Med-TSO
TeasiMed2 project

Mid-Term Adequacy Assessment
Horizon 2027 & 2030

Detailed Draft Report

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Abbreviations

CAGR – Compound Annual Growth Rate
CCGT – Combined Cycle Gas Turbine
EU – European Union
ENS – Energy Not Served
ENTSO-E – European Network of Transmission System Operators for Electricity
EENS Expected Energy Not Served
FCR – Frequency Containment Reserve
FRR – Frequency Restoration Reserve
Med-TSO – Association of the Mediterranean Transmission System Operators (TSOs)
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
IT – Italy
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 expected in 2027 and 2030. With this assessment, Med-TSO is aligning with the best practice and the latest development of the EU regulations.
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 Mid-Term Adequacy Assessment Report provides information about potential adequacy issues during years 2027 and 2030 in the 5 Med-TSO members: Morocco, Tunisia, Egypt, Lebanon and Jordan.

Data for Algeria & Libya are missing from this assessment due to limited engagement from their side. Data for Israel and Palestine is currently unavailable.

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.

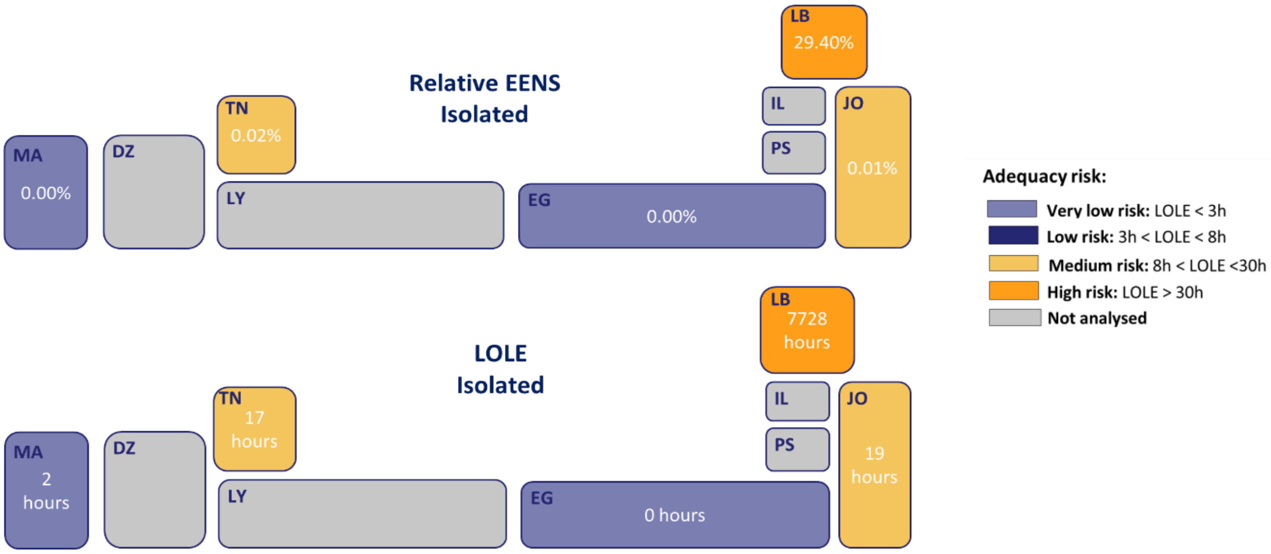


Figure 1 Relative EENS and LOLE for the isolated operational mode during normal operation 2027

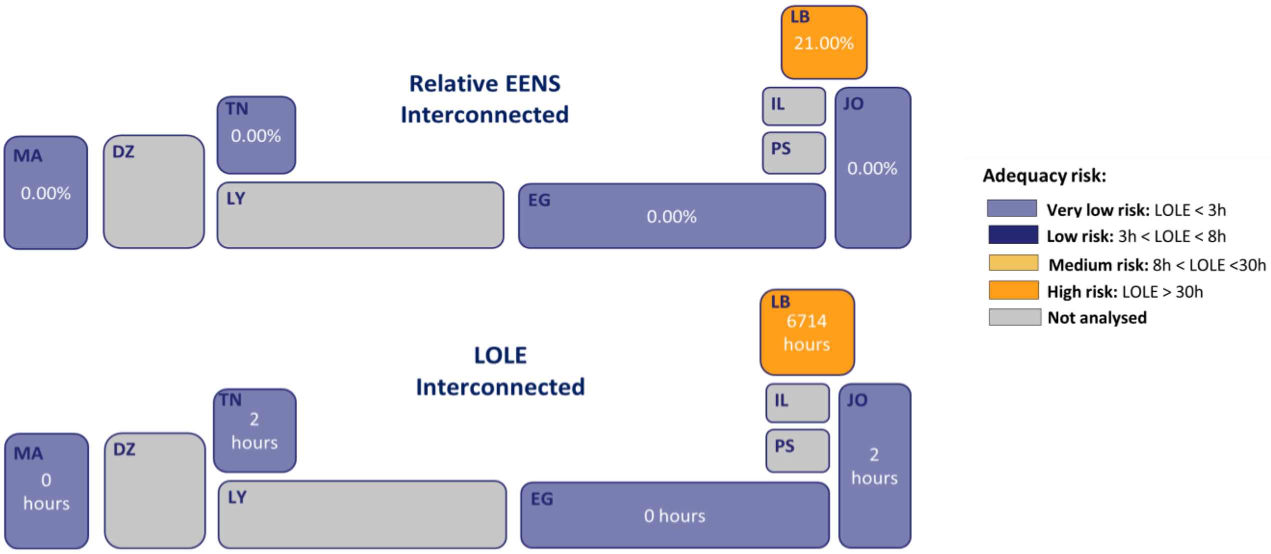


Figure 2 Relative EENS and LOLE for the interconnected operational mode during normal operation 2027

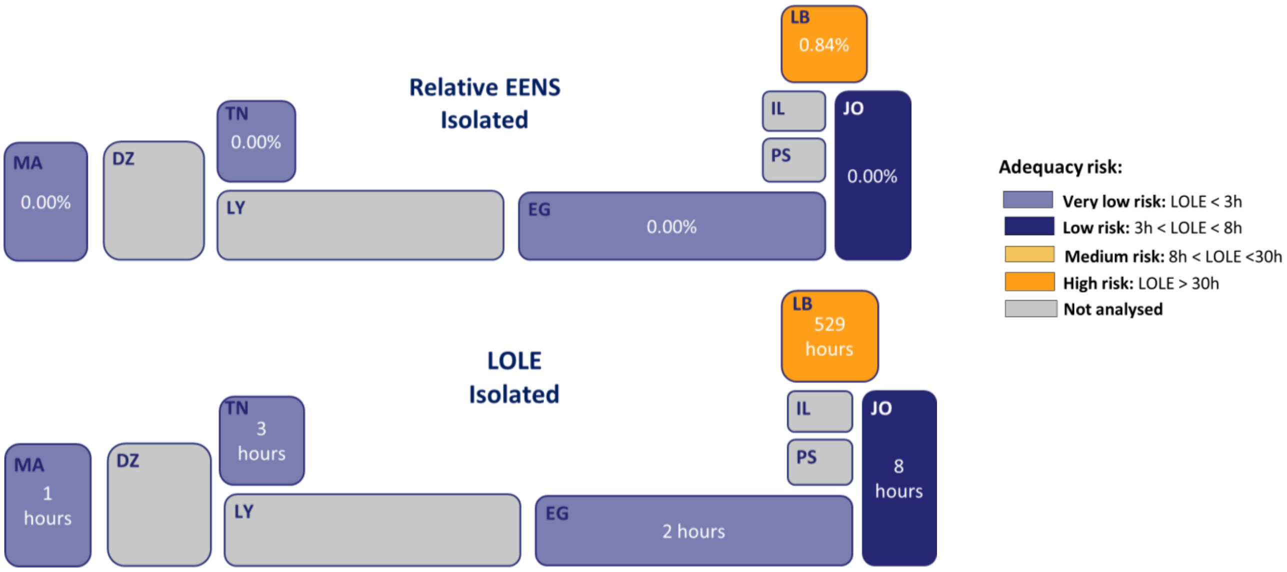


Figure 3 Relative EENS and LOLE for the isolated operational mode during normal operation 2030

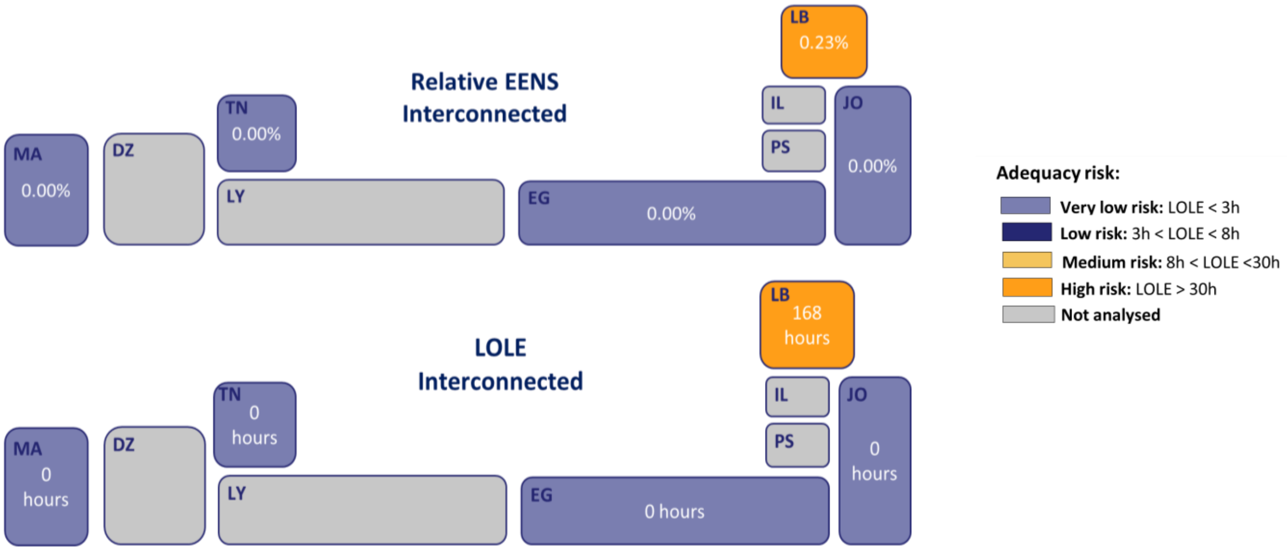


Figure 4 Relative EENS and LOLE for the interconnected operational mode during normal operation 2030.

Conclusion

The adequacy assessment of the regional power system for 2027 and 2030 highlights the significant impact of interconnection on system reliability, particularly in reducing loss-of-load risk and expected energy not served (EENS).

- 2027 Results

In the isolated mode, Figure 1 some countries face adequacy challenges. Lebanon (LB) is the most critical, with 7,728 LOLE hours, while Tunisia (TN) and Jordan (JO) also experience non-negligible risks (TN: 17 LOLE hours; JO: 19 LOLE hours).

In the interconnected mode, Figure 2 the adequacy situation improves substantially. Tunisia's LOLE decreases from 17 hours to 2 hours, while Jordan's falls to 2 hours. Lebanon still faces the highest risk (6,714 LOLE hours), but the regional interconnection reduces the overall system stress.

- 2030 Results

In the isolated mode, Figure 3 Lebanon remains the main adequacy concern, though the situation improves (529 LOLE hours). Other countries show very limited risks (e.g., Tunisia: 3 LOLE hours; Jordan: 8 LOLE hours).

In the interconnected mode, Figure 4 adequacy performance strengthens further. Most countries show negligible LOLE, and Lebanon significantly reduced to 168 LOLE hours.

The results confirm that while some countries face localized adequacy concerns, the regional interconnected system delivers much stronger adequacy performance compared to isolated operation, highlighting the value of cross-border electricity cooperation.

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 behaviour 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 Mid-term Adequacy Assessment 2027 & 2030 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.

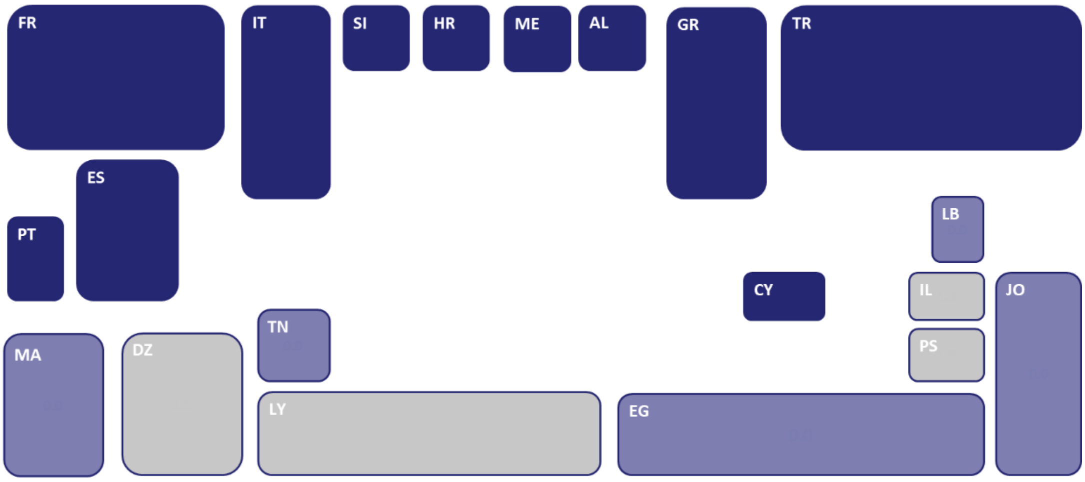
Data collections

In this report, we present the adequacy outlook for non-EU Med-TSO members for the horizons 2027 and 2030. The study builds on a comprehensive data collection exercise carried out in 2025, followed by detailed simulations and analysis.

It is important to note that the results presented here should not be directly compared with other studies, such as the Med-TSO Scenario Report 2025 edition covering 2030 horizon. The main differences lie in the methodological framework – notably the adoption of the latest PECD version – as well as the timing of the data collection. Given that the regional energy landscape has evolved significantly over the two-year interval, the findings of this report reflect recent changes in the regional energy system and provide a more current perspective on adequacy for horizon 2027 and 2030

3 Overview of the MED-TSO Power Systems in Mid-Term Adequacy Assessment

This Mid-Term Adequacy Assessment Report provides information about potential adequacy issues during years 2027 and 2030 in the 5 MED-TSO members: Morocco, Tunisia, Egypt, Jordan, and Lebanon depicted in Figure 5



▨	Med-TSO members analysed in this adequacy assessment
▨	Med-TSO members not analysed in this adequacy assessment[1]
■	Med-TSO members participating in the ENTSO-E adequacy study

Figure 5 Med-TSO members and neighbouring countries (source: Med-TSO)

The overview is organized 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.

A. Demand evolution

Table 1 & Figure 6 illustrate the projected electricity consumption in participating countries for the mid-term adequacy assessment (2027–2030). These values are the average annual consumption for 36 climatic years using PECD 4.2.

Egypt records the highest demand, with average energy consumption expected to increase from 258 TWh in 2027 to 293 TWh in 2030, reflecting a 13% growth and a CAGR of 4.27%.

Jordan shows the highest growth rate among the assessed countries, with consumption rising from 28 TWh to 35 TWh, corresponding to a 26% increase and a CAGR of 8.02%.

Morocco follows with a 21% growth (from 58 TWh to 70 TWh, CAGR 6.51%), while Tunisia and Lebanon demonstrate more moderate increases of 13% and 9%, with CAGR values of 4.10% and 3.00%, respectively.

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[1] Data for Algeria & Libya are missing from this assessment due to limited engagement from their side. Data for Israel and Palestine is currently unavailable.

These projections highlight a notable upward trend in electricity demand across the region, driven by economic and population growth, which must be considered for future capacity planning and adequacy assessments.

Table 1 Energy Demand Projections and CAGR Analysis by Country (2027–2030)

Country	Average Energy (TWh)		Percentage increase from 2027 to 2030 [%]	Compound Annual growth rate (CAGR)
	2027	2030		
EG	258	293	13%	4.27%
JO	28	35	26%	8.02%
LB	25	27	9%	3.00%
MA	58	70	21%	6.51%
TN	24	27	13%	4.10%

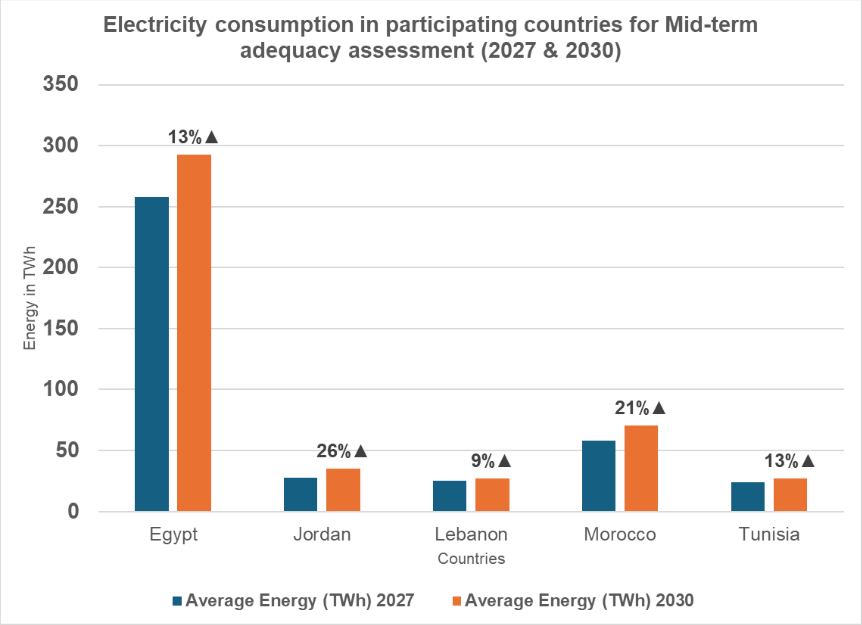

Figure 6 Expected annual consumption per country in 2027 and 2030

Table 2 & Table 3 present the projected electricity demand profiles for the participating countries in 2027 and 2030 under various weather conditions.

The seasonal variation in electricity demand across the assessed countries reveals notable differences in consumption patterns. In Egypt, Morocco, and Tunisia, the summer peak demand (26 May to October 2nd) aligns closely with the maximum demand due to increased air conditioning loads during high-temperature periods. In contrast, Jordan and Lebanon exhibit a different profile, where the winter peak demand (26 November to 1st of April) exceeds the summer peak.

This is primarily attributed to higher electricity usage for heating during colder months, coupled with lower reliance on air conditioning compared to North African countries.

Understanding these seasonal dynamics is critical for system adequacy planning, as it affects maintenance activities and reserve allocation to ensure reliability throughout the year.

