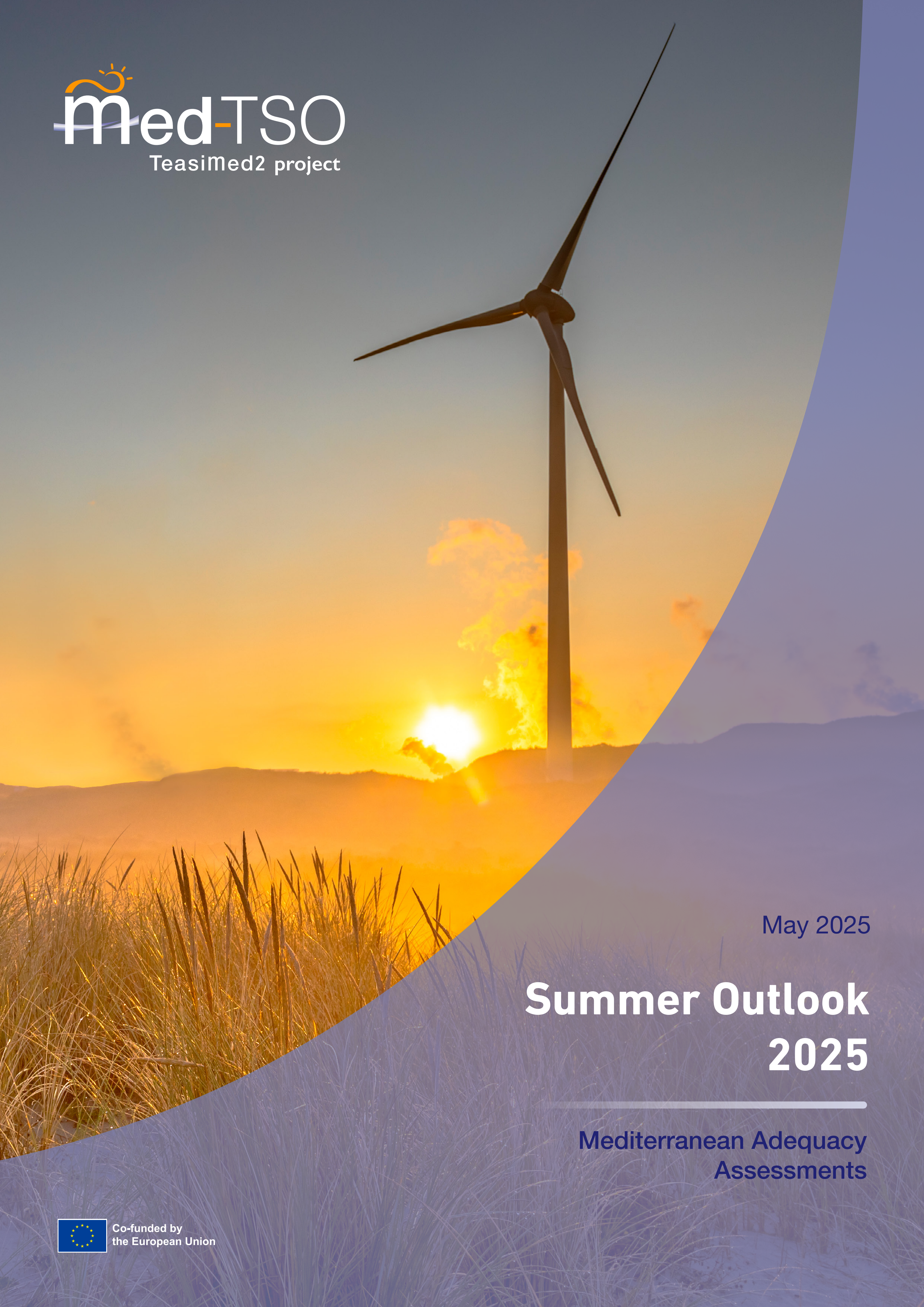

Med-TSO
TeasiMed2 project

May 2025

Summer Outlook 2025

Mediterranean Adequacy Assessments

Co-funded by
the European Union

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Abbreviations

CCGT	Combine Cycle Gas Turbine
EU	European Union
ENS	Energy Not Served
FCR	Frequency Containment Reserve
FRR	Frequency Restoration Reserve
NTC	Net Transfer Capacity
OCGT	Open Cycle Gas Turbine
O&M	Operating and Maintenance
PEMMDB	Pan-European Market Modelling Database (developed by ENTSO-E)
PECD	Pan-European Climate Database
RES	Renewable Energy Sources that generally include wind, solar and hydro capacities. In this study, RES refers only to wind and solar as VRES (Variable RES) capacities.
ROR	Run-of-River
TSO	Transmission System Operator
TYNDP	Ten-year Network Development Plan (Europe’s Network Development Plan prepared bi-annually by ENTSO-E)
MCY	Monte Carlo climatic Year
CY	Climatic Year

Market areas/countries:

Med-TSO	Association of the Mediterranean Transmission System Operators (TSOs) for electricity
DZ	Algeria
EG	Egypt
IL	Israel
JO	Jordan
LY	Libya
MA	Morocco
PS	Palestine
TN	Tunisia
LB	Lebanon
ES	Spain

1 Executive Summary

This report presents the projected adequacy situation among non-EU Med-TSO members for the summer of 2025. With this assessment, Med-TSO aligns with global best practices and with the latest developments in EU regulation[1]. These investigations evaluate the security of electricity supply to consumers through a detailed power system adequacy assessment, using probabilistic criteria. This approach is necessary due to the stochastic nature of renewable energy systems (RES) and their intermittency, and also due to power system operation, which is increasingly based on open market conditions; all these aspects call for the assessment of power system adequacy in the short-, mid- and long-term. Moreover, the integration of substantial quantities of RES must be closely followed by the commissioning of devices that can provide adequate power system flexibility.

This Summer Outlook 2025 Report provides important information about potential adequacy issues during the period from 26 May through to 5 October 2025 in six MED-TSO countries: Morocco, Tunisia, Libya, Egypt, Jordan, and Lebanon.

Data for Algeria is missing from this assessment due to limited engagement from Algeria. Data for Israel and Palestine are not available at the present time. The main adequacy indicators assessed are as follows:

Main adequacy indicators that have been assessed are:

- **Loss of Load Duration (LOLD)** in a given geographical zone for a given period is the number of hours during which the zone experiences ENS during a single Monte Carlo sample/simulation year.
- **Loss of Load Expectation (LOLE)** in a given geographical zone for a given period is the expected (average) number of hours per year when there is a lack of resources to cover the demand needs, within a sufficient transmission grid operational security limit.
- **Expected Energy Not Served (EENS)** in a given geographical zone for a given period, is the (average) value of energy anticipated not to be supplied due to lack of resources while complying with transmission grid operational security limits.
- **Relative EENS:** is a more suitable indicator to compare adequacy across geographical scope as it represents the percentage of annual demand expected not to be supplied.

The adequacy situation is assessed using a two-step approach. In the first step, adequacy under isolated system operation is evaluated. In the second, adequacy under interconnected system operation is determined in order to quantify the importance of interconnections.

For the interconnected mode, we identify the exchange needed to overcome the adequacy situation. Furthermore, sensitivity analyses have been conducted to identify the most severe Monte Carlo Climatic Year (MCY) for each country.

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[1] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=en

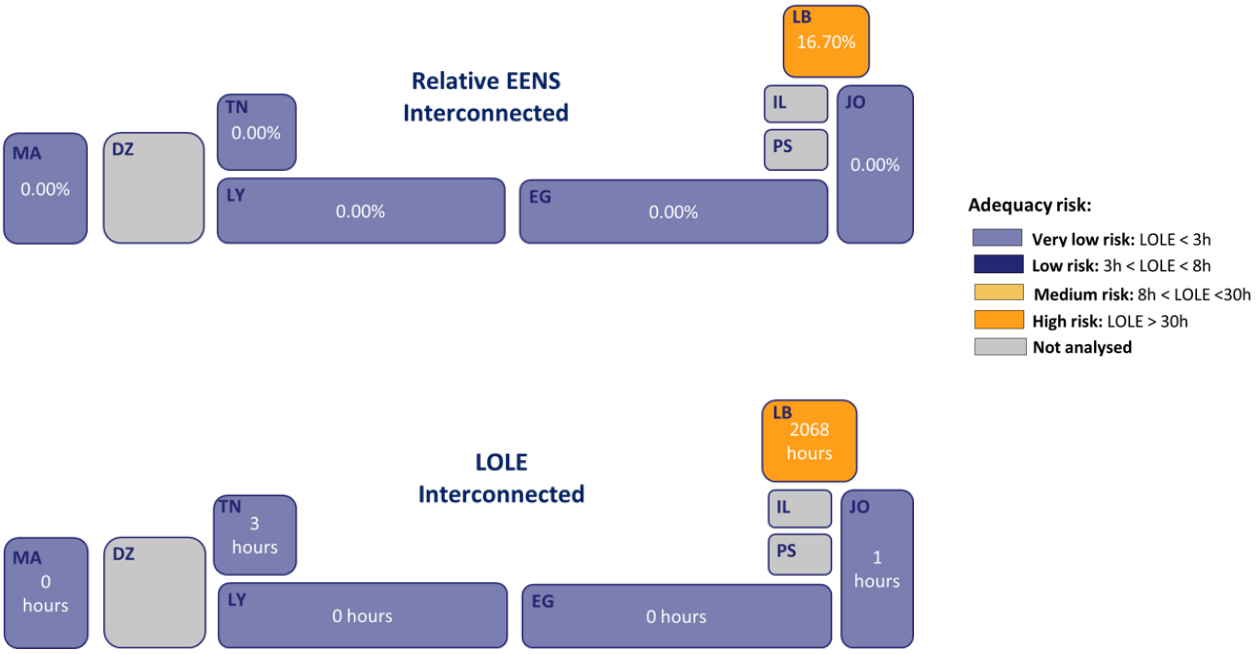

Figure 1 Seasonal relative EENS & LOLE for interconnected operational mode.

Conclusions

The conclusions of this assessment show that during this summer, the most severe adequacy issues may occur in Lebanon (Figure 1), where LOLE reaches around 2,068 hours (around 65% of the summer season), and expected energy not supplied is higher than 16.7% of the power demand in the relevant period. On the other hand, a very low adequacy risk is registered in all countries.

The situation in Lebanon is completely different to that of the other five countries analysed, with energy not supplied during the whole summer period. However, it should be noted that the operation of the Lebanese power system is very challenging, with a frequent lack of supply and regularly scheduled load shedding programmes. It should be emphasised that, in the case of Lebanon, even if all generation capacities were available and the maximum potential electricity import from the neighbouring systems were taken into account, adequacy risks could possibly be reduced, but electricity demand during peak hours of the observed period could not be supplied. Recent regional developments have intensified the situation, exacerbating supply challenges and making the power system even more unstable.

Sensitivity case - Most Severe MCY

After identifying the most severe Monte Carlo Climatic Year (MCY) for each country, it becomes apparent from Figure 2 that interconnection plays a crucial role in mitigating its impact. Jordan registers low adequacy risks, with a LOLE of seven hours. However, Tunisia (medium risk) and Lebanon (high risk) experience the most severe situations during the MCY, with LOLE reaching approximately 24 and 2,413 hours, respectively. In Lebanon, this represents around 76% of the summer season (3,192 hours), indicating a significantly higher level of risk compared to other countries.

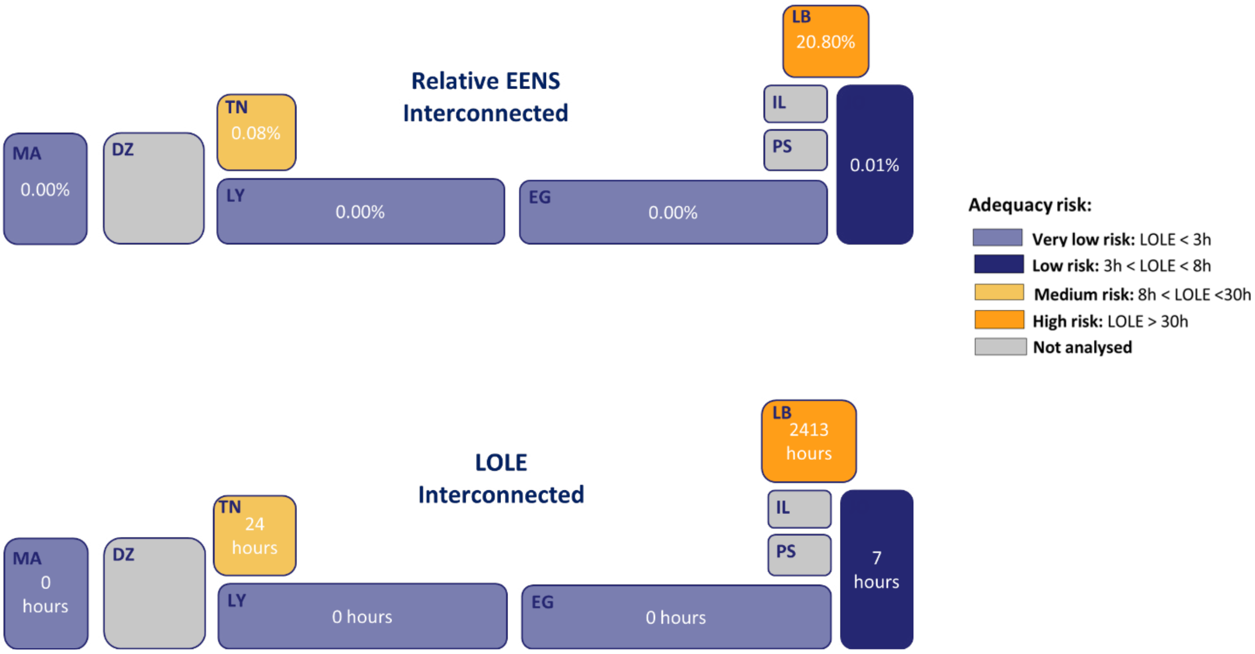

Figure 2 Seasonal relative ENS and LOLE for the interconnected mode of operation for the most severe MCY for summer outlook 2025.

2 Overview of the MED-TSO power systems in Summer 2025

This Summer Outlook 2025 Report provides information regarding potential adequacy issues during summer 2025 in six MED-TSO member states: Morocco, Libya, Tunisia, Egypt, Jordan, and Lebanon.

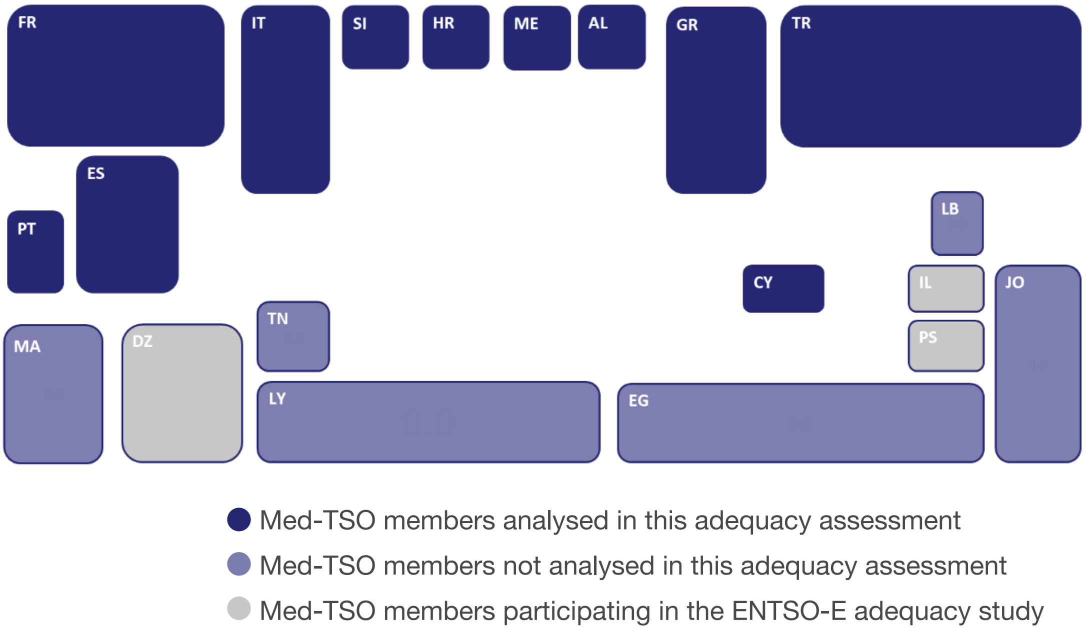

Figure 3 Med-TSO members and neighboring countries (source: Med-TSO)

- *Data for Algeria is missing from this assessment due to limited engagement from the Algerian side. Data for Israel and Palestine is currently unavailable.*

The analysed period includes all hours between the beginning of week 22 and the end of week 40, 2025, which constitutes the period between Monday 26 May and Sunday, 5 October. The overview is organised in alphabetical order, including submitted data, assumptions and proxies used to develop the corresponding market model using the Antares software tool.

