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Original scientific paper

ASSESSMENT OF THE FUTURE FLEXIBILITY NEEDS OF THE MACEDONIAN POWER SYSTEM

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A b s t r a c t: To achieve the strategic goals in the energy sector during the ascension path towards the European Union, North Macedonia has set ambitious goals in the Macedonian strategic framework for the power sector. Namely, the investment plans in conventional generation technologies are ambiguous, while the planned investments in variable renewable energy sources (VRES) are quick paced. Furthermore, with interest in VRES investment with total installed capacities above the hourly load during hours of maximal VRES generation, it is crucial to assess the future flexibility needs of the Macedonian power system. This paper uses multiple metrics to obtain a high-level estimate of the system inertia and flexibility needs of the Macedonian power system on a mid-term planning horizon. The system inertia and flexibility need estimates are calculated using a multi-scenario approach where the model dispatch is calculated using a Monte Carlo optimization on a market model enclosing Southeast Europe. The obtained results give a high-level estimate of the evolution of flexibility needs and system inertia of the Macedonian power system on a mid-term planning horizon.

Key words: power system flexibility; power system inertia; res integration; market simulation

ПРОЦЕНА НА ИДНИТЕ ПОТРЕБИ ОД ФЛЕКСИБИЛНОСТ НА МАКЕДОНСКИОТ ЕЛЕКТРОПРЕНОСЕН СИСТЕМ

А п с т р а к т: За да се постигнат стратешките цели во енергетскиот сектор на патот кон Европската Унија, Северна Македонија во својата стратешка рамка има поставено амбициозни цели за електроенергетскиот сектор. Во Македонската стратешка рамка инвестицискиот план за конвенционалните електрични централи е проследен со голем број неизвесности, додека инвестициите во обновливите извори на електрична енергија (ОИЕ) се реализираат со брзо темпо. Имајќи предвид дека вкупниот интерес за инвестиции во обновливи извори по капацитет го надминува системското оптоварување во часови кога производството од ОИЕ е најголемо, неопходно е да се направи процена на идните потреби од флексибилност на македонскиот електроенергетски систем. Во овој труд се пресметани неколку метрики со цел да се направи процена на системските потреби од флексибилност и инерција на македонскиот електроенергетски систем на среднорочен планирачки хоризонт. Потребите од системска инерција и флексибилност се пресметуваат со помош на методот Монте Карло на повеќе сценарија на пазарниот модел за Југоисточна Европа со часовна резолуција. Резултатите од истражувањето даваат јасна слика на системската потреба од флексибилност и инерција на среднорочен планирачки хоризонт.

Клучни зборови: флексибилност на ЕЕС; инерција на ЕЕС; интеграција на обновливи извори; пазарни симулации

INTRODUCTION

With the evolution of the Macedonian power sector towards a green energy sector, the Macedonian generation portfolio is supposed to undergo drastic structural changes in the years to come where the plan is to substitute the heavy emission power plants with VRES. According to the Macedonian strategic framework [1–3], the decommissioning of the lignite and fuel oil power plants will take place from 2019 to 2027. While the strategic goals for investments in VRES are ambitious, the investment plans in conventional generation technologies remain ambiguous. The possible changes to the conventional generation portfolio, combined with ambitious investment plans in VRES, will result in increased flexibility needs [4] and may reduce the system inertia on a national level. The difficulties of VRES integration and exploitation in the Macedonian power system will vary depending on the VRES production and installed capacity, the system load profile for the analyzed time horizon, and the flexibility of the power system [5]. Hence, the uncertain nature of the Macedonian energy strategy is analyzed using a multi-scenario approach to cover a broad spectrum of possible future scenarios.

As defined by [6], power system flexibility is the capability of a power system to cope with the variability and uncertainty that VRES generation introduces into the system in different time scales, from the very short to the long term, avoiding curtailment of VRES and reliably supplying all the demanded energy to customers. For a transmission system operator tasked to integrate large-scale VRES projects in their power system, a reasonable estimate of the future system flexibility needs, and inertia is essential. There are multiple approaches to assessing the flexibility and inertia of a power system differing in their complexity and computation resource requirements. So far, in academia and the power sector, there is no consensus on the best approach to tackle this problem since power system flexibility and inertia are system-specific [4].

There are numerous papers and technical reports covering the assessment of flexibility needs on a planning horizon written to this date. While the research focus is on algorithms that treat time series to assess the flexibility needs of a power system, such as in [7] and [8], there are not many papers that treat the problem using a stochastic market modeling approach.

Recent papers that treat the problem using a stochastic market modeling approach are [9], where the authors use flexibility metrics to analyze the flexibility needs from a ramp requirements point of view, while in [10] the authors focus on the impact of time-step granularity of the stochastic market modeling approach. The authors in [9] and [10] opt for a stochastic modeling approach using a European market model. In [11], the authors explore various scenarios and flexibility mechanisms to analyze a high share of RES scenarios. Furthermore, the authors in [11] developed a linear programming model POWER to solve a US-based market model.

Additionally, there are papers and studies on system flexibility that treat the problem on a national level while considering the regional implications on the national results. Such is the case in [12], where the authors examine the impact on system inertia during high penetrations of wind power to the power system of Ireland using the non-synchronous penetration ratio (SNSP) metric, and in [13], where the authors assess the flexibility needs of the Greek power system using two metrics, the flexibility index (FIX) and present VRE penetration potential (PVP). From the power system sector in Europe, two reports are of outstanding quality, namely [14] and [15].

When analyzing system inertia and flexibility, it is crucial to get a rough estimate of future needs before developing a complicated methodology that would cover the system specifics. In this paper, the inertia and flexibility assessment of the Macedonian power system is based on the net load, which represents the difference between system load and non-dispatchable power generation [16]. More specifically, the research focus is on the following flexibility metrics: a renewable penetration index (RPI) and renewable energy penetration index (REPI) [17], system probability for VRES curtailment (LORE) [18], and system inertia metric SNSP [19]. Furthermore, the ramp-up and ramp-down capability of the Macedonian power system was analyzed for two VRES development scenarios to obtain an estimate of the most frequent and volatile ramps in the future. The analysis was done, and the parameters were calculated using a regional market model of Southeast Europe, where each country is modeled with one/or multiple areas on the copper plate principle where the total production and load on a power system level are aggregated to the area/s representing a given country and interconnected with other neighboring countries on NTC-based interfaces [20].