Table 2 Projected Electricity Demand by Country Under Extreme and Mild Weather Conditions – 2027 Summary

Country Demand 2027 summary	Maximum demand in extreme weather conditions (GW)	Summer peak in extreme weather conditions (GW)	Winter Peak in extreme weather conditions (GW)	Minimum demand in mild weather conditions (GW)	Average Energy (TWh)
EG	45.15	45.15	35.73	17.52	258
JO	6.20	6.12	6.20	1.17	28
LB	4.88	4.39	4.88	1.24	25
MA	9.56	9.56	8.34	4.27	58
TN	6.80	6.80	3.86	1.29	24

Table 3 Projected Electricity Demand by Country Under Extreme and Mild Weather Conditions – 2030 Summary

Country Demand 2030 summary	Maximum demand in extreme weather condition (GW)	Summer peak in extreme weather condition (GW)	Winter Peak in extreme weather condition (GW)	Minimum demand in mild weather condition (GW)	Average Energy (TWh)
EG	50.98	50.98	40.53	20.32	293
JO	7.48	7.40	7.48	1.37	35
LB	5.34	4.84	5.34	1.45	27
MA	11.55	11.55	10.28	5.10	70
TN	7.68	7.68	4.73	1.36	27

Concerning daily patterns, in each country there are seven rather similar daily profiles with one or two peaks within a day, In the case of Egypt and Jordan, demand is slightly lower on Fridays while in Morocco, Tunisia and Lebanon on Sundays.

B. Expected evolution of installed capacities

Table 4 & Table 5 shows the expected installed generation capacities for participating countries by 2027 and 2030, highlighting the evolving balance between thermal power plants (TPP) and renewable energy sources (RES).

In 2027, thermal generation remains dominant, representing around 67% of the total installed capacity (71.2 GW out of 106.7 GW). Among the countries, Egypt is the main contributor, with 50.9 GW of TPP capacity, accounting for 78% of its national mix. Similarly, Tunisia and Lebanon show a high dependency on thermal power, at 68% and 54%, respectively.

By 2030, although thermal power remains the largest contributor, its share is projected to decline to 56% (71.8 GW out of 127.2 GW), reflecting a gradual shift towards renewable energy integration. Notably, Egypt’s reliance on TPP decreases slightly to 64% despite an absolute reduction in capacity, while Morocco and Jordan diversify their generation mix by significantly expanding solar PV and wind capacities.

Table 4 Total installed capacities (MW) per technology in 2027

Country	Expected WPP capacity [MW]	Expected solar PV capacity [MW]	Expected CSP capacity (with storage) [MW]	Expected CSP capacity (without storage) [MW]	Expected HPP capacity [MW]	Expected battery storage capacity [MW]	Expected hydro pump storage capacity [MW]	Expected TPP capacity [MW]	TOTAL [MW]
EG	4336	6491	-	140	2831	910	-	50939	**65647**
JO	621	2852	-	-	-	8	-	5365	**8846**
LB	-	1665	-	-	341	-	-	2341	**4347**
MA	4868	3524	540	-	1306	1600	1140	7436	**20414**
TN	322	1877	-	-	-	160	-	5117	**7476**
TOTAL	**10147**	**16409**	**540**	**140**	**4478**	**2678**	**1140**	**71198**	**106730**

Table 5 Total install capacities (MW) per technology in 2030

Country	Expected WPP capacity [MW]	Expected solar PV capacity [MW]	Expected CSP capacity (with storage) [MW]	Expected CSP capacity (without storage) [MW]	Expected HPP capacity [MW]	Expected battery storage capacity [MW]	Expected hydro pump storage capacity [MW]	Expected TPP capacity [MW]	TOTAL [MW]
EG	13236	8041	-	140	2831	1660	-	46756	**72664**
JO	850	3620	-	-	-	133	450	6181	**11234**
LB	226	2130	-	-	435	-	-	4566	**7357**
MA	5868	5071	540	-	1306	1600	1740	8756	**24881**
TN	1642	3291	-	-	-	565	-	5587	**11085**
TOTAL	**21822**	**22153**	**540**	**140**	**4572**	**3958**	**2190**	**71846**	**127221**

Renewable energy sources show substantial growth over the period. Total RES capacity (including wind, solar PV, CSP, and hydro) is expected to increase from 33.8 GW in 2027 to 53.2 GW in 2030, raising their share from 31% to 42% of the total installed capacity. The largest contributors are Morocco and Egypt, driven by extensive wind and solar PV developments, while Jordan achieves a remarkable 32% solar PV share in both 2027 and 2030, supported by gradual wind and storage deployment.

Overall, these projections indicate a progressive energy transition in the region, where thermal power remains essential for adequacy and reliability, but renewable penetration is accelerating, reshaping the generation mix towards a more sustainable and diversified portfolio.

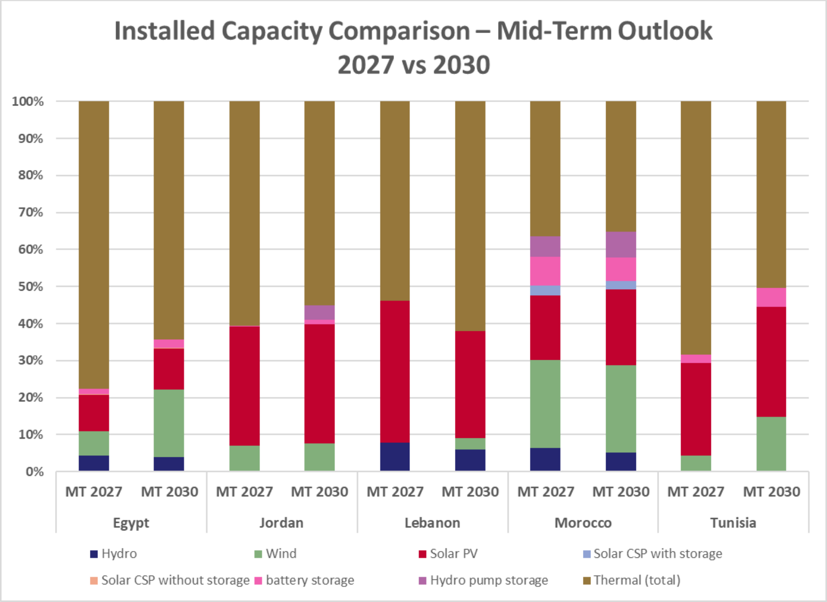

Figure 7 Share of Installed Capacity by Technology – Mid-Term Outlook 2027 vs 2030 (% Share)

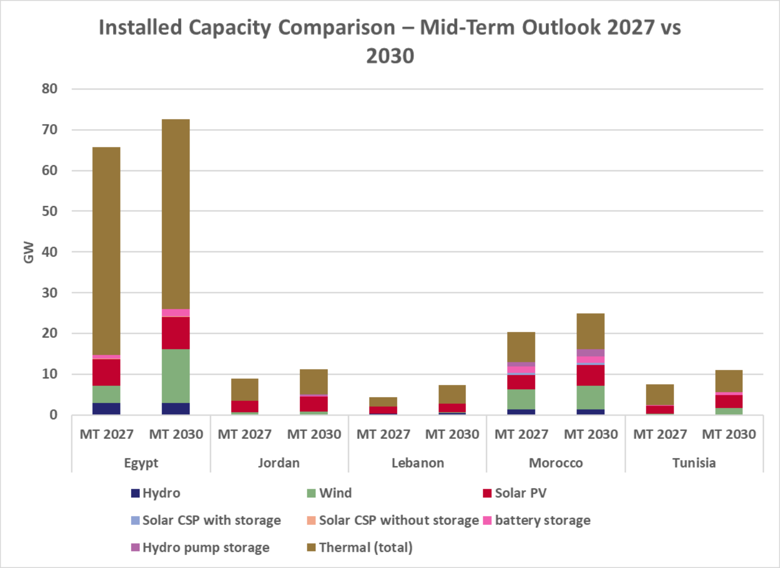

Figure 8 Installed Capacity Comparison by Technology – Mid-Term Outlook 2027 vs 2030 (in GW)

Capacity factors related to wind and solar generation are presented in Table 6. It is worth mentioning that capacity factors consider the technology used and the zone splitting of each country according to PECD v4.2.

Table 6 Wind and solar capacity factors for all countries during Mid-term 2027 & 2030.

	2027			2030		
Country	**Wind CF**	**Solar PV CF**	**Solar CSP CF**	**Wind CF**	**Solar PV CF**	**Solar CSP CF**
EG	53.8%	24.7%	27.3%	53.8	24.7%	27.3%
JO	31.2%	27%	-	31.2%	27%	-
LB	-	18.6%	-	14.4	19%	-
MA	51.6%	17.2%	38%	50.3%	17.2%	38%
TN	23.5%	23.2%	-	38%	23.6	-

Planned outages are modelled as random planned outages, while respecting certain predefined rules as shown in the table below.

Table 7 shows the months when maintenance is allowed and when it is not

Country	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
EG	yes	yes	yes	yes	yes	no	no	no	no	yes	yes	yes
JO	No	No	yes	yes	yes	Yes	no	no	no	yes	yes	no
LB	yes	yes	yes	yes	yes	no	no	no	yes	yes	yes	yes
MA	yes	yes	yes	yes	yes	no	no	no	no	yes	yes	yes
TN	yes	yes	yes	yes	yes	no	no	no	yes	yes	yes	yes

From the table above, we can clearly see that all participating countries is strictly prohibited maintenance during summer months (primary June, July, August and often September)

Maintenance is strategically scheduled for the spring and fall seasons and winter (not in the case for Jordan), when overall electricity demand is lower, thereby ensuring grid reliability during times of stress.

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.

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 modelled 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 & Libya, it is assumed that the countries can export electricity to neighbouring countries in the event of adequacy risk. Furthermore, it is assumed that Algeria & Libya do not face any adequacy risk.

During 2027 horizon as seen in Figure 9, 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. Also, 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 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 during 2029, 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.

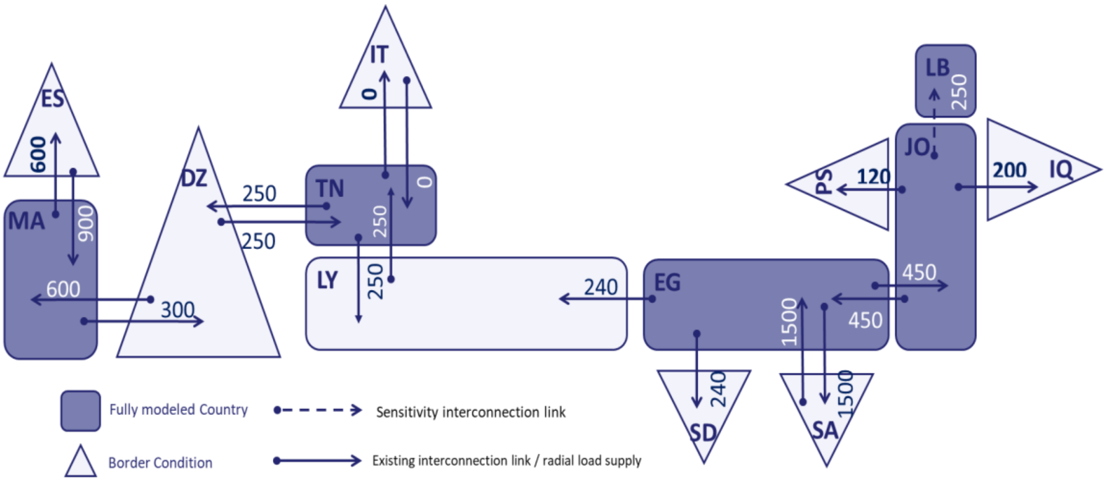

Figure 9 Maximum Net transfer capacity during year 2027

For the 2030 horizon as seen in Figure 10, we considered that Tunisia and Italy plan to commission their first electricity interconnection project by year 2028.

The interconnection will link the transmission systems of Europe and North Africa to achieve an increasingly safe, sustainable and renewable future for energy.

The 500 kV power line will run from the electrical substation at Partanna (Sicily) to the substation at Mlaabi on the Tunisian peninsula of Capo Bon, for a total length of 220 km (200 km of which is undersea cable). It will have a capacity of 600 MW and a maximum depth of approximately 800 m, along the Strait of Sicily.

Furthermore, the following capacity increases are anticipated:

- The Net Transfer Capacity (NTC) between Morocco and Algeria will be increased to 1000 MW in both directions.
- The NTC between Egypt and Jordan will be raised to 1100 MW in both directions, with 300 MW allocated for export to Syria and 500 MW to Lebanon.
- A new 500 MW interconnection between Jordan and Saudi Arabia is scheduled for commissioning by 2030.

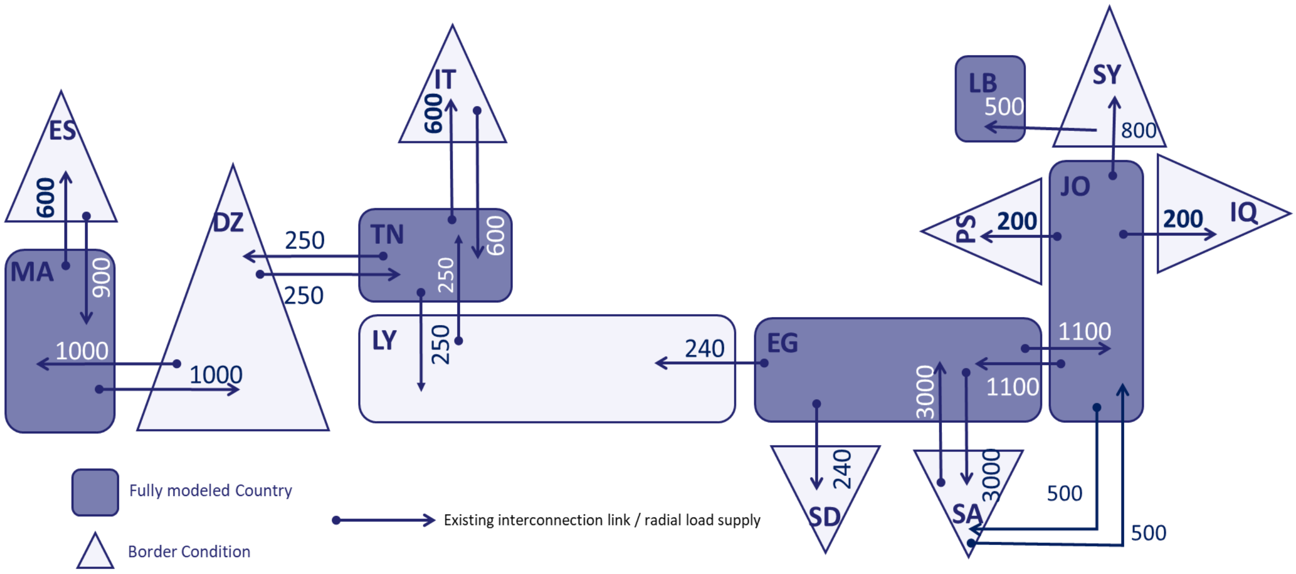

Figure 10 Maximum Net transfer capacity during year 2030

D. Reserve requirements and modelling

Reserve requirements have been provided for each country (Table 8). In some countries, the percentages of 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 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.

Table 8 Balancing reserve requirements.

Country	Reserve	Mid-Term 2027 & 2030
EG	FCR+FRR [MW]	1200
JO	FCR+FRR [MW]	200
LB	FCR+FRR [MW]	120
MA	FCR+FRR [MW] [2]	900
TN	FCR+FRR [MW]	220

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[2] FCR for MA has been modelled through reduced thermal capacity by a total of 400 MW.

4 Adequacy Situation Overview

4.1 Adequacy assessment

The adequacy situation has been assessed using a two-step approach. First, adequacy under isolated system operation is evaluated. Second, adequacy under interconnected system operation is analysed to highlight the importance of cross-border interconnections.

In a theoretical isolated scenario (Figure 11), focusing on the 2027 horizon, adequacy risks are identified in Jordan, Tunisia, and Lebanon. While Tunisia and Jordan face a medium adequacy risk, Lebanon experiences a very high adequacy risk under isolated system conditions.

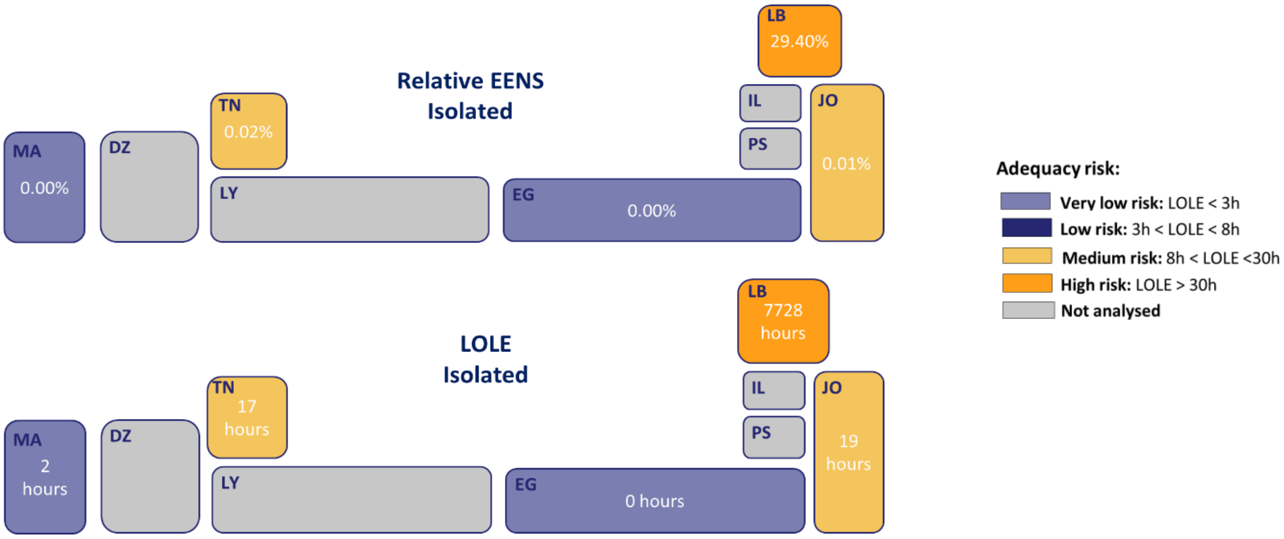

Figure 11 Relative EENS and LOLE for the isolated operational mode during normal operation 2027

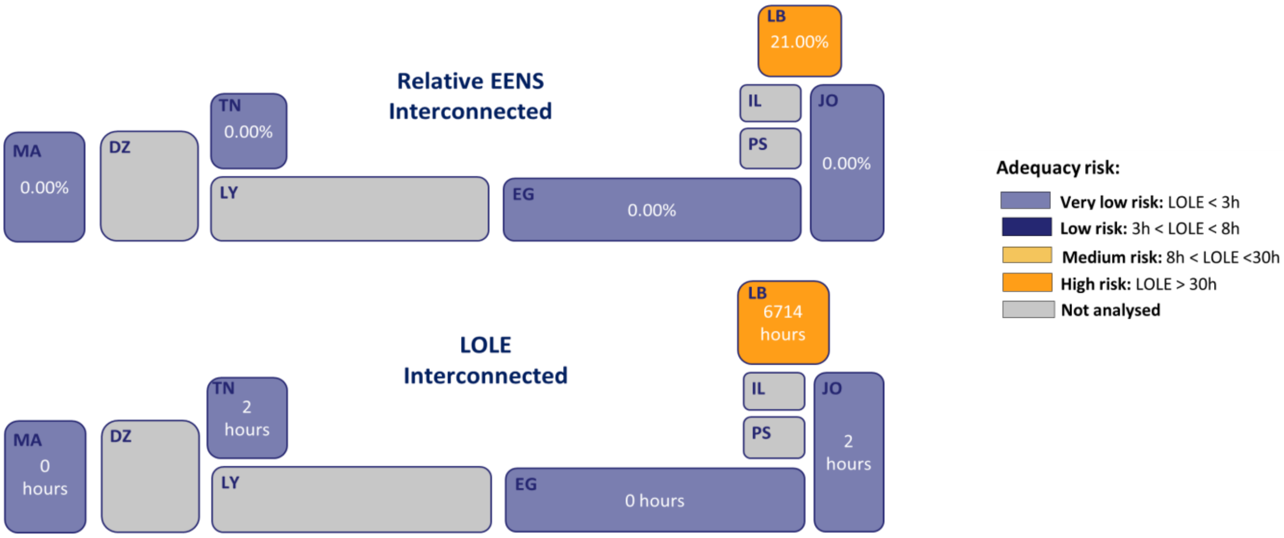

Figure 12 Relative EENS and LOLE for the interconnected operational mode during normal operation 2027

In contrast, under the interconnected operation scenario for 2027, energy exchanges with neighbouring countries significantly reduce adequacy risks. For Tunisia and Jordan, adequacy concerns are minimized. However, for Lebanon, even in this more flexible operating mode, adequacy risks remain at an unacceptably high level. Figure 12 illustrates the adequacy outlook under interconnected conditions for the 2027 horizon.

