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Renewable energy in North Africa: Modeling of future electricity scenarios and the impact on manufacturing and employment

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Abstract

The transition of the North African electricity system towards renewable energy technologies is analyzed in this thesis. Large potentials of photovoltaics (PV), concentrating solar power (CSP) and onshore wind power provide the opportunity to achieve a long-term shift from conventional power sources to a highly interconnected and sustainable electricity system based on renewable energy sources (RES). A multi-dimensional analysis evaluates the economic and technical effects on the electricity market as well as the socio-economic impact on manufacturing and employment caused by the large deployment of renewable energy technologies.

The integration of renewable energy (RE) into the electricity system is modeled in a linear optimization model RESlion which minimizes total system costs of the long-term expansion planning and the hourly generation dispatch problem. With this model, the long-term portfolio mix of technologies, their site selection, required transmission capacities and the hourly operation are analyzed. The focus is set on the integration of renewable energy in the electricity systems of Morocco, Algeria, Tunisia, Libya and Egypt with the option to export electricity to Southern European countries. The model results of RESlion show that a very equal portfolio mix consisting of PV, CSP and onshore wind power is optimal in long-term scenarios for the electricity system. Until the year 2050, renewable energy sources dominate with over 70% the electricity generation due to their cost competiveness to conventional power sources. In the case of flexible and dispatchable electricity exports to Europe, all three RE technologies are used by the model at a medium cost perspective.

The socio-economic impact of the scenarios is evaluated by a decision model (RETMD) for local manufacturing and job creation in the renewable energy sector which is developed by incorporating findings from expert interviews in the RE industry sector. The electricity scenarios are assessed regarding their potential to create local economic impact and local jobs in manufacturing RE components and constructing RE power plants. With 40,000 to 100,000 new jobs in the RE sector of North African countries, scenarios with substantial RE deployment can provide enormous benefits to the labor market and lead to additional economic growth.

The deployment of renewable energy sources in North Africa is consequently accelerated and facilitated by finding a trade-off between an optimal technology portfolio from an electricity system perspective and the opportunities through local manufacturing. By developing two model approaches for evaluating the effects of renewable energy technologies in the electricity system and in the industrial sector, this thesis contributes to the literature on energy economics and energy policy for the large-scale integration of renewable energy in North Africa.

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This dissertation would not have been possible without the support and guidance of a large group of people who contributed to this work on different ways. First, I am very thankful to Prof. Dr. Dominik Möst for supervising this thesis and supporting me with scientific guidance and profound discussions during the whole process in the last years. I also want to thank my co-advisor Prof. Dr. Edeltraud Günther who was in the thesis committee and gave me additional comments and advice.

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I am grateful to work in this exciting research field of renewable energy technologies and energy economics.

Finally, I am in deep gratitude to my family for being there for me in any situation of life.

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List of abbreviations

AC	Altering current
AUPTDE	Arab Union of Producers, Transporters and Distributors of Electricity
BOOT	Build-own-operate-transfer
BOT	Build-operate-transfer
CCGT	Combined cycle gas turbine
CDM	Clean Development Mechanism
CO_2	Carbon dioxide
Coal	Hard-coal fired power plant
CSP	Concentrated solar power
DC	Direct current
DNI	Direct normal irradiance
DSM	Demand-side-management
EEHC	Egyptian Electricity Holding Company
EETC	Egyptian Electricity Transmission Company
EU-27	Member states of the European Union (27)
EUMENA	Europe and Middle East and North Africa
EUR	Euro
FNME	Energy Efficiency and Renewable Energy Fund
FTE	Full-time equivalent jobs
GCI	Global Competiveness Index
GDP	Gross domestic product
GECOL	General Electricity Company of Libya
GHI	Global horizontal irradiance
GIS	Geographic information system
GT	Gas turbine
HVAC	High voltage altering current
HVDC	High voltage direct current

IEA	International Energy Agency
IPP	Independent power producer
ISCC	Integrated Solar Combined Cycle
JEDI	Jobs and Economic Development Impact
LCOE	Levelized cost of electricity
Li-Ion	Lithium-ion battery
LP	Linear program
Masen	Moroccan Agency for Solar Energy
MIP	Mixed integer program
NaS	Sodium sulfide
NEAL	New Energy Algeria
NG	Natural gas
NREL	National Renewable Energy Laboratory
NTC	Net transfer capacity
ONE	Office National d'Electricité
PLVC	Potential of local value creation
PP	Power plant
PS	Pumped hydroelectric storage
PV	Photovoltaic
RE	Renewable energy
REAOL	Renewable Energy Authority of Libya
RES	Renewable energy sources
RES-E	Electricity produced by renewable energy sources
RESlion	Renewable Energy Sources: Linear Program for Investment and Operation
RETMD	Renewable Energy Technology Market Development Model
SAM	System Advisory Model
STEG	Société Tunisienne de l'Electricité et du Gaz
TES	Thermal energy storage
TMY	Typical meteorological year
US$	Dollar of United States of America

1 Introduction

The idea of transforming electricity systems into sustainable, highly interacting and regionally connected renewable energy power markets spreads over all continents of the world. North Africa with its extreme climate conditions in the Sunbelt has excellent geographical and meteorological potentials for large-scale deployment of renewable energy (RE). An interconnected electricity market based on high shares of solar and wind power with the option to supply Europe with electricity throws up new research questions. A renewed electricity system with many widely distributed power plants, larger electricity exchange and more interactions within the electricity infrastructure has to be developed and operated in the future.

Currently, the North African electricity system is based on conventional power generation and is weakly interconnected between countries and local regions. The economic development and population growth have led to a strong increase of electricity demand over the last twenty years. Therefore, the national electricity systems suffer from an urgent need of large modernization programs for new infrastructure such as additional power plants and transmission lines. However due to global and local limitations and a price increase of fossil resources, the countries are forced to evaluate new options in reforming their power sectors. Between 2000 and 2014, costs of wind and solar technologies have been decreased strongly. At many locations renewable energy has become competitive to other power generation technologies. To reduce environmental problems caused by global warming, future energy strategies in North Africa also have to take into account the problem of CO_2 emissions. The trend of liberalization in electricity markets to create a more efficient power sector can support investments in renewable energy technologies. However, this process has been started slowly in North Africa from the recent nearly monopolistic market structure.

In many countries, the transformation towards renewable energy sources (RES) has started with an adjustment of the energy policy and investment activities to achieve a large-scale integration of renewable energy within a time period over the next 20 to 30 years (Schleicher-Tappeser, 2012). In the long-term, it involves dramatic changes of the current technology portfolio, operational conditions of power plants, market structures and regulatory frameworks. According to Steger et al. (2005), future energy systems should fulfill three basic requirements: protecting the environment, considering the rational use of resources and respecting the society. The last topic can be interpreted as the request of the people to be integrated on a social and economic level and to benefit from this energy transformation. If the societies in North Africa can receive – after first democratic achievements of the Arab Spring – appropriate personal welfare and profit from a large-scale RE deployment, the acceptance of this transformation increases. Support for the implementation phase and extra spending for updating the electrical grid can gain additional commitment. Benefits for North African societies can be gained in particular by positive prospects for employees, companies and industries through economic growth and job creation in the sector of RE technologies. An understanding of value chain effects and an assessment of manufacturing potentials are very beneficial to confirm the expectations concerning the benefits of the renewable energy transformation.

1.1 Renewable energy in North Africa

To completely understand the effects of transforming the electricity system, knowledge of the historical developments in the power sector of North Africa is important. Average growth rates between 6% and 10% of total annual electricity demand and maximum daily peak demand are fueled by a long-term stable economic development since 1990 and high population growth rate in all North African countries from Morocco to Egypt (EIA, 2013). However, this strong growth has increased pressure on the electricity markets.

Due to the discovery and extraction of national oil and gas fields in Algeria, Tunisia, Libya and Egypt, a strong dependency on fossil fuels was established in the power sector. However, particularly in Tunisia and Egypt, today the resources no longer fulfill national energy demand anymore. Egypt currently imports oil from the Gulf countries in addition to its national resources of natural gas. Libya and Algeria have built their power plant portfolio almost exclusively on the consumption of oil and natural gas since they still have sufficient national resources. Both countries are important energy exporters to other countries of the region and to Europe. In contrast, the absence of national fossil energy resources has always made Morocco reliant on energy imports. Today Morocco and Tunisia are large energy importers and both countries have also added other conventional generation technologies such as coal-fired power plants to their generation portfolio (Supersberger and Führer, 2011). The long-term energy planning in both countries has included – stronger than in the other countries – the need of reducing the dependency from energy imports. A reasonable solution is the shift to energy sources such as wind and solar which are widely available in the countries. Due to decreasing cost of renewable energy with a parallel increase of fossil fuel prices, Algeria and Egypt started to choose a similar path in the last years.

In 2010, electricity produced by renewable energy sources (RES-E) such as wind, solar and hydro power had a share of approximately 7% of the total electricity production in the North African countries: Morocco, Algeria, Tunisia, Libya and Egypt (EIA, 2013). However, most of the RES-E stems from large hydro power plants in a few locations in Egypt (Aswan Dam) and Morocco (Al Wahda Dam and a few others). Solar and wind technologies contribute less than 1% to the generation (EEHC, 2011; ONE, 2011). Nevertheless, over the last five years, all countries have created ambitious targets to increase the share of renewable energy sources in the national electricity generation portfolios. The abundance of local renewable resources due to the geographical and meteorological conditions heavily influenced the plans of the national governments to structure their RE targets with a focus on wind and solar power. Electricity generation from onshore wind power plants, photovoltaic systems (PV) and concentrating solar power plants (CSP) play a major role within these targets. By 2030, RES-E should contribute 20% to 40% of the total electricity generation according to national targets (Brand and Zingerle, 2011). The nuclear option is recently discussed by policy-makers mainly in Egypt and Morocco, but the economic, technical and social barriers and drawbacks are relatively high compared to other technology options (Jewell, 2011; Marktanner and Salman, 2011). In the future, an integrated or partly coordinated electricity market of all countries in the region can facilitate the integration of high RES-E shares by matching of demand and supply in a larger system (Ben Romdhane et al., 2013).

In recent years, North African countries have been intensely attracted by the powerful vision of connecting their electricity markets with Europe and exporting RES-E over high voltage interconnections to Europe (Desertec Foundation, 2009). An important advantage for renewable energy sources in North Africa is the high direct solar irradiation which can be used by CSP. The dispatchable CSP technology with its integrated thermal energy storage is a key technology in these energy scenarios. In the context of this vision, the following questions arise: What RES-E quantity can be generated in a future connected and harmonized electricity system and to what price? How much electricity will be used for national consumption in North Africa? To what extent do the regional electrical grids in North Africa have to be modernized and interconnected to reduce generation costs and balance out fluctuations of RES generation? And how much electricity can be exported over different electricity corridors to Europe and what price does Europe have to pay for each MWh?

For European countries, the option of importing electricity from North Africa is a complex question dealing with technology choice and cost of electricity under the overall conditions of higher investment risks and political instability in the region which are analyzed in Lacher and Kumetat (2011), Komendantova et al. (2012), Lilliestam and Ellenbeck (2011) and Kost et al. (2011a). This large-scale electricity exchange over thousands of kilometers however is only possible if intercontinental transmission capacities are strengthened. Transmission lines using high voltage direct current (HVDC) are the basis for intercontinental Supergrids or SuperSmart Grids[1], which are required to facilitate the electricity transport without large losses over long distances between the point of generation and demand centers. For realization of the vision however, these grids have to be simultaneously installed to large-scale RES deployment.

1.2 Research questions and aim of this thesis

Research on renewable energy in North Africa identifies huge generation potentials based on the use of solar irradiation and wind supply in the region (Trieb et al., 2005). Energy strategies following a renewable energy roadmap in the Mediterranean area describe the options of electricity exchange between Europe and North Africa by realizing the potential of renewable energy sources in North Africa. This would allow exporting electricity to countries in the EU with lower generation potential or higher generation costs (Trieb et al., 2006; Scholz, 2012; Zickfeld et al., 2012; Brancucci Martínez-Anido et al., 2013; Zickfeld et al., 2013). These research studies start to evaluate the electricity systems in North Africa with or without connected electricity markets of North Africa and Europe in a target year, e.g. the year 2050. But specific contribution of each technology (renewable and conventional energy technologies), a detailed regional assessment of optimal locations for renewable energy power plants, the influence on regional grid expansions as well as a consistent deployment path for the North African electricity systems are not carried out in detail so far.

The economic activities of a large-scale deployment of RE technologies stimulate economic growth and socio-economic impact in terms of employment effects in the sector of renewable energy sources (Ragwitz et al., 2009; Rutovitz and Atherton, 2009). So far, this economic and social impact for North Africa created by potential renewable energy scenarios is less discussed in the literature although an increasing emphasis is placed on this question by decision makers in the energy sector and policy.

[1] The term "SuperSmart Grids" is described by Battaglini et al. (2009)

The overarching research question of this thesis seeks to fill this knowledge gap by linking both topics with each other.

> **Research Question 1 – Combined energy system analysis:** *What are cost-optimal development strategies (scenarios) for the North African electricity systems with large-scale renewable energy integration and what is their economic and social impact?*

To declare an electricity system "optimal", it has to fulfill multi-objective requirements of decision makers and societies. From an economic point of view, welfare optimization is achieved by minimizing total system costs consisting of expenses for extension, modernization and operation of the electricity system (Johansson, 1991). This is valid in the absence of a demand function. For a society the impact of value creation (e.g. by new manufacturing capabilities) and employment caused by a specific energy scenario might be a further decision variable. Therefore, this thesis combines the energy system analysis with a model to evaluate manufacturing and employment impact. This combination aims to satisfy the multi-objective requirements on a future sustainable energy system in North Africa (Figure 1). Annual installed power plant capacities (project pipeline) determined by an electricity market model serves as an input for the model which calculates local sales and local job creation.

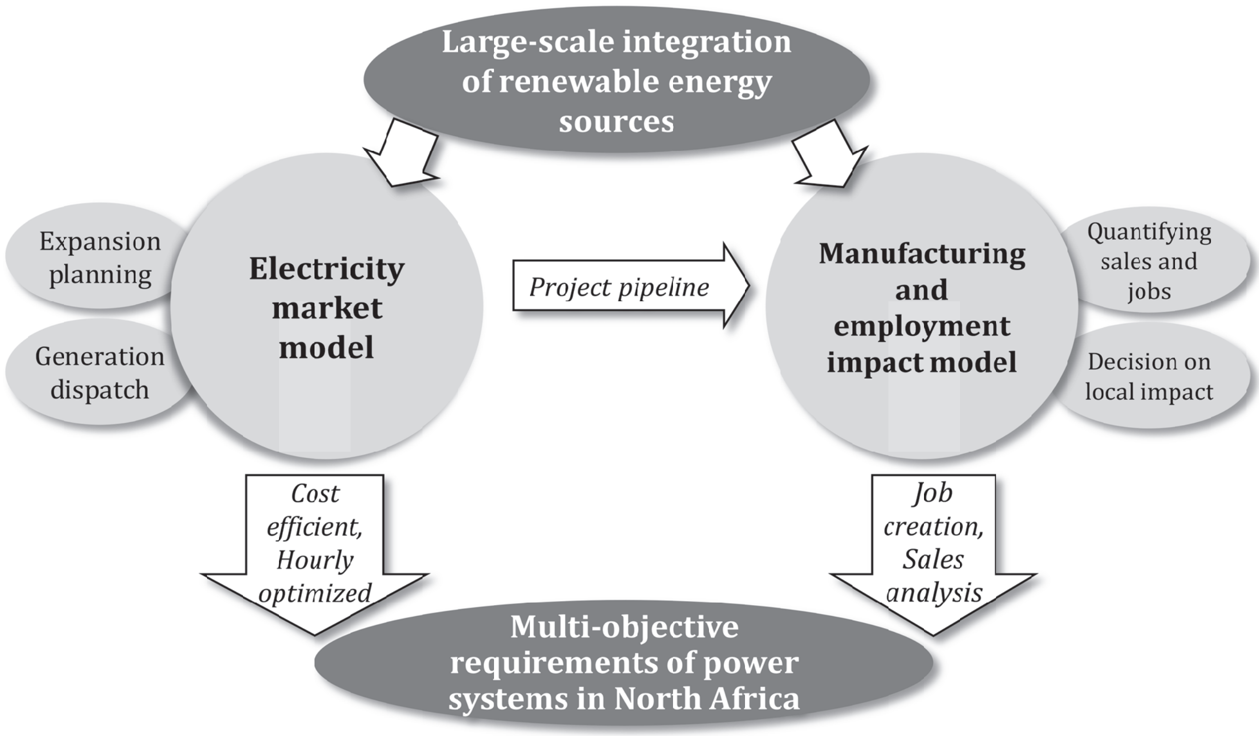

Figure 1: Structure of the combined analysis with an electricity market model and a manufacturing and employment impact model

1.2.1 Modeling of electricity systems

The first part of the thesis is focused on the analysis of the future electricity system in North Africa. Comprehensive and in-depth results for the RE deployment and integration should expand the findings of the green field analysis for North Africa described by Scholz (2012). This target should be reached by developing a bottom-up, long-term expansion planning model approach which includes a long-term perspective of new capacity planning and an hourly generation dispatch. For an electricity system with high shares of renewable energy, Nicolosi (2011) shows a modeling solution which is discussed and modified for the research questions of this thesis. The following research questions (2-5) detail the overarching research question (1) regarding the RE integration into the electricity system and the implementation into energy system models.

> **Research Question 2 – Modeling of electricity system:** *How can long-term expansion planning in the electricity system of North Africa be linked with the need of hourly energy security and an optimal hourly operation of power plants?*

The target of the electricity market model is to include the main decision parameters of the North African electricity systems to be able to analyze the large-scale integration of renewable energy into the existing power plant portfolio. The expansion of the system with a complete deployment path from today to 2050 should be obtained by the modeling.

> **Research Question 3 – Coordination of energy infrastructure:** *What are the optimal site selection for power plants and the optimal extension of the transmission grid in an integrated electricity system of North Africa?*

The site selection for RE power plants is carried out while considering grid constraints and hourly electricity demand and long-term demand forecast though 2050. The highest renewable energy potential in terms of excellent wind speeds or high solar irradiation does not mean that the electricity system positively benefits from electricity generation at these sites as the electricity transport to demand centers adds further costs to the generation. Therefore, at each site hourly operation schemes have to be identified and matched with the whole electricity system. This constraint leads to the next research question:

> **Research Question 4 – Operation of renewable energy sources:** *What are the operational implications of each technology in a future electricity system with high shares of renewable energy sources?*

Operation of RE technologies can not only be optimized for CSP with its dispatchable power generation, but curtailment of PV and wind power plants as well as the existence of energy storages also influence their future use within an electricity system. In combination with large shares of RES-E, unit commitment of conventional power plants certainly change due to decreasing full-load hours and increasing need for rapidly reacting back-up capacities.

With the model, the technical and economic implications of electricity export from North Africa to Europe are also explored:

> **Research Question 5 – Electricity exports:** *Which technologies should be selected to cover the additional electricity generation to allow export to Europe and what are the costs of such a scenario?*

By focusing the analysis on the North African electricity system, the modeling does not cover the European electricity system. The potential of electricity exports in terms of hourly generation volumes and their costs is evaluated for different export routes from North Africa to Europe.

1.2.2 Modeling of manufacturing and employment impact

Promotion of renewable energy in North Africa (and many other countries in the world) is almost always linked with the desire to create industry growth and employment in the field of renewable energy technologies. A model-based analysis of manufacturing potentials of CSP is presented in (Fraunhofer and Ernst&Young, 2011). By extending the dynamic decision model for manufacturing and employment impact, the economic and socio-economic effects are evaluated for all renewable energy technologies of the electricity market model. Therefore, research question 6 and 7 broaden the energy system perspective by the local socio-economic impact created by economic developments and employment in the RE sector.

> **Research Question 6 – Impact model for manufacturing and employment:** *In terms of company sales and employment, what is the economic and socio-economic impact of different renewable energy deployment scenarios in North Africa?*

Positive socio-economic impact is aimed in case of large RE investments and implementation strategies (IRENA, 2011). Economic activities by local companies and industries include local manufacturing of RE components and provision of construction services to install RE power plants in North Africa. The dynamic development of local industry involvement is evaluated by the decision model which calculates quantitative results related to sales and jobs creation.

1.2.3 Optimal renewable energy scenarios

A large range of models in the field of energy system analysis uses least-cost approaches to define the optimal power plant portfolio (Henning and Palzer; Pfluger; Nitsch et al., 2012). Technology options such as PV, CSP and wind power are frequently analyzed in scenarios for European countries or the US in the literature (Heide et al., 2010; Nikolakakis and Fthenakis, 2011; Zubi, 2011; Lynch et al., 2012). In addition to minimizing the total system costs for different scenarios, optimal renewable energy scenarios however often have to fulfill different policy targets besides their economic optimum within the electricity system:

> **Research Question 7 – Optimal renewable energy scenarios:** *How can a technology portfolio for the North African electricity system satisfy a multi-dimensional objective including the electricity market perspective and potential socio-economic impact?*

Following (Foley et al., 2010), the implementation of socio-economic aspects within the energy system analysis will be one of the future issues under research. In this thesis, a link is developed between the scenario results for the deployment of renewable energy sources and their impact on manufacturing and employment.

1.3 Related research

Some topics of this thesis are based on research results which are already published by the author in review journals, conference papers and research studies. This section provides a link between existing references and new research findings in this thesis.

- In contrast to the use of an energy system model in this thesis, the idea of exporting electricity from solar and wind is examined based on an LCOE approach in Kost et al. (2011a). In this paper, bundling electricity from wind power plants and CSP plants and its policy implications are discussed.
- The analysis of cost of renewable energy technologies in Europe and North Africa is published in three studies about levelized cost of electricity generated by renewable energy technologies (Kost and Schlegl, 2010; Kost et al., 2012e; Kost et al., 2013c). The cost data obtained in these studies is integrated in the models.
- An approach for optimization of design and operation of the CSP technology and its thermal storage is presented for a policy question in the Spanish electricity market and an export case of generating CSP electricity in Morocco and exporting to Europe in (Kost et al., 2012a) and (Kost et al., 2013a). This modeling concept for CSP is reflected in the implementation of the electricity system model.
- The development of the electricity system model was carried out in the Fraunhofer "Supergrid" project (a short project description can be found in Fraunhofer (2012)). The first idea of the modeling concept is presented in Kost et al. (2013b).
- A first model version of the manufacturing and employment impact model was developed for CSP in the project "*MENA Assessment of Local Manufacturing Potentials of CSP Projects*" for the World Bank (Fraunhofer and Ernst&Young, 2011). The model for CSP is extensively discussed and the idea of a regional market integration is extended in Kost et al. (2012g). In this thesis, the model is extended to PV and onshore wind power, data for CSP is updated and the model is coupled with the results of the electricity system analysis.

1.4 Structure of thesis

This section outlines the structure of this thesis (Figure 2). Following the introduction in chapter 1, chapter 2 provides the modeling fundamentals of electricity systems with high shares of electricity from renewable energy sources. By describing modeling approaches and technics applied to the North African electricity system, the research status of energy system modeling with a specific focus on optimization of electricity system is described. The electricity system in North Africa and prospects of renewable energy sources are summarized in chapter 3. The modeling approach of the electricity market model is explained with its mathematical formulation in chapter 4. After a description of the scenario assumption and input parameters, the model is applied to the electricity system of North Africa and its future development in chapter 5. The next two chapters (6 and 7) deal with the manufacturing and employment impact model and the economic and socio-economic impact analysis of the RE technologies (CSP, PV and onshore wind power). The last chapter summarizes the results of the thesis, draws conclusions regarding the effects of large-scale integration of renewable energy sources and their socio-economic impact in the North African countries and provides an outlook on further research.

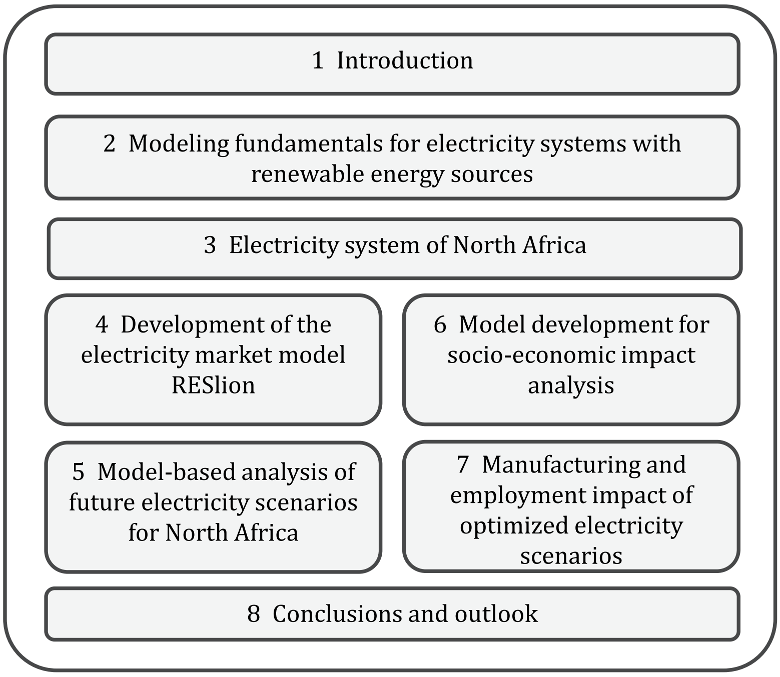

Figure 2: Structure of thesis

2 Modeling fundamentals for electricity systems with renewable energy sources

2.1 Energy system modeling

Energy system modeling is a common approach with a long research history since the 1970ies to analyze and to forecast technical and economic effects and interactions in energy systems (Connolly et al., 2010). An energy supply which satisfies all obligatory requirements of energy security, economic efficiency, consumer friendliness and sustainability is crucial for any kind of private and public activities as well as the economic progress of a society (compare Bundestag (2005)). As central decisions in the energy sector usually represent large long-term financial investments and commitments for power plants and grid infrastructure by investors and operators, in-depth assessments and long-term planning analysis of energy systems are often needed to facilitate and support the decision process (Dieckhoff et al., 2011). Mathematical or computational models can reproduce complex energy problems to allow a profound investigation of the problem. An energy system analysis includes assumptions and definitions regarding the current status or future development of specific elements in an energy system such as technological features, operational constraints or economic parameters. For a few years research activities have sought to include the market and technology characteristics of RE technologies in energy systems modeling. These novel modeling approaches for the integration of RES change and extend former modeling approaches without RES.

Energy models are able to include many different input parameters and variables in order to analyze their influence on a problem, such as an investment decision or a short-term operation decision in an interacting system. Complex technical and economic relations and interactions between technologies and applications could be expressed. By modeling these problems or decisions financial and economic risks of large investments and system operation can be diminished. Furthermore, uncertainties caused by volatile commodity prices, variable operating hours or changing specific technology costs complicate problems of the energy sector. Therefore, research in the field of energy economics assesses regional, national and international energy systems by using modeling approaches with large geographical or temporal coverage. For solving these problems, methods from the field of Operation Research such as optimization algorithms or mathematical solvers are applied.

An overview of different energy models for commercial and academic use can be found at Foley et al. (2010) and Connolly et al. (2010). A historical review of energy models published by Jebaraj and Iniyan (2006) describes the approach, first application and typical use of planning models, energy supply-demand models, forecasting models, renewable energy models, emission reduction models and optimization models from the late 1970s.

The typical **modeling process** starts with a problem formulation of the real system and the data collection and preparation. By using logic rules, system dependencies and mathematical functions the problem is formulated and implemented to serve the needs and requirements of the model developer or user (Murthy and Rodin, 1987). An iterative process can improve the model by adding further mathematic formulation or more information and data of the system. When the model is validated, the process of model experiments and calculation of model outcomes is carried out. If the model results are analyzed and satisfy the requirements of the user, results are transferred to the real system in order to obtain answers for the problem (Möst, 2010). The typical modeling process is displayed in Figure 3.

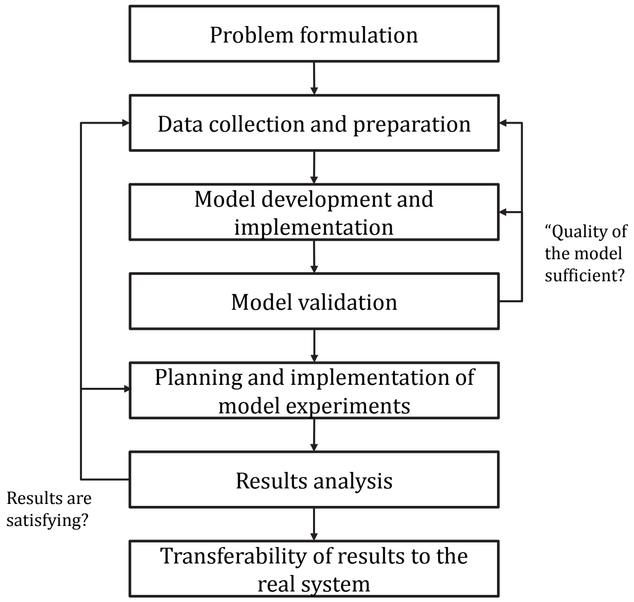

Figure 3: Modeling process for energy system analysis (Möst, 2010)

One of the main targets of a model development is to describe interactions and relations between different technology options or system components. When it comes to the decision making of stakeholders in the energy market, model outcomes can support the decision either qualitatively or quantitatively depending on the chosen model structure and approach. Model results can also help to understand the implications of a certain energy planning option in terms of economic feasibility, environmental impact and required political framework conditions. However, many model approaches simplify certain aspects of the problem or reduce the included options due to computing constraints or to facilitate the interpretation of certain result alternatives obtained by the model for decision makers (Möst and Fichtner, 2009). It is important to note that models never represent *Reality* or *Truth*, but support the understanding of potential short-term or long-term effects in a system.

To reflect the existing and future energy system, models include an abstract description of the technological and economic characteristics of existing energy infrastructure (power plants, transmission lines, energy storage systems, etc.). To simplify the model input and reduce computing time, single entities of power plants (e.g. one power block) can be aggregated to technology classes (e.g. all power plants of one technology). But these simplifications are subject to the temporal, sectorial or geographical resolution of the models and the aim of the developer or user (Remme, 2006).

The technical and economic data input for energy models can be roughly clustered into four groups (Grunwald, 2009):

- Accepted knowledge
- Expectations of future developments (supported by forecasting models)
- Ceteris-paribus conditions for issues with long-term stable settings
- Ad-hoc assumptions by the model developer to simplify the case.

The use of input data from all groups is very typical for energy system analyses. Consequently, collecting and describing of input data is a very important and challenging task of the model development.

Classification of energy models is difficult due to many different approaches and mixes of modeling methods which makes it challenging to cluster or characterize the models consistently (Möst and Fichtner, 2009). A potential classification could differentiate the models according to the following aspects:

- Mathematical approach
- Market environment and underlying economic framework
- System perspective (top-down or bottom-up approach)
- Planning horizon and scope of time:
    - Long-term energy scenarios (e.g. forecasts of demand and supply)
    - Long-term investment planning (e.g. expansion planning models)
    - Short- to mid-term operation (planning) models (e.g. generation dispatch models)
    - Short-term models for energy trading
- Geographical resolution (regional, national, international, etc.)
- Software and implementation environment

This general classification is detailed in section 2.2 for electricity models regarding the specific tasks and issues for the electricity system.

In terms of market environment and underlying economic system, different stakeholder perspectives can be implemented:

- Country perspective
- Macroeconomic perspective
- Sector perspective
- Investor perspective
- Consumer perspective

Each actor in an energy system has his personal objectives which directly influence the model structure and the modeling of the decision processes. Therefore, specific conditional relations are used to represent these different perspectives.

The country perspective and macroeconomic perspective is used when an optimal national or supra-national energy system is analyzed. In such a case, the social welfare can be optimized (maximized) or a minimization of total system cost is applied. The perspective of a society could be represented by a single entity which is described as "*social planner*" (Lynch et al., 2012). This social planner decides centrally on new power plants or transmission lines as well as on their optimal use and operation in the energy system. Moreover, he is responsible for balancing demand and supply in the energy system which is one mandatory constraint in many energy models. This means that supply side has to satisfy the basic requirement of energy security at any time, but it also has to fulfill a certain level of quality regarding the product energy or electricity. Technical requirements might be the provision of reserve energy or grid stability at each voltage level.

Nowadays, energy modeling can support the energy transition from a fossil based energy system to a system which will primarily use energy from renewable energy sources by describing potential scenarios, implementation paths and new operation strategies (Martinot et al., 2007). As this large energy transition has a long-term time horizon of years to decades, these models usually have to use forecasting techniques and scenario methods to cover these timeframes. As shown in Figure 4, predictions and forecasts for the future energy systems highly influence present decisions in the energy sector as the results provide orientation for long-term planning, fundamentals for decisions and awareness of potential problems today. Based on modeling results, recommendations for adjustment and adaptions can be formulated. As a reaction, concrete physical actions and interventions can take place to change the existing system at an early stage. Regarding the energy transition, modeling of new technologies, market structures or policy targets helps to analyze the effect of new technologies (such as renewable energy technologies) or other changes in the infrastructure.

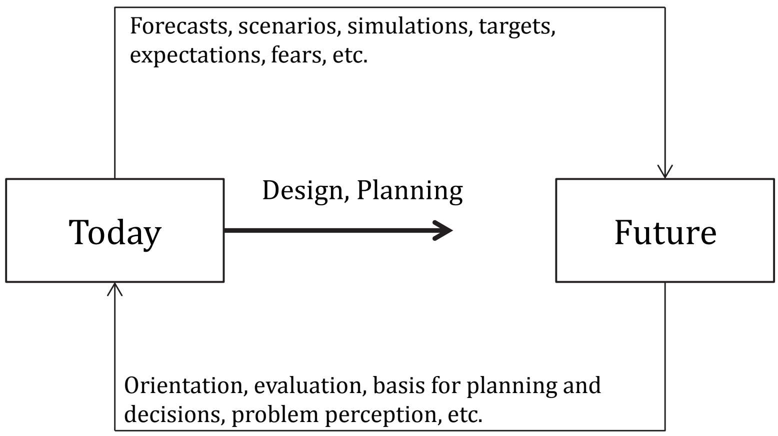

Figure 4: Theoretical decision circle according to Grunwald (2008)

Scenario analysis with different paths or development options are carried out to ensure that the bundle of scenarios covers a wide range of potential alternatives of how an energy system could change in the future, as introduced by Kahn and Wiener (1968, p.6) saying that "scenarios are hypothetical sequences of events constructed for the purpose of focusing attention on causal processes and decision points". The main principle of a scenario analysis can be demonstrated by the “Scenario Cone” which shows the relation between today and multiple future developments (Kosow and Gaßner, 2008). One of the most well-known world energy scenarios is the World Energy Outlook published by the International Energy Agency (IEA) every year.

Scenario methods are widely used in economic and social science. But a good choice of suitable scenario techniques is also highly important (Bishop et al., 2007). Börjeson et al. (2006) summarizes commonly used scenario methods in energy modeling and energy economics. The three main categories of scenarios (*predictive, explorative and normative scenarios*) could be divided into six sub-types of scenarios (Figure 5). In contrast to short-term predictive scenarios which are used to analyze the near future, explorative scenario should support the question, “what can happen” in the future (Börjeson et al., 2006). Normative scenarios are in the focus of interest for energy modeling (particular when using optimization models), as these models have explicitly normative starting points and a defined future situation or objective (e.g. integration of renewable energy sources in the energy system up to a certain share in the energy system). If such an objective is analyzed with the target of how to realize it most efficiently or most cost-efficiently, Börjeson et al. (2006) define such a scenario as an *normative preserving scenario*. However, Nowack et al. (2011) argue that normative elements can also be found in predictive and explorative scenarios to define the scenario framework. Therefore, it can be concluded that an optimization for the long-term RES integration can be defined as explorative, normative scenario if the long-term future under a normative (RES) target is analyzed.

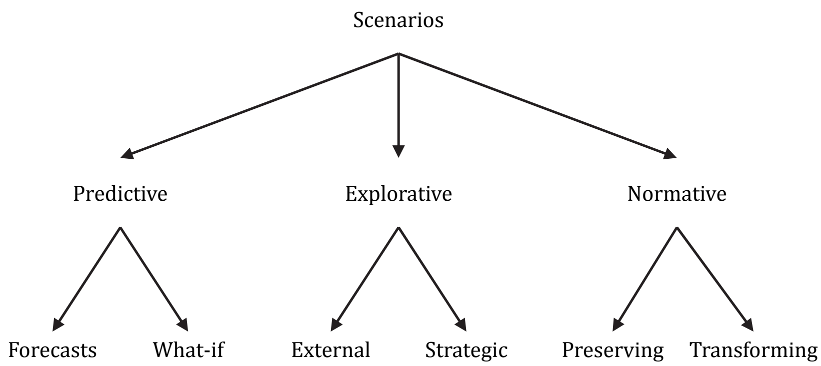

Figure 5: Scenario typology for energy systems based (Börjeson et al., 2006)

A stringent and logical development of scenarios is always mandatory as the interpretation of scenario results is widely reported as a critical issue in the literature (Götze, 1994; Millett, 2003). Kosow and Gaßner (2008) conclude from their experience that a general or formal scenario development progress does not exist due to an extensive use of scenario methods in different sciences. Therefore, they propose a general development process for scenarios based on five phases:

1) Definition of the scenario area
2) Identification of key scenario drivers
3) Analysis of these drivers
4) Generation (or modeling) of scenarios
5) Interpretation of scenarios (transfer of results)

A clear definition of the scenario development is also highlighted by Keles et al. (2011) in their paper analyzing energy scenarios of the German energy system. As the outcomes of many energy models are difficult to validate, the emphasis should be set on a comprehensible and high quality development process. During the calculation of scenario results the authors recommend an iterative procedure which includes latest knowledge and diverse views of experts for the generation of scenario results. Furthermore, the results should be improved by avoiding ad-hoc assumptions and using sensitivity analysis with a change of important input factors such as commodity prices, interest rates or wind and solar resources. Additionally, models could be extended by using stochastic distributions of input parameters to reduce uncertainties. As the use of stochastic models leads to increased complexity and higher computing effort, sensitivity analysis can solve the problem of uncertainties in a first step. When modeling long-term scenarios of renewable energy integration, it had to be further noticed that some RE technologies are in an early stage of research and deployment. Therefore, the modeling system should maintain openness for new technological discoveries and technology options which do not offer a high market maturity today (Droste-Franke et al., 2012).

It is recommended that verifiable quality of model results should be easily judged by the reader to provide sustainable benefit to him. According to Grunwald (2011), model results have to be fulfilled the following requirements if comprehensible and reasonable scenario outcomes are to be achieved:

- Integration of data and parameters (important to include various future developments)
- Consistency of results by considering external constraints or resource restrictions
- Transparency of results by describing the relations between input and output
- Consideration of a multi-perspective to include the objectives of different stakeholders
- Outcomes based on a democratic foundation as the energy system is part of the society (social acceptance)

During the modeling process, the fulfillment of these requirements is important as results could only be interpreted and used later in the evaluation phase, if these guidelines are fulfilled by the model. Therefore, the model of this thesis aims to satisfy the scenario techniques and guidelines described in the last sections. The model also should provide links between model approach and outcomes. Additionally, it is necessary to carefully describe all model parameters, the model structure and its evolution process.

However, in the beginning of an energy system analysis, a key difficulty is the **selection of the model approach** which are the best technical solution to analyze the given research questions. Modeling methods to solve planning or operation problems for energy systems use many different mathematical approaches and solutions. The final selection of the most accurate method is a long and important decision process, as the model approach primarily depends on the problem definition and research questions themselves. Additionally the available data, the structure of the data, the configuration of variables as well as the number of these variables have to be taken into account. Particularly, relations between variables and parameters or data are structured in each problem differently. These relations depend on the interactions of technologies, power plant operations or energy flows in the analyzed energy system. In the functional relation between parameters and variables, the economic impact in terms of costs or revenues can also be integrated, if the problem should be solved while taking economic aspects into account. In the case of the integration of RE technologies, new model requirements in terms of data volume, temporal resolution and technology models (wind and solar power plants) are in the field of research interest as they strongly differ from models which describe an energy market based on large-scale, flexible and centralized conventional power plants. Connolly et al. (2010) publish a survey of a large number of energy models. In this paper, they highlight that only a few of the models include RE technologies sufficiently (see also section 2.2.1). As each group of potential methods or tools has its own advantages compared to others, many different mathematical approaches and modeling tools are reported in literature.

Large **Equilibrium models** or **Input-Output models** are often used to solve long-term, macroeconomic problems, e.g. such as the long-term forecast and development of energy demand or CO_2 emissions (important models are e.g. GEM-E3 by the European Joint Research Center (Joint Research Center, 2012) and NEMESIS (Brécard et al., 2006)). These equilibrium models express an equilibrium after negotiations or dependencies between many players or firms (Ventosa et al., 2005). The solution of equilibrium models often is found in a Cournot equilibrium.

If a decision is optimized from the perspective of a single player, **optimization models** represent another important class of energy models. Optimization models often cover only a part of the total economy which consists of many other sectors besides the energy sector. However, the energy sector is modeled very carefully by using for example bottom-up approaches to match demand and supply in the energy system. Therefore, these models are classified as partial equilibrium models. An optimization program maximizes or minimizes one objective function by an optimal choice of variable values under defined constraints. Solutions represent cost-efficient or profit maximizing options that can be explored under a given technological or economic framework. Typical assumptions postulate perfect markets with perfect information. Well-known optimization models are for example MARKAL and TIMES (IEA, 2012) or EFOM (Energy Flow Optimization Model, see e.g. Grohnheit (1991)). Compared to other models, the use of an optimization model which solves the formulated objective of a problem provides the "best" solution. However, this advantage could also be a disadvantage as the real world normally does not produce such an optimum as many compromises are necessary between opposite stakeholders. Particularly, decision making in the energy sector consists of many single decisions which can be contrary to an overall optimum calculated by the optimization model. Furthermore, solving large optimization problems requires powerful algorithms which demand long computing times. Nevertheless, the potential to solve a problem by integrating all variables and parameters in a single objective function is an approach of which the logic is often understandable to others.

Besides equilibrium models and optimization models, **simulation models** are the third important class of model approaches to analyze energy systems. The specific focus of simulations is to model interactions and relations between different entities such as technologies or market participants in detail. In a simulation approach, decisions and relations of individuals (market players) and objects (technologies) are designed by implementing functional dependencies, pre-defined rules or reactions. Complex system relations and technology interactions which cannot be pressed in a (partial) equilibrium model could be modeled by a continuous simulation approach which is a more flexible model option as specific relations can be defined for each problem. Actions and reactions between different objects could be implemented to describe relations of the objects in the energy system. A drawback of the method is that each of these actions has to be pre-defined based on assumptions which have to be confirmed by reality. This limits a simulation to the pre-defined options of actions and reactions which are implemented by the user. Time steps of the simulation model usually are defined as continuous actions with limited foresight to future decisions or developments. Therefore, alternatives as well as barriers sometimes cannot be reflected or chosen in the model outcomes as they have not been considered before. Simulation models often are related to equilibrium assumptions as actors refer to the Cournot equilibrium during the decision process (Ventosa et al., 2005).

A sub-group of simulation models, **agent-based simulations**, offers more flexibility during the decision process of different objects (agents). Agents could have the possibility to start negotiations with their counterparts based on a changing environment, to learn from the past or to reflect strategic behavior based on asymmetric information or non-economic influences. Therefore, these models can be used to model market development including such behaviors of different agents (see e.g. Sensfuß et al. (2007); Held (2010); Gerst et al. (2012); Reeg et al. (2012)).

A second sub-group of simulation models, **simulations with System Dynamics**, emphasizes the use of feedback loops and delays of interactions in a system. Gaidosch (2008) highlights the strengths of System Dynamics when investment circles of power plant construction are analyzed as project delays and authorization process are a central issue of this problem. Feedback loops are used in these models to build up a chain of causal connections which have an effect on themselves. System Dynamics describe problems by using differential equations which are solved numerically. Therefore, delays and nonlinear behavior can be considered more easily.

2.2 Electricity models

The power sector – as part of the energy system – is an important research area for energy system analysis. Most of the modeling techniques which are presented in the last section are also applied to electricity systems. The decision process in terms of planning and operating an electricity system is complex due to various interactions and linkages between the different electricity generation technologies and the constraints of the electrical grid while matching demand and supply at any time. The modeling framework of electricity models in the overall context to macroeconomic models and energy system models in terms of their level of abstraction, covered technologies and treatment of input parameters is described by Kannan and Turton (2012) and presented in Figure 6. Recent literature shows the development of linking electricity models to sectoral models such as the complete building sector with heating and hot water supply (Henning and Palzer, 2012) or the mobility sector with the energy system via electric vehicles (Nitsch et al., 2012). Currently both issues do not seem of relevance for the North African electricity market[2]; therefore a link between the power sector and other sectors is less important in the following model development.

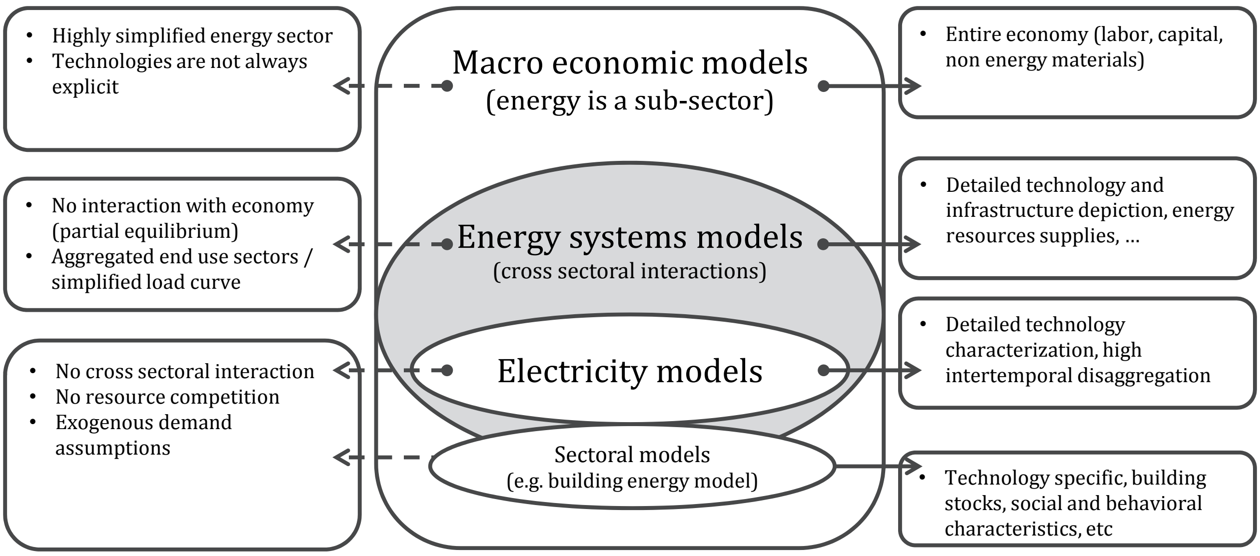

Figure 6: Model framework of electricity models (Kannan and Turton, 2012)

[2] Residential heating is not necessary due to climatic reasons; cooling (air conditioning) is included in the electricity system. Electrical vehicles are not yet a topic in North Africa.

Starting with an overview of existing approaches of electricity models, this section should set the foundation for the development of a new electricity market model in chapter 4. A special focus is set on the description of optimization models and their model structures. To determine the fundamentals for the later model development, potential objective functions of optimization models are described to summarize the approaches of formulating an objective function within optimization models for the electricity market. Another section highlights potential operational and economic restrictions of the power systems in the field of generation technologies, storages or transmission grid by a description of the mathematical formulation of these constraints. The model classifications, scenario methods and general approaches of energy models presented in section 2.1 are usually valid for electricity models.

Depending on the specific problem and research question, many hybrid models using combinations of different mathematical approaches and models exist in the research field of energy system analysis. Academic and commercial model developments which cover the power sector and electricity markets have created various approaches and classifications in the last years. With respect to the model development of this thesis, the following discussion will focus on the selection of appropriate approaches to answer the research question of this thesis.

2.2.1 Classifications and taxonomy

Electricity as a commodity itself implies different requirements to the development of electricity models (Rebhan, 2002).

First, short-term or long-term storage of electricity is only possible with energy storage systems like pumped storage power plants or batteries which have a limited availability and overall capacity due to geographical constraints or scarcity of required materials or other resources. Storage volume and capacity both are only usable up to their maximum values in a system and restrict the maximum volume of electricity which can be shifted between the generation and its final consumption.

Second, security of electricity supply is based on physical links between supply and demand centers. Thus, electricity demand only can be supplied with a sufficient transmission capacity between two points by using the appropriate voltage levels of the electricity grid. The N-1 criterion of the power sector has to be valid for any point of time. It states that a system has to be resistant to the case of an unforeseen shutdown of one facility in the system.

Third, the quality of the commodity electricity has to fulfill the technical requirements and regulations of the system in terms of frequency as well as voltage level and voltage shape as these parameters are constrained between generation and distribution.

Additionally, consumers of electricity often cannot substitute their electricity consumption to other sources or shift the consumption to other points of time as business processes (machines, computers, etc.) and domestic applications (cocking, washing machine, TV, etc.) are based on a stable supply. Demand-side management and shifting electricity consumptions currently are under investigation for the future deployment.

When planning a future electricity system by applying a modeling method, the above mentioned requirements have to be considered while choosing a modeling method and later during the technical implementation. As physical constraints like frequency stability have to be modeled in short time periods (seconds or minutes) compared to long-term investment planning which has to be analyzed over 10 to 20 years, each model has to choose its time horizon perfectly. Schweppe et al. (1988) categorize the basic functions of an electric power system by dividing its tasks into two scopes of time. In the short run, the power system has to provide a generation dispatch minute by minute between demand and supply, operate the transmission system efficiently, control the system during emergency state or set a market price to customers. In the long-term, planning issues are added to operation issues such as unit commitment, maintenance scheduling and fuel purchasing. Investment planning based on forecasting of future conditions has to take new capacities of generation units, sufficient transmission lines and capacities as well as a local distribution system to the electricity consumers into account. For the model approach of this thesis, both scopes of times will be linked in the model development. From these basic functions described by Schweppe et al. (1988), four aspects can be extracted which explicitly have to be considered during the modeling process (Krey, 2006):

- Model tasks
- Market environment
- Scope of time
- Level of uncertainties

A fundamental precondition for the selection of a best-fitting model approach or for the development of a new approach before the start of the development process is the definition of tasks and applications of the model. Therefore, the following basic questions have to be clarified and answered before starting the modeling process:

1) *Should the model represent an expansion planning, operation planning or operation management problem?*
2) *What technologies, system interactions and technical issues will be covered in the model: e.g. generation technologies, transmission lines or both?*
3) *What is the geographical coverage of the model including the aspect of geographical resolution?*

Underlying of the answers to these questions is the general market environment which is assumed or required for a certain market or a specific research question. The market environment has to be defined by using the common assumption of perfect or imperfect market (competition) between technologies or firms. This assumption has to consider the regional, national or international regulatory framework of the modeled electricity market.

With a strong dependency to the tasks of the model, the scope of time ranges from short-term time periods, in which only a few hours of power plant or grid operation management can be analyzed, to long-term planning periods, which are used by models for expansion planning with annual or even longer time steps. In Figure 7, a summary for temporal coverage in electricity models is given: The relation between the tasks in an electricity system and time horizons are linked with potential tools and the level of aggregation.

