Med-TSO

TeasiMed2 project

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Winter Outlook 2025/2026

Mediterranean Adequacy Assessments

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Abbreviations

CCGT	Combine Cycle Gas Turbine
EU	European Union
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 adequacy situation among non-EU Med-TSO members for the winter 2025/2026. With this assessment, Med-TSO aligns with the world-wide best practices and the latest developments of EU regulation[1]. These investigations consider the security of electricity supply to consumers through a detailed power system adequacy assessment, using probabilistic approach.

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 run. Moreover, the integration of immense amounts of RES must be closely followed by the commissioning of devices that can provide adequate power system flexibility.

This **Winter Outlook 2025/2026 Report** provides information about potential adequacy issues during the period from 24 November 2025 to 5 April 2026 in 6 MED-TSO countries: **Morocco, Tunisia, Libya, Egypt, Jordan and Lebanon.**

Data for Algeria is missing during this assessment due to limited engagement from Algerian side and data for Israel and Palestine are not available at the moment.

The main adequacy indicators assessed are as follows:

- **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.

A key advancement in this report is the adoption of the new PECD 4.2 for the first time in Med-TSO studies, which provides a more probabilistic and realistic view of adequacy risks compared to earlier studies.

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

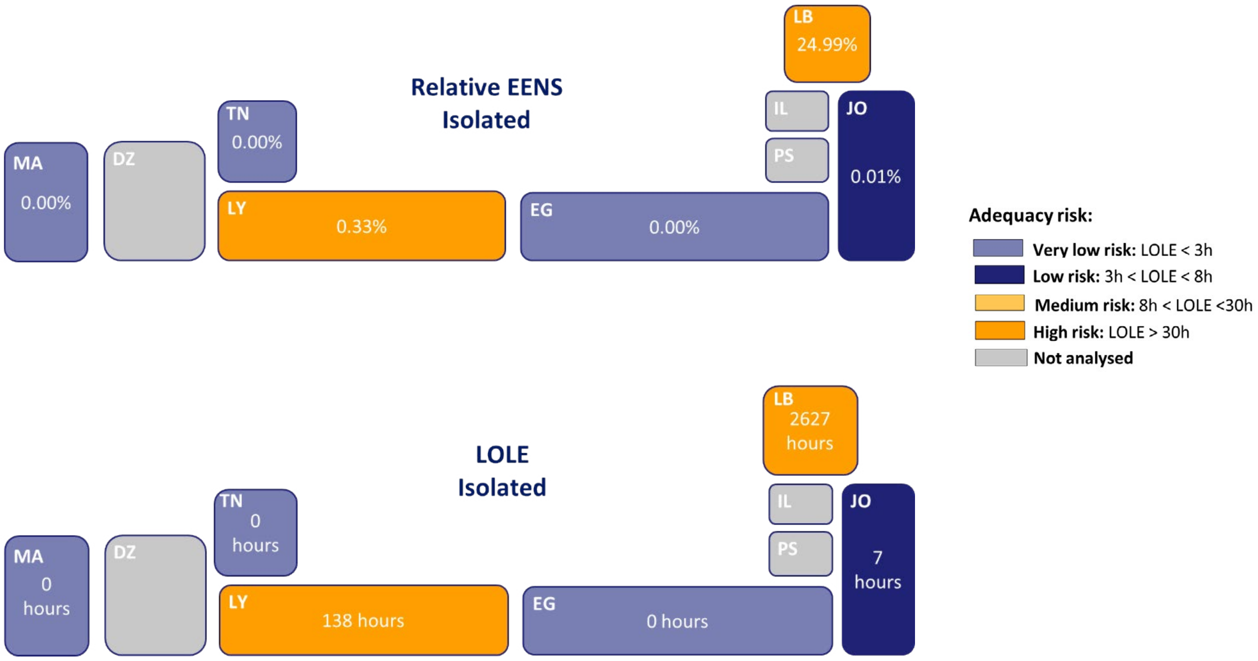


Figure 1 Relative EENS and LOLE for the isolated operational mode during normal operation WO 2025/2026

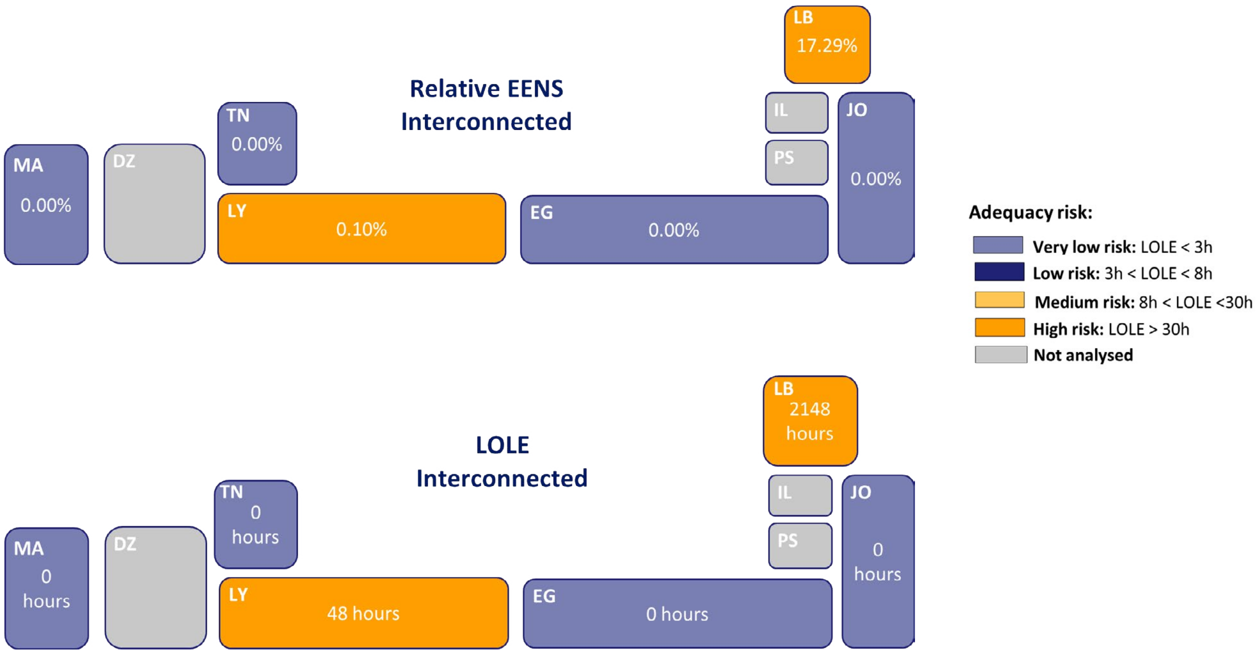


Figure 2 Seasonal relative EENS and LOLE for interconnected mode of operation during normal operation WO2025/2026.

Conclusions

The adequacy assessment of the regional power system for WO 2025/2026 highlights the significant impact of interconnection on system reliability, particularly in reducing loss-of-load risk (LOLE) and expected energy not served (EENS).

In the isolated mode (Figure 1), several countries face notable adequacy challenges:

- **Lebanon (LB)** emerges as the most critical case, with 2627 LOLE hours, indicating severe energy shortfalls and an extended duration of supply interruptions.
- **Libya (LY)** also experiences considerable adequacy difficulties, recording 138 LOLE hours, reflecting limited generation adequacy and dependence on constrained system conditions.
- **Jordan (JO)** shows 7 LOLE hours, suggesting a relatively low adequacy risk.
- Other countries—including **Morocco (MA)**, **Tunisia (TN)**, and **Egypt (EG)**, reflecting very low adequacy risk under isolated operation.

In the interconnected mode (Figure 2), the situation improves substantially.

- **Lebanon (LB)** still faces a high adequacy risk, with 2148 LOLE hours, but this represents a notable improvement compared to isolated conditions.
- **Libya (LY)** shows 48 LOLE hours, indicating that interconnection significantly enhances system adequacy and reduces potential shortages.
- **Jordan (JO)** highlighting very high reliability levels within the interconnected network.

Challenges in Libya

Despite the improvements noted in the previous release, the situation in Libya has deteriorated again due to renewed political instability and operational constraints. The system continues to face long-standing structural and technical difficulties that limit its reliability and resilience.

- Aging infrastructure and limited transmission capacity continue to hinder the full utilization of interconnection benefits.
- The dependency on imports from neighboring systems remains essential to sustain adequacy during peak or stressful conditions.

Ensuring lasting improvement requires rehabilitation of the domestic grid, reinforcement of interconnections, and stabilization of fuel and gas supplies through better coordination between the power and gas sectors.

The earlier assessment assumed stable political and operational conditions, but recent developments have shown that such stability cannot be guaranteed, reversing some of the previous gains.

Challenges in Lebanon

The adequacy situation in Lebanon remains highly critical, although interconnection scenarios indicate the potential for partial improvement. Even under the hypothesis of full interconnection and full generation availability, the overall risk would remain elevated.

- High LOLE values persist due to insufficient generation capacity in the power system.

- Fuel and gas shortages, alongside frequent outages and aging assets, continue to constrain operational reliability.
- Grid limitations and restricted import capacity reduce the extent to which interconnections can mitigate supply deficits.

Significant enhancement of domestic generation, fuel availability, and cross-border transmission capacity would be required to achieve a sustainable adequacy improvement.

While interconnection could alleviate part of the adequacy risk, it alone cannot fully resolve Lebanon's structural energy challenges without addressing the underlying supply and fuel issues.

2. What's New in This Release

PECD 4.2

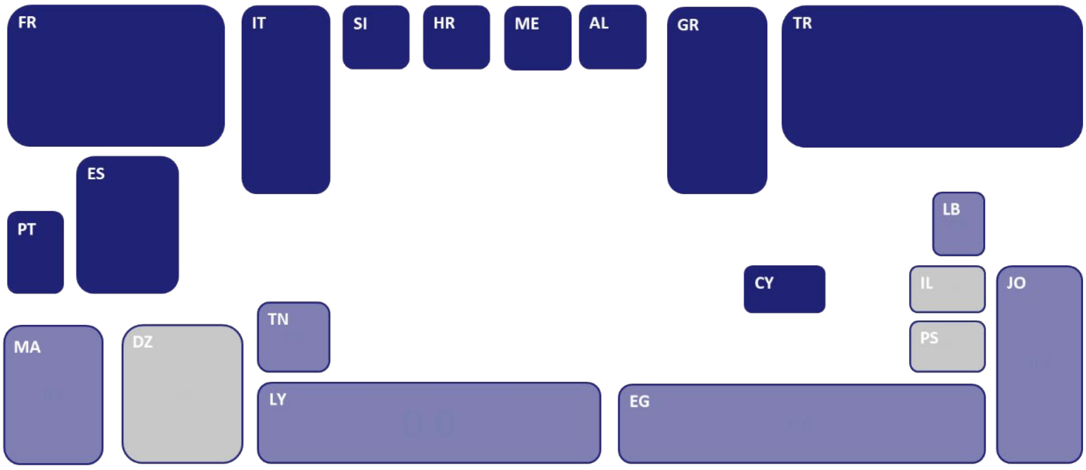
In previous editions of our adequacy assessment, we relied on PECD 3.5, which was based on adjusted historical weather and climate data. While useful, this approach was limited in its ability to capture renewable energy behavior under evolving climate conditions, as the coverage of future climate projections was restricted.

Thanks to the cooperation agreement between Med-TSO and ENTSO-E, we gained early access to the newly released PECD v4.2 (2025). This updated dataset includes both long-term historical records (from 1950 onwards) and forward-looking climate projections based on four Shared Socioeconomic Pathways (SSPs) and six CMIP6 climate models, covering the period 2015–2100. Developed by the Copernicus Climate Change Service (C3S), PECD v4.2 provides scientifically robust futures rather than relying solely on past data.

By integrating PECD v4.2, the Med-TSO Seasonal Adequacy Assessment WO 2025/2026 can now simulate electricity demand, renewable output, and cross-border flows with hourly resolution across multiple climate scenarios. This offers a much clearer picture of how extreme weather events, seasonal variability, and long-term climate shifts could impact adequacy risks. Overall, it represents a major methodological step forward and significantly strengthens the robustness of our assessment.

3. Overview of the MED-TSO Power Systems in Winter Outlook 2025/2026

This Winter outlook 2025/2026 report provides information about potential adequacy issues during WO 2025/2026 in the 5 MED-TSO members: Morocco, Tunisia, Egypt, Jordan, and Lebanon depicted in Figure 3.



Med-TSO members analyzed in this adequacy assessment

Med-TSO members not analyzed in this adequacy assessment

Med-TSO members taking part to the ENTSO-E adequacy study

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

Data for Algeria is missing during this assessment due to limited engagement from Algerian side and data for Israel and Palestine are not available at the moment.

For the Winter Outlook 2025/2026 data have been collected in September 2025.

This database will be updated in January 2026 with the latest information that will be used for the preparation of the next report – Summer Outlook 2026.

The overview is organized in alphabetical order, including submitted data, assumptions and proxies that are used to develop the corresponding market model using the Antares software tool.

All relevant parameters are presented so that the reader may check their plausibility and confirm their usability for the adequacy analyses.

A. Demand Evolution.

Table 1 presents the expected consumption per week from the 48th week in the year 2025 to week 13th in the year 2026. These values are the average weekly consumption for 36 climatic years from PECD 4.2.