Looking ahead to the 2030 horizon, the regional adequacy outlook shows a notable improvement. Under the isolated system scenario (Figure 13)[3], most countries experience a stable or improved situation compared to 2027. Tunisia's LOLE drops significantly to 3 hours, while Jordan's decreases markedly to 8 hours., effectively resolving its previous medium adequacy risk. However, Lebanon's situation remains critical, with an extremely high LOLE of 529 hours, highlighting a persistent and severe generation capacity shortfall that cannot be addressed in isolation.

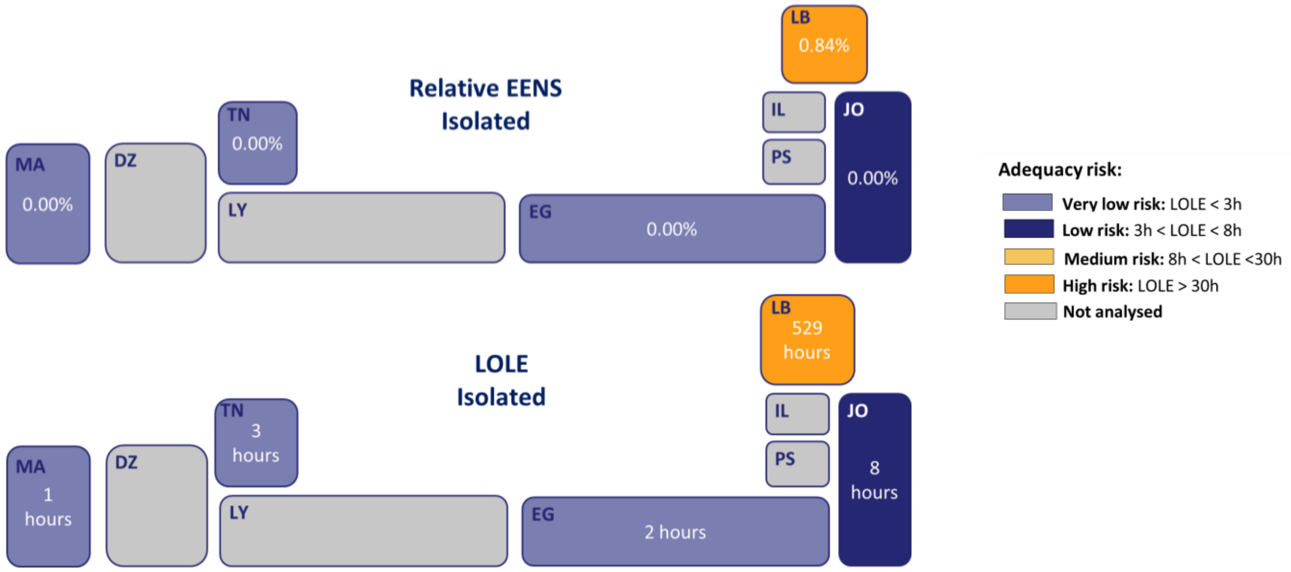

Figure 13 Relative EENS and LOLE for the isolated operational mode during normal operation 2030

By 2030, the benefits of regional interconnections become even more evident. In the interconnected scenario (Figure 14), adequacy risks are reduced to very low levels for nearly all countries, including Jordan and Tunisia, thanks to coordinated energy exchanges. Importantly, Lebanon's adequacy situation improves, with its LOLE decreasing to 168 hours. While this represents substantial progress supported by regional cooperation, the risk remains unacceptably high, underlining that interconnections alone are insufficient. Addressing Lebanon's fundamental capacity and infrastructure gaps remains essential to ensure long-term adequacy.

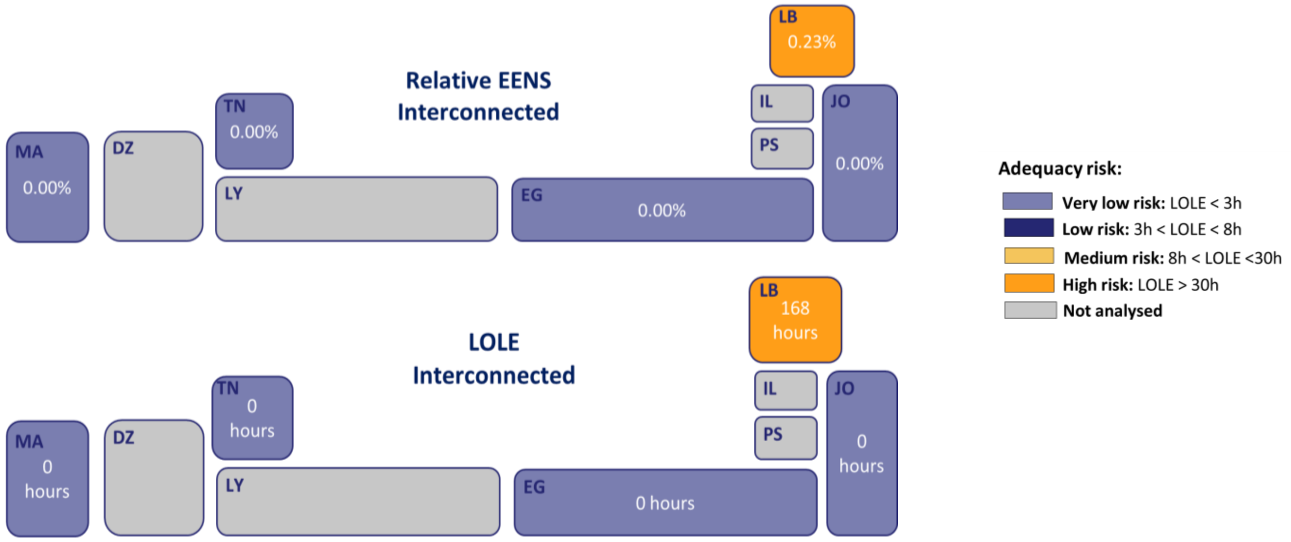

Figure 14 Relative EENS and LOLE for the interconnected operational mode during normal operation 2030

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[3] Color coding of adequacy risk levels presented in Figure 11 & Figure 13 does not reflect national thresholds for loss of load expectation (LOLE usually specified within the network codes of corresponding Transmission System Operators).

in order to have insights into the distribution of adequacy risks by illustrating how likely different outcomes are across numerous simulated scenarios, we use Percentiles to capture the range and variability of results, highlighting both typical conditions and extreme events.

- 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.

Analysing 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.

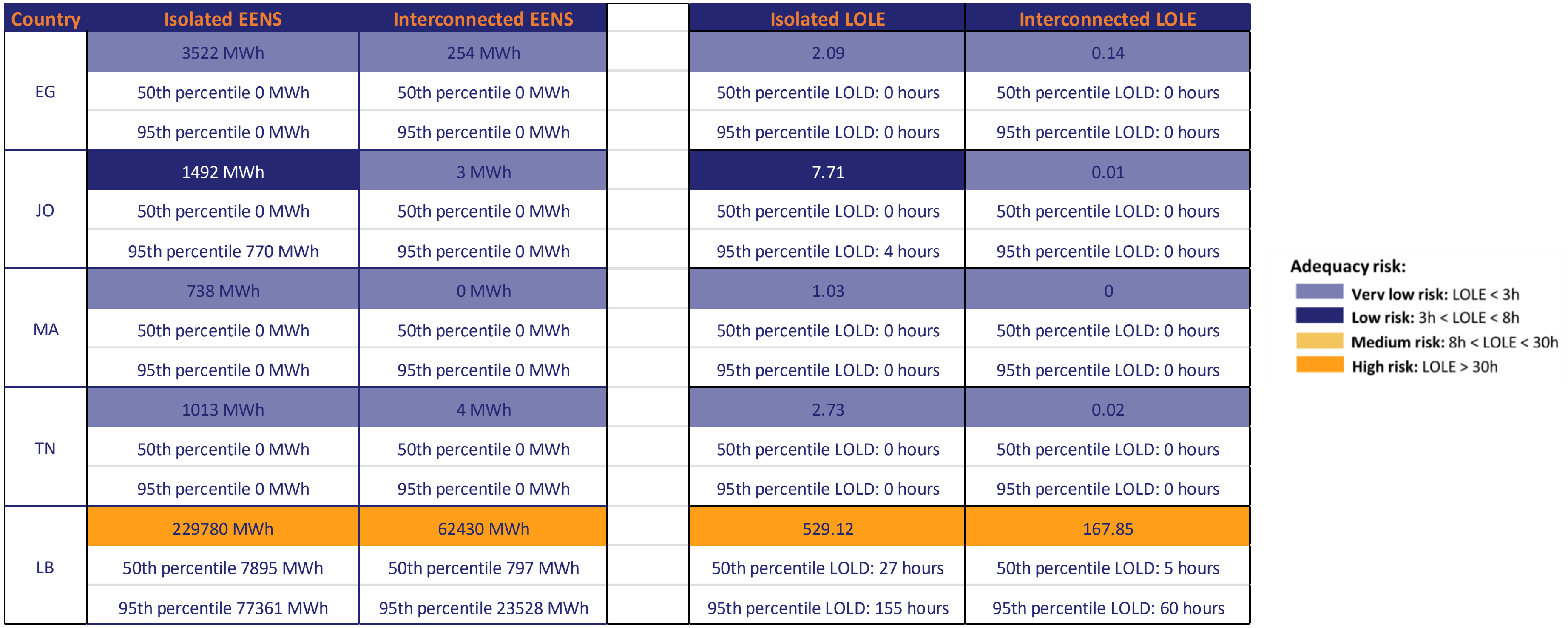
Table 9 EENS and LOLE for isolated and interconnected scenarios - 2027

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	3901 MWh	309 MWh		19.26	1.96
	50th percentile 0 MWh	50th percentile 0 MWh		50th percentile LOLD: 0 hours	50th percentile LOLD: 0 hours
	95th percentile 1875 MWh	95th percentile 74 MWh		95th percentile LOLD: 8 hours	95th percentile LOLD: 1 hours
MA	876 MWh	0 MWh		1.5	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	4620 MWh	555 MWh		16.76	2.09
	50th percentile 0 MWh	50th percentile 0 MWh		50th percentile LOLD: 0 hours	50th percentile LOLD: 0 hours
	95th percentile 1709 MWh	95th percentile 0 MWh		95th percentile LOLD: 9 hours	95th percentile LOLD: 0 hours
LB	7322913 MWh	5232095 MWh		7727.87	6713.7
	50th percentile 609313 MWh	50th percentile 432006 MWh		50th percentile LOLD: 668 hours	50th percentile LOLD: 582 hours
	95th percentile 920714 MWh	95th percentile 736782 MWh		95th percentile LOLD: 744 hours	95th percentile LOLD: 732 hours

Adequacy risk:

🟪 **Verv low risk:** LOLE < 3h
🟦 **Low risk:** 3h < LOLE < 8h
🟨 **Medium risk:** 8h < LOLE < 30h
🟧 **High risk:** LOLE > 30h

Table 10 EENS & LOLE for isolated and interconnected scenarios - 2030



Country	Isolated EENS	Interconnected EENS	Isolated LOLE	Interconnected LOLE
EG	3522 MWh	254 MWh	2.09	0.14
	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	1492 MWh	3 MWh	7.71	0.01
	50th percentile 0 MWh	50th percentile 0 MWh	50th percentile LOLD: 0 hours	50th percentile LOLD: 0 hours
	95th percentile 770 MWh	95th percentile 0 MWh	95th percentile LOLD: 4 hours	95th percentile LOLD: 0 hours
MA	738 MWh	0 MWh	1.03	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	1013 MWh	4 MWh	2.73	0.02
	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	229780 MWh	62430 MWh	529.12	167.85
	50th percentile 7895 MWh	50th percentile 797 MWh	50th percentile LOLD: 27 hours	50th percentile LOLD: 5 hours
	95th percentile 77361 MWh	95th percentile 23528 MWh	95th percentile LOLD: 155 hours	95th percentile LOLD: 60 hours

Adequacy risk:

🟪 **Verv low risk:** LOLE < 3h
🟦 **Low risk:** 3h < LOLE < 8h
🟨 **Medium risk:** 8h < LOLE < 30h
🟧 **High risk:** LOLE > 30h

Table 9 & Table 10 provides detailed EENS and LOLE results for all analysed countries, including P50 and P95 sensitivity scenarios for 2027 and 2030 horizons.

4.2 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. Our primary objective is to evaluate potential cross-border exchanges among the five analysed countries and quantify each one's requirements to address adequacy risks during periods of isolation.

The following table summarizes the feasible exchanges needed to overcome adequacy risks and NTC among the countries subject to our analysis for horizon 2027

Table 11 Exchanges needed to overcome adequacy risks in 2027 horizon

Link		Total Exchanges for Adequacy (GWh)	Country A – Country B NTC (MW)	Country B – Country A NTC (MW)
Country A	Country B			
DZ00	MA00	0	600	300
DZ00	TN00	2	250	250
EG00	JO00	10	450	450
ES00	MA00	0	900	600
LY00	TN00	2	250	250
JO00	LB00	795	250	0
EG00	SA00	0	1500	1500

Exporting electricity (around 10 GWh) from Egypt to Jordan positively contributes to enhancing Jordan's adequacy. Furthermore, Algeria and Libya support Tunisia to overcome adequacy risks, as for the situation in Lebanon is completely different, in that hypothetical interconnections with Jordan through Syria and imported energy play a substantial role. While interconnections help decrease adequacy concerns by 13%, alone they are insufficient to fully mitigate these potential risks.

Table 12 Exchanges needed to overcome adequacy risks in 2030 horizon

Link		Total Exchanges for Adequacy (GWh)	Country A – Country B NTC (MW)	Country B – Country A NTC (MW)
Country A	Country B			
DZ00	MA00	0	1000	1000
DZ00	TN00	0	250	250
EG00	JO00	3	1100	1100
ES00	MA00	0	900	600
LY00	TN00	0	250	250
EG00	SA00	-1	3000	3000
IT00	TN00	0	600	600
JO00	SY00	456	800	0
LB00	SY00	-285	0	500
JO00	SA00	0	500	500

For the 2030 horizon (Table 12), the adequacy situation shows some significant changes compared to 2027. The exchanges required to overcome adequacy risks decrease for most North African links, with Tunisia able to rely more on internal resources.

Egypt's exports to Jordan remain relevant but reduced to around 3 GWh, while flows from Saudi Arabia to Egypt around 1 GWh, indicating a potential export from Saudi Arabia to Egypt under certain conditions.

Southern Europe–North Africa exchanges, such as Spain–Morocco, remain stable and continue to support regional adequacy. The Italy–Tunisia (IT–TN) interconnection, with 0 GWh needed for adequacy and a bilateral NTC of 600 MW, indicates that Tunisia can rely on imports from Italy if necessary.

In the Eastern Mediterranean, Jordan exports electricity to Syria (456 GWh), which then transmits power to Lebanon (285 GWh), highlighting Lebanon's reliance on transit through Syria. This emphasizes that interconnections are crucial for adequacy in the Levant region, with flows from Jordan via Syria effectively supporting Lebanon's adequacy.

5 Adequacy Situation at Country Level

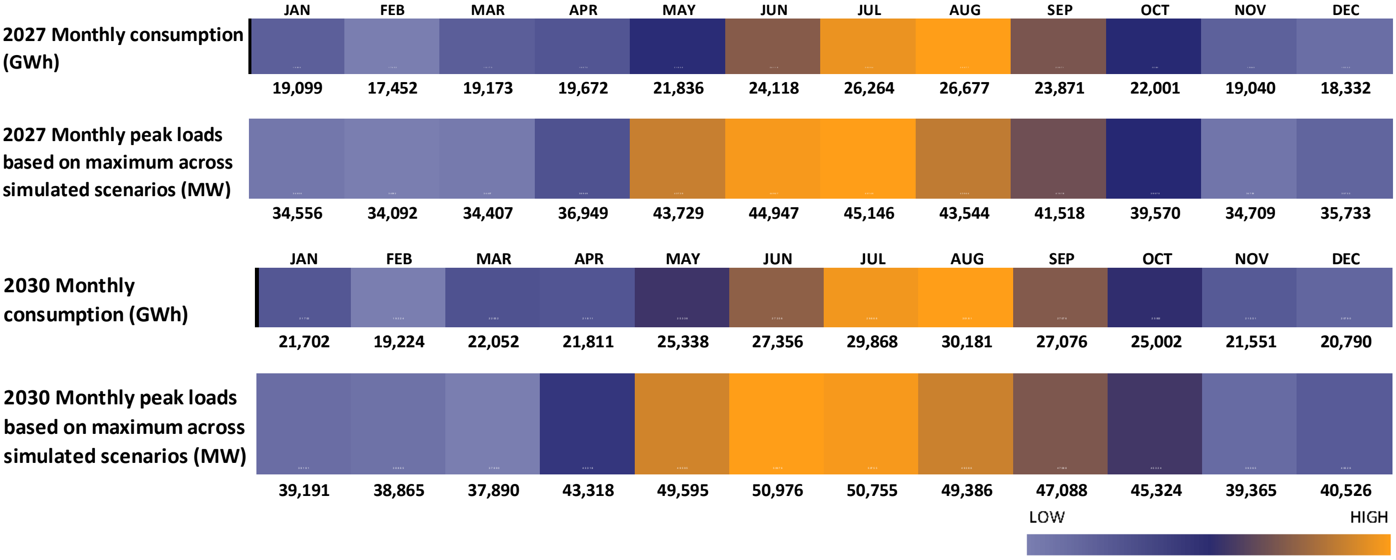
5.1 Egypt

DEMAND

Figure 15 presents the forecasted Egyptian monthly demand in 2027 (top) and 2030 (bottom). In 2027, forecast monthly consumption ranges from 17,452 GWh to 26,677 GWh, while monthly peak demand varies from 34 GW to 45 GW. It should be noted that monthly demand refers to the average values across all 36 climatic years analysed, whereas peak hourly demand corresponds to the monthly maximum for all 36 climatic years.

