, biomass): total capacity per technology + generation at the hourly level with hourly profiles that correspond to available capacity factors, this generation is treated as "must run";
- Interconnection grid constraints with neighboring systems: defined as NTCs taken from TYNDP database.

All of the data listed above is sourced from the ENTSO-E TYNDP databases.

IV.1.7 Distant Market Modeled as Power Exchange

For distant market zones, such as Central Europe, wholesale market prices were applied for 2030 from the TYNDP 2020 Scenario Report, which contains average yearly marginal cost indicators for

[4] With the except of Turkey, which has been modeled at the technology cluster level

the ENTSO-E. That average yearly price is used to scale the different prices presented in the TYDNP 2018 for each market separately. Table 4 shows the assumptions for average yearly prices on the modeled external market.

Table 4: Average 2030 yearly price on external market

Market	Average Annual Marginal Price (€/MWh)
Central Europe	32

In order to model the variation of hourly prices throughout the year, a time series of observed market prices in the respective electricity markets for the last three years are applied to create an hourly profile. Therefore, the hourly profile of electricity prices for Central Europe were based on the observed market prices from 2017 to 2019 on the European Energy Exchange (EEX), i.e. EPEX SPOT prices for Germany and Austria.

IV.1.8 Forecasted Electricity Exchange (Armenia – Central Asia)

Armenia does not produce domestic gas and relies on imports from Russia. In addition to its supply from Russia, there is also a gas supply from Centra Asia. Armenia is contractually obligated to deliver 3 kWh of electricity for each cubic meter of gas coming from Central Asian partner. In 2017, as a part of the "gas-for-electricity" swap agreement, Armenia exported 1218 GWh to its Central Asian partner and it is assumed this arrangement will continue until 2030.

Central Asia is included in the BSTP model, as envisaged export under the "gas-for-electricity" agreement (1,218 GWh at the annual level).

IV.2 Summary of the input data for all countries

This chapter reviews the expected status of all power systems for the target year 2030, in alphabetical order, along with an overview of the data, assumptions and proxies that are used to develop the corresponding model in the Antares Software Tool.

All relevant parameters were presented within Interim Report, in order to enable each BSTP member to verify their plausibility and confirm their usability for upcoming forecasts and analyses. Review of the agreed and verified data for each BSTP member are presented in Appendix.

Several tables with overview of the expected development of consumption and generation per different technologies are presented below:

Table 5: Referent demand growth

BSTP Member	Demand in 2017/2018 (TWh)	Referent scenario	
		Growth rate from 2018 to 2030	Demand in 2030 (TWh)
AM	6.20	1.71%	7.70
BG	34.10	0.76%	37.35
GE	13.65	5.00 %	23.34
MD	6.06	1.09%	6.90
RO	57.90	0.81%	63.50
UA	149.13	1.05%	169.00
TR	301.00	2.7%	414.00
TOTAL	**571.04**	**2.01%**	**721.79**

Average consumption growth rate is around 2% although majority of the countries have the rate around 1% or less. The reason is obvious impact of high rate in Turkey which has a consumption higher than the sum of consumption in all other BSTP members. This impact is also visible at the following Figure 6.

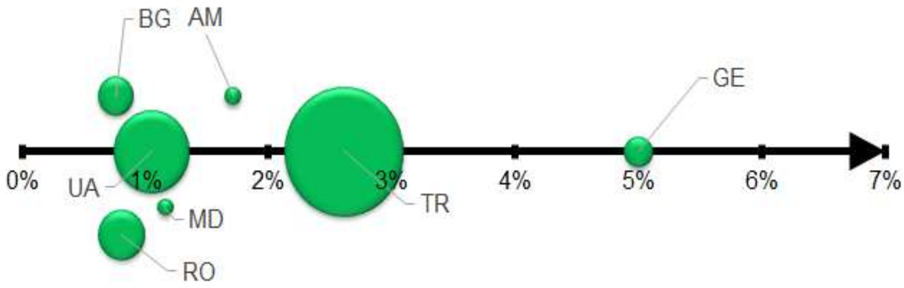


Figure 6: Consumption growth rates

The next four tables summarize the changes expected across BSTP market areas in installed generation capacities per technology from 2018 to 2030.

As Table 6 indicates, significant increase in wind power capacity in the coming decade could be expected. Increase is in the range of 16842 MW to 21175 MW (referent vs high RES scenario), which is 2.5 to 3.1 times more in WPPs than in 2018. In a number of cases, in the 2018 starting point, installed wind generation was zero or near zero. The largest growth of WPP capacities in absolute terms by 2030 is expected in TR (more than 11,000 MW) while in relative terms, the largest growth is anticipated in GE and MD where practicaly no capacity is present currently.

Table 6: Installed wind power plant (WPP) capacities

BSTP Member	**Total WPP installed capacity 2018 (MW)**	**Total installed WPP capacity 2030 (MW)** **Ref. / High**	**Increase from 2018 (MW)** **Ref. / High**
AM	4	20 / 50	16 / 46
BG	700	887 / 1,109	187 / 409
GE	21	1,300 / 2,500	1,279 / 2,479
MD	31	742 / 1,060	711 / 1,029
RO	2,977	4,200 / 5,100	1,223 / 2,123
UA	704	4,393 / 6,641	3,689/5,937 (>5 times)
TR	7,591	18,415/20,000	11,067/12,652 (140%)
TOTAL	**11,785**	**29,957/36,460**	**18,172/24,675**

Even more rapid development is expected in solar power capacity. There will be an additional 21244 – 31972 MW (referent vs high RES scenario) of SPPs in the region, or 2 – 3 times more than in 2018, as given in the following table. By far the largest installed SPP capacity (and almost half of the regional new SPP capacity) is expected in Turkey, followed by Ukraine. In 2030, these two market areas combined are expected to comprise 80% and 75% of SPP capacity in the region, respectively, in the referent and high RES scenarios.

Table 7: Installed solar power plant (SPP) capacities

BSTP Member	**Total SPP installed capacity 2018 (MW)**	**Total installed SPP capacity 2030 (MW) Ref. / High**	**Increase from 2018 - 2030 (MW) Ref. / High**
AM	19	1,000 / 1,200	981 / 1,181
BG	1,052	2,929 / 3,661	1,877 / 2,609 (>3 times)
GE	0	550 / 2,200	550 / 2,200
MD	3	119 / 170	116 / 167
RO	1,262	2,000 / 3,700	738 / 2,438 (>2 times)
UA	2,667	7,874 / 11,669	5,207 / 9,002 (>3 times)
TR	5,997	17,400/20,000	11,775/14,375 (>2 times)
TOTAL	**10,628**	**31,872/42,600**	**21,244/31,972**

The following table shows expected changes in total installed hydro capacity by 2030. All BSTP members, except BG and MD, are planning to increase total HPP capacity. The most significant changes in the period 2018-2030, in absolute terms, are expected in Turkey. On the level of the entire region, total increase in installed HPPs capacity will be significant, but almost all changes are expected in Turkey. It should be also noted that capacity of PS HPPs in the region will increase, especially in GE and UA. There is new PS HPPs of 570 MW planned to be in operation in Georgia in 2030, while in Ukraine, new 1329 MW in pump-storage HPPs will be added to existing 1509 MW.

Table 8: Installed hydro power plant (HPP) capacities

BSTP Member	**Total HPP installed capacity 2018 (MW)**	**Total installed HPP capacity 2030 (MW)**	**Increase from 2018 - 2030 (MW)**
AM	1,335	1,470	135
BG	3,207	3,207	0
GE	3,070	6,271	3,201 (100%)
MD	61	61	0
RO	6,420	6,742	308
UA	4,704	4,842	138
TR	28,499	37,064	8,565 (30%)
TOTAL	**46,725**	**62,035**	**15,296**

Finally, the following table here shows expected changes (both positive and negative) in total installed capacities in thermal power, including nuclear power plants from 2018 to 2030. Four BSTP members are planning to decrease total TPP capacity while increase is expected in GE, RO and TR. The most significant change in this period, in absolute terms, is observed in Ukraine. Ukraine plans to decommission more than 14,000 MW of TPPs (coal fired units) by 2030. On the other hand, the largest TPP increase, in absolute terms, is expected in Turkey with a capacity increase of almost 2,000 MW, mainly due to increase of 4,500 MW in nuclear capacity.

Table 9: Installed thermal power plant (TPP) capacities

BSTP Member	**Total TPP installed capacity 2018 (MW)**	**Total installed TPP capacity 2030 (MW)**	**Increase from 2018 - 2030 (MW)**
AM	1,600	1,440	-160
BG	7,442	7,269	-173
GE	925	1,119	194
MD	2,648	2,643	-5
RO	8,198	8,635	437
UA	34,602	19,881	-14,721 (-40%)
TR	46, 862	55,140	8,278
TOTAL	**104,324**	**92,337**	**-11,987**

Changes from 2018 to 2030 are significant in almost all power systems. However, dominant installed generation capacity will remain in TPPs and HPPs, around 40% in TPPs and 30% in HPPs.

WPPs and SPPs installed capacity share in BSTP region will increase from 13% to 30% with almost same share in WPPs and SPPs. Looking at each BSTP member, in some cases starting from almost zero share in 2018, share in WPPs and SPPs will reach similar level in all countries in 2030, around 25-30%.

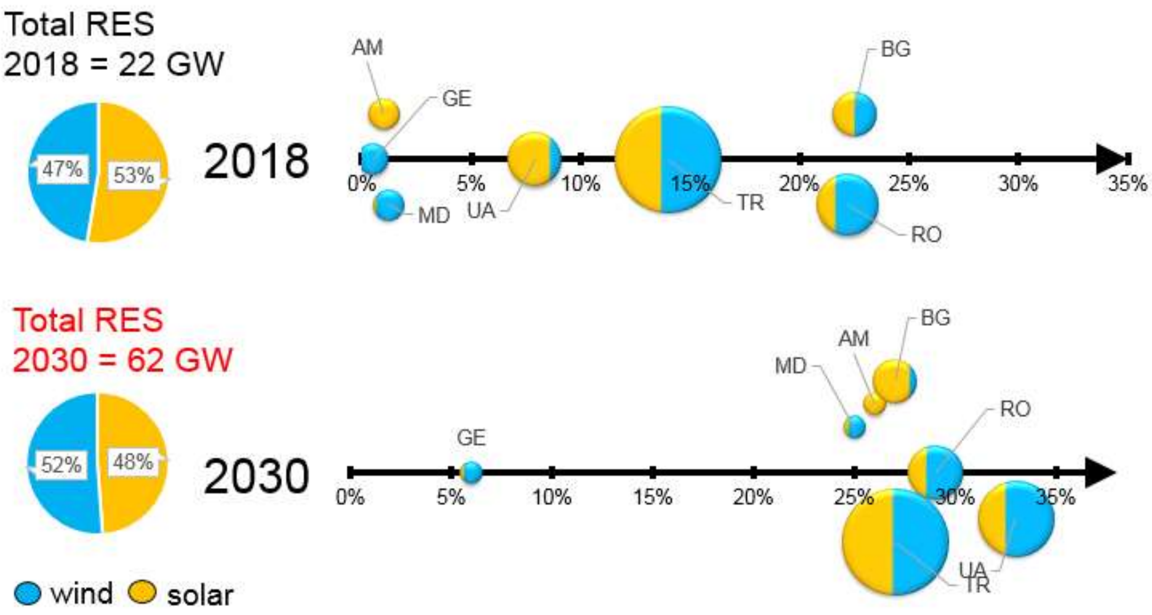


Figure 7: Monthly energy consumption (GWh) for 2030 – Armenia

IV.3 Results of the market simulations

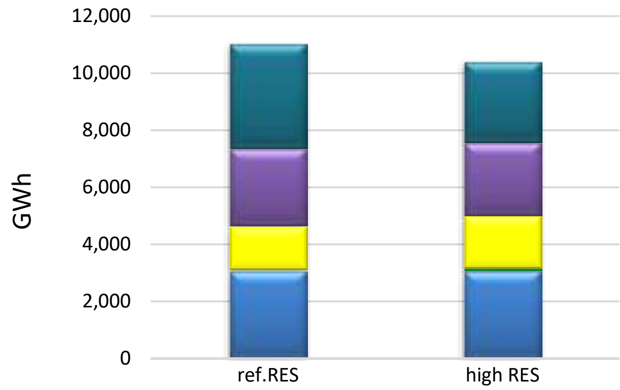
Market results are obtained for two different scenarios, ref. RES and high RES, as it is described in chapter II.2. In short, ref. RES represents a scenario with the expected RES development in 2030, while high RES represents a scenario with the higher RES penetration, either given by the TSO or estimated as +25% of the increase in comparison with the referent scenario. For both analyzed scenarios following results are presented:

- Overview of main system operating indicators
- Generation mixes and consumptions
- Generation of fossil fuel-fired TPPs
- CO2 emissions
- Spillages
- Net interchanges
- Prices

Each of the listed results is presented per each BSTP country, and for both scenarios, in side by side manner in order to facilitate comparison of results.

IV.3.1 Armenia

Generation mix and selected set of indicators, as the main results of market analysis for Armenia, are presented in Figure 8 and Figure 9, respectively.



	ref.RES	high RES
Other	0	0
Gas	3679	2850
Coal	0	0
Lignite	0	0
Nuclear	2715	2564
Solar	1537	1844
Wind	37	92
Hydro	3084	3084
Consumption	7730	7730

Figure 8: Generation mix of Armenia in 2030 – ref. RES vs high RES

By observing results from Figure 8 in conjunction with indicators shown in and Figure 9, the following can be concluded for Armenian power system operation in 2030 in high RES scenario in comparison with ref. RES scenario:

- RES generation will be increased from 1.6 TWh in ref. RES scenario to almost 2TWh in high RES scenario (+23%).

- At the same time generation from fossil fuel fired TPPs will be decreased from 3.7 TWh to 2.9 TWh (-13%). With this, CO2 emission will be also decreased from 1.55 mil.T CO_2 to 1.16 mil.T CO_2 (-25%).

- With greater RES generation, spillages will be increased from 0.1 TWh to 0.4 TWh. It should be noted that RES generation increase of around 0.4 TWh will lead to a spillage increase of around 0.3 TWh as result. This means that almost all additional generation from RES would be curtailed, which should not be allowed.
  A situation like this points to the need for more detailed analyses that should be done with the aim to find the measures and potential solutions in the provision of the flexibility to the system (storages, regional market integration, balancing cooperation,…) before putting in operation this high level of RES capacities.

- Additional RES generation and spillages will lead to a decrease in prices from 33.7 $/MWh to 22.7 $/MWh, either due to the engagement of less expensive TPPs or due to zero prices during hours with spillages.

- Although prices will decrease, the export will be also decreased from 3.2 TWh to 2.3 TWh (-29%). This drop of around 0.9 TWh is almost the same as the decrease in fossil fuel TPP generation. Having in mind that Armenia could export electricity only to Georgia and Central Asia (limited to 1.2 TWh) and that in high RES scenario Georgia would also increase export and decrease prices, the reason for Armenian export decrease could be found in the fact that in high RES scenario, Armenian TPPs will be less competitive.

In Armenia, an increase of around 0.4 TWh of RES generation will be allocated almost entirely to increase of spillages (around 0.3 TWh) which will provoke a decrease in prices. In high RES Scenario, there is a high excess of generation in Georgia and Armenian power plants become less competitive than in ref. RES scenario, which leads to a decrease in TPPs generation and a decrease in export of around 1 TWh.

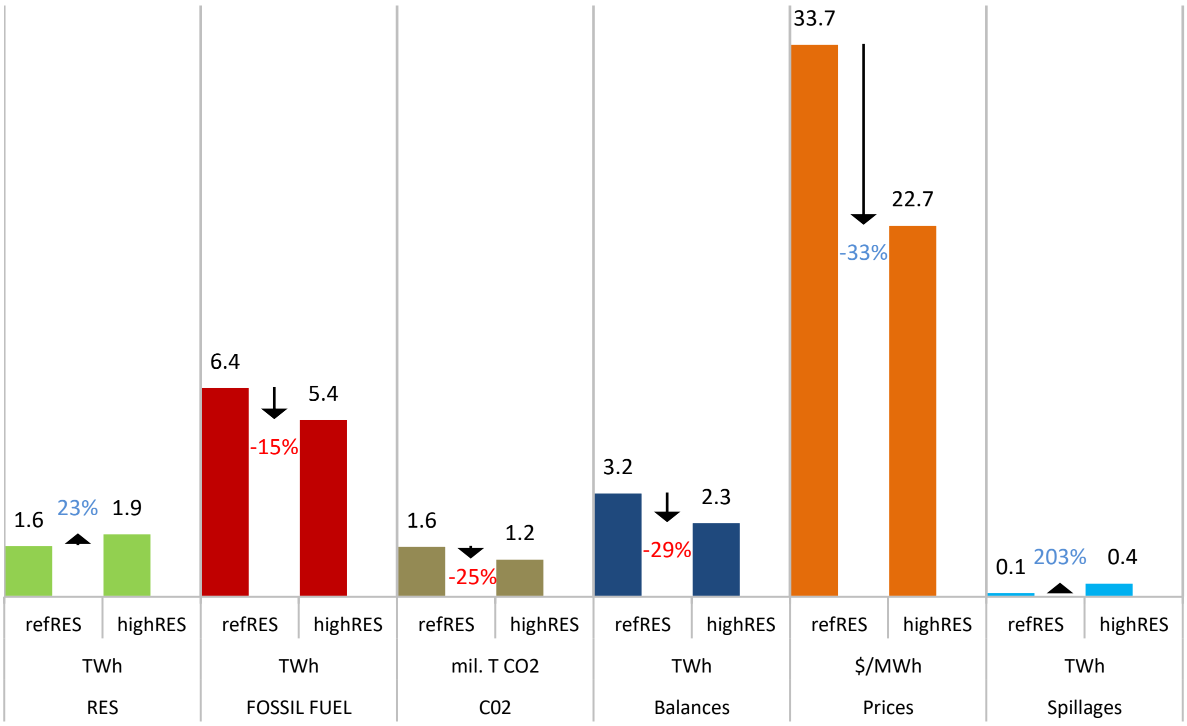
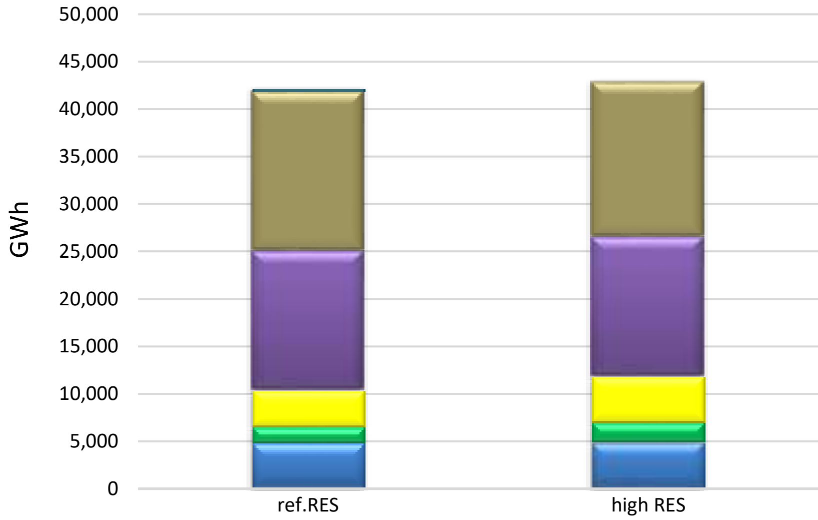


Figure 9: Main system operating indicators in Armenia in 2030 – ref. RES vs high RES

Having in mind that additional RES capacities, besides the needs for flexibility, also increase the needs for balancing reserve, we checked if the estimated required reserve (FCR+FRR[5]) can be satisfied with unengaged capacity in TPPs and HPPs with storages. In the case of Armenia, the required balancing reserve of 100 MW can be provided in all hours during the year in all analysed climatic years and hydrological conditions.

IV.3.2 Bulgaria

Generation mix and selected set of indicators, as the main results of market analysis for Bulgaria, are presented in Figure 10 and Figure 11, respectively.



	ref.RES	high RES
Other	0	0
Gas	413	207
Coal	0	0
Lignite	16811	16356
Nuclear	14667	14667
Solar	3853	4816
Wind	1678	2098
Hydro	4886	4954
Consumption	36986	37076

Figure 10: Generation mix of Bulgaria in 2030 - ref. RES vs high RES

Considering the Generation mix presented in Figure 10, in conjunction with the main system indicators depicted in Figure 11, the following conclusions could be drawn about the operation of the Bulgarian power system in the high RES scenario, in comparison with ref. RES:

- RES generation will rise from 5.5 TWh to 6.9 TWh (+25%).

[5] Estimated reserve is based on balancing reserve applied in BSTP Adequacy Study from 2019, which is increased by 4% of corresponding RES increase

- Fossil fuel fired TPPs will decrease their generation from 17.2 TWh to 16.6 TWh (-4%), which will lead to a decrease of CO2 emission from 15.9 mil.T to 15.3 mil.T.

- At the same time, the export of Bulgaria will be increased from 5.3 TWh to 6 TWh (+13%). This increase of 0.7 TWh is almost equal to the difference between RES generation increase and TPP generation decrease. It means that in case of increased RES generation, part of the thermal generation fleet becomes non-competitive. Then, one part of the increase in RES generation will compensate for a decrease of TPP generation, while the other part of the RES generation increase, will lead to an increase in export.

- Higher RES capacities increase the need for flexible sources, so an increase of the PS HPPs utilization is presented in Table 10. Engagement in pumping mode is somewhat larger due to the PS HPP inefficiency.

Table 10: PS HPPs generation in Bulgaria

Generation from PS HPPs (GWh)	All hydrological conditions			Wet hydrological conditions	Average hydrological conditions	Dry hydrological conditions
	Expected[6]	Min	Max	Expected	Expected	Expected
Ref. RES	56.2	31.3	86.9	50.4	57.1	60.9
High RES	124.0	81.2	165.8	112.3	125.9	133.8
Difference	**67.8**	**49.9**	**78.9**	**61.9**	**68.8**	**72.9**

Generation from PS HPP in the high RES scenario is more than doubled in comparison with ref. RES scenario, because greater non-costly RES generation gives a higher possibility for pumping and storing energy for utilization in some other hours. Different hydrological conditions do not have a big impact on the generation of this type of HPPs.

- As a result, greater RES generation leads to a decrease in prices from 57.8 $/MWh to 55.9 $/MWh (-3%). Namely, an increase in RES generation, means that cheaper power plants become marginal.

In Bulgaria, an increase of around 1.4 TWh of RES generation will be allocated to the decrease of TPP generation (around -0.6 TWh), and increase of export (around 0.7 TWh).

[6] Expected values represent average of a set of MC years, Min and Max values represent extremes.

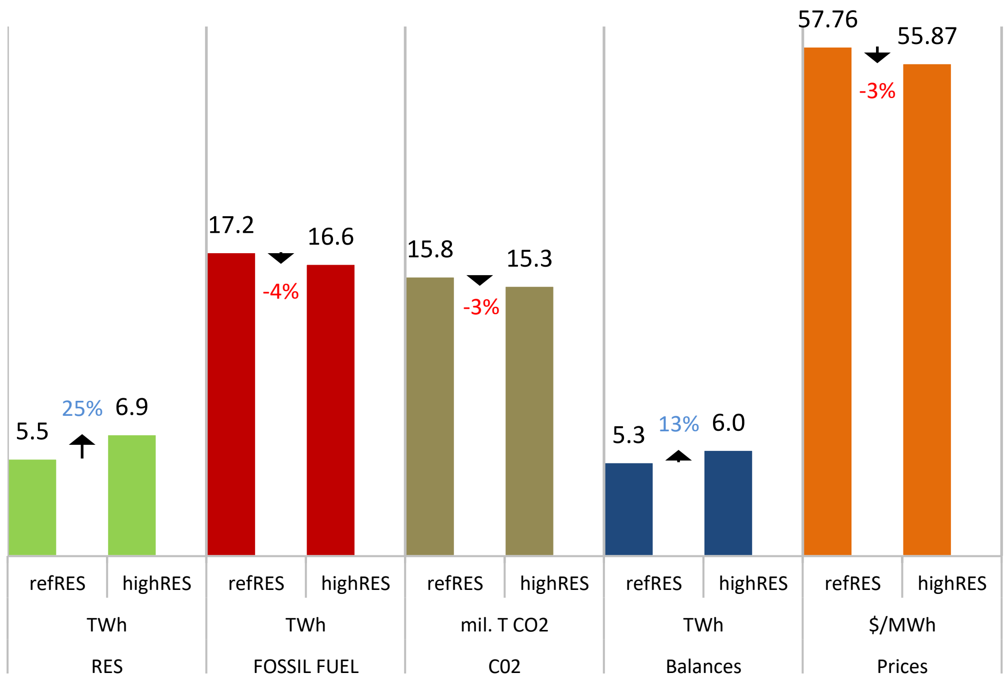
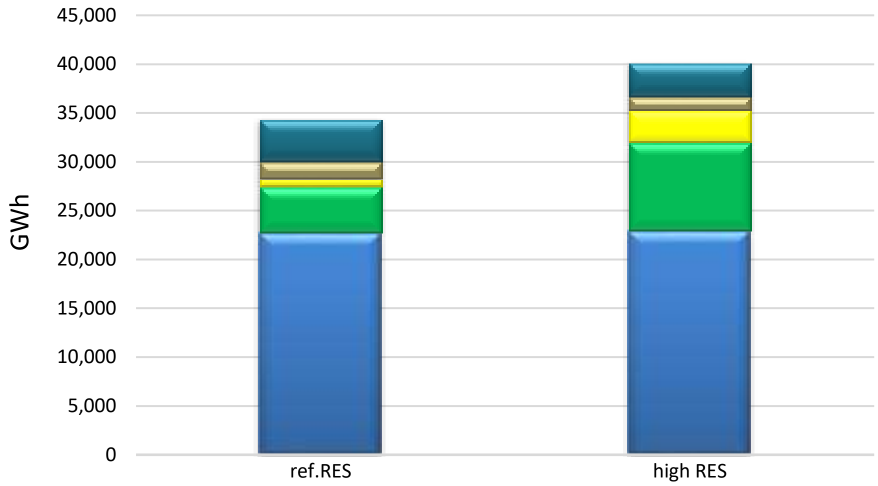


Figure 11: Main system operating indicators in Bulgaria in 2030 – ref. RES vs high RES

As in the case of Armenia, the fulfillment of the estimated required reserve (FCR+FRR) has been checked, and, in the case of Bulgaria, the required balancing reserve of 400 MW can be provided in all hours during the year in all analysed climatic years and hydrological conditions.

IV.3.3 Georgia

Generation mix and selected set of indicators, as the main results of market analysis for Georgia, are presented in Figure 12 and Figure 13, respectively.



	ref.RES	high RES
Other	0	0
Gas	4382	3469
Coal	0	0
Lignite	1730	1370
Nuclear	0	0
Solar	823	3291
Wind	4720	9078
Hydro	22735	22947
Consumption	23518	23822

Figure 12: Generation mix of Georgia in 2030 – ref. RES vs high RES

Considering the Generation mixes presented in Figure 12, in conjunction with main system indicators depicted in Figure 13 for both scenarios, conclusions regarding the operation of the Georgian power system in 2030 are as follows:

- RES generation will be more than doubled in high RES scenario in comparison with ref. RES. It will be increased from 5.5 TWh to 12.4 TWh (+123%). It should be noted that in this Study, only generation from wind and solar power plants are considered as RES generation.

- At the same time generation from TPPs on fossil fuel will be decreased from 6.1 TWh to 4.9 TWh (-21%), which will lead to a decrease in CO2 emission from 3.5 mil. T to 2.7 mil. T (-21%).

- RES generation increase of almost 7 TWh will lead to an increase in spillages/curtailment from 1.4 TWh to 3.4 TWh. This means that 2 TWh (+28%) of additional generation from wind and solar power plants would be curtailed which is too high and points to the need for more detailed analyses that should be done with the aim to find the optimal solution for the provision of additional system flexibility, before putting in operation such a high level of RES capacities.

- In these analyses, it has been assumed that in 2030 in Georgia new pumped-storage HPP will be in operation. This power plant helps the Georgian (and regional) power system in the provision of flexibility that is needed especially in scenarios with high levels of RES. regardless, the level of spillages remains high (see the previous bullet) and, in addition to this PS HPP, other solutions for flexibility provision should be investigated.

The engagement of this plant in generating (turbining) mode is presented in Table 11. Engagement in pumping mode is similar, just increased due to PS HPP inefficiency.

Table 11: PS HPP Enguri Generation

Generation from PS HPPs (GWh)	All hydrological conditions			Wet hydrological conditions	Average hydrological conditions	Dry hydrological conditions
	Expected[7]	Min	Max	Expected	Expected	Expected
Ref. RES	202.2	143.7	243.7	191.3	186.4	228.8
High RES	415.3	309.8	512.7	353.9	419.2	472.7
Difference	**213.1**	**166.1**	**269.0**	**162.6**	**232.8**	**243.9**

Generation from PS HPP in the high RES scenario is more than doubled in comparison with ref. RES scenario, because greater non-costly RES generation gives a higher possibility for pumping and storing energy for utilization in some other hours.

Its generation in average and wet hydrology is rather similar, while the maximum generation is reached in dry hydrological conditions. This is expected since in dry hydrological conditions, the system operates in a more variable manner, with higher maximums and lower minimums of generation from HPPs, which generate higher needs for PS HPP engagement.

- Increase of RES generation and spillages will lead to a decrease in prices from 34.6 $/MWh to 23.1 $/MWh (-33%) because with higher RES generation cheaper plants will become marginal and with more hours with spillages, more hours will have a price of 0 $/MWh, which decreases the value of the average annual price.

- Additional generation from RES and decreased prices will enable an increase of export which will rise from 9.5 TWh to 13 TWh (+36%).

In Georgia, an increase of RES generation of 7 TWh will be allocated to the decrease of TPP generation (around -1.3 TWh), an increase of spillages (around +2 TWh) and, due to decreased prices, an increase of export (around +3.5 TWh).

[7] Expected values represent average of a set of MC years, Min and Max values represent extremes.

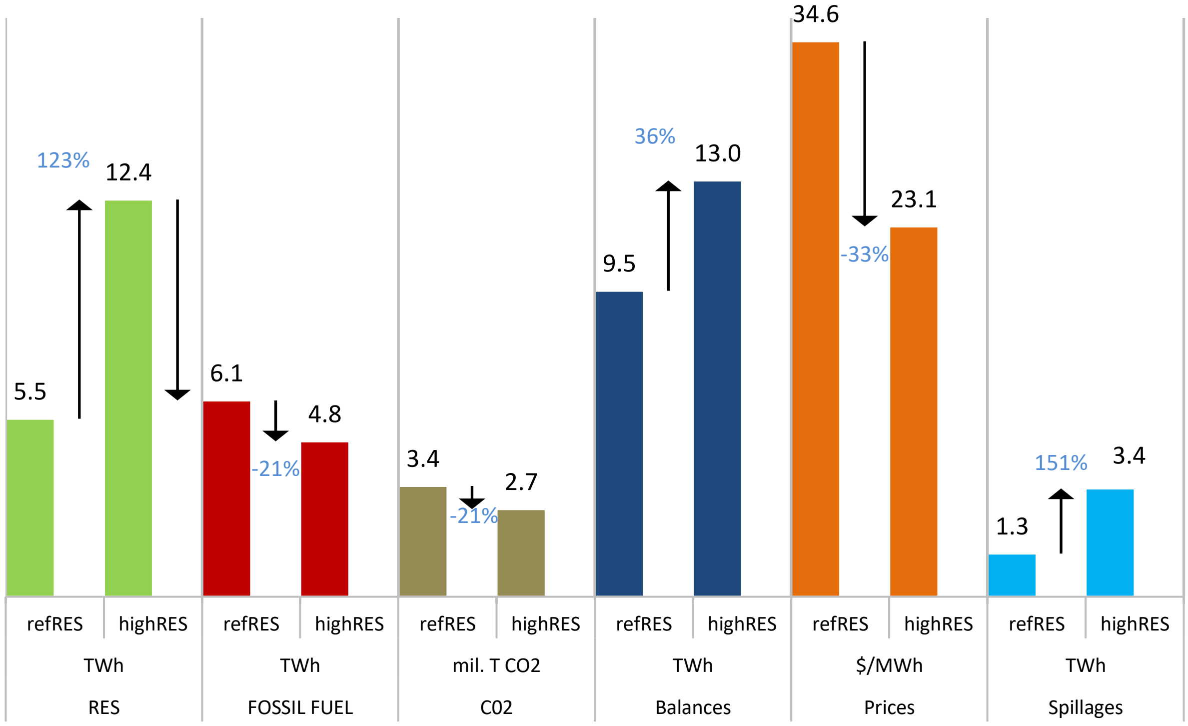
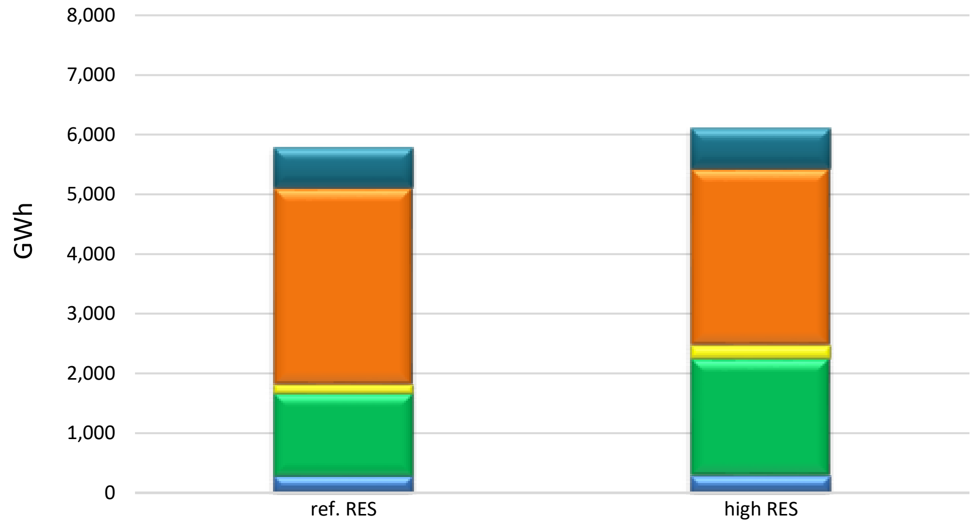


Figure 13: Main system operating indicators in Georgia in 2030 – ref. RES vs high RES

As in previous cases, we checked if the estimated required reserve (FCR+FRR) is satisfied and in the case of Georgia, we have found that, required balancing reserve of 390 MW cannot be satisfied in 65 and 56 hours during the year, in ref. and high RES scenarios respectively. Analyses showed that a lack of the balancing reserve can be expected practically only during the flooding season.

IV.3.4 Moldova

Generation mix and selected set of indicators, as the main results of market analysis for Moldova, are presented in Figure 14 and Figure 15, respectively.



	ref. RES	high RES
Other	0	0
Gas	676	676
Coal	3297	2963
Lignite	0	0
Nuclear	0	0
Solar	147	210
Wind	1382	1975
Hydro	277	277
Consumption	6879	6879

Figure 14: Generation mix of Moldova in 2030 – ref. RES vs high RES

By observing generation mixes presented in Figure 14: , in conjunction with main system indicators presented in Figure 15, conclusions regarding the operation of the Moldovan power system in 2030 in high RES scenario, compared to ref. RES, are as follows:

- RES generation will grow from 1.5 TWh to 2.2 TWh (+43%) and it is almost only provided by wind power plants.

- RES increase will be compensated with a decrease of TPPs generation from 4 TWh to 3.6 TWh (-8%), which will lead to a decrease in CO_2 emission from 3.1 mil. T to 2.8 mil. T (-9%). It should be noted that the generation from MGRES and exchange with Moldelectrica is limited to the current level (around 4 TWh).

- RES generation increase will also lead to a decrease of import from 1.1 TWh to 0.8 TWh (-29%).

- Higher RES generation also leads to a decrease of average annual price from 57.8 $/MWh to 54.9 $/MWh (-5%), due to the fact that cheaper power plants become marginal.

In Moldova, an increase of around 0.7 TWh of RES generation will be allocated to decrease of TPP generation (around -0.4 TWh), and decrease of import (around -0.3 TWh). It should be noted that the decrease in TPP generation comes from decreased MGRES generation.

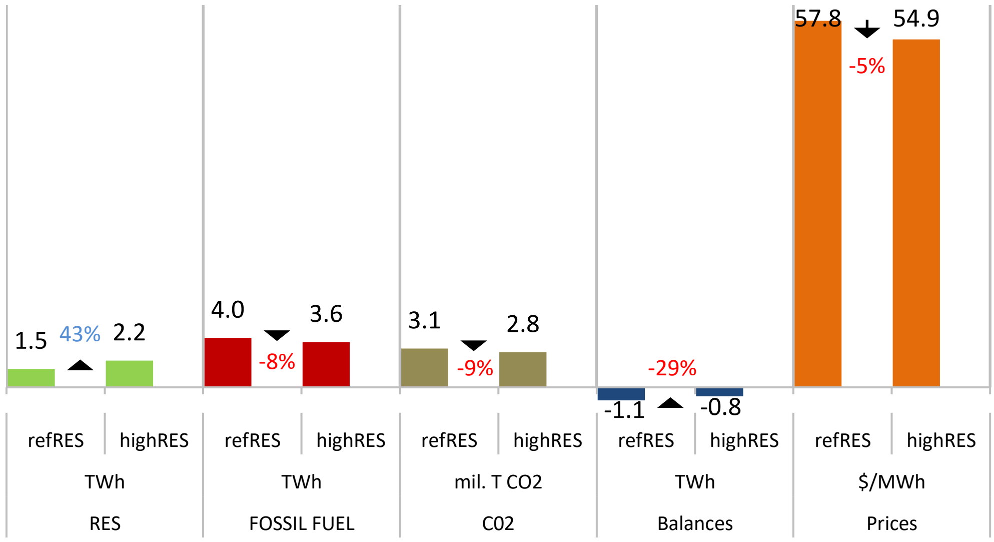
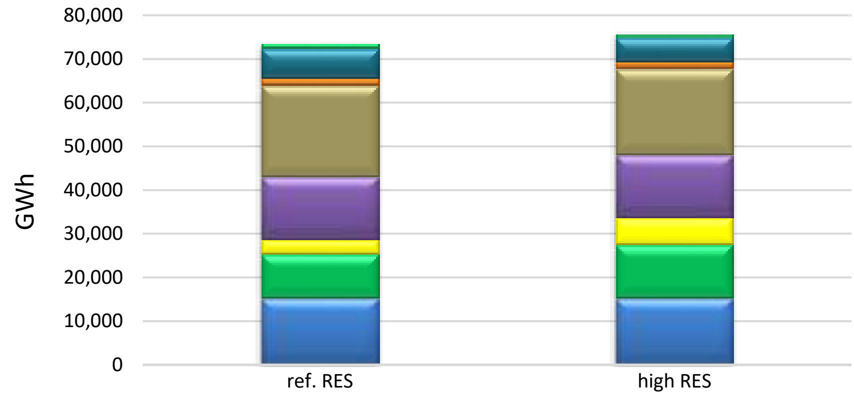


Figure 15: Main system operating indicators in Moldova in 2030 – ref. RES vs high RES

Assessment of the estimated required reserve (FCR+FRR) fulfillment has been carried out also for Moldova, and, we concluded that a balancing reserve of 80 MW can be provided in all hours during the year and in all analysed climatic years and hydrological conditions.