Our research aims to provide energy system planners with assessment of the power system flexibility and inertia needs which is supposed to help them take this aspect of the power system into account when drafting the national strategy framework. The proposed metrics are calculated based on the outputs of a Monte Carlo based market simulation, and by doing so the variability of Load, RES, water inflows, and outages is properly considered. The proposed methodology should serve as a link between the process of energy and power system planning.

The remainder of this paper is organized as follows: Section 2 gives an overview of the market model from a national and regional point of view and scenario definitions for analysis, Section 3 gives a detailed overview of the methodology for calculation of the selected metrics, Section 4 presents the results of the analysis, while Section 5 presents a summary of the findings.

2. MEASUREMENT SYSTEM DESCRIPTION

The developed market model is for a mid-term time horizon (2030), based on the Energy Market Initiative Data Base (EMIDB) by USEA, [23], and Pan-European Climate Database (PECD) by ENTSO [20]. The EMIDB contains data on a unit-by-unit basis for the thermal and hydropower plants in the region, data for the installed capacity of VRES, data for demand, and data for the net transmission capacities on an interface level between the countries of SEE. The PECD dataset contains weather data for Europe from 1982 to 2016. This data is processed to obtain the production profiles for wind and solar on a country basis.

The simulation scope is the area of Southeast Europe in light gray in Figure 1. In this research, the following countries from the SEE region were modeled in detail: Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Greece, Hungary, Kosovo, Montenegro, North Macedonia, Romania, Serbia, and Slovenia.

Fig. 1 Modeling scope of the Regional Market Model

The exchanges with the exogenous power systems, given in dark gray in Figure 1, represent the rest of the European power system modeled as hourly market-driven power flows.

The Macedonian strategy framework for the power sector is ambiguous when it comes to the investment plan in conventional power plants. Namely, there is uncertainty in the mid and long term whether the investments will be in gas power plants or a pump storage power plant (PSP). According to the Macedonian strategy framework, the investments in gas power plants by 2030 might amount to 450 MW. On the other hand, the PSP potential is around 333 MW in turbine mode and 363 MW in pump mode, based on the authors' best estimate.

Since both investments in gas power plants and PSP contribute to power system flexibility, both scenarios are analyzed, comparing the results of both scenarios to a base case scenario that takes no investment decision in conventional power plants. Moreover, the analysis considers two VRES profiles (wind and solar) named slow-paced and rapid development. The two VRES development profiles paired with the business-as-usual and the investment in gas and PSP scenarios yield a total of six scenarios:

Low RES BC: a base case with slow-paced VRES development.

Low RES wTPP: investment in gas power plants with slow-paced VRES development.

Low RES wPSP: investment in PSP with slow-paced VRES development.

High RES BC: a base case with rapid VRES development.

High RES wTPP: investment in gas power plants with rapid VRES development.

High RES wPSP: investment in PSP with rapid VRES development.

Figure 2 shows the installed capacities of different production technologies for the six scenarios of the Macedonian power system analyzed in this paper.

Table 1 shows the installed capacities per fuel type technology in MW for each of the modeled countries in the region for the 2030 planning horizon excluding the data for North Macedonia. From the table data, we can see that in 2030 the installed capacities from VRES and hydro are dominant in the region, while the capacity from the conventional power plants is on the lower end.

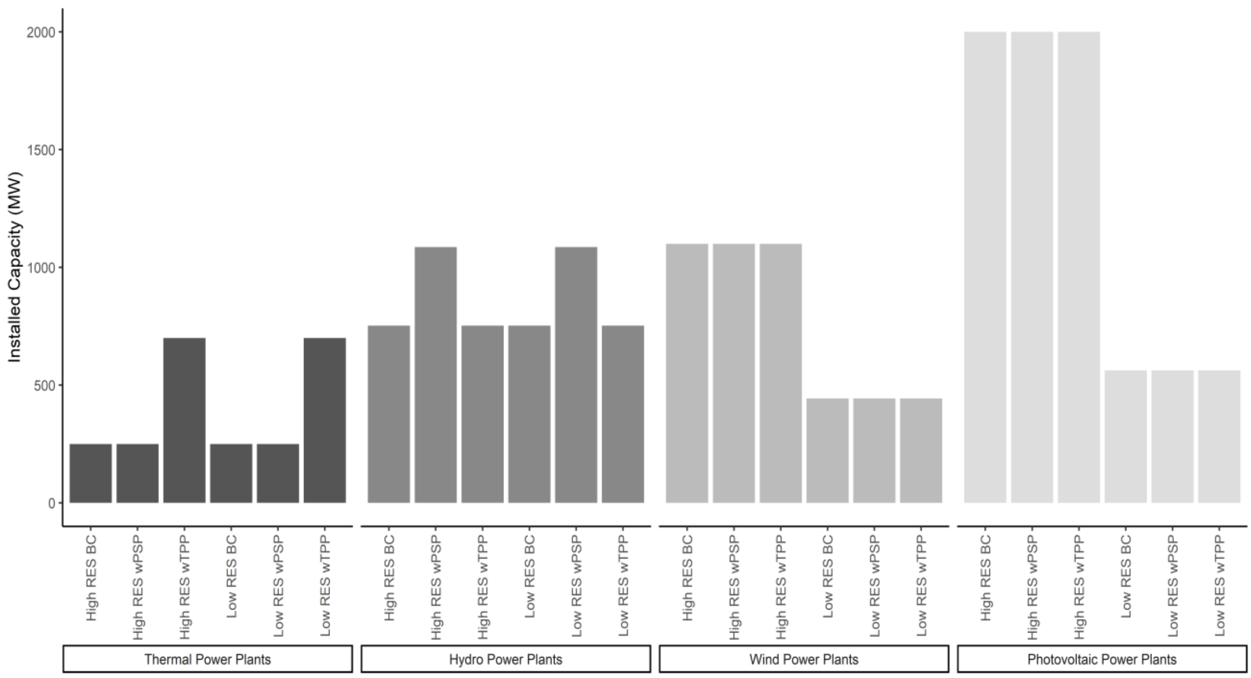

Fig. 2. Installed capacity per generation technology for the six scenarios in North Macedonia on a mid-term planning horizon

