TeasiMed2 project

SEASONAL ADEQUACY ASSESSMENT

Summer Outlook 2023

Detailed Report

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Abbreviations

CCGT	–	Combine Cycle Gas Turbine
EU	–	European Union
FCR	-	Frequency Containment Reserve
FRR	-	Frequency Restoration Reserve
HPP	–	Hydro Power Plant
NTC	–	Net Transfer Capacity
OCGT	–	Open Cycle Gas Turbine
O&M	–	Operating and Maintenance
PEMMDB	–	Pan-European Market Modelling Database (developed by ENTSO-E)
PS HPP	–	Pump Storage Hydro power Plant
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)

Market areas/countries:

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

1 Executive Summary

This Report presents the adequacy situation among non-EU Med-TSO members during summer 2023. With this assessment, Med-TSO is aligning with the world-wide best practice and the latest development of the EU regulations[1]. These investigations consider the security of electricity supply to consumers through a detailed power system adequacy assessment, using probabilistic methodology and Key Performance Indicators (KPIs). 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 Summer Outlook 2023 Report provides information about potential adequacy issues during summer period 2023 in 7 MED-TSO members: Morocco, Algeria, Tunisia, Libya, Egypt, Jordan and Lebanon.

Main adequacy indicators that have been assessed are:

- **Loss of Load Expectation (LOLE)** in a given geographical zone for a given period is the expected 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 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.

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

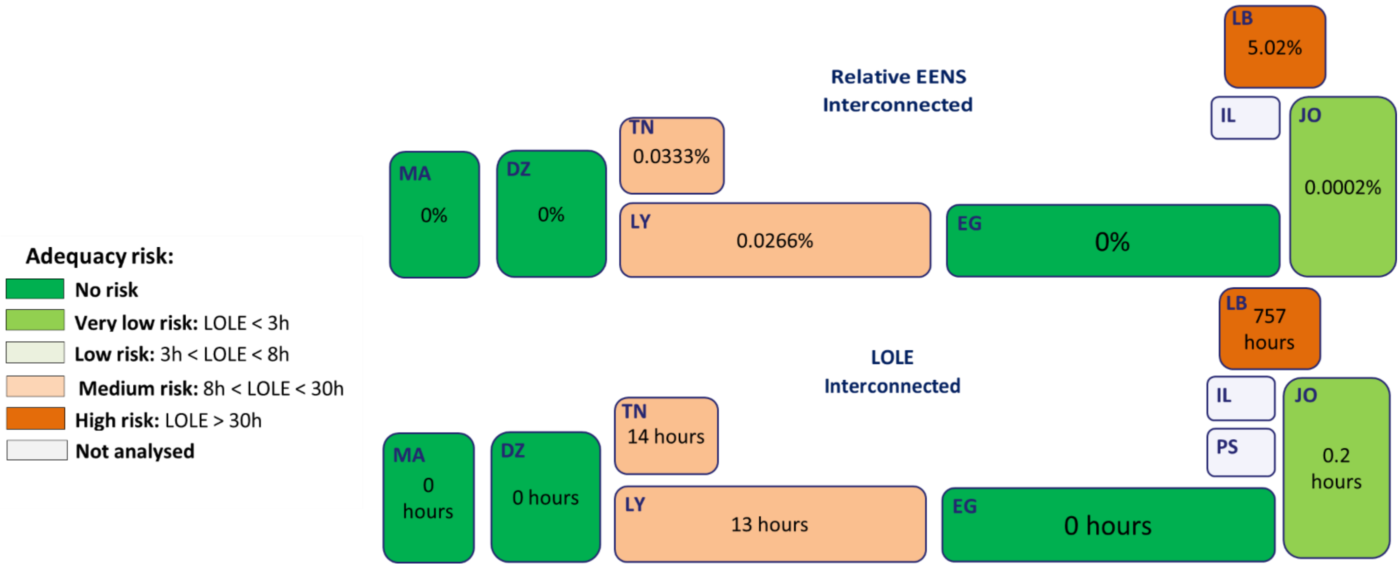


Figure 1: Seasonal relative EENS and LOLE for interconnected mode of operation

During this summer, the most severe adequacy issues may occur in Lebanon. Also in Libya and Tunisia adequacy can be endangered but at significantly lower level in comparison to Lebanon. (see Figure 1). The situation is more critical in case of Lebanon, where LOLE reaches around 760 hours and energy not supplied is higher than 5% of demand in the observed summer period. On the other hand, very low adequacy risk can be expected in Jordan (LOLE lower than 1 hour).

The period when there is the highest probability that generation (+import) will not be sufficient to cover Libya's electricity demand are end of July/beginning of August, while in the rest of the analyzed period the risk is lower, mainly due to lower demand. The situation in Lebanon is completely different, with expected energy not supplied during the whole summer period. However, 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.

In the next table seasonal EENS and LOLD results are given for all analysed countries.

Table 1: Seasonal EENS for Interconnected and isolated scenario

Country	Isolated EENS	Interconnected EENS		Isolated LOLE	Interconnected LOLE
DZ	25 MWh	0 MWh		0.06	0
	50TH percentile 0 MWh	50TH percentile 0 MWh		50TH percentile 0 hours	50TH percentile 0 hours
	95th percentile 0 MWh	95th percentile 0 MWh		95th percentile 0 hours	95th percentile 0 hours
EG	0 MWh	0 MWh		0	0
	50TH percentile 0 MWh	50TH percentile 0 MWh		50TH percentile 0 hours	50TH percentile 0 hours
	95th percentile 0 MWh	95th percentile 0 MWh		95th percentile 0 hours	95th percentile 0 hours
JO	113 MWh	19 MWh		0.82	0.16
	50TH percentile 0 MWh	50TH percentile 0 MWh		50TH percentile 0 hours	50TH percentile 0 hours
	95th percentile 64 MWh	95th percentile 0 MWh		95th percentile 3 hours	95th percentile 0 hours
MA	40 MWh	0 MWh		0.09	0
	50TH percentile 0 MWh	50TH percentile 0 MWh		50TH percentile 0 hours	50TH percentile 0 hours
	95th percentile 0 MWh	95th percentile 0 MWh		95th percentile 0 hours	95th percentile 0 hours
TN	34358 MWh	3128 MWh		123.04	13.79
	50TH percentile 4184 MWh	50TH percentile 0 MWh		50TH percentile 46 hours	50TH percentile 0 hours
	95th percentile 174670 MWh	95th percentile 16884 MWh		95th percentile 534 hours	95th percentile 90 hours
LY	13922 MWh	4787 MWh		35.28	12.93
	50TH percentile 0 MWh	50TH percentile 0 MWh		50TH percentile 0 hours	50TH percentile 0 hours
	95th percentile 102788 MWh	95th percentile 30216 MWh		95th percentile 253 hours	95th percentile 104 hours
LB	1028924 MWh	411607 MWh		1564.32	756.56
	50TH percentile 966446 MWh	50TH percentile 327930 MWh		50TH percentile 1566 hours	50TH percentile 698 hours
	95th percentile 1889403 MWh	95th percentile 1126837 MWh		95th percentile 2277 hours	95th percentile 1646 hours

Adequacy risk:
- No risk
- Very low risk
- Low risk
- Medium risk
- High risk

2 Approach and methodology

2.1 Adequacy assessment methodology

This Report presents the adequacy situation among non-European Med-TSO members during summer 2023. 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 de-carbonize energy systems - adequacy monitoring becomes even more important.

This Summer Outlook 2023 Report provides information about potential adequacy issues during summer 2023 in the 7 MED-TSO members: Morocco, Algeria, Libya, Tunisia, Egypt, Jordan and Lebanon.

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

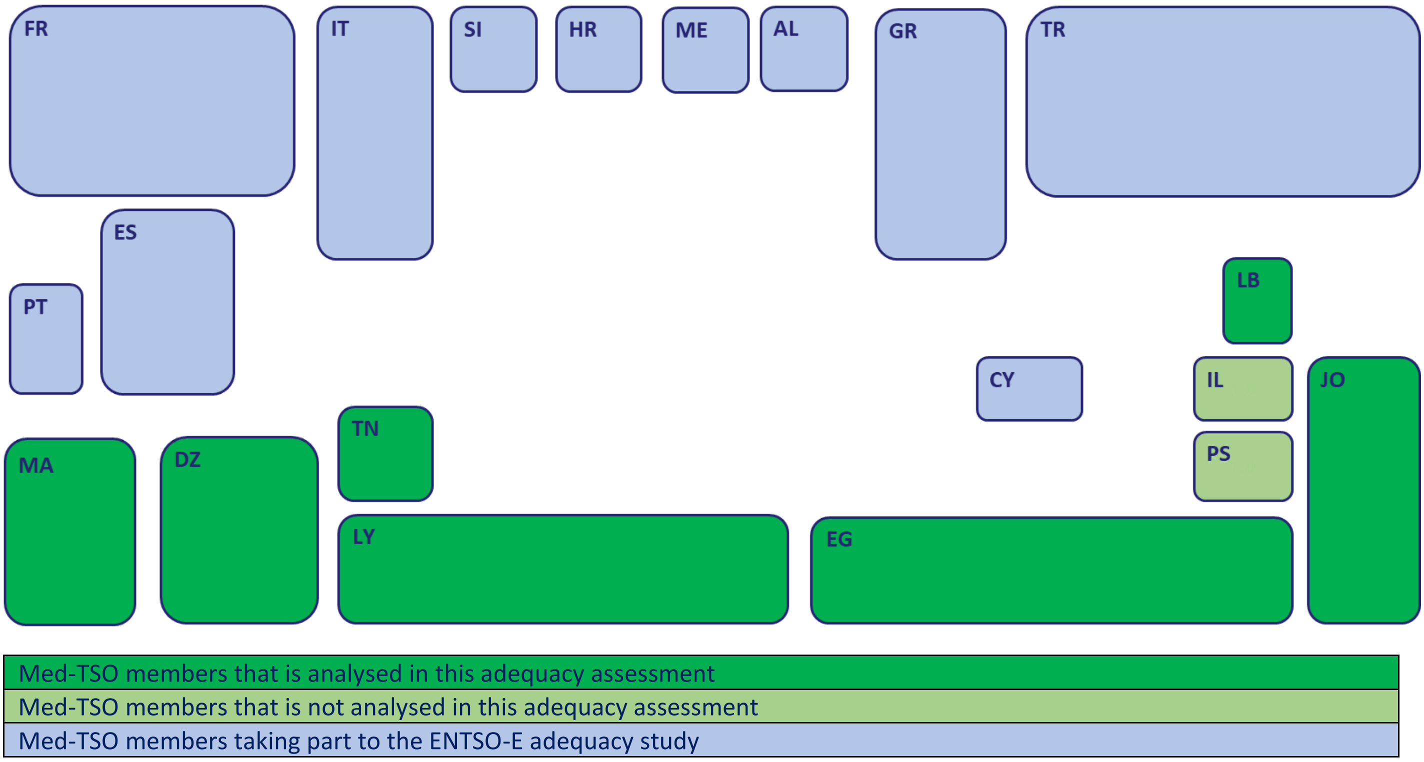


Figure 2: Med-TSO members and neighbouring countries (source: Med-TSO)

Data for Israel and Palestine are not available at the moment.

The analysed period includes all hours between the beginning of week 22 and the end of week 39 in 2023 which is the period between Monday, May 29th and Sunday, October 1st.

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

- 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.
- 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)
- ANTARES simulator was already used by Med-TSO in the project “Mediterranean Master Plan 2020”;
- 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 six months 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 Med-TSO, 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 analysed timeframe. For all those MC years, hourly calculations are performed for the whole geographical scope.

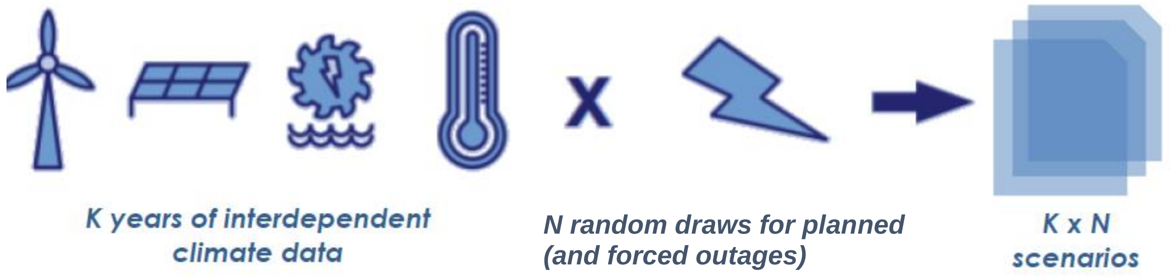


Figure 3: Probabilistic modelling general approach (source: ENTSO-E)

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 EENS 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
- **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.

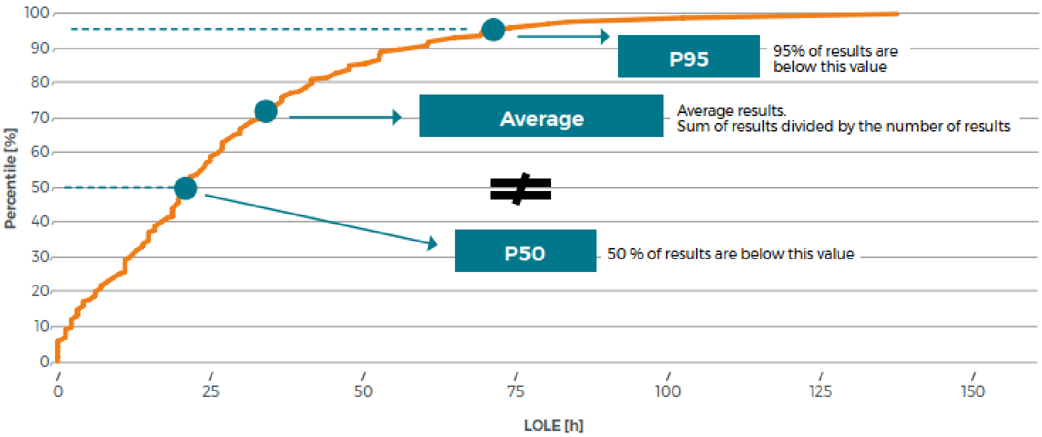


Figure 4: Illustrative Example of the relation between average, P50 and P95 values

- **P95/P50 Energy Not Serve (P95/P50 EENS).** While EENS 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 EENS are EENS in more or less severe operational conditions:
  - P95: EENS that happens once in 20 years
  - P50: EENS 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.

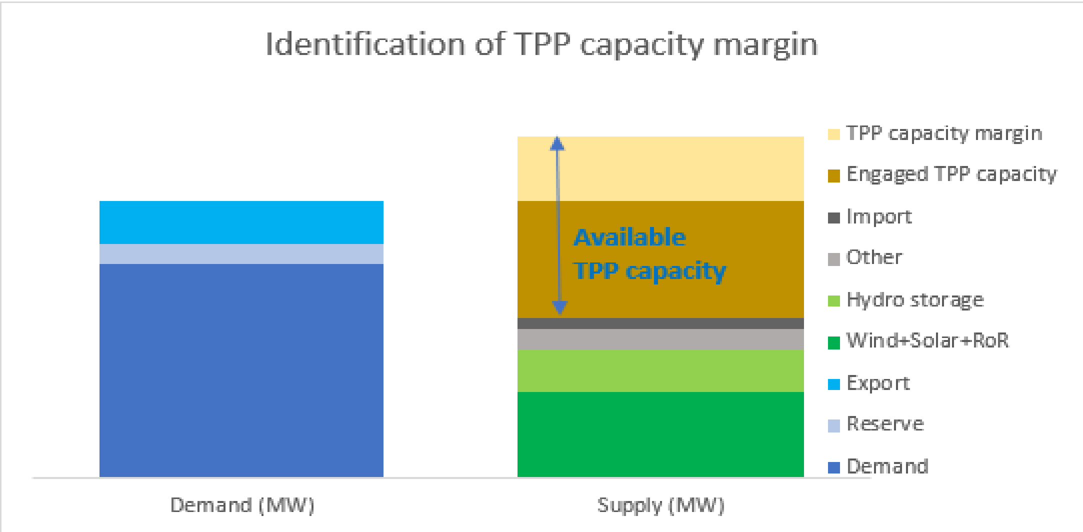


Figure 5 Illustrative Example of TPP capacity margin identification

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 6.

