TeasiMed2 project

SEASONAL ADEQUACY ASSESSMENT

Summer Outlook 2024

Detailed Report

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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)
RES	–	Renewable Energy Sources that in general include wind, solar and hydro capacities, but 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 Summer 2024. 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 criteria. This approach is necessary due to the stochastic nature of renewable energy systems (RES) and their indeterminacy, and because also of the power system operation, more and more based on open market conditions; all these aspects call for the assessment of power system adequacy in the short, mid, and long run. Moreover, the integration of huge amounts of RES must be closely followed by the commissioning of tools that can provide adequate power system flexibility.

This Summer Outlook 2024 Report provides information about potential adequacy issues during the period from 27 May 2024 to 6 October 2024 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.

Main adequacy indicators that have been assessed are:

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

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.

For the interconnected mode, we identify the exchange needed to overcome adequacy situation

Furthermore, two sensitivity analyses have been conducted to identify the following:

- The most severe Monte Carlo Climatic Year (MCY) for each country.
- Focus on Libyan system during upcoming SO 2024

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

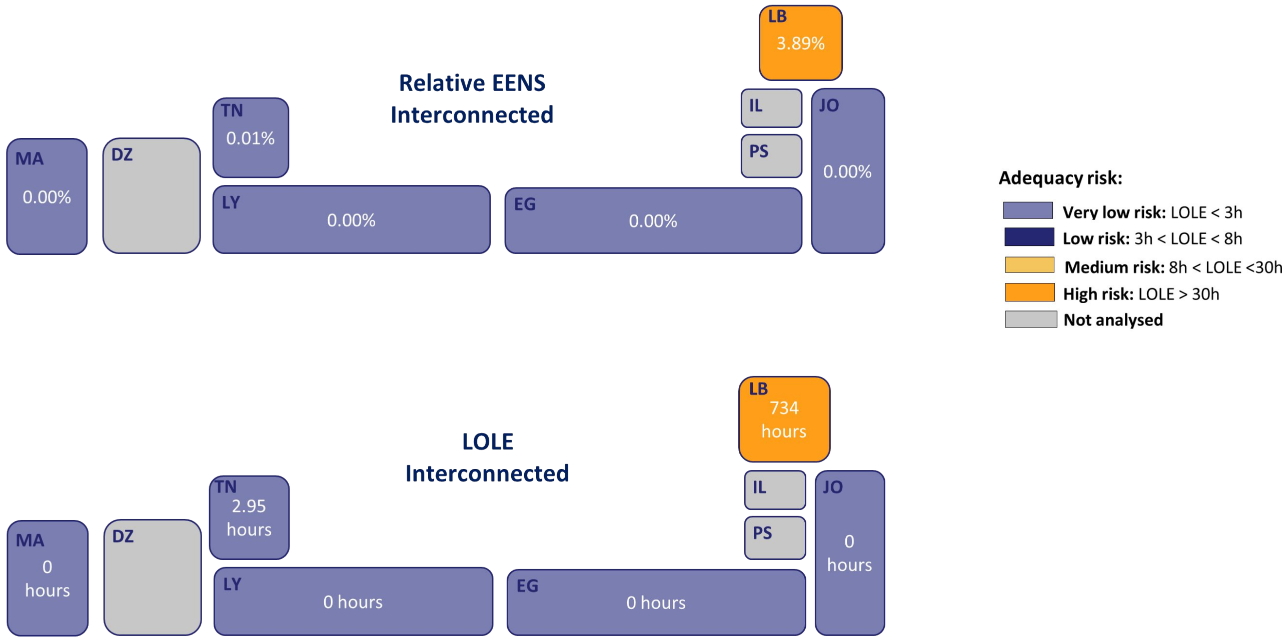


Figure 1 Seasonal relative EENS & LOLE for interconnected mode of operation.

Conclusion

The conclusions of this assessment show that during this Summer the most severe adequacy issues may occur in Lebanon (see Figure 1), where LOLE reaches around 734 hours (around 23 % of the Summer season) and energy not supplied is higher than 4% of the power demand in the relevant period. On the other hand, a very low adequacy risk is registered in all countries.

For Tunisia, the highest probability that generation (+import) will not be sufficient to cover electricity demand in Tunisia is expected in July and August with LOLE below 3 hours, while in the rest of the analyzed period the risk is lower.

The situation in Lebanon is completely different, with energy not supplied during the whole summer period. However, it should be noted that the operation of the Lebanese power system is very difficult, with very frequent lack of supply and regularly scheduled load shedding programs. It should be emphasized that, in the case of Lebanon, even if all generation capacities are available and the maximum potential electricity import from the neighboring systems is taken into account, it could possibly reduce the adequacy risks but electricity demand during peak hours of the observed period cannot be supplied.

Sensitivity case 1 Most Severe MCY

After identifying the most severe Monte Carlo Climatic Year (MCY) for each country, it becomes apparent from Figure 2 that interconnection plays a crucial role in mitigating its impact of the most severe MCY.

Morocco and Jordan register very low adequacy risks, with LOLE of 1 and 2 hours respectively. Conversely, Tunisia faces a medium risk with LOLE reaching approximately 23 hours.

However, Lebanon experiences the most severe situation during the MCY, with LOLE reaching approximately 1175 hours (around 37% of the summer season), indicating a significantly higher level of risk compared to other countries.

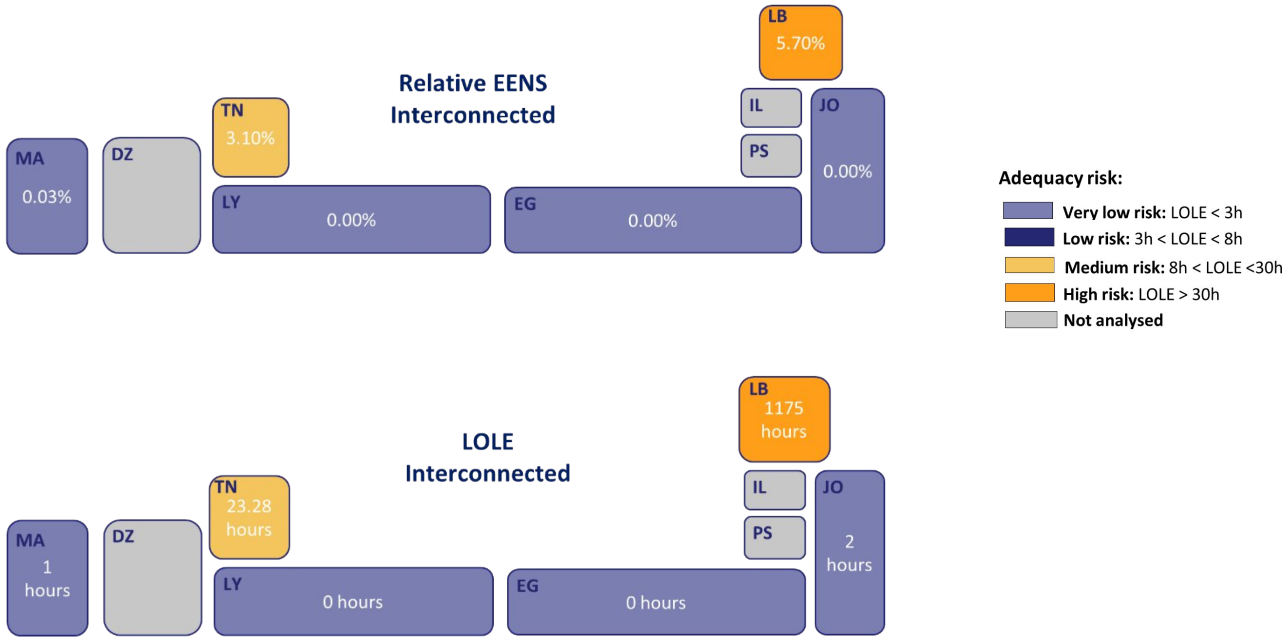


Figure 2 Seasonal relative ENS and LOLE for the interconnected mode of operation for the most severe MCY for summer.

Sensitivity case 2 Focus on Libya's System

If the maintenance activities on numerous units within Libya's thermal fleet are not completed before the commencement of the SO 2024 season, Libya's energy situation could potentially face a high adequacy risk even with help of Interconnection from Egypt.

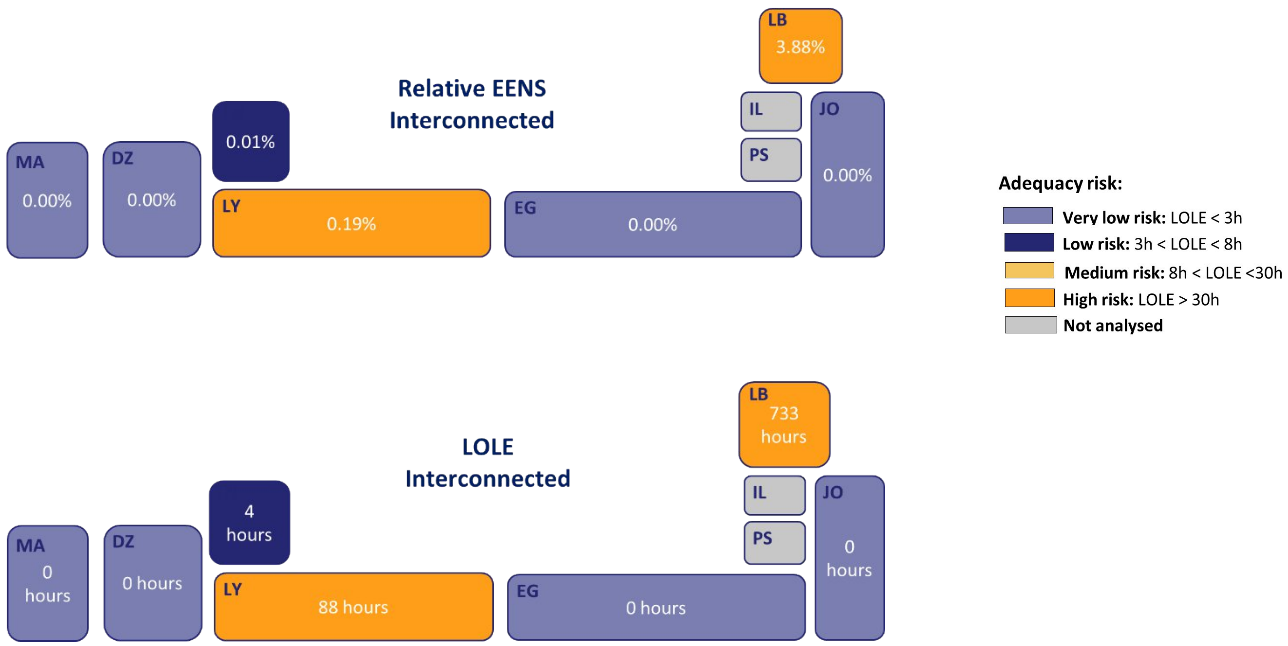


Figure 3 Seasonal relative ENS and LOLE for the interconnected mode of operation Libya Sensitivity case for summer season.

2 Approach and Methodology

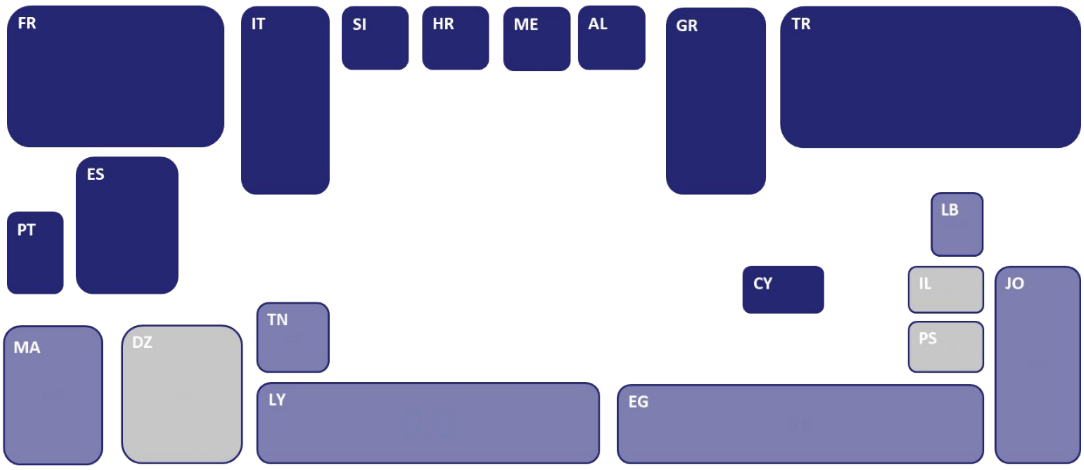
2.1 Adequacy assessment methodology

This Report presents the adequacy situation among non-European Med-TSO members during Summer 2024. With this assessment, Med-TSO is aligning with the worldwide best practice and the latest development of the EU regulations[2].

These investigations consider the security of electricity supply to consumers through a detailed power system adequacy assessment, using probabilistic criteria. This approach is inevitable due to the stochastic nature of renewable energy systems (RES), their intermittency, and the power system operation based on open electricity market conditions which raise the question of power system adequacy in the short, mid, and long 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.

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.

This Summer Outlook 2024 Report provides information about potential adequacy issues during Summer 2024 in the 6 MED-TSO members: Morocco, Libya, Tunisia, Egypt, Jordan and Lebanon.



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 4 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.

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

The analyzed period includes all hours between the beginning of week 22 till the end of week 40 in 2024 which is the period between Monday, May 27th and Sunday, October 6th.

The analyses have been carried out with the ANTARES simulator v8.03, considering the following:

- The ANTARES (ANTARES – A New Tool for Adequacy Reporting of Electric Systems) simulator, 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 in ENTSO-E for TYNDP and Adequacy assessments (ENTSO-E) 2020 edition of the Mid-Term Adequacy Forecast (MAF) was carried out with ANTARES)
- The ANTARES simulator was already used by Med-TSO in the project “Mediterranean Master Plan 2022”.
- ANTARES Simulator is an Open-Source software; hence it is accessible to all Med-TSO members.

Within this seasonal assessment, short-term risks that might occur in the following four months 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 included the collection 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 specificities of the assessed geographical perimeter. The hourly resolution has been implemented in the model and the Monte-Carlo approach has been used to reflect the variability of weather as well as the randomness of supply and transmission outages.

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

Figure 5 Probabilistic modelling general approach (source: ENTSO-E)

2.2 Adequacy indicators and other results of adequacy assessment

Seasonal adequacy assessment is based on the following main indicators:

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

1. **Loss of Load Expectation (LOLE)** in a given geographical zone for a given period is the expected (average) number of hours per year when there is a lack of resources to cover the demand needs, within a sufficient transmission grid operational security limit.

A more detailed presentation of the relations between average, P50 and P95 values is presented in the following diagram.

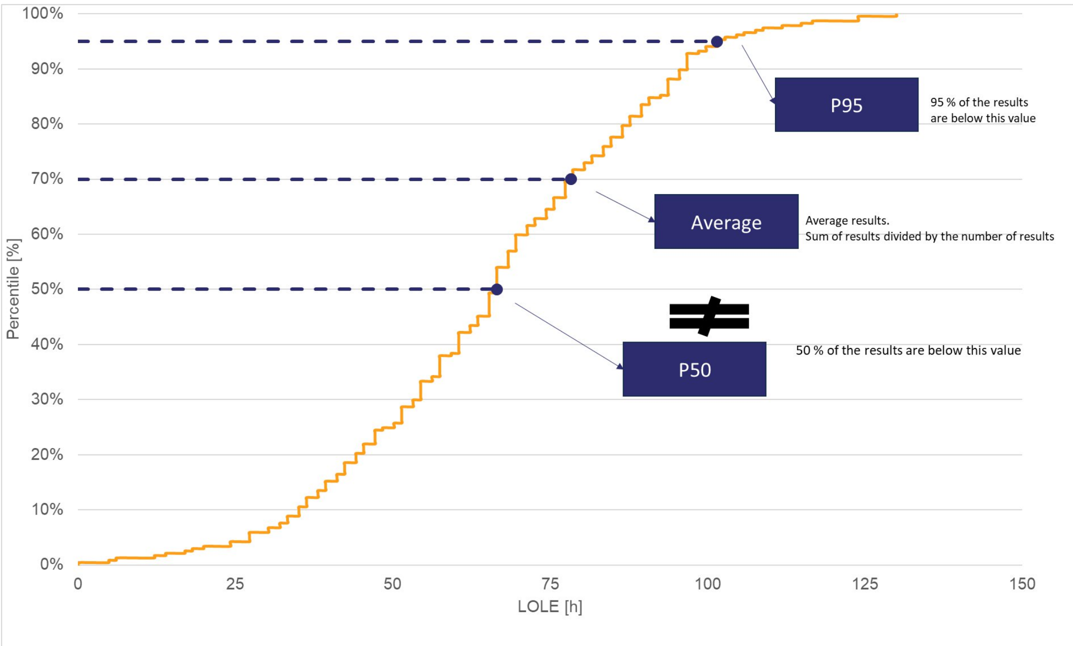


Figure 6 Illustrative Example of the relation between average, P50 and P95 values.

