TeasiMed2 project

SEASONAL ADEQUACY ASSESSMENT

Winter Outlook 2023/2024

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)

Market areas/countries:

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

1 Executive Summary

This Report presents the adequacy situation among non-EU Med-TSO members for the winter 2023/2024. 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 intermittency, 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 devices that can provide adequate power system flexibility.

This Winter Outlook 2023/2024 Report provides information about potential adequacy issues during the period from 26 November 2023 to 1 April 2024 in 7 MED-TSO countries: 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.

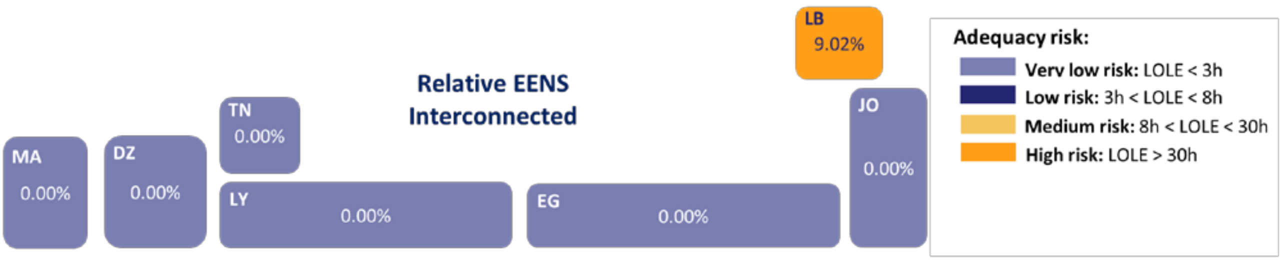


Figure 1 Seasonal relative ENS for interconnected mode of operation

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

Figure 2 Seasonal LOLE for interconnected mode of operation

The conclusions of this assessment show that during this winter the most severe adequacy issues may occur in Lebanon (see Figure 1 & Figure 2), where LOLE reaches around 1171 hours (around 39 % of the winter season) and energy not supplied is higher than 9% of the power demand in the relevant period. On the other hand, a very low adequacy risk is registered in Libya and Jordan (LOLE lower than 1 hour). The highest probability that generation (+import) will not be sufficient to cover electricity demand in Libya is expected in December and January, 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 winter 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 programmes. 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.

2 Approach and methodology

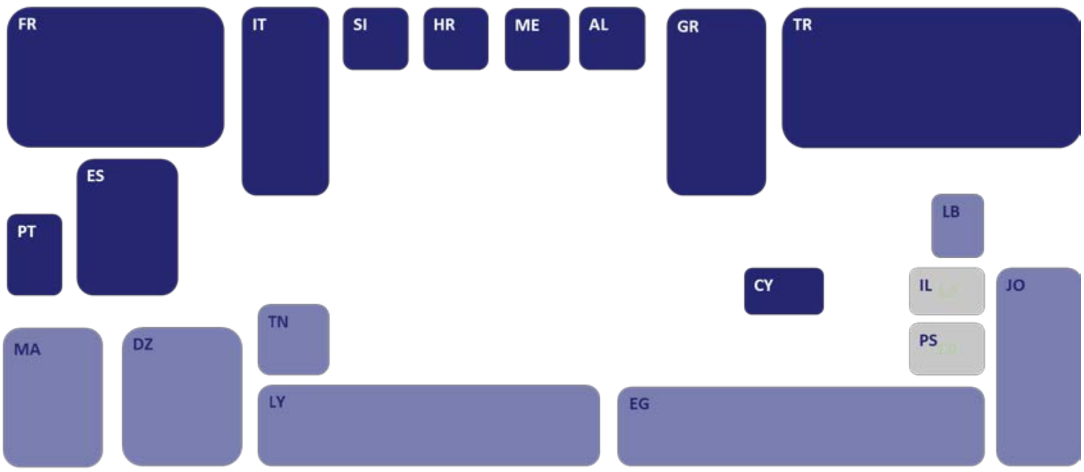
2.1 Adequacy assessment methodology

This Report presents the adequacy situation among non-European Med-TSO members during winter 2023/2024. 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 decarbonise energy systems - adequacy monitoring becomes even more important.

This Winter Outlook 2023/24 Report provides information about potential adequacy issues during winter 2023/24 in the 7 MED-TSO members: Morocco, Algeria, Libya, Tunisia, Egypt, Jordan and Lebanon.



Med-TSO members analysed in this adequacy assessment
Med-TSO members not analysed in this adequacy assessment
Med-TSO members taking part to the ENTSO-E adequacy study

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

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

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

The analysed period includes all hours between the beginning of week 48 in 2023 and the end of week 13 in 2024 which is the period between Monday, November 27th and Monday, April 1st.

The analyses have been carried out with the ANTARES simulator, 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 analysed.

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 analysed timeframe. For all those MC years, hourly calculations are performed for the whole geographical scope.

Figure 4 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
- **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.

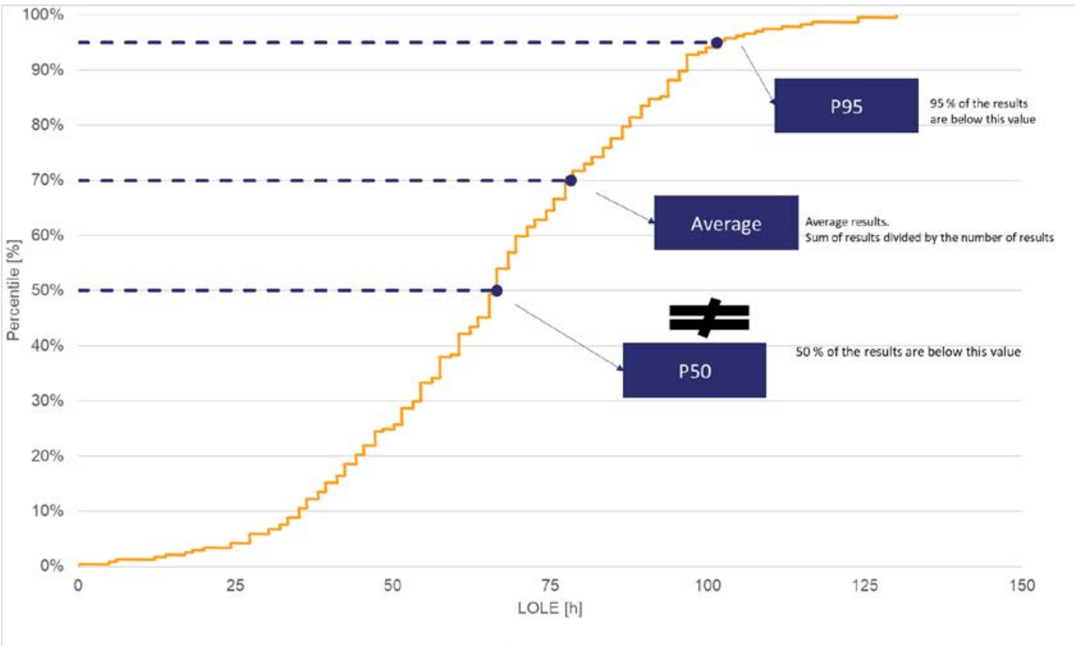


Figure 5 Illustrative Example of the relation between average, P50 and P95 values

- **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.

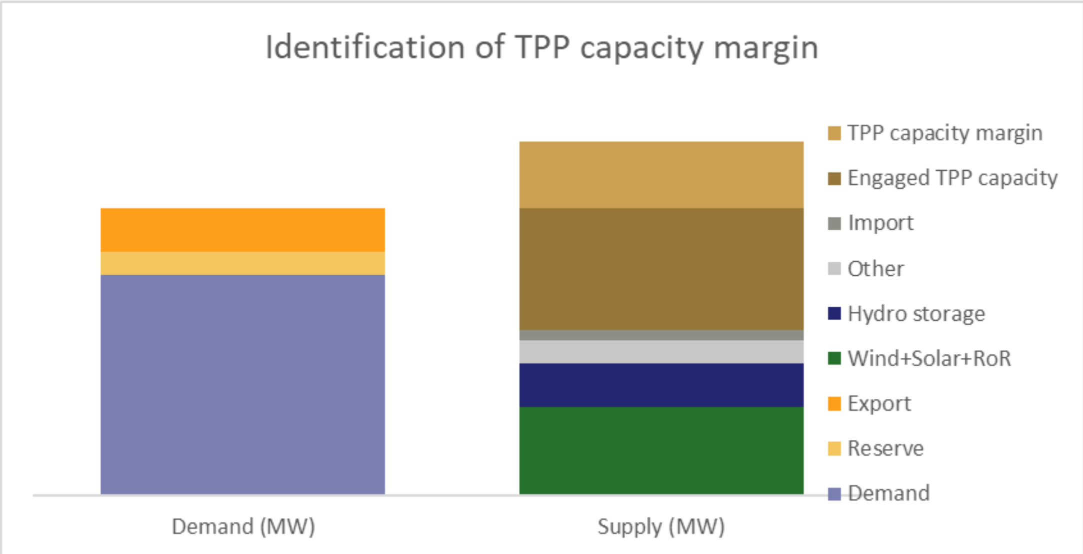


Figure 6 Illustrative Example of TPP capacity margin identification

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 7.
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.

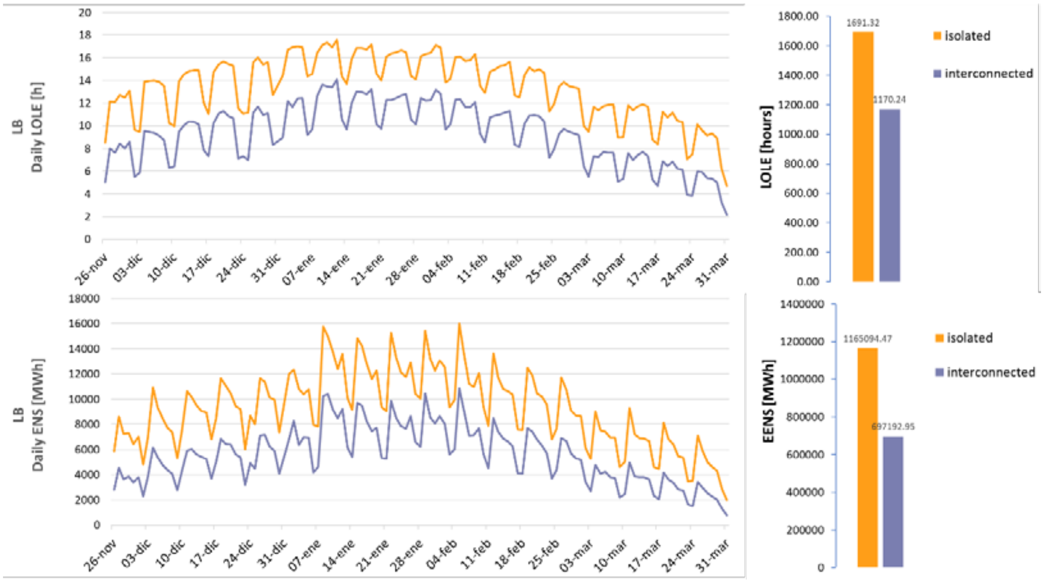


Figure 7 Illustrative example of average daily LOLE and EENS

In addition, available thermal capacities and thermal capacity margins are also presented at a daily & 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.

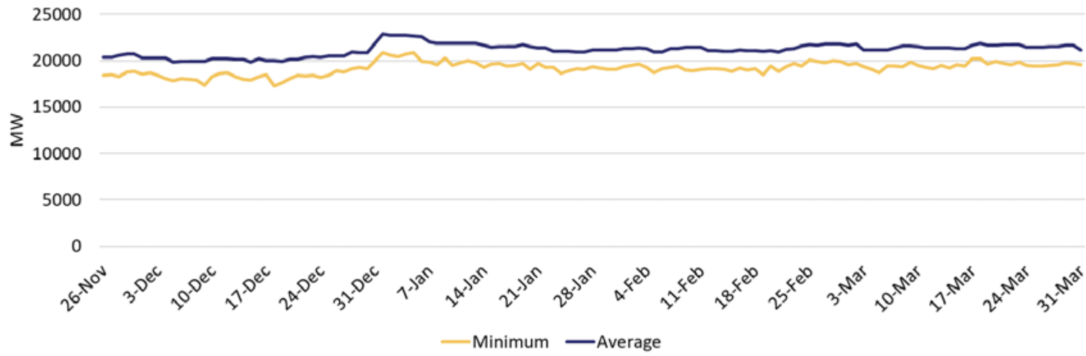


Figure 8 Illustrative example of available TPP capacity

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 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 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 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 Winter Outlook 2023/24 data have been collected in August/September 2023.