IV.3.5 Romania

Generation mix and selected set of indicators, as the main results of market analysis for Romania, are presented in Figure 16 and Figure 17, respectively.



	ref. RES	high RES
Other	1296	991
Gas	6869	5608
Coal	1546	1546
Lignite	20988	19767
Nuclear	14374	14374
Solar	3359	6214
Wind	10040	12192
Hydro	15357	15357
Consumption	63316	63316

Figure 16: Figure 16Generation mix of Romania in 2030 - ref. RES vs high RES

By jointly analyzing results presented in Figure 16 and in Figure 17, and by comparing high RES and ref. RES results, the following can be concluded:

- RES generation will be increased from 13.4 TWh in ref.RES scenario to 18.4 TWh in high RES (+37%).

- At the same time, fossil fuel TPP generation will fall from 29.4 TWh to 26.9 TWh (-8%), which leads to a decrease in CO2 emission from 26.2 mil.T to 24.5 mil.T (-7%).

- The net export of Romania will rise from 10.5 TWh to 12.7 TWh (+21%).

- Also, with higher RES generation, prices will be decreased, from 56.4 $/MWh to 54.1 $/MWh.

In Romania, an increase of around 5 TWh of RES generation will be allocated to decrease of TPPs generation (around -2.5 TWh), and increase of export (around + 2.2 TWh).

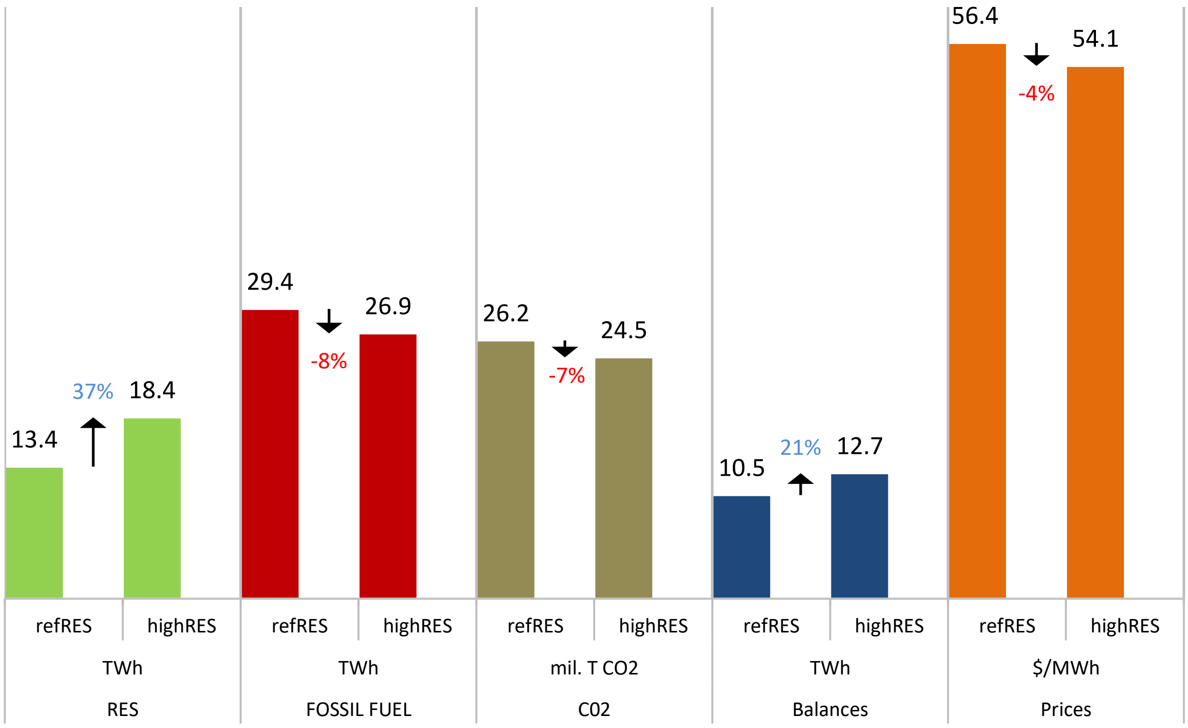
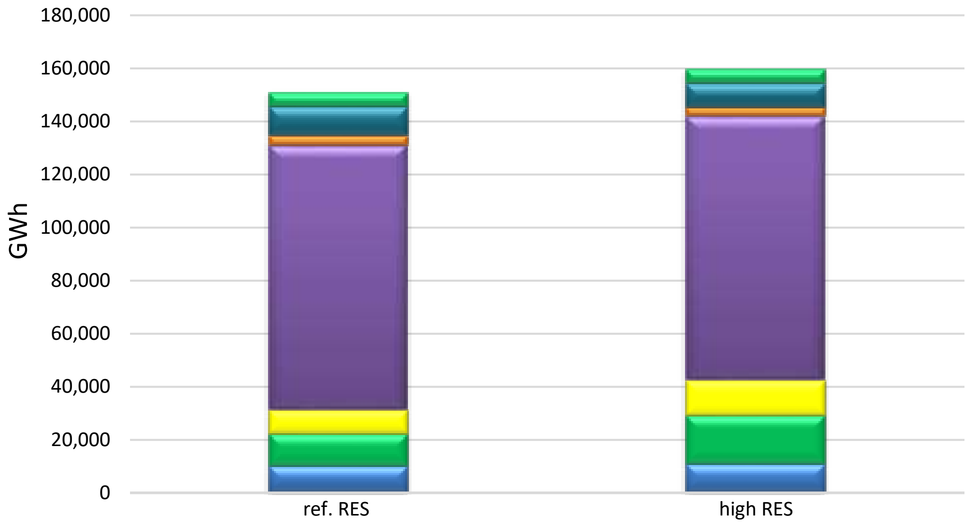


Figure 17: Main system operating indicators in Romania in 2030 – ref. RES vs high RES

As in previous cases, we checked if the estimated required reserve (FCR+FRR) is satisfied and in the case of Romania, we have found that, required balancing reserve of 1400 MW cannot be satisfied in 251 and 230 hours in average, during the year, in ref. and high RES scenarios respectively. Analyses showed that lack of the balancing reserve can be expected in all seasons except in spring.

IV.3.6 Ukraine

Generation mix and selected set of indicators, as the main results of market analysis for Ukraine, are presented in Figure 18 and Figure 19, respectively.



	ref. RES	high RES
Other	5272	5198
Gas	10907	9130
Coal	3795	3208
Lignite	0	0
Nuclear	99757	99709
Solar	8951	13265
Wind	12016	18164
Hydro	10129	10879
Consumption	169624	170619

Figure 18: Generation mix of Ukraine in 2030 - ref. RES vs high RES

Considering the Generation mixes presented in Figure 18, in conjunction with the main system indicators depicted in Figure 19 for both scenarios, conclusions regarding the operation of the Ukrainian power system in 2030 are as follows:

- RES generation will be increased from 21 TWh to 31.4 TWh (+50%).
- At the same time generation from TPPS on fossil fuel will be decreased from 14.7 TWh to 12.3 TWh (-16%), which will lead to a decrease in CO_2 emission from 10.7 mil. T to 9.1 mil. T (-15%).
- Higher RES capacities increase the needs for flexible sources, so increases in the utilization of the PS HPPs are presented in Table 12. Engagement in pumping mode is similar, just somewhat increased for PS HPP inefficiency.

Table 12: PS HPPs Generation in Ukraine

Generation from PS HPPs (GWh)	All hydrological conditions			Wet hydrological conditions	Average hydrological conditions	Dry hydrological conditions
	Expected[8]	**Min**	**Max**	**Expected**	**Expected**	**Expected**
Ref. RES	902,047	572,588	1,266,664	685,425	900,854	1,119,863
High RES	1,651,953	1,269,633	2,248,285	1,415,227	1,653,083	1,887,550
Difference	**749,906**	**697,045**	**981,621**	**729,802**	**752,230**	**767,687**

Generation of this type of power plant in the high RES scenario is almost doubled in comparison with ref. RES scenario, because greater non-costly RES generation gives the higher possibility for pumping and storing of energy, for utilization in some other hours. It should be noted that this type of HPPs has a high utilization factor in Ukraine, higher than in any of the BSTP countries. This is driven by the size and structure of the power generation portfolio: high participation of nuclear (flat) generation as well as high participation of nondispatchable RES generation. Also, since HPPs are an important source, ther is an impact of different hydrological conditions on the generation of PS HPPs.

- The increase of RES generation will lead to a decrease in prices from 62.2 $/MWh to 56.8 $/MWh (-9%) because with higher RES generation cheaper plants will become marginal.

- Also, an increase of must run RES generation will lead to a decrease of import from 18.8 TWh to 11.1 TWh (-41%).

In Ukraine, an increase of around 10.4 TWh of RES generation will be mainly allocated to the decrease of TPPs generation (around -2.4 TWh), and to decrease of import (around -7.7 TWh), followed by a decrease of wholesale prices in Ukraine.

[8] Expected values represent average of a set of MC years, Min and Max values represent extremes.

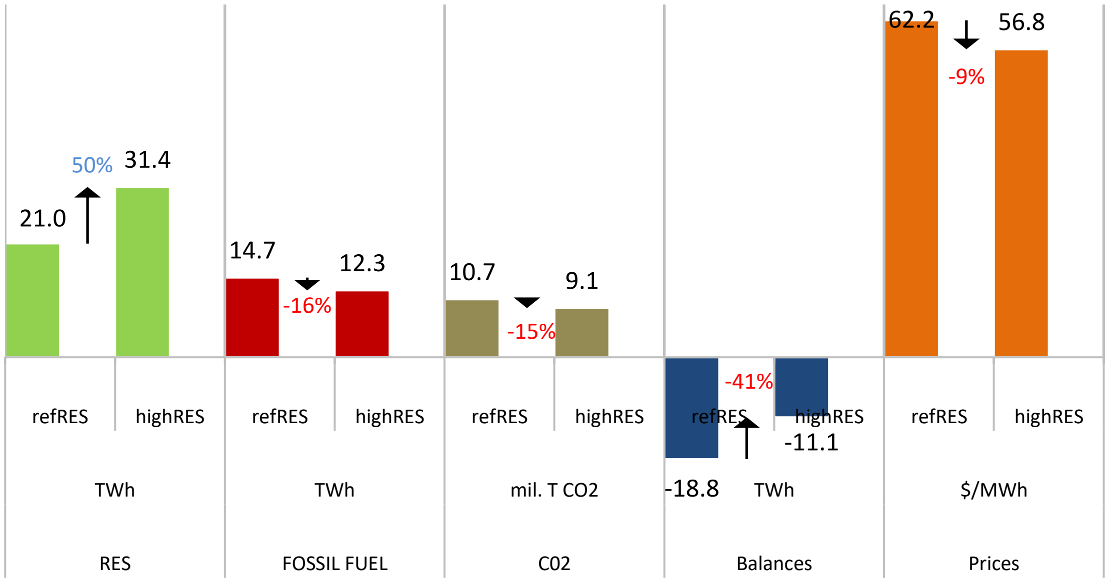
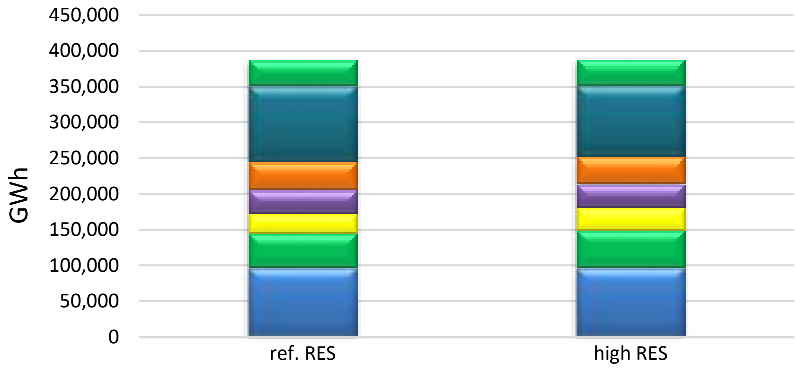


Figure 19: Main system operating indicators in Ukraine in 2030 – ref. RES vs high RES

As in previous cases, the fulfillment of the estimated required reserve (FCR+FRR) has been checked, and, in the case of Ukraine, the required balancing reserve of 1400 MW can be provided in almost all hours during the year in all analysed climatic years and hydrological conditions. Results showed that reserve is not satisfied in 5 and 1 hour on average during the year, in ref. and high RES scenario, respectively.

IV.3.7 Turkey

Generation mix and selected set of indicators, as the main results of market analysis for Turkey, are presented in Figure 20 and Figure 21, respectively.



	ref. RES	high RES
Other	36859	36859
Gas	106398	99039
Coal	38755	38619
Lignite	0	0
Nuclear	33418	33212
Solar	27387	31480
Wind	48204	52353
Hydro	97514	97515
Consumption	412871	412871

Figure 20: Generation mix of Turkey in 2030 - ref. RES vs high RES

By observing results from Figure 20 in conjunction with indicators shown in Figure 21: , the following can be concluded for the Turkish power system operation in 2030 in ref. and high RES scenarios:

- In 2030, RES generation will rise from 75.6 TWh in ref. RES scenario to 83.8 TWh in high RES scenario (+11%).

- RES increase will be almost entirely compensated with a decrease in fossil fuel TPPs generation from 145.1 TWh to 137.7 TWh (-5%), which will lead to a decrease in CO_2 emission from 78.3 TWh to 75.1 TWh (-4%).

- The increase of non-dispatchable RES generation will lead to a decrease in prices from 70.6 \$/MWh to 69.21 \$/MWh (-2%) because with higher RES generation cheaper plants will become marginal. Although, this decrease in prices can be considered negligible.

- Also, a small part of the RES generation increase will be allocated to a decrease in import from 24.4 TWh to 23.9 TWh (-2%).

In Turkey, an increase of around 8.2 TWh of RES generation will be mainly allocated to the decrease of TPPs generation (around -7.5 TWh), and decrease of import (around -0.5 TWh).

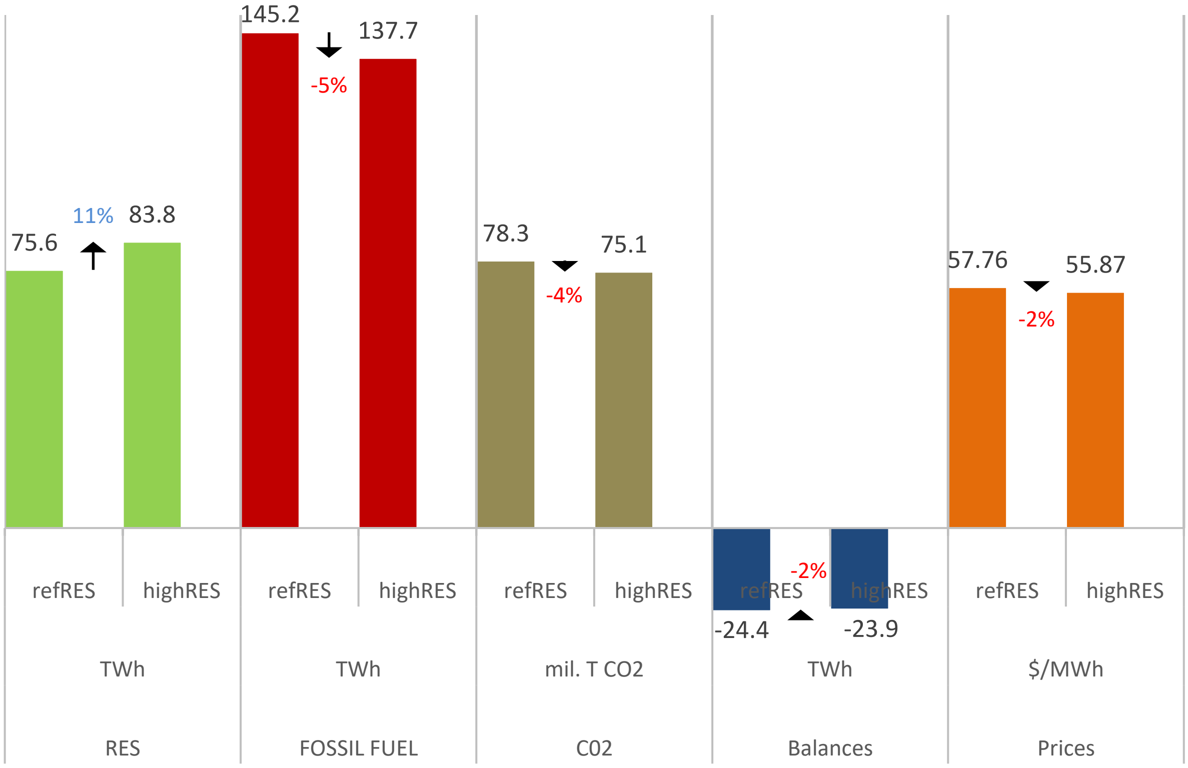


Figure 21: Main system operating indicators in Turkey in 2030 – ref. RES vs high RES

A check of the fulfillment of the estimated required reserve (FCR+FRR) has been carried out also for Turkey, and, we concluded that a balancing reserve of 2600 MW can be provided in all hours during the year in all analysed climatic years and hydrological conditions.

IV.4 Regional Summary

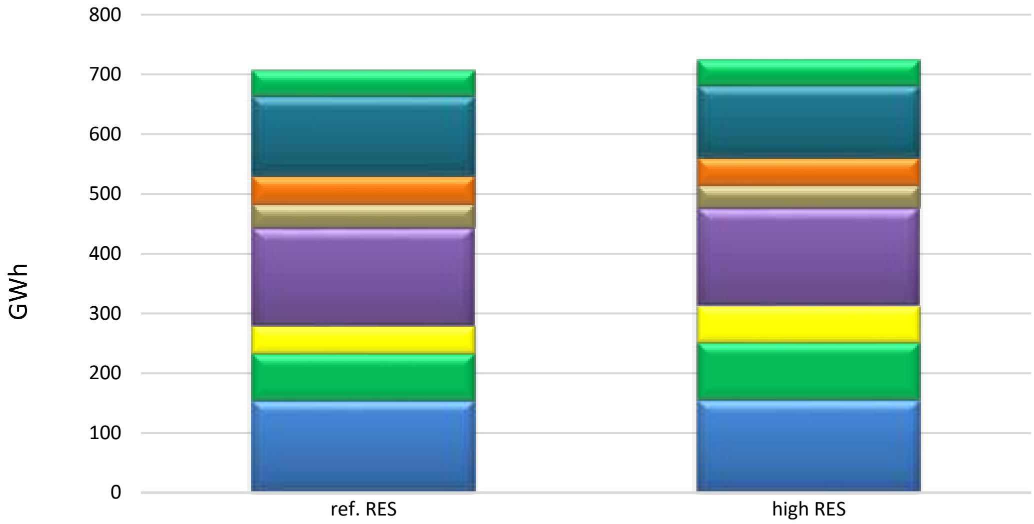
In this chapter, results are presented on a regional level, in order to analyse changes in BSTP system operation as a whole and in order to compare BSTP countries' performance for selected indicators.

In Table 13 main results of Antares simulations, for all BSTP countries in ref. RES and high RES scenario are presented encompassing RES capacities and generation, forecasted annual consumption, expected generation, spillages, exchanges and prices.

Table 13: Main system operating indicators for the BSTP region in 2030 – ref. RES vs high RES

Country	Scenario	RES (wind+solar) capacities (MW)	RES (wind+solar) generation (GWh)	Consumption (GWh)	Generation (GWh)	Spillages (GWh)	Net interchange (GWh)	Prices ($/MWh)
AM	Ref	1,020	1,574	7,730	10,910	142	3,180	33.7
	High	1,250	1,936	7,730	10,003	432	2,273	22.7
BG	Ref	3,816	5,531	36,986	42,308	0	5,322	57.8
	High	4,770	6,914	37,076	43,098	0	6,022	55.9
GE	Ref	1,850	5,543	23,518	33,044	1,346	9,526	34.6
	High	4,700	12,369	23,822	36,783	3,373	12,961	23.1
MD	Ref	861	1,530	6,879	5,779	0	-1,100	57.8
	High	1,230	2,185	6,879	6,101	0	-778	54.9
RO	Ref	6,200	13,399	63,316	73,830	0	10,514	56.4
	High	8,800	18,406	63,316	76,049	0	12,733	54.1
UA	Ref	12,267	20,968	169,624	150,828	0	-18,796	62
	High	18,310	31,429	170,619	159,553	0	-11,066	56.8
TR	Ref	35,815	75,591	412,871	388,516	19	-24,355	70.6
	High	40,000	83,833	412,871	388,999	77	-23,872	69.2
BSTP	Ref	**61,829**	**124,135**	**720,924**	**705,215**	**1,507**	**-15,709**	**53.3**
	High	**79,060**	**157,072**	**722,313**	**720,586**	**3,882**	**-1,727**	**48.1**

In Figure 22, the generation mix for the BSTP region as a whole in ref. RES and high RES scenarios are depicted, also in Figure 23 selected indicators for the BSTP region as a whole is given, which represents the main results of market simulations.



	ref. RES	high RES
Other	43.4	43.0
Gas	133.3	121.0
Coal	47.4	46.3
Lignite	39.5	37.5
Nuclear	164.9	164.5
Solar	46.1	61.1
Wind	78.1	96.0
Hydro	154.0	155.0
Consumption	720.9	722.3

Figure 22: BSTP generation mix in 2030 - ref. RES vs high RES

Considering the BSTP generation mixes presented in Figure 21, in conjunction with main system indicators depicted in Figure 22 for both scenarios, conclusions regarding the operation of the BSTP power system as a whole, in 2030 are as follows:

- RES generation (Wind + Solar) will be increased from 124.1 TWh to 157.1 TWh (+27%). Wind generation will grow from 78 TWh to 96 TWh, while solar will rise from 46 TWh to 61 TWh. This is the consequence of the increase in wind capacities from 30 to 36 GW and in solar capacities form 32 to 42 GW.

- As one of the main consequences of increased RES generation, TPP generation will fall, from 220 TWh to around 205 TWh (- 7%). The majority of that decrease will come from decreased gas-fired generation due to the fact that higher RES generation means that most expensive power plants will be out of the merit order.

- Together with the decrease of fossil fuel fired TPP generation, CO2 emission will be decreased from 139.2 mil.T to 130.7 mil.T (-6%).

- Considering that the region as a whole is importer, the net import will be decreased from -15.7 TWh to -1.7 TWh (-89%), due to higher RES generation.

- At the same time, higher RES generation leads to lower prices, due to the fact that cheaper power plants become marginal, so the average annual price in BSTP region as a whole will fall from 53.3 $/MWh to 48.1 $/MWh (-10%)

- In some countries higher RES generation will lead also to increased spillages (like in Armenia and Georgia), due to the fact that in some hours generation is greater than consumption, cross border lines are congested and technical limitation of power plants don't allow a further decrease of generation. During these hours part of RES generation has to be curtailed. Spillages will be increased from 1.5 TWh to 3.9 TWh (+160%). Having in mind that these spillages are substantial for countries in which they appear, further flexibility analysis of respective power systems are advised.

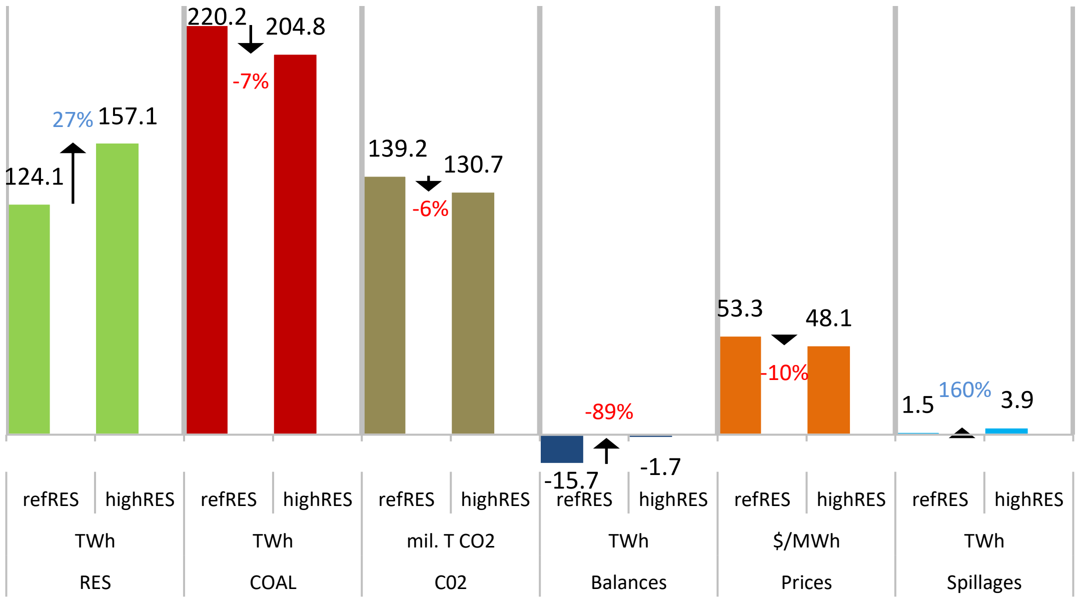


Figure 23: Main system operating indicators for the BSTP region in 2030 – ref. RES vs high RES

Considering the fact that the BSTP region is comprised from countries which are different in size, population and electricity needs, it is impractical to directly compare them with energy indicators, such as TPP generation, CO2 emission and balances, so in Figure 24 average annual prices for each BSTP country and both scenarios are given, as a universal indicator.

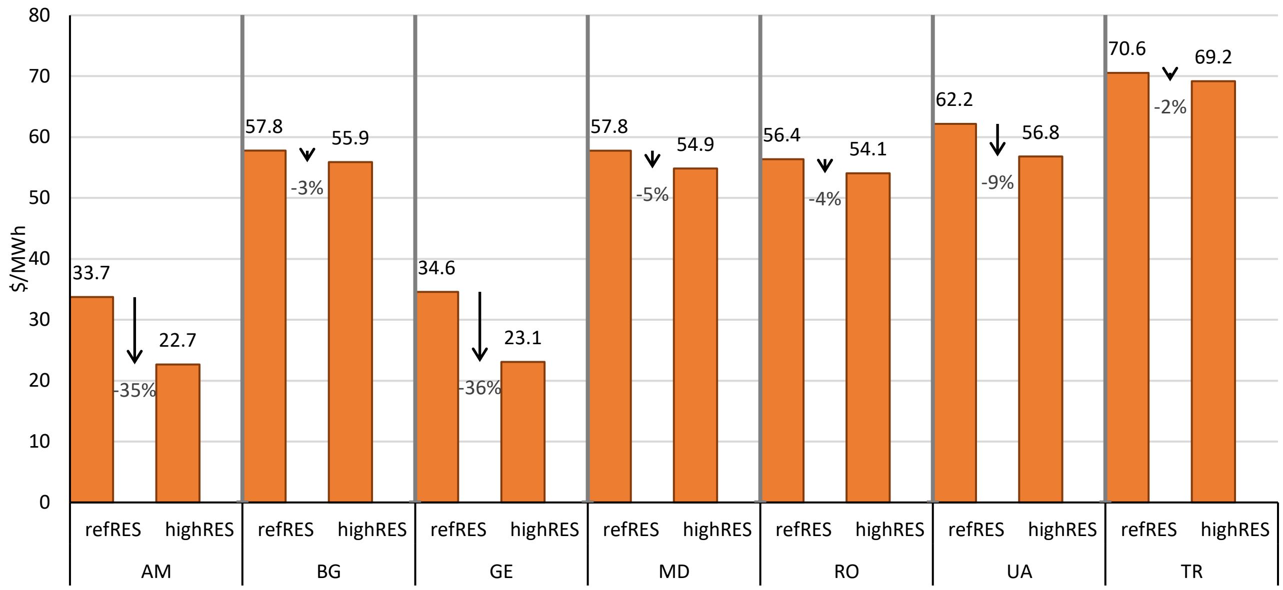


Figure 24: Average annual prices per BSTP country in 2030: ref. RES vs high RES

Conclusions regarding prices in 2030 are the following:

- BSTP countries are grouped in 3 price zones: Armenia and Georgia (around 25-35$/MWh), Bulgaria, Moldova, Romania and Ukraine (around 55$/MWh-60$/MWh) and Turkey (around 70 $/MWh). Armenia and Georgia have lower prices than the central part of the BSTP region due to cheaper gas (and non-CO2 taxes) and excess of HPPs generation, while prices in Turkey are the highest since it is a big importing market zone.

- Regarding the decrease in prices, Armenia and Georgia will have the largest decrease (around 35%) mainly due to increased spillages. Having in mind that both countries are exporters, this could decrease benefits from energy trade.

- Armenia can increase it's export only toward Georgia (export to Central Asia is considered limited) and spillages in Armenia and Georgia are connected. Having in mind that a large part of additional RES generation would be curtailed (spilled), the level of new RES capacities in Armenia and Georgia should be carefully considered.

- Prices in other BSTP countries will decrease from 2% in Turkey to 9% in Ukraine.

- Considering that Ukraine, Turkey and Moldova are net importers of electricity, a decrease in prices could have a positive impact on energy trade.

V. NETWORK: MODELING, ANALYSES AND RESULTS

V.1 System Modeling for Grid Analyses

For the network simulation, this Study applied the Regional Transmission System Models (RTSMs) for the following referent cases:

- the **Winter maximum load regime** (corresponding to the third Wednesday in January 2030 at 18:00 CET);
- the **Summer minimum load regime** (corresponding to the third Wednesday in May 2030 at 04:00 am CET)
- the **Summer maximum load regime** (corresponding to the third Wednesday in July at 11.00 CET and time in which maximum solar generation can be expected).

Each regime includes two variants related to RES integration:

- the expected/forecasted level of RES integration (MW) for 2030, and
- a higher level of RES integration, either one specified by the TSO, or as a default, a level 25% higher than the expected level

To create a corresponding regional BSTP network model, the Consultant first developed a review of the individual country models already present in the current regional BSTP model and updated at the end of 2019. Also, a preliminary analysis of the country TSO models was conducted and presented in the Interim Report. The same is presented in Appendix.

The initial network models then have been updated based on the data provided by the TSOs in the form of tables with a list of large-scale RES projects and their location in the grid. For each country, there were two lists: one related to the referent RES scenario and another referring to more aggressive, high RES scenario. Based on the initial models and these lists, two different sets of network models have been developed.

Updated individual models have been merged into regional models and these have been used for detailed AC load flow simulations. For each analyzed regime, the Consultant used generation dispatch obtained from the market simulations of the scenarios with different levels of RES.

In the following chapters we present the methodology we applied in selection of the characteristic hours and complete results of the network simulations in the presence of referent and high level of wind and solar capacities in year 2030.

V.2 Selection of the hours that corresponds to specific regimes

There are three critical regimes selected for the network analysis, considered to be the most critical regarding high RES integration impact on transmission network:

1) **Max load regime:** Regime expected on third Wednesday in January 2030 at 18:00 CET
2) **Max WPP+SPP regime:** Regime expected in the hour in which maximum of the sum of wind and solar generation in the whole region is realized
3) **Max SPP regime:** Regime expected in the hour in which maximum of the solar generation in the whole region is realized

Selection of these three regimes (that corresponds to specific hour within a year) are based on the results of the market study, conducted on Monte Carlo principle with different climatic years (for both analyzed scenarios, referent and high RES), and represent load and generation pattern as well as cross-border exchanges, for the whole BSTP region.

Beside selection of the specific regime or hour, it was necessary to choose only one of the 10 climatic years, the one that corresponds to most specific climatic year from the analysed set of 10 years, from 2006 to 2015. The approach was as follows:

1. Winter max regime: The hour that corresponds to winter maximum regime is hour 402, January 17th, 6 pm. For this analyses only relevant was a selection of the climatic year and year 7 (2012) has been selected as the year in which sum of the generation from WPPs and SPPs in hour 402 is the lowest. This option has been intentionally chosen in order to check if the power system is able to provide secure and reliable transmission of power in case when production from RES is at minimum level and load is maximal.

   In observed hour total generation from wind and solar power plants is 2571 MW (3029 MW), for the whole BSTP region. Generation from wind and solar power plants per each country in all selected regimes are presented in Table 14.

2. Selection of the regime with maximum SPP generation: The climatic year 3, as a year with maximum annual generation from SPPs in the whole BSTP region has been selected. Annual generation from SPPs in MC 3 (climatic year 2008) for the whole BSTP region is 47.4TWh and 58.8TWh in referent and high RES scenarios, respectively.

   Then, hour in which SPPs generation is maximal has been selected – hour 3732. This hour corresponds to June 5th at 11 AM. The total generation from solar power plants for the whole BSTP region in observed hour is 22336 MWh and 29566 MWh in referent and high RES scenarios, respectively.

3. Selection of the regime with maximum WPP+SPP generation: The climatic year 7, as a year with maximum annual generation from WPPs and SPPs in the whole BSTP region has been

selected. Annual generation from WPPs and SPPs in year 7 (climatic year 2012) for the whole BSTP region is 129.4 TWh and 144.8TWh in referent and high RES scenarios, respectively.

Then, hour in which sum of the WPPs and SPPs generation is maximal has been selected – hour 5795. This hour corresponds to August 30th at 10 AM. The total generation from wind and solar power plants for the whole BSTP region in observed hour is 38411 MWh and 49990 MWh in referent and high RES scenarios, respectively.

Table 14: Generation from WPPs and SPPs in selected regimes

Country	Hourly generation (MWh)	Winter max regime		Max SPP		Max WPP+SPP	
		Referent RES	High RES	Referent RES	High RES	Referent RES	High RES
AM	SPP	0	0	900	1,080	659	790
	WPP	9	23	1	3	0	1
BG	SPP	0	0	1,920	2,400	1,683	2,103
	WPP	69	86	8	10	572	715
GE	SPP	0	0	324	1,298	335	1,339
	WPP	78	150	226	435	1,170	2,250
MD	SPP	0	0	78	111	82	118
	WPP	51	73	149	212	348	497
RO	SPP	0	0	1,674	3,097	1,749	3,236
	WPP	752	914	278	337	2,139	2,597
TR	SPP	0	0	12,824	14,740	11,161	12,829
	WPP	1,538	1,671	1,898	2,062	10,162	11,037
UA	SPP	0	0	4,616	6,840	4,875	7,224
	WPP	74	112	1,128	1,705	3,476	5,254
BSTP	SPP	**0**	**0**	**22,336**	**29,566**	**20,544**	**27,639**
	WPP	**2,571**	**3,029**	**3,688**	**4,764**	**17,867**	**22,351**

It should be noted that in some cases (hours), production from WPPs and SPPs has been curtailed. It happens in Armenia and Georgia in high RES scenarios:

- in max SPP regime - curtailment is 518 MW in AM and
- in max WPP+SPP regime - curtailment is 489 MW in GE.

Curtailment has been shared between WPPs and SPPs proportionally to the actual generation.

In further network analyses, hourly load and dispatch has been taken from market simulations and applied in corresponding initial network models:

- for winter max regime – winter max model has been used
- for max SPP and max WPP+SPP regimes – summer max models have been used.

Required demand has been achieved by scaling total load found in referent models, maintaining constant P/Q ratio in order to achieve as realistic voltage values as possible.

V.3 Results of the network analyses

V.3.1 Armenia

Results obtained from the market simulations for selected timestamps which are applied to regional network models are given in the following tables.

Table 15: Totals - Armenia

AM	Max load		Max SPP		Max WPP + SPP	
	Ref	High	Ref	High	Ref	High
Load	1178.6	1178.6	998.3	998.3	929	929
Generation	1694	1599	1457	1667	1775	1070
Losses	40.4	37	46.7	59.2	54	41.8
Desired interchange	475	380	412	622	792	87

Table 16: Generation per technology - Armenia

AM	Generation (MW)					
	Max load		Max SPP		Max WPP + SPP	
	Ref	High	Ref	High	Ref	High
RoR	130	130	320	320	178	146
Storage	242	237	62	90	151	133
Gas	877	773	174	174	351	174
Nuclear	436	436	0	0	436	344
SPP	0	0	900	1080	659	272
WPP	9	23	1	3	0	1

Generation dispatch from market simulations has been implemented to network models per each power generating unit and RES has been modeled as negative loads located in specified nodes. Generation from renewables, obtained from market simulations as summed values per type, is distributed proportionally to original negative loads found in referent models.

Main characteristics of relevant regimes in the power system of Armenia, are the following:

- In the Max load regime, the production from renewable sources is at a minimum level and high load demand is mostly covered by conventional sources such as nuclear and thermal power plants.

- Regarding Max SPP regime, high generation from solar power plants covers most of the consumption and there is no power generated from nuclear power plant in this regime.
- As for Max WPP + SPP regime, in the specified hour solar generation capacities are curtailed causing less RES generation then in Max SPP regime. This is the consequence of the higher RES generation in Georgia.

Load flow simulations performed on updated network models indicate no violations of operational security limits in terms of voltages outside of permissible limits or overloading of elements.

Overview of voltages and loading of elements in the system is given in the following figures.