Weekly consumption based on average among 36 CY (GWh)		EG	JO	LB	LY	MA	TN
Total		81705	9968	8379	16251	16595	7475
Week	48	4169	480	422	794	840	372
Week	49	4133	482	424	816	836	374
Week	50	4129	492	430	837	835	379
Week	51	4148	507	438	884	836	382
Week	52	4181	510	448	914	835	392
Week	1	4301	544	456	942	874	401
Week	2	4309	549	462	938	887	411
Week	3	4309	551	463	940	881	412
Week	4	4335	558	465	930	881	410
Week	5	4339	557	463	933	883	411
Week	6	4371	564	472	928	882	410
Week	7	4367	553	460	912	885	409
Week	8	4363	543	447	861	889	397
Week	9	4361	531	435	820	891	394
Week	10	4372	530	430	817	892	394
Week	11	4383	518	424	766	895	390
Week	12	4209	498	419	761	861	360
Week	13	4447	504	412	733	907	389
Week	14	4479	498	407	726	908	389

High Value
Low Value

Table 1 Expected consumption in the winter weeks – 2025/2026.

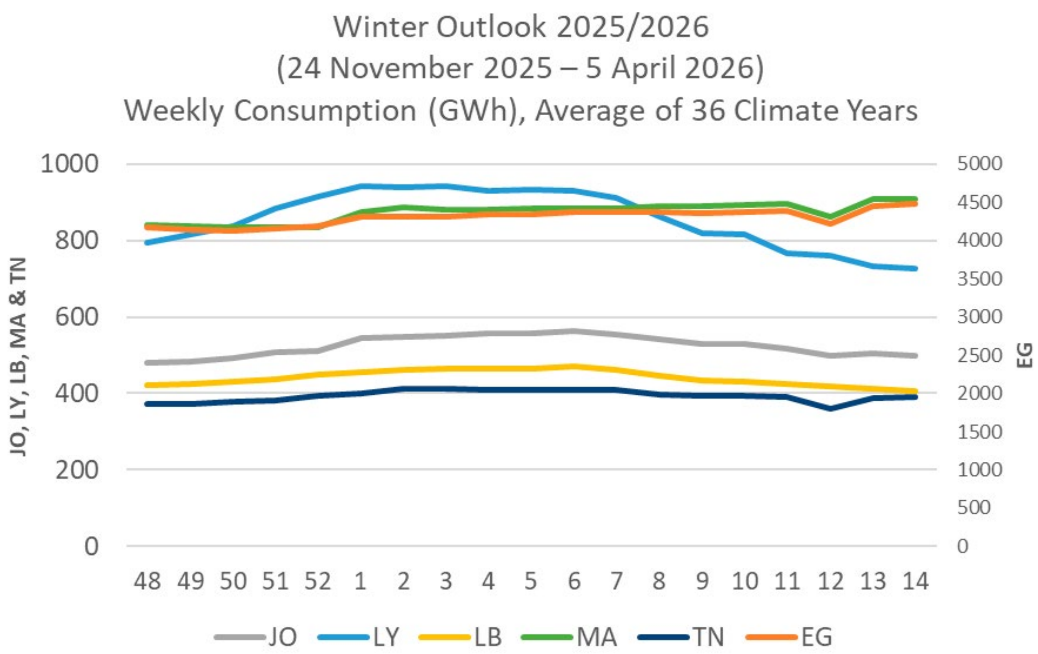


Figure 4 Expected weekly consumption per country in the analysed season.

Weekly consumption in Jordan, Lebanon and Tunisia is the lowest among the analyzed 6 countries

The highest is consumption in Egypt, almost 10 times higher. Consumption in Libya, Morocco are in between, although still with high differences among them.

It should be noted weekly consumption is rather constant during this period.

Hourly peak demand values are presented in the following table and figure. Presented values represent maximum values among peak loads for each week for all 36 climatic years.

Peak load, based on maximum among 36 CY (MW)		EG	JO	LB	LY	MA	TN
Maximum		**33611**	**5456**	**4289**	**8091**	**6911**	**3576**
Week	48	31487.75	4314.5	3361.5	6614.75	6378	3128.75
Week	49	30748.75	4316.5	3367.5	6913.5	6375	3145
Week	50	31267.5	4437.75	3584.5	6925.5	6376	3179
Week	51	31883.5	4581.5	3619.25	7920.75	6418	3314
Week	52	33404	4599.25	3752.5	7589	6388	3463.75
Week	1	32892.25	4906.5	3857.5	7743	6687	3406.5
Week	2	32728.25	5169.75	4066.5	7572	6692	3575.75
Week	3	32928	5085.75	3997.25	7620.5	6679	3550.5
Week	4	32731.5	4909.75	3787.5	7772.5	6601	3424.25
Week	5	32600	5101	4041.5	7903.75	6588	3443.75
Week	6	33403.75	5456	4289.25	8090.5	6537	3491.5
Week	7	33611	5122	4136.5	7898.25	6673	3458.25
Week	8	32758.5	5269	4221.75	7468.5	6748	3128.5
Week	9	33085.75	4991.75	3889.5	7036.5	6737	3053.5
Week	10	31770.75	4722.75	3517.25	7024.5	6716	3029.5
Week	11	31845	4700	3504	6851.75	6674	2955.5
Week	12	32027.75	4588.5	3480	6544.5	6730	3098.5
Week	13	32592.5	4600	3321.75	6213.25	6843	3081.5
Week	14	32202.5	4350.25	3113.25	6289.75	6911	3023.5

High Value
Low Value

Table 2 the 95th Percentile weekly peak loads in winter weeks 2025/2026

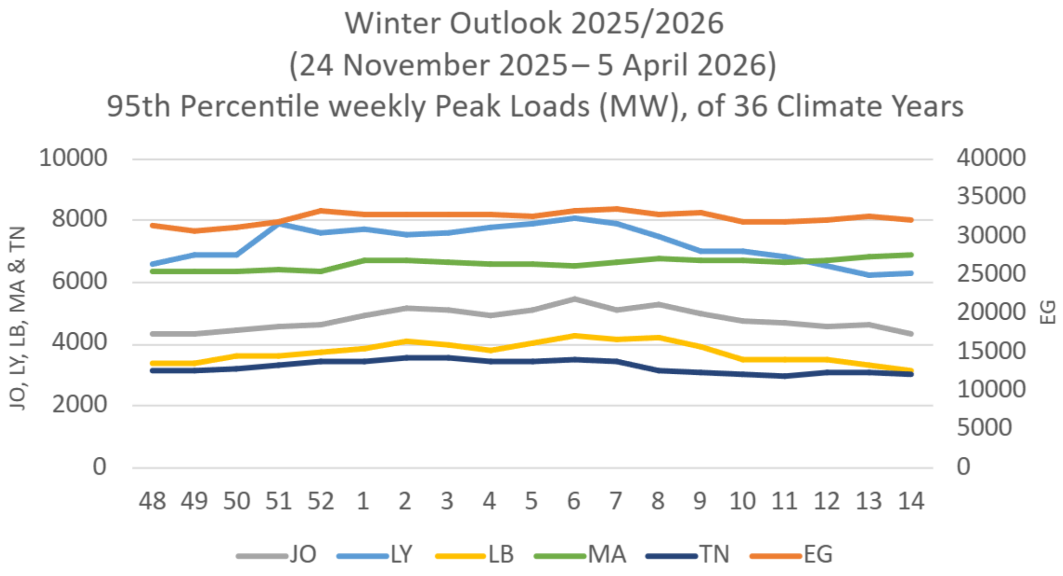


Figure 5 95th Percentile weekly Peak Loads (MW), of 36 Climate Years

In Jordan, the peak load is observed during winter, with values 10% higher than those in the summer season.

Regarding daily patterns, each country experiences seven relatively similar daily profiles, typically with one or two peaks throughout the day. In Egypt and Jordan, demand tends to be slightly lower on Fridays, while in Morocco and Tunisia, it is lower on Sundays.

B. Expected evolution of installed capacities

The following tables provide information about install capacities during winter period in 2025/2026. Total install capacities in the observed region are expected to reach 97 GW, with almost 77 GW (or around 79%) in thermal units. Compared to WO 2024/2025, changes in installed capacities are highlighted using two colors: green for increases and orange for decreases.

A major milestone is the introduction of battery storage in the region for the first time. Egypt has deployed 300 MWh battery storage with a 2-hour discharging (150 MW per hour), while in Morocco, 800 MWh of battery storage with a 2-hour duration (400 MW per hour).

The discharge of the battery 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 as an exception, where the current regional situation has severely impacted solar rooftop systems by 2%.

[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 solar PV capacity		Expected CSP capacity (with storage)		Expected CSP capacity (without storage)		Expected HPP capacity		Expected battery storage capacity		Expected hydro pump 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 (42%▲)	5%	2241 (0%▲)	4%	-	-	140 (No Change)	0%	2831 (No Change)	5%	150 (New Capacity▲)	0%	-	-	50419 (0%▼)	86%	58817
JO	621 (No Change)	8%	2332 (7%▲)	30%	-	-	-	-	-	-	-	-	-	-	4785 (0%▲)	62%	7738
LB	-	-	1470 (-2%▼)	35%	-	-	-	-	285 (No Change)	7%	-	-	-	-	2481 (-15%▼)	59%	4236
LY	-	-	50 (No Change)	1%	-	-	-	-	-	-	-	-	-	-	7790 (-28%▼)	99%	7840
MA	2410 (3%▲)	19%	523 (24%▲)	4%	540 (No Change)	4%	-	-	1306 (No Change)	11%	400 (New Capacity▲)	-	790 (No Change)	6%	6445.69 (No Change)	52%	12415
TN	229 (-5%▼)	4%	720 (109%▲)	12%	-	-	-	-	-	-	-	-	-	-	5117 (-1%▼)	84%	6066
TOTAL	6296	6%	7336	8%	540	1%	140	0%	4422	5%	550	1%	790	1%	77038	79%	97112

Table 3 Total install capacities (MW) per technology in WO 2025/2026 from week 48 in year 2025 to week 14 in year 2026

It is important to highlight that Libya's power system relies entirely on thermal power plants, making it highly vulnerable to fuel supply disruptions and operational failures. Unlike previous adequacy assessments, the recent re-evaluation of the thermal fleet has revealed a deterioration in generation reliability. The reassessment considers recent maintenance activities within the Libyan system; however, these efforts have been insufficient to offset the persistent degradation of several units. Many power plants remain out of service due to severe damage, while only a limited number of units have been partially restored. Moreover, the addition of new generation capacity has not compensated for the loss of existing units, leading to an overall decline in available capacity. Consequently, the updated assessment provides a more realistic but less favorable picture of Libya's current thermal generation capability and its impact on system adequacy.

Relevant hydro capacities exist only in Egypt and Morocco.
In Morocco, there is also a hydro pump storage (HPPS) with capacity of 790 MW generating and 784 MW pumping.

The highest wind and solar capacities participation in total generation capacities is noted in Lebanon, Jordan and Morocco where their participation reaches more than 35%. 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 also the zone splitting of each country.

	2025/2026		
Country	Wind CF	Solar PV CF	Solar CSP CF
EG	53.8%	24.7%	27.3%
JO	31.2%	27%	-
LB	-	18.6%	-
MA	51.6%	17.2%	38%
TN	23.5%	23.2%	-

Table 4 Wind and solar capacity factors for all countries during WO 2025/2026

The impact of RES generation in Egypt and Tunisia is marginal since the participation of thermal units is above 80%. Among thermal technologies, the main part is presented by gas-fired units.

Concerning thermal units, it should be noted that available capacities take into account forced outages, as well as derating factors which define the reduction in available thermal capacities due to various reasons. Planned outages are modelled according to data provided by TSOs (TN and MA) or as random outages but respecting certain predefined rules as seen in the below table:

Market Node	January	February	March	April	May	June	July	August	September	October	November	December
EG00	yes	yes	yes	yes	yes	no	no	no	no	yes	yes	yes
JO00	no	no	yes	yes	yes	yes	no	no	no	yes	yes	no
LB00	no	no	yes	yes	yes	no	no	no	no	yes	yes	no
LY00	no	yes	yes	yes	yes	no	no	no	yes	yes	yes	no
MA00	yes	yes	yes	yes	yes	no	no	no	no	yes	yes	yes
TN00	yes	yes	yes	yes	yes	no	no	no	yes	yes	yes	yes

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

- In all countries except Jordan, Lebanon and Libya planned outages are envisaged in the period from the 1st of November to 1st of April.
- In Jordan & Lebanon planned outages are not envisaged in the period from 1st of December to the 1st of March.
- In Libya planned outages are not envisaged in the period from 1st of December to the 1st of February.
- In Jordan, Morocco & Tunisia, detailed planned outages are provided and taking into consideration during the simulations

Practically, when predetermined rule is applied, period analyzed in winter outlook should not include maintenance on any of the thermal units. This is the case also in this winter outlook.

Forced outages of thermal units are in all cases and all countries modeled as random. Similarly, for thermal units, commissioning/decommissioning dates are taken into account.

C. Interconnections between countries

Summarized 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 modeled 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 modeled in the market simulator. Furthermore, in the case of borders with countries outside of the Med-TSO region, exchanges have been modeled using hourly data provided by our members. In the case of Algeria and Libya, it is assumed that the countries can export electricity to neighboring countries in the event of adequacy risk. Furthermore, it is assumed that Algeria and Libya do not face any adequacy risk.