This database will be updated in March 2024 with the latest information that will be used for the preparation of the next report - Summer Outlook 2024.

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,...) 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 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 analysed countries**
- **Isolated operation of the analysed countries**

2.4 Overview of the MED-TSO power systems in Winter 2023/24

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.

DEMAND EVOLUTION

Table 1 presents the expected consumption per week from the 48th week in 2023 to the 13th 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 Winter weeks – 2023/24

Weekly consumption (GWh)		DZ	EG	JO	LB	LY	MA	TN
Total		28620	70050	8071	7728	16312	14477	6838
Week	48	1509	3792	424	409	812	779	369
Week	49	1525	3780	434	420	859	780	373
Week	50	1544	3781	442	428	894	780	378
Week	51	1547	3781	448	433	912	782	381
Week	52	1575	3785	449	433	946	782	386
Week	1	1618	3909	459	438	997	807	386
Week	2	1651	3933	468	456	1001	806	390
Week	3	1658	3937	469	451	993	814	390
Week	4	1651	3904	467	452	986	814	391
Week	5	1647	3926	464	453	982	814	390
Week	6	1648	3927	460	447	985	814	393
Week	7	1637	3918	455	437	961	813	392
Week	8	1617	3916	452	434	917	811	385
Week	9	1590	3929	446	423	851	813	378
Week	10	1573	3939	439	412	842	815	378
Week	11	1565	3952	435	410	820	814	360
Week	12	1539	3962	431	400	792	819	357
Week	13	1527	3979	428	393	760	819	359

High Value
Low Value

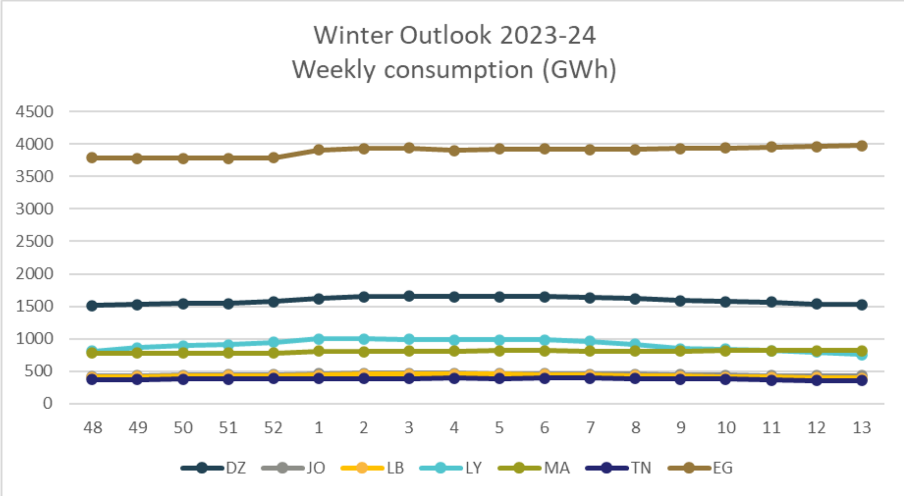


Figure 10 Expected weekly consumption per country in the analysed season

Weekly consumption in Jordan, Lebanon and Tunisia is the lowest among the analysed 7 countries. The highest is consumption in Egypt, almost 10 times higher. Consumption in Libya, Morocco and Algeria 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 winter weeks 2023/24

Peak load, based on maximum among 38 CY (MW)		DZ	EG	JO	LB	LY	MA	TN
Maximum		13716	30716	4601	4870	10126	6756	3507
Week	48	12038	29607	3706	3569	6695	6285	3106
Week	49	12097	29031	3891	3725	7471	6314	3226
Week	50	12351	28958	4174	4234	7769	6278	3221
Week	51	12758	28732	4453	3982	8115	6329	3286
Week	52	12765	29629	4174	4489	8856	6338	3346
Week	1	12989	30280	4424	4576	9383	6538	3359
Week	2	13267	30408	4392	4522	10126	6421	3388
Week	3	13427	30094	4258	3966	9557	6500	3439
Week	4	13716	30716	4286	4610	8655	6598	3405
Week	5	13432	30032	4354	4452	9680	6756	3507
Week	6	13624	30388	4601	4870	9363	6560	3349
Week	7	13485	29643	4105	4222	9002	6451	3323
Week	8	12894	30251	4478	4160	8463	6438	3195
Week	9	13175	29530	4284	4275	7670	6600	3202
Week	10	12761	30299	3900	4035	7782	6413	3107
Week	11	12510	30609	3895	3699	7022	6595	2925
Week	12	12692	30150	3897	3721	7035	6615	3049
Week	13	12230	29915	3861	3702	6979	6647	2888

High Value
Low Value

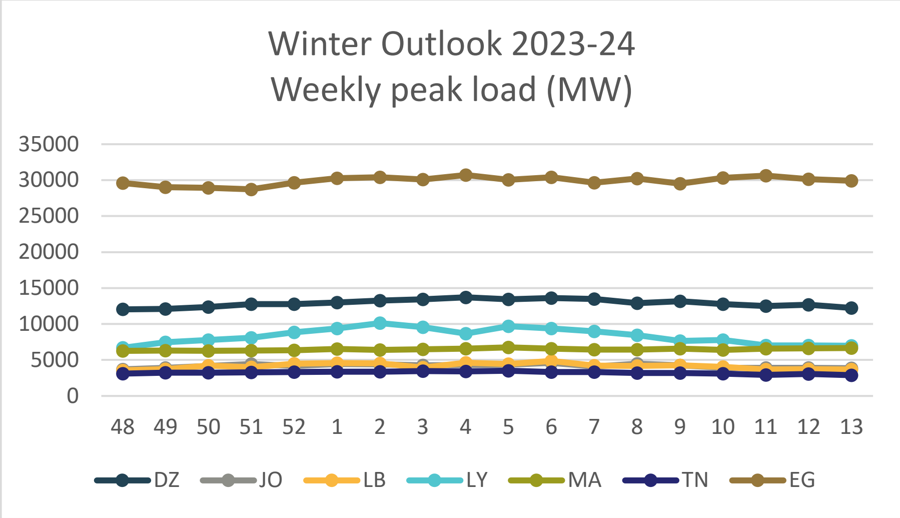


Figure 11 Maximum weekly peak loads per country in the analysed season

In all countries, except Jordan, peak load is observed in summer. In Jordan, the peak load is observed in winter and the value of 4601 MW presents the peak load for 2024.

It should be noted weekly consumption is rather constant during this period although there are more evident fluctuations of the peak load, especially in Libya Figure 11.

Concerning, daily patterns, in each country there are seven rather similar daily profiles with one or two peaks within a day. In Algeria, daily profiles are almost the same and no day within a week is different. In the case of Egypt and Jordan, demand is slightly lower on Fridays while in Morocco and Tunisia on Sundays.

GENERATION CAPACITIES EVOLUTION

The following tables provide information about generation capacities in 2023 and 2024. Total generation capacities in the observed region are expected to reach 123 GW, with almost 107 GW (or around 87%) in thermal units.

Table 3 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	1.16%	100	0.44%	22543	98.40%	**22909**
EG	1634	2.77%	1674	2.84%	2831	4.81%	52776	89.58%	**58915**
JO	621	8.57%	2062	28.46%	-	-	4561	62.96%	**7244**
LB	-	-	1500	31.98%	280	5.97%	2911	62.05%	**4691**
LY	-	-	-	-	-	-	11724	100.00%	**11724**
MA	2017	17.57%	831	7.24%	1770	15.42%	6860	59.77%	**11478**
TN	242	3.99%	345	5.68%	-	-	5483	90.33%	**6070**
TOTAL	**4514**	**3.67%**	**6678**	**5.43%**	**4981**	**4.05%**	**106858**	**86.85%**	**123031**

Total Capacity [GW]	Peak Load [GW]
22909	20686
58915	38054
7244	5051
4691	3770
11724	10090
11478	6784
6070	5628

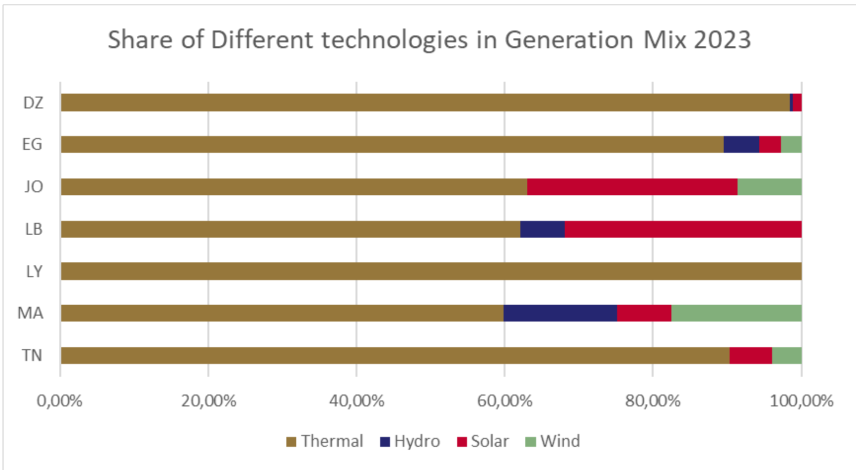


Figure 12 Generation capacity mix and peak load in 2023

Table 4 Total generation 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	
DZ	-	-	266	1.06%	100	0.40%	24657	98.54%	**25023**
EG	1634	2.77%	1674	2.84%	2831	4.81%	52776	89.58%	**58915**
JO	621	8.57%	2062	28.46%	-	-	4561	62.96%	**7244**
LB	-	-	1500	31.98%	280	5.97%	2911	62.05%	**4691**
LY	-	-	-	-	-	-	11724	100.00%	**11724**
MA	2017	17.57%	831	7.24%	1770	15.42%	6860	59.77%	**11478**
TN	242	3.99%	345	5.68%	-	-	5483	90.33%	**6070**
TOTAL	**4514**	**3.61%**	**6678**	**5.34%**	**4981**	**3.98%**	**108972**	**87.08%**	**125145**

Total Capacity [GW]	Peak Load [GW]
25023	21429
58915	39251
7244	4894
4691	3917
11724	10126
11478	6950
6070	5704

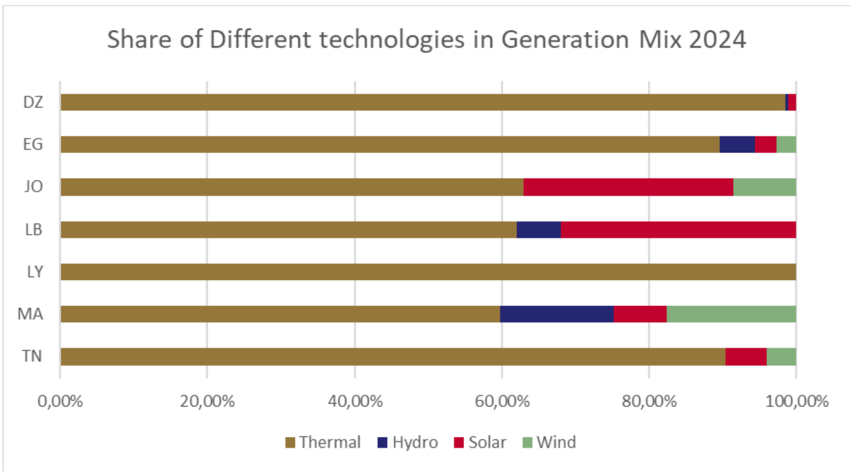


Figure 13 Generation capacity mix and peak load in 2024

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, taking into account maintenance performed by the Libyan system and the introduction of 2 GW of new power plants.

Relevant hydro capacities exist only in Egypt and Morocco. In Morocco, there is also a PS 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 5. It is worth mentioning that capacity factors consider the technology used and also the zone splitting of each country.

Table 5 Wind and solar capacity factors for all countries in 2023/24

Country	2023/24	
	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 Algeria, Egypt and Tunisia is marginal since the participation of thermal units is above 89%. 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 (DZ, JO, TN) or as random outages enabled during the whole analysed period December-March.

It should be emphasized that in case of winter outlook adequacy analysis, months of two different calendar years are used within simulations. Therefore, all input data such as load time-series or wind and solar installed capacities and capacity factors refer to two different years. In other words, for winter months November-December, input data given for 2023 were used while for period January-April input data for 2024 were used. As a consequence of such an approach, large discontinuity in time series may appear on 1st January, depending on the country and changes in forecasted/planned values.

Similar, for thermal units, commissioning/decommissioning dates are taken into account. In practice there are cases when a group of thermal units enter into operation at the same date, usually on 1st January, which may cause large discontinuity in installed capacities at the middle of the analyzed period.

In order to overcome these effects, it is recommended that commissioning/decommissioning dates should be given more precisely.