- **P95/P50 Energy Not Serve (P95/P50 ENS).** While ENS in a given geographical zone for a given period is the energy that is not supplied during a single Monte Carlo sample/simulation year due to the demand in the zone exceeding the combination of available resource capacity and electricity imports, P95/P50 ENS are ENS in more or less severe operational conditions:
  - P95: ENS that happens once in 20 years
  - P50: ENS that happens once in 2 years

- **Expected Energy Not Served (EENS)** in a given geographical zone for a given period, is the expected (average) value of energy not to be supplied due to a lack of resources while complying with transmission grid operational security limit.
- **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 renewable 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.

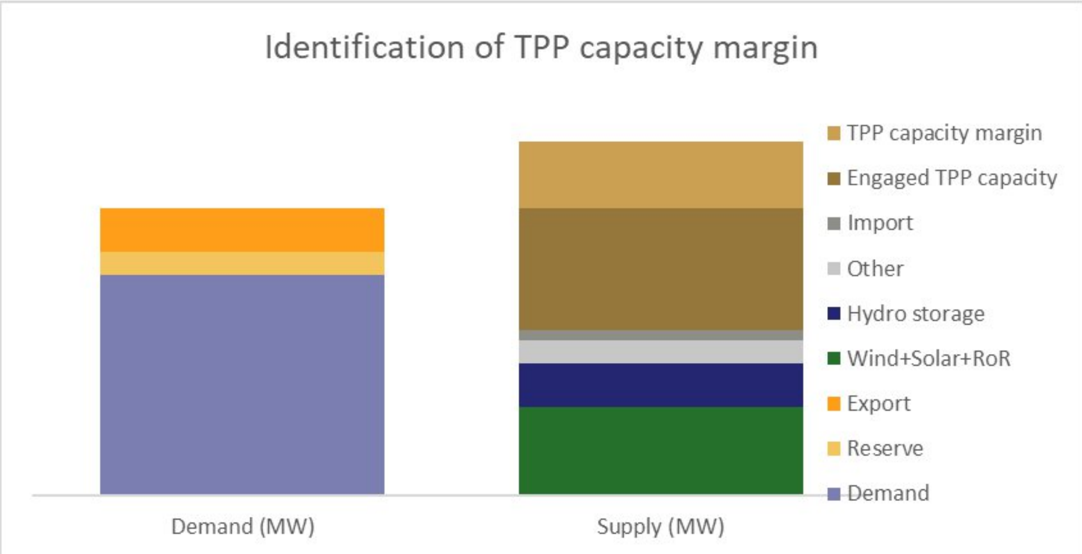


Figure 7 Illustrative Example of TPP capacity margin identification.

Presentation of the adequacy indicators also include the following:

1. The seasonal spatial screening gives a general indication of the adequacy risks for the coming season in the Med-TSO region. A relative EENS indicator is used, as illustrated in Figure 8
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 8. This would allow the detection of which weeks are mostly at risk.

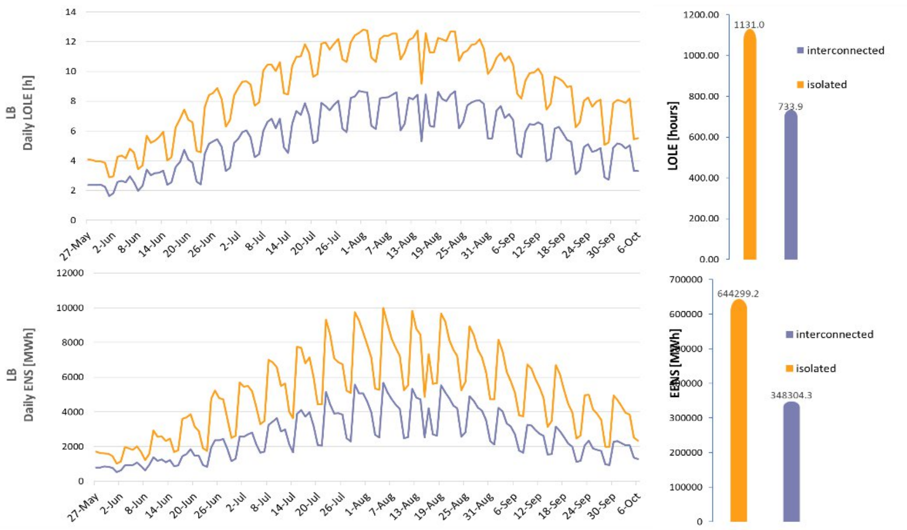


Figure 8 Illustrative example of average daily LOLE and EENS

In addition, available thermal capacities and thermal capacity margins are also presented at a daily & the minimum hourly level pointing to the excess of thermal capacities in cases when adequacy risks do not exist or pointing to the specific weeks when adequacy risks are at maximum.

In both cases, the average and minimum daily values as well as minimum hourly of all simulated MC years are presented as given in the following figures.

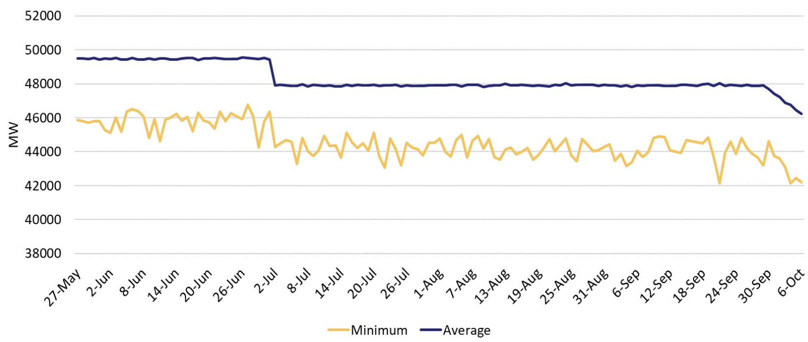


Figure 9 Illustrative example of available TPP capacity

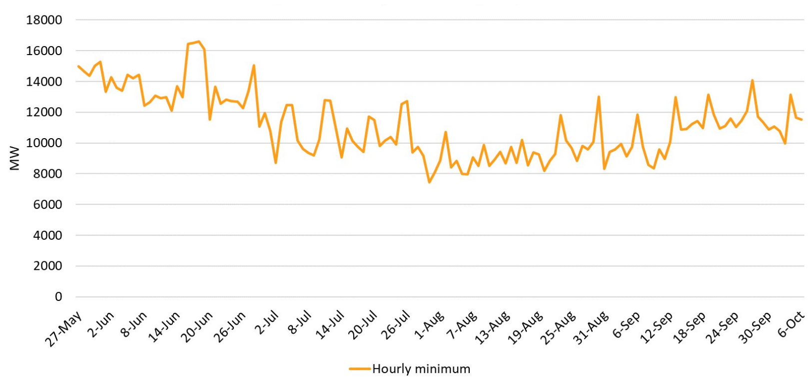


Figure 10 Minimum hourly TPP margin on each day of the analyzed period

2.3 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. In case of missing data, standard values and appropriate assumptions have been used, all based on publicly available data from relevant sources such as National network development plans and annual reports, Med-TSO publications[3], TYNDP 2020/2022, ERAA 2021 and any other relevant documents from ENTSO-E website.

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

Relevant data have been collected via standardized forms specialized for the collection of the 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.

For the Summer Outlook 2024 data have been collected in January 2024.

This database will be updated in July/August 2024 with the latest information that will be used for the preparation of the next report - Winter Outlook 2024/2025.

Within data collection particular attention has been paid to the following data:

1. Hourly demand per each market area/country
   Hourly demand data per each market area (country) that are modelled have been provided by our members. These time series refer to different climatic conditions (mainly for the period 1982-2019 or similar, depending on the country). Demand data include losses in the transmission network but do not include the self-consumption of generating units.
   Data about market-based demand-side responses are not provided and are not modelled.
   Additional demand during the charging of storage units is obtained as the result of the simulations.

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

2. Supply

Supply data include 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 on the unit-by-unit level. For some countries schedules for the maintenance of thermal units have been provided by our members and these schedules have been modelled as predetermined planned outages for corresponding units. Any additional maintenance activities have not been considered.

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

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

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

The 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 of demand for the required balancing reserve (FRR or FCR+FRR). A difference between these two ways of reserve modelling lies in the fact that in the first type of reserve modelling, no energy requirements are involved and only a certain level of the capacity in TPPs is always kept aside (and not engaged to cover the load). This does not make any distortions in system operation results, but there may be some hours during the year in which not full balancing requirements are satisfied due to outages of TPPs (planned or forced).

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

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

Considering the above-mentioned, 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.
- 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 1 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**

Furthermore, two sensitivity analyses have been conducted to identify the following.

- **The most severe Monte Carlo Climatic Year (MCY) for each country.**
- **Focus on Libyan system during upcoming SO 2024**

2.4 Overview of the MED-TSO power systems in Summer 2024

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 22nd week to the 40th week in the year 2024. These values are the average weekly consumption for 38 climatic years in the period from 1982 to 2019.

Table 1 Expected consumption in the summer weeks – 2024.

Weekly consumption (GWh)		EG	JO	LB	LY	MA	TN
Total		91465	9190	8508	18115	16431	9211
Week	22	4743	450	421	824	884	424
Week	23	4855	488	432	861	891	443
Week	24	4889	489	443	895	900	463
Week	25	4861	477	454	924	859	464
Week	26	5122	517	467	981	916	527
Week	27	5121	524	475	1015	922	551
Week	28	5169	524	483	1035	925	555
Week	29	5243	536	490	1057	940	560
Week	30	5235	542	496	1077	942	575
Week	31	5343	546	499	1078	933	579
Week	32	5352	541	499	1093	947	576
Week	33	5342	543	496	1089	930	547
Week	34	5276	534	498	1084	916	554
Week	35	5198	521	490	1068	930	532
Week	36	5088	507	479	1060	917	498
Week	37	4976	496	470	1023	901	471
Week	38	4863	481	463	990	892	457
Week	39	4788	474	451	961	885	436
Week	40	4637	440	440	916	885	425

High Value
Low Value

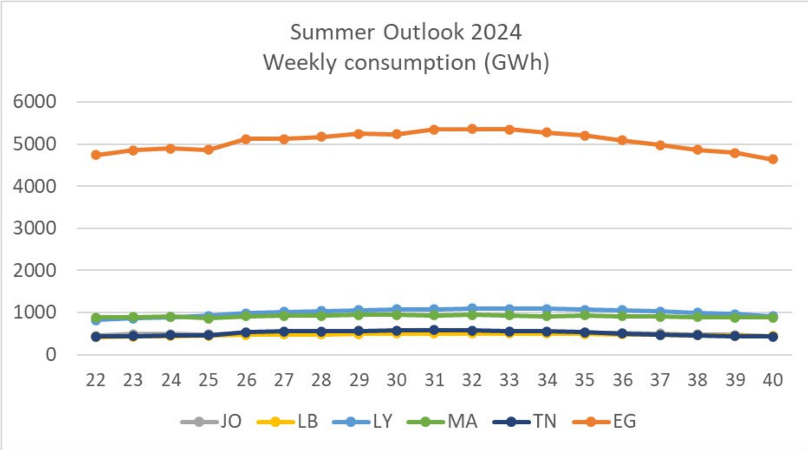


Figure 11 Expected weekly consumption per country in the analyzed season.

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.

Hourly peak demand values are presented in the following table and figure. Presented values represent maxim values among peak loads for each week for all 38 climatic years.

Table 2 Maximum weekly peak loads in summer weeks 2024

Peak load, based on maximum among 38 CY (MW)		EG	JO	LB	LY	MA	TN
Maximum		**39251**	**5160**	**3851**	**9827**	**6950**	**5704**
Week	22	35087	4386	3342	7525	6674	4104
Week	23	36150	4624	3465	8174	6708	4229
Week	24	36423	4618	3388	8049	6836	4822
Week	25	37433	4464	3518	7774	6722	4992
Week	26	37214	4417	3558	9260	6831	5376
Week	27	38704	4754	3625	9827	6851	5404
Week	28	37684	4637	3634	9186	6910	5418
Week	29	37342	4849	3766	9068	6898	5490
Week	30	37470	4760	3663	9692	6912	5159
Week	31	39251	5144	3821	8550	6903	5169
Week	32	38817	4945	3849	8869	6887	5704
Week	33	37982	4846	3686	9062	6816	5182
Week	34	37941	5160	3851	9196	6874	4847
Week	35	37184	4433	3687	8588	6950	5120
Week	36	37085	4491	3585	9355	6792	4537
Week	37	37069	4483	3650	9254	6720	4334
Week	38	35794	4208	3501	8587	6645	4282
Week	39	35347	4202	3500	8617	6738	3956
Week	40	34855	3980	3415	7935	6643	3849

High Value
Low Value

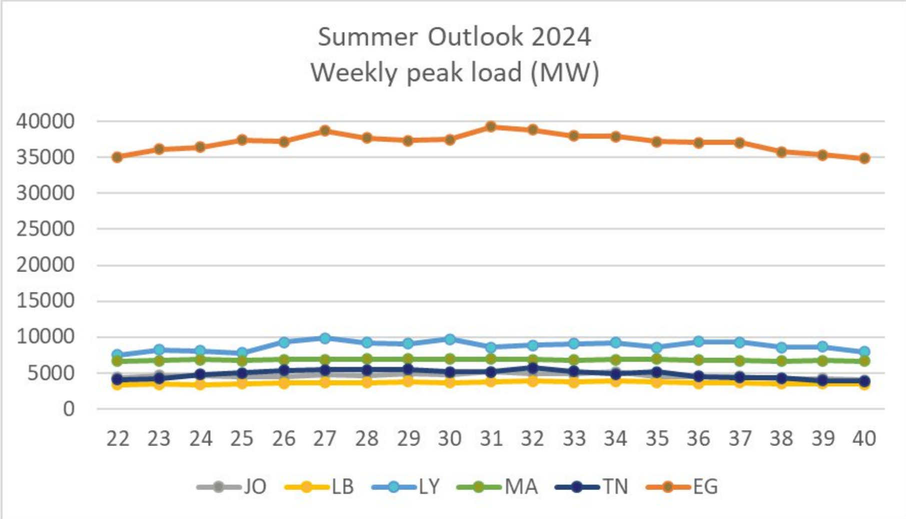


Figure 12 Maximum weekly peak loads per country in the analyzed season.

In all countries, except Jordan, peak load is observed in summer. In Jordan, the peak load is observed in winter and its value is 10% higher than in summer season.

B. Install capacities evolution.

The following tables provide information about install capacities in 2024. Total install capacities in the observed region are expected to reach 100 GW, with almost 83 GW (or around 83%) in thermal units.

Table 3 Total Install capacities (MW) per technology in 2024

Med-TSO Member	Expected WPP capacity		Expected SPP capacity		Expected HPP capacity		Expected TPP capacity		TOTAL [MW]
	[MW]	Share in Total	[MW]	Share in Total	[MW]	Share in Total	[MW]	Share in Total	
EG	1634	2.74%	2374	3.98%	2831	4.75%	52776	88.53%	**59615**
JO	621	8.25%	2123	28.20%	-	-	4785	63.55%	**7529**
LB	-	-	1500	31.98%	280	5.97%	2911	62.05%	**4691**
LY	-	-	-	-	-	-	11473	100.00%	**11473**
MA	2287	19.47%	831	7.07%	1770	15.07%	6861	58.40%	**11749**
TN	242	4.19%	345	5.98%	-	-	5183	89.83%	**5770**
TOTAL	**4784**	**4.74%**	**7173**	**7.11%**	**4881**	**4.84%**	**83989**	**83.30%**	**100827**

	Install Capacity [GW]	Peak Load [GW]
EG	59615	39251
JO	7529	5160
LB	4691	3851
LY	11473	9827
MA	11749	6950
TN	5770	5704

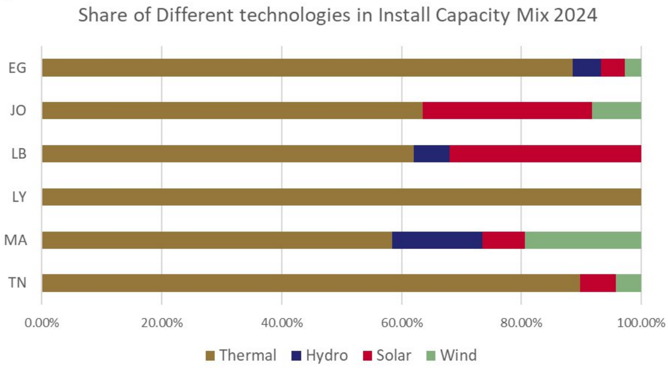


Figure 13 Install capacity mix and peak load in 2024.