Similarly, in 2030, Egyptian monthly demand ranges from approximately 19,224 GWh to 30,181 GWh, with monthly peak demand varying from 37.8 GW to 50.9 GW. Increase of peak load in the period from 2027 to 2030 is 5.9 GW or 13%.

Maximum electricity needs are expected in July and August, due to high temperatures and high cooling consumption, similar as in all other countries. Due to this monthly distribution of the load, TPPs' maintenance activities are not allowed during summer, in months, June, July, August and September.



	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2027 Monthly consumption (GWh)	19,099	17,452	19,173	19,672	21,836	24,118	26,264	26,677	23,871	22,001	19,040	18,332
2027 Monthly peak loads based on maximum across simulated scenarios (MW)	34,556	34,092	34,407	36,949	43,729	44,947	45,146	43,544	41,518	39,570	34,709	35,733

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2030 Monthly consumption (GWh)	21,702	19,224	22,052	21,811	25,338	27,356	29,868	30,181	27,076	25,002	21,551	20,790
2030 Monthly peak loads based on maximum across simulated scenarios (MW)	39,191	38,865	37,890	43,318	49,595	50,976	50,755	49,386	47,088	45,324	39,365	40,526

Figure 15 Forecasted monthly demand in Egypt – 2027 (Top) and 2030 (Bottom)

SUPPLY AND NETWORK OVERVIEW

In 2027, Egyptian power generation is almost exclusively based on natural gas, with the gas TPP share in total installed capacities at around 77%, further divided into conventional and CCGT TPPs. The oil TPP share is 1%, while the hydro share is 4%. RES wind and solar capacities amount to 7% and 10% sequentially. The system is supported by 910 MW of battery storage which represents almost 1%

Total net generation installed capacities (NGIC) (Including hydro and RES) reach 65,738 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 45 GW. In terms of demand and installed capacities, Egypt represents the biggest of all the analysed power systems.

Similarly, in 2030, Egypt introduces nuclear power generation with an installed capacity of 2.4 GW, representing 4% of the total installed capacity. with the gas TPP share in total installed capacities at around 61%, further divided into conventional and CCGT TPPs. The hydro share is 4%. RES wind and solar capacities amount to 18% and 11% sequentially. The system is supported by 1660 MW of battery storage which represents almost 2%. The total net installed generation capacity reaches 71 GW, while the available import capacity from Jordan of up to 4,100 MW is significantly higher than the projected peak load of 50.9 GW.

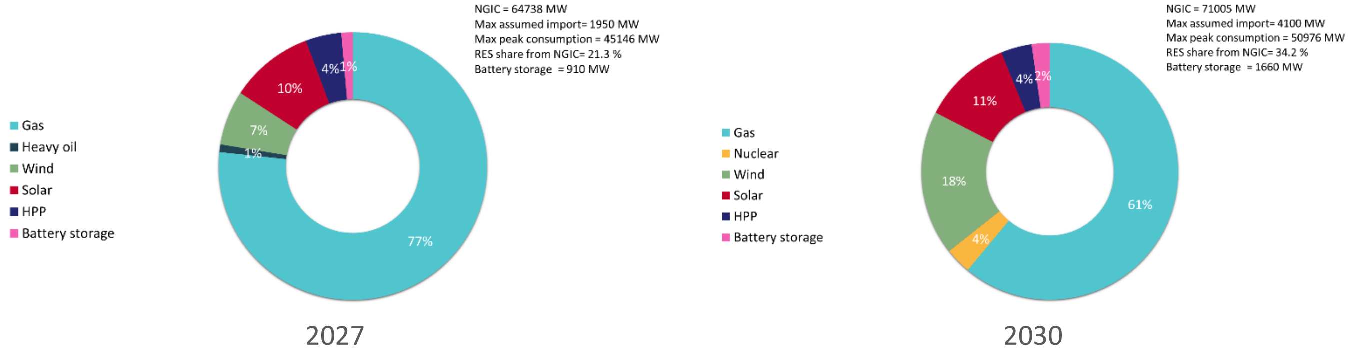


Figure 16 Installed capacity mix with total NGIC, max assumed import NTC, and peak demand in Egypt

The average daily available TPP capacity, after reduction due to forced outages, is shown in Figure 17. 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.

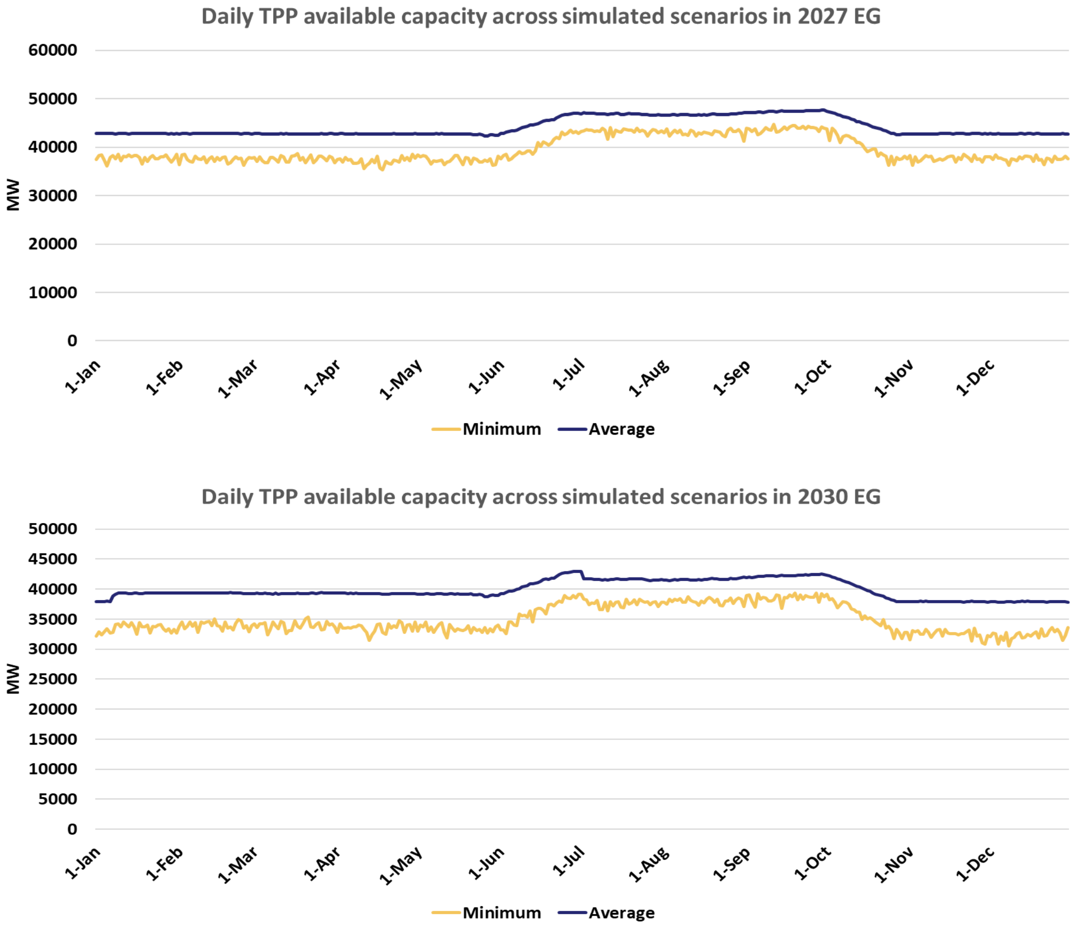


Figure 17 Average and minimum TPP available capacity among all simulated MC years in Egypt – 2027 (Top) and 2030 (Bottom)

As a result of system simulation, the minimum hourly TPP capacity margin among all simulated MC years is depicted in Figure 18. It represents the difference between available and activated TPP capacities. The hourly minimum TPP margin is between 2 GW and 12 GW during the analysed summer season.

A very high TPP capacity margin indicates that Egypt will not have adequacy issues during 2027 and 2030, and that it has huge export capabilities that can benefit neighbouring countries' adequacy deficits.

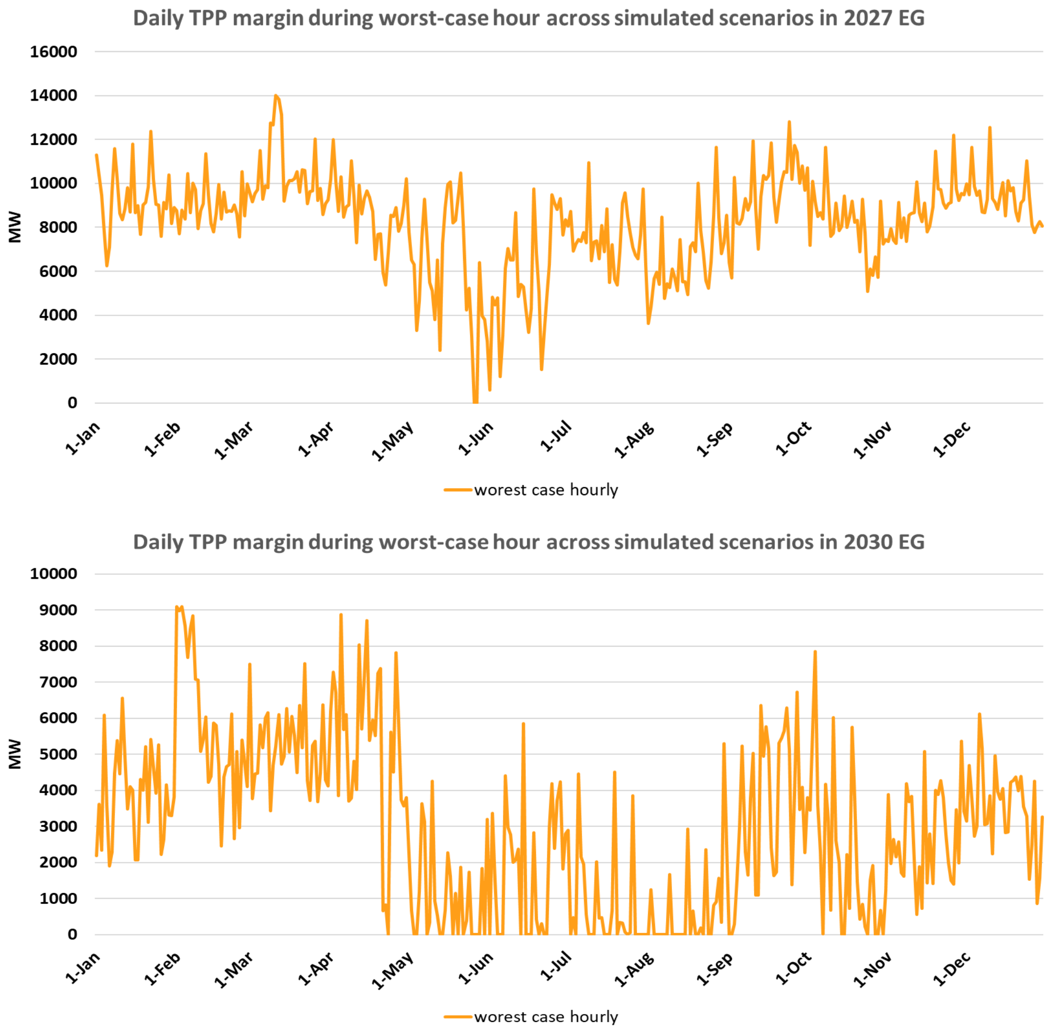


Figure 18 Minimum hourly TPP margin on each day of the analysed period among all simulated MC years in Egypt 2027(top) and 2030 (bottom)

ADEQUACY ASSESSMENT

Figure 19 presents adequacy assessments for both 2027 and 2030. Egypt demonstrates a robust adequacy position, with only very limited load-shedding risk. The results confirm that the system is expected to reliably meet demand across both horizons, irrespective of interconnection status. The minor occurrences of load-shedding are mainly attributed to random maintenance outages rather than structural adequacy shortcomings. Such risks can be effectively mitigated through a planned maintenance strategy that schedules outages away from periods of high demand.

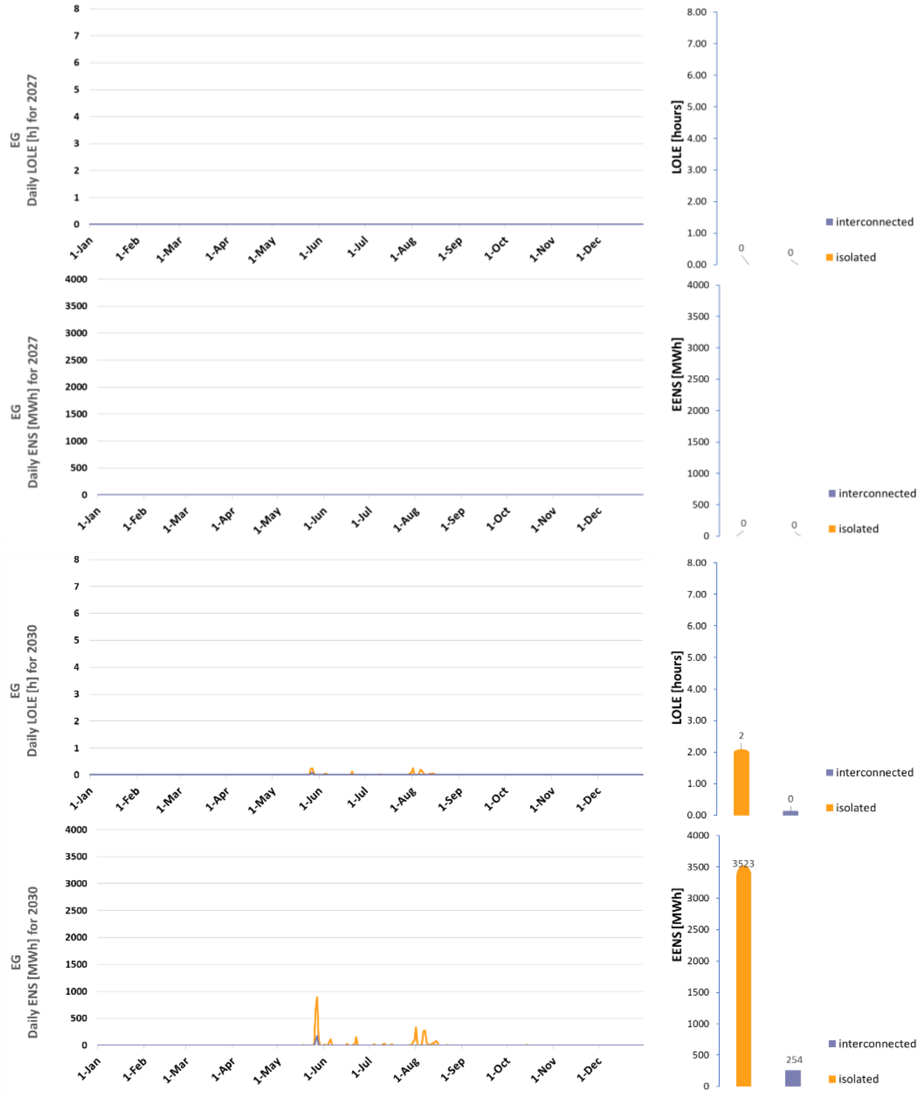


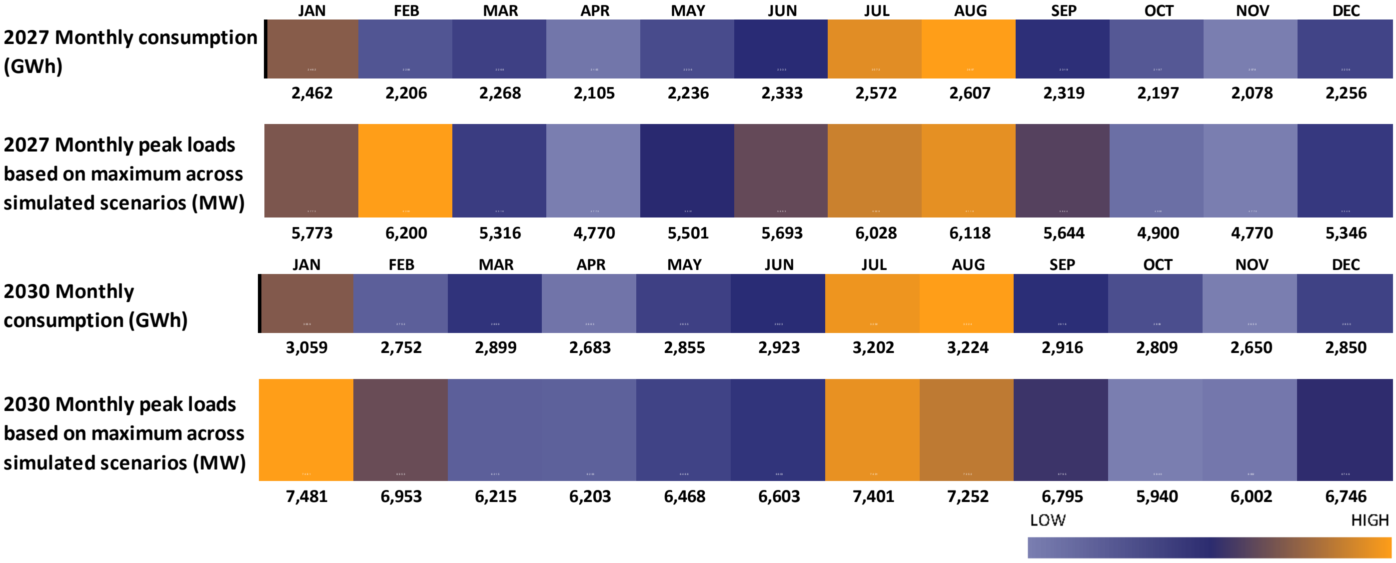
Figure 19 Daily LOLE and EENS for the interconnected and isolated mode of operation in Egypt – 2027 (Top) and 2030

5.2 Jordan

DEMAND

Figure 20 presents the forecasted Jordanian monthly demand in 2027 (top) and 2030 (bottom). In 2027, forecasted monthly consumption ranges from 2,078 GWh to 2,607 GWh, while monthly peak demand varies from 4.7 GW to 6.2 GW. Monthly demand refers to the average values across all 36 climatic years analysed, whereas peak hourly demand corresponds to the monthly maximum for all 36 climatic years.