All relevant parameters are presented so that the reader can verify their credibility and confirm their usability for adequacy analyses.

2.1 Demand Evolution

Table 1 presents the expected consumption per week from week 22 through to week 40, in 2025. These values constitute the average weekly consumption for 38 climatic years in the period from 1982 to 2019.

The following table highlights the highest and lowest values for each country during the summer period.

Weekly consumption based on average among 38 CY (GWh)		EG	JO	LB	LY	MA	TN
Total		**106796**	**9960**	**9231**	**17614**	**18450**	**9711**
Week	22	5271	488	435	770	945	431
Week	23	5255	490	445	810	915	424
Week	24	5517	509	457	835	961	474
Week	25	5630	520	468	872	970	501
Week	26	5692	532	482	916	971	522
Week	27	5688	538	490	940	986	562
Week	28	5791	545	499	973	998	560
Week	29	5820	547	505	979	1006	567
Week	30	5821	554	512	996	1008	583
Week	31	5929	558	515	1001	996	581
Week	32	5935	550	515	1012	1012	577
Week	33	5910	553	512	1005	993	558
Week	34	5845	545	514	998	974	555
Week	35	5747	532	505	988	989	530
Week	36	5617	519	494	966	939	486
Week	37	5503	513	485	932	958	476
Week	38	5428	504	478	911	948	459
Week	39	5290	488	466	875	941	438
Week	40	5109	474	454	835	940	425

High Value
Low Value

Table 1 Expected consumption in the summer weeks – 2025.

The table shows that Egypt's consumption is significantly higher than that of other countries.
To better illustrate this, it is plotted using a separate y-axis on the right side of the graph below.

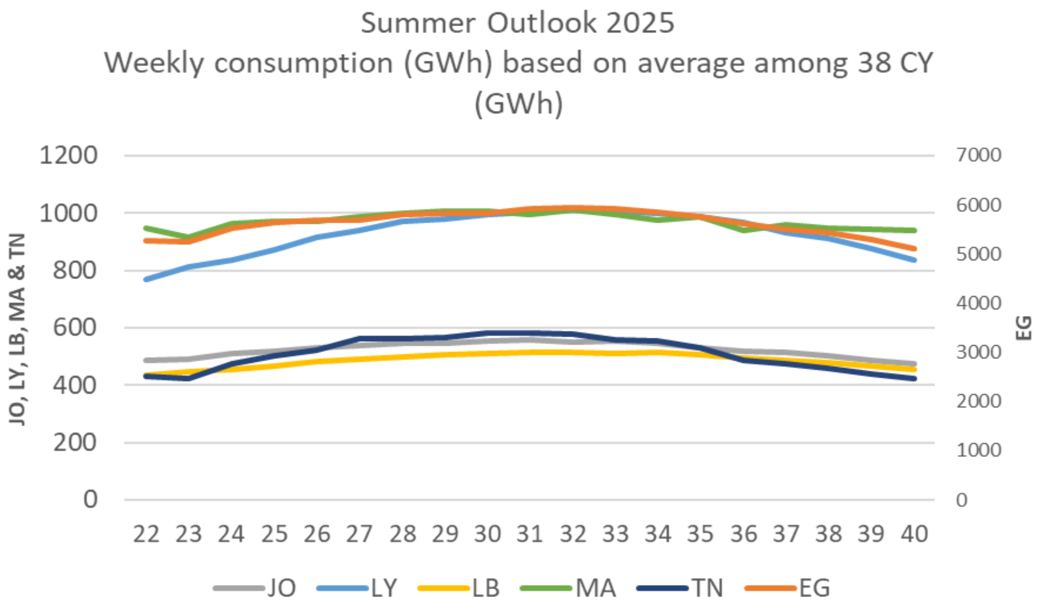

Figure 4 Expected weekly consumption per country in the analysed season.

Weekly consumption in Jordan, Lebanon, and Tunisia is the lowest among the six analysed countries. The highest is in Egypt, where it is almost 10 times higher, comparatively. Consumption in Libya and Morocco falls in between, although we can still observe significant differences between them.

The following table and figures present the hourly peak demand values, showing the maximum weekly peak loads across all 38 climatic years.

Peak load, based on maximum among 38 CY (MW)		EG	JO	LB	LY	MA	TN
Maximum		**43526**	**5464**	**3973**	**9084**	**7553**	**5754**
Week	22	39572	4356	3448	6956	7116	4310
Week	23	40088	4684	3574	7555	7173	4221
Week	24	40636	4559	3495	7194	7397	4865
Week	25	41879	4571	3629	8354	7248	5239
Week	26	42920	4476	3671	8559	7425	5593
Week	27	41953	4861	3740	9084	7375	5265
Week	28	41788	4722	3749	8491	7461	5466
Week	29	41409	4578	3885	8959	7510	5539
Week	30	43094	4976	3779	8769	7490	5214
Week	31	43526	5464	3942	7903	7454	5193
Week	32	42948	5044	3970	8257	7506	5754
Week	33	43275	4949	3802	8376	7396	5228
Week	34	42074	5409	3973	8500	7391	4865
Week	35	41234	4628	3803	8545	7553	5166
Week	36	41374	4522	3698	8647	7347	4429
Week	37	41024	4666	3765	8205	7209	4373
Week	38	39693	4296	3612	7965	7186	4320
Week	39	39197	4242	3611	7296	7183	3991
Week	40	38651	4178	3523	7335	7034	3883

High Value
Low Value

Table 2 Maximum weekly peak loads in summer weeks 2025.

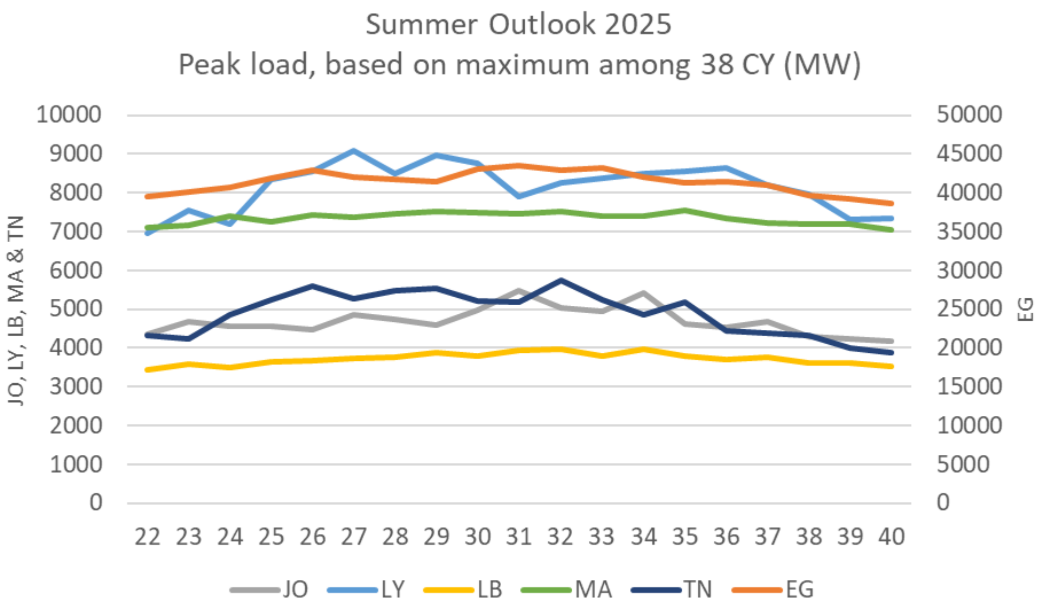

Figure 5 Maximum weekly peak loads per country in the analysed season.

It's worth mentioning that In Jordan, the peak load is observed during winter as well as summer.

2.2 Install capacities evolution

The following tables present the expected installed capacities during the summer period of 2025. Total installed capacity in the observed region is expected to reach 101 GW, with nearly 80 GW (approximately 79%) coming from thermal units.

Compared to SO 2024, changes in installed capacities are highlighted using two colours: green for increases and orange for decreases.

The introduction of battery storage in the region for the first time constitutes a major milestone. Egypt[2] has deployed 810 MWh battery storage with a two-hour discharge (405 MW per hour), while in Morocco[3], 800 MWh of battery storage with a two-hour duration (400 MW per hour) has been deployed, and an additional 1,000 MWh with a five-hour duration (200 MW per hour). The battery discharge depends on the need of the system or during peak demand.

Another key observation is the rapid expansion of renewable installed capacities across almost all countries. However, Lebanon stands out as an exception, as the current regional situation has severely impacted solar rooftop systems.

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[2] For Egypt (EETC), battery storage is expected to be commission during April, July and September 2025

[3] For Morocco (ONEE), battery storage tender has launched and expected to be out I operation between Q3/Q4 2025 and 2026

Med-TSO Member	Expected WPP capacity		Expected SPP capacity		Expected CSP Capacity (With Storage)		Expected CSP Capacity (Without Storage)		Expected HPP capacity		Expected Battery Storage capacity		Expected HydroPump Storage capacity		Expected TPP capacity		TOTAL [MW]
	[MW]	Share in Total	[MW]	Share in Total	[MW]	Share in Total	[MW]	Share in Total	[MW]	Share in Total	[MW]	Share in Total	[MW]	Share in Total	[MW]	Share in Total	
EG	3036.37 (86%▲)	5%	3134 (40%▲)	5%	-	-	140 (No Change)	0%	2831 (No Change)	5%	405 (New Capacity▲)	1%	-	-	50677 (-4%▼)	84%	**60223**
JO	621 (No Change)	8%	2202 (4%▲)	29%	-	-	-	-	-	-	-	-	-	-	4785 (No Change)	63%	**7608**
LB	-	-	1300 (-13%▼)	31%	-	-	-	-	285 (No Change)	7%	-	-	-	-	2561 (-12%▼)	62%	**4146**
LY	-	-	50 (New Capacity▲)	0%	-	-	-	-	-	-	-	-	-	-	10525 (-8%▼)	100%	**10575**
MA	2410 (5%▲)	19%	621 (113%▲)	5%	540 (No Change)	4%	-	-	1306 (No Change)	10%	600 (New Capacity▲)	5%	790 (70%▲)	6%	6445.69 (-6%▼)	51%	**12713**
TN	230 (-5%▼)	4%	440 (28%▲)	8%	-	-	-	-	-	-	-	-	-	-	5183 (No Change)	89%	**5853**
OTAL	**6297**	**6%**	**7747**	**8%**	**540**	**1%**	**140**	**0%**	**4422**	**4%**	**1005**	**1%**	**790**	**1%**	**80177**	**79%**	**101118**

Table 3 Total expected installed capacities (MW) per technology during summer period from Week 22 to Week 40, 2025.

	Installed Capacity [GW]	Peak Load [GW]
EG	60.2	43.5
JO	7.6	5.5
LB	4.1	3.97
LY	10.6	9.1
MA	12.7	7.6
TN	5.9	5.8

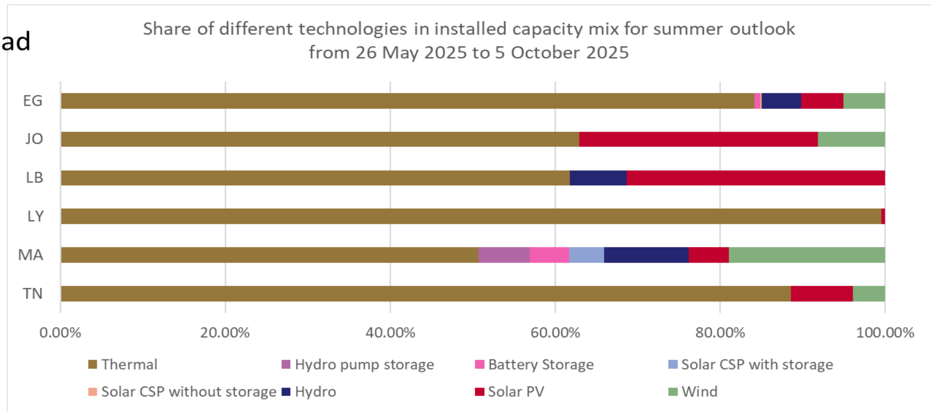

Figure 6 Installed capacity mix and peak load in summer period.

It's important to highlight that Libya's power system relies exclusively on thermal power plants. In contrast to prior adequacy assessments, its thermal fleet has undergone a thorough re-evaluation. This reassessment considers the maintenance activities performed by the Libyan system, which has led to the restoration of certain power plants that were previously offline. Additionally, some power plants have been excluded due to severe damage, while newly introduced power plants have also been incorporated into the evaluation. This comprehensive approach ensures a more accurate reflection of the current state of Libya's thermal generation capacity.

Relevant hydro capacities exist only in Egypt and Morocco. Morocco currently operates a pumped storage hydro power plant (PSHPP) with a capacity of 464 MW. In addition, a new pumped storage facility with a capacity of 326 MW has recently been commissioned, bringing the total pumped storage capacity in the country to 790 MW.

The highest participation of wind and solar in total generation capacities is found in Lebanon, Jordan, and Morocco, reaching more than 35% of the installed capacity. It should be noted that in Morocco, 540 MW of solar capacity is in solar thermal farms with storage.

Capacity factors related to wind and solar generation are presented in Table 4. It is worth mentioning that capacity factors consider the technology used and the zone splitting of each country according to PECD v3.5

	2025	
Country	**Wind CF**	**Solar CF**
EG	49.5%	26.3%
JO	33.23%	25.82%
LB	-	18%
LY	-	21.7%
MA	50.3%	30.4%
TN	30%	20%

Table 4 Wind and solar capacity factors for all countries during SO 2025.

The impact of RES generation in Egypt and Tunisia is marginal since the participation of thermal units is above 80%.

Among thermal technologies, the majority is gas-fired units. Regarding thermal units, available capacities consider the forced outages rate according to data provided, as well as derating factors, which define the reduction in available thermal capacities for various different reasons.

Planned outages are modelled according to data provided by TSOs (JO, TN & MA) or as random planned outages, while respecting certain predefined rules as shown in the table below.

Market Node	January	February	March	April	May	June	July	August	September	October	November	December
EG00	**yes**	**yes**	**yes**	yes	yes	no	no	no	yes	yes	yes	yes
LB00	**yes**	**yes**	**yes**	yes	yes	no	no	no	yes	yes	yes	yes
LY00	**no**	**yes**	**yes**	yes	yes	no	no	no	yes	yes	yes	no

Table 5 shows the months when maintenance is allowed and when it is not.

- In Egypt, Lebanon, and Libya, planned outages are not envisaged in the period from 1 June to 1 September.
- In Jordan, Morocco, and Tunisia, detailed planned outages are provided and considered during the simulations.

Forced outages of thermal units are modelled as random events in all cases and across all countries, based on predefined parameters. Similarly, for thermal units, commissioning/decommissioning dates are considered.

2.3 Interconnections between countries

Summarised NTC values are used as available cross-border capacities, and we assume that these capacities are only used if a country is facing adequacy issues for the entire calculation period.