It's important to highlight that Libya's power system relies exclusively on thermal power plants. In contrast to prior adequacy assessments, the thermal fleet has been re-evaluated, considering the maintenance carried out by the Libyan system and the assumption that certain power plants have been brought back into service due to this maintenance, along with the introduction of 2 GW of new power plants,

Relevant hydro capacities exist only in Egypt and Morocco. In Morocco, there is also a pump storage (PS) Hydro Power plant (HPP) with capacity of 464 MW. The highest wind & 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.

Table 4 Wind and solar capacity factors for all countries in 2024

	2024	
Country	**Wind CF**	**Solar CF**
DZ	-	21.2%
EG	39.3%	26.3%
JO	33.23%	26.56%
LB	-	-
LY	-	-
MA	54.63%	32.2%
TN	30%	20%

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 (JO) or as random outages but respecting certain predefined rules:

- In all countries Except Morocco, planned outages are not envisaged in the period from the 1st of May to 1st of October.
- In Morocco, planned outages are not envisaged in the period from 1st of May to the 1st of September.

Practically, when predetermined rule is applied, period analyzed in summer outlook should not include maintenance on any of the thermal units. This is the case also in this summer outlook except that in JO there are couple of units in maintenance in May, and October.

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

C. Interconnections between countries

Summarized NTC values provided are used as available cross-border capacities and we assumed 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 6 analyzed Med-TSO members 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. In addition to this, in the case of some borders with countries outside of the Med-TSO region, exchanges have been modelled using hourly data provided by our members. In the case of Algeria, it is assumed that the country can export electricity to neighboring countries in the event of adequacy risk. Additionally, it is assumed that Algeria itself does not face any adequacy risk.

For Lebanon, we evaluated the 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.

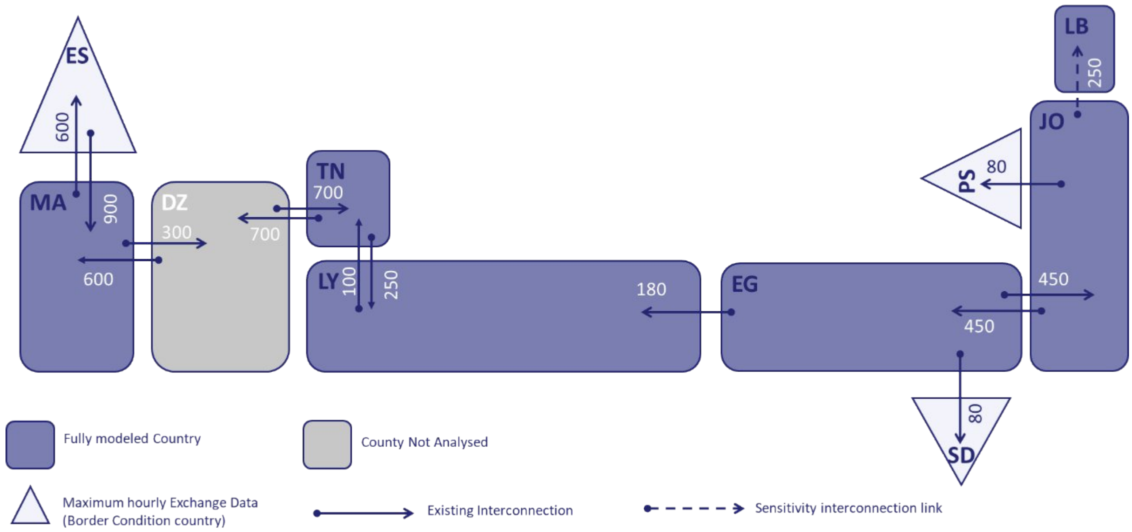


Figure 14 Net Transfer Capacity during SO2024

D. Reserve requirements and their modelling.

Reserve requirements have been provided for each country (Table 5). 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.

Table 5 Balancing reserve requirements.

Reserve		SO 2024
EG	FCR+FRR [MW]	1200
JO	FCR+FRR [MW]	200
LB	FCR+FRR [MW]	30
LY	FCR+FRR [MW] [4]	500
MA	FCR+FRR [MW] [5]	700
TN	FCR+FRR [MW]	220

[4] FCR for LY has been modeled through reduced thermal capacity by 5%.
[5] FCR for MA has been modeled through reduced thermal capacity by total of 300 MW.

3 Adequacy Situation Overview

3.1 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. Then the MC combinations have been developed as follows:

- Climate years (each of 38 years from the period 1982- 2019) are selected one by one.
- Each climate year is associated with random outage samples, i.e. randomly assigned unplanned (and planned)[6] outage patterns for thermal units.

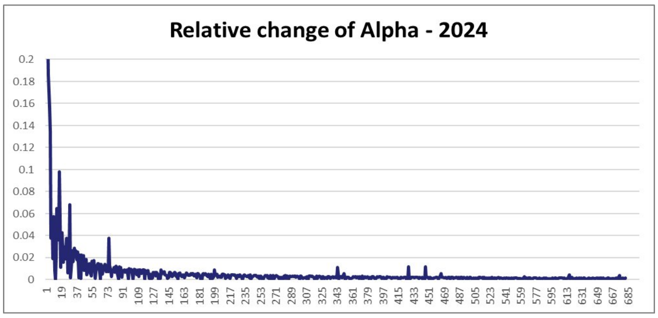
The developed model was thoroughly tested concerning all relevant parameters of the generation portfolios of the different power generation technologies including RES, different weather conditions and different status of the interconnections. The sufficient number of MC years that can provide sufficiently good convergence of the main results has been determined as 684 (38 x 18).

The sufficient 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.



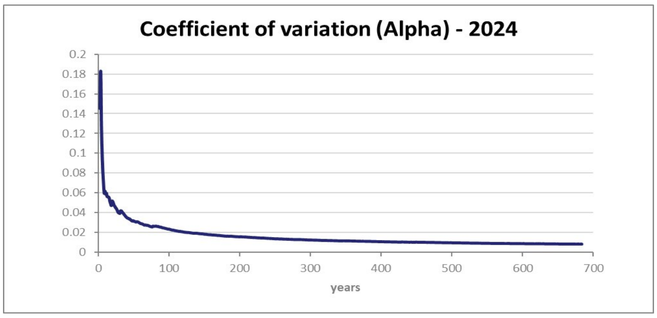


Figure 15 Evolution of convergence criteria for 684 MC years, simulations for the year 2024.

6

3.2 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 the case of a theoretical isolated scenario (Figure 16) shows the summer season only, adequacy risks are observed in Morocco, Tunisia & Lebanon, although they could be considered medium risk in Morocco.

For of Tunisia & Lebanon adequacy risk is very high under isolated system operating mode.

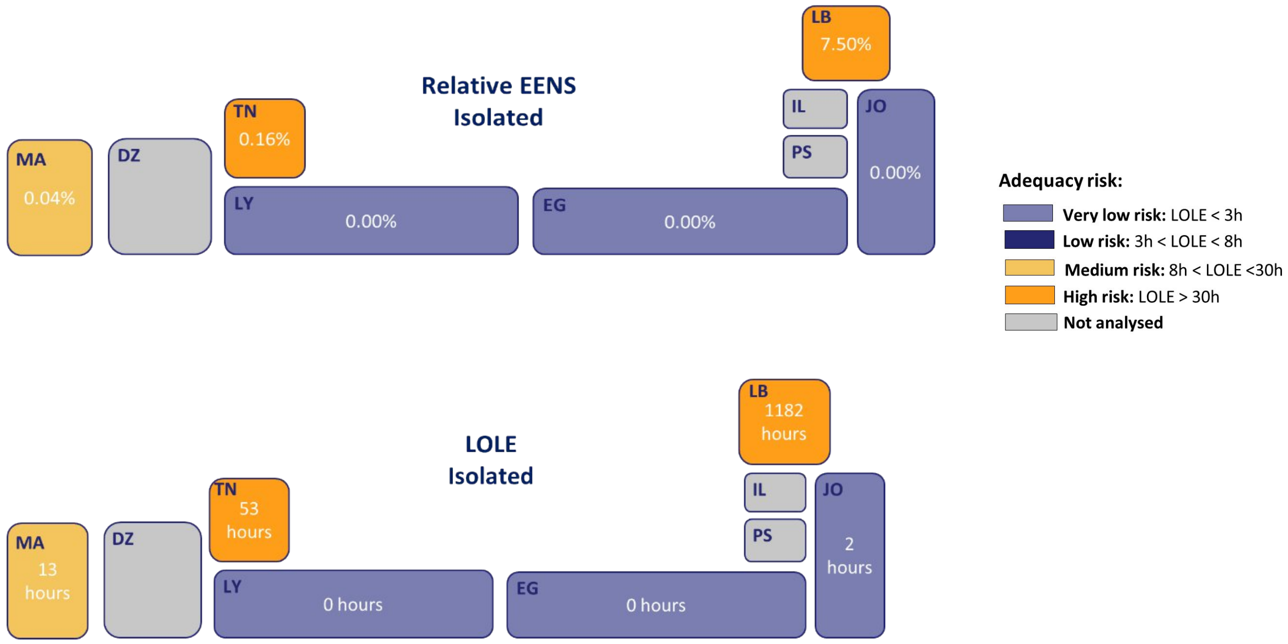


Figure 16 Seasonal Relative EENS and LOLE for the isolated mode of operation for only summer season.

Interconnections and energy exchanges needed to overcome adequacy issue with neighboring countries reduce adequacy risks to very low risk in the case of Morocco & Tunisia but, in Lebanon even in this more relaxed operating mode, adequacy risks are at an unacceptable level (Figure 17) [7] shows interconnected scenario for the summer season only.

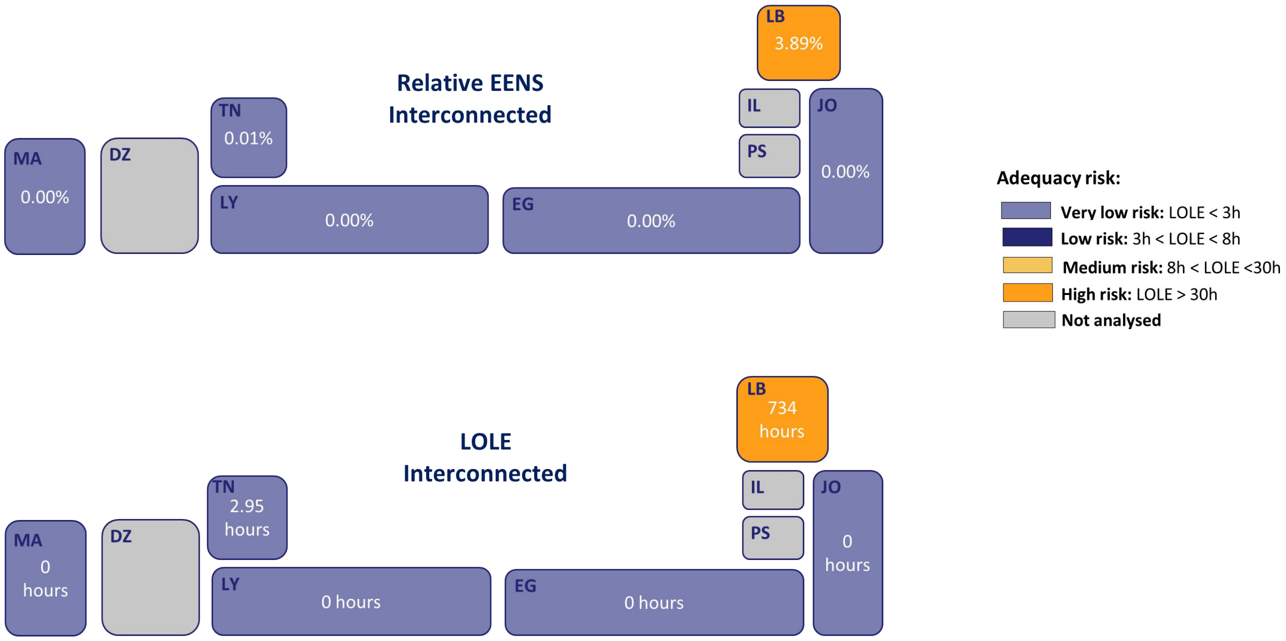


Figure 17 Seasonal relative ENS and LOLE for the interconnected mode of operation for only summer season.

[7] Color coding of adequacy risk levels presented in Figure 15 & Figure 16 does not reflect national thresholds for loss of load expectation (LOLE) that is usually specified within Network Codes of corresponding Transmission System Operators.

Table 6 Seasonal EENS for Interconnected and isolated scenario

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	384 MWh	16 MWh		2.42	0.11
	50th percentile 0 MWh	50th percentile 0 MWh		50th percentile LOLD: 0 hours	50th percentile LOLD: 0 hours
	95th percentile 2229 MWh	95th percentile 42 MWh		95th percentile LOLD: 13 hours	95th percentile LOLD: 1 hours
MA	6365 MWh	8 MWh		12.79	0.04
	50th percentile 0 MWh	50th percentile 0 MWh		50th percentile LOLD: 0 hours	50th percentile LOLD: 0 hours
	95th percentile 30749 MWh	95th percentile 0 MWh		95th percentile LOLD: 75 hours	95th percentile LOLD: 0 hours
TN	15317 MWh	508 MWh		53.12	2.95
	50th percentile 9884 MWh	50th percentile 0 MWh		50th percentile LOLD: 42 hours	50th percentile LOLD: 0 hours
	95th percentile 64588 MWh	95th percentile 2915 MWh		95th percentile LOLD: 156 hours	95th percentile LOLD: 21 hours
LY	17 MWh	0 MWh		0.11	0
	50th percentile 0 MWh	50th percentile 0 MWh		50th percentile LOLD: 0 hours	50th percentile LOLD: 0 hours
	95th percentile 0 MWh	95th percentile 0 MWh		95th percentile LOLD: 0 hours	95th percentile LOLD: 0 hours
LB	670967 MWh	348304 MWh		1181.98	733.92
	50th percentile 663226 MWh	50th percentile 339189 MWh		50th percentile LOLD: 1180 hours	50th percentile LOLD: 726 hours
	95th percentile 925402 MWh	95th percentile 521087 MWh		95th percentile LOLD: 1487 hours	95th percentile LOLD: 976 hours

Adequacy risk:

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

In Table 6 detailed EENS and LOLD seasonal results are given for all analyzed countries.

Results point to adequacy issues in some countries. Notable in:

- Jordan

  In the interconnected mode of operation, Jordan demonstrates a very low adequacy risk, with an EENS of just 16 MWh and LOLE of less than one hour. However, in a rare and more critical scenario (P95), the ENS can potentially rise to 22 MWh with a LOLD of 1 hour. Adequacy risks increase in the isolated operating mode but still remain within acceptable limits.

- Libya[8]

  In the interconnected mode of operation, Libya exhibits a very low adequacy risk, with an EENS of just 17 MWh and a LOLE of less than one hour.

  However, we conducted a sensitivity case specifically focusing on the Libyan system and assumptions regarding maintenance activities.

- Tunisia

  In isolated operation mode, Tunisia faces a high risk to adequacy, with ENS potentially reaching 15 GWh and LOLE lasting for 53 hours. However, in more critical P95 scenarios, EENS can escalate to 64 GWh with a LOLD of up to 156 hours. In contrast, when operating in interconnected mode, the risk to adequacy is minimal to only 508 MWh and LOLE of 3 hours.

- Morrocco

  In isolated operation mode, Morocco faces a moderate risk to adequacy, with ENS potentially reaching 6 GWh and LOLE lasting for 13 hours. However, in more critical P95 scenarios, EENS can escalate to 31 GWh with a LOLD of up to 75 hours. In contrast, when operating in interconnected mode, the risk to adequacy is minimal.

- Lebanon

  Lebanon experiences the highest EENS and LOLE during the Summer of 2024 in the region, with 348 GWh of ENS and 733 hours of LOLE (equivalent to 23% of the time) in the interconnected mode.

  These figures highlight an extremely precarious adequacy situation (daily LOLD during the whole season can be ranged from 2 hours to 9 hours). In the event of more critical but less probable P95 cases, ENS can reach a staggering 521 GWh with an unavailability to supply the load for over 31% of the time.

  In the isolated mode of operation, adequacy is even more at risk, with EENS reaching 925 TWh and LOLE extending to 1487 hours (daily LOLD during the whole season can be ranged from 3 hours to 13 hours). This emphasizes that Lebanon's interconnection with Jordan significantly reduces adequacy risks by 62%.

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.

[8] For Libya we can see that is facing very low risk of adequacy compared with previous studies that was performed. This improvement is attributed to the assumption that a considerable number of power plants have been assumed to be back into service following maintenance activities & the commissioning of new power plants, so input data were reevaluated for this assessment.

4 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 Summer. 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.