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

A summary of the interconnection capacities and given exchanges is presented in the following Figure.

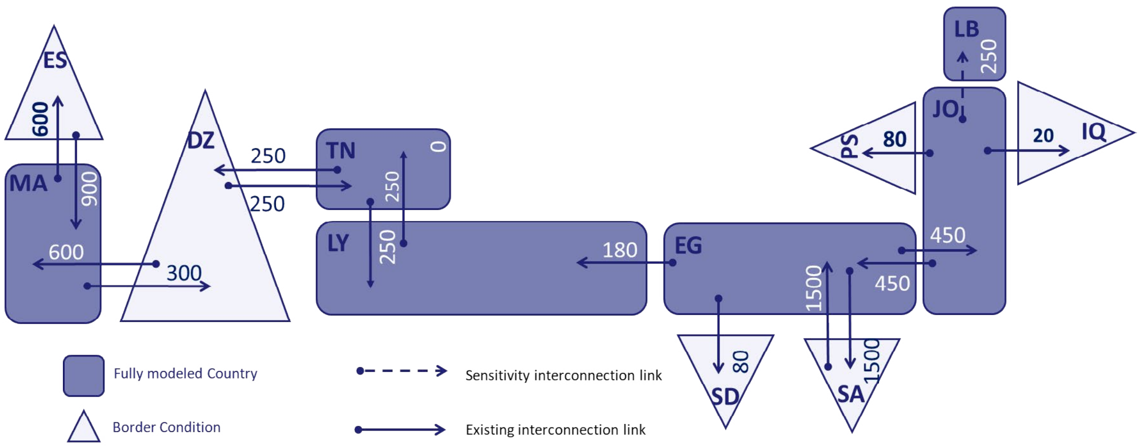


Figure 6 Net Transfer Capacity during WO 2025/2026

D. Reserve requirements and their modeling.

Reserve requirements have been provided for each country (Table 6). In some countries (LY, MA) the percentages of the capacity reduction at thermal units due to the provision of FCR 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 rest of world (ROW).

FRR requirements have been modelled as a negative balance (Export) with rest of world (ROW) 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.

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

4. Adequacy Situation Overview

4.1 Adequacy assessment

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 assessed to quantify the importance of interconnections.

In a theoretical isolated scenario (Figure 7), which focuses on the winter season, adequacy risks are identified in Jordan, Libya and Lebanon. While Jordan faces low risk, Libya and Lebanon experiences a very high adequacy risk under an isolated system operating mode.

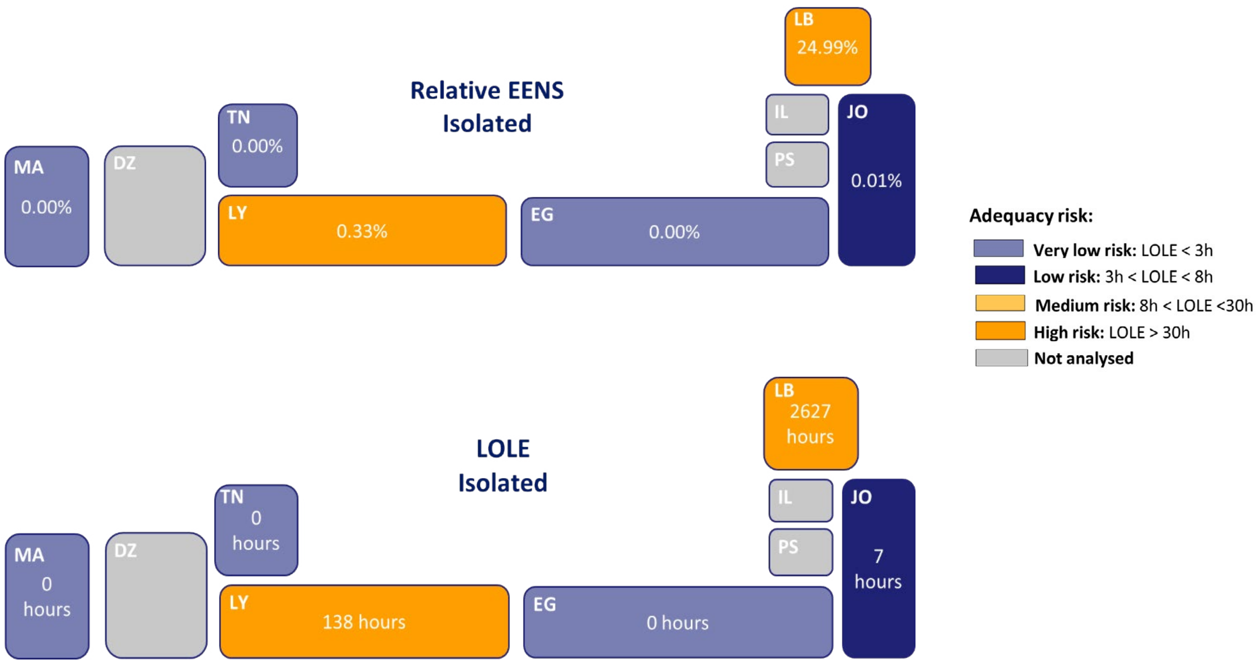


Figure 7 Seasonal Relative EENS and LOLE for the isolated mode of operation for only winter season.

In contrast, under the Interconnections scenario, energy exchanges with neighboring countries significantly reduce adequacy risks to very low risk in the case of Jordan but, in Libya and Lebanon even in this more relaxed operating mode, adequacy risks are at an unacceptable level. Figure 8 shows interconnected scenario for the winter season only.

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

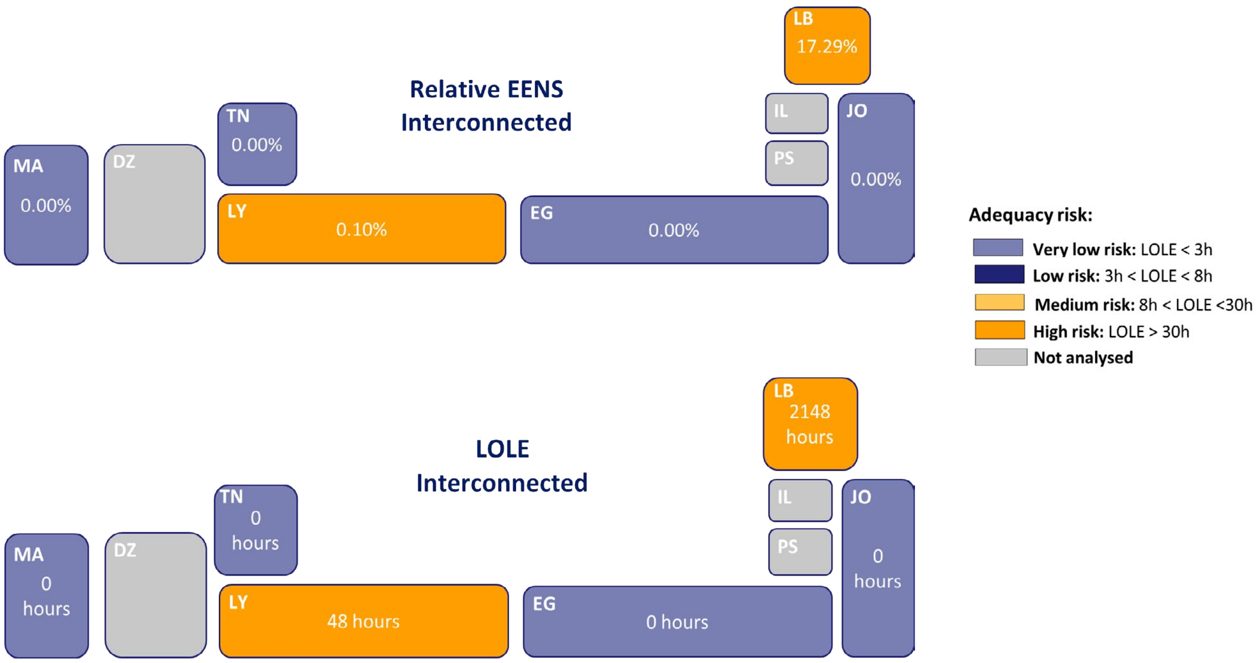


Figure 8 Seasonal relative ENS and LOLE for the interconnected mode of operation for only winter season.

In order to have insights into the distribution of adequacy risks by illustrating how likely different outcomes are across numerous simulated scenarios, we present percentiles:

- **50th Percentile (Median Outcome):**

Represents the most probable adequacy outcome. In well-balanced and resilient systems, the 50th percentile often shows low or even zero adequacy risk, indicating that, under normal operating conditions, generation capacity is sufficient to meet demand without significant shortages.

- **95th Percentile (High-Risk Outcome):**

Reflects the extreme edge of potential scenarios, capturing rare but high-impact events. Elevated adequacy risks at this percentile indicate the possibility of severe supply shortages under stressed system conditions, such as exceptionally high demand, low renewable generation, or unplanned outages.

Analyzing both percentiles allows for a comprehensive assessment of system robustness. A large gap between the 50th and 95th percentiles suggests that while the system performs adequately under typical conditions, it remains vulnerable during extreme events. Conversely, a narrower gap reflects a more resilient and reliable system, even under adverse circumstances.

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	989 MWh	17 MWh		7.15	0.19
	50th percentile 543 MWh	50th percentile 0 MWh		50th percentile LOLD: 5 hours	50th percentile LOLD: 0 hours
	95th percentile 3378 MWh	95th percentile 101 MWh		95th percentile LOLD: 22 hours	95th percentile LOLD: 1 hours
MA	22 MWh	0 MWh		0.12	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	50 MWh	3 MWh		0.33	0.02
	50th percentile 0 MWh	50th percentile 0 MWh		50th percentile LOLD: 0 hours	50th percentile LOLD: 0 hours
	95th percentile 382 MWh	95th percentile 0 MWh		95th percentile LOLD: 3 hours	95th percentile LOLD: 0 hours
LY	53616 MWh	16407 MWh		138.22	48.2
	50th percentile 38552 MWh	50th percentile 7716 MWh		50th percentile LOLD: 115 hours	50th percentile LOLD: 32 hours
	95th percentile 152371 MWh	95th percentile 57761 MWh		95th percentile LOLD: 344 hours	95th percentile LOLD: 149 hours
LB	2093699 MWh	1448435 MWh		2627.05	2147.68
	50th percentile 2075439 MWh	50th percentile 1427027 MWh		50th percentile LOLD: 2636 hours	50th percentile LOLD: 2147 hours
	95th percentile 2551061 MWh	95th percentile 1886927 MWh		95th percentile LOLD: 2816 hours	95th percentile LOLD: 2428 hours

Adequacy risk:

- **Very low risk:** LOLE < 3h
- **Low risk:** 3h < LOLE < 8h
- **Medium risk:** 8h < LOLE < 30h
- **High risk:** LOLE > 30h

Table 7 Seasonal EENS for Interconnected and isolated scenario

In Table 7 detailed EENS and LOLD seasonal results are given for all analyzed countries. Results point to adequacy issues in some countries.

Jordan, in isolated operation mode, faces a moderate risk to adequacy, with ENS potentially reaching 1 GWh and LOLE lasting for 7 hours. However, in more critical P95 scenarios, EENS can escalate to 3.3 GWh with a LOLD of up to 22 hours. In contrast, when operating in interconnected mode, the risk to adequacy is minimal to only 101 MWh and LOLE of less than one hour.

Libya continues to face severe adequacy challenges, reflecting the fragility of its power system and heavy dependence on thermal generation. In the isolated operation mode, the situation remains critical, with (EENS) reaching 53.6 GWh and (LOLE) extending to 138 hours.
Under more severe (P95) conditions, the adequacy risk intensifies sharply, with EENS rising to 152 GWh and LOLE exceeding 340 hours.

In the interconnected mode, the situation improves only partially. Despite the support from neighboring systems, Libya still experiences EENS of 16.4 GWh and LOLE of around 48 hours, corresponding to an improvement of roughly 65% compared to the isolated scenario. However, this reduction does not eliminate the adequacy risk, as fuel shortages, out of service generation assets, and operational instability continue to limit the effectiveness of interconnection.

Overall, these results confirm that the Libya system remains highly vulnerable, and interconnection alone cannot fully mitigate the underlying challenges stemming from infrastructure degradation, unstable gas supply, and insufficient reserve capacity.

Lebanon experiences the highest EENS and LOLE during the winter of 2025/2026 in the region, with 1.4 TWh of ENS and 2148 hours of LOLE (equivalent to 68% of the time during Winter season) in the hypothetical interconnected mode.

These figures highlight an extremely precarious adequacy situation (daily LOLD during the whole season can be ranged from 2 hours to 15 hours). In the event of more critical but less probable P95 cases, ENS can reach a staggering 1.8 TWh with an unavailability to supply the load for over 76% of the time.

In the isolated mode of operation, adequacy is even more at risk, with EENS reaching 2.1 TWh and LOLE extending to 2627 hours (daily LOLD during the whole season can be ranged from 4 hours to 18 hours). This emphasizes that Lebanon's interconnection with Jordan significantly reduces adequacy risks by 18%.

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

The rationales behind these results are given in relevant country chapters.

5. Importance of interconnections

In this chapter, we will thoroughly explore the interconnections between the countries under analysis and their need for energy exchange to mitigate the anticipated adequacy challenges in the upcoming winter. Our primary objective is to evaluate potential cross-border exchanges among the six analyzed nations and quantify each country's requirements to address adequacy risks during periods of isolation.

