TOWARDS AN EFFICIENT, ADEQUATE, SUSTAINABLE AND INTERCONNECTED MEDITERRANEAN POWER SYSTEM

SEASONAL ADEQUACY ASSESSMENT

Summer Outlook 2022

Detailed Report

Released on 03.06.2022

MEDITERRANEAN TRANSMISSION SYSTEM OPERATORS

Co-funded by the European Union

Table of content

Abbreviations

CCGT	–	Combine Cycle Gas Turbine
EKC	–	Electricity Coordinating Center
EU	–	European Union
FCR	-	Frequency Containment Reserve
FRR	-	Frequency Restoration Reserve
NTC	–	Net Transfer Capacity
OCGT	–	Open Cycle Gas Turbine
O&M	–	Operation and Maintenance
PEMDB	–	Pan-European Market 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
TPP	–	Thermal Power Plant
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

PS	-	Palestine
LB	-	Lebanon
ES	-	Spain

1 Executive Summary

This Report presents the adequacy situation among non-EU Med-TSO members during this (2022) summer. 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 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.

This Summer Outlook 2022 Report provides information about potential adequacy issues during summer 2022 in the 5 MED-TSO members: Morocco, Algeria, Tunisia, Egypt and Jordan.

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.

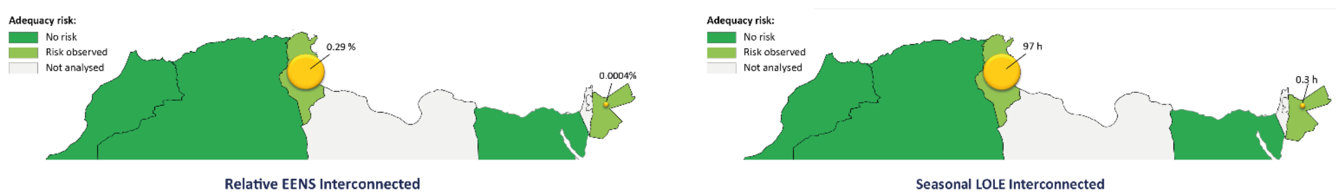

Figure 1: Seasonal relative ENS and LOLE for interconnected mode of operation

The conclusion is that during this summer some potential adequacy issues might occurred in Tunisia. The period when there is the highest probability that generation (+import) will not be sufficient to cover Tunisian electricity demand

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

are expected between the middle of July and the middle of August, as a result of multiple factors: highest electricity demand and lowest thermal power plant availability due to possible unplanned outages but also derating (i.e. reduction in available thermal capacities due to reduced possibilities for efficient cooling during the summer season). After 1st September adequacy risk again goes practically to zero.

STEG statement with regards to adequacy concern identified in present report

STEG welcome Med-TSO work to perform coordinated adequacy assessment. STEG representatives in Med-TSO Technical Committee actively contributed to the development of methodology, data collection, review of results and drafting of the report.

STEG was already expecting possible adequacy constraints for the summer period due to high demand and the decrease of generation capacity, both elements correlated with high temperature typical of summer period. Nevertheless, STEG acknowledge the added value of a systematic assessment to check the role of interconnection and the possibility to import in time of scarcity.

To ensure the balance between supply and demand in Tunisia during this summer, STEG took the following actions:

- Coordinate with SONELGAZ (Algeria) to secure the possibility to import up to 450MW;
- Develop measure to encourage large customers to limit their consumption during peak hours;
- Prepare communication campaigns to reach low and medium voltage consumers inviting them to reduce their consumption during peak periods;
- Review and prepare a manual rotating load shedding plan to keep the system safe as the last resort.

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2 Approach and methodology

2.1 Adequacy assessment methodology

This Report presents the adequacy situation among non-EU Med-TSO members during this (2022) summer. With this assessment, Med-TSO is aligning with the world-wide best practice and the latest development of the EU regulations[2]

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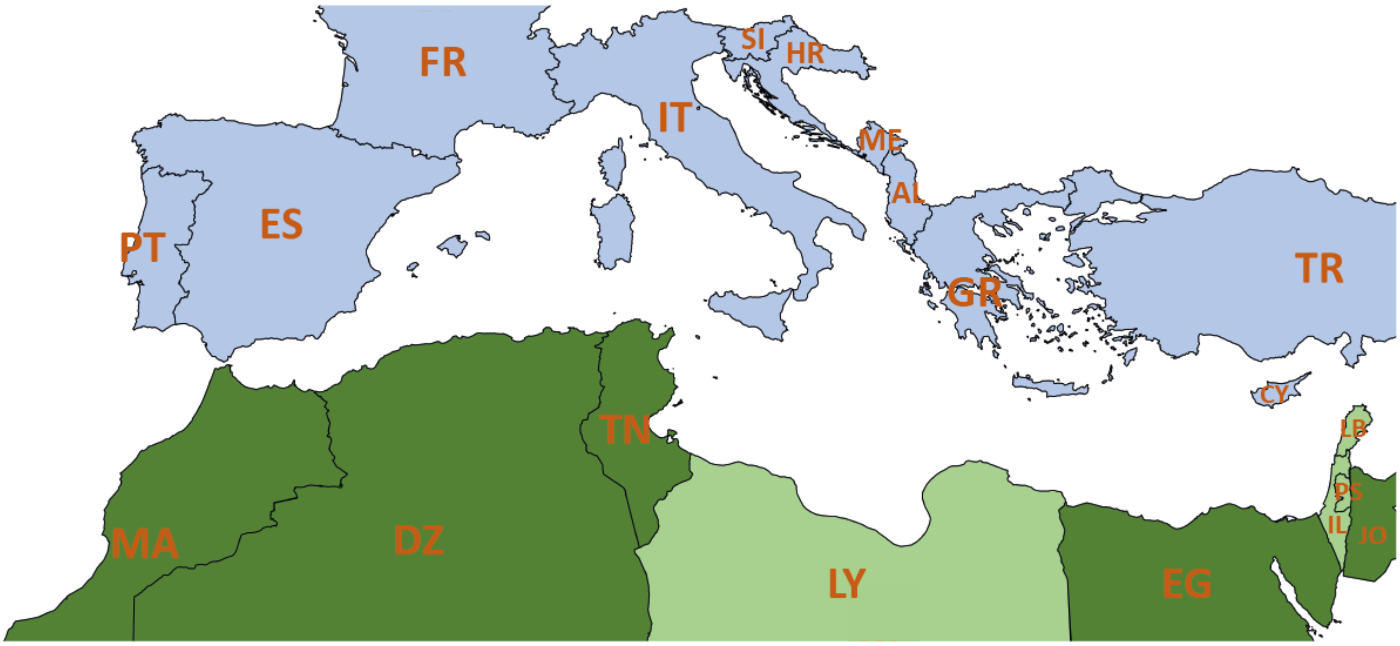
These investigations consider the security of electricity supply to consumers through a detailed power system adequacy assessment, using probabilistic criteria. This approach is inevitable due to the stochastic nature of renewable energy systems (RES), their intermittency, and the power system operation 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 countries around the Mediterranean Sea - from the energy markets development, integration of renewable energy sources and efforts to decarbonise energy systems - adequacy monitoring becomes more and more important.

This Summer Outlook 2022 Report provides information about potential adequacy issues during summer 2022 in the 5 MED-TSO members: Morocco, Algeria, Tunisia, Egypt and Jordan.

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



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

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

Data for Israel, Lebanon, Libya and Palestine were not available at the moment this study has been performed.

The analysed period includes all hours between the beginning of week 22 and the end of week 39 which is the period between Saturday, May 28th and Friday, September 30th

The analyses have been carried out with the ANTARES simulator, having in mind 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 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 inter-zonal and inter-temporal 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 time-frame. For all those MC years, hourly calculations are performed for the whole geographical scope.

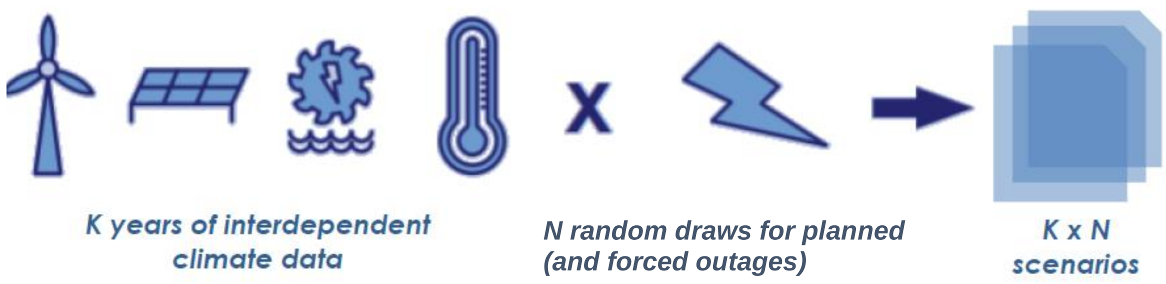


Figure 3: Probabilistic modelling general approach (source: ENTSO-E)

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 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 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.

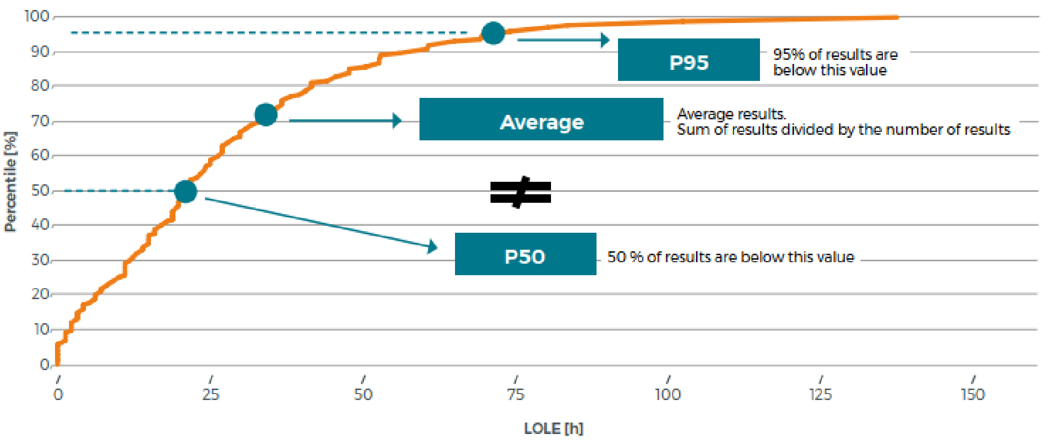


Figure 4: Illustrative Example of the relation between average, P50 and P95 values

- **P95/P50 Energy Not Serve (P95/P50 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 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.
- **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 of capacity in the system.

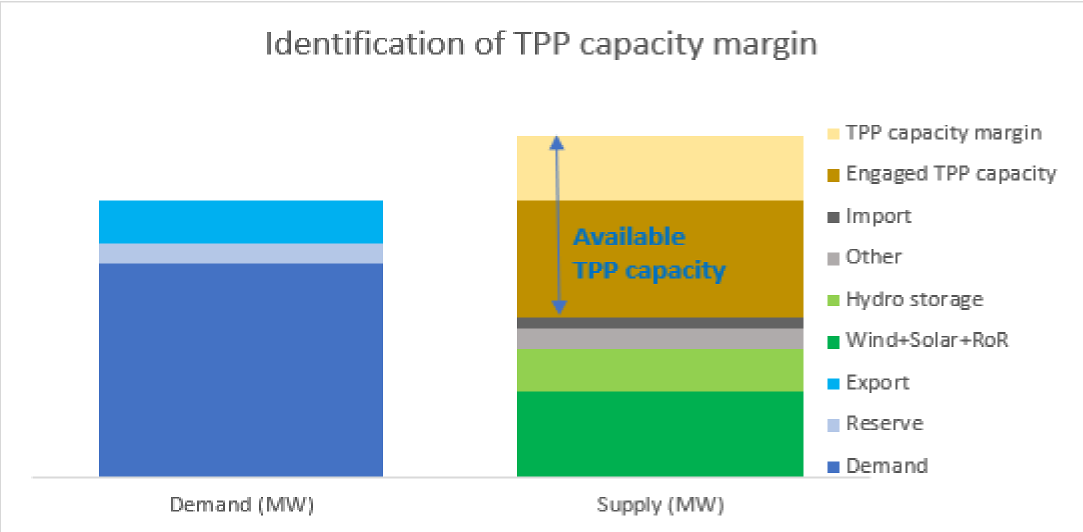


Figure 5: Illustrative Example of TPP capacity margin identification

Besides the above-mentioned main indicators, seasonal adequacy assessment analyses included 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.

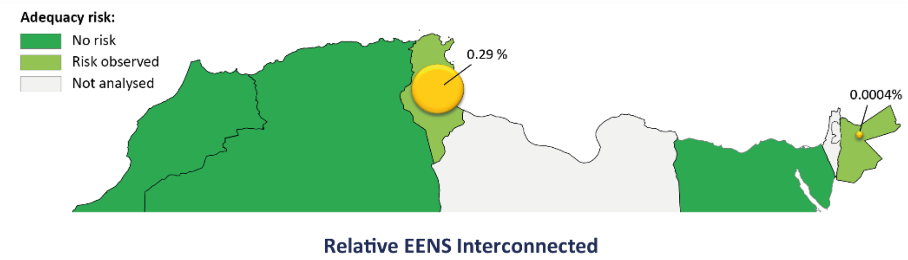


Figure 6: Illustrative Example of Spatial Screening result chart – Relative ENNS chart

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 detecting which weeks are mostly at risk.