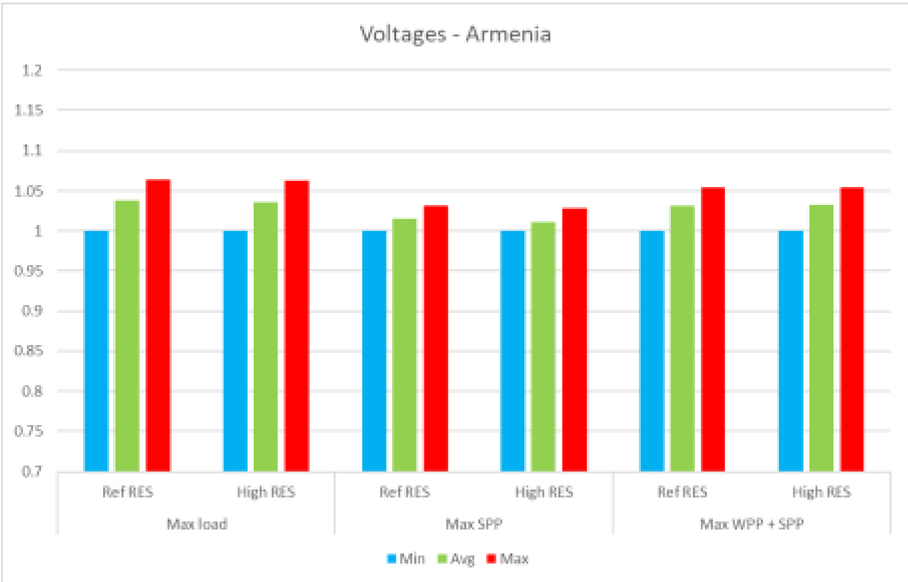


Figure 25: Overview of voltages in Armenia

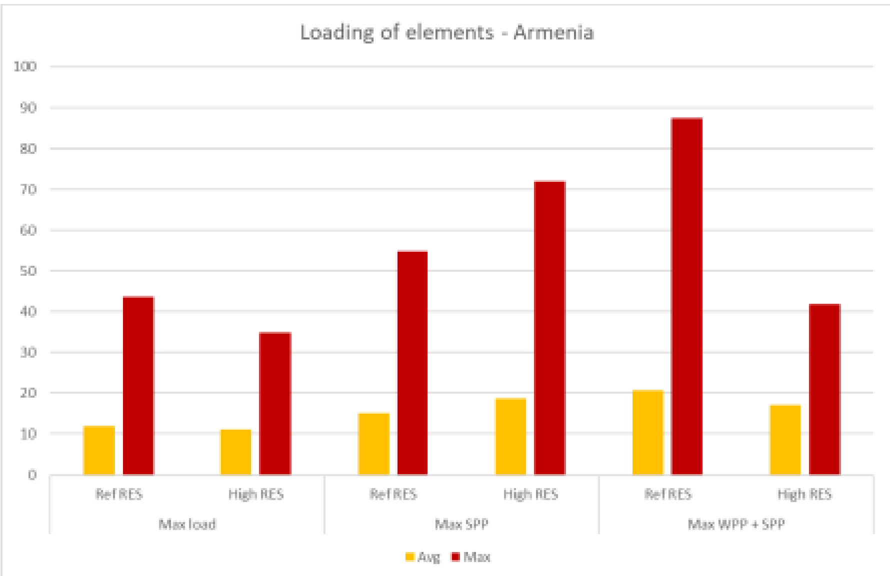


Figure 26: Overview of loadings in Armenia

Analysis of the results of power system simulations indicate that voltages in the power system of Armenia are not significantly impacted by higher RES integration in the system and remain similar in High RES scenarios compared to referent RES scenarios.

Loading of elements is in proportion with the balance of the country, indicated by higher average loading of elements and consequently losses in the system, in cases when export increases. This is clearly indicated in Max SPP regime since Armenian power system includes high solar capacities and small capacities in wind. In Max SPP+WPP regime, High RES scenario, solar generation capacities are curtailed, causing lower export of power, which is followed by decrease of average loading of elements and overall losses in the system.

Contingency analyses have been performed for all operating regimes and RES integration scenarios in order to identify possible network congestions and bottlenecks. In Armenian power system, single issue has been identified which violates N-1 security criterion. Specifically:

- Outage of 400 kV line **Ddmashen – Ayrum** causes overloading of 220 kV line **Alaverdy 2 – Vanadzor 2** and 220 kV line **Alaverdy 2 – Ayrum**. This issue occurs in all observed operating regimes and it is direct consequence of exchange of power via B2B link between Armenia and Georgia. Most significant impact is observed in Max SPP+WPP regime, referent RES scenario, where B2B link is utilized at its full capacity of 700 MW from Armenia to Georgia. It is important to notice that in case of the observed contingency, power exchanged via B2B link should be curtailed in order to preserve network security conditions, since remaining 220 kV network is not sufficient to support high energy exchange.

V.3.2 Bulgaria

Overview of total load, generation, losses and export as well as generation per each type of technology for power system of Bulgaria is given in the following tables.

Table 17: Totals - Bulgaria

BG	Max load		Max SPP		Max WPP + SPP	
	Ref	High	Ref	High	Ref	High
Load	6144.4	6144.4	4095.3	4095.3	3902.7	3902.7
Generation	6788	6816	4040	4522	6221	6784
Losses	173.6	182.7	99.7	122.3	182.3	234.8
Desired interchange	470	498	-155	327	2163	2726

Table 18: Generation per technology - Bulgaria

BG	Generation (MW)					
	Max load		Max SPP		Max WPP + SPP	
	Ref	High	Ref	High	Ref	High
RoR	72	72	304	304	156	156
Storage	1450	1461	0	0	0	0
Coal	2212	2212	1808	1808	1810	1810
Gas	985	985	0	0	0	0
Nuclear	2000	2000	0	0	2000	2000
SPP	0	0	1920	2400	1683	2103
WPP	69	86	8	10	572	715

In the Bulgarian network model, all renewables are modeled as machines and summed RES generation obtained in market simulations is divided between units proportionally to maximum power (installed capacities).

Main characteristics of the observed regimes are the following:

- In Max load regime, the production from renewable sources is at a minimum and high load demand is mostly covered by nuclear and thermal power plants.
- In Max SPP regime, solar power plants supply half of total demand in referent RES scenario and around 60% of total demand in high RES scenario, which exceeds the total production of all conventional power plants in the observed regime.
- As for Max WPP + SPP regime, the combined production of solar and wind power plants is at the highest level which is followed by increased export of power.

As a consequence of increased RES integration, losses are 23% higher in Max SPP regime and 29% higher in Max SPP+WPP, when high RES and referent RES scenarios are compared.

Overview of the minimum, average and maximum voltage values, as well as maximum and average loading of elements is given in the following figures.

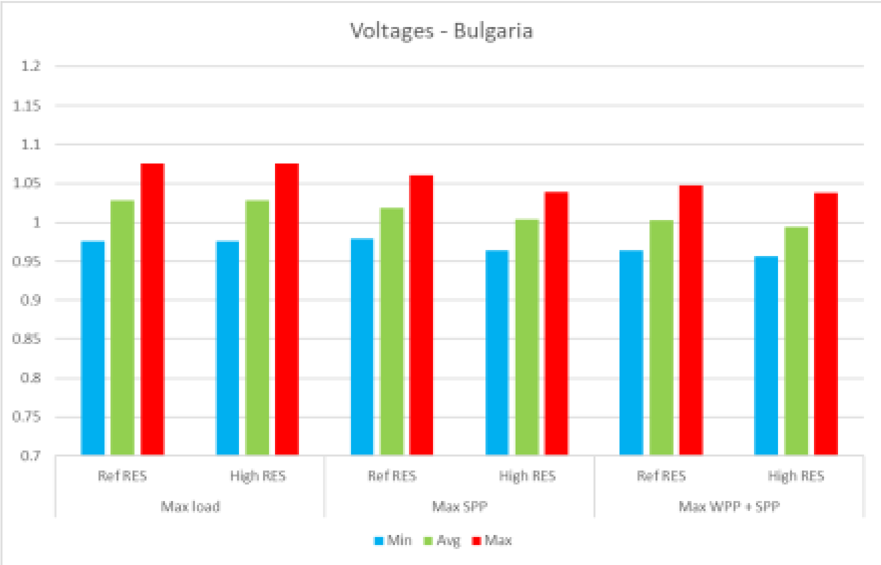


Figure 27: Overview of voltages in Bulgaria

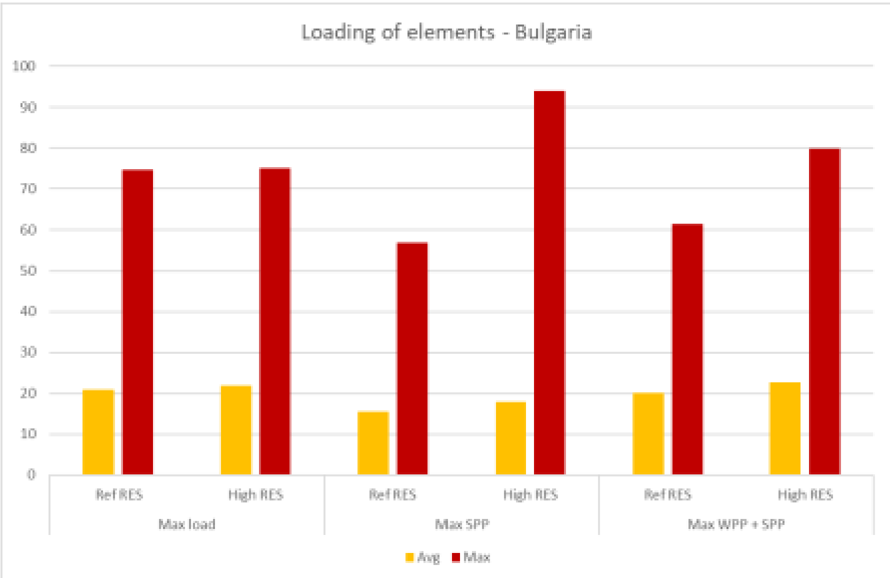


Figure 28: Overview of loadings in Bulgaria

Power flow analysis indicates that no significant voltage changes occur between referent RES and high RES scenarios in the power system of Bulgaria. In Max load regime there is no significant difference, while in Max SPP and Max SPP+WPP regimes loadings of elements' are increased in high RES scenarios, followed by slight decrease of voltages throughout the system.

Contingency analyses performed on network models for all observed regimes and RES integration scenarios indicate several security violations in Bulgarian power system. No violations have been noted in referent RES scenario in any of the regimes as well as in Max Load regime in highn RES scenario. Security violations have been noted in the following cases:

- In high RES scenario, in Max SPP and Max SPP+WPP regime, 400 kV tie line between Romania and Bulgaria, **Kozloduy – Tantareni circuit 1** is already highly loaded in referent RES scenario (94% for Max SPP and 70% for Max SPP+WPP). Consequently, several contingencies cause overloading of the mentioned line, of up to 120% for Max SPP and 104% for Max SPP+WPP. However, second parallel circuit of this tie line is out of operation in the observed network state. In cases of high exchange of power between Romania and Bulgaria, second circuit **Kozloduy – Tantareni circuit 2** should be put into service which would resolve the identified security violation. It is important to mention that both circuits have different ratings observed from Bulgarian (1310 MVA) and Romanian (1188.5 MVA) side.
- In high RES scenario in Max SPP+WPP regime, 400 kV lines **C. Mogila - Sofia** circuit 1&2 are both highly loaded (59%) which causes overloading of one circuit (103%) when the other is out of operation. This is caused by high export of power from Bulgaria towards North Macedonia and Greece caused by high RES generation in the observed regime.

V.3.3 Georgia

Main results obtained from market simulations for all three relevant regimes for the power system of Georgia are given in the following tables.

Table 19 Totals - Georgia

GE	Max load		Max SPP		Max WPP + SPP	
	Ref	High	Ref	High	Ref	High
Load	3652.1	3652.1	3251.3	3251.3	2383.1	2383.1
Generation	3882	4435	5695	5639	3985	5727
Losses	125.9	117.7	171.7	195.2	96.9	237.7
Desired interchange	104	657	2272	2216	1505	3247

Table 20 Generation per technology - Georgia

GE	Generation (MW)					
	Max load		Max SPP		Max WPP + SPP	
	Ref	High	Ref	High	Ref	High
RoR	760	760	2345	2318	1658	1658
Storage	2004	2485	2800	2077	409	425
TPP	1040	1040	0	0	413	55
SPP	0	0	324	931	335	1339

WPP	78	150	226	312	1170	2250

Specific locations of renewables are not defined for the Georgian power system. Because of this, negative loads have been created in all 110 kV nodes, and total RES generation is then equally divided between the 110 kV nodes in order to achieve desired levels of RES generation, determined in market simulations. In such manner, load is equally reduced throughout the system enabling analyses of high RES integration to be performed.

Main characteristics of the observed regimes are the following:

- Max load is the regime with the highest consumption, which is mostly supplied from hydropower plants and the least from renewable sources. Due to the increase in production from wind and hydropower plants in the high RES scenario, there is a slight reduction in network losses.
- In Max SPP regime, most of the consumption is still covered by hydropower plants, while the increased production of solar and wind power plants eliminates the need for power generated from thermal power plants.
- Significant amount of power generated from solar and wind capacities in Max SPP + WPP regime in high RES scenario and consequently high export from Georgian power system, cause major increase of network losses in the system. However, due to the manner in which RES has been modeled in the system, this value would probably change if the exact locations of RES sources would be defined.

Load flow analyses performed on network models for observed scenarios indicate several voltage violations given in the following tables. These violations have been observed in initial models, as well as in both referent RES and high RES scenarios indicating that level of RES integration has no significant impact on the observed voltage violations.

Table 21 Voltage violations - Max load regime

Bus Number	Bus Name	Max load			
		Ref Res		High Res	
		Voltage [p. u.]	Voltage [kV]	Voltage [p. u.]	Voltage [kV]
620945	TKVARCHELI	0.8666	190.66	0.8701	191.43
620950	SOKHUMI	0.7727	170	0.7769	170.92
620955	BZIFI	0.7185	158.07	0.7231	159.08

Table 22 Voltage violations - Max SPP regime

Bus Number	Bus Name	Max SPP			
		Ref Res		High Res	
		Voltage [p. u.]	Voltage [kV]	Voltage [p. u.]	Voltage [kV]
620950	SOKHUMI	0.8809	193.79	0.8506	187.14
620955	BZIFI	0.8457	186.06	0.8138	179.04

Table 23 Voltage violations - Max SPP + WPP

Bus Number	Bus Name	Max WPP + SPP			
		Ref Res		High Res	
		Voltage [p. u.]	Voltage [kV]	Voltage [p. u.]	Voltage [kV]
620955	BZIFI	within limits		0.8879	195.34

Additionally, following loading violations are observed in Max SPP+WPP in high RES scenario.

Table 24 Loading violations - Max SPP + WPP regime

Branch name	Rate [MVA]	Max WPP + SPP			
		Ref Res		High Res	
		Loading [MVA]	Loading [%]	Loading [MVA]	Loading [%]
220 kV TELAVI - GURJAANI	200	below limit		204.8	102.4
220 kV QSANI - JINVALI	227	below limit		240.2	105.8

In the Max WPP+SPP regime, simulated RES generation in 110 kV substations **Udzilauri**, **Jinvali**, **Barisaxo** and **Hkada** causes power to flow towards 220 kV network which is followed by overloading of 220 kV line **Jinvali – Qsani** (106%). Similarly, RES generation in 110 kV substations **Khadori, Samyuri, Akhmeta, Telavai** network causes power to flow towards 220 kV network causing overloading of 220 kV line **Telavi – Gurajaani**.

Overview of the voltage and loading conditions in the system is given in the following figures. In general, it can be observed that high RES integration causes higher element loadings which, consequently, causes slight drop in voltages and increase in network losses.

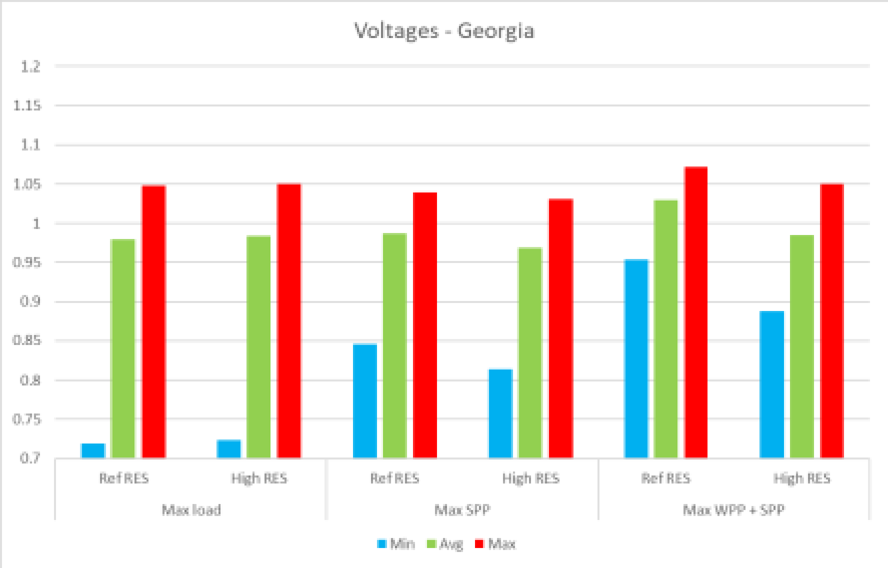


Figure 29 Overview of voltages - Georgia

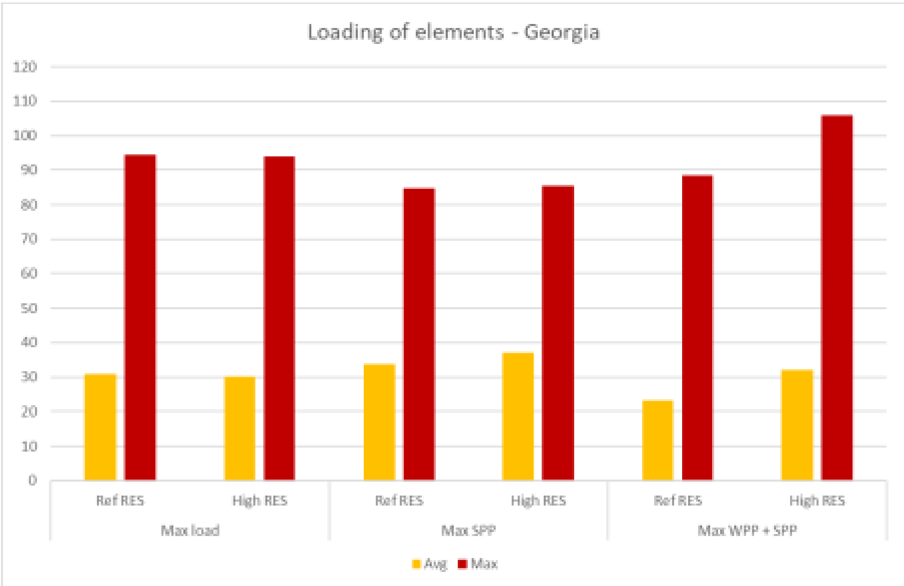


Figure 30 Overview of loadings – Georgia

Contingency analyses performed on network models for all observed operating regimes show no security violations apart from mentioned overloadings observed in base case.

In general, locations of RES generation for high RES integration scenarios should be defined and modeled in detail in order to establish precise results of network state in such cases. This would be necessary in order to determine potential network weak spots and bottlenecks, enabling assessment of required network reinforcements to be considered.

Finally, precise reactive power capabilities of the RES generating units should be considered in order to improve voltage regulation conditions and subsequently overall network security and flexibility.

V.3.4 Moldova

Overview of network totals as well as generation per each type of technology (fuel) for observed regimes is given in the following tables.

Table 25 Totals - Moldova

MD	Max load		Max SPP		Max WPP + SPP	
	Ref	High	Ref	High	Ref	High
Load	1101.4	1101.4	855.1	855.1	689	689
Generation	1773	1795	617	657	768	953
Losses	26.6	26.1	29.9	32.5	40.5	78
Desired interchange	645	667	-268	-228	44	229

Table 26 Generation per technology - Moldova

MD	Generation (MW)					
	Max load		Max SPP		Max WPP + SPP	
	Ref	High	Ref	High	Ref	High
RoR	33	33	30	30	34	34
CHP	169	169	0	0	0	0
TPP	1520	1520	360	304	304	304
SPP	0	0	78	111	82	118
WPP	51	73	149	212	348	497

Some of the power generating units in the power system of Moldova are modeled as negative loads, defined according to results of market simulations. Renewables generation has been distributed proportionally to installed capacities found in the referent models.

Main characteristics of the observed regimes are the following:

- The Max load regime is the regime with both the highest export and consumption which is mostly supplied from thermal power plants.
- As for the Max SPP regime and Max SPP + WPP, the need for power generated from thermal power plants is greatly reduced due to the high integration of solar and wind capacities.
- In Max SPP + WPP regime, export is increased due to high RES generation, causing significant increase of 93% of losses in the system.

Overview of the voltages and loadings in the system is shown on the following tables. The most significant difference between referent and high RES scenario can be noticed in Max WPP + SPP regime, caused by high levels of generated power followed by decrease of overall voltages and increas of loading of elements.

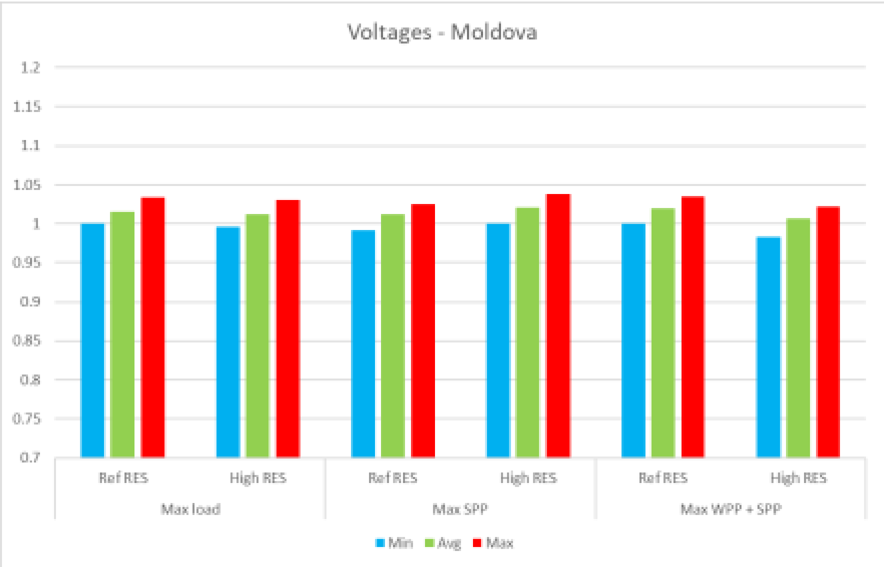


Figure 31 Overview of voltages – Moldova

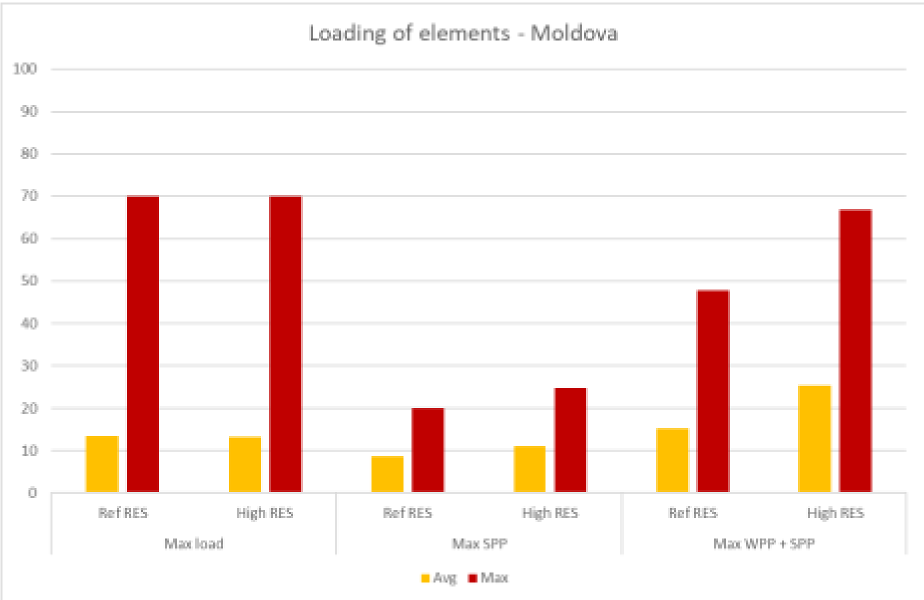


Figure 32 Overview of loadings - Moldova

Contingency analysis indicated possible voltage violations in the power system of Moldova. However, this is due to modeling of some of the generating units in the system. Specifically, when modeled as negative loads, generating units have no ability to regulate voltage and reactive power generation/consumption and are observed as constant PQ nodes. Consequently, voltages may not be realistic, since no regulation is possible in cases of contingencies.

It is highly recommended to model power generating units as machines, since voltage setpoint can then be defined and maintained at selected values, enabling better and more realistic voltage conditions.

V.3.5 Romania

Totals obtained in market simulations which are implemented in the network models and generation per technology (fuel) for the Romanian power system is given in the following tables.

Table 27 Totals - Romania

RO	Max load		Max SPP		Max WPP + SPP	
	Ref	High	Ref	High	Ref	High
Load	9311.8	9311.8	7425.8	7425.8	7281	7281
Generation	12708	12870	6898	7162	7638	9233
Losses	419.2	332.4	302.2	431.2	159	227
Desired interchange	2977	3139	-830	-566	198	1793

Table 28 Generation per technology - Romania

RO	Generation (MW)					
	Max load		Max SPP		Max WPP + SPP	
	Ref	High	Ref	High	Ref	High
RoR	1010	1010	1444	1444	1172	1172
Storage	3386	3386	310	0	0	0
TPP	5594	5594	3191	2283	2577	2227
Nuclear	1965	1965	0	0	0	0
SPP	0	0	1674	3097	1749	3236
WPP	753	914	278	337	2139	2597

In Romanian network model, renewables are modeled as machines and total RES generation obtained from market analyses is distributed between units proportionally to maximum defined power (installed capacities).

Main characteristics of the observed regimes are the following:

- In Max load regime, additional wind capacities in the high RES scenario causes reduction of network losses compared to referent RES scenario at level of 21%.

- In Max SPP regime, Romania is importing power despite high generation from solar power plants, which is almost double in high RES scenario compared to referent RES scenario.
- In Max WPP + SPP regime, high generation from both wind and solar power plants cause increased export of power, which is 9 times higher in high RES compared to referent RES scenario. Increase in export matches increase in solar generation.

As previously mentioned, in Max load regime losses are reduced 21% in high RES scenario compared to referent RES. In both Max SPP and Max SPP + WPP losses are increased 43% in cases of higher RES integration.

Load flow analyses performed on network models for observed scenarios show two loading violations that occur in Max SPP high RES scenario.

Table 29 Loading violations - Max SPP

Branch name	Rate [MVA]	Max SPP			
		Ref Res		High Res	
		Loading [MVA]	Loading [%]	Loading [MVA]	Loading [%]
400 kV Kozloduy - Tantareni	1188.5	below limit		1242.7	104.6
220 kV Slatina - Gradiste	285.1	below limit		306.6	107.5

Tie line 400 kV **Kozloduy - Tantareni circuit 1** between Bulgaria and Romania is highly loaded because of high power exchange (1500 MW from Romania to Bulgaria) in the observed scenario. However, second existing parallel circuit of this tie line is out of operation in the observed network state. In cases of high exchange of power between Romania and Bulgaria, second circuit **Kozloduy – Tantareni circuit 2** should be put into service in order to maintain secure network operating conditions. It is important to mention that both circuits have different ratings observed from Bulgarian (1310 MVA) and Romanian (1188.5 MVA) side.

Additionally, 220 kV line **Slatina – Gradiste** is highly loaded (107.5%) due to high generation of power from SPP in SS **Gradiste** and TPP Isalnita, which supply load in 220 kV SS **Slatina** and flows towards 400 kV voltage level.

Overview of the overall voltage conditions and loading in the system is given in the following diagrams, indicating expected increase of loading of elements and subsequent drop of voltages in high RES integration scenarios compared to referent RES scenarios.

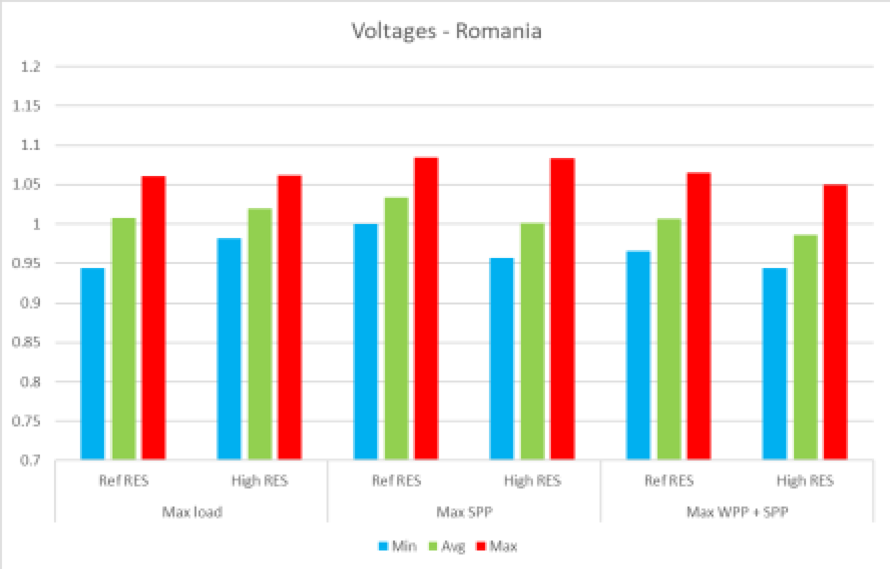


Figure 33 Overview of voltages - Romania

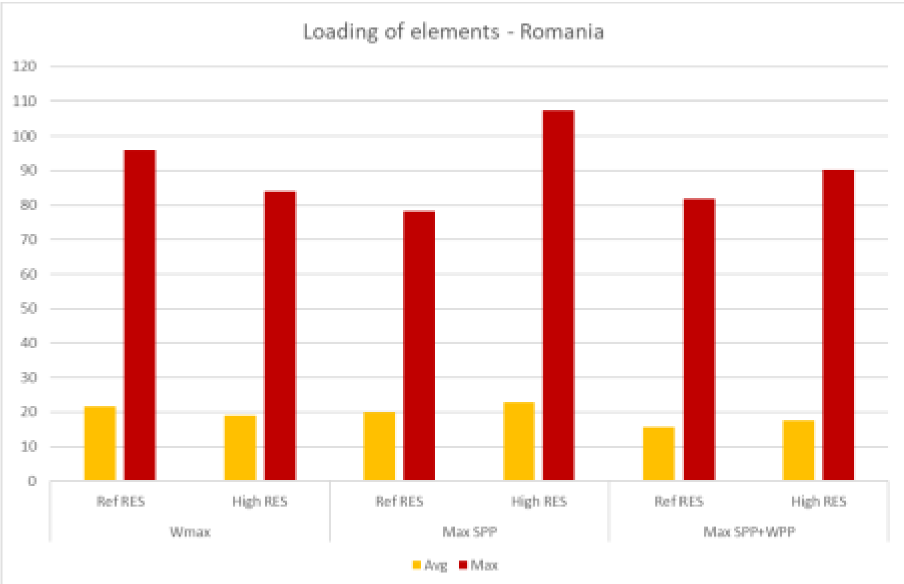


Figure 34 Overview of loadings - Romania

Contingency analyses performed on the observed network scenarios indicate several security violations:

- In Max load regime, in both referent and high RES scenarios, HPP Retezat is operating at full capacity (350 MW). In case of outage of 220 kV line **Hasdat - Pestis**, overloading is observed on 220 kV **Hasdat – Mintia** of 112.4% in referent RES and 102.3% in high RES scenario. In case of outage of 220 kV line **Hasdat – Mintia**, 220 kV line **Hasdat - Pestis** is overloaded – 116.5% in referent RES and 106.1% in high RES scenario.

- In Max load regime, in both referent and high RES scenarios, HPPs Lotru, Malaia and Bradisor are operating at high capacity (628 MW) causing loading of 220 kV lines **Lotru – Sobiu circuit 1** and 220 kV line **Lotru – Sobiu circuit 2** of around 70% each in referent RES and high RES scenarios. Consequently, outage of one of the lines causes overloading of the second line of up to 150%.
- In Max SPP regime, both referent RES and high RES scenario, TPP Isalnita operates at high capacity (582 MW), causing high loading of 220 kV lines **Isalnita A – Gradiste**, **Isalnita A – Craiova Nord circuit 1** and **Isalnita A – Craiova circuit 2** of around 74% percent each. Outage of 220 kV line **Isalnita A – Gradiste,** causes overloading on both 220 kV circuits **Isalnita A – Craiova Nord** lines of around 105% in referent RES and 109% in high RES scenarios. Also, outage of one circuit of 220 kV line **Isalnita A – Craiova Nord** causes overloading of the second circuit of 127% in referent RES and 133% in high RES scenario.+
- In Max SPP+WPP regime, 220 kV line **Slatina - Gradiste** is loaded 60% in referent RES and 86% in high RES scenario. Consequently, outage of 220 kV line **Slatina – Craiova circuit 2** causes overloading of 107% in referent RES and 145% in high RES scenario of 220 kV **Slatina – Gradiste** line.

In the observed regimes, internal 220 kV lines are highly loaded, mostly due to high generation from power plants, causing several loading violations. However, results show that there are just a few critical elements in Romania and that in all cases, problems exist already in referent RES scenario. It should be also noted that in some cases, violations are even relieved in high RES scenario, which points to the fact that observed critical elements are not new to the network operator or just provoked by additional RES capacities. In this kind of situations, when there are problems with evacuation of the generation, causing issues in the system, it is recommended to direct generation towards higher voltage level (400 kV). This improves security conditions and reduces losses in the system. In some cases, the solution could be proper topological changes, or, in other cases, upgrade of existing substations to higher voltage levels is recommended.

V.3.6 Ukraine

Results obtained from market simulations for selected timestamps which are applied to regional network models are given in the following tables.

Table 30 Totals - Ukraine

UA	Max load		Max SPP		Max WPP + SPP	
	Ref	High	Ref	High	Ref	High
Load	25290.7	25290.7	17853.5	17853.5	16760.9	16760.9
Generation	23642	23724	15692	18373	19834	20250
Losses	910.3	927.4	515.5	434.6	489.1	820.5

Desired interchange	-2559	-2477	-2677	4	2584	3000

Table 31 Generation per technology - Ukraine

UA	Generation (MW)					
	Max load		Max SPP		Max WPP + SPP	
	Ref	High	Ref	High	Ref	High
RoR	31	31	37	37	15	15
Storage	4217	4261	0	0	0	0
Pump storage	1296	1296	0	0	0	-3414
TPP	1492	1492	318	318	318	318
CHP	2960	2960	780	660	816	816
Nuclear	13132	13132	8374	8374	9895	9598
Biomass	440	440	440	440	440	440
SPP	0	0	4616	6840	4875	7224
WPP	74	112	1128	1705	3476	5254

Renewables are modeled as negative loads in the Ukrainian power system and summed RES generation obtained from market analyses is divided proportionally to values found in referent models.

Main characteristics of the observed regimes are the following:

- In Max load regime, the generation from renewable sources is at a minimum level and due to maximum load demand, loading of elements on a higher level, causing significant losses in the system, which are similar in both referent RES and high RES scenarios.
- In Max SPP regime, higher integration of solar power plants reduces the need for generation from thermal and nuclear power plants leading to increase of balance of the country, as well as decreased network losses in high RES compared to referent RES scenario.
- In Max WPP + SPP regime, increased production of solar and wind power plants in high RES scenario lead to significant export of power, as well as activation of pump storage facilities.

In Max load regime, losses in the system remain almost the same in high RES, as in referent RES scenario. In Max SPP, high solar generation causes decrease of import of power, reducing the losses 16% in high RES compared to referent RES scenario. In Max SPP + WPP scenario, however, losses are increased 68% due to significantly higher generation from renewables in high RES scenario and higher export.

Overview of the minimum, average and maximum voltage values, as well as maximum and average loading of elements is given in the following figures.

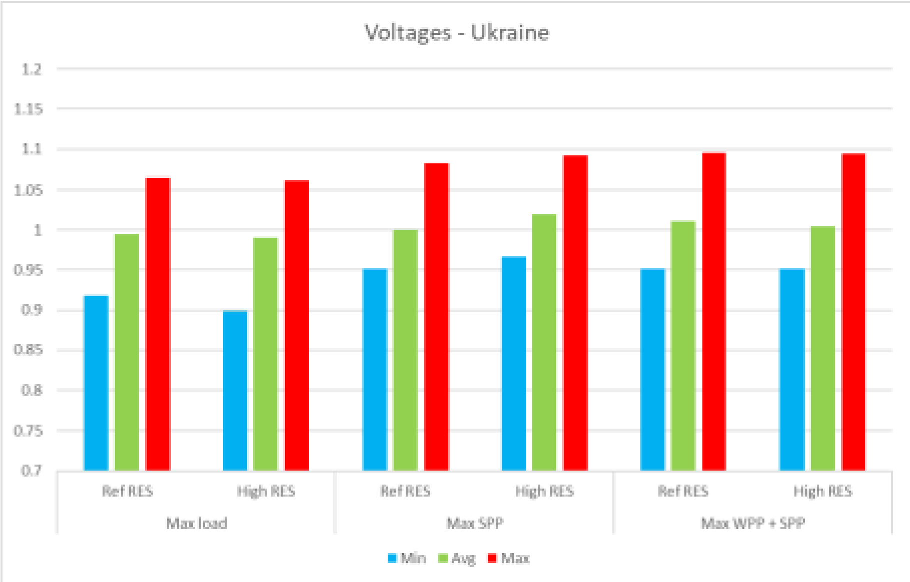


Figure 35: Overview of voltages – Ukraine

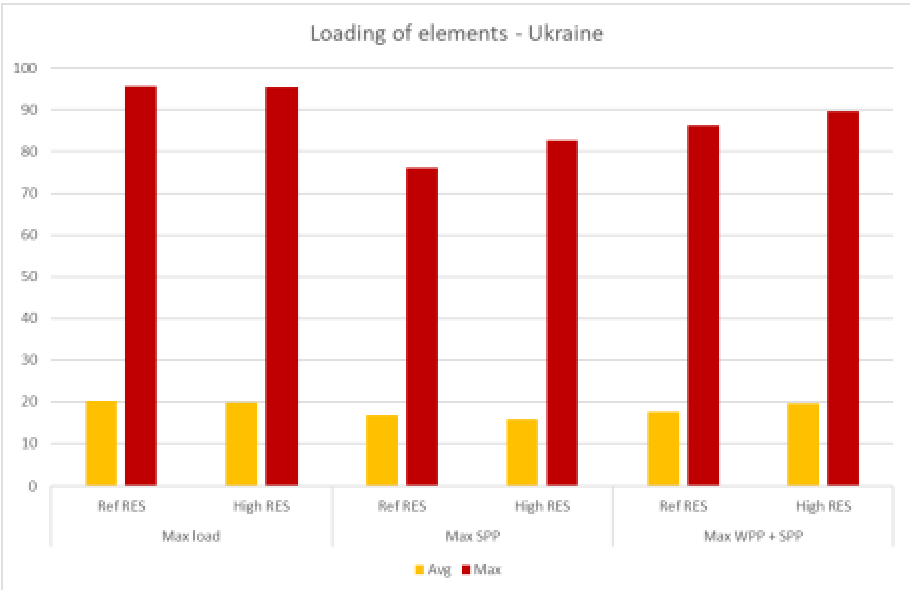


Figure 36: Overview of loadings - Ukraine

Voltages in the system are only slightly changed in all regimes, while loading of elements is reduced in Max load and Max SPP and increased in Max SPP+WPP when referent and high RES scenarios are compared.