The table provided below summarizes the feasible exchanges needed to overcome adequacy risk and NTC among the countries subject to our analysis.

Link		Country A - Country B Exchanges for Adequacy (GWh)	Country A - Country B NTC (MW)	Country B - Country A Exchanges for Adequacy (GWh)	Country B - Country A NTC (MW)
Country A	Country B				
DZ00	MA00	0	600	0.00	300
DZ00	TN00	0	250	0.00	250
EG00	JO00	5	450	0.00	450
EG00	LY00	20	180	0.00	0
ES00	MA00	0	900	0.00	600
LY00	TN00	-17	250	0.03	250
JO00	LB00	641	250	0.00	0

Figure 8 Seasonal relative ENS and LOLE for the interconnected mode of operation for only winter season.

Exporting electricity from Egypt to Jordan contributes positively to enhancing Jordan's adequacy. Furthermore, Egypt and Jordan are actively exporting approximately 255 GWh to meet Sudan's and Palestine energy needs while Jordan is exporting approximately 64 GWh to support Iraq's energy demands.

Morocco, on the other hand, relies solely on electricity imports from Spain to alleviate any adequacy concerns that may happen, while Tunisia relies solely on electricity imports from Algeria.

The situation in Lebanon is completely different where interconnections and imported energy play a substantial role. While interconnections help decrease adequacy concerns by 18%, they alone are insufficient to completely mitigate these potential risks.

6 Adequacy Situation on Country Level

6.1 Egypt

Demand

Egyptian winter seasonal weekly demand, depicted in Figure 9 goes from around 4133 GWh to 4479 GWh, while 95th percentile peak hourly demand in each week varies from 30.7 GW to 33.6 GW. It should be noted that weekly consumption refers to the average values of all 36 analyzed climatic years, while peak hourly demand values refer to the 95th percentile of the weekly maximum hourly demand across all 36 analyzed climatic years.

	week 48	week 49	week 50	week 51	week 52	week 1	week 2	week 3	week 4	week 5	week 6	week 7	week 8	week 9	week 10	week 11	week 12	week 13	week 14
EG - WO 2025/2026 - average Weekly consumption (GWh)	4,169	4,133	4,129	4,148	4,181	4,301	4,309	4,309	4,335	4,339	4,371	4,367	4,363	4,361	4,372	4,383	4,209	4,447	4,479
EG - WO 2025/2026 - P95 - Weekly Peak Demand across climatic years (MW)	31,488	30,749	31,268	31,884	33,404	32,892	32,728	32,928	32,732	32,600	33,404	33,611	32,759	33,086	31,771	31,845	32,028	32,593	32,203

LOW HIGH

Figure 9 Seasonal Weekly demand in Egypt.

Supply and network overview

Egyptian power generation fleet is almost exclusively based on natural gas, with the gas TPP share in total installed capacities around 85%, which is divided further into conventional and CCGT TPPs. Oil TPPs share is 1%, while Hydro share is 5%. RES wind and solar capacities amount only to 4% and 5% respectively. The system is supported by 300 MWh of battery storage which represents almost 1%.

NGIC (Total net generation installed capacities including hydro and RES but not battery storage) are 58668MW with import capacity up to 1950 MW from Jordan and Saudi Arabia which combined is substantially higher than the maximum hourly consumption of 33611 MW. In sense of demand and installed capacities, Egypt is the biggest of all analyzed power systems.

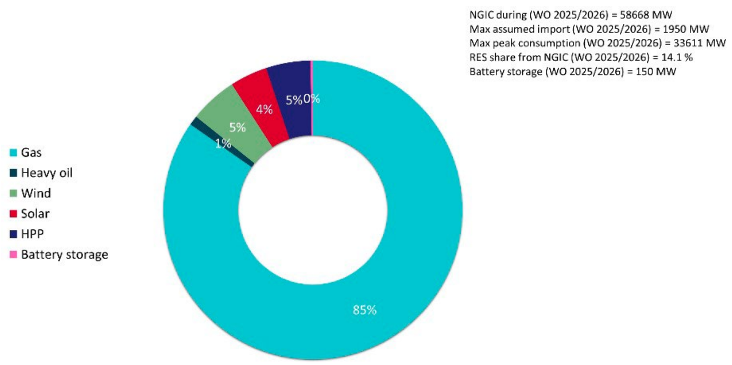


Figure 10 Installed Capacity mix with total NGC, import NTC and peak demand in Egypt.

The average daily available TPP capacity, after reduction due to forced outages, is shown in Figure 11. Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated mode of operation. Egyptian average available TPP capacity fluctuates in this period due to planned and forced outages. The minimal average daily available TPP capacity (minimum among all simulated MC years) fluctuates around 36 GW.

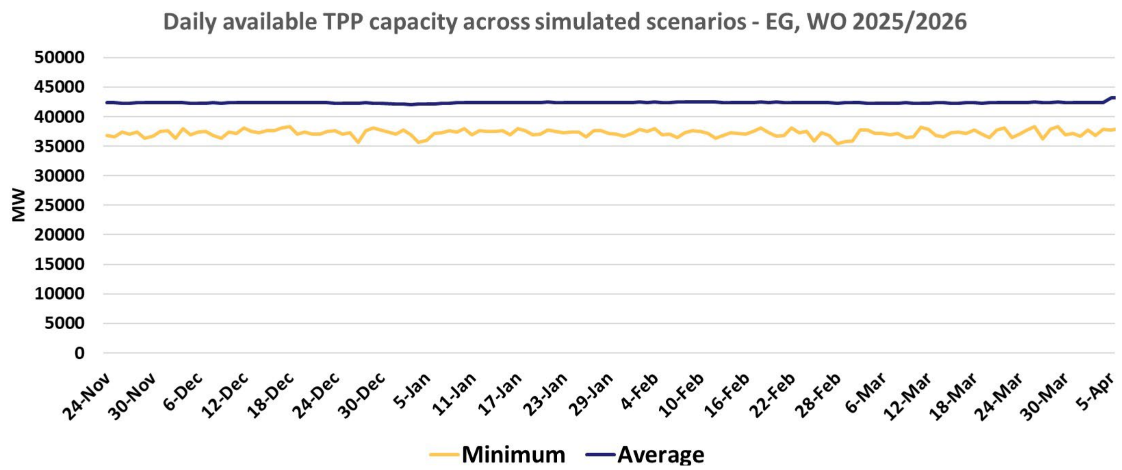


Figure 11 Average and minimum TPP available capacity among of all simulated MC years in Egypt.

As a result of system simulation, the minimum hourly TPP capacity margin among all simulated MC years is calculated and depicted in Figure 12, which represents the difference between available and activated TPP capacities. The hourly minimum TPP margin is between 4.5 GW and 12.5 GW during the analyzed winter 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 bring benefit to neighboring countries' adequacy situation.

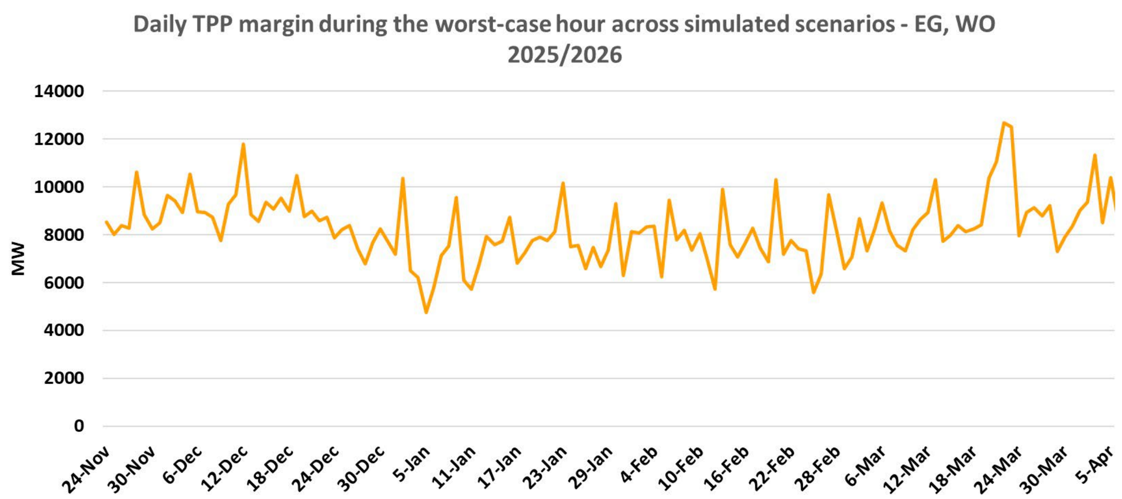


Figure 12 Minimum hourly TPP margin on each day of the analyzed among of all simulated MC years period in Egypt.

Adequacy Assessment

The temporal distribution of detected adequacy risk is given in Figure 13 , for both modes of operation – interconnected and isolated. In the first picture, daily LOLE distribution is given, while in the second one daily EENS is depicted.

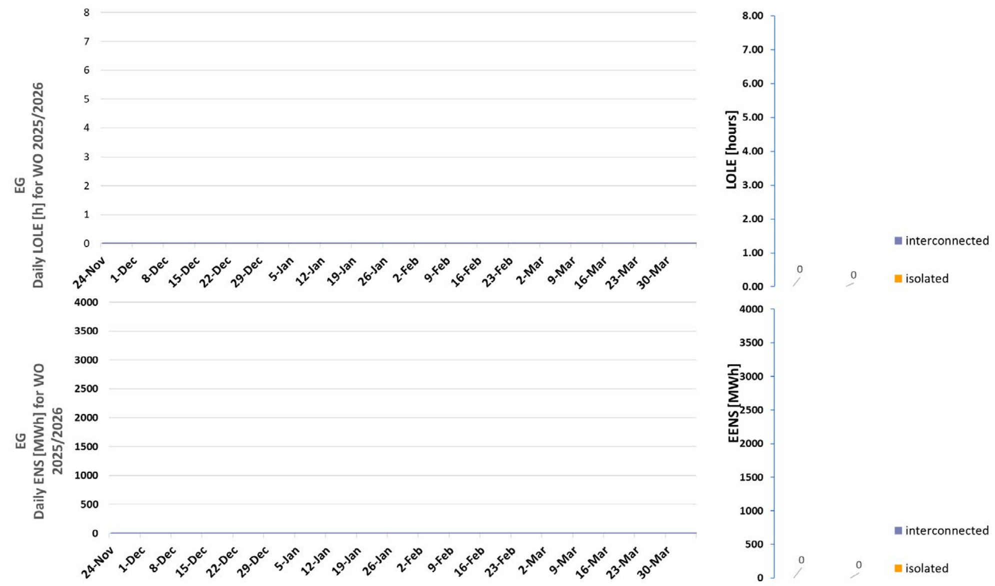


Figure 13 Daily LOLE and EENS for the interconnected and isolated mode of operation in Egypt

At the right-hand part of the figure, LOLE and EENS for the entire season for both modes of system operation are given.

The conclusion no adequacy concerns are detected for both analyzed modes of operation in the case of Egypt.

6.2 Jordan

Demand

Jordan's winter seasonal weekly demand, depicted in Figure 14, goes from around 480 GWh to 564 GWh (fluctuation at the level of 15%), while 95th percentile peak hourly demand in each week goes from 4315 MW to 5456 MW which presents even higher fluctuation – 20%. It should be noted that weekly consumption refers to the average values of all 36 analyzed climatic years, while peak hourly demand values refer to the 95th percentile of the weekly maximum hourly demand across all 36 analyzed climatic years.

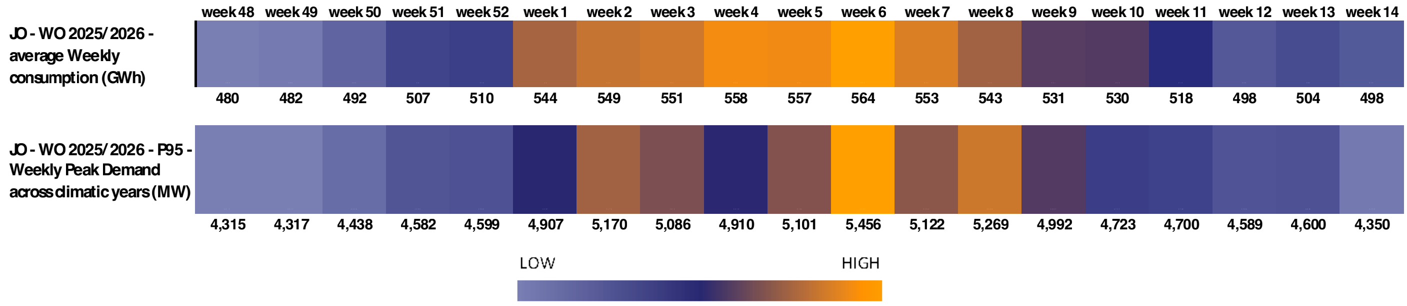


Figure 14 Seasonal Weekly demand in Jordan.

Supply and network overview

Jordan's power generation fleet is dominantly based on gas fueled TPPs, with the share in total installed capacities around 56%, which is divided further 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 30% respectively. NGIC (Total net generation installed capacities including hydro and RES but not battery storage) are 7738 MW with an import capacity up to 450 MW from Egypt.