Table 7 Exchanges needed to overcome Adequacy in the region

Link	Direct Exchanges for Adequacy (GWh)	NTC direct (MW)	Reverse Exchanges for Adequacy (GWh)	Reverse NTC (MW)
DZ00 - MA00	0.17	600	0.00	300
DZ00 - TN00	14.38	700	0.00	700
EG00 - JO00	0.97	450	0.00	450
EG00 - LY00	0.01	180	0.00	0
ES00 - MA00	6.23	900	0.00	600
LY00 - TN00	0.38	100	0.00	250
JO00 - LB00	691.53	250	0.00	0

Exporting electricity from Egypt to Jordan contributes positively to enhancing Jordan's adequacy, even though Jordan's adequacy risks remain within acceptable levels, even without this external support. Furthermore, Egypt & Jordan are actively exporting approximately 240 GWh to meet Sudan's & Palestine energy needs.

In the case of Tunisia, the country is involved in importing electricity from both Algeria and Libya, but primarily relies on imports from Algeria to mitigate its adequacy issues to a minimum.

Morocco, on the other hand, relies solely on electricity imports from Spain to alleviate their adequacy concerns. Interconnections with Spain are pivotal in reducing Morocco's adequacy issues to a minimum.

The situation in Lebanon is completely different where interconnections and imported energy play a substantial role. While interconnections help decrease adequacy concerns by a factor of 1.4, they alone are insufficient to completely mitigate these potential risks.

5 Adequacy Situation on Country Level

5.1 Egypt

DEMAND

Egyptian seasonal weekly demand, depicted in Figure 18 goes from around 4637 GWh to 5352 GWh, while peak hourly demand in each week varies from 34.8 GW to 39.3 GW. It should be noted that weekly demand refers to the average values of all 38 analyzed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analyzed climatic years.

As can be seen from the figure below, maximum electricity needs are expected from the second half of July until the end of August (29th - 35th week), due to high temperatures and high cooling consumption, similar to in all other countries. The maximum hourly demand in all 38 climatic years reaches 39251 MW in the 31st week. It should be noted that during the summer season, maximum hourly demand changes by a very narrow range of 11%.

	week 22	week 23	week 24	week 25	week 26	week 27	week 28	week 29	week 30	week 31	week 32	week 33	week 34	week 35	week 36	week 37	week 38	week 39	week 40
Weekly consumption (GWh)	4,743	4,855	4,889	4,861	5,122	5,121	5,169	5,243	5,235	5,343	5,352	5,342	5,276	5,198	5,088	4,976	4,863	4,788	4,637
Weekly peak loads (MW)	35,087	36,150	36,423	37,433	37,214	38,704	37,684	37,342	37,470	39,251	38,817	37,982	37,941	37,184	37,085	37,069	35,794	35,347	34,855

LOW HIGH

Figure 18 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 88%, 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 3% each. Total installed capacities are 59615 MW with import capacity up to 450 MW from Jordan, which combined is substantially higher than the maximum hourly consumption of 39 251 MW. In sense of demand and installed capacities, Egypt is the biggest of all analyzed power systems.

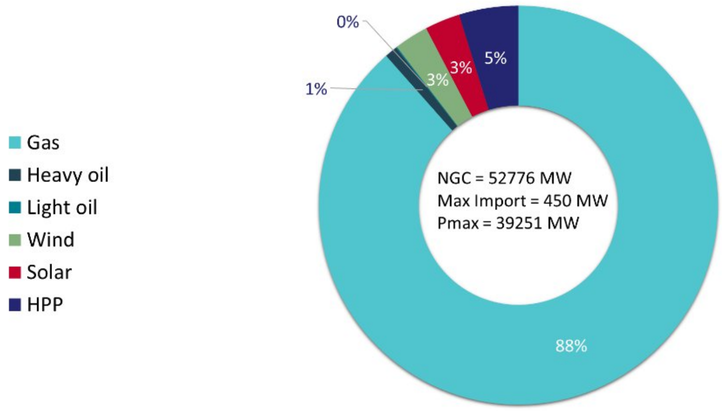


Figure 19 Installed Capacity mix with total NGC, import NTC and peak demand in Egypt.

The average daily available TPP capacity, after reduction due to forced outages, is shown in Figure 20. 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 forced outages, but also due to decommissioning of some units from July 1st. The minimal average daily available TPP capacity (minimum among all simulated MC years) fluctuates from 42 GW to 46 GW.

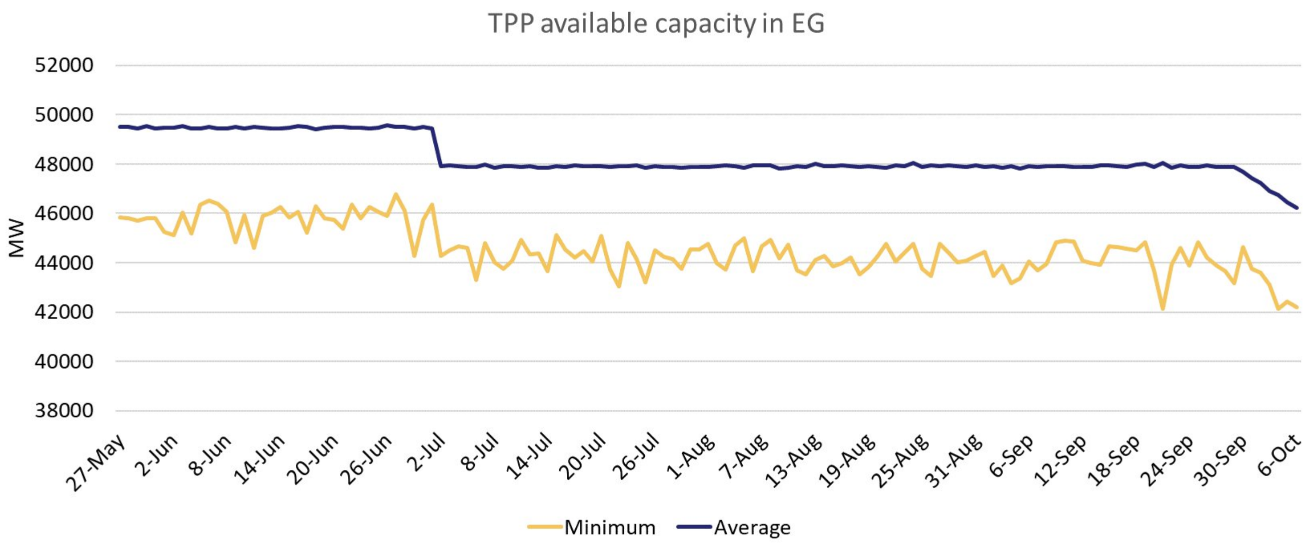


Figure 20 Average and minimum TPP available capacity in Egypt.

As a result of system simulation, the minimum hourly TPP capacity margin is calculated and depicted in Figure 21 It represents the difference between available and activated TPP capacities. The hourly minimum TPP margin is between 7 GW and 16.5 GW during the analyzed summer season.

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

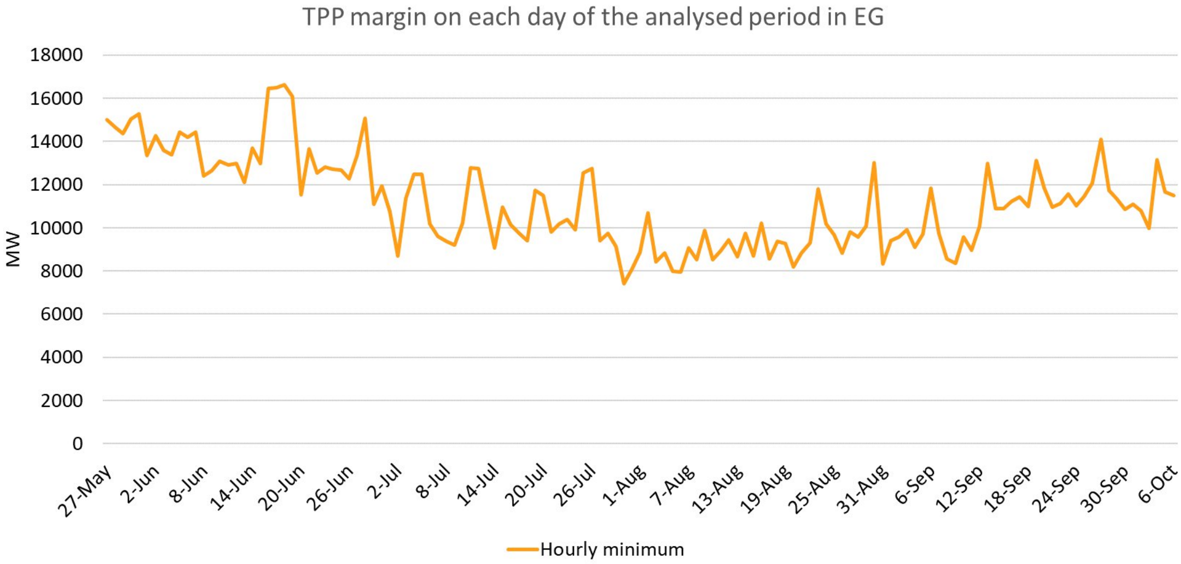


Figure 21 Minimum hourly TPP margin on each day of the analyzed period in Egypt.

ADEQUACY ASSESSMENT

No adequacy concerns are detected for both analyzed modes of operation in the case of Egypt.

5.2 Jordan

DEMAND

Jordan's seasonal weekly demand, depicted in Figure 22, goes from around 440 GWh to 546 GWh (fluctuation at the level of 20%), while peak hourly demand in each week goes from 3980 MW to 5144 MW which presents even higher fluctuation – 22%. It should be noted that weekly demand refers to the average values of all 38 analyzed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analyzed climatic years.

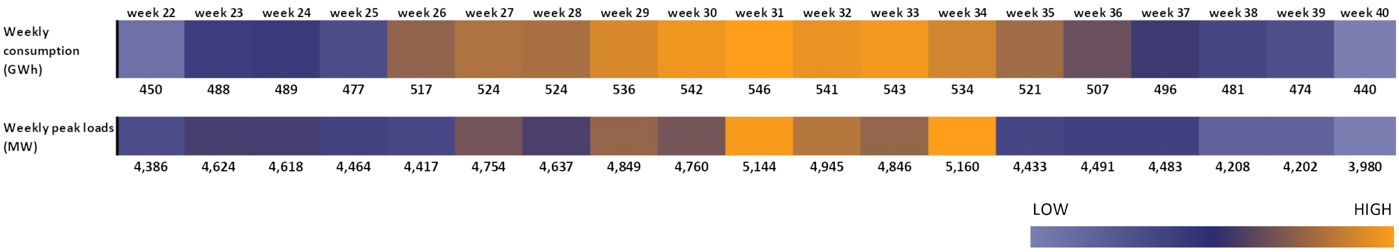


Figure 22 Seasonal Weekly demand in Jordan.

SUPPLY AND NETWORK OVERVIEW

Jordan's power generation fleet is dominantly based on gas fueled TPPs, with the share in total installed capacities around 58%, 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 28% respectively. Total installed capacities amount to 7528 MW with an import capacity up to 450 MW from Egypt.

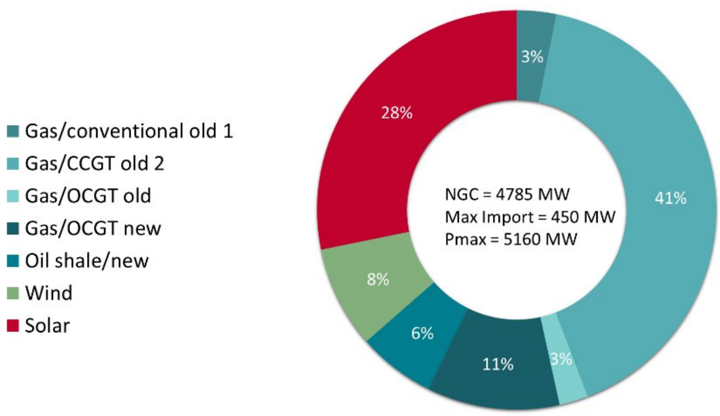


Figure 23 Installed Capacity mix with total NGC, import NTC and peak demand in Jordan.

The average daily available TPP capacity, after reduction due to derating factors, and forced and planned outages is shown in Figure 24. Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated mode of operation. The average available TPP capacities start from 3892 MW and rise to 4100 MW in early July due to maintenance stops aimed at meeting the demand during the summer season. The minimal average daily available TPP capacity (minimum among all simulated MC years) goes from 2700 MW to only 3500 MW.

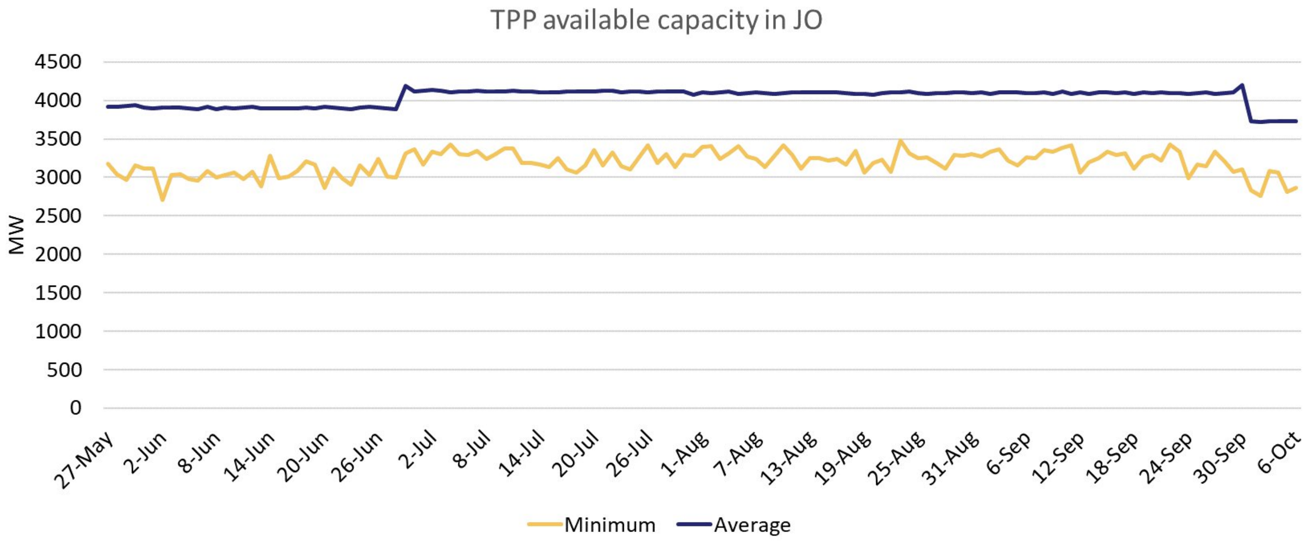


Figure 24 Average and minimum TPP available capacity in Jordan.

As a result of system simulation, the minimum hourly TPP capacity margin is calculated and depicted Figure 25 It represents the difference between available and activated TPP capacities. The minimum hourly value of the TPP margin are often at zero value most of summer season. These results point to the fact that there is a possibility that during some hours adequacy can be endangered. Notably, the daily margin follows daily consumption patterns, and it is the lowest during working days, due to higher demand.

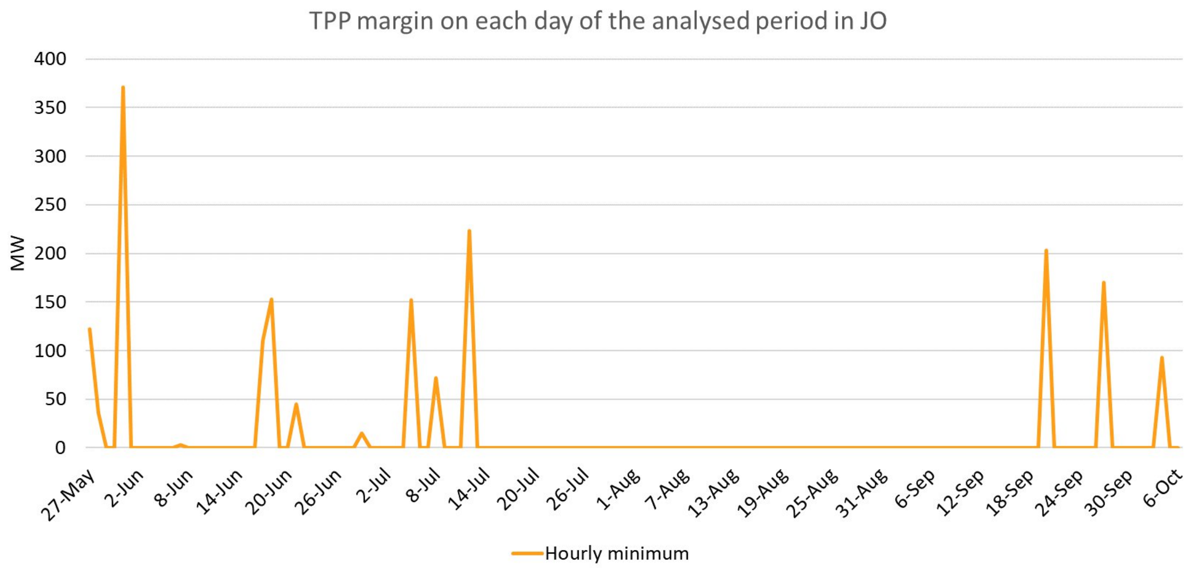


Figure 25 Minimum hourly TPP margin on each day of the analyzed period in Jordan.