In 2030, Jordanian monthly demand is projected to range from approximately 2,650 GWh to 3,224 GWh, with monthly peak demand varying from 5.9 GW to 7.5 GW. The increase in peak load from 2027 to 2030 is 1.2 GW, corresponding to approximately 21%. Maximum electricity needs are expected twice per year: in summer (July–August) due to high temperatures and cooling consumption, and in winter (December–February) due to heating. Because of this monthly load distribution, maintenance of thermal power plants is not allowed during summer (July–September) and winter (December–February).



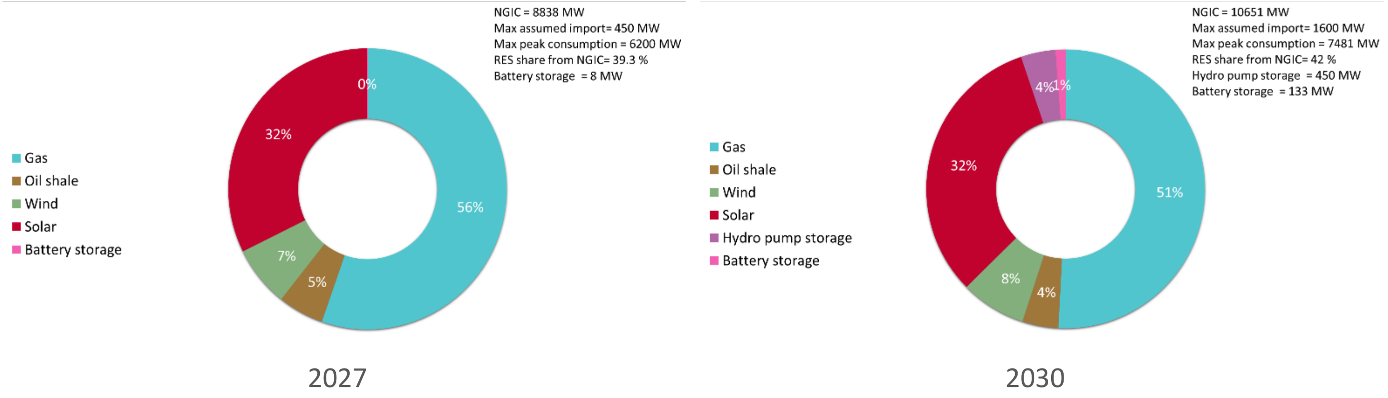
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2027 Monthly consumption (GWh)	2,462	2,206	2,268	2,105	2,236	2,333	2,572	2,607	2,319	2,197	2,078	2,256
2027 Monthly peak loads based on maximum across simulated scenarios (MW)	5,773	6,200	5,316	4,770	5,501	5,693	6,028	6,118	5,644	4,900	4,770	5,346
2030 Monthly consumption (GWh)	3,059	2,752	2,899	2,683	2,855	2,923	3,202	3,224	2,916	2,809	2,650	2,850
2030 Monthly peak loads based on maximum across simulated scenarios (MW)	7,481	6,953	6,215	6,203	6,468	6,603	7,401	7,252	6,795	5,940	6,002	6,746

Figure 20 Forecasted monthly demand in Jordan – 2027 (Top) and 2030 (Bottom)

SUPPLY AND NETWORK OVERVIEW

In 2027, Jordanian power generation is predominantly based on natural gas, with the gas TPP share in total installed capacities at around 56%, further divided into conventional and OCGT TPPs. Oil share amounts to 5% of installed capacities, while RES wind and solar share in installed capacities are 7% and 32%, respectively. Total net generation installed capacities (NGIC) (Including hydro and RES) reach 8,838 MW with import capacity up to 450 MW from Egypt, which combined, is substantially higher than the maximum hourly consumption of 6.2 GW.

Similarly, in 2030 Total net generation installed capacities reach 10.6 GW with import capacity from Egypt of up to 1100 MW and 500 MW from Saudi Arabia which is significantly higher than peak load of 7.5 GW.

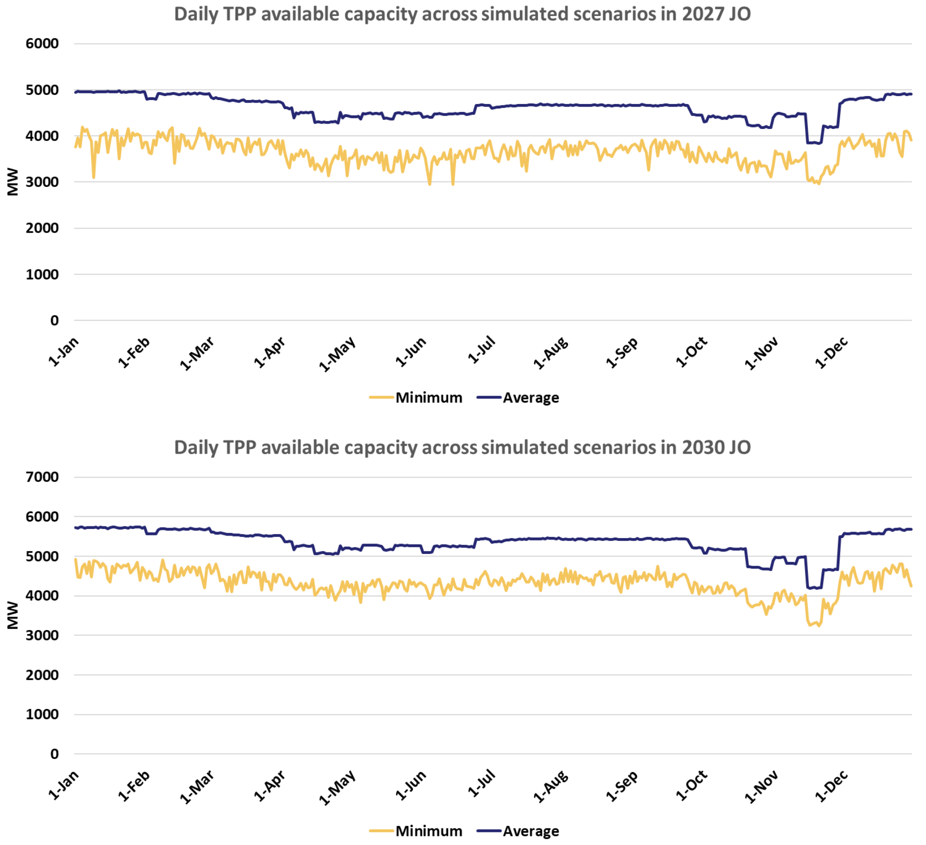


NGIC = 8838 MW
Max assumed import= 450 MW
Max peak consumption = 6200 MW
RES share from NGIC= 39.3 %
Battery storage = 8 MW

NGIC = 10651 MW
Max assumed import= 1600 MW
Max peak consumption = 7481 MW
RES share from NGIC= 42 %
Hydro pump storage = 450 MW
Battery storage = 133 MW

Figure 21 Installed capacity mix with total NGIC, max assumed import NTC, and peak demand in Jordan

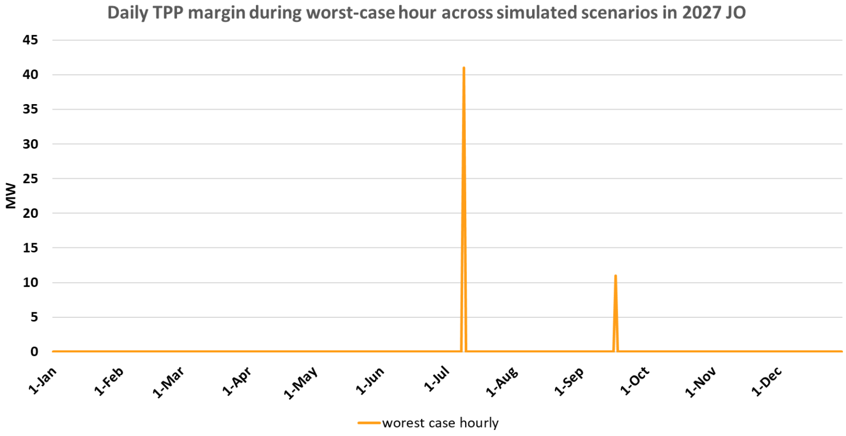
The average daily available TPP capacity, after reduction due to derating factors, and forced and planned outages, is shown in Figure 22. Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated modes of operation.


Daily TPP available capacity across simulated scenarios in 2027 JO

Daily TPP available capacity across simulated scenarios in 2030 JO

Figure 22 Average and minimum TPP available capacity among all simulated MC years in Jordan – 2027 (Top) and 2030 (Bottom)

As a result of system simulation, the minimum hourly TPP capacity margin among all simulated MC years is depicted in Figure 23. It represents the difference between available and activated TPP capacities. The minimum hourly value of the TPP margin is often at zero throughout 2027 and 2030 horizon. 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.



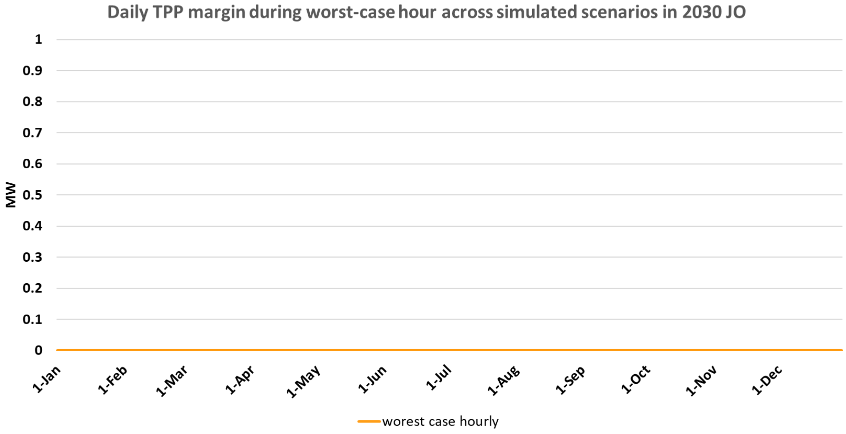


Figure 23 Minimum hourly TPP margin on each day of the analysed period among all simulated MC years in Jordan 2027 (top) and 2030 (bottom)

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is shown in Figure 24, for both modes of operation: interconnected and isolated in 2027 and 2030. The first panel illustrates the daily LOLE distribution, while the second shows the daily EENS. On the right-hand side of the figure, the total LOLE and EENS are presented for both operational modes.

In 2027, interconnections reduce LOLE from 19 h to less than 2 h and decrease expected EENS from 3,901 MWh to just 308 MWh. In 2030, the situation improves further: interconnections reduce the LOLE from 8 h to almost negligible levels and expected EENS drops from 1,490 MWh to just 2 MWh.

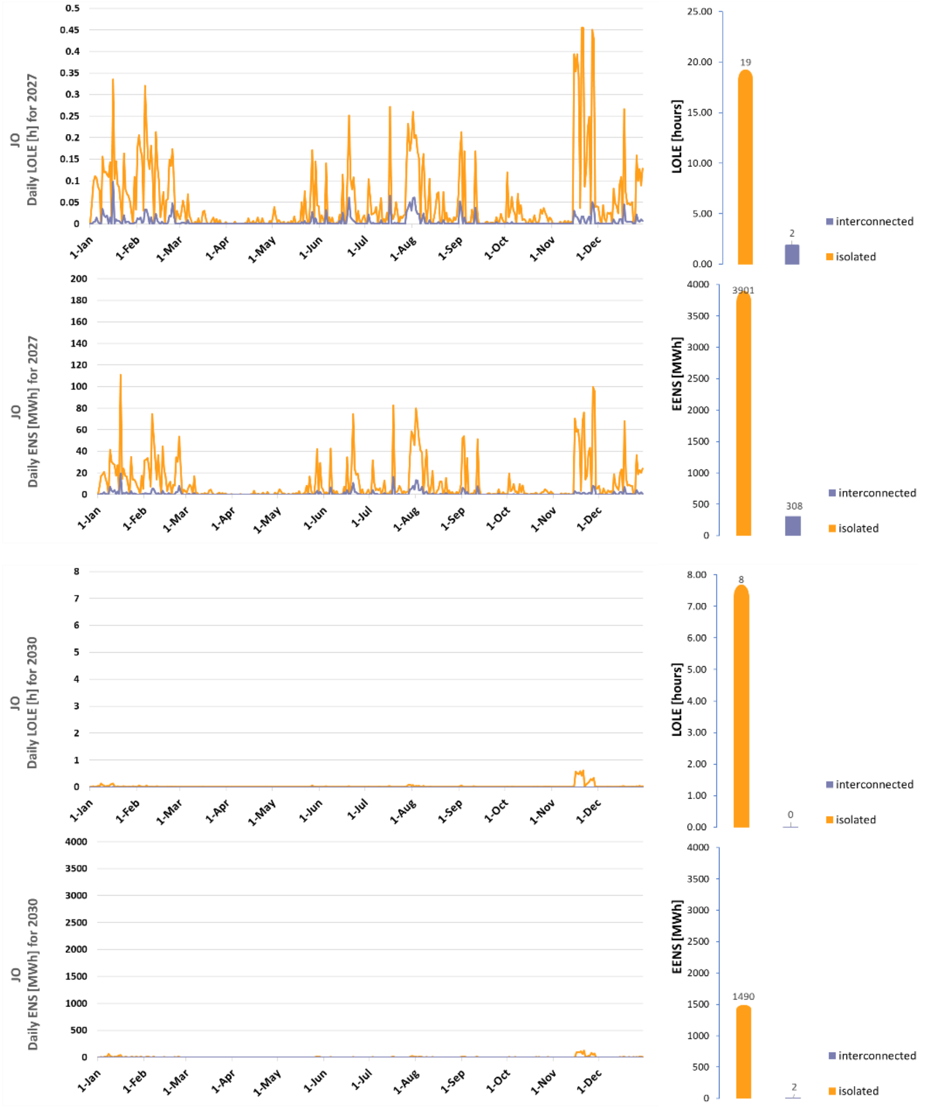


Figure 24 Daily LOLE and EENS for the interconnected and isolated mode of operation in Jordan – 2027 (Top) and 2030 (Bottom)

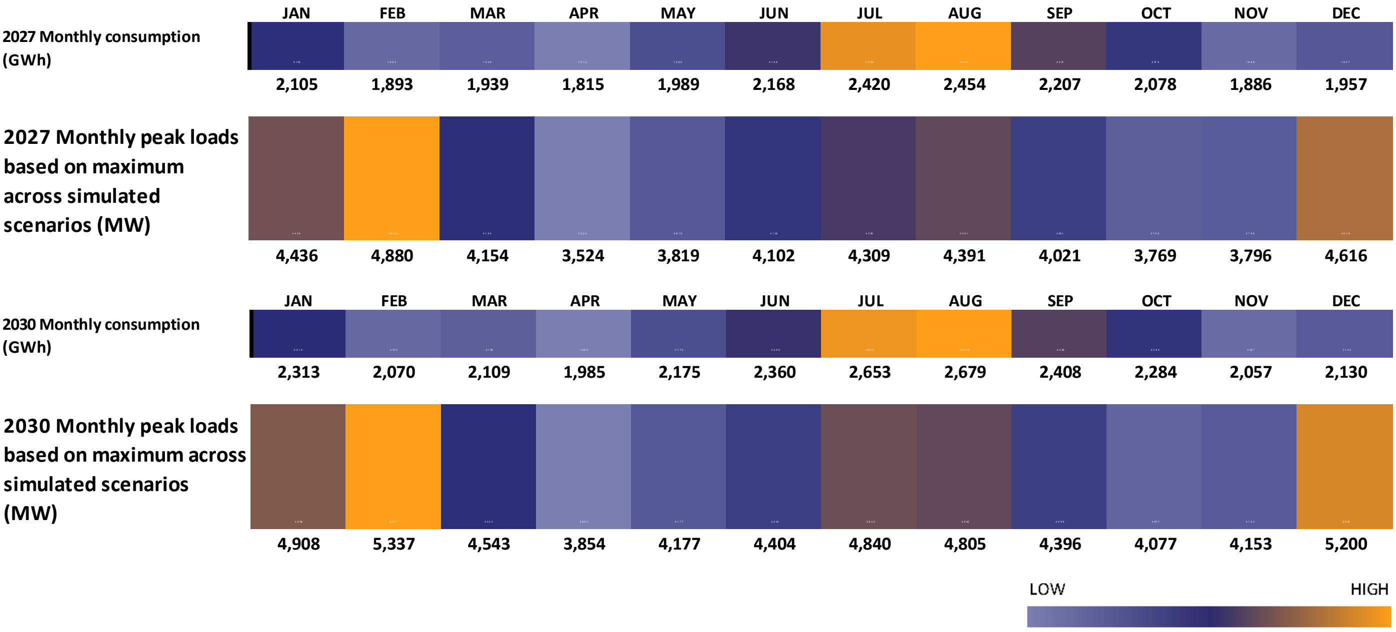
Results indicate that, under interconnected operation, adequacy risks are significantly lower compared to isolated operation. Moreover, the adequacy situation improves further in 2030 relative to 2027, mainly due to the addition of new generation capacities in Jordan and the increase in interconnection capacity with Egypt (from 450 MW to 1,100 MW).

5.3 Lebanon

DEMAND

Figure 25, presents the forecasted Lebanon monthly demand in 2027 (top) and 2030 (bottom). In 2027, forecasted monthly consumption ranges from 1,815 GWh to 2,454 GWh, while monthly peak demand varies from 3.5 GW to 4.9 GW. Monthly demand refers to the average values across all 36 climatic years analysed, whereas peak hourly demand corresponds to the monthly maximum for all 36 climatic years.

In 2030, Lebanon monthly demand is projected to range from approximately 1,985 GWh to 2,680 GWh, with monthly peak demand varying from 3.8 GW to 5.3 GW. The increase in peak load from 2027 to 2030 is 0.5 GW, corresponding to approximately 9.4%. Maximum electricity needs are expected twice per year: in summer (July–August) due to high temperatures and cooling consumption, and in winter (December–February) due to heating. Because of this monthly load distribution, maintenance of thermal power plants is not allowed during summer (July–September).
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.