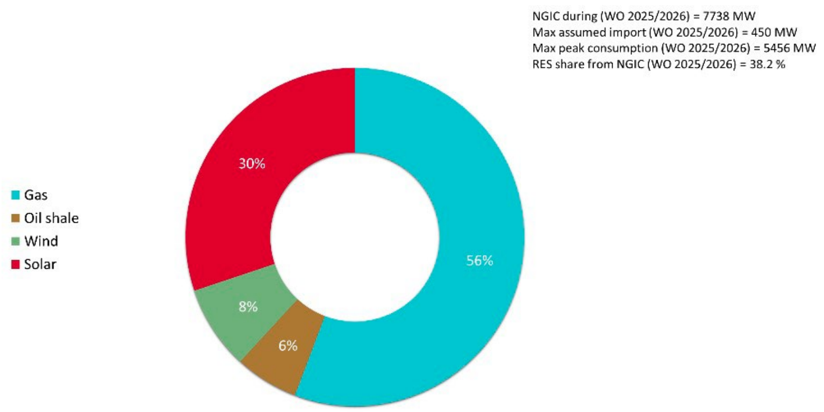


Figure 15 Installed Capacity mix with total NGC, import NTC and peak demand in Jordan

The average daily available TPP capacity, after reduction due to derating factors, and forced and planned outages is shown in Figure 16. Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated mode of operation.

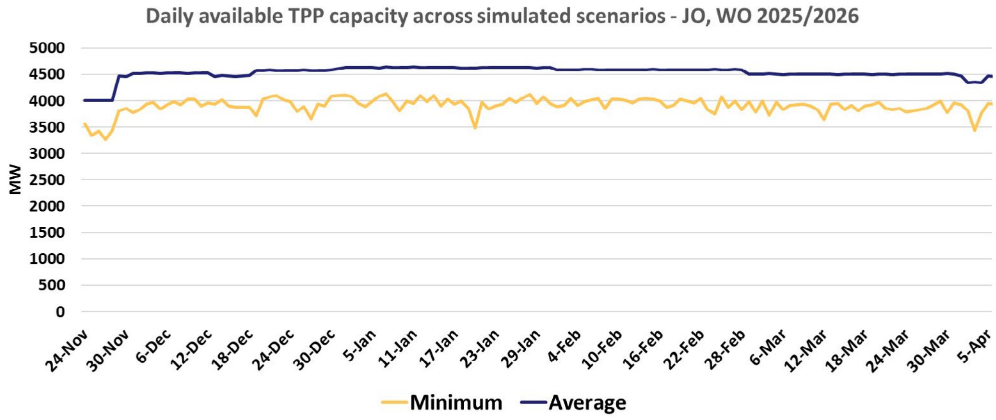


Figure 16 Average and minimum TPP available capacity among of all simulated MC years in Jordan.

As a result of system simulation, the minimum hourly TPP capacity margin among all simulated MC years is calculated and depicted in Figure 17, which represents the difference between available and activated TPP capacities. The minimum hourly value of the TPP margin is often at zero value most of winter season. These results point to the fact that there is a possibility that during some hours and under extreme weather conditions, adequacy can be endangered. Notably, the daily margin follows daily consumption patterns, and it is the lowest during working days, due to higher demand.

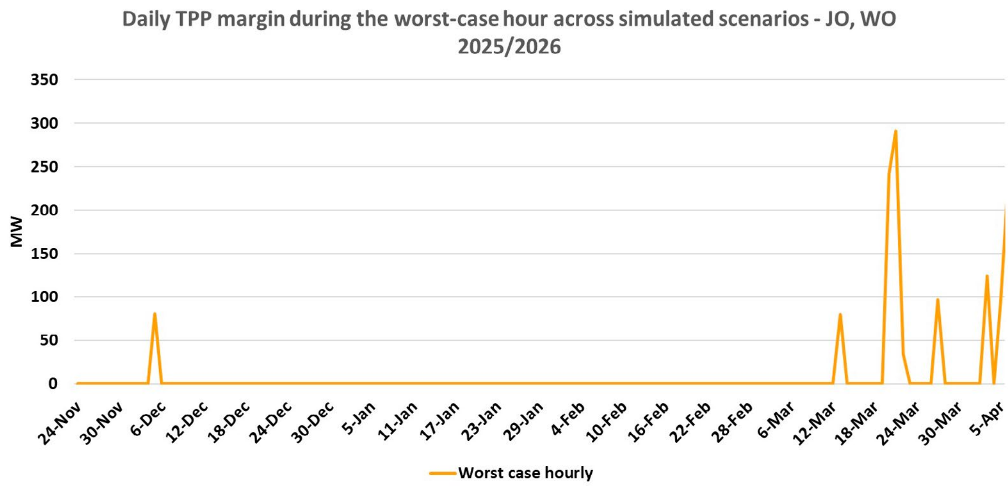


Figure 17 Minimum hourly TPP margin on each day of the analyzed among of all simulated MC years period in Jordan.

Adequacy Assessment

The temporal distribution of detected adequacy risk is given in Figure 18, for both modes of operation – interconnected and isolated. In the first picture, daily LOLE distribution is given, while in the second one daily EENS is depicted.

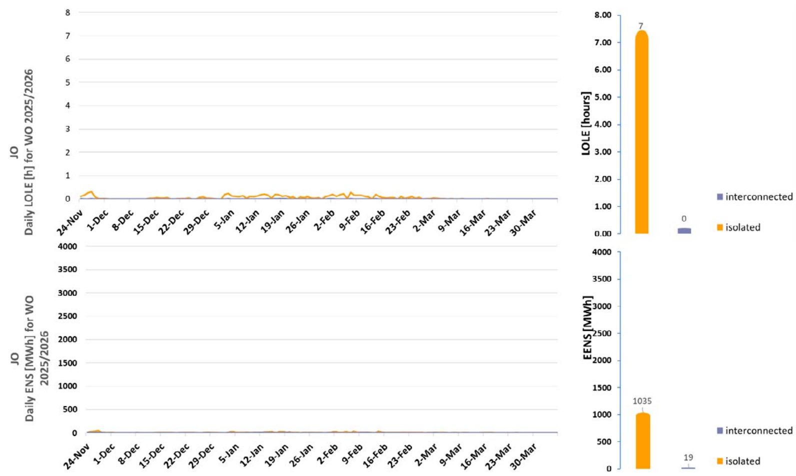


Figure 18 Daily LOLE and EENS for the interconnected and isolated mode of operation in Jordan.

At the right-hand part of the figure, LOLE and EENS for the entire season for both modes of system operation are given. Interconnections substantially reduce already small seasonal LOLE from 7 h to less than 1 h and expected winter seasonal EENS from 1035 MWh to just 19 MWh.

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

6.3 Lebanon

Demand

Lebanon's winter seasonal weekly demand, depicted in Figure 19, goes from around 407 GWh to 472 GWh, while peak hourly demand each week goes from 3113 MW to 4289 MW. It should be noted that weekly consumption refers to the average values of all 36 analyzed climatic years, while peak hourly demand values refer to the 95th percentile of the weekly maximum hourly demand across all 36 analyzed climatic years.

Maximum electricity needs are expected during the first weeks of 2026, due to low temperatures and increased heating demand. The maximum hourly demand of 4289 MW is reached in the 6th week of 2026.

It should be noted that the operation of Lebanon's power system is especially difficult, with a continuous lack of supply and organized regular load shedding.

	week 48	week 49	week 50	week 51	week 52	week 1	week 2	week 3	week 4	week 5	week 6	week 7	week 8	week 9	week 10	week 11	week 12	week 13	week 14
LB - WO 2025/2026 - average Weekly consumption (GWh)	422	424	430	438	448	456	462	463	465	463	472	460	447	435	430	424	419	412	407
LB - WO 2025/2026 - P95 - Weekly Peak Demand across climatic years (MW)	3,362	3,368	3,585	3,619	3,753	3,858	4,067	3,997	3,788	4,042	4,289	4,137	4,222	3,890	3,517	3,504	3,480	3,322	3,113

LOW HIGH

Figure 19 Seasonal Weekly demand in Lebanon.

Supply and network overview

Lebanon's power generation fleet is exclusively oil fueled, with the share in total installed capacities around 35% and 7% goes to hydro power plants and rest of 35% goes to solar rooftop capacities. NGIC (Total net generation installed capacities including hydro and RES but not battery storage) are 3236 MW, but as serious support to system operation, also the additional capacity of 1000 MW in diesel units is considered in this analysis.

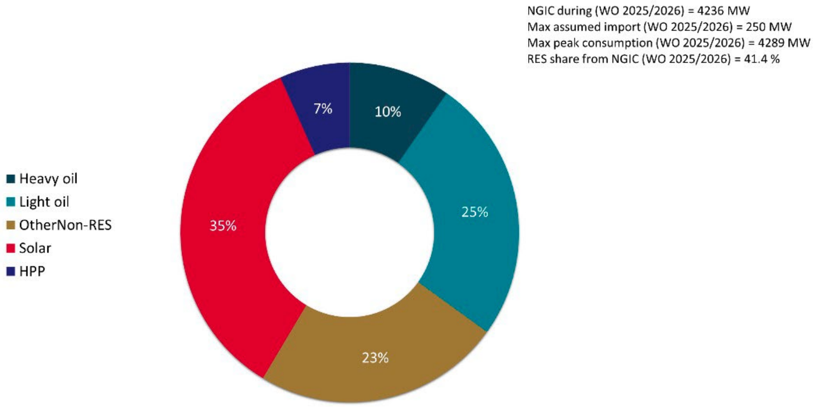


Figure 20 Installed Capacity mix with total NGC, import NTC and peak demand in Lebanon.

The average daily available TPP capacity, after reduction due to forced outages, is shown Figure 21. Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated mode of operation.

It should be noted that the total NGIC in Lebanon is lower than the maximum expected hourly demand which points to a difficult system operation and dependence on import.
The average daily available TPP capacity among all simulated MC years is around only 2300 MW.

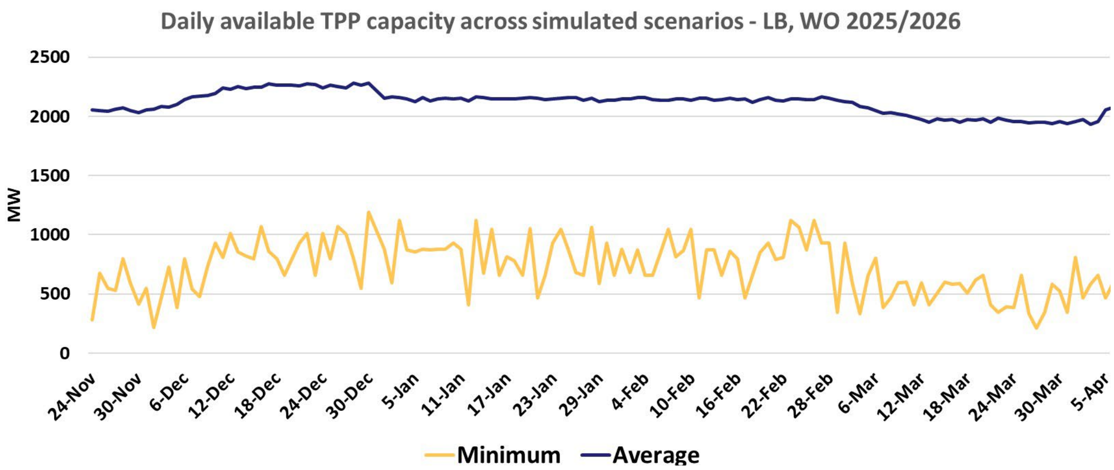


Figure 21 Average and minimum TPP available capacity among of all simulated MC years in Lebanon.

As a result of system simulation, the minimum hourly TPP capacity margin among all simulated MC years is calculated and depicted in Figure 22, which represents the difference between available and engaged TPP capacities. No margin exists in Lebanon's power system.

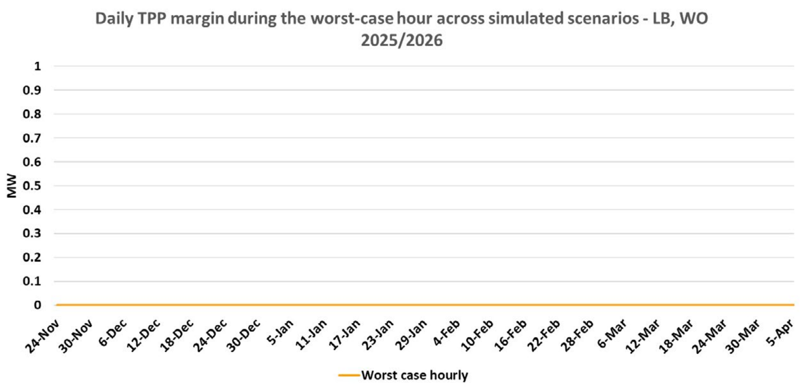


Figure 22 Minimum hourly TPP margin on each day of the analyzed period among of all simulated MC years in Lebanon.

Adequacy Assessment

The temporal distribution of detected adequacy risk is given in Figure 23 for both modes of operation – hypothetical interconnected and isolated. In the first picture, daily LOLE distribution is given, while in the second one daily EENS is depicted.

The first 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 presents the regular, everyday action planned in advance.