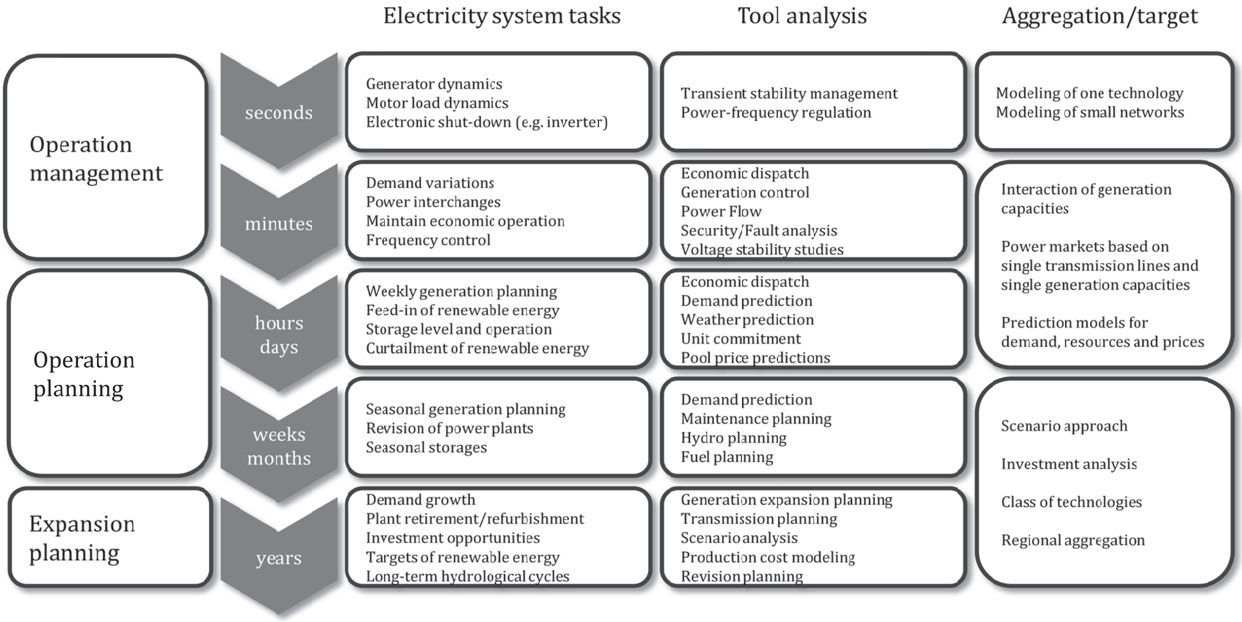

Figure 7: Relation of modeling tasks and time horizons in electricity systems (adapted based on Foley et al. (2010) and Möst and Fichtner (2009))

The available data and information of the problems support the decision which level of certainty and uncertainty can be implemented in the model. Perfect information of input parameters is given in deterministic optimization models, whereas uncertainties of demand, generation availability or resources of renewable energy have been increasingly modeled with stochastic parameters in electricity models. The liberalization of the electricity sector has raised the need for models which reflect the high uncertainties in the operation management or in the investment decision process during the last years due to high variable input parameters like uncertain weather conditions, variable fuel prices or uncertain economic and political conditions which changes operation patterns rapidly within hours or days and also overall operation hours of a technology over the its lifetime.

To evaluate the use and the application of a large number of electricity models, which fully or partly cover the integration of RES, Connolly et al. (2010) carry out a study based on interviews with developers and users of 37 energy models which are commercially available or free to download. 62% of these models use a bottom-up approach and 82% integrate district heating or the transport sector into their analysis. But only 35% of the models could model a 100% renewable energy scenario (study is undertaken in 2010). This evaluation of the data provided by the paper of Connolly et al. (2010) indicates a low coverage of renewable energy sources in existing electricity models. Currently, some efforts of model development are ongoing in the scientific community to improve or extend existing models. When analyzing the model coverage of operation and investment problems, only 24% of the models provide the option to link an analysis of operation and investment problems in one single model (Figure 8). This is an indicator that most of the models focus on either the operation planning or the expansion planning of infrastructure for energy markets. The motivation of focusing on one problem is to simplify the problem complexity compared to approaches which try to solve both problems in one model. Hourly time-steps are widely used in 41% of the models (Figure 8). One reason is that many input parameters such as electricity prices, unit commitment or resource data (e.g. solar irradiance and wind) are based on hourly values.

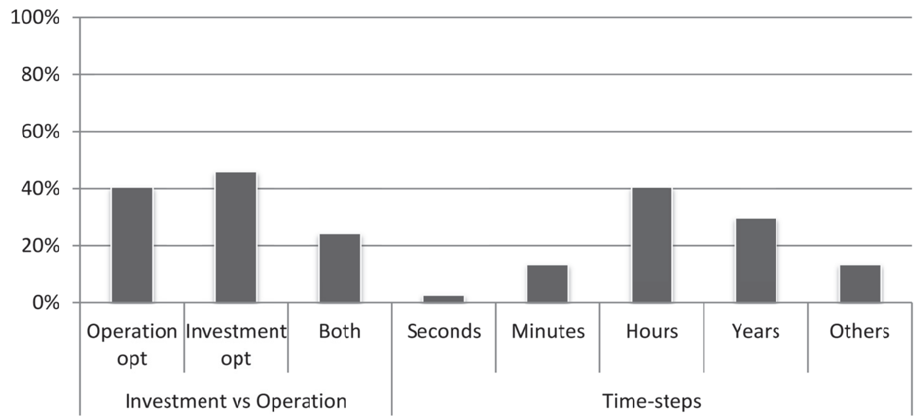

Figure 8: Evaluation of energy model characteristics based on the study of (Connolly et al., 2010)

(Short-term) operation planning and (long-term) expansion planning (investment planning) are different targets of either short-term or and long-term electricity models as it is shown in Figure 7. In cases of large integration of renewable energy sources, however, it is important to link the expansion planning with operation planning as renewable energy technologies increase the number of different operation patterns of the electricity total generation portfolio due to the decentralized and fluctuating generation from RES. Operation and expansion problems are modeled in the literature by using three main model approaches which are discussed here: Optimization models, stochastic models (often based on an optimization model) and agent-based simulation models. Due to the novel and important implications of the resource assessment of renewable energy sources and their data integration, models which try to analyze the integration of RE technologies into the electricity system have new characteristics in terms of data, technical interactions and system performance. They are described separately in section 2.4.

2.2.2 Differences between operation models and planning models

As explained in the last section, a link between a long-term and a short-term modeling horizon is important if RES integration into an electricity system is modeled. Therefore, modeling issues regarding operation models and planning models are compared in this section.

Modeling of the operational behavior of a single technology (technology models) supports operators to decide about the technical layout and the short-term operation mode. Technical operation parameters such as energy flows, temperatures or pressures are simulated in these models. In contrast to system models, technology models have their focus in analyzing the technical operation of one technology to fully understand the behavior of the technology in operation.

Interactions of operation problems between different generation entities (power plants) including grid constraints are modeled in electricity system models, e.g. generation dispatch models, grid models or pricing models to analyze the interactions and relations of technologies in operation. Temporal changes between demand and supply as well as different operation characteristics of power plants require a detailed analysis of the hourly operation of each unit in the electricity system or in the market. By modeling the unit commitment of power plants in an electricity system, costs as well as revenues of a single power plant can be calculated by taking technical operation parameters and constraints of the total system into account. Economic dispatch models also offer the potential to simulate or to forecast electricity pool prices (day-ahead or spot market) for a given electricity system by applying the market mechanism such as marginal pricing and merit order.

Without renewable energy sources such as wind and solar, the generation dispatch is analyzed for conventional power plants to obtain the optimal unit commitment under the technical constraints (see e.g. (Slomski, 1990)). These models are adapted by integration of feed-ins of wind power plants or PV (see e.g. (Wiese, 1994)). To integrate fluctuating generation from renewable energy sources, generation dispatch models can also consider the stochastic generation from wind or solar technologies (see e.g. (Hetzer et al., 2008)). Other approaches tried to connect the short-term dispatch problem with the congestion management of transmission lines (see e.g. (Leuthold et al., 2008)) or with the long-term investment planning of power plants (see e.g. (Richter, 2011)).

As the decision for new power plants requires long investment horizons and large investment volumes, the planning process includes a detailed analysis of the long-term economic and technical feasibility of the power plant. Additionally, projections and forecasts of future system developments support the planning process of utilities, transmission operators and political decisions in the power sector based on scenario and sensitivity analyses. Site selection, secondary infrastructure and economic effects (price effects) of an investment decision are therefore analyzed in expansion planning models. To consider all interactions on the market environment, the geographical coverage can range from regional and national to international electricity markets.

Over the last 20 to 30 years, a few important model families of expansion planning have been developed and are given here by adding latest publications based on these models: MARKAL (Market Allocation Model, e.g. Kannan (2011)), TIMES (The Integrated MARKAL EFOM System, e.g. Remme (2006), Pina et al. (2011)), MESSAGE (Model for Energy Supply System Alternatives and their General Environmental Impact, e.g. Borba et al. (2012)), DIMENSION (Dispatch and Investment Model for European Electricity Markets, e.g. Golling (2011)), BALMOREL (e.g. Karlsson and Meibom (2008)) and PERSEUS (Programme Package for Emission Reduction Strategies in Energy Use and Supply, e.g. Rosen et al. (2007)).

2.2.3 Typical modeling approaches

As discussed for energy models generally, optimization models and agent-based models represent widely used approaches to analyze electricity systems. Both approaches are discussed in this section to further detail the selection of the model approach of this thesis.

If electricity systems should be operated and planned on an economic evaluation, the electricity market can be optimized by maximizing profits or returns of companies or minimizing the overall system costs (Kallrath, 2009). In **optimization models**, an electricity system is implemented by the use of the graph theory with a directed graph. Nodes of the graph represent generation capacities, storage capacities or grid nodes. Electricity flows are realized by the edges. A central planner or a company optimizes the electricity system by implementing its decision variables in the objective function of the model. After solving the model, a closed solution is obtained by the optimization program (typical solvers are e.g. CPLEX, CONOPT, NLPEC, etc.). Several approaches based on mathematical optimization models are often used. An approach is usually chosen depending on the model task and the structure of variables:

- Linear program
- Nonlinear program
- Mixed integer program
- Dynamic optimization
- Genetic algorithm
- Network Flow algorithm

Optimization models normally assume a perfect market with perfect information availability (Held, 2010). The assumption of perfect foresight and perfect markets in optimization models can lead to results which are “too perfect” for the reality. For example, “option one” can be preferred by the model due a small advantage of the input parameters compared to “option two” which is only a bit worse. This minimal effect can considerably influence the results. The model can select only “option one” whereas in reality always a combination of option one and option two is chosen by decision makers.

In deregulated and liberalized energy market using increasing shares of RES-E, uncertainties increase as more independent stakeholders make decisions according to their preferences or cannot completely forecast electricity generation in a specific hour. Therefore, this increasing challenge of handling uncertainties lead to the use of stochastic elements in optimization models (but also in other models). Stochastic distributions of input parameters or the use of scenario trees are implemented in many models. Potential uncertainties range from volatile fossil fuel prices, fluctuating renewable energy sources, uncertain availability of power plants and rapidly changing political and regulatory framework conditions in the electricity system. Stochastic modeling is implemented for three different categories of problems according to Möst and Keles (2010). First, stochastic development of commodity prices is analyzed by modeling the temporal variation over days, weeks or years. Second, the development of analytical and simulative scenario generation includes a stochastic variation of the input parameters. Third, stochastic models optimize short-term market decisions (Swider and Weber, 2007) or long-term system planning (Schroeder, 2012).

A disadvantage of stochastic modeling is the higher computing time when stochastic distributions of parameters are included in the model approach. Nagl et al. (2012) compare the results of a deterministic and stochastic model approach for uncertain availability of wind and solar power plants. The stochastic investment and dispatch model gives a similar capacity development with and without modeled uncertainty of renewable resources (wind and solar). But the value of electricity from renewable energy sources is overestimated and total system costs are underestimated in the deterministic approach. Although stochastic models provide some advantages in terms of including uncertainties into the model, the high computing time reduces the possibility to implement a large amount of variables into the model. However, the findings of Nagl et al. (2012) should be considered when interpreting deterministic model results, especially the value of RES-E and total system costs.

To represent individual preferences, heterogeneity of actors and dynamic decision process in deregulated electricity markets, **agent-based modeling concepts** have been developed. An overview of different approaches and the use of agent-based models can be found in Sensfuß (2007). Agent-based models offer the potential to include the principles of evolutionary economics in the analysis of electricity markets. Optimization models require a stable equilibrium which is difficult to find for highly interdependent systems (Reeg et al., 2012). By modeling different agents such as single market players or companies, the interactions of these agents can be analyzed. Agents could embody utilities, grid operators, retail companies or market operators. In the NEMSIM model of the Australian power market, agents simulate their trading behavior on the electricity market (Grozev et al., 2005). In Germany, the PowerACE model covers the German spot market for electricity in which traders (agents) negotiate on the electricity pool price and/or the $C0_2$ emissions price (Sensfuß, 2007; Genoese, 2010). In Held (2010), development path for renewable energy sources are included to PowerACE by using cost potential curves and agent learning. Reeg et al. (2012) present the AMIRIS model in which investors base their decisions to invest in RE power plants on the availability of support schemes. Based on these market decisions, long-term deployment scenarios are derived and consequently the efficiency of the support schemes can be tested.

As described before, (agent-based) simulation models require a range of parameters and relations to describe the behavior of the agents. If an (agent-based) simulation approach would be applied for the North African electricity systems, this model would consequently use very detailed information of the different stakeholders. As the literature of the North African electricity markets and relations between potential agents is very rare, an agent-based approach would be based on many assumptions which have to be made by the author.

2.3 Optimization models

2.3.1 Basic model structure

Optimization models describe a problem by using an objective function and at least one constraint. They are solved by algorithms implemented in mathematical solvers. Optimizing the objective function is subject to a number of constraints which represent technical and economic boundaries of the problem. Typical objectives of electricity models are the minimization of costs or the maximization of profits which result from electricity generation or transmission. Related to the problem structure and characteristics of variables, different mathematical methods exist to formulate and solve a problem. If the mathematical methods are transferred in models that can be used for a wide range of applications, these models can be classified as applied mathematics (Leuthold, 2010). Many electricity models have been developed by using methods and research from the field of Operations Research in which many methods for complex problems and powerful algorithms are developed to find suitable and comprehensive solutions based on a mathematical foundation.

The general mathematical formulation of linear programs (linear optimizations) and mixed integer linear programs are presented here to show the mathematical basis for the electricity market model developed in this thesis. Linear programs (LP) are a special class of optimization models which aims to minimize (maximize) a linear function F(x) with n variables subject to equalities and inequalities. Every linear program can be transformed to the standard form. The standard form of linear programs is given by the following equations (Castillo et al., 2002).

Objective function:

$$\text{minimize } F(x) = \sum_{j=1}^{n} c_j * x_j \qquad (2\text{-}1)$$

Subject to:

$$A_1 x = b_1 \qquad (2\text{-}2)$$

$$A_2 x \leq b_2 \qquad (2\text{-}3)$$

With A_1 and A_2 as parameter matrices to the variables x_j and the right hand side parameters b_1 and b_2. Variables x_j are multiplied by parameters c_j. Maximization problems are obtained by multiplying the objective function by -1. Inequalities can be also converted from $\geq$ to $\leq$ by multiplying with -1.

If a mixed integer linear program (MIP) is used, at least one variable of x_j is restricted to natural numbers (N = 0, 1, 2, 3,….). Often this approach is chosen if binary variables are used in dispatch problems to indicate operational status as online = 1 and offline = 0. Then the following constraint is necessary:

$$\text{at least one } x_j \; \varepsilon \; \mathrm{N} \qquad (2\text{-}4)$$

2.3.2 Objective functions of electricity models

Models which optimize operation management and operation planning based on economic decision parameters include economic values (costs, revenues, etc.) related to short-term operation. Technical restrictions are implemented by the constraints. Table 1 provides an overview on the wide range of cost and revenue items that can be considered in the objective function of short-term electricity models. The list is extended from findings in different papers (Hetzer et al., 2008; Boqiang and Chuanwen, 2009; Guo et al., 2012; Schroeder, 2012).

Table 1: Items considered in objective functions of short-term operation models

Class of cost/revenue	Specific item of the electricity system
Operation costs	• Variable operation costs (auxiliary materials, wear of components, replacement, cleaning) without fuel costs • Costs for consumable goods such as fossil fuels (coal, oil, natural gas, uranium) or biomass • Load change costs • Start-up/shut-down costs • Costs for external costs such as environmental emissions (CO2 emission allowances) • Penalties for failing to meet the demand (curtailment of renewable energy sources)
Costs for provision of energy	• Costs for providing reserve capacity • Costs for providing spinning reserve (depending on kind of operating power plants) • Costs for energy security which incorporates stochastic security
Costs for electricity transport	• Costs for energy transport to consumers • Network charges
Revenues for electricity sales	• Revenues from sold energy (electricity, heat) • Revenues from flexible demand (shut down of large consumers) • Revenues from provided spinning reserve or reserve capacity • Revenues from compensations and subsidies related to sold energy

Expansion planning models take the whole life cycle of the infrastructure covered by the model into account. Expenses for new power plant and transmission lines reduced by obtained subsidies are implemented as well as costs for dismantling and recycling of power plants. In the objective function following items can be included, but final selection strongly depends on the problem and target of the model. Table 2 shows the findings which are extended from findings in different papers (Graeber, 2002; Remme, 2006; Weber, 2008; Lynch et al., 2012; Nagl et al., 2012).

Table 2: Items considered in objective functions of long-term planning models

Class of cost/revenue	**Specific item of the electricity system**
Costs for infrastructure	• Expenses of expansion (investment expenses for new power plants and transmission lines) • Fix costs for operation (staff, rents, non-consumable equipment) • Dismantling and recycling costs of power plants • Residual value after lifetime or use of power plants
Operation costs	• Variable operation costs (auxiliary materials, wear of components, replacement, cleaning) without fuel costs • Costs for consumable goods such as fossil fuels (coal, oil, natural gas, uranium) or biomass • Costs for external costs such as environmental emissions (CO_2 emission allowances) • Taxes for operation or investment • Penalties for failing to meet the demand (curtailment of renewable energy sources)
Costs for electricity transport	• Costs for energy transport to consumers
Revenues for electricity sales	• Revenues from sold energy (electricity, heat) • Revenues from provided spinning reserve or reserve capacity • Revenues from compensations and subsidies related to sold energy
Further revenues	• Compensations and subsidies for investments • Willingness to pay of consumers if elastic demand is considered

This list can be extended in relation to the market environment or problem which should be covered by the model. The optimization of electricity systems normally is carried out for economic aspects, such as the optimization of costs or profits. Therefore, cash flows which appear at different points in time have to be converted (discounted) to a base year to guarantee comparability of values from different years (e.g. by using the net present value approach). An optimization of other items and preferences in the energy system seems to be possible, but these items are often converted into economic values, see e.g. reduction of CO_2 emissions which are normally implemented by using a price for CO_2 emissions. This price is set to include costs of external effects by CO_2 emissions or it represents costs for avoiding CO_2 emissions in an emission trading system with limited CO_2 emission allowances.

2.3.3 Technical aspects of electricity systems as models constraints

The minimization or maximization of variables in the objective function is subject to further economic or technical constraints. Again, these constraints can be split into short-term operational constraints and constraints for expansion planning models which model long-term developments, new investment decisions, policy targets and security of supply. Depending on the model focus, the level of formulation of each issue is extended by using a very detailed description of the issue or is shortened or left out if the issue makes it more difficult to solve the problem. Table 3 summarizes potential constraints which are extended from findings of Slomski (1990) and Remme (2006).

Table 3: Technical and economic constraints in electricity models

Class of constraints	Specific constraint in models
Potential constraints for operation of power plants	• Maximum turbine or generator capacity limits • Restricted capacity ranges (low capacities) • Turbine efficiencies • Heat generation of power plants • Part-load behavior • Temporal potential to change capacities • Start-up/shut-down times • Minimum hours for offline and online of power plants • Revision cycles • Required spinning reserve • Constraints of availability of consumable goods such as fossil fuels
Specific operational constraints of RE power plants:	• Technical conversion from renewable energy to electricity • Generation profiles for RE technologies (exogenously generated) • Available resources (e.g. seasonal water availability) • Included storage application
Specific operational constraints of storage power plants (pumped storage power plants, compressed air storage or storage batteries)	• Conversion efficiencies • Storage losses (hourly, seasonal, etc.) • Inflow and Outflow of the storage • Storage level • Storage maximum volume • Lifetime depending on storage cycles
Potential constraints for grid operation and network flows	• Grid structure and flow mechanisms (DC-flows, AC-flows) • Maximum of net transfer capacity between nodes (regions) • Voltage levels • Transmission efficiencies and losses • Distributions losses
Potential constraints of demand	• Timely demand and its geographical distribution • Demand-side management and its behavior in the power market (electricity which can shifted to other points in time) • Import and export from the modeled area to the world around • New applications and players in the sector such electric vehicles which can react as demand or storage application

Class of constraints	Specific constraint in models
Potential constraints in expansion planning models	• Maximum new capacity and its geographical distribution • Lifetime of infrastructure (power plants, grid, etc.) • Construction time of new infrastructure (including potential delays) • Maximum annual budget to be invested • Security of supply in each time level • Relations between short-term and long-term market requirements (e.g. nuclear power phase-out, availability of resources, market framework) • Strategic targets of investment policies (e.g. investment in national key technologies) • Policy targets of renewable energy sources

When developing a new optimization model for the electricity market all required constraints should be described qualitatively in the planning process. Then, this qualitative system characterization has to be implemented regarding logical, technical or economic relations into mathematical constraints in the model. Often, a problem or issue is formulated by a large range of constraints in the mathematical model to cover a technical or economic behavior adequately. It could be necessary to start with a model using a lower number of constraints to validate the model. Later, additional constraints are added to detail a specific element in the system and to restrict potential solutions of the optimization model.

2.3.4 Combining different objectives in energy scenarios

Energy scenarios support the decision making process by providing more information concerning potential development strategies and structures of future energy systems. In this regard, optimization models can find cost-efficient solutions to the problem by minimizing overall system costs, variable operation costs or investments in new infrastructure. As seen before, one noticeable drawback of optimization models and other modeling approaches is the limitation of including only options in the evaluation process which have been identified and investigated during the implementation and development process. If long-term time horizons are covered, the uncertainty of input data increases due to unknown prospective developments in terms of cost, technology parameters or economic and political framework conditions (Börjeson et al., 2006). Another problem emerges from the difficulty of monetizing some important decision variables and technical, economic and social implications of a future energy system in the objective function of the mathematical model. These unmodeled implications of the energy system can generate negative effects on societies, e.g. permanent storage of nuclear waste is a negative effect. This long-term environmental and economic damage for the society is often not included in the decision making process for nuclear power plants. External effects of conventional power plants such as CO_2 emissions or other environmentally damaging materials can satisfactorily be included in models by adding a penalty for each produced emission entity. Especially, CO_2 emission allowances are commonly used in energy system analyses. Other environmental policies (such as national targets for RES defined by many governments around the world) can be considered in models as exogenous constraints. The support of RE technologies is either implemented by modeling the specific support mechanism or by setting quotas for the contribution of renewable energy sources.

Foley et al. (2010) propose in their paper to include further decision variables linked with socio-economic constraints in the model approaches of energy system analyses. According to the paper, socio-economic effects increasingly influence the decision making process. These additional effects should improve the economic or most cost-efficient solution, which is found by an energy model. The meaning and consequences of the solutions should be widened through the use of a multi-perspective. Due to the fact that some RE technologies still require political support in the form of an incentive programs or use a high amount of land, these requirements are justified either by environmental policy targets or socio-economic benefits. These benefits can be represented by new employment created by the installation of RE projects and component manufacturing. Other positive developments for the society are the increase of economic wealth or social security.

Today, socio-economic analyses of energy systems are carried out in separate studies. In these studies the scenario results of energy system modeling are used as inputs. This implies that socio-economic effects are discussed and evaluated after the optimization of the electricity systems. Consequently, these additional conclusions from the socio-economic analysis do not influence the outcomes of the energy system analysis as it is normally carried out by other experts. Adjustment of scenario assumptions or recalculation after linking with socio-economic parameters is often not possible. Technologies with a positive effect on a region or country on a socio-economic level could be underrated in pure cost-efficient scenarios.

Therefore, this thesis aims to combine a socio-economic objective for an energy scenario with the objective of cost minimization. In the optimization model for electricity market, it is necessary to analyze new scenario options which extensively vary the use of different technologies. Only a range of selected scenarios are then evaluated regarding their socio-economic effects caused by different technology paths.

2.4 Models for high shares of renewable energy

The transformation from an energy system based on conventional power plants to a system with high shares of renewable energy currently implies a realization of new models or extension of existing energy models to cover the new requirements adequately. The main targets are to find solutions how high shares of RES-E can be integrated in electricity systems and to analyze the effects on the system. Golling (2011) summarizes how different model approaches integrate renewable energy sources into electricity models:

- Modeling of electricity generation or deployment paths of RE technology is separated from other market players (such as conventional power plants). Focus is often set on RE deployment in connection with policy instruments.
- Modeling of power markets includes exogenous model results for renewable energy generation.
- Iterative modeling approach links generation model for conventional power plants with a separate model of renewable energy sources (e.g. residual loads after feed-in of renewable energy are iteratively linked to a conventional dispatch model).
- Integrative modeling implements all technologies in one single model approach. Allocation and operations of all infrastructure projects (power plants, transmission lines, storages, etc.) are equally reflected by using a single model.

An integrative model approach has the advantage of considering all different technologies and their relations within model. However, dividing a problem into different models with focus on specific parts of the electricity system (e.g. optimal RES expansion without parallel expansion planning for conventional power plants) can help to detail the results of a specific problem. Furthermore, this approach can facilitate solving time.

A key issue for the selection of the modeling approach covering renewable energy sources is the large amount of variables which is mainly caused by many small-sized and decentralized RE generation capacities. In contrast to large centralized conventional power plants, RE power plants produce electricity at many different locations with non-flexible generation profiles depending strongly on weather conditions. According to different site conditions and project costs, many RE power plants at different sites have to be implemented in the model to obtain a representative coverage. Three modeling solutions from the literature are presented here. They simplify the investment planning and reflect a large number of variables or increasing computing time:

a) Investment planning on a green field site with hourly time steps of one year with reduced coverage of some technologies or electrical grid (e.g. (Scholz, 2012))
b) Investment planning based on the use of (synthetic) typical days of different years while considering shut-down of old power plants (e.g. (Golling, 2011))
c) Investment planning based on full-load hours and peak-demand analysis

In case (b), the problem of choosing a few type days makes the solution very. For instance, Traber and Kemfert (2012) use only a selection of 48 hours to define the long-term technology portfolio with specific capacities per technology. In scenarios with high shares of renewable energy sources, this approach is not proven to sufficiently reflect the different weather conditions and thus electricity generation throughout the year. Therefore, the approach of using type days to simplify the expansion planning on a few representative days during one year (weekday, weekend, winter, summer) has to be extended and adapted to RES.

The following four models from literature present different solutions how large expansion problems with RES are addressed in literature. Iterative and integrative approaches are discussed in terms of their advantages and limitations.

Scholz (2012) optimizes the composition of the electricity system of one target year (e.g. 2050) for Europe and North Africa by using also a linear optimization model. Hourly generation profiles for RE technologies ae pre-processed by a C-code and input to the optimization model. A large resource assessment of renewable energy sources is based on a GIS (geographical information system) analysis to obtain the maximum of installable capacities and power generation potentials per 10km x 10km raster in Europe and North Africa. Conventional power plants are implemented by only one technology due to constraints of the computing resources and to simplify the model. Therefore a gas turbine is implemented to provide a flexible technology for the final dispatch in a scenario with high shares of renewable energy. Although the model optimizes the composition of the electricity system by using the data of one year (8760 hours), the model has to use different approaches for the reduction of model variables to be solvable within a reasonable time period. Therefore the amount of time steps of one model run was reduced to 876 hours (5 runs with only every second hour on each fifth day) and/or the number of regions was reduced from 36 to 9. To be able to use hourly data for renewable energy sources with a parallel approach of operation and investment analysis, this model the conventional power sector is almost completely reduced in the model as explained. In contrast to this, the deployment of renewable energy sources and the resource assessment including an in-depth cost potential analysis are modeled very carefully.

Golling (2011) presents a sequential approach to find cost-efficient scenarios for the EU. Firstly, the model calculates optimal RE deployment for a certain policy target which is set exogenously. Those targets can be defined according to the National Renewable Energy Action Plans by 2020 or by other long-term target. Then the model approach optimizes the conventional power plant capacities and their generation dispatch by using a linear optimization. The developed approach always selects the cheapest renewable energy sources based on levelized cost of energy in the first step of the model approach. Consequently, market value of renewable energy is not covered as interactions with the conventional power plants are not modeled in the investment decision for RE power plants. This approach is valid due to the current energy policy which helps renewable energy to enter the market under feed-in tariffs. Market value of renewable energy is only partly represented under such investment conditions. Technologies which generate electricity during hours of high demand or which provide dispatchable generation should be underestimated in this approach.

A similar approach with a separate modeling of the RE deployment is proposed by Pfluger and Wietschel (2012). In the model PowerACE-Europe, generation profiles of renewable energy sources are generated by using annual data from the PowerACE-ResInvest model described by Held (2010). In a second step, the model can optimize the European power sector including conventional storages and interconnector capacities with a least-cost approach of a linear optimization problem. The use of satellite data for PV and meteorological stations for wind helps to include the correlation between weather conditions at different sites. Therefore, the model is able to analyze the interactions of renewable energy sources in a large deployment scenario based on resource data with highly geographical resolution. Regarding their model approach of having two models, one for the investment decision of renewable energy sources and one for the final dispatch, Pfluger and Wietschel (2012) come to the conclusion that an detailed integration of renewable energy diffusion seems to be interesting. Development of conventional and renewable energy sources should be simulated simultaneously, if computing resources are available.

A combination of an investment and dispatch model is presented by Nicolosi (2011) by using Benders decomposition algorithm. In his work, the investment decision (master problem) considering different years was enriched by additional constraints obtained by Benders cuts which provide upper bounds for the investment decision of installed capacities by solving the dispatch problem (sub problem) for each month of the observation period. With an iterative approach the capacity mix is improved by each step and then the current capacity mix is used in the dispatch problem. In the analysis, it is necessary to include exogenous inputs from RES. In addition a fixed annual peak demand and a fixed annual demand are necessary in order to generate sufficient results, because the iterative approach requires several steps (13).

As shown, all four model approaches demonstrate solutions to solve the problem of large data connected with renewable energy sources by choosing methods to simplify the overall problem. Especially, the interactions between renewable energy projects and the conventional power system require simplifications which often are implemented by using iterative or reduced investment decisions. The models also limit the number of model nodes by defining a certain number of regions for Germany, Europe or North Africa (country as one region). The transmission problem is only partly covered in the models to reduce model variables (copperplate approach or one model node per country). Further transmission problems (local distribution, line losses, etc.) are excluded from the analysis to reduce the complexity of the models.

2.5 Models for North African electricity systems

Most of the models referenced before are not developed for the energy markets of North African countries. So far, studies and models analyzing the energy and electricity markets of North Africa are limited, especially those which cover more than one country. One important reason for low modeling efforts of regional energy markets is the limited interconnection of the national electricity markets which reduces the need to analyze more than one country in the past. Likewise the electricity consumption of the countries (2010: 213 TWh, sum of all countries) is relatively low compared to industrialized countries. Additionally, the operation and planning responsibility is mainly carried out by national authorities, national energy utilities and grid operators. Regarding the future development of the system, each country has a national mid-term investment plan for the electricity sector over the next five to ten years. In the last years, targets for market development of renewable energy also have been set by all of the countries (see Brand and Zingerle (2011) and Hawila et al. (2012)). Public information concerning methodology of the planning process and use of electricity market models is difficult to find. Thus, the investment plans are rarely supported, neither qualitatively or quantitatively, by modeling and publications. Following studies focus on the long-term development of the electricity market in North Africa.

The World Energy Outlook 2010 of the IEA proposes different renewable energy scenarios for the Middle East and North Africa region. Solar technologies will play a key role for the future development of renewable energy in the region due to the abundant availability of locations with excellent solar resources (IEA, 2010). Based on different policy paths for the market introduction of renewable energy technologies, the IEA develops three different scenarios which last to the year 2035. Under the assumption that current policy efforts will be stable in the future, 17% of the electricity (representing 85 TWh) will be produced by renewable energy sources in 2035 in the Current Policy scenario. Higher shares of RES-E with 26% (120 TWh) and 58% (226 TWh) coming mainly from solar or wind technologies can only be reached in scenarios which assume an active commitment of national governments to reduce CO_2 emissions and to support a fast market introduction of renewable energy technologies. The scenarios are calculated by the World Energy Model which is used by the IEA in their projections. This model reduces the electricity market of North Africa to one single region. Consequently, detailed national results could not be provided and are missing in the report.

Three scientific studies ((Scholz, 2012), (Pfluger and Wietschel, 2012) and (Brand et al., 2012)) recently modeled the electricity system of more than one of the North African countries by using optimization methods to obtain results regarding the future development of electricity markets in the region. Scenario studies like the report *MED-CSP* (Trieb et al., 2005) are not discussed here due to their different approaches which do not use mathematical models based on an hourly electricity dispatch and economic investment modeling. However, these scenario studies have to be considered as important expert views of potential scenario options of the electricity markets. In section 2.4, the methodology and model approach of Scholz (2012) and Pfluger and Wietschel (2012) are described and classified. Scholz (2012) provides results for the North African region, but Pfluger and Wietschel (2012) only give the methodology which is finally used in the report *Desert Power 2050* by Zickfeld et al. (2012) and (Zickfeld et al., 2013) which are a collaborative works between Dii GmbH (an industry association which promotes the Desertec vision) and Fraunhofer Institute for Systems and Innovation Research ISI. The results of all studies are presented below.

Brand et al. (2012) analyze the value of CSP plants in the electricity systems in the Morocco and Algeria. This paper uses also a modeling approach of both electricity systems but the markets are not linked because there is currently a low electricity exchange between both countries. With a linear optimization program for a cost minimizing dispatch and an optimal investment path the electricity markets of both countries are optimized for 32 typical days under the constraint to include a certain share of electricity generated from renewable energy sources in different scenarios by the year 2030. The results show that in Morocco and Algeria, PV is the preferred solar technology by the optimization model compared to CSP which increases its value if the PV capacities reach a certain share in the electricity markets. In Algeria large capacities of flexible gas power plants support the market entrance of PV. In Morocco, a smaller share from solar electricity was assumed which could be more easily fulfilled by the "low-hanging renewable fruits" of PV (Brand et al., 2012).

Scholz (2012) has the objective to find a low cost solution for a sustainable power supply (near 100% of renewable energy) for North Africa and Europe in an integrated model for all countries in the year 2050. A specific focus is set on a high geographical resolution for the use renewable energy resources (in the total area covered by the model). The decision criterion of the model is to minimize the overall system costs of the North African and European electricity system. System costs vary between -20% and +30% in all sensitivity analysis. A change of technology costs compared to the base cost assumptions gives a strong technology shift by a multiple as reported in the study. The model strongly reacts with an increase of PV capacities under the assumption of lower costs. In case of higher specific technology costs, the optimization can switch to other technologies by eliminating one technology completely. Therefore, sensitivity of the model is high regarding small cost changes of the selected technologies, but overall system costs are reported to be relatively stable. The study revealed that availability of sufficient transmission capacities between regions is highly necessary for an increasing share of renewable energy. But risks and barriers for these infrastructures are estimated as high due to the relevance of local and international acceptance of the projects. Storage capacities have to be sized up to 7.2% of the total generated electricity. Results for the North African region are presented in both, a connected and island-scenario (transmission between countries possible or not). In the connected scenario Algeria, Libya and Tunisia are declared as strong exporter of electricity due to their geographical location and their excellent solar resources. To a large extend wind power and PV are not selected by the model. CSP is the dominating technology in North African electricity systems due to the assumptions in the model regarding cost, lifetime and output of the power plants. CSP costs are assumed to approximately 3000 EUR/kW for a power plant with 12-hour storage in 2050. That is less than a third of 2010-costs which requires enormous progress for the CSP technology.

The report *Desert Power 2050* by Zickfeld et al. (2012) also examines the power supply in year 2050 while the path to 2050 is not considered by the model. This electricity system is mainly based on electricity from renewable energy sources and targets of CO_2 emission reduction in Europe by 95% and in North Africa by 50% of today's values. North Africa and Europe are analyzed in different scenarios by adding Middle East and Turkey to the modeled regions compared to Scholz (2012). High cost savings (33 bn EUR per year) can be reached by connecting all electricity markets and the use of the best resources of renewable energy in the whole area. Exports from MENA are calculated to be beneficial up to 63 bn EUR per year. This South to North electricity trade leads to European imports of 20% of its electricity. In the connected scenario 833 TWh are generated in North Africa mainly from wind (approx. 70%), PV (approx. 15%) and CSP (approx. 15%). Transmission capacities are calculated at 189 GW in the connected scenario between North Africa and Europe. The average system costs are calculated to 61 EUR/MWh for all regions; whereas in North Africa each additional generated MWh has a cost of 57 EUR/MWh. Morocco and Libya are identified as the largest exporter of the North African countries due to their enormous wind potential assumed in the model.

Both reports highlight the large benefits of a HVDC supergrid to exchange large volumes of electricity from renewable energy sources over long distance. The fluctuating generation from renewable energy sources is very well balanced in the total system as curtailment is relatively low. The substantial integration of renewable energy sources is shown in both models that cover a large area, but cannot give a detailed national perspective of each country as the implementation of each country as one node does not allow a detailed assessment. Whereas both studies show cost assumptions for the RE technologies in a similar range, the large difference in the technology selection, especially the different results for wind and CSP, cannot be explained without an assessment of all data and used assumptions. A detailed model description of Zickfeld et al. (2012) is missing and makes it difficult to evaluate the study results comprehensively. Both electricity system of the year 2050 are planned without taking existing infrastructure into account (e.g. from the year 2049). Dynamic developments from today to 2050 have a strong influence on the electricity system in the year 2050 and might change the outcomes. Both studies provide an insight how a new electricity system in 2050 might look like if it would be built on a green field. However, both studies do not answer the question whether the results for the electricity system are the best solutions if a continuous long-term path would be considered and optimized, e.g. a time period form today to 2060.

In 2013, the report *Desert Power – Getting started* (Zickfeld et al., 2013) was published to provide a first analysis on the path from today to 2050 (from the similar group of authors such as *Desert Power 2050*). By combining a RE diffusion model (GreenX from Technical University of Vienna) with a generation dispatch model (PowerACE), the CO_2 emission targets of the EUMENA is reached on a continuous path. In terms of power generation, the North African countries are completely based on renewable energy sources without any conventional power plants in 2050 according to the model results. Wind power remains the most important resource with about 70% of the total electricity generation, 25% comes from CSP, about 4% from PV and about 1% from hydro power. Compared to Desert Power 2050, the share of PV has significantly decreased. As costs of CSP might become competitive later in time than PV, this discrepancy of the results between both reports cannot be explained as PV deployment has to start earlier compared to CSP, but this is not projected in the results. At the same time a cost projection of 2000 EUR/kW for a CSP plant with eight hours is used which does seem to be reached as the conventional part of this technology (including the thermal storage system) exceeds the price of 2000 EUR/kW today. The results per country in terms of technology share look quite similar to the overall situation whereas PV obtains the highest share in Egypt and CSP in Algeria. In total, a capacity of 624 GW of renewable energy sources is installed in the year 2050 of the connected scenario with export. Between North Africa and South of Europe a transmission capacity of 134 GW will be installed for an electricity export from North Africa of 745 TWh in 2050. When analyzing the results of the *Desert Power* studies, Schubert and Möst (2014) indicate some critical problems of very large electricity export to Europe: The model results might be an outcome of using the green-field approach, disregard of decentralized PV and important model assumptions such as cost for grid expansion or demand forecast.

2.6 Conclusions for model development

In the literature, many different model approaches to analyze the technical interactions and economics of electricity systems are described. Optimization models are a widely used class of energy models which provide the opportunity to obtain a cost-optimized solution when analyzing the total electricity system and the contribution of each technology.

Four key issues can be summarized as current and future trends in energy system modeling based on the discussions in the previous sections 2.2 to 2.4.[3]:

1) Time perspective and temporal resolution
2) Interaction between expansion planning and hourly generation dispatch
3) Geographical information of the technical infrastructure
4) Coordination of power plants and grid structure

The development process of the electricity market model for the North African electricity system has to find modeling solutions to adequately implement these key issues.

Time horizon of the model is a key question when linking operation and expansion planning decisions. Kannan and Turton (2012) clearly emphasize the importance of two temporal dimensions: A sufficient long-term perspective should be linked with a sufficient intra-temporal resolution of the problem. Therefore two models can be connected (e.g. Golling (2011)) or a model provide two layers of time horizons (e.g. Kannan and Turton (2012)). Pina et al. (2011) also emphasize to develop a single model which includes different time steps, as high temporal resolution is mandatory when analyzing the system integration of renewable energy sources. Models which do not use two temporal dimensions split the expansion planning of renewable energy sources and the hourly operation into two separate models such as the approach of Pfluger and Wietschel (2012). In this thesis, a focus is set on implementing a model with different time horizons which covers expansion planning and operation. Additionally, a balance should be found between reducing model variables and improving coverage of renewable energy sources.

The geographical resolution required by the widely distributed RE projects has to be defined early in the model development as it has a large implications on the amount of data to be handled by the model. Typically, weather and generation profiles of many locations for renewable energy sources are included in the analysis. An often used approach is to generate cost potentials of renewable energy sources via a geographical raster and to expand the RES capacity related to the cost potential curves. However, the selection of new RE power plants is weakly connected to the requirements of the total electricity system including conventional sources and demand. Therefore, direct model integration of many explicit locations with their specific generation profiles and cost is also an option. In combination with the geographical implimentation of power plants, the electricity exchange via transmission lines which match supply and demand has to be modeled integratevely. Planning of RE power plants does not allow neglecting of technical and economic effects which are caused by constraints of the electrical grid. Similar to this, transmission losses depending on the amount of transferred electricity which also are rarely covered in existing long-term planning model should be included for a profound energy system analysis.

[3] Further modeling trends such as the modeling of market mechanisms or policy effects are less considered in this thesis.

For the model development, it can be concluded that expansion planning of an electricity system should reflect effects of the electrical grid within the investment decisions. Generation capacities (especially renewable energy sources) and grid capacities also have to be implemented with a sufficient geographical resolution. Additionaly, including of transmission losses leads to an endogenously total electricity demand (demand of consumers plus transmission losses) which is directly depended on the amount of transported electricity. As shown in section 2.5, exsting electricity scenarios for North Africa have to clearly detailed on the national and sub-national level. Integration of the existing infrastructure and development of a continous technology paths from today to 2050 are still analyzed to a low extend. Furthermore, the extension to the field of socio-economic impact expands the findings and results of an electricity system analysis. This extension is implemented and analyzed in chapter 6 and 7 after the electricity system modeling in chapter 3, 4 and 5.

3 Electricity system of North Africa

This chapter provides an outline of current energy situation in the five North African countries Morocco, Algeria, Tunisia, Libya and Egypt. A focus is set on the electricity market, power plant structure, the role of renewable energy and policy targets. A specific section in this chapter deals with the long-term development of electricity demand in each North African country. By taking a forecast for annual electricity demand from the literature into account, a transformation procedure is applied to create hourly load curves for each country from today until 2050. As additional electricity demand arises in scenarios with RES-E export to Europe, current findings and strategies for export volumes, export corridors and costs are analyzed. For long-term scenarios (including large-scale electricity export to Europe), the geopolitical situation of North Africa might be very critical. Therefore, external risks and barriers which delay or postpone development paths are identified in order to embed potential electricity scenarios in political framework conditions.

3.1 Market structure

The energy markets of all North African countries, especially the electricity sector, show a continuous and strong growth over the last twenty years. The electricity production of the five North African countries (Morocco, Algeria, Tunisia, Libya and Egypt; see Figure 9 with a geographic map of the region) has raised from 87 TWh in 1990 to 248 TWh in 2010 (EIA, 2013). This represents an average increase of annual electricity generation by 5.1% while the annual peak demand also increased by about 7% during the last years. Most important reasons for this challenging development are economic growth, demographic changes, higher electrification rates and larger private consumption for cooling, lighting, cooking and communications services. Electrification of small, remote villages and rural areas is an enormous political and social achievement which enables access to information and a higher standard of living (Bryden et al., 2013). By using subsidies to sell electricity at very low consumer prices to private households with limited funding and other consumers, the governments have strengthened their efforts to make electricity accessible and affordable to all levels of society. But, this artificial discount of the electricity has created the need of large governmental subsidies (Fattouh and El-Katiri, 2013; Hawila et al., 2014).

Figure 9: Target countries for electricity system analysis

Besides the pressure of demand growth, the electricity generation portfolio in the region suffers under a high dependency on fossil fuels.

Table 4: Electricity generation per type and fuel consumption in 2013 (AUPTDE, 2013)

Electricity generation (2013)	**Morocco** [GWh]	**Algeria** [GWh]	**Tunisia** [GWh]	**Libya** [GWh]	**Egypt** [GWh]	**Total** [GWh]
Steam Turbines	14,897	9,654	5,544	6,347	69,811	106,253
Gas Turbines	1,892	22,056	1,851	14,130	3,795	43,724
Combined Cycle	4,051	15,701	7,662	12,082	58,203	97,699
Diesel	475	464	0	0	209	1,148
Hydro	2,139	378	54	0	13,046	15,617
Wind	692	0	110	0	1,485	2,287
Solar	0	0	0	0	219	219
Total	**24,146**	**48,253**	**15,221**	**32,559**	**146,768**	**266,947**

Fuel consumption (2013)	**Morocco** [000 TOE]	**Algeria** [000 TOE]	**Tunisia** [000 TOE]	**Libya** [000 TOE]	**Egypt** [000 TOE]	**Total** [000 TOE]
Natural Gas	804	1,2817	1,875	5,647	15,095	36,238
Light fuel oil	17	196	1,1	3,229	104	3,547
Heavy fuel oil	1,176	0	16,1	870	6,551	8,613
Hard coal	2,950	0	0	0	0	2,950
Total	**4,947**	**13,013**	**1,892**	**9,746**	**21,750**	**51,348**

Due to availability of national oil and natural gas reserves, Algeria and Libya exploit their own reserves to generate electricity. Consequently, the power sector of both countries is dominated by the consumption of fossil fuels (oil and natural gas). Both countries are also energy exporters to other countries, whereas Morocco and Tunisia are energy importers without any or very limited natural gas reserves. Strategic energy roadmaps of both countries emphasize to reduce the dependency from energy imports by a shift to other new sources. The by far largest country in the region, Egypt, currently imports oil and can still use own natural gas reserves. The availability of national natural gas and oil reserves implies low cost for producing electricity as the costs for fuels are neglected in the budgeting of the governments. Consequently, calculated electricity production costs strongly differ between the countries due to the preconditions of national fuel reserves. In Algeria and Libya, the average production costs per MWh electricity produced are given by 17 and 26 US$ as costs for own natural gas and oil was assumed to be close to zero, whereas a country without large resources like Tunisia has to pay 114 US$/MWh (AUPTDE, 2011b). Therefore, the cessation of this reliance on fossil fuel imports (Morocco, Tunisia and Egypt) or export revenues (Algeria and Libya) remains another challenge for the electricity market (Supersberger and Führer, 2011).

Regarding the performance and quality of the electricity system, existing energy infrastructure often produces high losses and inefficiencies by using out-of-date generation capacities and old transmission lines or by providing limited maintenance to the electrical installations. Therefore, the need for large investments in generation, transmission and distribution capacities has increased in all countries over the last years. A long-term energy planning is required to obtain a sufficiently large amount of new power plants, which have to be planned, constructed and commissioned annually, in order to cover the strongly increasing electricity demand and to avoid regional or national blackouts. At the same time, the efforts to modernize the electrical grid have to be reinforced to secure the electricity transmission and distribution to the consumers and to reduce the number of electrical blackouts which are caused by grid congestion. The existing electrical grid is mainly based on 220 kV transmission lines with only a few 400 kV lines representing an important new backbone of the grid. The new connection by a 400 kV line from Morocco to Egypt at the coastal area is currently under development within the ELTAM initiative, which helps to stabilize the electricity exchange within one country and the exchange with neighbor countries. The national grids of Morocco, Algeria and Tunisia are synchronized with the European electricity grid of ENTSO-E (European Network of Transmission System Operators for Electricity), whereas Libya and Egypt are connected with the Middle East. Synchronization between Tunisia and Libya is intended to be achieved, but does not exist yet. The utilization rate of the existing interconnections between the countries of North Africa mostly dips below 10% per year due to the isolated electricity markets of each country. The use is mainly limited to unscheduled electricity demand in one country which can be supplied by the neighbor country at short notice. The net balance of imports and exports equals almost zero for most of the countries with a low volume of exchanged electricity. Only Morocco requires electricity imports from Spain up to 20% of its electricity consumption over the only intercontinental link with Europe in the Strait of Gibraltar (transmission capacity NTC of 1400 MW with a distance of 40 km) as Morocco is not able to cover its booming electricity demand with the national generation portfolio (MED-EMIP, 2010). High voltage direct current (HVDC) transmission lines to Europe with distance of 300 to 800 km are in an early planning stage as first feasibility studies are on the way, but realization of those lines requires additional political and financial commitment to a large-scale electricity exchange between North Africa and Europe.

In the past, the electricity markets were fully managed by governmental bodies and state-owned companies that have been responsible for generation, transmission and distribution in each country. Only the sector of generation has been partly opened to independent power producers (IPP) during a liberalization process in the last years as the sector required additional investments for new power plants to satisfy the peak demand. International investors are intended to be attracted for financing of new power plant capacities (Table 5 shows the participations and roles of stakeholders in the electricity market of each country). Consequently, an ongoing liberalization process aims to create more efficient structures within the electricity sector. However the opening process has been slowly developed in all countries for almost 15 years now. Operation and management of transmission grids is still completely the responsibility of state-owned companies which act as single buyers who collect the generated electricity and sell it to regional distribution companies.

Table 5: Market participants in North African electricity markets based on annual reports of national utilities (ONE, 2011), (STEG, 2011), (Gecol, 2011), (Sonelgaz, 2012), (EEHC, 2011)

Country	Generation	Transmission	Distribution	Share of IPP (concessions) in terms of generation (2010)
Morocco	Office National d'Electricité (ONE), IPP	ONE	ONE, concessions	53.5 %
Algeria	Sonelgaz, Shariket Kahraba Hadjeret En Nouss	Sonelgaz	Sonelgaz Spa	21 %
Tunisia	Société Tunisienne de l'Electricité et du Gaz (STEG), Carthage Power Company, SEEB (Société d'Electricité d'El Bibane)	STEG	STEG	23 %
Libya	General Electricity Company of Libya (Gecol)	GECOL	GECOL	0 %
Egypt	Egyptian Electricity Holding Company (EEHC), IPP	Egyptian Electricity Transmission Company (EETC)	Regional companies, concessions	9 %

Within the liberalization process, some efforts have been undertaken to achieve a larger international integration and harmonization of the different national electricity markets. While separation of the national electricity markets protects national market participants today, some activities exist for a future common regional electricity market which could merge the national markets into one market area. A first step of these political ambitions was commenced by the foundation the Maghreb electricity committee (Comité Maghrebin de l'Electricité - COMELEC). With an increase of the use of renewable energy, electricity exchange has to be facilitated to efficiently balance the fluctuating generation between the countries. To create more competitive market structures, transparency and open market access have to be implemented in all markets (Brand and Zingerle, 2011).