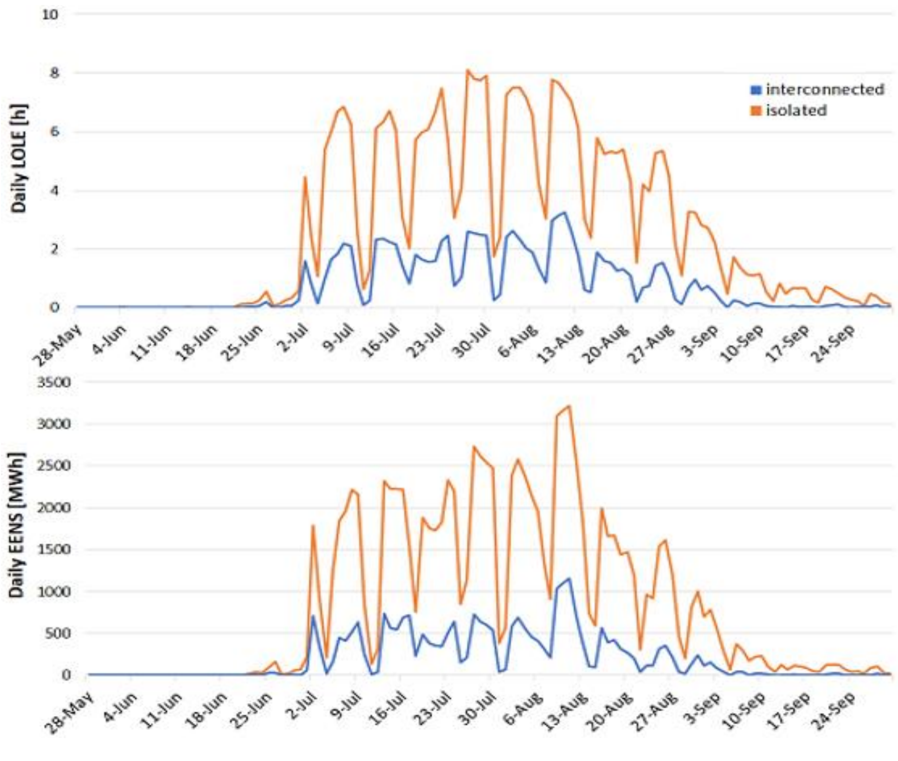


Figure 7: Illustrative example of average daily LOLE and EENS

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

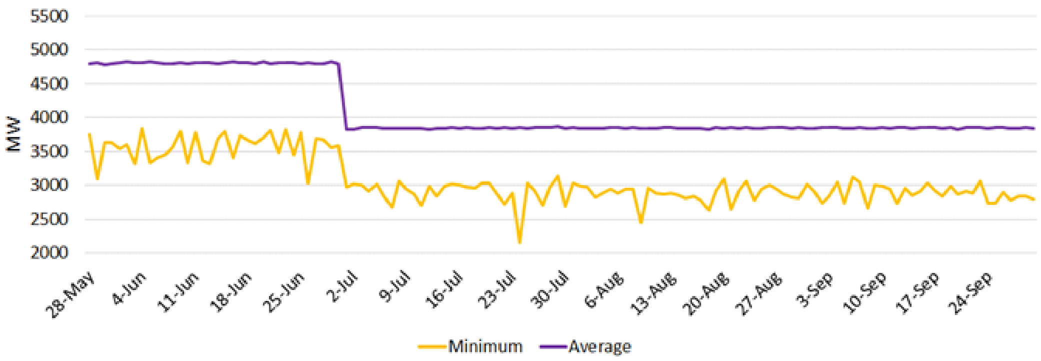


Figure 8: Illustrative example of available TPP capacity

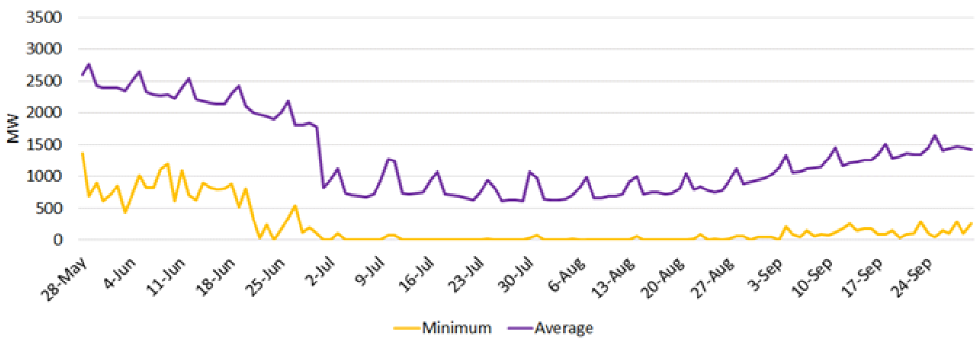


Figure 9: Illustrative example of capacity margin in TPPs

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. 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.

Relevant data have been collected via forms specialized for 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 2022 data have been collected in February/March 2022.

This database will be updated in September 2022 with the latest information that will be used for the preparation of the next report - Winter Outlook 2022/2023.

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 prepared by representatives in Med-TSO Technical Committee. 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 self-consumption of generating units.

   Data about market-based demand-side responses were not provided and, thus, are not modelled.
   Additional demand during the charging of storage units is obtained as the result of the simulations.

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

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 prepared by representatives in Med-TSO Technical Committee and these schedules have been modelled as determined planned outages. When this information is not provided, planned outages are modelled 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 provision of FCR, etc.

Non-dispatchable weather-dependent generation (wind, solar or other renewable generation) is modelled by direct application of the time series prepared by representatives in Med-TSO Technical Committee . These time series are based on PECD, but takes 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 Prepared by representatives in Med-TSO Technical Committee and provision of the reserve is modelled by combining the reduction of available thermal capacity (usually due to provision of FCR) and increase of demand for the required balancing reserve (FRR or FCR+FRR). A difference between these two ways of reserve modelling lays in the fact that 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 large participation of hydro power plants.

In the first type of reserve modelling, no energy requirements are involved and only 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 it can happen that there maybe some hours during the year in which not full balancing requirements are satisfied due to outages of TPPs (planned or forced).

Having in mind the structure of analysed power systems (almost no hydro generation), balancing reserve has been modelled as demand increase 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 prepared by representatives in Med-TSO Technical Committee 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, Prepared by representatives in Med-TSO Technical Committee.

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 the rate of 6% and 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 separated 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 Summer 2022

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 22nd week to the 39th week in the year 2022. These values are the average weekly consumption for 38 climatic years in the period from 1982 to 2019.

Table 1: Expected consumption in the summer weeks of the year 2022

Consumption (GWh)	Total	week 22	week 23	week 24	week 25	week 26	week 27	week 28	week 29	week 30	week 31	week 32	week 33	week 34	week 35	week 36	week 37	week 38	week 39
DZ	**31451**	1443	1492	1559	1658	1797	1914	1886	1974	2008	1990	1960	1915	1887	1781	1653	1568	1519	1446
EG	**87655**	4551	4667	4765	4865	4893	4970	4526	5042	5074	5142	5141	5119	5063	4970	4854	4756	4689	4568
JO	**7596**	393	401	407	415	425	432	397	442	448	443	446	448	441	430	418	411	403	395
MA	**15577**	838	843	854	859	867	872	849	889	890	885	894	890	879	877	865	849	841	836
TN	**8621**	399	417	437	464	497	522	502	526	539	529	533	519	514	490	460	440	425	406
TOTAL	**150900**	**7625**	**7819**	**8022**	**8263**	**8479**	**8711**	**8160**	**8873**	**8959**	**8989**	**8973**	**8891**	**8783**	**8548**	**8249**	**8026**	**7876**	**7651**

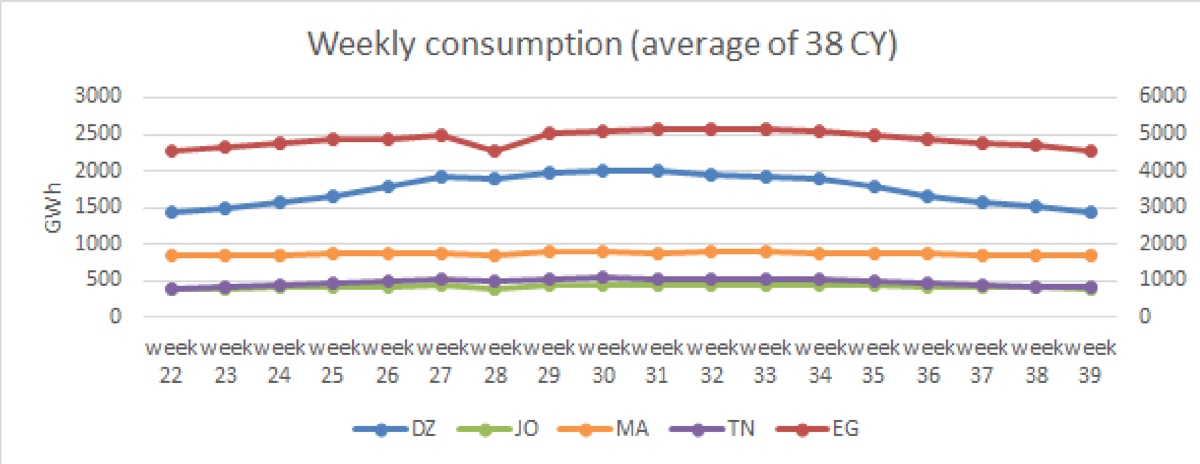


Figure 10: Expected weekly consumption per country in summer 2022

Weekly consumption in Jordan and Tunisia is the lowest among the analysed 5 countries. The highest is consumption in Egypt, almost 10 times higher than in Jordan or Tunisia. Consumption in Morocco and Algeria are in between, higher than in Jordan or Tunisia around 2 or 4 times.

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

Table 2: Maximum weekly peak loads in summer weeks of the year 2022

Peak load (MW)	MAX	week 22	week 23	week 24	week 25	week 26	week 27	week 28	week 29	week 30	week 31	week 32	week 33	week 34	week 35	week 36	week 37	week 38	week 39
DZ	**18857**	14970	13743	14670	15083	16321	17344	17342	17858	18418	18857	17583	17381	16871	15369	14416	13617	12677	12416
EG	**38188**	34087	35923	35747	36660	36721	36769	33120	36243	36429	38188	37771	37960	36617	36336	36096	35910	35254	33932
JO	**4185**	3454	3654	3500	3558	3486	3793	3525	4023	3846	4134	4185	3959	3992	3600	3517	3573	3344	3349
MA	**6666**	6298	6340	6461	6440	6456	6431	6531	6533	6467	6666	6569	6496	6497	6459	6419	6245	6323	6279
TN	**5373**	4159	3833	4352	4903	5264	4991	4926	5089	4795	4657	5373	4967	4524	4539	4079	3996	3920	3835

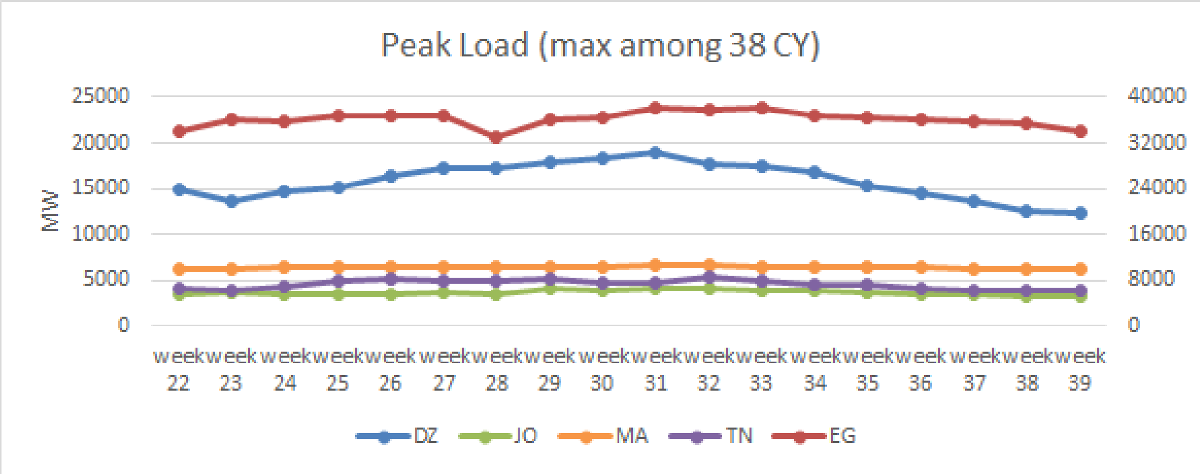


Figure 11: Maximum weekly peak loads per country in summer 2022

In all countries, except Jordan, peak load is observed in summer. In Jordan, peak load is observed in winter. 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 table provides information about generation capacities in 2022. Total generation capacities in the observed region in 2022 are expected to be 105 GW, with more than 92 GW (or around 88%) in thermal units.