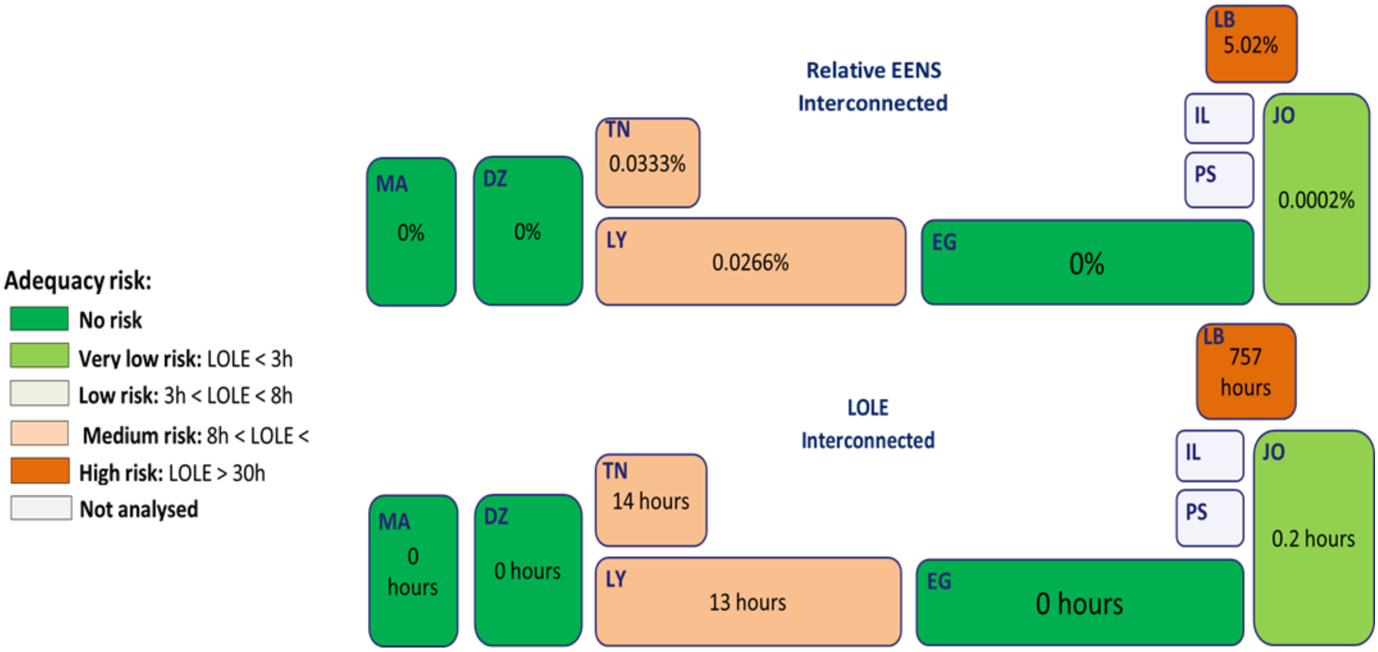


Figure 6: Illustrative Example of Spatial Screening result chart – Relative EENS and LOLE chart

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 7. This would allow the detection of which weeks are mostly at risk.

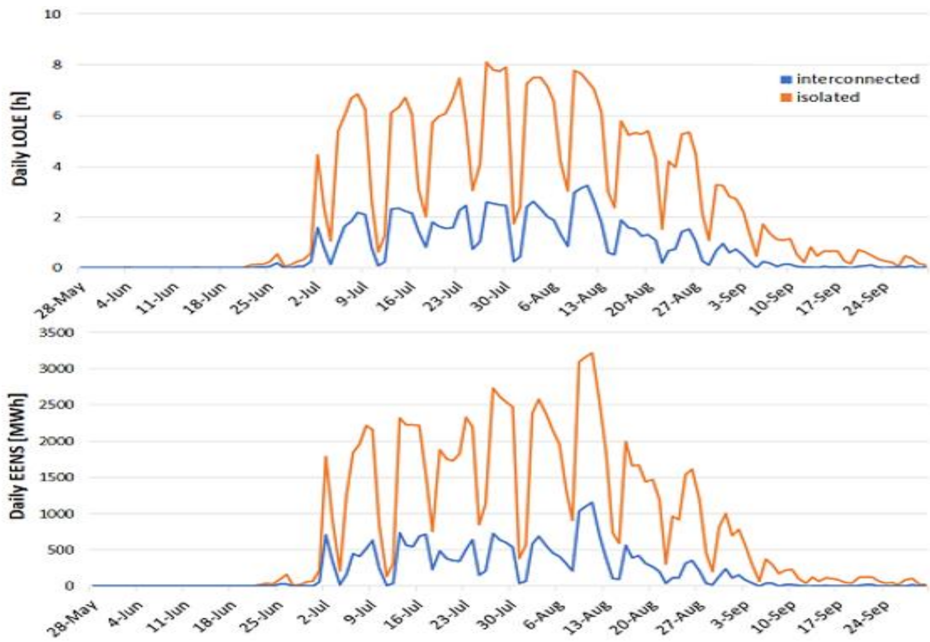


Figure 7: Illustrative example of average daily LOLE and EENS

In addition, available thermal capacities and thermal capacity margins are also presented at a daily 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 of all simulated MC years are presented as given in the following figures.

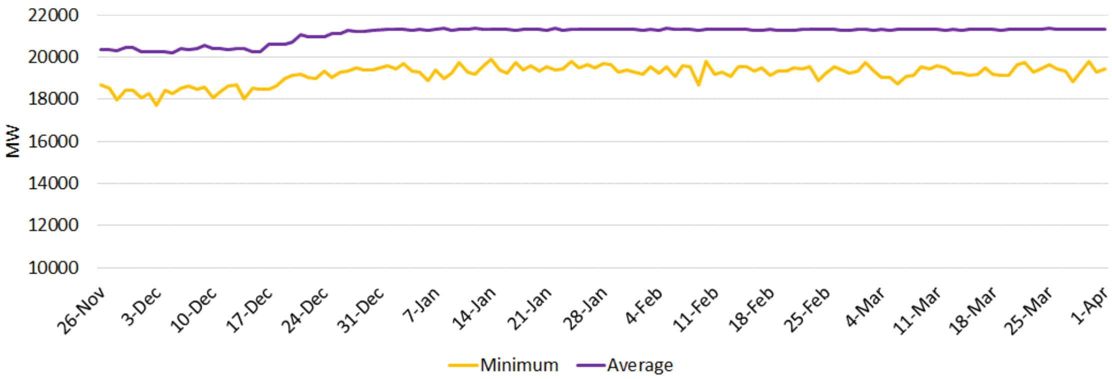


Figure 8: Illustrative example of available TPP capacity

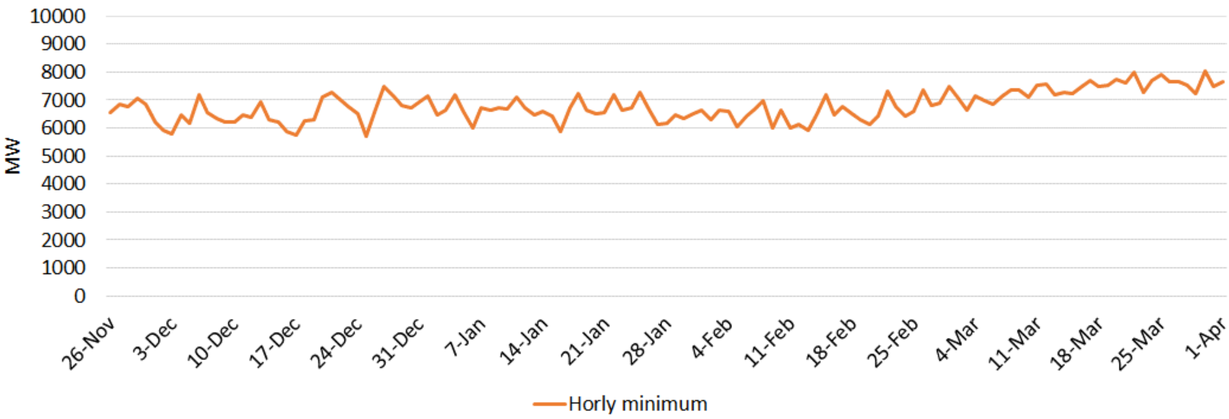


Figure 9: Minimum hourly TPP margin on each day of the analysed period

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 Mediterranean analysed 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 analysed 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 relevant TSOs 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 (set of excel files) presents a database that will be regularly updated for each seasonal and mid-term adequacy assessment.

For the Summer Outlook 2023 data have been collected in August/September 2022 and updated in December 2022.

This database will be updated in August/September 2023 with the latest information that will be used for the preparation of the next report – Winter Outlook 2023/2024.

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

2.3.1 Hourly demand per each market area/country

Hourly demand data per each market area (country) that are modelled have been provided by Adequacy Study Team (AST). These time series refer to different climatic conditions (mainly for the period 1981-2019 or similar, depending on the country). Demand data include losses in the transmission network but do not include the self-consumption of generating units.

3 https://www.med-tso.com/publications.aspx?f=&title=Reports

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.

2.3.2 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 systems which are modelled on the unit-by-unit level. For some countries schedules for the maintenance of thermal units have been provided by the 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 provided by the members. These time series are based on PECD, 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 the 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,...) calculated within the simulations. Due to artificial energy requirements in this case, this way of reserve modelling is not applicable for the systems with a large participation of hydropower plants.

Considering the structure of analysed power systems (almost no hydro generation), balancing reserve has been modelled as demand increases in all countries having in mind that this approach is more strict 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 demand increase).

Considering the above-mentioned, the data provided by the members 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

2.3.3 Grid

Countries are modelled as copper plates, coupled via interconnectors described by NTCs values, provided by the 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 analysed countries**
- **Isolated operation of the analysed countries**

2.4 Overview of the analysed power systems in Summer 2023

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

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

DEMAND EVOLUTION

Table 2 presents the expected consumption per week from the 22nd week to the 39th week in the year 2023. These values are the average weekly consumption for 38 climatic years in the period from 1982 to 2019.

Table 2: Expected consumption in the Summer weeks – 2023

Weekly consumption (GWh)		DZ	EG	JO	LB	LY	MA	TN
Total		33982	92835	8196	8195	18016	17405	9387
Week	22	1580	4821	438	418	803	946	441
Week	23	1626	4948	435	429	854	952	460
Week	24	1706	5058	441	436	899	962	481
Week	25	1820	5150	449	448	935	969	513
Week	26	1921	4920	433	459	960	931	517
Week	27	2072	5259	465	468	1046	981	569
Week	28	2066	5303	471	472	1060	990	565
Week	29	2136	5269	464	478	1062	983	563
Week	30	2135	5395	478	485	1089	992	586
Week	31	2151	5430	480	486	1093	995	582
Week	32	2101	5431	477	482	1102	994	581
Week	33	2086	5394	478	483	1088	979	567
Week	34	2015	5341	470	472	1073	975	557
Week	35	1899	5236	460	459	1059	975	529
Week	36	1773	5114	449	443	1030	961	500
Week	37	1693	5019	444	436	992	947	480
Week	38	1639	4942	435	425	958	940	463
Week	39	1563	4806	429	416	912	933	434

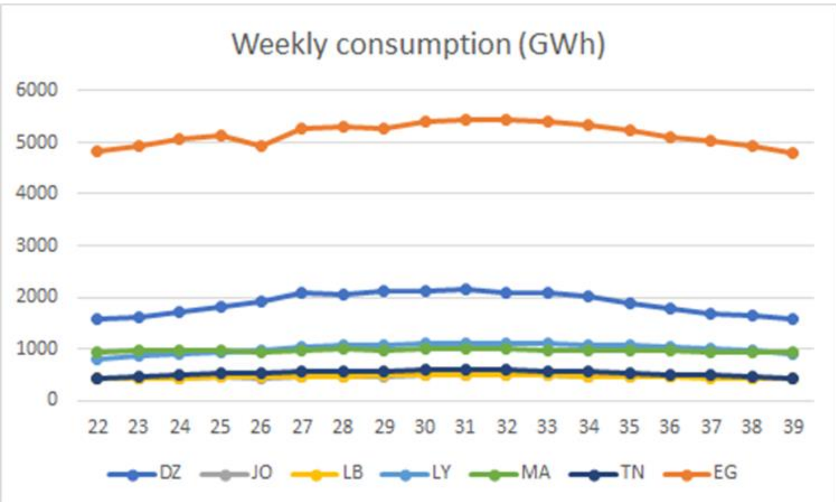


Figure 10: Expected weekly consumption per country in the analysed season

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 3: Maximum weekly peak loads in summer weeks in 2023

Peak load, based on maximum among 38 CY (MW)		DZ	EG	JO	LB	LY	MA	TN
Maximum		**19634**	**39328**	**3911**	**4717**	**10095**	**6784**	**5635**
Week	22	14309	36333	3203	3930	8366	6453	3936
Week	23	15275	37035	3189	3795	8933	6576	4564
Week	24	15705	37981	3303	3765	9254	6555	4882
Week	25	16424	37277	3226	3724	10095	6571	5306
Week	26	18059	37207	3546	4109	9049	6545	5234
Week	27	18091	37629	3490	4010	9706	6647	5086
Week	28	18594	37549	3643	4392	9922	6624	5163
Week	29	19177	38989	3481	4201	9742	6634	5028
Week	30	19634	38925	3909	4639	8864	6784	4884
Week	31	18308	39132	3911	4717	9573	6686	5635
Week	32	18098	39328	3701	4252	9051	6612	5209
Week	33	17567	37900	3907	4643	9148	6613	4745
Week	34	16003	37645	3366	3898	8603	6585	4760
Week	35	15010	37396	3320	3825	9136	6533	4278
Week	36	14178	37204	3341	3885	8855	6405	4191
Week	37	13199	35878	3128	3558	8719	6392	4111
Week	38	12928	34991	3132	3581	8525	6481	3913
Week	39	12560	34968	3130	3398	7931	6317	3682

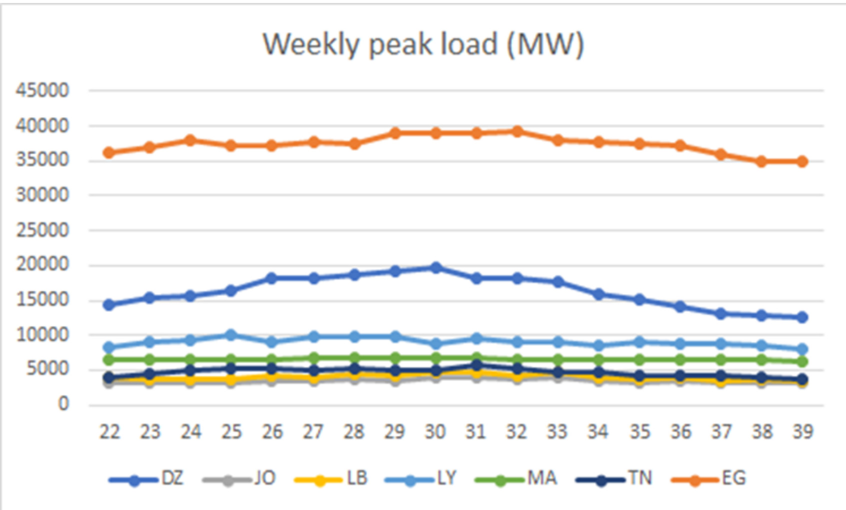


Figure 11: Maximum weekly peak loads per country in the analysed season

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.

GENERATION CAPACITIES EVOLUTION

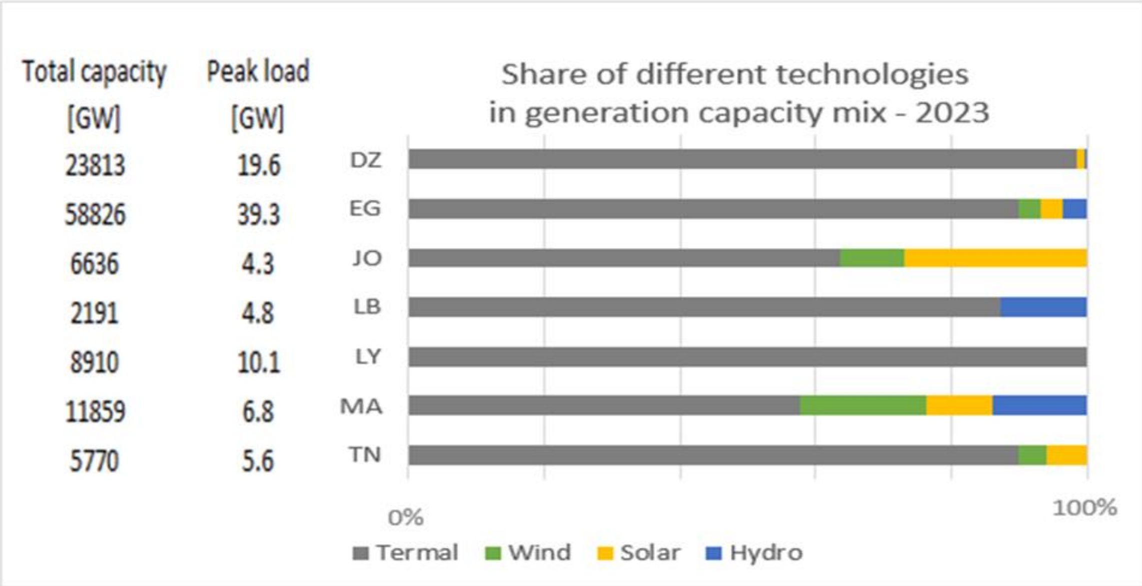
The following tables provide information about generation capacities in 2023. Total generation capacities in the observed region are expected to reach 118 GW, with almost 104 GW (or around 88%) in thermal units.

Table 4: Total generation capacities (MW) per technology in 2023

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	
DZ	-	-	266	1.12%	95	0.40%	23452	98.48%	**23813**
EG	1875	3.19%	1963	3.34%	2128	3.62%	52860	89.86%	**58826**
JO	621	9.36%	1795	27.05%	-	-	4220	63.59%	**6636**
LB	-	-	-	-	280	12.78%	1911	87.22%	**2191**
LY	-	-	-	-	-	-	8910	100.00%	**8910**
MA	2197	18.53%	1157	9.76%	1656	13.96%	6849	57.75%	**11859**
TN	242	4.19%	345	5.98%	-	-	5183	89.83%	**5770**
TOTAL	4935	4.18%	5526	4.68%	4159	3.52%	103385	87.61%	**118005**

It should be noted that the Libya's power system is characterized by thermal power plants only.