During the last years a new field of action in the power sector of North Africa has emerged as renewable energy technologies currently gain increasingly more attention by the electricity planners. Mainly wind and solar technologies moved into the focus of the expansion planning of future electricity systems due to strongly decreasing generation costs and large installations in EU countries along the Mediterranean Sea. Adding up all existing installations of solar and wind power plants, the number of RE power plants in all North African countries is quite limited. Only three smaller CSP plants have been constructed with international financing support in Morocco, Algeria and Egypt. Wind farms have been installed in Morocco, Tunisia and Egypt with a total installed capacity of approximately 800 MW in 2012. Until 2012, large grid-connected PV systems are not operated in North Africa at all. Compared to the low market penetration from renewable energy sources by the end of 2012, the policy goals to install large-scale RE power plants in North Africa are very ambitious.

3.2 National targets for renewable energy

Today, electricity generation in all North African countries is highly based on conventional fossil fuels such as oil, natural gas and coal. In Morocco and Egypt, electricity generation from hydro power plants contributes about 8 to 10% to the annual electricity mix. Generation from other renewable energy sources (mostly first wind power projects in Morocco, Tunisia and Egypt) is below 2% of the total electricity generation (Table 4). But until 2020 and 2030, ambitious RE targets have been set by national governments. An overview of the national RE targets is given in Table 6. The table also provides a summary of the detailed country analysis in the following sections.

Table 6: Status (2010) and targets (2020 and 2030) of electricity generation from renewable energy sources (data sources are given in the following subsections)

Country	Status in 2010	Target for 2020	Target for 2030
Morocco	23% RES of installed capacity (19.5% of hydro power and 3.5% of wind power)	42% RES of installed capacity (2 GW of wind and 2 GW of solar)	6 GW of wind power
Algeria	<1% RES-E (hydro power) of electricity generation	10% RES-E of electricity generation	37% RES-E of electricity generation: CSP (70%), wind power (20%) and PV (10%)
Tunisia	<2% RES-E (hydro and wind power) of electricity generation	No defined policy roadmap (study with ~12% RES-E of electricity generation)	No defined policy roadmap (study with ~12% RES-E of electricity generation)
Libya	0% RES-E of electricity generation	10% RES-E of electricity generation	30% RES-E of electricity generation
Egypt	10% RES-E of electricity generation (8.8% based on hydro power)	20% RES-E of electricity generation including 7.2 GW of wind power	not identified

3.2.1 Morocco

Due to the lack of national reserves of fossil fuels, Morocco imports over 95% of its primary energy demand in form of natural gas, crude oil, oil products, coal and electricity from abroad. Furthermore, the installed power plants are not sufficient anymore to satisfy the strongly increasing electricity demand. Additionally, the load profile shows problematic daily demand peaks during evening hours. These are reasons why Morocco has to import large amounts of electricity from Spain over the HVAC interconnection in the Strait of Gibraltar. These imports represent up to 20% of annually consumed electricity in Morocco (ONE, 2011).

To overcome the deficient national supply situation, a renewable energy strategy was formulated in 2009 to increase the energy share from own resources such as wind farms and solar power plants which can benefit from excellent weather and site conditions in Morocco. By 2020, the share of installed capacities based on renewable energy sources is targeted with 42% compared to 26% in 2008 (Benkhadra, 2009). A renewable energy law (Law 13.09 of February 11, 2010) was adopted to facilitate the grid access of RE projects at the medium and high voltage level while power purchase agreements can guarantee payments to the investors over a time period of 25 years. As these payments are oriented on the general electricity prices of ONE, the investment security and higher tariffs for the promotion of RE projects are not included in this general law (ONE, 2011). The renewable energy strategy includes specific installation targets for solar and wind power plants. By 2020, the installed capacity of wind power plants should be increased up to 2 GW, mainly at wind power sites located at the country’s Atlantic coast and in the Northern regions. In the long-term by 2030, the capacity forecasts range up to 6 GW of wind power installed in Morocco (Benkhadra, 2009). In 2009, Morocco also passed a national solar strategy for the implementation of solar power plants with a total capacity of 2 GW by 2020. By 2015, the Moroccan Agency for Solar Energy (Masen) created by the law (57.09) in spring 2010 is obliged to provide the project tenders and support the financing of 500 MW of installed CSP and PV capacities which will diversify the generation portfolio of Morocco. In a second step, the full capacity of 2 GW should be reached by 2020. Exporting electricity from renewable energy sources from Morocco to Europe could enhance the renewable energy sector by external stimulation as the existing interconnection with Spain gives the Moroccan electricity sector a potential pioneering role for a future scenario of Mediterranean electricity exchange (Kost et al., 2011a).

3.2.2 Algeria

Electricity generation in Algeria is largely based on conventional power plants which run with fossil fuels from national resources (natural gas and oil). Similar to its neighbor countries, Algeria has a strong roadmap to invest in new power plant capacities over the next 10 years. The long-term strategic plans for renewable energy sources include defined goals for the deployment of renewable electricity until 2030. In the medium term, a share of 5% should be reached by constructing first wind farms and large CSP solar fields which feed their thermal heat into the steam cycle of combined cycle plants. By 2030, the Algerian government aims the implementation of RE power plants contributing up to 37% of the total generation. The generation mix of renewable energy sources should consist of CSP (70%), wind (20%) and PV (10%) (CIF, 2009). The Ministry of Energy and Mining plans the installation of 12 GW based on renewable energy sources which means an installation of approximately 8 GW of CSP, 1 GW of PV and 1.8 GW of wind power (MEM, 2013). But installed capacities of RE projects are quite small and limited to a few pilot projects for wind onshore, PV and CSP (Stambouli, 2011). The only large RE capacity is the integrated solar combined cycle (ISCC) power plant in Hassi R'mel with an electricity capacity of 30 MW. But is generation share on the country’s electricity demand is insignificant and the wind projects are at an early stage of development although the legal support for renewable energy has been in place for several years now (Boukelia and Mecibah, 2013). The promotion of renewable energy is controlled by the Electricity Law of 5th of February 2002 which defines the financing of renewable energy projects either by premium tariffs or direct subsidies from the government. This framework offers premiums for electricity generated by renewable energy sources which range for +100% to +300% of the regular electricity prices (Tsikalakis et al., 2011). But all RE projects suffer under very low regular prices. Nevertheless, decentralized, autonomous systems have gained some attraction during the implementation phase of the rural electrification program by substituting diesel units. As large areas of Algeria are not grid-connected due to large distances of some regions from the existing electrical grid, further potential for off-grid solutions of renewable energy sources does exist in these areas (Tsikalakis et al., 2011).

3.2.3 Tunisia

Due to a relatively higher share of electricity demand by industry and tourism in Tunisia, the daily peak load appears during 1 to 3 pm. That contrasts all other North African countries which show a daily peak load between 8 and 11 pm. Similar to the neighbor countries, the generation portfolio is also based on conventional power plants (99%) which are supplied by national fuel resources and fuel imports from Libya and Algeria. Tunisia expects to increase the share from renewable energy sources during the next years as the first wind farms (total about 100 MW) are already commissioned and in operation (STEG, 2011). However, defined long-term policy goals for the development of renewable energy sources and a national strategy do currently not exist. By 2030 a total capacity of 4.3 GW from RES is planned to be reached by solar and wind projects. In 2009, the Energy Efficiency and Renewable Energy Fund (FNME) was installed to support the market introduction in Tunisia. Short-term renewable energy targets are set to share of 4.3% from RES of the electricity total generation in 2014. The achievement of targets should be provided by a high share of wind power as the wind potential at the Tunisian coast shows attractive conditions. A strategic study of renewable energy development in Tunisia projects a future share of renewable energy sources of approximately 12% in 2020 and 2030 (ANME, 2013). Small-scale solar projects of PV and CSP have been supported financially by the Tunisian Solar plan for a few years now.

3.2.4 Libya

In Libya, the electricity is completely generated by power plants using oil (62%) and natural gas (38%) (Zaroug, 2012). The state-owned utility company GECOL (General Electricity Company of Libya) is responsible for electricity generation, transport and distribution. It targets to expand the generation portfolio and to replace old oil-fired power plants by new open cycle gas turbines and combined cycle power plants in the next years. System efficiency and losses are an important issue in the power system of Libya as the efficiency of old existing power plants is reported as very low (~29% in 2006) while transmission and distribution losses account for about 14% of the total generation (Reegle, 2013).

During the revolution in 2011, a large portion of the electrical grid was damaged and construction of new power plants has been interrupted or stopped. This causes large problems for the electricity system in Libya in 2012 and 2013 as regular power cuts in the capital Tripoli show the vulnerability of the electricity system. In many evening hours available power capacity is below demand peaks (Grant and Wahab, 2012). With Egypt and Tunisia, commercial arrangements regulate the electricity exchange. However, the volume of exchanged electricity between Libya and Egypt or Tunisia is negligible. The interconnection to Tunisia should be put into practice but the synchronization with the Maghrebian-European electrical grid has failed so far.

National targets for renewable energy sources are set to 10% in 2020 and 30% in 2030 and they should be reached by the installation of large wind and solar power plants. Within the next

5 to 10 years, 750 MW of wind capacity are announced for the Mediterranean coastal area, which has a good wind potential. The Renewable Energy Authority of Libya (REAOL) was founded in 2007 and subordinated to the Ministry of Energy, Water and Gas. REAOL has the objective to implement RE projects, increase the share of renewable energy sources, coordinate the national and international industry in the field of renewable energy in Libya and define the required legislation to promote renewable energy (Zaroug, 2012). However, by 2013 the installed capacity of renewable energy sources is limited to small wind and PV power plants.

3.2.5 Egypt

The Egyptian electricity market represents the largest electricity market in the region with an annual electricity demand of 118 TWh in 2010 (which comprises about 51% of the total annual electricity demand in North Africa). Due to the depletion of national oil and gas resources, the Supreme Council of Energy declared a new energy strategy in 2008 to increase the use of RE technologies and to reduce the dependency from fossil fuels at the same time as fossil fuels provide over 90% of the generated electricity today (Ibrahim, 2012). The remaining 10% of the electricity are generated by hydro power plants at the river Nile and by recently developed wind farms in the Zafarana region along the coast of the Red Sea. In 2011, the first CSP project in Kuyamat started operation by feeding thermal energy into a combined cycle gas power plant. The electricity grid in Egypt consists of backbone line of 500 kV (connection between Aswan dam and Cairo region) and further high-voltage transmission lines of 400 kV, 220 kV and 133 kV which cover the populated Nile Valley and Delta as well as Sinai with an overall distance of 21,253 km in 2013 (AUPTDE, 2013).

The strongly increasing electricity demand in Egypt (6.7% in 2010) leads to a large annual investment demand for new power plants. Ageing generation and transmission infrastructure coupled with a rising demand of the industrial and private sector cause recurrent electricity blackouts. During the summer of 2010, these problems have resulted in problematic, nationwide electricity blackouts during peak load hours (Saad Hussein, 2012). Without private investments and larger competition in the electricity sector, it seems to be difficult for the national utility (Egyptian Electricity Holding Company EEHC) to cover the rising electricity in the long run. Therefore, the business divisions for generation, transmission and distribution of EEHC have been unbundled and separated into smaller entities during the last years to create a more liberalized market, but none of these companies have been privatized so far. In 2010, a share of about 9% of annually generated electricity is produced by independent power producers (EEHC, 2011).

For electricity generation from renewable energy sources, a long-term target of 20% is set for the year 2020, including a high share of wind power (7.2 GW). The implementation of first large-scale RE projects and framework conditions are under the aegis of the state-owned New and Renewable Energy Authority (NREA) which is active in research and testing, decides on policy frameworks and support tariffs, and holds the ownership of power plants in Egypt. Although prior grid access for electricity from renewable energy sources is already defined by law, financing and support situation of renewable energy is still very difficult in Egypt. Further barriers for renewable energy technologies are set by a market environment which puts large subsidies on fossil fuels in the electricity sector (Castel, 2012). This clearly limits the competiveness of renewable energy technologies in the Egypt energy system at the same time.

3.3 Long-term development of electricity demand

In this section, the hourly, seasonal and annual development of electricity demand of consumers in North Africa over the next 40 years is discussed intensively and is modeled for hourly values considering the key drivers for the development of electricity demand.

By 2050, the electricity demand of North African countries will strongly increase compared to today's values. Between 2004 and 2010, the peak demand increased on average between 5.5% and 8.1% per year (AUPTDE, 2011a). Consequently, large capacities of new power plants have been commissioned every year without large potential to shut down old and inefficient power plants. At the same time, annual electricity demand was raised between 3.8 % and 7.8% per year. When comparing electricity generation and consumption, generation exceeds consumption by 10% to 20% during the last years (AUPTDE, 2011a). This is an important finding as it reflects high system losses between electricity generation and consumption and needs to be implemented in the model. These system losses also depend on the structure of the electricity system and electricity theft (Fattouh and El-Katiri, 2013; Al-Shuwekhi, 2014).

The long-term electricity demand of all North African countries per year is projected to follow a continuous growth which is presented in Table 7. A study by Fraunhofer ISI forecasts the yearly electricity demand by using projections of national GDP development and population growth during the next 40 years (ISI, 2012). By 2050, the electricity demand will be about four times higher (1070 TWh) compared to a demand of 254 TWh in 2010. The average growth rate of the electricity demand is about 4% over all countries which is lower than the demand growth in the past. Egypt represents the largest electricity system in the region with about half of the total annual demand (139 TWh in 2010, 546 TWh in 2050). Highest growth rates are expected for Morocco which will be the second largest electricity market due to highest GDP and population growth. Libya, however, will show the smallest growth. One reason might be that today electricity consumption per capita in Libya (4270 kWh) is five times higher than in Morocco (781 kWh) today (IEA, 2013). A comparable forecast of electricity generated is yearly published by (AUPTDE, 2013) with 645 TWh of generated electricity already in 2024.

Table 7: Electricity demand of North African countries, data of 2010 by (EIA, 2013), projected data until 2050 (ISI, 2012)

Year	Morocco [TWh]	Algeria [TWh]	Tunisia [TWh]	Libya [TWh]	Egypt [TWh]	Total [TWh]
2010	24	36	13	22	119	214
2020	52	56	21	34	184	347
2030	90	85	31	44	272	522
2040	148	122	44	55	390	759
2050	231	165	61	67	546	1070

To analyze future electricity systems, the specific development of the electricity demand (consumption) in terms of seasonal and hourly demand has a significant impact on the system configuration of the electricity system. In many energy studies, today's hourly electricity demand is extrapolated by using an overall annual projection. An hourly shifting within one day is often neglected in energy studies of European countries, as well as in studies for North African electricity systems by Zickfeld et al. (2012) or Scholz (2012). Due to the very large increase of electricity demand and economic growth in North African countries, a change of the hourly demand curve is highly probable. In case of large changes in the hourly demand curves over time, the impact on the system analysis cannot be ignored as fluctuating energy sources, required peaking power plants or grid capacities might respond very sensitively. Since the high increase of electricity demand in North Africa will be based on an increasing industrialization of the economies and a higher share of electricity consumption by cooling technologies, a shift of the daily peak from evening hours to midday and afternoon hours can be assumed.

The projections of hourly electricity demand in Morocco and Egypt which are presented here are based on hourly demand curves of the year 2010 (hourly data from national utilities ONE and EEHC). In the projection, daily peak demand of the year 2010 between 7pm and 10pm is shifted from evening hours to midday and afternoon hours (11am to 6pm).

The weekly and seasonal course of the demand curves is considered to be similar in all North African countries. As only representative demand curves of one day from the years 2004 to 2006 are available for Algeria, Tunisia and Libya (MED-EMIP, 2010), these representative curves ($curve_{country,refday}$) have been extrapolated by using the Moroccan load curve to obtain load curves for the full year of 2010 with weekly and seasonal characteristics[4]. The hourly demand ($demand_{country,t,year}$) of each other country (Algeria, Tunisia and Libya) is therefore:

$$demand_{country,t,year} = curve_{country,refday} * \frac{demand_{Moroc,t,refyear}}{curve_{Moroc,refday}} * \left(growth_{country,year}\right) * adj_t^{ydif} \qquad \textbf{(Eq 1)}$$

with	t	: hour
	refday	: reference day (of representative curve)
	refyear	: reference year (of reference day)
	growth	: electricity demand compared to reference year in %
	ydif	: Difference to reference year (in years)
	adj_t	: adjustment of long-term daily shift $adj_t = 1.000\ if\ t \in 7\ to\ 10\ (hour\ of\ day)$ $adj_t = 1.002\ if\ t \in 11\ to\ 19\ (hour\ of\ day)$ $adj_t = 0.998\ if\ t \in 20\ to\ 22\ (hour\ of\ day)$ $adj_t = 0.999\ if\ t \in 23\ to\ 6\ (hour\ of\ day)$

The applied method provides the long-term electricity demand with hourly resolution for the next 40 years. In contrast to existing studies, this method includes the change of the daily electricity demand over time and the provision of hourly electricity demand values for all countries. Uncertainties of economic and social developments, temporary shocks and rare weather events are excluded in the demand projections.

Figure 10 shows the seasonal distribution of electricity demand in the year 2010 and 2050 for all five countries. The monthly electricity demand is up to 25% higher in summer months than in winter months due to a higher electricity demand for air conditioning. This effect is lower in Morocco due to a more temperate climate. The different sizes of electricity markets reflect the results of Table 7. By 2050, the high increase of electricity demand in Morocco will lead to Morocco being the second largest market; whereas the size of Libyan electricity market shows a relative decrease.

[4] The specific day is shifted if the country's weekend is different to Morocco; time-zones are also considered. Reference time zone is GMT+1.

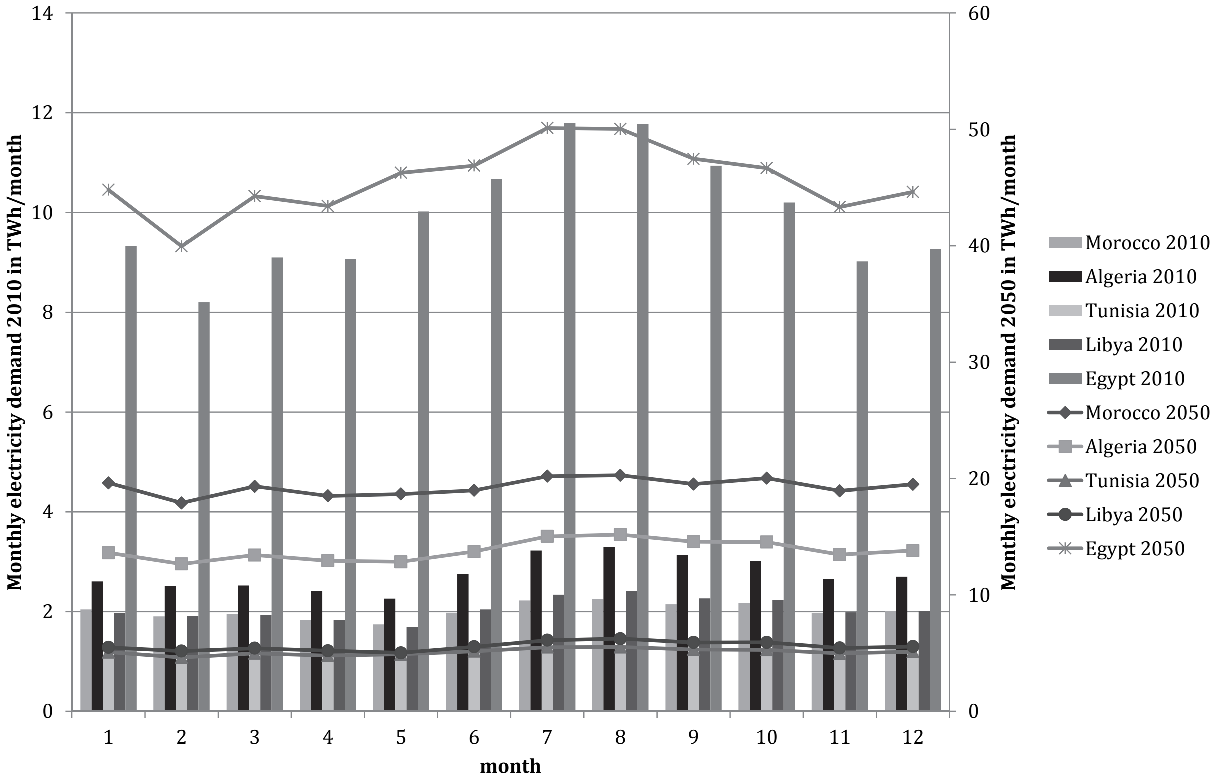

Figure 10: Modeled monthly electricity demand of North African countries in 2010 and 2050

The daily electricity demand in 2010 can be characterized by a strong increase in the morning and another steep increase during evening hours at the daily peak hours between 7 pm and 10 pm. By 2050, the demand curve is shifted to a peak demand between 1pm and 10pm (Figure 11). Today's daily peak demand can be up to 50% higher than the minimum demand. Assuming higher industrial electricity consumption, this effect is lowered in the future due to 24-hours-service of industrial production.

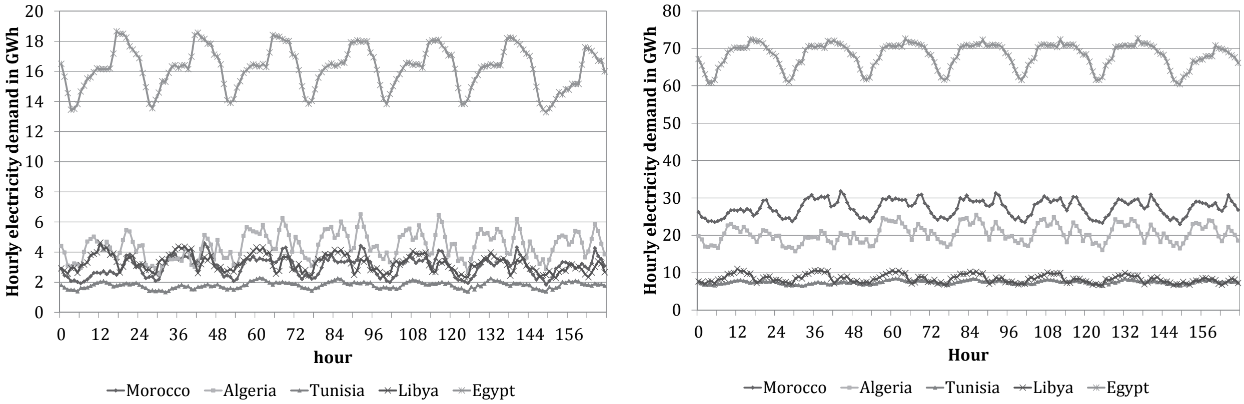

Figure 11: Hourly electricity demand in the first week in August in 2010 (left) and 2050 (right)

Due to the overall demand growth, absolute differences between the seasonal demands subsequently increase between 2010 and 2050, as well as the difference between daily minimum and maximum values enlarges. These higher daily and seasonal spreads consequently influence the structure of power plant portfolio in each country (see Figure 12 with values of Algeria).

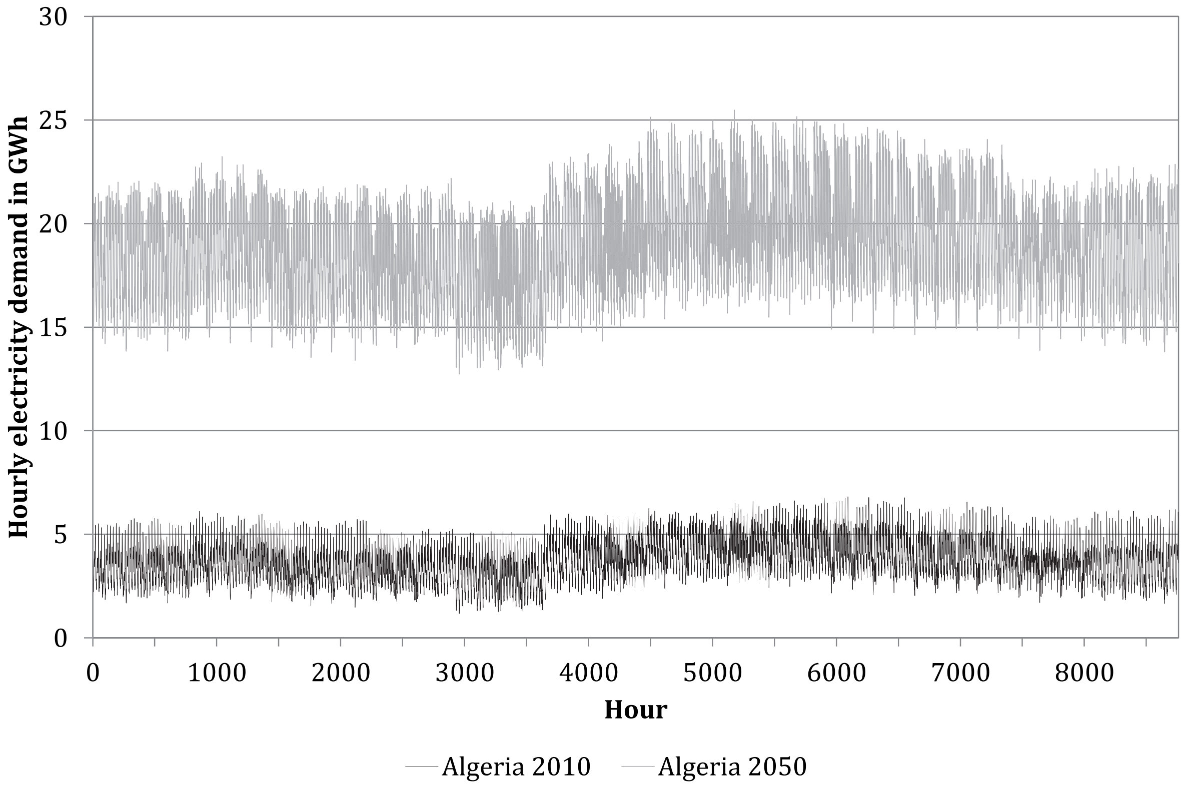

Figure 12: Hourly electricity demand of Algeria in year 2010 and 2050

To obtain regional electricity demand within each country, the national values are calculated in more detail on regional level by considering the population distribution of each country. Electricity consumption is assumed to be proportional to the population in each region (Table 33, appendix). Hourly electricity demand per model region ($demand_{r,t}$) is calculated by multiplying the population ratio of one region ($population.ratio_{r,country}$) compared to the total country with the electricity demand of the total country.

$$demand_{r,t} = population.ratio_{r,country} * demand_{country,t} \quad \textbf{(Eq 2)}$$

Consequently, the hourly demand curve of one region within a country is similar to all other regions of this country. The modeling of the hourly electricity demand development by the year 2050 represents a substantial modification and improvement compared to existing models in literature which only extrapolated a few representative type days into the future without taking into account 8760 different profiles and a shift of peak demand over time.

3.4 Electricity exports to Europe

Huge solar potentials of global and direct irradiation in North Africa have created the idea of producing solar electricity in North Africa which can be exported to Europe to diversify the RE generation portfolio regionally and technologically. In addition to the literature review in section 2.5 with a focus on the electricity model approach for North Africa, this section analyzes the results and findings regarding electricity exports to Europe.

Diversification of the European electricity system is an important advantage which could be reached by the deployment of large CSP plants with thermal energy storage. This type of technology can only be implemented in an environment with very high direct irradiation as the solar irradiation is focused on a solar receiver to reach high temperature in a thermal heat transfer fluid. Therefore Trieb et al. (2005) elaborate the potentials and prospects of a scenario in which CSP plants represent an important key stone in the power systems of North Africa and Europe. The idea of electricity exports from North Africa is extended by:

- analyses of the required transmission corridors between North Africa and Southern Europe crossing the Mediterranean Sea (Trieb et al., 2006)
- proposals of new financing and support mechanisms (Williges et al., 2010; Kost et al., 2011a)
- evaluations of import electricity into European markets and integration aspects (Egerer et al., 2009; Scholz, 2010; SRU, 2011; Zickfeld et al., 2012; Brancucci Martínez-Anido et al., 2013).

Potential transmission corridors (export lines) are displayed schematically in Figure 13, which indicates interconnections between North Africa and Europe, namely Morocco – Spain, Algeria – Spain/France/Italy, Tunisia – Italy and Libya – Italy/Greece. The figure indicates (additional required) cross-border transmission capacity connecting the markets at the borderline on both sides of the Mediterranean Sea.

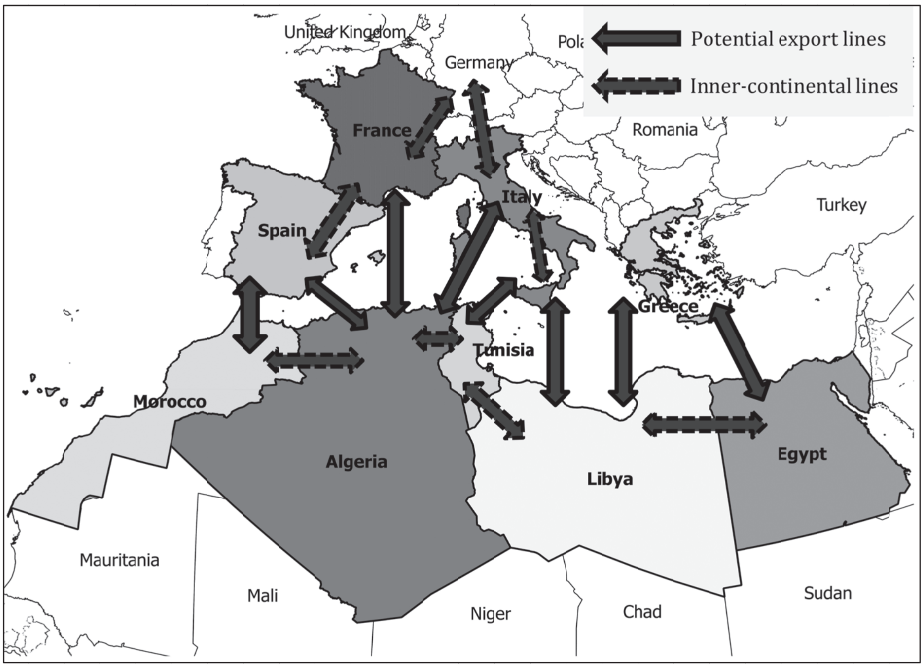

Figure 13: Potential energy flows of electricity between North African and European countries

Land resources for potential RE power plants which are needed for electricity exports are assessed by GIS based analyses which identify economic potentials of 15 to 20 TW of PV and CSP, and 3.4 TW of wind power in North Africa (Scholz, 2012). Fluctuating generation from renewable energy sources normally profits by a large regional distribution of power plants (Grossmann et al., 2012) and by an optimal technology mix in the RE portfolio (Heide et al.,

2010) due to balancing effects of weather conditions (daily and seasonal). Consequently, different technologies at many different locations should be aimed in an electricity system with a high RES-E share.

Existing studies which analyze electricity generation for export in North Africa do not give very specific results regarding the geographically optimized sites of new RE power plants (compare Scholz (2012); Trieb et al. (2012); Zickfeld et al. (2012)) as results are often aggregated to overall generation capacities per country (or group of countries). Furthermore, balanced generation portfolio are rarely calculated and proposed in those studies. For example, Trieb et al. (2012) select 11 potential sites for CSP production with a total CSP capacity of 132 GW to transfer annually 707.5 TWh to Europe (15% of demand) in 2050 without considering further technologies.

Further visionary scenarios for the European and North African electricity market are described by Zickfeld et al. (2012) and Scholz (2012). A "connected scenario" for EU and MENA for 2050 by Zickfeld et al. (2012) leads to an optimized system in which a RE capacity of 388 GW is installed in the Maghreb, 445 GW in Libya and Egypt and an interconnector capacity to Europe of 189 GW exists. In this scenario, about 70% of the installed capacity is based on wind power, and 15% based on CSP and PV respectively. This scenario covers an approximately 50% higher electricity demand in Europe compared to today with 20% of RES-E generated in North Africa. In contrast to the results of (Zickfeld et al., 2012), the RE portfolio mix of Scholz (2012) for large-scale electricity exports from North Africa to Europe (Germany) consists of a high share of CSP power plants contributing more than 85% of the generated electricity in North Africa. This contradiction might be caused by different technology cost assumptions and the underlying renewable energy potentials (wind speeds and solar irradiation). An additional discussion of these contradictory results compared to the presented work will be given in section 5.9.

The implementation of scenarios with large electricity exchange and their probability for realization are strongly depending on the economic value and costs. (Trieb et al., 2012) analyze a pure CSP scenario for export which leads to average cost for imported electricity to Europe of about 79 EUR/MWh. For CSP imports to Germany from North Africa representing about 15% of the electricity consumption, the report of German Advisory Council on the Environment assumes cost of about 148 EUR/MWh in 2011 (SRU, 2011). As low generation costs of CSP can only be reached in the long-term (2030 – 2050), exports from different renewable energy sources such as PV and wind can lower the average generation costs in the short- or medium-term (by 2030). (Kost et al., 2011a) propose a bundling of large electricity packages from wind power and CSP in order to decrease financing support and facilitate the implementation of electricity exchange between North Africa and Europe in the short-term. In 2013 and 2017, a solar-wind portfolio has levelized cost of electricity (LCOE) of 112 EUR/MWh and 101 EUR/MWh including costs of transmission, subject to specific financing schemes of first RE installations in North Africa. Such bundling of RE technologies might become the only short-term business model to export solar electricity, as financing support for pure CSP scenarios exceeds the cost for other renewable energy options in Europe (Kost et al., 2011a). In the report of Zickfeld et al. (2012), the average cost of each additional MWh generated in MENA is forecasted with 58 EUR/MWh when it is exported to Europe (in 2050). These very low values are also subject to the cost assumption and the implemented resources in this report which gives very low LCOE of wind (40 EUR/MWh), PV (45 EUR/MWh) and CSP (59 EUR/MWh) in North Africa. Compared to generation in Europe, this imported electricity can be about 15 EUR/MWh cheaper than generation alternatives in Europe. However, if all transmission fees are included, RES-E from South of Spain or Italy might be cheaper for Northern Europe than from North Africa (Schubert and Möst, 2014).

Other reports focus on the economic and technical integration of imported electricity in European electricity market. Egerer et al. (2009) calculate a potential profit for import electricity in the EU of about 70 – 80 EUR/MWh in 2030, which increases to 90 EUR/MWh and 100 to 110 EUR/MWh in 2050 due to increasing prices of other generation technologies in Europe. However, these profits are based on very low cost assumptions for CSP and transmission to Europe. Electricity from North Africa is mainly sold in Spain, France and Italy in 2050. This finding points out a potential need of electricity exports to Europe as generation prices in Europe can also increase due to the higher RES-E shares in the electricity system by 2050. Then, higher RES-E shares and fluctuating RE feed-in in Europe might require a wider distribution of generation capacities and the use of dispatchable CSP generation at locations with above-average solar conditions in North Africa.

The paper of Brancucci Martínez-Anido et al. (2013) adds some further European aspects, but also gives a detailed analysis for the Italian electricity market with electricity imports from North Africa. Electricity imports reduce the price for electricity in Europe due to cheaper generation cost, but this effect is higher in Southern Europe compared to Northern Europe as transmission and demand restrictions limit the exchange with Northern Europe. Replacement of other generation capacities in Europe takes place mainly by reducing the need for gas and coal power plants. The analysis of national effects in Italy indicates a high utilization rate of import transmission lines (about 80%) due to the competitive import electricity on the Italian market. However, a high import share into the national grid introduces the need for larger grid extension within the national electricity markets as the transmitting capacity of the electricity might reach its limits (e.g. in Southern Italy).

The large amount of potential electricity export in the *Desert Power* studies and Scholz (2012) creates a range of problems for the realization of transmission lines and the integration into the European electricity market. As the electricity export is a model result, Schubert and Möst (2014) compare these reports with national studies commissioned by the German government. The authors find out very large differences between national studies and results of the *Desert Power* studies. The share of RES-E from external sources (26-30%) clearly exceeds the scenarios of the German government. In addition to the reasons such as the use of green-field or specific scenario assumption which is mentioned before, the aim of national energy security with local generation capacities seems to be implemented with a reduced approach. In contrast to the *Desert Power* studies, Schubert and Möst (2014) conclude that electricity exports from North Africa can contribute to the energy transition in Europe (Germany), but the expectations should be clearly lower than the model results of the mentioned studies. However, exports from North Africa are important from a system perspective, if resources in Europe are already used or widely distributed generation can balance local weather conditions more effectively.

Following conclusions can be drawn for the scenario development and analysis of integrated electricity markets in North Africa with potential to export electricity from renewable energy sources to Europe:

- Literature shows high benefits for an optimized energy mix which is based on a balanced portfolio using different RE technologies.
- Wide-spread regional distribution of renewable energy sites (locations of power plants) is beneficial for the total system.

- Identification of transmission corridors and grid extensions is rarely connected with RES scenarios for North African electricity systems. But national developments in North Africa and corridors for electricity exports should be implemented in an energy system analysis and electricity scenarios.
- Specific identification of optimal sites which host generation capacities for national electricity demand in North Africa and for electricity export is necessary for reliable national energy scenarios.
- As existing scenarios show strong dependencies on the selection of technical and financial parameters, a careful analysis of these parameters in North Africa is important to obtain reasonable and reliable modeling results of the electricity system and generation cost.
- Required fossil back-up capacities should be identified to also project the long-term planning of conventional power plants in addition to scenarios for renewable energy sources. This aspect is very limited in current scenarios in the literature.

3.5 Geopolitical risks for the electricity system

In Europe, very high concerns regarding political stability and security situation in North African countries exist. Geopolitical risks are often mentioned as a key drawback for the success of RE projects in North Africa which will supply European consumers. Additional costs for back-up capacities in Europe in case of a sudden breakdown of supply from North Africa might lower the benefits from electricity exports. On the other hand, national realization of RE targets by North African countries also has to overcome large barriers and problems. Therefore, geopolitical risks generally are a critical aspect for all renewable energy projects in North Africa although all energy infrastructure projects underlie large external risks during their planning process and operational use. Therefore, this section summarizes current framework conditions and future boundaries for a large-scale integration of renewable energy sources for domestic and export use. Komendantova et al. (2012) identifies three relevant classes of risk: regulatory, political and force majeure risks. This classification is extended to the following risks of future electricity systems with a high share of RES:

1) **Regulatory risks:** For the construction of new power plants, the regulatory framework has to be clear and stable over a long period to lower investment risks. Higher regulatory risks by uncertain tariffs or uncertain guarantees by national governments increase financing cost for RE projects in North Africa.

   For electricity exports, regulatory risks mainly exist regarding the remuneration schemes of exported electricity and the availability of sufficient transmission capacity to Europe after commission of new RE power plants. Responsibilities between North African and European authorities as well as grid operators and utilities are not defined yet.

2) **Political risks:** Recent political changes in North African countries also influence the success of RE projects as the uncertainty of long-term policy frameworks and security situation has increased.

   To classify political risks for electricity exports, (Lacher and Kumetat, 2011) evaluate the political and terroristic threats for an energy infrastructure (power plants and transmission lines) by comparing electricity export with the existing natural gas export of Algeria. First of all, the authors distinguish between governmental decisions which could threaten the energy supply and terroristic activity, insurgency and sabotage. They conclude that North African countries have been reliable energy exporters and problems within or between North African countries did not reveal any influence on the export of natural gas in the past. Furthermore, the authors point out, that exporters will lose revenues if they interrupt electricity exports to Europe as the good "renewable electricity" cannot be stored for later use. On the other hand, it is highlighted that wide-spread RE projects are difficult to be protected by security forces. Also, damage of high voltage transmission lines which carries large amount of energy can deeply impact the national and international electricity system.

3) **System vulnerability:** Grid stability and security of supply increase their significance in scenarios with high RES-E shares in an electricity system as need for operational interventional and short-term (re)-dispatch should be higher. Growth of electricity exchange across different countries leads to higher dependencies of the national electricity systems.

   A sudden stop or severe reduction of energy export can affect the electricity system of the importing country dramatically, as reaction speed of customers in importing countries is depending on the time of activating local control and reserve capacities in Europe (Lilliestam and Ellenbeck, 2011). The authors present a scenario analysis of sudden stops of electricity exports from North Africa to Europe. On such occasions, the costs for European countries increase strongly due to the effects on economy and society, but the losses for exporting countries are relatively modest as only revenues of electricity export are affected. This bargaining power of North African countries is important to note for the electricity security in Europe. Nevertheless, large-scale export scenarios might only enhance considerable vulnerability to Europe, if a jointed action of export stop is organized. The rather limited weight of a single country on the power market can hardly destabilize the European power market as exchanges between European electricity markets commonly balance disruption of external supply (Lilliestam and Ellenbeck, 2011).

Recently, it has been reported that in Libya the electrical grid and transformers had been under attack and in Tunisia wind farms had do shut down due to damage during and after the national revolutions in 2011 (Dodd, 2012; Chikhi, 2013). This emphasizes the need for a stable political situation in North Africa which guarantees a secure environment for large RE power plants and new interconnections. However, geopolitical risks are not technology specific if national generation and supply are covered. In case of electricity exports, a further risk dimension for the European electricity market has to be considered. Model results and electricity scenarios, however, should weight the advantages of a large interconnected electricity system with the risks created for the different stakeholders. Implementation of all risk factors into the energy system analysis (optimization model) would strongly increase the model size and model horizon. Therefore, a risk analysis of electricity scenarios is carried out during the interpretation process and transformation on the real system.

4 Development of the electricity market model RESlion

For the model based analysis of the long-term development of the electricity systems in North Africa with large-scale integration of renewable energy sources, an optimization model called RESlion[5] with a linear programming approach is presented in this chapter. Firstly, the main model requirements and modeling goals are defined to circumscribe the scope and the limits of the model approach. In this regard, this chapter also is mainly focused on providing the information on modeling approach and underlying assumptions as well as a detailed description of the electricity market model. An important part of the model is the prepossessing of hourly electricity generation profiles of renewable energy sources at different locations. Therefore, the implementation and use of external technical performance tools are described. However, a large part of this chapter represents the detailed description of the RESlion model and its mathematical formulation. Key model elements are the investment decision for new infrastructure projects and the operation of generation capacities, transmission lines and storage systems within an electricity system.

4.1 Model requirements and modeling goals

Before specifying the methodological approach of the electricity market model, technical and economic requirements and modeling goals are conducted from the required aggregation level, available input data, temporal and geographic coverage as well as from technological parameters. Some of these requirements are caused by existing energy market frameworks. But most of them are derived from the research questions regarding optimal technology choice and large-scale integration of renewable energy sources into the electricity system of North Africa.

1) **Link between expansion planning and operation**: The two problems of long-term expansion planning and the hourly operation (generation dispatch) of power plants by considering the constraints of the transmission grid have to be analyzed to evaluate the long-term development of the electricity systems.

2) **Focus on electricity markets:** The model is focused on the electricity systems and markets of North African countries and does not analyze other sectors such as the transportation and heating sector. As the heating sector in North Africa is relatively small, private and commercial consumption of energy for heating is mainly based on electricity. Further energy consumption usually takes place in industry (process heat) or transportation sector. Cooling by conventional air-conditioning systems is typically supplied by electricity as well. The transportation sector is excluded as the integration of renewable energy sources and the link to the European energy markets are limited.

[5] RESlion: ***R***enewable ***E***nergy ***S***ources: ***L***inear program for ***i***nvestment and ***o***peratio***n***)

Electric vehicles are not covered as currently this issue is not under research or discussion for the North African market.

3) **Interconnections with Europe**: The electricity market model should include the electricity demand and supply of the five North African countries (Morocco, Algeria, Tunisia, Libya and Egypt) and their potential interconnections to Southern Europe through the Mediterranean Sea via high voltage cables. Today, only the existing interconnection between Morocco and Spain in the Strait of Gibraltar with a maximum net transfer capacity (NTC) of 1400 MW offers potential for electricity exchange between North Africa and Southern Europe. Due to the strong demand increase in Morocco, this line is used for Moroccan electricity imports from Spain up to 10% of the electricity demand in Morocco today. However, the model will define the European electricity markets of Spain, France, Italy and Greece as demand nodes for electricity export from North Africa to Europe as exporting electricity to Europe seems to be more valuable as vice versa. This is justified by very good resources for renewable energy in terms of solar irradiation and wind (high average wind speeds in some areas) in North Africa. Therefore, electricity exports from North Africa to Europe via transmission lines (HVDC and HVAC) are analyzed. High penetration scenarios with a high share of fluctuating production from renewable energy sources also require electricity flows from North to South, but they will not be analyzed as a detailed implementation of European electricity market with its generation capacities and demand would be necessary.

4) **Regional transmission costs and losses:** In addition to the need of new international transmission lines, large integration of renewable energy sources in the national electricity systems will overstress the existing HVAC lines between the regions. Distances between preferable sites for renewable energy sources with sufficient resource conditions (including available, flat land) and electricity load centers exceed several hundred kilometers. Consequently new large transmission lines have to connect locations of supply and demand. Therefore, regional grid connections have to be analyzed in order to find an optimized electricity system as trade-off between good site conditions and low costs of electricity transport. Only by considering losses and costs of electricity transport, the model can answer the question on the best portfolio and power plant locations of the electricity sector. Otherwise, the transmission costs are underestimated and grid congestion takes place like in electricity markets with highly concentrated renewable energy generation in a small area (e.g. wind power in Northern Germany). Above-average wind conditions and similar feed-in tariffs for whole Germany have led to a high penetration of wind power plants in this area. However, this area shows lower regional electricity demand. This situation necessitates high investments for electricity transport to demand centers in Central and Southern Germany (50Hertz et al., 2013). Therefore, the electricity market model has to include costs for investment in new transmission lines, variable transmission costs and losses depending on electricity flows and the distance between generation and consumption.

5) **Site selection of renewable energy sources:** The potential for renewable energy in North Africa is enormous as wide areas of land cannot be used for agriculture or human settlement due to the arid and semi-arid climate conditions in these areas (Trieb et al., 2005). The model should be able to provide information in which sub-national regions power plants have to be constructed. Explicit sites should be implemented and optimally selected by the model optimization which uses site specific generation

profiles, costs, electricity demand and transmission constraints to other sub-national regions.

6) **Implementation of RE specific operation:** Technology specific findings might be interesting as PV power plants could also be built in areas with lower (global) solar irradiance in coastal areas. Compared to this, CSP plants usually require a high and stable direct irradiance which is only available in areas far away from the coast to achieve high turbine efficiencies, optimal storage operation and high energy yields. Detailed technology modeling is also compulsive for the RE technologies such as PV, CSP and wind power. It is especially important, to carefully implement the electricity generation from CSP into the electricity market model, as the model should be able to optimally dispatch CSP plants equipped with thermal storage tanks or with the alternative of hybridization with natural gas. As CSP plants are operated similar to conventional power plants, the hourly dispatch and operation mode of CSP plants have to be optimized by the model itself. Generation of PV and wind power is less flexible and can only be reduced (curtailed) by the optimization model.

7) **Conventional power plants:** Besides RE technologies, the model has to include a wide range of technology options to generate or store electricity. Conventional power plants remain an important part of the electricity system due to the strong increase of electricity demand and as necessary back-up solution during hours of low wind and solar feed-in. Therefore, the model input data should include existing conventional power plants such as coal power plants, steam turbines, open cycle gas turbines based on natural gas or oil (diesel), combined cycle gas turbines as well as the option to invest in new power plants of these technologies. By taking the current situation into account, the model will be able to project a consistent expansion plan until the year 2050. This approach increases the reliability of the prediction as typical structures of the existing system are not neglected by the analysis compared to other model approaches which plan the whole electricity system of year 2050 on a green field (compare Scholz (2012) and Zickfeld et al. (2012)).

8) **Energy storages:** Storage potentials in form of pumped hydroelectric storage power stations or large hydropower station using large dams are limited in the region. Large storage power plants only exist and are planned in Morocco and Egypt. In long-term scenarios the model should be open to include further storage options such as large centralized or small decentralized batteries. As a modeling approach for demand-side management can be similar to a modeling approach for batteries, potentials for shifting electricity over a few hours per day are also implemented.

9) **Adequate time horizons:** With numerous operation possibilities due to high variability of weather conditions throughout the regions and the effect of very different generation conditions which might vary within hours, the model has to be based on hourly time steps for the dispatch optimization of all power plants. The time horizon for the dispatch problem is set to one calendar year. For the analysis of the long-term development of the electricity system, it is necessary to model the power plant expansion over 20 to 40 years. Therefore, the model has to use an integrated investment decisions for new power plants and transmission lines, instead of using a myopic approach. This means that investment decisions are based on information of different years which includes future developments for costs, full-load hours or demand. Expansion planning is then tested for certain years by the detailed generation dispatch.

10) **CO_2 emission reduction and RE targets:** Reduction of CO_2 emissions are the major reason for many countries to formulate binding targets of electricity generation based on renewable energy sources (see National Renewable Energy Action Plan (NREAP) in member states of the European Union). To lower the dependencies from increasing costs for fossil fuels, North African countries have also declared national targets to install power plants of RE generation technologies to be reached by 2020 or 2030. In the model, the shift from conventional to renewable energy is taken into account by defining obligatory shares of RES-E. If long-term national policies are lacking, own targets can be defined by the model user.

By sufficiently including these requirements into the model, the results reflect the current market structures, technology specific electricity generation profiles and important consequences of renewable energy technologies acceptably.

4.2 Modeling of renewable energy technologies

The electricity market model RESlion operates dispatchable power plants with appropriate flexibility by using variables for hourly operation strategy. However, hourly electricity generation based on renewable energy sources strongly depends on local weather conditions of each power plant. Therefore the modeling approach has to be slightly different. In terms of wind and PV power plants, the generated electricity is a fixed electricity profile resulting from the hourly weather conditions of wind speeds and solar irradiation. CSP plants have a fixed profile for the thermal energy output which is generated in the solar field and feeds the power block. Curtailment of electricity is a necessary option in future electricity scenarios as high shares of RES-E will consequently require the option to curtail surplus electricity generation in case of low demand or high generation from RES.

The RESlion model includes the option of using onshore wind power plants, large ground-mounted PV power plants and small roof-top PV systems, CSP plants with thermal energy storage, hydro power plants and biomass power plants. Geothermal and biomass power plants are not considered due limited potentials in North Africa and a lack of data.

To reduce the size of the electricity market model, the generation of the production profiles for wind power plants, PV systems and CSP plants is preprocessed by more detailed external models which simulate the technical performance and the electricity output of wind and PV reference power plants or the thermal output of CSP solar fields. For wind energy, a model ("Wind Model") is used which calculates the electricity output of a single wind turbine within a wind farm. It transfers wind speeds, air density, surface characteristics, tower height, turbine layout, rotor area into an hourly electricity generation profile. For solar energy, the performance model SAM (System Advisory Model) by NREL (National Renewable Energy Laboratory, USA) creates hourly electricity generation profiles for PV and profiles for the CSP thermal energy output of the solar field (NREL, 2012). The CSP power block is modeled in the RESlion model to be able to optimally dispatch CSP plants in the electricity system. Applying these technical performance models allows obtaining high quality output profiles based on a component specific configuration of the modeled system. This is achieved by including parameters such as temperature coefficients, system performance losses depending on irradiation and wind speeds or component efficiencies (e.g. solar cells, inverter, CSP receivers, mirrors or heat transfer fluid etc.) at each reference site for a reference power plant (Figure 14).