Table 3: Total generation capacities (MW) per technology in 2022

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	0	0.00%	266	1.15%	95	0.41%	22768	98.44%	**23129**
EG	1875	3.16%	1763	2.97%	2128	3.58%	53629	90.29%	**59395**
JO	621	9.49%	1705	26.05%	-	-	4220	64.47%	**6546**
MA	1847	17.06%	827	7.64%	1306	12.06%	6849	63.25%	**10829**
TN	242	4.31%	191	3.40%	-	-	5183	92.29%	**5616**
TOTAL	**4585**	**4.35%**	**4752**	**4.50%**	**3529**	**3.34%**	**92649**	**87.81%**	**105515**

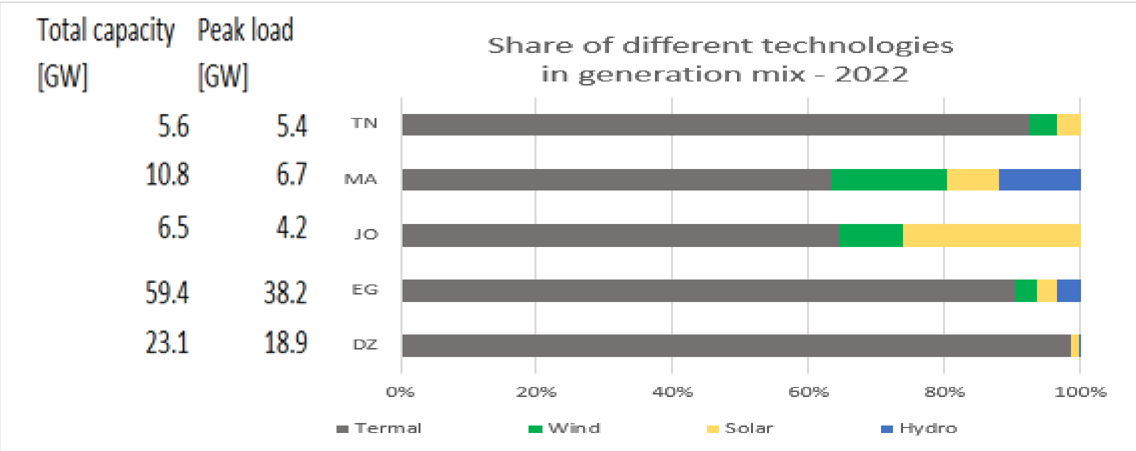


Figure 12: Generation mix and peak load in 2022

Relevant hydro capacities exist only in Egypt and Morocco. In Morocco, there is also a PS HPP of 464 MW. 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 4. It is worth mentioning that capacity factors take into account the technology used and also the zone splitting of each country.

Table 4: Wind and solar capacity factors for all countries in 2022

	2022	
Country	**Wind CF**	**Solar CF**
DZ	N/A	21.2%
EG	39.3%	26.3%
JO	32.5%	22.8%
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. In general, planned outages are not envisaged during the summer season.

INTERCONNECTIONS BETWEEN COUNTRIES

Summarized NTC values prepared by representatives in Med-TSO Technical Committee 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 5 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 prepared by representatives in Med-TSO Technical Committee.

Summary of the interconnection capacities and given exchanges are presented in the following tables.

Table 5: Summarized NTC values

Interconnection NTC [MW]	2022
DZ-TN	400
TN-DZ	400
DZ-MA	600
MA-DZ	300
EG-LY	180
TN-LY	0
EG-JO	450
JO-EG	450
MA-ES	600
ES-MA	900

Table 6: Max hourly exchanges

Interconnection Max hourly exchanges [MW]	2022
EG-SD	80
JO-LB	150-250
JO-PS	80
JO-IQ	150-200

RESERVE REQUIREMENTS AND THEIR MODELLING

Reserve requirements have been prepared by representatives in Med-TSO Technical Committee (Table 7). In some countries (EG, MA) the percentages of the capacity reduction at thermal units due to the provision of FCR has 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.

Table 7: Balancing reserve requirements

Reserve		2022
DZ	FCR+FRR [MW]	400
EG	FCR+FRR [MW][4]	600
JO	FCR+FRR [MW]	360
MA	FCR+FRR [MW]	600
TN	FCR+FRR [MW]	450

[4] 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 (and planned)[5] outage patterns for thermal units.

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

The sufficient number of MC years that ensures good convergence of results has been defined by assessing the coefficient of variation (α) of the EENS metric and its change.

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

Where EENSN is the expectation estimate of ENS over N, the number of Monte Carlo years, i.e., $EENS_N = \frac{\sum_{i=1}^{N} ENS_i}{N}$, i=1…N and Var[EENSN] is the variance of the expectation estimate, i.e. $Var[EENS_N] = \frac{Var[ENS]}{N}$.

The evolution of convergence criteria is presented in the following figures.

5 Planned outages have not been considered in summer period in almost all countries (except in JO in September).

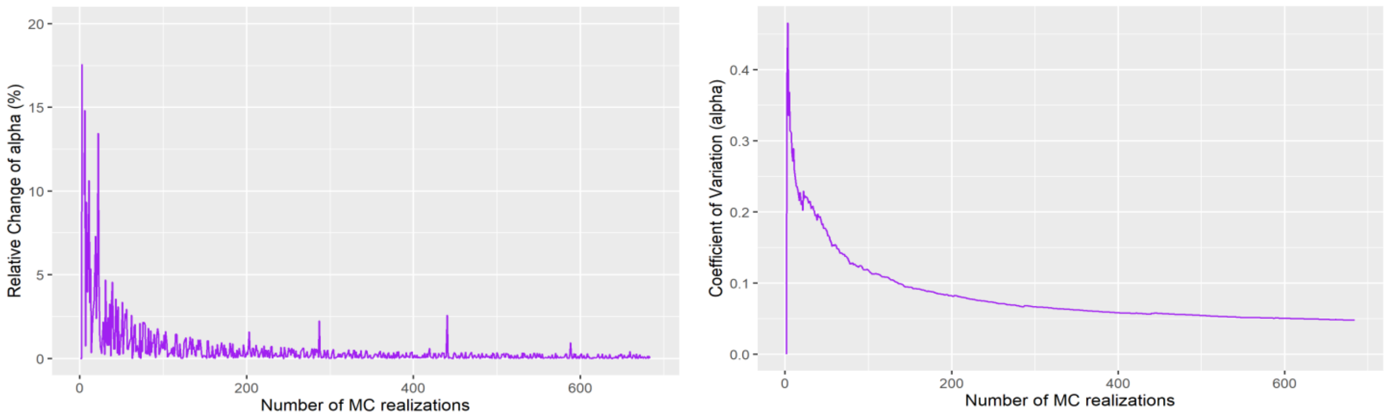
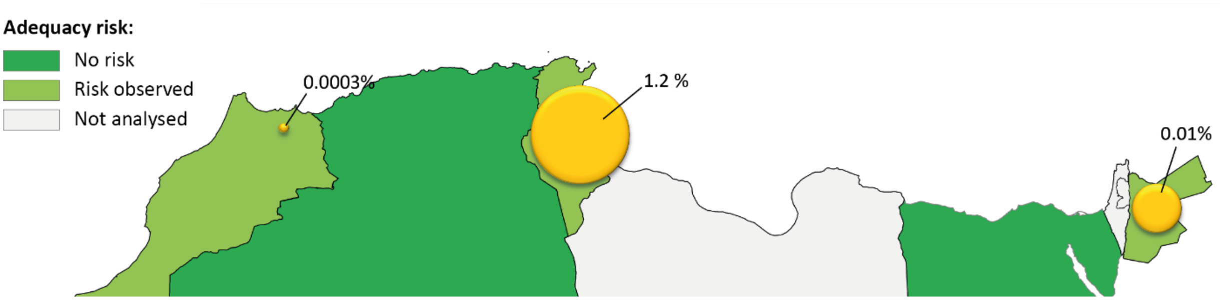


Figure 13: Evolution of convergence criteria for 684 MC years

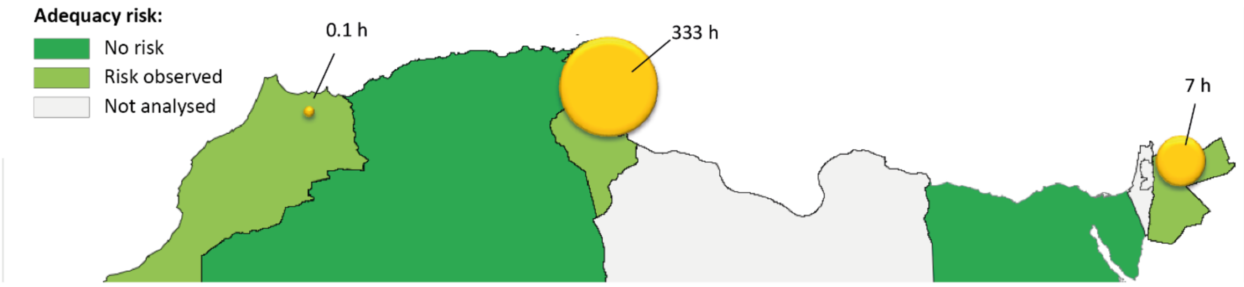
3.2 Adequacy assessment

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 all countries except Egypt, although they could be considered as small or marginal in Jordan, Morocco and Algeria (Figure 14). Only in case of Tunisia, adequacy risk is very high under isolated system operating mode. Interconnections and energy exchanges with neighboring countries reduce adequacy risks to zero or close to zero in Algeria, Jordan and Morocco. In Tunisia, even under interconnected - normal condition, adequacy risks have been identified (Figure 15).

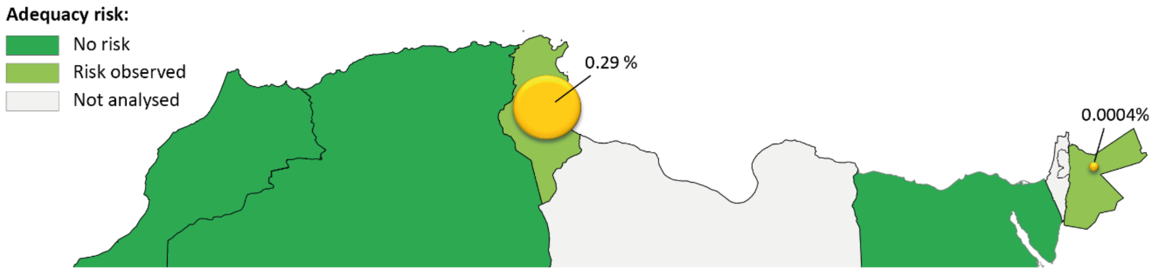


Relative EENS Isolated

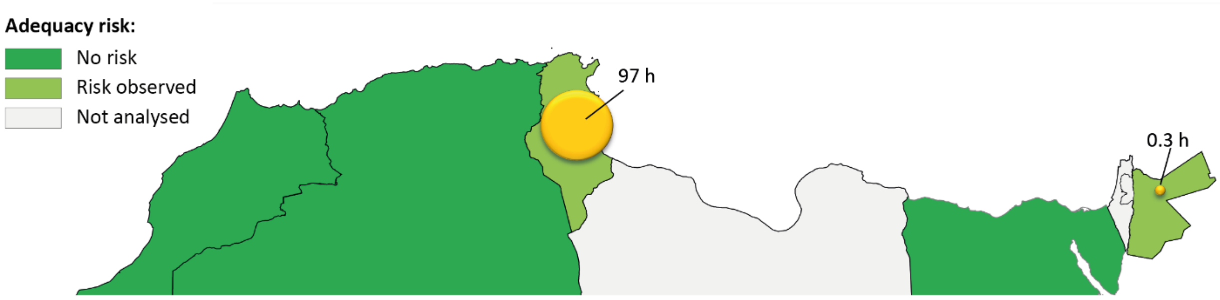


Seasonal LOLE Isolated

Figure 14: Seasonal Relative EENS and LOLE for isolated mode of operation



Relative EENS Interconnected



Seasonal LOLE Interconnected

Figure 15: Seasonal relative ENS and LOLE for interconnected mode of operation

In Table 8 and Table 9 detailed ENS and LOLD seasonal results are given for all analysed countries. Results point to adequacy issues in some countries. Notably in:

- Tunisia

  This is the country with the highest EENS and LOLE observed in Summer 2022: 25 GWh and 97 hours in the interconnected mode of operation. These expected values of ENS and LOLE point to seriously endangered adequacy. If more critical, but less probable (P95) cases happen (extreme hot summer, higher demand, higher outages of TPPs) ENS can reach 85 GWh and LOLD 247 hours.

  In the isolated mode of operation, adequacy is even more endangered: EENS reaches 104 GWh and LOLE is 333 hours. This also points to the fact that interconnection between Algeria and Tunisia reduces adequacy risks 3 times!

- Jordan

  Jordan with EENS of only 34 MWh for the interconnected mode of operation and LOLE less than one hour shows a small adequacy risk. However, in a rare situation, but more critical one (P95), ENS can reach 182 MWh and LOLD 2 hours.