Relevant hydro capacities exist only in Egypt and Morocco. In Morocco, there is also a PS HPP with capacity of 464 MW in 2022 and 814 MW in 2023. The highest wind + solar capacities participation in total generation capacities is noted in Jordan and Morocco where their participation reaches more than 35%. It should be noted that in Morocco, 530 MW of solar capacity is in solar thermal farms with storage.



Capacity factors related to wind and solar generation are presented in Table 5. These capacity factors take into account the technology used and also the zone splitting of each country.

Table 5: Wind and solar capacity factors for all countries in 2023

	2023	
Country	**Wind CF**	**Solar CF**
DZ	N/A	21.2%
EG	39.3%	26.3%
JO	32.5%	22.8%
LB	-	-
LY	-	-
MA	46.5%	33.5%
TN	30%	21.5%

The impact of RES generation in Algeria, Egypt and Tunisia is marginal since the participation of thermal units is above 90%. 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 reduced possibilities for efficient cooling during the summer season. Planned outages are modelled according to data provided by TSOs (JO, TN) or as random outages but respecting certain predefined rules:

- In all countries, planned outages are not envisaged in the period from the 1st of May to 1st of October[4],
- Except in Jordan, where planned outages are not envisaged in the period from 1st of June to the 1st of 1st of October and from 1st of December to the 1st of February.

Practically, when predetermined rule is applied, period analysed in summer outlook should not include maintenance on any of the thermal units. This is the case also in this summer outlook e3xcept that in JO and TN there are couple of units in maintenance in May, June and September.

Forced outages of thermal units are in all cases and all countries modelled as random.

INTERCONNECTIONS BETWEEN COUNTRIES

Summarized NTC values provided by Med-TSO are used as available cross-border capacities and we assumed that these capacities are fully available for commercial exchanges for the entire calculation period.

The Antares model included the power systems of 7 analysed 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 Med-TSO. A summary of the interconnection capacities and given exchanges is presented in the following tables.

[4] In some countries periods without maintenance on thermal units are different , like e.g. in Tunisia where maintenance on TPPs are not realized between June 15th and September 15th.

Table 6: Summarized NTC values

Interconnection NTC [MW]	2023
DZ-TN	600
TN-DZ	600
DZ-MA	600
MA-DZ	300
EG-LY	180
TN-LY	250
EG-JO	450
JO-EG	450
MA-ES	600
ES-MA	900
JO-LB	250
LB-JO	0

Table 7: Max hourly exchanges

Interconnection Max hourly exchanges [MW]	2023
EG-SD	80
SD-EG	0
JO-PS	80
PS-JO	0
IQ-JO	0
JO-IQ	150-200

RESERVE REQUIREMENTS AND THEIR MODELLING

Reserve requirements have been provided by Med-TSO (Table 6). In some countries (EG, 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 demand increase.

FRR requirements have been modelled as demand increase in all countries. In the case of Lebanon and Libya reserve requirements have not been considered or modelled.

Table 6: Balancing reserve requirements

Reserve		2023
DZ	FCR+FRR [MW]	400
EG	FCR+FRR [MW][5]	600
JO	FCR+FRR [MW]	360
MA	FCR+FRR [MW]	600
TN	FCR+FRR [MW]	120

[5] FCR for EG & MA has been modeled through reduced thermal capacity.

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 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 $EENS_N$ 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 $Var[EENS_N]$ 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.

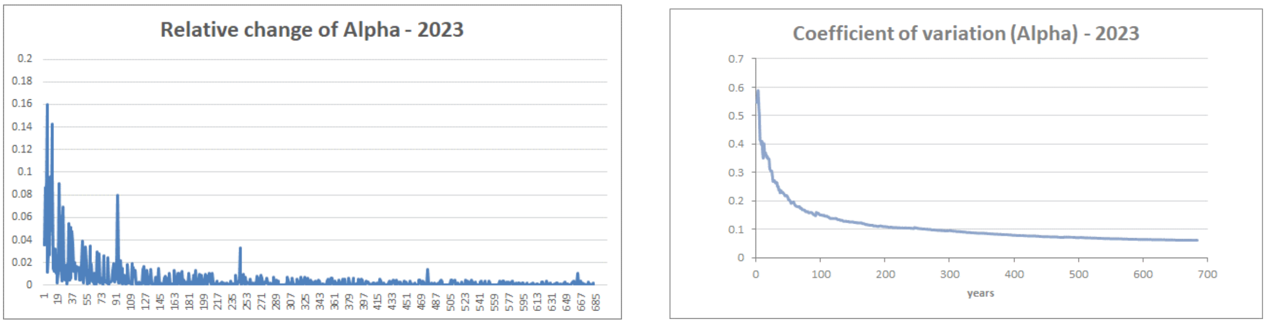


Figure 12: Evolution of convergence criteria for 684 MC years, simulations for the year 2023

3.2 Adequacy assessment

operation is evaluated. In the second, adequacy under interconnected system operation is assessed to quantify the importance of Med-TSO interconnections.

In the case of a theoretical isolated scenario, adequacy risks are observed in all countries except Egypt, although they could be considered small or marginal in Algeria, Jordan and Morocco (Figure 13). In case of Lebanon, Libya and Tunisia adequacy risk is very high under this isolated system operating mode, especially in Lebanon where LOLE is above 1000 hours (of simulated 3024 hours). Interconnections and energy exchanges with neighbouring countries reduce adequacy risks to zero in the case of Algeria and Morocco, and to almost zero in Jordan. In case of Tunisia and Lybia LOLE drops to "acceptable" 13-14 hours, while in Lebanon, even in this more relaxed operating mode, adequacy risks are at an unacceptable level (Figure 14)[6].

[6] Colour coding of adequacy risk levels presented in Figure 13 and Figure 14 does not reflect national thresholds for loss of load expectation (LOLE) that is usually specified within Network Codes of corresponding Transmission System Operators.

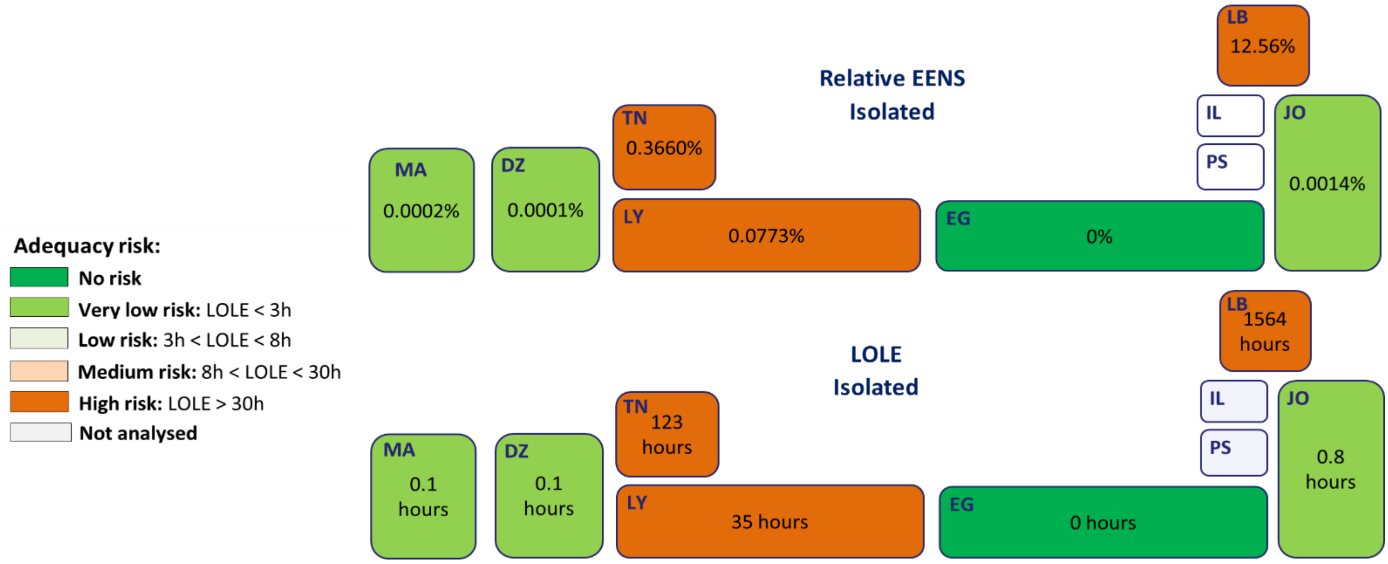


Figure 13: Seasonal Relative EENS and LOLE for the isolated mode of operation

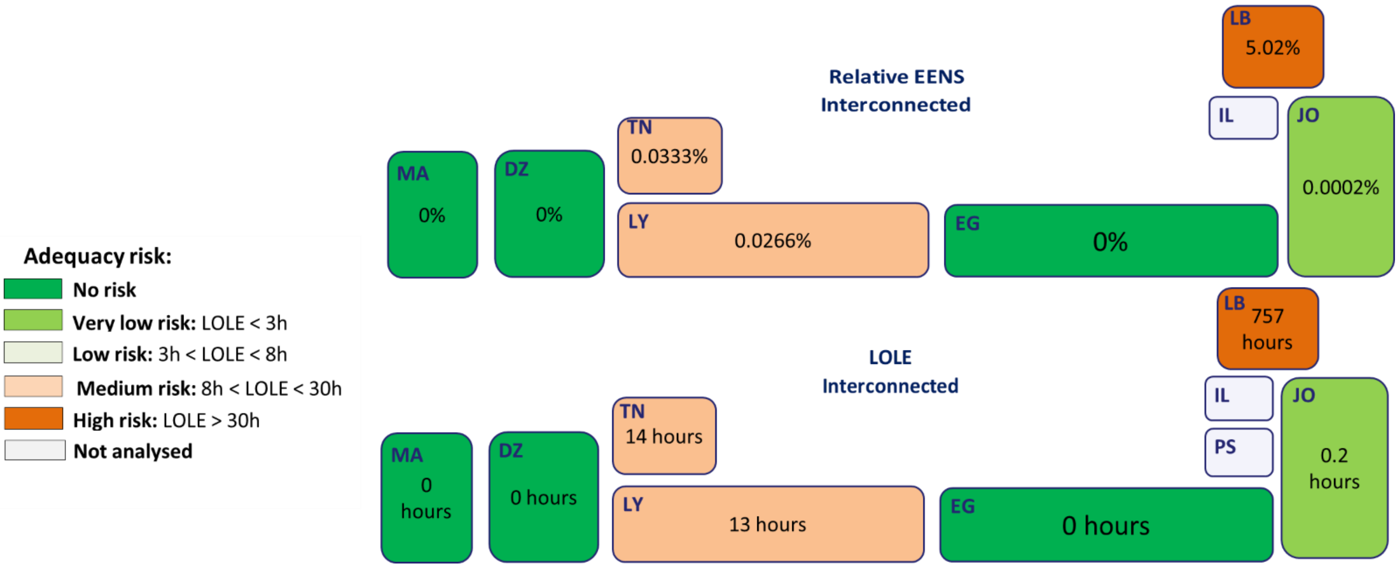


Figure 14: Seasonal relative EENS and LOLE for the interconnected mode of operation

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

- Jordan

Jordan with EENS of only 19 MWh for the interconnected mode of operation and LOLE of less than one hour, shows a very low adequacy risk. Adequacy risks increase in isolated operating mode, but they are still within the acceptable range.

- Libya

  This is the country with medium adequacy risk observed in summer 2023: 4.8 GWh of EENS and 13 hours of LOLE in the interconnected mode of operation. These values of EENS and LOLE point to endangered adequacy, but not drastically. If more critical, but less probable (P95) cases happen (higher demand, frequent outages of TPPs) EENS can reach 30 GWh for 104 hours.

  In the isolated mode of operation, adequacy is more endangered: EENS reaches 14 GWh and LOLE is 35 hours. This also points to the fact that interconnections with Egypt and Tunisia reduce adequacy risks 2 times!

- Lebanon

  This is the country with the highest EENS and LOLE observed in Summer 2023 in this region:412 GWh of EENS and 757 hours of LOLE (25% of the time!) in the interconnected mode of operation. These expected values of EENS and LOLE point to extremely endangered adequacy. If more critical, but less probable (P95) cases happen EENS can reach 1126 GWh with unavailability to supply the load during more than 50% of the period.

  In the isolated mode of operation, adequacy is even more endangered: EENS reaches 1029 GWh and LOLE is 1564 hours. This also points to the fact that interconnection with Jordan reduces adequacy risks 2 times!

- Tunisia

  This is the country with medium adequacy risk. In Summer 2023, EENS and LOLE can be expected on the level of 3 GWh and 14 hours in the interconnected mode of operation. These expected values of EENS and LOLE point endangered adequacy but significantly less than expected in summer 2022 (mainly due to more efficient utilization of the interconnection with Algeria and lower reserve requirement). If more critical, but less probable (P95) cases happen (hot summer, higher demand, higher outages of TPPs) EENS can reach 17 GWh and LOLD 90 hours.

  In the isolated mode of operation, adequacy is even more endangered: EENS reaches 34 GWh and LOLE is 123 hours. This also points to the fact that interconnection between Algeria and Tunisia reduces adequacy risks 9 times!

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

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.

Table 7: Seasonal EENS for Interconnected and isolated scenario

Country	Isolated EENS	Interconnected EENS	Isolated LOLE	Interconnected LOLE
DZ	25 MWh	0 MWh	0.06	0
	50TH percentile 0 MWh	50TH percentile 0 MWh	50TH percentile 0 hours	50TH percentile 0 hours
	95th percentile 0 MWh	95th percentile 0 MWh	95th percentile 0 hours	95th percentile 0 hours
EG	0 MWh	0 MWh	0	0
	50TH percentile 0 MWh	50TH percentile 0 MWh	50TH percentile 0 hours	50TH percentile 0 hours
	95th percentile 0 MWh	95th percentile 0 MWh	95th percentile 0 hours	95th percentile 0 hours
JO	113 MWh	19 MWh	0.82	0.16
	50TH percentile 0 MWh	50TH percentile 0 MWh	50TH percentile 0 hours	50TH percentile 0 hours
	95th percentile 64 MWh	95th percentile 0 MWh	95th percentile 3 hours	95th percentile 0 hours
MA	40 MWh	0 MWh	0.09	0
	50TH percentile 0 MWh	50TH percentile 0 MWh	50TH percentile 0 hours	50TH percentile 0 hours
	95th percentile 0 MWh	95th percentile 0 MWh	95th percentile 0 hours	95th percentile 0 hours
TN	34358 MWh	3128 MWh	123.04	13.79
	50TH percentile 4184 MWh	50TH percentile 0 MWh	50TH percentile 46 hours	50TH percentile 0 hours
	95th percentile 174670 MWh	95th percentile 16884 MWh	95th percentile 534 hours	95th percentile 90 hours
LY	13922 MWh	4787 MWh	35.28	12.93
	50TH percentile 0 MWh	50TH percentile 0 MWh	50TH percentile 0 hours	50TH percentile 0 hours
	95th percentile 102788 MWh	95th percentile 30216 MWh	95th percentile 253 hours	95th percentile 104 hours
LB	1028924 MWh	411607 MWh	1564.32	756.56
	50TH percentile 966446 MWh	50TH percentile 327930 MWh	50TH percentile 1566 hours	50TH percentile 698 hours
	95th percentile 1889403 MWh	95th percentile 1126837 MWh	95th percentile 2277 hours	95th percentile 1646 hours

Adequacy risk:

- **No risk**
- **Very low risk**
- **Low risk**
- **Medium risk**
- **High risk**

3.3 Importance of interconnections[7]

As presented in the previous chapter, interconnections present the crucial support for adequacy in almost all countries except Egypt, which have a surplus of generation capacity. Exchanges on the borders of the seven analysed countries show that in almost all cases there is the prevailing direction of the power flows (Figure 15):

- From DZ to MA
- From DZ to TN
- From MA to ES (from North Africa to Europe)
- From EG to JO
- From JO to LB
- From EG and TN to LY

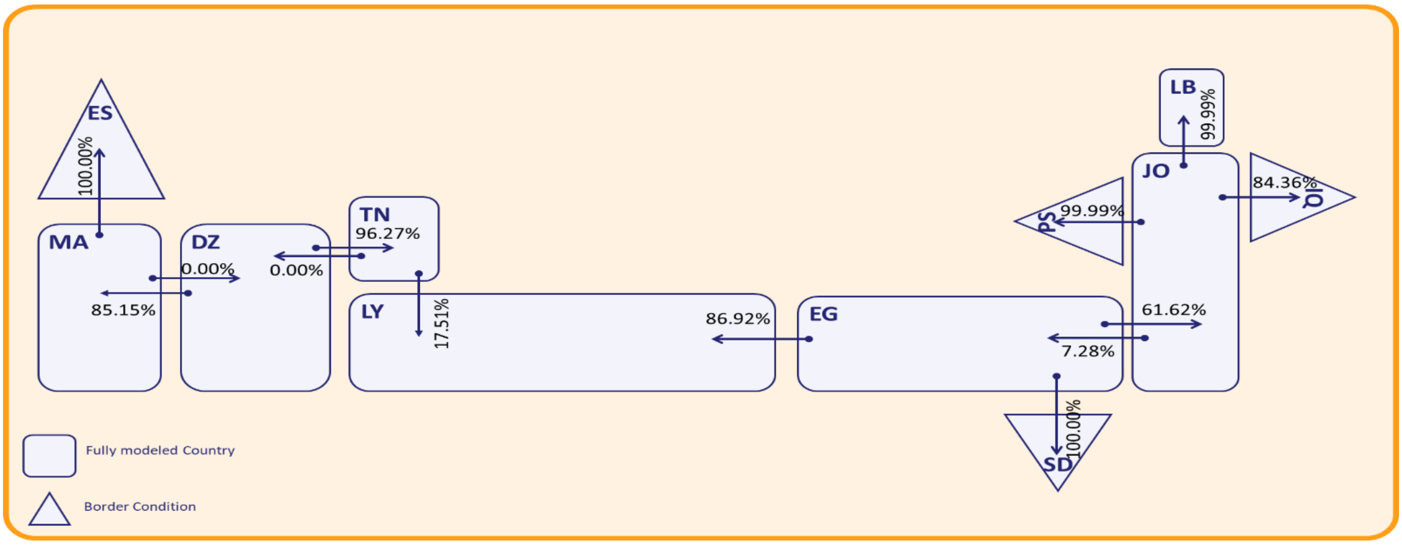


Figure 15: Exchange direction and transfer capacity utilization for 18 weeks of 2023 summer season (average of all MC years)

[7] **Please have in mind that exchanges are not completely in line with market operation since loads are increased for required reserve**

Table 8: Seasonal exchanges and utilization of the links in the region

Link	Possible Annual Exchanges (GWh)	NTC direct (MW)	NTC indirect (MW)	Utilization factor (%)
DZ00 - MA00	1,540	600	300	84.86%
DZ00 - TN00	1,744	600	600	96.13%
EG00 - JO00	740	450	450	54.35%
EG00 - LY00	474	180	0	87.13%
EG00 - SD00	242	240	0	33.33%
ES00 - MA00	-1,814	900	600	100.00%
IQ00 - JO00	-510	0	200	84.36%
JO00 - PS00	242	80	0	99.98%
JO00 - LB00	756	250	250	100.00%
LY01 - TN	-131	0	250	17.30%

Presented exchanges point to the fact that Algeria has sufficient excess of energy to support the secure operation of Tunisia and that this support is just limited by the transmission constraints (NTC=600 MW). remaining thermal generation in Algeria is also used for export to Spain via Morocco. Part of the export to Spain comes also from Morocco.