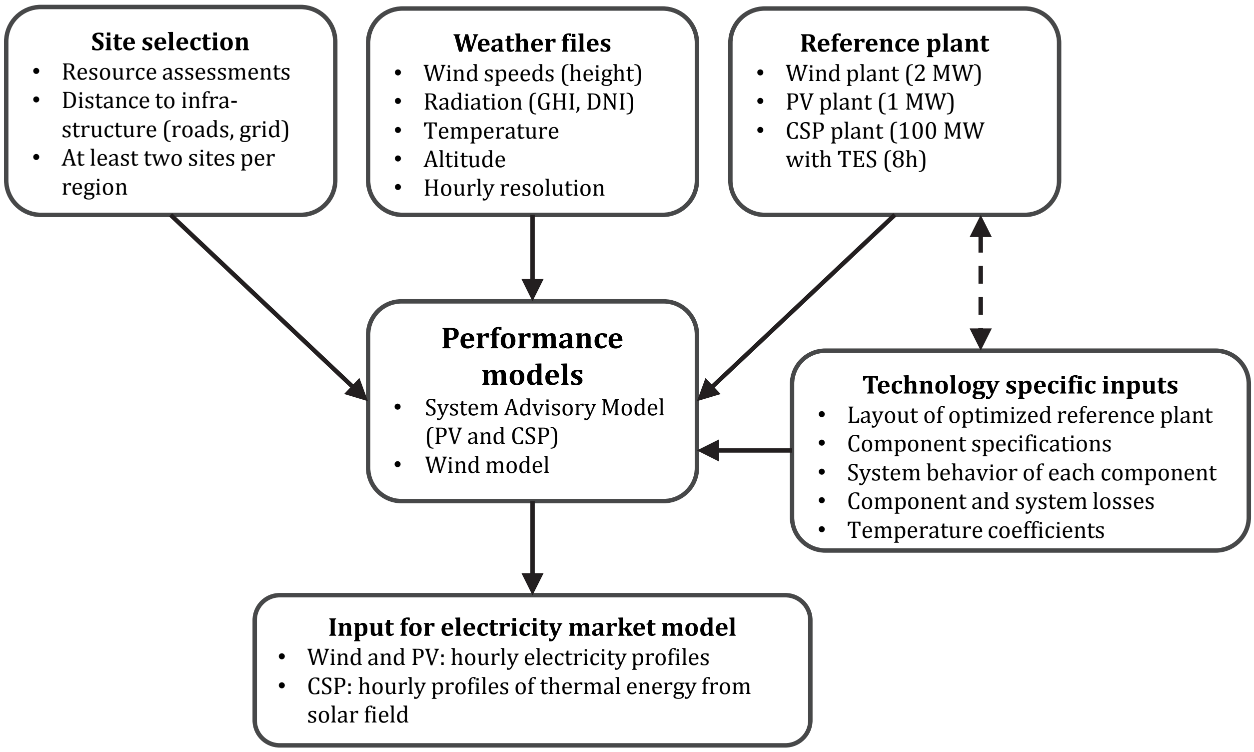

Figure 14: Use of performance models for renewable energy technologies

Each reference plant and its reference generation profile at representative sites in each region can be scaled up by the electricity market model to each site's a maximum potential. The generation profiles are generated for 53 wind sites, 60 PV sites and 50 CSP sites (the number of sites are limited to reduce computing time as all generation profiles have to be compared in the optimization). These representative sites are selected close to existing infrastructure (roads, transmission lines) and according to existing development plans to install RE power plants at these sites. The development plans are mainly based on resource assessments for solar and wind potentials by local authorities and researches in each country (see section 4.2.1 to 4.2.3 for more details). Large areas in the Sahara without any civilization (without existing electricity and transportation infrastructure) are not included as potential sites. They provide too high technical barriers and very significant security issues to be exploited by large RE power plants (but they are described as potentials for installations in other studies). With the selection of representative sites, a geographical coverage with a GIS approach is not necessary.[6] In regions with very different geographical characteristics, more sites are selected compared to region with uniform environmental conditions. Each region obtains at least two representative sites per technology (Figure 15 and Table 34, appendix). At each site, RE power plants of one technology with a maximum size up between 5 to 10 GW are assumed. Power plants can be located within a distance of several kilometers, but use the same weather file. This assumption is made due to large land potentials at many sites (desert-like areas with low slopes and stony ground), but with the constraint to limit the distance to the specific geographical location (with its weather file). The land use of a PV power plant with a capacity of 1 GW represents a covered area of 10 km^2; a CSP plant with 1 GW and a thermal storage (8 hours) requires about 30 km^2. Compared to the selected approach, GIS based analyses usually use raster resolution of about 10 to 10 km. Their resolution on a specific site consequently is in a similar range.

[6] A very detailed assessment of RE potentials with GIS can be found in Scholz (2012)

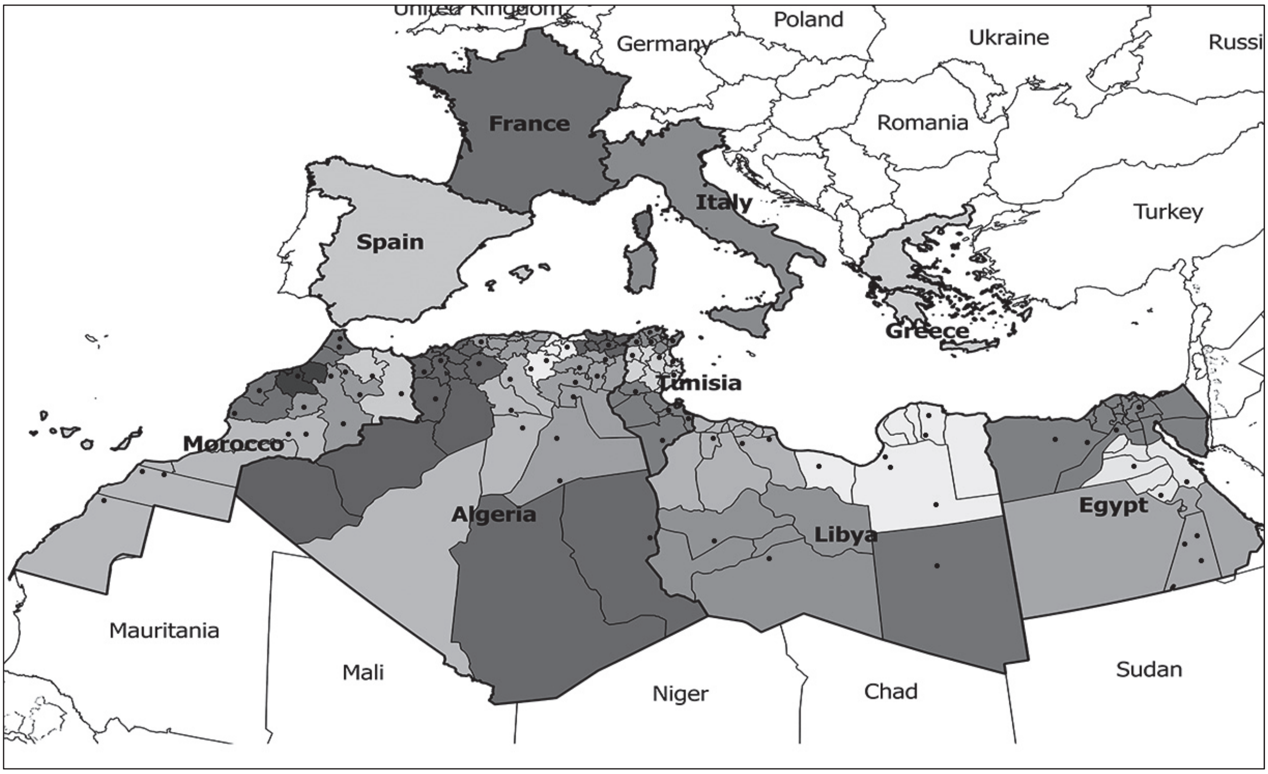

Figure 15: Potential sites for renewable energy projects in the electricity market model

The advantage of the selected approach is that it includes detailed performance models of each technology and it is able to analyze the hourly operation of each power plant. Furthermore, by direct integration of specific RE sites in the model, the optimization identifies these locations which fit very well to the electricity demand of the electricity system and grid constraints on a sub-national level. Such a detailed approach and coverage of the national electricity systems with transmission capacities cannot be found in literature for the total region so far.

Weather information of wind speeds and solar irradiation are obtained from the database of Meteonorm (detailed information about the software can be found at Meteotest (2011)). Meteonorm contains interpolation models for weather data that calculate meteorological values for a selected site based on real values of 8300 meteorological stations globally. A weather file is created for a specific geographical position. With a stochastic model, hourly values of a “typical year” are generated for the user by Meteonorm Meteotest (2011). Extreme weather conditions, daily and seasonal effects are consequently included, but extreme years are only partly reflected in these weather data sets. Investment decisions can be made on these weather data (typical year) as investment decisions should be based on long-term average values. However, the electricity model has to be able to response to extreme weather effects (e.g. long periods without wind or with extreme cold weather conditions) by using back-up capacities.

4.2.1 Onshore wind power plants and wind resources

4.2.1.1 Modeling of the electricity output

A wind turbine represents the smallest entity of a wind power plant which combines several wind turbines at one geographical site to a wind farm. The generation profile of a wind farm is modeled based on the electricity output of a single wind turbine which is then scaled up by the electricity market model. The electricity output of a reference onshore wind turbine is modeled in a special wind model extended from Schermeyer (2011). The size of the wind farm (= number of wind turbines) is endogenously found by the electricity market model in the expansion planning decision (model variable for installed capacity of wind farm). The generation profile already considers output reductions such as self-consumption, operational losses, weak and turbulence effects which occur by the interaction of different turbines in a wind farm. A medium-size wind turbine from Gamesa with 2 MW (G80) and a hub height of 78 m is used with its typical power curve for standard conditions (air density of 1.225 kg/m^3) (Gamesa, 2009). This turbine has already been used in Moroccan, Tunisian and Egyptian wind projects before (Gamesa, 2011). The size and height of this turbine is in a middle range. Also cost and quality of this turbine is in the same range. The maximum available wind power (P_{Wind}) can be calculated by the equation (Eq 3) according to (IEC, 2005):

$$P_{Wind} = \frac{1}{2} * \rho_{Air} * A_R * v_{Wind}{}^3 \qquad \textbf{(Eq 3)}$$

The power of wind consequently depends on the air density (ρ_{Air}), the rotor area (A_R) and the wind speed (v_{Wind}). As one data set of measurement data for each site increase the use of extreme values and fluctuation in the wind profiles, feed-in profiles of wind turbines are lowered by the pooling effect between several wind turbines and farms. As some wind farms with distance of several kilometers (10 to 50 km) use the same wind profile, a smoothing approach for the generation profile (wind speeds) is used. This approach is recommended to lower the effect of fluctuations on the electricity system (Norgaard and Holttinen, 2004; Klobasa et al., 2009). An average wind speed of five time steps ($v_{meas.opt}$) is calculated to decrease these fluctuations in the time series of wind speeds at each site.

$$v_{meas.opt,i} = \frac{v_{meas,t-2} + v_{meas,t-1} + v_{meas,t} + v_{meas,t+1} + v_{meas,t+2}}{5} \qquad \textbf{(Eq 4)}$$

As the weather data are measured at a height of 10m, the used wind speeds have to be adjusted to the hub height of the wind turbine. In the model, the Hellmann altitude formula (Eq 5) is applied to obtain this calibration of the wind data according to the surface characteristics (Kaltschmitt et al., 2010). This method can easily be applied by using the Hellmann exponent which provides a value related to the structure of the ground surface (the barometric formula with roughness length is another method to adjust the measurement data). The Hellmann exponent h_c is assumed to 0.34 for areas with hills or villages, to 0.25 for desert areas with flat ground and to 0.16 for coastal areas.

$$v_{hub} = v_{meas} * (\frac{h_{hub}}{h_{meas}})^{h_c} \qquad \textbf{(Eq 5)}$$

Each wind turbine has a specific power curve where the power coefficient ($c_p(v)$) is displayed for each wind speed. This coefficient reflects turbine layout, turbine efficiency, start-up and shut-down behavior depending on the current wind speed and air density (p) for the specific technical layout of a wind turbine. As hourly values for pressure and temperature are included in the weather file of each site, the power coefficient can be related to the air density calculated at each site. This coefficient has a theoretical maximum according to the Betz Limit of 0.593 (=16/27) (Carrillo et al., 2013). The power coefficient for different air densities is calculated based on the power curve of Gamesa G80. Electricity power of a wind turbine ($P_{WT}(v)$) is the result of the wind power multiplied by the power coefficient ($c_p(v)$) (IEC, 2005):

$$P_{WT}(v) = P_{Wind}(v) * c_p(v) \quad \textbf{(Eq 6)}$$

Whereas the power curve data of turbine manufacturers includes mechanical and electrical losses and the aerodynamic behavior of blades, the overall electricity output of a turbine in a wind farm ($P_{TWF}(v)$) has to take into account the electricity self-consumption for turbine tracking ($losses_{self}$), wake effects within a wind farm ($losses_{wake}$) and technical availability of the wind farm ($losses_{avail}$).

$$P_{TWF}(v) = P_{WT}(v) * (1 - losses_{self} - losses_{wake} - losses_{avail}) \quad \textbf{(Eq 7)}$$

The power losses by self-consumptions due to tracking the wind turbine to the wind direction are assumed to be 2% of the power generation (Kaltschmitt and Fischedick, 1995). Losses due to wake effects between wind turbines in a wind farm are generally reported to be lower than 10% (Manwell et al., 2002). Availability due to revision and maintenance of the wind turbine is reduced by 1% to 3% according to Manwell et al. (2002) and Abderrazzaq and Hahn (2006). In a case study for Ireland, Conroy et al. (2011) find an output reduction of 3 – 11% if availability is related to time (3%) or energy output (11%). In the model, average overall losses of 12% for the electricity output of a wind park compared to the modeling of a single wind turbine are considered (all main parameters are displayed in Table 8). Furthermore, the use of hourly values for the electricity generation of wind turbines underestimates the effects of wind gusts and strong declines.

Table 8: Technical parameters of reference wind power plant

Technical parameter	Input definition
Turbine name	Gamesa G80
Turbine capacity	2 MW
Rotor diameter	80 m
Hub height	78 m
Cut-out speed	25 m/s
Total system losses (wind farm)	12 %
Source of weather information	(Meteotest, 2011)
Measurement height (wind speed)	10 m
Hellmann factor	0.16 to 0.34 depending on geographical location

4.2.1.2 Resource assessment and site selection for wind farms

The selection of potential sites is based on a literature review of national wind resource assessments in each country as these assessments are very detailed for each country and usually integrate many local decision factors (land use, grid access, visible impact, etc.) to identify suitable sites and areas for the installation of wind power (see Table 9). In all countries, measurement data are reported with average wind speeds between 5 to 6 m/s at 10 m height of measurement. Even higher values could be found in Morocco at the coastal area, in Libya at some areas of the Mediterranean coast and in Egypt at the coast of the Red Sea. To limit the maximum installed capacity in each area (around the specific site) to a reasonable size, a general upper bound for wind power capacity at each site is assumed with 10 GW. This overall capacity can be divided into many smaller wind farms in the area around one identified wind site. This upper bound is set to the value of 10 GW as this value is assumed to be a maximum capacity which can be installed within a distance of up to 50 km to the point of the weather measurement data. As other studies have found large potentials and huge areas of available land for renewable energy sources in general, this assumption is not in contrast to the potentials at most of the sites. Further geographical restrictions and limitations such as use and slope of land or environmental issues (visibility effects, noise, etc.) are not included in this analysis here. A full list of all selected wind sites is shown in Table 34 (appendix).

After the selection of potential sites, the wind model generates profiles of the electricity output at each site by using the reference wind turbine (2 MW) and the meteorological data of Meteonorm.

Table 9: Wind resource assessment as reported in literature

Country	Range of average wind speeds (reported in source)	Measurement height	Source
Morocco	3.5 – 8.7 m/s	10 m	(Ouammi et al., 2010),
	9.0 – 9.5 m/s	–o–	(Oukili et al., 2010),
Algeria	1.0 – 6.0 m/s	10 – 12 m	(Merzouk, 2000)
	1.9 – 6.3 m/s	10 m	(Chellali et al., 2011),
	2.6. – 5.9 m/s	10 m	(Diaf and Notton, 2013),
Tunisia	2.4 – 5.4 m/s	6 – 12 m	(Elamouri and Ben Amar, 2008),
	5.5 m/s	30 m	(Ben Amar et al., 2008)
Libya	~ 6 m/s	10 m	(Elmabrouk, 2009),
	4.5 – 4.9 m/s	10 m	(Mohamed and Elmabrouk, 2009)
	6.4 – 8.3 m/s	50 m	(Ekhlat et al., 2007)
Egypt	6.9 – 10.4 m/s	25 m	(El-Sayed, 2002),
	5.5 – 6.5 m/s	25 m	(Ahmed, 2012),

4.2.2 PV power plants and solar resources

4.2.2.1 Modeling of the electricity output

PV power plants are modeled by the simulation software System Advisory Model (SAM, v.2012.5.11.) which is developed by NREL (NREL, 2012). The software calculates the hourly electricity output by using a detailed simulation model for the operation of module and inverter. SAM offers a selection of specific components (including power curves, component specific performances, etc.) for the system configuration by the user and coverage of technical effects such as handling of fluctuating solar irradiance input or operation under variable temperature conditions. A PV reference power plant which can be replicated and enlarged to

GW-size is simulated with a module capacity of 1 MW at all selected sites. A monocrystalline silicon PV module with a high efficiency (Sunpower SPR 350 WHT, efficiency: 18.41%) is selected because system costs can only continue to decrease in the long-term as modules with higher efficiencies will be installed. Other module technologies (based on thin film or polycrystalline silicon solar cells) could provide slightly different profiles compared to the used module type, but these small differences can be neglected in a system analysis. Thin film modules have been selected for hot climate conditions in the past, but due to the strong module price decrease the role of higher efficiencies (18% vs. 10 - 14%) plays an important role when PV system costs are calculated for large PV power plants. Therefore, it is assumed that PV modules with higher efficiency will have cost advantages in the future. PV modules with lower efficiencies increase the costs (per capacity in kW installed) for mounting, cabling, installation and land (Wang et al., 2011).

Two central inverter of 500 kW (SMA SC500) transform the DC output of the PV modules to AC power for the feed-in in medium voltage grids. The mounting is a fixed system which is oriented to the South with an inclination angle of 26%. Tracked systems are not considered due to higher operation costs and risk of soiling. Annual degradation is assumed with 0.5% for North Africa which is higher than current findings for European installation. Annual availability of the power plant is 98%. The electricity output based on the power curves for PV module and inverter included in SAM is reduced by system performance losses of about 10% (soiling of modules, mismatch as well as cable and transport losses to the AC grid).

Table 10: Technical parameters of reference PV power plant

Technical parameter	Input definition
PV modules	Sunpower SPR 300 WHT
Module efficiency	18.41%
Inverter	SMA SC500 (AC 500kW)
Mounting system	Fixed
Annual degradation	0.5%
Annual availability	98%
Modeled system size	1 MW
Source of weather information	(Meteotest, 2011)
Solar data	Global horizontal irradiance

4.2.2.2 Resource assessment and site selection for PV

In North Africa, potentials for small and large PV power plants are enormous due to good solar conditions throughout the region. So far, specific studies of site assessment for PV power plants are limited in the literature, but all recommendations for CSP sites presented in the next section are also seen as potential sites for PV. As potential sites for CSP are assumed to be prepared for MW-sized power plants, further potentials for PV installations are expected to be in urban areas which are not suitable for CSP. Therefore, additional sites for potential PV projects are chosen in urban areas to include different applications such as roof-top systems or smaller ground-mounted system into the analysis. Electricity generation profiles of these smaller PV systems (1kW to 1MW) are very analogous to the output of large-scale ground-mounted reference power plants (>1 MW). Similar to wind, an upper bound of potential capacity per site is assumed. This maximum capacity is set to 10 GW which corresponds to a land area of approximately 70 km². This capacity can be installed within an overall area with a reasonable distance of up to 50 km to the specific site of the weather measurement. Weather conditions within such a distance are assumed to be very similar if hourly values are used. Global horizontal irradiance from Meteotest (2011) serves as input data for each reference power plant. Consequently all PV power plants at one site have a similar output profile, but all PV power plants should be installed in a distance smaller than 30 km to the specific site. Effects of clouds and short weather changes should have an effect on all power plants within a few minutes. As only hourly values are used, larger discrepancies are not expected to the electricity output profiles. A full list of all selected PV sites is shown in Table 34 (appendix).

4.2.3 CSP plants and solar resources

4.2.3.1 Modeling of the thermal output of a CSP solar field

As CSP plants can contribute with flexible electricity generation to the electricity market by integration of thermal energy storages (e.g. large tanks filled with molten salt mixture), operation and electricity output is internally modeled in the electricity market model. (Sioshansi and Denholm, 2010) propose a modeling approach for an optimized power plant operation to perfectly serve the demand in the electricity market. First, they generate profiles of hourly thermal energy output of the solar field with SAM while the storage process and turbine generation is not taken into account. Second, these profiles are used in an optimization model for the hourly electricity generation of the power block and an optimal storage use (Figure 16).

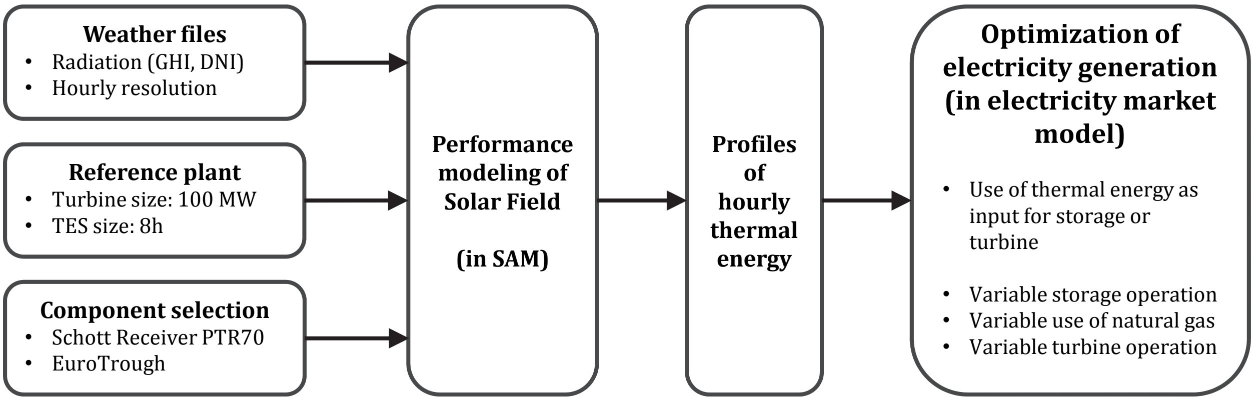

Figure 16: Data flow of CSP modeling

The different CSP technology concepts (Parabolic Trough, Solar Tower, Fresnel System and Dish Stirling) are represented by only one technology. Parabolic Trough with thermal energy storage (TES) is selected as this technology has a market share of over 90% and about 3000 MW installed capacity in 2012 (Vallentin and Viebahn, 2010; IRENA, 2012). A reference power plant of the parabolic trough technology is modeled in SAM to obtain the hourly thermal output of the solar field. A turbine capacity of 100 MW and a storage capacity of 8 hours (approx. 1000 MWh_{th}) is assumed and a solar multiple of 2.8 (compare Kost et al. (2012d)). The solar multiple is the factor for the amount of thermal output by the solar field compared to the maximum inflow of the turbine at standard conditions. A fixed storage size of 8 hours is used to provide electricity during evening and night hours. Variable storage size optimized by the electricity model would increase the computing time of the overall model. A standard solar receiver (Schott Receiver PTR70) and mounting structure (EuroTrough) as well as thermal oil as heat transfer fluid with a working temperature up to 393°C is selected. The availability of the power plant is set to 96% to include down-time hours and time for revision (summary of all parameters in Table 11).

Modeling of the power block, particularly operation of storage and turbine, is carried out in the electricity market model. In the model, hourly electricity generation is optimized depending on hourly demand and electricity generation of other technologies.

Table 11: Technical parameters of reference CSP power plant

Technical parameter	Input definition
CSP technology concept	Parabolic Trough with thermal energy storage, dry cooling
Storage concept and size	Two tank molten salt storage, size of 8 hours (approx. 1000 MWh_{th})
Solar Multiple	2.8
Turbine size	100 MW (net capacity)
Solar field size	~ 5.2 km^2
Heat transfer fluid	Thermal oil at working temperature of 393°C
Receiver technology	Schott Receiver PTR70
Mounting system	EuroTrough (150m)
Annual degradation	0.0%
Annual availability	95%
Source of weather information	(Meteotest, 2011)
Solar data	Direct normal irradiance (DNI)

4.2.3.2 Resource assessment and site selection for CSP

For CSP projects a few sites in Morocco, Algeria and Egypt have already been chosen for existing CSP plants or are defined as potential sites for power plants. During the definition of the Moroccan Solar Plan, five sites have been selected due to their solar conditions and geographical location (ONE, 2010). The sites Ain Beni Mathar and Ouarzazate host the first CSP installations in Morocco. Also in Algeria the sites Hassi-R'mel, Meghaïr and Naâma are already identified by New Energy Algeria (NEAL). In Hassi-R'mel, the first Algerian power plant using CSP technology has been commissioned in 2011 as Integrated Solar Combined Cycle (ISCC) power plant which feeds thermal energy from a parabolic trough solar field into a conventional steam turbine of a combined cycle power plant. In Egypt, a first ISCC power plant was constructed in Kuraymat and a feasibility study of a pure CSP plant is ongoing in Kom Ombo.

Potential sites are selected similar to PV in short distance to existing infrastructure (Table 34, appendix). In coastal and urban areas, CSP technology is not expected to be the preferred power generation technology due to lower direct irradiance and resource competition with agricultural land use. Analogous to PV, CSP plants should be constructed in a distance of 30 km around the specific location. As dry cooling is applied at all CSP plants, restrictions of available water supply by rivers or lakes are not given.

4.2.4 Hydro power plants and energy storage systems

Very small hydro power plant capacities (311 MW installed in total) exist in Algeria, Tunisia and Libya. In Morocco and Egypt, a total capacity of hydro power plants of 4135 MW is part of the generation system. Power plants with a capacity of 3312 MW are equipped by large water reservoirs and large storage dams; the others work as run-of-the-river power plants (Platts, 2011). New potentials of hydro power plants are very limited in North Africa according to the resource assessment by (Trieb et al., 2005) and therefore expansion is not possible in electricity market model.

Power plants with storage capacities could shift their electricity production between several days to weeks or even seasons. Therefore, energy production is modeled very flexible, only considering maximum conditions of turbines and a maximum seasonal output. As data about water levels are not available, the annual production (historical data of the national utilities) is split into two seasonal productions according to an exemplary rainfall distribution of 70% during winter months (November to March) and 30% during summer months (April to October)[7].

One pumped-storage hydro power plant exists in Morocco (Afourer, 465 MW) and another one is under development (Abdelmoumen, 412 MW). These power plants are used for short-term balancing effects in the electricity systems. For the RE targets of Morocco, they open the potential for a higher flexible reaction of the power system to large fluctuating feed-in of PV or wind power plants.

For the modeling of future electricity scenarios, the possibility to install a wider range of storage applications and to use further demand-side management technologies was implemented in the model. Similar to pumped-storage power plants, each region obtains the possibility to invest in storage or demand-side management capacity to shift electricity of a few hours to the future (time period of a few days). Regions with large electricity demand obtain the potential of 2.5 GW, regions with smaller demand 1.0 GW.

4.3 General model approach of RESlion

Two central decision processes in the power sector have to be analyzed with the electricity market model to evaluate system effects and system costs of long-term energy scenarios with large-scale RE deployment:

- **Expansion planning problem:** This problem is answered regarding the optimal deployment path of renewable energy sources in North Africa: Which new conventional, RE power plants and storage systems have to be built and how has the electricity system to be extended?
- **Generation dispatch and hourly operation:** To show a complete validation of the power plant portfolio, the hourly operation over one year under economic decision variables has to be analyzed with the model.

[7] Rainfall data of Fes and Marrakech (Morocco) have been analyzed to obtain an approximation.

Four central model requirements have a strong implication on structure and scope of the RESlion model as they extremely influence the volume of input data and the solving complexity of the model:

1) Existing infrastructure should always be considered in the decision making of expansion planning and hourly generation dispatch.
2) Existing power plants are modeled separately at each location (no pooling to technology classes). The specific location and the explicit capacity of each power plant (especially of renewable energy technologies) can be found in the results.
3) Regional resolution of the electricity market is implemented to split the national electricity system of each country into several sub-national regions (nodes) connected by transmission lines.
4) Transmission capacities (net transfer capacities = NTC) and transmission losses between regions are considered in the model. This leads to a varying total generation as it depends on the transmission losses directly.

The first requirement enables to obtain development paths from today to the future (year 2050). However, the amount of variables in the model is increased by considering the existing infrastructure and the temporal development with different time slices from today to 2050. Models used by Scholz (2012) and Zickfeld et al. (2012) examine the optimal setting in year 2050 without reflecting existing infrastructure or deployment paths.

Separately modeled power plants increase the size of the model as each power plant is expressed by a variable. Potential power plants of each technology have to be included into the model and each potential location for future RE power plants obtains its own variable. In the optimization the model decides whether it is cost-efficient to invest in a new infrastructure project and operate it over the time horizon of the model. Each power station is linked to a region within the model. Each country is separated into different regions and electricity exchange between the regions requires sufficient transmission capacities. In total, the North African countries are split into 23 electricity regions. Five regions for South Europe are added to allow electricity exchange between North Africa and Europe. A key constraint in the model is the balancing constraint of electricity demand and supply in each region for every model hour.

Particularly in the case of renewable energy sources, wide distribution of power plants increase the distance between generation and demand. Conventional power plants are normally built closer to the demand as existing supply infrastructures such as gas pipelines, harbors or rivers for the transport of fuels are usually considered as reason for decision. Therefore, site selection of RE projects should incorporate the implications of a potential grid extension and reinforcement. This can be achieved by monetize these additional costs in the objective function

For the model development of RESlion, a two-step approach to solve a global LP problem consisting of a bottom-up, long-term expansion planning and an hourly operation of all elements in the electricity system in certain years is chosen. The RESlion model minimizes overall system costs of the electricity systems in North Africa. The global LP problem is divided into two problems: In a first step, an expansion planning model determines the installed capacities of each technology (power plants and transmission lines). Then in a second step, a detailed generation dispatch model optimizes the detailed hourly operation of each power plant in one year. To solve the expansion planning problem of step one, the number of operation hours for power plants is reduced to a selection of a few weeks per year. That means that a generation dispatch is also carried out in the expansion planning model; but for the reduced number of hours. These selected hours are widely distributed over different seasons and weather conditions. The selected hours represent different years with a time horizon of 20 years to cover the long-term development of the electricity system. Based on the time horizon of 20 years, the integrated investment planning is done with the same constraints which describe the operational constraints of the electricity system and are later used in the detailed dispatch problem of one year. After transforming the decision variables for installed capacities of all power plants and transmission lines (existing and new) to fixed input parameters of the generation dispatch problem, the problem of step two can be solved. For consistency and uniformity of the model results, both steps use the same mathematical model structure. However the first step uses variables to determine the setting of the infrastructure (power plants and transmission lines), whereas the second step transforms the solution of step one into annual and hourly results in terms of electricity generation, costs and losses.

The approach of RESlion has an important similarity to (Nicolosi, 2011) as it connects the investment decision with a dispatch model in a combined two-step approach, but due to the model size (amount of variables for power plants and transmission) a direct iterative process is not possible. However, the detailed generation dispatch model provides data of the electricity system for each hour of the year. With a consistency check, adjustments of input parameters in the expansion planning model are possible. Especially, the assumptions for capacity reserves of power plants and transmission lines can be validated as more different system conditions are modeled by optimizing all hours of the year. Also, utilization rates per technology can be calculated and compared with the outcomes of the expansion planning model.

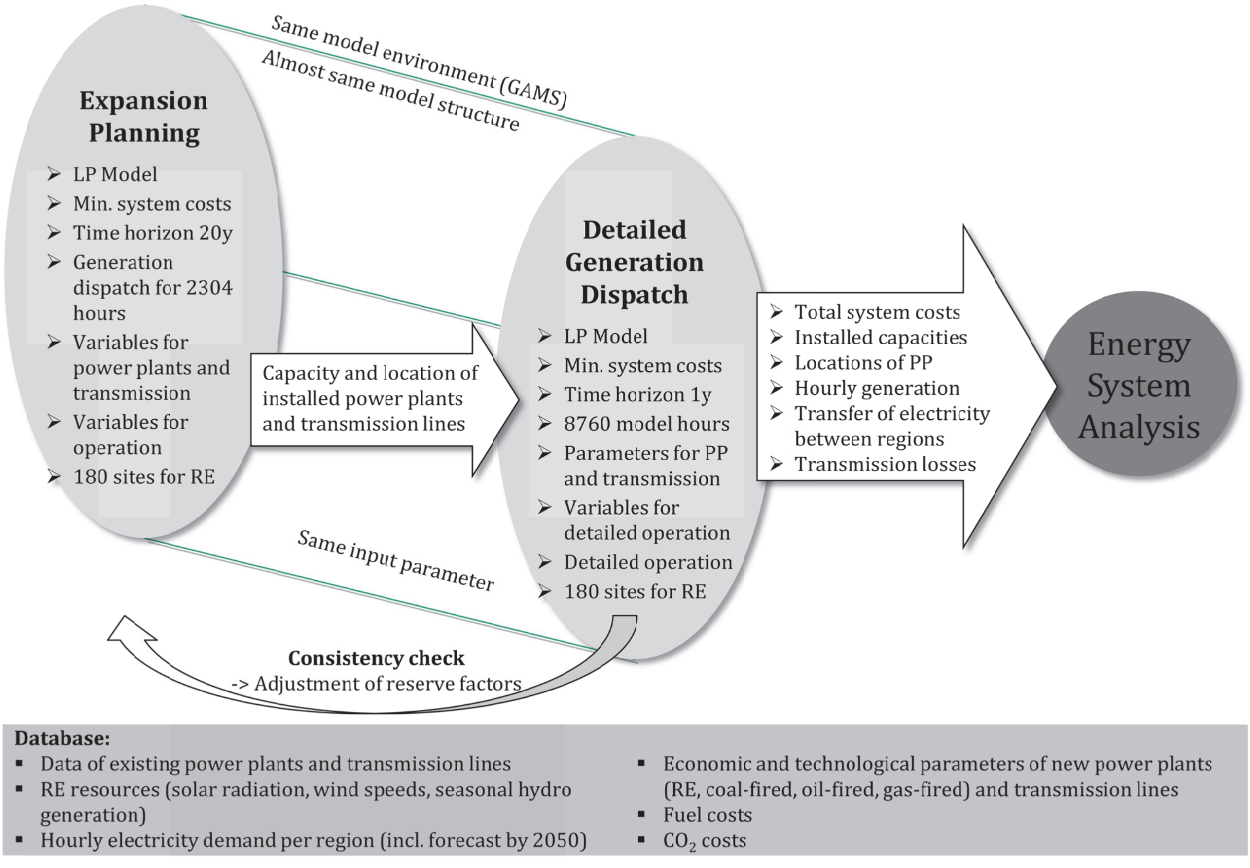

Figure 17: Relations between the expansion planning and hourly generation dispatch in RESlion

The model is implemented in the software GAMS, a modeling system for mathematical programming and optimization (GAMS - General Algebraic Modeling System (GAMS, 2013)). An overview of the model structure is given by Figure 17.

The LP approach is selected due to the possibility to include a large amount of decision variables and input parameters in the model. The requirements of the model show that a large integration of input parameters is necessary, as well as the potential to include grid constraints and optimal site selection for new power plants into the model. Mixed integer programs MIP with integer or binary variables have the disadvantage to increase the computing time of the model. The advantages of the use of integer variables would be a more realistic implementation of conventional power plants as ramping and part-load behavior can be expressed more realistically by binary variables for offline and online status of a power plant. In section 4.7, the option to extend the basic LP model to an MIP model is explained and additional model constraints are proposed if an improvement of the basic LP model is intended.

The optimization of overall system costs means that the model problem is formulated and implemented from the decision perspective of a central social planner who intends to optimize the total system for all countries and regions most cost-efficiently, subject to the given constraints. In North Africa, such a social planner can be assumed on a country level as central national authority which usually defines the energy policy and the expansion planning over the next years. The single objective function of the LP model implicates that only one planner optimizes the whole system for North Africa instead of five different ones. This leads to the consequence, that all countries are analyzed together in the same idealistic model environment and framework. Thereby the planner decides with the knowledge and the (political) power on all electricity markets. The overall system costs might decrease under this assumption as the setting of the power system is optimized on a larger area by taking more different options into account. For example, one country can supply the pumped-storage power plant of the neighbor country with surplus electricity, or power plant sites with best resources for renewable energy sources are chosen by the model to minimize the overall system costs.

The expansion planning part of the optimization model selects those technologies which best fulfill the cost-efficient objective. Decentralized investment decisions (instead of a central planner) of different investors however lead to slightly different allocations. Similar to the investment decision, independent market players operate power plants with limited information or apply a strategic decision making. Therefore, scenarios with the centralized optimization have to be interpreted carefully as central minimization of the overall system costs by the LP model could underestimate the real costs.

In the following section, RESlion is explained in detail and described by mathematical functions and relations.

4.4 Model description of RESlion

4.4.1 Introduction to the model structure

Aim of the energy system analysis is to find with RESlion cost-optimized options for the future electricity system in North Africa. The model provides results in terms of power plant portfolio, site selection, electricity generation profiles, transmission impact, cost distribution of different technologies, fuel consumption, CO_2 emissions and others (Figure 18).

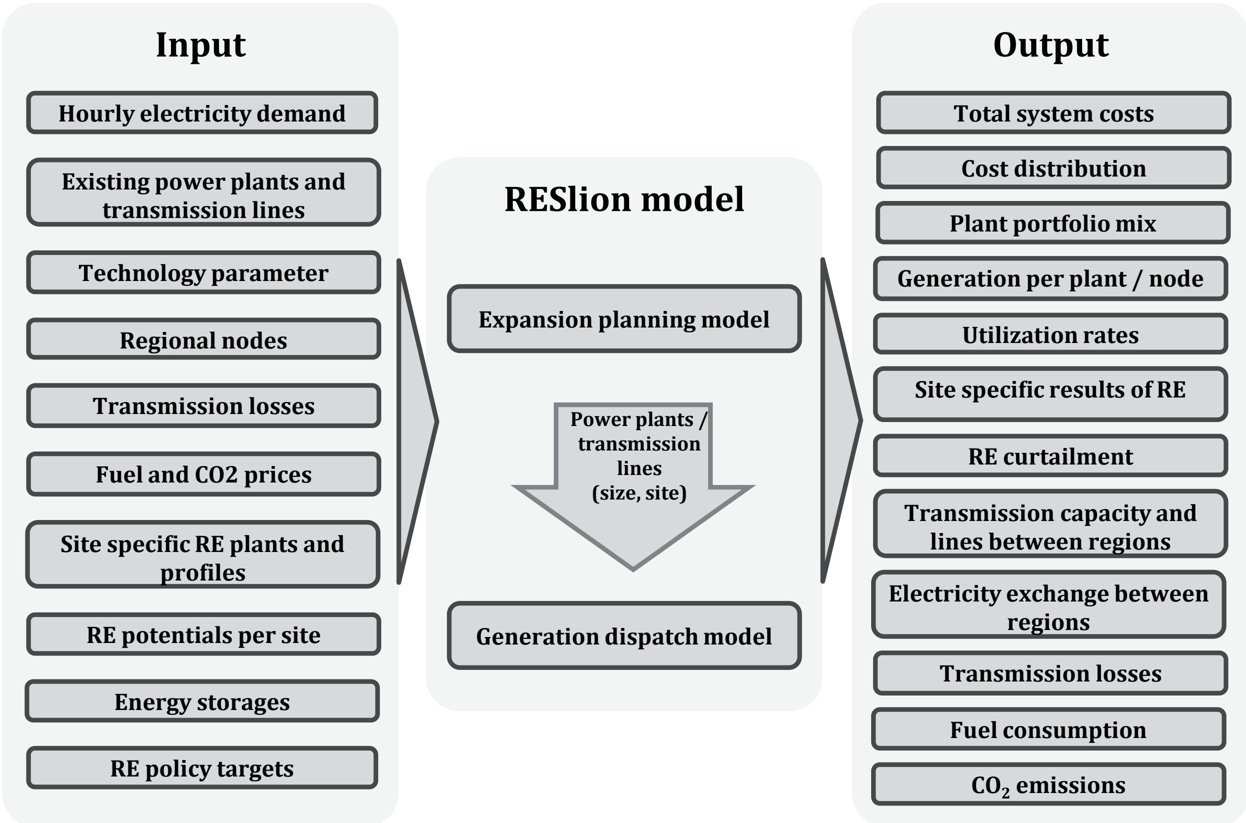

Figure 18: RESlion model structure

Model variables are indicated by capital letters, parameters by lower cases. Indices[8] of variables and parameters are collected in Table 12. All entities of with a specific capacity are represented by its index. For example, all infrastructure projects (power plants, transmission lines and energy storage systems) are included in the index (*infra*). A specific group of entities with the same capacity in an index can also be grouped in a sub-index. For example, all power plants *(tech)* and transmission lines (*line*) belong as sub-index to the index (*infra*), written as $tech \subseteq infra$. The index (*csp*) for all CSP plants is part of the index (*tech*) which is also part of the index (*infra*). Sub-indices obtain characteristics of the index to which they belong.

The electricity systems in North Africa are subdivided into 23 geographic regions (plus five regions representing European countries) and implemented as nodes (*r*) in the model. All infrastructure projects are linked with a node depending on their geographical location. Each

[8] In GAMS, indices are named as sets.

transmission line connects two regions with start and end point (*start* and *end*). The different time layers are presented by an index (*year*) to differentiate among the years. The index (*t*) includes all modeled hours over all years, whereas the index (*tyear*) only includes the hours of a certain year. Hours of winter and summer months are associated either with the index (*season_W*) or the index (*season_S*).

Table 12: Model indices

Index	Description
infra	Infrastructure projects (power plants, transmission lines and energy storage systems)
$tech \subseteq infra$	Power plants (conventional and RE power plants) (Each power plant is linked to one technology and to one model node.)
$storage \subseteq infra$	Energy storage systems (e.g. pumped-storage, batteries)
$line \subseteq infra$	Transmission lines (HVAC or HVDC)
$cp \subseteq tech$	Conventional power plants
$re \subseteq tech$	RE power plants
$WindPV \subseteq re$	Wind power and PV power plants
$csp \subseteq re$	CSP plants
year	Years
t	Operation hours (Each hour is linked to one year.)
$t..year \subseteq t$	Specific hours of a certain year
$season\_W \subseteq t$	Hours of the months November to March
$season\_S \subseteq t$	Hours of the months April to October
r	Regions
$eu \subseteq r$	European regions

4.4.2 Temporal coverage

The model is implemented by using hourly time steps for electricity demand and generation. Smaller time steps (e.g. 15 minutes) might be necessary in future electricity models as gradients by renewable energy sources will increase and electricity pools start to offer energy trading for intervals of 15 minutes.

The expansion planning model has a larger time horizon compared to the detailed generation dispatch model. As mentioned before, long-term expansion planning takes into account the development of the following 20 years by including each fifth year into the decision process. The same weather information is used in the model for all years modeled in the long-term expansion planning model and in the detailed hourly dispatch model (see also section 4.2). The selection of the years in the expansion planning problem is provided as follows:

$$year_{n+1} = year_n + 5\,, \qquad n \in 0,1,2,3$$
$$with\ year_0 = 2010\ or\ 2030 \qquad \textbf{(Eq 8)}$$

The time horizon of the expansion planning problem by 2050 can be divided into two time periods from 2011 to 2030 and from 2031 to 2050. Consequently the long-term expansion planning is split into two model runs.

The selection of a reduced number of operation hours has to be carried out very carefully as the decision to shut-down existing power plants or to construct new power plants depends on economic and technical valuation considering the need of construction (initial investment) and operation patterns during these hours (operation costs, system benefits, electricity generation). The use of typical days is more complicated as a high number of different daily demand profiles and RES feed-in profiles exist. Especially, the total RES feed-in strongly varies under different technology portfolios or weather conditions. Also the final generation is not available before a model run as the model uses the electricity consumption by the end users and adds the transmission losses depending on the transferred electricity which also depends on the location and capacity of each power plant. Therefore, a huge number of situations and generation structures appear in the electricity system. Golling (2011) examine the selection of typical days for wind speeds in Europe in detail by analyzing the statistical distribution of wind speeds in different months. The model hours used in the expansion planning model in RESlion are chosen according to the following restrictions:

1) Maximum number of hours should not exceed 2500 hours due to computing time.
2) To include all seasons equally, the same number of hours from each month is selected.
3) Inter-daily weather effects have to be covered by including several consecutive days of the month.
4) Each weekday has to be selected equally as electricity demand is depending on the weekday.

The final selection of days (in total 2304 days) implemented in the model can be found in Table 13. The first and second day of each month is selected in $year_1$, third and fourth day of the month in $year_1$ and so forth.

Table 13: Selection of days implemented in the expansion planning model

	$year_1$	**$year_2$**	**$year_3$**	**$year_4$**
Selected days per month (identical in all months)	1. + 2. (of the month)	3. +4.	5. +6.	7. + 8.

The model optimizes power plant operation during all hours of these selected days. The days are ordered for the optimization according to their date within the year. The issue of year date is not considered for the ordering of the days. This approach makes it possible to include continuous power plant and storage operations as well as the influence of weather conditions which appear over a time horizon of eight days.[9]

The detailed generation dispatch model solves the operation problem over one year by using hourly values (8760 hours). If an extreme weather condition or another system situation cannot be balanced by the installed capacity in the generation dispatch problem, another model run of the expansion planning has to be started. In this run, additional generation capacities (back-up capacity) in the specific region which caused the problem can be predefined or reserve factors for power plants and transmission lines have to be increased (more details for

[9] The use of similar weather information for all years is responsible for this effect.

infeasibilities of the generation dispatch model and the influence on the expansion planning model are described in section 4.6).

4.4.3 Objective function

Total system costs of the electricity system of North Africa are minimized in the objective function of the optimization model over a certain time period. The objective function considers investments in new infrastructure (power plants, transmission lines and energy storage systems) and operation costs which are caused by the operation of infrastructure projects. The model decisions are based on the assumption of perfect markets, complete information and perfect foresight (deterministic model). These simplifications of the electricity markets are necessary to obtain a solvable model in combination with other requirements postulated for the model development. In scenarios with electricity export to Europe, the effects of these exports should be determined. Therefore, the objective function includes external revenues from export electricity if a variable volume of export is possible (see price based scenarios in chapter 5). Consequently, the objective function covers:

- Expenses for the construction of new infrastructure projects (*INVEST*)
- Operation costs of all infrastructure projects (*OPERATION.COSTS*)
- Revenues from electricity exports from North Africa to Europe (*EXPORT.REVENUES*)

$$minimize \qquad TOTAL.SYSTEM.COSTS = INVEST + OPERATION.COSTS - EXPORT.REVENUES \qquad \textbf{(Eq 9)}$$

The variables of the objective function can be detailed by the following three equations.

$$INVEST = interval.years * \qquad \textbf{(Eq 10)}$$

$$\left[\begin{array}{ll} \sum_{tech}\sum_{year}\left[NEW.CAPACITY_{tech,year} * a_{tech} * \frac{tech.cost_{tech,year}}{disc_{year}}\right] & \textit{Costs for new power plants} \\ +\sum_{line}\sum_{year}\left[NEW.CAPACITY_{line,year} * a_{line} * \frac{tech.cost_{line,year}}{disc_{year}}\right] & \textit{Costs for new transmission lines} \\ +\sum_{storage}\sum_{year}\left[NEW.CAPACITY_{storage,year} * a_{storage} * \frac{tech.cost_{storage,year}}{disc_{year}}\right] & \textit{Costs for new energy storages} \end{array} \right]$$

Capacities of new power plants ($NEW.CAPACITY_{tech,year}$), transmission lines ($NEW.CAPACITY_{line,year}$) and energy storage systems ($NEW.CAPACITY_{storage,year}$) are multiplied by the specific technology cost (in EUR/kW) of the reference system in the year of construction ($tech.cost_{tech,year}$) and the annuity factor ($a_{i,LT}$). The annuity factor provides an annual payment for the initial investment over a specific period of time by taking into account lifetime (LT) and interest rate (i) of the project (weighted average cost of capital (WACC) are used to approximate the interest of the projects).

The interval length between specific years in the expansion planning problem is implemented by the factor (*interval.years*) to calculate the costs over the full time period of 20 years. Costs of different years are discounted by using the Net Present Value method and the parameter (*count_year*) as indicator for the time distance to the base year.

$$disc_{year} = (1 + discount.rate)^{count\_year} \qquad \textbf{(Eq 11)}$$
$$disc_{t.year} = (1 + discount.rate)^{count\_year}$$

The general discount rate is assumed with 3%. A discount factor for annual and hourly values was defined, depending on the index of the calculation.

Operation costs and revenues from export in the expansion planning model have to be multiplied by factors which represent the number of modeled years (*number.of.years*) and number of interval years. As the expansion model uses a reduced number of modeled hours (*number.of.hours*), the values also have to be multiplied by this number related to all hours of one year (8760), in order to extrapolate the operation costs.

$$\begin{aligned}
&OPERATION.COSTS && \textbf{(Eq 12)}\\
&= interval.years * \sum_{infra} \sum_{year} [INST.CAPACITY_{infra,year} * fix.op.costs_{infra} / disc_{year}] && \textit{Fixed costs}\\
&\quad + (interval.years * 8760/number.of.hours * number.of.years\ ) &&\\
&\quad * \Bigg[\sum_{tech} \sum_{t} \big[[TEC.GEN_{tech,t} * var.op.costs_{tech}] && \textit{Var. costs}\\
&\quad + [TEC.GEN_{tech,t} * fuel.costs_{tech,fuel}/tec.eff_{tech}] && \textit{Fuel costs}\\
&\quad + [(LOAD.CHANGE.UP_{tech,t} + LOAD.CHANGE.DOWN_{tech,t}) && \textit{Load change costs}\\
&\quad * load.change.costs_{tech}] &&\\
&\quad + [PART.LOAD_{tech,t} * part.load.costs_{tech}] && \textit{Part-load costs}\\
&\quad + [TEC.GEN_{tech,t} * factor.CO2_{tech}]\big] / disc_{t.year} && \textit{CO2 costs}\\
&\quad + \sum_{line} \sum_{t} [LINE.TRANSFER_{line,t} * transmission.costs_{line}] / disc_{t.year} && \textit{Transmission costs}\\
&\quad + \sum_{storage} \sum_{t} [STORAGE.GEN_{storage,t} * var.op.costs_{storage}] / disc_{t.year}\Bigg] && \textit{Var. costs (storage)}
\end{aligned}$$

For each infrastructure project ($INST.CAPACITY_{infra}$) fixed operation costs ($fix.op.costs_{infra}$) have to be paid. Operation costs related to the electricity output ($TEC.GEN_{tech,t}$) include variable costs ($var.op.costs_{tech}$) for the power plant operation, fuel costs ($fuel.costs_{tech,fuel}$) depending on the power plant efficiency ($tech.eff_{tech}$) and costs for buying CO_2 emission allowances ($factor.CO2_{tec}$). Costs for load change ($load.change.costs_{tech}$) and for operating in a part-load mode ($part.load.costs_{tech}$) are added if necessary for the specific technology. Increasing part-load operation is presented by ($PART.LOAD_{tech}$) Also for each transferred or stored entity ($LINE.TRANSFER_{line,t}$, $STORAGE.GEN_{storage,t}$) variable operation costs ($transmission.costs_{line}$, $var.op.costs_{storage}$) have to be paid.