No security violations are identified as a result of contingency analyses performed.

V.3.7 Turkey

Overview of overall load, generation, losses and balance as well as generation per each type of technology (fuel) for power system of Turkey is given in the following tables.

Table: 32 Totals - Turkey

TR	Max load		Max SPP		Max WPP + SPP	
	Ref	High	Ref	High	Ref	High
Load	56060	56060	53545	53545	50973.2	50973.2
Generation	54748	54748	52625	52625	49019	49019
Losses	1648	1507	2040	1392.7	1005.8	861.6
Desired interchange	-2960	-2960	-2960	-2960	-2960	-2960

Table 33: Generation per technology - Turkey

TR	Generation (MW)					
	Max load		Max SPP		Max WPP + SPP	
	Ref	High	Ref	High	Ref	High
RoR	3124	3124	4902	4902	2064	2064
Storage	14834	13926	15898	12633	8529	5986
TPP	30812	31587	13839	15024	13839	13839
Nuclear	4440	4440	3264	3264	3264	3264
SPP	0	0	12824	14740	11161	12829
WPP	1538	1671	1898	2062	10162	11037

Wind power plants in the Turkish power system are modeled as machines, so total generation obtained from market analyses is distributed between units proportionally to power generated in referent models. On the other hand, no specific locations were defined for solar generation, so overall load demand in the system was decreased for the amount of solar generation in the corresponding regimes.

Key characteristics of the observed regimes are the following:

- Turkey is importing power in all observed regimes.
- In Max load regime, majority of power is supplied from thermal power plants and hydro power plants.
- In Max SPP, significant amount of solar power is generated, reducing operation of thermal power plants by around 50%.
- In Max SPP+WPP, both solar and wind power plants are operating at a high capacity, covering 42% in referent RES and 47% in high RES, of total load.

In all observed regimes, losses in the system are reduced in high RES scenario, compared to referent RES scenario - Max load regime – 8%, Max SPP regime - 32% and Max SPP+WPP – 14%.

Overview of the minimum, average and maximum voltage values, as well as maximum and average loading of elements is given in the following figures.

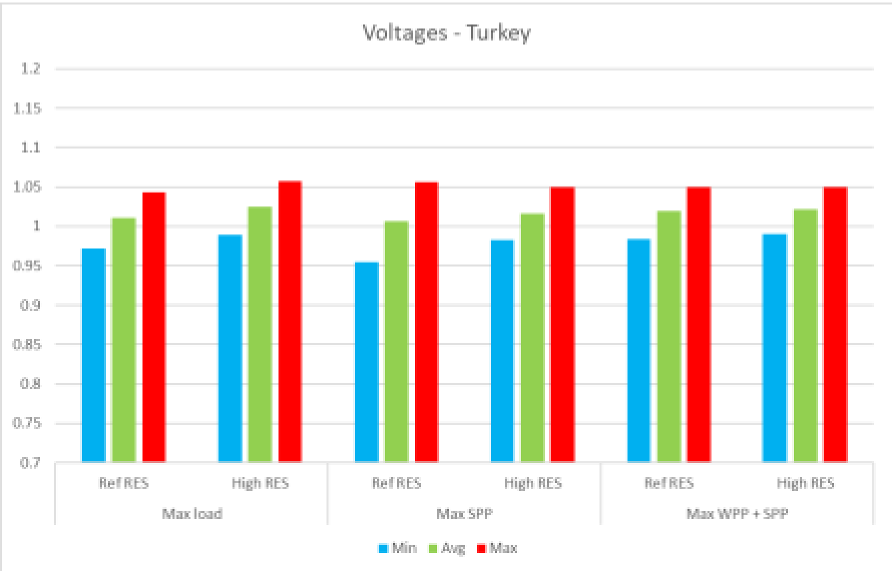


Figure 37: Overview of voltages – Turkey

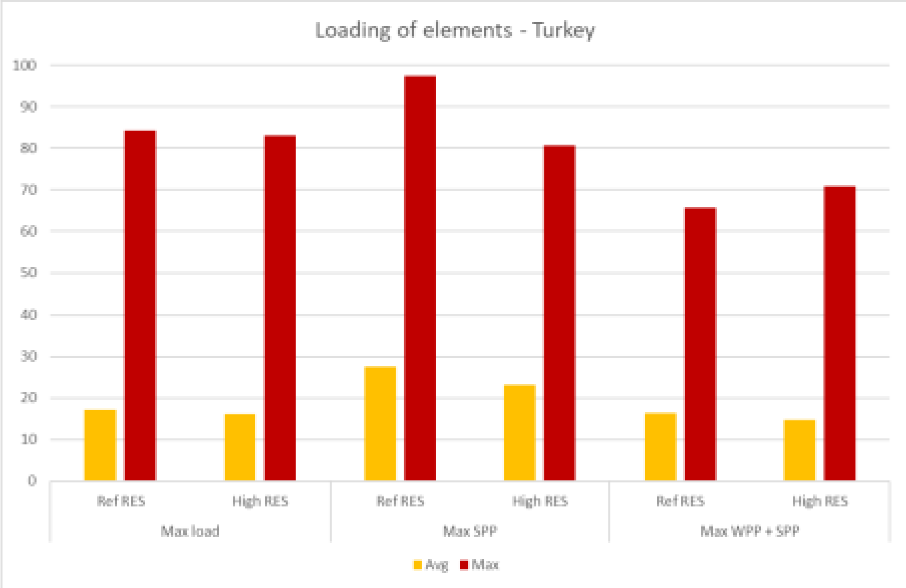


Figure 38: Overview of loadings – Turkey

Load flow analysis indicate slight decrease of loading in high RES scenarios of Max SPP and Max WPP compared to referent RES, which is followed by slight increase of voltages in the system. In Max load regime, no significant differences appear.

Contingency analyses performed on Turkish network for all analyzed regimes indicate several security violations:

- In Max load regime, in both referent RES and high RES scenarios, contingency of 400 kV line **Kartal – Yeni DGKCS** causes overloading of 125% of 400 kV line **Kucukbakkalkoy – Umraniye** which is already highly loaded (82%) in base case.
- In Max SPP regime, referent RES scenario 400 kV line **Adapazari – Izmit** is highly loaded (97%) and consequently, multiple contingencies cause overloading of the mentioned line, most significant being the overloading of 125% in case of contingency of 400 kV line **Adapazari – Tepeoren**. In high RES integration scenario, loading of 400 kV line **Adapazari – Izmit** is reduced to 81% in base case, which causes reduction of number of contingency violation issues to one. In case of the mentioned outage 400 kV line **Adapazari – Tepeoren**, loading of the **Adapazari – Izmit** is slightly above upper limit – 104.5%.
- Additionally in Max SPP regime, referent RES scenario, 400 kV line **Kursunlu – Kayabasi** is loaded 87% in base case which is followed by two overloadings: 112% in case of contingency of 400 kV line **Baglum – Cankiri – Kayabasi** and 106% in case of contingency of 400 kV line **Kursunlu – Boyabat**. As in previous case, loading of 400 kV line **Kursunlu – Kayabasi** is reduced in case of high RES integration scenario, eliminating all contingency violations.
- In the same scenario, contingency of 400 kV line **Resadiye – Kose,** causes overloading of 107% of 400 kV line **Altinordu – Tirebolu**, which is also resolved in high RES integration scenario.

In general, lower loading of the elements, followed by minimization of contingency violations in high RES scenario is due to the fact that solar generation in Turkey is modeled by reduction of total load in the system, which causes lower loadings of lines throughout the system, especially in Max SPP, high RES scenario.

However, in order to mitigate identified security violations, different measures should be analysed. In general, non-costly remedial actions in terms of topological changes in the network are often sufficient to reduce potential overloadings. Most often used non-costly remedial actions are switching on/off of lines and busbar couplers, adjustment of taps on power transformers or phase shifters and bus shunts commissioning. If no such remedial actions are identified as sufficient, costly measures must be taken into account, ranging from curtailment of RES to load shedding in more extreme cases.

V.4 Regional Summary

In general, high RES integration in the Black Sea Region causes no significant issues in the transmission network. In several cases, security violations that exist in the high voltage network in referent RES scenario are resolved by integration of high RES capacities at lower voltage levels, by relieving loading of elements caused by conventional flow of power from higher towards lower voltage levels.

Load flow simulations performed on updated network models indicate almost no violations of operational security limits in terms of voltages outside of permissible limits or overloading of elements for all countries. There are some violations in Georgia, Romania and Turkey.

In case of Georgia, some voltage violations and overloadings have been observed, but majority of them already exist in initial models and are not provoked by increase of RES capacities. Only in the Max WPP+SPP regime in high RES scenario, there is an overloading of 220 kV line **Jinvali – Qsani** (106%) and 220 kV line **Telavi – Gurajaani** (102%) with undervoltages in SS Bzifi (89%).

In case of Romania, 220 kV line **Slatina – Gradiste** is highly loaded (107.5%) in high RES scenario in Max SPP regime, due to high generation of power from SPP in SS **Gradiste** and TPP Isalnita, which supply load in 220 kV SS **Slatina** and flows towards 400 kV voltage level. Contingency analyses performed on the observed network scenarios indicate several security violations.

In the observed regimes, internal 220 kV lines are highly loaded, mostly due to high generation from power plants, causing several loading violations. However, results show that there are just a few critical elements in Romania and that in all cases, problems exist already in referent RES scenario. It should be also noted that in some cases, violations are even relieved in high RES scenario, which points to the fact that observed critical elements are not new to the network operator or just provoked by additional RES capacities. In this kind of situations, when there are problems with evacuation of the generation, causing issues in the system, it is recommended to direct generation towards higher voltage level (400 kV). This improves security conditions and reduces losses in the system. In some cases, the solution could be proper topological changes, or, in other cases, upgrade of existing substations to higher voltage levels is recommended.

In case of Turkey, contingency analyses indicated several security violations in 400 kV network. In almost all cases, violations are lower in high RES scenario due to the fact that solar generation in Turkey is modeled by reduction of total load in the system, which causes lower loadings of lines throughout the system, especially in Max SPP, high RES scenario.

However, in order to mitigate identified security violations, different measures should be analysed. In general, non-costly remedial actions in terms of topological changes in the network are often sufficient to reduce potential overloadings. Most often used non-costly remedial actions are switching on/off of lines and busbar couplers, adjustment of taps on power transformers or phase shifters and bus shunts commissioning. If no such remedial actions are identified as sufficient, costly measures must be taken into account, ranging from curtailment of RES to load shedding in more extreme cases.

Concerning the losses, summary for all analysed countries is presented in Table 34 and in Figure 39.

Table 34: Losses per country

Country	Losses (MW)					
	Max load		Max SPP		Max WPP + SPP	
	Ref	High	Ref	High	Ref	High
AM	40.4	37	46.7	59.2	54	41.8
BG	173.6	182.7	99.7	122.3	182.3	234.8
GE	125.9	117.7	171.7	195.2	96.9	237.7
MD	26.6	26.1	29.9	32.5	40.5	78
RO	419.2	332.4	302.2	431.2	159	227
UA	910.3	927.4	515.5	434.6	489.1	820.5
TR	1648	1507	2040	1392.7	1005.8	861.6
BSTP	3344	3130.3	3205.7	2667.7	2027.6	2501.4

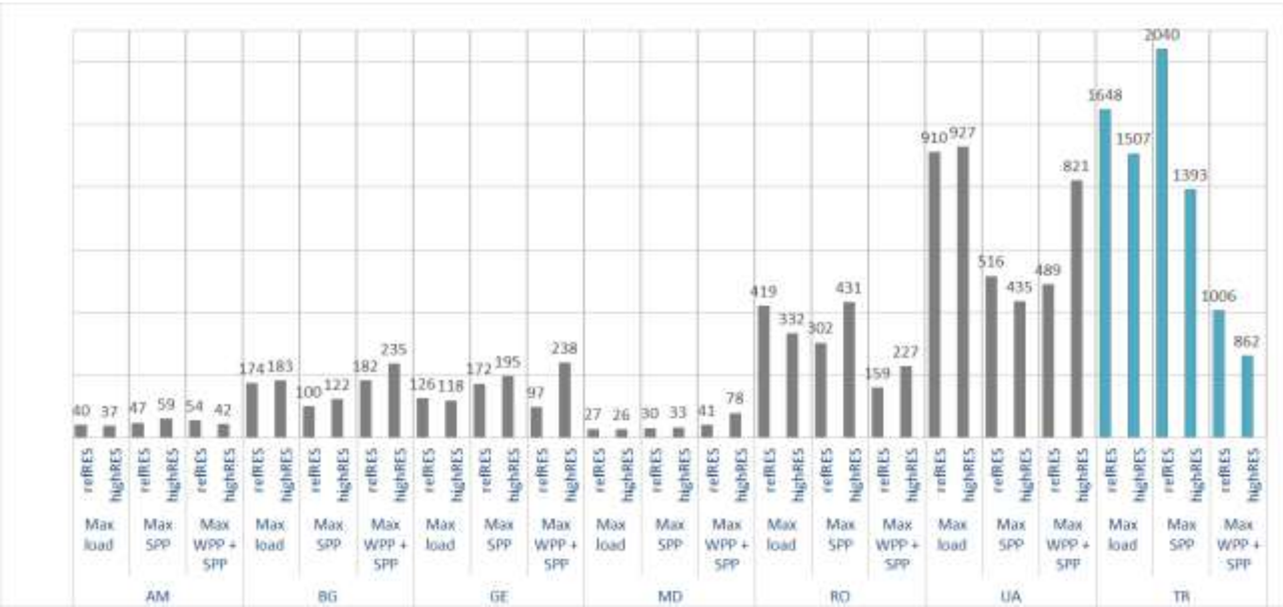


Figure 39: Losses in all regimes in all countries

In almost all countries, additional RES generation leads to increase in losses, except in Turkey where losses decrease has been detected in all regimes. The difference in losses is the lowest in Max load regime where RES generation is lower than in Max SPP and Max WPP+SPP regimes. In different regimes with Max SPP or Max WPP+SPP, countries also change their balance positions which provokes bigger changes in losses.

It should be also noted, that, for most countries, higher RES generation leads to increase of export.

VI. CONCLUSIONS

This study should help Black Sea TSOs better prepare for future large-scale RES integration and anticipate the expected changes in network and market operations that will take place as cross-border transactions and markets open up region wide.

The study addressed both how electricity markets and prices will be affected by substantial amounts of RES development, and how the transmission grid will need to adapt – both within the BSTP countries and between them – as RES becomes a more significant share of the generation mix by 2030.

The study results refer to the year 2030, with market analyses that included hourly simulations of the power system with subsequent results for each hour of the year and network analysis focused on snapshots at moments of network stress.

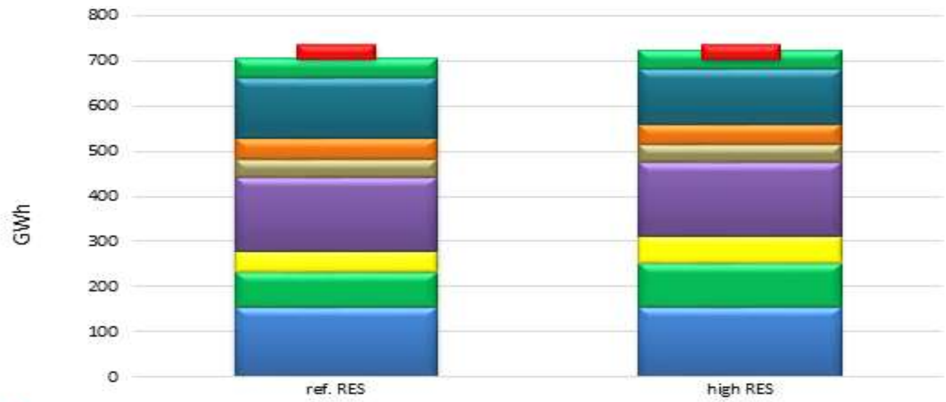
In Table 35 main results of Antares simulations are presented.

Table 35: Main system operating indicators for the BSTP region in 2030 – ref. RES vs high RES

Country	Scenario	RES (wind+solar) capacities (MW)	RES (wind+solar) capacities (GWh)	Consumption (GWh)	Generation (GWh)	Spillages (GWh)	Net interchange (GWh)	Prices ($/MWh)
AM	Ref	1,020	1,574	7,730	10,910	142	3,180	33.7
	High	1,250	1,936	7,730	10,003	432	2,273	22.7
BG	Ref	3,816	5,531	36,986	42,308	0	5,322	57.8
	High	4,770	6,914	37,076	43,098	0	6,022	55.9
GE	Ref	1,850	5,543	23,518	33,044	1,346	9,526	34.6
	High	4,700	12,369	23,822	36,783	3,373	12,961	23.1
MD	Ref	861	1,530	6,879	5,779	0	-1,100	57.8
	High	1,230	2,185	6,879	6,101	0	-778	54.9
RO	Ref	6,200	13,399	63,316	73,830	0	10,514	56.4
	High	8,800	18,406	63,316	76,049	0	12,733	54.1
UA	Ref	12,267	20,968	169,624	150,828	0	-18,796	62
	High	18,310	31,429	170,619	159,553	0	-11,066	56.8
TR	Ref	35,815	75,591	412,871	388,516	19	-24,355	70.6
	High	40,000	83,833	412,871	388,999	77	-23,872	69.2
BSTP	Ref	**61,829**	**124,135**	**720,924**	**705,215**	**1,507**	**-15,709**	**53.3**
	High	**79,060**	**157,072**	**722,313**	**720,586**	**3,882**	**-1,727**	**48.1**

Main conclusions based on the results of market simulations are as follows:

- Main technology in 2030 in BSTP region is nuclear technology (due to high nuclear generation in Ukraine) and it supplies more than 23% of the BSTP load. At similar levels there are hydro and gas technologies (21% and 18%), mainly due to high participation of these technologies in Turkish generation mix.
- RES generation (Wind + Solar) is also at similar level – 17% and 22% of the BSTP demand is supplied by RES technologies in 2030 which can be considered as high. Together with generation from hydro power plants, "green" energy supplies more than 40% of the regional demand.



	ref. RES	high RES
Other	43.4	43.0
Gas	133.3	121.0
Coal	47.4	46.3
Lignite	39.5	37.5
Nuclear	164.9	164.5
Solar	46.1	61.1
Wind	78.1	96.0
Hydro	154.0	155.0
Consumption	720.9	722.3

Figure 40: BSTP generation mix in 2030 - ref. RES vs high RES

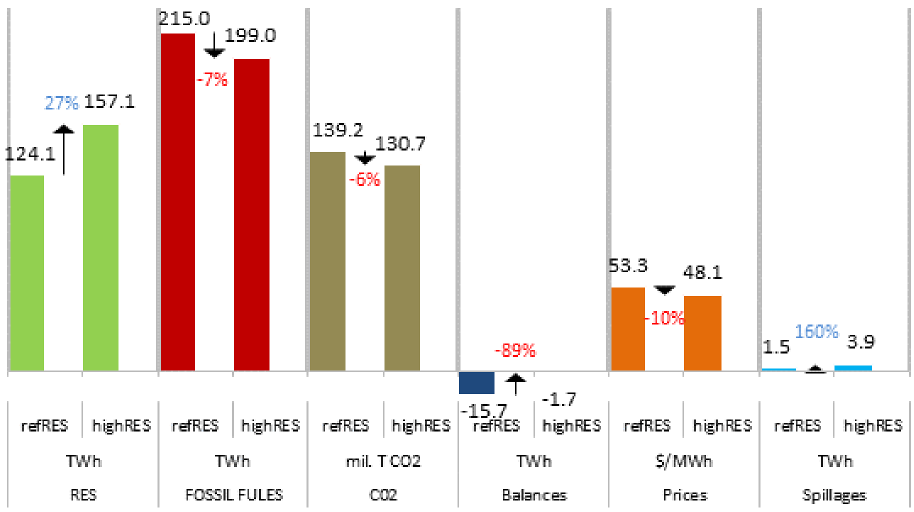


Figure 41: Main system operating indicators for the BSTP region in 2030 – ref. RES vs high RES

- As one of the main consequences of increased RES generation, TPPs generation falls, from 215 TWh to around 199 TWh (- 16 TWh). Decrease in TPPs generation is equally divided between gas and lignite/coal technologies pointing to the fact that all fossil fuel technologies will have reduced profitability.
- Together with decrease of fossil fuel fired TPPs generation, CO2 emission decrease from 139.2 mil.T to 130.7 mil.T (-6%).
- Considering that the region as a whole is importer, additional generation from RES will decrease the net import from 15.7 TWh to 1.7 TWh (-89%). Higher RES generation provokes decrease of TPPs generation but at the smaller level, and this leads to decrease of the net import. Changes in balance positions for all countries (Figure 41) shows that in almost all countries, due to additional RES generation, export is increased or import is decreased. The only different behavior can be seen in Armenia. The reason for this lies in extreme increase in RES generation in Georgia which push down thermal generation in Armenia and decreases its net export.

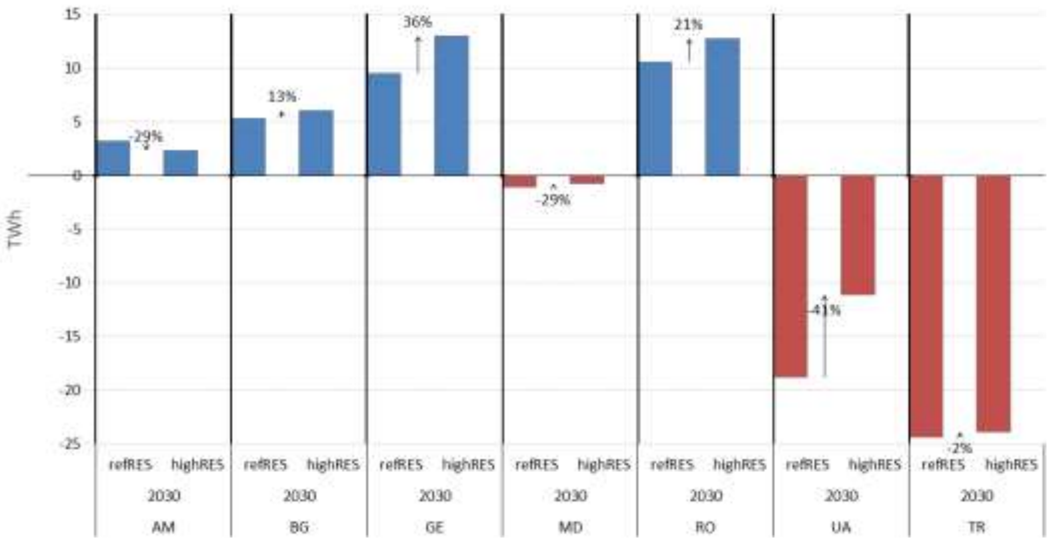


Figure 42: Balance positions per countries in 2030 - ref. RES vs high RES

- At the same time, higher RES generation leads to lower prices, due to the fact that cheaper power plants become marginal. The average annual price in BSTP region as a whole will fall from 53.3 $/MWh to 48.1 $/MWh (-10%).

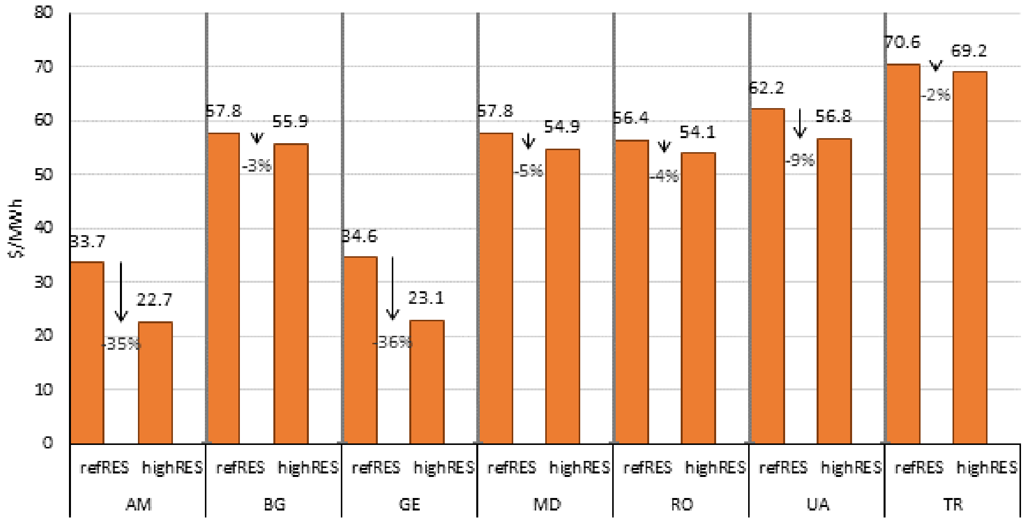


Figure 43: Average annual prices per BSTP country in 2030: ref. RES vs high RES

- BSTP countries are grouped in 3 price zones:
    - Armenia and Georgia (around 25-35$/MWh); Armenia and Georgia have lower prices than the central part of the BSTP region due to cheaper gas (and non-CO2 taxes) and excess of HPPs and RES generation
    - Bulgaria, Moldova, Romania and Ukraine (around 55$/MWh-60$/MWh) and
    - Turkey (around 70 $/MWh), since it is a big importing market zone.
- Regarding the decrease in prices, Armenia and Georgia will have the largest decrease (around 35%) mainly due to increased spillages. Having in mind that both countries are exporters, this could decrease benefits from energy trade. This big decrease in wholesale market prices may seriously endanger business environment for the thermal plants in both countries.
- In Armenia and Georgia higher RES generation will lead to increased spillages, due to the fact that in some hours generation is greater than consumption, cross border lines are congested and technical limitation of power plants don't allow a further decrease of generation. During these hours, part of RES generation has to be curtailed. With high RES generation, spillages in Armenia rise from 0.1 TWh to 0.4 TWh while in Georgia this increase is extreme: from 1.3 TWh to 3.3 TWh. Having in mind that these spillages present a big part of the RES and total generation of these countries, further investigations related to acceptable levels of RES capacities and introduction of flexibility levers are advised.
- In case of Ukraine and Turkey, high RES integration and prices decrease could have a positive impact on wholesale market and energy trade. However, maybe more interesting are expected changes in these power systems from today till 2030:
    - In case of Ukraine, large scale decommissioning of coal TPPs is envisaged till 2030 which will drastically change generation mix and balance: coal-fired TPPs generation will drop from around 50 TWh in 2017 to around 3.5 TWh in 2030. This drop will be partially compensated (hopefully) by large scale RES generation which will rise from around 2 TWh (in 2017) to 20 TWh in referent and 31 TWh in high RES scenario, but

balance will be changed from +5 TWh in 2017 to -19 TWh in referent RES and -11 TWh in high RES scenario in 2030.
  - In case of Turkey, expected consumption growth from 300 TWh to 412 TWh in 2030 will be hardly compensated with new HPPs, nuclear plants and rather high level of RES: +48 TWh in referent and + 56 TWh in high RES scenario, and Turkish import will increase from 2.7 TWh (2018) to 24 TWh.
- Having in mind that additional RES capacities, besides the needs for flexibility, also increase the needs for balancing reserve, we checked if the estimated required reserve (FCR+FRR) can be satisfied with unengaged capacity in TPPs and HPPs with storages. Results showed that in almost all countries, the required balancing reserve can be provided in all hours during the year in all analysed climatic years and hydrological conditions except:
  - In case of Georgia, where required balancing reserve of 390 MW cannot be satisfied in 65 and 56 hours during the year, in ref. and high RES scenarios respectively. Analyses showed that a lack of the balancing reserve can be expected practically only during the flooding season
  - In case of Romania, where required balancing reserve of 1400 MW cannot be satisfied in 251 and 230 hours in average, during the year, in ref. and high RES scenarios respectively. Analyses showed that lack of the balancing reserve can be expected in all seasons except in spring.

Concerning the network operation, in general, high RES integration in the Black Sea Region causes no significant issues in the transmission network. In several cases, security violations that already exist in the high voltage network in the referent RES scenario are resolved by the integration of more RES capacities at lower voltage levels and by relieving the loading of elements caused by the conventional flow of power from higher towards lower voltage levels.

In the observed regimes, problems have not been observed on tie lines, which is very important.

In just a few cases, security violations have been observed at internal lines (220 or 400 kV in Romania and Turkey) usually highly loaded, mostly due to the high generation from power plants. When there are problems with the evacuation of the generation, causing issues in the system, it is recommended to direct the generation towards a higher voltage level (400 kV). This improves security conditions and reduces losses in the system. In some cases, the solution could be proper topological changes, or, in other cases, the upgrade of existing substations to higher voltage levels is recommended.

The results of the analyses show that, for most countries, higher RES generation leads to an increase in the export of power. In order to enable evacuation of this amount of energy and avoid curtailment of RES capacities, strong interconnection and cross border mechanisms should be maintained.

In order to improve network flexibility and reliability, national Grid Codes should define all relevant requirements that newly connected RES power generating units should fulfill. This includes the provision of ancillary services such as balancing and frequency regulation, as well as voltage and reactive power regulation which improves security and enables flexibility in achieving optimum network operation.

Finally, RES generating capacities should be integrated into the network models as precisely as possible, in order to provide operational and planning engineers with the possibility to precisely analyse perspective network states and identify any potential issues that may occur. This precise modeling includes both active and reactive power capabilities of the generating units to be defined in the network models which enables higher model flexibility, better convergence and more accurate results.

Also, set of the border nodes and status and parameters of tie lines should be defined in cooperation between neighboring TSOs in order to ensure that updated national grid models may be easily integrated into the regional grid model, enabling the latest network improvements to be included.

VII. REFERENCES

[1] **"Identification of Appropriate Generation and System Adequacy Standards for the Internal Electricity Market"**; EC, 2016

[2] **"Assessing resource adequacy in an integrated EU power system"**, Wind Europe, 2016

[3] **"Zvit-z-otsinky-vidpovidnosti-dostatnosti-generuyuchyh-potuzhnostej**"; UKRENERGO, 2017

[4] **"TYNDP_GE-2019-2029_ENG"**; GSE, 2019

[5] **"MAF2019"**; ENTSO-E, 2019

[6] **TYNDP 2018,** ENTSO-E, 2018

[7] **TYNDP 2018,** ENTSO-E, 2018

[8] **IEA "Current Policies",** World Energy Outlook 2015

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VIII. APPENDIX – Market input data sets

VIII.1 Armenia

Armenia – Demand

Considering the annual growth rate of 1.7%, the forecasted Armenian consumption for the target year 2030 is approximately 7.7 TWh (Table 36). The expected peak load is approximately 1450 MW, while the expected minimum is approximately 465 MW. The load factor is nearly 61.6%. The highest consumption is observed in the winter months (December, January), while the lowest expected consumption is in the mid-Spring and Autumn months (April, May, September), as depicted in Figure 44.

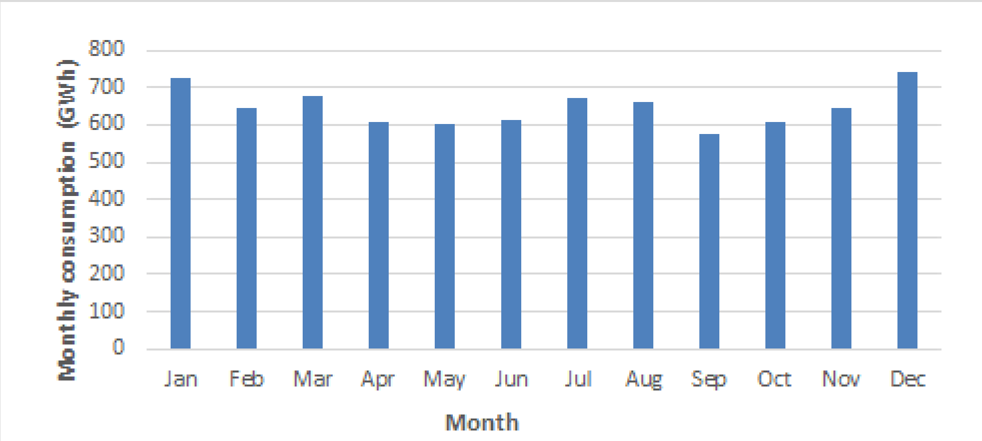

Figure 44: Monthly energy consumption (GWh) for 2030 – Armenia

Table 36: Forecasted demand in 2030 – Armenia

Country	Demand in 2017 (TWh)	Referent scenario	
		Growth rate from 2018 to 2030	Demand in 2030 (TWh)
AM	6.2	1.71%	7.7

Armenia – Generation

According to the data provided by the Armenian TSO, there are expected significant changes in installed capacities by the target year 2030. These include the decommissioning of TPP Hrazdan and commissioning of the new CCGT unit. Furthermore, wind and solar installed capacities will grow to

20 MW and 1000 MW, respectively. The commissioning of HPP Shnokh as well as an additional 59 MW of small HPPs will result in 1470 MW of HPP installed capacity.

Table 37: Installed capacities per technology in 2030 – Armenia

Technology	Installed capacity (MW)	
	2018	2030
Thermal - gas	1128	968
Thermal – nuclear	472	472
Hydro	1335	1470
Wind	4	20/50[9]
Solar	19	1000/1200[9]

With a primarily solar rise in forecasted RES development, the Armenian generation portfolio will diversify by the target year 2030. The share of gas and nuclear TPPs as well as HPPs in total installed capacity is approximately 37%, while RES share is approximately 26%.

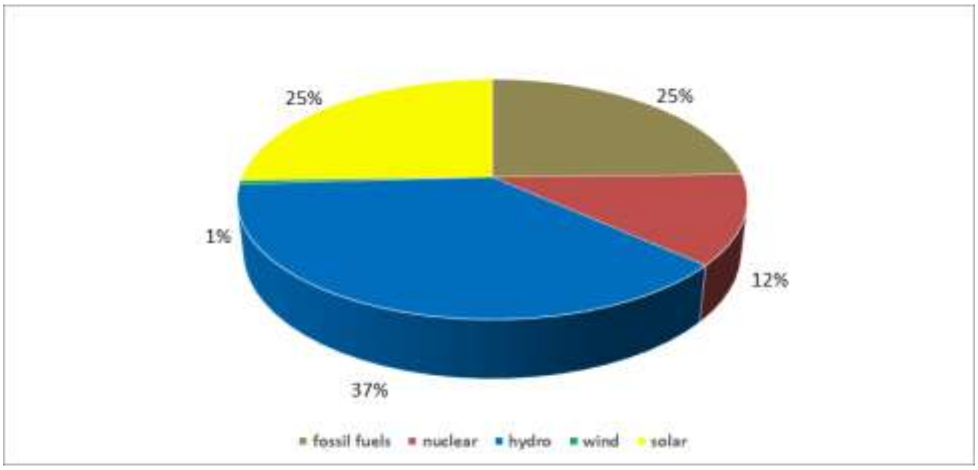

Figure 45: Installed capacity per fuel type in 2030 – Armenia

The techno-economic data for modeling of TPPs is given in Table 37. While the commissioning year and nominal output power were provided by TSO representatives, heat rate data is sourced from the TYNDP 2018 common base and fuel prices are taken from Georgia – Armenia HVDC study[10].

[9] Installed capacities expected in Referent/High RES Scenarios
[10] ARMENIA-GEORGIA SUB-REGIONAL TRANSMISSION PLANNING PROJECT: ECONOMIC ANALYSIS OF GEORGIA-ARMENIA INTERCONNECTION

Table 38: Armenia TPP data

Thermal Plant Name	Fuel type	Nominal Output Power [MW][11]	Heat Rate at Pmax [GJ/MWh]	Fuel price in 030 [$/GJ]	Variable O&M [$/MWh]	MOR (days)	FOR(%)	Min up time (h)	Min down time (h)	C02 (T/MWh)
ANPP	NUCLEAR	2 x 218	11	0.39	9	54	5	168	24	0
Hrazdan-5 TPP	CHP	468	8.8	5.41	1.76	27	5	3	5	0.50
YTPC CCGT	CCGT	235	7.5	5.41	1.76	27	5	8	4	0.43
CCGT-1 250	CCGT	235	6.21	5.41	1.76	27	5	8	4	0.35

For wind and solar, the hourly capacity factors are taken from publicly available databases developed by ETH Zurich[12] In addition, wind hourly capacities are then scaled to correspond to average annual levels of wind capacity factor given in the USAID Study[13]. Table 39 presents the average wind and solar capacity factors for varying climatic years.

Table 39: Average wind and solar capacity factors for climatic years 2006 to 2015 – Armenia

Armenia – average wind and solar capacity factors										
Year	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Wind CF	22.1%	22.1%	19.7%	21.9%	21.7%	18.6%	20.4%	22.4%	20.6%	21.5%
Solar CF	17.70%	17.85%	18.06%	17.29%	17.33%	17.51%	17.52%	17.71%	17.43%	17.42%

The annual HPPs generation for the target year 2030, considering variant hydrological conditions, is given in Table 40:

Table 40: Annual generation for all HPPs for dry, average and wet hydrology in 2030– Armenia

Annual generation (GWh)	Dry	Average	Wet
ROR	1906	1940	2284
HPPs with reservoirs	832	989	1306

[11] Nominal power output is the net capacity (without self consumption)
[12] https://www.renewables.ninja/
[13] WIND ENERGY IN ARMENIA: OVERVIEW OF POTENTIAL AND DEVELOPMENT PERSPECTIVIES, 2010

Total	2738	2929	3590

VIII.2 Bulgaria

Bulgaria – Demand

The forecasted consumption in the ESO EAD market area is 37.4 TWh for the target year 2030, as described in Table 41. The observed peak load is 7054 MW with a load factor of 60.93%, while the minimum load is approximately 2443 MW. The highest monthly consumption is observed during Winter, while the lowest consumption occurs in Spring and September, although a rather flat profile can be observed in the central part of the year (Figure 46).