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in Figure 26, 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.

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

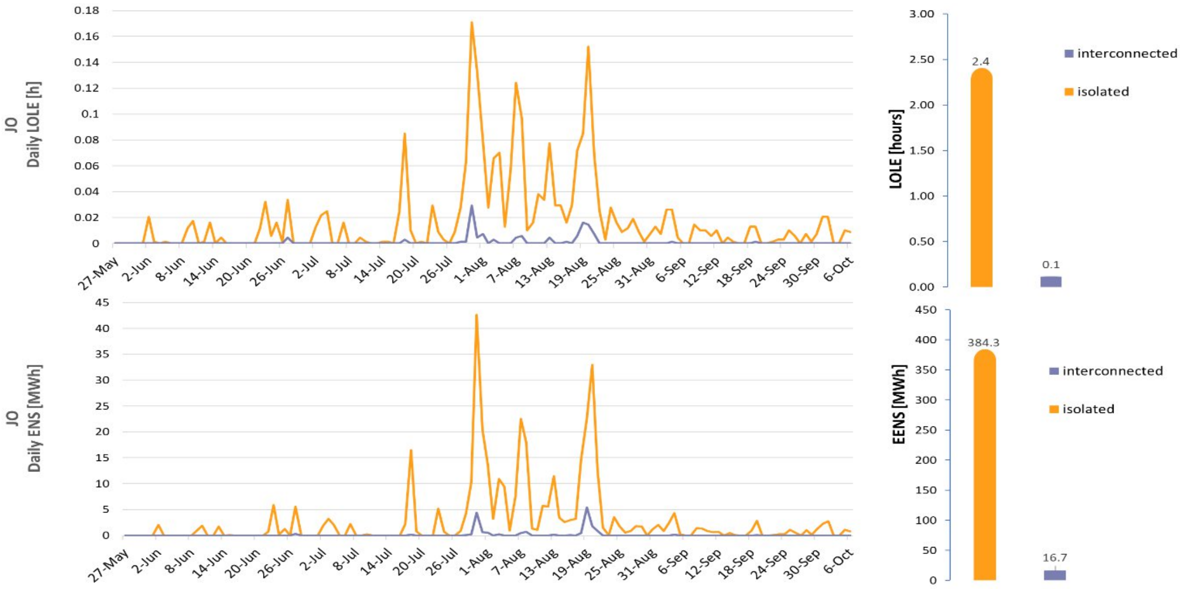


Figure 26 Daily LOLE and EENS for the interconnected and isolated mode of operation in Jordan.

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 2.4 h to less than 0.1 h and expected seasonal EENS from 384 MWh to just 16.7 MWh.

5.3 Lebanon

DEMAND

Lebanon's seasonal weekly demand, depicted in Figure 27, goes from around 420 GWh to 500 GWh, while peak hourly demand each week goes from 3342 MW to 3849 MW. It should be noted that weekly demand refers to the average values of all 38 analyzed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analyzed climatic years.

Maximum electricity needs are expected during August (week 31-34), due to high temperatures and high cooling demand. The maximum hourly demand of 3849 MW is reached in the 32nd week of 2024. It should be noted that during the summer season, maximum hourly demand changes in the range of 13%. Also, operation of Lebanon's power system is especially difficult, with a continuous lack of supply and organized regular load shedding.

	week 22	week 23	week 24	week 25	week 26	week 27	week 28	week 29	week 30	week 31	week 32	week 33	week 34	week 35	week 36	week 37	week 38	week 39	week 40
Weekly consumption (GWh)	421	432	443	454	467	475	483	490	496	499	499	496	498	490	479	470	463	451	440
Weekly peak loads (MW)	3,342	3,465	3,388	3,518	3,558	3,625	3,634	3,766	3,663	3,821	3,849	3,686	3,851	3,687	3,585	3,650	3,501	3,500	3,415

LOW HIGH

Figure 27 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 62% and 6% goes to hydro power plants & rest of 32% goes to solar rooftop capacities. Total installed capacities amount to 4691 MW, but as serious support to system operation, also the additional capacity of 1000 MW in diesel units is considered in this analysis.

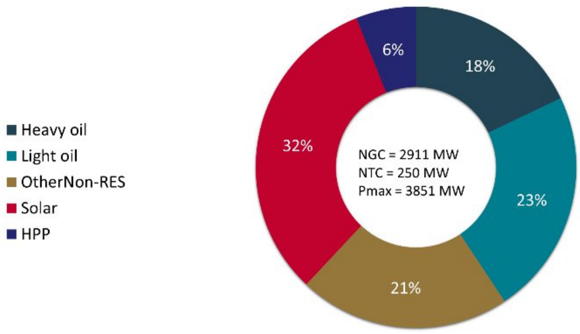


Figure 28 Installed Capacity mix with total NGC, import NTC and peak demand in Lebanon.

The average daily available TPP capacity, after reduction due to forced outages, is shown Figure 29. 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 NGC 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 is around only 2650 MW.

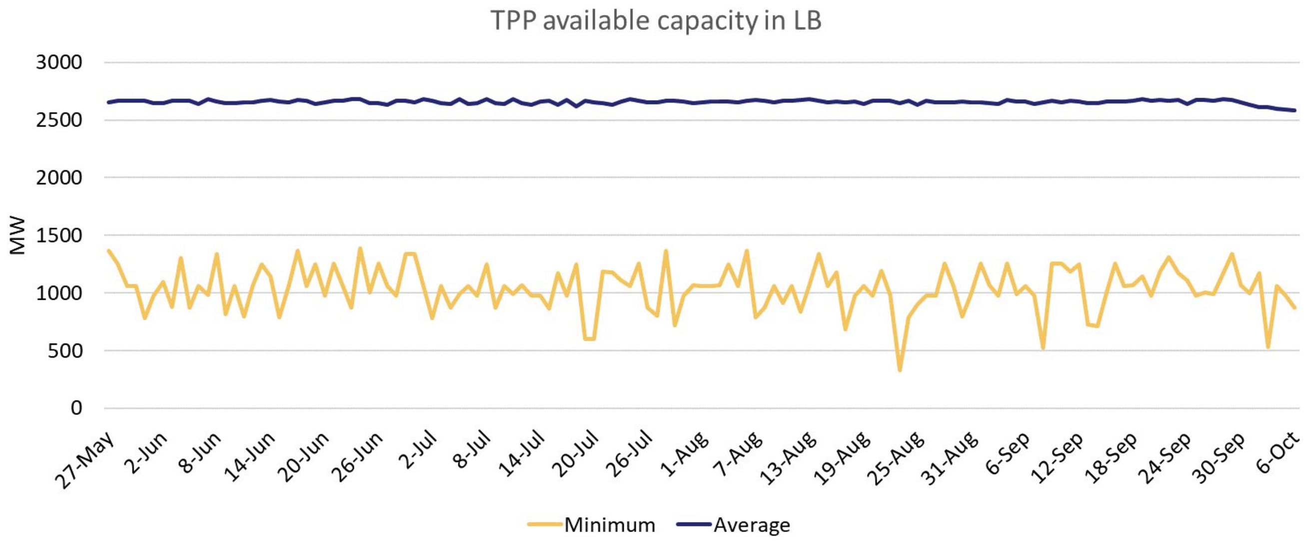


Figure 29 Average and minimum TPP available capacity in Lebanon.

As a result of system simulation, the minimum hourly TPP capacity margin is calculated and depicted in Figure 30 It represents the difference between available and engaged TPP capacities. No margin exists in Lebanon's power system.

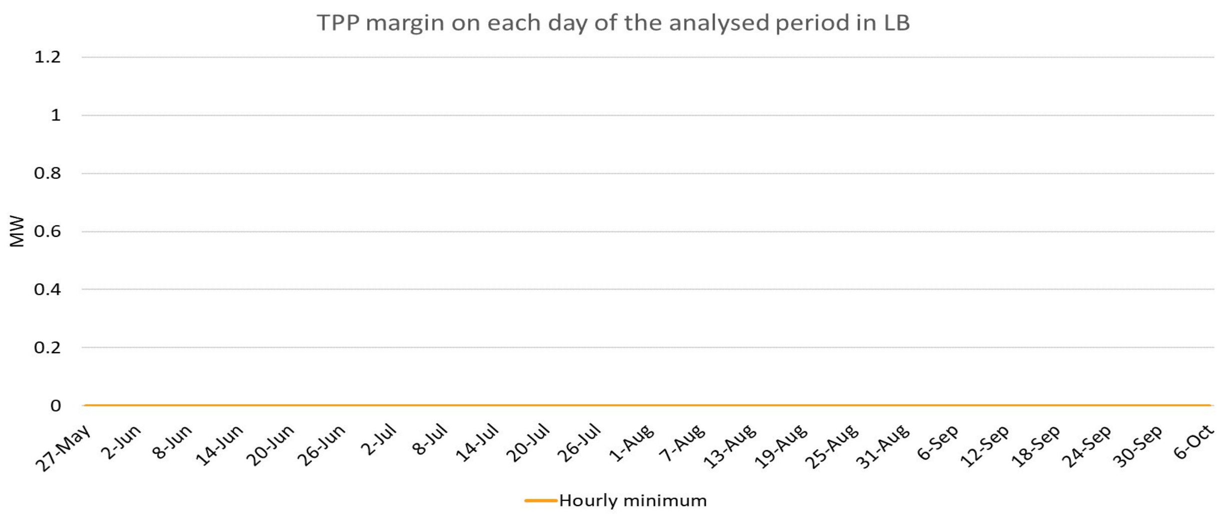


Figure 30 Minimum hourly TPP margin on each day of the analyzed period in Lebanon.

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in Figure 31 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.

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 interconnected mode of operation: EENS is 348 GWh and LOLE is 734 hours (around 23 % during the summer 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=2 hours and LOLE Max=8 hours in average of 684 MC years.

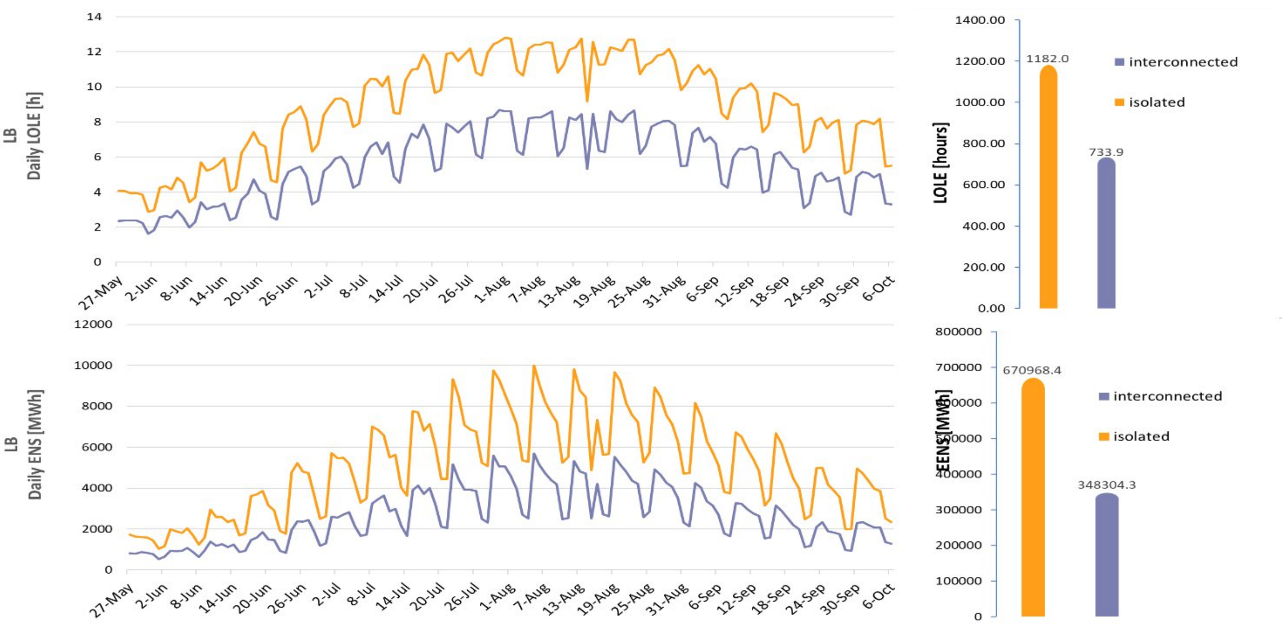


Figure 31 Daily LOLE and EENS for the interconnected and isolated mode of operation In Lebanon

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

5.4 Libya

DEMAND

Libya's seasonal weekly demand, depicted in Figure 32, goes from around 824 GWh to 1093 GWh, while peak hourly demand each week goes from 7725 MW to 9827 MW. This variation of the peak load is almost 25% which is very high. It should be noted that weekly demand refers to the average values of all 38 analyzed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analyzed climatic years.

Maximum electricity needs are expected in August (32nd week). The maximum hourly demand in all 38 MC years reaches 9827 MW in the week 27th of 2024.

	week 22	week 23	week 24	week 25	week 26	week 27	week 28	week 29	week 30	week 31	week 32	week 33	week 34	week 35	week 36	week 37	week 38	week 39	week 40
Weekly consumption (GWh)	824	861	895	924	981	1,015	1,035	1,057	1,077	1,078	1,093	1,089	1,084	1,068	1,060	1,023	990	961	916
Weekly peak loads (MW)	7,525	8,174	8,049	7,774	9,260	9,827	9,186	9,068	9,692	8,550	8,869	9,062	9,196	8,588	9,355	9,254	8,587	8,617	7,935

LOW HIGH

Figure 32 Seasonal Weekly demand in Libya.

SUPPLY AND NETWORK OVERVIEW

Libya's generation portfolio is based exclusively on gas-fired power plants, with 100% in generation capacity mix. The majority of installed thermal capacities refer to gas turbines (67%) and light oil (24%), while only 9% of capacities of heavy oil. It should be emphasized that according to provided data for summer outlook 2024 there are no RES capacities installed in Libya.

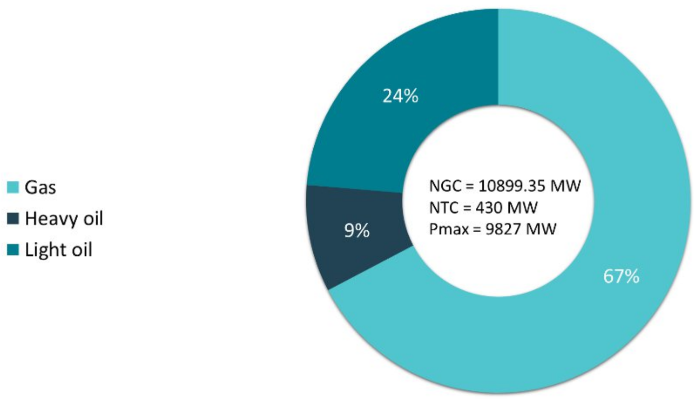


Figure 33 Installed Capacity mix with total NGC, import NTC and peak demand in Libya.

The average daily available TPP capacity, after reduction due to forced outages, is shown Figure 34 Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated mode of operation. Libya's average available thermal capacity is stable at the level of 10100 MW.

The minimal daily available TPP capacity between all analyzed MC years is between 8000 MW to 9000 MW.

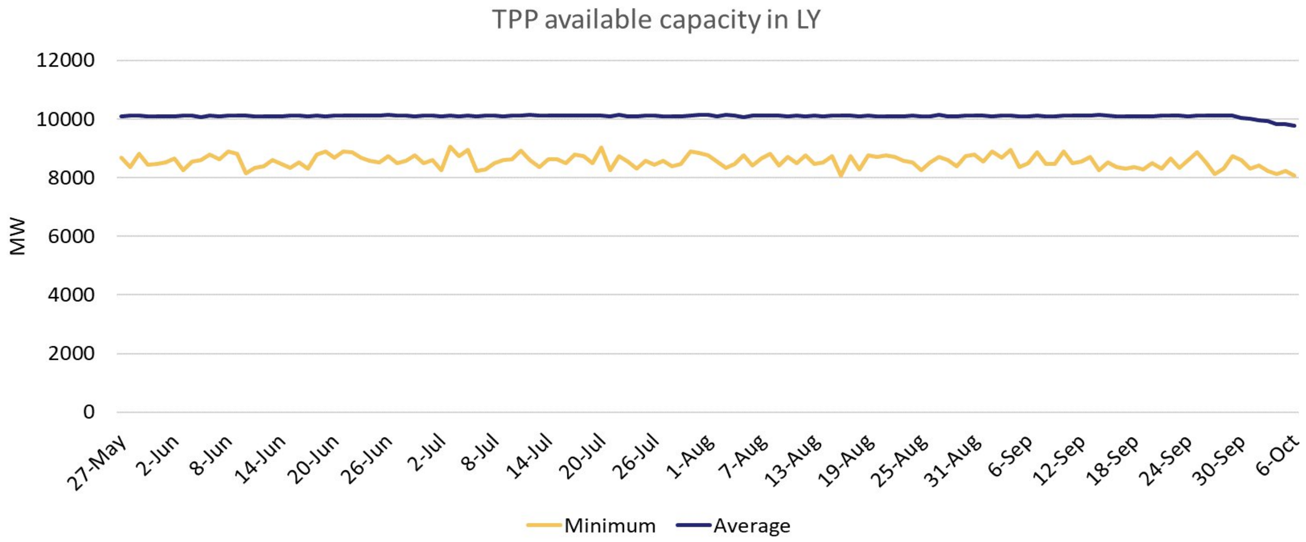


Figure 34 Average and minimum TPP available capacity in Libya.