Table 1

Installed capacities per technology in the region in MW of Southeast Europe

Capacity (MW)	AL	BA	BG	GR	HR	HU	ME	RO	RS	SI	SUM
Nuclear	0	1632	0	0	297	165	225	2174	5406	584	10483
Coal	300	0	2728	7477	684	2981	0	5742	410	529	21101
Gas	0	0	0	290	0	0	0	0	0	0	290
Oil	0	0	2000	0	0	4248	0	1965	0	703	8916
Hydro	2949	2493	3207	4545	3117	0	1117	6783	3469	1715	30438
Wind	384	500	3216	7700	600	3589	250	5054	4889	150	26895
Solar	445	650	948	7000	1300	304	243	5255	657	1866	19111
Batteries	0	0	0	1000	0	0	0	0	0	0	1000

Table 2 shows the transfer capacities of the NTC-based interfaces connecting the areas that represent countries where their capacity is in MW. The NTC-based interfaces allow for bidirectional power flow between each country (node).

Table 3 shows the economic and technical parameters for each thermal power plant technology per fuel type as in [20]. These parameters were used to create the market model.

Using the data from Table 3 for each of the technologies given in [20], we can calculate the marginal price of each TPP unit χ_θ (€/MWh) by the following formula:

$$\chi_\theta = VO\&M + \frac{CO_2\ emmissions}{efficiency} \cdot CO_2\ price + \\ + \frac{Fuel\ Price \cdot 3.6\ (GJ/MWh)}{efficiency} \tag{1}$$

where the CO_2 price in our research is 66 €/t.

Table 4 shows the parameters for the forced and planned outage and maintenance rate for the thermal power plant technologies per fuel type as in [20]

Table 2

Transfer capacities of NTC-interfaces connecting areas

Link name	Capacity (MW)	Link name	Capacity (MW)
AL – GR	400	ME – RS	600
AL – ME	450	ME – XK	300
AL – MK	500	MK – AL	1000
AL – XK	650	MK – BG	800
BA – HR	1200	MK – GR	850
BA – ME	800	MK – RS	400
BA – RS	1100	MK – XK	330
BG – GR	1700	RO – BG	2600
BG – MK	800	RO – HU	1400
BG – RO	2600	RO – RS	2000
BG – RS	800	RS – BA	1200
GR – AL	400	RS – BG	800
GR – BG	1400	RS – HR	500
GR – MK	1100	RS – HU	1000
HR – BA	1200	RS – ME	600
HR – HU	1700	RS – MK	400
HR – RS	500	RS – RO	2000
HR – SI	2000	RS – XK	300
HU – HR	1700	SI – HR	2000
HU – RO	1300	SI – HU	1200
HU – RS	1000	XK – AL	500
HU – SI	1200	XK – ME	300
ME – AL	450	XK – MK	350
ME – BA	750	XK – RS	400
AL – GR	400	ME – RS	600

Table 3

Economic and technical parameters for thermal power plants per fuel type

Technology	Fuel Price (€/GJ)	Efficiency (%)	CO_2 emissions (kg/Net GJ)	VO&M cost (€/MWh)	Heat Rate (GJ/MWh)
Nuclear	0.47	33	0	9	10.9
Lignite	1.1	35 – 46	101	3.3 – 6.6	7.8 – 10.3
Hard Coal	4.3	35 – 46	94	3.3 – 6.6	7.8 – 10.3
Gas	6.91	36 – 58	57	1.1 – 1.6	7.1 – 10.3
Heavy Oil	14.6	35 – 40	78	3.3	9 – 10.3

Table 4

Forced and planned outage rate for thermal power plants per fuel type

Technology	Forced outage		Planned outage annual rate (days)
	Annual rate (%)	Repair time (days)	
Nuclear	5	7	54
Lignite	7.5 – 10	1	27
Hard coal	7.5 – 10	1	27
Gas	5 – 8	1	13 – 27
Heavy oil	10	1	27

The parameters from Table 4 were used to create random yearly outage patterns for each of the TPPs modeled in ANTARES while the data from PECD was used to create Climatic Years (CY) from the weather data. Each CY is a combination of hourly time series for load, wind, solar, hydro inflows, run-of-river, and other renewable energy sources for one of the PECD weather yearly data.

Table 5 shows the flexibility parameters data for the hydropower and thermal power plants which are eligible for flexibility provision.

Table 5

Flexibility parameters of the hydro and thermal power plants in North Macedonia

Power plant	No. Units	Ramp up/down (MW/min)	Cold start (min)
HPP 1	4	10	15
HPP 2	2	10	15
HPP 3	4	25	15
HPP 4	2	10	15
HPP 5	2	10	15
HPP 6	3	10	15
TPP 1	1	6	56

3. PROBLEM FORMULATION

Using the detailed economy and power system data, we can create market models in the tool ANTARES. In this tool, each power system modeled is represented as a vertex (area) that is connected to other areas (vertices) through links (edges, NTC-based interfaces) based on the actual interconnections between each power system that are modeled. The areas and links form an undirected graph (2) of the regional power system that's being modeled.

$$G(N, L), \forall\, n \in N, \forall\, l \in L \tag{2}$$

where $G(N, L)$ is the undirected graph of the power system, N is the ordered set of vertices of G, n is a vertex of N, L is the set of edges of G, and l is an edge of L.

Each of the modeled links allows for energy in both directions either from u_l to d_l or vice versa where: u_l is a vertex upstream from l, and d_l is a vertex downstream from l.

ANTARES uses the Monte Carlo optimization method with weekly resolution T where in each optimization period it dispatches an optimal mix of dispatchable generators for each hour t to serve the hourly net load. Hence, each optimization period consists of 168 hours, and we have 54 optimization periods in each MCY.