Results of the simulations point to the fact that LOLE and ENS are above all acceptable values even in the hypothetical interconnected mode of operation: EENS is 1.4 TWh and LOLE is 2138 hours (around 67 % during the winter season of 3192 hours). There are climatic years without adequacy issues, but there is no day without adequacy issues in all 684 analyzed MC years. Looking at the whole season, even in the best case, everyday there are adequacy issues: LOLE Min=10 hours and LOLE Max=22 hours in average of 684 MC years.

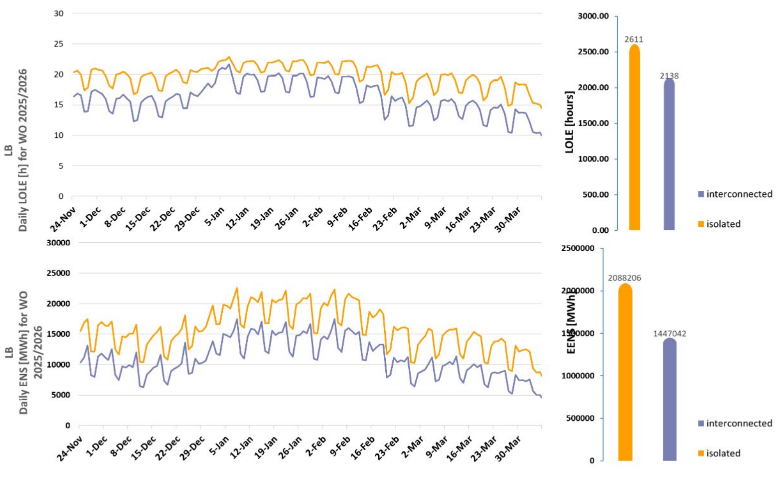


Figure 23 Daily LOLE and EENS for the interconnected and isolated mode of operation In Lebanon

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

6.4 Libya

Demand

Libya's winter seasonal weekly demand, depicted in Figure 24, goes from around 726 GWh to 942 GWh, while peak hourly demand each week goes from 6213 MW to 8091 MW. This variation of the peak load is almost 23% which is very high. It should be noted that weekly consumption refers to the average values of all 36 analyzed climatic years, while peak hourly demand values refer to the 95th percentile of the weekly maximum hourly demand across all 36 analyzed climatic years.

	week 48	week 49	week 50	week 51	week 52	week 1	week 2	week 3	week 4	week 5	week 6	week 7	week 8	week 9	week 10	week 11	week 12	week 13	week 14
LY - WO 2025/ 2026 - average Weekly consumption (GWh)	794	816	837	884	914	942	938	940	930	933	928	912	861	820	817	766	761	733	726
LY - WO 2025/ 2026 - P95 - Weekly Peak Demand across climatic years (MW)	6,615	6,914	6,926	7,921	7,589	7,743	7,572	7,621	7,773	7,904	8,091	7,898	7,469	7,037	7,025	6,852	6,545	6,213	6,290

LOW HIGH

Figure 24 Seasonal Weekly demand in Libya.

Supply and network overview

Libya's generation portfolio is based exclusively on gas-fired power plants, with 99% in generation capacity mix. The majority of installed thermal capacities refer to gas turbines (55%) and light oil (34%), while only 11% of capacities of heavy oil. NGIC (Total net generation installed capacities including hydro and RES but not battery storage) are but 14341 MW only 7840 MW in service.

It should be emphasized that according to provided data for winter outlook 2025/2026 we consider 50 MW rooftop solar capacities installed in Libya.

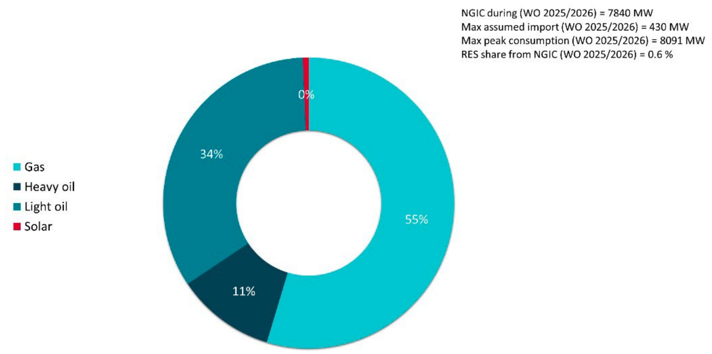


Figure 25 Installed Capacity mix with total NGC, import NTC and peak demand in Libya.

The average daily available TPP capacity, after reduction due to forced outages, is shown in Figure 26.

Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated mode of operation.

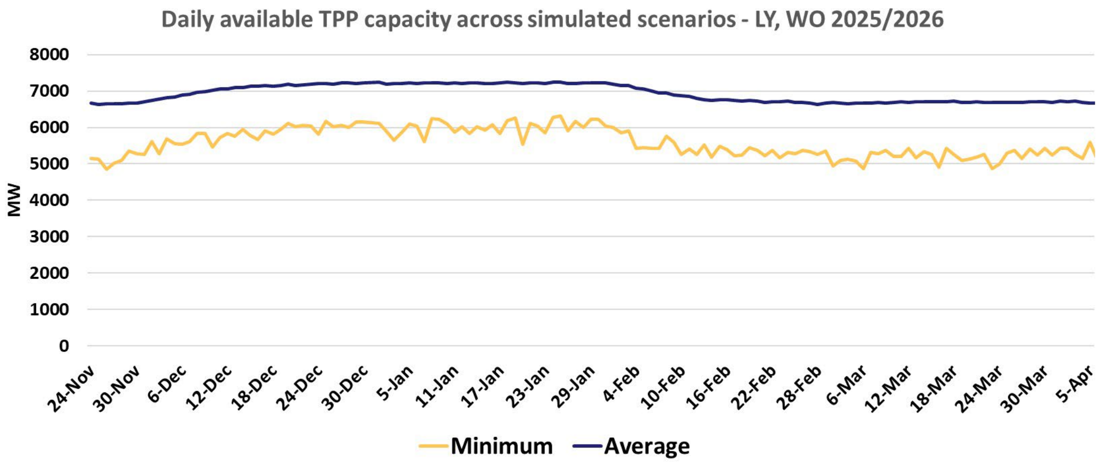


Figure 26 Average and minimum TPP available capacity among of all simulated MC years in Libya.

As a result of system simulation, the minimum hourly TPP margin among all simulated MC years for each day is calculated and depicted in Figure 27, which represents the difference between available and activated TPP capacities. No margin exists in Lebanon's power system.

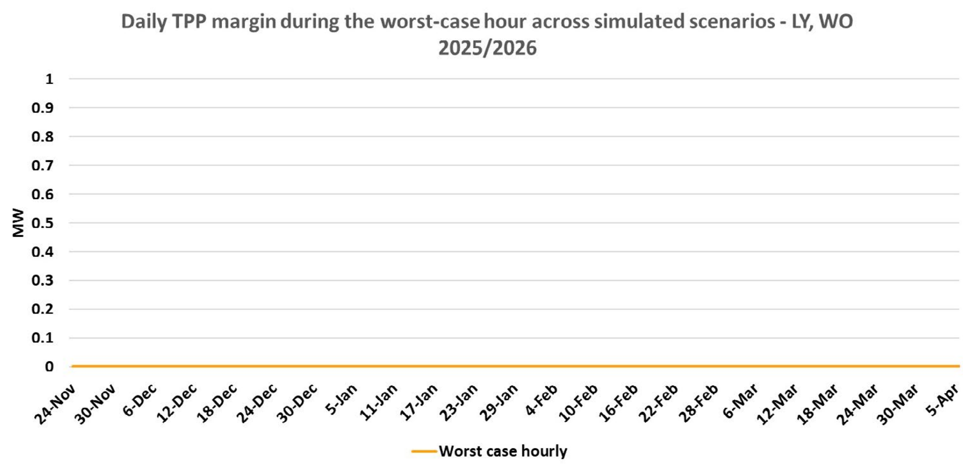


Figure 27 Minimum hourly TPP margin on each day of the analyzed period among of all simulated MC years in Libya.

Adequacy Assessment

The temporal distribution of detected adequacy risk is given in Figure 28 , for the interconnected and isolated mode of operation. In the first picture, daily LOLE distribution is given, while in the second one daily EENS is depicted.

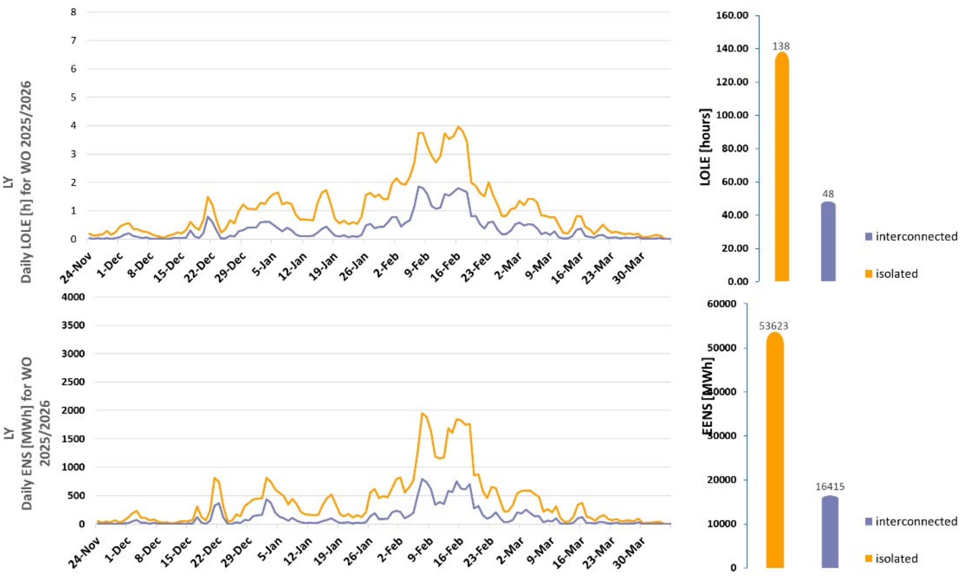


Figure 28 Daily LOLE and EENS for the interconnected and isolated mode of operation in Libya.

At the right-hand part of the figure, LOLE and EENS for the entire season for the interconnected and isolated mode of system operation are given.

As can be seen, adequacy issues are significantly more pronounced in the isolated mode, with LOLE reaching 138 hours and EENS amounting to 53.6 GWh, compared to 48 hours and 16.4 GWh respectively in the interconnected mode. The highest adequacy risks occur between late January and mid-February, corresponding to periods of elevated demand. Outside this interval, both LOLE and EENS remain at relatively low levels.

These results indicate that while interconnection substantially improves system adequacy, the isolated Libyan system would still experience frequent and severe adequacy challenges, requiring load shedding during peak winter weeks.

6.5 Morocco

Demand

Moroccan winter seasonal weekly demand, depicted in Figure 29, goes from around 835 GWh to 908 GWh, while peak hourly demand each week goes from 6376 MW to 6911 MW. It should be noted that weekly consumption refers to the average values of all 36 analyzed climatic years, while peak hourly demand values refer to the 95th percentile of the weekly maximum hourly demand across all 36 analyzed climatic years.

	week 48	week 49	week 50	week 51	week 52	week 1	week 2	week 3	week 4	week 5	week 6	week 7	week 8	week 9	week 10	week 11	week 12	week 13	week 14
MA - WO 2025/2026 - average Weekly consumption (GWh)	840	836	835	836	835	874	887	881	881	883	882	885	889	891	892	895	861	907	908
MA - WO 2025/2026 - P95 - Weekly Peak Demand across climatic years (MW)	6,378	6,375	6,376	6,418	6,388	6,687	6,692	6,679	6,601	6,588	6,537	6,673	6,748	6,737	6,716	6,674	6,730	6,843	6,911

LOW HIGH

Figure 29 Seasonal Weekly demand in Morocco

Supply and network overview

Moroccan power generation fleet is balanced and well-diversified in comparison with other analyzed countries, with the TPP share in total installed capacities around 52%, which is divided further into Coal, Gas and Oil TPPs. Hydro capacities amount to 11%, while RES wind and solar share in installed capacities are 19% and 9% respectively. NGIC (Total net generation installed capacities including hydro and RES but not battery storage) are 11225 MW with total import capacity up to 1500 MW, which is about 12.5% of peak load in the analyzed period.

To enhance system flexibility, the capacity includes 790 MW of hydro pump storage and 800 MWh of battery storage and 540 of solar are CSP with storage.

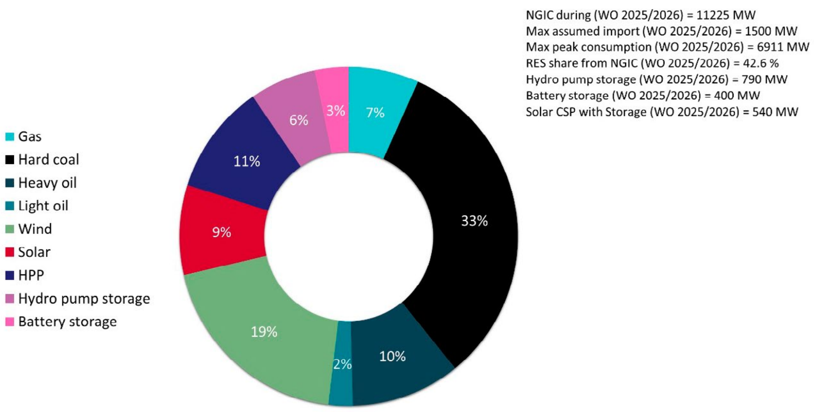


Figure 30 Seasonal Weekly demand in Morocco.