As a result of system simulation, the minimum hourly TPP margin for each day is calculated and depicted Figure 35 It represents the difference between available and activated TPP capacities. The minimum hourly value of the TPP margin on some days is at zero. There are only a few days with non/zero minimum daily margin, which are noted at the beginning and end of the summer season.

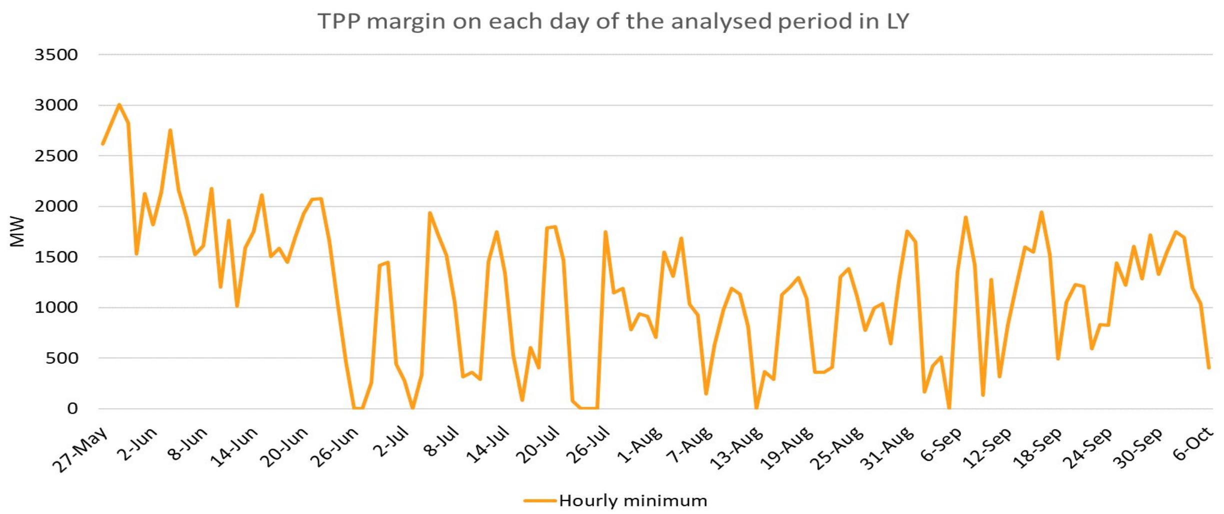


Figure 35 Minimum hourly TPP margin on each day of the analyzed period in Libya.

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in Figure 36 , 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. The conclusion is that for both modes of operation adequacy risk is marginal.

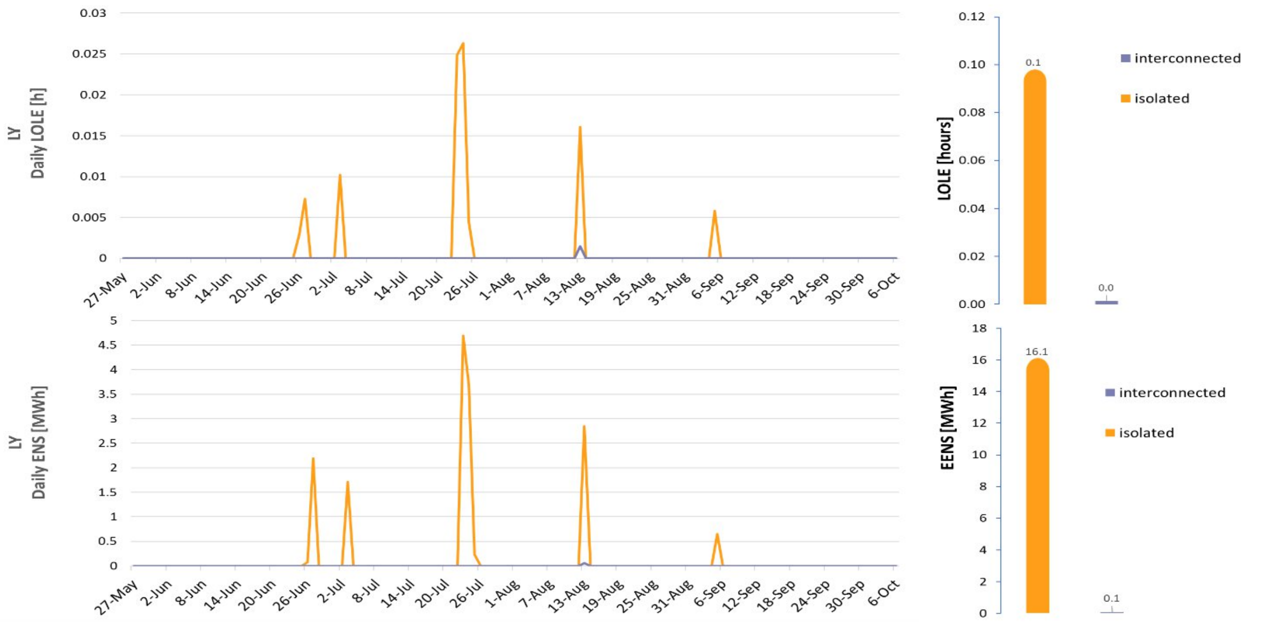


Figure 36 Daily LOLE and EENS for the interconnected and isolated mode of operation in Libya.

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. LOLE for the entire season in the isolated case is minor, while for the interconnected regime of operation seasonal LOLE is significantly lower.

5.5 Morocco

DEMAND

Moroccan seasonal weekly demand, depicted in Figure 37 goes from around 859 GWh to 947 GWh, while peak hourly demand each week goes from 6643 MW to 6950 MW. It should be noted that weekly demand refers to the average values of all 38 analyzed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analyzed climatic years.

Maximum electricity needs are expected in July & August, while the maximum hourly demand in all 38 MC years reaches 6950 MW in the 34th week.

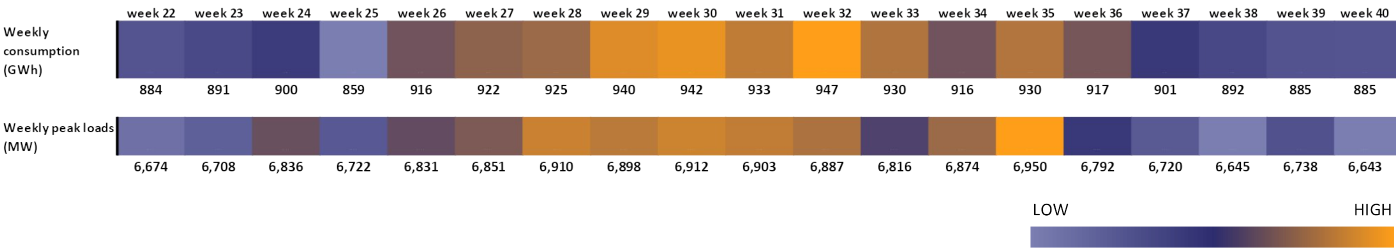


Figure 37 Seasonal Weekly demand in Morocco.

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 60%, which is divided further into Coal, Gas and Oil TPPs. Hydro capacities amount to 15%, while RES wind and solar share in installed capacities is 20% and 7% respectively. Total installed capacities are 11408 MW with total import capacity up to 1500 MW, which is about 21% of peak load in the analyzed period.

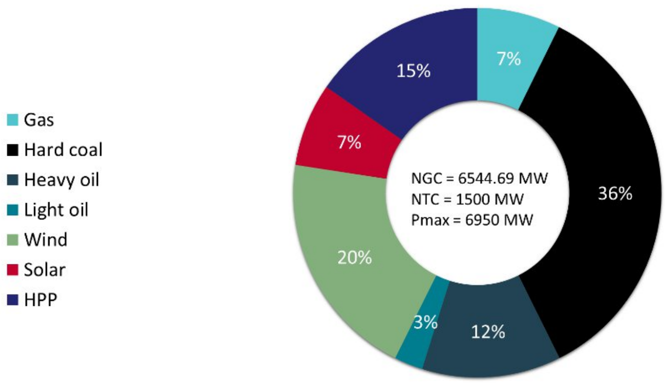


Figure 38 Seasonal Weekly demand in Morocco.

The average daily available TPP capacity, after reduction due to forced outages, is shown Figure 39 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 level is stable, and it is around 5920 MW during June, July, August while starting from September planned outage is implemented. The minimal average daily available TPP capacity (minimum among all simulated MC years) goes from 2500 MW to 4600 MW.

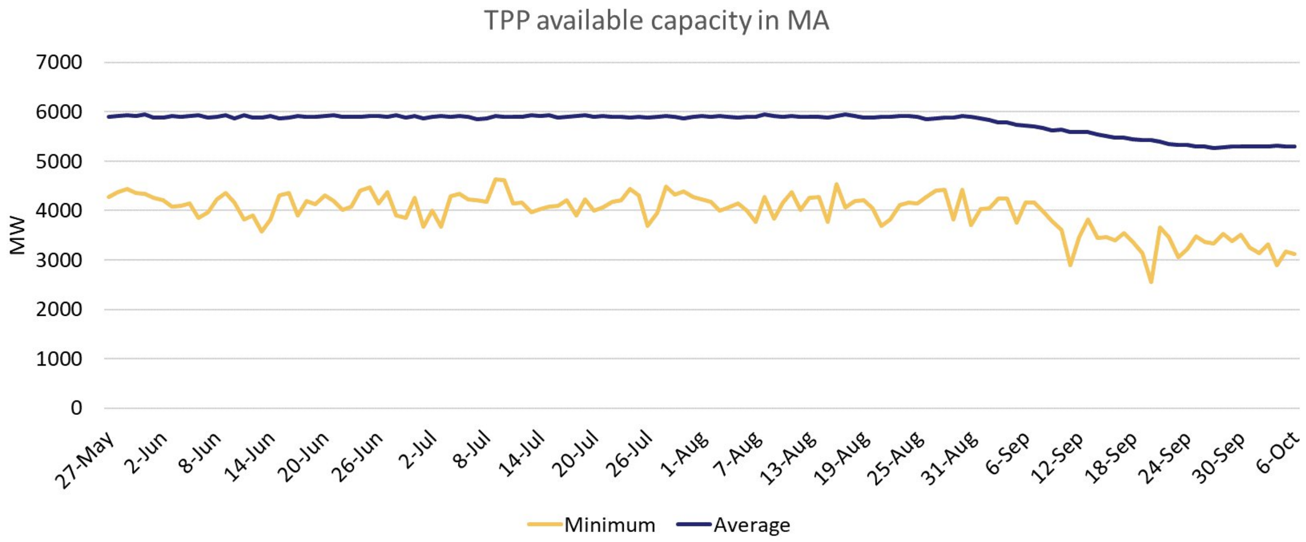


Figure 39 Average and minimum TPP available capacity in Morocco.

As a result of system simulation, the minimum hourly TPP capacity margin on each day is calculated and depicted in Figure 40 It represents the difference between available and engaged TPP capacities. Obviously, TPP margin in some days are at zero level during September month, but adequacy is not endangered since there are other sources and interconnections to support adequacy.

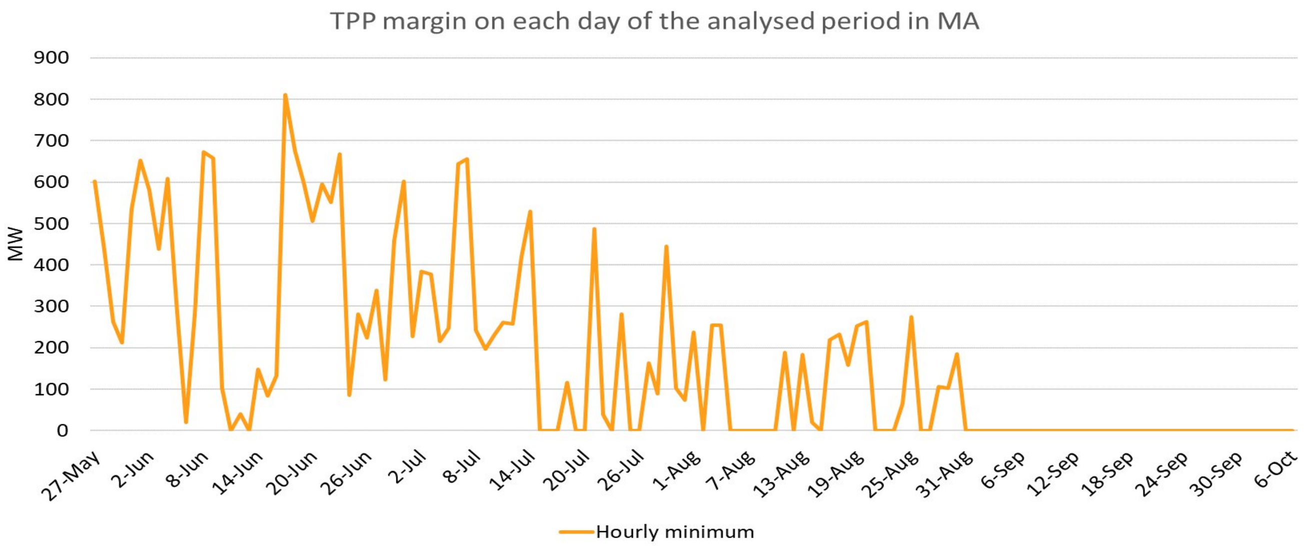


Figure 40 Minimum hourly TPP margin on each day of the analyzed period in Morocco.

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in Figure 41 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 summer period of 2024 in Morocco.

No adequacy risks are present in the interconnected mode of operation.

In the case of the isolated mode of operation, adequacy risk is present, with daily LOLE values above zero during the end of season when maintenance activity is enabled.

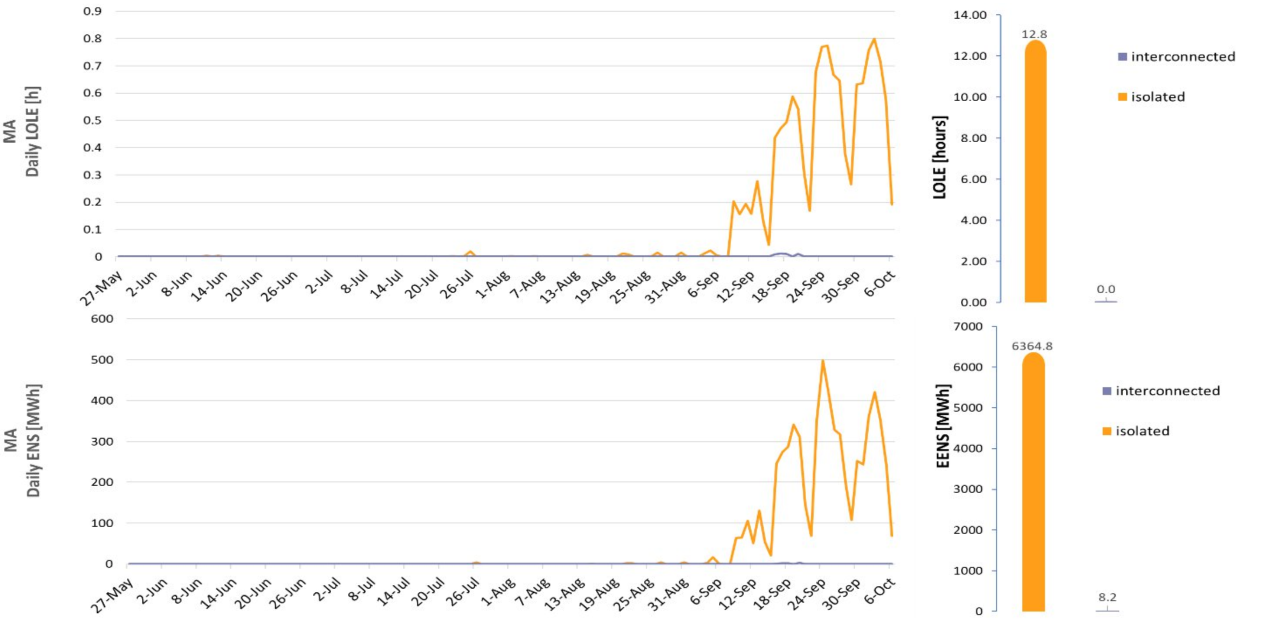


Figure 41 Daily LOLE and EENS for the interconnected and isolated mode of operation in Morocco.