The Antares model included the power systems of six analysed Med-TSO member countries with detailed generation capacities and demand, and a simplified representation of the transmission network and cross-border capacities, represented as NTC values. The internal transmission network has not been modelled in the market simulator. Furthermore, in the case of borders with countries outside of the Med-TSO region, exchanges have been modelled using hourly data provided by our members. In the case of Algeria, it is assumed that the country can export electricity to neighbouring countries in the event of adequacy risk. Furthermore, it is assumed that Algeria itself does not face any adequacy risk.

For Lebanon, we evaluated a hypothetical interconnection between Lebanon and Jordan through Syria, which would enable Lebanon to potentially import up to 250 MW of electricity as a sensitivity measure.

A significant milestone is anticipated for summer 2025, as Egypt and Saudi Arabia prepare to commission their first electricity interconnection project. This project will be implemented in two phases.

- **Phase 1:** Scheduled to commence operations during Summer 2025, this phase will enable the exchange of 1,500 MW of electricity between the two countries.
- **Phase 2:** this phase will add another 1,500 MW capacity, bringing the total exchange capacity to 3,000 MW.

The interconnection spans approximately 1,350 km, incorporating overhead transmission lines and subsea cables. It represents the first large-scale high-voltage direct current (HVDC) link in the Middle East and North Africa region.

This project is expected to enhance grid stability, facilitate energy exchange, and support the integration of renewable energy sources in both countries. A summary of the interconnection capacities and given exchanges is presented in the following figure.

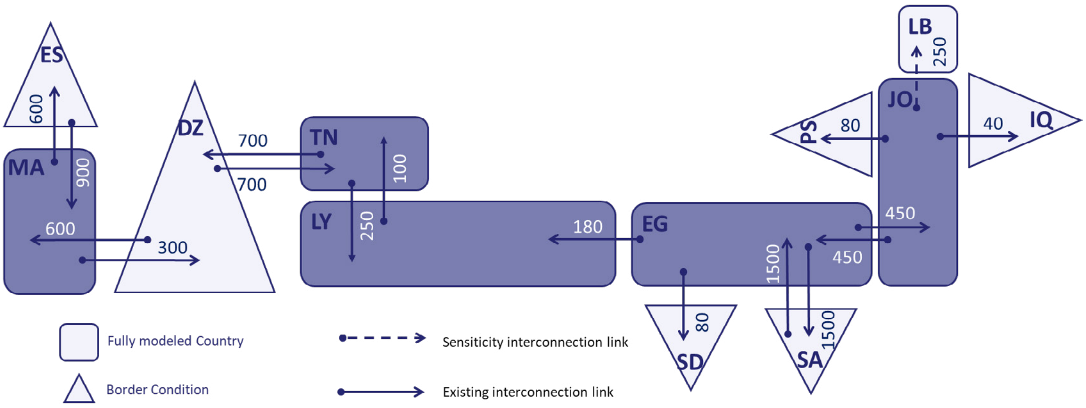

Figure 7 Net Transfer Capacity during SO 2025

2.4 Reserve requirements and their modelling

Reserve requirements have been provided for each country (Table 6). In some countries (LY, MA), the percentages of capacity reduction at thermal units due to the provision of FCR[4] have been provided and these percentages have been applied in the Antares modelling. No additional FCR requirements have been modelled. In countries in which these percentages are not known, FCR has been modelled as a negative balance (Export) with the rest of world (ROW) node in our simulation tool. FRR requirements have been modelled as a negative balance (Export) with the rest of world (ROW) node in our simulation tool, in all countries.

Reserve		WO 2025
EG	FCR+FRR [MW]	1200
JO	FCR+FRR [MW]	200
LB	FCR+FRR [MW]	120
LY	FCR+FRR [MW]	250
MA	FCR+FRR [MW][4]	700
TN	FCR+FRR [MW]	220

Table 6 Balancing reserve requirements.

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[4] FCR for MA has been modeled through reduced thermal capacity by total of 300 MW.

3 Adequacy Situation Overview

3.1 Adequacy assessment

The adequacy situation has been assessed using a two-step approach. In the first, adequacy under isolated system operation is evaluated. In the second, adequacy under interconnected system operation is assessed to quantify the importance of interconnections.

In a tIn a theoretical isolated scenario (**Figure 8**), which focuses on the summer season, adequacy risks are identified in Jordan, Tunisia, and Lebanon. While Jordan faces low risk, Tunisia and Lebanon experience a very high adequacy risk under an isolated system operating mode.

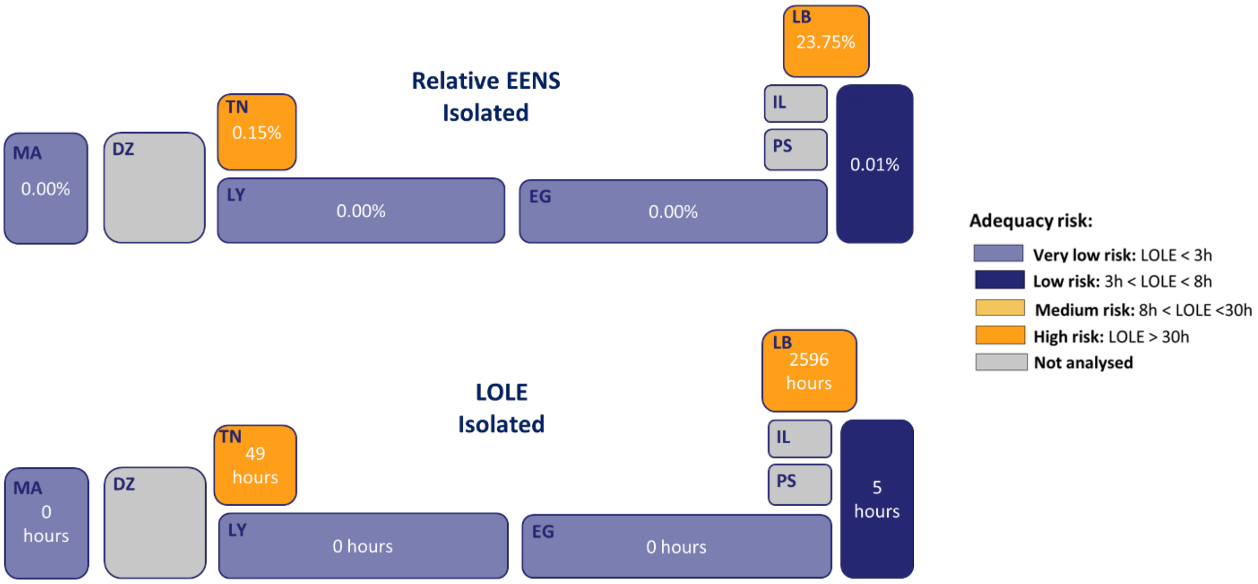
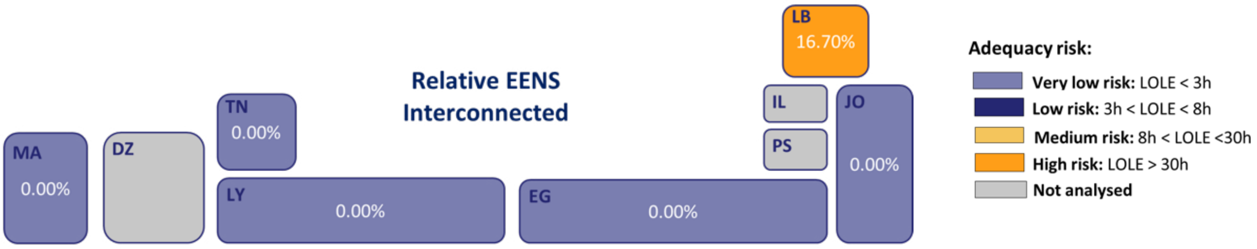


Figure 8 Seasonal relative EENS and LOLE for the isolated operational mode for the summer season.

Interconnections and energy exchanges needed to overcome adequacy issues with neighbouring countries reduce adequacy risks to a minimum in the case of Tunisia and Jordan but in Lebanon, even in this more relaxed operating mode, adequacy risks are at an unacceptable level. Figure 9 shows the interconnected scenario for the summer season.



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[5] Color coding of adequacy risk levels presented in Figure 8 & Figure 9 does not reflect national thresholds for loss of load expectation (LOLE) that is usually specified within Network Codes of corresponding Transmission System Operators.

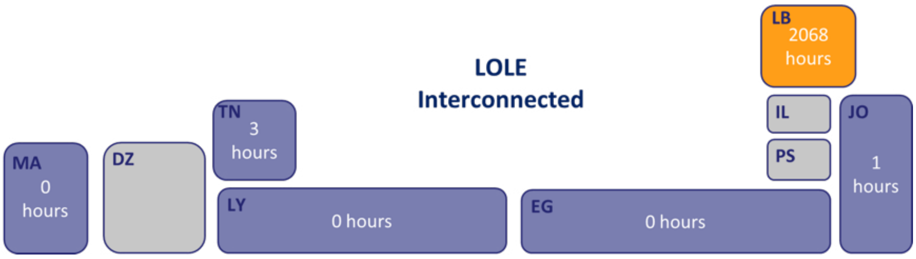

Figure 9 Seasonal relative EENS and LOLE for the interconnected mode of operation for the summer season.

Country	Isolated EENS	Interconnected EENS		Isolated LOLE	Interconnected LOLE
EG	0 MWh	0 MWh		0	0
	50th percentile 0 MWh	50th percentile 0 MWh		50th percentile LOLD: 0 hours	50th percentile LOLD: 0 hours
	95th percentile 0 MWh	95th percentile 0 MWh		95th percentile LOLD: 0 hours	95th percentile LOLD: 0 hours
JO	1110 MWh	104 MWh		5.31	0.62
	50th percentile 3 MWh	50th percentile 0 MWh		50th percentile LOLD: 1 hours	50th percentile LOLD: 0 hours
	95th percentile 7950 MWh	95th percentile 819 MWh		95th percentile LOLD: 30 hours	95th percentile LOLD: 6 hours
MA	0 MWh	0 MWh		0	0
	50th percentile 0 MWh	50th percentile 0 MWh		50th percentile LOLD: 0 hours	50th percentile LOLD: 0 hours
	95th percentile 0 MWh	95th percentile 0 MWh		95th percentile LOLD: 0 hours	95th percentile LOLD: 0 hours
TN	14300 MWh	452 MWh		48.86	2.58
	50th percentile 9951 MWh	50th percentile 0 MWh		50th percentile LOLD: 41 hours	50th percentile LOLD: 0 hours
	95th percentile 66096 MWh	95th percentile 3366 MWh		95th percentile LOLD: 156 hours	95th percentile LOLD: 21 hours
LY	11 MWh	0 MWh		0.08	0
	50th percentile 0 MWh	50th percentile 0 MWh		50th percentile LOLD: 0 hours	50th percentile LOLD: 0 hours
	95th percentile 0 MWh	95th percentile 0 MWh		95th percentile LOLD: 0 hours	95th percentile LOLD: 0 hours
LB	2192078 MWh	1541774 MWh		2596.43	2067.77
	50th percentile 2191477 MWh	50th percentile 1535076 MWh		50th percentile LOLD: 2615 hours	50th percentile LOLD: 2073 hours
	95th percentile 2623127 MWh	95th percentile 1962831 MWh		95th percentile LOLD: 2864 hours	95th percentile LOLD: 2400 hours

Table 7 Seasonal EENS for Interconnected and isolated scenario

Table 7 provides detailed seasonal EENS and LOLD results for all analysed countries, including P50 and P95 sensitivity scenarios. Results point to adequacy issues in some countries, notably the following:

- **Jordan**

  Under normal conditions, Jordan faces a low adequacy risk, with EENS reaching 1.1 GWh and LOLE lasting five hours in isolated mode. In interconnected mode, these values drop significantly to 100 MWh and less than one hour, respectively.

  However, when considering the P95 sensitivity scenario, which represents more critical conditions, ENS in isolated mode can escalate to 7.9 GWh, with LOLD reaching 30 hours. In contrast, in interconnected mode, the impact remains much lower, with ENS at 800 MWh and LOLD limited to six hours.

These findings highlight the crucial role of interconnections in enhancing Jordan's adequacy under extreme conditions.

- **Tunisia**

  Under normal conditions, Tunisia faces a high adequacy risk in isolated operational mode, with EENS reaching 14 GWh and LOLE lasting 49 hours. However, in interconnected mode, the risk is significantly reduced, with EENS dropping to 450 MWh and LOLE limited to less than three hours.

  When considering the P95 sensitivity scenario, which reflects more critical conditions, ENS in isolated mode can surge to 66 GWh, with LOLD reaching 156 hours. In interconnected mode, the impact remains much lower, with ENS at 3 GWh and LOLD limited to 21 hours.

These findings emphasise the vital role of interconnections in mitigating Tunisia's adequacy risks under extreme conditions.

- **Lebanon**

  Lebanon experiences the highest EENS and LOLE in the region during the summer of 2025, with 1.5 TWh of EENS and 2,067 hours of LOLE (equivalent to 65% of the time) in the hypothetical interconnected mode.

  These figures highlight an extremely precarious adequacy situation (daily LOLD during the whole season can range from 8 to 19 hours). In the event of more critical but less probable P95 cases, ENS can reach a staggering 1.9 TWh with an unavailability to supply the load for over 75% of the time.

  In the isolated operational mode of, adequacy is at even greater risk, with EENS reaching 2.1 TWh and LOLE extending to 2596 hours (daily LOLD during the whole season can range from 12 hours to 23 hours.) This highlights how Lebanon's interconnection with Jordan can significantly reduce adequacy risks by 10%.

It should be noted that curtailment of RES generation can only happen in Jordan and Morocco in isolated operations, but that this curtailment is marginal, far below 1% of RES generation.

The rationales behind these results are explained in the relevant country chapters.

3.2 Importance of interconnections

In this chapter, we thoroughly explore the interconnections between the countries under analysis and their need for energy exchange to mitigate anticipated adequacy challenges in the coming summer. Our primary objective is to evaluate potential cross-border exchanges among the six analysed countries and quantify each one's requirements to address adequacy risks during periods of isolation. The following table summarises the feasible exchanges needed to overcome adequacy risks and NTC among the countries subject to our analysis.

Link	Total Exchanges for Adequacy (GWh)	NTC direct (MW)	Reverse NTC (MW)
DZ00 - MA00	0	600	300
ES00 - MA00	0	900	600
DZ00 - TN00	13	700	700
LY00 - TN00	0	100	250
EG00 - LY00	0	180	0
EG00 - JO00	4	450	450
JO00 - LB00	651	250	0

Table 8 Exchanges needed to overcome Adequacy in the region.

Exporting electricity from Egypt to Jordan positively contributes to enhancing Jordan's adequacy. Furthermore, Egypt and Jordan are actively exporting approximately 240 GWh to meet Sudan and Palestine's energy needs, while Jordan is exporting approximately 128 GWh to support Iraq's energy demands. Furthermore, a new interconnection between Egypt and Saudi Arabia is set to be commissioned in summer 2025, enabling a bi-directional energy exchange of 1 TWh.

The situation in Lebanon is completely different, in that interconnections and imported energy play a substantial role. While interconnections help decrease adequacy concerns by 10%, alone they are insufficient to fully mitigate these potential risks.

4 Sensitivity Cases

In our previous analysis, we presented the adequacy situation based on a probabilistic approach, which averaged data from all 38 analysed climatic years, repeated 18 times to ensure strong convergence of results, as detailed in the appendix below. However, as we further explore the adequacy outlook for summer 2025, we recognise the need to pinpoint the most severe Monte Carlo Climatic Year (MCY) within this dataset. This exploration aims to uncover extreme scenarios that may challenge the resilience of energy systems in each country.

Interconnected Operation:

This scenario explores the operation of the analysed countries under the same interconnected grids mentioned on page 28, where they can exchange electricity only if and when an adequacy risk is identified.

Isolated Operation:

In contrast, this scenario investigates the operation of the analysed countries in isolation, where each country operates independently without interconnections. Isolated operation poses challenges to energy security, especially during peak demand.