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 our members. A summary of the interconnection capacities and given exchanges is presented in the following tables.

Table 6 Summarized NTC Values

Intercopnnection NTC [MW]	2023/2024
DZ-TN	700
TN-DZ	700
DZ-MA	600
MA-DZ	300
EG-LY	180
LY-EG	0
TN-LY	250
LY-TN	100
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]	2023/2024
EG-SD	80
JO-PS	80

RESERVE REQUIREMENTS AND THEIR MODELLING

Reserve requirements have been provided for each country (Table 8). 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 8 Balancing reserve requirements

Reserve		2023 and 2024
DZ	FCR+FRR [MW]	700
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., $EENS_N = \frac{\sum_{i=1}^{N} \quad ENS_i}{N}$, 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.

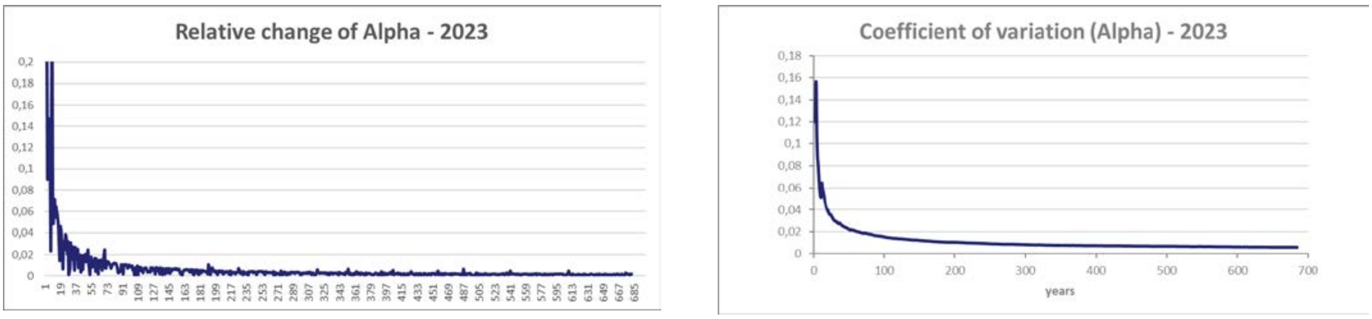


Figure 14 Evolution of convergence criteria for 684 MC years, simulations for the year 2023

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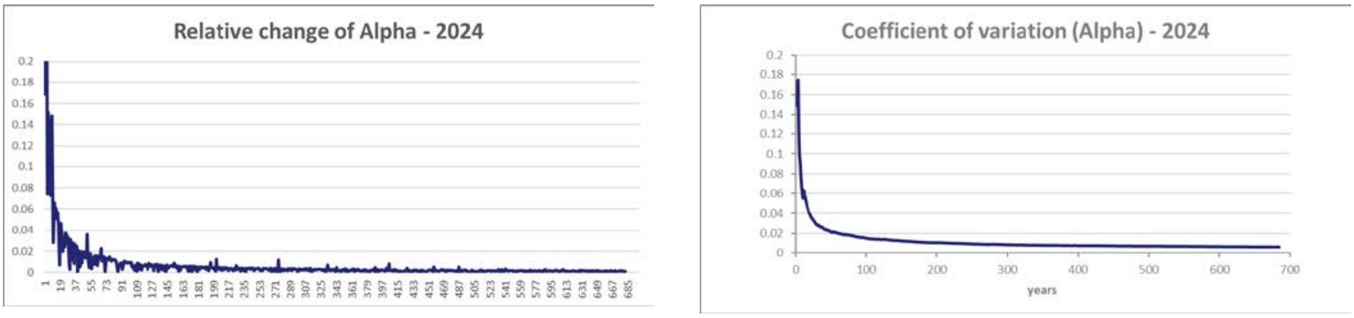

Figure 15 Evolution of convergence criteria for 684 MC years, simulations for the year 2024

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 Med-TSO interconnections.

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

Only in the case of Lebanon adequacy risk is very high under isolated system operating mode. Interconnections and energy exchanges with neighbouring countries reduce adequacy risks to zero in the case of Morocco, 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 winter season only.

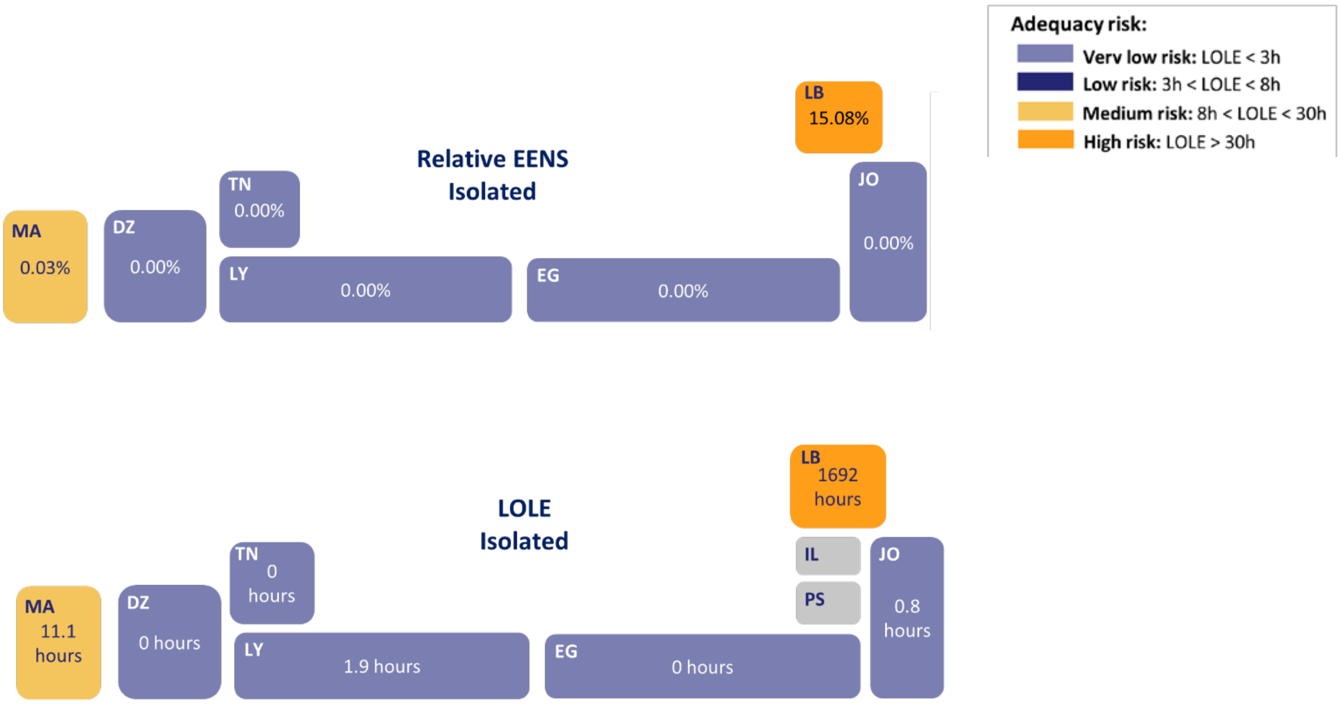

Figure 16 Seasonal Relative EENS and LOLE for the isolated mode of operation for only winter season

[7] Color coding of adequacy risk levels presented in REF _Ref1018 Figure 17 andF_Ref1017h Figure 18 does not reflect national thresholds for loss of load expectation (LOLE) that is usually specified within Network Codes of corresponding Transmission System Operators.

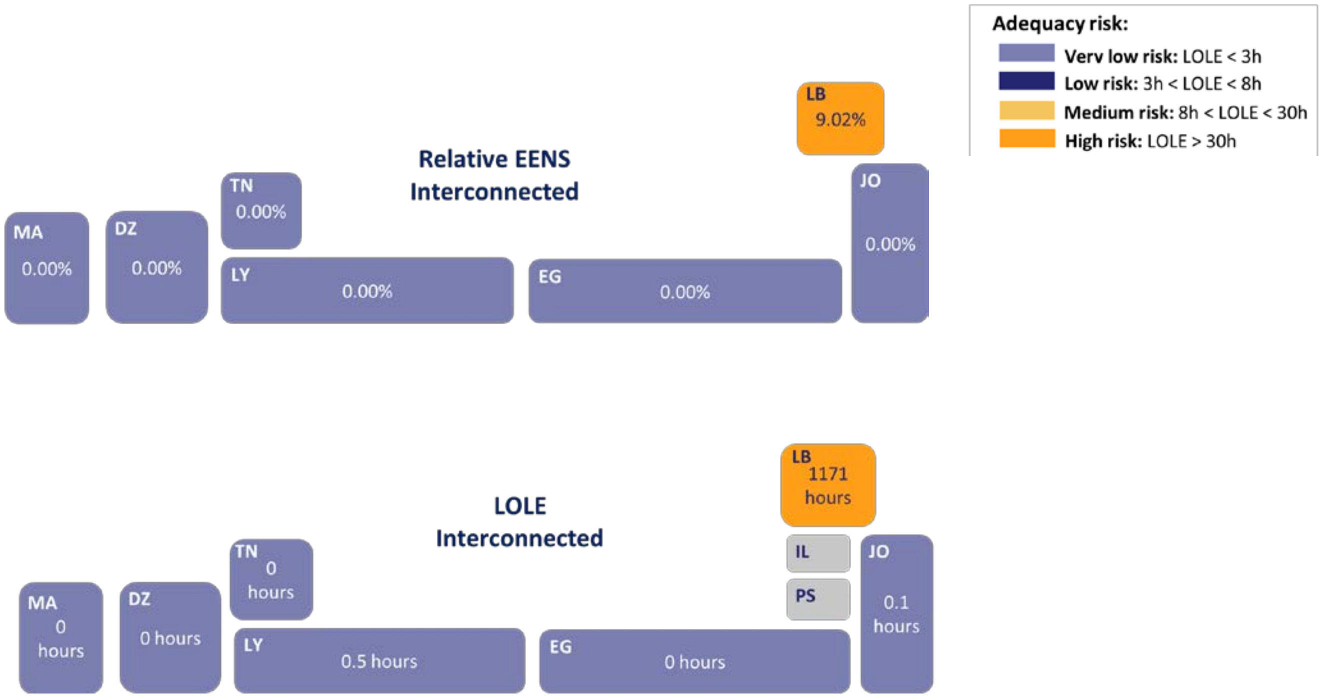

Figure 17 Seasonal relative ENS and LOLE for the interconnected mode of operation for only winter season

Table 9 Seasonal ENS for Interconnected and isolated scenario

Country	Isolated EENS	Interconnected EENS		Isolated LOLE	Interconnected LOLE
DZ	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
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	120 MWh	10 MWh		0.83	0.06
	50th percentile 0 MWh	50th percentile 0 MWh		50th percentile LOLD: 0 hours	50th percentile LOLD: 0 hours
	95th percentile 746 MWh	95th percentile 22 MWh		95th percentile LOLD: 4 hours	95th percentile LOLD: 1 hours
MA	5051 MWh	0 MWh		11.14	0
	50th percentile 0 MWh	50th percentile 0 MWh		50th percentile LOLD: 0 hours	50th percentile LOLD: 0 hours
	95th percentile 29692 MWh	95th percentile 0 MWh		95th percentile LOLD: 66 hours	95th percentile LOLD: 0 hours
TN	1 MWh	0 MWh		0.01	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
LY	637 MWh	144 MWh		1.93	0.54
	50th percentile 0 MWh	50th percentile 0 MWh		50th percentile LOLD: 0 hours	50th percentile LOLD: 0 hours
	95th percentile 5340 MWh	95th percentile 983 MWh		95th percentile LOLD: 15 hours	95th percentile LOLD: 5 hours
LB	1165431 MWh	697384 MWh		1691.9	1170.7
	50th percentile 1139414 MWh	50th percentile 668969 MWh		50th percentile LOLD: 1683 hours	50th percentile LOLD: 1157 hours
	95th percentile 1639986 MWh	95th percentile 1103222 MWh		95th percentile LOLD: 2055 hours	95th percentile LOLD: 1614 hours

Adequacy risk:

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

In Table 9 detailed ENS and LOLD seasonal results are given for all analysed countries.