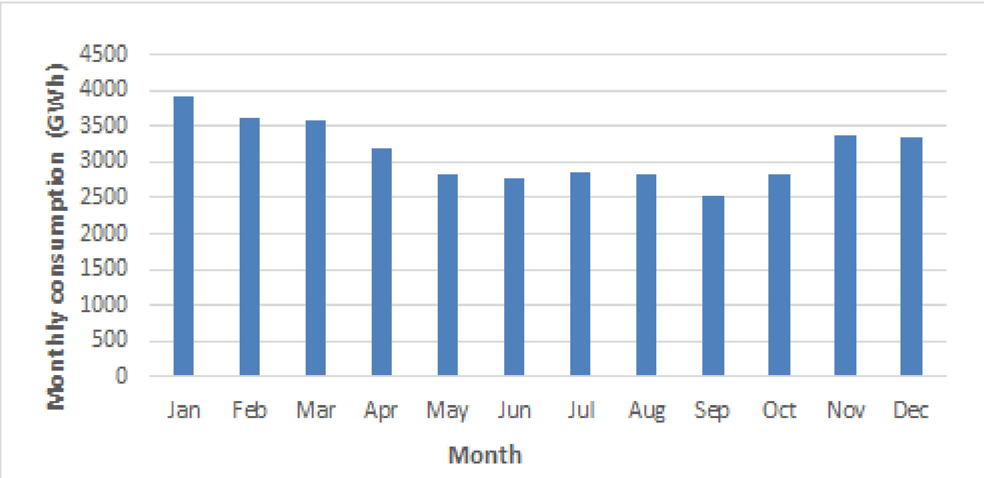

Figure 46: Monthly energy consumption (GWh) for 2030 – Bulgaria

Table 41: Referent and low demand scenarios in 2030 – Bulgaria

Country	Demand in 2018 (TWh)	Referent scenario	
		Growth rate from 2020 to 2030	Demand in 2030 (TWh)
BG	34.1	0.76%	37.35

Bulgaria – Production

In 2030, Bulgaria will have a balanced and diversified electricity production mix. Approximately 53% of the installed capacity is resultant of thermal plants, primarily the nuclear and lignite plants. The installed capacity in wind and solar renewables will rise to 3,816 MW in 2030, while the hydro generation will stay at the 2018 rate and will amount to approximately 22% of total installed capacity

(Table 42 and Figure 47). TPP Sliven, the only hard coal-fired thermal power plant in Bulgaria, will be decommissioned by 2030.

Table 42: Installed capacities per technology in 2030 – Bulgaria

Technology	Installed capacity (MW)	
	2018	**2030**
Thermal - Lignite	3894	2508
Thermal - Gas	1368	2611
Thermal - Hard Coal	30	0
Thermal – Nuclear	2150	2150
Hydro	3207	3207
Wind	700	887/1109[9]
Solar	1052	2929/3661[9]

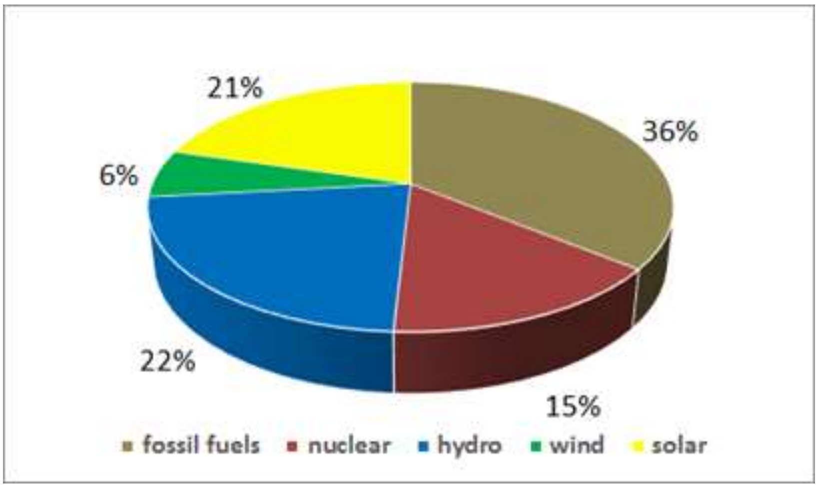

Figure 47: Installed capacity per fuel type in 2030 – Bulgaria

Table 43 shows the average annual capacity factors for wind and solar power plants, calculated based on time series, as provided by the ESO EAD.

Table 43: Average annual wind and solar capacity factors from 2006 - 2015 – Bulgaria

Bulgaria - average wind and solar capacity factors										
Year	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Wind CF	21.87%	21.20%	19.99%	19.90%	21.19%	20.94%	24.21%	21.21%	21.54%	24.86%
Solar CF	14.99%	15.28%	15.50%	14.90%	14.69%	15.18%	15.46%	15.06%	14.43%	14.92%

The annual generation of all HPPs for variant hydrological conditions are given in Table 44. The ESO EAD did not provide generation data for dry and wet hydrological conditions. Therefore, these values were calculated by the Consultant, using 20% lower values for dry hydrology and 20% higher values for wet hydrology.

Table 44: Annual generation for all HPPs for dry, average and wet hydrology – Bulgaria

Annual generation (GWh)	Dry	Average	Wet
ROR	1365	1706	2047
HPPs with reservoirs	2516	3145	3774
Total	3881	4851	5821

Table 45 shows the data necessary for modeling the PSHPPs for the target year 2030. The overall efficiency of the PSHPP is estimated by the Consultant, while additional data was provided by the ESO EAD.

Table 45: PSHPP data – Bulgaria

Name	Number of units	Pgen (MW)	Ppump (MW)	Efficiency
PSHPP Chaira	4	216	198	75%
PSHPP Belmeken	2	75	52	75%
PSHPP Orfei	1	40	40	75%

VIII.3 Georgia

Georgia – Demand

The Georgian peak load for the target year 2030 is approximately 4,155 MW, with a minimum load of approximately 1,480 MW. The load factor is expected to be 64.4%. The yearly consumption shows a typical seasonal pattern, with the highest monthly consumption anticipated in Winter and Summer months, while the lowest consumption will occur in Spring and Autumn, as depicted in Figure 48.

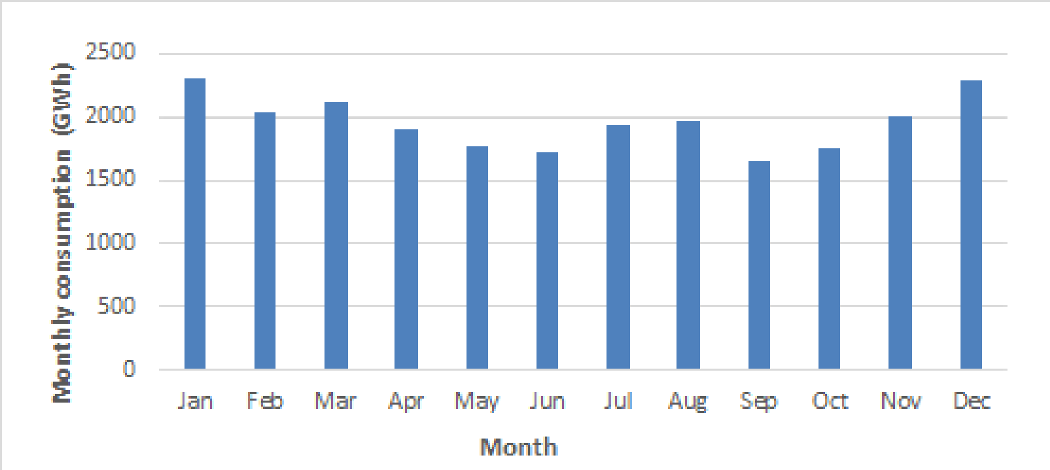

Figure 48: Monthly energy consumption (GWh) for 2030 – Georgia

The total consumption for the target year 2030 is approximately 23.34 TWh, which corresponds to 5% of the annual growth rate between 2018 and 2030.

Table 46: Expected demand in 2030 – Georgia

Country	Demand in 2019 (TWh)	Referent scenario	
		Growth rate from 2018 to 2030	Demand in 2030 (TWh)
GE	13.65	5 %	23.34

Georgia – Generation

The Georgian HPP installed capacities are expected to double by the target year 2030, by a substantial increase in RES penetration. In the referent RES case, 1300 MW of wind and 550 MW of solar capacities are expected. A new 300 MW coal TPP and new 250 MW CCGT are envisaged also, while the gas fired Tbiliresi TPP will be decommissioned.

Table 47: Installed capacities per technology in 2030 – Georgia

Technology	Installed capacity (MW)	
	2018	2030
Thermal - gas	912	890
Thermal - coal	13	300
Hydro	3070	6271
Wind	21	1300/2500[9]
Solar	0	550/2200[9]

Considering the expected high HPP development and relatively high RES penetration, nearly 80% of installed capacities will be HPPs, 6% will be RES and the rest will be coal and gas TPPs by the target year 2030. Please see Figure 49:

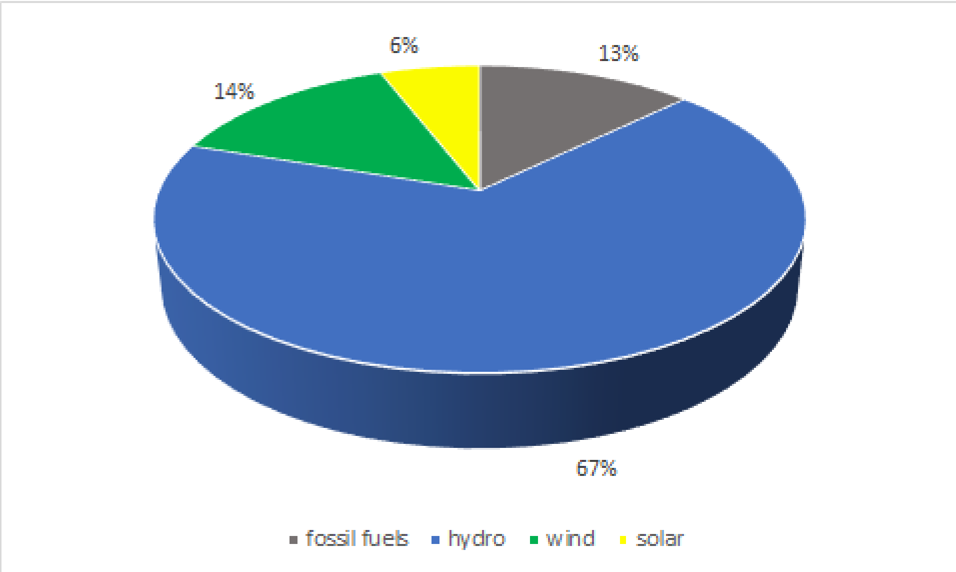

Figure 49: Installed capacity per fuel type in 2030 – Georgia

The basic techno-economic parameters for existing and new TPPs are presented in the following table. All data regarding the TPP status, installed capacity and marginal prices for TPPs were provided by GSE.

Table 48: Basic Parameters of Existing and New TPPs in Georgia

Thermal Plant	Fuel type	No of units	Unit	In operation in 2018 [Yes/No]	In operation in 2030 [Yes/No]	Nominal Output	Marginal price [$/MWh]

						Power [MW][14]	
Mtkvari	Gas	1	1	Yes	Yes	250	40.90
Gpower	Gas	2	1	Yes	Yes	85	38.93
			2	Yes	Yes		
Gardabani CCGT	CCGT	3	1, 2,3	Yes	Yes	230	29.19
1-Thermal	CCGT	1	1	No	Yes	235	29.19
2-Thermal	Coal	1	1	No	Yes	282	28.24

On the basis of the hourly profiles of capacity factors for wind and solar generation extracted from the online database[15], the average annual capacity factors for varying climatic years are calculated and presented in Table 49:

Table 49: Average wind and solar capacity factors for climatic years 2006 to 2015 – Georgia

Georgia – average wind and solar capacity factors										
Year	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Wind CF	43.12%	46.07%	46.71%	45.66%	41.76%	44.98%	46.17%	46.19%	47.83%	48.51%
Solar CF	16.75%	16.95%	17.51%	16.88%	16.92%	16.46%	17.03%	17.66%	17.57%	17.28%

Hourly capacity factors taken from the online database, have been scalled to correspond to average capacity factors provided by GSE:

- Average capacity factor for wind: 45.7%
- Average capacity factor for solar: 17.1%

The hydro generations for average, dry and wet hydrology were provided by GSE, on a plant by plant level. The total annual generation for Run of River and storage HPPs, varying hydrology conditions for the target year 2030 and in accordance with the expected development plan, are given in Table 50.

Table 50: Annual generation for all HPPs for dry, average and wet hydrology – Georgia, expected development plan, 2030

[14] Nominal power output is the net capacity with output power limitations
[15] www.ninjarenewables.com

Annual generation (GWh)	Dry	Average	wet
ROR	6933	11489	14257
HPPs with reservoirs	7431	12350	15286
Total	14364	23839	29543

As a new facility available from 2030, PSP Enguri has been modeled with the following characteristics:

- Nominal capacity of the PSP (turb/pump) = 570/570 MW
- Upper reservoir is Enguri reservoir with size of 631.92 GWh
- Tail storage size = 2.93 GWh (2930 MWh)
- PSP operates in CLOSED CYCLE with 70% efficiency

VIII.4 Moldova

Moldova – Demand

The Moldovan expected peak load is approximately 1140 MW, with a minimum load of approximately 445 MW for the target year 2030. The load factor will be 69%, and consumption shows typical seasonality, as it is depicted in Figure 50 below:

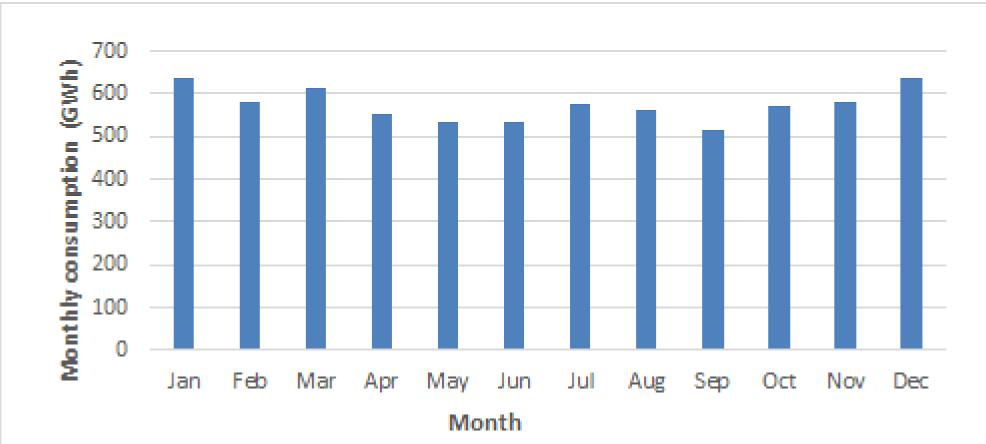

Figure 50: Monthly energy consumption (GWh) for 2030 – Moldova

Based on the data provided by Moldelectrica, the expected annual growth of consumption between 2018 and 2030 is approximately 1.09%. As a result, the expected annual consumption in 2030 is around 6.9 TWh (Table 51).

Table 51: Expected demand in 2030 – Moldova

Country	Demand in 2018 (TWh)	Referent scenario	
		Growth rate from 2018 to 2030	Demand in 2030 (TWh)
MD	6.06	1.09%	6.9

Moldova – Production

In 2030, the Moldovan generation fleet will still rely primarily on fossil fuel with almost 75% in installed capacities. Nevertheless, a significant increase in RES share is expected. The installed capacities of RES will grow from a negligible rate to up to 24% of the entire generation fleet. The total installed capacities will increase from 2743 MW to 3565 MW as indicated in Table 52 and Figure 51:

Table 52: Installed capacities per technology in 2030 – Moldova

Technology	Installed capacity (MW)	
	2018	2030
Thermal – coal	1520	1520
Thermal - gas	1128	1123
Hydro	61	61
Wind	31	742/1060[9]
Solar	3	119/170[9]

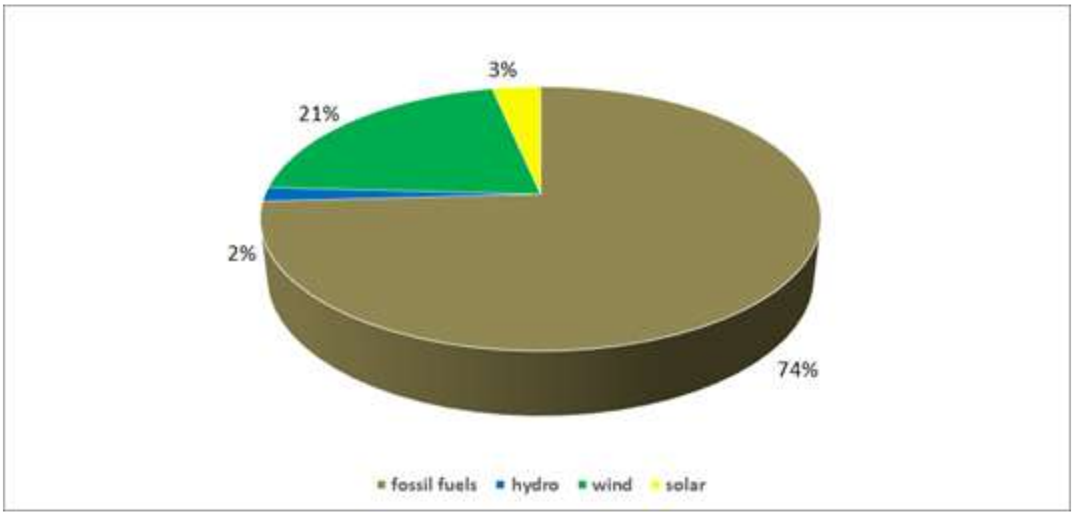

Figure 51: Installed capacity per fuel type in 2030 – Moldova

Table 53 shows the annual average wind and solar capacity factors, for variant climatic years.

The solar hourly capacity factors are procured from an online database[16], while wind hourly capacity factors are calculated using the same online source and the Romanian average annual capacity factor.

Table 53: Average wind and solar capacity factors from 2006 – 2015 - Moldova

Moldova – average wind and solar capacity factors										
Year	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Wind CF	21.45%	22.32%	21.85%	20.63%	21.19%	20.18%	21.48%	22.09%	20.32%	21.68%
Solar CF	14.11%	14.66%	14.12%	13.80%	13.59%	14.56%	14.60%	14.11%	13.94%	14.11%

In the case of hydro power plants, Moldelectrica only provided the expected generation for average hydrology, while the expected generation in a case of dry and wet hydrological conditions is concluded as 80% and 120% of the average generation. Please see Table 54:

Table 54: Annual generation for all HPPs for dry, average and wet hydrology - Moldova

[16] https://www.renewables.ninja/

Annual generation (GWh)	Dry	Average	wet
ROR	221	276	331
HPPs with reservoirs	0	0	0
Total	220	276	331

VIII.5 Romania

Romania – Demand

Regarding load and production, the Romanian power system is one of the largest power systems in the region. The highest monthly consumption occurs during the Winter (especially in January and December), while the lowest monthly consumption is present in April or June, as depicted in Figure 52 below:

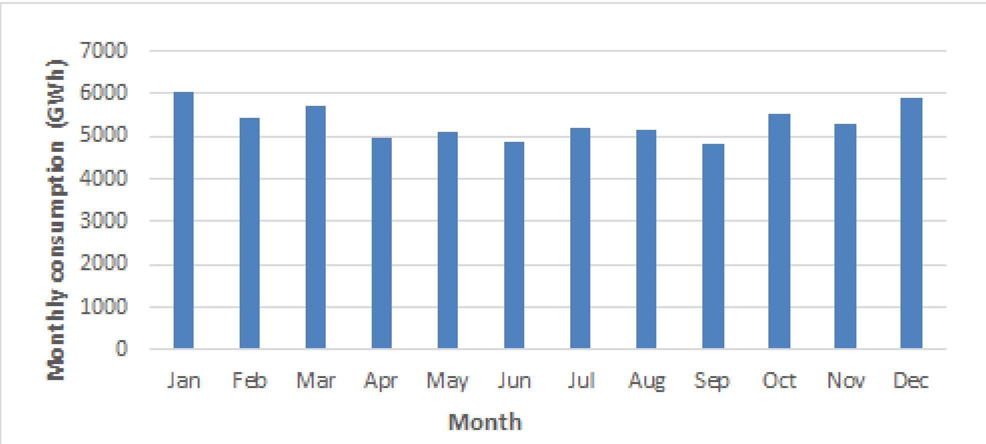

Figure 52: Monthly energy consumption (GWh) for 2030 – Romania

The total consumption in the referent scenario is expected to be 63.5 TWh in 2030 (Table 55).

Table 55: Forecasted annual demand in 2030 – Romania

Country	Demand in 2018 (TWh)	Referent scenario	
		Growth rate from 2018 to 2030	Demand in 2030 (TWh)
RO	57.9	0.81%	63.50

Romania – Production

Romania's electricity mix is one of the most balanced in the European Union. Table 56 provides a detailed breakdown of installed generation capacity, broken down by technology, for the target year 2030. The share of installed capacity for TPPs is expected to be 29% of the total installed generation capacity. Nuclear power is prominent in the Romanian generation mix, with a share of approximately 9% of installed power. Hydropower will also have a significant share: 31%.

Table 56: Installed capacities per technology in 2030 – Romania

Technology	Installed capacity (MW)	
	2018	2030
Thermal - lignite	3073	3073
Thermal - gas	2672	2835
Thermal - hard coal	1032	412
Thermal - nuclear	1300	1965
Thermal - biomass	121	350/500[9]
Hydro	6420	6742
Wind	2977	4200/5100[9]
Solar	1262	2000/3700[9]

Renewable power is expected to play a very significant role in the Romanian power system, as wind and solar power are expected to have a 29% share of the energy mix by 2030. Wind power plants are expected to contribute 20% and solar power plants 9% of the total generation capacity. In addition to wind and solar, biomass is expected to contribute a share of 2%. A detailed representation of the generation mix of the Romanian power system is given in Figure 53:

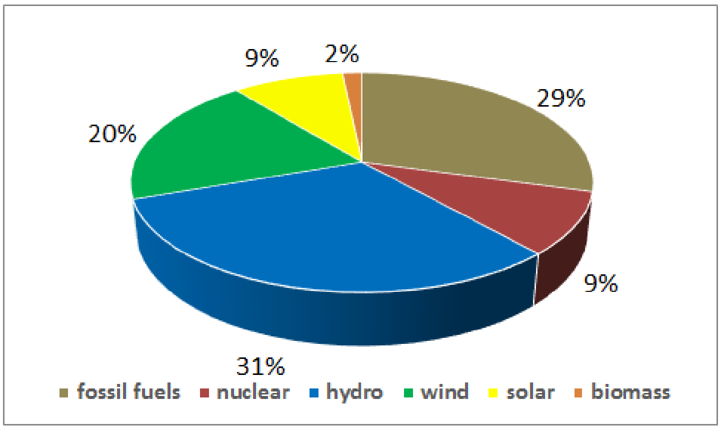

Figure 53: Installed capacity per fuel type in 2030 – Romania

On the basis of the TSO's hourly profiles of capacity factors for wind and solar generation, Table 57 depicts the average capacity factors for the following climatic years:

Table 57: Average wind and solar capacity factors from 2006 to 2015 – Romania

Romania - average wind and solar capacity factors										
Year	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Wind CF	26.5%	27.7%	27.3%	25.6%	28.2%	25.0%	28.9%	27.9%	28.3%	28.2%
Solar CF	19.11%	19.48%	19.46%	19.09%	18.53%	19.62%	19.70%	19.19%	18.62%	19.18%

Transelectrica provided detailed data for hydro generation for average and dry hydrology, while the data related to wet hydrology is taken from the datasets provided by the TSO for the BSTP System Adequacy Study completed in 2019. The total annual generation for Run of River (ROR) and storage HPPs (with reservoir) are given in Table 58:

Table 58: Annual generation for all HPPs for dry, average and wet hydrology – Romania

Annual generation (GWh)	Dry	Average	Wet
ROR	8297	10371	11408
HPPs with reservoirs	4443	5553	6109
Total	12739	15924	17517

VIII.6 Ukraine

Ukraine – Demand

The forecasted consumption in Ukraine is 169 TWh in 2030 (Table 59), with 1.05% of annual growth. The expected peak load is slightly above 27,000 MW, the minimum load is around 14,700 MW and the load factor is 71.2%. The highest monthly consumption is anticipated in the Winter season (December, January), while the lowest consumption will occur from mid-Spring to early Autumn (May-September), as shown in Figure 54.

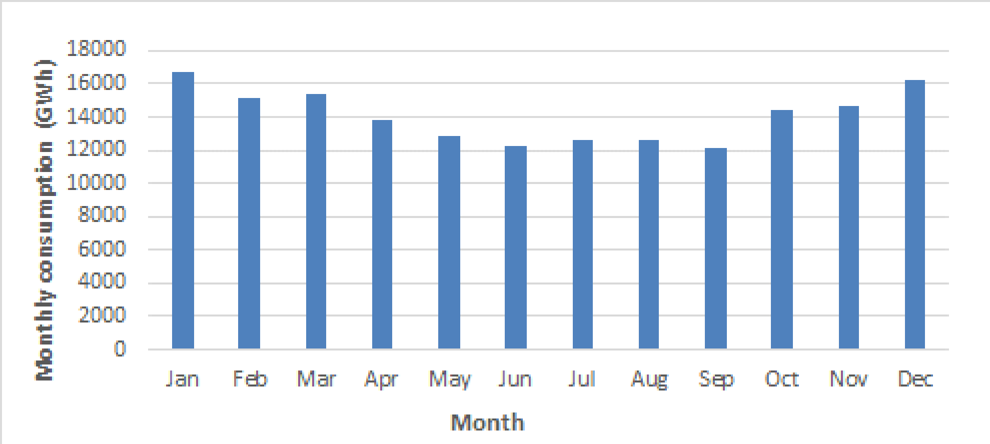

Figure 54: Monthly energy consumption (GWh) for 2030 – Ukraine

Table 59: Expected demand in 2030 – Ukraine

Country	Demand in 2018 (TWh)	Referent scenario	
		Growth rate from 2018 to 2030	Demand in 2030 (TWh)
UA	149.13	1.05%	169

Ukraine – Production

According to data provided by Ukrenergo (Table 60), two parallel processes are envisaged by the target year 2030: a substantial decrease in fossil fuel (from around 16500 MW to around 2500 MW) installed capacities and a significant increase in RES capacities (from 3500 MW to nearly 12500 MW). Also, pumped storage capacity will grow from 1509 MW to 2838 MW. By 2030, the Ukrainian power system is expected to diversify as follows: Only 15% of installed capacities will be fossil fuels based, 34% will be NPPs and approximately 32% will be RES (mainly wind and solar). Please see Table 60 and Figure 55 below:

Table 60: Installed capacities per technology in 2030 – Ukraine

Technology	Installed capacity (MW)	
	2018	2030
Thermal - CHP	2484	1818
Thermal - coal	16514[17]	2648
Thermal - nuclear	13835	13835
Thermal - blockstation	1769	1580
Hydro - PS	1509	2838
Hydro - small	67	80
Thermal - biomass	100	550 / 943[9]
Hydro	4637	4762
Wind	704	4393 / 6641 [9]
Solar	2667	7874 / 11669[9]

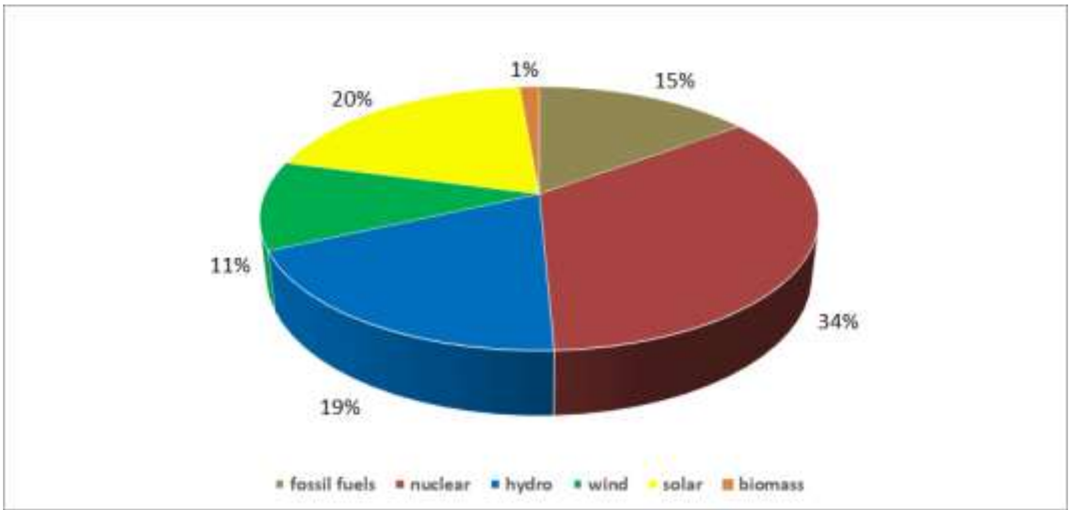

Figure 55: Installed capacity per fuel type in 2030 – Ukraine

[17] Including Kharivksa and Kyivska CHP

The average annual wind and solar capacity factors for the 2006-2015 climatic years are given in Table 61. They are calculated from hourly capacity factors, which are taken from a publicly available online database[18] and scaled to average more realistic values.

Table 61: Average wind and solar capacity factors for climatic years 2006 to 2015 – Ukraine

Ukraine – average wind and solar capacity factors										
Year	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Wind CF	30.48%	31.96%	31.46%	29.17%	33.64%	30.61%	31.17%	29.55%	29.55%	35.42%
Solar CF	12.78%	13.34%	13.09%	12.69%	12.82%	13.31%	13.46%	12.84%	12.84%	12.80%

Table 62 shows the generation of large HPPs on an annual basis, concerning dry, average and wet hydrology. All figures presented below are provided by Ukrenergo.

Table 62: Annual generation for all HPPs for dry, average and wet hydrology – Ukraine

Annual generation (GWh)	Dry	Average	wet
ROR	219	265	323
HPPs with reservoirs	6101	9265	11585
Total	6320	9530	11908

Table 63 contains data provided by Ukrenergo and is used to model the Ukrainian PSHPP in ANTARES software.

Table 63: PSHPP data – Ukraine

Name	Number of units	Pgen (MW)	Ppump (MW)	Efficiency
Kyivska PSHPP	6	40	45	67%
Dnistrovska PSHPP	3 (4 in 2030)	324	421	77%
Tashlytska PSHPP	2	151	210	72%
Kanivska PSHSPP	0 (4 in 2030)	250	260	78%

[18] https://www.renewables.ninja/

VIII.7 Turkey

Turkey – Demand

The data related to the Turkish hourly load profile for 2030 was calculated on the basis of realized load for 2015, climatic data for the period of 2006-2015 and forecasted total consumption of 414 TWh (Table 64), provided by TEIAS. In 2030, the peak load is approximately 67 GW, with the minimum load approximately 35 GW. The load factor will be approximately 70%. The highest consumption is observed in July and August, while the lowest consumption is present during Spring and Autumn months, as depicted in Figure 56:

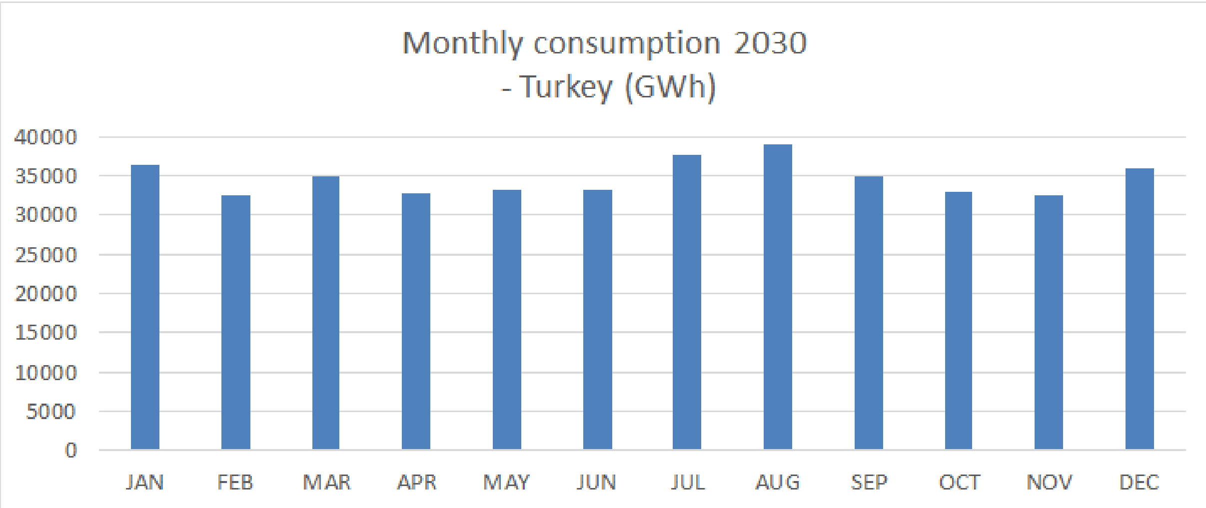

Figure 56: Monthly energy consumption (GWh) for 2030 – Turkey

Table 64: Expected demand in 2030 – Turkey

Country	Demand in 2018 (TWh)	Referent scenario	
		Growth rate from 2018 to 2030	Demand in 2030 (TWh)
TR	301	2.7%	414

Turkey – Production

On the basis of the data provided by TEIAS for the planned year 2030, till 2030 installed capacities of the Turkish power system will grow from approximately 90 GW to almost 132 GW. It is expected that RES capacities will grow from almost 15 GW to 39 GW, which will be followed by the commissioning of 4.8 GW of NPP, 8.5 GW of HPPs. Total capacity of coal units will be increased for 2.5GW while gas capacity will almost stay uncganged. This will make the Turkish power system more diverse, with almost 40% of installed capacities based on fossil fuels and nuclear, almost 30% on HPPs and 30% sourced from RES (Figure 57).

Table 65: Installed capacities per technology in 2030 – Turkey

Technology	Installed capacity (MW)	
	2019	2030
Thermal – coal	19879	22024
Thermal - gas	25903	26116
Thermal – nuclear	0	4800
Other non-RES	1080	2200
Hydro	28499	37064
Wind	7591	18415/20000[9]
Solar	5997	17400/20000[9]
Biomass and other RES	2315	3899

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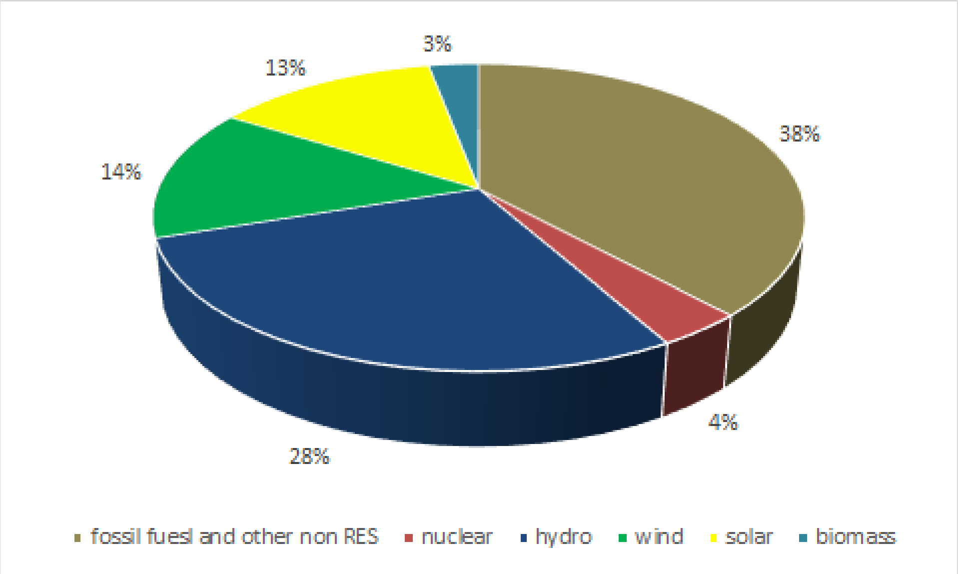

Figure 57: Installed capacity per fuel type in 2030 – Turkey

Table 66 shows the average annual capacity factors for wind and solar plants, taken from a publicly available web database[19] and scalled to correspond to average capacity factors provided by TEIAS (wind-30% ansd solar -18%).

Table 66: Average wind and solar capacity factors from 2006 to 2015 – Turkey

Armenia – average wind and solar capacity factors										
Year	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Wind CF	30.34%	30.25%	31.24%	29.08%	28.94%	31.51%	32.73%	28.97%	27.07%	29.85%
Solar CF	17.90%	18.10%	18.71%	17.22%	17.49%	18.41%	17.75%	18.35%	17.93%	18.13%

The annual generation of all HPPs for different hydrological conditions are given in Table 67. The generation average hydrological condition is sourced from the TYNDP database. The Consultant, using 20% lower values for dry and 20% higher values for wet, calculated values for dry and wet hydrology.

Table 67: Annual generation for all HPPs for dry, average and wet hydrology – Turkey

Annual generation (GWh)	Dry	Average	wet
Total	78000	97755	117306

VIII.8 NTC Values Applied in Market Modeling

When simulating the electricity markets, the cross-border network capacities between countries are labeled Net Transfer Capacities (NTC) values. The NTC value is the maximum total exchange capacity (in MW) between two interconnected power systems that is available for commercial purposes in a given period, and a specified direction of active power flow. The NTC is obtained using the following formula:

$$NTC = TTC - TRM$$

Where:

- Total Transfer Capacity (TTC) is the maximum total exchange program (in MW) between two interconnected power systems that will meet the security standards established by those systems for a certain period and direction of active power flow.

[19] https://www.renewables.ninja/

- Transmission Reliability Margin (TRM) is the security margin that accounts for uncertainties in the computed TTC values.

The future NTC values are used as input data in this Study and are subject to many uncertainties, including the following: internal network development, internal generation unit commitments, realization of new cross-border interconnection capacities, demand growth, and more. The NTC values for 2030 were provided by the BSTP members and included in the Antares market model. They are presented in Table 68:

Table 68: Cross-border capacities available for commercial exchanges (NTCs) - 2030

Zone I	Zone II	2030 NTC I to II W/S [MW]	2030 II to I W/S [MW]
Armenia	Georgia	700	700
Armenia	Central Asia	1200	1200
Georgia	Azerbaijan	1400	1400
Georgia	Turkey	1400	1400
Romania	Bulgaria	1400	1500
Romania	Hungary	1400	1300
Romania	Serbia	1920	1690
Romania	Moldova	950	950
Bulgaria	North Macedonia	500	400
Bulgaria	Greece	1350	800
Bulgaria	Turkey	900	500
Bulgaria	Serbia	400	400
Turkey	Greece	580	660
Ukraine	Poland	2475/2235	2475/2235
Ukraine	Moldova	400	800
Ukraine	Slovakia	774/713	774/713
Ukraine	Hungary	1253/1175	1253/1175
Ukraine	Romania	773/712	773/712

The Study applies available transmission capacities between borders as equal to the summarized NTCs and will consider this capacity fully available for commercial exchanges during the entire calculation period.

The Antares Model will include the power systems of all the BSTP members and the neighboring countries/markets, and it will include generation capacities and a simplified representation of the transmission network and cross-border capacities represented as NTC values.