	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2027 Monthly consumption (GWh)	2,105	1,893	1,939	1,815	1,989	2,168	2,420	2,454	2,207	2,078	1,886	1,957
2027 Monthly peak loads based on maximum across simulated scenarios (MW)	4,436	4,880	4,154	3,524	3,819	4,102	4,309	4,391	4,021	3,769	3,796	4,616

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2030 Monthly consumption (GWh)	2,313	2,070	2,109	1,985	2,175	2,360	2,653	2,679	2,408	2,284	2,057	2,130
2030 Monthly peak loads based on maximum across simulated scenarios (MW)	4,908	5,337	4,543	3,854	4,177	4,404	4,840	4,805	4,396	4,077	4,153	5,200

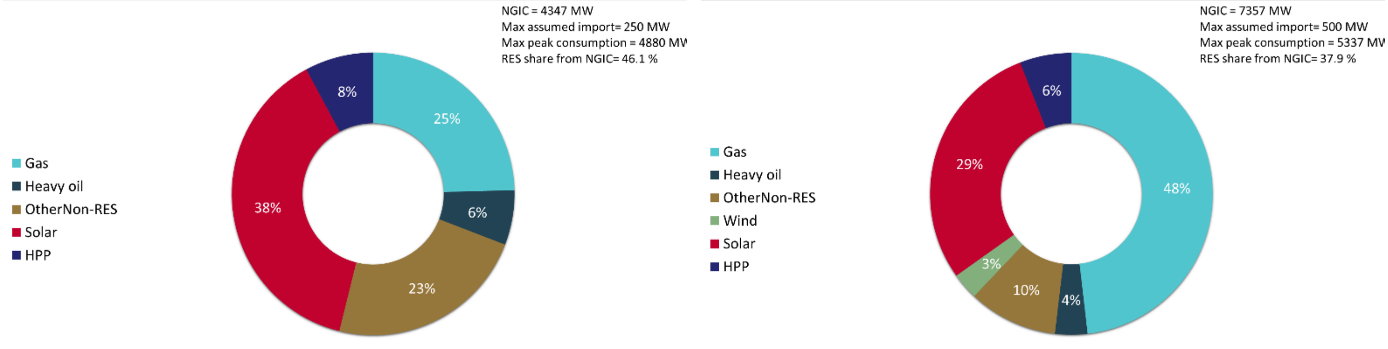
Figure 25 Forecasted monthly demand in Lebanon – 2027 (Top) and 2030 (Bottom)

SUPPLY AND NETWORK OVERVIEW

In 2027, Lebanon's total net generation installed capacity (NGIC) amounts to 3,347 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
The maximum assumed import capacity of 250 MW and a maximum peak consumption of 4,880 MW. The generation mix is dominated by Solar (38%), followed by gas (25%), diesel units (23%), hydropower (8%), and heavy oil (6%). Renewable energy sources (RES) represent 46.1% of the NGIC, primarily driven by solar and hydropower contributions.

In 2030, the NGIC increases to 6,607 MW, but as a substantial support to system operation, the capacity of 750 MW in diesel units is also considered in this analysis in addition to the total installed capacity along with maximum assumed imports doubling to 500 MW and peak consumption rising to 5,337 MW.

The generation structure changes significantly, with gas becoming the dominant source (48%), followed by Solar (29%), diesel units (10%), hydropower (6%), heavy oil (4%), and wind (3%). The share of RES in NGIC decreases to 37.9%, reflecting a relative shift toward gas-fired generation despite growth in wind and solar capacities.



2027 2030

Figure 26 Installed capacity mix with total NGIC, max assumed import NTC, and peak demand in Lebanon

The average daily available TPP capacity, after reduction due to forced outages, is shown Figure 27. Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated modes of operation.

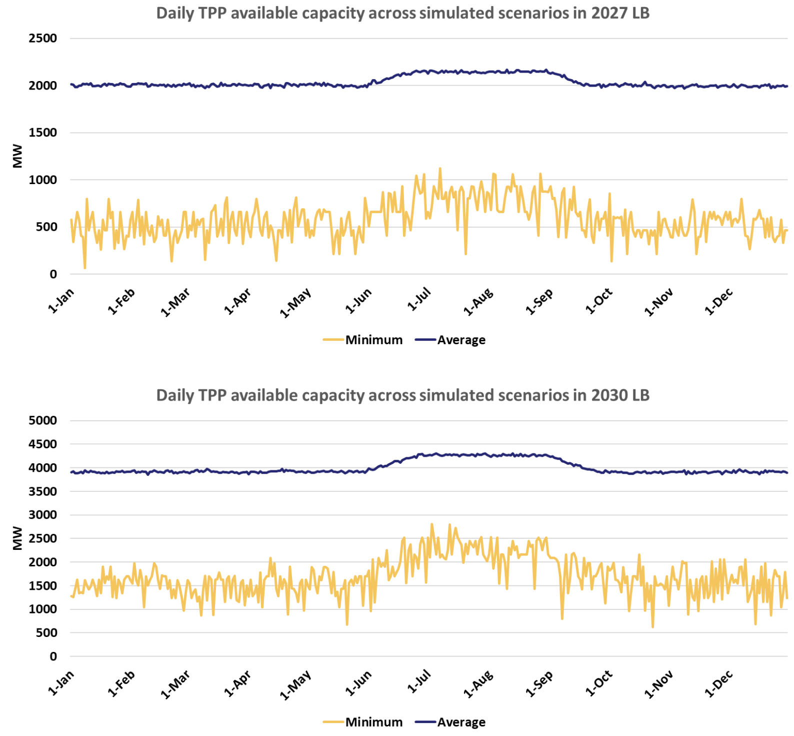
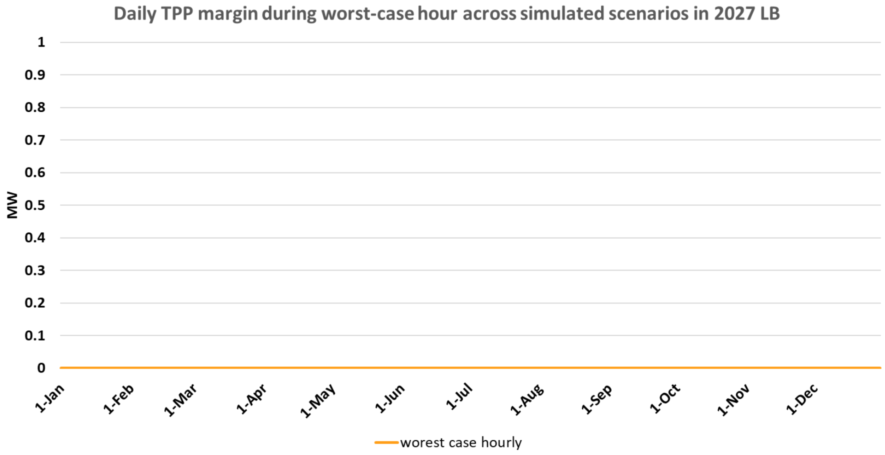


Figure 27 Average and minimum TPP available capacity among all simulated MC years in Lebanon – 2027 (Top) and 2030 (Bottom)

As a result of system simulation, the minimum hourly TPP capacity margin among all simulated MC years is depicted in Figure 28. It represents the difference between available and engaged TPP capacities. No margin exists in Lebanon's power system.



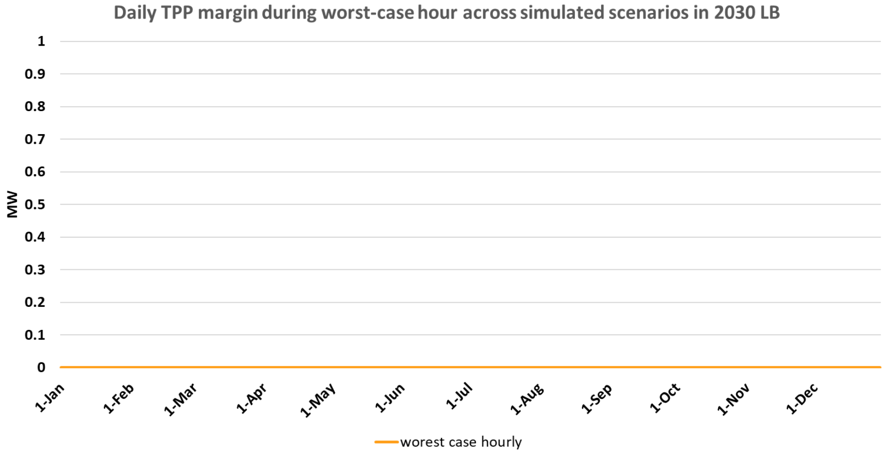


Figure 28 Minimum hourly TPP margin on each day of the analysed period among all simulated MC years in Lebanon 2027 (top) and 2030 (bottom)

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk for Lebanon is shown in Figure 29 for both modes of operation: hypothetically interconnected and isolated in 2027 and 2030. The first panel illustrates the daily LOLE distribution, while the second shows the daily EENS. On the right-hand side of the figure, the total LOLE and EENS are presented for both operational modes.

in 2027, the results indicate that adequacy issues remain extremely critical for Lebanon, even under the hypothetical interconnected scenario. The LOLE reaches approximately 6,714 hours in interconnected mode and 7,728 hours in isolated mode, implying significant load-shedding risks throughout the year. Similarly, the EENS remains extremely high, with around 5.23 TWh in the interconnected mode and 7.32 TWh in the isolated mode.

While interconnection with neighbouring systems slightly alleviates the adequacy challenges, it does not eliminate them. The high LOLE and EENS values indicate that persistent adequacy issues are expected across most of the year, with daily load-shedding scenarios remaining inevitable even when interconnected.

In 2030, the results continue to highlight Lebanon’s severe adequacy challenges, although the situation improves slightly compared to 2027. The LOLE is still critical, reaching about 529 hours in isolated mode and 168 hours under the interconnected mode. Similarly, the EENS remains very high, with around 230 GWh in the isolated scenario and 62 GWh when interconnected.

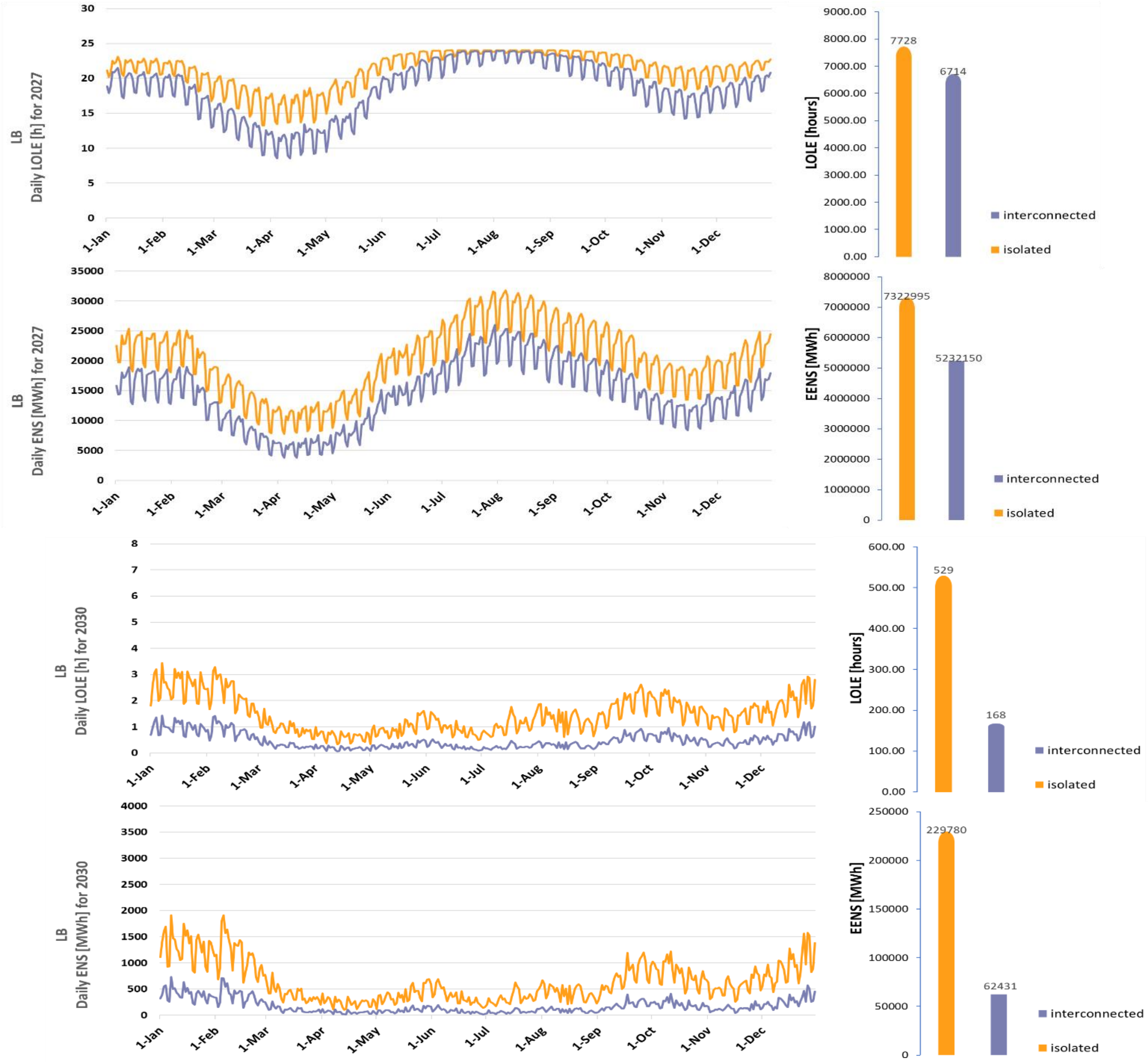


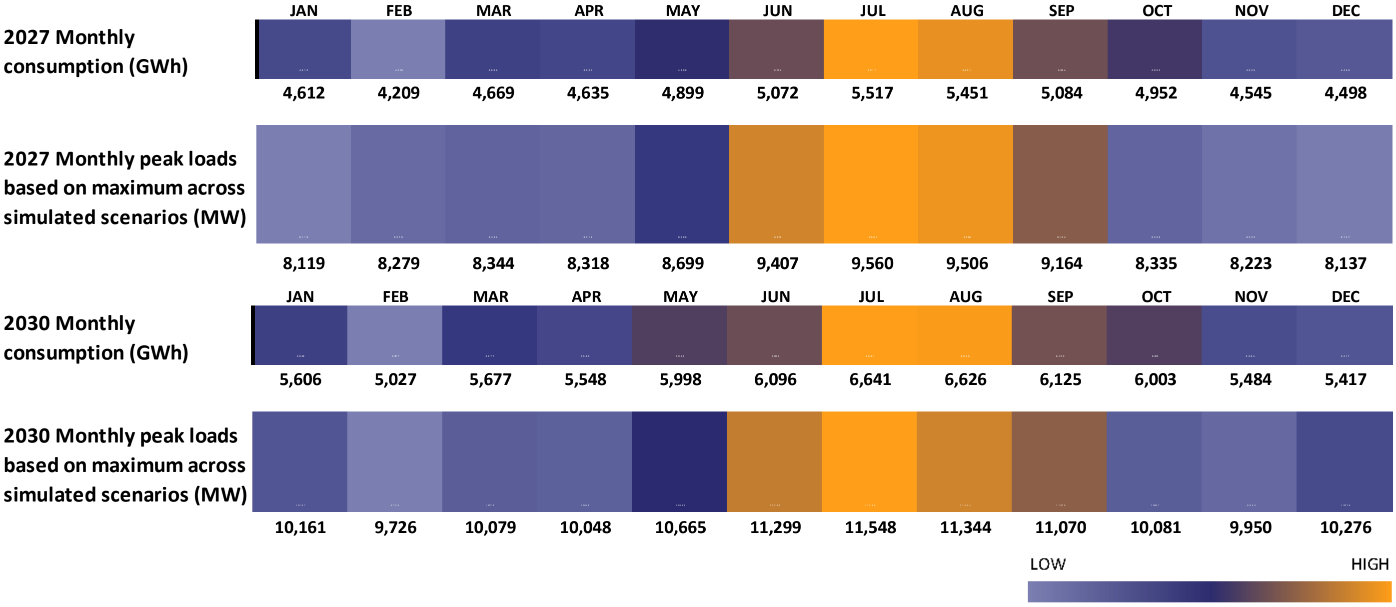
Figure 29 Daily LOLE and EENS for the interconnected and isolated mode of operation in Lebanon – 2027 (Top) and 2030 (Bottom)

5.4 Morocco

DEMAND

Figure 30, presents the forecasted Morocco monthly demand in 2027 (top) and 2030 (bottom). In 2027, forecasted monthly consumption ranges from 4,209 GWh to 5,517 GWh, while monthly peak demand varies from 8.1 GW to 9.6 GW. Monthly demand refers to the average values across all 36 climatic years analysed, whereas peak hourly demand corresponds to the monthly maximum for all 36 climatic years.

In 2030, Morocco monthly demand is projected to range from approximately 5,027 GWh to 6,641 GWh, with monthly peak demand varying from 9.7 GW to 11.5 GW. The increase in peak load from 2027 to 2030 is 1.9 GW, corresponding to approximately 19.8%. Maximum electricity needs are expected in summer (July–August) due to high temperatures and cooling consumption. Because of this monthly load distribution, maintenance of thermal power plants is not allowed during summer (June–September).



	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2027 Monthly consumption (GWh)	4,612	4,209	4,669	4,635	4,899	5,072	5,517	5,451	5,084	4,952	4,545	4,498
2027 Monthly peak loads based on maximum across simulated scenarios (MW)	8,119	8,279	8,344	8,318	8,699	9,407	9,560	9,506	9,164	8,335	8,223	8,137

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2030 Monthly consumption (GWh)	5,606	5,027	5,677	5,548	5,998	6,096	6,641	6,626	6,125	6,003	5,484	5,417
2030 Monthly peak loads based on maximum across simulated scenarios (MW)	10,161	9,726	10,079	10,048	10,665	11,299	11,548	11,344	11,070	10,081	9,950	10,276

Figure 30 Forecasted monthly demand in Morocco – 2027 (Top) and 2030 (Bottom)

SUPPLY AND NETWORK OVERVIEW

In 2027, Morocco's total net generation installed capacity (NGIC) amounts to 17,674 MW. To enhance system flexibility, the capacity includes 1,140 MW of hydro pump storage and 1,600 MW of battery storage. The maximum assumed import capacity is 1,500 MW, while the maximum peak consumption reaches 9,560 MW.

The generation mix is balanced and well diversified, with wind (24%) and solar (20%) forming the largest shares, followed by hard coal (20%), Gas (9%), battery storage (8%), heavy oil (6%), hydropower (6%), hydro pump storage (6%), and a minor contribution from light oil (1%). Renewable energy sources (RES) represent 57.9% of the NGIC, mainly driven by strong wind, solar, and hydropower integration.

In 2030, Morocco's total net generation installed capacity (NGIC) increases to 21,541 MW. In addition to this, system flexibility is supported by 1,740 MW of hydro pump storage and 1,600 MW of battery storage. The maximum assumed import capacity rises to 1,900 MW, while peak consumption reaches 11,548 MW.
The generation mix becomes more diversified, with wind (24%) and solar (23%) forming the largest shares, followed by gas (15%), hard coal (16%), hydro pump storage (7%), battery storage (6%), hydropower (5%), heavy oil (3%), and

a smaller contribution from light oil (1%). Renewable energy sources (RES) represent 59.4% of NGIC, primarily driven by wind, solar, and hydropower development.