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

- Jordan

  In the interconnected mode of operation, Jordan demonstrates a very low adequacy risk, with an EENS of just 10 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.
- Morocco

  In isolated operation mode, Morocco faces a moderate risk to adequacy, with ENS potentially reaching 5 GWh and LOLE lasting for 11 hours. However, in more critical P95 scenarios, EENS can escalate to 29 GWh with a LOLD of up to 66 hours. In contrast, when operating in interconnected mode, the risk to adequacy is minimal.
- Libya[8]

  In the interconnected mode of operation, Libya exhibits a very low adequacy risk, with an EENS of just 144 MWh and a LOLE of less than one hour. However, in rare but more critical situations (P95), ENS can reach 983 MWh with a LOLD of 5 hours. While adequacy risks do increase in isolated operation, they still remain within acceptable limits. In more critical yet less probable P95 cases (higher demand and frequent power plant outages), ENS can reach 5 GWh for 15 hours, leading to a medium adequacy risk. It's worth noting that interconnections with Egypt and Tunisia minimize adequacy risks.
- Lebanon

  Lebanon experiences the highest EENS and LOLE during the Winter of 2023/24 in the region, with 697 GWh of ENS and 1170 hours of LOLE (equivalent to 39% 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 14 hours). In the event of more critical but less probable P95 cases, ENS can reach a staggering 1.1 TWh with an unavailability to supply the load for over 53% of the time. In the isolated mode of operation, adequacy is even more at risk, with EENS reaching 1.2 TWh and LOLE extending to 1690 hours (daily LOLD during the whole season can be ranged from 4 hours to 17 hours). This emphasizes that Lebanon's interconnection with Jordan significantly reduces adequacy risks by 40%.

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 is due to the fact that a lot of power plants are back into service due to maintenance & 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 winter. Our primary objective is to evaluate potential cross-border exchanges among the seven analyzed nations and quantify each country's requirements to address adequacy risks during periods of isolation.

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

Table 10 Seasonal exchanges and utilization of the links in the region

Link	Direct Exchanges for Adequacy (GWh)	NTC direct (MW)	Reverse Exchanges for Adequacy (GWh)	Reverse NTC (MW)
DZ00 - MA00	0.06	600	0.00	300
DZ00 - TN00	0.00	700	0.00	700
EG00 - JO00	0.29	450	0.00	450
EG00 - LY00	0.24	180	0.00	0
ES00 - MA00	4.93	900	0.00	600
LY00 - TN00	0.00	100	0.21	250
JO00 - LB00	655.20	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 Libya, they are engaged in importing electricity from both Egypt and Tunisia to support their adequacy situation, even though Libya's adequacy risks in isolation fall within acceptable parameters.

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 Algeria

DEMAND

Algerian seasonal weekly demand, depicted in Figure 18 goes from around 1500 GWh to 1650 GWh, while peak hourly demand in each week varies from 12000 MW to 13700 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 first couple of weeks in 2023 (in January), due to low temperatures and some heating demand. The maximum hourly demand in all 38 climatic years reaches 13716 MW in the 4th week of 2024.

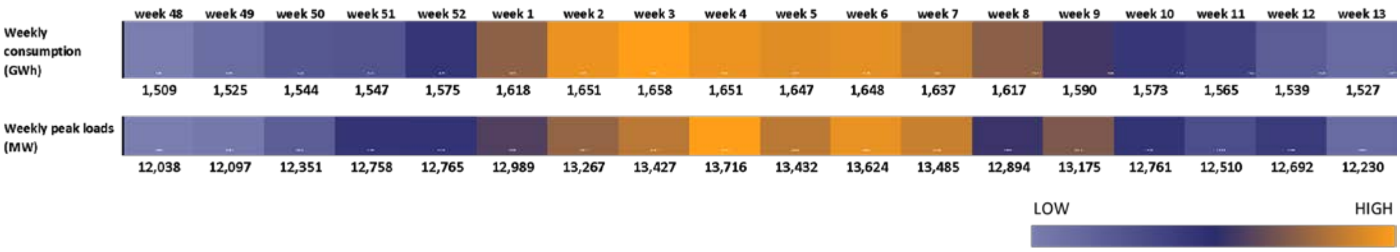

Figure 18 Seasonal Weekly demand in Algeria

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 OCGT TPPs. Hydro and Solar capacities amount to only 1% each. Total installed capacities are 25023 MW with import capacity up to 1000 MW, which combined is substantially higher than the maximum peak demand of 13716 MW.

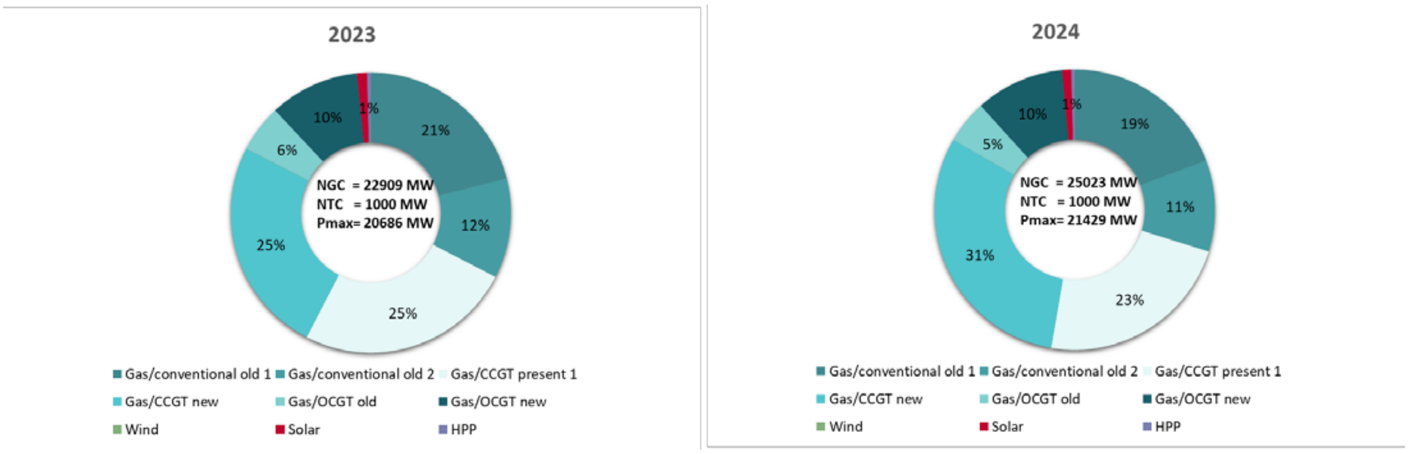

Figure 19 Installed Capacity mix with total NGC, import NTC and peak demand in Algeria.

The average daily available TPP capacity, after reduction due to forced and planned 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.

Algerian average available TPP capacities level is almost constant during the winter 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.

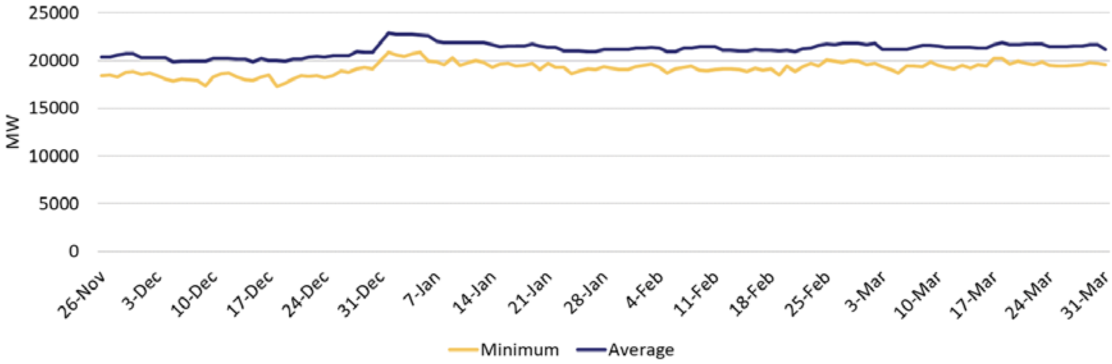

Figure 20 Average and minimum TPP available capacity in Algeria

As a result of system simulation, the minimum hourly TPP capacity margin is calculated and depicted in Figure 21. It represents the difference between available and activated TPP capacities. The hourly minimum TPP margin is between 6 GW and 8 GW during the analysed winter season. The high Algerian TPP capacity margin indicates that Algeria doesn't have adequacy issues and has significant export capabilities that can provide support to neighbouring power systems. Also, the daily capacity margin follows both seasonal and daily consumption patterns, and it is the lowest during the first couple of weeks in 2024 when demand is the highest.

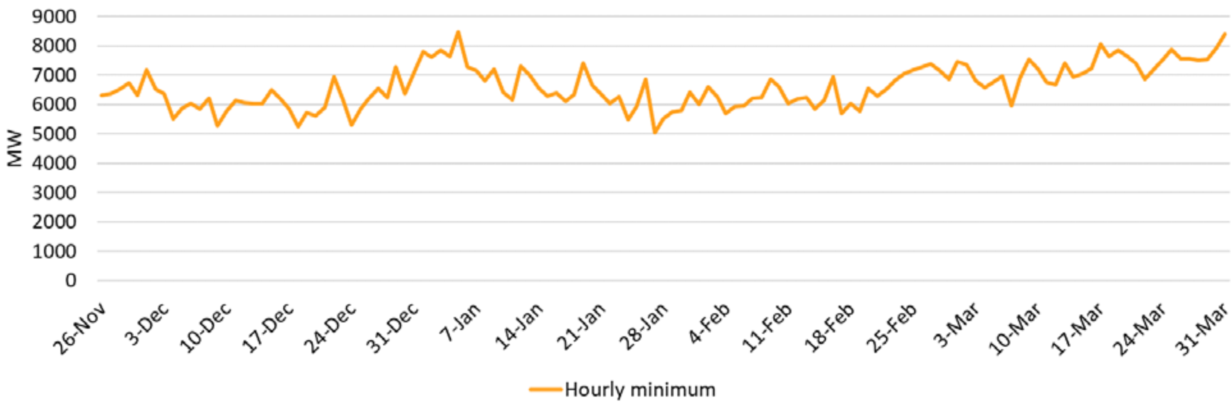

Figure 21 Minimum hourly TPP margin on each day of the analysed period in Algeria

ADEQUACY ASSESSMENT

Considering that Algeria does not have any adequacy risk in the next winter season, further investigations are not relevant.

5.2 Egypt

DEMAND

Egyptian seasonal weekly demand, depicted in Figure 22 goes from around 3780 GWh to 3970 GWh, while peak hourly demand in each week varies from 28.7 GW to 30.7 GW. It should be noted that weekly demand refers to the average values of all 38 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analysed climatic years.

As can be seen from the figure below, consumption is rather constant during the first 3 months of 2024 and higher than consumption at the end of 2023. This increase is a consequence of the expected annual increase in total consumption between these two years. Peak load is more fluctuating with maximum value at the beginning of the year 2024.

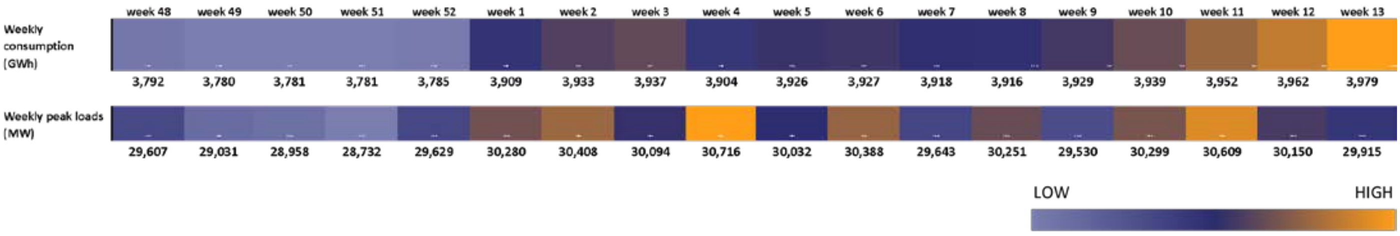

Figure 22 Seasonal Weekly demand in Egypt

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 89%, which is divided further into conventional and CCGT TPPs. Oil TPPs share is 2%, while Hydro share is 4.8%. RES – wind and solar capacities amount only to 3% each. Total installed capacities are 58 915 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 analysed power systems.

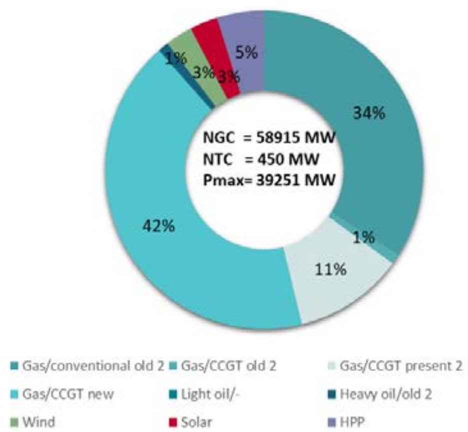

Figure 23 Installed Capacity mix with total NGC, import NTC and peak demand in Egypt

The average daily available TPP capacity, after reduction due to forced outages, is shown in Figure 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. Egyptian average available TPP capacity fluctuates in this period due to planned and forced outages, there is also a reduced capacity of TPPs during February (derating factor of 10%). The minimal average daily available TPP capacity (minimum among all simulated MC years) fluctuates around 36 GW.