The average daily available TPP capacity, after reduction due to forced outages, is shown in Figure 3. Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated mode of operation. Moroccan average available TPP capacities among of all simulated MC years level is stable, and it is around 6000 MW. It should be noted that fluctuations in the average curve are due to the planned outage schedule.

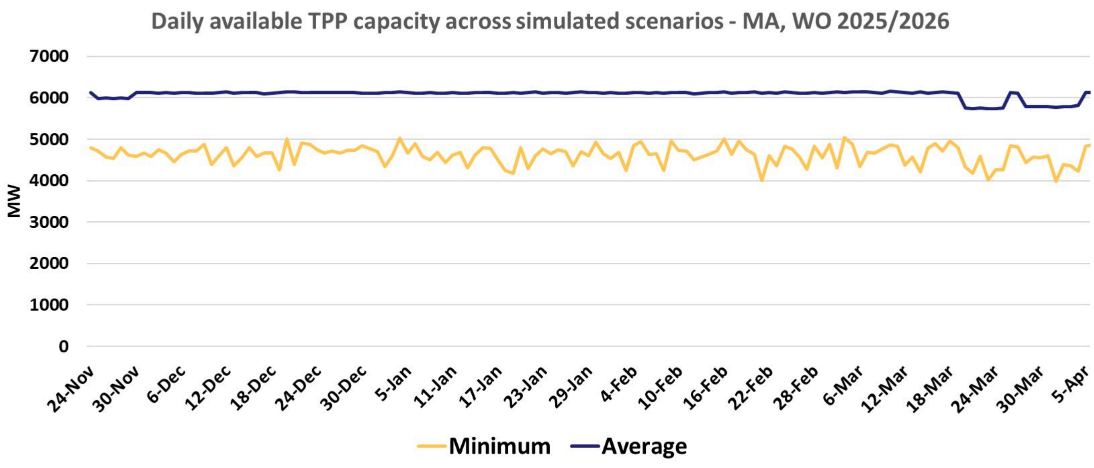


Figure 31 Average and minimum TPP available capacity among of all simulated MC years in Morocco.

As a result of system simulation, the minimum hourly TPP capacity margin among of all simulated MC years on each day is calculated and depicted in Figure 32, which represents the difference between available and engaged TPP capacities. The minimum hourly value of the TPP margin is often at zero value most of winter season. These results point to the fact that there is a possibility that during some hours adequacy can 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.

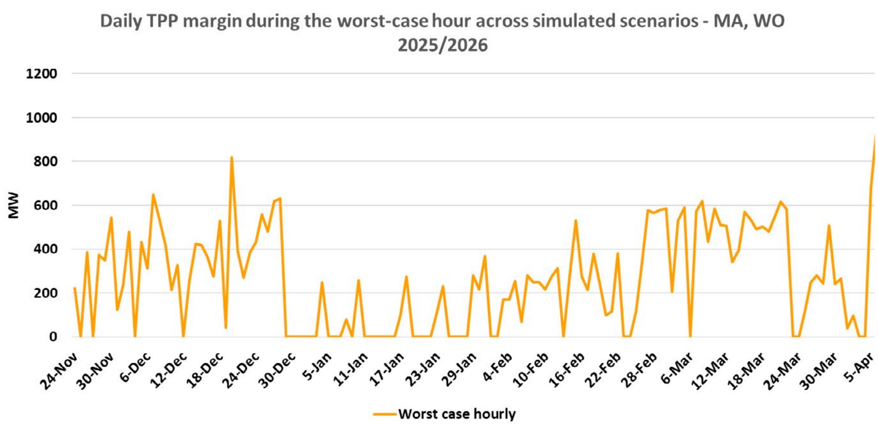


Figure 32 Minimum hourly TPP margin on each day of the analyzed period in Morocco.

Adequacy Assessment

The temporal distribution of detected adequacy risk is given in Figure 33 for the interconnected and isolated mode of operation. In the first picture, daily LOLE distribution is given, while in the second one daily EENS is depicted. It can be seen that there is no adequacy risk in the winter period of 2025/2026 in Morocco.

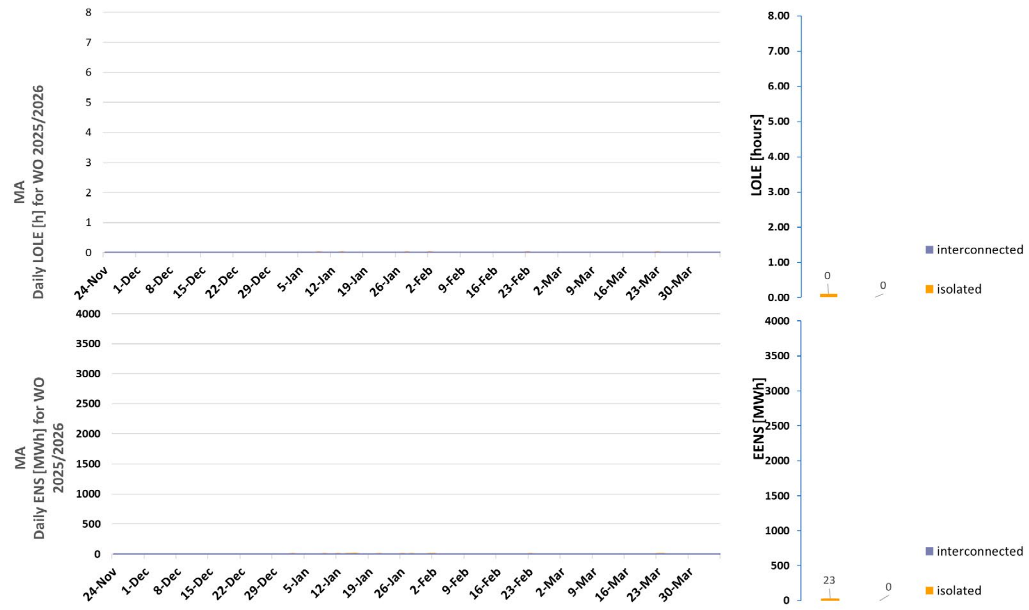


Figure 33 Daily LOLE and EENS for the interconnected and isolated mode of operation in Morocco.

At the right-hand part of the figure, LOLE and EENS for the entire season for the isolated mode of system operation are given. LOLE for the entire season is about 0 hours, while EENS is around 23 MWh.

The conclusion no adequacy risks are present in the Isolated and interconnected mode of operation.

6.6. Tunisia

Demand

Tunisian seasonal weekly demand, depicted in Figure 34 ranges between 360 GWh and 412 GWh, while peak hourly demand each week goes from 2956 MW to 3576 MW. It should be noted that weekly consumption refers to the average values of all 36 analyzed climatic years, while peak hourly demand values refer to the 95th percentile of the weekly maximum hourly demand across all 36 analyzed climatic years. Maximum electricity needs are expected during from the end of December to the end of February.

	week 48	week 49	week 50	week 51	week 52	week 1	week 2	week 3	week 4	week 5	week 6	week 7	week 8	week 9	week 10	week 11	week 12	week 13	week 14
TN - WO 2025/2026 - average Weekly consumption (GWh)	372	374	379	382	392	401	411	412	410	411	410	409	397	394	394	390	360	389	389
TN - WO 2025/2026 - P95 - Weekly Peak Demand across climatic years (MW)	3,129	3,145	3,179	3,314	3,464	3,407	3,576	3,551	3,424	3,444	3,492	3,458	3,129	3,054	3,030	2,956	3,099	3,082	3,024

LOW HIGH

Figure 34 Seasonal Weekly demand in Tunisia.

Supply and network overview

Tunisian power generation fleet is almost exclusively gas fired, with the share in total installed capacities around 84%, which is divided further into conventional, CCGT and OCGT TPPs. RES, i.e. wind and solar share in installed capacities is only around 16%. NGIC (Total net generation installed capacities including hydro and RES but not battery storage) are 6066 MW with import capacity up to 500 MW, while maximum hourly consumption is around 3576 MW.

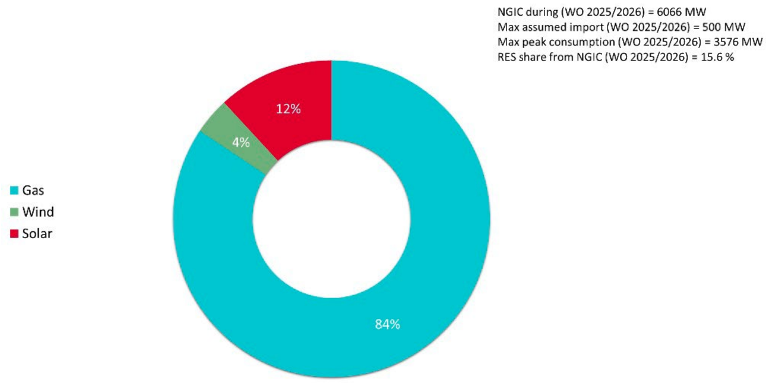


Figure 35 Installed Capacity mix with total NGC, import NTC and peak demand in Tunisia.

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 mode of operation.

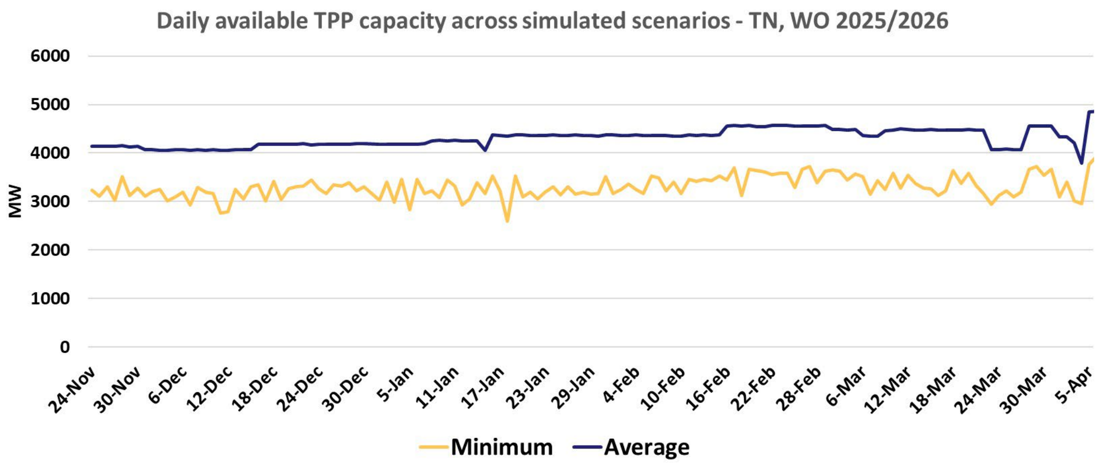


Figure 36 Average and minimum TPP available capacity among of all simulated MC years in Tunisia

As a result of system simulation, the minimum hourly TPP capacity margin on each day is calculated and depicted in Figure 37, which represents the difference between available and activated TPP capacities.

It can be seen that the minimum hourly margin is always higher than zero (except for some days during winter season).

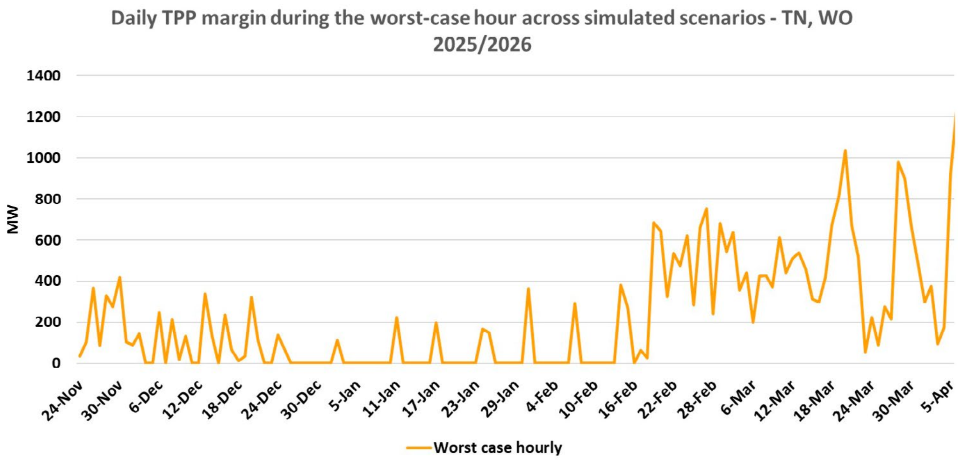


Figure 37 Minimum hourly TPP margin on each day of the analyzed period in Tunisia.

Adequacy Assessment

The temporal distribution of detected adequacy risk is given in Figure 38 for both modes of operation – interconnected and isolated. In the first picture, daily LOLE distribution is given, while in the second one daily EENS is depicted.