The internal transmission network has not been modeled in the market simulator as it is not relevant for this regional analysis and zonal market perspective (internal networks are included in the network model – PSS/E).

IX. APPENDIX – Initial network models

IX.1.1 Electro Power System Operator of Armenia Models (AM)

The current development stage of the high voltage grid of area under the responsibility of EPSO of Armenia is shown in Figure 58. By 2030, the Armenian transmission system is expected to have a total of 5 tie-lines of the following voltage levels:

- 1 tie-lines of voltage level 500 kV
- 2 tie-lines of voltage level 400 kV
- 2 tie-line of voltage level 220 kV

The number of elements used to model the Armenian power system is shown in Table 69.

Table 69: Number of elements in models of AM

106 BUSES	16 PLANTS	13 MACHINES	0 INDUCTION GENS	0 INDUCTION MOTORS
46 LOADS	0 FIXED SHUNTS	2 SWITCHED SHUNTS		
144 BRANCHES	49 TRANSFORMERS	0 DC LINES	0 FACTS DEVICES	0 GNE DEVICES

The installed generation capacities in the Armenian power system is shown on Table 70. This table shows the total maximum active power output, total rated apparent power and well as the number of generation units. The data is given per each type of unit (fuel/technology type) and the last row shows the sum of all data in the corresponding column.

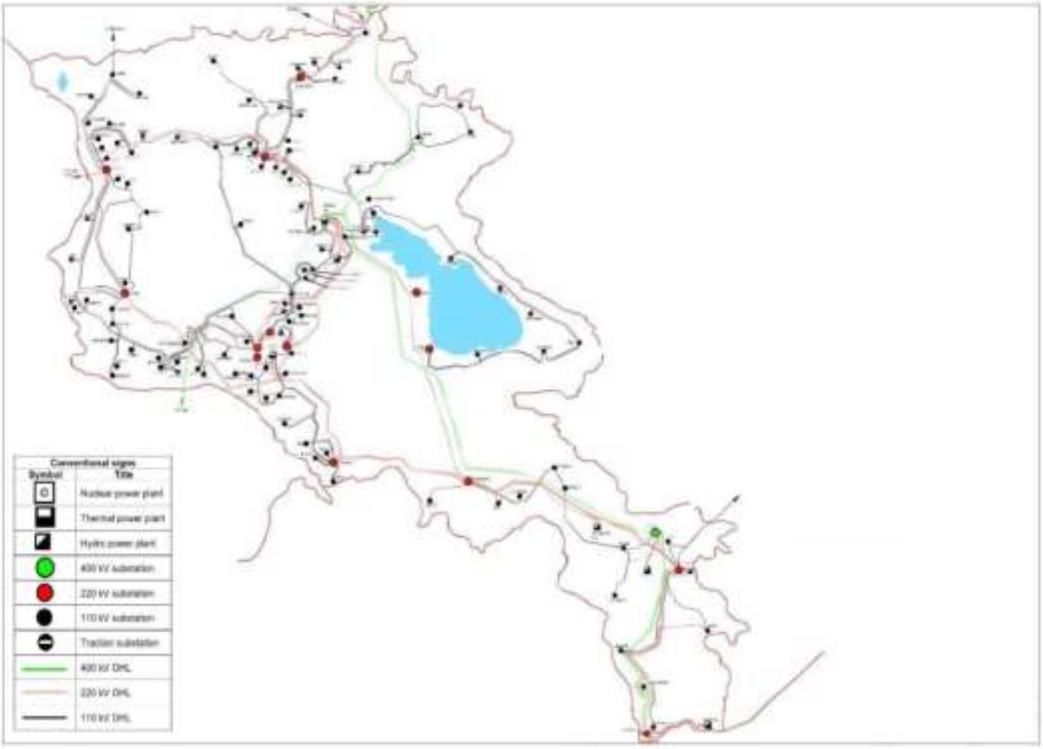

Figure 58: HV transmission network of Armenia, current development stage

Table 70: Installed generation capacities in power system of AM

Unit (fuel) type	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Nuclear	408.00	518.00	2
Natural gas	943.50	1,088.50	6
Daily storage	303.70	379.70	7
Weekly storage	168.00	198.00	3
Run of river	81.60	102.00	2
Shore intake	17.00	21.25	1
Small HPP (negative load)	145.00	145.00	3
Solar (negative load)	1,007.00	1,007.00	17
Total	**3,073.80**	**3,459.45**	**41**

The loading of branches in the transmission grid is shown in Figure 59. Only branches at the voltage level of 110 kV and above are included.

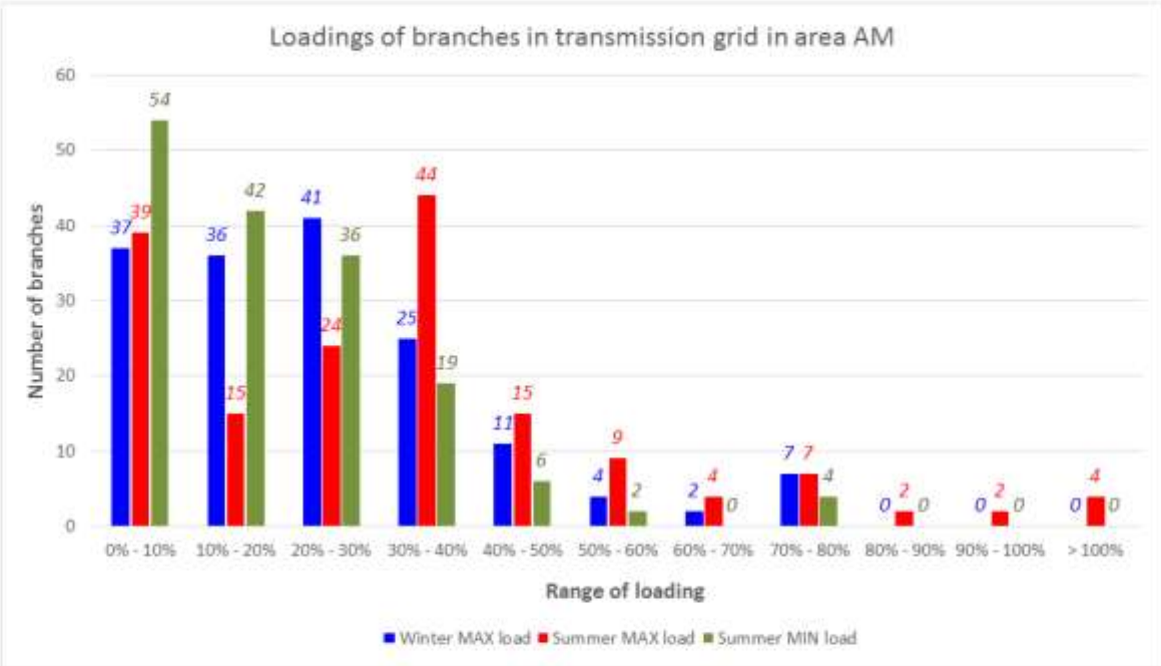

Figure 59: Histogram of branch loading in expected winter and summer maximum as well as in summer minimum regimes in 2030 in transmission grid of AM

Figure 16 shows the overloaded branches on the transmission grid with most elements loaded below 40%. In the case of the Winter maximum load regime, there are nine branches loaded over 60%, and seven are loaded in 70-80% range. In the case of Summer maximum load regime there are six branches loaded over 90%, and four are overloaded.

In the case of Summer minimum load regime, almost all elements are loaded below 40%. There are only six branches with loading above 50% and four are loaded in the 70% – 80% range.

Winter Maximum Load Regime

As report from PSS®E, a summary of area totals for Winter maximum load for the 2030 regime is shown in Table 71. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 71: Area summary of AM power system in winter maximum load 2030 regime, initial model

	FROM ------AT AREA BUSES-------				TO					-NET INTERCHANGE-		
	GENE-	FROM IND	TO IND	TO	TO BUS	GNE BUS	TO LINE	FROM	TO	TO TIE	TO TIES	DESIRED
X-- AREA --X	RATION	GENERATN	MOTORS	LOAD	SHUNT	DEVICES	SHUNT	CHARGING	LOSSES	LINES	+ LOADS	NET INT
68	1493.4	0.0	0.0	686.5	0.0	0.0	4.5	0.0	27.7	774.6	774.6	774.6
AM	253.5	0.0	0.0	354.6	203.3	0.0	135.7	705.3	341.3	-76.2	-76.2	

The total system load is 686.5 MW (reduced for generation modeled as negative load) and 354.6 MVar. This total load includes auxiliary loads as well. The value of active power losses is approximately 32,2 MW or 2,68% of total system active load. In this regime, the CJSC exports approximately 774.6 MW to neighboring systems.

The system summary per voltage level is shown in Table 72. For each voltage level, this table shows the assigned total active and reactive power losses as well as losses which result from line shunts (i.e. transformer magnetizing losses). The last column shows reactive power generated by line charging.

Table 72: Summary per voltage levels in power system of AM for winter maximum load 2030, initial model

VOLTAGE		X----- LOSSES	-----X	X-- LINE SHUNTS	--X	CHARGING
LEVEL	BRANCHES	MW	MVAR	MW	MVAR	MVAR
400.0	9	8.03	97.81	0.8	107.3	469.4
220.0	64	11.64	107.33	2.2	18.5	200.6
135.0	2	0.00	0.00	0.0	0.0	0.0
110.0	56	5.39	17.02	0.2	0.7	35.4
20.0	2	0.70	38.54	0.2	1.0	0.0
15.8	2	0.87	39.02	0.4	2.3	0.0
15.0	2	0.63	28.07	0.2	0.3	0.0
13.8	1	0.10	3.90	0.1	0.1	0.0
10.5	6	0.39	9.63	0.4	4.9	0.0
TOTAL	144	27.74	341.34	4.5	135.2	705.3

The active power generation for the Winter maximum load regime 2030, is shown in Table 73. This table shows data per unit type (fuel/technology type) as well as the sum of all data in the corresponding columns. Only the data of units in operation are included in this table. The data shows output from generation units (values on the transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data includes total active power generation and total maximum available active power, so active power reserve can be estimated. In addition, total rated apparent power is shown and reactive power possibilities can be estimated. Finally, each row contains the number of units in operation as well as the number of units that are overloaded.

Table 73: Active power generation in power system of AM in winter maximum load regime, initial model

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Units out of limits
Nuclear	420.00	408.00	518.00	2	0
Natural gas	901.44	943.50	1,088.50	6	0
Daily storage	172.00	256.70	320.90	5	0

Small HPP (negative load)	115.00	115.00	115.00	3	0
Solar (negative load)	398.00	398.00	398.00	16	0
Total	**2,006.44**	**2,121.20**	**2,440.40**	**32**	**0**

In the Winter maximum load regime, the number of units in operation is 32. There are no generation units that are out of the acceptable operating range.

Summer Maximum Load Regime

As report from PSS®E, a summary of area totals for the Summer maximum load for the 2030 regime is shown in Table 74. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 74: Area summary of AM power system in summer maximum load 2030 regime, initial model

	FROM ------AT AREA BUSES-------					TO				-NET INTERCHANGE-		
X-- AREA --X	GENE- RATION	FROM IND GENERATN	TO IND MOTORS	TO LOAD	TO BUS SHUNT	GNE BUS DEVICES	TO LINE SHUNT	FROM CHARGING	TO LOSSES	TO TIE LINES	TO TIES + LOADS	DESIRED NET INT
68	1439.7	0.0	0.0	223.5	0.0	0.0	5.0	0.0	62.2	1149.0	1149.0	1149.0
AM	431.5	0.0	0.0	356.6	197.4	0.0	137.8	688.0	602.2	-174.5	-174.5	

The total system load is 222,5 MW (reduced for generation modeled as negative load) and 356,6 MVar. The total load includes auxiliary loads as well. The value of active power losses is approximately 67,2 MW or 4,89% of the total system active load. In this regime, the CJSC exports approximately 1149 MW to neighboring systems.

The system summary per voltage level is shown in Table 75. For each voltage level this table shows assigned total active and reactive power losses as well as losses which resulted from line shunts (i.e. transformer magnetizing losses). The last column shows reactive power generated by line charging.

Table 75: Summary per voltage levels in power system of AM for summer maximum load 2030, initial model

```
VOLTAGE        X----- LOSSES -----X    X-- LINE SHUNTS --X    CHARGING
LEVEL BRANCHES        MW        MVAR        MW        MVAR        MVAR
400.0       9      20.11      237.87       0.7       103.7       455.8
220.0      64      26.33      219.92       2.2        18.3       197.1
135.0       2       0.00        0.00       0.0         0.0         0.0
110.0      56      13.08       36.74       0.2         0.7        35.2
 20.0       2       0.67       37.27       0.2         1.0         0.0
 15.8       2       0.71       31.93       0.4         2.3         0.0
 15.0       2       0.46       20.75       0.2         0.3         0.0
 13.8       1       0.07        2.70       0.0         0.1         0.0
 11.5       1       0.05        1.11       0.1         0.7         0.0
 11.0       1       0.05        0.90       0.1         1.0         0.0
 10.5       9       0.61       12.82       0.8         8.9         0.0
  6.3       1       0.01        0.16       0.0         0.1         0.0
TOTAL     150      62.16      602.16       5.0       137.2       688.0
```

The active power generation for Summer maximum load regime 2030 is shown in Table 76. This table shows data per unit type (fuel/technology type) as well as the sum of all data in the corresponding columns. Only data of units in operation are included in this table. The data shows output from generation units (values at the transmission level must be decreased by auxiliary loads and losses in step up transformers). The data includes total active power generation and total maximum available active power, so active power reserve can be estimated. In addition, total rated apparent power is shown, so reactive power possibilities can be estimated. Finally, each row contains the number of units in operation as well as the number of overloaded units

Table 76: Active power generation in power system of AM in summer maximum load regime, initial model

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Units out of limits
Nuclear	380.00	408.00	518.00	2	0
Natural gas	770.00	943.50	1,088.50	6	0
Daily storage	149.00	282.30	352.90	6	0
Weekly storage	85.00	168.00	198.00	3	0
Run of river	41.24	62.80	78.50	2	0
Shore intake	14.50	17.00	21.25	1	0
Small HPP (negative load)	145.00	145.00	145.00	3	0
Solar (negative load)	1,007.00	1,007.00	1,007.00	17	0
Total	**2,591.73**	**3,033.60**	**3,409.15**	**40**	**0**

The Summer maximum load regime number of units in operation is 40. There are no generation units that are out of acceptable operating range.

Summer Minimum Load Regime

As reported from PSS®E, a summary of area totals for the Summer minimum load 2030 regime is shown in Table 77. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 77: Area summary of AM power system in summer minimum load 2030 regime, initial model

	FROM	------AT AREA BUSES-------				TO				-NET INTERCHANGE-		
	GENE-	FROM IND	TO IND	TO	TO BUS	GNE BUS	TO LINE	FROM	TO	TO TIE	TO TIES	DESIRED
X-- AREA --X	RATION	GENERATN	MOTORS	LOAD	SHUNT	DEVICES	SHUNT	CHARGING	LOSSES	LINES	+ LOADS	NET INT
68	1247.0	0.0	0.0	438.9	0.0	0.0	5.0	0.0	23.6	779.5	779.5	779.5
AM	237.3	0.0	0.0	343.1	213.7	0.0	143.2	746.2	273.6	9.8	9.8	

The total system load is 438,9 MW (reduced for generation and modeled as negative load) and 343.1 MVar. This total load includes auxiliary loads. In comparison to the Summer maximum load regime, the total system active load is 48% of Summer maximum load. The value of active power losses is approximately 28,6 MW, which is 4,33% of total system active load. In this regime, CJSC exports approximately 779.5 MW to neighboring systems.

The system summary per voltage level is shown in Table 78. For each voltage level, this table shows the assigned total active and reactive power losses as well as part of the losses resulting from line shunts (i.e. transformer magnetizing losses). The last column shows reactive power generated by line charging.

Table 78: Summary per voltage levels in power system of AM for summer minimum load 2030, initial model

VOLTAGE		X----- LOSSES -----X		X-- LINE SHUNTS --X		CHARGING
LEVEL	BRANCHES	MW	MVAR	MW	MVAR	MVAR
400.0	9	8.41	99.15	0.8	111.9	492.2
220.0	64	10.95	85.50	2.4	20.1	215.4
135.0	2	0.00	0.00	0.0	0.0	0.0
110.0	56	2.49	7.76	0.2	0.7	38.6
20.0	2	0.47	25.94	0.3	1.1	0.0
15.8	2	0.66	29.81	0.5	2.5	0.0
15.0	2	0.44	19.49	0.2	0.4	0.0
13.8	1	0.06	2.39	0.1	0.1	0.0
10.5	7	0.12	3.54	0.5	5.7	0.0
TOTAL	145	23.60	273.58	4.9	142.6	746.2

The active power generation, for the Summer minimum load regime 2030 in the initial model, is shown in Table 79. This table shows data per unit type (fuel/technology type) as well as the sum of all data in the corresponding columns. Only the data of units in operation are included in this table. This data shows output from generation units (transmission level values must be decreased by auxiliary loads and losses in step up transformers).

The data includes total active power generation and total maximum available active power, so active power reserve can be estimated. In addition, total rated apparent power is shown, so reactive power possibilities can be estimated. Finally, each row contains the number of units in operation as well as the number of units which are slightly overloaded.

Table 79: Active power generation in power system of AM in summer minimum load regime, initial model

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Units out of limits
Nuclear	385.00	408.00	518.00	2	0
Natural gas	775.20	943.50	1,088.50	6	0
Daily storage	67.00	233.20	291.50	4	0
Run of river	15.00	40.80	51.00	1	0
Shore intake	4.80	17.00	21.25	1	0
Small HPP (negative load)	145.00	145.00	145.00	3	0
Solar (negative load)	76.00	76.00	76.00	3	0
Total	**1,468.00**	**1,863.50**	**2,191.25**	**20**	**0**

The Summer minimum load regime number of units in operation is 20. There are no generation units that are out of acceptable operating range.

Referent and High RES Scenarios

The initial models are updated based on the data provided by the TSOs in the form of tables with a list of large scale RES projects and their location on the grid (Table 80). There are two lists: one related to referent RES scenario and the other, which refers to a more aggressive and high RES scenario. Based on the initial models and these lists, two different sets of network models have been developed.

Table 80: Referent and high RES scenarios in AM

Project name	RES type	Bus Number	Bus Name	Id	exists in PSS/E as load/gen	2030, istalled capacity [MW]	
						base case	high res
	Solar	681006	8SEVAN5 110.00	2	negative load	-170	-180
	Solar	681008	8VANDZ5 110.00	2	negative load	-0.5101	-10.5101
	SmallHPP	681010	8DZORA5 110.00	1	negative load	-15	-25
	Solar	681014	8GYUMR5 110.00	1	negative load	-100	-110
	Solar	681016	8ASHNK5 110.00	2	negative load	-250	-260
	Solar	681017	8AMNPP5 110.00	2	negative load	-20	-30
	Solar	681020	8SHAHM5 110.00	2	negative load	-100	-110
	Solar	681023	8ZOVUN5 110.00	2	negative load	-20	-30
	Solar	681025	8ARGEL5 110.00	2	negative load	-20	-30
	Solar	681026	8CHARN5 110.00	2	negative load	-20	-30
	Solar	681028	8MARSH5 110.00	1	negative load	-20	-30
	Solar	681031	8ARART5 110.00	2	negative load	-20	-30
	SmallHPP	681043	8YEHGN5 110.00	1	negative load	-40	-50
	Solar	681043	8YEHGN5 110.00	2	negative load	-20	-30
	SmallHPP	681044	8LICHK5 110.00	1	negative load	-90	-100
	Solar	681044	8LICHK5 110.00	2	negative load	-40	-50
	Solar	681045	8HAGHT1 110.00	2	negative load	-20	-30
	Solar	681046	8APARN5 110.00	1	negative load	-1.2243	-11.2243
	Solar	681050	8SHINU5 110.00	3	negative load	-75	-85
	Solar	681005	8HRZ_H5 110.00	2	negative load	-111.076	-121.076

IX.1.2 ESO Models (BG)

The current development stage of the high voltage grid of area of the ESO is shown below:

In target year 2030, the ESO transmission system has 10 tie-lines at the following voltage levels:

- 10 tie-lines of voltage level 400 kV

The number of elements used to model the power system of Bulgaria is shown in Table 81.

Table 81: Number of elements in models of BG

663 BUSES	84 PLANTS	87 MACHINES	0 INDUCTION GENS	0 INDUCTION MOTORS
528 LOADS	1 FIXED SHUNTS	0 SWITCHED SHUNTS		
891 BRANCHES	163 TRANSFORMERS	0 DC LINES	0 FACTS DEVICES	0 GNE DEVICES

The installed generation capacities of the power system of Bulgaria is shown in Table 82. This table shows total maximum active power output, total rated apparent power and well as the number of generation units. The data is given per unit type (fuel/technology type) and the last row shows the sum of all the data in the corresponding column.

Table 82: Installed generation capacities in power system of BG

Unit (fuel) type	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Nuclear	2,200.00	2,222.00	2
Coal	3,992.00	4,710.00	21
Gas	1,335.60	1,705.20	26
Seasonal storage	1,514.20	1,814.00	36
Storage PS	864.00	940.00	4
WIND	2,045.00	2,369.00	10
Solar (Photovoltaic)	319.00	354.25	7
Total	**12,269.80**	**14,114.45**	**106**

The branch loads of the Bulgarian transmission grid are shown in Figure 60. Only branches at the voltage level of 110 kV and above are included.

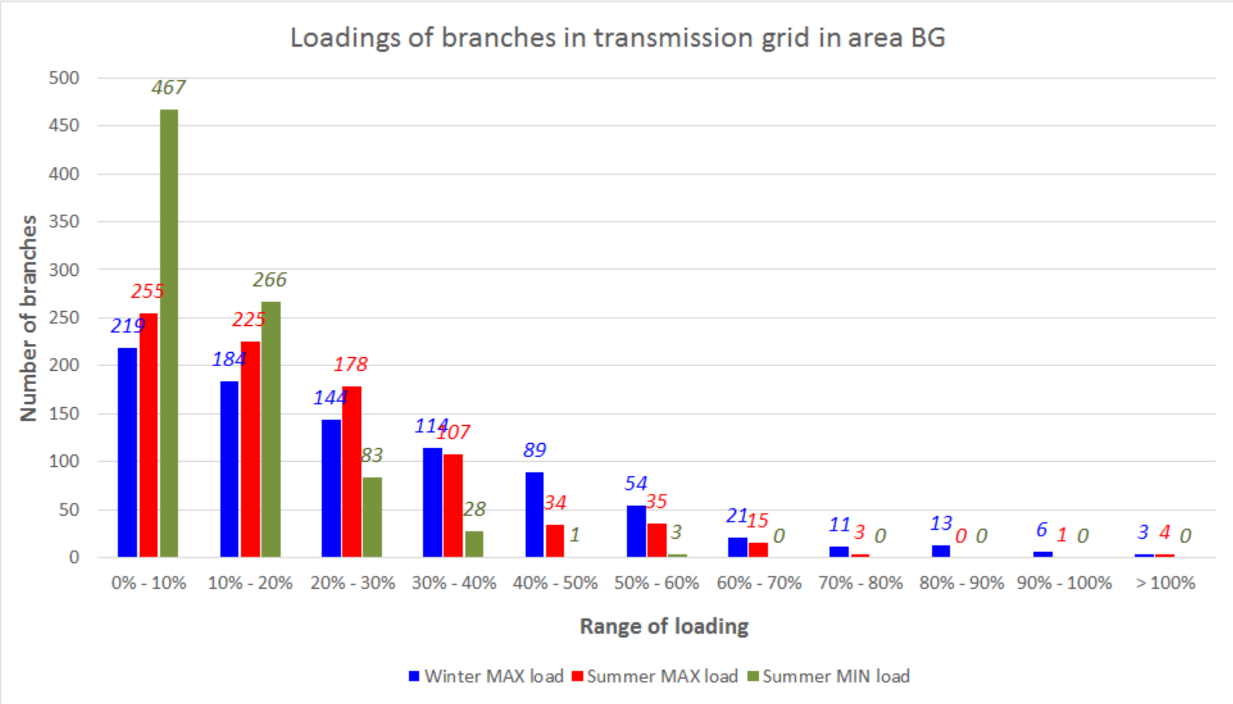

Figure 60: Histogram of branch loading in expected winter and summer maximum as well as in summer minimum regimes in 2030 in transmission grid of BG

The figure above shows overloaded branches in the Bulgarian transmission grid. The elements are loaded below 40%. In the case of Winter maximum load regime, there are nine branches loaded over 90% with three overloaded. In the case of Summer maximum load regime, there are five branches loaded over 90%, and four are overloaded.

In the case of Summer minimum load regime, almost all elements have a loading below 30%. There are only three branches with a loading in the 50% – 60% range.

Winter Maximum Load Regime

As report from PSS®E, a summary of area totals for the Winter maximum load 2030 regime is shown in Table 83. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 83: Area summary of BG power system in winter maximum load 2030 regime, initial model

	FROM	------AT AREA BUSES-------				TO				-NET INTERCHANGE-		
	GENE-	FROM IND	TO IND	TO	TO BUS	GNE BUS	TO LINE	FROM	TO	TO TIE	TO TIES	DESIRED
X-- AREA --X	RATION	GENERATN	MOTORS	LOAD	SHUNT	DEVICES	SHUNT	CHARGING	LOSSES	LINES	+ LOADS	NET INT
14	9190.1	0.0	0.0	8000.0	0.0	0.0	22.7	0.0	167.5	1000.0	1000.0	1000.0
BG	2802.0	0.0	0.0	2731.6	-51.9	0.0	199.8	2676.5	2331.6	267.3	267.3	

The total system load is 8.000 MW and 2.731,6 MVar. The total load includes auxiliary loads as well. The value of active power losses is approximately 190,2 MW or 2,38% of total system active load. In this regime, ESO exports approximately 1000 MW to neighboring systems.

The system summary per voltage level is shown in Table 84. For each voltage level this table shows the assigned total active and reactive power losses as well as part of these losses which resulted from line shunts (i.e. transformer magnetizing losses). The last column shows reactive power generated by line charging.

Table 84: Summary per voltage levels in power system of BG for winter maximum load 2030, initial model

VOLTAGE		X----- LOSSES	-----X	X-- LINE SHUNTS	--X	CHARGING
LEVEL	BRANCHES	MW	MVAR	MW	MVAR	MVAR
400.0	47	27.00	304.96	0.0	0.0	1805.4
220.0	62	37.66	281.06	0.6	30.3	387.0
110.0	685	86.47	794.92	6.6	60.8	484.0
33.0	14	0.21	17.57	3.0	16.8	0.0
24.0	2	3.35	271.98	1.7	11.7	0.0
20.0	2	0.44	71.98	0.3	2.2	0.0
19.0	2	0.31	49.39	0.3	5.6	0.0
18.0	3	2.16	59.41	0.5	4.9	0.0
15.8	3	0.45	53.21	0.5	3.0	0.0
15.8	9	3.60	199.11	2.0	10.1	0.0
13.8	9	1.32	38.98	2.1	10.2	0.0
10.5	27	3.99	143.63	3.1	28.5	0.0
6.3	26	0.55	45.44	2.0	15.6	0.0
TOTAL	891	167.49	2331.64	22.7	199.8	2676.5

The active power generation of the Bulgarian power system, in Winter maximum load regime 2030 as part of the initial model, is shown in Table 85. This table shows data per unit type (fuel/technology type) as well as the sum of all data in the corresponding columns. Only data of units in operation are included in this table. The data shows output from generation units (values at the transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data includes total active power generation and total maximum available active power, so active power reserve can be estimated. In addition, total rated apparent power is shown, so reactive power possibilities can be estimated. Finally, each row contains the number of units in operation as well as the number of units that are overloaded.

Table 85: Active power generation in power system of BG in winter maximum load regime, initial model

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Units out of limits
Nuclear	2,200.00	2,200.00	2,222.00	2	0
Coal	3,832.11	3,967.00	4,678.00	20	0
Gas	1,055.00	1,149.80	1,472.20	23	0
Seasonal storage	1,243.00	1,334.20	1,598.00	32	0
Storage PS	400.00	432.00	470.00	2	0
WIND	460.00	1,765.00	2,057.00	8	0
Solar (Photovoltaic)	0.00	0.00	0.00	0	0
Total	**9,190.11**	**10,848.00**	**12,497.20**	**87**	**0**

The winter maximum load regime number of units in operation is 87. There are no generation units that are out of acceptable operating range.

Summer Maximum Load Regime

As report from PSS®E, a summary of area totals for the Summer maximum load 2030 regime is shown in Table 86. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 86: Area summary of BG power system in summer maximum load 2030 regime, initial model

	FROM	------AT AREA BUSES-------				TO				-NET INTERCHANGE-		
	GENE-	FROM IND	TO IND	TO	TO BUS	GNE BUS	TO LINE	FROM	TO	TO TIE	TO TIES	DESIRED
X-- AREA --X	RATION	GENERATN	MOTORS	LOAD	SHUNT	DEVICES	SHUNT	CHARGING	LOSSES	LINES	+ LOADS	NET INT
14	6570.2	0.0	0.0	5433.9	0.0	0.0	20.6	0.0	115.7	1000.0	1000.0	1000.0
BG	1510.9	0.0	0.0	1862.6	-53.9	0.0	189.7	2732.7	1743.5	501.6	501.6	

The total system load is 5.433,9 MW and 1862,6 MVar. This total load includes auxiliary loads as well. The value of active power losses is around 262,7 MW or 2,07% of total system active load. In this regime, ESO exports approximately 1000 MW to neighboring systems.

The system summary per voltage level is shown in Table 87. For each voltage level, this table shows the assigned total active and reactive power losses as well as part of the losses which result from line shunts (i.e. transformer magnetizing losses). The last column shows reactive power generated by line charging.

Table 87: Summary per voltage levels in power system of BG for summer maximum load 2030, initial model

VOLTAGE LEVEL	BRANCHES	LOSSES MW	LOSSES MVAR	LINE SHUNTS MW	LINE SHUNTS MVAR	CHARGING MVAR
400.0	46	31.26	344.78	0.0	0.0	1845.9
220.0	62	19.25	168.87	0.7	31.0	390.1
110.0	685	52.58	527.51	6.7	61.9	496.7
33.0	14	0.03	2.81	3.2	17.5	0.0
24.0	2	3.29	266.40	1.7	12.0	0.0
20.0	1	0.21	34.25	0.1	1.1	0.0
19.0	2	0.34	53.97	0.3	5.7	0.0
18.0	3	2.38	65.68	0.5	4.8	0.0
15.8	1	0.18	24.11	0.1	1.0	0.0
15.8	3	1.20	66.96	0.7	3.3	0.0
13.8	8	0.89	26.23	1.8	8.9	0.0
10.5	26	3.59	129.05	3.0	28.4	0.0
6.3	23	0.54	32.88	1.8	14.1	0.0
TOTAL	876	115.74	1743.50	20.6	189.7	2732.7

The Summer maximum load regime for target year 2030 is shown in Table 88. This table shows the data per unit type (fuel/technology type) as well as the sum of all data in the corresponding columns. Only the data of units in operation are included in this table. This data shows output from generation units (values at the transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data includes the total active power generation and total maximum available active power, so active power reserve can be estimated. In addition, total rated apparent power is shown, so reactive power possibilities can be estimated. Finally, each row contains the number of units in operation as well as the number of units that are overloaded.

Table 88: Active power generation in power system of BG in summer maximum load regime, initial model

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Units out of limits
Nuclear	2,200.00	2,200.00	2,222.00	2	0
Coal	1,842.21	1,943.00	2,305.00	11	0
Gas	835.00	926.80	1,211.75	19	0
Seasonal storage	1,133.00	1,214.20	1,453.00	31	0
Storage PS	420.00	432.00	470.00	2	0
WIND	140.00	1,765.00	2,057.00	8	0
Solar (Photovoltaic)	0.00	0.00	0.00	0	0
Total	**6,570.21**	**8,481.00**	**9,718.75**	**73**	**0**

The Summer maximum load regime number of units in operation is 73. There are no generation units that are out of acceptable operating range.

Summer Minimum Load Regime

As report from PSS®E, a summary of area totals for the Summer minimum load 2030 regime is shown in Table 89. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 89: Area summary of BG power system in summer minimum load 2030 regime, initial model

	FROM	------AT AREA BUSES-------				TO				-NET INTERCHANGE-		
	GENE-	FROM IND	TO IND	TO	TO BUS	GNE BUS	TO LINE	FROM	TO	TO TIE	TO TIES	DESIRED
X-- AREA --X	RATION	GENERATN	MOTORS	LOAD	SHUNT	DEVICES	SHUNT	CHARGING	LOSSES	LINES	+ LOADS	NET INT
14	4299.8	0.0	0.0	3245.0	0.0	0.0	16.6	0.0	38.2	1000.0	1000.0	1000.0
BG	818.1	0.0	0.0	1624.8	731.7	0.0	150.5	2735.5	668.7	377.9	377.9	

The total system load is 3.245MW and 1.624,8 MVar. The total load includes auxiliary loads as well. In comparison to the Summer maximum load regime, the system active load is 59,71% of Summer maximum load. The value of active power losses is approximately 54,8 MW or 1,69% of the total system active load. In this regime, ESO exports approximately 1000 MW to neighboring systems.

The system summary per voltage level is shown in Table 90. For each voltage level, this table shows the assigned total active and reactive power losses as well as part of the losses which resulted from line shunts (i.e. transformer magnetizing losses). The last column shows reactive power generated by line charging.

Table 90: Summary per voltage levels in power system of BG for summer minimum load 2030, initial model

VOLTAGE		X----- LOSSES	-----X	X-- LINE SHUNTS	--X	CHARGING
LEVEL	BRANCHES	MW	MVAR	MW	MVAR	MVAR
400.0	47	13.21	143.83	0.0	0.0	1817.1
220.0	62	4.08	46.65	0.7	30.5	407.1
110.0	680	16.51	148.86	6.4	57.6	511.3
33.0	8	0.06	5.35	2.0	10.9	0.0
24.0	2	2.15	174.65	1.7	11.9	0.0
20.0	2	0.17	26.94	0.3	2.2	0.0
19.0	1	0.06	9.92	0.1	2.8	0.0
18.0	2	0.81	23.47	0.4	2.6	0.0
15.8	5	0.96	62.13	1.1	5.5	0.0
13.8	8	0.00	2.37	1.9	9.2	0.0
10.5	3	0.05	2.59	0.3	2.7	0.0
6.3	23	0.15	21.95	1.9	14.8	0.0
TOTAL	843	38.21	668.70	16.6	150.5	2735.5

The initial model active power generation for Summer minimum load regime 2030 is shown in Table 91. This table shows data per unit type (fuel/technology type) as well as sum of all data in corresponding columns. Only data of units in operation are included this table. The data shows output from generation units (values at the transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data includes total active power generation and total maximum available active power, so active power reserve can be estimated. In addition, total rated apparent power is shown, so reactive power possibilities can be estimated. Finally, each row contains the number of units in operation as well as the number of units which are slightly overloaded.

Table 91: The active power generation in the Bulgarian power system for Summer minimum load regime, initial model

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Units out of limits
Nuclear	1,840.00	2,200.00	2,222.00	2	0
Coal	1,565.81	2,343.00	2,822.00	12	0
Gas	435.00	707.90	916.00	17	0
Seasonal storage	9.00	16.80	23.00	1	0
Storage PS	180.00	432.00	470.00	2	0
WIND	180.00	845.00	989.00	5	0
Solar (Photovoltaic)	90.00	319.00	354.25	7	0
Total	**4,299.81**	**6,863.70**	**7,796.25**	**46**	**0**

In Summer minimum load regime, the number of units in operation is 46. There are no generation units that are out of acceptable operating range.

Referent and High RES Scenarios

In the next step, the initial models will be updated based on the data provided by BSTP members in the form of tables with a list of large-scale RES projects and their location in the grid. In case of Bulgaria, there is only one list related to referent RES scenario. Initial models will be harmonized with this list and network models related to referent RES scenario will be prepared. high RES scenario will be modeled by scaling of the presented capacities to reach expected total solar and wind capacity in high RES scenario.

RES type	Bus Number		Id	exists in PSS/E as load/gen	2030, istalled capacity [MW]	
					base case	high res
wind	149501	VBALTCW1 33.000	W1	yes	45	
wind	149511	VBINKOW1 33.000	W1	yes	180	
wind	149521	VGILIAW1 33.000	W1	yes	100	
wind	149531	VKAVARW1 33.000	W1	yes	200	
wind	149541	VMAJAKW1 33.000	W1	yes, in the model this generation is higher 300MW, should be changed	100	
solar	149541	VMAJAKW1 33.000	S1	no	200	
solar	149551	VORIAHW1 33.000	W1	become S1	100	
wind	149561	VPLEVEW1 33.000	W1	yes	120	
wind	149571	VV_DOLW1 33.000	W1	yes, in the model this generation is higher 200MW, should be changed	142	
solar	149601	VKARADS1 13.800	S1	yes	50	
solar	149611	VSAMOVS1 6.3000	S1	yes	25	
solar	149621	VLACH_S1 13.800	S1	yes	50	
solar	149631	VELHO_S1 13.800	S1	yes	48	
solar	149641	VKAZANS1 13.800	S1	yes	50	
solar	149651	VSLIV_S1 13.800	S1	yes	76	
solar	149661	VZLATAS1 6.3000	S1	yes	20	
solar	141070	VMETAL1 400.000	S1	no	767	
solar	142095	VMAIZ22 220.000	S1	instead of 149041 till 149044 (the thermal generations at these buses should be deleted or switched off)	650	
solar	141115	VVARNA1 400.000	S1	no	200	
solar	142035	VBOBOV2 220.000	S1	instead of 149073 (the thermal generation at this bus should be deleted or switched off)	530	
solar	146320	VNHK_15 110.000	S1	no	163	

IX.1.3 GSE Models (GE)

The current development stage of the high voltage grid of area under the responsibility of GSE is shown in Figure 61. In the year 2030, the GSE transmission system will have 8 tie-lines at the following voltage levels:

- 4 tie-lines of voltage level 500 kV
- 2 tie-lines of voltage level 400 kV
- 1 tie-line of voltage level 330 kV
- 1 tie-line of voltage level 154 kV

The number of elements used to model the power system of Georgia is shown in Table 92.

Table 92: Number of elements in models of GE

403 BUSES	199 PLANTS	210 MACHINES	0 INDUCTION GENS	0 INDUCTION MOTORS
40 LOADS	14 FIXED SHUNTS	0 SWITCHED SHUNTS		
475 BRANCHES	257 TRANSFORMERS	3 DC LINES	0 FACTS DEVICES	0 GNE DEVICES

The installed generation capacities in the Georgian power system is shown in Table 93. This table shows total maximum active power output, total rated apparent power and well as the number of generation units. The data is given per each type of unit (fuel/technology type) and the last row shows the sum of all data in the corresponding column.