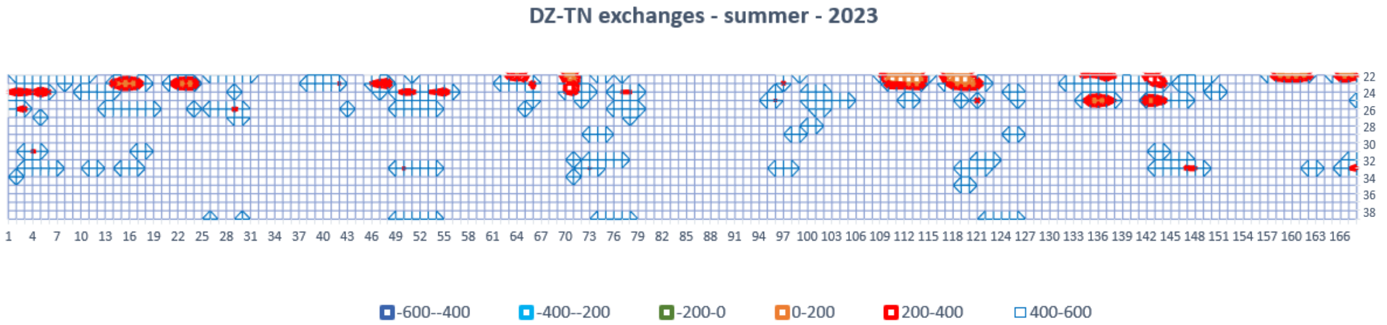
Export from Egypt to Jordan also improves the adequacy situation in Jordan, although even without this support, adequacy risks in Jordan are within acceptable limits.

The situation in Lebanon and Libya is completely different and interconnections and imported energy are of large importance to these countries. Interconnection enables a reduction in adequacy issues by 2-3 times in these two countries.

The following heat maps present the hourly flows (168 hours in each week during the summer season) on the selected borders for the selected MC year (first MC year):

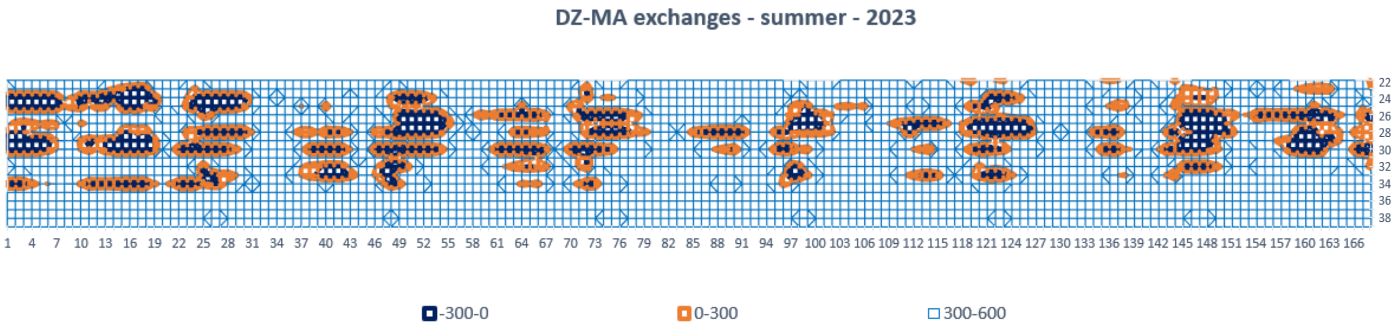
- DZ - TN

  Flows in all hours are towards Tunisia, between 0 MW and 600 MW (which is the NTC value).



- DZ - MA

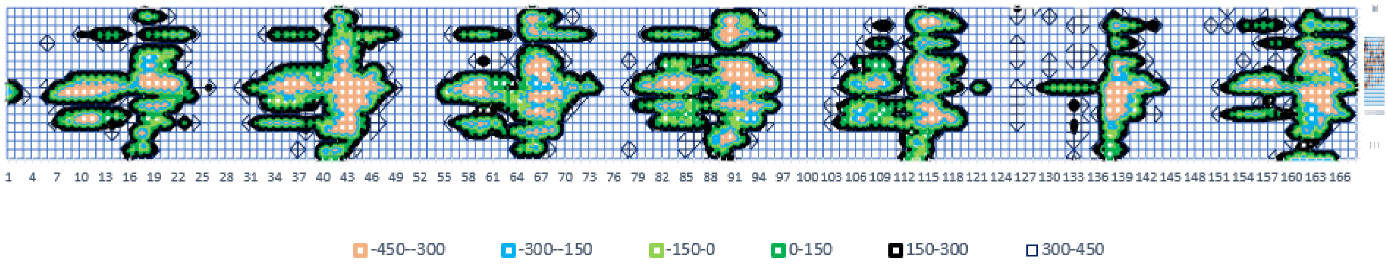
Prevailing flows are from Algeria to Morocco mainly due to high export to Spain (since Spain is modelled as a border condition node with a fictive high marginal price). Flows from Morocco to Algeria are noted only during the night and early morning hours when demand is still low, and Morocco has an excess in RES generation.



- EG - JO

  Prevailing flows are from Egypt to Jordan, with reduction and even counterflows during afternoon and evening hours when the load in Jordan is lower.

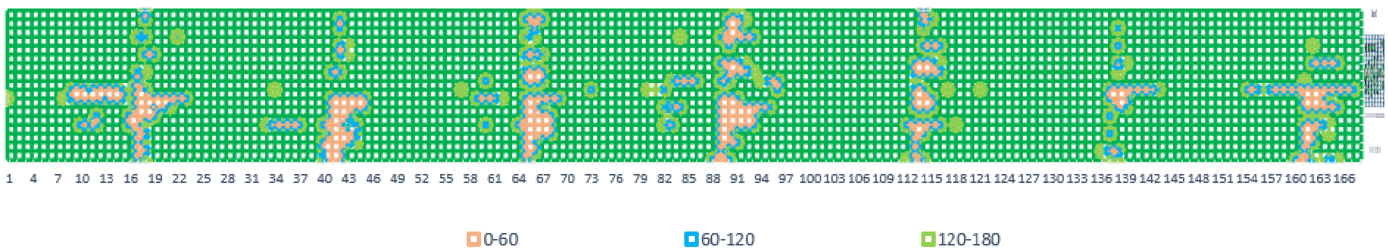
EG-JO exchanges - summer - 2023



- EG - LY

  There are only flows towards Libya. Mainly flow is at its maximum (180 MW) with a reduction during afternoon hours when the load in Libya is lower.

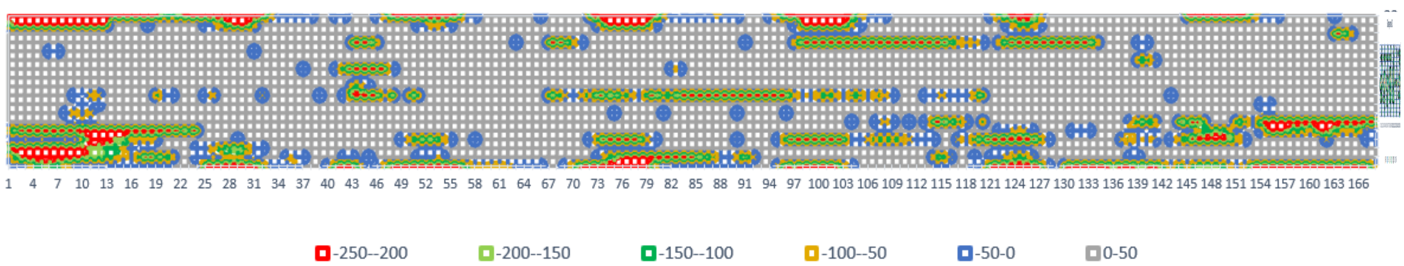
EG-LY02 exchanges - summer - 2023



- TN - LY

  There are flows only towards Libya. However, interconnection capacity is not utilized by 100% since excess of generation is not present in Tunisia at all hours. During hours with higher demand in Tunisia, export to Libya is reduced.

LY-TN exchanges - summer - 2023



4 Adequacy Situation on Country Level

4.1 Algeria

DEMAND

Algerian seasonal weekly demand, depicted in Figure 16 goes from around 1560 GWh to 2150 GWh, while peak hourly demand in each week varies from 12500 MW to 19600 MW. It should be noted that weekly demand refers to the average values of all 38 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analysed climatic years.

Maximum electricity needs are expected during the peak of the summer season: end of July – beginning of August, due to high temperatures and high cooling consumption. The maximum hourly demand in all 38 climatic years reaches 19634 MW in the 30th week of 2023. It should be noted that during summer season, maximum hourly demand changes in a very wide range of 56%, which is the widest range among analysed countries. This points to the fact that the highest demand is concentrated during short period of time.

Week	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39
Weekly consumption (GWh)	1580	1626	1706	1820	1921	2072	2066	2136	2135	2151	2101	2086	2015	1899	1773	1693	1639	1563
Peak load (MW)	14309	15275	15705	16424	18059	18091	18594	19177	19634	18308	18098	17567	16003	15010	14178	13199	12928	12560

LOW HIGH

Figure 16: Seasonal Weekly demand in Algeria

SUPPLY AND NETWORK OVERVIEW

Algerian power generation fleet is almost exclusively based on natural gas, with the gas TPP share in total installed capacities around 98%, which is divided further into conventional, CCGT and OOCGT TPPs. Hydro and Solar capacities amount to only 1% each. Total installed capacities are 23813 MW with import capacity up to 900 MW, which combined is higher than the maximum peak demand of 19634 MW.

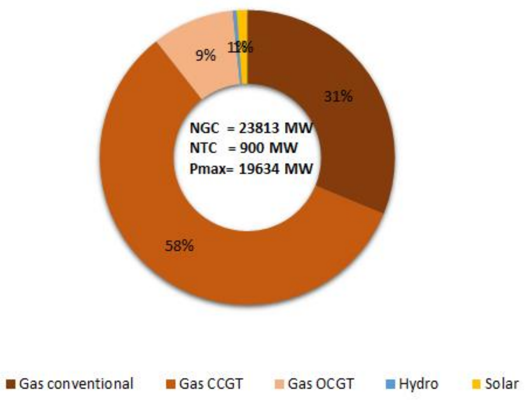


Figure 17: Installed Capacity mix with total NGC, import NTC and peak demand in Algeria

The average daily available TPP capacity, after reduction due to forced outages and derating factors, is shown in Figure 18. Each daily value presents the average of all simulated MC years. These values are the same for the interconnected and isolated mode of operation.

Algerian average available TPP capacities level is almost constant during the summer season, at the level of 20 GW. The minimal average daily available TPP capacity (minimum among all simulated MC years) has small fluctuations around 19 GW.

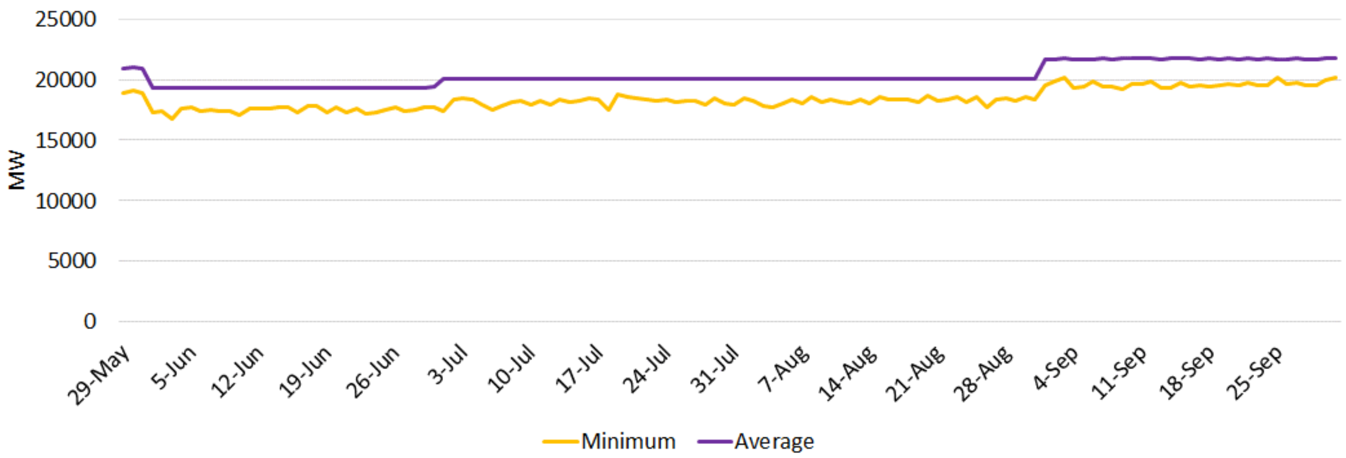


Figure 18: Average and minimum TPP available capacity in Algeria

As a result of system simulation, the minimum hourly TPP capacity margin is calculated and depicted in Figure 19. It represents the difference between available and activated TPP capacities. The hourly minimum TPP margin in some days at the peak of the season is 0, which means that Algeria in rare but possible cases can face the lack in supplying the load. The results of the LOLE and EENS points to the same.

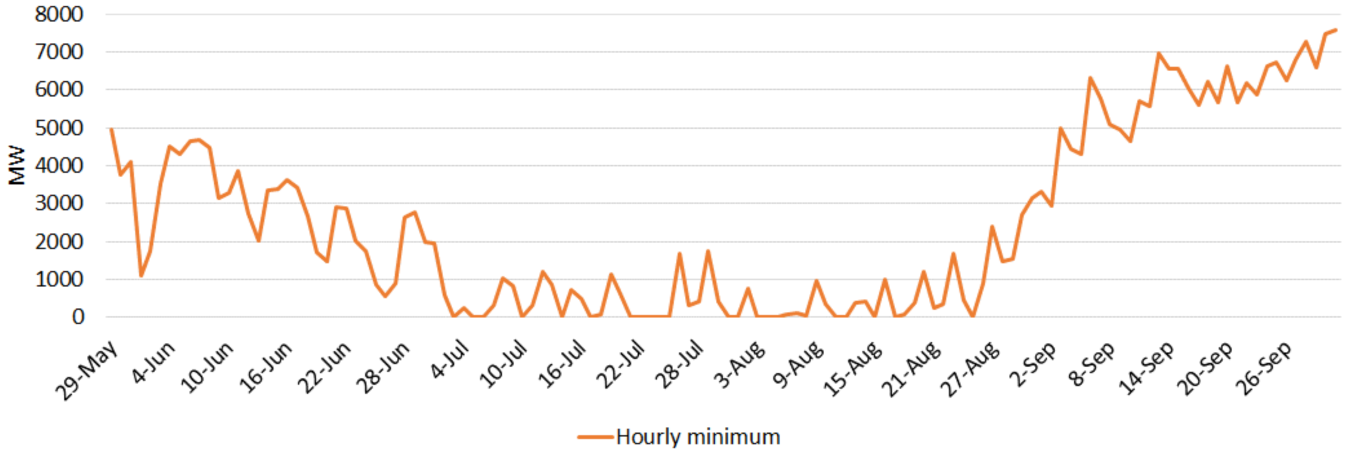


Figure 19: Minimum hourly TPP margin on each day of the analysed period in Algeria

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in Figure 29, for both modes of operation – interconnected and isolated. The values of EENS and LOLE are extremely low, but not zero.