If revenues from electricity export are considered, the export electricity ($EXPORT.TO.EU_{eu,t}$) is multiplied with an hourly price ($eu.price_t$) that is assumed in the scenarios.

$$EXPORT.REVENUES = interval.years * (8760/number.of.hours * number.of.years) * \sum_{eu}\sum_{t}\left[EXPORT.TO.EU_{eu,t} * eu.price_t\right] /disc_{t.year} \quad \textbf{(Eq 13)}$$

4.4.4 Technology independent model constraints

Some constraints are generally valid and independently from a specific technology. In addition to technical constraints required for all technology types, a few constraints are necessary to describe electricity market structure and policy framework. As the role of renewable energy in the future electricity systems is a key question of this thesis, the scenarios should analyze different targets for the RES-E share. These targets can be differently implemented: They can be set explicitly for each year or the model itself finds the optimal RES-E share by selecting the technology portfolio with the lowest system costs. The problem of explicit targets is a too ambitious or hypothetical assumption for the RES-E share. An additional assumption for scenarios with export is the constraint of restricting electricity exports ($EXPORT.TO.EU_{eu,t}$) to RES-E (or not to increase the use of conventional power plants). Due to this assumption, the variable total generation and potential curtailment of RES in each region ($energy.dump_{r,t}$), the share for RES-E ($share.re_{year}$) on the total generation is achieved by limiting the electricity generation for conventional power plants ($TEC.GEN_{cp,t}$).

$$\sum_{cp}\sum_{t.year} TEC.GEN_{cp,t.year} = \left(1 - share.re_{year}\right) * \left[\sum_{tech}\sum_{t.year} TEC.GEN_{tech,t.year} - \sum_{r}\sum_{t.year} energy.dump_{r,t.year} - \sum_{re}\sum_{t.year} EXPORT.TO.EU_{eu,t.year}\right], \quad \forall\, year \quad \textbf{(Eq 14)}$$

Each country should remain partly independent from energy supply from other countries. Therefore, a condition is introduced that requires a certain level of national generation ($energy.security_{country}$) related to the demand in every hour. Thus, energy security of one country can be satisfied by equation 15.

$$\sum_{tech\ of\ country}\ \sum_{r\ of\ country} TEC.GEN_{tech,t,r} \geq energy.security_{country} * \sum_{r\ of\ country} demand_{r,t}\ , \quad \forall\, t, country \quad \textbf{(Eq 15)}$$

If electricity exports to Europe ($EXPORT.TO.EU_{eu,t}$) are analyzed, export volumes can be optionally limited to a maximum volume ($maximum.export_{year}$) defined or assumed by the model user.

$$\sum_{eu} \sum_{t.year} \left[EXPORT.TO.EU_{eu,t.year}\right] \leq maximum.export_{year}, \quad \forall\, year \qquad \textbf{(Eq 16)}$$

The following equations express the basic generation constraints of the power plants which are not technology specific. Therefore, they are valid for all technologies ($tech$).

$$TEC.GEN_{tech,t.year} \leq INST.CAPACITY_{tech,year} * availibility_{tech}, \quad \forall\, tech, t.year, year \qquad \textbf{(Eq 17)}$$

Each power plant could only produce its maximum installed capacity (cap) multiplied by the factor availability which reduces the nominal capacity by an average value for revisions, planned and unexpected shut-downs and reserve capacity.

The database contains information of the existing infrastructure which are loaded in ($INST.CAPACITY_{infra,year}$) in $year_0$.

Using construction year and lifetime of power plants and energy storage systems, the variable ($CLOSE.CAP_{infra,year}$) contains the information in which year an infrastructure projects has to be closed. It is assumed that transmission lines have an infinite lifetime, therefore costs for operation and maintenance are considered to renovate and modernize existing lines continuously. But the shut-down of power plants and storages is depending on lifetime and construction. Extension of lifetime or premature shut-down is not possible, but a new investment in a similar infrastructure is implemented. Consequently the project disappears after the end of its lifetime from the list of existing infrastructure. New infrastructure projects ($NEW.CAPACITY_{infra,year}$) and currently installed capacities ($INST.CAPACITY_{infra,year}$) are modeled as variables in the expansion planning problem. In the generation dispatch model, results of the expansion planning model for each year are used to fix the variables and set explicit values for (newly) installed capacity and shut-down capacity. All three variables ($INST.CAPACITY_{infra,year}$, $NEW.CAPACITY_{infra,year}$, $CLOSE.CAP_{infra,year}$) are parameters in this case.

$$\begin{aligned} &INST.CAPACITY_{infra,year} \\ &= NEW.CAPACITY_{infra,year} + INST.CAPACITY_{infra,year-1} - CLOSE.CAP_{infra,year}, \quad \forall\, infra, year \end{aligned} \qquad \textbf{(Eq 18)}$$

To avoid over-investments by the model (e.g. to modernize the power plant portfolio in the first time step), a maximum value for new power plant investments is set for each year.

$$NEW.CAPACITY_{infra,year} * a_{tech} * tech.cost_{tech,year} \leq max.annual.plantinvest_{year}, \quad \forall\, tech, year \qquad \textbf{(Eq 19)}$$

Mainly conventional power plants and CSP plants show a lower efficiency and higher costs, if they are operated with frequent load changes and in part load of 40 to 80% of their maximum turbine capacity. Including conditions for load change and part load behavior helps to allocate additional costs for higher turbine wear and maintenance. For large steam and gas turbines a maximum load change (*max.load.change*$_{tech}$) per hour is necessary as turbines cannot operate totally flexible due to temperature, pressure and material conditions.

$$LOAD.CHANGE.UP_{tech,t} \leq max.load.change.up_{tech}\,, \quad \forall\, tech, t \tag{Eq 20}$$

$$LOAD.CHANGE.UP_{tech,t} = TEC.GEN_{tech,t} - TEC.GEN_{tech,t-1}\,, \quad \forall\, tech, t \tag{Eq 21}$$

$$LOAD.CHANGE.DOWN_{tech,t} \leq max.load.change.down_{tech}, \quad \forall\, tech, t \tag{Eq 22}$$

$$LOAD.CHANGE.DOWN_{tech,t} = TEC.GEN_{tech,t-1} - TEC.GEN_{tech,t}, \quad \forall\, tech, t \tag{Eq 23}$$

$$PART.LOAD_{tech,t.year} = INST.CAPACITY_{tech,year} - TEC.GEN_{tech,t.year}, \quad \forall\, tech, t.year, year \tag{Eq 24}$$

4.4.5 Regional electricity exchange: Transmission lines

Grid modeling of single transmission lines and physical electricity flows in AC and DC grids with different voltage levels are still a complex modeling problem in the field of energy system analysis if grid and generation planning is implemented in the same model and if many time steps and a large amount of model variables are used in the model approach simultaneously. An alternative to reduce the complexity of grid modeling and electricity exchange between each region is to neglect phase conditions of electricity flows, which is a common approach in the literature (Graeber, 2002). As each geographical region with its demand and supply is represented by a node in the grid structure, the electricity exchange between these nodes is possible by direct transmission lines which can transfer electricity up to a defined maximum net transfer capacity (NTC). That means that only real power is calculated in the transportation part of the model, reactive power and Kirchhoff's law are neglected. Consequently, electricity flows between regions are possible in the optimization up to the maximum NTC (Schweppe et al., 1988; Groschke et al., 2009). The existing grid structure is covered for the high voltage transmission lines (110 kV, 225 kV and 380 kV) between the regions based on the grid plan of (AUPTDE, 2011a) and (ENPI, 2012). To account for line losses in the model, the transmission lines between two nodes are represented by two lines of which each line can transport positive flows in one direction. Each line has defined start and end regions. In the model, new HVAC transmission lines for interregional electricity exchange could be only built as 380 kV lines (NTC of 580 MW) between regions which already have a connection today. New HVDC lines between North Africa and Europe are included as 400 kV lines with a NTC of 1000 MW lines.

The model regions (nodes) are obtained by sub-dividing each country into smaller grid regions (3 to 7 regions per country) according to grid typology as well as political and geographical reasons. Administration districts are taken into account to use population data of each region. Geographical constraints and grid typology help to group districts together, in order to design exchange of electricity between regions most viable. In each model region, demand has to be balanced by generation capacities in the region itself or by electricity exchange with neighboring regions. The hourly demand of each region is calculated by multiplying the national electricity demand with the quotient of the regional population to the total national population. This approach assumes a proportional relation between population and electricity demand. Specific load curves or demand per region are not used as these data are not available.

Figure 19 with the underlying grid map and the sites for renewable energy sources shows all 28 model regions of which 23 are located in North Africa and of which 5 regions are demand regions for electricity export to Europe. Imports from other countries (e.g. Jordan, Palestine) outside of the model regions are not taken into account.[10]

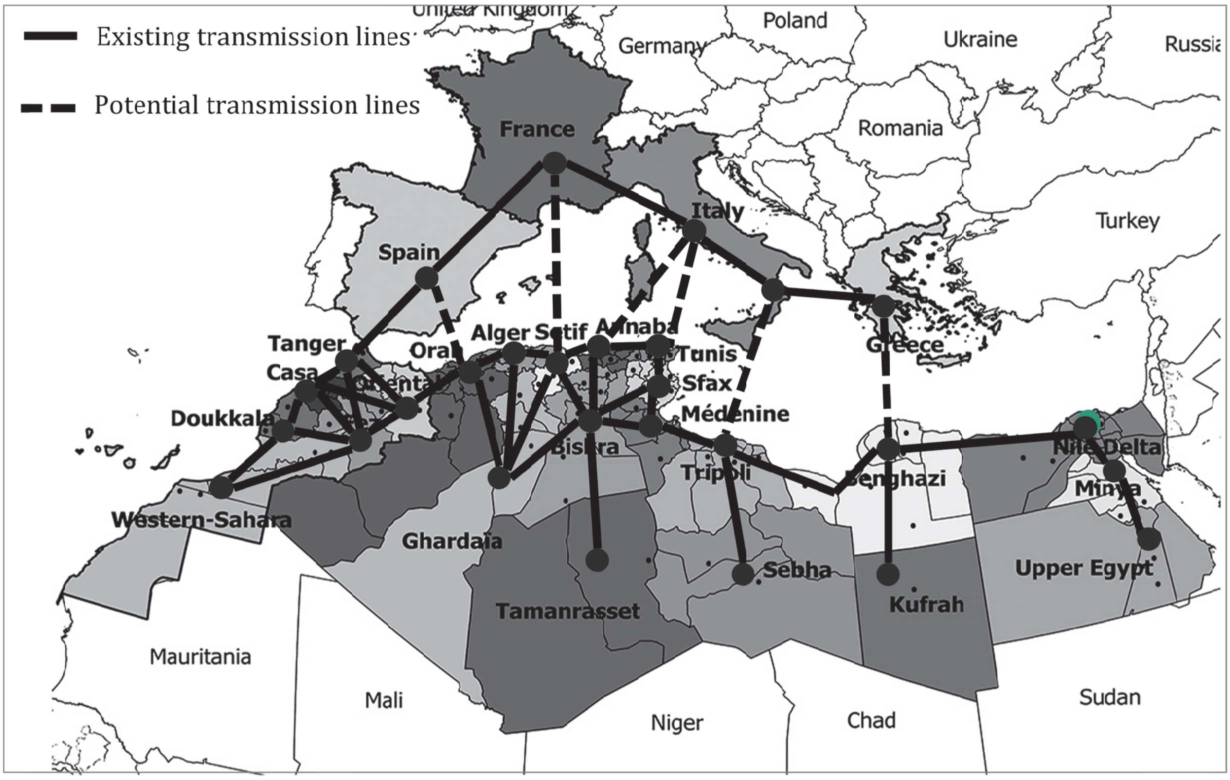

Figure 19: Model regions of RESlion with existing and potential transmission lines, underlying grid structure based on (AUPTDE, 2011a)

As electricity demand of consumers ($demand_{r,t}$) per region (r) has to be covered either by generation in the region or by exchange of electricity with neighbor regions ($IN.OUT_{r,t}$), the following equation is valid:

$$demand_{r,t} * (1 + distribution.losses + reserve.capacity) \quad \textbf{(Eq 25)}$$
$$= \sum_{tech\ in\ r}^{N} TEC.GEN_{tech,t} - IN.OUT_{r,t} - ENERGY.DUMP_{r,t} - EXPORT.TO.EU_{eu,t}\ ,$$
$$\forall\ r, t, eu$$

The final electricity demand of each region is increased by the distribution losses in the lower voltage levels. A reserve is considered to be able to balance unexpected short-term demand changes. Costs for transmission and new grid connections on the distribution level (low and medium voltage levels) are not included in the analysis. Existing grid structure can be sufficient today, but further demand increase and the installation of widely distributed RE power plants will also require new investments in distribution grids of the medium and low voltage level (An analysis of the effects in the distribution grids is not intended in this thesis). Surplus electricity

[10] Further interconnections of North African countries to other countries do only exist between Egypt and Jordan. This transmission line has a low utilization rate with very low volumes in 2010.

generated due to operational constraints or abundant feed-in of renewable energy sources is controlled by the variable ($ENERGY.DUMP_{r,t}$). This variable is necessary to integrate curtailment of RE power plants as shut downs are not possible as feed-in profiles of the RE power plants are exogenously given (see section 4.2). If connections to Europe exist, the variable ($EXPORT.TO.EU_{eu,t}$) is used to transfer electricity to Europe.

The electricity exchange of a regions r_j with its neighboring regions depends on the volume of outflows ($LINETRANSFER_{line,t}$, all lines with start r_j) to other regions and inflows ($LINETRANSFER_{line,t}$, all line with end r_j) from other regions. Transmission line losses ($losses_{line}$) depend on the distance of the geographic centers of the two regions which are connected by transmission lines (Table 31, appendix).

$$IN.OUT_{r,t} = \sum_{line\ with\ start(r)} \left[LINETRANSFER_{line,t} * (1 + losses_{line})\right] - \sum_{line\ with\ end(r)} LINETRANSFER_{line,t}, \qquad \forall\, r,t \tag{Eq 26}$$

The dependency of losses on the transferred electricity in equation (Eq 26) provides a variable overall electricity demand in (Eq 25) which is lower in the case of low exchange of electricity between the regions and increases vice versa.

Electricity transmission ($LINETRANSFER_{line,t}$) between regions is limited to the NTC capacity which is installed ($ex.line_{line}$) in the past or is constructed newly ($NEW.LINES_{line,year}$). In this constraint, line losses and a security margin ($l.sec_{line}$) are considered.

$$LINETRANSFER_{(line,t.year)} * (1 + losses_{line} + l.sec_{line}) \leq ex.line_{line} + NEW.LINES_{line,year}, \quad \forall line, t.year, year \tag{Eq 27}$$

By using transmission losses which depend on the volume of transferred electricity and distance between sub-national model regions, the RESlion model clearly improves other analyses which neglect grid effects in scenarios for renewable energy in North Africa. Furthermore, dependency of technology choice and site selection on investment costs for transmission lines and transmission losses is implemented in RESlion which offers a distinguished improvement to models without these features.

4.4.6 Renewable energy technologies

Electricity generation of RE power plants is implemented in two steps. Firstly, electricity generation profiles of reference power plants (Wind: turbine with 2.0 MW in a wind park, PV: 1 MW system) and thermal energy output profiles of reference CSP solar fields are calculated at each geographical site by external technology models described in chapter 4.2. These profiles consist of hourly values considering the weather conditions in the data set of the typical meteorological year. Then secondly, the hourly profiles of PV and wind onshore are multiplied by the installed capacity at each site to obtain the hourly electricity generation of each power plant.

$$TEC.GEN_{WindPV,t.year} = profile.ee_{WindPV,t.year} * INST.CAPACITY_{WindPV,year}, \quad \forall\, WindPV, t.year, year \tag{Eq 28}$$

As a CSP plant can be operated in the electricity system as dispatchable power plant by using its thermal storage, the use of the storage system is managed flexibly under the constraints of demand and supply. In coordination with the storage, the CSP steam turbine transfers heat from the solar field or storage system into electricity. Madaeni et al. (2012) proposes a CSP operation model which is included into to the model. Further operational modes ae included in RESlion as constraints such the input of natural gas and costs for load change (Kost et al., 2013a). In RESlion, a fixed ratio between turbine size (100MW), storage size (8 hours) and solar field is used. Due to this setting, generation profiles of the thermal output of the reference solar field can also be multiplied by the installed capacity of the power plant to obtain the thermal generation of each power plant ($CSP.SF_{CSP,t}$).

$$CSP.SF_{CSP,t.year} = profile.ee_{CSP,t.year} * \ INST.CAPACITY_{CSP,year}\ , \qquad \forall\ CSP, t, year, year \tag{Eq 29}$$

$$CSP.SF_{CSP,t} = CSP.DIRECT_{CSP,t} + CSP.ST.IN_{CSP,t} + CSP.DEFOCUS_{CSP,t,}\ , \qquad \forall\ CSP, t \tag{Eq 30}$$

The thermal output of the solar field at 390°C can be transferred directly into the steam turbine ($CSP.DIRECT_{CSP,t}$) via heat exchangers, stored in the large thermal storage tanks ($CSP.ST.IN_{CSP,t}$) or dumped by the variable ($CSP.DEFOCUS_{CSP,t}$). Defocusing of CSP mirrors is necessary when the turbine operates in full-load mode and the storage is already completely full.

$$\begin{gathered} CSP.ST.LEVEL_{CSP,t} \\ = (1 - csp.st.loss_{CSP}) * CSP.ST.LEVEL_{CSP,t-1} + CSP.ST.IN_{CSP,t} - CSP.ST.OUT_{CSP,t} * (1 + eff.ST_{CSP}), \\ \forall\ CSP, t \end{gathered} \tag{Eq 31}$$

The thermal energy storage (two-tank molten salt storage) stores the thermal energy with hourly losses ($csp.st.loss_{CSP}$). Further efficiency losses ($eff.ST_{CSP}$) appear during the process of providing electricity from the storage to the turbine. The storage level ($CSP.ST.LEVEL_{CSP,t}$) in each time period t depends on the hourly losses, hourly input and output, and the storage level of the hour before.

$$CSP.ST.LEVEL_{CSP,t.year} \leq\ csp.hours.st_{CSP} * INST.CAPACITY_{CSP,year}\ ,\ \forall\ CSP, t, \text{year, year} \tag{Eq 32}$$

The maximum level of the storage system is limited to a certain volume which represents a full supply of the turbine during eight hours of full load ($csp.hours.st_{CSP} = 8$).

Electricity generation in the steam turbine could be either supplied directly by the solar field, storage or use of natural gas ($CSP.GAS_{CSP,t}$). In the case of an energy flow from the storage tank, the turbine efficiency is reduced as the output temperature of the storage is lower compared to the energy flow from the solar field. A fixed efficiency of the turbine ($csp.eff_{CSP}$) is assumed, however, part-load losses and costs for load change are covered by the five equations (Eq 20) to (Eq 24).

$$\begin{gathered} TEC.GEN_{CSP,t} \\ = (CSP.DIRECT_{CSP,t} + CSP.ST.OUT_{CSP,t} * (1 - \frac{csp.eff_{CSP}}{csp.out.eff_{CSP}}) + CSP.GAS_{CSP,t})/csp.eff_{CSP}\ , \qquad \forall\ CSP, t \end{gathered} \tag{Eq 33}$$

The inflow to the turbine has to be restricted by a maximum turbine heat coefficient ($max.heat_{CSP}$) due to thermal constraint of the turbine.

$$CSP.DIRECT_{CSP,t.year} + CSP.ST.OUT_{CSP,t.year} + CSP.GAS_{CSP,t.year} \le max.heat_{CSP} * INST.CAPACITY_{CSP,year}\,, \quad \forall\, CSP, t.year, year \tag{Eq 34}$$

With the constraints (Eq 29) to (Eq 32), the operation mode of CSP plants is endogenously chosen by the model. Flexible dispatch of the CSP plant according to generation of other power plants and demand loads is possible with this approach in RESlion.

4.4.7 Hydro and storage power plants

In North Africa, hydroelectricity is very limited due to climate conditions and the scarcity of water in the region. Electricity production from hydro power plants is modeled by dividing the total annual potential of hydro power ($max.annual_{Hydro}$) into two seasonal potentials which correspond to the average volume of seasonal rain falls[11]. Therefore electricity production is distributed by about 70% in winter months and 30% in summer months ($season.max_{hydro}$). The annual maximum potentials of each hydro power plant which are set as maximum for the annual output of each plant are derived from the average values of historical data.

$$\sum_{season\_W} TEC.GEN_{Hydro,season\_W} \le seasonal.max_{Hydro,season\_W} * max.annual_{Hydro}\,, \qquad \forall\, Hydro \tag{Eq 35}$$

$$\sum_{season\_S} TEC.GEN_{Hydro,season\_S} \le seasonal.max_{Hydro,season\_S} * max.annual_{Hydro}\,, \qquad \forall\, Hydro \tag{Eq 36}$$

Hydro power plants without storage dam (run-of-river power plants) operate less flexibly compared to hydro power plants with dam or pumped-storage power plants. Therefore, these run-of-river hydro power plants are operated on an average hourly production level.

$$TEC.GEN_{Hydro,t} = seasonal.max_{Hydro,season\_W} * max.annual_{Hydro}/8760 * number.of.hours_{season\_W}\,, \quad \forall\, Hydro\ (run.of, river), t \tag{Eq 37}$$

$$TEC.GEN_{Hydro,t} = seasonal.max_{Hydro,season\_S} * max.annual_{Hydro}/8760 * number.of.hours_{season_S}\,, \quad \forall\, Hydro\ (run.of.river), t \tag{Eq 38}$$

Hydro power plants with dam and water reservoir can flexibly shift their production to hours with high demand.

[11] Average rain fall in Morocco and Egypt has been assessed. The seasons are defined as winter months (November to March) and as summer months from (April to October).

A few pumped-storage power plants exist in the region (mainly in Morocco). The model contains an option for the future to invest into other storage technologies such as Li-Ion batteries and NaS batteries. Storage power plants are modeled with a specific maximum storage volume ($st.max.level_{storage}$), an hourly storage capacity ($st.max.up_{storage}$) and an hourly generation capacity ($st.max.gen_{storage}$).

$$ST.LEVEL_{storage,t} = ST.LEVEL_{storage,t-1} * (1 - st.losses_{storage}) + ST.UP_{storage,t} * eff_{storage} - ST.GEN_{storage,t}\,, \quad \forall\, storage, t \tag{Eq 39}$$

The hourly storage level ($ST.LEVEL_{storage,t}$) depends on input ($ST.UP_{storage,t}$) and output ($ST.GEN_{storage,t}$) in each hour, efficiency of energy transformation in storage ($eff_{storage}$) and hourly losses ($st.losses_{storage}$).

$$ST.LEVEL_{storage,t} \leq st.max.level_{storage}\,, \quad \forall\, storage, t \tag{Eq 40}$$

$$ST.UP_{storage,t} \leq st.max.up_{storage}\,, \quad \forall\, storage, t \tag{Eq 41}$$

$$ST.GEN_{storage,t} \leq st.max.gen_{storage}\,, \quad \forall\, storage, t \tag{Eq 42}$$

All these constraints limit the hourly operational mode of storage to maximum values of the storage level, storage input and storage output per hour. One additional constraint sets the storage level of the first hour of the model run equal to the last one.

$$ST.LEVEL_{storage,t.first} = ST.LEVEL_{storage,t.last}\,, \quad \forall\, storage \tag{Eq 43}$$

Seasonal storage is not implemented in the model, as high solar and wind resources through the whole year reduce the need for options such as Power-To-Gas or hydrogen storage systems of which cost efficiency is not foreseen to be given today.

As demand-side-management (DSM) shows similar effects like energy storages – shifting electricity from one hour to another – the process and potentials for DSM can be implemented analogously to a short-term energy storage (daily use of storage). Results for storage use and storage potentials can be interpreted easily as findings for the use of DSM in the North African electricity market.

4.4.8 Uncertainty of input parameters and assumptions

Input data cause several uncertainties in the results of forecasts and projections about the future development of energy systems. Especially, data structures and data quality impact the results of the energy system analysis. As described in section 2.2.3, stochastic models have the advantage to include statistical distributions of hourly demand, weather events, fuel prices and unexpected breakdown of power plants. Due to the large data set used in the model, the implementation of stochastic information would create an increased effort to solve the model problem and computing time would increase significantly.

Therefore, the optimization model uses a data set with deterministic values and decides on perfect foresight over all input parameters. The parameter sets are defined and implemented as deterministic values which are loaded into the program before each model run. Obviously, perfect foresight in the energy system is in contrast to several findings in the literature.

Especially, the integration of renewable energy sources into the electricity system adds further uncertainties and unpredictable events and problems which are discussed in the literature.

Short-term uncertainty of fluctuating power generation of RE technologies due to variable wind speeds and solar irradiation is discussed, e.g. by Focken et al. (2002) and Giannakoudis et al. (2010). Hodge et al. (2013) propose to cover short-term forecasting errors of renewable energy sources by sufficient reserve capacities within the power generation system. Therefore, they recommend directly including a reserve in the generation dispatch model. Then, power plants can manage these errors automatically by increasing or decreasing their output. Furthermore, a factor which increases the hourly electricity demand is implemented in the RESlion model to be able to take ancillary services into account and to have back-up capacities which allow balancing these short-term errors immediately.

Long-term uncertainty generated by strong deviations of wind and solar data in reality compared to prognosis data is analyzed regarding their influences on investment decisions by Nagl et al. (2012) in a European case for wind and solar technologies. A stochastic model calculates ten different distributions for full load hours of wind and PV in thirteen European countries. In comparison to a deterministic approach, the overall system costs are underestimated by 1.4% (at a RES-E share of 40%) and 12.5% (at 95%). This effect on total system costs has to be taken into account when interpreting the scenarios with different RES-E shares.

Some market risks of North African countries can be captured by including higher financing cost and higher cost for each technology. However compared to the perfect model world, real investment decisions on new infrastructure projects are faced by additional project risk which is related to the imperfect markets and incomplete information. Gaidosch (2008) describes several risk factors of investment decisions in the energy sector which can only be included in the RESlion model to a limited extend:

- Regulatory risks
- Social acceptance of energy infrastructure projects
- Risk of technical innovations
- Risk of delays and costs increase during construction time
- Incomplete information of the investor

Investments in renewable energy sources can also be influenced by strategic choices of the investor. This is difficult to reflect in the model as portfolio aspects, heterogeneity of investors, role of cognition and bounded rationality can influence the decision process (Wüstenhagen and Menichetti, 2012). Further uncertainty of the model results is generated by the long-term forecast of cost and technology parameters which have to be assumed for future energy projects in North Africa until 2050. Finally, each model decision to construct new power plants and transmission lines is based on a limited number of operating hours and on a time horizon of maximum 20 years. However, the effect is reduced by the widely distributed model hours (see section 4.4.2). Potentially, time horizon of the model can also be extended if the interval between the model years is enlarged or more model years are selected.

4.5 Modeling of expansion planning

In the first step, the model optimizes the long-term development of the electricity system by determining for each power plant, transmission line or energy storage system:

- construction size
- date of construction
- site (with corresponding node)
- date of shut-down (depending on lifetime)

The problem to construct a new project is solved by the model through the variable ($NEW.CAPACITY_{infra,year}$). In time steps of five years, the model can extend the existing capacity up to maximum capacity for each technology. For example, a wind park can be installed with a capacity of 150 MW in $year_1$, and some years at the same site, another wind park with another capacity can be constructed (up to the maximum capacity). In reality only discrete values of capacity can be installed, e.g. turbine sizes are standardized to a few values. Due to linearity of the model, continuous values for installed capacities can be chosen. That means that in some cases small capacities of one technology can be installed (e.g. a 10 MW coal power plant). This effect is possible as the value of the variable can be between zero (power plant not yet constructed) and the maximum capacity.

The result of the expansion planning model is a defined development program for the installation of power plants, transmission lines and energy storage systems.

4.6 Modeling of detailed hourly generation dispatch

Hourly operation of each power plant and electricity exchange between regions over one year is modeled in the second step of the RESlion approach. The results of the expansion planning model serve as input to be able to obtain the complete system operation of one year. This consistency check of the results by a detailed hourly generation dispatch for one explicit year aims to:

- Validate the results for the expansion planning in terms of energy security for each hour of one year (matching peak demand with all weather conditions of one year)
- Operate the whole system over 8760 hours and prove its feasibility
- Obtain annual values of the system operation and of each power plant, in particular values for each model region, fuel and operation costs and utilization rates (full load hours) per technology
- Derive typical operation modes and strategies of power plants and energy storages

In the second step of solving the overall model, the problem formulation can now be reduced by the main results of step one:

1) The values of installed technologies in the electricity system (results of variable $INST.CAPACITY_{infra,year}$) are transformed to an input parameter set ($inst.capacity_{infra,year}$) which contains the power plant and grid structure of a certain year.
2) The index (t) now consists of 8760 values which corresponds to all hours of one year (1...8760).
3) The generation dispatch is solved over all 8760 hours of one year.

The case of infeasibility of the generation dispatch due to extreme weather conditions or other problematic system situations (e.g. high demand) can increasingly appear in scenarios with higher shares of renewable energy. In these scenarios, problem of balancing demand and supply in one region due to insufficiently installed generation or transmission capacities is possible. If infeasibility of the hourly generation dispatch model exists, assumptions in the expansion planning model have to be adjusted in an iterative way. By slightly increasing the input parameters for the reserve value for power plants (*reserve.capacity*) or transmission lines ($l.sec_{line}$) and by running the expansion planning model again, the dispatch generation model can be started with new results including larger capacities. This process can be repeated, until the generation dispatch is feasible. Another option is to add additional generation capacities (e.g. gas turbines) to the region which causes the problem of infeasibility. This might be a fast solution if only one region is responsible for infeasibility.

4.7 Extension options to a Mixed Integer Linear Programming model

The linearity of the RESlion model facilitates solving of the model compared to other model structures. The large amount of variables for many different infrastructure projects and their operation increases the overall size of the model. Compared to a linear program, the advantages of converting the problem into a mixed integer linear program model are essentially accomplished by using (binary) integer variables to allow a fixed minimum installed capacity per power plant or to implement part-load effects and operation restrictions of shut-down times and revisions in more detail.

1) **Integer scalability of power plant capacities:** Scalability of reference power plants is possible by integer multiple of the reference power plants if the installed capacity can be increased only by integer values.
2) **Minimum power block sizes:** If a binary variable is used to model the decision if a power plant is constructed or not, the minimum of installed power plant capacity can be set to a level which represent a reasonable generator size. This variable can be equal to 1 in case a new power plant is constructed or is zero if the power plant is not commissioned.
3) **Part-load efficiencies:** The implementation of part-load behavior and decreasing efficiencies of the electricity generation at lower temperatures or lower energy inflows in a turbine can be improved as a binary variable can indicate if a power plant runs below a certain design parameter (e.g. below 80% of the nominal turbine capacity).
4) **Shut-downs and cold starts:** Another binary variable can be used if a restart of the power plant is only possible after a defined period or with additional costs for cold starts.

Further model extensions are possible if required for a certain problem.

4.8 Solver selection and implementation environment

The RESlion model is implemented as linear program in the modeling software GAMS 23.9.1 (General Algebraic Modeling System) which uses CPLEX 12.4.0.1 by IBM to solve LP problems (GAMS, 2013). The mathematical solution of the objective functions and the equations depends strongly on the data input and the scenario assumptions which should be solved. The expansion planning problem consists of about 10 million nonzero elements. The scenarios of chapter 5 require a solving time of the CPLEX solver for the expansion planning problem between 2 and 8 days depending on the problem formulation and input parameters (The GAMS program runs on a desktop computer with 48 GB RAM and 8 CPU cores.). The hourly dispatch problem can be solved within 4 to 8 hours

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5 Model-based analysis of future electricity scenarios for North Africa

In the previous chapter, model development and implementation of RESlion is explained by a description of the model approach which is suitable to analyze the existing North African electricity system and its long-term expansion with increasing shares of RES-E until the year 2050. Different scenarios are applied to the electricity system in this chapter. By setting long-term targets for the RES-E share in the electricity systems, detailed technology choice and site selection as well as effects on conventional power plants, grid structure and demand for energy storages are investigated. Furthermore, results for a continuous development path of the power sector are presented in form of a closed technology and system roadmap from today (reference year is 2010) to the year 2050 by a long-term outlook.

The expansion planning is based on an analysis of each fifth year (2010, 2015, 2020 etc.). The analysis of future electricity scenarios is split in two scenario groups. As many problems and barriers face large-scale electricity transport to Europe, export of electricity is only a potential option for the electricity systems in North Africa. Therefore, general feasibility, economic benefits and total system costs of RES integration in North African electricity are analyzed in a first group of scenarios without effects from other international electricity markets. In a second group, export of RES-E to Europe is possible.

In scenarios of group 1, RES-E share is evaluated with starts to increase from a value of 7% in 2010 to different shares between 50%, 80% and 100% in year 2050 depending on the scenario definition. In contrast to electricity scenarios mainly based RES, a business-as-usual (BAU) scenario projects a slow development of RES in North Africa and very limited RES-E share of 20% in 2050. Another scenario without any technology target purely focuses on lowest total system costs. With detailed sensitivity, the change of technology costs, fuel costs, technology potentials and regulatory framework conditions in the electricity markets are analyzed. The analysis of scenarios of group 2 provides more information on optimal technology choice, site selection, grid expansion and economic effects including generation and transmission costs for an expansion of electricity export to Europe.

5.1 Scenario assumptions

The scenario analysis aims to show the long-term development of the electricity by using renewable energy technologies. As the RE integration should be assessed for different RES-E shares from a cost-optimal perspective, *explorative, normative scenarios* are implemented in the RESlion model (see section 2.1). Technical constraints of the infrastructure clearly influence the scenario results as the model results should represent a system configuration which provides secure and feasible energy supply for all system conditions.

Some general assumptions regarding future development of electricity markets in North Africa and integration of RES-E are set for all scenarios identically. It has to be noticed that these assumptions have a strong influence on the results of the scenarios. However, the time horizon of 40 years until 2050 provokes high uncertainties of some system intrinsic boundaries. In addition to the uncertainties regarding the framework condition of the electricity system in North Africa, technology options and technological parameters underlie a continuous development process. Technology assumptions are included based on current technology roadmaps for technical and economic features. However, disruptive changes are hardly to include in the model.

The following assumptions for the framework conditions of the electricity system and the energy technologies are implemented for the scenario analysis:

- **Status-quo of electricity system:** The existing electricity system of North African countries (power plants, transmission lines, electricity demand, and annual generation per type) is given for the reference year 2010 as described in chapter 3. Power plant projects in planning stage are in the database and will be commissioned according to plans of the year 2010, although the Arab Spring has strongly postponed some of the projects.
- **National supply:** As dependency of electricity imports from other countries increases the risk for economy and society during crises, national energy security is a key policy target in many countries. The security of energy supply on a national level is satisfied by an explicit requirement of 75% national electricity generation on the final electricity consumption in each modeled hour.
- **Target fulfillment:** The fulfillment of the RES-E targets in a certain year is mandatory in the model by satisfying the specific condition for the share of RES-E contribution compared to overall electricity generation from all sources. Over- and undersupply by RES-E is not possible. Different deployment paths of RE development are covered by the scenarios.
- **Curtailment of RE technologies:** In all scenarios, curtailment of RE power plants such as wind and PV is possible to avoid over-investment of grid capacities for a few hours per year when RES-E generation shows high feed-in peaks or demand is relatively low.
- **RE potential:** The RE resources are given according to the site selection in section 4.2. At all sites, sufficient land is available to install power plants and transmission lines. RE power plants could be distributed at one site over several kilometers. But the same wind speeds or solar irradiation are used for all power plants at one site.
- **Cost development of technologies:** In section 5.3, cost assumptions for electricity generation technologies are given based on learning curve models (Kost et al., 2012b).
- **Fuel prices:** Prices of coal, oil and natural gas from the moderate scenario of Nitsch et al. (2011) are used as reference. Due to local reserves of oil and natural gas, the prices for both fuels are reduced by 20% to take lower transportation cost into account, compared to German prices. Nevertheless, this price scenario only can be a reference for opportunity costs in countries such as Algeria or Libya as these countries calculate the price of fossil fuel consumption lower due to their national reserves of oil and natural gas.

- **Price for CO_2 emission allowances:** Targets of CO_2 emission reductions and prices for CO_2 emission allowances are not relevant for North African countries today. However, from 2025, the price for CO_2 emission allowances is assumed to increase from 7.5 EUR/t to 40 EUR/t in 2050 the BAU scenario. In scenarios with higher shares of RES-E, this price is 20 EUR/t from 2015 on, in order to facilitate the deployment of renewable energy. This assumption is based on a potential increasing importance of CO_2 emissions also in North Africa.
- **Transmission constraints:** Land for transmission lines is sufficiently available in all scenarios. New transmission lines are not subject to land constraints or social acceptance. Therefore, transmission expansion is not limited to any constraints in terms of capacities. In reality, planning of large-scale transmission lines between North Africa and Europe include the assessment of suitable geographical corridors and routes to be able to construct the required transmission lines in an acceptable period of time (in European and North African countries).
- **Interest rates:** Due to the economic and political system, project risks and inflation rates are generally higher in North Africa compared to Europe. Therefore, interest rates (as weighted average cost of capital) for infrastructure investments are assumed to 8% for all technologies. In principle, the model is able to include technology and country specific interest rates into the calculations.
- **Discount rate:** In the expansion planning model, a discount rate of 3% per year is used to discount costs of different time periods.

Today, the electricity markets of North African countries are weakly interconnected and exchange of electricity is very limited to some GWh per year as explained in chapter 3. Expansion planning, definition of targets and system operation in the power sector are task of the national governments, utilities and grid operators with limited exchange of information with neighboring countries. If a large-scale integration of renewable energy should be accomplished in North Africa, cooperation and electricity exchange have to be increased due to fluctuating RES-E feed-in which causes local over- or undersupply which can be balanced more efficiently in large areas covering a wide distribution of RE power plants. To analyze the future development of the electricity systems properly, the following assumptions regarding higher cooperation and integration of the different electricity markets are defined:

- **Integrated electricity market:** An integrated electricity market between the North African countries is assumed in the majority of the scenarios. This assumption strongly reduces the restrictions on exchange of electricity between the countries. In scenarios with integrated electricity markets, expansion planning and operation of power plants are modeled from an integrated, international point of view considering an optimal path for the energy system of the total region.
- **Combined RES-E targets:** National RES-E targets by 2020 and 2030 exist in all North African countries as presented in chapter 3. To obtain a long-term cost-optimized electricity system for the total region with large shares of renewable energy, a single long-term RES-E target for the total region is defined for each time step. This target can be met by different national contributions depending on the national RE resources and cost perspective in each country.

Further assumptions and input parameters regarding the modeled technologies and the electricity market model RESlion are given in chapter 4.

5.2 Scenario definition

Scenarios are divided into two groups: The first group of scenarios ("North Africa") focuses on the RES integration without imports and exports of electricity from and to Europe. In addition to six basis scenarios for North Africa, a sensitivity analysis of the High-RES scenario with a RES-E share of 80% on the overall electricity generation until 2050 is carried out to show the effects of a parameter change (scenario overview in Figure 20). The scenarios of group 2 ("Export Scenarios") describe different export cases which extend the scenario assumptions of the High-RES scenario by adding assumptions for export. Effects under a quantity and a prices mechanism are analyzed.

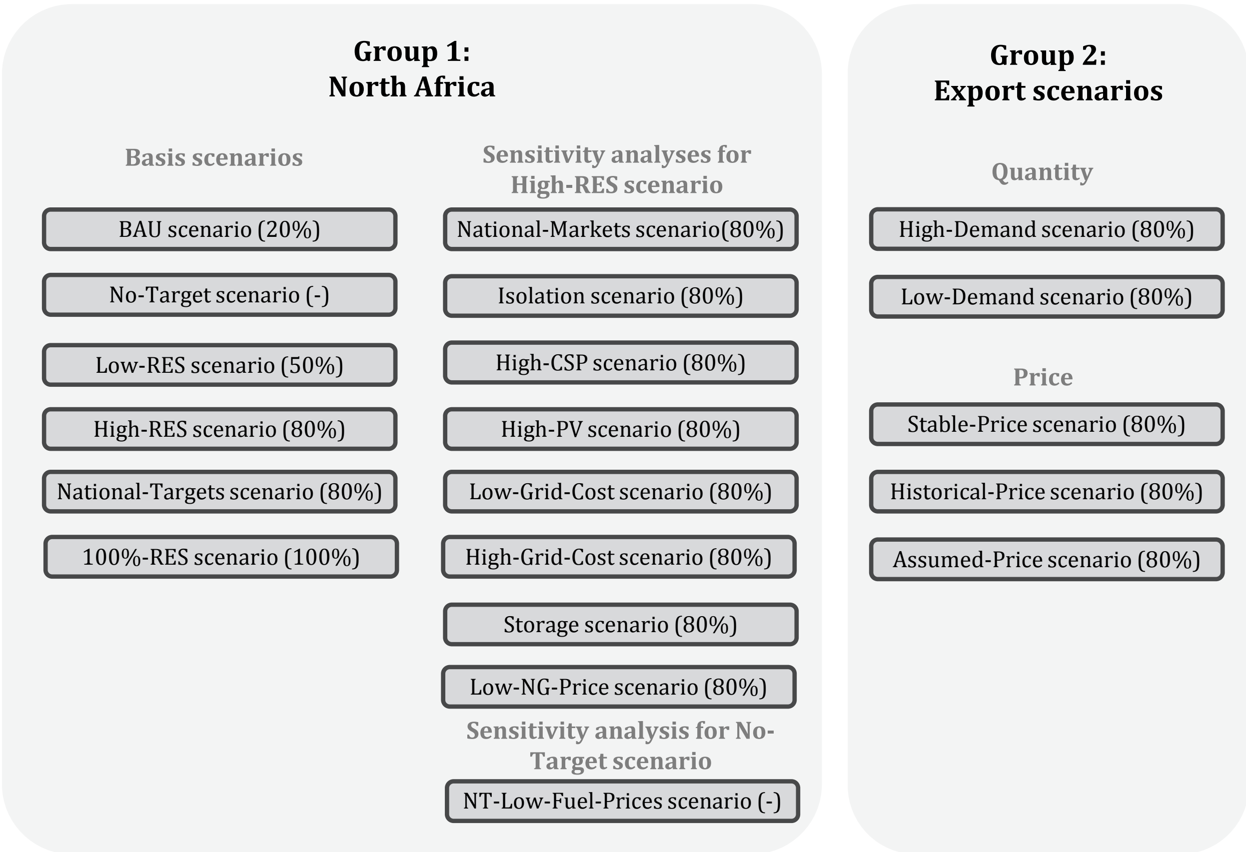

Figure 20: Model scenarios for electricity system analysis (value in brackets represents the RES-E target for year 2050 in each scenario)

Basis scenarios of group 1: RES integration into North African electricity system

- **Business-as-usual (BAU) scenario:** In the BAU scenario, a continuous slow integration of renewable energy is assumed. The electricity system continue to be mainly based on power generation from fossil fuels, capacities of conventional power plants such as CCGT and coal which have to be extended in the future due to the increasing demand. Furthermore, in this scenario, CO2 emission reduction does not play an important role as a price for CO2 emissions is only assumed after 2025. The RES-E share is stable below 20% until 2050.
- **No-Target scenario:** This scenario allows choosing the cheapest technology portfolio without limitations by targets for renewable energy or reduction of CO_2 emissions. Outcome of this scenario strongly depends on technology costs and fuel prices.

- **Low-RES scenario:** By 2050, the contribution of RES-E to the overall electricity generation is set to about 50% (Figure 21, with a comparison with the targets of the BAU scenario, High-RES scenario and 100%-RES scenario). In this scenario, conventional power plants still play an important role in the long-term perspective. RES-E targets of this scenario are below the RES-E targets of the real national plans for renewable energy for 2030. Therefore, this scenario seems to be possible if national plans are followed but due to realization problems or higher demand cannot be fulfilled.
- **High-RES scenario:** The High-RES scenario has an RES-E share target of 80% on the total electricity generation in year 2050. The RES-E target of 80% is selected as this RES-E share is a basic assumption in different international energy studies. This value makes it possible to back-up a system of a high RES-E share with conventional power plants in hours with lower feed-in from RES. The intermediate target of 32% by 2030 represents an approximate value of national targets in Morocco, Algeria and Libya. Figure 21 shows the temporal development of the RES-E share between 2010 and 2050. The High-RES scenario serves as base scenario for the sensitivity analysis and for electricity export (scenario group 2).
- **National-Targets scenario:** Currently, national targets have been set until the year 2020 or 2030. In this scenario, each country has to reach own RES-E targets of 80% instead of a combined RES-E target (compare High-RES scenario). Therefore, this scenario represents a national way of RES integration without international cooperation. Exchange of electricity between countries is possible in this scenario.
- **100%-RES scenario**: If the electricity systems in North Africa will exclusively use renewable energy sources in the year 2050, the outcomes can be assessed by the 100%-RES scenario (Figure 21). With this scenario it is possible to analyze the impact of a system which does not use any conventional back-up capacities.

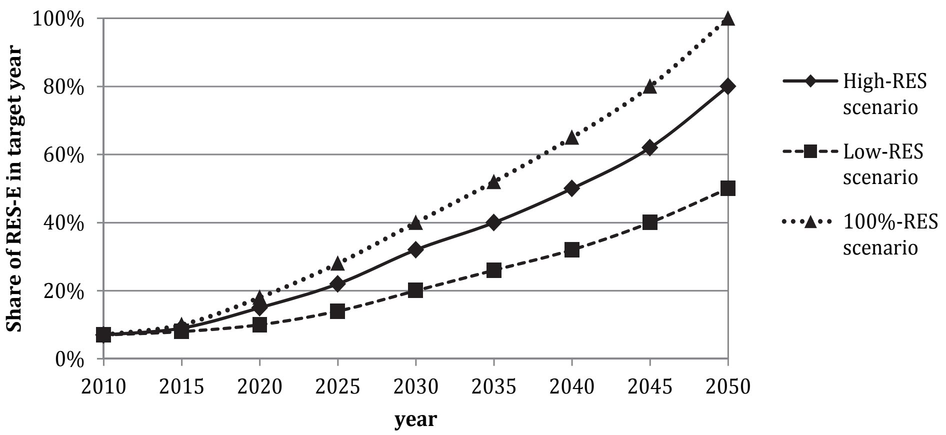

Figure 21: Development of RES-E targets

Sensitivity analysis for High-RES scenario

- **National-Markets scenario:** The effects of a disconnected scenario should be analyzed in order to quantify the drawbacks of a limited transmission capacity and interconnections between the countries. Due to the low international electricity exchange between the countries today, this scenario represents a continuous market separation of the national electricity markets of North Africa.

- **Isolation scenario:** Similar to National-Markets scenario, limited exchange of electricity is tested under the assumption that only one country decides not to take part in an integrated electricity market. As the Algerian economy shows very restrictive trade policy with international markets, it is assumed that Algeria limits its interconnections and exchange of electricity to its neighboring countries Morocco and Tunisia in this scenario, whereas the interconnections between Tunisia, Libya and Egypt allow exchange of electricity.
- **High-CSP scenario:** Since some national governments set a focus on the development of large CSP projects, this scenario assumes a minimum contribution of 50% from CSP within overall RES-E targets. The results will show costs and benefits of an electricity system with a higher share of RE dispatchable power plants as CSP plants operate more flexibly compared to wind or PV power plants.
- **High-PV scenario:** In this scenario, a higher penetration of PV is assumed by setting the minimum share from PV electricity to 50% within the overall RES-E targets. The high PV feed-in during sunshine is evaluated, whereas the rest of the day has to be supplied by other sources or by PV electricity stored in large storage systems.
- **Low-Grid-Cost scenario:** As investments in transmission lines are subject to the specific landscape, vegetation and existing infrastructure (roads etc.), basic assumptions for costs of transmission lines are assumed conservatively. The Low-Grid-Cost scenario reduces the costs for new transmission lines by 50% and sets specific cost for HVAC transmission lines to 350 EUR/(MW_{NTC}*km).
- **High-Grid-Cost scenario:** This scenario is similar to the Low-Grid scenario, but assumes costs for transmission lines of 1400 EUR/ MW_{NTC}*km (200%).
- **Low-NG-Price scenario:** Due to lower natural gas (NG) prices in some of the countries today compared to the underlying price scenario for natural gas and latest projections (due to fracking of NG in the US), the Low-NG-Price scenario analyzes the impact of a 50% lower natural gas price from today to 2050 compared to the basic assumption.
- **Storage scenario:** Fluctuating electricity generation will lead to increasing R&D for new energy storages and demand-side management (DSM) solutions. As the price and component assumptions for storage technologies and DSM are highly uncertain, the basic assumptions are set conservatively to avoid over-estimation of storages and DSM potentials by 2050. In the Storage scenario, prices for new storages are reduced by 50% and potentials for new applications are doubled.

Sensitivity analysis for No-Target scenario

- **NT-Low-Fuel-Price scenario:** To test the influence of lower fuel prices on the technology portfolio and the RES-E share, natural gas prices of 50% and coal prices of 75% compared to the basic assumptions are assumed in this scenario.

Scenarios of group 2: RES integration and electricity export to Europe

The analysis of RES integration in the electricity system of North Africa is extended by exploring also scenarios which assume potential electricity exports (of RES-E) to Europe (see Figure 20). As presented in section 3.4, electricity export from North Africa is proposed in different studies to diversify the use of RES-E in Europe. With the large and huge solar and wind resources in North Africa, potential benefits for the European electricity markets are lower costs compared to generation in Europe and stable feed-in from renewable energy sources such as CSP. Quantity mechanisms (quota/hourly fixed demand) and price mechanisms (tariffs for generation and transmission) are set for the export scenarios (group 2) to create RES-E exports from North African sites to Southern Europe. However, RESlion does not include European electricity generation. With this approach, potential electricity flows from North Africa to Spain, France, Italy and Greece are analyzed.

In two scenarios, fixed import volumes to Europe which increase up to 400 TWh (200 TWh) in year 2050 are assumed. The volume of 400 TWh is approximately 13% of EU-27 electricity demand of year 2010. Three other export scenarios offer optional tariffs for each kWh imported to the European countries up to a specific maximum which is set to 200 TWh in year 2050. Producer of RES-E in North Africa can decide in these scenarios to sell electricity for the specific tariff to Europe. In each scenario, the tariff is offered on an optional hourly basis in contrast to the quantity scenarios in which a specific volume of exports are predefined during each hour. That means that the producer can decide which volume he wants to export in each hour. With the price mechanisms, the amount of exportable electricity should be tested under tariffs which differ in terms of their height and structure.

In all export scenarios, impact on the generation portfolio and electrical grid is assessed by comparing overall system costs and installed capacity per technology. Electricity exports should not increase generation from conventional sources. However, electricity generation can be shifted between time periods to obtain a stable system.

- **High-Demand scenario:** This export scenario defines mandatory annual and hourly values for electricity export to Southern Europe. The annual values of electricity exports is based on assumptions for a continuous growth of electricity imports to five European regions up to 400 TWh in 2050 (see Table 14 with values of Low-Demand scenario, values of High-Demand scenario are two times the Low-Demand scenario values). All European model regions (nodes) obtain a net annual demand which has to be supplied by RES in North Africa. The country values are assumptions which are related to the size of the country and potential demand. The annual values are calculated to hourly values for each hour of a year to supply the electricity system. Targets are defined by a synthetic daily demand which assumes constant demand with peak demand hours between 6am to 9am and 6pm to 9pm (Central European Time), see Figure 22.