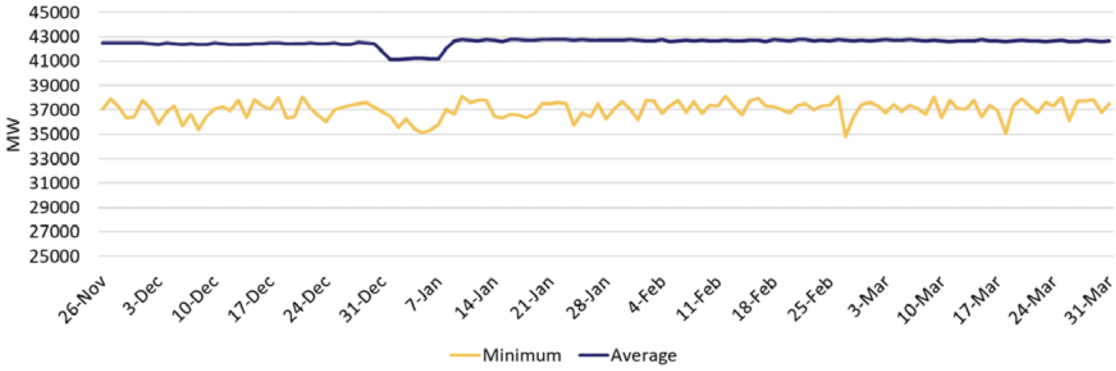

Figure 24 Average and minimum TPP available capacity in Egypt

As a result of system simulation, the minimum hourly TPP capacity margin is calculated and depicted in Figure 25 It represents the difference between available and activated TPP capacities. The hourly minimum TPP margin is between 7 GW and 12GW during the analysed winter season.

A very high TPP capacity margin indicates that Egypt will not have adequacy issues during the following season and that it has huge export capabilities that can bring benefit to neighbouring countries' adequacy situation. Also, the daily capacity margin follows both seasonal and daily consumption patterns, and it is the lowest during working days, due to higher demand.

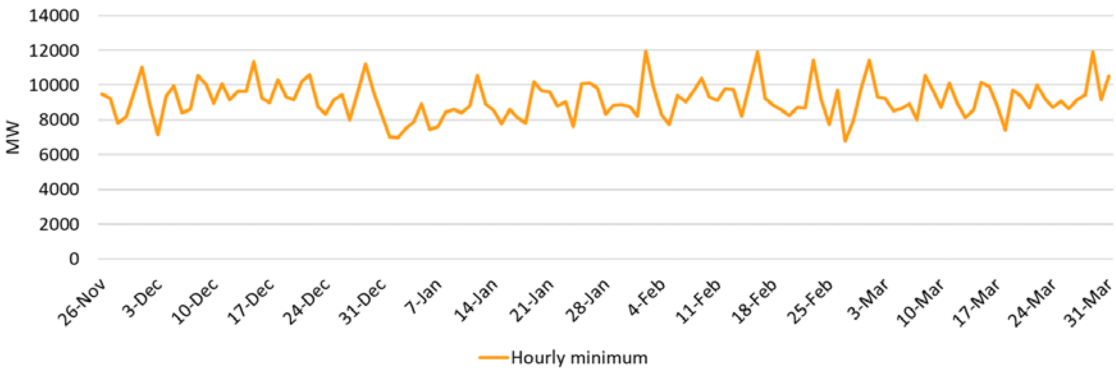

Figure 25 Minimum hourly TPP margin on each day of the analysed period in Egypt

ADEQUACY ASSESSMENT

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

5.3 Jordan

DEMAND

Jordan's seasonal weekly demand, depicted in Figure 26, goes from around 424 GWh to 469 GWh (fluctuation at the level of 10%), while peak hourly demand in each week goes from 3700 MW to 4600 MW which presents even higher fluctuation – 20%. 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 the second weeks of 2024, due to low temperatures and heating demand. The maximum hourly demand of 4600 MW is reached in the 2nd week of February 2024.

	week 48	week 49	week 50	week 51	week 52	week 1	week 2	week 3	week 4	week 5	week 6	week 7	week 8	week 9	week 10	week 11	week 12	week 13
Weekly consumption (GWh)	424	434	442	448	449	459	468	469	467	464	460	455	452	446	439	435	431	428
Weekly peak loads (MW)	3.706	3.891	4.174	4.453	4.174	4.424	4.392	4.258	4.286	4.354	4.601	4.105	4.478	4.284	3.900	3.895	3.897	3.861

LOW HIGH

Figure 26 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 28% respectively. Total installed capacities amount to 7244 MW with an import capacity up to 450 MW from Egypt.

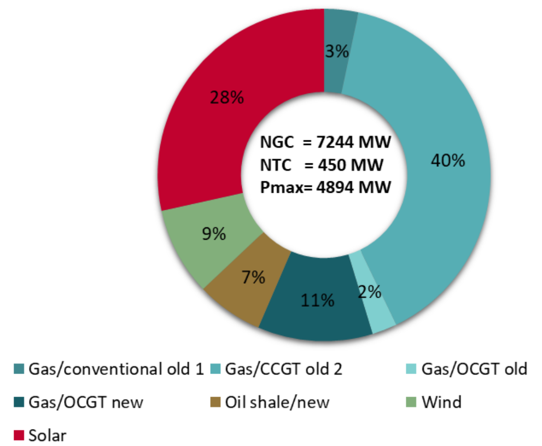

Figure 27 Installed Capacity mix with total NGC, import NTC and peak demand in Jordan

The average daily available TPP capacity, after reduction due to derating factors, and forced and planned outages is shown in Figure 28. 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 4400 MW and drop to 4100 MW mid of March of 2024. The minimal average daily available TPP capacity (minimum among all simulated MC years) goes from 3700 MW to only 3000 MW.

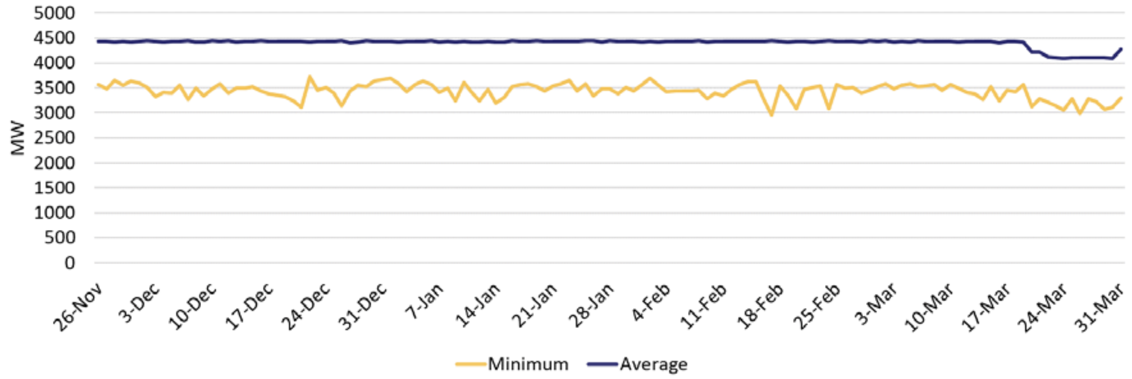

Figure 28 Average and minimum TPP available capacity in Jordan

As a result of system simulation, the minimum hourly TPP capacity margin is calculated and depicted Figure 29 It represents the difference between available and activated TPP capacities. The minimum hourly value of the TPP margin each day is at zero value during the last days of 2023 and the beginning of 2024. From March, this margin is a little bit higher due to a decrease in demand. Still, the TPP margin is at a low level, below 300 MW. 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.

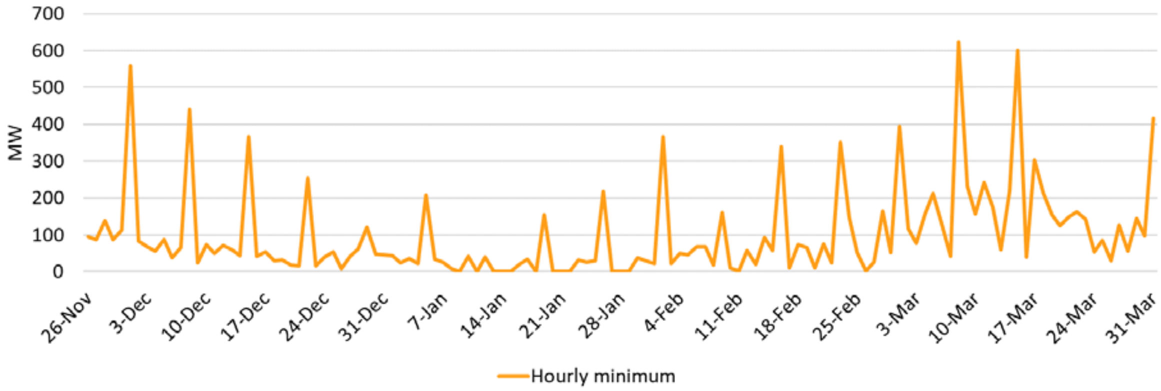

Figure 29 Minimum hourly TPP margin on each day of the analysed period in Jordan

Adequacy assessment

The temporal distribution of detected adequacy risk is given in Figure 30, 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 end of 2023 and the first month of 2024 because of high demand.

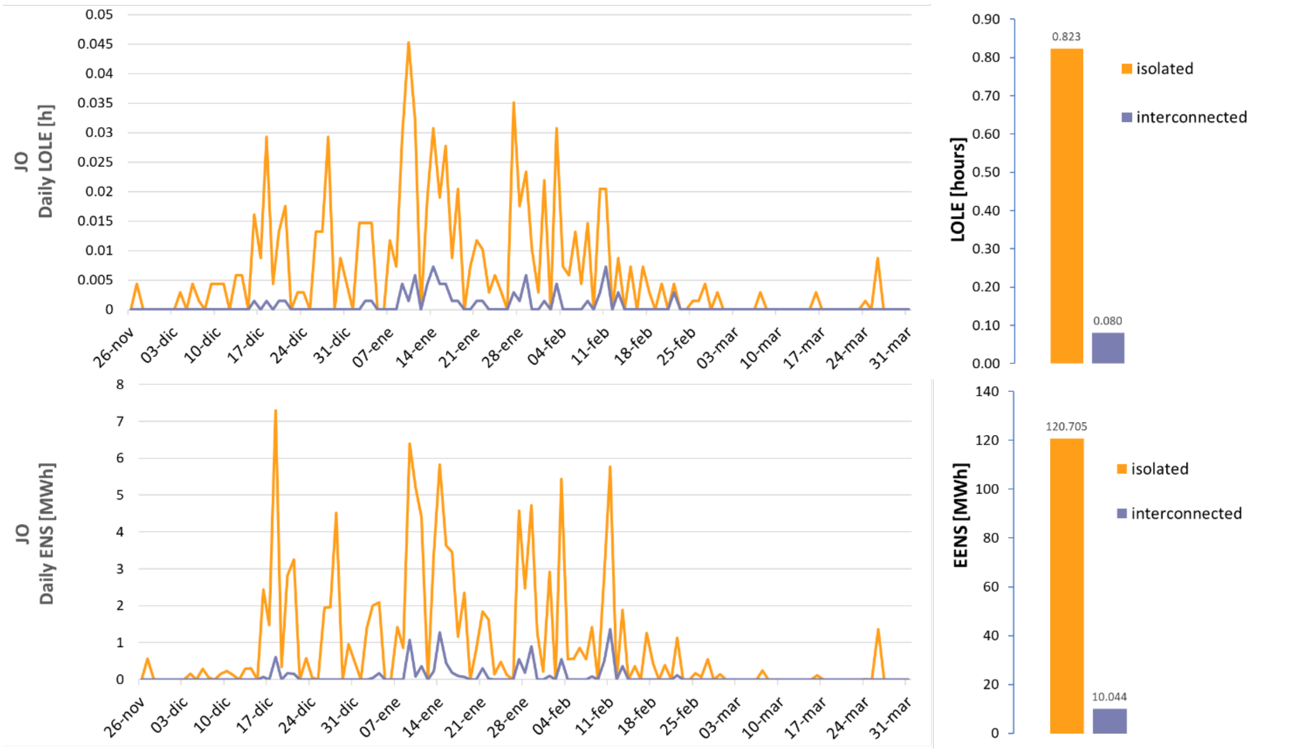

Figure 30 Daily LOLE and EENS for the interconnected and isolated mode of operation in Jordan

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 0.8 h to less than 0.08 h and expected seasonal EENS from 120 MWh to just 10 MWh.