4.1 The Most severe Monte Carlo Climatic Year

To determine the most severe Monte Carlo Year (MCY) among the 684 simulated cases, we began with the 38 distinct climatic years covering the period from 1982 to 2019. We averaged the results of all MCYs that share the same climatic year. From these, the most critical MCY was identified for further analysis.

In a theoretical isolated system scenario (Figure 10), our analysis for summer 2025 shows adequacy risks in Tunisia, Jordan, and Lebanon. These risks are considered significant under isolated operating conditions.

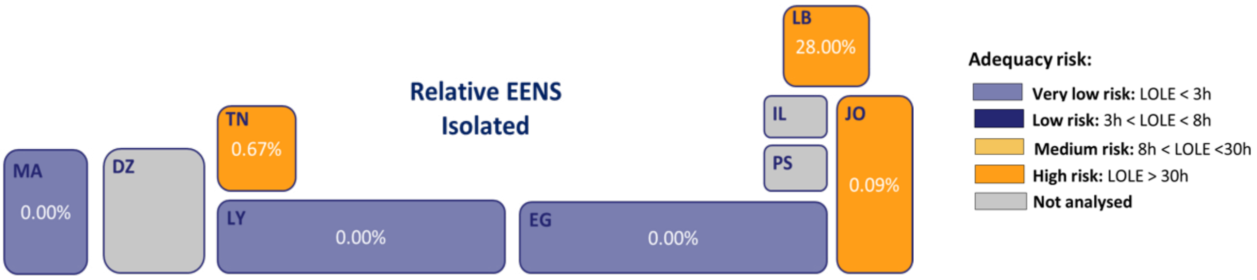

Figure 10 Seasonal relative EENS and LOLE for the isolated operational mode for the most severe MCY in summer.

When interconnections and energy exchanges with neighbouring countries are considered, adequacy risks are substantially reduced—dropping to low in Jordan and medium in Tunisia, while Lebanon still faces unacceptable risk levels of risk, as shown Figure 11, which reflects the interconnected scenario for summer 2025[6].

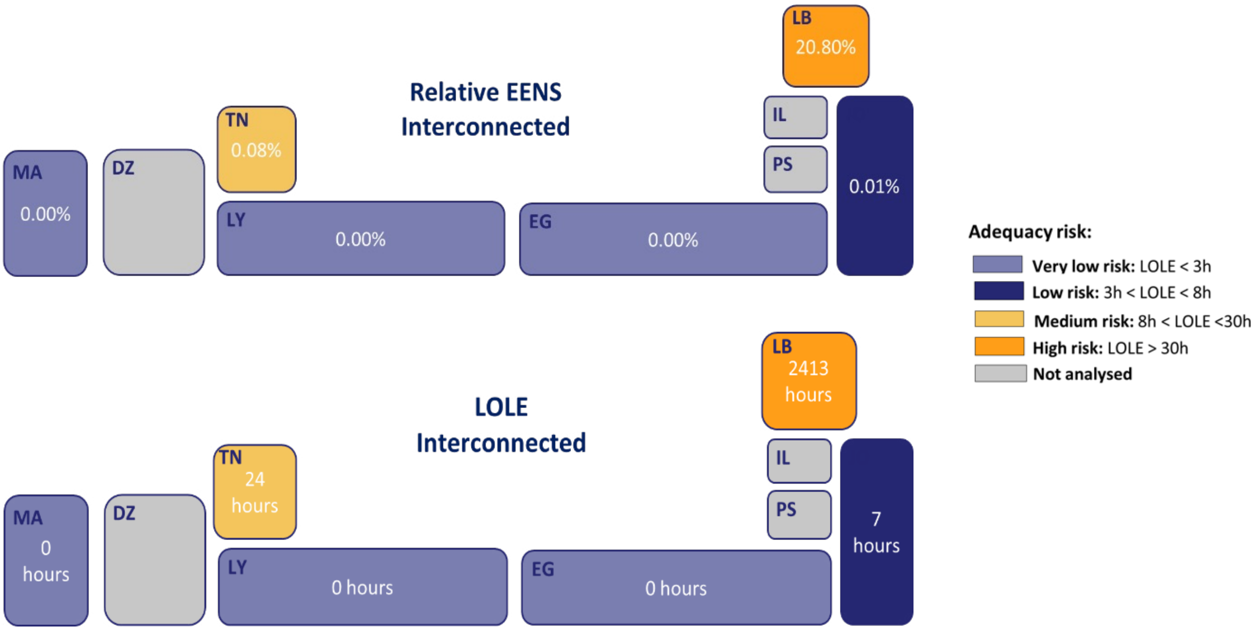

Figure 11 Seasonal relative ENS and LOLE for the interconnected mode of operation for the most severe MCY for Summer season.

The figures clearly demonstrate that interconnections play a key role in mitigating the impact of the most severe Monte Carlo Climatic Year (MCY) for both Jordan and Tunisia. However, even with the assumption of a hypothetical interconnection with Jordan, Lebanon looks set to face a high adequacy risk in summer 2025.

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[6] Color coding of adequacy risk levels presented in Figure 48 & Figure 49 does not reflect national thresholds for loss of load expectation (LOLE) that is usually specified within Network Codes of corresponding Transmission System Operators.

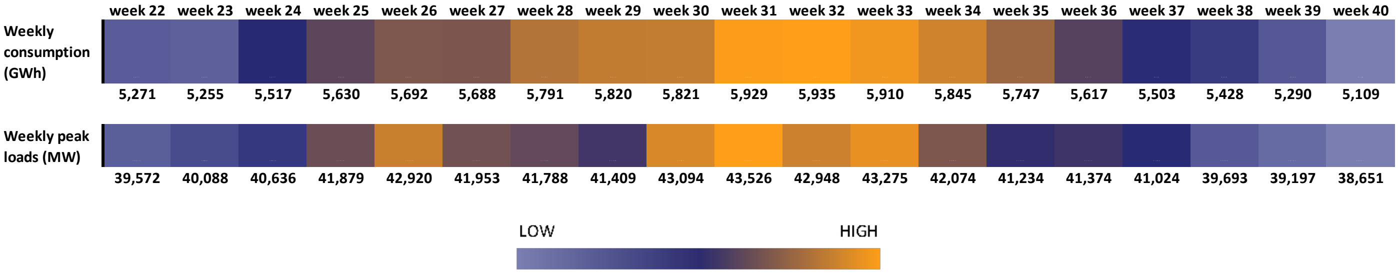
5 Adequacy Situation on Country Level

5.1 Egypt

Demand

Egyptian seasonal weekly demand for summer, depicted in Figure 12, ranges from around 5,109 GWh to 5,935 GWh, while peak hourly demand each week varies from 38 GW to 43 GW. It should be noted that weekly demand refers to the average values of all 38 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analysed climatic years.

As we can observe in the figure below, maximum electricity needs are expected from the second half of July to the end of August (29th – 35th week), due to high temperatures and high cooling consumption, similar to the scenario in all other countries. It should be noted that during the summer season, maximum hourly demand changes by around 14%.



	week 22	week 23	week 24	week 25	week 26	week 27	week 28	week 29	week 30	week 31	week 32	week 33	week 34	week 35	week 36	week 37	week 38	week 39	week 40
Weekly consumption (GWh)	5,271	5,255	5,517	5,630	5,692	5,688	5,791	5,820	5,821	5,929	5,935	5,910	5,845	5,747	5,617	5,503	5,428	5,290	5,109
Weekly peak loads (MW)	39,572	40,088	40,636	41,879	42,920	41,953	41,788	41,409	43,094	43,526	42,948	43,275	42,074	41,234	41,374	41,024	39,693	39,197	38,651

Figure 12 Seasonal weekly demand in Egypt.

Supply and network overview

Egyptian power generation is almost exclusively based on natural gas, with the gas TPP share in total installed capacities at around 86%, further divided into conventional and CCGT TPPs. The oil TPP share is 1%, while the hydro share is 5%. RES wind and solar capacities amount to 5% each. Total net generation installed capacities (NGIC) (Including hydro and RES) reach 59,819 MW with import capacity up to 1,950 MW: 450 MW from Jordan and 1,500 MW from Saudi Arabia, which combined, is substantially higher than the maximum hourly consumption of 43,526 MW. In terms of

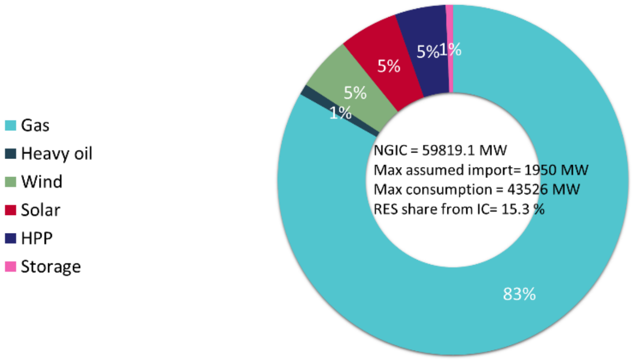


Figure 13 Installed capacity mix with total NGIC, max assumed import NTC, and peak demand in Egypt.

The average daily available TPP capacity, after reduction due to forced outages, is shown in Figure 14. Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated modes of operation. Egyptian average available TPP capacity fluctuates in this period due to derating, and planned and forced outages. The minimal average daily available TPP capacity (minimum among all simulated MC years) fluctuates around 38 GW.

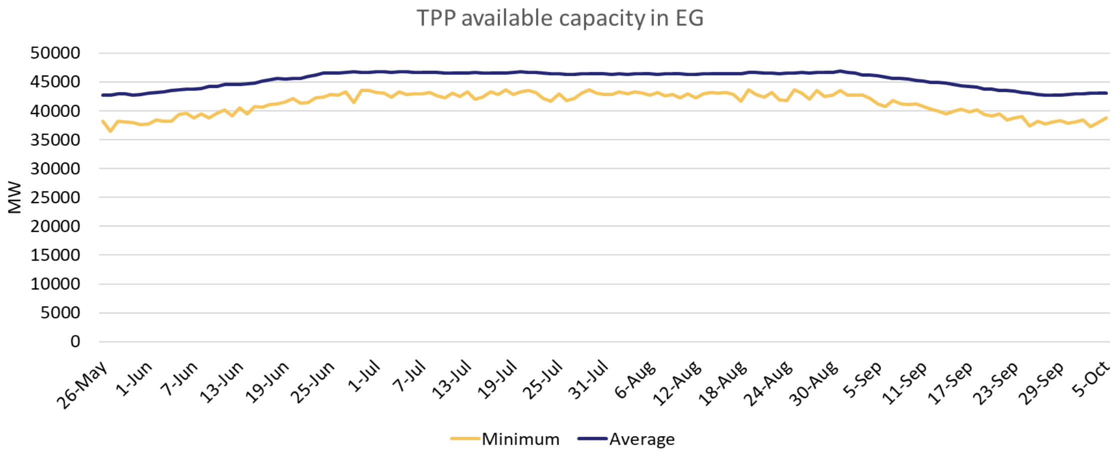


Figure 14 Average and minimum TPP available capacity among all simulated MC years in Egypt.

As a result of system simulation, the minimum hourly TPP capacity margin among all simulated MC years is depicted in Figure 15. It represents the difference between available and activated TPP capacities. The hourly minimum TPP margin is between 2 GW and 11 GW during the analysed summer season.

A very high TPP capacity margin indicates that Egypt will not have adequacy issues during the following season, and that it has huge export capabilities that can benefit neighbouring countries' adequacy deficits.

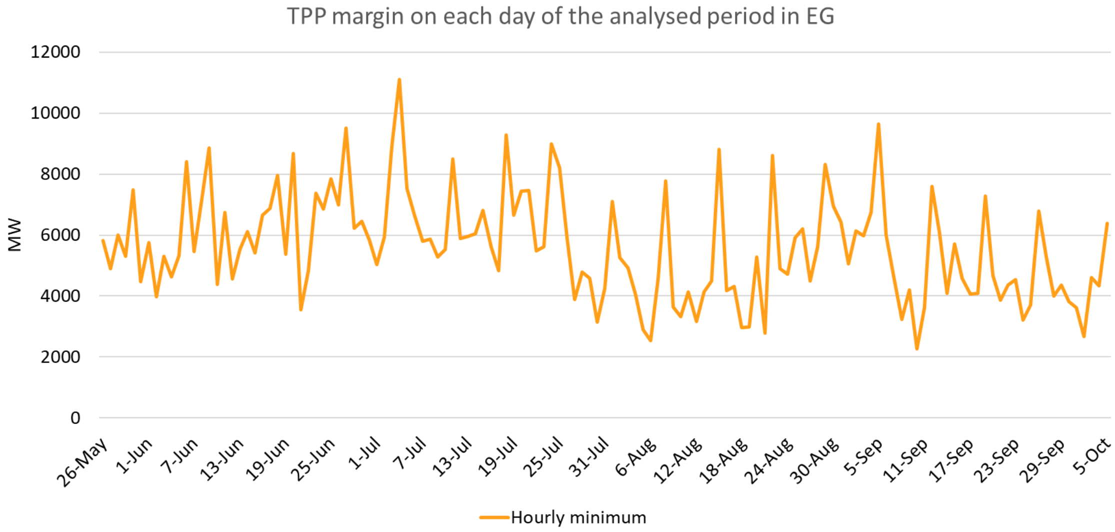


Figure 15 Minimum hourly TPP margin on each day of the analysed period among all simulated MC years in Egypt.

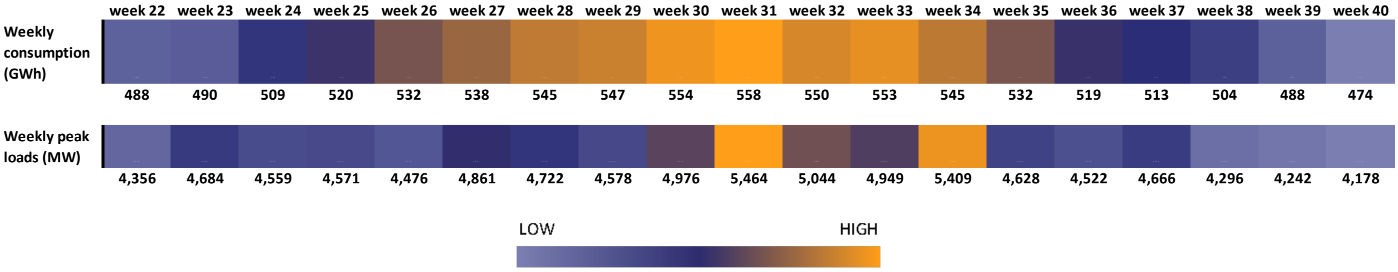
Adequacy Assessment

No adequacy concerns are detected for either analysed operational mode in the case of Egypt.

5.2 Jordan

Demand

Jordan’s seasonal weekly demand in summer, depicted in Figure 16, ranges from around 474 GWh to 558 GWh (with fluctuation at the level of 16%), while peak hourly demand in each week ranges from 4,178 MW to 5,464 MW, which presents even higher fluctuation of 23%. It should be noted that weekly demand refers to the average values of all 38 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analysed climatic years.



	week 22	week 23	week 24	week 25	week 26	week 27	week 28	week 29	week 30	week 31	week 32	week 33	week 34	week 35	week 36	week 37	week 38	week 39	week 40
Weekly consumption (GWh)	488	490	509	520	532	538	545	547	554	558	550	553	545	532	519	513	504	488	474
Weekly peak loads (MW)	4,356	4,684	4,559	4,571	4,476	4,861	4,722	4,578	4,976	5,464	5,044	4,949	5,409	4,628	4,522	4,666	4,296	4,242	4,178

Figure 16 Seasonal weekly demand in Jordan.

Supply and network overview

Jordan’s power generation is predominantly based on gas-fuelled TPPs, with the share in total installed capacities at around 57%, further divided into conventional and OCGT TPPs. Oil share amounts to 6% of installed capacities, while RES wind and solar share in installed capacities are 8% and 29%, respectively. Total net generation installed capacities (NGIC) (Including RES), amount to 7,608 MW with an import capacity of up to 450 MW from Egypt, which combined, is higher than the maximum hourly consumption of 5,464 MW.