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

Table 8: Seasonal ENS for Interconnected and isolated scenario

Country	Interconnected	Isolated
DZ	EENS: 1 MWh 50tH percentile ENS: 0 MWh 95th percentile ENS: 0 MWh	EENS: 7 MWh 50tH percentile ENS: 0 MWh 95th percentile ENS: 0 MWh
EG	EENS: 0 MWh 50tH percentile ENS: 0 MWh 95th percentile ENS: 0 MWh	EENS: 0 MWh 50tH percentile ENS: 0 MWh 95th percentile ENS: 0 MWh
JO	**EENS: 34 MWh** **50tH percentile ENS: 0 MWh** **95th percentile ENS: 182 MWh**	**EENS: 1071 MWh** **50tH percentile ENS: 428 MWh** **95th percentile ENS: 4257 MWh**
MA	EENS: 0 MWh 50tH percentile ENS: 0 MWh 95th percentile ENS: 0 MWh	EENS: 47 MWh 50tH percentile ENS: 0 MWh 95th percentile ENS: 0 MWh
TN	**EENS: 25310 MWh** **50tH percentile ENS: 17121 MWh** **95th percentile ENS: 85218 MWh**	**EENS: 103587 MWh** **50tH percentile ENS: 84922 MWh** **95th percentile ENS: 242972 MWh**

Table 9: Seasonal LOLD for Interconnected and isolated scenario

Country	Interconnected	Isolated
DZ	LOLE: 0.01 h 50tH percentile LOLD: 0 h 95th percentile LOLD: 0 h	LOLE: 0.04 h 50tH percentile LOLD: 0 h 95th percentile LOLD: 0 h
EG	LOLE: 0 h 50tH percentile LOLD: 0 h 95th percentile LOLD: 0 h	LOLE: 0 h 50tH percentile LOLD: 0 h 95th percentile LOLD: 0 h
JO	**LOLE: 0.3 h** **50tH percentile LOLD: 0 h** **95th percentile LOLD: 2 h**	**LOLE: 7.21 h** **50tH percentile LOLD: 5 h** **95th percentile LOLD: 23 h**
MA	LOLE: 0 h 50tH percentile LOLD: 0 h 95th percentile LOLD: 0 h	LOLE: 0.11 h 50tH percentile LOLD: 0 h 95th percentile LOLD: 0 h
TN	**LOLE: 97.04 h** **50tH percentile LOLD: 77.5 h** **95th percentile LOLD: 246.7 h**	**LOLE: 332.52 h** **50tH percentile LOLD: 301 h** **95th percentile LOLD: 596.85 h**

It should be noted that curtailment of RES generation can only happen in Morocco in isolated operations, but this curtailment is marginal: 0.24 GWh from a total wind + solar generation of 3,743GWh.

3.3 Importance of interconnections[6]

As presented in the previous chapter, interconnections play a crucial role to improve adequacy situation. Exchanges on the borders of the five analysed countries show that in almost all cases there are prevailing direction of the power flows. This is particularly true for the border between Algeria - Tunisia and Egypt - Jordan.

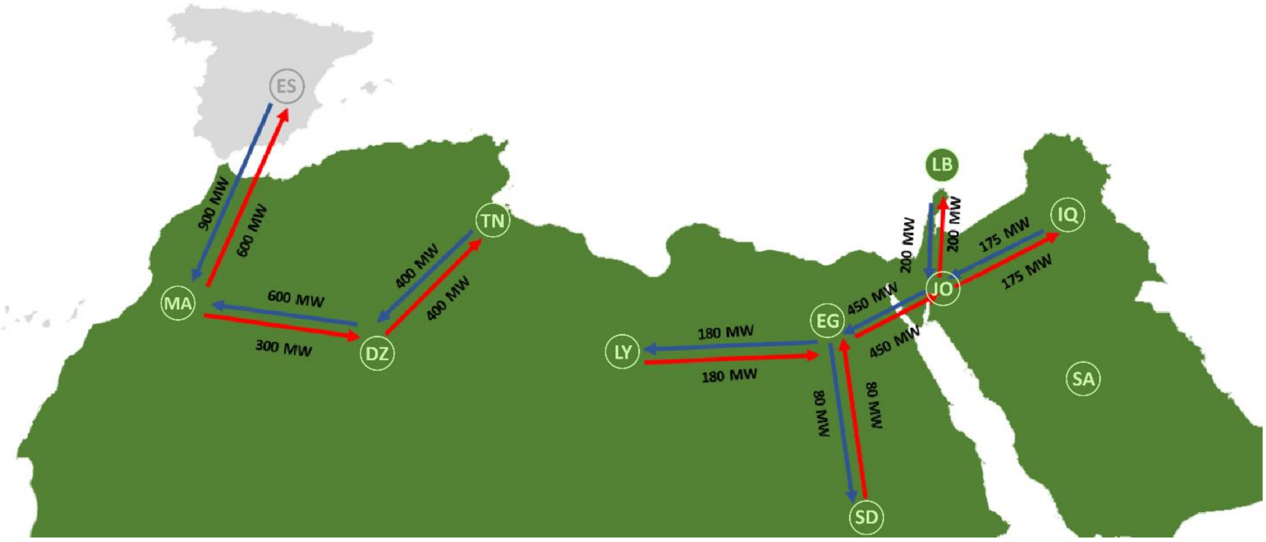


Figure 16: Net transfer capacity available in 2022 summer season

Presented exchanges point to the fact that Algeria has sufficient excess of energy to support secure operation of Tunisia and that this support is just limited by the transmission constraints (NTC=400 MW). Further increase of cross-border capacities between DZ and TN could be beneficial and improve adequacy situation in Tunisia.

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

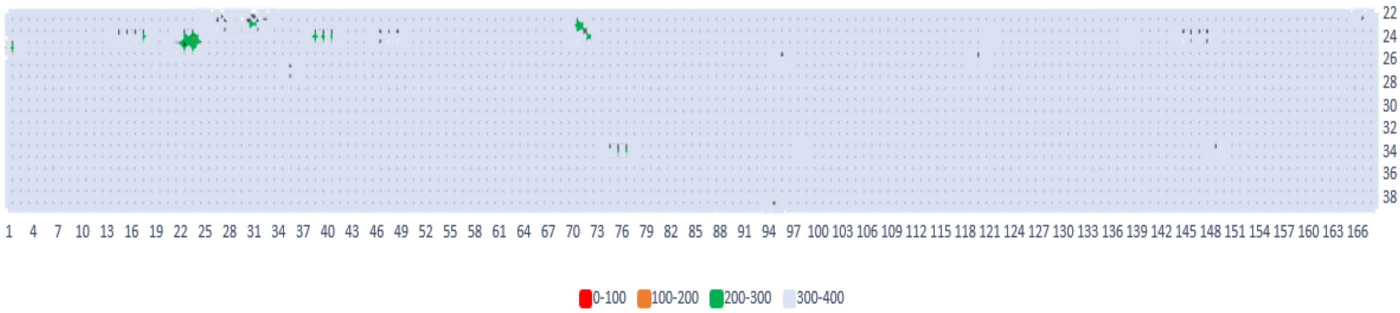
[6] **Please have in mind that exchanges are not completely in line with market operation since loads are increased to account reserve requirements**

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

- DZ - TN

  Flows in all hours are towards Tunisia, between 132 MW and 400 MW (which is NTC value).

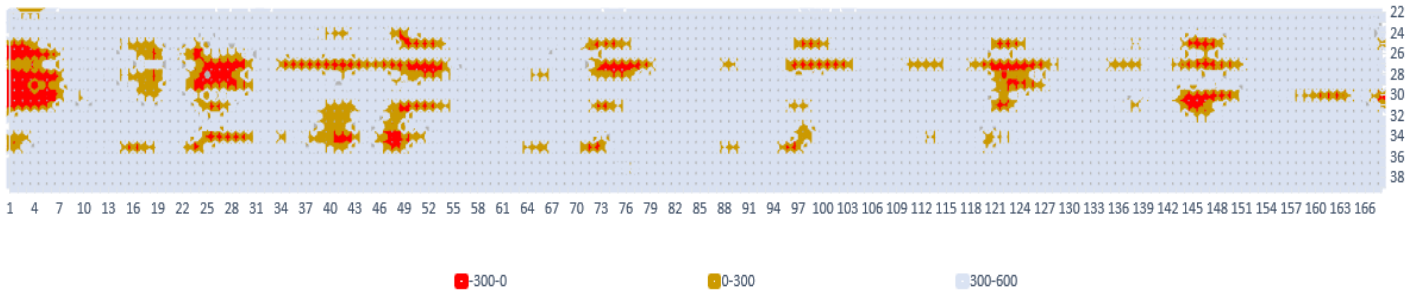
DZ-TN exchanges



- DZ - MA

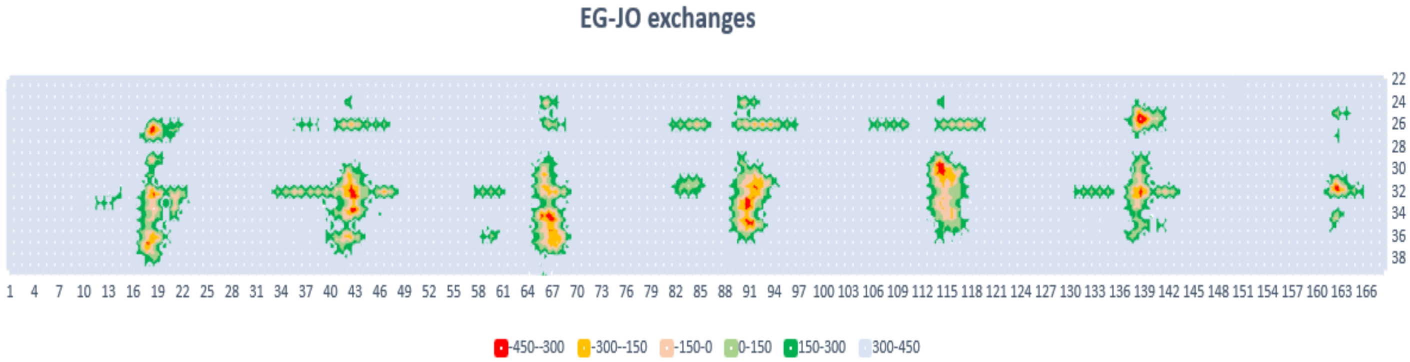
  Flows from Morocco to Algeria are noted only during night and early morning hours when demand is still low and Morocco has excess in RES generation.

DZ-MA exchanges



- EG - JO

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



4 Adequacy Situation on Country Level

4.1 Algeria

DEMAND

Algerian seasonal weekly demand, depicted in Figure 17 goes from around 1450 GWh to 2000 GWh, while peak hourly demand in each week varies from 12415 MW to 18857 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 the second half of July until the second half of August (29th - 32nd week), due to high temperatures and high cooling consumption. The maximum hourly demand in all 38 climatic years reaches 18857 MW in the 31st week.

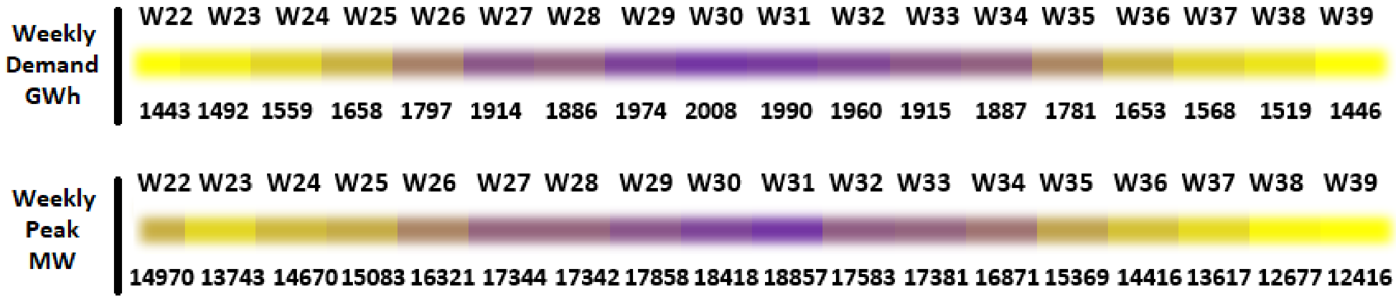


Figure 17: Seasonal Weekly demand in Algeria

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 89%, which is divided further into conventional, CCGT and OOCGT TPPs. Hydro and Solar capacities amount to only 1% each. Total installed capacities are 23129 MW with import capacity up to 700 MW, which combined is substantially higher than the maximum hourly consumption of 18857 MW.

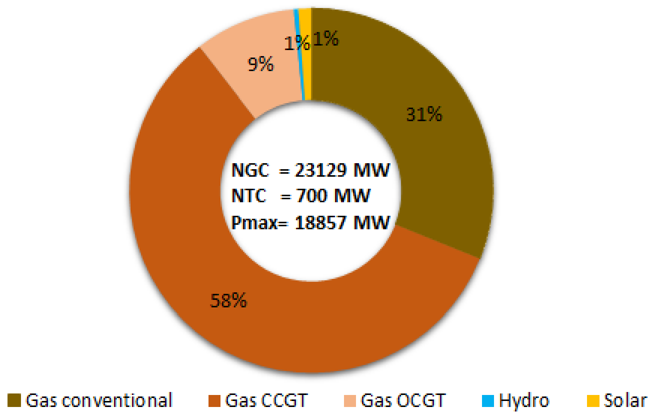


Figure 18: Installed Capacity mix with total NGC, import NTC and peak demand in Algeria

The average daily available TPP capacity, after reduction due to derating factors, forced and planned outages is shown in Figure 19. 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 varies from 21000 MW in the beginning of the summer season to 19150 MW during most of the summer. The minimal average daily available TPP capacity (minimum among all simulated MC years) fluctuates from 18900 MW to 16700 MW.