5.4 Lebanon

DEMAND

Lebanon's seasonal weekly demand, depicted in Figure 31, goes from around 400 GWh to 456 GWh, while peak hourly demand each week goes from 3569 MW to 4870 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 first weeks of 2024, due to low temperatures and increased heating demand. The maximum hourly demand of 4870 MW is reached in the 6th week of 2024.

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.

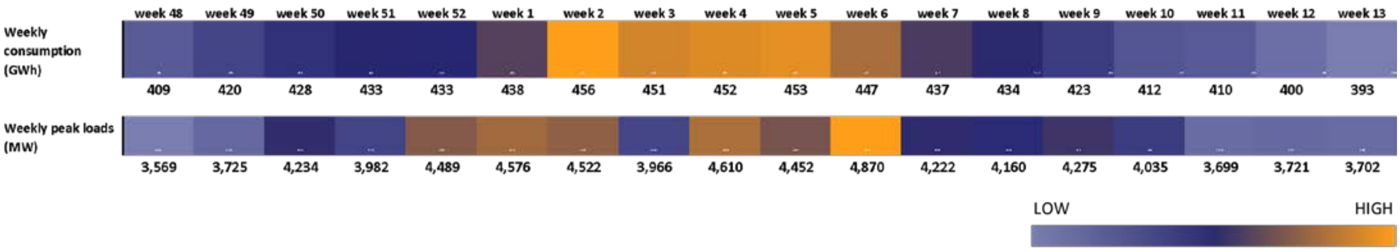

Figure 31 Seasonal Weekly demand in Lebanon

SUPPLY AND NETWORK OVERVIEW

Lebanon's power generation fleet is exclusively oil-fuelled, with the share in total installed capacities around 62% 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.

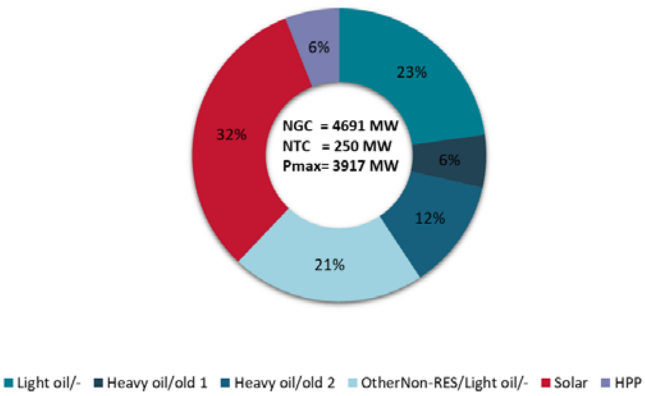

Figure 32 Installed Capacity mix with total NGC, import NTC and peak demand in Lebanon

The average daily available TPP capacity, after reduction due to forced and planned outages, is shown Figure 33. 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.

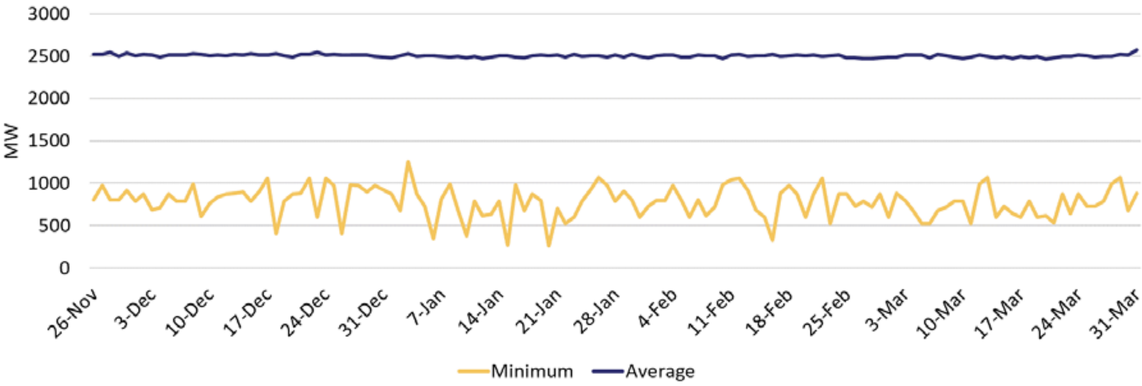

Figure 33 Average and minimum TPP available capacity in Lebanon

As a result of system simulation, the minimum hourly TPP capacity margin is calculated and depicted in Figure 34 It represents the difference between available and engaged TPP capacities. No margin exists in Lebanon's power system.

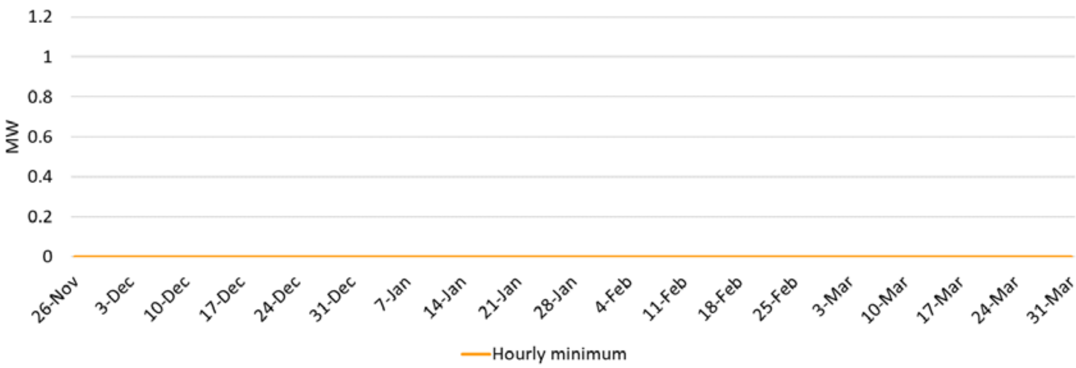

Figure 34 Minimum hourly TPP margin on each day of the analysed period in Lebanon

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in Figure 35 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 non comparable 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 ENS are above all acceptable values even in the interconnected mode of operation: EENS is 697 GWh and LOLE is 1170 hours (around 39 % during the winter season of 3024 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=14 hours in average of 684 MC years.

Maximum hourly shortage in supply during the winter season in the interconnected mode of operation and within all 684 MC years is enormous – 5500 MW (This happens in only one MC year in the hour with high demand and big units in either planned or forced outage).

The peak of adequacy issues is expected between the middle of December 2023 and the end of January 2024.

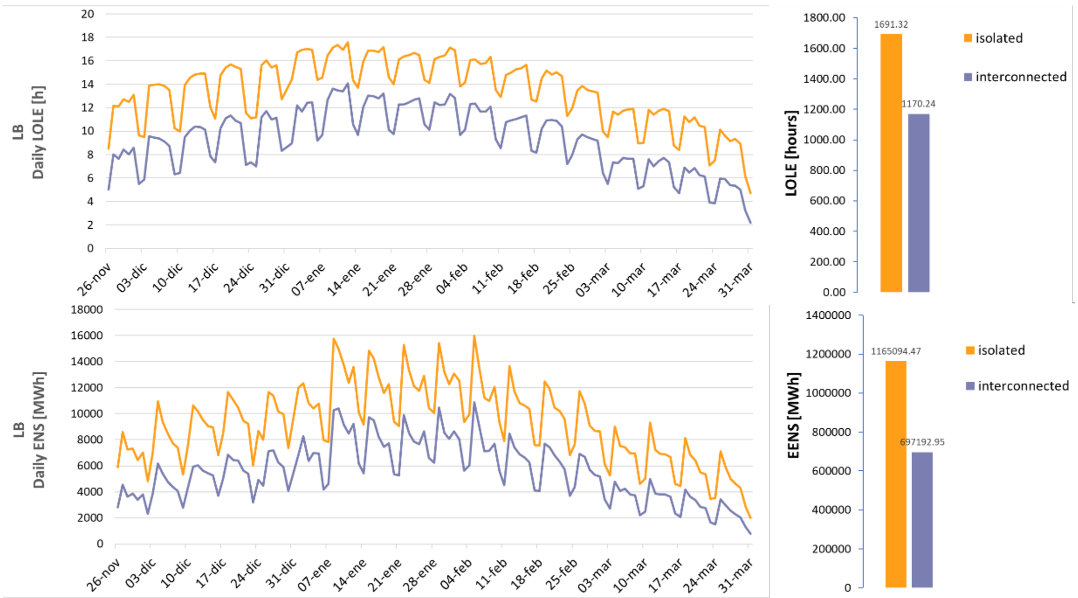

Figure 35 Daily LOLE and EENS for the interconnected and isolated mode of operation In Lebanon

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

5.5 Libya

DEMAND

Libya’s seasonal weekly demand, depicted in Figure 36, goes from around 760 GWh to 1000 GWh, while peak hourly demand each week goes from 6695 MW to 10126 MW. This variation of the peak load is almost 33% which is very high. It should be noted that weekly demand refers to the average values of all 38 analysed climatic years, while peak hourly demand values refer to the weekly maximum for all 38 analysed climatic years.

Maximum electricity needs are expected in January and February, (1st – 6th week). The maximum hourly demand in all 38 MC years reaches 10126 MW in the 2nd week of 2024.

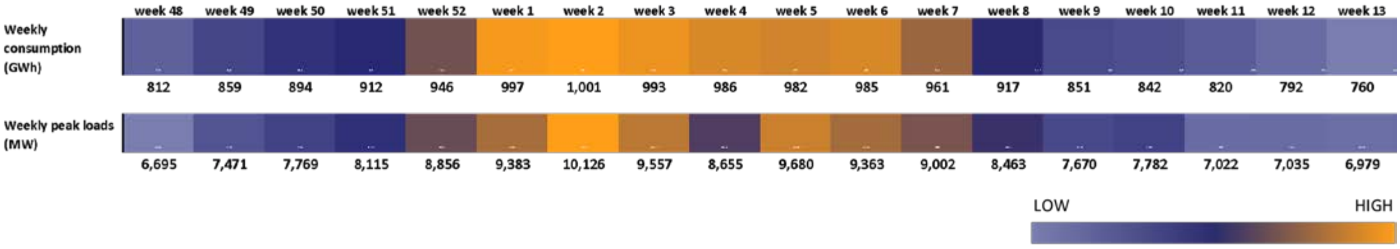

Figure 36 Seasonal Weekly demand in Libya

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 (51%) and combined cycle gas turbines (28%), while only 21% of capacities mix corresponds to conventional gas-fired power plants. It should be emphasized that according to provided data for winter outlook 2023/2024 there are no RES capacities installed in Libya.

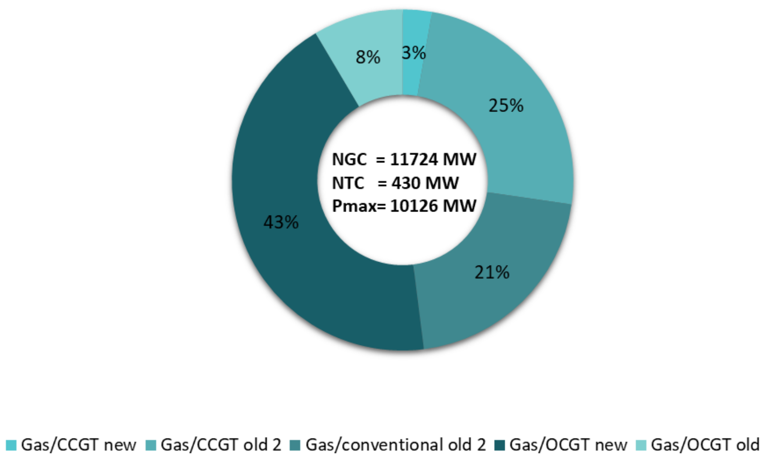

Figure 37 Installed Capacity mix with total NGC, import NTC and peak demand in Libya

The average daily available TPP capacity, after reduction due to planned and forced outages, is shown Figure 38 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 stable but grows moving from 2023 to 2024, since 1188 MW of gas fired power plants will be commissioned on 01/01/2023, according to provided input data. Therefore, for the winter months (November-December) in 2023, the average available thermal capacity is stable at the level of 9300 MW.

The minimal daily available TPP capacity between all analysed MC years is between 6700 MW to 7960 MW.