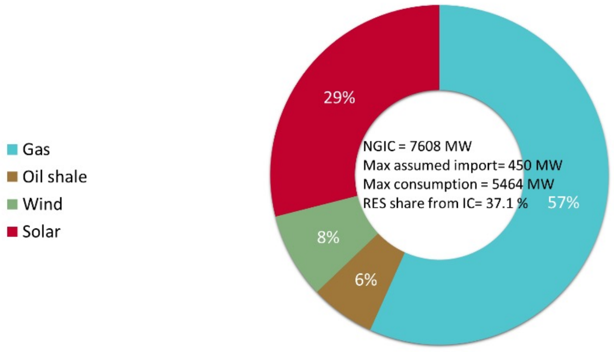


Figure 17 Installed capacity mix with total NGIC, max assumed import NTC, and peak demand in Jordan.

The average daily available TPP capacity, after reduction due to derating factors, and forced and planned outages, is shown in Figure 18. Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated modes of operation. The average available TPP capacities among all simulated MC years start from 4,130 MW and rise to 4,400 MW in early July due to maintenance stops aimed at meeting the demand during the summer season. The minimal average daily available TPP capacity among all simulated MC years ranges from 3,170 MW to 3,800 MW.

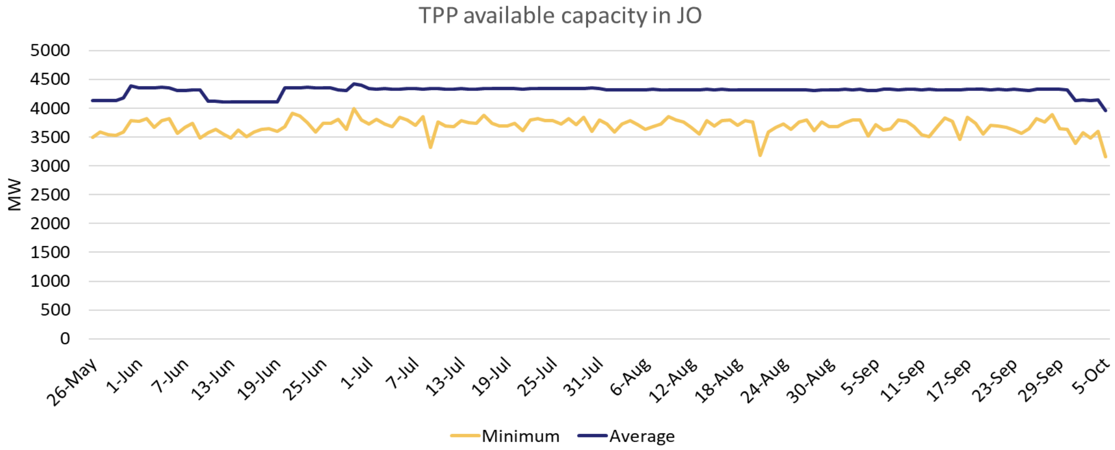


Figure 18 Average and minimum TPP available capacity among all simulated MC years in Jordan.

As a result of system simulation, the minimum hourly TPP capacity margin among all simulated MC years is depicted in Figure 19. It represents the difference between available and activated TPP capacities. The minimum hourly value of the TPP margin is often at zero throughout the summer season. These results indicate a possibility that during certain hours, adequacy can be endangered. Notably, the daily margin follows daily consumption patterns, and is at its lowest during working days, due to higher demand.

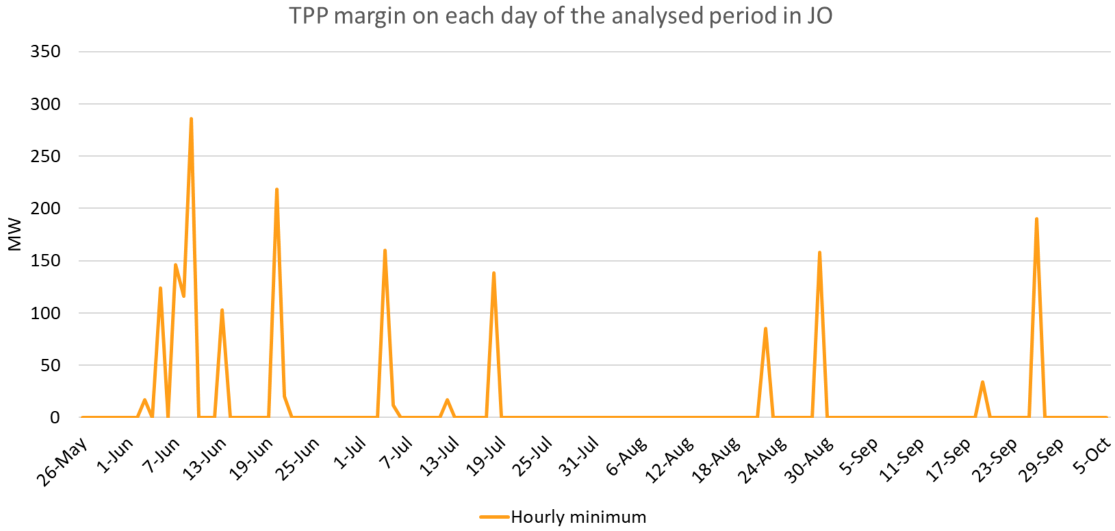


Figure 19 Minimum hourly TPP margin on each day of the analysed period among all simulated MC years in Jordan.

Adequacy Assessment

The temporal distribution of detected adequacy risk is shown in Figure 20, for both modes of operation: interconnected and isolated. The first image depicts daily LOLE distribution, while the second depicts daily EENS.

For both modes of operation, adequacy risk is marginal, although for the theoretical isolated scenario, the adequacy risk is higher.

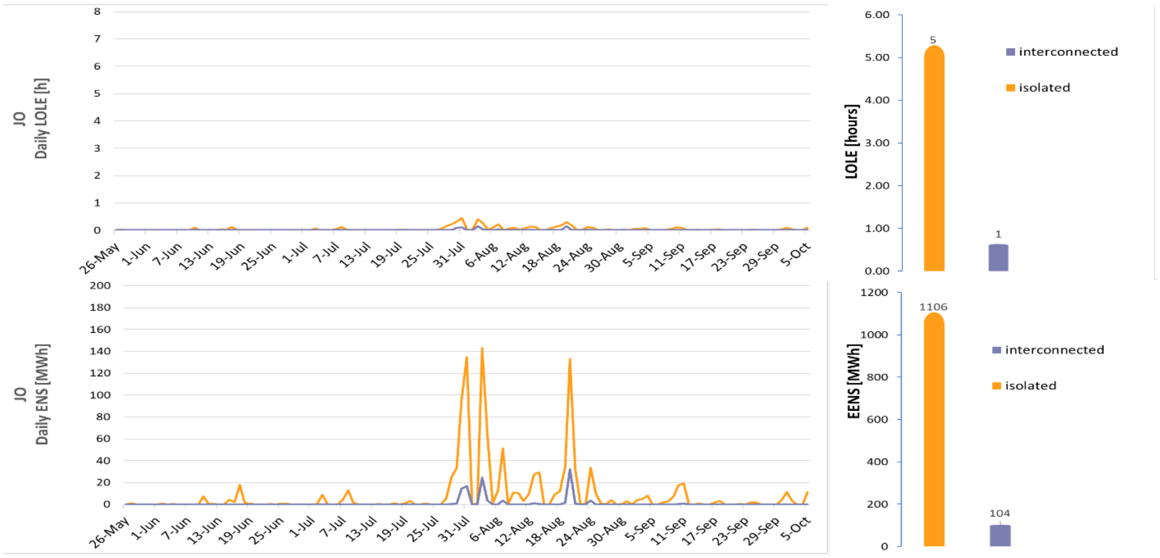


Figure 20 Daily LOLE and EENS for the interconnected and isolated mode of operation in Jordan.

On the right-hand side of the figure, LOLE and EENS for the entire season for both system operation modes are provided. Interconnections substantially reduce the already low seasonal LOLE from 5h to less than 1h and expected summer seasonal EENS from 1,106 MWh to just 104 MWh.

5.3 Lebanon

Demand

Lebanon's seasonal weekly demand in summer, depicted in Figure 21, ranges from around 435 GWh to 515 GWh, while peak hourly demand each week ranges from 3,448 MW to 3,942 MW. It should be noted that weekly demand refers to the average values of all 38 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analysed climatic years. Maximum electricity needs are expected during weeks 31 & 32 of 2025, due to high temperatures and increased cooling demand. It should be noted that the operation of Lebanon's power system is especially difficult, with a continuous lack of supply and organised regular load shedding.

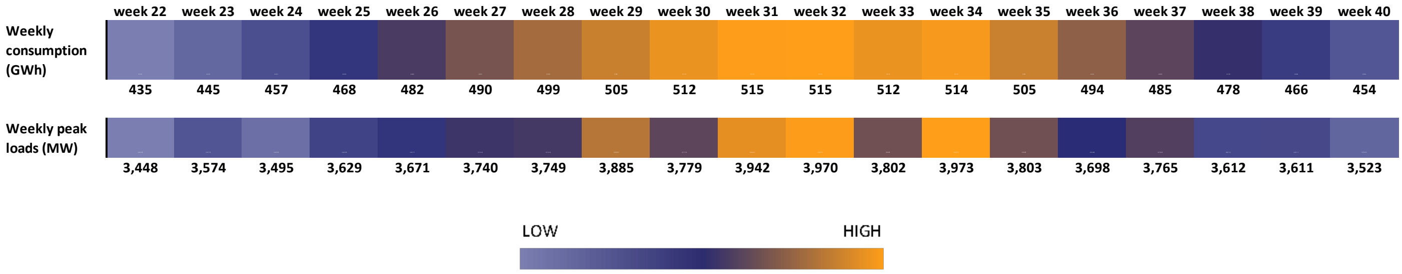


Figure 21 Seasonal Weekly demand in Lebanon.

Supply and network overview

Lebanon's power generation fleet is exclusively oil fuelled, with the share in total installed capacities around 62%, while 7% goes to hydro power plants and the remaining 31% goes to solar rooftop capacities. Total net generation installed capacities (NGIC) (including hydro and RES) amount to 3,146 MW, but as a substantial support to system operation, the capacity of 1,000 MW in diesel units is also considered in this analysis in addition to the total installed capacity.

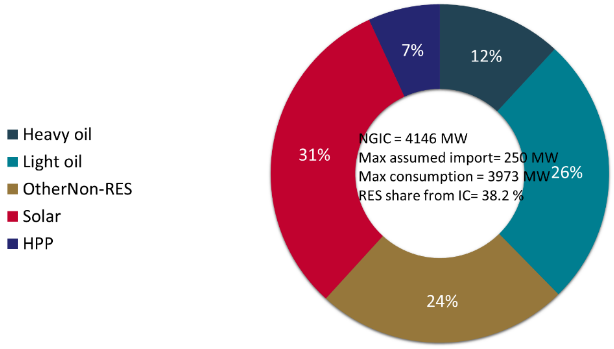


Figure 22 Installed Capacity mix with total NGC, import NTC and peak demand in Lebanon.

The average daily available TPP capacity, after reduction due to forced outages, is shown Figure 23. Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated modes of operation.

It should be noted that the total NGC in Lebanon is lower than the maximum expected hourly demand, which points to a challenging system operation and dependence on import. The average daily available TPP capacity among all simulated MC years is only around 2,500 MW.

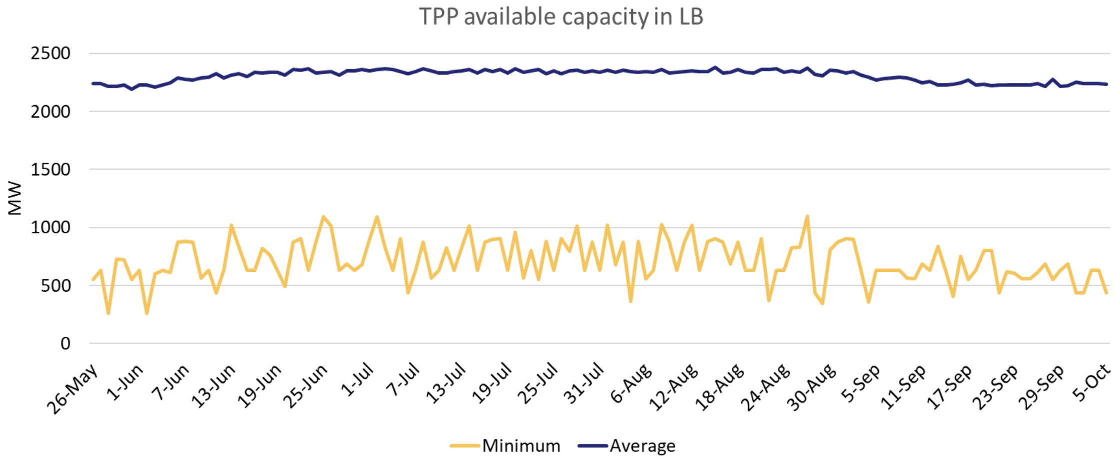


Figure 23 Average and minimum TPP available capacity among all simulated MC years in Lebanon.

As a result of system simulation, the minimum hourly TPP capacity margin among all simulated MC years is depicted in Figure 24. It represents the difference between available and engaged TPP capacities. No margin exists in Lebanon's power system.

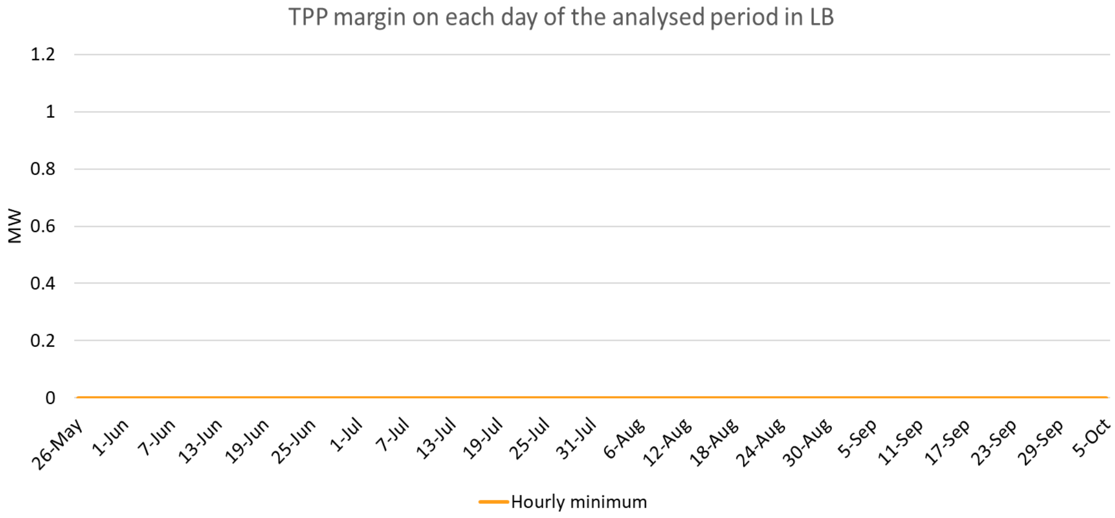


Figure 24 Minimum hourly TPP margin on each day of the analysed period among all simulated MC years in Lebanon.

Adequacy Assessment

The temporal distribution of detected adequacy risk is shown in Figure 25 for both modes of operation: hypothetically interconnected and isolated. The first picture depicts daily LOLE distribution, while the second depicts daily EENS.