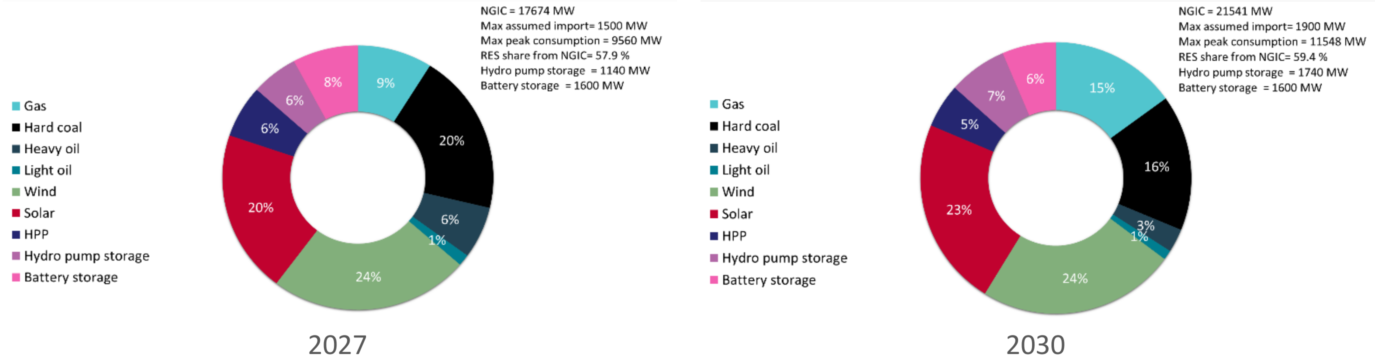


Figure 31 Installed capacity mix with total NGIC, max assumed import NTC, and peak demand in Morocco

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.

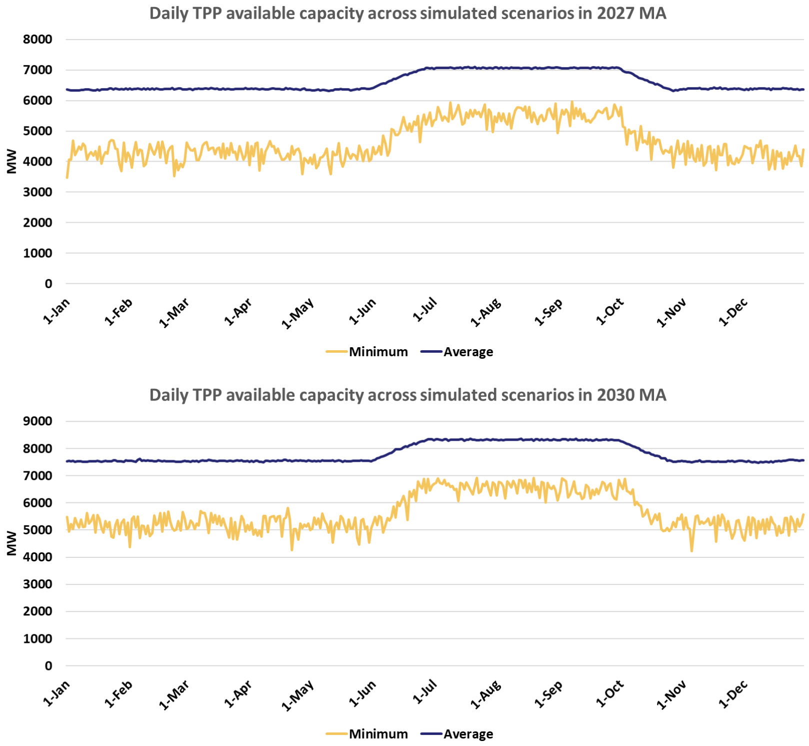


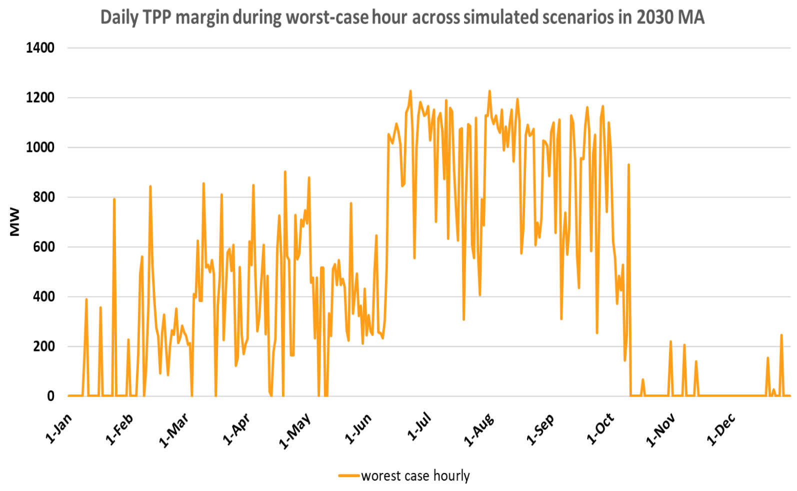
Figure 32 Average and minimum TPP available capacity among all simulated MC years in Morocco – 2027 (Top) and 2030 (Bottom)

As a result of system simulations, the minimum hourly TPP (thermal power plant) capacity margin among all simulated Monte Carlo (MC) years for each day is presented in Figure 33. This margin reflects the difference between available and committed TPP capacity under worst-case hourly conditions.

In 2027 (top figure), the margin shows strong variability, with extended periods of very low or zero capacity during November and December, as well as scattered shortages across the early months of the year. During the summer months (June–September), however, the system maintains relatively higher margins, often exceeding 1,000 MW.

In 2030 (bottom figure), the margin is more constrained, frequently staying below 500 MW, with occasional peaks exceeding 1,500–2,000 MW. Prolonged periods of near-zero margin occur in October and November, as well as intermittent shortages in December, indicating heightened adequacy concerns during those periods.

Overall, the results suggest that while the system generally maintains some reserve margin, critical adequacy risks emerge seasonally, particularly in late autumn and early winter. These risks underline the importance of interconnection support to ensure system stability. Moreover, the daily margin closely follows consumption patterns, being more stressed during high-demand periods on working days.


Daily TPP margin during worst-case hour across simulated scenarios in 2030 MA

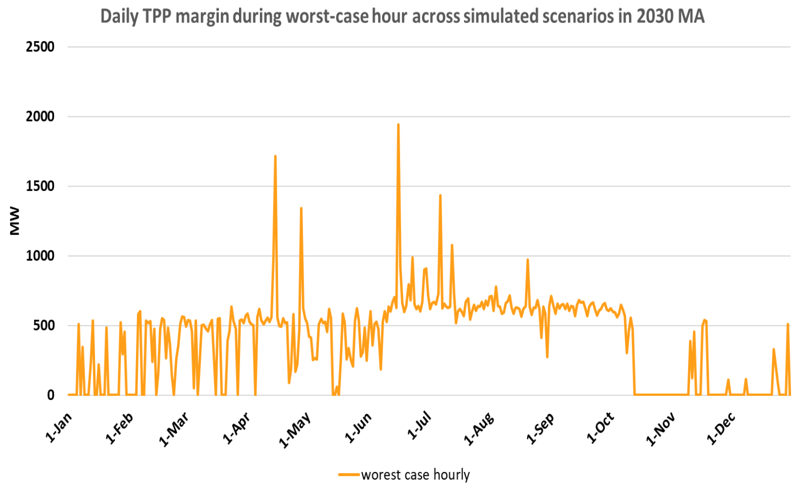

Daily TPP margin during worst-case hour across simulated scenarios in 2030 MA

Figure 33 Minimum hourly TPP margin on each day of the analysed period among all simulated MC years in Morocco 2027 (top) and 2030 (bottom)

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk for Morocco is shown in Figure 34 for both modes of operation: interconnected and isolated in 2027 and 2030. The first panel illustrates the daily LOLE distribution, while the second shows the daily EENS. On the right-hand side of the figure, the total LOLE and EENS are presented for both operational modes. presents adequacy assessments for both 2027 and 2030.

Morocco demonstrates a robust adequacy position, with only very limited load-shedding risk. The results confirm that the system is expected to reliably meet demand across both horizons, irrespective of interconnection status. The minor occurrences of load-shedding are mainly attributed to random maintenance outages rather than structural adequacy shortcomings. Such risks can be effectively mitigated through a planned maintenance strategy that schedules outages away from periods of high demand.

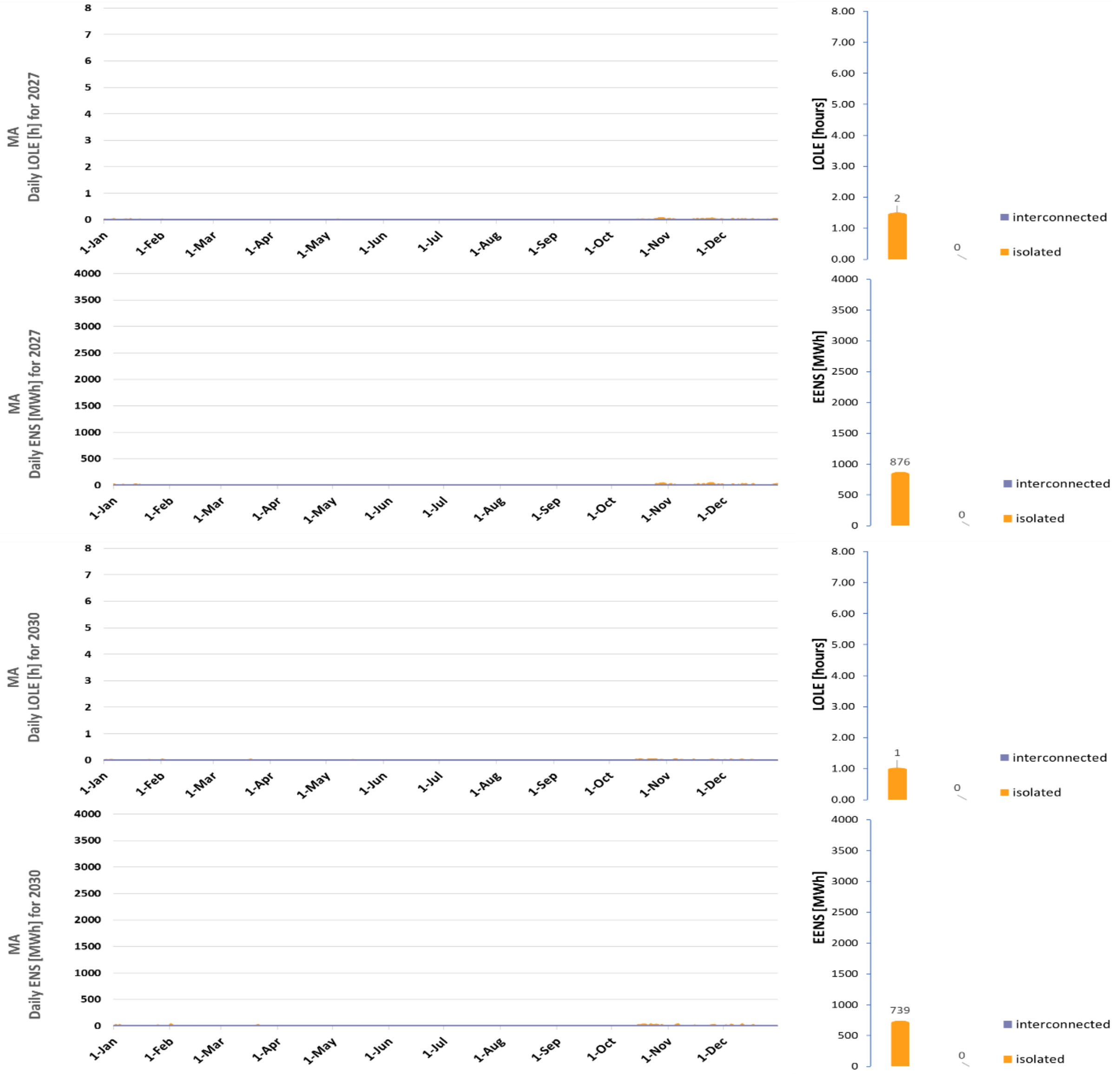


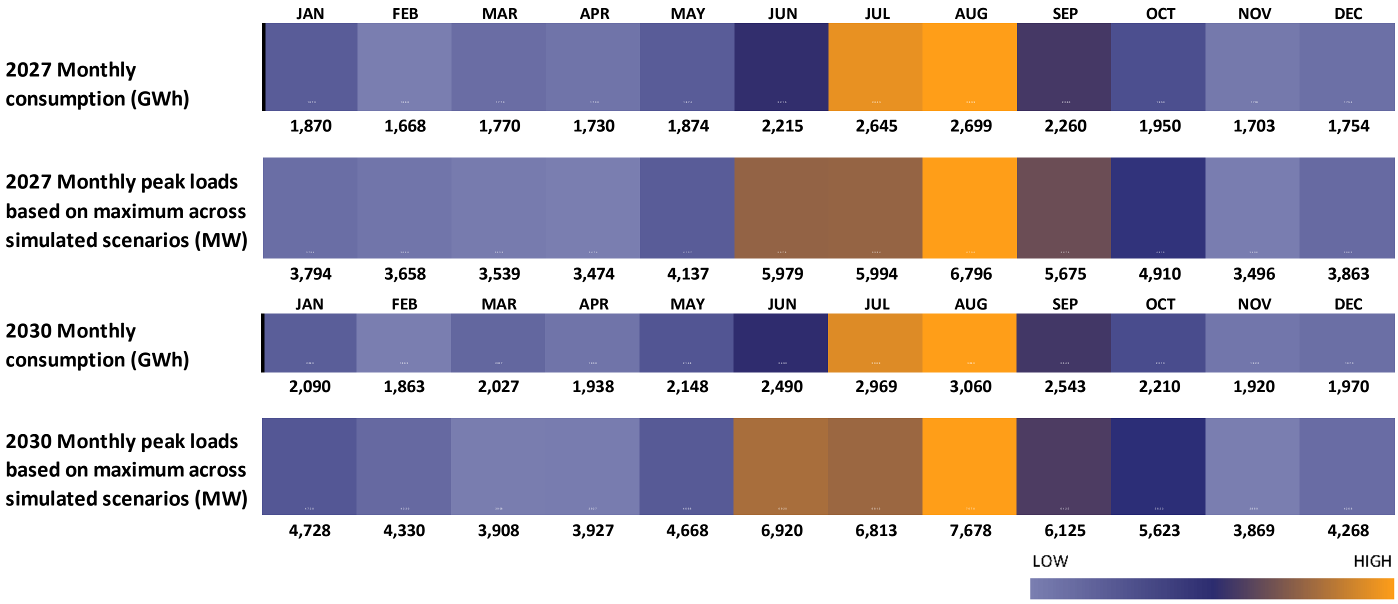
Figure 34 Daily LOLE and EENS for the interconnected and isolated mode of operation in Morocco – 2027 (Top) and 2030 (Bottom)

5.5 Tunisia

DEMAND

Figure 35, presents the forecasted Tunisia monthly demand in 2027 (top) and 2030 (bottom). In 2027, forecasted monthly consumption ranges from 1,668 GWh to 2,699 GWh, while monthly peak demand varies from 3.4 GW to 6.8 GW. Monthly demand refers to the average values across all 36 climatic years analysed, whereas peak hourly demand corresponds to the monthly maximum for all 36 climatic years.

In 2030, Tunisia monthly demand is projected to range from approximately 1,863 GWh to 3,060 GWh, with monthly peak demand varying from 3.9 GW to 7.7 GW. The increase in peak load from 2027 to 2030 is 0.9 GW, corresponding to approximately 13.2%. Maximum electricity needs are expected in summer (July–August) due to high temperatures and cooling consumption. Because of this monthly load distribution, maintenance of thermal power plants is not allowed during summer (June–August).



	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2027 Monthly consumption (GWh)	1,870	1,668	1,770	1,730	1,874	2,215	2,645	2,699	2,260	1,950	1,703	1,754
2027 Monthly peak loads based on maximum across simulated scenarios (MW)	3,794	3,658	3,539	3,474	4,137	5,979	5,994	6,796	5,675	4,910	3,496	3,863
2030 Monthly consumption (GWh)	2,090	1,863	2,027	1,938	2,148	2,490	2,969	3,060	2,543	2,210	1,920	1,970
2030 Monthly peak loads based on maximum across simulated scenarios (MW)	4,728	4,330	3,908	3,927	4,668	6,920	6,813	7,678	6,125	5,623	3,869	4,268

Figure 35 Forecasted monthly demand in Tunisia – 2027 (Top) and 2030 (Bottom)

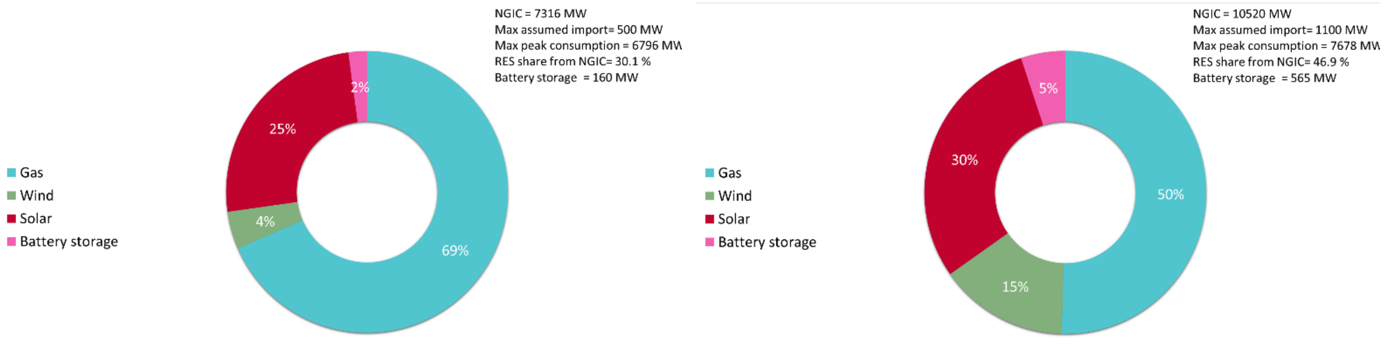
SUPPLY AND NETWORK OVERVIEW

In 2027, Tunisia's total net generation installed capacity (NGIC) amounts to 7,316 MW. The system is supported by 160 MW of battery storage, while the maximum assumed import capacity reaches 500 MW and the maximum peak consumption is 6,796 MW.

The generation mix is dominated by gas (69%), followed by solar (25%), with smaller shares from wind (4%) and battery storage (2%). Renewable energy sources (RES) account for 30.1% of NGIC, mainly driven by solar development.

In 2030, Tunisia's NGIC increases to 10,520 MW, alongside a significant rise in battery storage capacity to 565 MW. The maximum assumed import capacity nearly doubles to 1,100 MW, while maximum peak consumption reaches 7,678 MW.

The generation structure becomes more diversified, with gas (50%) and solar (30%) as the leading contributors, followed by wind (15%) and battery storage (5%). The share of RES grows to 46.9% of NGIC, reflecting the country's increasing reliance on wind and solar to complement its gas-based fleet.



2027 2030

Figure 36 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 Figure 37. Each daily value represents the average of all simulated MC years. These values are the same for the interconnected and isolated operational modes.