To achieve this the ANTARES simulator aims to minimize the system cost using the following objective function:

$$\min_{M_\theta \epsilon ArgMin(\Omega_{Unit\ com})} \left(\Omega_{dispatched}\right) \tag{3}$$

$$\Omega_{dispatched} = \Omega_{thermal} + \Omega_{hydro+} \\ + \Omega_{unsyplied} + \Omega_{spillage} \tag{4}$$

$$\Omega_{thermal} = \sum_{n \in N} \sum_{\theta \epsilon \Theta_n} (\chi_n P_\theta) \tag{5}$$

$$\Omega_{hydro} = \sum_{n \in N} \sum_{\lambda \epsilon \Lambda_n} (\varepsilon_\lambda + \varepsilon_\lambda^*)\,(H_\lambda - \rho_\lambda \Pi_\lambda + \mathrm{O}_\lambda) \tag{6}$$

$$\Omega_{unsyplied} = \delta_n^+ G_n^+ \tag{7}$$

$$\Omega_{spillage} = \delta_n^- G_n^- \tag{8}$$

$\Omega_{Unit\ com}$, committed dispatchable units in each time step (9)

where Θ_n, a set of all thermal clusters connected to n: θ, a cluster which is an element of Θ_n; Λ_n, the set of all reservoirs connected to n; λ, a reservoir which is an element of Λ_n; $\chi_\theta \in \mathbb{R}^T$, cost proportional to the output of the running unit in θ; $P_\theta \in \mathbb{R}_+^T$, power output from cluster θ; $\varepsilon_\lambda \in \mathbb{R}$, reference water value associated with the reservoirs initial state; $\varepsilon_\lambda^* \in \mathbb{R}^T$, random component added to the water value; $H_\lambda \in \mathbb{R}_+^T$, power output from reservoir λ; $\rho_\lambda \in \mathbb{R}_+$, efficiency ratio of pumping units (or equivalent devices) available in reservoir λ; $\Pi_\lambda \in \mathbb{R}_+^T$, power output from reservoir λ; $\mathrm{O}_\lambda \in \mathbb{R}_+^T$, power overflowing from reservoir λ; $\delta_n^- \in \mathbb{R}_+^T$, value of lost load; $\delta_n^+ \in \mathbb{R}_+^T$, value of wasted energy; $G_n^+ \in \mathbb{R}_+^T$, power not supplied, and $G_n^- \in \mathbb{R}_+^T$, supplied energy.

In the optimization process the following constraints were applied:

$$\forall\, n \in N: 0 \leq G_n^+ \leq \max(0, D_n) \tag{10}$$

$$\begin{gathered}\forall\, n \in N: 0 \leq G_n^- \leq -\min 0, Dn + \\ + \textstyle\sum_{\lambda \epsilon \Lambda_n} H_\lambda + \sum_{\theta \epsilon \Theta_n} P_\theta\end{gathered} \tag{11}$$

$$\forall\, l \in L: 0 \leq F_l^+ \leq C_l^+ \tag{12}$$

$$\forall\, l \in L: 0 \leq F_l^- \leq C_l^- \tag{13}$$

$$\forall\, l \in L: F_l = F_l^+ + F_l^- \tag{14}$$

$$\forall\, n \in N, \forall\, \lambda \in \Lambda_n: \underline{W_\lambda} \leq \textstyle\sum_{t \in T} H_{\lambda_t} \leq \overline{W_\lambda} \tag{15}$$

$$\begin{gathered}\forall\, n \in N, \forall\, \lambda \in \Lambda_n: \underline{W_\lambda} \leq \\ \leq \textstyle\sum_{t \in T} H_{\lambda_t} - \sum_{t \in T} \rho_\lambda \Pi_{\lambda_t} \leq \overline{W_\lambda}\end{gathered} \tag{16}$$

$$\forall\, n \in N, \forall\, \lambda \in \Lambda_n: \underline{H_\lambda} \leq H_\lambda \leq \overline{H_\lambda} \tag{17}$$

$$\forall\, n \in N, \forall\, \lambda \in \Lambda_n: 0 \leq \Pi_\lambda \leq \overline{\Pi}_\lambda \tag{18}$$

$$\forall\, n \in N, \forall\, \lambda \in \Lambda_n: 0 \leq \Pi_\lambda \leq \overline{\Pi}_\lambda \tag{19}$$

$$\begin{gathered}\forall\, n \in N, \forall\, \lambda \in \Lambda_n, \forall\, t \in T: R_{\lambda_t} - R_{\lambda_{t-1}} = \\ = \rho_\lambda \Pi_{\lambda_t} - H_{\lambda_t} - I_{\lambda_t} - O_{\lambda_t}\end{gathered} \tag{20}$$

$R_{\lambda_{t-1}}$ is not a viable parameter for the first time slot and because of so the Initial Reservoir State is used in its stead.

$$\forall\, n \in N, \forall\, \lambda \in \Lambda_n: \underline{R_\lambda} \leq R_\lambda \leq \overline{R}_\lambda \tag{21}$$

$$\forall\, n \in N, \theta \in \Theta_n: \underline{P_\theta} \leq P_\theta \leq \overline{P}_\theta \tag{22}$$

$$\forall\, n \in N, \theta \in \Theta_n: \underline{M_\theta} \leq M_\theta \leq \overline{M}_\theta \tag{23}$$

$$\forall\, n \in N, \theta \in \Theta_n: l_\theta M_\theta \leq M_\theta \leq u_\theta M_\theta \tag{24}$$

$$\begin{gathered}\forall\, n \in N, \theta \in \Theta_n, \forall\, t \in T: M_{\theta_t} = \\ = M_{\theta_{t-1}} + M_{\theta_t}^+ - M_{\theta_t}^-\end{gathered} \tag{25}$$

$$\begin{gathered}\forall\, n \in N, \theta \in \Theta_n, \forall\, t \in T: M_{\theta\ t}^{-} \leq \\ \leq \max\left(0, \overline{M}_{\theta_{t-1}} - \overline{M}_{\theta_t}\right)\end{gathered} \tag{26}$$

$$\forall\, n \in N, \theta \in \Theta_n, \forall\, t \in T: M_{\theta_t}^- \leq M_{\theta_t}^- \tag{27}$$

$$\begin{gathered}\forall\, n \in N, \theta \in \Theta_n, \forall\, t \in T: M_{\theta_t} \geq \\ \geq \textstyle\sum_{k=t+1-\Delta_\theta^+}^{k=t} \left(M_{\theta_t}^+ - M_{\theta\ k}^{--}\right)\end{gathered} \tag{28}$$

$$\begin{gathered}\forall\, n \in N, \theta \in \Theta_n, \forall\, t \in T: M_{\theta_t} \geq \\ \geq \sum_{k=t+1-\Delta_\theta^-}^{k=t} \max\left(0, \overline{M}_{\theta_k} - \overline{M}_{\theta_{k-1}}\right) - \\ - \textstyle\sum_{k=t+1-\Delta_\theta^-}^{k=t} \left(M_{\theta\ k}^-\right)\end{gathered} \tag{29}$$