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 12.8 hours, while EENS is around 6.3 GWh.

5.6 Tunisia

DEMAND

Tunisian seasonal weekly demand, depicted in Figure 42 ranges between 424 GWh and 579 GWh, while peak hourly demand each week goes from 3849 MW to 5704 MW. It should be noted that weekly demand refers to the average values of all 38 analyzed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analyzed climatic years.

Maximum electricity needs are expected during the whole of July and August. The maximum hourly demand is reached in the 32nd week - 5704 MW, which is the maximum in all 38 climatic years.

	week 22	week 23	week 24	week 25	week 26	week 27	week 28	week 29	week 30	week 31	week 32	week 33	week 34	week 35	week 36	week 37	week 38	week 39	week 40
Weekly consumption (GWh)	424	443	463	464	527	551	555	560	575	579	576	547	554	532	498	471	457	436	425
Weekly peak loads (MW)	4,104	4,229	4,822	4,992	5,376	5,404	5,418	5,490	5,159	5,169	5,704	5,182	4,847	5,120	4,537	4,334	4,282	3,956	3,849

LOW HIGH

Figure 42 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 90%, which is divided further into conventional, CCGT and OCGT TPPs. RES, i.e. wind and solar share in installed capacities is only around 10%. Total installed capacities amount to 5770 MW with import capacity up to 800 MW, while maximum hourly consumption is around 5704 MW.

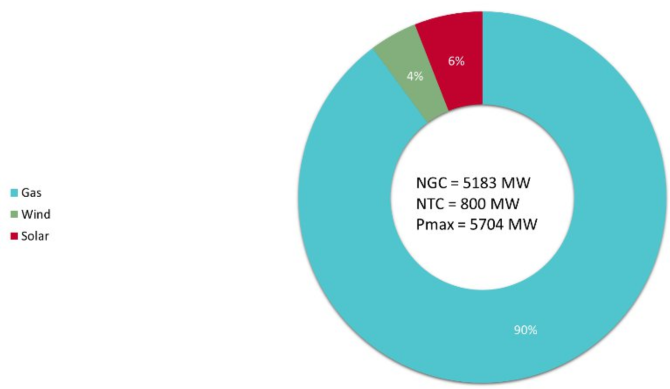


Figure 43 Installed Capacity mix with total NGC, import NTC and peak demand in Tunisia.

The average daily available TPP capacity, after reduction due to forced outages is shown in Figure 44 Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated mode of operation. The average thermal available capacity (for all 684 MC years) is 4857 MW, which is lower than the expected peak load of 5704 MW during the Summer season. However, the minimum average daily available thermal capacity (minimum among all 684 MC years for each day) is lower, with the lowest value of 2900 MW.

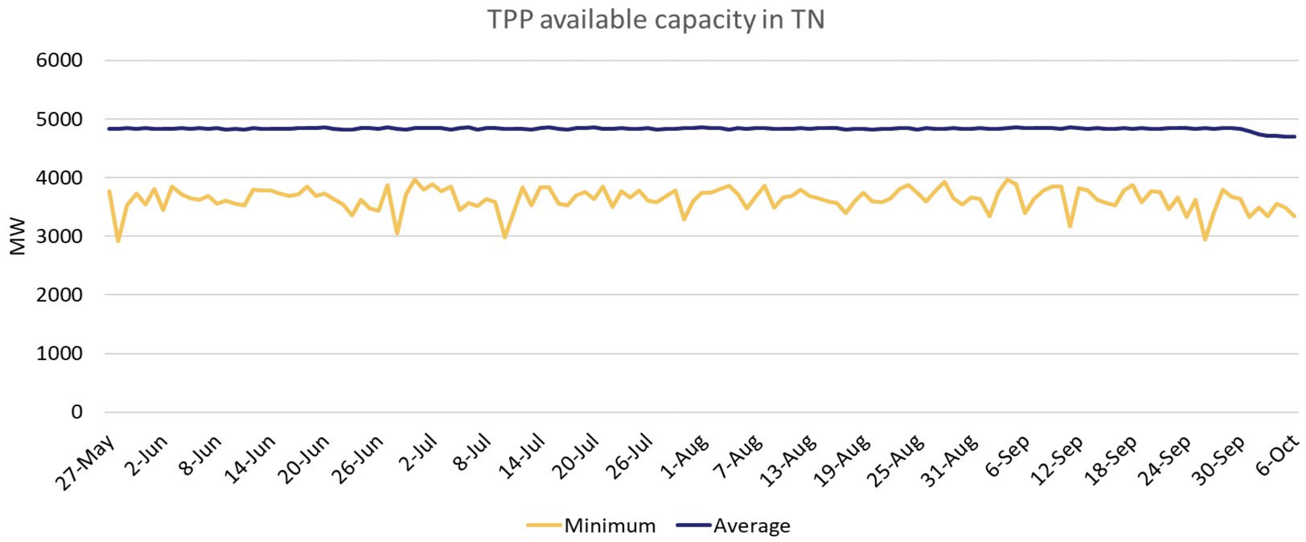


Figure 44 Average and minimum TPP available capacity in Tunisia

As a result of system simulation, the minimum hourly TPP capacity margin on each day is calculated and depicted in Figure 45 It represents the difference between available and activated TPP capacities. It can be seen that the minimum hourly margin is at zero value during 2-month period: whole July and August, which present in the period when majority of adequacy issues in Tunisia can be expected.

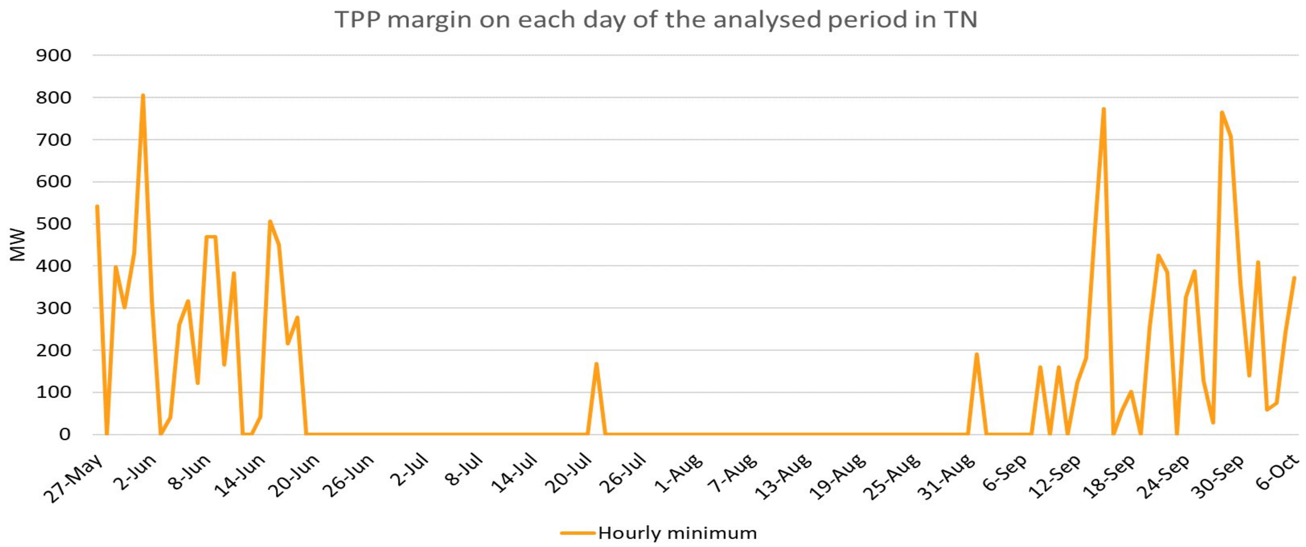


Figure 45 Minimum hourly TPP margin on each day of the analyzed period in Tunisia.

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in Figure 46 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.

The first conclusion is that until 1st July no adequacy issues are expected due to higher TPP availability and lower. demand.

From 1st July until the beginning of September adequacy issues are detected almost every day, although at low level. For the interconnected mode of operation, daily LOLE varies from 0 to 3 hours, while daily EENS goes from 0 to 509 MWh. These adequacy issues during summer are expected due to multiple reasons: high seasonal demand and lowest TPP availability due to outages but also derating.

After 1st September adequacy risk again goes practically to zero, due to demand being lower again.

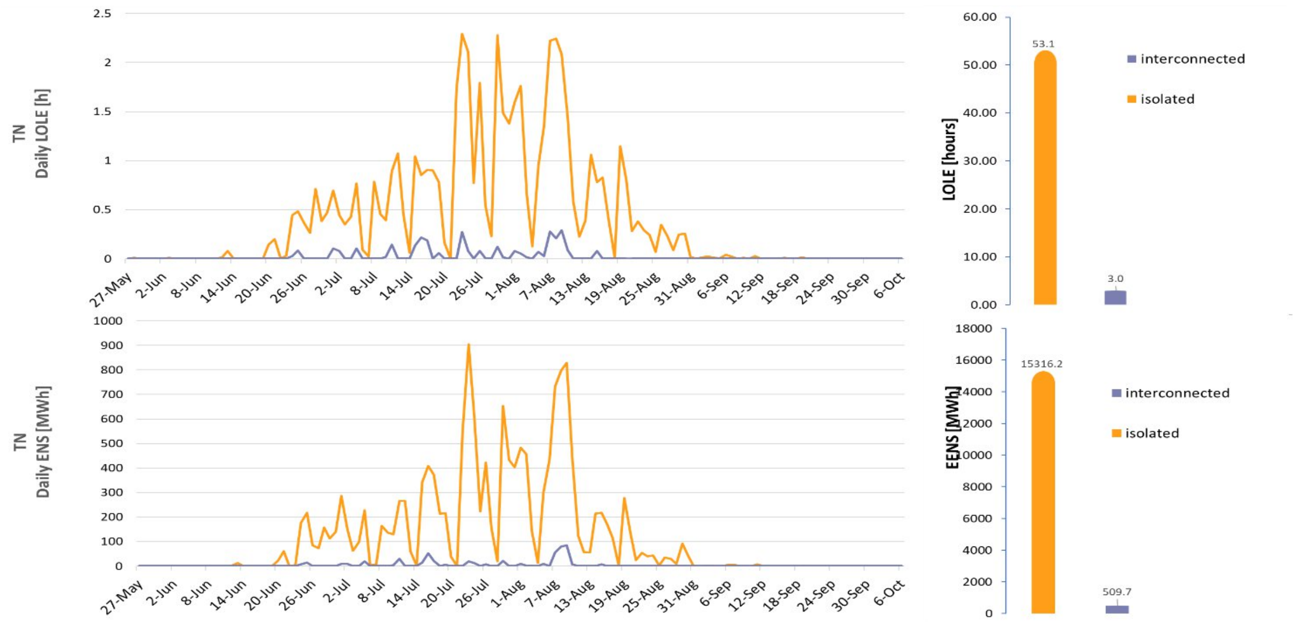


Figure 46 Daily LOLE and EENS for the interconnected and isolated mode of operation.

6 Sensitivity Cases

In our previous analysis, we presented the adequacy situation based on a probabilistic approach, which averaged data from all 38 analyzed climatic years repeated 18 times to ensure good convergence of results as discussed in page 24. However, as we further explore the summer outlook adequacy situation, we recognize the need to pinpoint the most severe Monte Carlo Climatic Year (MCY) within this dataset. This exploration aims to uncover extreme scenarios that may challenge the resilience of energy systems in each country.

Furthermore, we will focus specifically on the Libyan system during the upcoming SO 2024 period, aiming to provide insights into potential vulnerabilities incase assumptions regarding maintenance activities were not fulfilled.
For each sensitivity analysis, we examine two distinct scenarios that have been simulated.

Interconnected Operation:
This scenario explores the operation of the analyzed countries under the same interconnected grids mentioned in Page 22, where they can exchange electricity only if adequacy risk is identified.

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

6.1 The Most severe Monte Carlo Climatic Year

To identify the most severe MCY from all 684 MC years of our analyzes, we start from the 38 unique climatic years that we have (from period 1982 to 2019) then we average all MCY that shares the same climatic year. Finally, we identify the most severe MCY among them.

In the case of a theoretical isolated scenario (Figure 47) shows the summer season only, adequacy risks are observed in Morocco, Tunisia, Jordan & Lebanon, although they could be considered medium risk in Jordan.
For of Morocco, Tunisia & Lebanon adequacy risk is very high under isolated system operating mode.

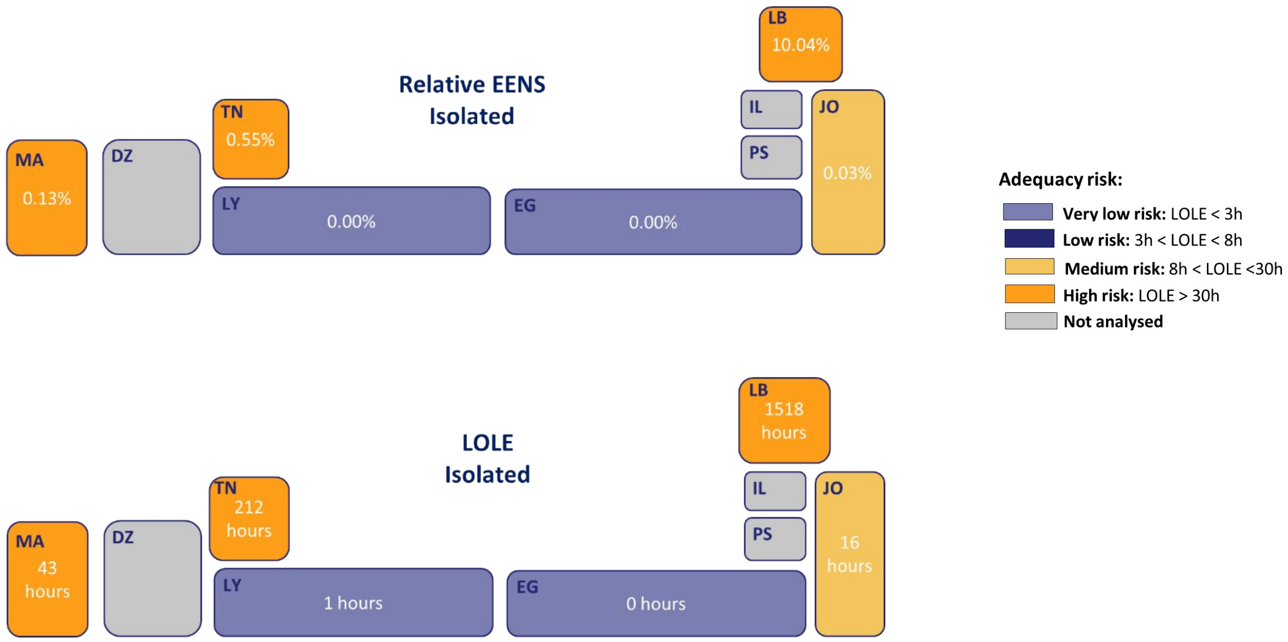
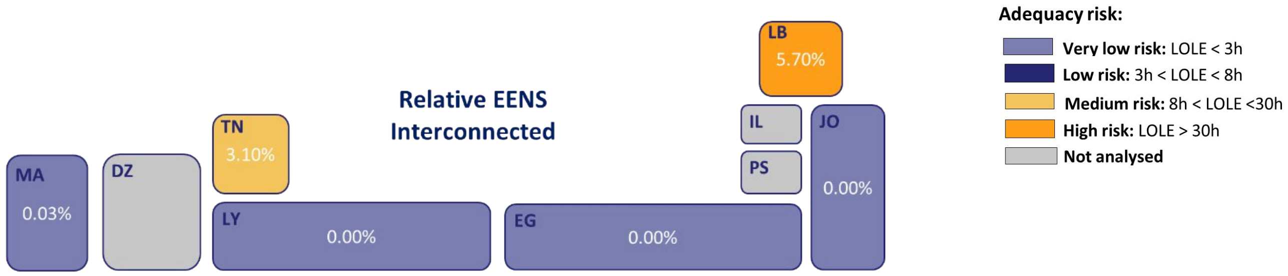


Figure 47 Seasonal Relative EENS and LOLE for the isolated mode of operation for the most severe MCY for summer season.

Interconnections and energy exchanges needed to overcome adequacy issue with neighboring countries reduce adequacy risks to very low risk in the case of Morocco & Jordan and Medium risk in Tunisia but, in Lebanon even in this more relaxed operating mode, adequacy risks are at an unacceptable level (Figure 48) [9] shows interconnected scenario for the summer season only.