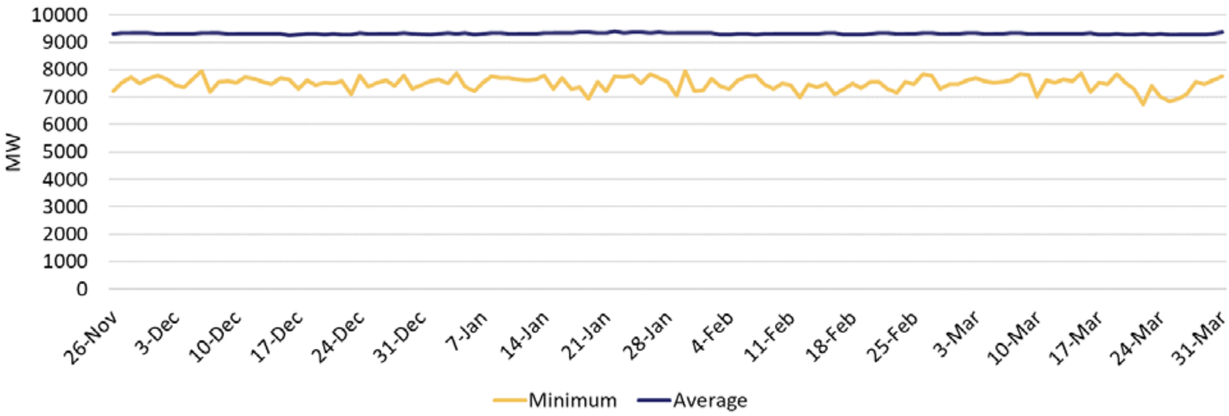

Figure 38 Average and minimum TPP available capacity in Libya

As a result of system simulation, the minimum hourly TPP margin for each day is calculated and depicted Figure 39 It represents the difference between available and activated TPP capacities. The minimum hourly value of the TPP margin on each day is at zero till the end of February. From March, this margin is a little bit higher due to a decrease in demand. However.

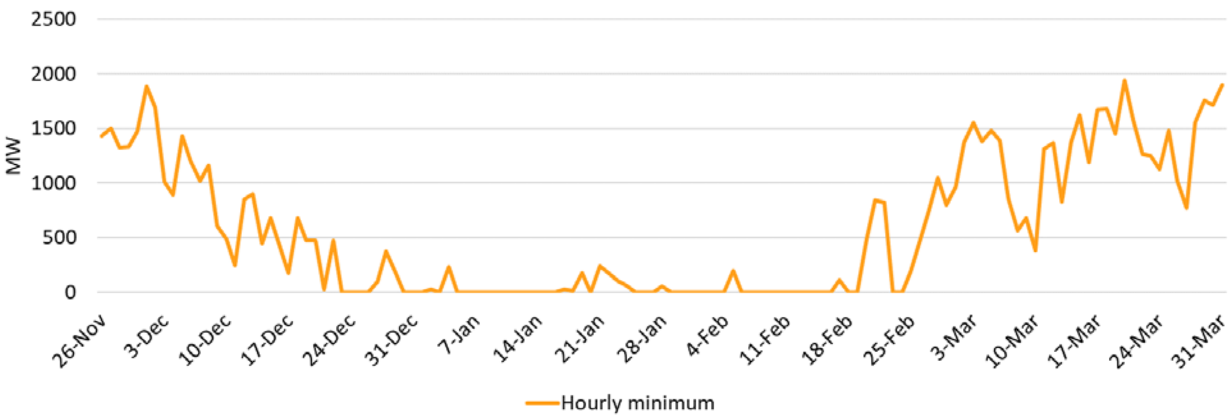

Figure 39 Minimum hourly TPP margin on each day of the analysed period in Libya

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in Figure 40, 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.

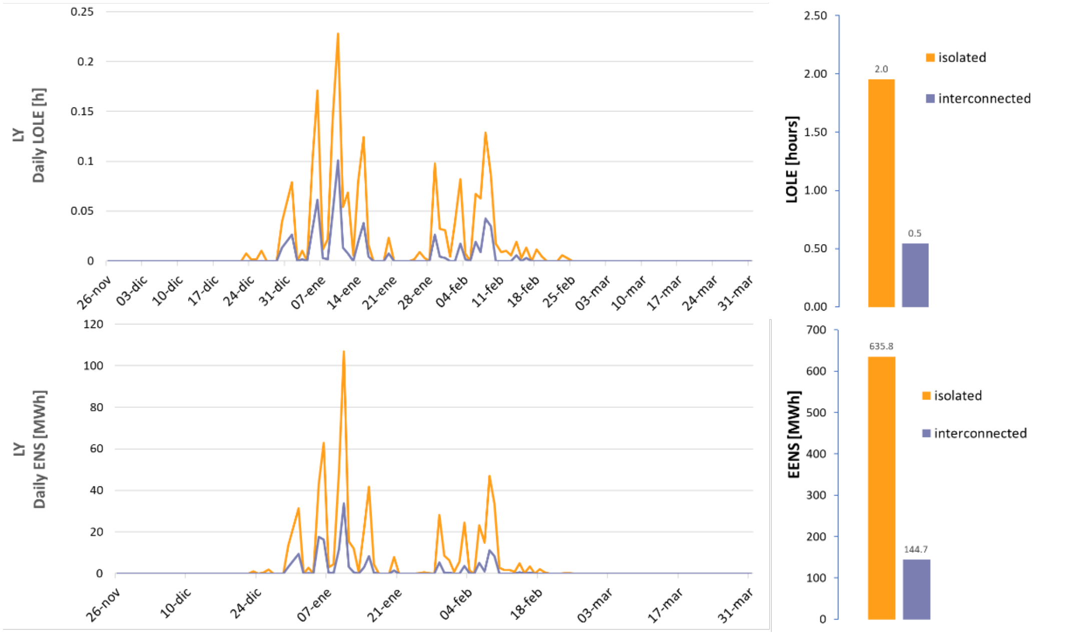

Figure 40 Daily LOLE and EENS for the interconnected and isolated mode of operation in Libya

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 above 2 hours, while for the interconnected regime of operation seasonal LOLE is significantly lower (around 0.5 hours). Energy not supplied in the interconnected case is around 4 times lower compared to the isolated case, which emphasizes the importance of interconnections.

5.6 Morocco

DEMAND

Moroccan seasonal weekly demand, depicted in Figure 41 goes from around 779 GWh to 819 GWh, while peak hourly demand each week goes from 6278 MW to 6756 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 January, as well as in the two last weeks of March (12^{th} - 13^{th} week). However, total consumption from January to March is pretty much constant. The maximum hourly demand in all 38 MC years reaches 6472 MW in the 4^{th} week of 2023.

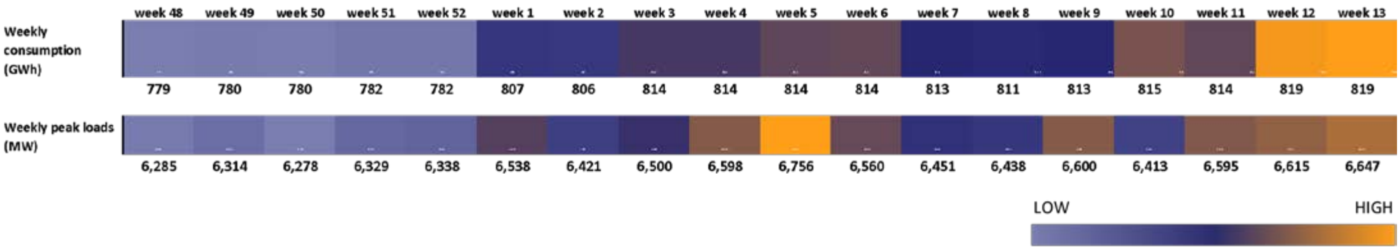

Figure 41 Seasonal Weekly demand in Morocco

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 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 18% and 8% respectively. Total installed capacities are 11479 MW with total import capacity up to 1500 MW, which is about 21.5% of peak load in the analysed period.

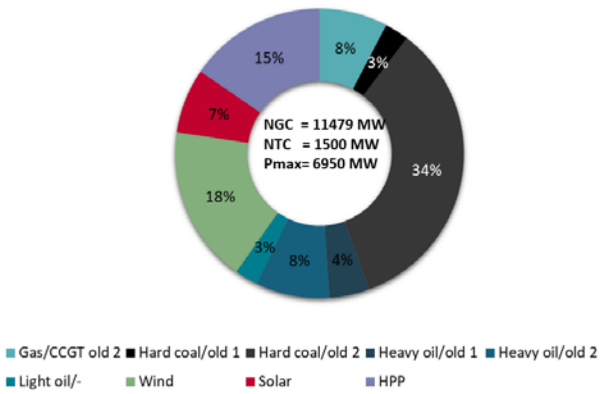

Figure 42 Seasonal Weekly demand in Morocco

The average daily available TPP capacity, after reduction due to forced and planned outages, is shown Figure 43 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 5375 MW during the entire season. The minimal average daily available TPP capacity (minimum among all simulated MC years) goes from 2400 MW to 3800 MW.

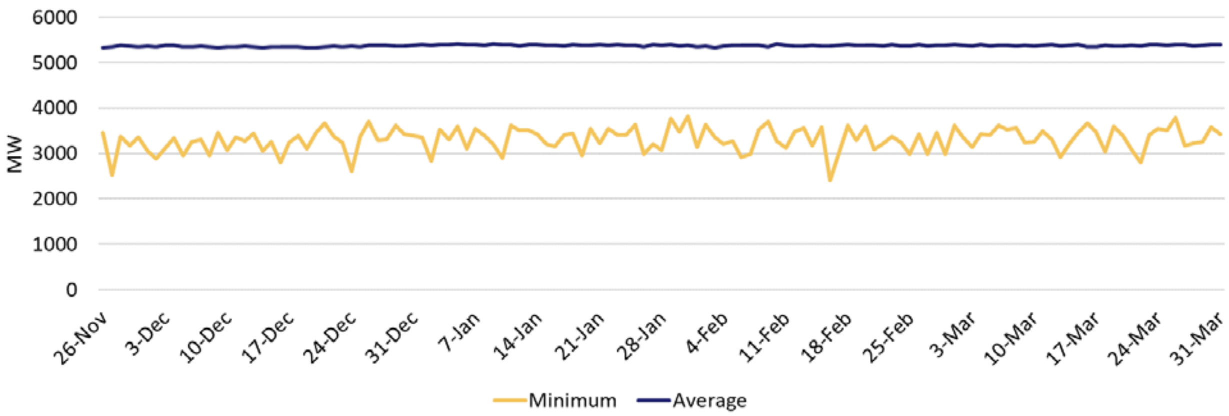

Figure 43 Average and minimum TPP available capacity in Morocco

As a result of system simulation, the minimum hourly TPP capacity margin on each day is calculated and depicted in Figure 44 It represents the difference between available and engaged TPP capacities. Obviously, no margin in TPPs exists in Morocco's power system, but adequacy is not endangered since there are other sources and interconnections to support adequacy.

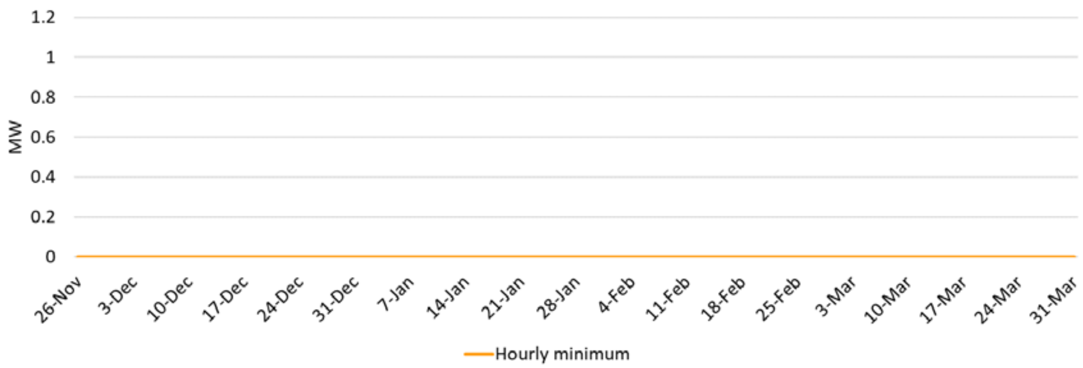

Figure 44 Minimum hourly TPP margin on each day of the analysed period in Morocco

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in Figure 45 for the interconnected and isolated mode of operation. In the first picture, daily LOLE distribution is given, while in the second one daily EENS is depicted. It can be seen that there is no adequacy risk in the winter period of 2023/2024 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 whole season (there are only a few days without any adequacy issues in March).