Figure 61: HV transmission network of Georgia, current development stage

Table 93: Installed generation capacities in power system of GE

Unit (fuel) type	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Coal	430.00	508.00	4
Natural gas	1,180.00	1,397.50	9
Seasonal storage	1,909.60	2,309.15	20
Yearly storage	1,661.20	2,008.00	20
Daily storage	341.00	391.63	17
Run of river	2,432.50	3,068.49	207
Total	**7,954.30**	**9,682.77**	**277**

The loading of branches in the transmission grid is shown in Figure 62. Only branches at the voltage level of 110 kV and above are included.

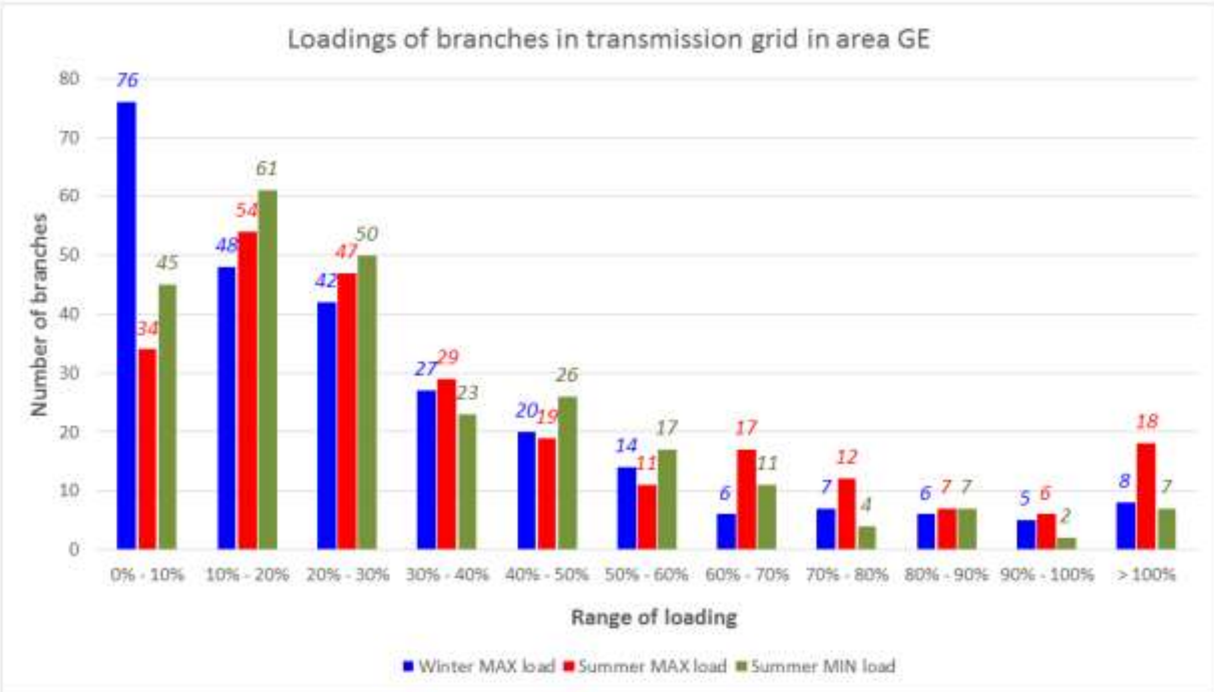

Figure 62: Histogram of branch loading in expected winter and summer maximum as well as in summer minimum regimes in 2030 in transmission grid of GE

Figure 20 shows overloaded branches in the Georgian transmission grid, with most elements loaded below 50%. However, in the case of Winter maximum load regime, there are thirteen branches loaded over 90%, and eight are overloaded. In the case of Summer maximum load regime, there are twenty-four branches loaded over 90%, and eighteen are overloaded.

In the case of Summer minimum load regime, almost all elements have a loading below 60%. There are nine branches with loading above 90% and seven are overloaded.

Winter Maximum Load Regime

As report from PSS®E, a summary of area totals for the Winter maximum load 2030 regime is shown in Table 94. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 94: Area summary of GE power system in winter maximum load 2030 regime, initial model

	FROM ------AT AREA BUSES-------					TO				-NET INTERCHANGE-		
	GENE-	FROM IND	TO IND	TO	TO BUS	GNE BUS	TO LINE	FROM	TO	TO TIE	TO TIES	DESIRED
X-- AREA --X	RATION	GENERATN	MOTORS	LOAD	SHUNT	DEVICES	SHUNT	CHARGING	LOSSES	LINES	+ LOADS	NET INT
62	4208.0	0.0	0.0	4382.0	0.0	0.0	0.2	0.0	125.7	-300.0	-300.0	-300.0
GE	1089.6	0.0	0.0	2190.5	-1030.6	0.0	0.0	1975.3	2228.8	-323.8	-323.8	

The total system load is 4.328 MW and 2.190,5 MVar. This total load includes auxiliary loads as well. The value of active power losses is approximately 125,9 MW or 2,9% of total system active load. In this regime, GSE will import approximately 300 MW from neighboring systems.

The system summary per voltage level is shown in Table 95. For each voltage level, this table shows the assigned total active and reactive power losses as well as part of the losses which result from line shunts (i.e. transformer magnetizing losses). The last column shows reactive power generated by line charging.

Table 95: Summary per voltage levels in power system of AM for winter maximum load 2030, initial model

VOLTAGE LEVEL	BRANCHES	X----- LOSSES -----X MW	MVAR	X-- LINE SHUNTS --X MW	MVAR	CHARGING MVAR
DC	3	12.55	877.69			
500.0	23	23.91	273.44	0.0	0.0	1554.8
400.0	2	2.65	33.92	0.0	0.0	42.5
330.0	2	1.51	16.12	0.0	0.0	18.8
220.0	95	64.25	619.38	0.2	0.0	297.7
154.0	1	1.19	9.38	0.0	0.0	1.5
110.0	147	17.29	151.15	0.0	0.0	59.9
35.0	29	0.53	5.07	0.0	0.0	0.0
20.0	1	0.40	23.49	0.0	0.0	0.0
18.0	12	0.01	33.79	0.0	0.0	0.0
15.8	7	0.12	84.88	0.0	0.0	0.0
15.8	3	0.00	5.64	0.0	0.0	0.0
15.0	1	0.00	3.43	0.0	0.0	0.0
13.8	3	0.25	19.16	0.0	0.0	0.0
10.5	32	0.99	47.49	0.0	0.0	0.0
10.0	48	0.04	11.04	0.0	0.0	0.0
6.6	6	0.03	2.27	0.0	0.0	0.0
6.5	1	0.00	0.00	0.0	0.0	0.0
6.3	58	0.00	11.30	0.0	0.0	0.0
6.0	4	0.00	0.15	0.0	0.0	0.0
TOTAL	478	125.72	2228.79	0.2	0.0	1975.3

The active power generation in the Georgian power system for Winter maximum load regime 2030 in the initial model, is shown in Table 96. This table shows data per unit type (fuel/technology type) as well as the sum of all data in the corresponding columns. Only data of units in operation are included in this table. The data shows output from generation units (values at the transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data includes total active power generation and total maximum available active power, so active power reserve can be estimated. In addition, total rated apparent power is shown. Therefore, reactive power possibilities can be estimated. Finally, each row contains the number of units in operation as well as the number of units that are overloaded.

Table 96: Active power generation in power system of GE in winter maximum load regime, initial model

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Units out of limits
Coal	240.00	270.00	315.00	3	0
Natural gas	710.00	860.00	1,011.50	7	0
Seasonal storage	895.00	1,498.40	1,813.20	16	0
Yearly storage	1,281.30	1,583.60	1,911.00	17	0
Daily storage	136.02	210.00	239.23	12	0
Run of river	945.65	1,731.20	2,236.39	155	0
Total	**4,207.97**	**6,153.20**	**7,526.32**	**210**	**0**

The Winter maximum load regime number of units in operation is 210. There are no generation units that are out of acceptable operating range.

Summer Maximum Load Regime

As report from PSS®E, the summary of area totals for Summer maximum load 2030 regime is shown in Table 97. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 97: Area summary of GE power system in summer maximum load 2030 regime, initial model

	FROM ------AT	AREA BUSES-------			TO					-NET INTERCHANGE-		
	GENE-	FROM IND	TO IND	TO	TO BUS	GNE BUS	TO LINE	FROM	TO	TO TIE	TO TIES	DESIRED
X-- AREA --X	RATION	GENERATN	MOTORS	LOAD	SHUNT	DEVICES	SHUNT	CHARGING	LOSSES	LINES	+ LOADS	NET INT
62	5796.8	0.0	0.0	4808.0	0.0	0.0	0.3	0.0	188.6	800.0	800.0	800.0
GE	884.0	0.0	0.0	2000.0	-1299.3	0.0	0.0	1975.8	3063.7	-904.6	-904.6	

The total system load is 4.808 MW and 2.000 MVar. The total load includes auxiliary loads as well. The value of active power losses is approximately 188,9 MW or 3,93% of total system active load. In this regime, Georgia will export approximately 1149 MW to neighboring systems.

The System summary per voltage level is shown in Table 98. For each voltage level, this table shows the assigned total active and reactive power losses as well as part of the losses resulting from line shunts (i.e. transformer magnetizing losses). The last column shows reactive power generated by line charging.

Table 98: Summary per voltage levels in power system of GE for summer maximum load 2030, initial model

VOLTAGE		X----- LOSSES	-----X	X-- LINE SHUNTS	--X	CHARGING
LEVEL	BRANCHES	MW	MVAR	MW	MVAR	MVAR
DC	3	12.55	826.70			
500.0	24	49.39	608.21	0.0	0.0	1552.8
400.0	2	2.50	32.00	0.0	0.0	43.5
330.0	2	2.02	21.64	0.0	0.0	18.3
220.0	94	82.14	914.30	0.3	0.0	301.3
110.0	144	34.89	251.16	0.0	0.0	59.9
35.0	30	1.66	22.71	0.0	0.0	0.0
18.0	12	0.00	5.34	0.0	0.0	0.0
15.8	6	0.00	116.50	0.0	0.0	0.0
15.8	3	0.00	15.23	0.0	0.0	0.0
15.0	1	0.00	8.74	0.0	0.0	0.0
13.8	3	0.35	15.01	0.0	0.0	0.0
10.5	32	2.79	144.57	0.0	0.0	0.0
10.0	48	0.19	45.24	0.0	0.0	0.0
6.6	6	0.09	4.50	0.0	0.0	0.0
6.5	1	0.00	0.00	0.0	0.0	0.0
6.3	58	0.00	31.52	0.0	0.0	0.0
6.0	4	0.00	0.35	0.0	0.0	0.0
TOTAL	473	188.59	3063.71	0.3	0.0	1975.8

The active power generation in the Georgian power system for Summer maximum load regime 2030 is shown in Table 99. This table shows data per unit type (fuel/technology type) as well as the sum of all data in the corresponding columns. Only data of units in operation are included in this table. The data shows output from generation units (values at the transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data includes total active power generation and total maximum available active power, so active power reserve can be estimated. In addition, total rated apparent power is shown. Therefore, reactive power possibilities can be estimated. Finally, each row contains the number of units in operation as well as the number of units that are overloaded.

Table 99: Active power generation in power system of GE in summer maximum load regime, initial model

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Units out of limits
Coal	81.32	160.00	193.00	1	0
Natural gas	0.00	0.00	0.00	0	0
Seasonal storage	1,852.33	1,909.60	2,309.15	20	0
Yearly storage	1,531.55	1,601.20	1,933.00	17	0
Daily storage	301.91	341.00	391.63	17	0
Run of river	2,029.73	2,328.70	2,959.05	204	0
Total	**5,796.84**	**6,340.50**	**7,785.83**	**259**	**0**

The Summer maximum load regime number of units in operation is 259. There are no generation units that are out of acceptable operating range.

Summer Minimum Load Regime

As report from PSS®E, a summary of area totals for Summer minimum load 2030 regime is shown in Table 100. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 100: Area summary of GE power system in summer minimum load 2030 regime, initial model

	FROM ------AT AREA BUSES-------				TO					-NET INTERCHANGE-		
X-- AREA --X	GENE- RATION	FROM IND GENERATN	TO IND MOTORS	TO LOAD	TO BUS SHUNT	GNE BUS DEVICES	TO LINE SHUNT	FROM CHARGING	TO LOSSES	TO TIE LINES	TO TIES + LOADS	DESIRED NET INT
62	3879.1	0.0	0.0	2886.0	0.0	0.0	0.3	0.0	92.9	900.0	900.0	900.0
GE	466.2	0.0	0.0	1443.0	-86.3	0.0	0.0	2022.6	1918.4	-786.3	-786.3	

The total system load is 2.886 MW and 1.443 MVar. The total load includes auxiliary loads as well. When compared to the Summer maximum load regime, the total system active load is 60% of Summer maximum load. The value of active power losses is approximately 93,2 MW or 3,23% of total system active load. In this regime, Georgia will export approximately 900 MW to neighboring systems.

The system summary per voltage level is shown in Table 101. For each voltage level this table shows the assigned total active and reactive power losses as well as part of the losses which result from line shunts (i.e. transformer magnetizing losses). The last column shows reactive power generated by line charging.

Table 101: Summary per voltage levels in power system of GE for summer minimum load 2030, initial model

VOLTAGE		X----- LOSSES	-----X	X-- LINE SHUNTS	--X	CHARGING
LEVEL	BRANCHES	MW	MVAR	MW	MVAR	MVAR
DC	3	12.55	778.15			
500.0	23	18.89	236.41	0.0	0.0	1585.7
400.0	2	2.29	29.23	0.0	0.0	43.4
330.0	2	1.93	20.76	0.0	0.0	19.4
220.0	94	33.46	421.31	0.3	0.0	312.9
110.0	143	20.34	174.59	0.0	0.0	61.2
35.0	30	1.67	20.14	0.0	0.0	0.0
20.0	1	0.00	0.00	0.0	0.0	0.0
18.0	12	0.00	4.88	0.0	0.0	0.0
15.8	7	0.35	39.39	0.0	0.0	0.0
15.8	3	0.00	16.23	0.0	0.0	0.0
15.0	1	0.00	9.15	0.0	0.0	0.0
13.8	3	0.21	7.29	0.0	0.0	0.0
10.5	32	0.90	82.02	0.0	0.0	0.0
10.0	48	0.20	45.36	0.0	0.0	0.0
6.6	6	0.09	4.09	0.0	0.0	0.0
6.5	1	0.00	0.00	0.0	0.0	0.0
6.3	58	0.00	29.12	0.0	0.0	0.0
6.0	4	0.00	0.32	0.0	0.0	0.0
TOTAL	473	92.87	1918.44	0.3	0.0	2022.6

The active power generation of the Georgian power system in the Summer minimum load regime 2030, initial model, is shown in Table 102. This table shows data per unit type (fuel/technology type) as well as the sum of all data in the corresponding columns. Only data of units in operation are included this table. The data shows output from generation units (values at the transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data includes total active power generation and total maximum available active power, so active power reserve can be estimated. In addition, the total rated apparent power is shown. Therefore, reactive power possibilities can be estimated. Finally, each row contains the number of units in operation as well as the number of units which are slightly overloaded.

Table 102: Active power generation in power system of GE in summer minimum load regime, initial model

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Units out of limits
Coal	83.62	160.00	193.00	1	0
Natural gas	0.00	0.00	0.00	0	0
Seasonal storage	837.37	1,009.60	1,232.90	13	0
Yearly storage	573.27	590.10	710.00	4	0
Daily storage	299.99	329.00	377.63	16	0
Run of river	2,084.87	2,328.70	2,959.05	204	0
Total	**3,879.13**	**4,417.40**	**5,472.58**	**238**	**0**

The Summer minimum load regime number of units in operation is 238. There are no generation units that are out of acceptable operating range.

Referent and High RES Scenarios

In the next step, the initial models are updated based on the data provided by the BSTP members. For Georgia, only the table with a sum of technologies is provided without locations of RES capacities. These capacities will be properly distributed in the initial model (Table 103). There are two lists: one related to the referent RES scenario and the other referring to the more aggressive, high RES scenario. Based on the initial models and these lists, two different sets of network models are developed.

Table 103: Referent and high RES scenarios in GE

Project name	RES type	Bus Number	Id	exists in PSS/E as load/gen	2030, installed capacity [MW]	
					Referent Case	High RES
Total wind capacity	WPP			No	385	1000
Total solar capacity	SPP			No	60	390

IX.1.4 Moldelectrica Models (MD)

The current development stage of the high voltage grid under the responsibility of Moldelectrica is shown in Figure 63. In year 2030, the Moldelectrican transmission system will have a total of 21 tie-lines at the following voltage levels:

- 2 tie-lines of voltage level 400 kV
- 7 tie-lines of voltage level 330 kV
- 12 tie-line of voltage level 110 kV

The number of elements used to model the Moldovan power system is shown in Table 104.

Table 104: Number of elements in models of MD

464 BUSES	6 PLANTS	6 MACHINES	0 INDUCTION GENS	0 INDUCTION MOTORS
304 LOADS	0 FIXED SHUNTS	0 SWITCHED SHUNTS		
512 BRANCHES	26 TRANSFORMERS	3 DC LINES	0 FACTS DEVICES	0 GNE DEVICES

The installed generation capacities in the Moldovan power system is shown in Table 105. This table shows the total maximum active power output, total rated apparent power and as well the number of generation units. The data is given per each type of unit (fuel/technology type) and the last row shows the sum of all data in the corresponding column.

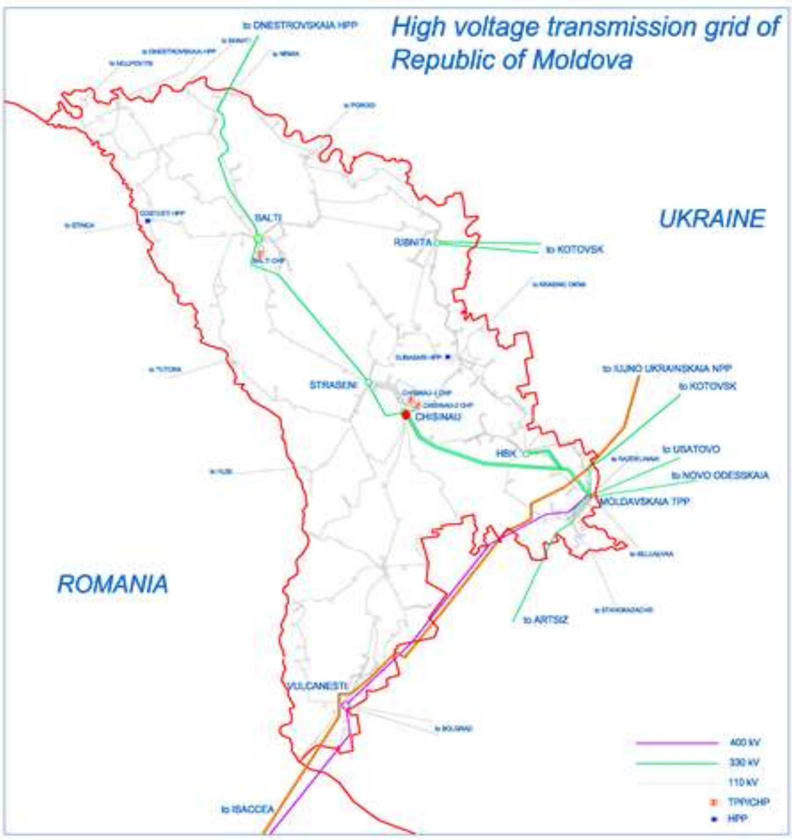

Figure 63: HV transmission network of Moldova, current development stage

Table 105: Generation capacities in power system of MD

Unit (fuel) type	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Gas	345.00	532.50	5
TPP Coal, Oil	1,200.00	1,411.80	6
TPP Coal, Oil, Gas	240.00	470.60	2
TPP Oil, Gas	840.00	941.20	4
Gas (negative load)	37.00	37.00	1
Run-of-river (negative load)	36.00	36.00	1
UNKNOWN (negative load)	42.00	42.00	3

Total	**2,740.00**	**3,471.10**	**22**

The loading of branches in the Moldovan transmission grid is shown in Figure 64. Only branches at the 110 kV voltage level and above are included.

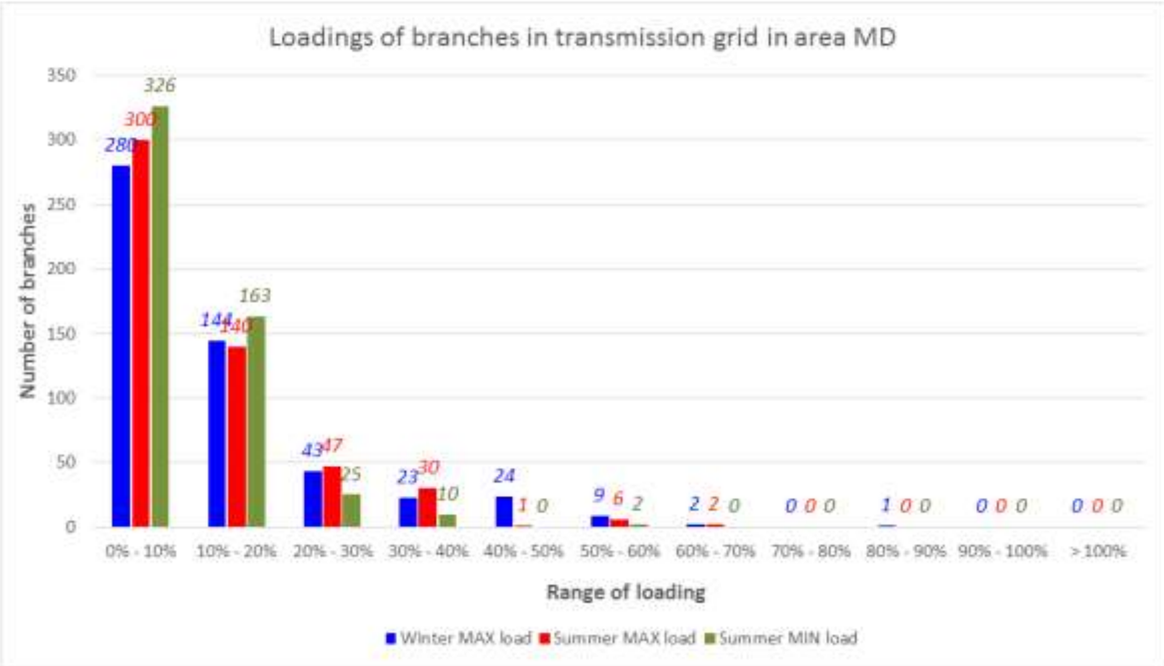

Figure 64: Histogram of branch loading in expected winter and summer maximum as well as in summer minimum regimes in 2030 in transmission grid of MD

The Figure shows that there are no overloaded branches in the Moldovan transmission grid and most elements are loaded below 20%. In the case of Winter maximum load regime, there are 3 branches loaded over 60% and one of them have a loading in the 80% – 90% range

In case of Summer minimum load regime, almost all elements have loading below 50%. There are only two branches with a loading in the 50% – 60% range.

Winter Maximum Load Regime

As reported from PSS®E, a summary of area totals for Winter maximum load 2030 regime in the initial model is shown in Table 106. The first row represents data related to active power (in MW), while second row shows data related to reactive power (in MVar).

Table 106: Area summary of MD power system in winter maximum load 2030 regime, initial model

	FROM ------AT AREA BUSES-------				TO					-NET INTERCHANGE-		
X-- AREA --X	GENE- RATION	FROM IND GENERATN	TO IND MOTORS	TO LOAD	TO BUS SHUNT	GNE BUS DEVICES	TO LINE SHUNT	FROM CHARGING	TO LOSSES	TO TIE LINES	TO TIES + LOADS	DESIRED NET INT
63	578.8	0.0	0.0	1287.0	0.0	0.0	5.1	0.0	36.7	-750.0	-750.0	-750.0
MD	117.7	0.0	0.0	470.5	0.0	0.0	28.5	625.2	484.2	-240.4	-240.4	

The total system load is 1.287 MW (reduced for generation modeled as negative load) and 470,5 MVar. The total load includes auxiliary loads as well. The value of active power losses is approximately 41,8 MW or 2,98% of total system active load. In this regime, Moldelectrica will import approximately 750 MW from neighboring systems.

The system summary per voltage level is shown in Table 107. For each voltage level, this table shows assigned total active and reactive power losses as well as part of the losses resulting from line shunts (i.e. transformer magnetizing losses). The last column shows reactive power generated by line charging.

Table 107: Summary per voltage levels in power system of MD for winter maximum load 2030, initial model

VOLTAGE LEVEL	BRANCHES	X----- LOSSES -----X MW	MVAR	X-- LINE SHUNTS --X MW	MVAR	CHARGING MVAR
DC	3	14.97	286.43			
400.0	4	4.14	52.06	0.0	0.0	248.6
330.0	20	2.91	33.63	0.0	0.0	200.7
110.0	482	13.87	83.93	0.7	1.6	175.9
15.8	3	0.53	18.43	0.6	3.0	0.0
10.5	3	0.28	9.76	0.4	2.2	0.0
TOTAL	515	36.70	484.24	1.7	6.8	625.2

The active power generation in the Moldovan power system for the Winter maximum load regime 2030, in the initial model, is shown in Table 108. This table shows data per unit type (fuel/technology type) as well as a sum of all data in the corresponding columns. Only data of units in operation are included in this table. The data shows output from generation units (values at the transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data includes total active power generation and total maximum available active power, so active power reserve can be estimated. In addition, the total rated apparent power is shown, so reactive power possibilities can be estimated. Finally, each row contains the number of units in operation as well as the number of units that are overloaded.

Table 108: Active power generation in power system of MD in winter maximum load regime, initial model

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Units out of limits
Gas	210.00	285.00	375.00	3	0
TPP Oil, Gas	368.77	630.00	705.90	3	0
Gas (negative load)	37.00	37.00	37.00	1	0
Run-of-river (negative load)	36.00	36.00	36.00	1	0
UNKNOWN (negative load)	42.00	42.00	42.00	3	0
Total	**693.77**	**1,030.00**	**1,195.90**	**11**	**0**

The Winter maximum load regime number of units in operation is 11. There are no generation units that are operating out of limits.

Summer Maximum Load Regime

As reported in PSS®E, a summary of area totals for Summer maximum load 2030 regime of the initial model is shown in Table 109. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 109: Area summary of MD power system in summer maximum load 2030 regime, variant Referent RES

	FROM ------AT AREA BUSES-------					TO				-NET INTERCHANGE-		
	GENE-	FROM IND	TO IND	TO	TO BUS	GNE BUS	TO LINE	FROM	TO	TO TIE	TO TIES	DESIRED
X-- AREA --X	RATION	GENERATN	MOTORS	LOAD	SHUNT	DEVICES	SHUNT	CHARGING	LOSSES	LINES	+ LOADS	NET INT
63	371.1	0.0	0.0	936.7	0.0	0.0	4.5	0.0	29.9	-600.0	-600.0	-600.0
MD	306.2	0.0	0.0	395.5	0.0	0.0	25.0	598.0	119.4	364.3	364.3	

The total system load is 936,7 MW (reduced for generation modeled as negative load) and 395,5 MVar. The total load includes auxiliary loads. The value of active power losses is approximately 34,4 MW or 3,35% of total system active load. In this regime, Moldelectrica will import approximately 600 MW from neighboring systems.

The system summary per voltage level is shown in Table 119. For each voltage level this table shows the assigned total active and reactive power losses as well as part of the losses resulting from line shunts (i.e. transformer magnetizing losses). The last column shows reactive power generated by line charging.

Table 110: Summary per voltage levels in power system of MD for summer maximum load 2030, initial model

```
VOLTAGE         X----- LOSSES -----X    X-- LINE SHUNTS --X    CHARGING
LEVEL  BRANCHES        MW        MVAR          MW        MVAR        MVAR
   DC       3       14.14      -35.45
400.0       4        2.51       31.36         0.0         0.0       244.6
330.0      20        2.05       24.90         0.0         0.0       187.9
110.0     482       10.49       69.33         0.6         1.4       165.4
 15.8       3        0.74       29.25         0.6         2.8         0.0
TOTAL     512       29.94      119.38         1.2         4.2       598.0
```

The active power generation in the Moldovan power system for the Summer maximum load regime 2030, initial model, is shown in Table 120. This table shows data per unit type (fuel/technology type) as well as the sum of all data in the corresponding columns. Only data of units in operation are included this table. The data shows output from generation units (values at the transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data includes total active power generation and total maximum available active power, so active power reserve can be estimated. In addition, total rated apparent power is shown, so reactive power possibilities can be estimated. Finally, each row contains the number of units in operation as well as the number of units that are overloaded.

Table 111: Active power generation in power system of MD in summer maximum load regime, initial model

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Units out of limits
TPP Oil, Gas	371.07	630.00	705.90	3	0
Gas (negative load)	13.00	13.00	13.00	1	0
Run-of-river (negative load)	36.00	36.00	36.00	1	0
UNKNOWN (negative load)	42.00	42.00	42.00	3	0

Total	**462.07**	**721.00**	**796.90**	**8**	**0**

The Summer maximum load regime number of units in operation is 8. There are no generation units that are overloaded.

Summer Minimum Load Regime

As reported from PSS®E, a summary of area totals for Summer minimum load 2030 regime for the initial model is shown in Table 124. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 112: Area summary of MD power system in summer minimum load 2030 regime, initial model

	FROM ------AT AREA BUSES-------					TO				-NET INTERCHANGE-		
X-- AREA --X	GENE- RATION	FROM IND GENERATN	TO IND MOTORS	TO LOAD	TO BUS SHUNT	GNE BUS DEVICES	TO LINE SHUNT	FROM CHARGING	TO LOSSES	TO TIE LINES	TO TIES + LOADS	DESIRED NET INT
63	283.9	0.0	0.0	656.0	0.0	0.0	4.4	0.0	23.5	-400.0	-400.0	-400.0
MD	131.1	0.0	0.0	282.3	0.0	0.0	25.0	623.4	340.7	106.5	106.5	

The total system load is 656 MW (reduced for generation modeled as negative load) and 282,3 MVar. The total load includes auxiliary loads. In comparison to the Summer maximum load regime, the total system active load is 70% of maximum load. The value of active power losses is approximately 27,9 MW or 3,70% of total system active load. In this regime, Moldelectrica will import approximately 400 MW from neighboring systems.

The system summary per voltage level is shown in Table 113. For each voltage level this table shows the assigned total active and reactive power losses as well as part of the losses resulting from line shunts (i.e. transformer magnetizing losses). The last column shows reactive power generated by line charging.

Table 113: Summary per voltage levels in power system of MD for summer minimum load 2030, initial model

```
VOLTAGE          X----- LOSSES -----X    X-- LINE SHUNTS --X    CHARGING
LEVEL  BRANCHES         MW          MVAR          MW          MVAR          MVAR
   DC        2        9.43        224.61
400.0        4        1.03         12.87         0.0           0.0         250.6
330.0       20        5.25         46.07         0.0           0.0         196.0
110.0      482        7.31         37.71         0.6           1.5         176.9
 15.8        2        0.45         19.46         0.4           2.0           0.0
TOTAL      510       23.46        340.72         1.0           3.5         623.4
```

The active power generation in the Moldovan power system for Summer minimum load regime 2030, in the initial model, in shown in Table 114. This table shows the data per unit type (fuel/technology type) as well as the sum of all the data in the corresponding columns. Only data of units in operation are included this table. The data shows output from generation units (values at the transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data includes total active power generation and total maximum available active power, so active power reserve can be estimated. In addition, total rated apparent power is shown, so reactive power possibilities can be estimated. Finally, each row contains the number of units in operation as well as the number of units which are slightly overloaded.

Table 114: Active power generation in power system of MD in summer minimum load regime, initial model

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Units out of limits
TPP Oil, Gas	283.90	420.00	470.60	2	0
Gas (negative load)	20.00	20.00	20.00	2	0
Run-of-river (negative load)	36.00	36.00	36.00	1	0
UNKNOWN (negative load)	42.00	42.00	42.00	3	0
Total	**381.90**	**518.00**	**568.60**	**8**	**0**

The Summer minimum load regime number of units in operation is 8. There are no generation units that are overloaded.

Referent and High RES Scenarios

In the next step, the initial models will be updated on the basis of the data provided by the BSTP members in the form of tables with a list of large scale RES projects and their location in the grid (Table 115). There are two lists: one related to the referent RES scenario and the other referring to the more aggressive high RES scenario. Based on the initial models and these lists, two different sets of network models will be developed.

Table 115: Referent and high RES scenarios in MD

Project name	RES type	Bus Number	Id	exists in PSS/E as load/gen	2030, istalled capacity [MW]	
					base case	high res
Badiceni	WPP	631002	G1	No	6.3	9
Gidroprivod	WPP	631007	G1	No	7.56	10.8
Donduseni	WPP	631008	G1	No	3.5	5
Drochia	PVPP	631009	G1	No	1.75	2.5
Chiscareni	WPP	632010	G1	No	21	30
Mihaileni	WPP	632014	G1	No	3.15	4.5
Ungheni	WPP	632026	G1	No	35	50
Soldanesti	WPP	632033	G1	No	35.28	50.4
Baimaclia	WPP	634006	G1	No	27.3	39
Caplani W	WPP	634011	G1	No	28	40
Caplani PV	PVPP	634011	G2	No	6.874	9.82
Carpineni	PVPP	634012	G1	No	7	10
Causeni	WPP	634013	G1	No	44.1	63
Anenii Noi	PVPP	634017	G1	No	42	60
Brinzeni	WPP	634018	G1	No	14	20
Olanesti	WPP	634077	G1	No	35	50
Rascaeti	WPP	634019	G2	No	28.35	40.5
Nisporeni	PVPP	634020	G1	No	0.7	1
Purcari 1	WPP	634026	G1	No	35.7	51
Taraclia	WPP	634027	G1	No	5.6	8
Sipoteni W	WPP	634028	G1	No	28	40
Sipoteni PV	PVPP	634028	G2	No	7	10
Straseni 1	PVPP	634033	G1	No	8.4	12
Cioburciu 1	WPP	634038	G1	No	41.16	58.8
Straseni 3	WPP	634059	G1	No	28.7	41
Cioburciu 2	WPP	634063	G1	No	51.94	74.2
Purcari 2	WPP	634076	G1	No	6.3	9
Straseni 2	PVPP	634086	G1	No	7	10
Serpeni	PVPP	634088	G1	No	1.4	2
Cahul	WPP	636016	G1	No	32.2	46
Congaz	WPP	636024	G1	No	37.8	54
Leova	PVPP	636025	G1	No	7	10
Ciadir	PVPP	636031	G1	No	28	40
Balabanu	WPP	636037	G1	No	47.6	68
Vulcanesti	WPP	636038	G1	No	126	180
SOK	PVPP	636098	G1	No	1.75	2.5
Giurgilesti	WPP	636112	G1	No	12.6	18

IX.1.5 Transelectrica Models (RO)

The current development stage of the high voltage grid area under the responsibility of Transelectrica is shown in Figure 65. In year 2030, the transmission system will have a total of 14 tie-lines at the following voltage levels:

- 12 tie-lines at the 400 kV voltage level

The number of elements used for modeling the Romanian power system is shown in Table 116.

Table 116: Number of elements in models of RO

1290 BUSES	354 PLANTS	289 MACHINES	0 INDUCTION GENS	0 INDUCTION MOTORS
734 LOADS	0 FIXED SHUNTS	12 SWITCHED SHUNTS		
1705 BRANCHES	445 TRANSFORMERS	0 DC LINES	0 FACTS DEVICES	0 GNE DEVICES

The installed generation capacities in the Romanian power system are shown in Table 117. This table shows the total maximum active power output, total rated apparent power and well as the number of generation units. The data is given per each type of unit (fuel/technology type) and the last row shows the sum of all data in the corresponding column.

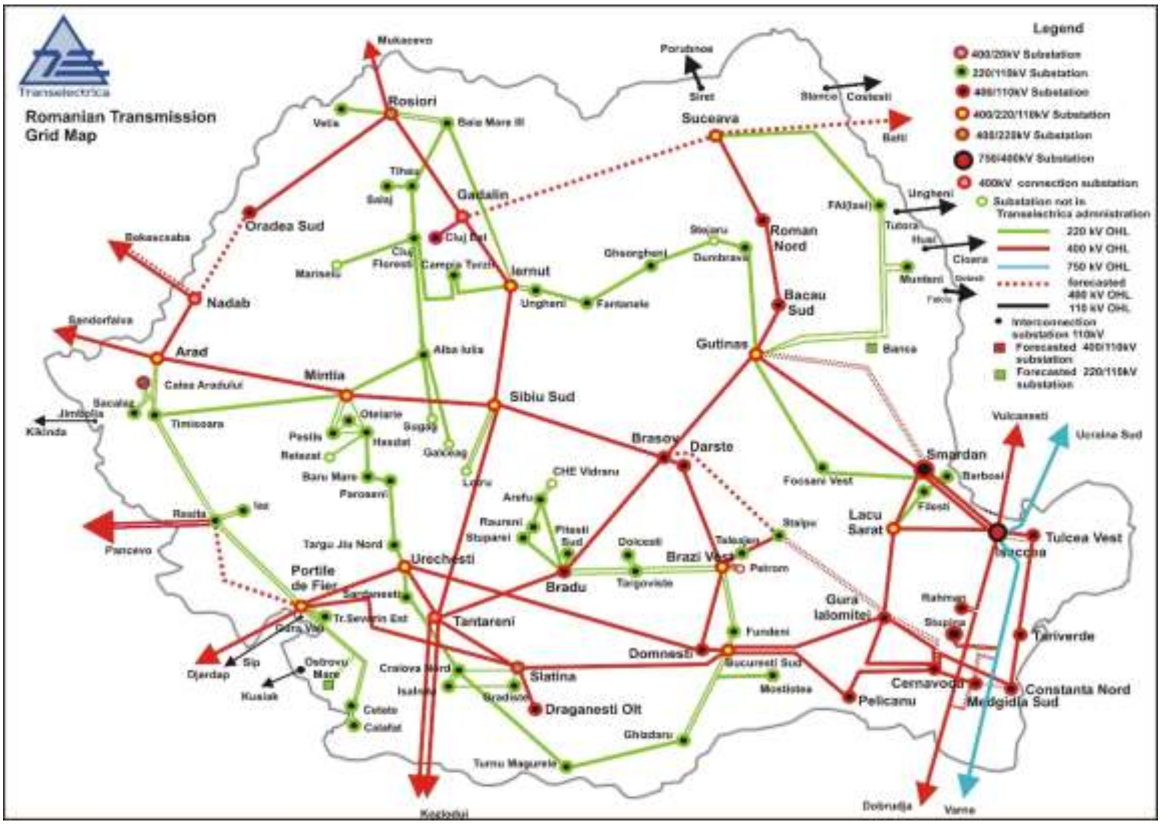

Figure 65: HV transmission network of Romania, current development stage (submitted by Transelectrica)

Table 117: Installed generation capacities in power system of RO forecasted for 2030

Unit (fuel) type	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Nuclear	1,416.00	1,600.00	2
Coal	4,505.00	5,359.50	22
CCGT	1,571.44	1,864.61	13
Gas	1,196.25	1523.84	17
Small gas	444.43	493.82	28
Seasonal storage	3,208.95	3,407.83	70
Run-of-river	2,728.75	2,852.12	41
Small hydro	98.45	100.1	17
Biomass	274.05	303.04	28
WIND	4,200.04	4,410.57	81
Solar (Photovoltaic)	1,800.01	1,999.98	68
Total	**21,443.37**	**23,915.41**	**387**

The loading of branches in the Romanian transmission grid is shown in Figure 66. Only branches at the 110 kV voltage level and above are included (for 3-winding transformers, the loading of each winding is considered separately).