[9] Color coding of adequacy risk levels presented in Figure 47 & Figure 48 does not reflect national thresholds for loss of load expectation (LOLE) that is usually specified within Network Codes of corresponding Transmission System Operators.

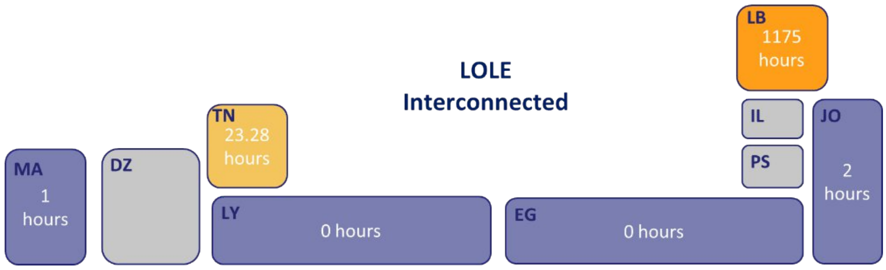


Figure 48 Seasonal relative ENS and LOLE for the interconnected mode of operation for the most severe MCY for summer season.

From the above figures it is evident that interconnection plays a crucial role in mitigating the impact of the most severe Monte Carlo Climatic Year (MCY) for Morocco and Jordan and reduce the adequacy risk in Tunisia by 90% for the upcoming SO 2024

6.2 Focus on Libyan system

During the data collection phase, we obtained detailed information on installed capacity and generation output from the Libyan system as of January 24, 2024. This data highlighted numerous units that were reported as unavailable due to ongoing maintenance activities.

In order to address the question of what the situation in Libya would be if all maintenance activities were not completed before the start of the SO 2024 season, we conducted a sensitivity analysis for the Libyan system. This analysis excluded all thermal units undergoing maintenance in Libyan system only, while maintaining all other factors unchanged (Demand evolution, interconnections between countries, and reserve requirements and their modelling).

Below, we present the results for both isolated and interconnected modes for this sensitivity.

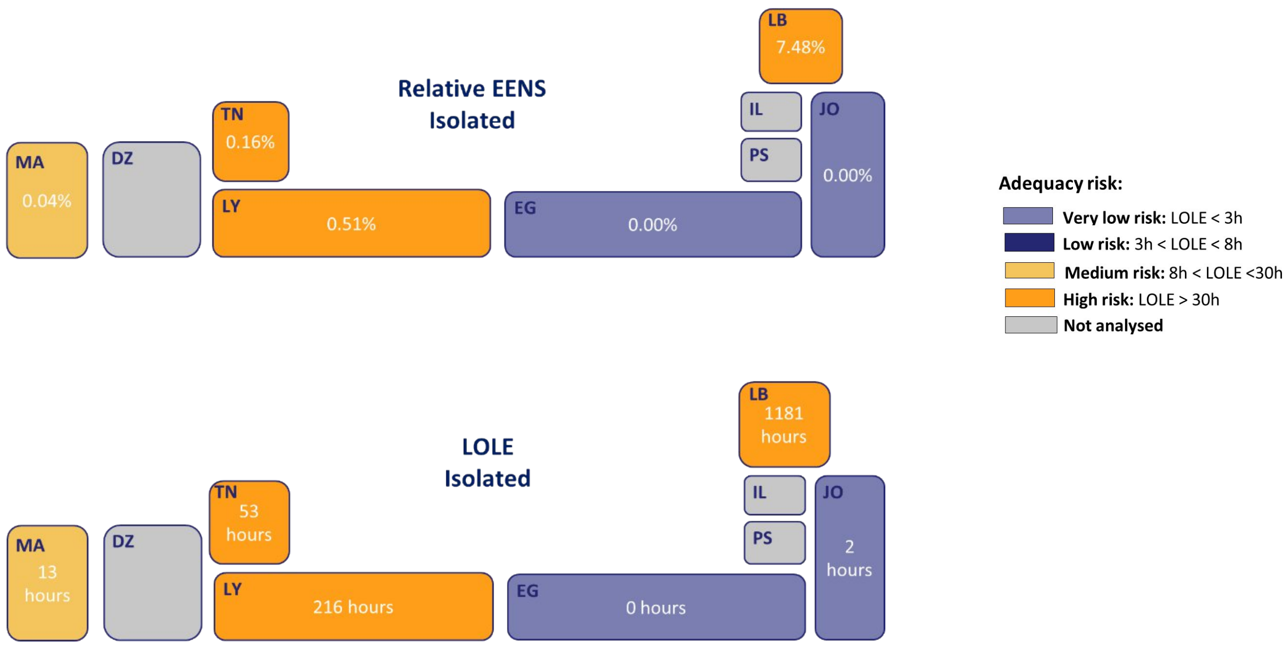


Figure 49 Seasonal relative ENS and LOLE for the Isolated mode of operation Libya Sensitivity case for summer season.

In isolated mode, it's evident that the Libyan system will face significant challenges without completing all maintenance activities, with a LOLE of 216 hours.

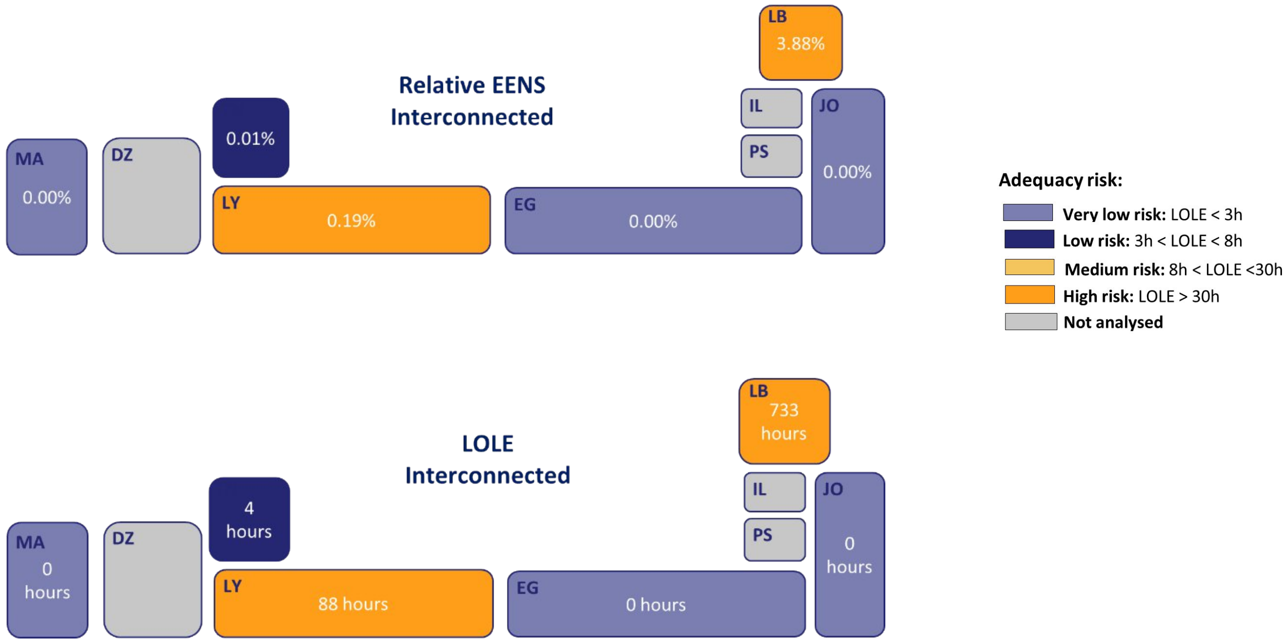


Figure 50 Seasonal relative ENS and LOLE for the interconnected mode of operation Libya Sensitivity case for summer season.

However, with the assistance of interconnection links from Egypt and Tunisia, the situation in Libya improves by 60% but not enough to face adequacy risk that is shown.
Libya's inability to export electricity may also impact Tunisia's adequacy situation, potentially exposing Tunisia to adequacy risks.

DEMAND

For the Demand we didn’t change anything compared to our base case

SUPPLY AND NETWORK OVERVIEW

Libya’s generation portfolio is based exclusively on gas-fired power plants, with 100% in generation capacity mix. The majority of installed thermal capacities in our sensitivity refer to gas turbines (65%) and light oil (22%), while only 9% of capacities of heavy oil. It should be emphasized that according to provided data for summer outlook 2024 there are no RES capacities installed in Libya.

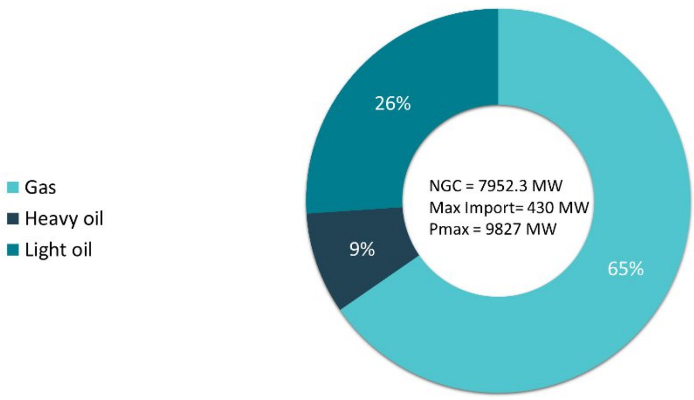


Figure 51 Installed Capacity mix with total NGC, import NTC and peak demand in Libya (Sensitivity Case).

The average daily available TPP capacity, after reduction due to forced outages, is shown Figure 52 Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated mode of operation. Libya's average available thermal capacity is stable at the level of 7300 MW.

The minimal daily available TPP capacity between all analyzed MC years is between 6500 MW to 5750 MW.

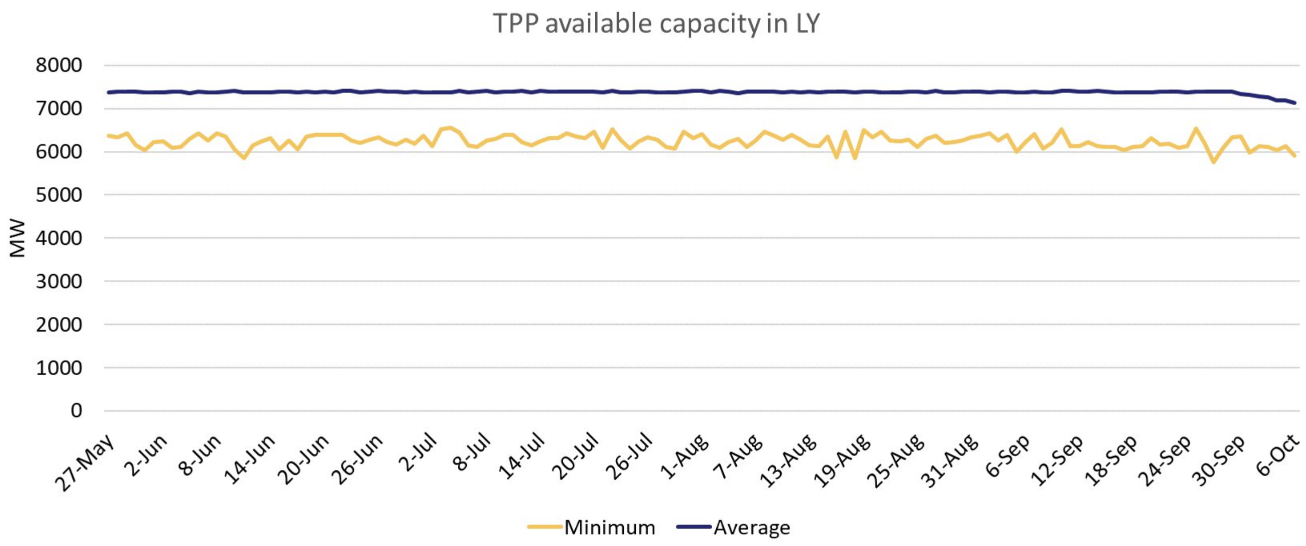


Figure 52 Average and minimum TPP available capacity in Libya (Sensitivity Case).

As a result of system simulation, the minimum hourly TPP margin for each day is calculated and depicted Figure 53 It represents the difference between available and activated TPP capacities. The minimum hourly value of the TPP margin on almost all days is at zero. There are only a few days with non/zero minimum daily margin, which are noted at the beginning of the summer season.

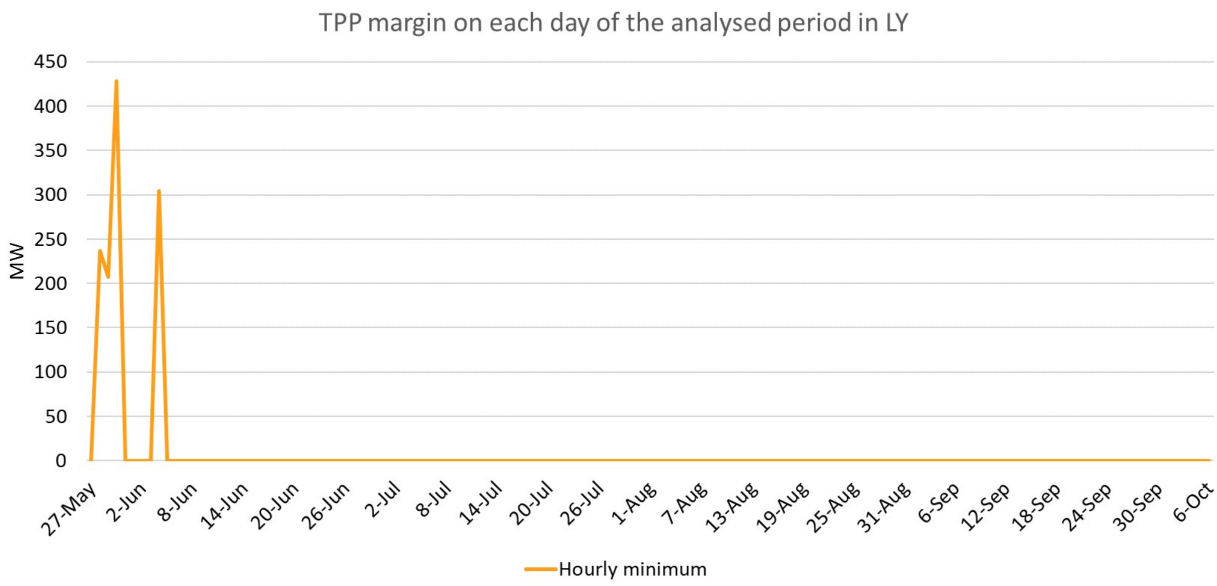


Figure 53 Minimum hourly TPP margin on each day of the analyzed period in Libya (Sensitivity Case).

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in Figure 54 for both modes of operation – interconnected and isolated. Results of the simulations point to the fact that LOLE and ENS are above all acceptable values even in the interconnected mode of operation: EENS is 36 GWh and LOLE is 88 hours (around 3 % during the summer season of 3192 hours). There are climatic years without adequacy issues. Looking at the whole season, even in the best case, everyday there are adequacy issues: LOLE Min=1 hours and LOLE Max=2 hours in average of 684 MC years.

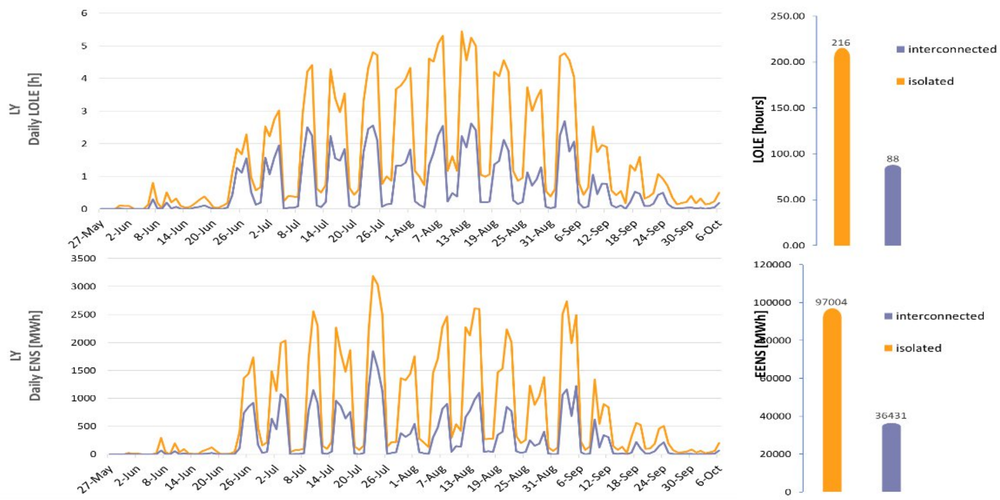


Figure 54 Daily LOLE and EENS for the interconnected and isolated mode of operation in Libya.

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

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