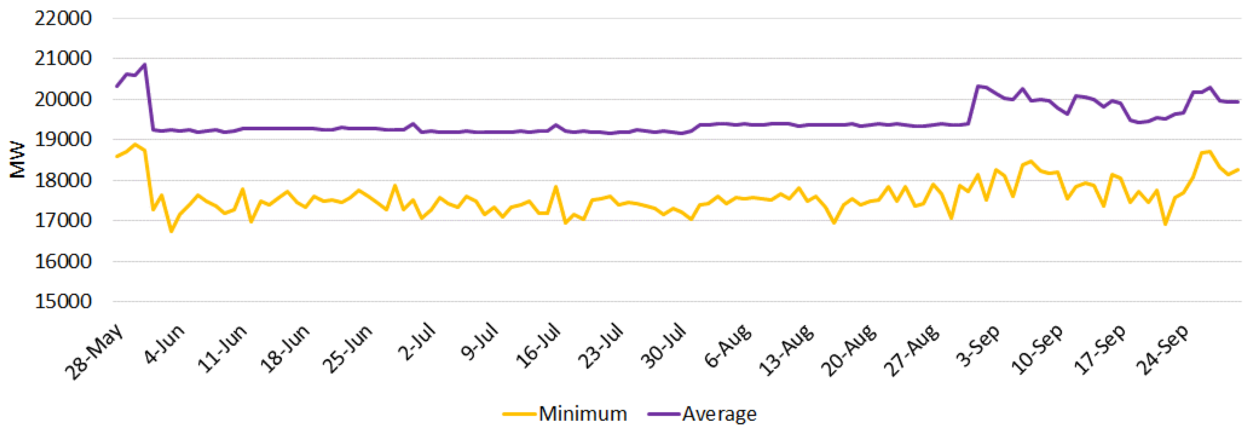


Figure 19: Average and minimum TPP available capacity in Algeria

As a result of system simulation, the average daily TPP capacity margin is calculated and depicted in Figure 20. It represents the difference between available and activated TPP capacities. The average daily capacity margin goes from 11450 MW at the beginning of the season to 5700 MW at the season's peak. The minimum daily margin goes from 8000 MW to 1700 MW. The high Algerian TPP capacity margin indicates that Algeria doesn't have adequacy issues.

Also, the daily capacity margin follows both seasonal and daily consumption patterns, and it is the lowest during the middle of summer and working days, due to higher demand.

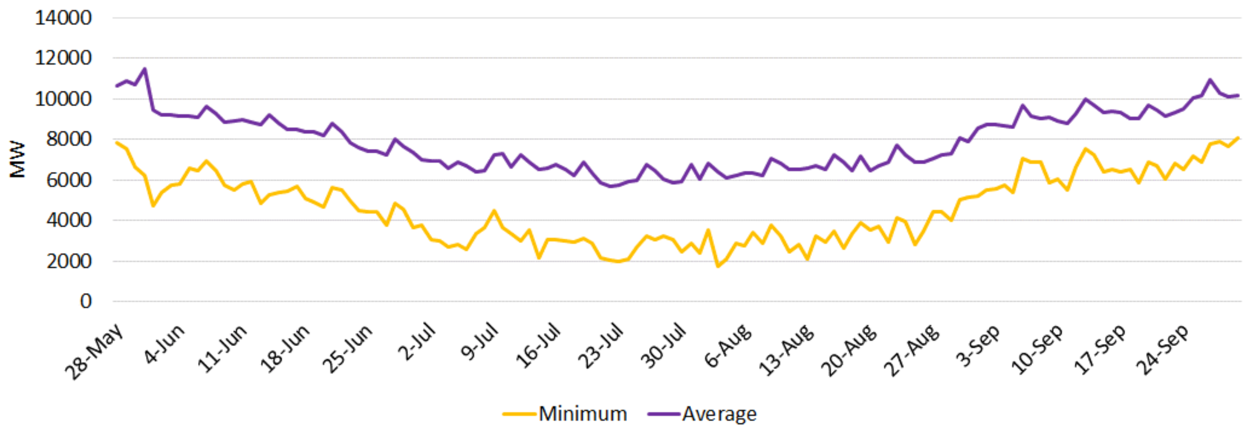


Figure 20: Average and minimum TPP margin in Algeria

Adequacy assessment

Considering that Algeria has only negligible adequacy risk and EENS of only 1 MWh in interconnected and 7 MWh in isolated mode, further investigations are not relevant.

4.2 Egypt

Demand

Egyptian seasonal weekly demand, depicted in Figure 21 goes from around 4550 GWh to 5150 GWh, while peak hourly demand in each week varies from 33900 MW to 38188 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 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 38188 MW in the 31^{st} week.

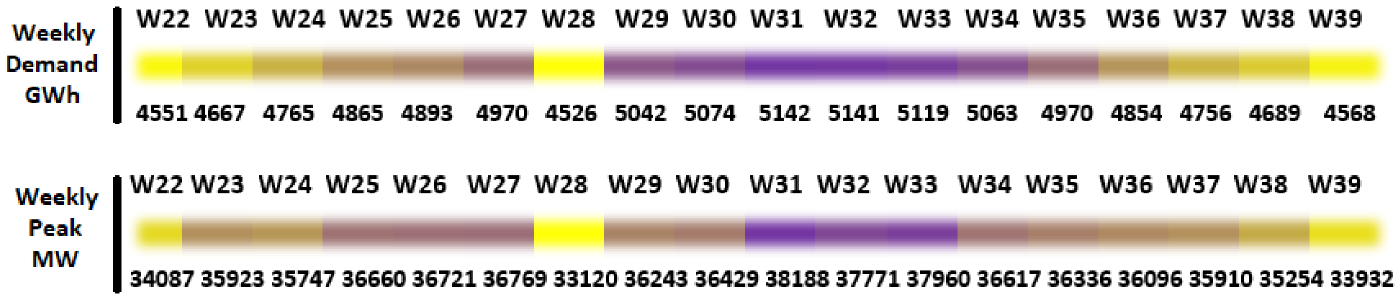


Figure 21: Seasonal Weekly demand in Egypt

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 88%, 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 59395 MW with import capacity up to 450 MW from Jordan, which combined is substantially higher than the maximum hourly consumption of 38188 MW. In sense of demand and installed capacities, Egypt is the biggest of all analysed power systems.

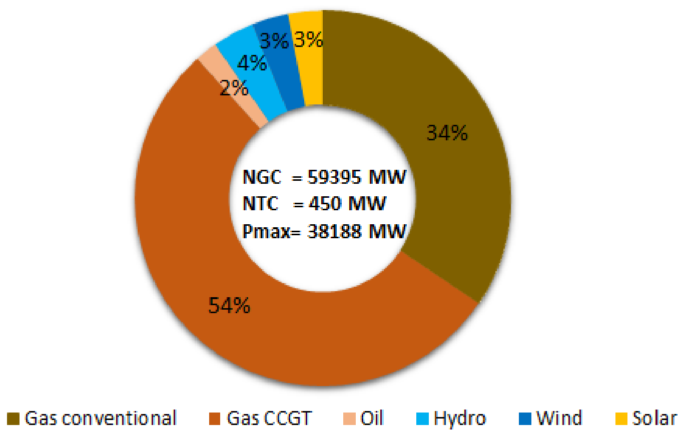


Figure 22: Installed Capacity mix with total NGC, import NTC and peak demand in Egypt

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 is stable during the entire summer season and it amounts to around 52000 MW. The minimal average daily available TPP capacity (minimum among all simulated MC years) fluctuates from 45450 MW to 47450 MW.

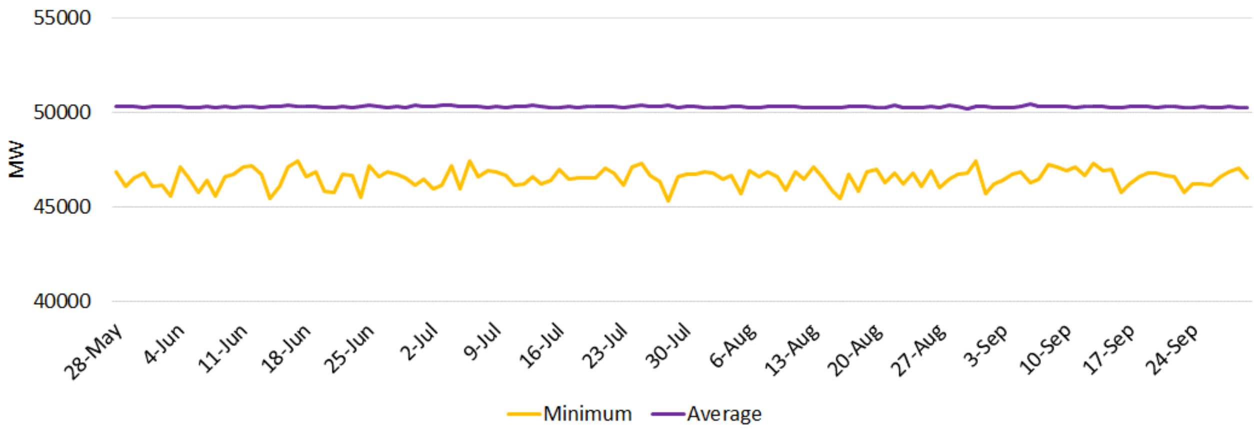


Figure 23: Average and minimum TPP available capacity in Egypt

As a result of system simulation, the average daily TPP capacity margin is calculated and depicted in Figure 24. It represents the difference between available and activated TPP capacities. The average daily capacity margin goes from 26400 MW at the beginning of the season to 20900 MW at the season's peak. The minimum daily margin goes from 21200 MW to 15450 MW. The very high TPP capacity margin indicates that Egypt will not have adequacy issues during the following season and that it has huge export capabilities that can bring benefit to neighboring countries' adequacy situation. Also, the daily capacity margin follows both seasonal and daily consumption patterns, and it is the lowest during the middle of summer and working days, due to higher demand. A small increase in TPPs margin at the begging of July is the consequence of the consumption decrease that is expected during week 28 (July 9th – July 16th).

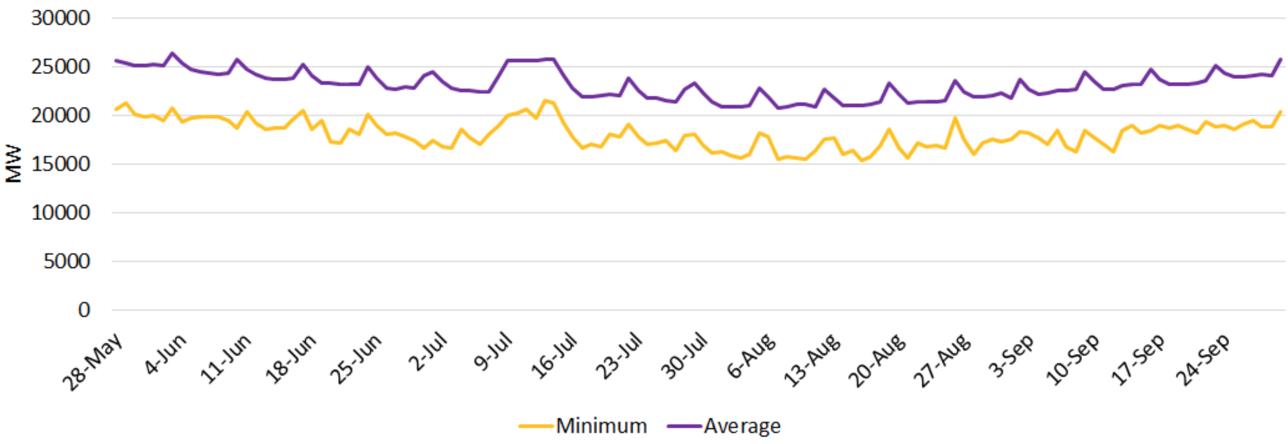


Figure 24: Average and minimum TPP margin

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 400 GWh to 450 GWh (12.5% increase), while peak hourly demand in each week goes from 3350 MW to 4185 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 the second half of July until almost the end of August (29th - 34th week), due to high temperatures and high cooling consumption. The maximum hourly demand of 4185 MW is reached in the 32nd week, which is the maximum in all 38 climatic years.

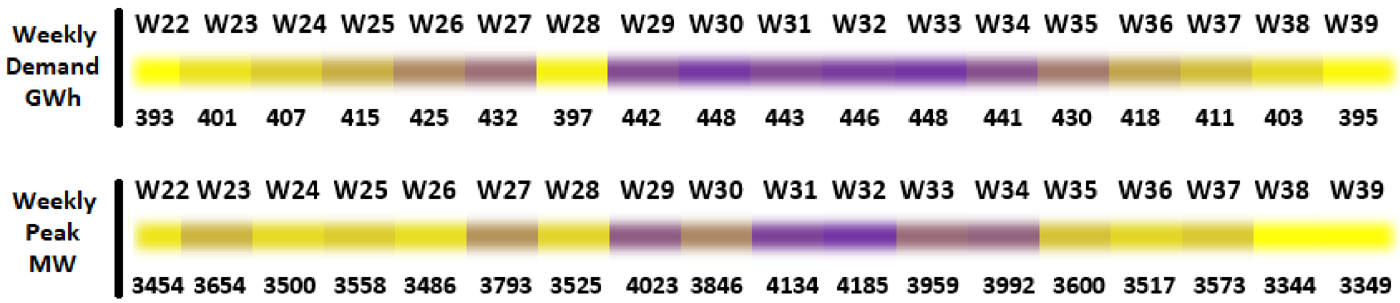


Figure 25: Seasonal Weekly demand in Jordan

SUPPLY AND NETWORK OVERVIEW

Jordan's power generation fleet is dominantly based on gas-fuelled TPPs, with the share in total installed capacities around 58%, which is divided further into conventional and OCGT TPPs. Oil shale amounts to 7% of installed capacities, while RES – wind and solar share in installed capacities are 9% and 26% respectively. Total installed capacities amount to 6546 MW with import capacity up to 450 MW from Egypt, while maximum hourly consumption is around 4185 MW.