while one of the following conditions must be satisfied always:

$$\Delta_\theta^- \leq \Delta_\theta^+ \tag{30}$$

$$\overline{M}_\theta \leq 1_T \tag{31}$$

where $D_n \in \mathbb{R}^T$, net load expressed in node n; $F_l^+ \in \mathbb{R}_+^T$, power flow through l from u_l to d_l; $F_l^- \in \mathbb{R}_+^T$, power flow through l from d_l to u_l; $C_l^+ \in \mathbb{R}_+^T$, initial transmission capacity from u_l to d_l; $C_l^- \in \mathbb{R}_+^T$, initial transmission capacity from d_l to u_l; $F_l \in \mathbb{R}^T$, total power flow through l; $\overline{W_\lambda} \in \mathbb{R}_+$, maximum energy output from λ through the optimization period; $\underline{W_\lambda} \in \mathbb{R}_+$, minimum energy output from λ through the optimization period; $\overline{H_\lambda} \in \mathbb{R}_+^T$, maximum power output from reservoir λ; $\underline{H_\lambda} \in \mathbb{R}_+^T$, minimum power output from reservoir λ; $\overline{\Pi}_\lambda \in \mathbb{R}_+^T$, maximum power absorbed by pumps of reservoir λ; $\overline{R_\lambda} \in \mathbb{R}_+^T$, upper bound of the admissible level in reservoir λ; $\underline{R_\lambda} \in \mathbb{R}_+^T$, lower bound of the admissible level in reservoir λ; $R_\lambda \in \mathbb{R}_+^T$, stored energy level in reservoir λ; $\overline{P}_\theta \in \mathbb{R}_+^T$, maximal power output from cluster θ; $\underline{P_\theta} \in \mathbb{R}_+^T$, minimal power output from cluster θ; $P_\theta \in \mathbb{R}_+^T$, stored energy level in reservoir λ; $\overline{M}_\theta \in \mathbb{N}^T$, maximal number of running units in cluster θ; $\underline{M_\theta} \in \mathbb{N}^T$, minimal number of running units in cluster θ; $M_\theta^+ \in \mathbb{N}^T$, number of units changing from off state to on state in cluster θ; $M_\theta^- \in \mathbb{N}^T$, number of units changing from on state to off state in cluster θ; $M_\theta^{--} \in \mathbb{N}^T$, number of units changing from on state to outage state in cluster θ; $\Delta_\theta^+ \in \{1, \ldots, |T|\}$, minimum on time when running for an unit in θ; and $\Delta_\theta^- \in \{1, \ldots, |T|\}$, minimum off time when not running for a unit in θ.

The models consist of thirty-five climatic years which represent a combination of load, solar, wind, and hydro production profiles from the PECD database. The use of a high number of climatic years helps to account for the VRES and load variability. Each climatic year is paired with one of the twenty outage patterns for the thermal power plants, which outage patterns are generated using Three-state Markov Chain, yielding seven hundred Monte Carlo years (MCY) or seven hundred future states of the regional power system. The simulation results are with hourly resolution on an annual basis for each of the seven hundred simulated MCY.

4. FLEXIBILITY METRICS

The flexibility analysis is based on the following flexibility metrics: RPI, REPI, LORE, and SNSP. The RPI and REPI metrics are calculated based on the climatic years' data (correlated load, wind, PV, and run-of-river time series). The LORE and SNSP metrics are calculated by analyzing the annual dispatch results from the market simulation on an hourly level. Additionally, net load (NL) and net load ramp (NLR) were calculated before calculating the LORE metric.

Calculation of RPI and REPI

The *RPI* and REPI metrics are calculated in a deterministic manner using the data from all the *CY*. The RPI metric is calculated using the following three step algorithm:

Step 1: Calculate RPI for each hour for the selected CY based on:

$$RPI = \max\left(\frac{Wind(t)+PV(t)}{Load(t)}\right), \forall t \in [1,8760] \quad (32)$$

Step 2: Repeat Step 1 for each of the thirty-five CY.

Step 3: From all calculated values for each hour of the thirty-five CY RPI is equal to the maximal value.

The REPI metric is calculated using the following three step algorithm:

Step 1: Calculate REPI for the selected CY as:

$$REPI = \frac{\sum_{t=1}^{8760}\left(Wind(t)+PV(t)\right)}{\sum_{t=1}^{8760}\left(Load(t)\right)} \quad (33)$$

Step 2: Repeat Step 1 for each of the thirty-five CY.

Step 3: From all calculated annual values for each of the thirty-five CY REPI is equal to the mean value.

In (32) and (33), $Wind(t)$ is the hourly production of wind power plants in MW, $PV(t)$ is the hourly production of solar power plants in MW, and $Load(t)$ is the hourly load in MW.

Calculation of LORE

The system probability for VRES curtailment is calculated similarly to the Loss of Wind Estimation (LOWE) metric presented in [18]. Since, in this paper, the research is extended to cover Wind and PV curtailment probability, the metric name is modified to Loss of renewable energy estimation (LORE).

Before calculating LORE, the *NL* and *NLR* were calculated, where *NL* is calculated as:

$$NL(t) = Load(t) - Wind(t) - PV(t) - \\ - Must\_Run(t) \quad (34)$$

while NLR is calculated as:

$$NLR(t) = NL(t+1) - NL(t) \quad (35)$$

$$NLR_{+}(t) = NLR(t), \forall NLR(t) \geq 0 \quad (36)$$

$$NLR_{-}(t) = NLR(t), \forall NLR(t) < 0 \quad (37)$$

where $Must\_Run(t)$ consists of the production of all technologies that are hard constrained to produce energy during predetermined periods on annual level in MW.

Calculating the *NL* and *NLR* with different time steps, e.g., two, four, or another arbitrary system-specific time step will yield different results. *NL* and *NLR* were calculated with an hourly time step.

The periods during which VRES curtailment might occur are similar to the ones described in [18], which are: *NL* lower than zero, NLR_{+} is higher than the ramp-up capability of online generators and offline generators that cannot be brought online, and NLR_{-} is higher than the ramp-down capability of online generators and online generators that can be shut down.