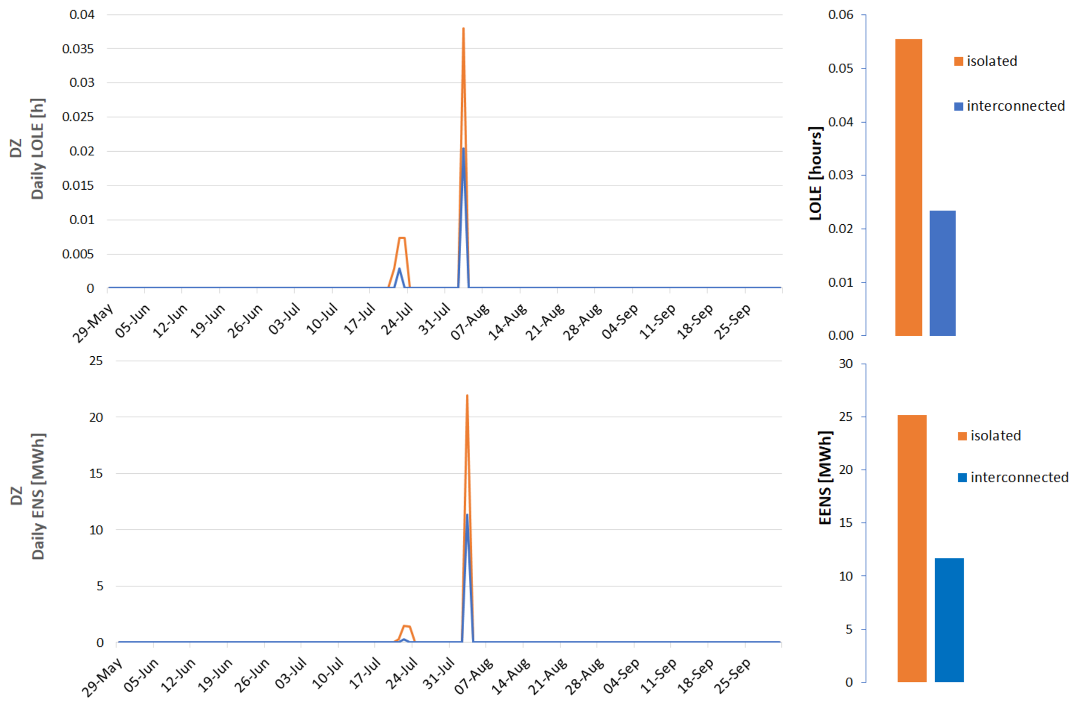


Figure 20: Daily LOLE and EENS for the interconnected and isolated mode of operation

4.2 Egypt

DEMAND

Egyptian seasonal weekly demand, depicted in Figure 21 goes from around 4800 GWh to 5400 GWh, while peak hourly demand in each week varies from 35 GW to more than 39 GW. It should be noted that weekly demand refers to the average values of all 38 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analysed climatic years.

Maximum electricity needs are expected from the second half of July until the end of August (29^{th} - 34^{th} week), due to high temperatures and high cooling consumption, similar as in all other countries. The maximum hourly demand in all 38 climatic years reaches 39328 MW in the 32^{nd} week. It should be noted that during summer season, maximum hourly demand changes in very narrow range of 12%.

Week	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39
Weekly consumption (GWh)	4821	4948	5058	5150	4920	5259	5303	5269	5395	5430	5431	5394	5341	5236	5114	5019	4942	4806
Peak load (MW)	36333	37035	37981	37277	37207	37629	37549	38989	38925	39132	39328	37900	37645	37396	37204	35878	34991	34968

LOW HIGH

Figure 21: 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 90%, which is divided further into conventional and CCGT TPPs. Oil TPPs share is 2%, while Hydro share is 4%. RES – wind and solar capacities amount only to 3% each. Total installed capacities are 58 826 MW with import capacity up to 450 MW from Jordan, which combined is substantially higher than the maximum hourly consumption of 30 592 MW. In sense of demand and installed capacities, Egypt is the biggest of all analysed power systems.

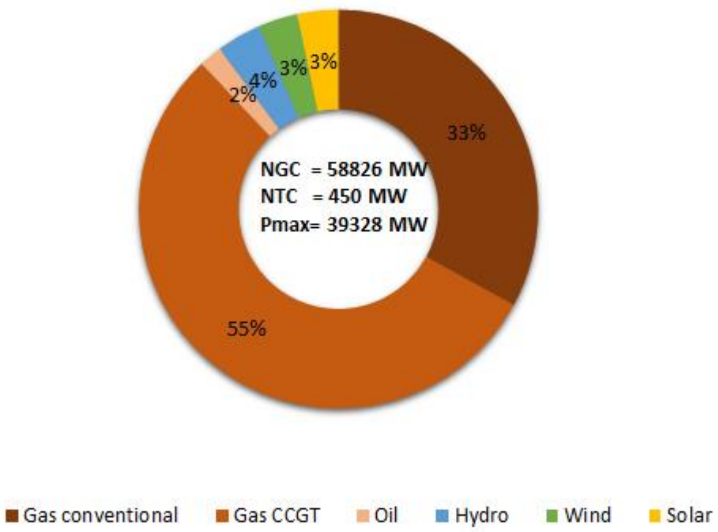


Figure 22: Installed Capacity mix with total NGC, import NTC and peak demand in Egypt

The average daily available TPP capacity, after reduction due to forced outages, is shown in Figure 23. 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 43 GW to 46 GW.

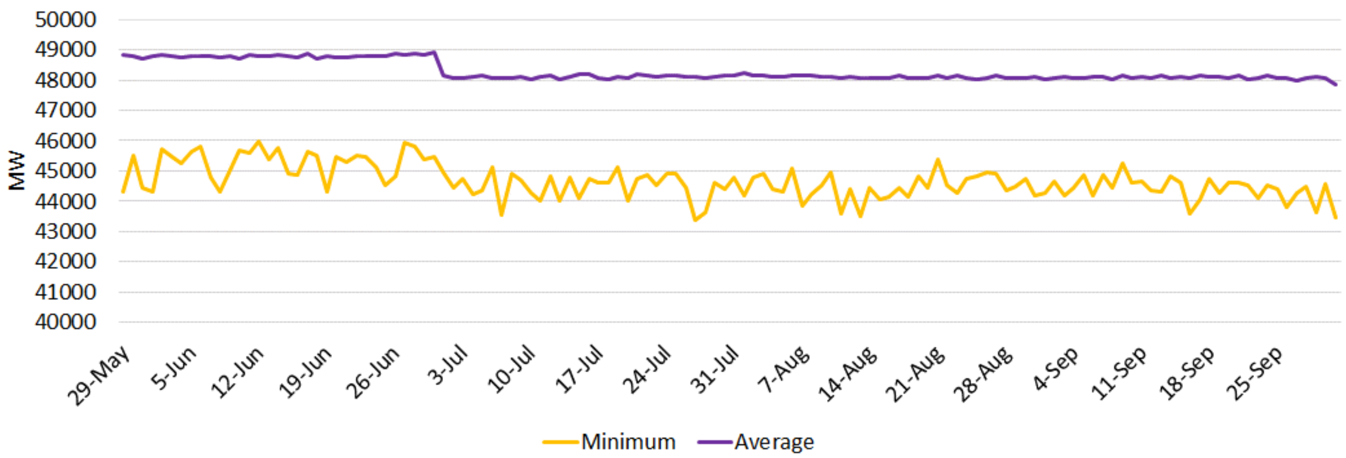


Figure 23: Average and minimum TPP available capacity in Egypt

As a result of system simulation, the minimum hourly TPP capacity margin is calculated and depicted in Figure 24. It represents the difference between available and activated TPP capacities. The minimum hourly value of the capacity margin is the lowest at the beginning of August and drops below 10 000 MW. The maximum in the summer period is around 15000 MW.

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 neighbouring countries' adequacy situation.

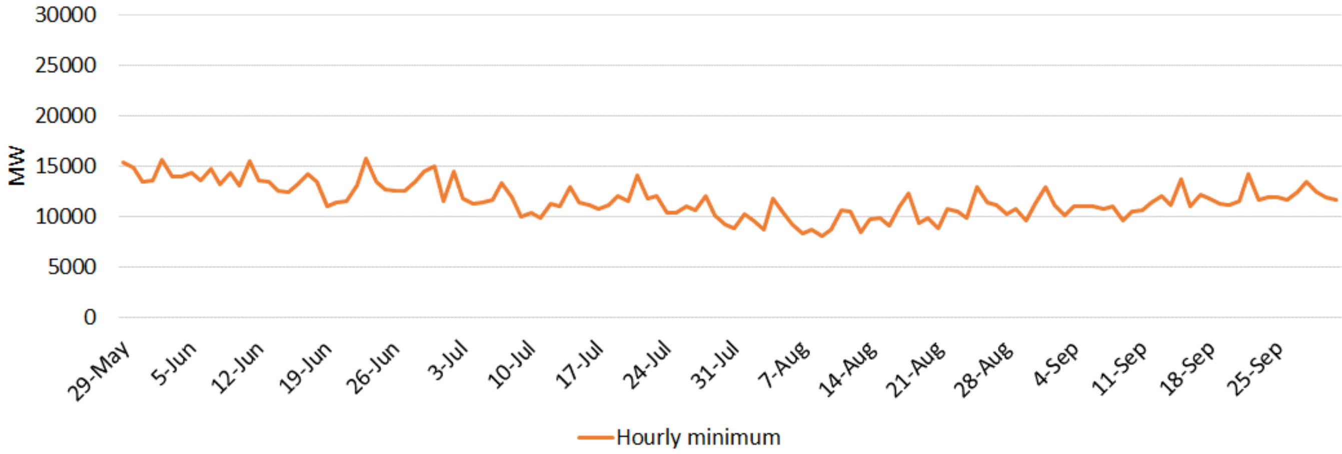


Figure 24: Minimum hourly TPP margin on each day of the analysed period in Egypt

ADEQUACY ASSESSMENT

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

4.3 Jordan

DEMAND

Jordan's seasonal weekly demand, depicted in Figure 25, goes from around 420 GWh to 480 GWh (14% increase), while peak hourly demand in each week goes from 3100 MW to 3900 MW. It should be noted weekly demand refers to average values of all 38 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analysed climatic years.

Maximum electricity needs are expected from during August (30th - 34th week), due to high temperatures and high cooling consumption. The maximum hourly demand of 3911 MW is reached in the 31st week, which is the maximum in all 38 climatic years. It should be noted that during summer season, maximum hourly demand changes in the moderate range of 25%.

Week	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39
Weekly consumption (GWh)	438	435	441	449	433	465	471	464	478	480	477	478	470	460	449	444	435	429
Peak load (MW)	3203	3189	3303	3226	3546	3490	3643	3481	3909	3911	3701	3907	3366	3320	3341	3128	3132	3130

LOW — HIGH

Figure 25: Seasonal Weekly demand in Jordan

SUPPLY AND NETWORK OVERVIEW

Jordan's power generation fleet is dominantly based on gas fuelled TPPs, with the share in total installed capacities around 63%, which is divided further into conventional and OCGT TPPs. Oil share amounts to 7% of installed capacities, while RES – wind and solar share in installed capacities are 9% and 27% respectively. Total installed capacities amount to 6636 MW with an import capacity up to 450 MW from Egypt. It should be noted that in Jordan peak load is reached in winter (4365 MW) and with respect to adequacy, summer season seams less critical.

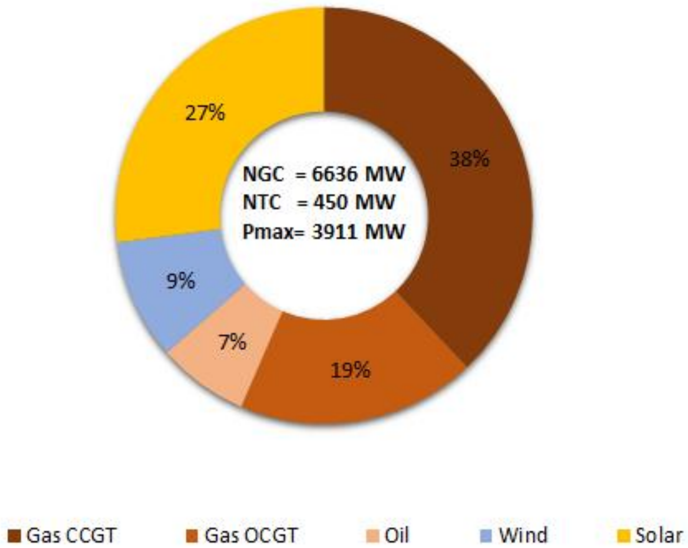


Figure 26: Installed Capacity mix with total NGC, import NTC and peak demand in Jordan

The average daily available TPP capacity, after reduction due to derating factors and forced outages is shown in Figure 27. 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 is between 3500 MW and 3800 MW. The minimal average daily available TPP capacity (minimum among all simulated MC years) goes from 2500 MW to only 3100 MW.

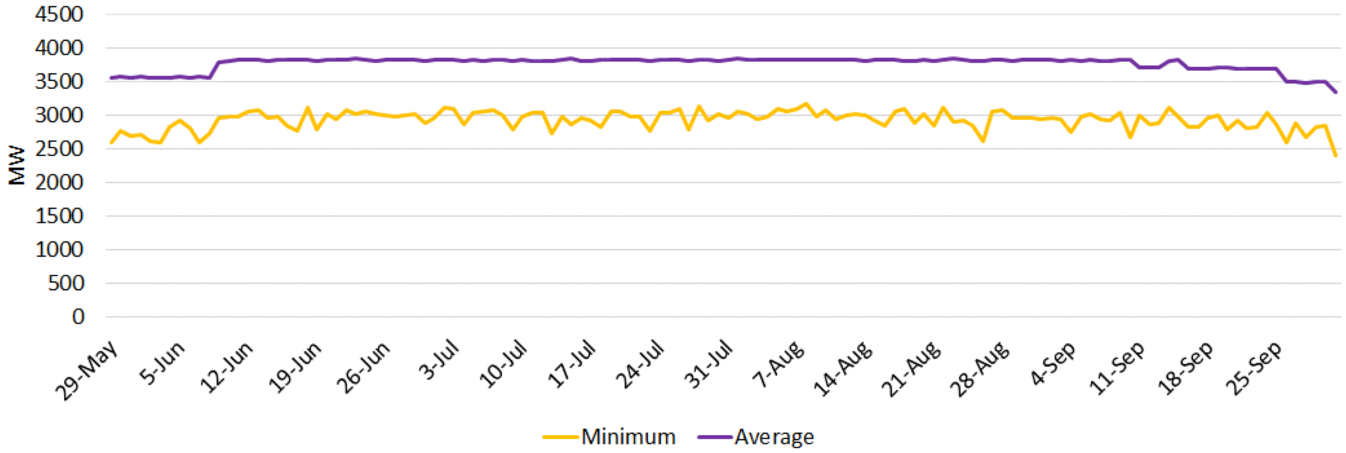


Figure 27: Average and minimum TPP available capacity in Jordan

As a result of system simulation, the minimum hourly TPP capacity margin is calculated and depicted in Figure 28. It represents the difference between available and activated TPP capacities. The minimum hourly value of the TPP margin are often at zero value, although the situation is better than in winter 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.

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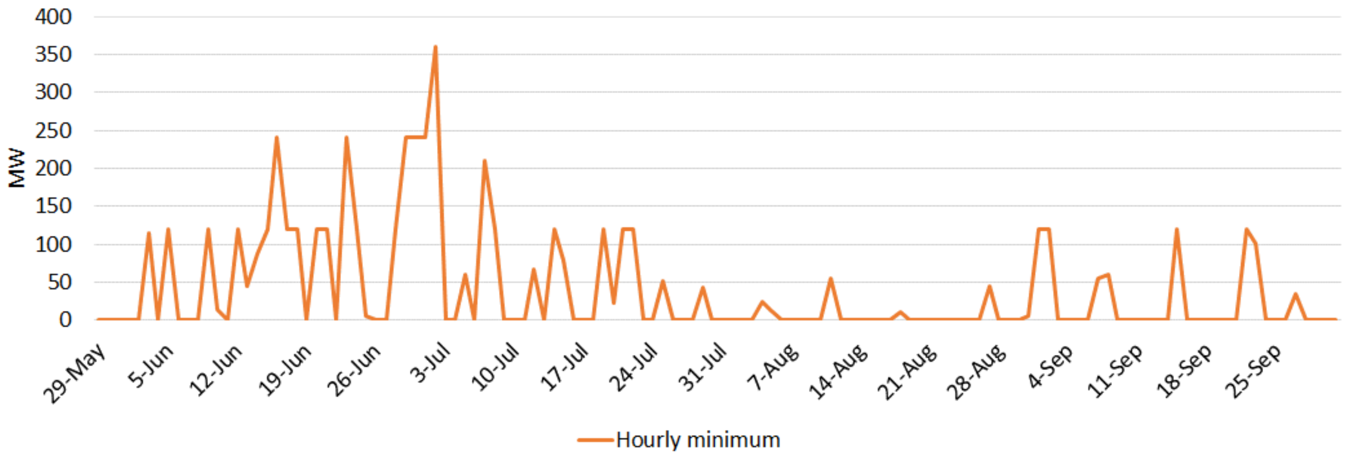

Figure 28: Minimum hourly TPP margin on each day of the analysed period in Jordan

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in Figure 29, 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, especially during the peak of the summer season because of high demand.