Table 14: Annual electricity exports from North Africa to Europe in Low-Demand scenario (maximum values for electricity exports in scenarios with price mechanisms)

Year	Spain	France	Northern Italy	Southern Italy	Greece	Total
	[TWh]	[TWh]	[TWh]	[TWh]	[TWh]	[TWh]
2010	0	0	0	0	0	0
2020	3.75	4.5	2.25	3	1.5	14
2030	12.5	15	7.5	10	5	50
2040	25	30	15	20	10	100
2050	50	60	30	40	20	200

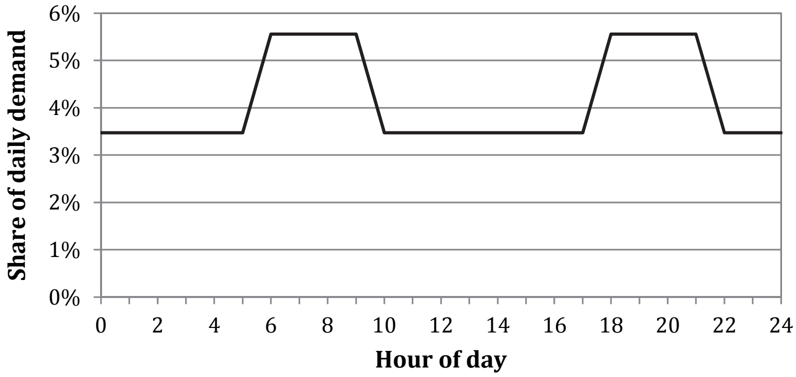

Figure 22: Share of daily exports in High-Demand scenario (and Low-Demand scenario)

- **Low-Demand scenario:** Similar to the High-Demand scenario, the Low-Demand scenario assumes mandatory volumes for export electricity to Europe with a total demand of 200 TWh in 2050 (values per year and country are presented in Table 14).
- **Stable-Price scenario:** A stable tariff remunerates each kWh exported with a fixed price of 70 EUR/MWh. The tariff is paid by European countries up to the maximum demand values of the Low-Demand scenario (see in Table 14). Aim of this tariff is to allow an analysis of the effect when and how much electricity is exported to Europe under a stable tariff. The revenues from this tariff have to refinance investment and operation of renewable energy power plants as well as required grid expansion. Additionally, the tariff has to finance transmission losses between the electricity generation and the final grid node in Europe as the tariff is paid only for imported electricity.
- **Historical-Price scenario:** As result of volatile electricity generation and demand, electricity pool prices (e.g. day-ahead market prices) demonstrate the value of electricity. Hourly values of historical electricity pool prices taken from the Spanish market of the year 2010 are added to an assumed premium of 30 EUR/MWh as tariff which is paid for imported electricity (OMIE, 2013). Other conditions are similar to the Stable-Price scenario (see Table 14 with maximum values). By using this volatile market price, the offered tariff for electricity refers to the electricity demand in the target countries.
- **Assumed-Price scenario:** Similar to the Historical-Price scenario, a premium tariff of 50 EUR/MWh plus a volatile electricity price is paid for imported electricity. But for each day, an assumed electricity tariff is implemented which pays 30 EUR/MWh during the night and up to 90 EUR/MWh in peak demand hours from 7am to 8am (CET) and 5pm to 6pm. Prices are similar at each day through the whole year. This price forecast takes future conditions in the European electricity market into account as it differentiates between hours of the day. Furthermore, it takes hourly demand and potential large solar electricity generation in Europe into account. Therefore, this price curve is different to the historical price of 2010. Other conditions are similar to the Stable-Price scenario (see Table 14 with maximum values).

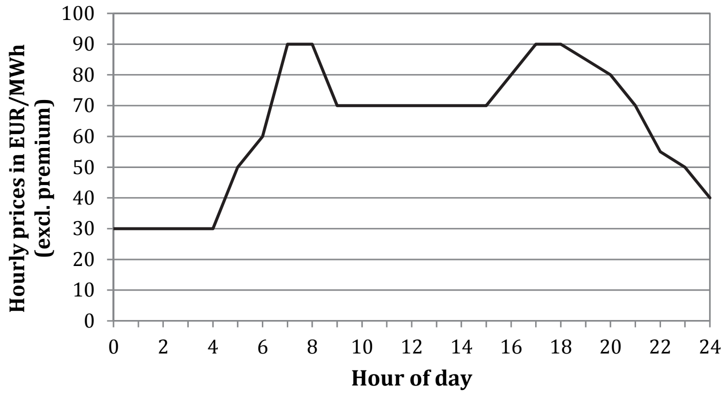

Figure 23: Assumed hourly electricity price for Assumed-Price scenario

These scenarios are evaluated in the following sections regarding generation portfolio, grid expansion and system costs as well as operational pattern.

5.3 Technical and economic input data

The RESlion model includes the main electricity generation technologies, energy storage systems and transmission lines of the high voltage level. Existing and planned power generation capacities are collected in a database with data from the national utilities, the Platts power plant database (Platts, 2011) and AUPTDE (Arab Union of Producers, Transporters and Distributors of Electricity) (AUPTDE, 2011b). Today, the North African countries have a power plant capacity of about 70 GW which is based on gas and oil power plants with nearly 95% (Table 15). Each existing power block (>50 MW) of conventional power plants in the region is included as single operating entity. Smaller capacities are grouped together to similar classes per region (type, construction year). Conventional power plant technologies are coal-fired power plant (coal), gas turbine (GT) running with oil or natural gas (NG) and combined cycle gas turbine power plant (CCGT). The efficiency of existing power plants is calculated based on the documentation of the Clean Development Mechanism (CDM) which provides information about electricity generation and burned fuels per power plant in Morocco, Tunisia and Egypt (UNFCCC, 2010; 2012b; a). The efficiency of power plants with a similar construction year in other countries is assumed to be related to the three countries (Table 35, appendix). Hydro power plants are either constructed as conventional hydro power plants with water reservoir, run-of-the-river power plants or as pumped-storage hydro power plant.

Table 15: Installed power plant capacities in North Africa

Year 2010*	**Morocco** [MW]	**Algeria** [MW]	**Tunisia** [MW]	**Libya** [MW]	**Egypt** [MW]
Coal	1785	0	0	0	0
CCGT	856	1260	837	915	8650
GT (NG)	900	10794	1691	2479	8025
GT (oil)	888	638	1213	5684	7080
Hydro	1265	271	40	0	2870
Wind	250	0	100	0	540
PS	465	0	0	0	0
Total	6409	12963	3881	9078	27165

*Data based on: (Platts, 2011), (AUPTDE, 2011a), (ONE, 2011), (STEG, 2011), (Gecol, 2011), (Sonelgaz, 2012), (EEHC, 2011).

Technology options for newly constructed power plants (state-of-the-art technologies with average turbine efficiencies) considered in the RESlion model are coal-, gas- and oil-fired power plants with high efficiency. The nuclear power plant option is not included due to a low likelihood of implementation, although some announcements for new nuclear power plants exist in Egypt and Morocco (Jewell, 2011).

RE technology options are PV power plants (1 MW, scalable), wind power plants (2 MW, scalable), CSP plants (parabolic trough, 100 MW, scalable) and hydro power plants (only existing capacities). The reference PV power plant is modeled by using fixed-tilt, high efficient, mono-crystalline silicon PV modules and centralized inverters. Wind farms are based on a Gamesa 2 MW turbine with hub height of 78 m. CSP parabolic trough plants use thermal energy storage of 8 hours and steam turbine with a net capacity of 100 MW using a dry-cooling system to avoid dependence on water availability. Biomass power plants can be implemented in the model as well, but due to missing potentials of bioenergy in all North Africa countries, this technology is neglected in the energy scenarios for these countries. More details on the RE technology assumptions are described in section 4.2.1 to 4.2.4.

For future power plant investments, a turbine efficiency (*eff.*) roadmap and a cost learning curve for each technology is assumed to include new technology developments and cost reduction based on optimized components or production processes (Table 16). All assumptions (and results) regarding costs and prices are provided in terms of the reference year 2013.

Table 16: Technical and economic technology assumptions (Weber, 2008; Kost et al., 2012b; Nagl et al., 2012)

		Year 2010		Year 2020		Year 2030		Year 2040		Year 2050	
	Reference size for assumptions	**eff.**	**invest**	**eff.**	**invest**	**eff.**	**invest**	**eff.**	**invest**	**eff.**	**invest**
	[MW]	[%]	[€/kW]	[%]	[€/kW]	[%]	[€/kW]	[%]	[€/kW]	[%]	[€/kW]
Coal	800	46.0%	1200	46.5%	1200	47.0%	1200	47.5%	1200	48.0%	1200
CCGT	500	58.0%	800	58.5%	800	59.0%	800	59.5%	800	60.0%	800
GT (oil)	150	36.0%	400	36.5%	400	37.0%	400	37.5%	400	38.0%	400
GT (NG)	150	36.0%	400	36.5%	400	37.0%	400	37.5%	400	38.0%	400
PV	1	18.4%	3000	21%	953	23%	745	24%	662	25%	613
CSP (TES: 8h)	100	var.	6000	var.	4025	var.	3550	var.	3177	var.	2988
Wind	2	var.	1500	var.	1345	var.	1305	var.	1273	var.	1254
PS (5h)	400	80.0%	1200	80.0%	1200	80.0%	1200	80.0%	1200	80.0%	1200
Batteries (5h)	1	80.0%	1800	80.0%	1800	80.0%	1800	80.0%	1800	80.0%	1800

Similarly, operation parameters (such as lifetime, O&M costs, load change costs and CO_2 factor) are defined for all technologies, but they are assumed to be stable over the model horizon. The availability of conventional power plants is set to 85% for old and 87% for new power plants (compare Hoster (1996)). Thus the available capacity of each power plant is reduced in each hour by the availability factor to include revision times and hourly reserve capacity which is not covered separately by the electricity market model. The reserve capacity should guarantee security of supply and load balance as well as provide short-term frequency control.

Table 17: Parameters for new power plant operation (sources: Weber (2008); Quaschning (2013) and own assumptions)

	Lifetime	**fixed O&M costs**	**var. O&M costs**	**Load change costs**	**Maximum hourly load change**	**CO_2 factor**	**Availability (includes revision & reserve capacity)**
	[years]	[€/kW]	[€/MWh]	[€/MW]	[%/hour]	[kg/kWh]	[%]
Coal	40	30.9	15	100	50%	0.34	87%
CCGT	30	18.4	27	30	50%	0.20	87%
GT (oil)	40	18.4	27	20	100%	0.28	87%
GT (NG)	30	18.4	27	20	100%	0.20	87%
PV	25	2.0	5	-	-	-	98%
CSP (8h)	30	10.0	20	10	50%	0.20 for NG	96%
Wind	20	2.0	5	-	-	-	98%
PS, batteries	50	16.0	10	-	-	-	100%

Storage power plants (e.g. pumped-storage hydro power plants) have additional efficiency parameters. Roundtrip efficiency of the storage and generation process is 80% and hourly storage losses are generalized to 0.02% per hour. Also the storage operation of CSP plants uses specific operational parameters to charge and discharge the thermal energy storage and to operate the steam turbine under efficiency constraints and transformation losses. Maximum charging power is limited to 340 MWh_{th} and maximum discharging power to 325 MWh_{th} for the storage volume of 8 hours in a 100 MW CSP plant. The storage process causes very low hourly losses of 0.031% due to isolation and large size. Losses for the heat exchanger between salt and thermo-oil are reported with 1.5%. Parasitic losses of the heat fluid pumping system and the power block reduce the available thermal energy by 5.3%. The turbine size restricts the maximum heat inflow to 280 MWh_{th} and produces electricity with an average efficiency of 40%. Natural gas hybridization is limited up to an electricity output of 10% from natural gas.

Table 18: Operational parameter of CSP power block and storage

Parameter	Value	Source
Charging power capacity of TES	340 MWh_{th}	Scaled based on (Relloso and Delgado, 2009)
Discharging power capacity of TES	325 MWh_{th}	Scaled based on (Relloso and Delgado, 2009)
Storage size (equivalent to full load hours of turbine)	8	-
Hourly losses of TES	0.031% per hour	(Sioshansi and Denholm, 2010)
Roundtrip efficiency (TES)	1.5% per storage process	(Sioshansi and Denholm, 2010)
Max. thermal operating capacity	280 MWh_{th}	Scaled based on (Relloso and Delgado, 2009)
Maximum share of natural gas	10%	-
Maximum turbine efficiency	40%	(Sioshansi and Denholm, 2010)
Parasitics of HTF and power block	5.3%	(Sioshansi and Denholm, 2010)

Prices for fossil fuels have increased during the last years. Although countries like Algeria and Libya can use own resources of natural gas or oil for relatively cheap prices, the long-term market price for fossil fuels is adapted from price forecasts of the European markets. The forecast of Nitsch et al. (2011) is used with the assumption of 20% lower prices for oil and natural gas compared to the scenario values of Nitsch et al. (2011) as the countries could also export their oil and natural gas at European prices. Emitted CO_2 in the power system is penalized by the price of CO_2 emission allowances[12]. In the BAU scenario, the CO2 emission allowances are priced at 0 EUR/t until 2025 and increase to 40 EUR/t in 2050. In all other scenarios, the price is set to 20 EUR/t for all years.

[12] Today, North African countries do not participate in any emission trading system. Prices for CO_2 emission allowances are assumed at a lower price level compared to projects for Europe. However, increasing awareness in North Africa on the negative impact of CO_2 emissions is reflected by the used price scenario.

Table 19: Prices for fossil fuels adapted from (Nitsch et al., 2012) and CO_2 emission allowances (own assumption)

Year	Oil	Natural Gas	Coal	Price of CO_2 emission allowance	
				BAU scenario	Other scenarios
	[EUR/MWh]	[EUR/MWh]	[EUR/MWh]	[EUR/t]	[EUR/t]
Real data 2013*	34.32	22.05	9.81	4.00	4.00
2010	30.68	16.49	10.48	0	13.80
2015	33.70	18.29	12.42	0	20.00
2020	36.46	20.16	14.36	0	20.00
2025	39.20	22.15	16.13	7.50	20.00
2030	41.62	24.02	17.57	15.00	20.00
2035	44.44	25.83	19.06	22.50	20.00
2040	47.26	27.65	20.56	30.00	20.00
2045	49.59	29.15	21.80	37.50	20.00
2050	51.93	30.64	23.04	45.00	20.00

*real data (Germany, 2013) included as reference (BMWi, 2014), 20% lower prices considered

The North African electricity grid mainly consists of 110 and 220 kV lines. However, in the last years high voltage lines (380 kV) have been extended on the main corridors along the coastal line from Morocco to Egypt. Values for existing NTC of the interconnectors between North African countries are displayed in Table 20.

Table 20: Existing transmission capacities between countries (ENPI, 2012)

Transmission line between countries	NTC capacity
Morocco – Algeria	ca. 800 MW
Algeria – Tunisia	ca. 450 MW
Tunisia – Libya	ca. 200 MW (not in use, but implemented in model)
Libya – Egypt	ca. 180 MW
Morocco – Spain	ca. 1400 MW

National transmission lines are presented with their assumed net transfer capacities between model regions in Table 31 and Table 32 (appendix). New transmission lines can be constructed according to the assumptions in Table 21. HVAC transmission lines are implemented as connections between the model nodes (regions) of North African countries considering the distance of the midpoints of each region. HVDC transmission lines can connect North Africa with Europe. Two converter stations are required at both ends of a HVDC line. Between Morocco and Spain, the interconnection via HVAC is possible, similar to the existing connection.

Table 21: Technology and cost parameter of transmission lines, based on own assumptions and (Zickfeld et al., 2012)

	Voltage level	Maximum NTC	Investment line	Investment converter	Transmission costs	Transmission losses/1000km	Losses per converter
	[kV]	[MW per line]	[EUR/MW_{NTC} *km]	[EUR/ $MW_{converter}$]	EUR/MWh	[%]	[%]
HVAC	380	580	700	0	10	8	0
HVDC	400	1000	1000	90,000	10	2.6	1.2

Expenses for the construction of new infrastructure projects are calculated as annuity and periodical payment over the lifetime of the project (Brealey et al., 2007). The lifetime represents the duration of which a technology can be operated with normal revisions and without large reinvestments in important parts of the technology (see Table 17). By using the WACC value (weighted average cost of capital) as discount factor in the annuity calculation, the model analysis includes financial cost. As project framework and technology risks can be different for each power plant, a technology or country specific (or power plant specific) WACC value can be determined. However for simplicity reason, a standard WACC of 8% for all new infrastructure projects in North Africa is assumed. This value is clearly higher than WACC assumptions in European energy system models, as project risks and country specific risks in this region are expected to be rated higher by investors. Consequently, technologies with lower specific investments obtain substantial advantages as they suffer less from the high WACC. All financial assumptions and results are expressed in real values with reference year 2010.

5.4 Model adjustment

5.4.1 Electricity generation in reference year 2010

A comparison of real generation data of the year 2010 with model results of the generation dispatch is undertaken to prove the model quality with historical data. Generation data of each country and of each generation type (fossil, hydro, wind, solar, net imports) are given by (EIA, 2013) for the year 2010. As the amount of electricity exchange between the countries is very low, transmission capacity between countries is set to zero to completely avoid export of electricity. But electricity imports from Spain to Morocco and exports from Egypt to Jordan are necessary to include as these imports represented 10% of the total electricity demand in Morocco and exports from Egypt were +1.4 TWh in 2010. Power plant data (installed capacity of each power plant) are implemented in RESlion based on the available data of year 2010 (data of Platts, EIA, AUPDTE, and national utilities, see sections 2.6 and 5.3).

As shown in Figure 24, small deviations between real data and modelled results for electricity generation per generation type exist. Annual electricity generation in North Africa modeled by RESlion with 246.9 TWh is very close to real data with 247.9 TWh in 2010. As the RESlion model only takes final electricity consumption as model input into account, electricity generation significantly depends on the inefficiencies between generation and demand in the national electricity systems. Therefore, the modeled results are in an acceptable range to show model validation with real data of 2010.

The difference between the data of hydroelectricity in Morocco is caused by very high hydroelectricity generation in year 2010 (+100% compared to the long-term average due to specific weather conditions in 2010). In RESlion, an average annual water supply of the last 10 years is implemented. Higher real electricity generation from fossil fuels in Algeria or Libya can result from higher system inefficiencies as well as transmission and distribution losses than assumed in RESlion. In Egypt, higher electricity generation from hydro and wind power is modeled due to assumptions for wind and water supply. It is balanced with generation from conventional power plants. For Tunisia, deviation of modeled results is also based on weather specific event (wind, rain) in 2010.

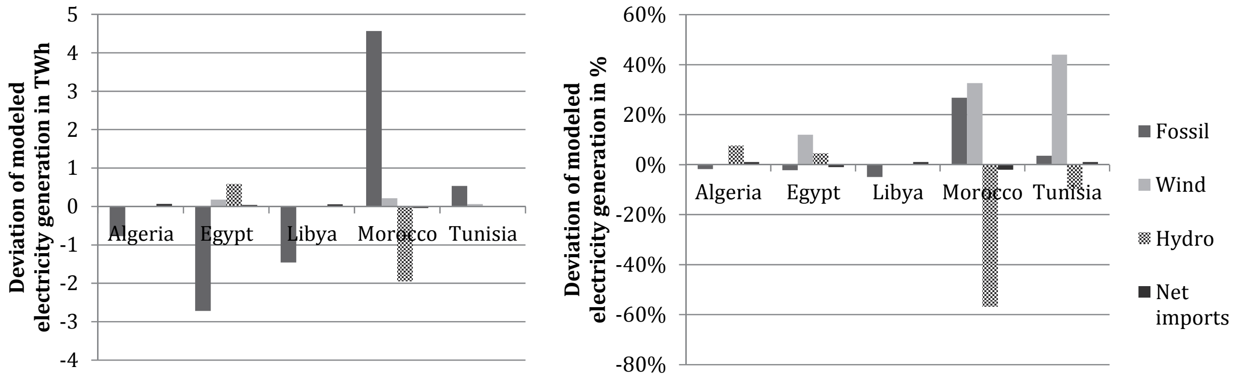

Figure 24: Deviation of modeled electricity generation to generation data of 2010 by EIA (2013)

5.4.2 Testing of results with detailed hourly generation dispatch

To test results of the expansion planning modeling with a detailed hourly generation dispatch, system operation is modeled by a detailed operation over all 8760 hours of a certain year. The results of the expansion planning model for all scenarios are used as input for the detailed hourly generation dispatch carried out for the years 2020, 2030, 2040 and 2050.

Security of supply is given when the power plant portfolio can cover all potential system conditions of demand and supply. The analysis included a test of sufficient generation capacity and transmission capacity in each hour of the year as well as similarity of results for electricity generation between expansion planning and hourly generation dispatch. If system conditions such as available back-up capacity and reserve capacity reach a minimum, the developed electricity system has to be declared as "not sufficient" as the system security cannot be guaranteed for all hours of the year. The expansion planning problem would be resolved with increasing back-up capacity and a security margin for transmission capacity.

The model test with the detailed hourly generation dispatch confirms the results of the expansion planning. An exemplary comparison of electricity generation per technology is provided in Figure 25. The generation volume per technology shows high similarity for each time step. The largest deviation is found for electricity generation from wind power. In 2020, 2040 and 2050, the generation dispatch calculates one percentage point higher generation from wind power compared to the results for this year in the expansion planning model. CSP generation in the detailed hourly generation dispatch is about 2% percentage point lower in 2050 than in the results of expansion planning.

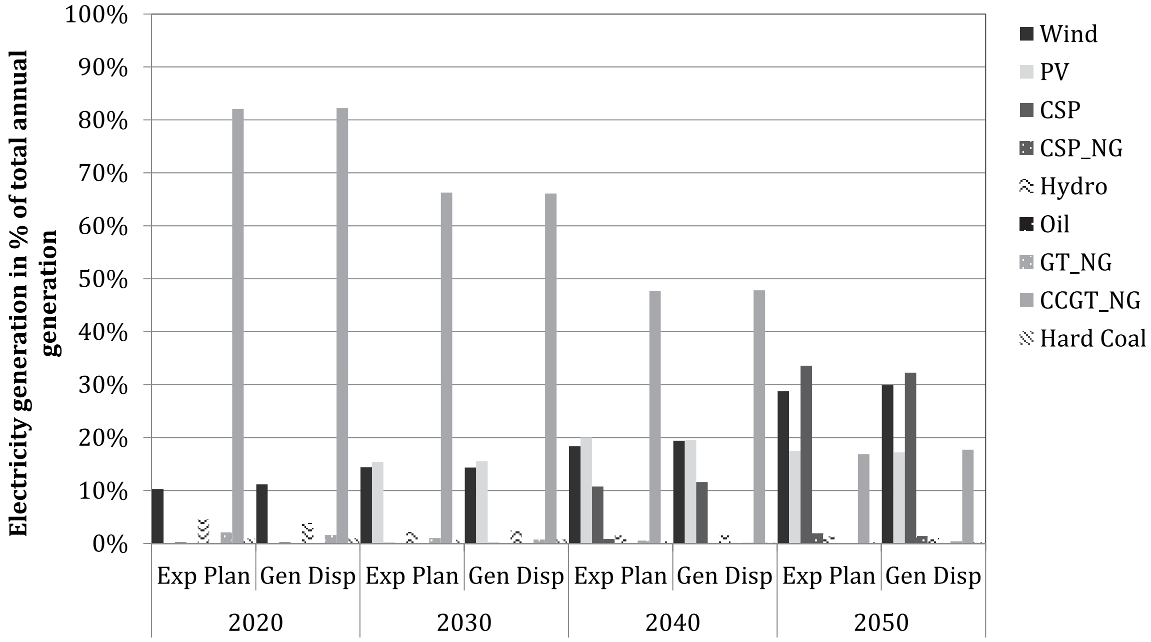

Figure 25: Comparison of generation per technology between expansion planning and generation dispatch (High-RES scenario)

The additional availability of flexible power generation units (conventional power plants and CSP) in the overall system can be analyzed with Figure 26. The figure shows the hourly capacity of flexible generation units which is not used in each hour of the year 2050. Minimum capacity which is not used is at least 20 GW. In some hours with high RES generation this capacity is above 150 GW. However, with this analysis the system security cannot be completely shown as an analysis of primary, secondary and tertiary reserve capacity as well as grid constraints would be necessary.

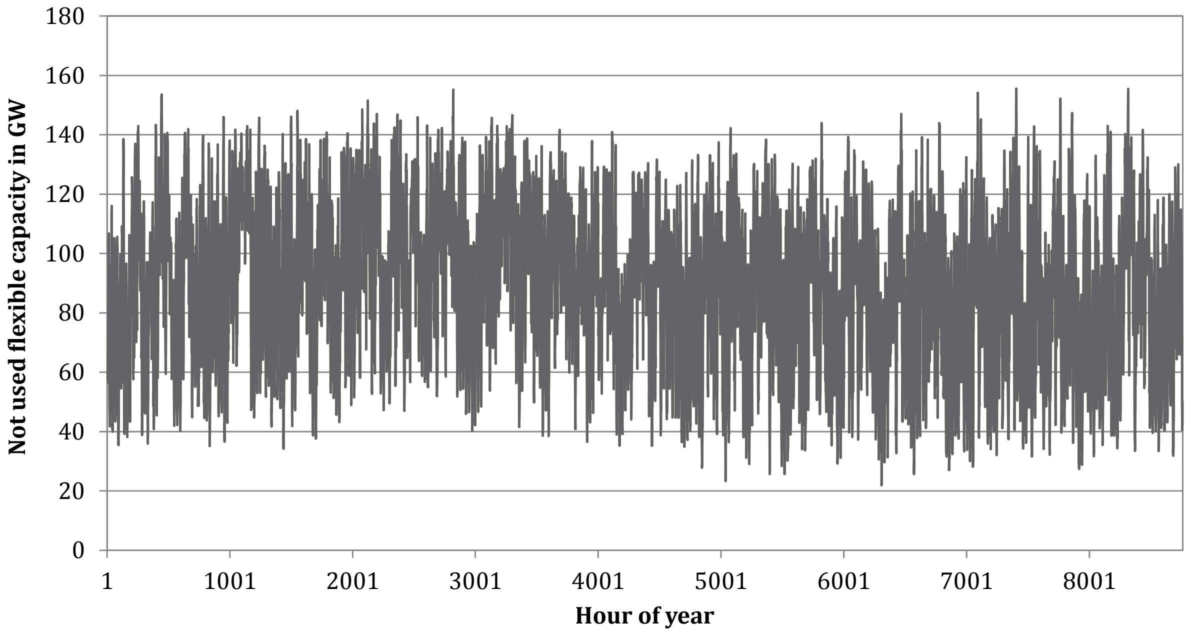

Figure 26: Not-used flexible capacity in each hour of the year 2050 in High-RES scenario

5.5 Electricity scenarios for North Africa by 2050

5.5.1 Development of the generation system

Large growth of electricity demand by 2050 with an average annual growth rate of about 4% influences the overall development of the electricity system essentially. As the model results for scenario group 1 (North Africa) show, electricity generation in 2050 increase to over 1200 TWh in all scenarios (Figure 27). In case of higher RES penetration, overall generation exceeds 1300 TWh as higher losses are caused by electricity transport. Likewise higher curtailment of renewable energy sources is necessary with increasing RES-E share. In the reference year 2010, electricity generation is highly based on conventional power plants operating with natural gas and oil. In all scenarios, an extension of hydro power does not take place until 2050 due to the limited potential of new power plants. Furthermore, until 2050 gas turbines and oil power plants (constructed before 2010) are only used a few hours per year as back-up capacities. Electricity generation from oil is completely decreased due to the cost disadvantages of oil compared to all other options for power generation. This model result is obtained under the constraint of projected world-market prices for oil and natural gas. State-owned utilities assume much lower costs for their fossil fuel consumption or uses highly subsidized energy prices. This is a common phenomenon if national resources of oil and gas are used (in Algeria or Libya), but also in countries with fuel imports such as Egypt or Tunisia. Between today and 2050, cheapest option for electricity generation from conventional power plants is the use of high-efficient CCGT power plants if price of CO_2 emission allowances is above 20 EUR/t.

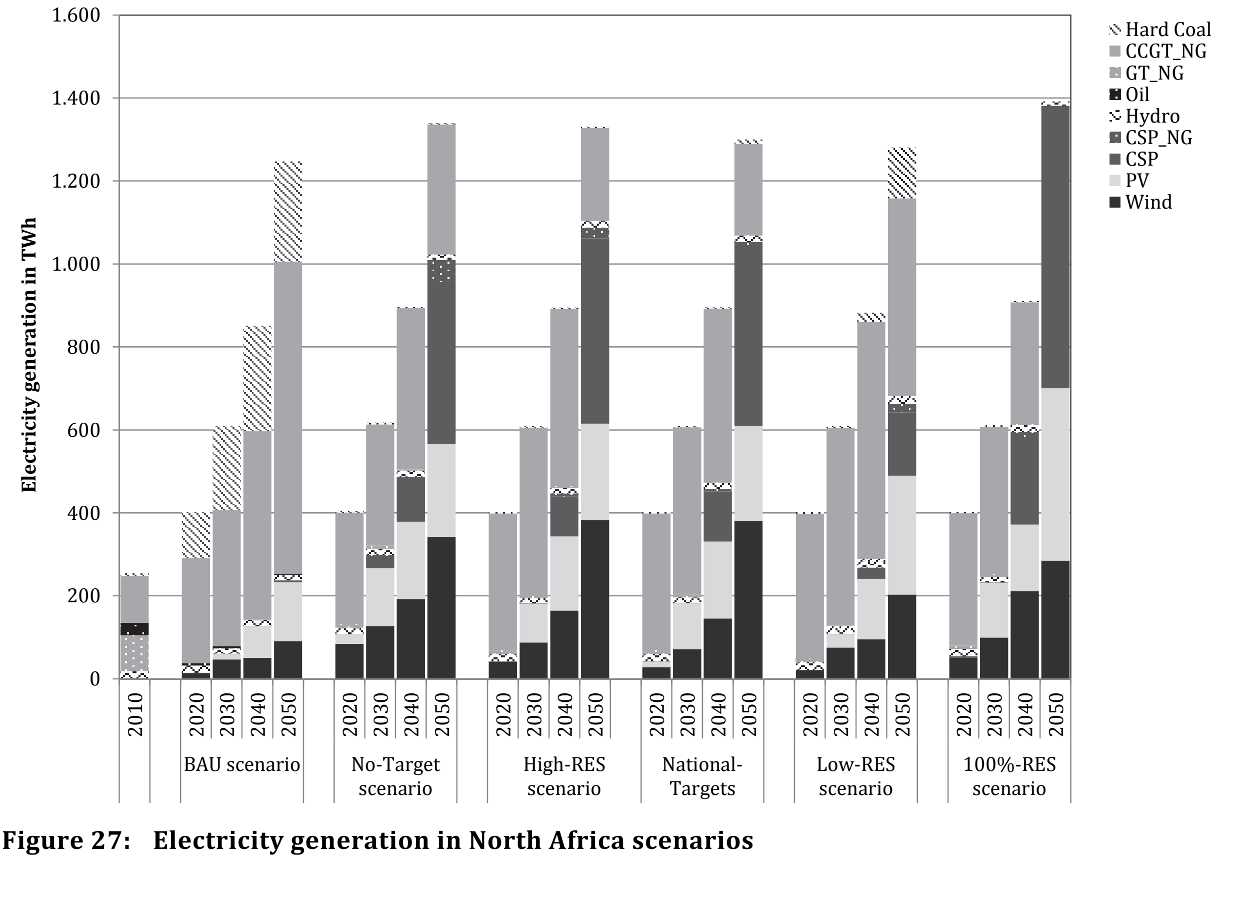

Figure 27: Electricity generation in North Africa scenarios

In the BAU scenario with a limited RE deployment (RES-E share is 20% in 2050), power generation in 2050 is highly based on CCGT power plants with a share over 60% of the total generation and an installed capacity of 107 GW (see Figure 29). Starting in 2015, additional coal-fired power plants will be installed due to competitive prices if a higher natural gas price is assumed compared to the current practice in some countries (e.g. Algeria, Libya) and CO_2 emission prices are not considered before 2025. In 2030, 33.1% of the generation is provided by coal-fired power plants which are mainly located in Egypt. Later in time, when a CO_2 emission price is assumed for North Africa, the share of coal-fired plants is reduced again. In this scenario, deployment of RES is very slowly. A few wind power plants and PV plants are installed by 2040. Their share is slightly increased by 2050 to 7.3% of the total generation for wind power and 11.4% for PV. Due to the assumptions, electricity generation from hydro power plants will remain on the level of the year 2010. CSP does not play any role in the BAU scenario.

The No-Target scenario is modeled under the assumption to minimize total system costs without a specific target for renewable energy sources or for CO_2 emission reduction by 2050. However, the share of RES-E automatically increases due to future assumed cost advantages of RES compared to conventional power sources. Again, the assumption of world-market prices for fossil fuels as well as a price for CO_2 emission allowances of 20 Euro/t negatively influences the costs of conventional power sources. In the model results of the No-Target scenario, the share of RES-E rapidly increases to over 50% in 2030, but does not exceed 72% in the long-term by 2050. This result shows the existence of an optimum share for the power generation from RES which is significantly below 80%. If a certain RES-E share with the electricity system is exceeds, additional integration costs for RES exceeds the benefits due to higher curtailment, required conventional back-up capacity and higher transmission costs. At the same time, a certain share from dispatchable conventional power sources is beneficial for the system. In the year 2050, CCGT power plants with a capacity of 70 - 80 GW are required in this scenario to balance hours without feed-in from RE power plants. Nevertheless, the largest share of electricity generation is provided by renewable energy sources, namely wind, PV and CSP. By 2020, most of the RE installations are wind projects due to their cost advantages at some locations with excellent wind conditions, primarily in Morocco and Egypt. Already by 2030, the amount of electricity generation from PV power plants reaches the generation level of wind power plants in the model. However, after a certain share of PV (17% of total generation) is installed between the years 2030 and 2040, a further increase of PV installations is limited by the system due to the competition with CSP and the lack of cheap storage options. An increase of electricity generation from RES will be mainly based on additional wind farms (up to 26% of total generation) and CSP plants with thermal heat storages. Wind farms have the advantage to provide electricity during the night. With their storage system, CSP plants play the largest role within the electricity system beyond 2040 by providing 33.1% of the total electricity generation under the assumed framework conditions. Model results show that the integration of CSP plants into the electricity system is the cheapest solution to increase the share of renewable energy after a certain share of electricity generation from wind power and PV is reached. A further increase of the share from both technologies is very difficult as both technologies provide fluctuating, non-flexible electricity generation. The lack of cheap storage solutions makes it difficult to completely supply the system by electricity from wind power and PV. This reason and the absence of other solutions to provide flexible power generation from RES are responsible for the large expansion of CSP plants which have slightly higher generation costs, but can be flexibly operated in the system. At that time, CSP plants also use their potential as a back-up function by running with natural gas, according to the model results.

Burning of natural gas provides additional electricity from CSP steam turbines with a share of 3.9% of the total electricity generation. From the model results, it can be concluded that renewable energy technologies are very competitive, also in the mid-term, in the North African electricity market. Under the assumptions and framework conditions, subsidies for RES are not really necessary, after barriers for market entrance and policy framework are overcome.

In the High-RES scenario, continuous and increasing RES-E targets are set from today until 2050 (RES-E share of 80% in 2050). Compared to the No-Target scenario, the deployment of RES is a bit slower by the year 2040 (following the continuous targets); however in 2050, the electricity generation from RES represents 80% of the total electricity generation. Similar to the No-Target scenario, each RE technology shows a certain phase, in which it is introduced into the electricity system. In 2050, the highest share is provided by CSP plants with 35% of the total generation; electricity generation from wind farms reaches 29% and PV has a share of 17% (Figure 28). The total capacity of RE power plants is 79 GW in 2030 and 366 GW in 2050. The RE capacity consists of 127 GW of wind power plants, 139 GW of PV and 100 GW of CSP plants. A back-up capacity through CCGT power plants is required with a maximum installed capacity of over 90 GW around 2040 (Figure 28). By 2050, the CCGT capacity slowly decreases to 63 GW due to a higher capacity of CSP. The used of oil power plants is almost completely reduced to a few hours per year of high demand and low RE generation. The total capacity of storage power plants (in addition to thermal storages of CSP plants) does not exceed 2 GW. This low value certainly is depending on the potential to construct CSP plants which are able to completely shift their electricity generation to night hours.

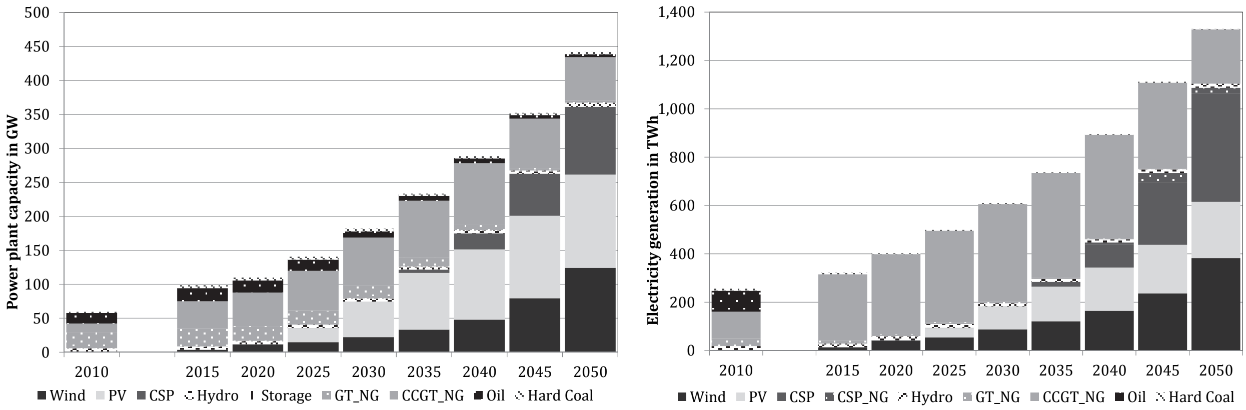

Figure 28: Continuous expansion of the North African electricity systems in the High-RES scenario

In the National-Targets scenario, specific RE targets which have to be fulfilled by each country are used. Largest impact of this requirement is a high share of electricity from PV in the time frame until 2030. PV has a cost advantage to wind power in some countries. However in the long-term, the National-Targets scenario shows smaller differences to the High-RES scenario. Countries balance their generation portfolio by using the different RE technology more equally. They install more wind power or CSP if they started to focus on PV during the first years. Finally in 2050, a balanced portfolio which is quite similar compared to the High-RES scenario is reached. Only a small amount of CSP plants and CCGT power plants are additionally installed to fulfill national targets. Storage systems and GT power plants are installed less. Although PV shows a stronger increase by 2030 in National-Targets scenario, PV installations are 2 GW lower in 2050 compared to the High-RES scenario. In general, national RE targets compared to overall RE targets reduce RE installations in Morocco and Egypt as both countries overfill their national targets due to their better wind resources. In 2050 of the National-Targets scenario, CSP capacity in Algeria, Tunisia and Libya is increased to fulfill national RE targets. PV and wind capacity is almost similar in this scenario compared to the High-RES scenario.

In the Low-RES scenario, a slow market integration and RES deployment in North Africa is assumed. 50% of the electricity generation in 2050 is still based on fossil fuels, mainly natural gas in this scenario. After 2030, a large CCGT capacity (about 100 GW) is responsible for the installation of more PV power plants compared to the High-RES scenario (170 GW vs. 137 GW). Consequently, the share of electricity generation from wind power (16%) and CSP (13%) in 2050 is relatively lower than in the High-RES scenario. Compared to scenarios with higher RES-E shares, total electricity generation is lower due to lower curtailment of RES and the higher use of flexible conventional power plants.

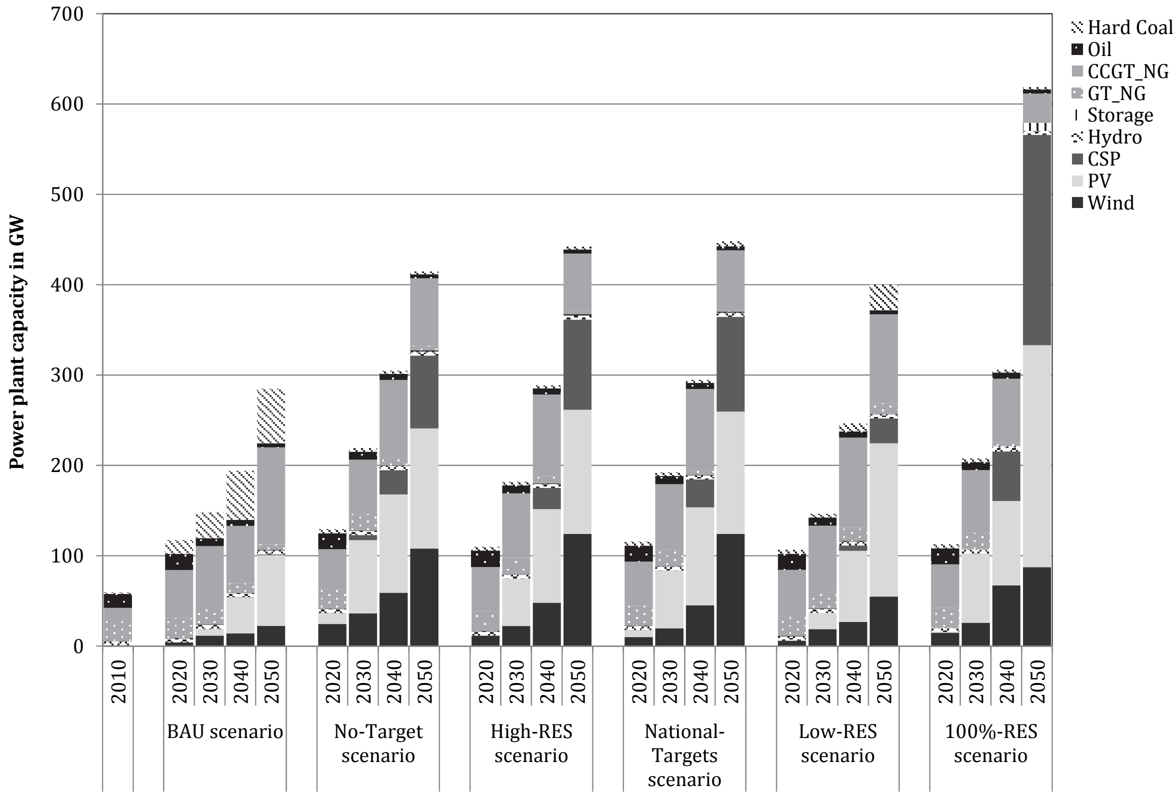

Figure 29: Deployment path of technology portfolio in North Africa scenarios

The 100%-RES scenario is the only scenario without any use of conventional power sources such as coal-fired, gas-fired or oil-fired power plants in the target year 2050. However, Figure 29 shows a small share of remaining CCGT power plants of which the lifetime will not expire in 2050. Total installed capacity of this scenario exceeds 600 GW to be able to exclusively use renewable energy sources for electricity generation. This total capacity consists of 87 GW wind power, 246 GW of PV and 233 GW of CSP (with thermal storage systems). The huge amount of CSP plants provides the possibility to generate electricity from RES at any time over the year. Additionally, 9 GW of storage systems are installed at widely distributed sites in all regions. 49% of the total electricity generation is based on CSP plants, 30% on PV and 19% on wind. Less than 1% is generated by existing hydro power plants.

5.5.2 System and generation costs

The expansion of the existing electricity system in North Africa to be able to supply a strong increasing electricity demand is a substantial challenge for the national governments and the societies in the regions over the next 40 years. Total system costs include all costs of construction and operation of the infrastructure in the electricity systems as sum over all countries. However, the costs for the grid only contain costs for transmission lines between regions and countries. Costs for distribution and transmission within a region are not included in the calculation. Additional transmission capacity usually is required to improve the local grid capacity between generation and supply. In case of widely distributed RE generation within a region, additional costs for connecting these power plants to the national grid are required. In case of large decentralized generation (mainly from PV), grid areas of lower voltage levels has to be extended if the feed-in of PV electricity increases strongly. The model results show that operation costs to run conventional power plants with fossil fuels (over 250 bn EUR) still represent the largest share of the total system costs by 2030 (see Figure 30 with results of High-RES scenario)

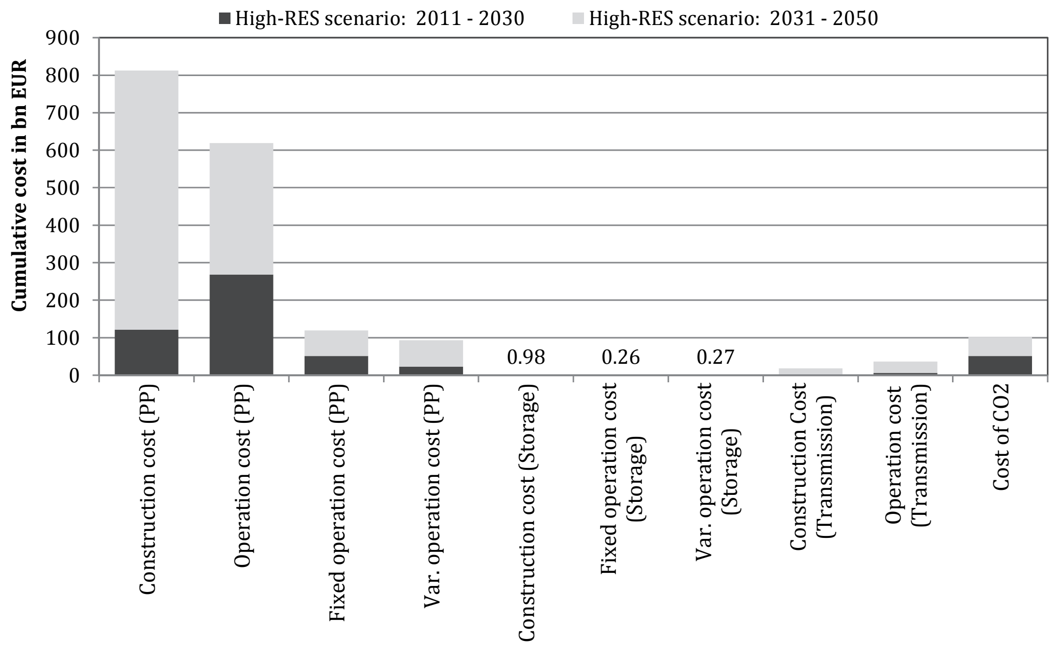

Figure 30: Structure of total system costs in High-RES scenario from 2010 to 2050

The continuous increase of demand and higher shares of RES affects a shift to the construction costs as about 700 bn EUR is necessary between 2030 and 2050. Operation costs slightly increase as the overall generation capacity grows further between 2030 and 2050. Costs of storages (1.5 bn EUR) and transmission lines (5.4 bn EUR) are relatively low. By 2050, cost of CO_2 emission allowances (20 EUR/t) is about 100 bn EUR in the High-RES scenario.

Until 2030, overall system costs differentiate only by about 3% between the different scenarios (Figure 31). As integration of first RE projects can be carried out very efficiently by using existing infrastructure and by avoiding large curtailment of RES-E. Furthermore, the best sites for new RE projects are chosen by the model. Therefore, these projects are highly competitive to the conventional power generation sources.

In the timeframe until 2050, total system costs of all scenarios (except the BAU scenario and the 100%-RES scenario) are around 1800 bn EUR (+/- 3%). The lowest costs are found in the No-Target, High-RES, National-Targets and Low-RES scenario. The BAU scenario suffers from the increase of fossil fuel prices (e.g. natural gas, oil and coal). The CO_2 emission price in this scenario increases from 0 EUR/t in 2025 to 45 EUR/t in 2050. In the National-Targets scenario, total system costs are higher than the High-RES scenario as the RE targets are less efficiently reached if each country optimizes its RES portfolio alone. The scenario with 100% RES-E is linked with high costs from larger storage capacity, larger transmission expansion and huge overcapacity of RES combined with the highest value of curtailment which leads to 16.9% higher total system costs compared to the No-Target scenarios. The difference between the scenarios is an interesting finding as the generation portfolio differs strongly between the scenarios. It can be concluded that the impact of different RES-E shares on total system costs very similar, if an optimal configuration (balance of different technology, optimal planning of transmission lines and optimal site selection) of the system is found for each target.

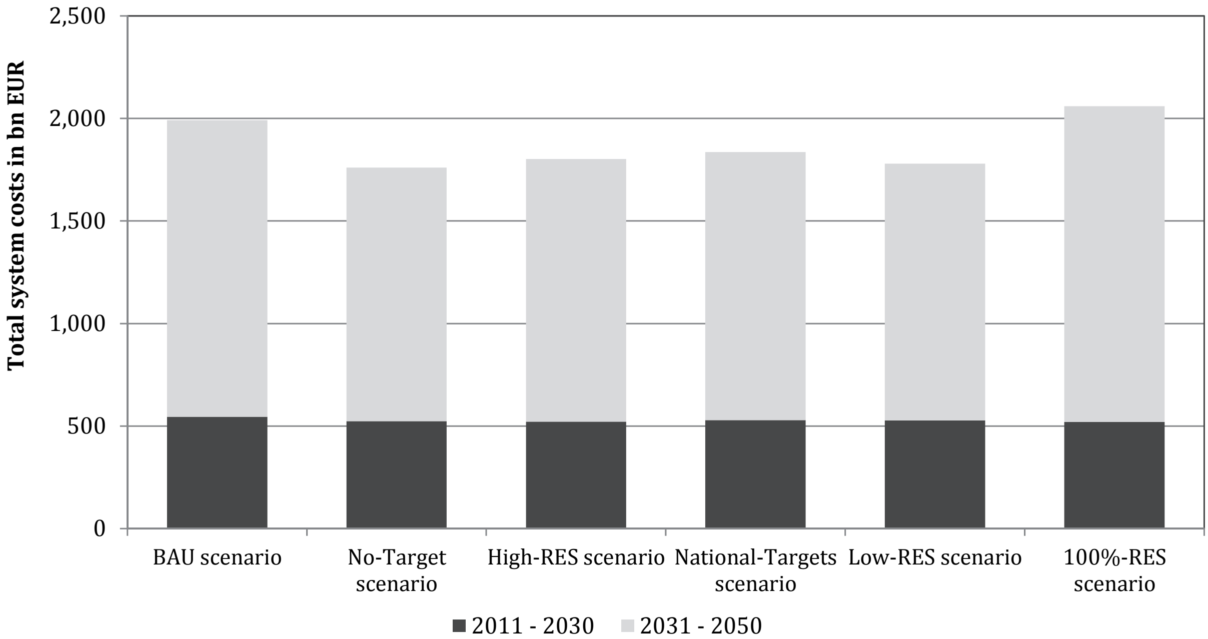

Figure 31: Total system costs of in (North Africa) scenarios from 2011 to 2050

Average generation costs (including also costs for storages and transmission lines) increase in all scenarios from minimal 58 EUR/MWh to maximal 82 EUR/MWh between 2010 and 2050 (Figure 32). The costs of consumption are always slightly higher (16% to 30% depending on curtailment) as energy consumption is equal to generation minus the transmission losses and curtailment. Two important cost trends oppositely influence the average generation costs. RE technologies continue to follow the assumed learning rate which decreases the costs for construction and installation of new power plants. On the other hand, best sites for RES are selected in early years and quality of wind speeds and solar irradiation can be lower for RE power plants installed later in time. Generation from conventional power plants such as CCGT and coal-fired power plants become more expensive as assumed prices of fossil fuels also increase (compare (Egerer et al., 2009) who also calculated increasing generation costs until 2050). In the 100%-RES scenario, the last step to completely avoid the use of conventional power plants adds further costs as additional storages and transmission lines are required to balance the system with RES and curtailment significantly increases.