The Ramp-up or Ramp-down capability more commonly known as the Ramping capability of a generator is defined as the sustained rate of change of generator output, in MW/s. In this paper the Ramp-up and Ramp-down capability of the generators is expressed in MW/h due to the time step granularity of the market simulation.

The first recognized period during which VRES curtailment might occur is when NL is lower than zero, so the probability of this event is computed as:

$$P(Period_1) = P(NL(t) \leq 0) \quad (38)$$

The second period is the one where NLR_{+} is higher than the Ramp-up capability of online generators and offline generators that cannot be brought online, for which the probability of occurrence is calculated as:

$$P(Period_2) = P\left(NLR_{+}(t) \geq \sum Ramp\_up(t)\right) \quad (39)$$

The last period is the one where $NLR\_$ is higher than the ramp-down capability of online generators and online generators that can be shut down, for which the probability of occurrence is calculated as:

$$P(Period_3) = P|NLR\_(t)| > \\ > \sum Ramp\_down(t) \quad (40)$$

The $\sum Ramp\_up(t)$ and $\sum Ramp\_down(t)$ capability of the Macedonian power system were calculated using the data in Table 5.

Finally, the $LORE$ metric is calculated as:

$$LORE = 1 - \left(1 - P(Period_1)\right) \cdot \\ \cdot (1 - P(Period_2)) \cdot (1 - P(Period_3)) \quad (41)$$

The LORE parameter is calculated by processing the results for all the seven hundred MCY. The results are given for each of the three periods (38 – 40) as well as the total probability represented by LORE (41).

Calculation of SNSP

The SNSP (Non-synchronous penetration ratio) is calculated as:

$$SNSP(t) = \frac{\sum P_{in_{inverter}}(t)}{\sum P_{out}(t)} = \frac{Wind(t)+PV(t)}{Load(t)+Export(t)} \quad (42)$$

where $Export(t)$ is the export to the neighboring countries in MW [19].

The SNSP parameter (42) is calculated by processing the results for all the seven hundred MCY.

5. RESULTS AND DISCUSSION

The flexibility analysis of the Macedonian power system was carried out using a regional market model covering Southeast Europe. Six different market models were created with the regional SEE model as a basis covering six scenarios for the development of the national generation portfolio. To account for the stochastic nature of VRES, in the analysis, the thirty-five unique climatic year scenarios for VRES and twenty outage patterns for the conventional power plants were used, which accounts for a total of seven hundred Monte Carlo years per scenario. Four main metrics were calculated: RPI, REPI, LORE, and SNSP, where RPI and REPI were calculated based on time-series analysis of the thirty-five different CY, while LORE and SNSP were calculated using the market model output for the seven hundred MCY. Furthermore, the ramp-up and ramp-down capability of the Macedonian power system was analyzed for two VRES development scenarios to obtain an estimate of the most frequent and volatile ramps that may occur in the future.

Table 6 shows the minimum, maximum, average, and standard deviation for RPI and REPI for the Macedonian power system. The data was calculated for the Low-RES and High-RES development scenarios.

Figures 3 and 4 display the histograms of RPI, while Figures 5 and 6 display the histograms of REPI for both RES development scenarios. From Figures 3 and 4 it can be concluded that for both RES development scenarios the distributions are similar, and, in both cases, centered around the mean. In both cases, the maximal recorded value is an outlier of the dataset. From Figures 5 and 6 it’s clear that the data is skewed to the left where most of the data is closer to the maximal value centered around the mean. Since high RPI were noted for both Low-RES and High-RES, in the future, to avoid VRES production curtailment, the Macedonian strategic framework should be reworked to consider different energy storage technologies or a shift from a fossil fuel-powered industry to an electricity-powered industry to increase the overall load profile [22]. As an alternative approach, the Macedonian strategic framework may be reworked to develop a generation portfolio with suitable flexibility, which would allow the country to become export oriented.

T a b l e 6

RPI and REPI for the Macedonian power system on a mid-term planning horizon

VRES development scenario	RPI				REPI			
	Min	Max	Mean	Standard deviation	Min	Max	Mean	Standard deviation
Low RES	0.938	1.811	1.114	0.148336	0.14	0.17	0.16	0.00004
High RES	2.804	5.403	3.320	0.447087	0.46	0.52	0.49	0.00030