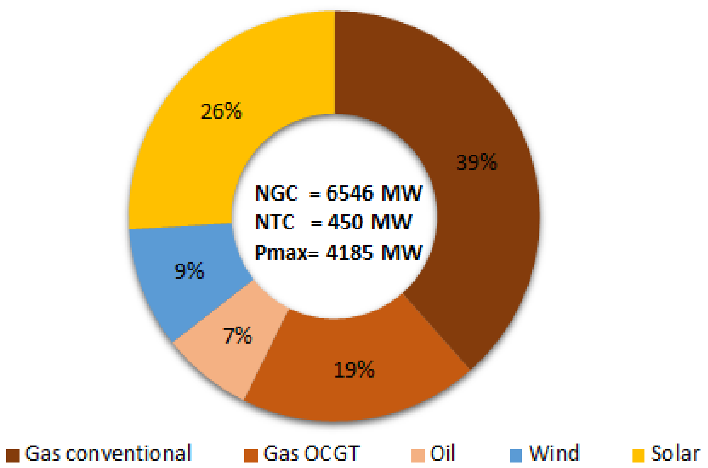


Figure 26: Installed Capacity mix with total NGC, import NTC and peak demand in Jordan

The average daily available TPP capacity, after reduction due to derating factors, forced and planned 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 start from 3800 MW and decrease to 3100 MW in the last part of the season. The minimal average daily available TPP capacity (minimum among all simulated MC years) goes from only 3150 MW to only 2150 MW.

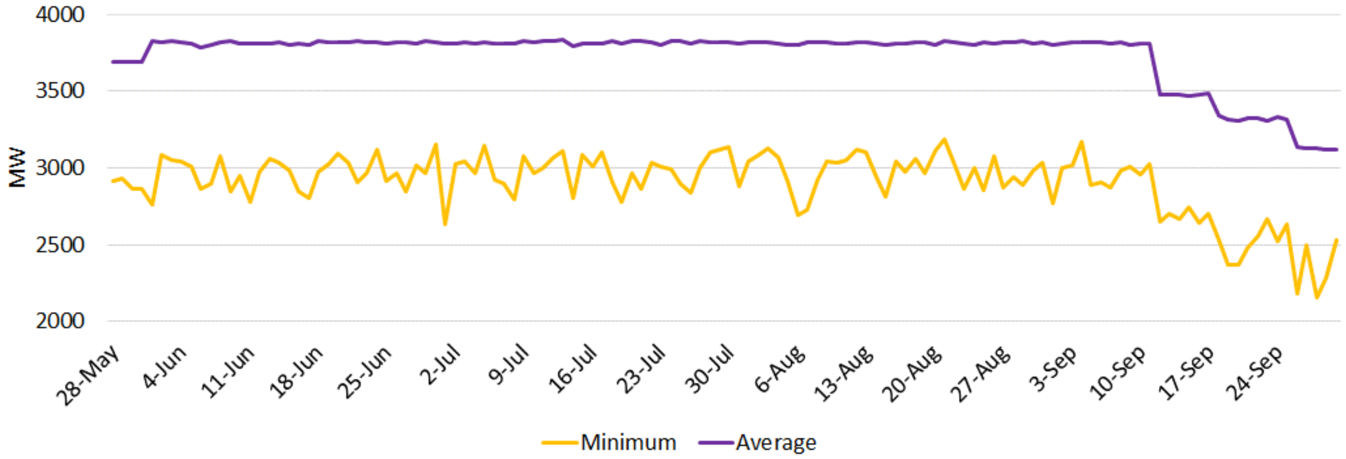


Figure 27: Average and minimum TPP available capacity in Jordan

As a result of system simulation, the average daily TPP capacity margin is calculated and depicted in Figure 28. It represents the difference between available and activated TPP capacities. The average daily capacity margin goes from 2000 MW at the beginning of the season to 900 MW at the season's end when planned outages for some units are envisaged. The minimum daily margin goes from 1100 MW to 50 MW pointing 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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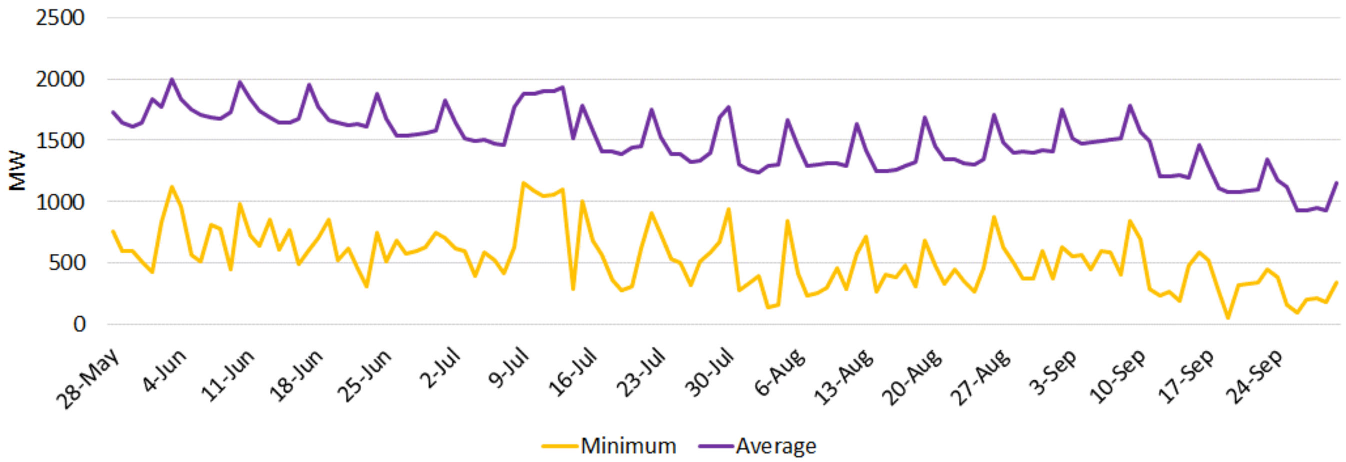

Figure 28: Average and minimum TPP margin in Jordan

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 the interconnected mode of operation adequacy risk is marginal, while for the theoretical isolated scenario adequacy risk is small but detectable, especially during September because of lower TPP availability.

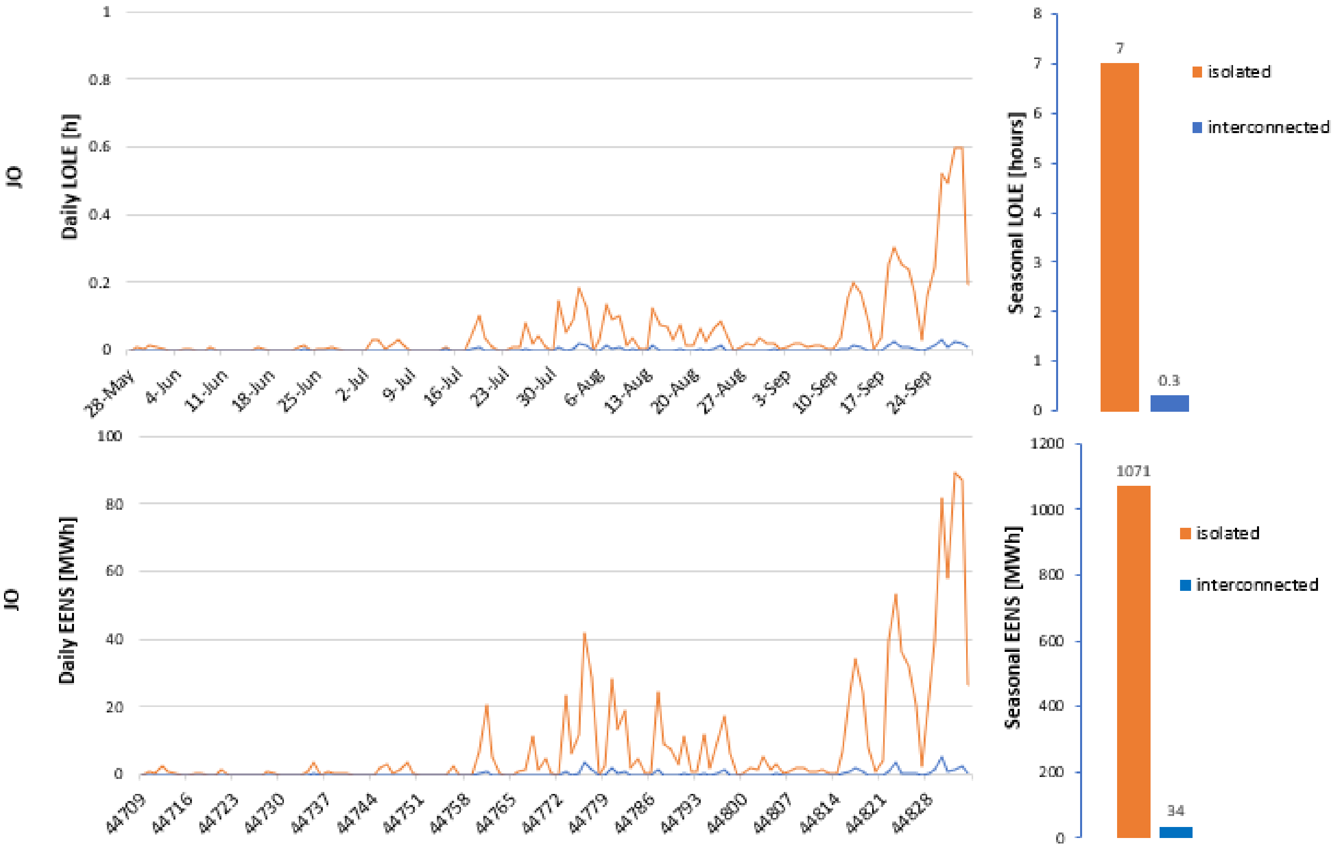

Figure 29: Daily LOLE and EENS for the interconnected and isolated mode of operation

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 7 h to less than 1 h and expected seasonal EENS from around 1000 MWh to 34 MWh.

4.4 Morocco

DEMAND

Moroccan seasonal weekly demand, depicted in Figure 30, goes from around 840 GWh to 900 GWh (10% increase), while peak hourly demand in each week varies from 6280 MW to 6666 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 the second half of July until the second half of August (29th - 33rd week), due to high temperatures and high cooling consumption. The maximum hourly demand in all 38 MC years reaches 6666 MW in the 31st week.

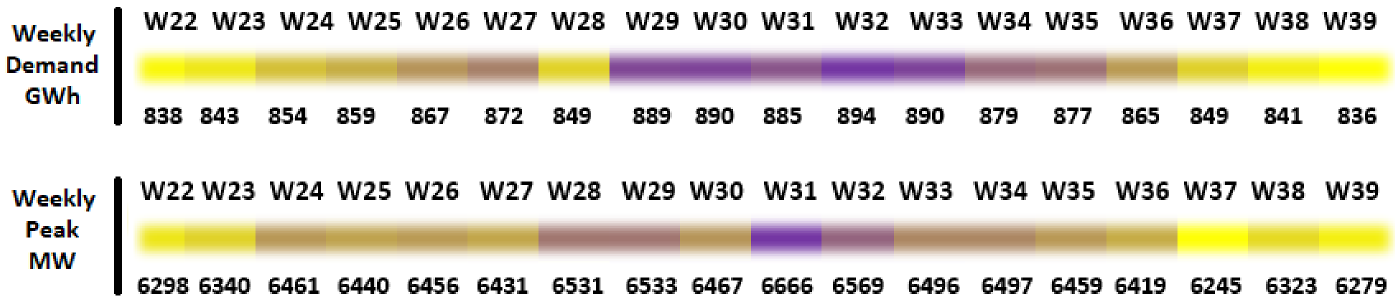

Figure 30: Seasonal Weekly demand in Morocco

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 61%, which is divided further into Coal, Gas and Oil TPPs. Hydro capacities amount to 16%, while RES – wind and solar share in installed capacities is 16% and 7% respectively. Total installed capacities are 11290 MW with import capacity up to 1500 MW, which combined is substantially higher than the maximum hourly consumption of 6666 MW.