The initial conclusion is that the operation of this power system is not comparable with any other in this region. The number of hours with difficulties in supplying the load is so high that load shedding is an anticipated, pre-planned everyday action. Results of the simulations point to the fact that LOLE and EENS are consistently above acceptable values even in the hypothetical interconnected mode of operation: EENS is 1.5 TWh and LOLE is 2,057 hours (around 64% during the summer season of 3,192 hours). There are climatic years without adequacy issues, but there is no day without adequacy issues in all 684 analysed MC years. Looking at the whole season, even in the best-case scenario, there are adequacy issues on a daily basis: LOLE Min=9 hours and LOLE Max=19 hours in the average of 684 MC years

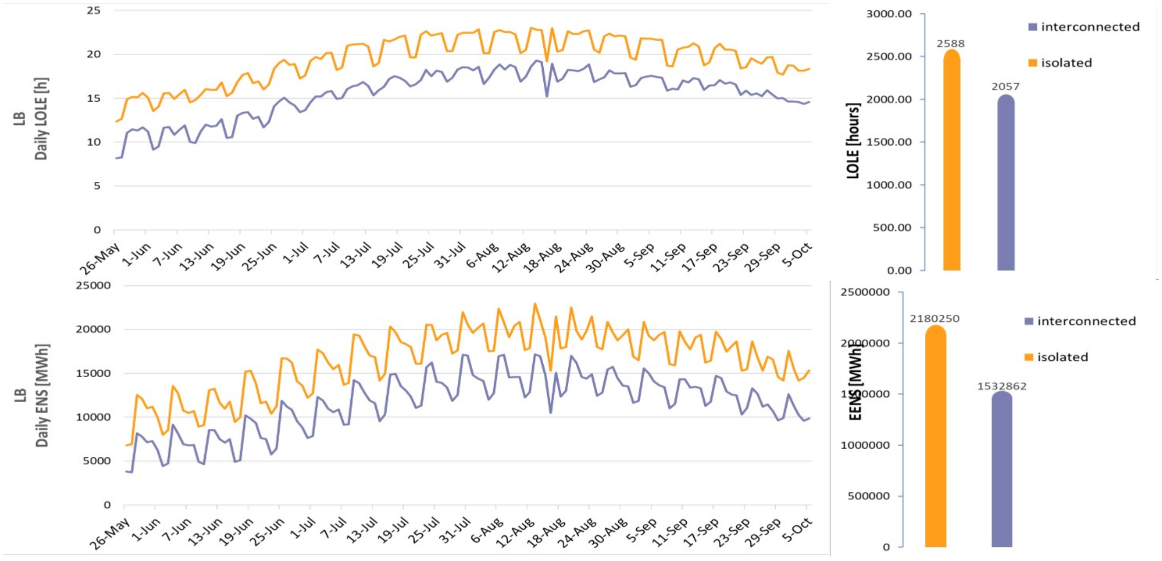


Figure 25 Daily LOLE and EENS for the interconnected and isolated operational modes in Lebanon.

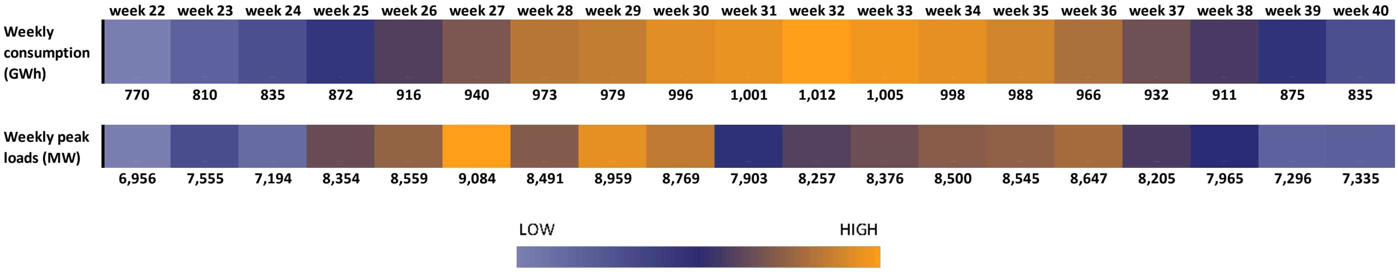
In the case of the isolated operating mode, LOLE and EENS are even higher. Hypothetical Interconnection with Jordan eases but cannot solve all adequacy issues.

5.4 Libya

Demand

Libya’s seasonal weekly demand in summer, depicted in Figure 26, ranges from around 770 GWh to 1 TWh, while peak hourly demand each week ranges from 6,950 MW to 9,000 MW. This variation of the peak load is almost 23%, which is relatively high. It should be noted that weekly demand refers to the average values of all 38 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analysed climatic years.

Maximum electricity needs are expected in August (week 32).



	week 22	week 23	week 24	week 25	week 26	week 27	week 28	week 29	week 30	week 31	week 32	week 33	week 34	week 35	week 36	week 37	week 38	week 39	week 40
Weekly consumption (GWh)	770	810	835	872	916	940	973	979	996	1,001	1,012	1,005	998	988	966	932	911	875	835
Weekly peak loads (MW)	6,956	7,555	7,194	8,354	8,559	9,084	8,491	8,959	8,769	7,903	8,257	8,376	8,500	8,545	8,647	8,205	7,965	7,296	7,335

Figure 26 Seasonal weekly demand in Libya.

Supply and network overview

Libya’s generation portfolio relies almost exclusively on gas-fired power plants, which make up 99% of the total generation capacity mix. The majority of installed thermal capacities encompass gas turbines (62%) and light oil (28%), while only 10% comes from heavy oil. It should be emphasised that according to data provided for the summer outlook 2025 we consider 50 MW of rooftop solar capacities installed in Libya. Total net generation installed capacities (NGIC) (Including RES) amount to 10,575 MW with an import capacity of up to 430 MW from Tunisia and Egypt. Combined, this is higher than the maximum hourly consumption of 9,084 MW.

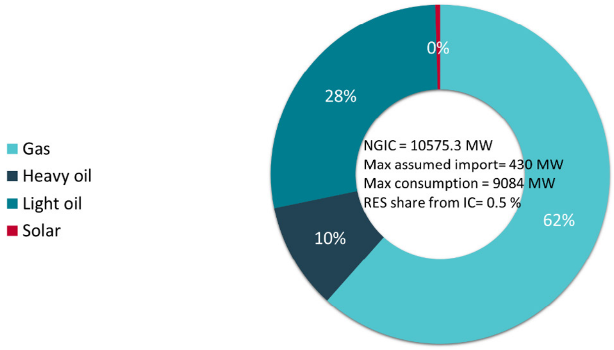


Figure 27 Installed Capacity mix with total NGC, import NTC and peak demand in Libya.

The average daily available TPP capacity, after reduction due to forced outages, is shown in Figure

28. Each daily value represents the average of all simulated MC years. These values are the same for the interconnected and isolated modes of operation. Libya's average available thermal capacity is stable at the level of 9,700 MW. The minimal daily available TPP capacity among all analysed MC years ranges from 6,500 MW to 8,200 MW.

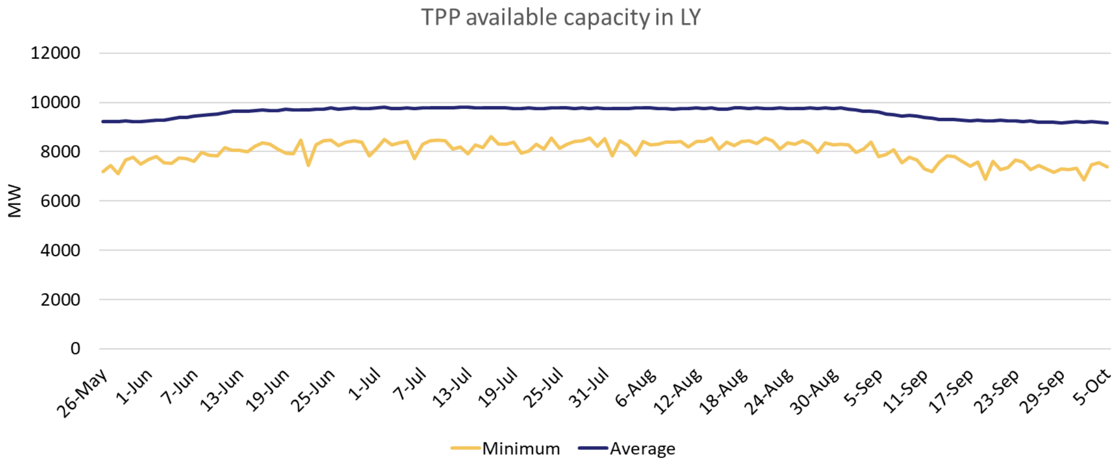


Figure 28 Average and minimum TPP available capacity among all simulated MC years in Libya.

As a result of system simulation, the minimum hourly TPP margin among all simulated MC years for each day is depicted in Figure 29. It represents the difference between available and activated TPP capacities. The minimum hourly value of the TPP margin on certain days is zero. The remaining days fall within a non/zero minimum daily margin, which are noted at the beginning and end of the summer season.

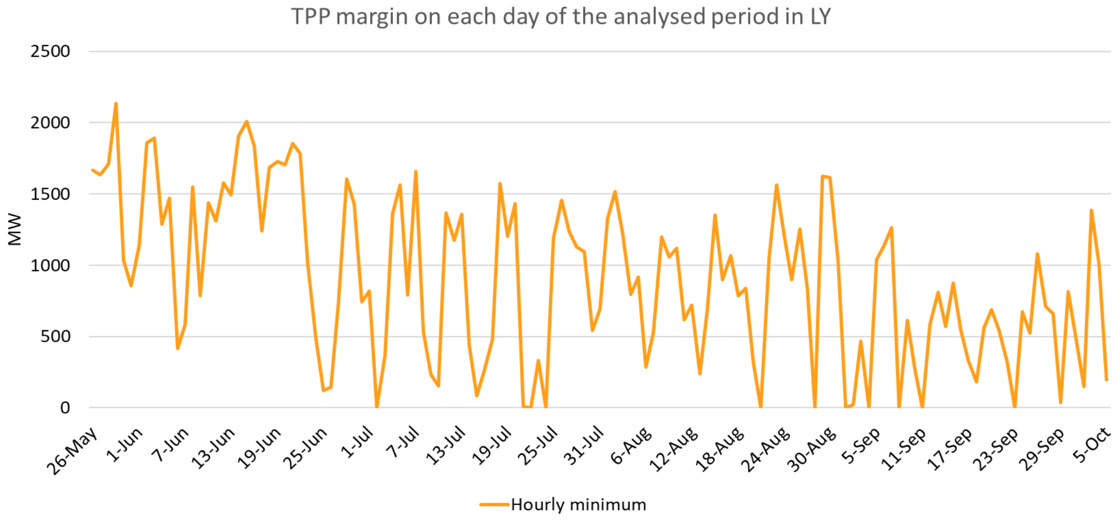


Figure 29 Minimum hourly TPP margin on each day of the analysed period among all simulated MC years in Libya.

Adequacy Assessment

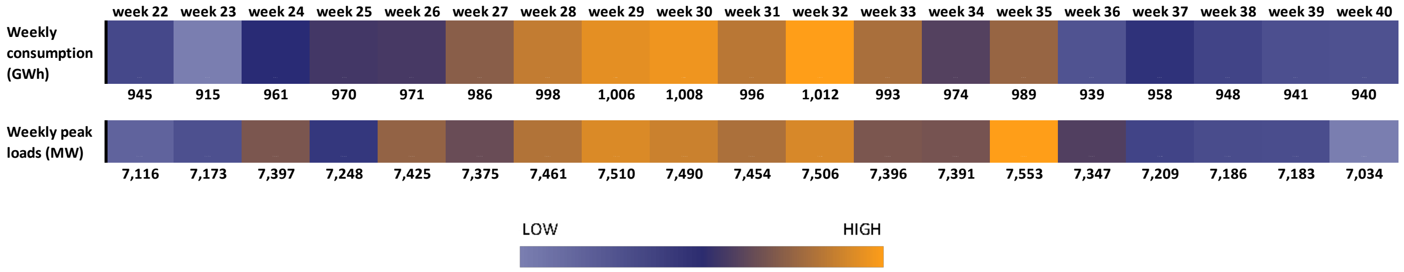
No adequacy concerns are detected for either analysed operational mode in the case of Libya.

5.5 Morocco

Demand

Moroccan summer seasonal weekly demand, depicted in Figure 30, ranges from around 915 GWh to 1 TWh, while peak hourly demand each week ranges from 7,000 MW to 7,500 MW. It should be noted that weekly demand refers to the average values of all 38 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analysed climatic years.

Maximum electricity needs are expected in July and August.



	week 22	week 23	week 24	week 25	week 26	week 27	week 28	week 29	week 30	week 31	week 32	week 33	week 34	week 35	week 36	week 37	week 38	week 39	week 40
Weekly consumption (GWh)	945	915	961	970	971	986	998	1,006	1,008	996	1,012	993	974	989	939	958	948	941	940
Weekly peak loads (MW)	7,116	7,173	7,397	7,248	7,425	7,375	7,461	7,510	7,490	7,454	7,506	7,396	7,391	7,553	7,347	7,209	7,186	7,183	7,034

Figure 30 Seasonal Weekly demand in Morocco.

Supply and network overview

The Moroccan power generation fleet is balanced and well-diversified in comparison with other analysed countries, with the TPP share in total installed capacities at around 61%, which is divided further into coal, gas and oil TPPs. Hydro capacities amount to 10%, while RES wind and solar share in installed capacities are 19% and 9%, respectively. Total net generation installed capacities (NGIC) (Including RES & hydro) reach 11,322 MW, with a total import capacity of up to 900 MW. Combined, this is higher than the maximum hourly consumption of 7,553 MW.

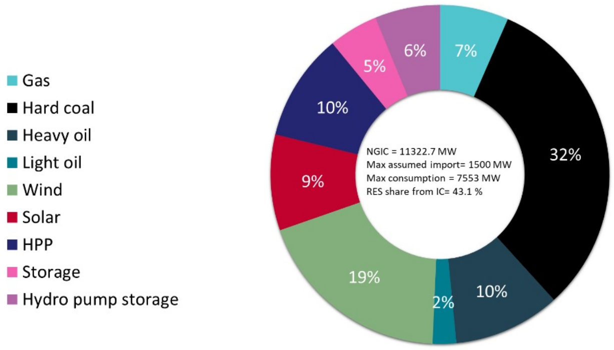


Figure 31 Installed capacity mix with total NGIC, max assumed import NTC, and peak demand in Morocco.

The average daily available TPP capacity, after reduction due to forced outages, is shown Figure 32. Each daily value represents the average of all simulated MC years. These values are the same for the interconnected and isolated operational modes. The Moroccan average available TPP capacities among all simulated MC years level is stable, at around 6,000 MW. The minimal average daily available TPP capacity (minimum among all simulated MC years) ranges from 3,700 MW to 5,000 MW.

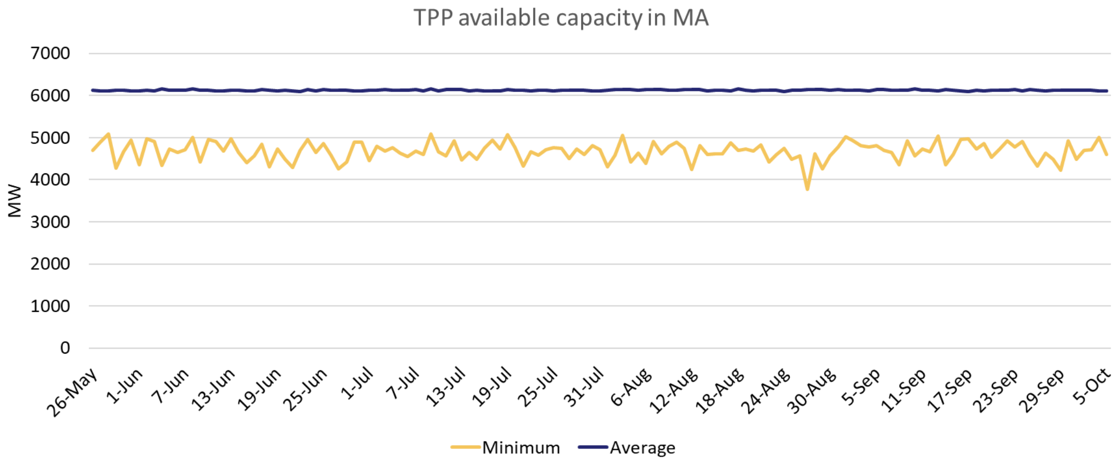


Figure 32 Average and minimum TPP available capacity among all simulated MC years in Morocco.