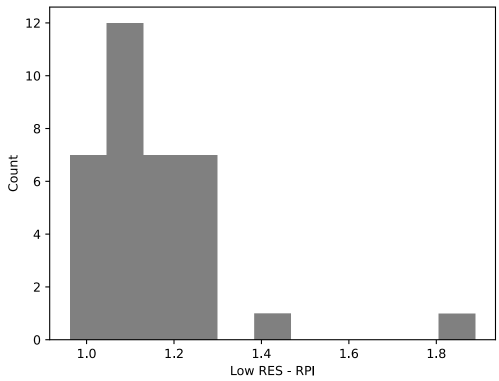

Fig. 3. RPI histogram for Low RES

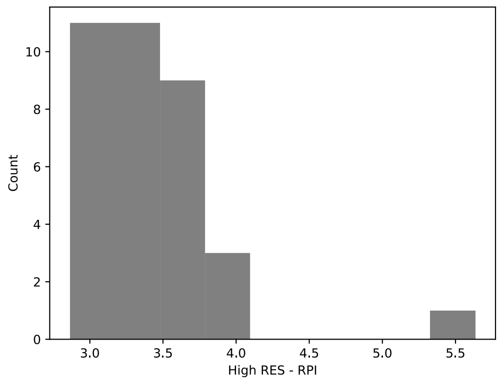

Fig. 4. RPI histogram for High RES

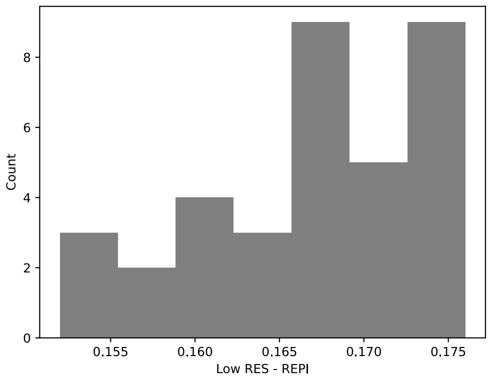

Fig. 5. REPI histogram for Low RES

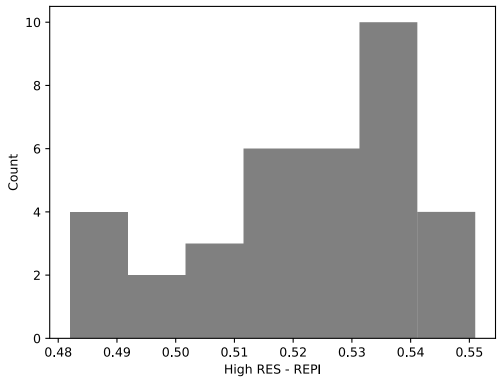

Fig. 6. REPI histogram for High RES

Figure 7 and Figure 8 present the RPI and REPI values on a regional basis for the Low-RES and High-RES development scenario in MK, respectively. Figure 3 and Figure 4 show that the VRES data in EMIDB and PECD for Southeast Europe is modest at best, while in most cases, it can be considered quite low, with VRES participation usually below 30%. Hence, the calculated flexibility metrics for North Macedonia might underestimate the flexibility needs since the needs are dependent on the development of the VRES generation portfolios in the region.

Fig. 7. Regional RPI distribution

Fig. 8. Regional REPI distribution

Table 7 shows the loss of renewable energy estimation (LORE) for the six analyzed scenarios as well as the results for the three different periods of interest. Period 3, or period during which the ramp-down capability of the system cannot match the $NLR_{-}(t)$, has an insignificant contribution to LORE in all six scenarios. Period 2, or period during which the ramp-up capability of the system cannot match the $NLR_{+}(t)$ contributes to LORE for all six scenarios. The commissioning of new TPPs (450 MW TPPs on gas) or the PSP project (333 MW) is crucial to reduce the curtailment probability, but we must check if this conclusion holds if we account for the latest interest of the private sector for RES connection. Period 1 contributes significantly to LORE in the High-RES scenarios due to the relatively low demand profile that the Macedonian power system experiences. In the future, to lower the probability of RES curtailment technologies such as power to hydrogen and hydrogen to power as well as power to gas and gas to power technologies (X2P and P2X) should be included in the energy and power mix on national level.

It is important to note that the results from the market model did not show curtailment of VRES as a result of the well-developed interconnections in the region of interest, but at the same time, the installed VRES capacities in the neighboring countries are quite modest, with exception to the installed capacities in Romania, Greece, Bulgaria, and the rapid development VRES scenarios for North Macedonia. From the results, it is expected that if each country follows a VRES development scenario, such as the rapid one we are using for North Macedonia, the region will experience curtailment of VRES.

T a b l e 7

LORE for the for Macedonian power system on a mid-term planning horizon

Scenario	Periods of interest (%)			LORE
	Period 1	Period 2	Period 3	
Low RES BC	0.12	4.17	0.00	4.29
Low RES wTPP	0.12	1.36	0.00	1.48
Low RES wPSP	0.12	0.99	0.00	1.11
High RES BC	23.47	8.37	0.50	30.23
High RES wTPP	23.47	2.35	0.35	25.53
High RES wPSP	23.47	1.62	0.50	25.09

Figure 9 and Figure 10 show the rate of occurrence of ramps for the slow-paced and rapid VRES development scenarios, respectively. The rate of occurrence of ramps is calculated as an average of the measurement of the duration of up and down periods of $NLR(t)$ for the thirty-five climatic years for the slow-paced and rapid VRES development scenarios, respectively. Based on the obtained results, we can conclude for both VRES development scenarios that the one-hour ramps are the most frequent. Moreover, the two-hour, three-hour, four-hour, eight-hour, nine-hour, ten-hour, and eleven-hour ramps occur frequently enough so that their effects should be analyzed in more detail in future flexibility studies of the Macedonian power system.

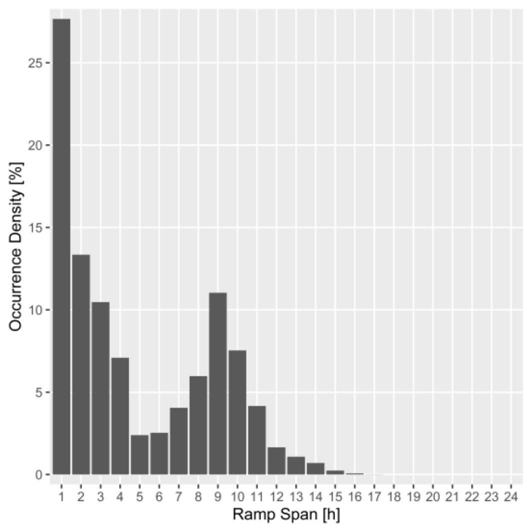

Fig. 9. Ramp span occurrence for the slow-paced VRES development scenario

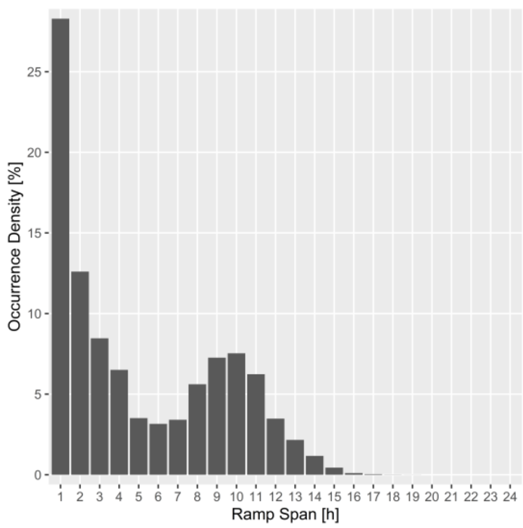

Fig. 10. Ramp span occurrence for the rapid VRES development scenario

Figure 11 shows the SNSP density for the analyzed scenarios of the Macedonian power system. In comparison to the slow-pace VRES development scenarios (Scenarios 1, 2, and 3), the rapid VRES development scenarios (Scenarios 4, 5, and 6) have a notable SNSP evolution which suggests that with the development of VRES and decommissioning of conventional brown power plants in MK and the region, the system inertia might be inadequate to maintain system stability. From the results for Scenarios 4, 5, and 6 in Figure 11, we can see that the tail of the graph goes to 1, and for Scenario 6, even above 1, which suggests that in the future in MK, we will have numerous regimes with extremely low inertia.