Maximum hourly shortage in supply during the summer season in the interconnected mode of operation and within all 684 MC years is high - 576 MW (this happens in week 32).

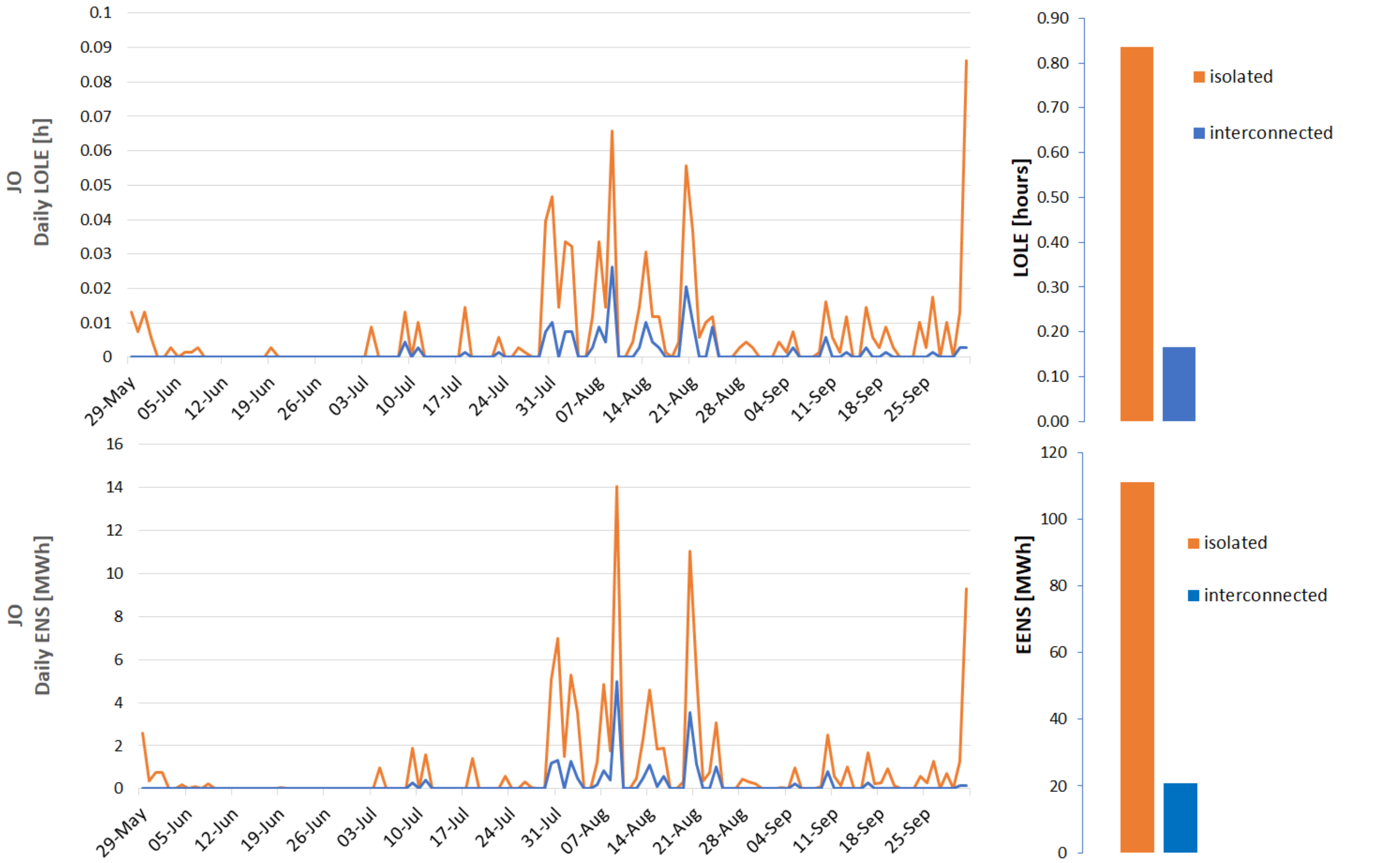

Figure 29: Daily LOLE and EENS for the interconnected and isolated mode of operation

At the righthand 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 0.8 h to less than 0.2 h and expected seasonal EENS from 115 MWh to 20 MWh.

4.4 Lebanon

DEMAND

Lebanon's seasonal weekly demand, depicted in Figure 30, goes from around 400 GWh to 490 GWh, while peak hourly demand each week goes from 3400 MW to 4700 MW. It should be noted that weekly demand refers to the average values of all 38 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analysed climatic years.

Maximum electricity needs are expected during August (week 31-34), due to high temperatures and high cooling demand. The maximum hourly demand of 4717 MW is reached in the 31st week of 2023. It should be noted that during summer season, maximum hourly demand changes in the wide range of 39%.

Also operation of Lebanon's power system is especially difficult, with a continuous lack of supply and organized regular load shedding.

Week	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
Weekly consumption (GWh)	418	429	436	448	459	468	472	478	485	486	482	483	472	459	443	436	425	416
Peak load (MW)	3930	3795	3765	3724	4109	4010	4392	4201	4639	4717	4252	4643	3898	3825	3885	3558	3581	3398

LOW HIGH

Figure 30: Seasonal Weekly demand in Lebanon

SUPPLY AND NETWORK OVERVIEW

Lebanon's power generation fleet is exclusively oil-fuelled, with the share in total installed capacities around 87%. The rest of the 13% goes to hydropower plants. No wind or solar capacities are yet installed. Total installed capacities amount to 2191 MW, but as serious support to system operation, also the additional capacity of 1000 MW in diesel units is considered in this analysis.

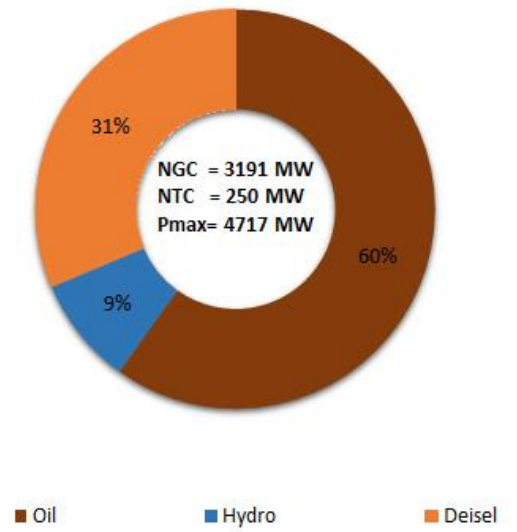

Figure 31: Installed Capacity mix with total NGC, import NTC and peak demand in Lebanon

The average daily available TPP capacity, after reduction due to forced outages, is shown in Figure 32. 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 2500 MW, but the minimum average daily available TPP capacity (minimum among all simulated MC years) goes down to even only 1200 MW.

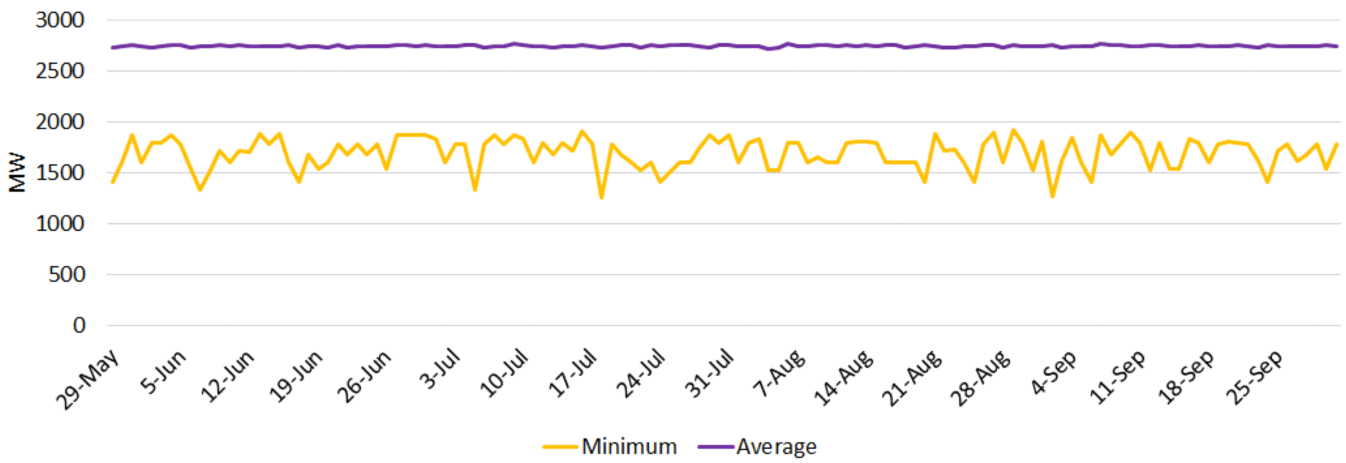

Figure 32: Average and minimum TPP available capacity in Lebanon

As a result of system simulation, the minimum hourly TPP capacity margin is calculated and depicted in Figure 33. It represents the difference between available and engaged TPP capacities. No margin exists in Lebanon's power system.
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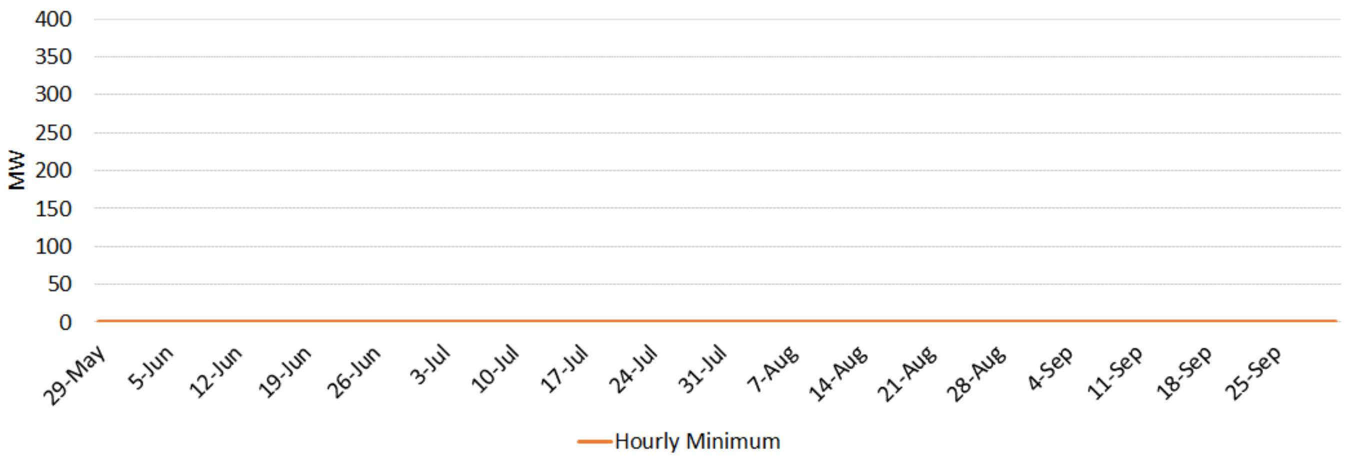


Figure 33: Minimum hourly TPP margin on each day of the analysed period in Lebanon

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in Figure 34 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 noncomparable with any other in this region. The level 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 points to the fact that LOLE and EENS are above all acceptable values even in the interconnected mode of operation: EENS is 411 GWh and LOLE is 757 hours (during the summer season of 3024 hours).
There are days without adequacy issues, but there is no day without adequacy issues in all 684 analysed MC years.
Looking at the whole season, there are days with adequacy issues: between LOLDmin=0.42 hours and LOLDmax=12.3hours in average of 684 MC years.
Maximum hourly shortage in supply during the summer season in the interconnected mode of operation and within all 684 MC years is enormous – 3142 MW (this happens in week 31).

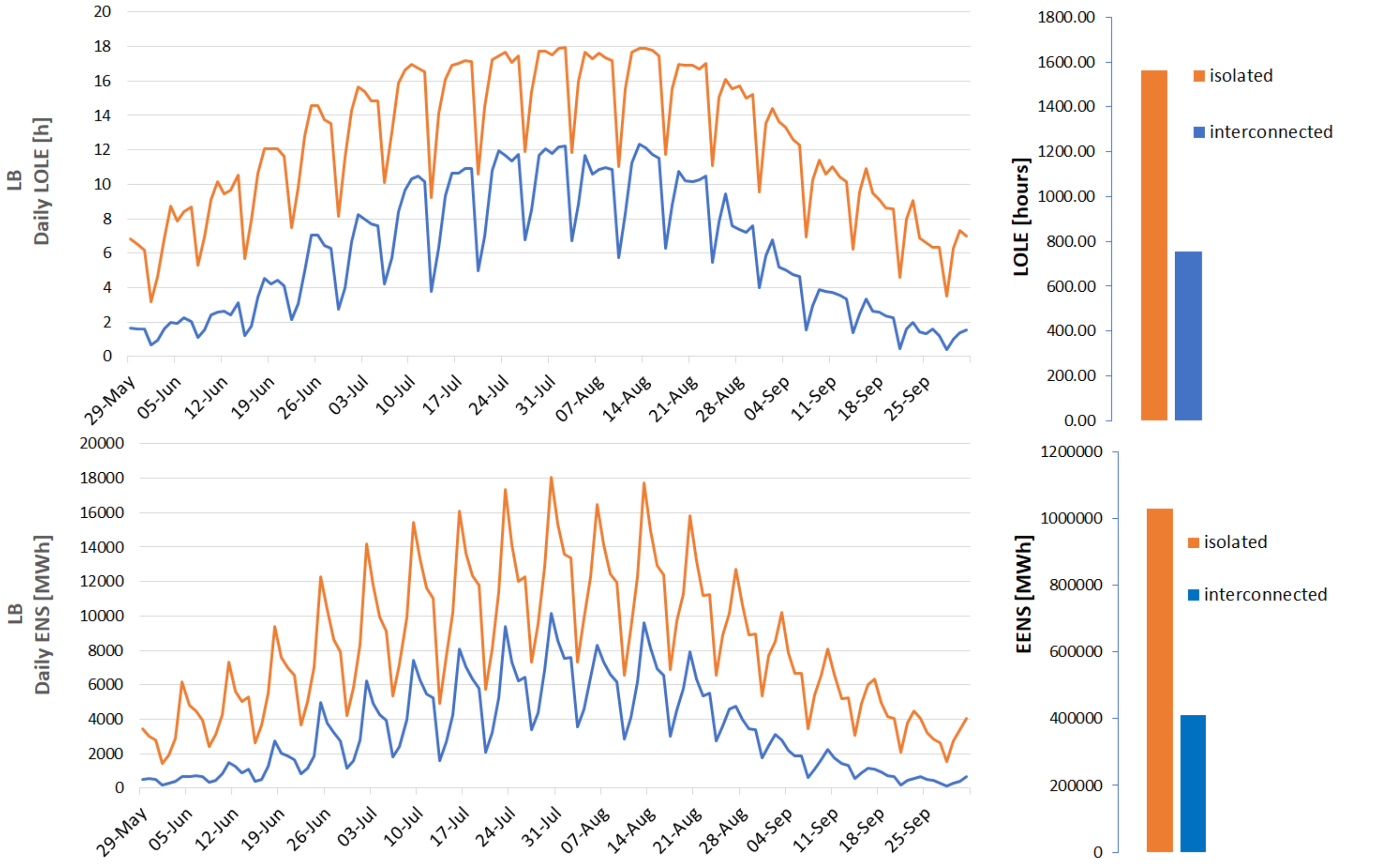


Figure 34: Daily LOLD and EENS for the interconnected and isolated mode of operation

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

4.5 Libya

DEMAND

Libya's seasonal weekly demand, depicted in Figure 35, goes from around 900 GWh to 1100 GWh, while peak hourly demand each week goes from around 7900 MW to 10100 MW. This variation of the peak load is around 30% which can be considered as moderate. It should be noted that weekly demand refers to the average values of all 38 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analysed climatic years.

Maximum electricity needs are expected in June, but also high during July. It should be noted that August is not characterized with the highest hourly demand as it is the case in other countries in the region. The maximum hourly demand in all 38 MC years reaches 10095 MW in the 25th week of 2023 and maximum hourly demand changes during summer season are in the moderate range of 27%.

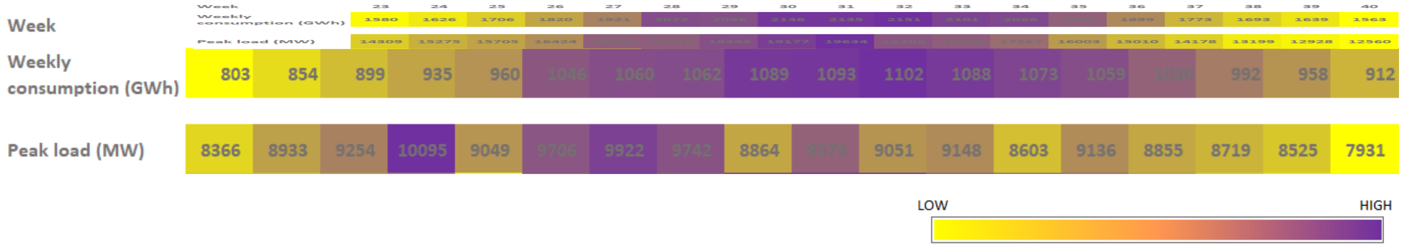


Figure 35: Seasonal Weekly demand in Libya

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 plants with open-cycle gas turbines (56%) and combined cycle gas turbines (26%), while only 16% of capacities mix corresponds to conventional gas-fired power plants. It should be emphasized that according to provided data for summer outlook 2023 there are no RES capacities installed in Libya. In addition, less than 5% of peak load refers to net import transfer capacities.