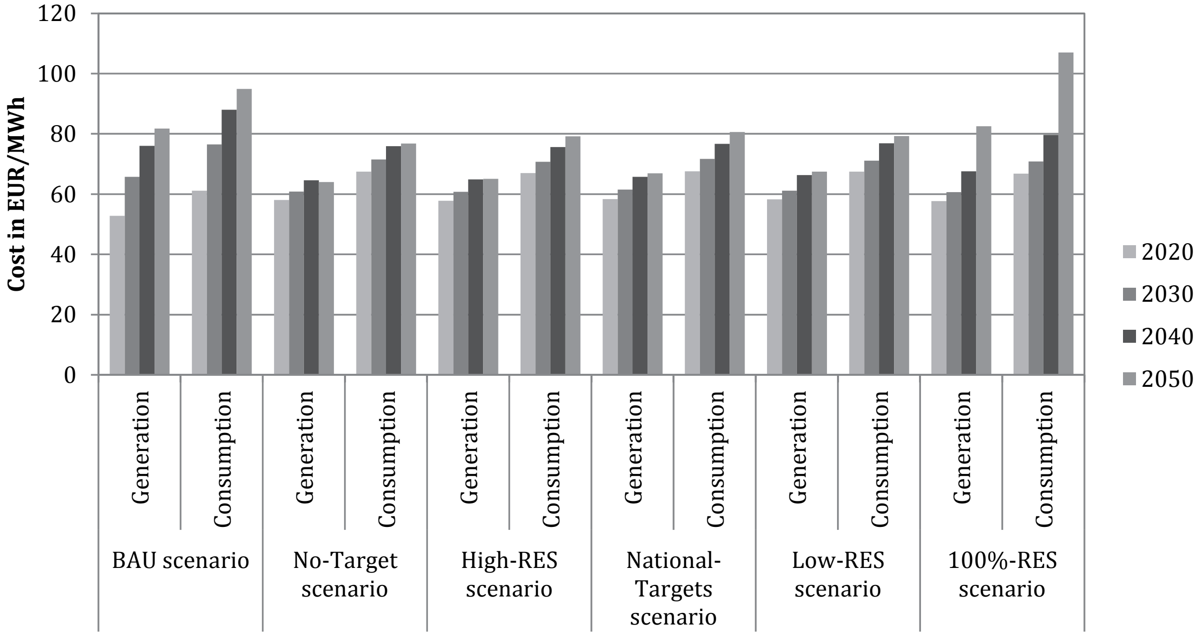

Figure 32: Average generation costs from 2010 to 2050

5.5.3 Site selection of RES generation capacities

Optimal site selection for new RE power plants is an important keystone for development of an optimized electricity system. Due to the constraints of electricity transportation between different grid regions, regional electricity demand and national energy security, the power plant portfolio per country varies in each scenario. Figure 33 shows the change of the power plant portfolio in terms of capacity per technology and country between the reference year 2010 until 2030. All six scenario graphs have the same shut-down capacities which mainly depend on the construction year in the past and lifetime. In the BAU scenario, new conventional power plants are equally distributed to all countries depending on the national (peak) demand. The No-Target scenario has the highest amount of newly installed power plant capacity by 2030 as the RES-E share increases more strongly than in all other scenarios (RES-E share is above 50% in 2030). Therefore, wind power plants are intensively installed in Morocco (19 GW) and Egypt (12 GW), whereas PV is primarily installed in Algeria (19 GW) and Egypt (42 GW). When comparing the National-Targets scenario with the High-RES scenario, larger PV installations in Algeria (+12 GW) and Tunisia (+5 GW) in the National-Targets scenario are the main difference compared to larger wind installations in Morocco (+6 GW) in the High-RES scenario. In the High-RES scenario, Morocco and Egypt overfills their national RE targets and balance lower generation from RES in Algeria, Tunisia and Libya which have additional CCGT power plants in their countries to fulfill the requirement of national security of supply. If each country has to fulfill its own RE targets, the three countries have additional PV installations whereas Morocco and Egypt decrease their capacities of wind power. In the 100%-scenario, a combined course of both forms is modeled to reach higher RE targets. A large expansion of wind farms takes place in Morocco with 14 GW and Egypt with 9 GW, as well as a larger national expansion of PV in Algeria with 15 GW, in Tunisia with 6 GW and in Libya with 8 GW. A very high amount of PV installations in Egypt is one of the main pillars to reach the RE targets in 2030. New wind installations at the sites in Egypt and Morocco with excellent wind conditions and PV projects in all countries are the RE projects in the Low-RES scenario.

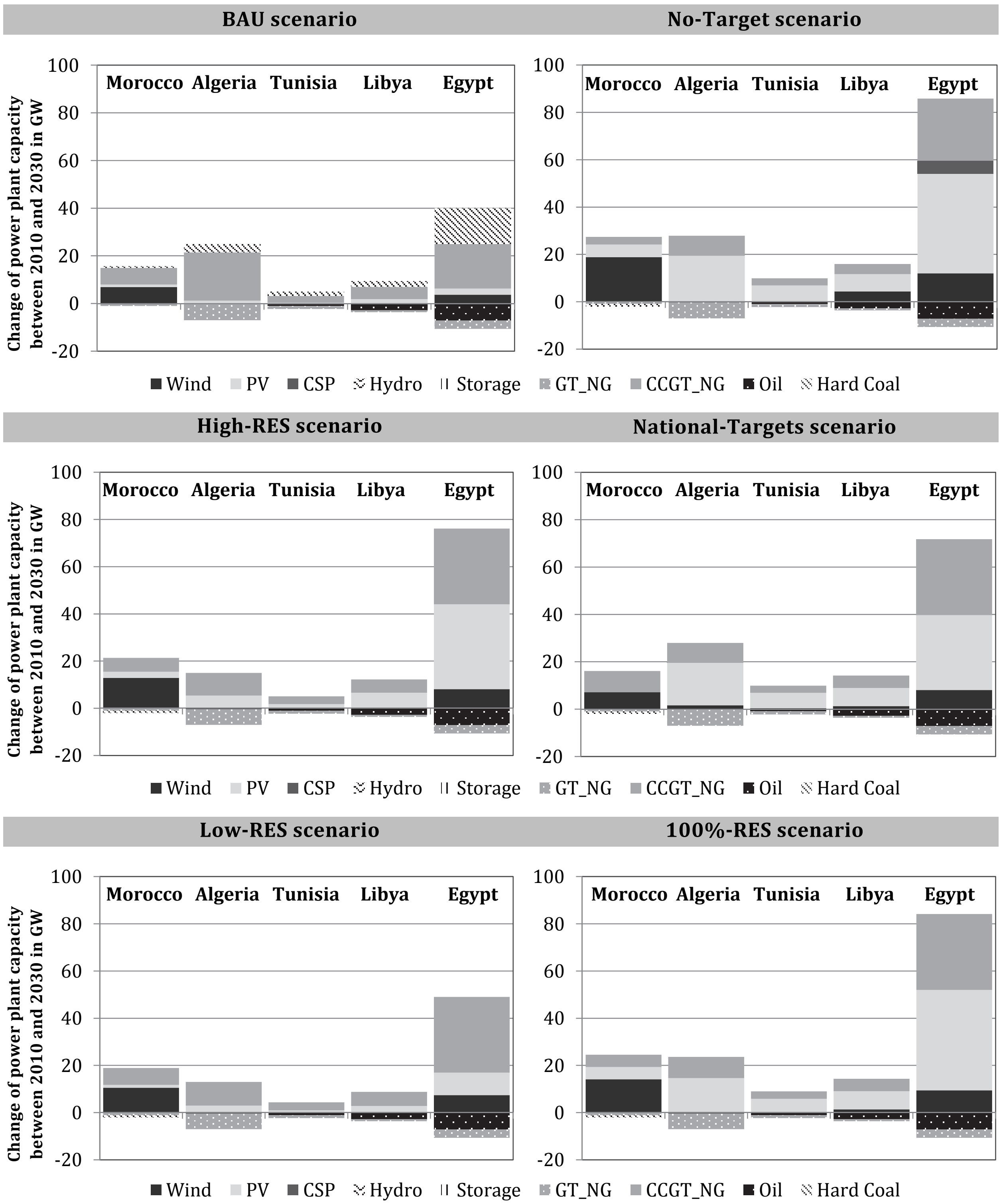

Figure 33: Change of power plant portfolio per country between 2010 and 2030

Until 2050, an enormous expansion of power plants compared to 2010 takes place in the model results to satisfy the high demand growth. In case of high RES-E targets, capacity growth is additionally higher due to decreasing full load hours of RE technologies. The main national trends which are identified for the time period from 2010 to 2030 continue. Wind power plants play a major role in Morocco and Egypt, whereas PV has a strong position in Algeria and Egypt.

In the No-Target scenario and High-RES scenario almost the same technology configuration is installed with a slightly lower CSP and PV capacity in the High-RES scenario in 2050. This shows how close the RE target of 80% is to a cost-optimal solution (without any RE target). In all scenarios with a RES-E share below 100%, CSP development is focused on the Egyptian electricity system which represents by far the largest country in North Africa. Instead of CSP, Morocco and Algeria will use a higher share of CCGT power plants to back-up the system in cases of low wind conditions and at night. In the 100%-RES scenario however, development of CSP projects takes place in every country. The total volume of CSP projects ranges from 17 GW in Tunisia to 122 GW in Egypt. It will be very challenging under technological and economic considerations to achieve this huge amount of power plants in the required time frame. In the Low-RES scenario, the CSP development is also focused on Egypt with an installed capacity of 27 GW. In this scenario, PV is installed up to 80 GW in Egypt, 38 GW in Algeria and 24 GW in Morocco. This high amount of PV projects in the scenario with the lowest RES-E share helps to understand the size and role of RE technologies in the future North African electricity systems. The BAU scenario includes a few installations of PV in Egypt and wind power in Morocco, but nevertheless the electricity system remains to be based on high efficient CCGT and coal-fired power plants.

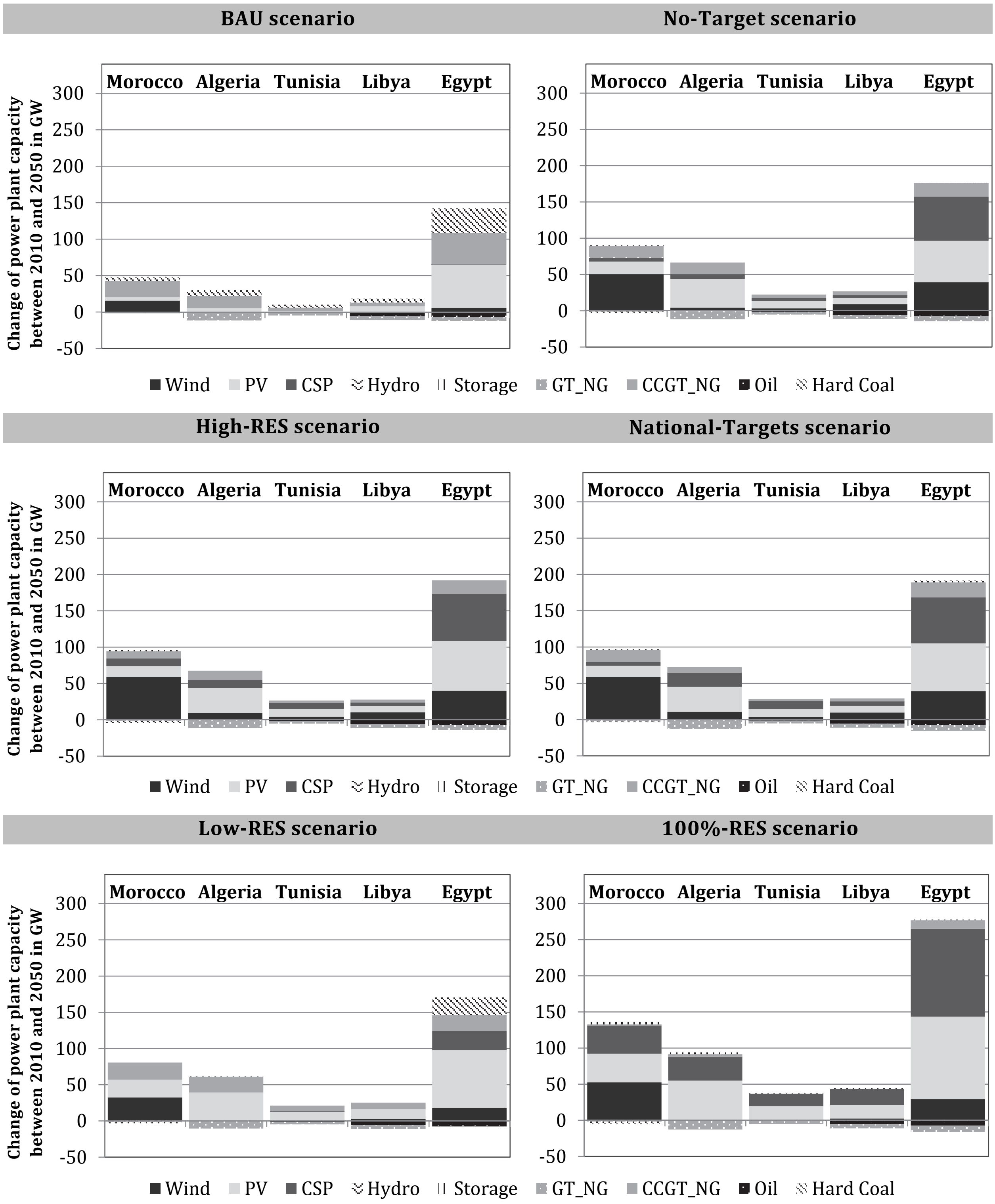

Figure 34: Change of power plant portfolio per country between 2010 and 2050

The analysis of the national power plant portfolios until 2030 and until 2050 indicates that each country has to define its own strategy on which technologies the electricity generation will be based in the future. In the following part, the analysis of the High-RES scenario is done on a sub-national level to evaluate detailed site selection. Furthermore, the impact on grid extension will be analyzed in section 5.5.4 to show the interaction between technology portfolio and required transmission extensions.

In Figure 35, the model results for all sites with an installed power plant capacity of wind power, PV, CSP and CCGT larger than 1000 MW in 2030 are shown. The sites of wind power are distributed in the South (Western Sahara) and North of Morocco and in Egypt close to the Red Sea. In 2013, wind power plants are exactly installed or at least are planned at these sites. As electricity demand is not that high in the Western Sahara and at the coast of the Red Sea, concurrent projects of other RE technologies are not projected until 2030. Large expansion of transmission capacity would be linked with a further increase of RE capacity in both regions. Due to higher cost of CSP in the time frame until 2030, CSP projects are not chosen at all by the model. In Morocco, PV plants in the area around Casablanca and Rabat are projected by the RESlion model to increase to about 3 GW as their proximity to high electricity demand makes PV here very useful. Large conventional capacities (new CCGT power plants) are installed also in the same area.

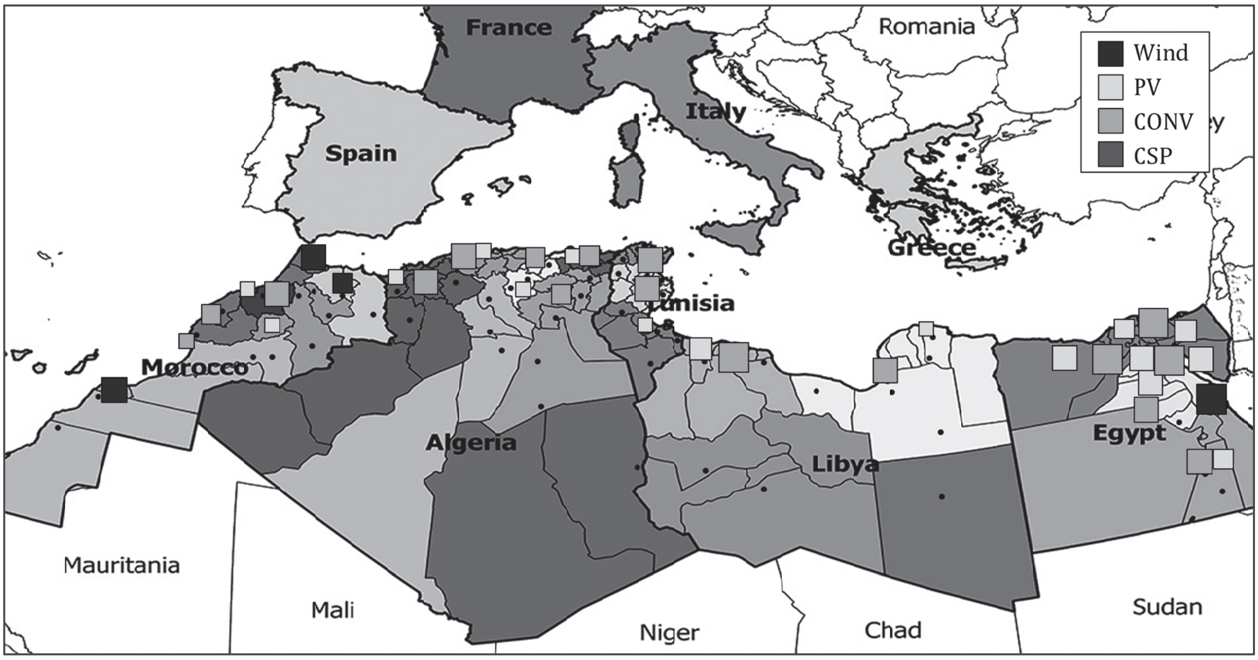

Figure 35: Geographical sites with high generation capacities (larger than 1 GW) in year 2030 of the High-RES scenario (1 GW = 2.5 mm²)

In Algeria, sites at the coast are mainly chosen for solar electricity generation using PV systems by the model. Due to high population and high electricity demand, PV power plants are located close to the demand (similar to the case of the area of Casablanca and Rabat in Morocco). At these sites, different PV system configurations and sizes (large ground-mounted PV power plants or roof-top systems) are possible to be installed. In addition to CCGT power plants close to the large cities at the Mediterranean coast, Algiers and Oran, further CCGT power plants are installed in the model around Biskra and Ghardaia. In Tunisia, PV power plants are constructed in the model in the South-East of the country, close to the city Medenine, whereas the North is supplied by large CCGT power plants. In Libya, sites for PV around Tripoli and Benghazi/Derna are chosen as these cities consume most of the electricity in the country.

Due to the size of the Egyptian electricity system, six areas in the Northern part of the country show a high number of installations. These locations are around the large cities Cairo, Alexandria and Port Said. In the South, an additional area contributes to the overall generation from PV in Egypt. Additionally, large wind power plants at the Red Sea play an important role in the electricity generation of Egypt. Large power plants based on natural gas remain to be mainly located in the Nile Delta and South of Cairo.

Until 2050, the installed capacity of RE power plants increases significantly to achieve the target fulfillment of 80% in the High-RES scenario. The trends indicated in the analysis of the site selection by 2030 continue. Therefore, additional power plants of the same type are installed at almost all of the sites analyzed for the period by 2030. Figure 36 shows the sites with more than 2.5 GW power plant capacity of each technology in the year 2050. The expansion of wind power is enlarged by the model in the Western Sahara of Morocco and in the region of Tanger in the North of Morocco. At the coast of the Red Sea in Egypt, the installation of wind farms will further be increased due to the excellent wind conditions at those areas. However, by 2050 wind farms are also developed in the North of Tunisia and the Mediterranean coast of Libya, close to Tripoli and Derna.

In Morocco, the model results show an increase of PV installations in areas of high irradiation (e.g. in the region South of Fez) or in regions with high demand (coast from Casablanca to Tangier). In Algeria, the amount of PV installations is further strengthened in the area around Algiers to about 12 GW of PV. In Tunisia, a PV capacity of around 3 GW each is installed in the North, close to Tunis, and in the South of the country, close to the city Medenine. The demand center Tripoli also uses about 6 GW of PV. In Egypt, indicated sites in the Nile Delta by 2030 are enlarged and additional PV power plants are developed in the area around Zafaga in the model.

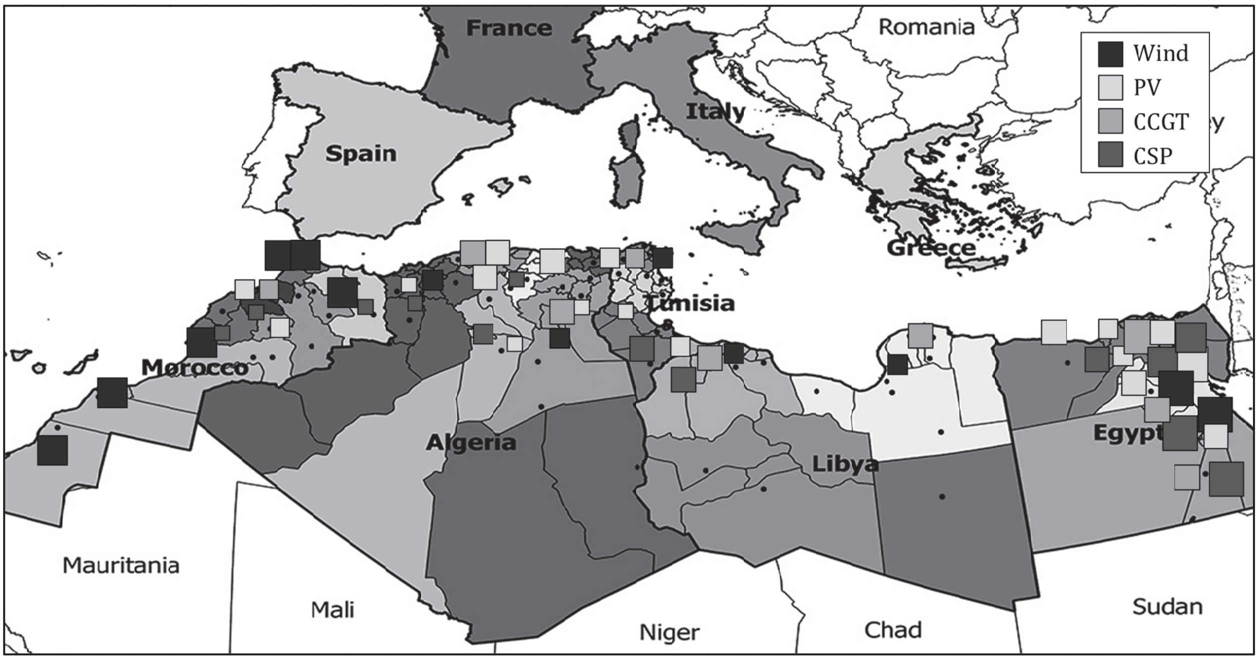

Figure 36: Geographical sites with high generation capacities (larger than 2.5 GW) in year 2050 of the High-RES scenario (2.5 GW = 2.5 mm²)

As described before, CSP plants are developed between 2035 and 2050, according to the model results. Compared to PV, CSP projects are developed in regions with very high solar irradiation (as only direct solar irradiation can be used to focus the sunlight on a receiver). These areas are mainly located in desert areas. Therefore, CSP projects are installed in Morocco at the Sahara Desert close to the border to Algeria (e.g. Ain Beni Mathar). In Algeria and Tunisia, potential sites in the South of both countries are also selected for construction of CSP plants due to their excellent solar irradiation. In Libya, large CSP projects (about 4 GW) are carried out in the South of Tripoli to supply the capital with electricity. In Egypt, potential sites are in all parts of the country ranging from the deserts around Cairo to Zafaga at the coast of the Red Sea and Kom Ombo between Luxor and Aswan in Upper Egypt.

In case of a lower RES-E share until 2050, the results for the site selection of the High-RES scenario until 2030 can be taken as indicator for potential sites. In general, RE power plants are installed closer to demand in the Low-RES scenario as potential of these areas is sufficient. Especially, higher generation from PV in the Low-RES scenario (see section 5.5.1) allows installing more PV power plants either as roof-tops systems or as ground-mounted PV power plants in short distances to larger cities (demand centers). The 100%-RES scenario with a higher volume of CSP projects shows a significant trend to CSP plants at sites in desert areas which are located in the South: Morocco (Ouarzazate), Algeria (Ghardaia), Tunisia (Medenine), Libya (South of Benghazi) and Egypt (Upper Egypt).

5.5.4 Regional transmission lines

Regional transmission lines (for the electricity exchange between the regions) are assessed to integrate larger volumes of RES-E and to transport them from their point of generation to other regions. The assumptions for the existing NTC capacities of the North African transmission grid include the situation of the year 2013 with all ongoing projects assumed to be completed. The rough estimations of NTC capacities between the regions are based on the knowledge of the voltage levels of the existing transmission lines (see Table 32, appendix). The size of the existing regional transmission lines (standardized in kilometers of transmission lines with a NTC capacity of 1 GW) is displayed in the following Figure 37 as basis for later analysis. The amount of transmission lines within a country or between countries depends on the number of regions per country as well as their specific definition and size. In Egypt, many transmission lines within the Nile Delta are not covered as this area is represented by one region. The displayed capacity mainly represents the large back-bone lines between regions in the North and the South along the river Nile.

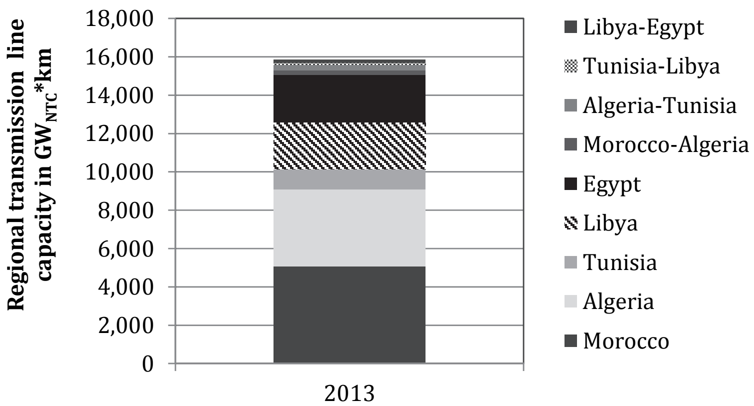

Figure 37: Assumed transmission line capacity between model regions in 2013 (own calculation)

In Figure 38, the analysis of the required transmission line capacity in GW_{NTC} and kilometer length until 2030 and 2050 is shown for the six scenarios. If the existing transmission lines with the NTC capacities of 2013 are available and can be fully operated in the future. By 2030 required extensions of the transmission lines between the model regions are relatively low. Only in some scenarios, the connection to the Western Sahara (in Morocco) is improved in the model to link the excellent wind and solar resources in this area to the industrial regions in the Northern parts of Morocco (Casablanca area). The results for the transmission grid in combination with the site selection in the previous section show that selection of the new RE power plants uses a strong trade-off between minimal grid extensions and renewable energy resources. In case of low RE penetration, power plants are constructed in areas which reduce the cost for electricity transport as existing transmission lines are used. However in all regions, local grid connection of each power plant from the concrete sites to the grid access point as well as transmission lines within each region to the demand centers certainly have to be improved. Due to the model limitations, these effects cannot be assessed here, but they should be studied with a more detailed grid model to analyze the additional grid extensions within each region.

In the long-term by 2050, an essential amount of new transmission lines between the regions have to be built. In the High-RES scenario, transmission lines with a length of 30,000 kilometers (with a capacity of one GW_{NTC}) are constructed to transport renewable energy from its point of generation to the demand centers. The No-Target scenario (with a slightly lower RES-E) requires also new transmission lines with a length of 18,000 kilometers. In the National-Targets scenario, the grid has to be extended by 37,000 kilometers. This value is higher due to the increase of CSP capacity in Algeria and Tunisia which requires new transmission lines to transport electricity from desert regions in the South to the demand in the North.

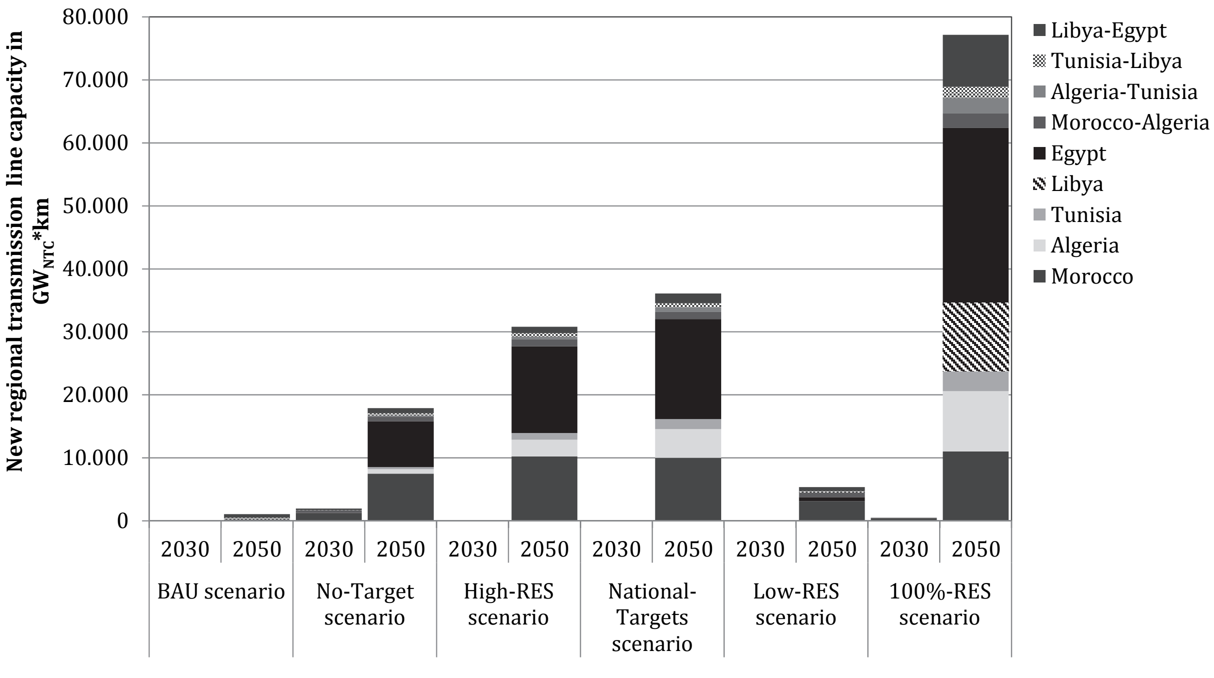

Figure 38: Extensions of regional transmission lines

In both scenarios, national transmission lines in Morocco, Algeria and Egypt have to be extended, in all three countries mainly in the North-South direction. These transmission lines have a high importance in the national electricity systems as the electricity demand is higher in the North of all these countries whereas sites for renewable energy sources in the South are very attractive to be exploited. Wind farms in the Southern Morocco, CSP in Southern Algeria as well as CSP and the hydro dam of Aswan in Upper Egypt are responsible for the high demand of new transmission lines. International capacities also have to be extended between 300 and 1200 kilometers (with a capacity of one GW_{NTC}) in the High-RES and No-Target scenario. The largest international transmission capacity extension in all scenarios between Morocco and Algeria (1.3 GW in BAU, 4.6 GW in High-RES and 8.5 GW in 100%-RES scenario) allows a higher electricity exchange between both countries (Table 22). In the High-RES scenario, the NTC capacity between Algeria and Tunisia is 1.8 GW, between Tunisia and Libya 1.6 GW and between Libya and Egypt 1.2 GW.

Table 22: Interconnection capacities between North African countries in year 2050

	2013	BAU scenario	No-Target scenario	High-RES scenario	National-Targets scenario	Low-RES scenario	100%-RES scenario
	[GW_{NTC}]	[GW_{NTC}]	[GW_{NTC}]	[GW_{NTC}]	[GW_{NTC}]	[GW_{NTC}]	[GW_{NTC}]
Morocco - Algeria	0.8	1.3	2.3	4.6	4.6	3.2	8.5
Algeria - Tunisia	0.4	0.8	1.4	1.8	2.4	0.8	6.1
Tunisia - Libya	0.2	0.5	1.0	1.6	1.8	0.7	4.7
Libya - Egypt	0.2	0.5	1.0	1.2	1.7	0.8	8.4

The volume of electricity exchanged between the region increases strongly from 2030 to 2050 (see Figure 39 and Figure 40). In 2030, the net volumes are still very low and the transmission grid has a balancing function. Expansion of wind power in Morocco influences the growth of transmission from the region in the South and from regions in the North. In Egypt, wind and hydro power is transferred from the South to the Nile Delta.

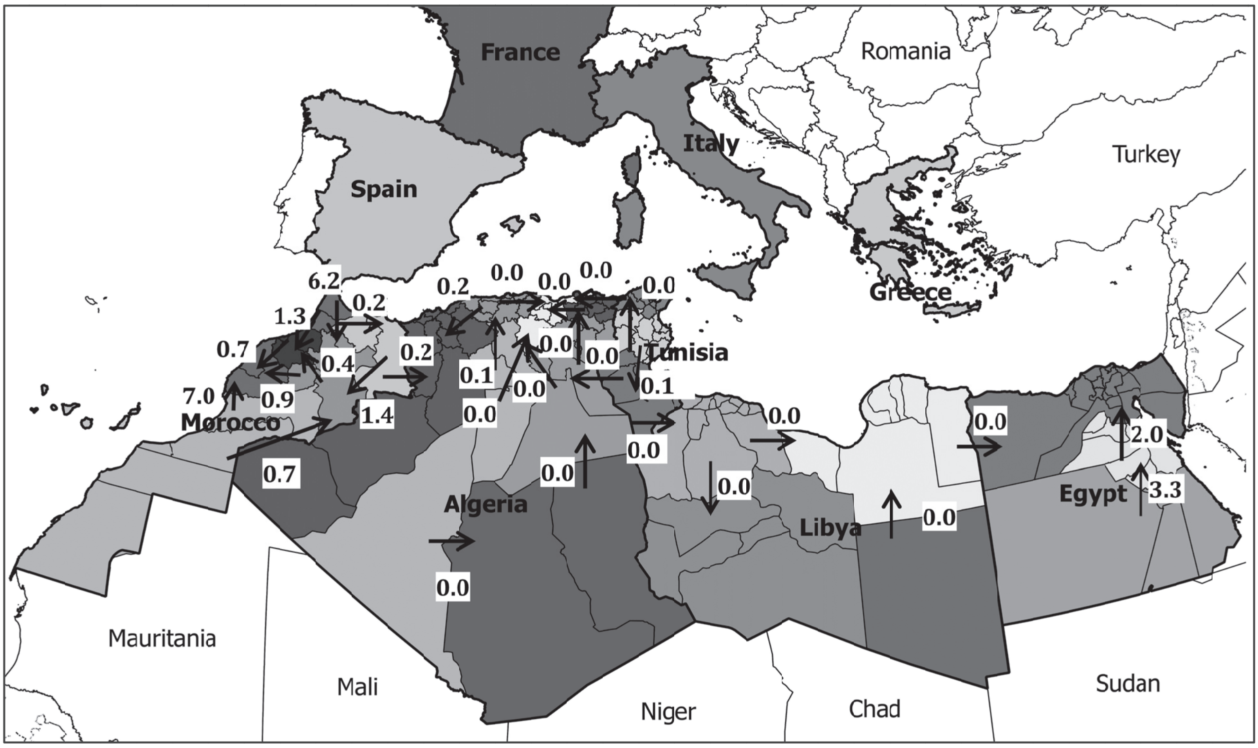

Figure 39: Exchange of electricity in TWh between regions in 2030 (High-RES scenario)

However in 2050 with 80% RES-E, the transmission grid transports high volumes of electricity from the sites of generation to the demand centers. In Morocco, the region of Western Sahara exports 28.4 TWh to regions in the North. Similar, regions in the North of Morocco produce electricity for the Casablanca area and the Algerian neighbor region. In Algeria and Tunisia, electricity is also transported from the South to regions with high demand (Algiers and Tunis). In Libya, electricity generation takes place close to the coast and the larger cities Tripoli and Benghazi. The Southern Egypt is highly important for the renewable energy strategy of Egypt as high volumes of electricity are exported from the region in the South to the Nile Delta.

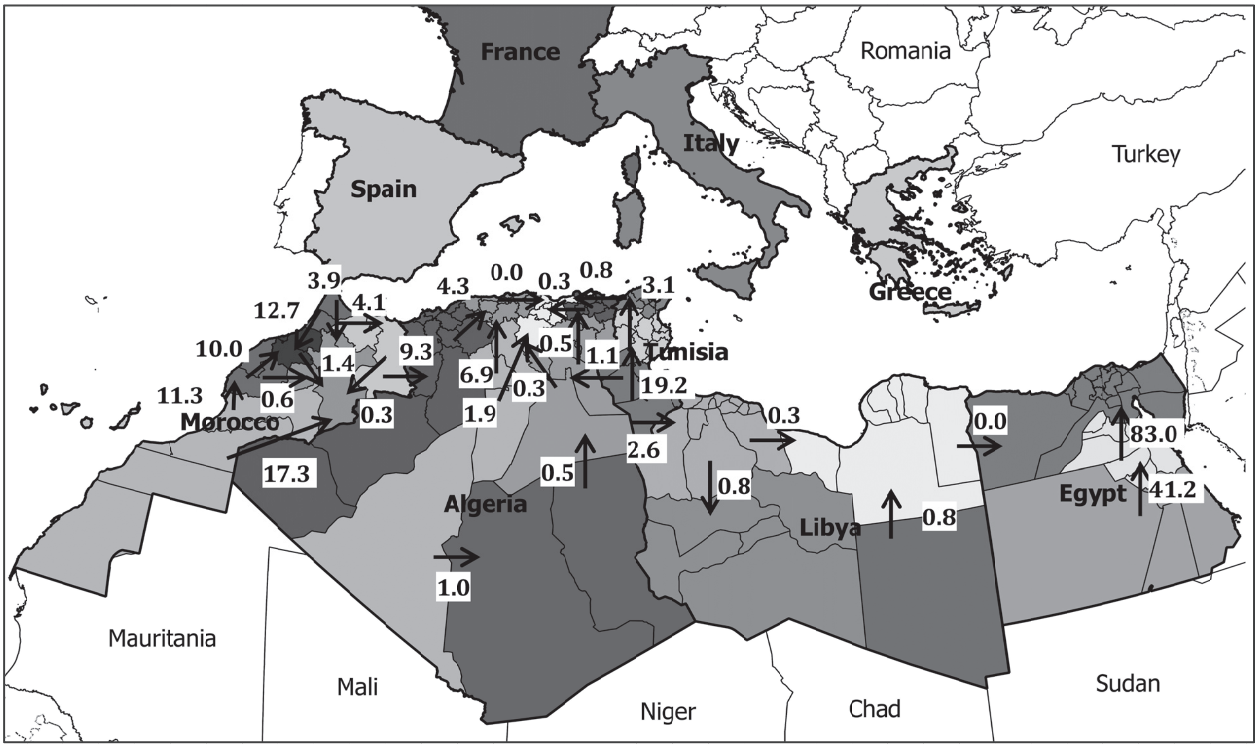

Figure 40: Exchange of electricity in TWh between regions in 2050 (High-RES scenario)

In the 100%-RES scenario, a line length of 78,000 kilometers is needed to balance the system with the different renewable energy sources without any conventional back-up power plants. This includes a substantial extension of the transmission grid compared to the High-RES scenario in Libya and Algeria (to connect CSP power plants in the desert) and between Libya and Egypt to increase the balance potential between both countries. The other international interconnections will be increased to improve the exchange of electricity from fluctuating RES.

Certainly, the extension of the electricity network is a key success factor for integration of renewable energy sources. However, the strong growth of electricity demand in North Africa leads to a reinforcement of existing transmission capacity anyway. With RE power plants generating electricity in some distance to the demand, further grid extension after 2030 are necessary. Between some regions (mainly South-North connections) a large additional transmission capacity is required to make RE integration possible. Under the model assumptions, these investments in grid capacity are balanced by lower installation costs of RE projects at the sites which require electricity transport to load centers. However in case of higher transmission costs, RE generation is moved from regions with lower demand to the load center. Technology portfolio is also influenced by a shift to PV (sensitivity analysis of transmission costs is provided in section 5.6.3).

5.5.5 Energy storage systems

To store and shift electricity from hours with surplus electricity generation to hours with lower generation, energy storage options have been integrated in the model. However, in most of the scenarios these storage options are not chosen by the model to shift electricity between different hours. Only in the 100%-RES scenario, storage systems with a size of 9 GW are constructed in North Africa. In the other scenarios, only a few extensions in Morocco are necessary. The model prefers to extend the transmission grid to exchange the surplus electricity from one region to another region. The cost assumptions for new transmission lines and new storage systems are one of the main drivers for this model result. Additionally, the more flexible power generation from power plants running with natural gas, allows being very flexible in the conventional power generation.

Table 23: Storage systems in North African countries in year 2050

	2013	BAU scenario	No-Target scenario	High-RES scenario	National-Targets scenario	Low-RES scenario	100%-RES scenario
	[GW]	[GW]	[GW]	[GW]	[GW]	[GW]	[GW]
Morocco	0.5		1.1	1.8	1.2		3.8
Algeria							2.6
Tunisia							0.6
Libya							1.0
Egypt							0.9

Average use of energy storage systems in 2050 is highly correlated with electricity generation from PV. During most of the hours, the storage is loaded during hours with high irradiation (2 to 4 pm). After sunset and increasing demand during evening hours, storages are unloaded and provide electricity to the grid (Figure 41). During the night, the rest of the stored energy is used.

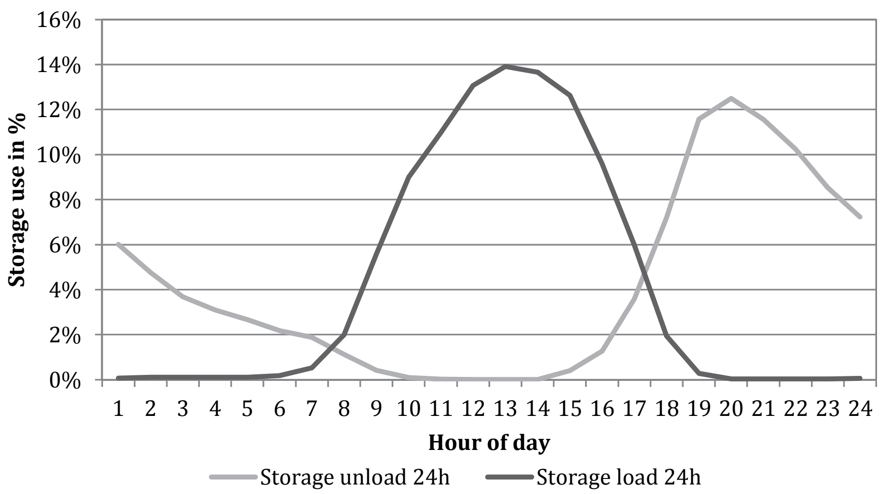

Figure 41: Average storage use of each hour in year 2050 (100%-RES scenario)

5.5.6 Technology specific generation

Monthly electricity generation from RES depends on the weather condition which shows higher wind speeds and solar irradiation from March to September than in the other months (Figure 42). In 2030 and 2050, generation from RES is significantly higher in these months (up to 50% compared to winter months) and influences generation from conventional power plants as CCGT power plants shows larger electricity generation during the months October to February. Higher electricity demand during summer months (due to air conditioning) is positively correlated to the electricity generation from RES. However, the monthly generation in 2050 usually exceeds the electricity demand (including transmission losses) and curtailment is necessary especially in the months with high generation from RES (see Figure 42, when generation is larger than demand).

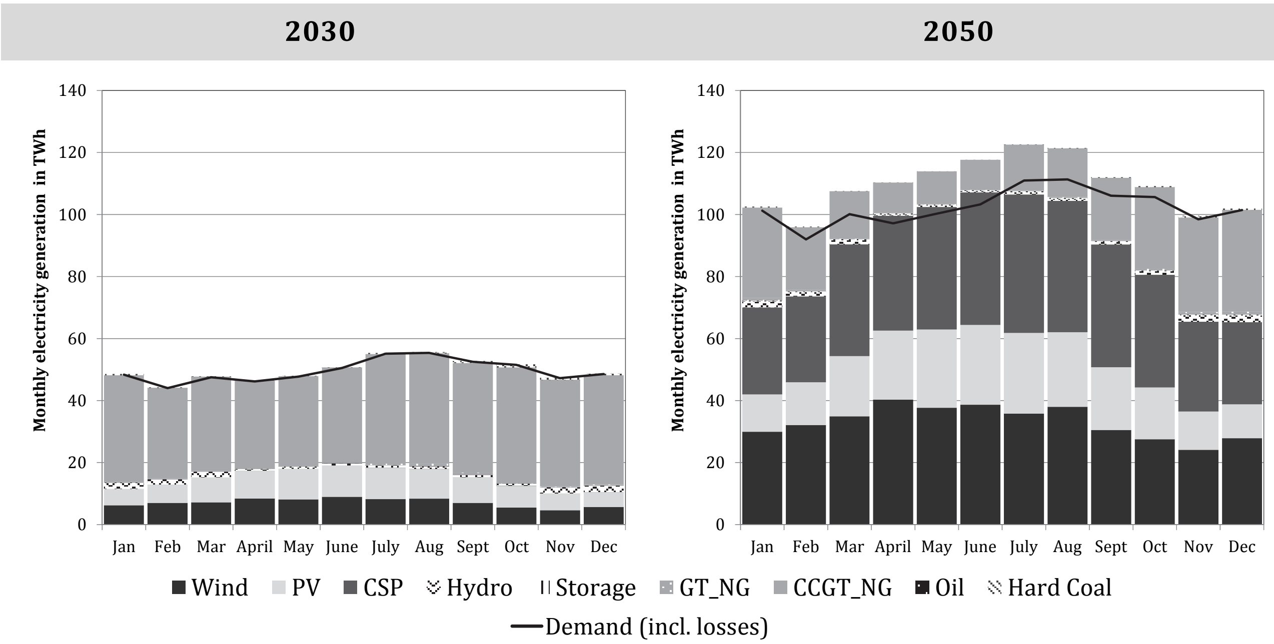

Figure 42: Monthly electricity generation (all countries) in 2030 and 2050 (High-RES scenario)

The increasing share of RES-E influences the hourly electricity generation from conventional power sources. During exemplary weeks of May 2030 and May 2050, fluctuating electricity generation shows strong hourly increases during each day (Figure 43). Especially PV is highly linked to the position of the sun. Generation from wind farms shows more randomly distributed generation which can increase to about 12 GW, but can be decreased below 1 GW totally at all locations in North Africa. Hydro, gas and storage power plants are only used to balance smaller fluctuations and high demand during evening hours. During high feed-in from PV, small amounts of curtailment already can be found in the model results.

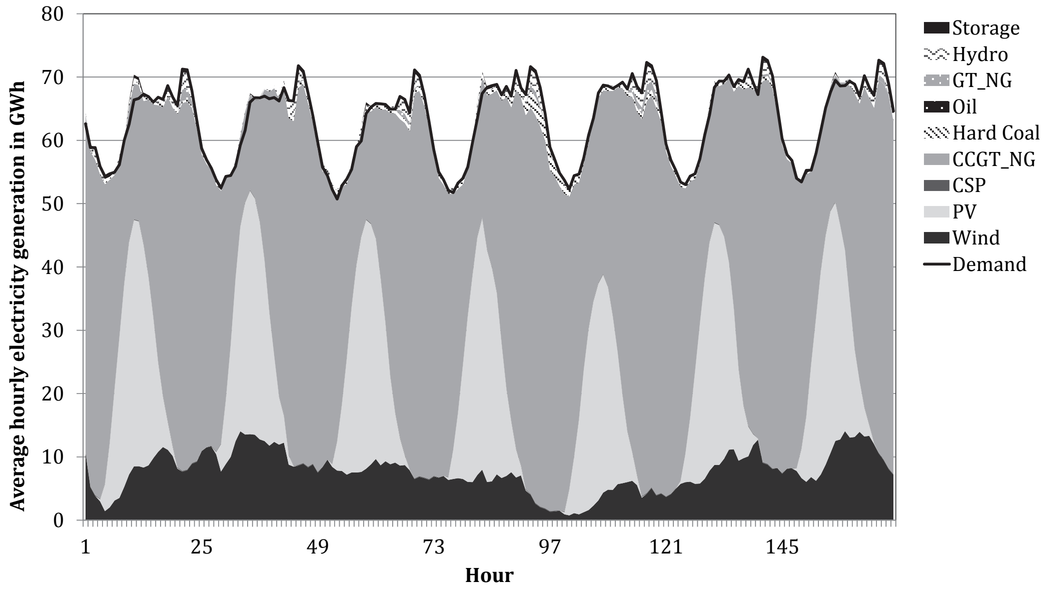

Figure 43: Electricity generation of all countries in first week of May 2030 (High-RES scenario)

In 2050, electricity generation from RES is based on wind, PV and CSP. A large share of the electricity from CSP is generated during evening hours to reduce the use of CCGT power plants as CCGT is only used during the night (Figure 44). In case of high generation from wind power and CSP, it might be possible to completely provide electricity from RES at night. PV and CSP generate enough electricity between 9 am and 5 pm that electricity demand is completely supplied by RES during these hours. High curtailment of wind and PV power plants is necessary at the same time. Other power plants (hydro power and gas turbines) are used exclusively at night in 2050.

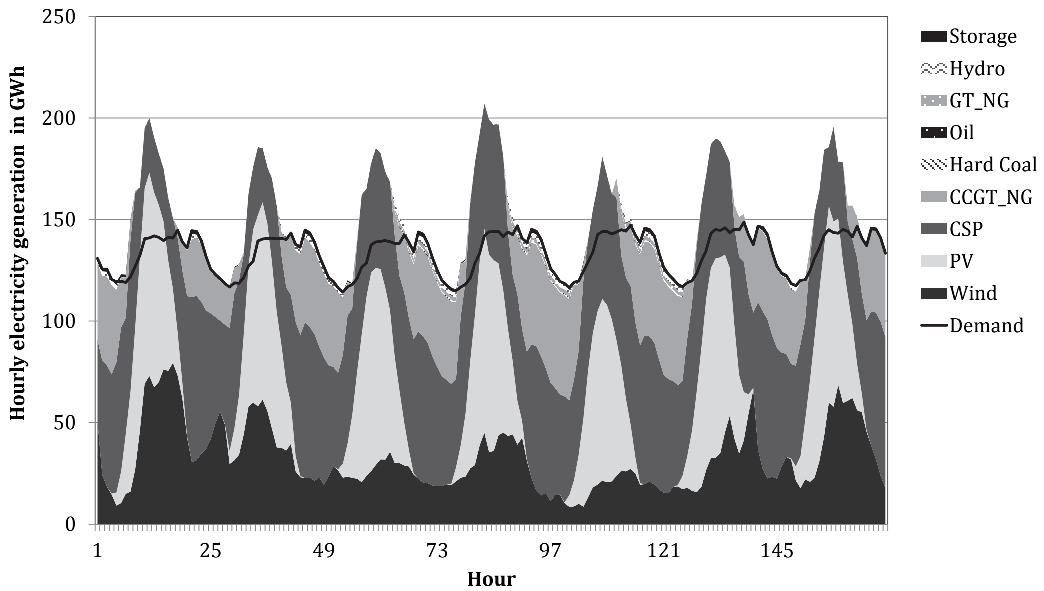

Figure 44: Electricity generation of all countries in first week of May 2050 (High-RES scenario)

Average daily generation for each season underlines the dependency on the weather conditions as the generation from PV and hydro power in 2030 impacts the use of the other technologies (Figure 45). PV generation starts at 6 am in the morning and ends at 6 pm in the evening after sunset. The variation between summer and winter is lower than PV generation profiles in Europe due to the proximity to the equator. Wind power shows a similar profile during all seasons with an increase of generation between 4 pm and 7 pm. Lowest hourly generation of wind farms is found during 5 am and 9 am.