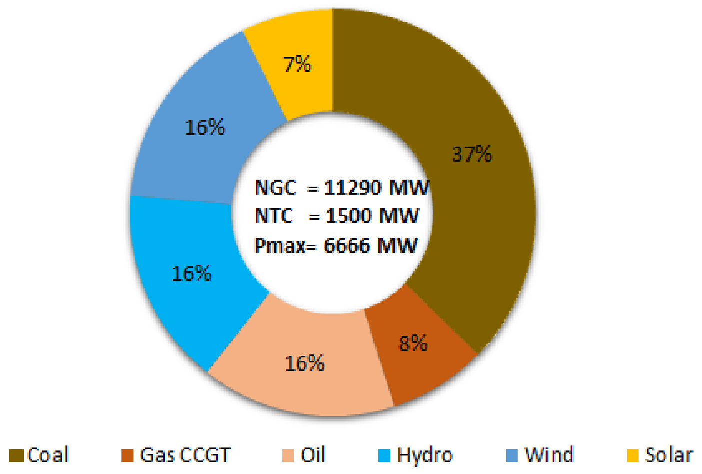

Figure 31: Installed Capacity mix with total NGC, import NTC and peak demand in Morocco

The average daily available TPP capacity, after reduction due to forced outages, is shown in Figure 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. Moroccan average available TPP capacities level is stable, and it is around 6150 MW during the entire season. The minimal average daily available TPP capacity (minimum among all simulated MC years) goes from only 3230 MW to 4850 MW.

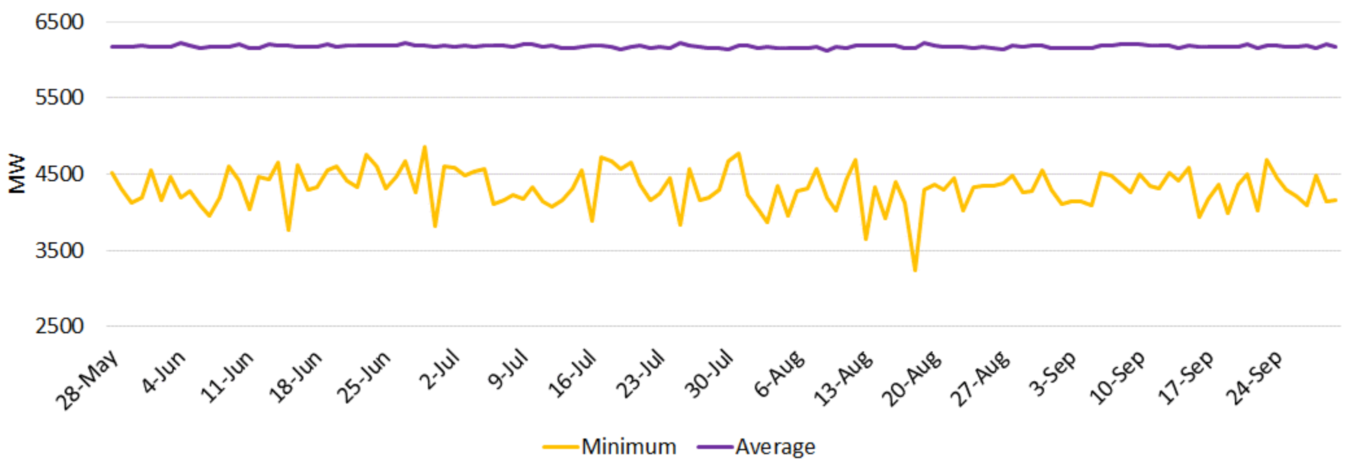

Figure 32: Average and minimum TPP available capacity in Morocco

As a result of system simulation, the average daily TPP capacity margin is calculated and depicted in Figure 33. It represents the difference between available and engaged TPP capacities. The average daily capacity margin goes from 2150 MW at the beginning of the season to 1370 MW at the season's peak. The minimum daily margin fluctuates between 1000 MW and 0 MW. Considering that Morocco has substantial hydro capacities and strong interconnections with Spain and Algeria, a low TPP capacity margin does not need to indicate adequacy risk. Also, the daily capacity margin follows both seasonal and daily consumption patterns, and it is the lowest during the middle of summer and working days, due to higher demand.

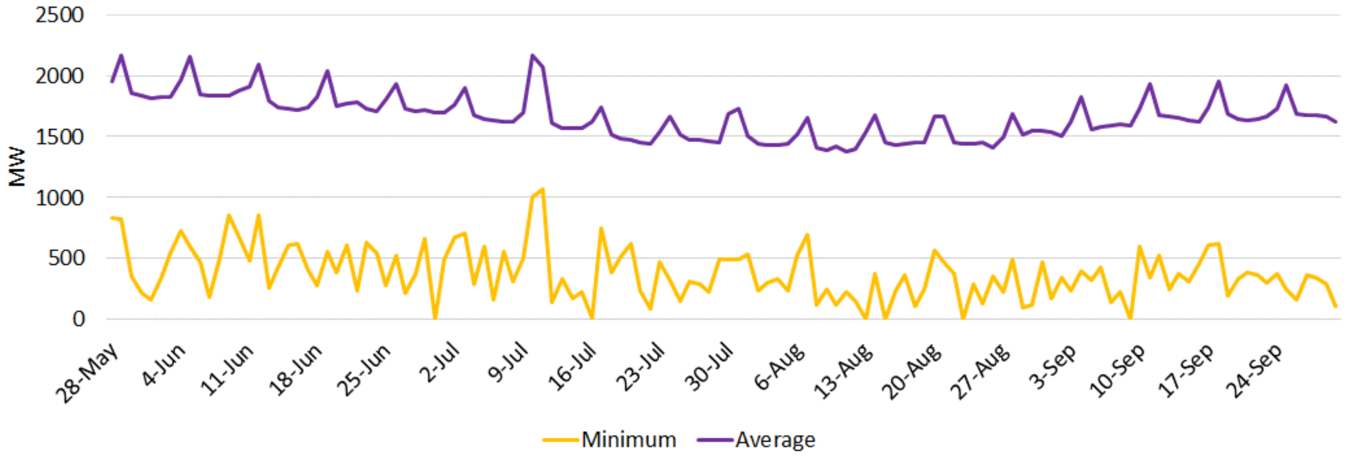

Figure 33: Average and minimum TPP margin in Morocco

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in Figure 34, only for an isolated mode of operation considering that for the interconnected mode of operation adequacy risk is not detected. In the first picture, daily LOLE distribution is given, while in the second one daily EENS is depicted.

Even for the isolated mode of operation, adequacy risk is almost negligible and it is only detected in a few days during July and August, with daily LOLE less than an hour and daily EENS less than 15 MWh.

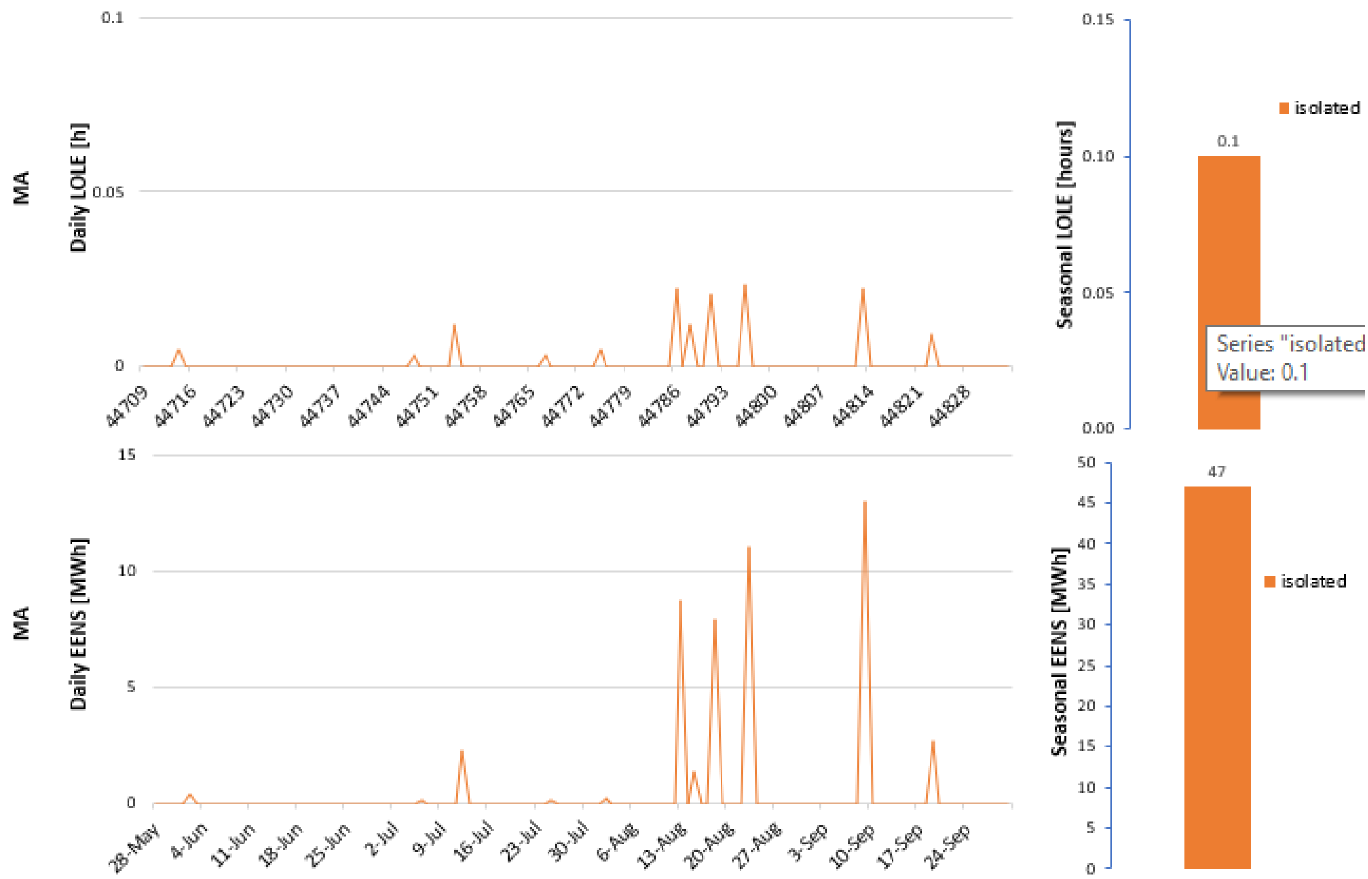

Figure 34: Daily LOLD and ENS for the interconnected and isolated mode of operation

At the righthand 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 less than one hour and EENS is less than 50 MWh.

4.5 Tunisia

DEMAND

Tunisian seasonal weekly demand, depicted in Figure 35, goes from around 400 GWh to almost 540 GWh (35% increase), while peak hourly demand in each week goes from 3835 MW to 5373 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 the second half of July until the second half of August (29th - 32nd week), due to high temperatures and high cooling consumption. The maximum hourly demand of 5373 MW is reached in the 32nd week, which is the maximum in all 38 climatic years.

	W22	W23	W24	W25	W26	W27	W28	W29	W30	W31	W32	W33	W34	W35	W36	W37	W38	W39
Weekly Demand GWh	399	417	437	464	497	522	502	526	539	529	533	519	514	490	460	440	425	406

	W22	W23	W24	W25	W26	W27	W28	W29	W30	W31	W32	W33	W34	W35	W36	W37	W38	W39
Weekly Peak MW	4159	3833	4352	4903	5264	4991	4926	5089	4795	4657	5373	4967	4524	4539	4079	3996	3920	3835

Figure 35: Seasonal Weekly demand in Tunisia

SUPPLY AND NETWORK OVERVIEW

Tunisian power generation fleet is almost exclusively gas-fuelled, with the share in total installed capacities around 92%, which is divided further into conventional, CCGT and OCGT TPPs. RES – wind and solar share in installed capacities is only around 4% each. Total installed capacities amount to 5616 MW with import capacity up to 400 MW, while maximum hourly consumption is around 5373 MW.

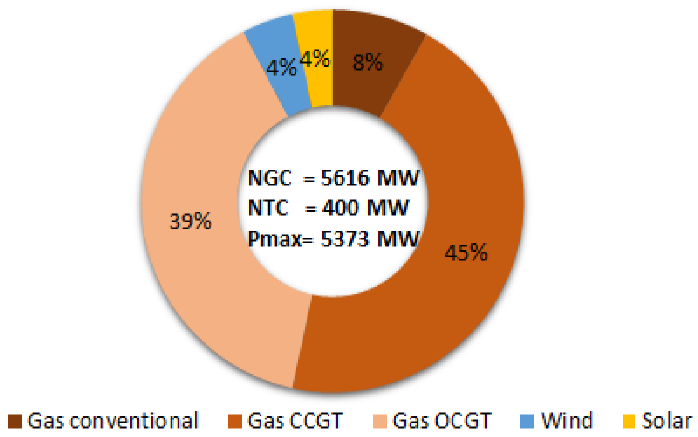

Figure 36: Installed Capacity mix with total NGC, import NTC and peak demand in Tunisia

The average daily available TPP capacity, after reduction due to derating factors and forced outages, is shown in Figure 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. While Tunisian TPP NGC is higher than the maximum expected hourly demand when we consider unplanned outages of TPPs (maintenance is not planned during the summer season) as well as given derating factors, the average available TPP capacities start from 4800 MW and decrease to only 3800 MW during the season. The minimal average daily available TPP capacity (minimum among all simulated MC years) goes from only 3850 MW to only 2150 MW.