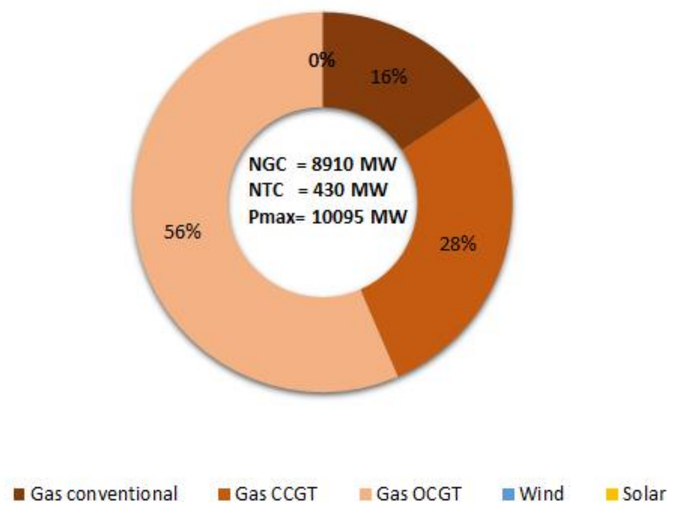


Figure 36: Installed Capacity mix with total NGC, import NTC and peak demand in Libya

The average daily available TPP capacity, after reduction due to forced outages, is shown in Figure 37. 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 TPP capacities level is constant during the whole season.

The minimal daily available TPP capacity between all analysed MC years is between around 7000 MW, which is significantly lower compared with the peak demand of 10GW.

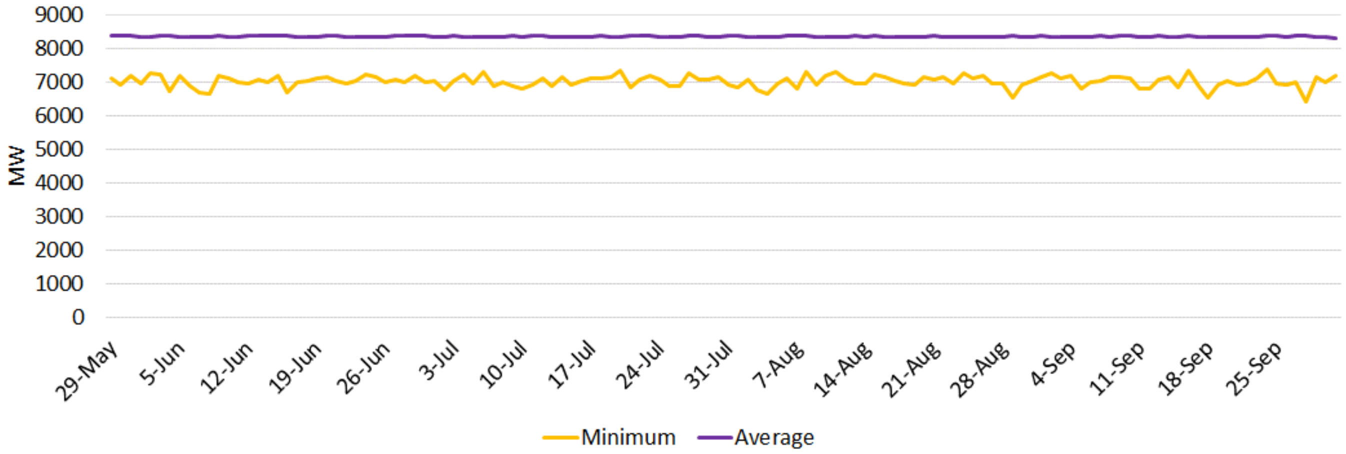


Figure 37: Average and minimum TPP available capacity in Libya

As a result of system simulation, the minimum hourly TPP margin for each day is calculated and depicted in Figure 38. It represents the difference between available and activated TPP capacities. The minimum hourly value of the TPP margin on each day is at zero during July and August and in the first part of September, due to high demand. There are only a few days with non/zero minimum daily margin, which are noted at the beginning and end of the summer season.

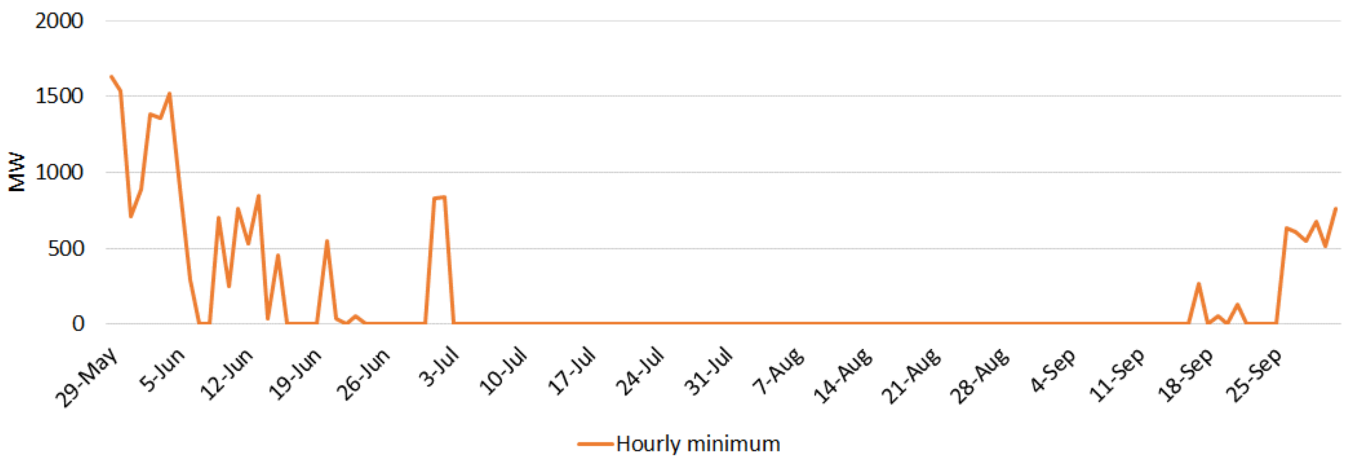


Figure 38: Minimum hourly TPP margin on each day of the analysed period in Libya

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in Figure 39, 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 concluded that shape of daily LOLE/EENS is very similar in both analysed regimes of operation (interconnected and isolated). This is because the difference between EENS in the two analysed regimes corresponds approximately to total imports from Tunisia and Egypt.

As total consumption in Libya increases moving to the peak of the season, energy not supplied increases as well, and the peak can be expected around July 24th. LOLE at the level of 13 hours in interconnected operation could be considered as moderate while in the case of isolated mode of operation, adequacy risk becomes 3 times higher and LOLE is 35 hours.

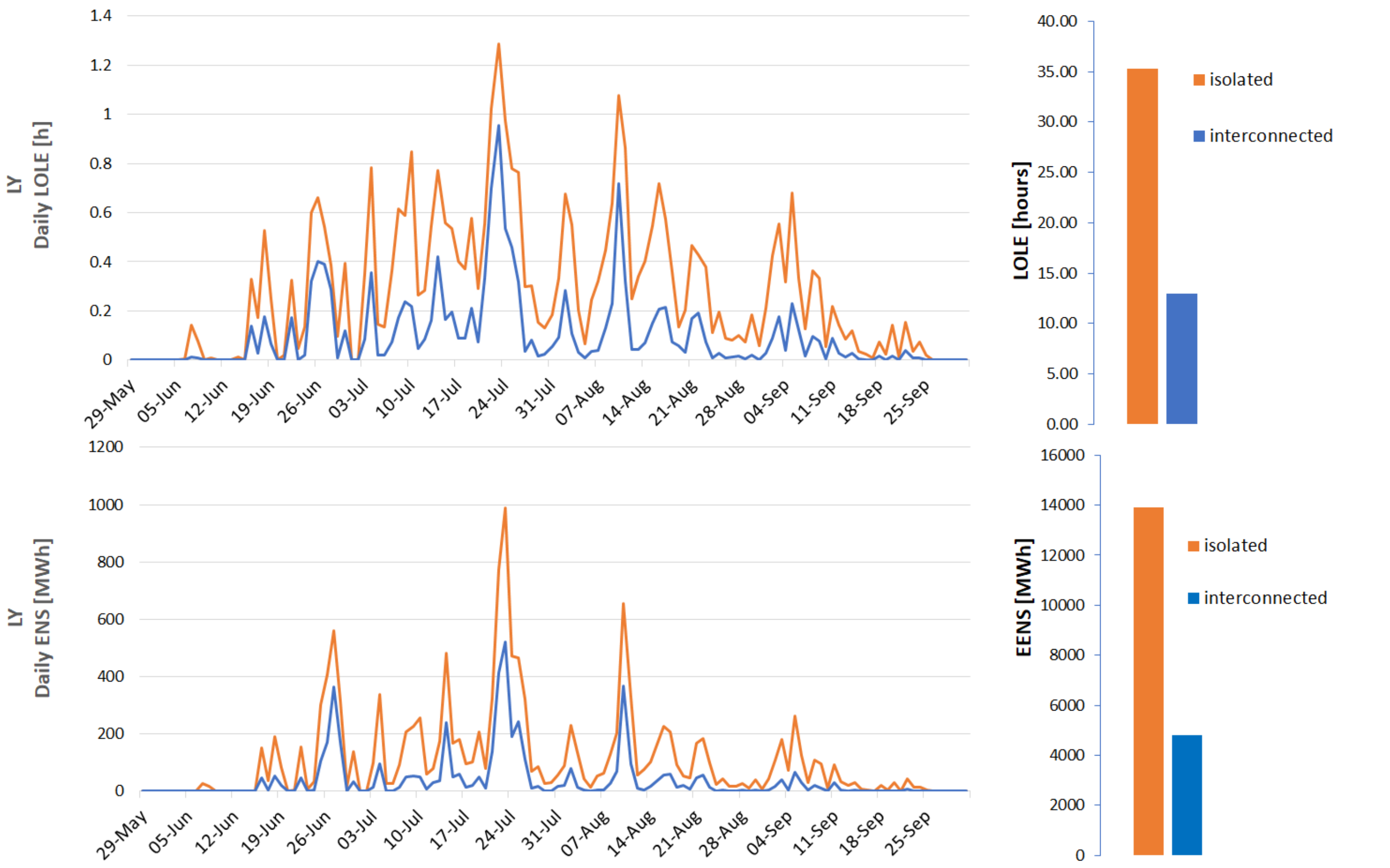


Figure 39: Daily LOLD and EENS for the interconnected and isolated mode of operation

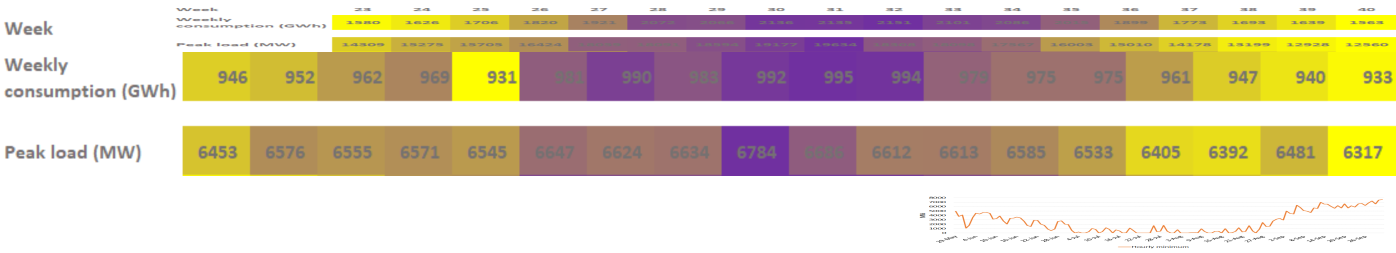
Maximum hourly shortage in supply during the summer season in the interconnected mode of operation and within all 684 MC years is high - 2620 MW (this happens in week 25).

4.6 Morocco

DEMAND

Moroccan seasonal weekly demand, depicted in Figure 40 goes from around 930 GWh to 1000 GWh, while peak hourly demand each week goes from 6300 MW to 6800 MW. It should be noted that weekly demand refers to the average values of all 38 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analysed climatic years.

Maximum electricity needs are expected in July and August while the maximum hourly demand in all 38 MC years reaches 6784 MW in the 30th week of 2023. It should be noted that during summer season, maximum hourly demand changes in the very narrow range of 7%.



Week	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
Weekly consumption (GWh)	946	952	962	969	931	981	990	983	992	995	994	979	975	975	961	947	940	933
Peak load (MW)	6453	6576	6555	6571	6545	6647	6624	6634	6784	6686	6612	6613	6585	6533	6405	6392	6481	6317

Figure 40: Seasonal Weekly demand in Morocco

SUPPLY AND NETWORK OVERVIEW

Moroccan power generation fleet is balanced and well-diversified in comparison with other analysed countries, with the TPP share in total installed capacities around 57%, which is divided further into Coal, Gas and Oil TPPs. Hydro capacities amount to 14%, while RES – wind and solar share in installed capacities is 18% and 10% respectively. Total installed capacities are 11859 MW while total import capacity is up to 1500 MW which is about 22% of peak load in the analysed period.

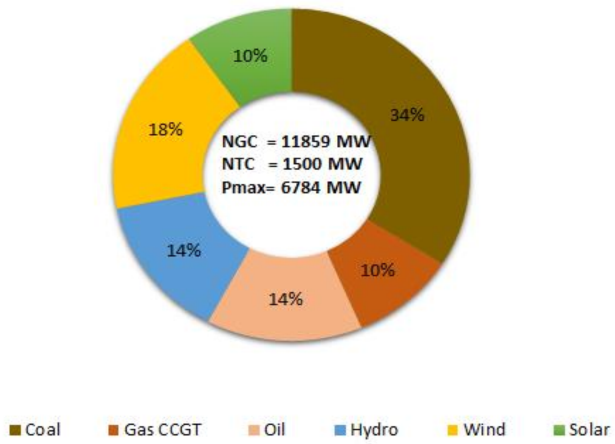


Figure 41: Installed Capacity mix with total NGC, import NTC and peak demand in Morocco

The average daily available TPP capacity, after reduction due to forced outages, is shown in Figure 42. 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 6000 MW during the entire season. The minimal average daily available TPP capacity (minimum among all simulated MC years) goes from 3200 MW to 4200 MW.

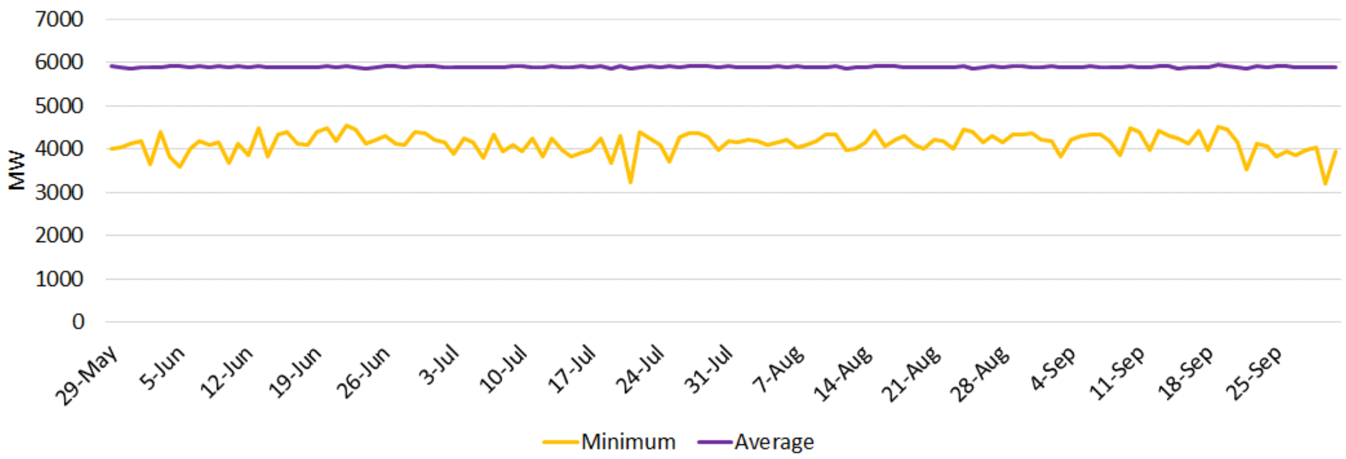


Figure 42: Average and minimum TPP available capacity in Morocco

As a result of system simulation, the minimum hourly TPP capacity margin on each day is calculated and depicted in Figure 43. It represents the difference between available and engaged TPP capacities. TPP margin in some days are at zero level, but adequacy is not endangered since there are other sources and interconnections to support adequacy.