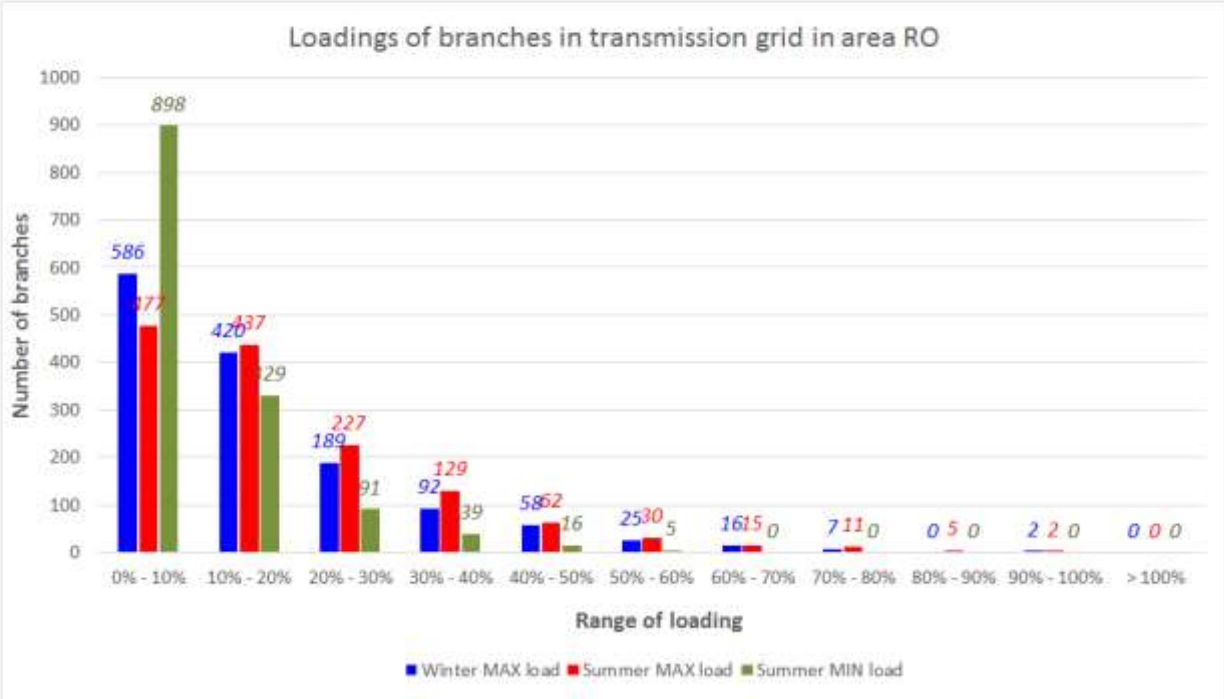

Figure 66: Histogram of branch loading in expected winter and summer maximum as well as in summer minimum regimes in 2030 in transmission grid of RO

The figure shows that there are no overloaded branches in the Romanian transmission grid. Also, most elements are loaded below 20%. In the case of Winter maximum load regime, there are nine branches loaded over 70%, and two of them have loading in the 90% – 100% range.

In case of Summer minimum load regime, almost all elements have a loading below 30%. There are only five branches with a load in the 50% – 60% range.

Winter Maximum Load Regime

As reported from PSS®E, a summary of area totals for Winter maximum load for the 2030 regime is shown in Table 118. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 118: Area summary of RO power system in winter maximum load 2030 regime, initial model

	FROM	------AT AREA BUSES-------				TO				-NET INTERCHANGE-		
	GENE-	FROM IND	TO IND	TO	TO BUS	GNE BUS	TO LINE	FROM	TO	TO TIE	TO TIES	DESIRED
X-- AREA --X	RATION	GENERATN	MOTORS	LOAD	SHUNT	DEVICES	SHUNT	CHARGING	LOSSES	LINES	+ LOADS	NET INT
44	11137.4	0.0	0.0	10253.8	0.0	0.0	95.6	0.0	237.8	550.1	550.1	550.0
RO	503.3	0.0	0.0	2219.5	1383.3	0.0	272.3	5536.6	2720.4	-555.7	-555.7	

The total system load is 10.253,8 MW and 2.219,5 MVar. The total load includes auxiliary loads. The value of active power losses is approximately 333,4 MW or 3,25% of total system active load. In this regime, Transelectrica exports approximately 550 MW to neighboring systems.

The system summary per voltage level is shown in Table 119. For each voltage level this table shows the assigned total active and reactive power losses as well as part of the losses resulting from line shunts (i.e. transformer magnetizing losses). The last column shows reactive power generated by line charging.

Table 119: Summary per voltage levels in power system of RO for winter maximum load 2030, initial model

```
 VOLTAGE        X----- LOSSES -----X   X-- LINE SHUNTS --X   CHARGING
 LEVEL BRANCHES         MW        MVAR         MW        MVAR       MVAR
 400.0     104       57.24      712.07       54.8        31.9     3727.4
 220.0      88       48.81      307.92       11.2         0.1      629.3
 110.0    1203      104.14      742.31       12.6       120.4     1179.9
  33.0      15        0.55       13.69        0.5         2.9        0.0
  30.0      16        0.34       14.16        0.6         2.8        0.0
  24.0       9        5.11      263.98        2.4        16.4        0.0
  20.0      13        0.25        8.02        0.4         1.7        0.0
  18.0       1        0.25        8.99        0.2         0.9        0.0
  17.0       2        0.66       47.21        0.3         2.8        0.0
  15.8      19        3.92      161.15        2.0        14.8        0.0
  15.0       1        0.27       11.94        0.1         0.0        0.0
  10.5     119       10.05      281.50        6.0        55.3        0.0
   6.3      72        4.38      126.51        1.9        17.7        0.0
   1.0       3        0.32        4.58        0.2         0.3        0.0
   0.7      34        1.43       15.74        2.2         3.9        0.0
   0.4       6        0.07        0.63        0.4         0.4        0.0
 TOTAL    1705      237.80     2720.43       95.6       272.3     5536.6
```

The active power generation in the Romanian power system for the Winter maximum load regime 2030, initial model, is shown in Table 120. This table shows data per unit type (fuel/technology type) as well as the sum of all data in the corresponding columns. Only the data of units in operation are included in this table. The data shows output from generation units (values at the transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data includes total active power generation and total maximum available active power, so active power reserve can be estimated. In addition, total rated apparent power is shown, so reactive power possibilities can be estimated. Finally, each row contains number of units in operation as well as number of units that are overloaded.

Table 120: Active power generation in power system of RO in winter maximum load regime, initial model

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Units out of limits

Nuclear	1,416.00	1,416.00	1,600.00	2	0
Coal	1,840.00	2,505.00	3,001.00	14	0
CCGT	1,230.00	1,560.00	1,853.00	12	0
Gas	377.00	582.00	714.00	9	0
Small gas	348.00	444.00	493.00	28	0
Seasonal storage	2,244.00	2,782.00	2,951.00	66	0
Run-of-river	2,208.00	2,684.00	2,808.00	40	0
Small hydro	54.00	93.00	95.00	11	0
Biomass	218.00	274.00	303.00	28	0
WIND	1,200.00	4,000.00	4,210.00	79	0
Solar (Photovoltaic)	0.00	0.00	0.00	0	0
Total	**11,135.00**	**16,340.00**	**18,028.00**	**289**	**0**

In the maximum load regime, the number of units in operation is 289. There are no generation units that are out of acceptable operating range.

Summer Maximum Load Regime

As report from PSS®E, a summary of area totals for the Summer maximum load 2030 regime is shown in Table 121. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 121: Area summary of RO power system in summer maximum load 2030 regime, initial model

	FROM ------AT AREA BUSES-------					TO				-NET INTERCHANGE-		
	GENE-	FROM IND	TO IND	TO	TO BUS	GNE BUS	TO LINE	FROM	TO	TO TIE	TO TIES	DESIRED
X-- AREA --X	RATION	GENERATN	MOTORS	LOAD	SHUNT	DEVICES	SHUNT	CHARGING	LOSSES	LINES	+ LOADS	NET INT
44	9591.6	0.0	0.0	8848.9	0.0	0.0	92.8	0.0	169.9	480.0	480.0	480.0
RO	-254.4	0.0	0.0	2796.5	685.4	0.0	254.3	5455.1	1884.3	-419.7	-419.7	

The total system load is 8.848,9 MW and 2.796,5 MVar. The total load includes auxiliary loads. The value of active power losses is approximately 262,7 MW or 2,97% of total system active load. In this regime, Transelectrica exports approximately 480 MW to neighboring systems.

The system summary per voltage level is shown in Table 122. For each voltage level, this table shows the assigned total active and reactive power losses as well as part of the losses which resulted from line shunts (i.e. transformer magnetizing losses). Last column shows reactive power generated by line charging.

Table 122: Summary per voltage levels in power system of RO for summer maximum load 2030, initial model

```
VOLTAGE        X----- LOSSES -----X   X-- LINE SHUNTS --X   CHARGING
LEVEL BRANCHES        MW         MVAR        MW         MVAR        MVAR
400.0    104       39.26      501.25       54.5        31.4      3710.2
220.0     88       30.85      202.09       11.0         0.1       618.3
110.0   1203       81.82      512.72       12.5       119.0      1126.6
 33.0     15        0.25        6.26        0.5         2.9         0.0
 30.0     16        0.15        6.22        0.6         2.8         0.0
 24.0     10        4.91      250.69        2.5        18.6         0.0
 20.0     12        0.13        4.22        0.3         1.5         0.0
 17.0      2        0.59       42.42        0.3         2.6         0.0
 15.8     13        2.63      121.39        1.4        12.2         0.0
 15.0      1        0.20        8.80        0.1         0.0         0.0
 10.5     97        5.56      146.53        4.6        42.1         0.0
  6.3     68        2.73       71.98        1.7        16.4         0.0
  1.0      3        0.15        2.09        0.2         0.3         0.0
  0.7     33        0.63        7.34        2.2         3.9         0.0
  0.4      6        0.03        0.28        0.4         0.4         0.0
TOTAL   1671      169.89     1884.29       92.8       254.3      5455.1
```

The active power generation in the Romanian power system for the Summer maximum load regime 2030 is shown in Table 126. This table shows data per unit type (fuel/technology type) as well as the sum of all data in the corresponding columns. Only the data of units in operation are included in this table. The data shows output from generation units (values on transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data include total active power generation and total maximum available active power, so active power reserve can be estimated. In addition, total rated apparent power is shown, so reactive power possibilities can be estimated. Finally, each row contains the number of units in operation as well as the number of units that are overloaded.

Table 123: Active power generation in power system of RO in summer maximum load regime, initial model

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Units out of limits
Nuclear	1,416.00	1,416.00	1,600.00	2	0

Coal	1,490.00	2,275.00	2,722.00	10	0
CCGT	955.00	1,279.00	1,533.00	8	0
Gas	133.00	247.00	263.00	5	0
Small gas	71.00	92.00	103.00	7	0
Seasonal storage	1,568.00	2,273.00	2,390.00	56	0
Run-of-river	1,673.00	2,728.00	2,852.00	41	0
Small hydro	50.00	95.00	96.00	12	0
Biomass	82.00	138.00	154.00	14	0
WIND	800.00	4,000.00	4,210.00	79	0
Solar (Photovoltaic)	1,350.00	1,800.00	2,000.00	68	0
Total	**9,588.00**	**16,343.00**	**17,923.00**	**302**	**0**

The maximum load regime number of units in operation is 302. There are no generation units that are out of acceptable operating range.

Summer Minimum Load Regime

As report from PSS®E, a summary of area totals for the Summer minimum load 2030 regime is shown in Table 124. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 124: Area summary of RO power system in summer minimum load 2030 regime, initial model

	FROM	------AT AREA	BUSES-------			TO				-NET INTERCHANGE-		
	GENE-	FROM IND	TO IND	TO	TO BUS	GNE BUS	TO LINE	FROM	TO	TO TIE	TO TIES	DESIRED
X-- AREA --X	RATION	GENERATN	MOTORS	LOAD	SHUNT	DEVICES	SHUNT	CHARGING	LOSSES	LINES	+ LOADS	NET INT
44	5710.1	0.0	0.0	5163.5	0.0	0.0	84.9	0.0	111.6	350.1	350.1	350.0
RO	-518.8	0.0	0.0	1665.2	2107.7	0.0	204.4	5433.7	1420.9	-483.3	-483.3	

The total system load is 5.163,5 MW and 1.665,2 MVar. The total load includes auxiliary loads. In comparison to the Summer maximum load regime, the total system active load is 58,35% of Summer maximum load. The value of active power losses is approximately 196.5 MW or 3,81% of total system active load. In this regime, Transelectrica exports approximately 350 MW to neighboring systems.

The system summary per voltage level is shown in Table 125. For each voltage level, this table shows the assigned total active and reactive power losses as well as part of the losses resulting from line shunts (i.e. transformer magnetizing losses). The last column shows reactive power generated by line charging.

Table 125: Summary per voltage levels in power system of RO for summer minimum load 2030, initial model

VOLTAGE LEVEL	BRANCHES	LOSSES MW	LOSSES MVAR	LINE SHUNTS MW	LINE SHUNTS MVAR	CHARGING MVAR
400.0	100	55.34	627.59	52.9	30.7	3626.1
220.0	83	19.76	116.45	10.5	0.1	585.9
110.0	1195	25.12	205.72	12.1	115.3	1221.7
33.0	11	0.37	9.57	0.5	2.6	0.0
30.0	10	0.45	15.31	0.4	2.2	0.0
24.0	8	4.17	215.55	2.1	14.7	0.0
20.0	5	0.08	2.84	0.2	0.7	0.0
17.0	2	0.48	34.87	0.3	2.8	0.0
15.8	9	1.93	90.84	1.2	9.9	0.0
15.0	1	0.39	16.86	0.1	0.0	0.0
10.5	36	1.62	46.76	1.9	15.7	0.0
6.3	23	0.89	26.86	0.7	6.3	0.0
1.0	2	0.18	2.60	0.1	0.1	0.0
0.7	22	0.67	7.66	1.6	2.8	0.0
0.4	5	0.13	1.39	0.4	0.4	0.0
TOTAL	1512	111.59	1420.87	84.9	204.4	5433.7

The active power generation in the Romanian power system for the Summer minimum load regime 2030, initial model, is shown in Table 126. This table shows data per unit type (fuel/technology type) as well as the sum of all data in the corresponding columns. Only data of units in operation are included this table. The data shows output from generation units (values on transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data include total active power generation and total maximum available active power, so active power reserve can be estimated. In addition, total rated apparent power is shown, so reactive power possibilities can be estimated. Finally, each row contains the number of units in operation as well as the number of units which are slightly overloaded.

Table 126: Active power generation in power system of RO in summer minimum load regime, initial model

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Units out of limits

Nuclear	1,380.00	1,416.00	1,600.00	2	0
Coal	1,161.06	1,755.00	2,061.50	7	0
CCGT	835.96	1,130.00	1,363.00	6	0
Gas	86.80	253.00	317.58	5	0
Small gas	65.40	102.36	113.74	7	0
Seasonal storage	175.00	292.00	318.00	6	0
Run-of-river	1,026.00	2,197.00	2,320.00	31	0
Small hydro	71.88	96.81	98.31	14	0
Biomass	106.80	158.01	175.38	17	0
WIND	800.80	2,860.59	3,011.14	43	0
Solar (Photovoltaic)	0.00	0.00	0.00	0	0
Total	**5,709.70**	**10,260.77**	**11,378.65**	**138**	**0**

In the Summer minimum load regime, the number of units in operation is 138. There are no generation units that are out of acceptable operating range.

Referent and High RES Scenarios

In the next step, the initial models will be updated based on the data provided by the BSTP members in the form of tables with a list of large scale RES projects and their location in the grid. Table 127 presents the sum per technologies only (as the entire list is too long to be presented here). There are two lists: one related to the referent RES scenario and the second referring to the more aggressive high RES scenario. Based on the initial models and these lists, two sets of network models are developed.

Table 127: Referent and high RES scenarios in RO

Project name	RES type	Bus Number	Id	exists in PSS/E as load/gen	2030, installed capacity [MW]	
					base case	high res
	Wind		W	gen	4200.04	5100.05
	Solar		S	gen	2000.00	2300.16
	Biomass		B	gen	320.00	500.07

IX.1.6 UKRENERGO Models (UA)

The current development stage of the high voltage grid of area under the responsibility of Ukrenergo is shown in Figure 67. In 2030, the Ukrenergo transmission system has 24 tie-lines at the following voltage levels:

- 2 tie-lines of voltage level 750 kV
- 3 tie-lines of voltage level 400 kV
- 5 tie-lines of voltage level 330 kV
- 2 tie-lines of voltage level 220 kV
- 12 tie-line of voltage level 110 kV

In this model, 220 kV network and higher are fully represented, while at the same time, networks 150 kV and below are mainly represented by the network equivalents with the preservation of transit connections of 110-150 kV and junction substations 110 (150) kV.

The number of elements used to model the Ukrainian power system is shown in Table 128.

Table 128: Number of elements in models of UA

922 BUSES	118 PLANTS	94 MACHINES	0 INDUCTION GENS	0 INDUCTION MOTORS
1105 LOADS	35 FIXED SHUNTS	0 SWITCHED SHUNTS		
1058 BRANCHES	444 TRANSFORMERS	0 DC LINES	0 FACTS DEVICES	0 GNE DEVICES

The installed generation capacities in the Ukrainian power system is shown in Table 129. This table shows the total maximum active power output, total rated apparent power and well as the number of generation units. The data is given per unit type (fuel/technology type) and the last row shows the sum of all data in the corresponding column.

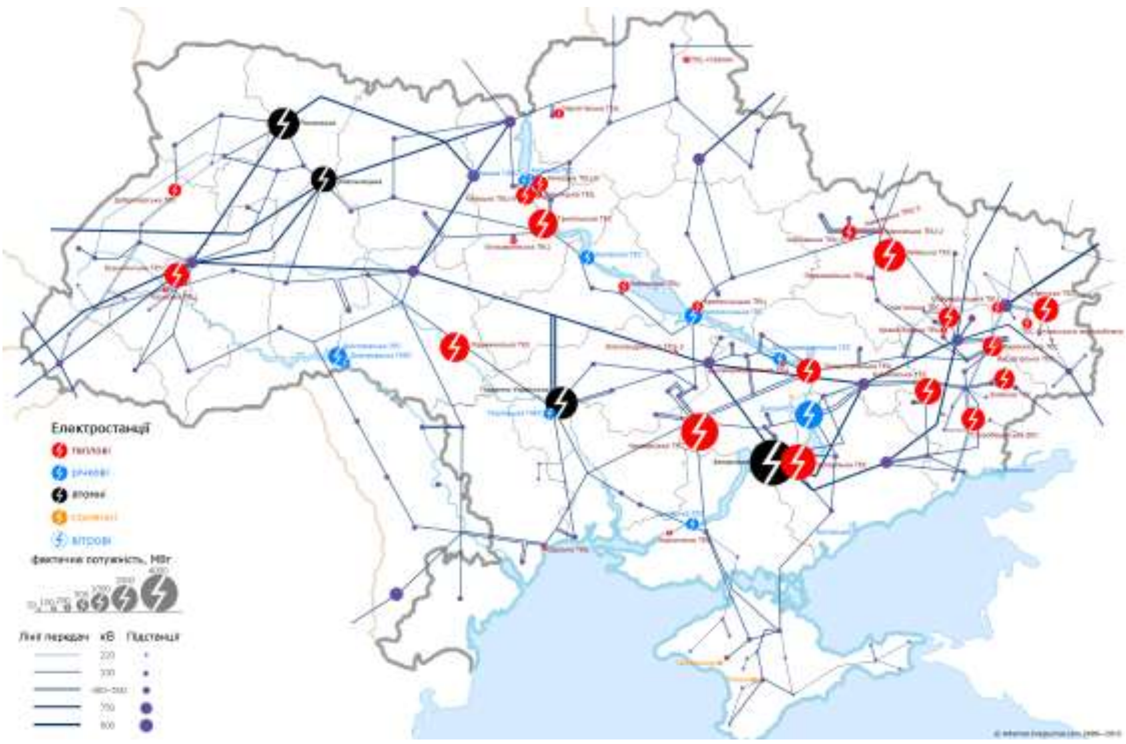

Figure 67: HV transmission network of Ukraine, current development stage

Table 129: Generation capacities in power system of UA

Unit (fuel) type	Total P_{max} (MW)	Total S_n (MVA)	Number of units
Nuclear	13,835.00	15,479.00	17
Coal	20,862.00	24,430.00	86
CHP	1,220.00	1,788.40	6
Storage seasonal/yearly/weekly/daily	4,872.80	5,687.60	65
Pump Storage weekly/daily	2,333.50	5,612.40	25
Hydro (negative load)	193.00	193.00	50
Biomass (negative load)	513.00	513.00	68
Wind (negative load)	4,200.00	4,200.00	34
Solar (negative load)	7,874.30	7,874.30	172
UNKNOWN (negative load)	1,758.00	1,758.00	65

Total	**57,661.60**	**67,535.70**	**588**

The branch loadings in the Ukrainian transmission grid is shown in Figure 68. Only branches at the 110 kV voltage level and above are included (for 3-winding transformers, the loading of each winding is considered separately).

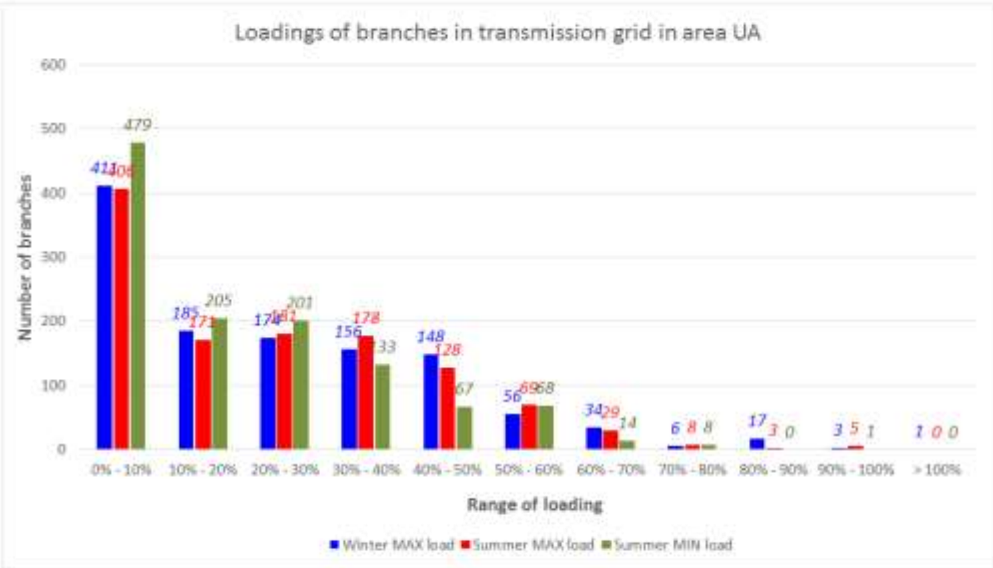

Figure 68: Histogram of branch loading in expected winter and summer maximum as well as in summer minimum regimes in 2030 in transmission grid of UA

The figure shows one overloaded branch in the Ukrainian transmission grid (330/110/35 kV transformer at the Rivne substation) with most of elements loaded below 60%. In the case of the Winter maximum load regime, there are 21 branches loaded over 80%, three have a loading in the 90% – 100% range, and one is overloaded.

In the case of Summer minimum load regime, almost all elements have loading below 50%. There is one branch with a loading in the 90% – 100% range.

Winter Maximum Load Regime

As report from PSS®E, a summary of area totals, including the Winter maximum load 2030 regime for the initial model, is shown in Table 130. The first row represents data related to active power (in MW), while second row shows data related to reactive power (in MVar).

Table 130: Area summary of UA power system in maximum load 2030 regime, initial model

X-- AREA --X	FROM GENE- RATION	------AT AREA BUSES------- FROM IND GENERATN	TO IND MOTORS	TO LOAD	TO BUS SHUNT	TO GNE BUS DEVICES	TO LINE SHUNT	FROM CHARGING	TO LOSSES	-NET INTERCHANGE- TO TIE LINES	TO TIES + LOADS	DESIRED NET INT
60	22239.3	0.0	0.0	20752.3	8.3	0.0	175.9	0.0	552.9	750.0	750.0	750.0
UA	6091.0	0.0	0.0	8262.6	9000.3	0.0	901.2	19262.0	6644.6	544.3	544.3	

The total system load is 20.752,3 MW (reduced for generation modeled as negative load) and 8.262,6 MVar. The total load includes auxiliary loads. The value of active power losses is approximately 728.8 MW, which is relatively low and presents 3,51% of the total system active load. In this regime, Ukrenergo will export approximately 750 MW to neighboring systems.

The system summary per voltage level is shown in Table 131. For each voltage level this table shows the assigned total active and reactive power losses as well as part of the losses resulting from line shunts (i.e. transformer magnetizing losses). The last column shows reactive power generated by line charging.

Table 131: Summary per voltage levels in power system of UA for maximum load 2030, initial model

VOLTAGE LEVEL	BRANCHES	X----- LOSSES -----X MW	MVAR	X-- LINE SHUNTS --X MW	MVAR	CHARGING MVAR
750.0	22	49.16	826.85	0.0	0.0	11575.7
500.0	3	0.61	8.51	0.0	0.0	52.7
400.0	11	2.64	30.07	0.6	4.1	414.8
330.0	246	275.76	2308.39	3.7	42.5	6420.3
220.0	58	13.37	103.00	0.4	3.7	258.5
150.0	148	50.16	377.33	9.7	147.6	255.8
110.0	454	113.30	879.07	121.9	195.7	284.2
24.0	12	12.79	988.51	6.2	228.0	0.0
20.0	25	9.72	380.21	7.2	43.1	0.0
18.0	5	1.21	47.33	1.1	6.4	0.0
15.8	9	5.41	145.40	2.9	15.8	0.0
15.8	23	7.41	235.45	4.8	44.9	0.0
13.8	23	4.41	153.73	2.5	28.6	0.0
10.5	8	3.28	76.11	0.7	13.1	0.0
10.0	3	0.80	20.50	0.4	3.5	0.0
6.3	4	1.46	30.51	0.3	3.7	0.0
3.1	4	1.42	33.59	0.3	1.6	0.0
TOTAL	1058	552.89	6644.55	162.8	782.2	19262.0

The active power generation in the Ukrainian power system, for Winter maximum load regime 2030 in the initial model, is shown in Table 132. This table shows data per unit type (fuel/technology type) as well as the sum of all data in the corresponding columns. Only data of units in operation are included this table. The data shows output from generation units (values at the transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data includes total active power generation and total maximum available active power, so active power reserve can be estimated. In addition, total rated apparent power is shown. Therefore, reactive power possibilities can be estimated. Finally, each row contains the number of units in operation as well as the number of units that are overloaded.

Table 132: Active power generation in power system of UA in winter maximum load regime, initial model

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Units out of limits
Nuclear	10,215.06	10,630.00	11,887.00	13	0
Coal	6,915.72	7,229.00	8,231.00	31	0
CHP	690.97	720.00	1,035.00	4	0
Storage seasonal/yearly/weekly/daily	2,562.00	2,713.00	3,141.00	36	0
Pump Storage weekly/daily	1,855.00	1,972.00	2,232.00	10	0
Hydro (negative load)	193.37	193.37	193.37	50	0
Biomass (negative load)	513.75	513.75	513.75	68	0
Wind (negative load)	4,200.00	4,200.00	4,200.00	34	0
Solar (negative load)	0.00	7,874.30	7,874.30	172	0
UNKNOWN (negative load)	1,341.00	1,341.00	1,341.00	52	0
Total	**28,486.87**	**37,386.42**	**40,648.42**	**470**	**0**

In the maximum load regime, the number of units in operation is 228. There are no generation units that are operating out of limits.

Summer Maximum Load Regime

As reported from PSS®E, a summary of area totals for the Summer maximum load 2030 regime in the initial model, is shown in Table 133. The first row represents data related to active power (in MW), while second row shows data related to reactive power (in MVar).

Table 133: Area summary of UA power system in summer maximum load 2030 regime, initial model

	FROM ------AT AREA BUSES-------					TO				-NET INTERCHANGE-		
	GENE-	FROM IND	TO IND	TO	TO BUS	GNE BUS	TO LINE	FROM	TO	TO TIE	TO TIES	DESIRED
X-- AREA --X	RATION	GENERATN	MOTORS	LOAD	SHUNT	DEVICES	SHUNT	CHARGING	LOSSES	LINES	+ LOADS	NET INT
60	18668.6	0.0	0.0	17390.5	0.0	0.0	65.0	0.0	563.1	650.0	650.0	650.0
UA	7858.7	0.0	0.0	6997.8	194.7	0.0	10768.9	17078.1	6965.0	10.3	10.3	

The total system load is 17.390,5 MW (reduced for generation modeled as negative load) and 6.997,8 MVar. The total load includes auxiliary loads as well. The value of active power losses is approximately 628.1 MW, which is relatively low and presents 3,61% of the total system active load. In this regime, Ukrenergo will export approximately 650 MW to neighboring systems.

The system summary per voltage level is shown in Table 134. For each voltage level, this table shows assigned total active and reactive power losses as well as losses resulting from line shunts (i.e. transformer magnetizing losses). The last column shows reactive power generated by line charging.

Table 134: Summary per voltage levels in power system of UA for summer maximum load 2030, initial model

VOLTAGE		X----- LOSSES -----X		X-- LINE SHUNTS --X		CHARGING
LEVEL	BRANCHES	MW	MVAR	MW	MVAR	MVAR
750.0	22	48.47	823.70	7.5	9968.8	10457.1
500.0	3	0.32	4.40	0.0	0.0	45.4
400.0	6	2.82	31.05	0.2	0.7	152.1
330.0	246	296.84	2542.47	3.2	37.3	5725.4
220.0	58	15.44	119.35	0.4	3.5	239.8
150.0	152	52.12	448.49	8.3	120.9	216.5
110.0	450	97.53	786.37	18.6	288.1	241.8
24.0	10	15.89	1184.64	4.5	159.5	0.0
20.0	8	6.88	265.99	2.4	13.9	0.0
18.0	3	1.52	52.64	0.5	7.4	0.0
15.8	8	6.67	190.08	2.6	13.4	0.0
15.8	13	9.15	291.88	2.7	25.0	0.0
13.8	10	3.52	93.63	0.9	10.2	0.0
10.5	4	2.14	48.36	0.6	6.2	0.0
10.0	3	1.48	36.22	0.4	3.1	0.0
6.3	4	2.28	45.73	0.3	3.2	0.0
TOTAL	1000	563.08	6965.02	53.0	10661.2	17078.1

The active power generation in the Ukrainian power system, for the Summer maximum load regime 2030, is shown in Table 135. This table shows data per unit type (fuel/technology type) as well as the sum of all data in the corresponding columns. Only data of units in operation are included this table. The data shows output from generation units (values at the transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data includes total active power generation and total maximum available active power, so active power reserve can be estimated. In addition, total rated apparent power is shown. Therefore, reactive power possibilities can be estimated. Finally, each row contains the number of units in operation as well as the number of units that are overloaded.

Table 135: Active power generation in power system of UA in summer maximum load regime, initial model

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Units out of limits
Nuclear	9,598.00	9,835.00	11,035.00	13	0
Coal	5,644.00	6,075.00	6,657.00	25	0
CHP	220.00	220.00	282.00	2	0
Storage seasonal/yearly/weekly/daily	1,029.00	1,075.00	1,275.00	16	0
Pump Storage weekly/daily	2,176.00	2,176.00	2,487.00	10	0
Hydro (negative load)	193.00	193.00	193.00	50	0
Biomass (negative load)	513.00	513.00	513.00	68	0
Wind (negative load)	4,200.00	4,200.00	4,200.00	34	0
Solar (negative load)	0.00	7,874.30	7,874.30	172	0
UNKNOWN (negative load)	813.00	813.00	813.00	51	0
Total	**24,386.00**	**32,974.30**	**35,329.30**	**441**	**0**

In the Summer maximum load regime, the number of units in operation is 202. There are no generation units that are out of acceptable operating range.

Summer Minimum Load Regime

As reported from PSS®E, a summary of area totals for the minimum load 2030 regime in the initial model, is shown in Table 136. The first row represents data related to active power (in MW), while the second row shows data related to reactive power (in MVar).

Table 136: Area summary of UA power system in summer minimum load 2030 regime, initial model

	FROM	------AT AREA BUSES-------				TO				-NET INTERCHANGE-		
	GENE-	FROM IND	TO IND	TO	TO BUS	GNE BUS	TO LINE	FROM	TO	TO TIE	TO TIES	DESIRED
X-- AREA --X	RATION	GENERATN	MOTORS	LOAD	SHUNT	DEVICES	SHUNT	CHARGING	LOSSES	LINES	+ LOADS	NET INT
60	14160.8	0.0	0.0	13014.4	0.0	0.0	67.9	0.0	428.4	650.0	650.0	650.0
UA	5043.3	0.0	0.0	5858.4	225.4	0.0	11303.2	18263.7	5638.2	281.9	281.9	

The total system load is 13.014,4 MW (reduced for generation modeled as negative load) and 5.858,4 MVar. The total load includes auxiliary loads. In comparison with the maximum load regime, the total system active load is 74,84% of Summer maximum load. The value of active power losses is approximately 496.3 MW or 3,81% of the total system active load. In this regime, Ukrenergo will export approximately 650 MW to neighboring systems.

The system summary per voltage level is shown in Table 137. For each voltage level, this table shows assigned total active and reactive power losses as well as part of the losses resulting from line shunts (i.e. transformer magnetizing losses). The last column shows reactive power generated by line charging.

Table 137: Summary per voltage levels in power system of UA for summer minimum load 2030, initial model

VOLTAGE		X----- LOSSES	-----X	X-- LINE	SHUNTS --X	CHARGING
LEVEL	BRANCHES	MW	MVAR	MW	MVAR	MVAR
750.0	22	43.80	704.13	7.8	10465.0	11086.3
500.0	3	0.04	0.53	0.0	0.0	51.2
400.0	6	1.07	10.61	0.2	0.7	158.2
330.0	246	238.51	2221.11	3.2	36.0	6198.7
220.0	58	7.24	55.91	0.4	3.8	270.5
150.0	152	45.80	413.44	9.1	132.0	228.7
110.0	450	54.37	416.82	20.1	309.2	270.1
24.0	10	14.39	1072.91	4.8	166.1	0.0
20.0	8	5.99	232.53	2.6	15.3	0.0
18.0	3	1.31	45.65	0.6	8.0	0.0
15.8	5	5.58	155.58	1.7	9.1	0.0
15.8	13	7.35	239.13	2.9	26.8	0.0
13.8	3	0.71	19.45	0.3	2.9	0.0
10.5	3	0.77	16.29	0.6	6.9	0.0
10.0	3	1.00	25.42	0.4	3.5	0.0
6.3	1	0.50	8.65	0.1	1.4	0.0
TOTAL	986	428.44	5638.16	54.8	11186.9	18263.7

The active power generation in the Ukrainian power system, for the Summer minimum load regime 2030 in the initial model, in shown in Table 138. This table shows data per unit type (fuel/technology type) as well as the sum of all data in the corresponding columns. Only the data of units in operation are included in this table. The data shows output from generation units (values at the transmission level must be decreased by auxiliary loads and losses in step up transformers).

The data includes total active power generation and total maximum available active power, so active power reserve can be estimated. In addition, total rated apparent power is shown, so reactive power possibilities can be estimated. Finally, each row contains the number of units in operation as well as the number of units which are slightly overloaded.

Table 138: Active power generation in power system of UA in summer minimum load regime, initial model

Fuel type	Total P_{gen} (MW)	Total P_{max} (MW)	Total S_n (MVA)	Number of units	Units out of limits
Nuclear	9,580.00	9,835.00	11,035.00	13	0
Coal	5,659.00	6,075.00	6,658.00	25	0
CHP	217.00	220.00	282.00	2	0
Storage seasonal/yearly/weekly/daily	258.00	272.00	305.00	4	0
Pump Storage weekly/daily	-1,555.00	0.00	1833	0	0
Hydro (negative load)	193.00	193.00	193.00	50	0
Biomass (negative load)	513.00	513.00	513.00	68	0
Wind (negative load)	4,200.00	4,200.00	4,200.00	34	0
Solar (negative load)	0.00	7,874.30	7,874.30	172	0
UNKNOWN (negative load)	883.00	883.00	883.00	52	0
Total	**19,948.00**	**30,065.30**	**33,776.30**	**420**	**0**

The maximum load regime number of units in operation is 180. There are no generation units that are operating out of limits.

Referent and High RES Scenarios

The initial models will be updated by the Consultant based on the data provided by the BSTP members. The models will include an update of large-scale RES projects and their location on the grid. Table 139 depicts the sum per technology only, as the entire list is too lengthy to be presented in this Interim Report. There are two lists included: the first related to the referent RES scenario and the second referring to a more aggressive, high RES scenario. Based on the initial models and these lists, the Consultant will prepare two sets of network models.

Table 139: Referent and high RES scenarios in UA

Project name	RES type	Bus Number	Id	exists in PSS/E as load/gen	2030, installed capacity [MW]	
					base case	high res
Bio Power Plant	Bio		BP	negative load connected to bus	550.0	943.2
Wind Power Plant	Wind		WP	negative load connected to bus	4393.4	6641.3
Solar Power Plant	Solar		SP	negative load connected to bus	7874.3	11668.9
Hydro Power Plant	Hydro		HP	negative load connected to bus	40.2	50.3