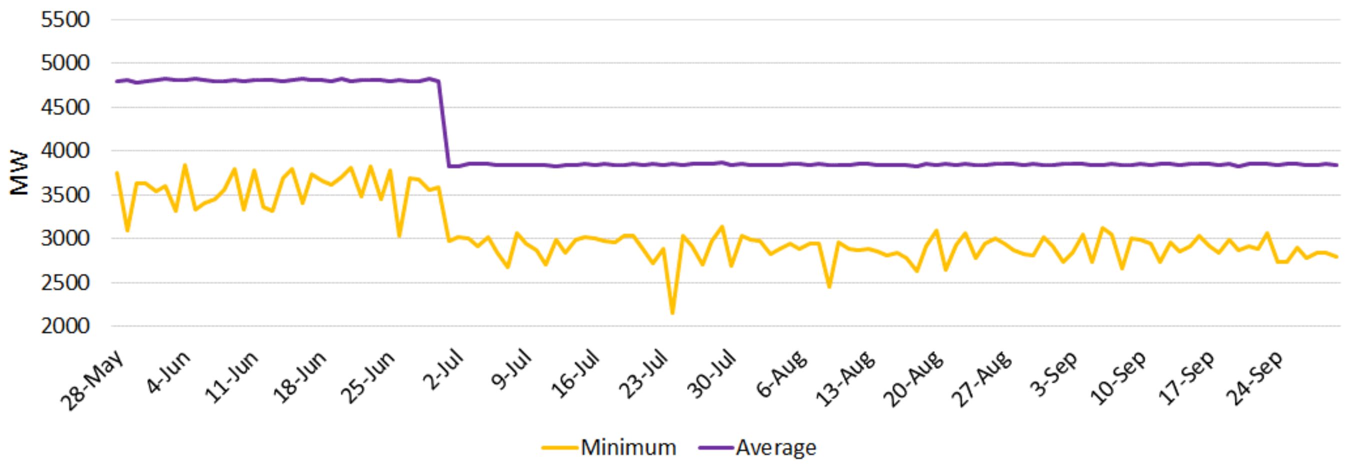

Figure 37: Average and minimum TPP available capacity in Tunisia

As a result of system simulation, the average daily TPP capacity margin is calculated and depicted in Figure 38. It represents the difference between available and engaged TPP capacities. The average daily capacity margin goes from 2750 MW at the beginning of the season to only 600 MW at the season's peak. The minimum daily margin goes from 1400 MW to 0 MW pointing to the fact that there are MC years in which no margin in TPPs exists and that adequacy issues are expected. Notably, the daily margin follows daily consumption patterns, and it is the lowest during working days, due to higher demand.

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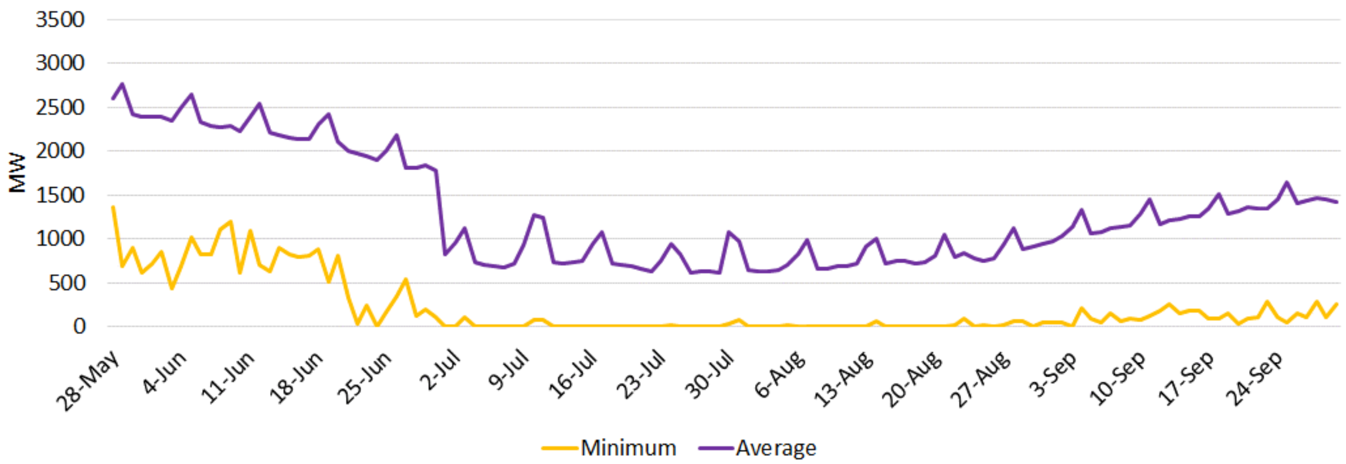

Figure 38: Average and minimum TPP margin in Tunisia

ADEQUACY ASSESSMENT

The temporal distribution of detected adequacy risk is given in Figure 39, 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. For the interconnected mode of operation, daily LOLE varies from 0 to 3 hours, while daily EENS goes from 0 to 1000 MWh. The peak of adequacy issues is expected between the middle of July and the middle of August, as a result of multiple factors: 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.

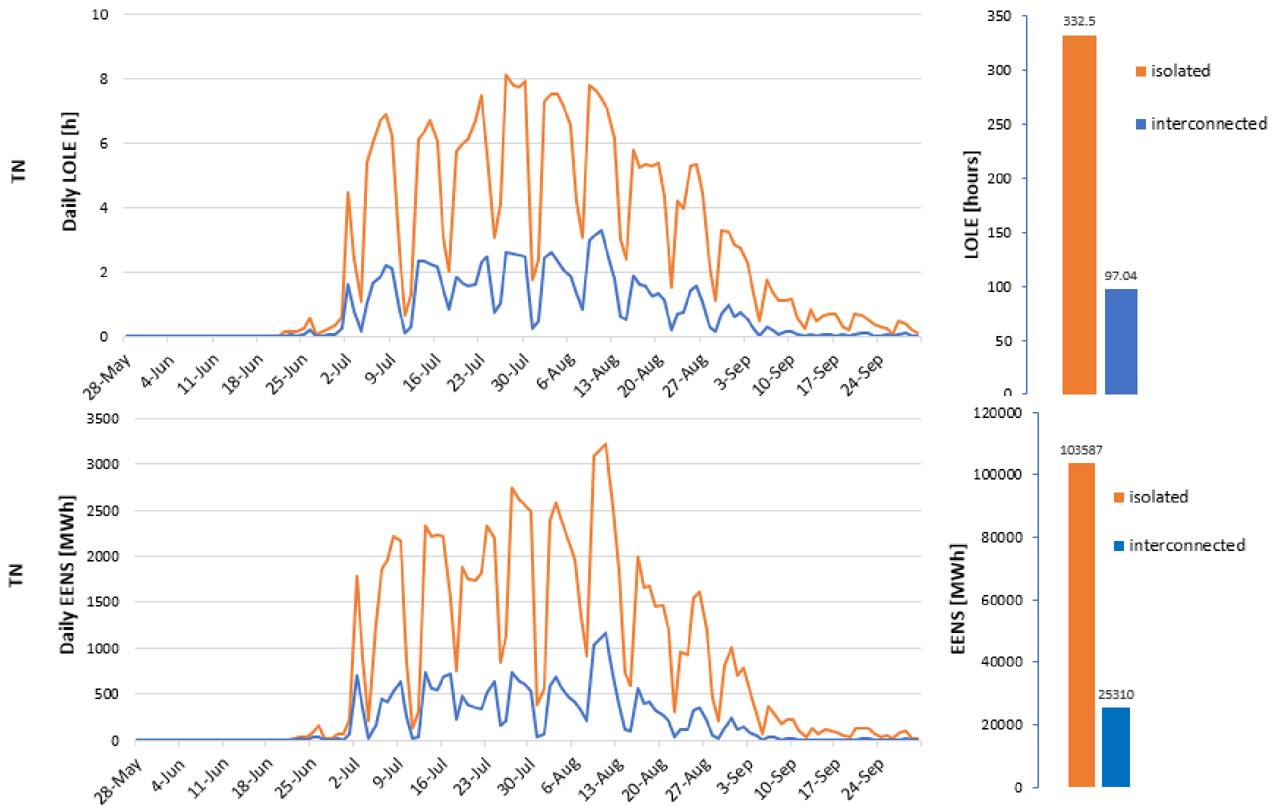

Figure 39: Daily LOLD and ENS for the interconnected and isolated mode of operation

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 336 h to 97 h and expected ENS from around 103 GWh to 25 GWh.

In case of Tunisia, additional sensitivity analyses has been carried out- adequacy assessment with assumption that required reserve (FCR+FRR) of 450 MW is not respected. Even in this case, as presented in , adequacy risks are lower but still above acceptable level.

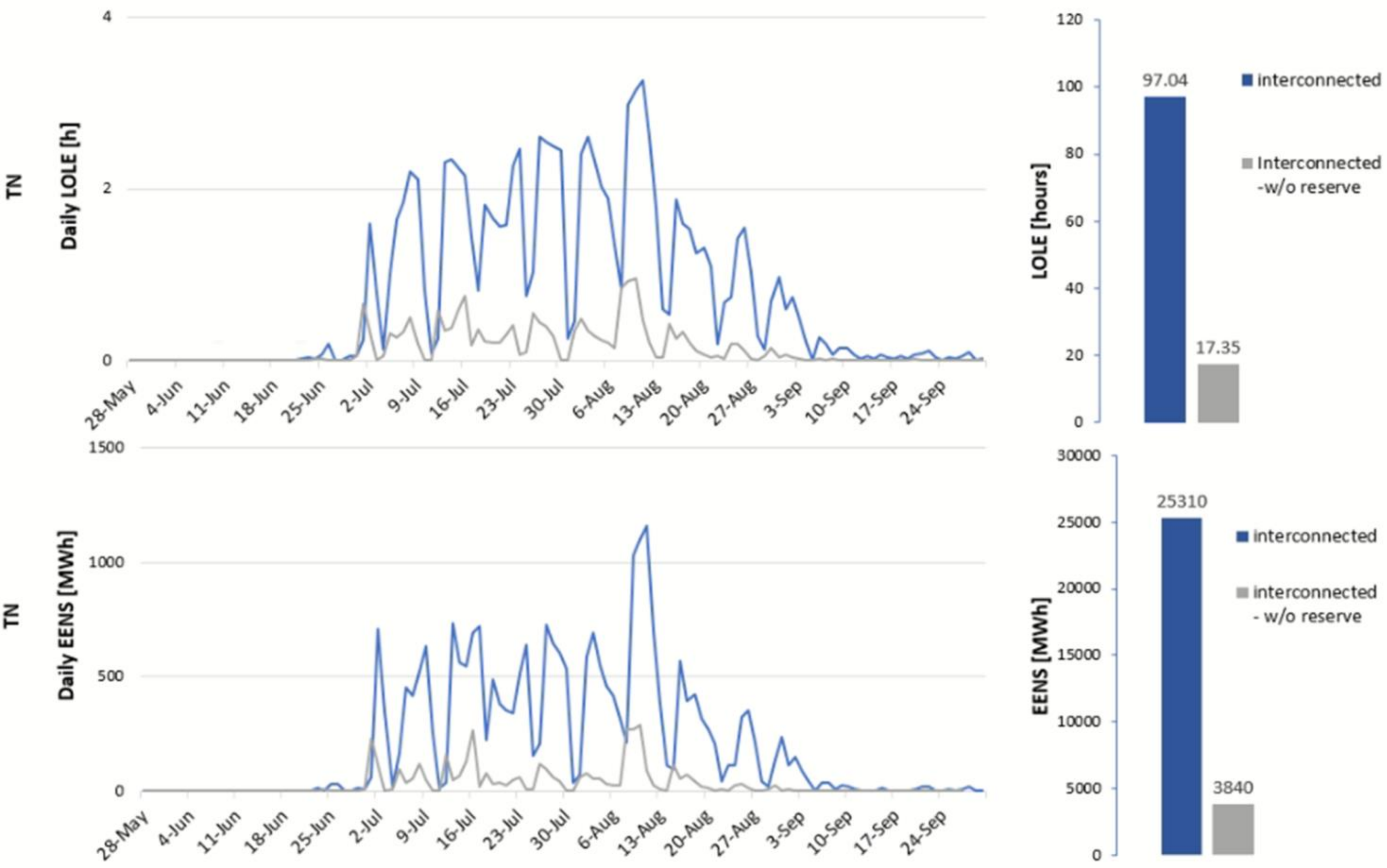

Figure 40: Daily LOLD and ENS for the interconnected mode of operation, with and without reserve

STEG statement with regards to adequacy concern identified in present report

STEG welcome Med-TSO work to perform coordinated adequacy assessment. STEG representatives in Med-TSO Technical Committee actively contributed to the development of methodology, data collection, review of results and drafting of the report.

STEG was already expecting possible adequacy constraints for the summer period due to high demand and the decrease of generation capacity, both elements correlated with high temperature typical of summer period. Nevertheless, STEG acknowledge the added value of a systematic assessment to check the role of interconnection and the possibility to import in time of scarcity.

To ensure the balance between supply and demand in Tunisia during this summer, STEG took the following actions:

- Coordinate with SONELGAZ (Algeria) to secure the possibility to import up to 450MW;
- Develop measure to encourage large customers to limit their consumption during peak hours;
- Prepare communication campaigns to reach low and medium voltage consumers inviting them to reduce their consumption during peak periods;
- Review and prepare a manual rotating load shedding plan to keep the system safe as the last resort.

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