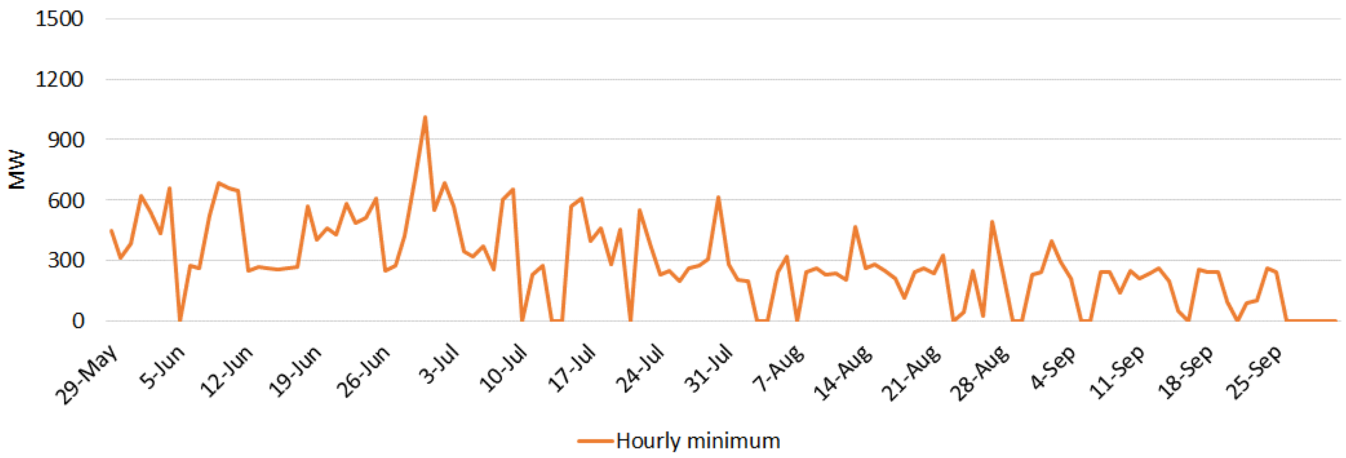


Figure 43: Minimum hourly TPP margin on each day of the analysed period in Morocco

ADEQUACY ASSESSMENT

No adequacy risks are present in the interconnected mode of operation and, even in isolated mode of operation the risks are very low, as presented in Figure 44.

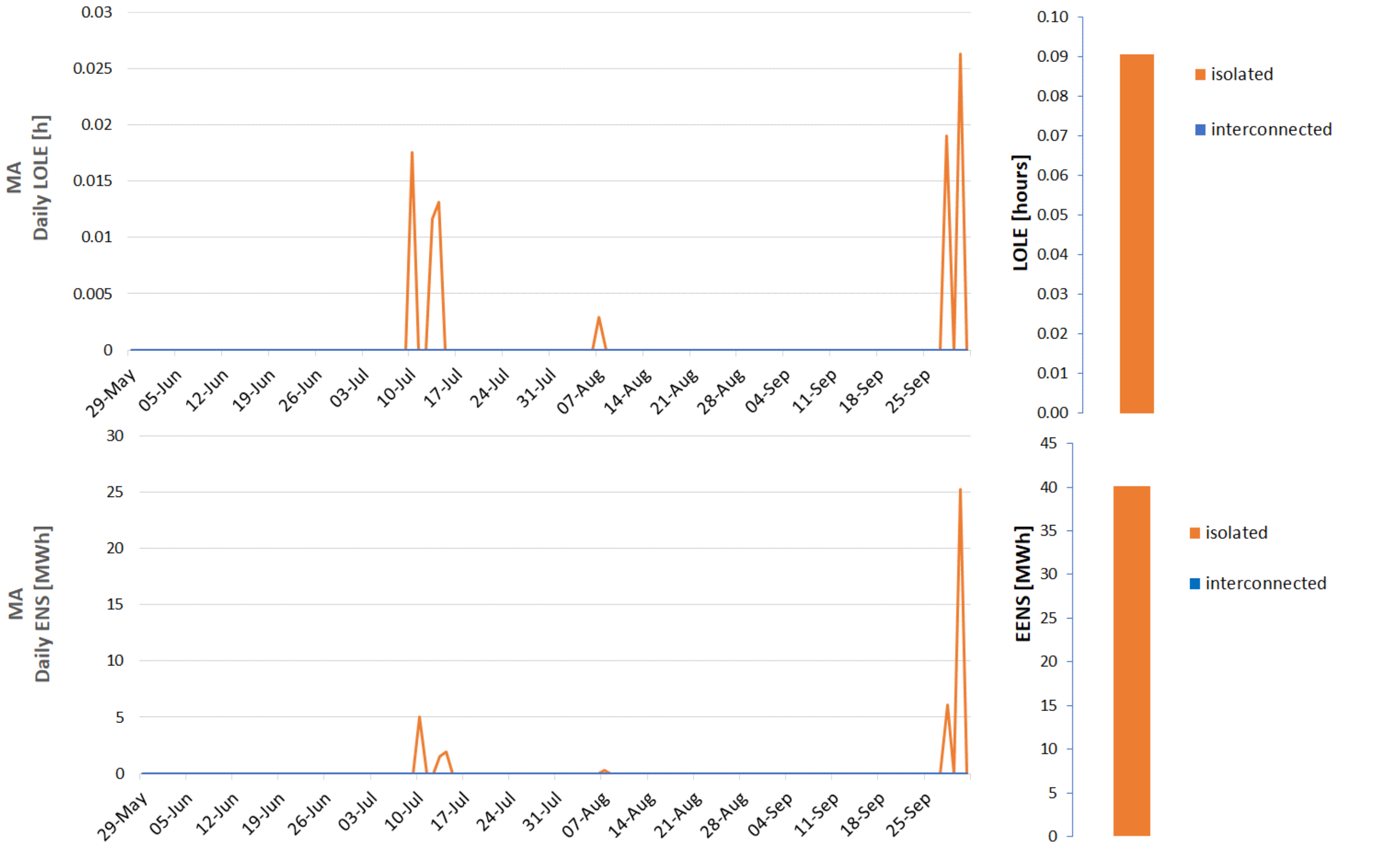


Figure 44: Daily LOLD and EENS for the isolated mode of operation

4.7 Tunisia

DEMAND

Tunisian seasonal weekly demand, depicted in Figure 45, is between 434 GWh and 586 GWh, while peak hourly demand each week goes from 3680 MW to 5635 MW. It should be noted that weekly demand refers to the average values of all 38 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analysed climatic years.

Maximum electricity needs are expected from during whole July and August. The maximum hourly demand is reached in the 31st week - 5635 MW, which is the maximum in all 38 climatic years. It should be noted that during summer season, maximum hourly demand changes in the very wide range of 53%.

Week	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39
Weekly consumption (GWh)	441	460	481	513	517	569	565	563	586	582	581	567	557	529	500	480	463	434
Peak load (MW)	3936	4564	4882	5306	5234	5086	5163	5028	4884	5635	5209	4745	4760	4278	4191	4111	3913	3682

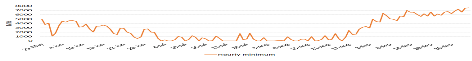


Figure 45: Seasonal Weekly demand in Tunisia

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 600 MW, while maximum hourly consumption is around 3541 MW.

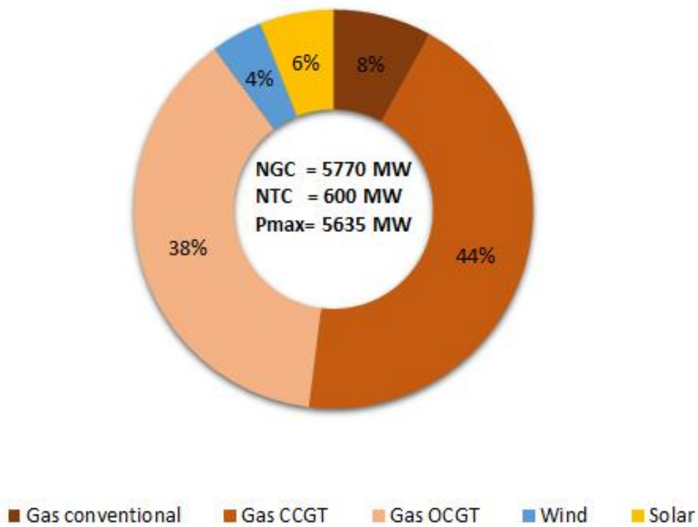


Figure 46: Installed Capacity mix with total NGC, import NTC and peak demand in Tunisia

The average daily available TPP capacity, after reduction due to derating factors and forced outages is shown in Figure 47. 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 between 4000 MW and 4900 MW, which is lower than expected peak load of 5635 MW. The minimum average daily available thermal capacity (minimum among all 684 MC years for each day) is even lower, with the lowest value of 2647 MW which is less than a half of the peak load.

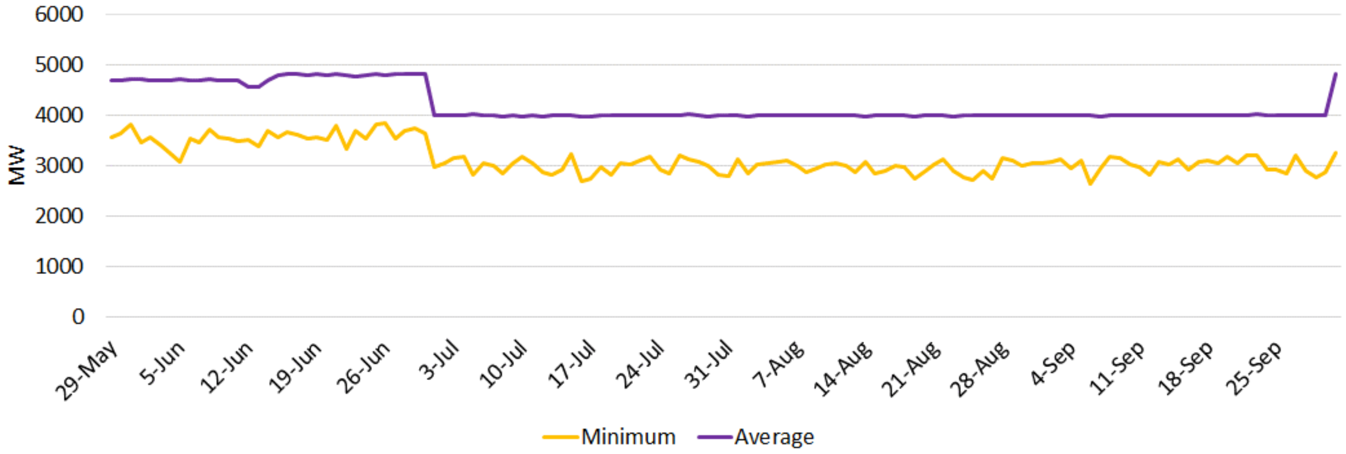


Figure 47: Average and minimum TPP available capacity in Tunisia

As a result of system simulation, the minimum hourly TPP capacity margin on each day is calculated and depicted in Figure 48. 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 s the period when majority of adequacy issues in Tunisia can be expected.

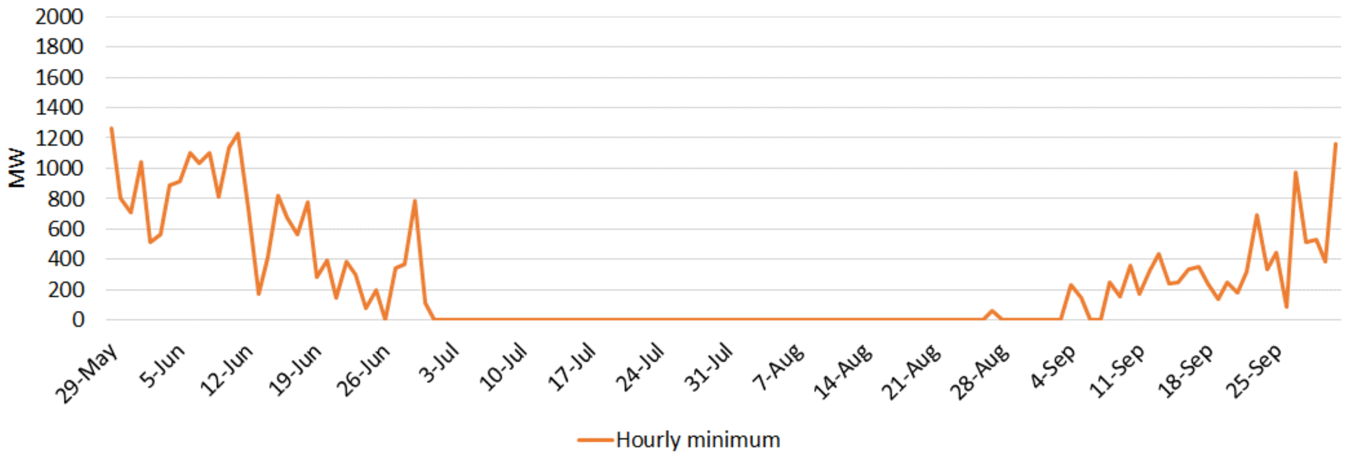


Figure 48: Minimum hourly TPP margin on each day of the analysed period in Tunisia

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in Figure 49, 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 1 hour, while daily EENS goes from 0 to 200 MWh. These adequacy issues during summer are expected due to multiple reasons: highest 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.

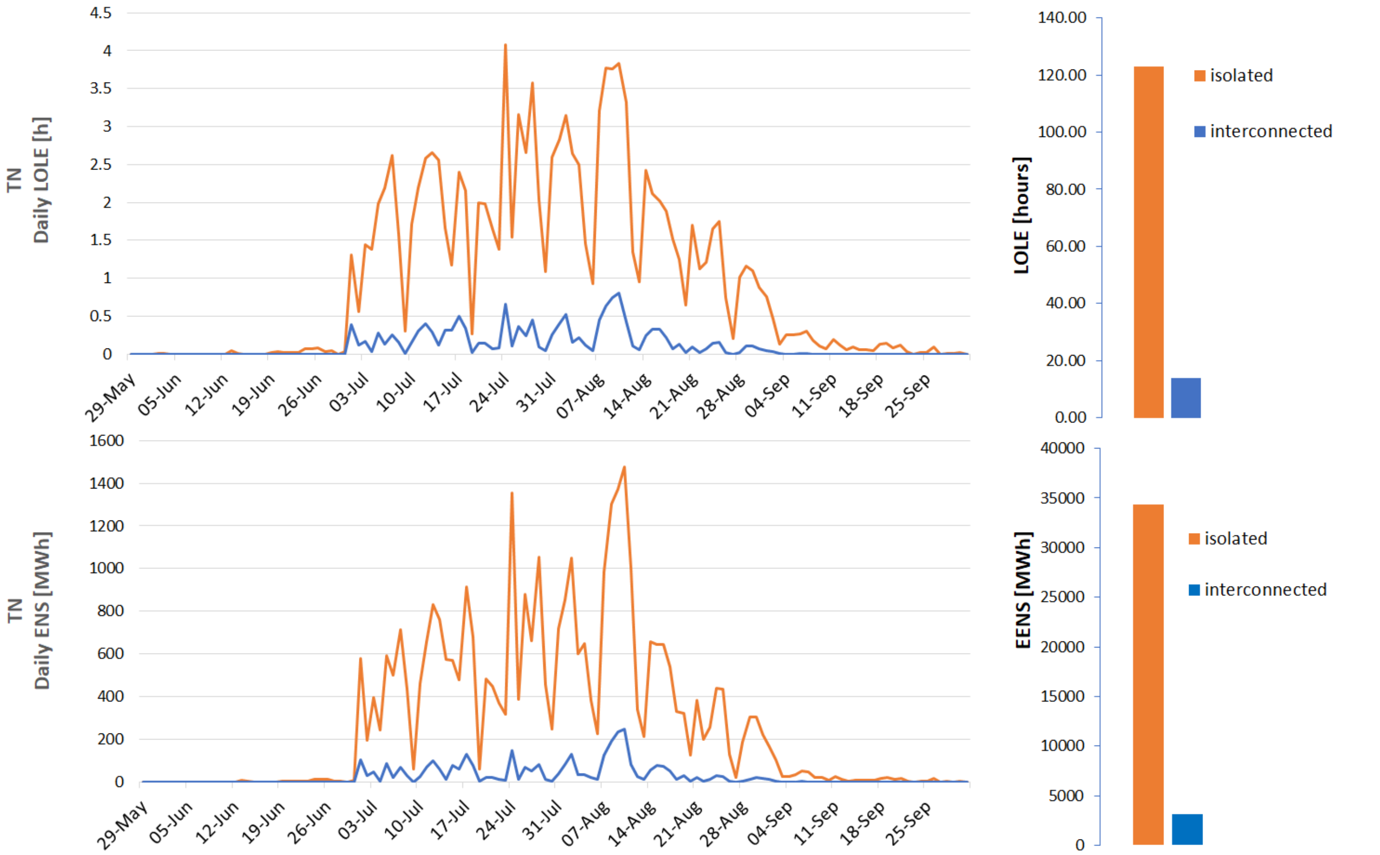


Figure 49: Daily LOLD and EENS for the interconnected and isolated mode of operation

At the right-hand part of the figure, LOLE and EENS for the entire season for both modes of system operation are given. Interconnections substantially reduce LOLE from 120 h to less than 20 h and EENS from around 35 GWh to 3 GWh. Maximum hourly shortage in supply during the summer season in the interconnected mode of operation and within all 684 MC years is high - 1230 MW (this happens in week 31).

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