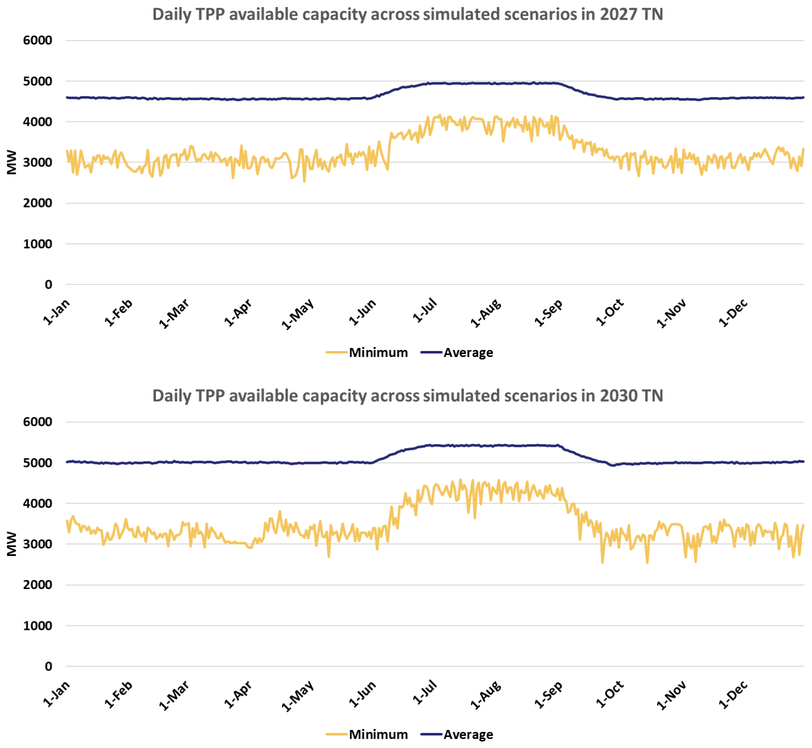


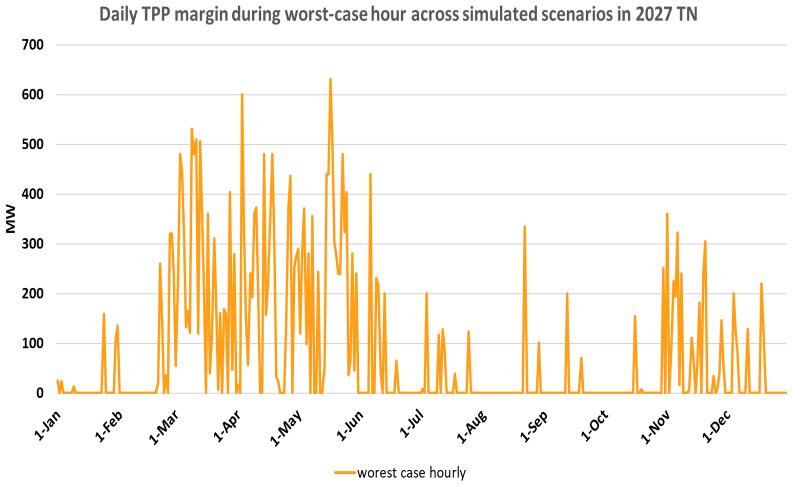
Figure 37 Average and minimum TPP available capacity among all simulated MC years in Tunisia – 2027 (Top) and 2030 (Bottom)

As a result of the system simulations, the minimum hourly TPP capacity margin for each day is presented in Figure 38. This margin reflects the difference between available and activated thermal generation capacities.

In 2027, the results show frequent periods where the margin approaches zero, particularly during July and August, but also scattered across other months. This indicates a tight adequacy situation, with limited reserve available to cover unexpected outages or demand spikes.

By 2030, the situation improves, with generally higher margins observed, especially in the spring months (March–May), when the margin occasionally exceeds 1,000 MW. Nonetheless, periods of near-zero margin still appear, particularly during the summer and early autumn, highlighting that adequacy concerns, while less severe than in 2027, remain present.

Overall, the results suggest that Tunisia faces structural adequacy risks in 2027, which are somewhat alleviated by 2030 thanks to capacity expansion and diversification. However, critical hours with minimal margin persist, requiring careful operational planning and the potential support of imports or storage to ensure system reliability.



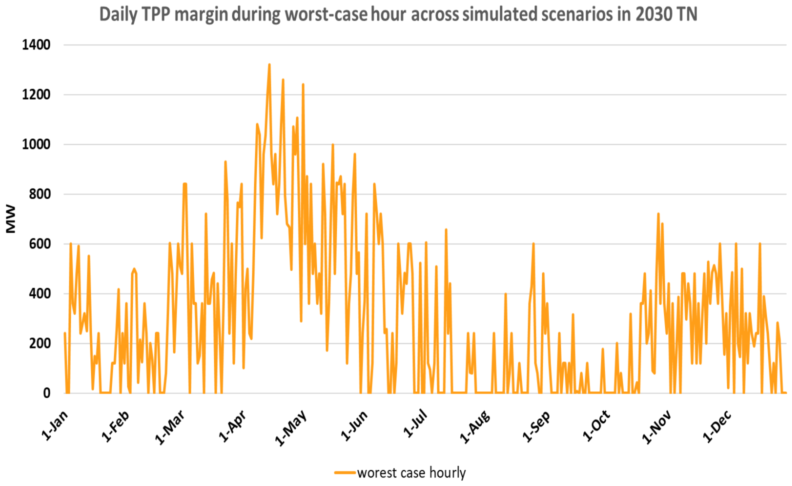


Figure 38 Minimum hourly TPP margin on each day of the analysed period among all simulated MC years in Tunisia 2027 (top) and 2030 (bottom)

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk for Tunisia is shown in Figure 38 for both the interconnected and isolated operational modes. The first image depicts the daily LOLE distribution, while the second illustrates daily EENS. On the right-hand side of the figure, the total LOLE and EENS are presented for both operational modes. presents adequacy assessments for both 2027 and 2030.

In 2027, adequacy concerns emerge mainly during July and August, coinciding with high demand and lower TPP availability. Under the interconnected mode, annual LOLE reaches about 2 hours and EENS around 554 MWh, while under the isolated mode, these values rise significantly to 17 hours of LOLE and 4,620 MWh of EENS. This highlights the important role of interconnections in mitigating adequacy risks.

By 2030, the situation improves considerably. Adequacy risks become very limited, with only minor issues observed around August. In the interconnected mode, annual LOLE is reduced to just 3 hours and EENS to about 1,013 MWh, while in the isolated mode, LOLE falls to almost negligible levels and EENS remains negligible at 4 MWh.

Overall, the results indicate that Tunisia faces notable adequacy risks in 2027, particularly under isolation, but by 2030 the system demonstrates a much stronger adequacy position, with risks largely contained and strongly alleviated by interconnections.

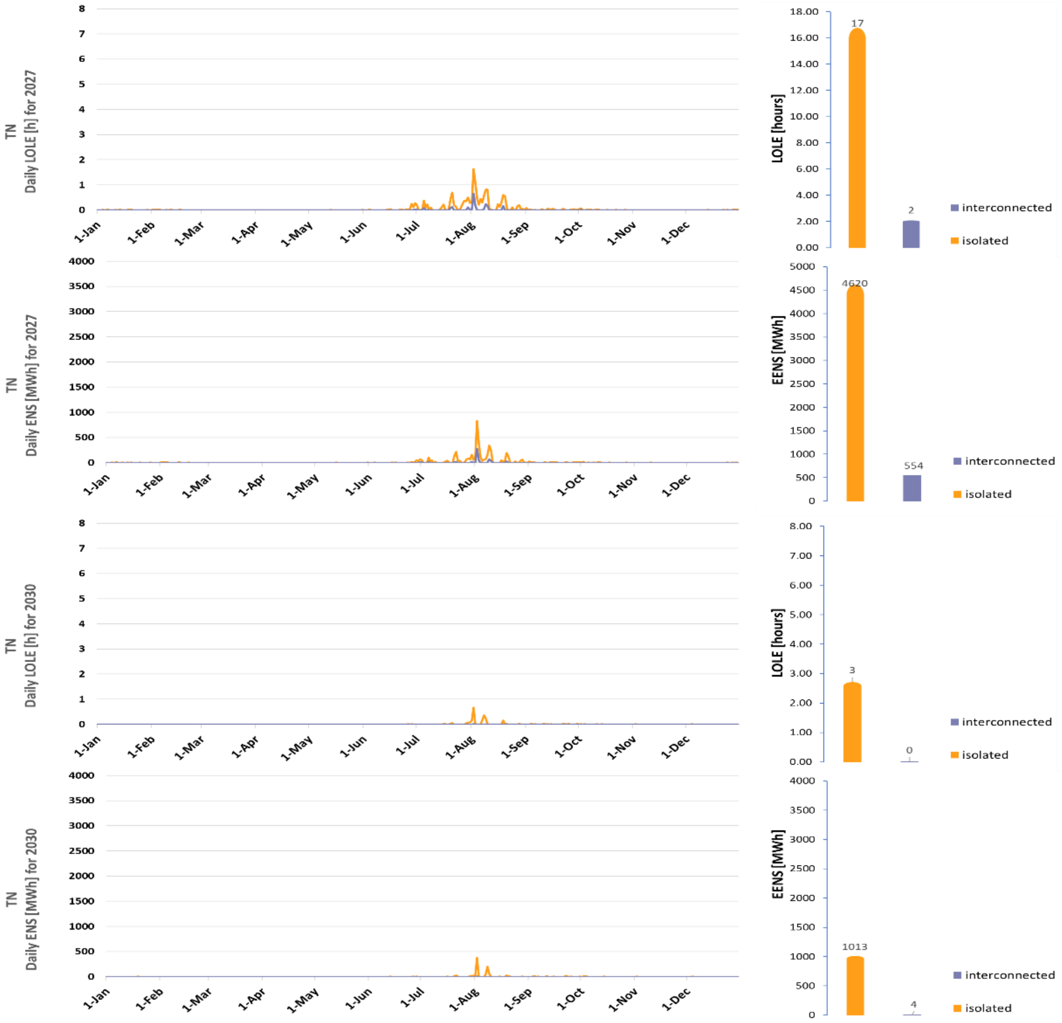


Figure 39 Daily LOLE and EENS for the interconnected and isolated mode of operation in Tunisia – 2027 (Top) and 2030 (Bottom)

Appendix

Approach and Methodology

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[4].

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, Mid-term risks that might occur in the following +3 & +5 years, 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. Several 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 geographical scope.

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

Figure 40 Probabilistic modelling general approach (source: ENTSO-E).

Adequacy indicators and results of the 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.

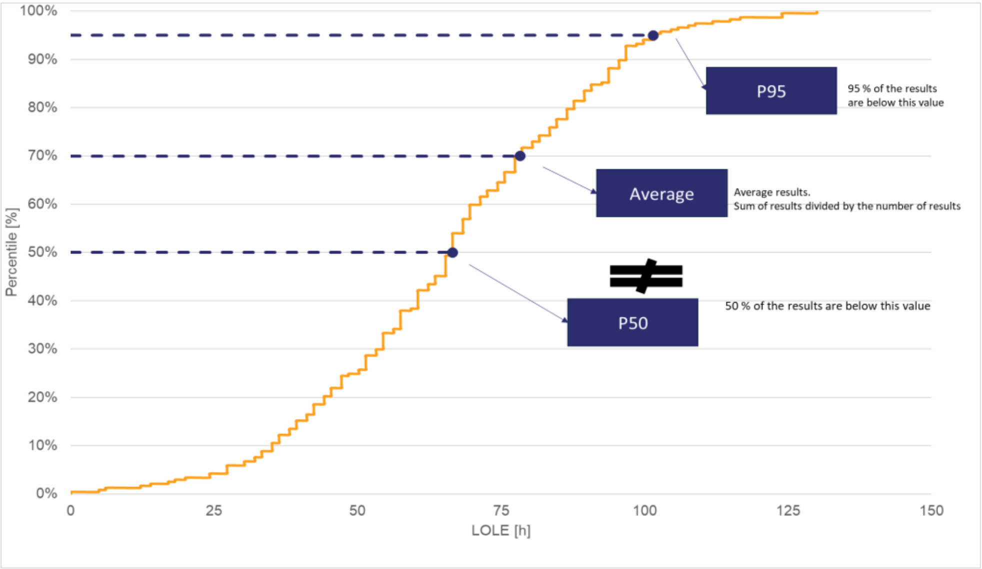

Figure 41 Illustrative example of the relation between average, P50, and P95 values

- **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 every 20 years.
  - P50: ENS that happens once every 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.

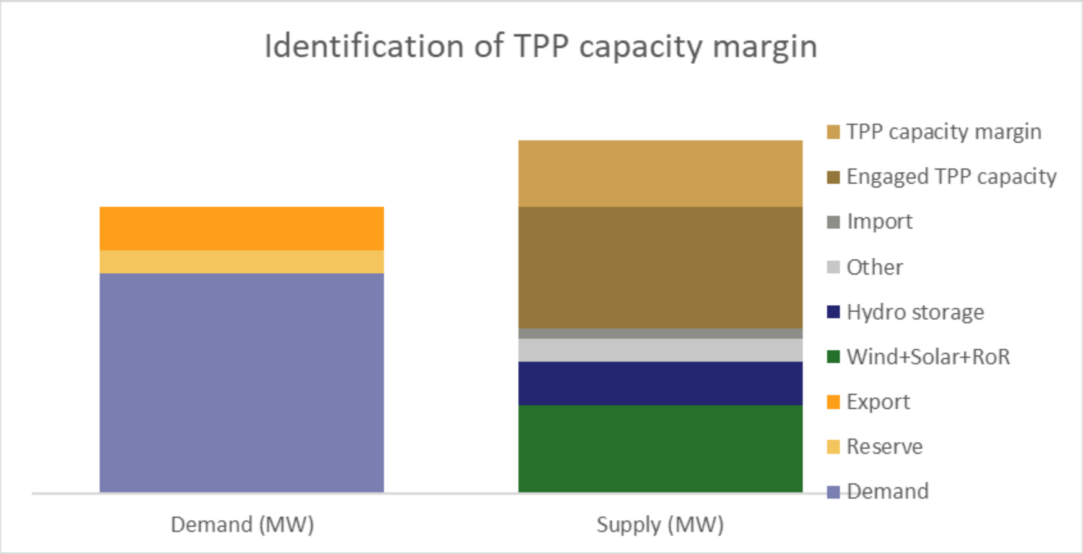

Figure 42 Illustrative example of TPP capacity margin identification

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 43
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 43. This would allow the detection of which weeks are most at risk.

Figure 43 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.

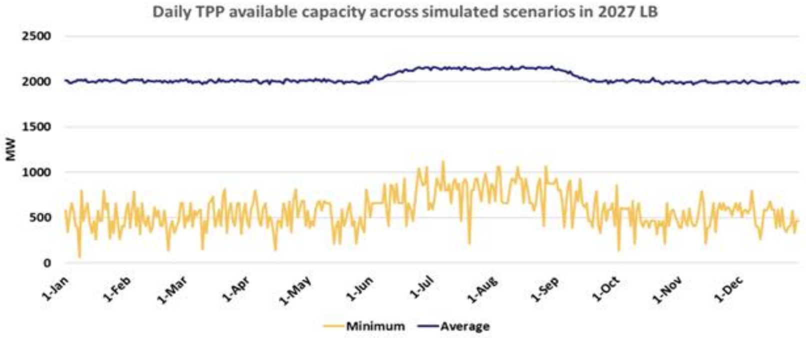

Figure 44 Illustrative example of available TPP capacity

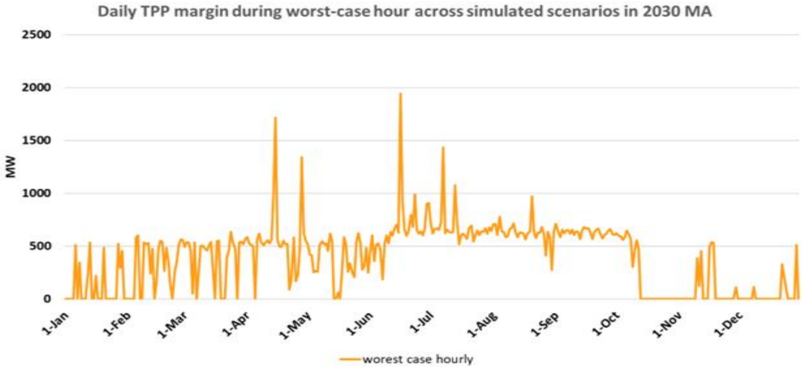

Figure 45 Minimum hourly TPP margin on each day of the analysed period

Data collection and database preparation

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[5], 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 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 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:

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

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 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, 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. 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:

  - ○ 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.**

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 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 (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.

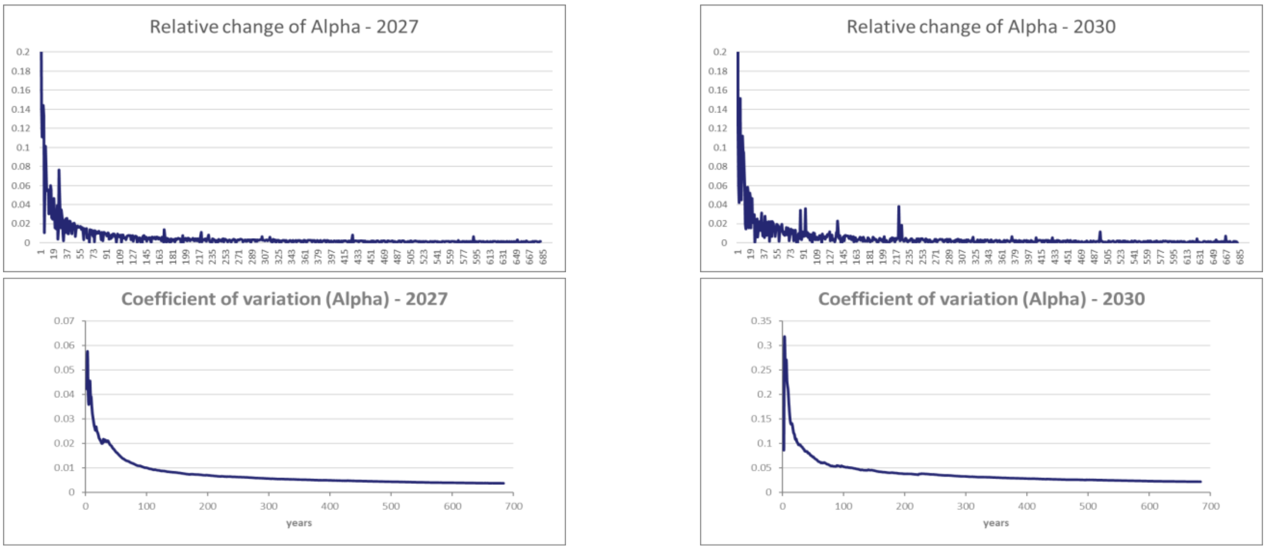

Figure 46 Evolution of convergence criteria for 684 MC years, simulations for the year 2027 and 2030

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