The results in Figure 11 clearly show that as the VRES profile in MK evolves, the Macedonian power system would rely on the neighboring power systems for system inertia provision. Additionally, as more and more conventional brown power plants get decommissioned, the region will have even fewer power plants that could provide the needed system inertia. Hence, with the VRES evolution on a regional level, the focus should be on a share of reserves and regional balancing market in Southeast Europe, which will lead to an optimal interconnection use and investments in synthetic inertia from large VRES plants.

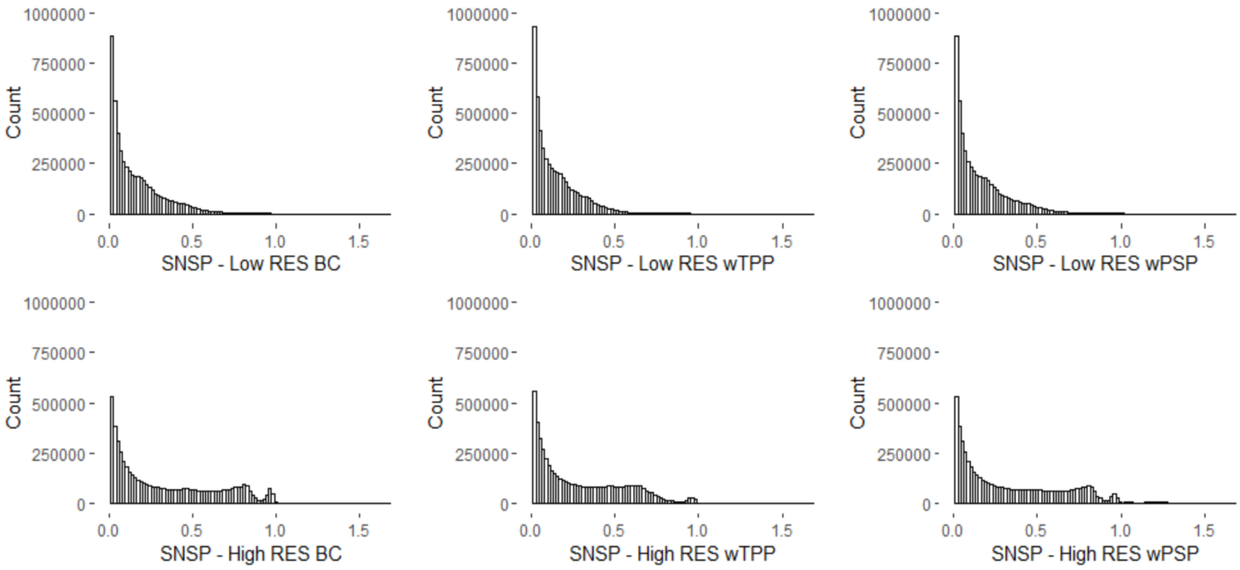

Fig. 11. Non-synchronous penetration ratio (SNSP) on a national level for the analyzed scenarios

6. CONCLUSION

The flexibility analysis for the Macedonian power system was done using a probabilistic market-based calculation on a PEMMDB-based market model for Southeast Europe. For North Macedonia, six national scenarios were analyzed as a combination of three development scenarios for the conventional power plants in MK and two VRES development scenarios, Section 3. The flexibility was assessed by computing the RPI, REPI, LORE, and SNSP metrics. Additionally, an analysis of the ramp span occurrence was done for the two VRES development scenarios.

The introduction of VRES to the system leads to a high ratio between RPI and REPI, which is mainly driven by the low load levels during the periods where the VRES production is the highest. Moreover, as shown in Table 2, the LORE parameter increases as more VRES are introduced to the system, which means that the risk for VRES curtailment in the future will be high. Since the flexibility needs are dependent on the regional evolution of the generation profiles in the neighboring countries, it is expected that as more VRES are introduced, the curtailment risk in MK and the region will be even higher. To avoid future VRES curtailment, it is important to run dedicated flexibility studies to assess the flexibility needs and optimize the conventional generation portfolio to a sufficiently flexible one while introducing smart technologies and techniques for flexibility provision. Furthermore, the Macedonian strategic framework for the energy sector should be reworked to consider different energy storage technologies, a shift from a fossil fuel-powered industry to an electricity-powered industry so to increase the overall load profile, or a redesign of the investment plan in the generation and storage portfolio to be suitably flexible to allow the country to become export oriented. Lastly, as the evolution of the generation profile is optimized, the national and regional legislation must be appropriately updated to support the needed changes.

Figures 5 and 6 show the ramp span occurrence for the slow-paced and rapid VRES development scenarios, respectively. As the results show, the one-hour ramp is the most frequent, followed by the two-hour, three-hour, four-hour, eight-hour, nine-hour, ten-hour, and eleven-hour ramps. In future flexibility studies, the one, two-hour, three-hour, four-hour, eight-hour, nine-hour, ten-hour, and eleven-hour ramps on system flexibility should be analyzed in more detail on a national level.

With the rapid development of the VRES profile in the region, a decarbonization phase is envisioned where conventional brown power plants are planned to be decommissioned. This will lead to a reduction of the available system inertia in the region, and in MK, it is expected that there will be periods with extremely low system inertia in the future if the evolution of the generation profile follows the rapid VRES development scenario. To avoid long periods of system instability, the focus should be on participation in regional markets for a share of reserves to optimally use the well-developed interconnections as well as developing the national markets to facilitate synthetic inertia provision from the large VRES parks.

The metrics in this paper are relatively easy to compute, and their computation isn't computationally intensive compared to other more detailed methods. The obtained results represent a first-of-a-kind screening of the future flexibility needs in the Macedonian power sector, and they pave the way for future developments in this field on a national level. In the future, on a national level, the research focus should be on optimizing the flexibility portfolio from two aspects: reducing cost for adequate flexibility provision and introducing a flexibility analysis as an integrated part of the national adequacy studies. Furthermore, since the analysis of the system inertia showed that in the future, with the rapid development of VRES, the Macedonian power system would experience periods of extremely low system inertia, an analysis of the expected Rate of Change of Frequency (RoCoF) should be carried with a regional scope.

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