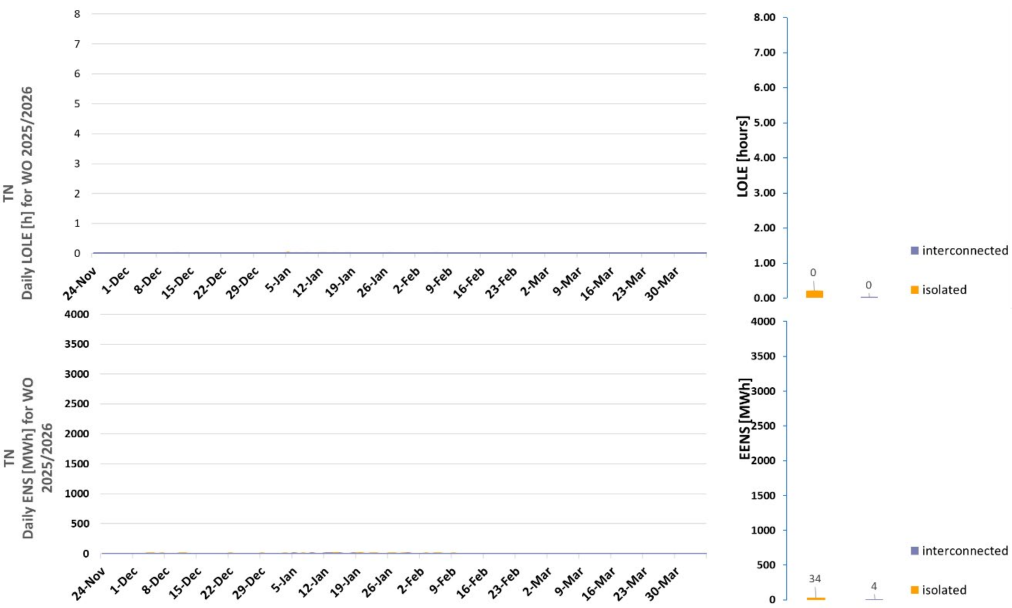


Figure 38 Daily LOLE and EENS for the interconnected and isolated mode of operation

At the right-hand part of the figure, LOLE and EENS for the entire season for the isolated mode of system operation are given. LOLE for the entire season is about 0 hours, while EENS is around 23 MWh.

The conclusion no adequacy risks are present in the Isolated and interconnected mode of operation.

7 Appendix

Approach and Methodology

7.1 Adequacy assessment methodology

This report presents the 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[6].** These investigations consider the security of electricity supply to consumers through a detailed power system adequacy assessment, using probabilistic approach. 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 decarbonize energy systems, adequacy monitoring becomes even more important.

The analysis has 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 recognized 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 Open-Source software, and therefore accessible to all Med-TSO members.

Within this assessment, seasonal risks that might occur in the following +6 months, and that are likely to result in a significant deterioration of the electricity supply situation, are analyzed.

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. Several Monte Carlo (MC) years are constructed to assess adequacy risks under various conditions for the analyzed timeframe. For all these MC years, hourly calculations are performed for the whole geographical scope.

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

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

7.2 Adequacy indicators and other results of adequacy assessment

The 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 every 20 years.
    - **P50:** LOLD that happens once every 2 years.

- **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.

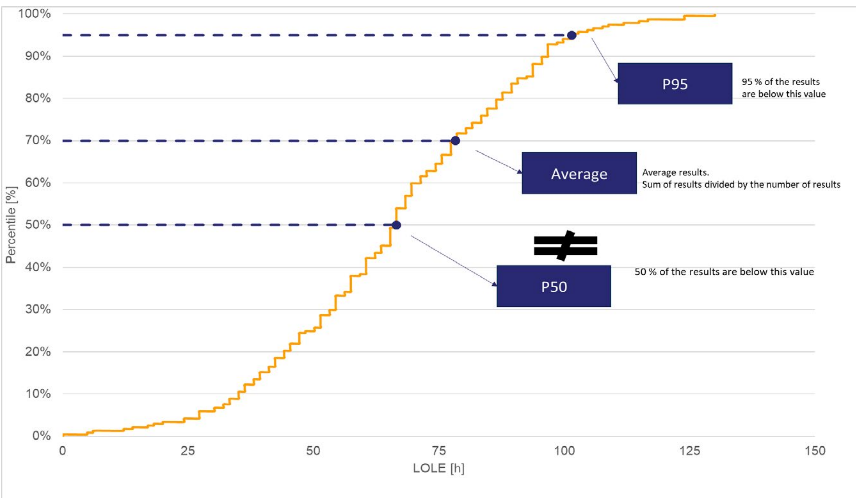


Figure 40 Illustrative example of the relation between average, P50, and P95 values.

- **P95/P50 Energy Not Served (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.

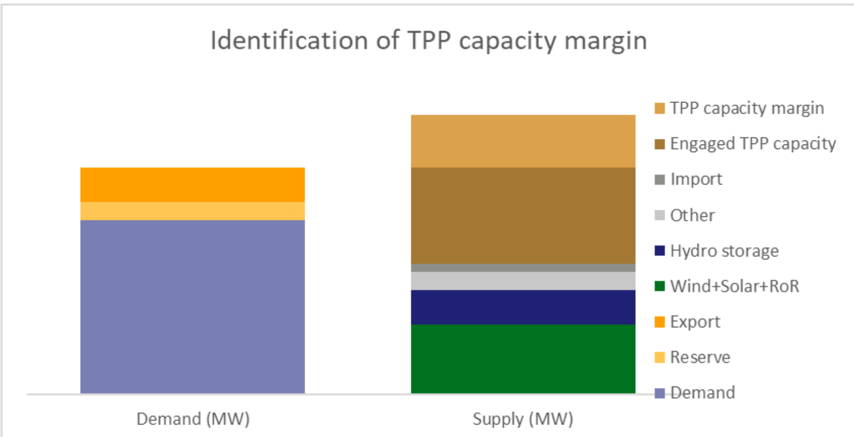


Figure 41 Illustrative example of TPP capacity margin identification.

Presentation of the adequacy indicators also includes the following:

1. The 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.

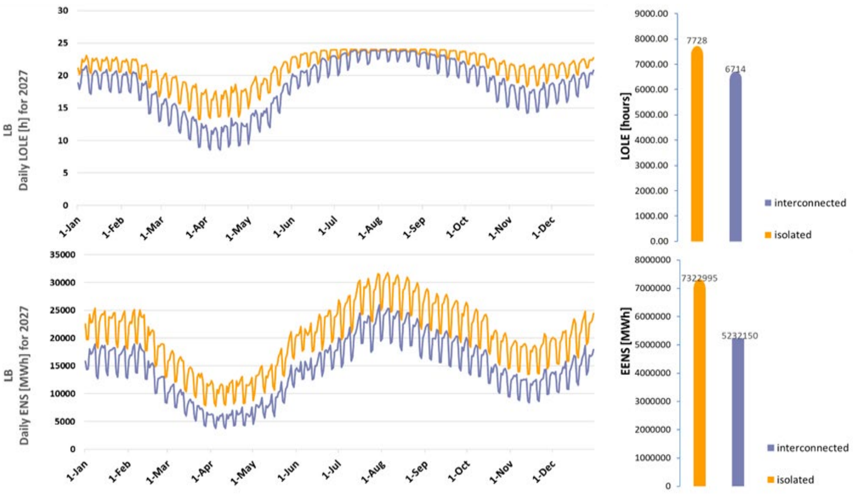


Figure 42 Illustrative example of average daily LOLE and EENS.

The available thermal capacities and thermal capacity margins are analyzed 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.

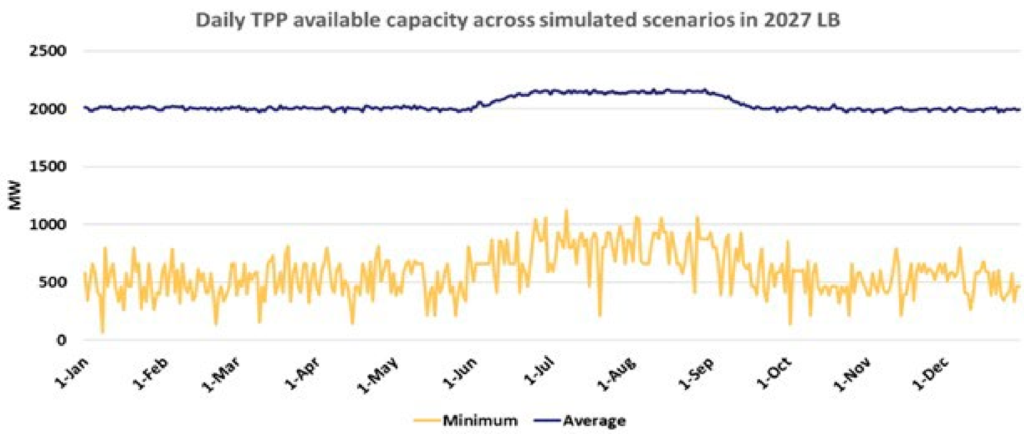


Figure 43 Illustrative example of available TPP capacity.

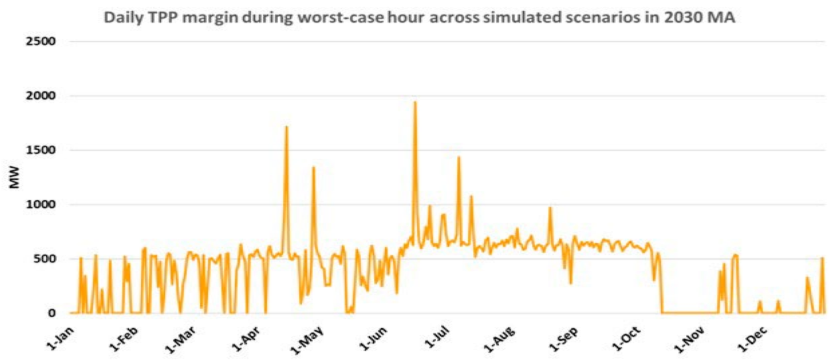


Figure 44 Minimum hourly TPP margin on each day of the analysed period.

7.3 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 , TYNDP 2020/2022, ERAA 2021, and any other relevant documents from the ENTSO-E website.

As an additional quality assurance, all the data provided have been analyzed 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 standardized 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. 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 is not modelled. Additional demand during the charging of storage units has been obtained as the result of the simulation.

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, schedules for the maintenance of thermal units have been provided

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

by our members and these have been modelled as predetermined planned outages for corresponding units. No 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, 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 4.2 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). The 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 of 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 analysis 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:

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

7.4 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 36 years) 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 (36 x 19). The number of MC years that ensures good convergence of results has been defined by assessing the coefficient of variation (*a*) of the EENS metric and its change.

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

Where EENSN is the expected value estimate of ENS over N Monte Carlo years, i.e.

$$EENS_N = \frac{\sum_{i=1}^{N} \quad ENS_i}{N} \qquad \text{i=1...N}$$

and Var(EENSN) is the variance of the expectation estimater, i.e

$$Var[EENS_N] = \frac{Var[ENS]}{N}$$

The evolution of convergence criteria is presented in the following figures

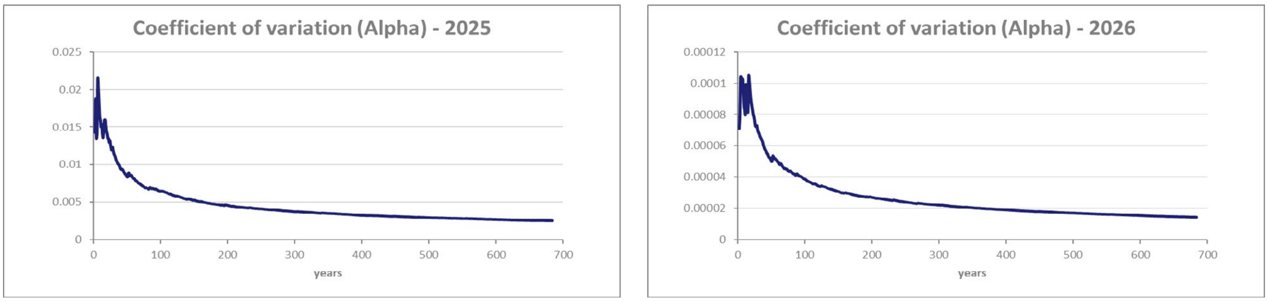


Figure 45 Evolution of convergence criteria for 684 MC years, simulations for the year 2025.

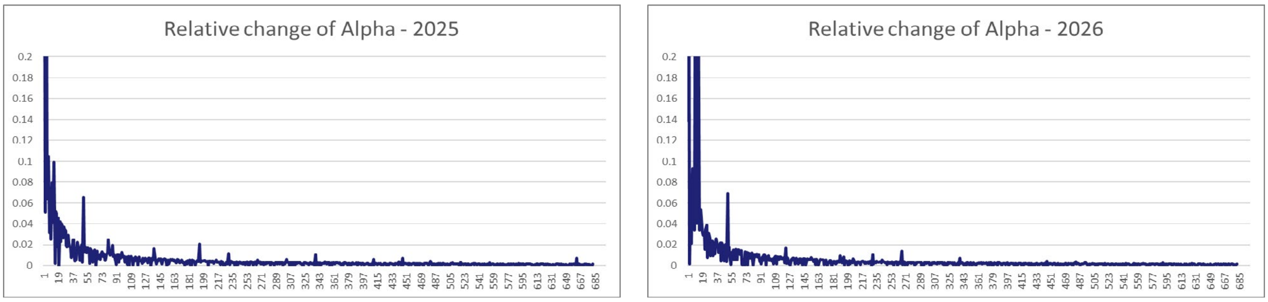


Figure 46 Evolution of convergence criteria for 684 MC years, simulations for the year 2026

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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