As a result of system simulation, the minimum hourly TPP capacity margin among all simulated MC years on each day is depicted in Figure 33 It represents the difference between available and engaged TPP capacities. The minimum hourly value of the TPP margin is often at zero throughout the summer season. These results point to the possibility that during certain hours adequacy might be endangered, however, with the support of interconnections, the system remains stable. Notably, the daily margin follows daily consumption patterns, and it is the lowest during working days, due to higher demand.

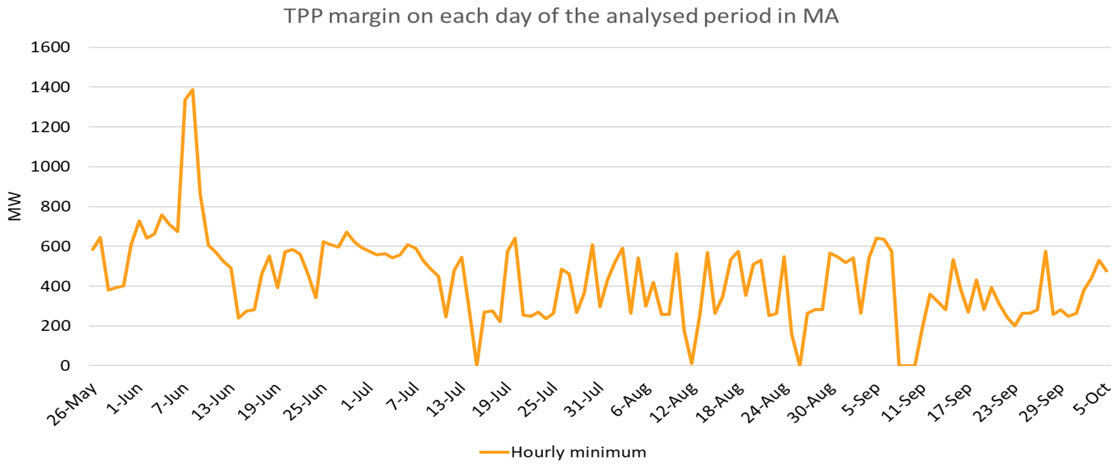


Figure 33 Minimum hourly TPP margin on each day of the analysed period in Morocco.

Adequacy Assessment

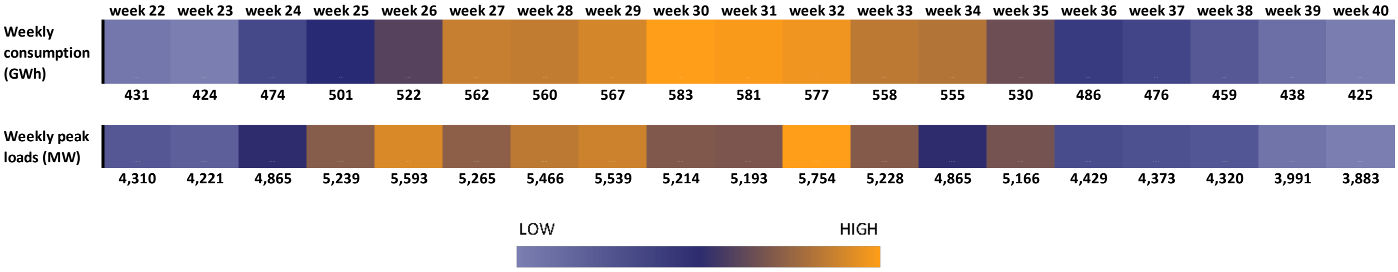
No adequacy concerns are detected for either analysed operational mode in the case of Morocco.

5.6 Tunisia

Demand

Tunisian seasonal weekly demand, depicted in Figure 34, ranges between 425 GWh and 581 GWh, while peak hourly demand ranges from 4,220 MW to 5,750 MW each week. It should be noted that weekly demand refers to the average values of all 38 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analysed climatic years.

Maximum electricity needs are expected during the whole of July and August.



	week 22	week 23	week 24	week 25	week 26	week 27	week 28	week 29	week 30	week 31	week 32	week 33	week 34	week 35	week 36	week 37	week 38	week 39	week 40
Weekly consumption (GWh)	431	424	474	501	522	562	560	567	583	581	577	558	555	530	486	476	459	438	425
Weekly peak loads (MW)	4,310	4,221	4,865	5,239	5,593	5,265	5,466	5,539	5,214	5,193	5,754	5,228	4,865	5,166	4,429	4,373	4,320	3,991	3,883

Figure 34 Seasonal weekly demand in Tunisia.

Supply and network overview

Tunisian power generation is almost exclusively gas-fired, with the share in total installed capacities at around 89%, further divided into conventional, CCGT and OCGT TPPs. RES, i.e., wind and solar share in installed capacities, is only around 11%. Total net generation installed capacities (NGIC) (including RES) amount to 5,853 MW with an import capacity of up to 800 MW, while maximum hourly consumption is around 5,754 MW.

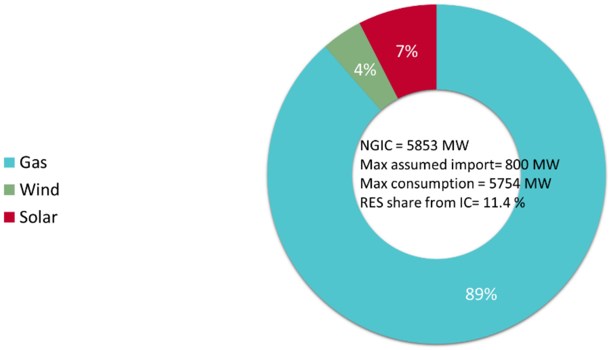


Figure 35 Installed capacity mix with total NGIC, max assumed import NTC, and peak demand in Tunisia.

The average daily available TPP capacity, after reduction due to forced outages, is shown in Figure 36. Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated operational modes. The average available thermal capacity, across all 684 MC years, is approximately 5,000 MW. However, the minimum average daily available thermal capacity (the lowest value among all 684 MC years for each day) is lower, with a minimum of 3,500 MW.

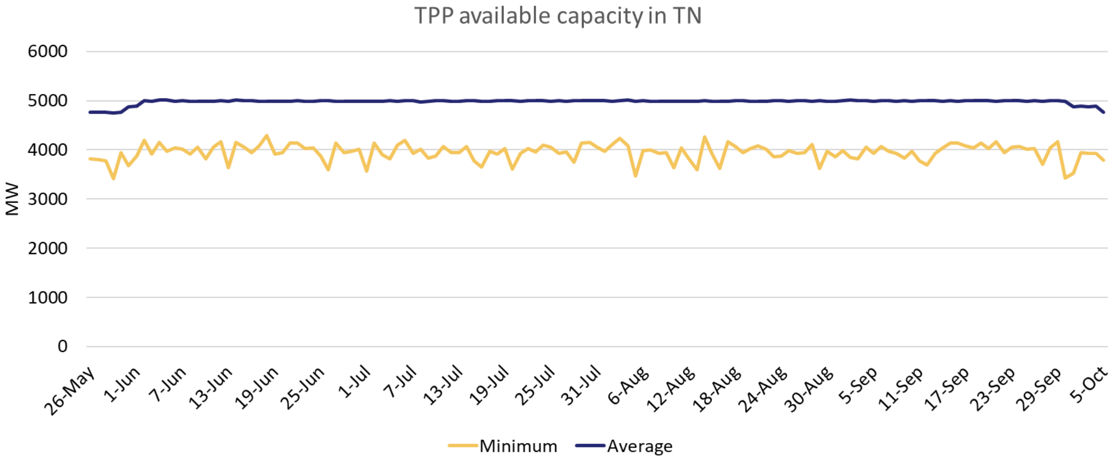


Figure 36 Average and minimum TPP available capacity among all simulated MC years in Tunisia.

As a result of system simulation, the minimum hourly TPP capacity margin on each day is depicted in Figure 37. It represents the difference between available and activated TPP capacities.. We can observe that the minimum hourly margin is at zero throughout July and August, which represents the period in which the majority of adequacy issues in Tunisia can be expected.

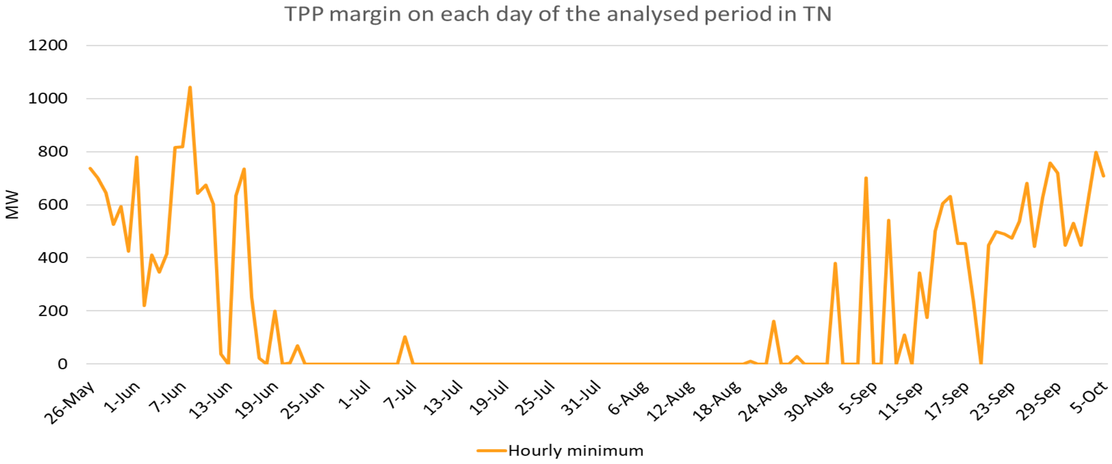


Figure 37 Minimum hourly TPP margin on each day of the analysed period in Tunisia.

Adequacy Assessment

The temporal distribution of detected adequacy risk is shown in Figure 38 for both the interconnected and isolated operational modes. The first image depicts the daily LOLE distribution, while the second depicts daily EENS.

The initial conclusion is that until 1 July no adequacy issues are expected, due to higher TPP availability and lower demand. From 1 July through to the beginning of September adequacy issues are detected almost every day, albeit at a low level. For the interconnected operational mode, daily LOLE varies from 0 to 3 hours, while daily EENS ranges from 0 to 450 MWh. These anticipated adequacy issues during summer are due to multiple reasons: high seasonal demand and the lowest TPP availability caused by outages and derating. From 1 September onwards, the adequacy risk falls practically to zero, due to demand being lower again.

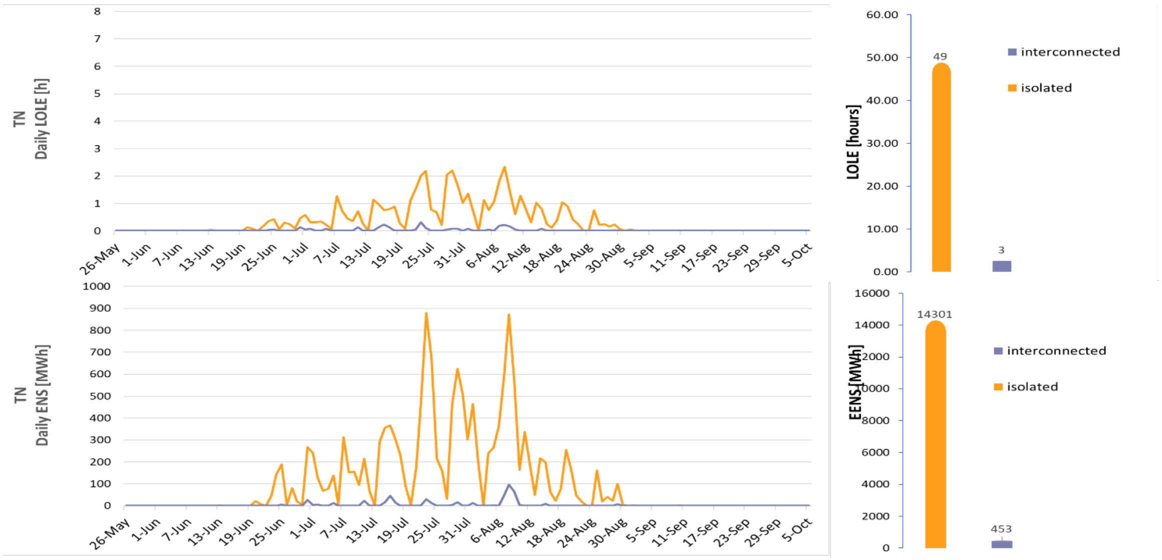


Figure 38 Daily LOLE and EENS for the interconnected and isolated operational modes.

6 Appendix

Approach and Methodology

6.1 Adequacy assessment methodology

This report presents the seasonal adequacy situation among non-EU Med-TSO members. With this assessment, Med-TSO is aligning with global best practices and with the latest development in EU regulations[7].

These investigations consider the security of electricity supply to consumers through a detailed power system adequacy assessment, using probabilistic criteria. This approach is inevitable due to the stochastic nature of renewable energy systems (RES), their intermittency, and the power system operation based on open electricity market conditions, which raise the question of power system adequacy in the short-, mid- and long-term. Moreover, the integration of immense amounts of RES must be closely followed by the commissioning of devices that can provide adequate power system flexibility.

With all the changes in the electricity sector in Mediterranean countries, from the energy markets development, integration of renewable energy sources and efforts to decarbonise energy systems, adequacy monitoring becomes even more important.

The analyses have been carried out with the Antares-Simulator v8.6, considering the following aspects:

- The Antares–simulator (A New Tool for Adequacy Reporting of Electric Systems), developed by the French TSO RTE, was specifically designed and created to tackle generation adequacy assessments in a probabilistic manner.
- The Antares–simulator is well recognised and used by ENTSO-E for TYNDP and adequacy assessments. For example, the 2020 edition of the Mid-Term Adequacy Forecast (MAF) was conducted using Antares.
- The Antares–simulator was already used by Med-TSO in the Mediterranean Masterplan 2022.
- Antares is an Open-Source software, and therefore accessible to all Med-TSO members.

Within this seasonal assessment, short-term risks that might occur in the following four months, and that are likely to result in a significant deterioration of the electricity supply situation, are analysed.

The data collection process has been carried out by our members, and it includes the capture of all relevant data and information necessary to model the power systems of Med-TSO countries. As a general approach, a probabilistic Monte Carlo with Unit Commitment and Economic Dispatch (UCED) model has been used, ensuring interzonal and intertemporal correlation of model variables, and considering the specificities of the assessed geographical perimeter. The hourly resolution has been implemented in the model and the Monte Carlo approach has been used to reflect the variability of weather, as well as the randomness of supply and transmission outages. A number of Monte Carlo (MC) years are constructed to assess adequacy risks under various conditions for the analysed timeframe. For all these MC years, hourly calculations are performed for the whole

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[7] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=en

geographical scope.

Figure 39 Probabilistic modelling general approach (source: ENTSO-E).

6.2 Adequacy indicators and other results of adequacy assessment

The seasonal adequacy assessment has been based on the following main indicators:

- **P95/P50 loss of load duration (P95/P50 LOLD).** While LOLD in a given geographical zone for a given period is the number of hours during which the zone experiences ENS during a single Monte Carlo sample/simulation year, P95/P50 LOLD are LOLD in more or less severe operational conditions.
  - P95: LOLD that happens once in 20 years.
  - P50:LOLD that happens once in 2 years.

1. **Loss of Load Expectation (LOLE)** in a given geographical zone for a given period is the expected (average) number of hours per year when there is a lack of resources to cover the demand needs, within a sufficient transmission grid operational security limit. A more detailed presentation of the relations between average, P50, and P95 values is found in the following diagram.