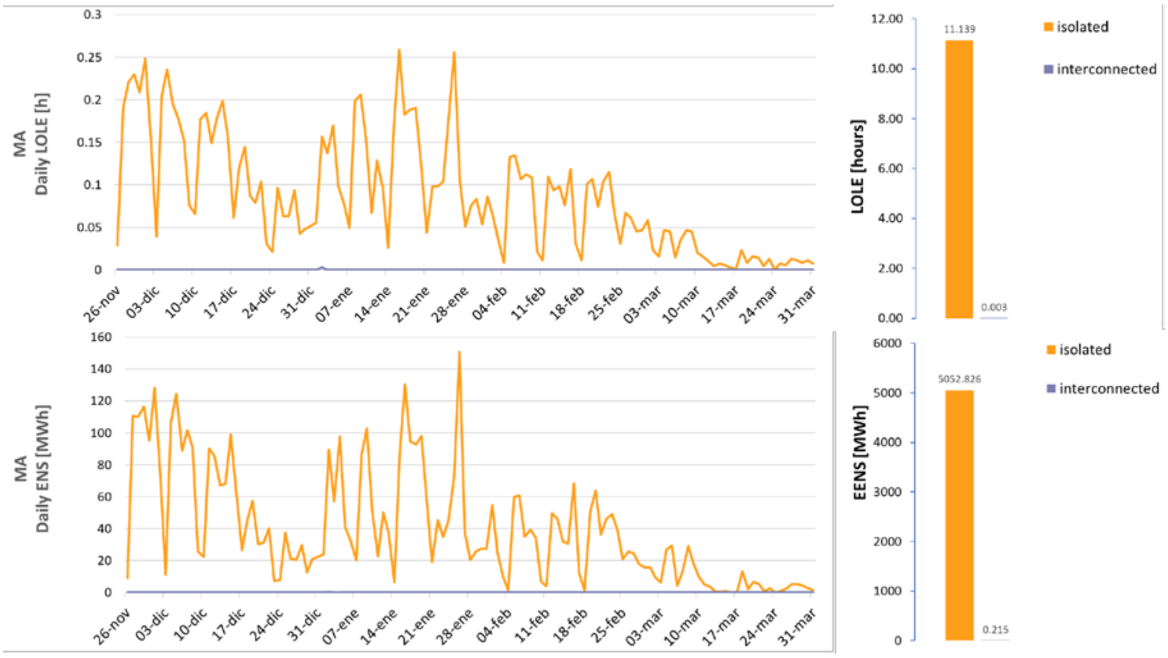

Figure 45 Daily LOLE and EENS for the interconnected and isolated mode of operation in Morocco

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 11 hours, while EENS is around 5 GWh.

5.7 Tunisia

DEMAND

Tunisian seasonal weekly demand, depicted in Figure 46 ranges between 357 GWh and 393 GWh, while peak hourly demand each week goes from 2888 MW to 3507 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 the end of December to the end of February. The maximum hourly demand is reached in the 5th week - 3507 MW, which is the maximum in all 38 climatic years.

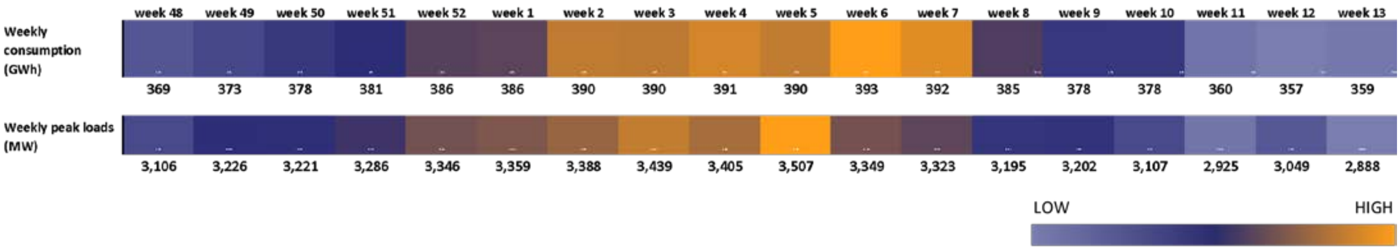

Figure 46 Seasonal Weekly demand in Tunisia

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 6070 MW with import capacity up to 800 MW, while maximum hourly consumption is around 3507 MW.

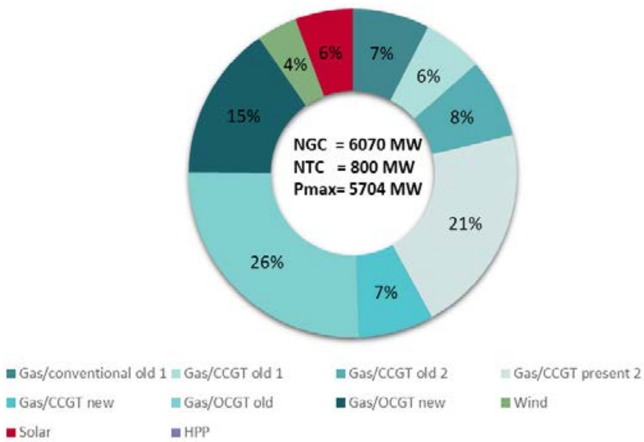

Figure 47 Installed Capacity mix with total NGC, import NTC and peak demand in Tunisia

The average daily available TPP capacity, after reduction due to forced and planned outages is shown in Figure 48 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 4350 MW and 5125 MW, which is higher than the expected peak load of 3507 MW during the winter 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 2842 MW.

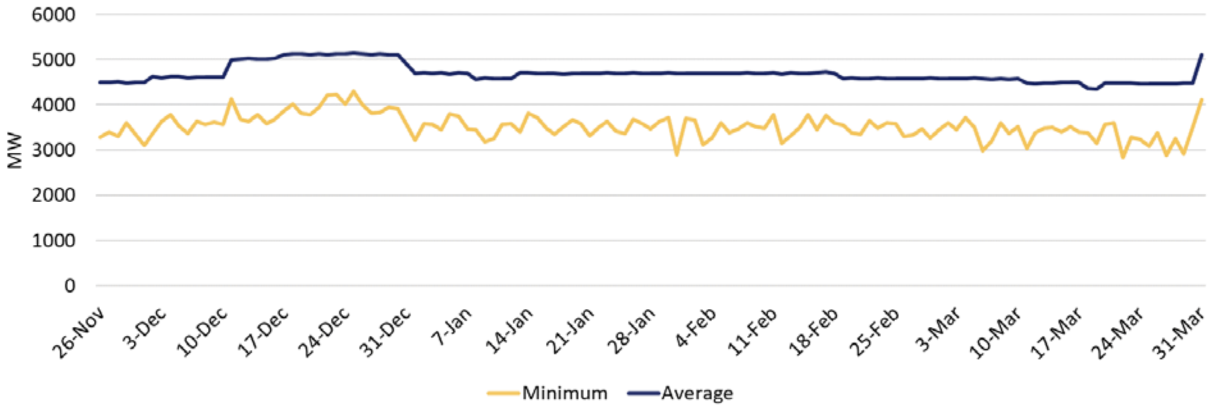

Figure 48 Average and minimum TPP available capacity in Tunisia

As a result of system simulation, the minimum hourly TPP capacity margin on each day is calculated and depicted in Figure 49 It represents the difference between available and activated TPP capacities. It can be seen that the minimum hourly margin is always higher than zero (except for some days at December & January).

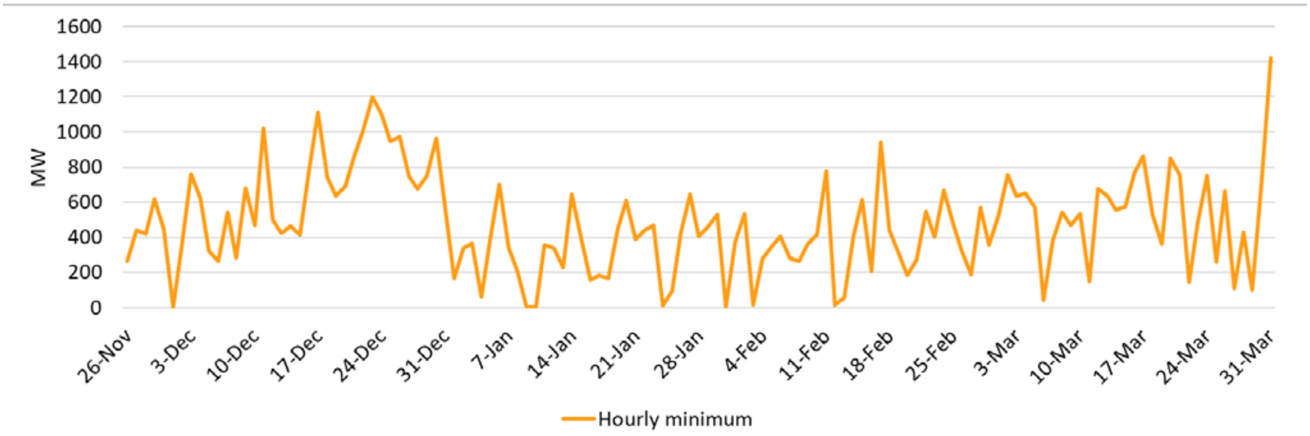

Figure 49 Minimum hourly TPP margin on each day of the analysed period in Tunisia

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in Figure 52 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 there is no adequacy risk in Tunisia for the interconnected regime of operation, while in isolated case adequacy risk is very low during the whole season, with daily LOLE lower than 0.005 hour. In fact, only in a few days, there is a lack of energy, always below 1.5 MWh.

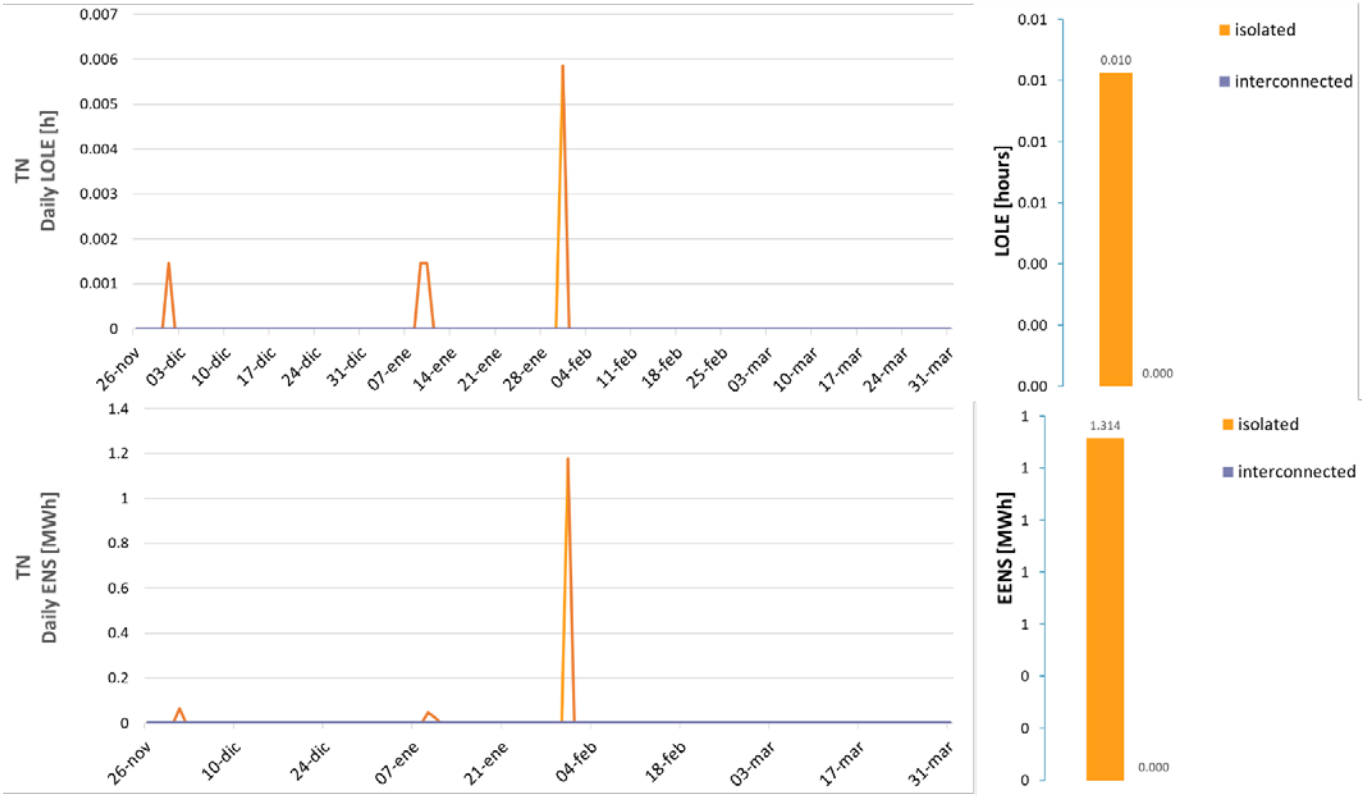

Figure 50 Daily LOLE and EENS for the interconnected and isolated mode of operation

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