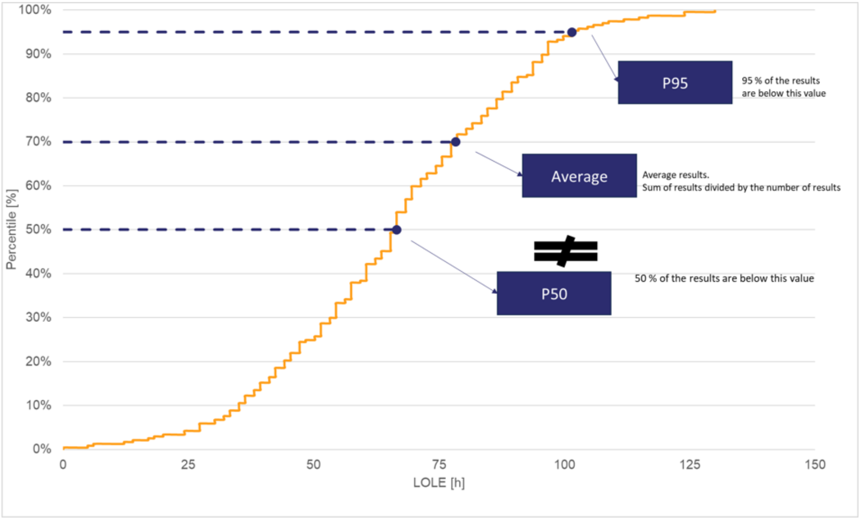

Figure 40 Illustrative example of the relation between average, P50, and P95 values.

- **P95/P50 Energy Not Serve (P95/P50 ENS).** While ENS in a given geographical zone for a given period is the energy that is not supplied during a single Monte Carlo sample/simulation year due to the demand in the zone exceeding the combination of available resource capacity and electricity imports, P95/P50 ENS are ENS in more or less severe operational conditions.
  - P95: ENS that happens once in 20 years.
  - P50: ENS that happens once in 2 years.
- **Expected Energy Not Served (EENS)** in a given geographical zone for a given period, is the expected (average) value of energy not to be supplied due to a lack of resources, while complying with transmission grid operational security limits.
- **Relative EENS:** is a more suitable indicator to compare adequacy across geographical scope as it represents the percentage of annual demand which is expected to be not supplied.
- **Dump Energy:** or RES curtailment, in a given geographical zone for a given period, is the energy generated in excess that cannot be balanced, for instance when the load is low and the in-feed from renewables is high.
- **The Capacity Margin** for a given geographical zone for a given point in time is the difference between the available and engaged TPP capacity, as presented in the following diagram. These values point to the excess capacity in the system.

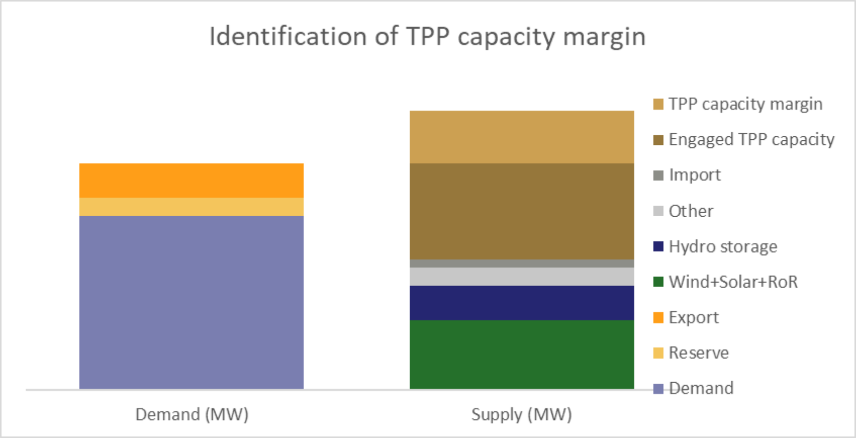

Figure 41 Illustrative example of TPP capacity margin identification.

Presentation of the adequacy indicators also includes the following:

1. The seasonal spatial screening gives a general indication of the adequacy risks for the coming season in the Med-TSO region. A relative EENS indicator is used, as illustrated in Figure 42.
2. The temporal screening gives the indication when adequacy risks are the highest. Temporal risk screening is supported by the chart of daily LOLE and EENS at the country level, as illustrated in Figure 42. This would allow the detection of which weeks are most at risk.

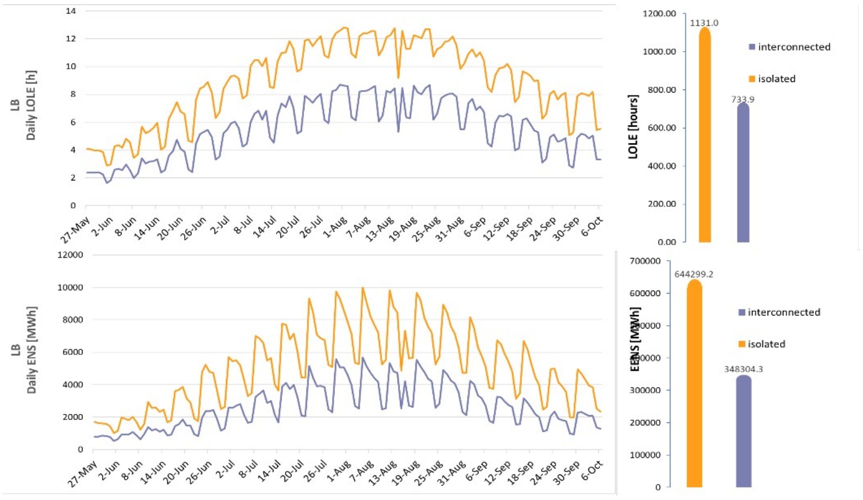

Figure 42 Illustrative example of average daily LOLE and EENS.

The available thermal capacities and thermal capacity margins are analysed and presented on both a daily and minimum hourly basis across all Monte Carlo (MC) simulation years. These analyses provide insights into periods of excess thermal capacity when no adequacy risks are present, as well as the specific weeks where adequacy risks are at a maximum.

Both the average and minimum daily values, as well as the minimum hourly values, are examined for all simulated MC years, as illustrated in the following figures. These figures offer a detailed breakdown, allowing for a clearer understanding of the trends in thermal capacity availability and the timing of adequacy risks.

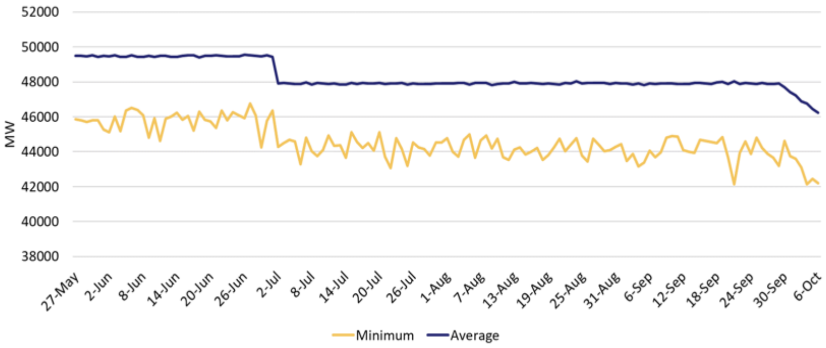

Figure 43 Illustrative example of available TPP capacity.

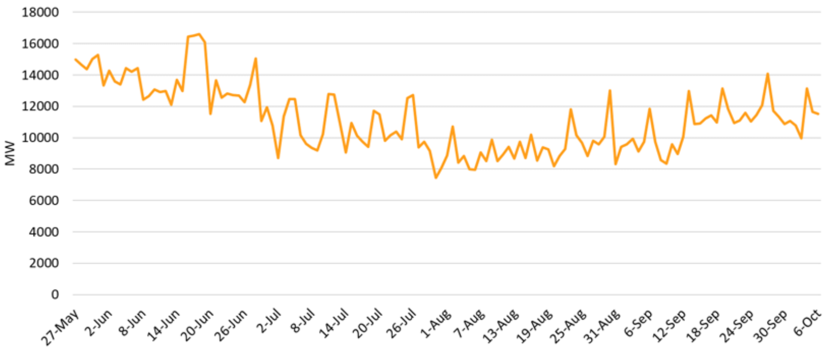

Figure 44 Minimum hourly TPP margin on each day of the analysed period.

6.3 Data collection and preparation of the database

This process included a collection of all relevant data and information necessary to model the power systems of Med-TSO countries. Where data was missing, standard values have been used and appropriate assumptions made, all based on publicly available data from relevant sources such as national network development plans and annual reports, Med-TSO publications[8], TYNDP 2020/2022, ERAA 2021, and any other relevant documents from the ENTSO-E website.

As an additional quality assurance, all provided data have been analysed and sanity checks conducted. In the case of suspicious data (i.e., technical data significantly deviating from relevant sources and literature), we discussed them with our members and updates/confirmations were provided.

Relevant data have been collected via standardised forms, designated for the compilation of data for different generation technologies, interconnections, and demand. The set of forms (PEMMDB V 3.5 Excel files) presents a database that will be regularly updated for each seasonal and mid-term adequacy assessment. Within the data collection, particular attention has been paid to the following parameters:

1. Hourly demand per each market area/country

Hourly demand data for each market area (country) that is modelled has been provided by our members. These time series refer to different climatic conditions (mainly for the period 1982-2019 or similar, depending on the country). Demand data includes losses in the transmission network but does not include the self-consumption of generating units.

Data about market-based demand-side responses are not provided and are not modelled.

Additional demand during the charging of storage units has been obtained as the result of the simulations.

2. Supply

Supply data includes the best estimates of available supply resources considering planned and unplanned outages. Supply resources are all available generation and storage units in the assessed Med-TSO systems, which are modelled at a unit-by-unit level. For some countries,

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[8] https://med-tso.org/en/adequacystudies/

schedules for the maintenance of thermal units have been provided by our members and these have been modelled as predetermined planned outages for corresponding units. Any additional maintenance activities have not been considered.

When this information is not provided, planned outages are modelled for all units as random with a specified duration and period of occurrence. Unplanned outages are not known of in advance and to incorporate them, many random drawings are made, assuming standard rates of forced outage of generation assets.

Supply-side technical constraints are also considered. These constraints include minimum and maximum generating capacities, possible capacity reduction, seasonal loss of efficiency, must-run obligation, reduced capacity due to the provision of FCR, etc.

Non-dispatchable weather-dependent generation (wind, solar or other renewable generation) is modelled by direct application of the time series. These time series are based on PECD version 3 but take into account the technologies used and zone splitting of each country.

Hydro generation is modelled using provided generation data, reservoir size and other relevant information, where available. Storage units are defined in terms of net discharge capacity, net charging capacity, storage capacity and cycle efficiency rate.

Reserve requirement values have been provided by our members and the provision of the reserve is modelled by combining the reduction of available thermal capacity (usually due to the provision of FCR) and the increase in demand for the required balancing reserve (FRR or FCR+FRR). A difference between these two ways of reserve modelling lies in the fact that in the first type of reserve modelling, no energy requirements are involved and only a certain level of the capacity in TPPs is kept aside (and not engaged to cover the load). This does not generate any distortions in system operation results, but there may be some hours during the year in which full balancing requirements are not satisfied due to outages of TPPs (planned or forced).

In the second one, reserve capacity requirements (MW) are followed by energy requirements (MWh) which then make a distortion to all market or economic indicators (exchanges, price,... etc,) calculated within the simulations. Due to artificial energy requirements in this case, this way of reserve modelling is not applicable for the systems with a large participation of hydropower plants.

Considering the structure of analysed power systems (practically no hydro generation), balancing reserve has been modelled as a negative balance (Export) with a fictitious node called rest of world (ROW) in all countries, bearing in mind that this approach is stricter and conservative in providing adequacy results that are on the safe side. Only in cases when a TSO provided capacity reduction at TPPs due to FCR provision, has the given reduction been applied (and only FRR requirements have been modelled as negative balance with ROW).

Considering the above-mentioned criteria, the data provided mainly included the following information:

- Installed capacities per technology.
- Technical characteristics of generating units, such as Pmin, Pmax.
- Expected maintenance schedule or other information for some countries.
- Must run obligations.
- Derating obligations.
- Expected generation for HPPs.
- Net discharge capacity, net charging capacity, storage capacity and cycle efficiency rate for storage units.
- Hourly wind and solar generation for several climatic years
- Reserve requirements.

3. Grid

Countries are modelled as copper plates, coupled via interconnectors described by NTCs values, provided by our members. Since NTC values related to HVAC interconnections already take into account n-1 security constraints, no additional outages are applied to them. In the case of HVDC interconnections, forced random outages are applied with a rate of 6% and an outage duration of one day (similar to what was applied in ERAA2021 by ENTSO-E).

Considering that the interconnection grid can play a key role in the country's security of supply and to assess that influence, two separate scenarios have been simulated:

- **Interconnected operation of the analysed countries.**
- **Isolated operation of the analysed countries.**

6.4 Number of MC years and results' convergence

MC years have been constructed by combining climate-dependent variables (wind, solar and demand from 38 climatic years), available hydro time series and given/random outages. Since hydro data are not available for the same climatic years as for the wind, solar and demand, available years of hydro generation have been combined with other climate-dependent data and MC combinations have been developed as follows:

- Climate years (each of 38 years from the period 1982-2019) are selected one by one.
- Each climate year is associated with random outage samples, i.e.. randomly assigned, unplanned (and planned) outage patterns for thermal units.

The developed model was thoroughly tested concerning all relevant parameters of the generation portfolios of the different power generation technologies including RES, variable weather conditions and the status of the interconnections. The sufficient number of MC years to provide consistently good convergence of the main results has been determined as 684 (38 x 18). The number of MC years that ensures good convergence of results has been defined by assessing the coefficient of variation (α) of the EENS metric and its change.

$$\propto_N = \frac{\sqrt{Var[EENS_N]}}{EENS_N}$$

Where EENSN is the expectation estimate of ENS over N, the number of Monte Carlo years, i.e., $EENS_N = \frac{\sum_{i=1}^{N} ENS_i}{N}$,

i=1…N and Var[EENSN] is the variance of the expectation estimate, i.e. Var$[EENS_N] = \frac{Var[ENS]}{N}$. The evolution of convergence criteria is presented in the following figures.

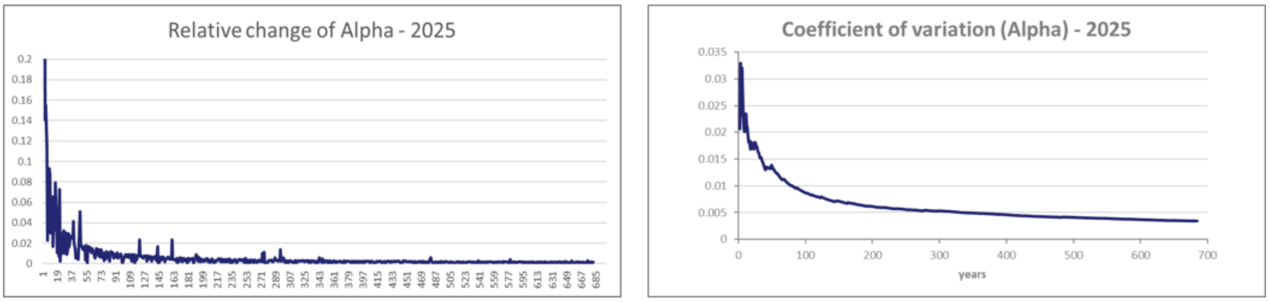

Figure 45 Evolution of convergence criteria for 684 MC years, simulations for the year 2025.

Med-TSO

TeasiMed2 project

Med-TSO is the Association of the Mediterranean Transmission System Operators (TSOs) for electricity, operating the High Voltage Transmission Networks of 20 Mediterranean Countries. It was established on 19 April 2012 in Rome as a technical platform that, using multilateral cooperation as a strategy of regional development, could facilitate the integration of the Mediterranean Power Systems and foster Security and Socio – economic Development in the Region.

Med-TSO members share the primary objective of promoting the creation of a Mediterranean energy market, ensuring its optimal functioning through the definition of common methodologies, rules and practices for optimizing the operation of the existing infrastructures and facilitating the development of new ones.

Read more about our Adequacy Studies

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