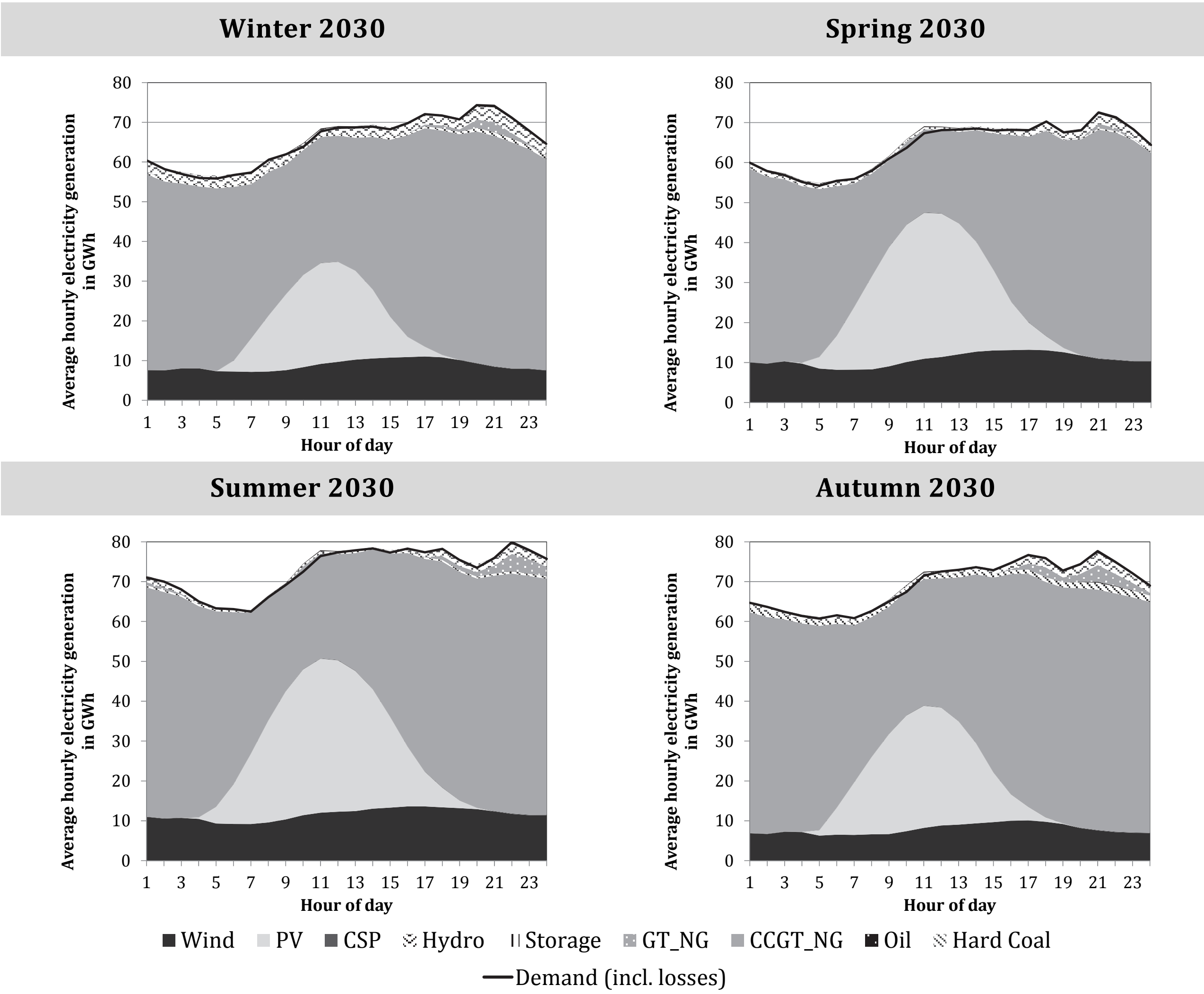

Figure 45: Average daily electricity generation per season in 2030 (High-RES scenario)

In 2050, CSP power plants play a key role in the electricity generation system. As the average daily generation profiles for each season show, CSP power plants provide a large share of their electricity generation at night by using their thermal storage to store thermal energy for electricity generation in the evening or at night (Figure 46). However, RE power plants have to be curtailed in spring and summer when high solar irradiation provides more electricity than is needed in the system.

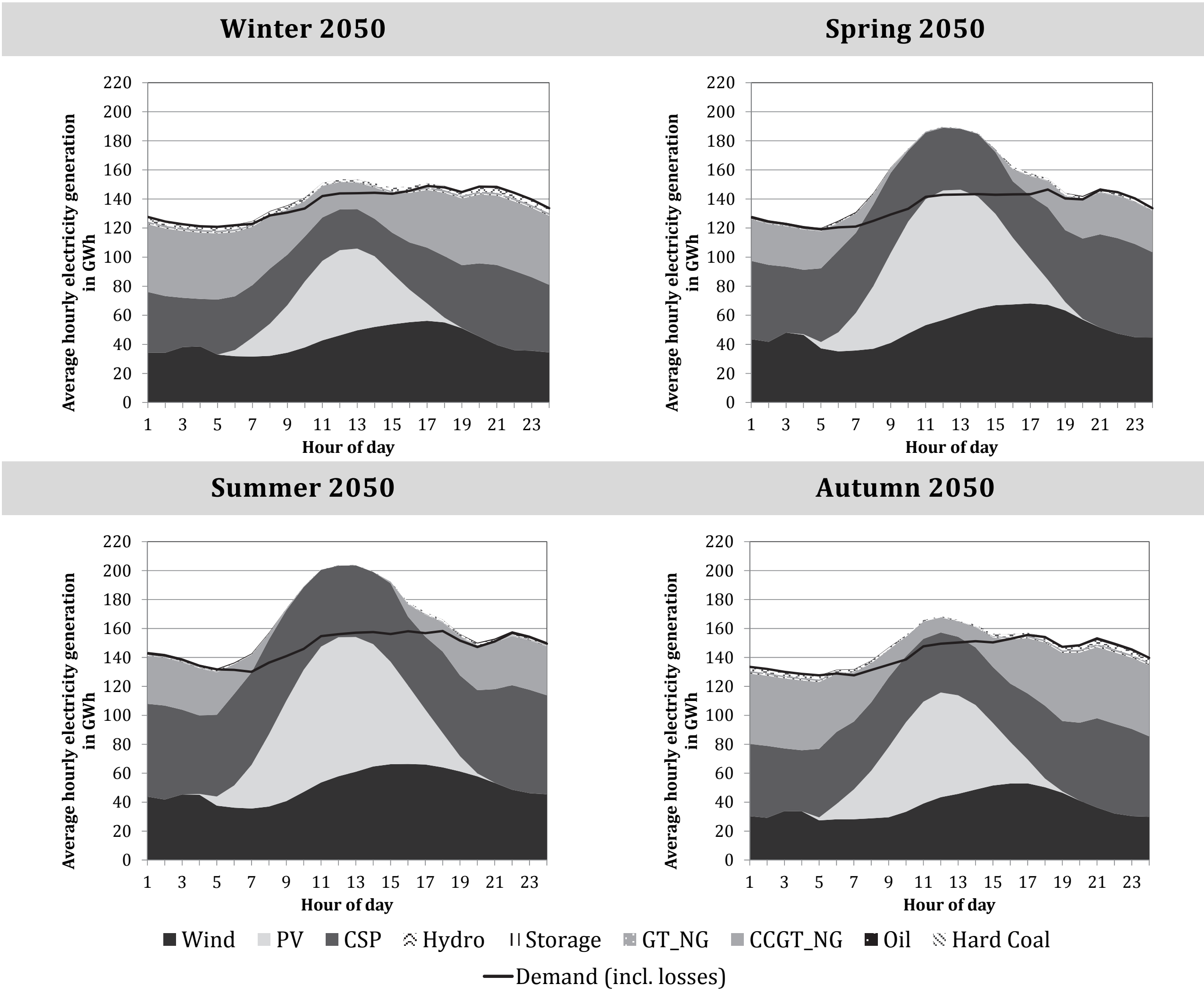

Figure 46: Average daily electricity generation per season in 2050 (High-RES scenario)

Average daily generation between the scenarios differs depending on the RES-E share within the system (Figure 47). In case of lower RES-E share, conventional power plants provide high shares of electricity at night. In the 100%-RES scenario, CSP plants substitutes this conventional generation by using their thermal storages.

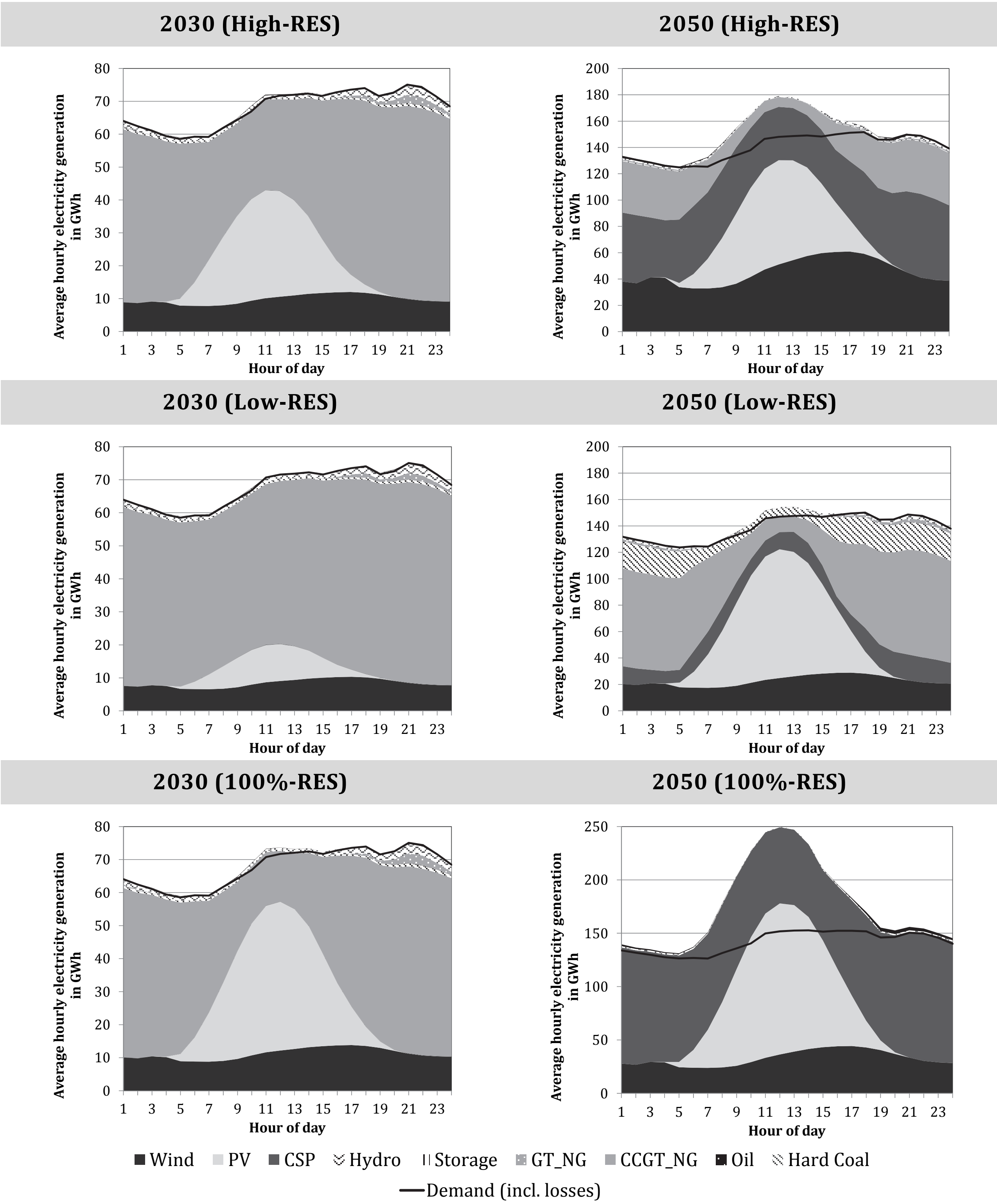

Figure 47: Average daily electricity generation in 2030 and 2030 for High-RES scenario, Low-RES scenario and 100%-RES scenario

Operation of each technology in terms of average full load hours changes over time by an increase of the RES-E share in the electricity system of North Africa. RES almost provide constant full load hours to the system. However, this does not mean that the total RES-E can be used within the system, therefore the height of curtailment has to be analyzed.

As the model only selects sites for wind with excellent wind conditions the full load hours are in the range between 3000 and 4000 due to the high average wind speeds at the coast of Morocco and Egypt. In the long-term however, the full load hours of wind power decrease to about 3000 on average because some sites with worse wind conditions are selected then. PV systems have on average 1800 to 2000 full load hours as the solar conditions are very similar in many regions in which PV is mainly installed. CSP plants have full load hours in the range of 4000 to 5000 hours depending on the share of natural gas which is used in the certain year (this value changes over time depending on the power plants in the system).

Gas-fired power plants show a strong decline in full load hours per year. By 2025, the CCGT power plants have a high number of operating hours with over 6000 hours per year. Between 2035 and 2050 the full load hours of CCGT power plants decrease to 3500 hours per year and for gas turbines to a few hours per year. Existing oil-fired plants are only used during a few hours per year.

Due to the price assumptions for coal and natural gas, CCGT power plants are preferred by the model, therefore existing hard coal-fired power plants in Morocco are only used as back-up capacity in the system with a low number of operating hours (about 1000). A shift to a larger use of coal-fired power plants is possible in case of a lower coal price and a CO_2 emission price of 0 EUR/t (compare results of BAU scenario).

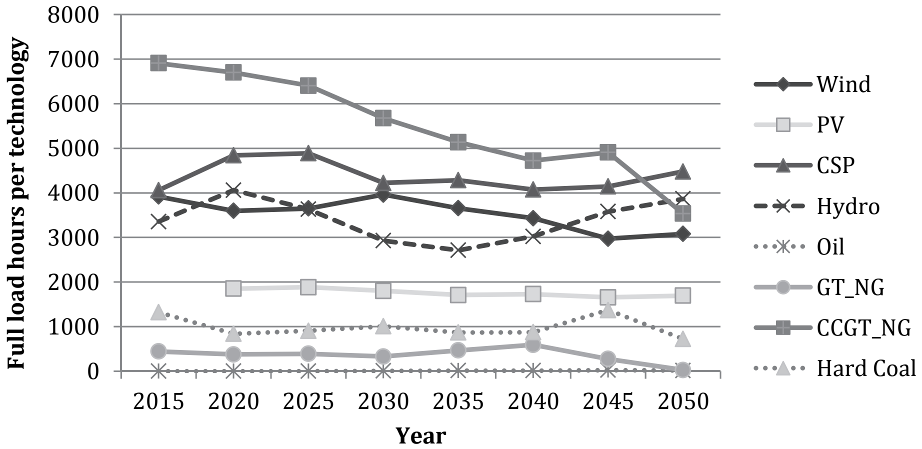

Figure 48: Average full load hours of each technology in High-RES scenario

Related to the analysis of the full load hours, the curtailment of RES strongly grows with an increase of the RES-E share (Figure 49). Therefore, the number of full load hours of RES is actually reduced as a consequence. The scenario with the first significant use of curtailment is the No-Target scenario. In case of full optimization of the generation portfolio in this scenario, the costs for curtailment are preferred instead of using each MWh produced.

Generally, if the RES-E share increases above 50% in all scenarios, the curtailment of RES starts to rise to a substantial volume per year. In case of an 80% RES-E share, curtailment is between 20 and 50 TWh per year. In the 100%-RES scenario this value increases up to 120 TWh per year. More transmission lines, cheaper storage systems or additional shift of demand might lower this value in the future. But the fluctuating generation of RES will certainly always require shutting down RE power plants during hours of low demand or high generation through to favorable weather conditions.

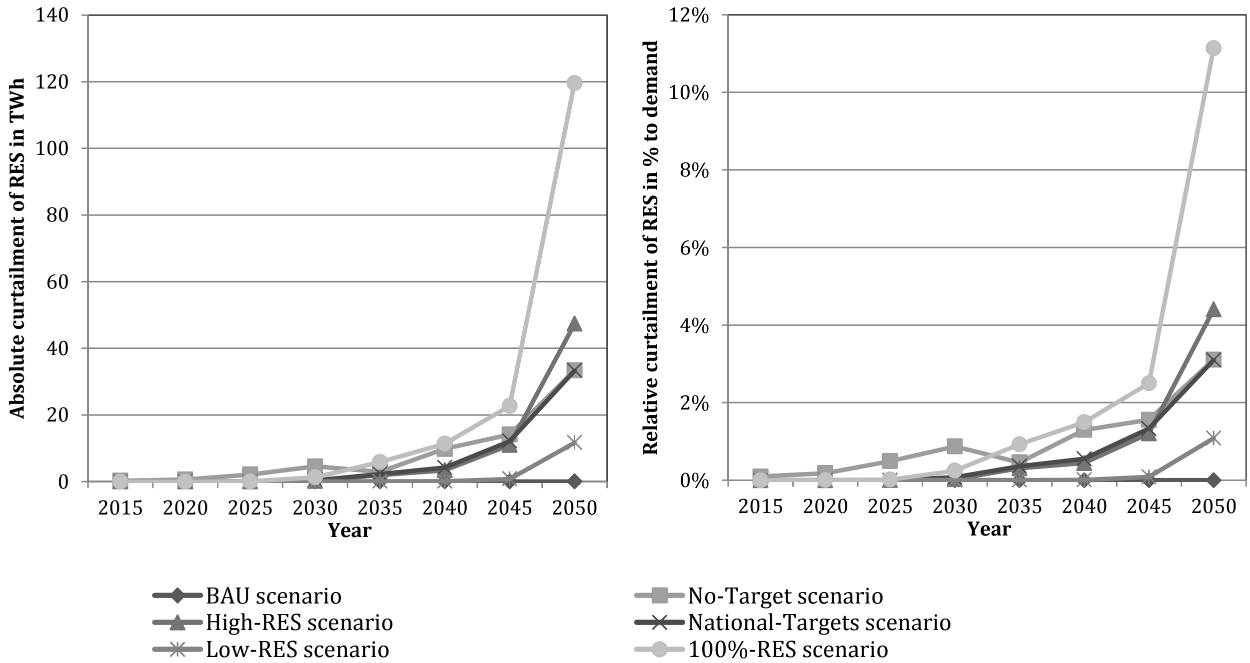

Figure 49: Curtailment of RES per year from 2010 to 2050

5.5.7 CO_2 emissions

To achieve stable CO_2 emissions from the power sector from today's value beyond 2050, ambitious deployment of RE technologies is required to cover the increasing electricity demand without exceeding CO_2 emission targets. The scenarios with a target of 80% RES-E can stabilize the CO_2 emissions until 2050 on 50,000,000 t CO_2 (see Figure 50). In the BAU scenario, CO_2 emissions increase to almost 250,000,000 t CO_2 in 2050. Only the 100%-RES scenario completely avoids CO_2 emissions by exclusive use of RES for electricity generation.

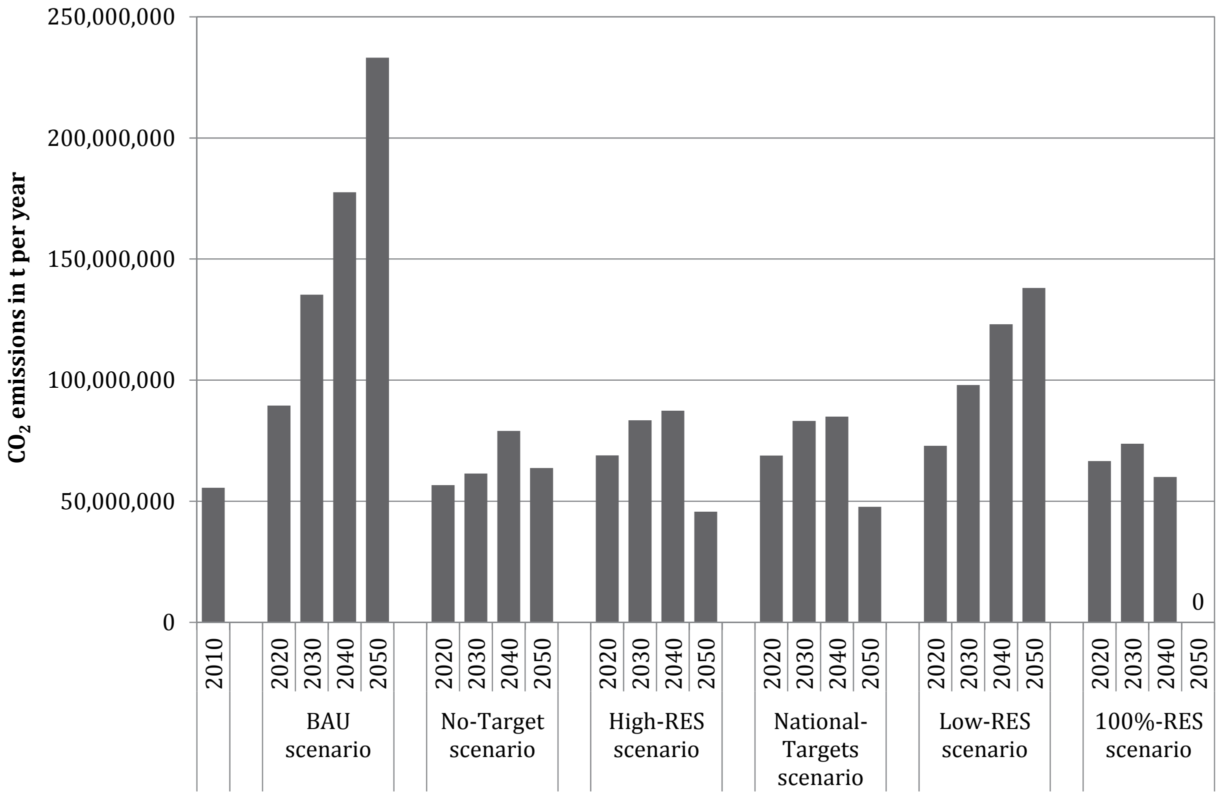

Figure 50: Annual CO_2 emission in the power sector of North Africa

5.6 Sensitivity analyses

Target of the sensitivity analyses is to assess the influence of certain assumption and parameters on the model results. Four areas of sensitivity are analyzed in the following:

1) Adaption of market conditions: Split of electricity markets (2 cases)
2) High technology focus (2 cases)
3) Adaption of cost trends for transmission lines, fossil fuels and storage systems (4 cases)
4) Influence of lower fuel prices in No-Target scenario (1 case)

The sensitivity cases 1) to 3) are carried out for the High-RES scenario with its RES-E share of 80% in 2050 and its integrated electricity market.

5.6.1 Adaption of market conditions: Split of electricity markets

The national electricity systems in North Africa are nowadays very separate and autonomous with low international exchange of electricity between the countries. Furthermore the international interconnections to other countries in the South or in the North are limited to an interconnection to Spain and Jordan. The general assumption in the scenarios is an increasing integration towards a single electricity market with larger exchange of electricity. The National-Markets scenario assumes national electricity markets without the option to exchange electricity with foreign countries; the Isolation scenario does not allow exchange of electricity with Algeria. In both cases, the overall results in terms of installed capacity per technology are very similar and overall costs are only slightly higher compared to the High-RES scenario. However, a comparison of the national power plant portfolios with the High-RES emphasizes the country specific differences in year 2050 (Figure 51). In case of limited exchange of electricity between Morocco and Algeria, RE power plants in Morocco are replaced by additional conventional power plants. Algeria builds additional RE power plants, mainly CSP and wind. If only national markets are assumed, Tunisia has a lower CSP capacity due to a strong PV and CSP deployment in Libya. Wind power plants are shifted from Libya to Egypt in the National-Markets scenario compared to the High-RES scenario. The optimal configuration is 2 GW of wind power in Libya instead of in Egypt. In the Isolation scenario, the differences for Tunisia, Libya and Egypt are lower as electricity exchange between these countries is allowed. Only a few power plants are shifted between Egypt and Tunisia.

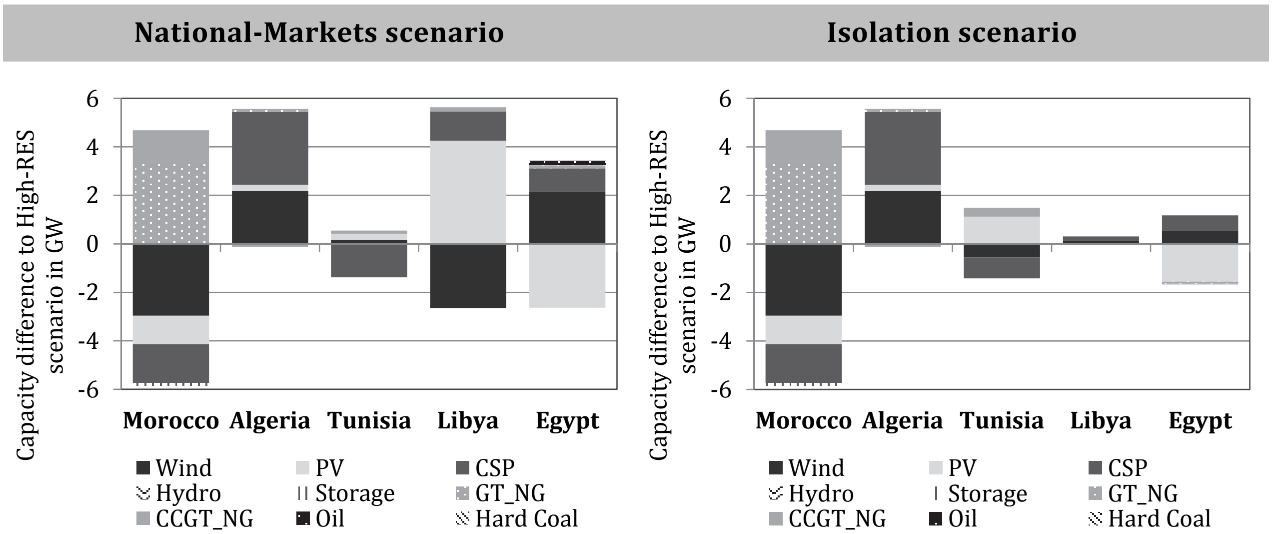

Figure 51: Comparison of installed capacity in 2050 with High-RES scenario

5.6.2 Technology focus

If countries decide to strictly prefer one technology due to higher socio-economic benefits through local manufacturing, a specialization instead of having a broad technology portfolio is a potential scenario for the future energy system. Therefore, two cases with either high CSP or PV penetration are evaluated. With these scenarios, a technology focus should be analyzed regarding its system effects in terms of additional costs and structural changes. In both cases, the minimum share of PV or CSP is set to 50% of the total RE generation (RES-E share in 2050 is 80%). The model results show that such a technology focus on one solar technology (CSP or PV) increases the total system costs by a maximum of 2%.

In the case of high CSP penetration (CSP generation always >50% of RE generation), a higher CSP capacity (18 GW) is installed by the model in Egypt by 2030 whereas PV (30 GW), wind (6 GW) and CCGT power plants (10 GW) are replaced, compared to the High-RES scenario. By 2050, 5 to 10 GW of wind and PV projects are replaced in Morocco, Algeria, Tunisia and Libya. 9 GW of total 13 GW additional CSP plants are installed in Egypt to replace 35 GW of PV in Egypt. The difference in 2050 is not that high as also in the High-RES scenario the share from CSP is already 45% of the total RES-E compared to the scenario specific target of 50%. In 2030, the differences are larger as only 1% of the produced RES-E comes from CSP in the High-RES scenario. With high CSP penetration, more transmission lines are required in all countries except in Egypt. But with Egypt, the total amount of transmission lines is lower in this scenario. Storage systems are required less in this scenario due to the higher CSP capacity. Due to the lower PV capacity and the higher full load hours of CSP, the total installed capacity in 2050 decreases from 432 GW to 366 GW in year 2050, compared to the High-RES scenario.

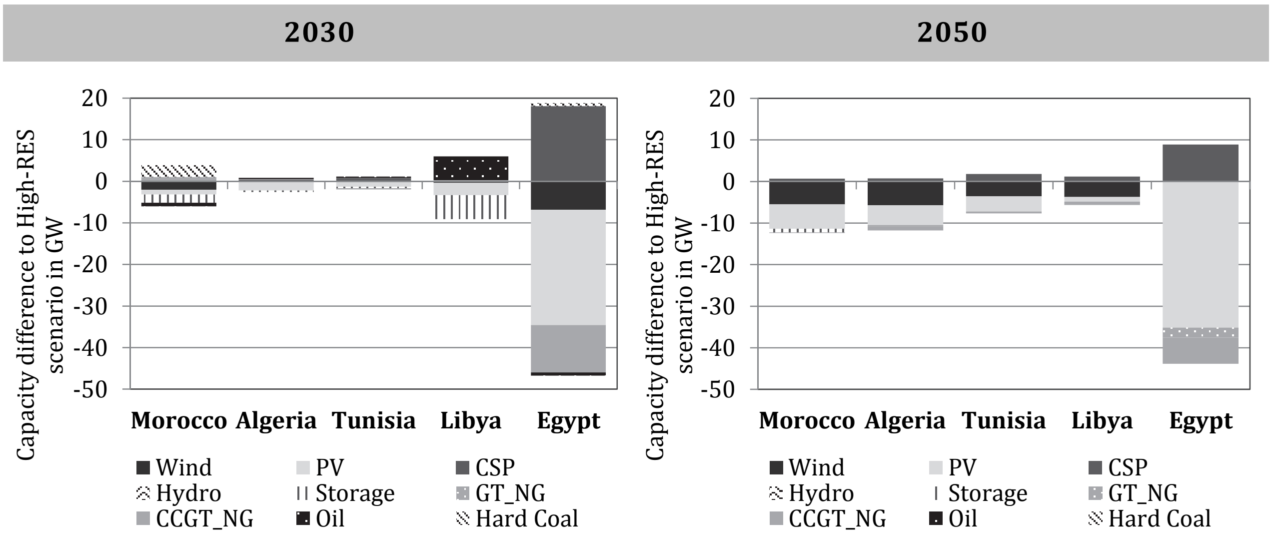

Figure 52: Comparison of installed capacity per country between High-CSP scenario and High-RES scenario

In the High-PV scenario (PV generation always >50% of RE generation, 80% RES-E share in 2050), a very high amount of PV power plants are installed by the model. Large differences exist on a national level compared to the power plant portfolio of the High-RES scenario. Figure 53 shows the replacement of wind power plants in Morocco, Libya and Egypt with additional PV power plants (10 GW) in all countries. Until 2050, it becomes more difficult to integrate PV usefully into the electricity system as only 30 GW of wind power and CSP are installed less compared to the High-RES scenario. However, about additional 130 GW of PV is installed to reach the RE target of 80%. The increase of a higher amount of conventional back-up capacities clearly is another negative aspect of this scenario. The curtailment is 2.5 times higher in 2050 and a few more storage systems (2.8 GW) are constructed in Libya compared to the High-RES scenario.

The total system costs of both high penetration scenarios do not increase strongly; however overcapacity of PV and curtailment are enormous in the High-PV scenario. In this scenario, PV mainly replaces CSP. By installing additional gas turbines and CCGT power plants, demand is covered during the night. Total system costs do not increase strongly as less CSP power plants with the highest specific cost of all technologies are installed.

In the High-CSP scenario, dispatchability of CSP lowers an increase of the total system costs as the system increases its flexibility compared to a system based on higher shares of PV and wind power. But until 2030, additional costs are significantly added to the overall system costs due to the higher technology costs of CSP (basically before 2030) compared to the other technology options.

The specialization on PV or CSP could have an additional benefit if local potential of manufacturing is increased due to higher amount of a certain technology in one country. This topic will be extensively discussed in the next two chapters.

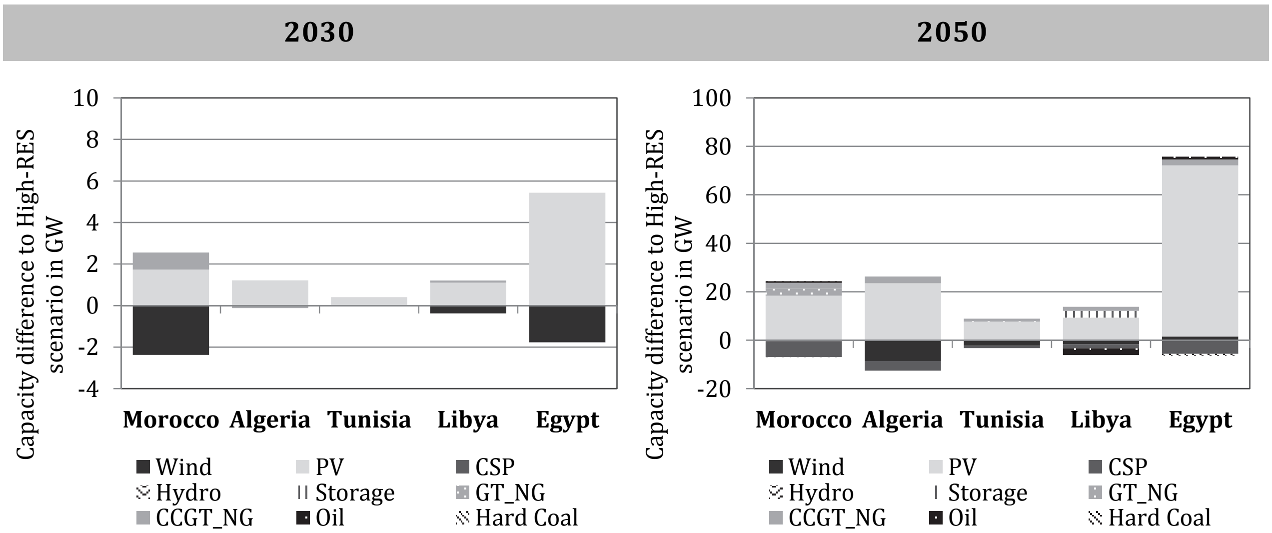

Figure 53: Comparison of installed capacity per country between High-PV scenario and High-RES scenario

5.6.3 Adaption of cost trends for fossil fuels, transmission lines and storage systems

A very large impact on the total system cost with minus 25% has a low fossil fuel price for natural gas, oil and coal (Low-NG-Price scenario: a price level of 50% compared to the High-RES scenario is used). But the power plant portfolio is very similar in both cases as the RES share is set equally to the High-RES scenario: Only gas turbine power plants are used a bit more, whereas CCGT power plants have a reduced installed capacity during all years.

But if a sensitivity analysis of the No-Target scenario is modelled with no RES targets, a price for natural gas of 50% and also a price for coal of 75% compared to the basic assumptions (see Table 19), the results (No-Target+low-price scenario) are significantly changed by the lower fossil fuel prices. In the No-Target scenario, RES share is about 72% in 2050 with a strong increase of RES until 2030. However, if North African countries use their fossil fuels (especially natural gas) for a price below a world-market price, the model shows very different results in the No-Target-Low-Fuel-Prices scenario (Figure 54). In this case, the results show only a RES-E share of approximately 55%.

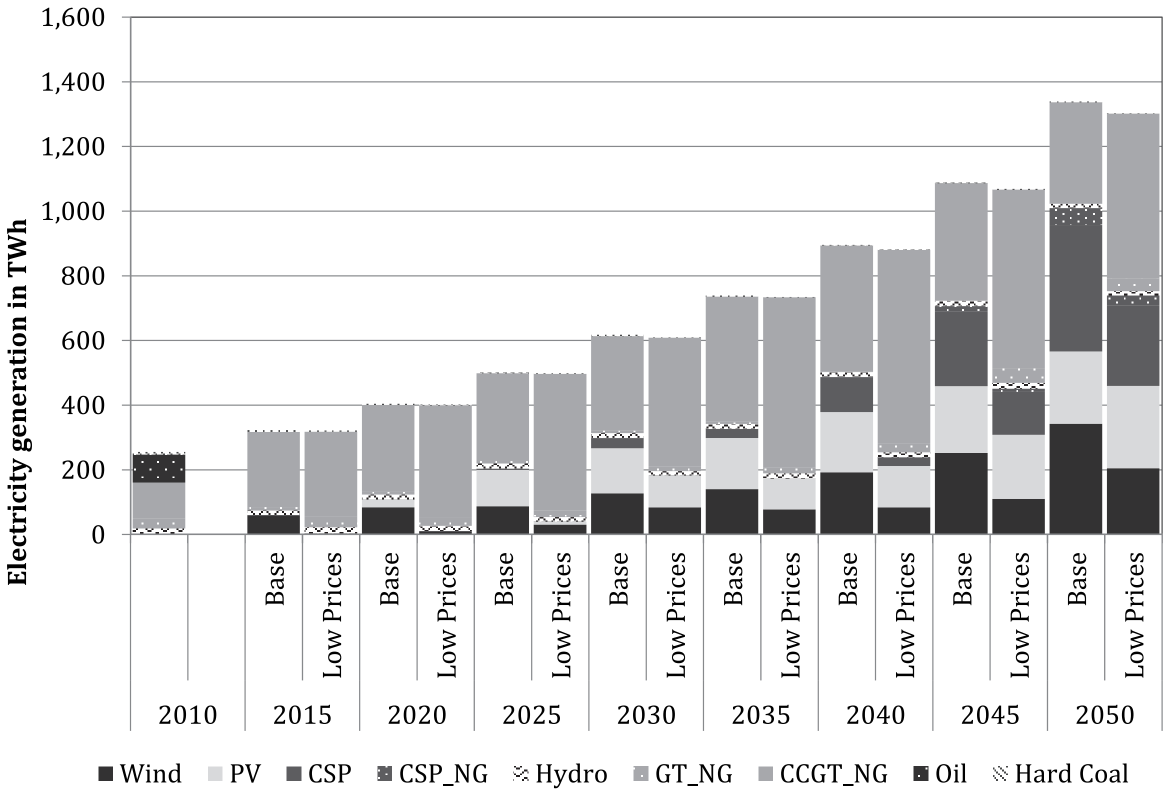

Figure 54: Sensitivity analysis of No-Target scenario with low prices for natural gas and coal

Further sensitivity analyses change the construction costs of transmission lines compared to the basic assumptions. If construction of new HVAC transmission lines in North Africa would cost only half of the assumptions (350 Euro/km*MW_{NTC}), additional transmission lines with a length 13,000 km*GW_{NTC} are constructed by 2050 (Low-Grid-Cost scenario). The additional lines improve the grid in all countries and lead to a larger use of wind in Libya and less PV in all countries (8 GW) compared to the High-RES scenario. Total system costs decrease consequently. If transmission costs are assumed to be at 1400 Euro/km*MW_{NTC} (HVAC), then transmission lines are extended by about 8,000 km less than in the High-RES scenario. Higher transmission costs have directly impact on RE installations in regions with low own demand and with required transmission to the demand centers. In Morocco, mainly wind power plants at the Southern Atlantic coast are reduced in this scenario (High-Grid-cost scenario). CSP and PV power plants are significantly less installed in areas with higher irradiation but the need to transport the electricity to other regions (in Algeria, Tunisia and Libya). In Egypt, the effect is slightly lower as the distance between the region (Nile Delta and Minya) is relatively low compared to the distance of between other regions. Therefore, higher grid costs do not influence the site selection of RE technology strongly.

If the prices for storage systems such as electrochemical storages (Lithium-ion batteries) decrease significantly, storage use is increased in 2050 by a few GW to 5.1 GW compared to 1.7 GW in the High-RES scenario. As a consequence, additional 10 GW of PV is installed under this assumption. This is logical as PV has a very low LCOE and a large technical potential in North Africa. However, the simultaneity of PV generation limits the maximum capacity. With cheaper storage, more electricity from PV can be shifted to other hours with low solar irradiation and high demand.

5.7 Technology specific findings for CSP, PV and wind power

5.7.1 Typical sites and locations for electricity generation from RES

In section 5.5.2, the regional distribution of wind power, PV and CSP is shown. Sites are chosen predominantly by the quality of the natural resources of wind and solar power and by the structure of the electricity demand.

Sites of wind farms at the Moroccan Atlantic coast or at the Red Sea in Egypt offer excellent wind conditions with 3000 to 4000 full load hours. Therefore, wind farms at these sites are the first RES option in all scenarios. However, due to their distance to other countries, electricity transport from these sites to other countries is not chosen as a very prominent solution.

At other locations, wind power and PV compete with each other. In many regions with high demand (areas of Casablanca, Algiers, Tripoli or Cairo) PV power plants play an important role between 2025 and 2040 as the capacity of PV is strongly increased. At these sites, PV profits from its potential to be installed close to the demand centers.

CSP plants prefer sites with higher direct solar irradiation which is higher at locations with some distance to the sea. Therefore, CSP plants are constructed in the Southern regions of each country. In most of the cases, this leads to additional transmission lines between regions with higher CSP capacity and regions with higher demand.

5.7.2 Influence of wind speeds and solar irradiation

Site conditions highly influence the penetration of wind power in each region. Due to the competitiveness with PV and CSP, only locations with best site conditions are chosen in the model as potential areas for large wind farms. Sites with best wind conditions have between 3000 to 4000 full load hours compared to sites with about 2000 full load hours. Due to the assumption of high technical potential for wind farms at the coastal area of Morocco and Egypt, both areas dominate all other regions as potential sites for wind farms. Sites with lower average wind speeds (e.g. in Algeria and Tunisia) directly compete with PV power plants.

PV power plants benefit from very stable solar conditions throughout North Africa. Best sites only have 20% higher energy output compared to sites with lower irradiation as the energy output is negatively influenced by high temperatures in the PV module at sites with very high solar irradiation. As very high irradiation is only available in regions without large own consumption, electricity from PV power plants in these regions has to be transported to other regions with higher demand. Due to maximum full load hours of 2000 per year, extension of transmission lines only for transport of electricity from PV adds further costs on electricity from PV. Therefore, sites for PV power plants are mainly chosen in regions with high demand at the coast of the North African countries.

Due to high direct solar irradiation in combination with the use of thermal energy storages, CSP plants can dispatch the fluctuating generation from PV and wind power. From sites with excellent site conditions (in areas with proximity to deserts), CSP plants provide a high share of the electricity which is needed at night if conventional power plants are limited in scenarios with high RES-E shares. Figure 55 shows a comparison between resource availability for solar and wind (average feed-in from all potential sites, similar installed capacity at each site) and the electricity generation of CSP, PV and wind power in 2050 of the High-RES scenario.

Electricity generation from wind power and PV shows similarity to the average resources of wind and solar. CSP power plants actively use their thermal storage and shift electricity generation to night hours. Additionally, electricity generation from CSP depends on the profiles of PV and wind power as it tries to fulfill the demand during hours with low PV and wind feed-in.

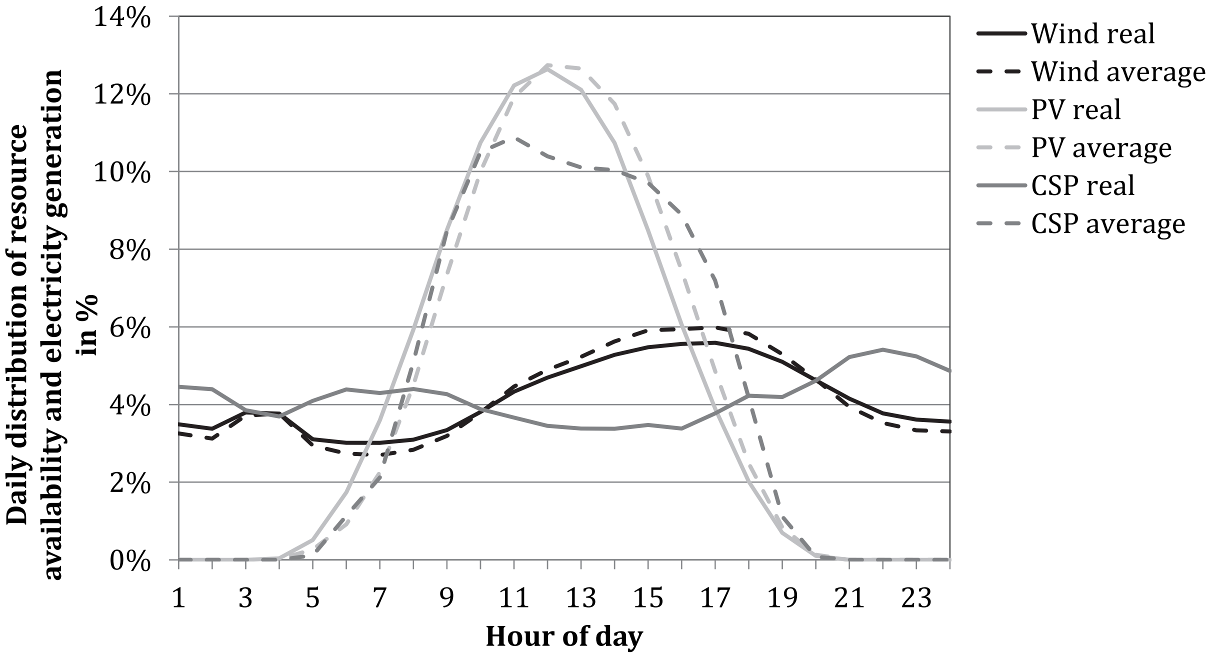

Figure 55: Daily distribution of resource availability of all sites and hourly electricity generation from CSP, PV and wind power of all countries in 2050 (High-RES scenario)

5.7.3 Interactions with conventional power plants

Structure of the RE Technology portfolio clearly influences the power plant portfolio of conventional power plants in terms of technology, capacity and geographical distribution. But, technology selection for conventional power plants also depends on the operation costs of each technology itself. Costs for fuels and CO_2 emission prices are the key factors for the decision between coal-fired and CCGT power plants. If a CO_2 emission price is assumed and natural gas prices are relatively low compared to coal, first choice is always CCGT technology. These CCGT are preferred in all of the scenarios compared to pure gas turbines as in the scenarios, CCGT power plants provide most of their electricity over the whole night. Natural gas turbines are only used for electricity generation during a few single hours. In case of CO_2 emission price close to 0 EUR/t, coal-fired power plants are a clear alternative to provide base load electricity. As currently the use of coal-fired power plants is relatively low in North African countries, a trend to more coal-fired power plants seems possible in the next years (see results of the BAU scenario). As mentioned before, oil power plants continue to decrease their role, especially in the Egyptian and Libyan electricity system compared to today. The only RE technology which can partly overtake the role to provide back-up capacity during hours without wind and solar irradiation is CSP. However, due to its higher specific costs, CSP is only used in scenarios with higher shares of RES-E.

Site selection of new wind farms, PV and CSP plants can completely avoid the installation of conventional power plants in some areas with very high RES penetration. Preferred sites for

CCGT power plants are in regions without large CSP and wind farms. As shown in section 5.5.2, conventional power plants are mainly focused to the areas of Casablanca, Algiers, Tunis, Tripoli and Cairo in 2050 of the High-RES scenario. Basically, these power plants remain to be located at sites where they are currently constructed.

5.8 Electricity scenarios with export to Europe

Export of large volumes of RES-E from North Africa to Europe can change the development paths for the electricity system in North Africa presented in the last sections. Based on the assumption of the High-RES scenario with a RES-E target of 80% in 2050, five additional scenarios develop the vision of large-scale electricity exports from North Africa to Europe by implementation of quantity mechanism (two scenarios) and price mechanism (three scenarios).

The two scenarios with defined quantities consist of a High-Demand scenario with a total volume of electricity imports of 400 TWh in 2050 and an hourly defined import demand for Southern European countries (Figure 56). The Low-Demand scenario still requires 200 TWh of electricity imports from North Africa to Southern Europe. In the three other scenarios with price mechanisms a specific tariff is given to the producers of RES-E which is exported to Europe. In all scenarios, electricity generation from conventional power plants is not allowed to be increased, but technology portfolio and time of generation for conventional power plants can be changed to supply the overall (domestic and export) demand (more detailed scenario assumptions in section 5.2).

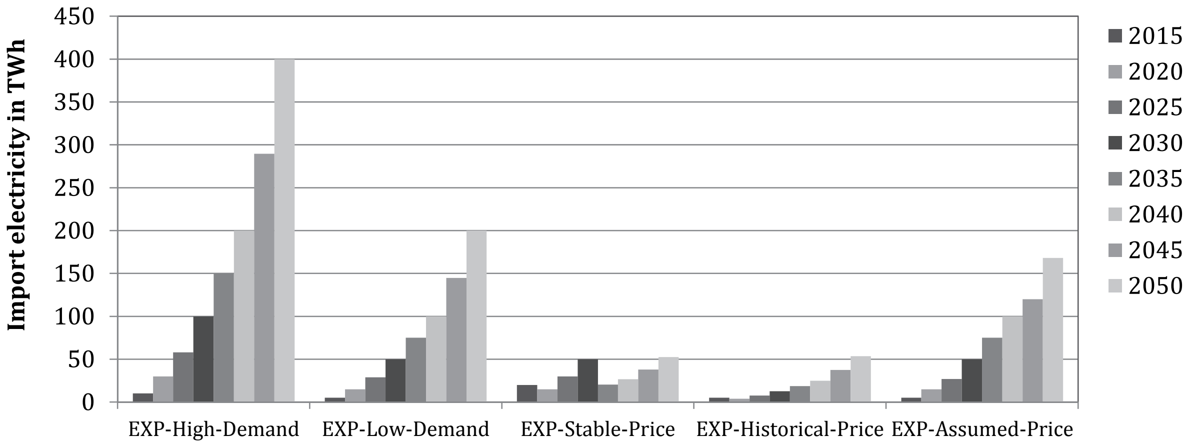

Figure 56: Volume of electricity imports of Southern Europe from North Africa

In the model results of scenarios with price mechanisms, electricity exports also continuously increase until 2050. In 2050, between 52.5 and 168.0 TWh are imported into the electricity systems of Spain, France, Italy and Greece. In the Stable-Price scenario, 52.5 TWh are imported (average offered tariff is 70 EUR/MWh) in 2050 and 53.4 TWh in the Historical-Price scenario (average tariff of 67 EUR/MWh). The Assumed-Price scenario with an average tariff of 94 EUR/MWh creates a pull effect of 168.0 TWh in 2050. The amount of electricity export in the Low-Demand scenario is not reached in the scenarios with price mechanisms. According to the model results, potential tariffs for high export values including costs for transmission and grids have to be above the price of 94 EUR/MWh. Electricity exports continuously increase until 2050. Only in the Stable-Price scenario, the technology shift to CSP leads to decreasing export in 2050. By using more CSP starting in 2035, less surplus electricity is exported in 2035. The tariff of 70 EUR/MW does not provide a pull effect to trigger additional investments in RE capacity in this scenario.

Electricity generation in the export scenarios need to be strongly increased up to 41% compared to the High-RES scenario (Figure 57). In 2050, total electricity generation in North Africa range between 1369 and 1846 TWh depending on the volumes exported to Europe. Contribution share of each RE and conventional technology in the power plant portfolio is similar compared to the High-RES scenario. However, the use of PV is relatively lower in scenarios with fixed demand (quantity mechanism) as a lower electricity demand during daytime is assumed for Europe (due to own solar potentials). In the High-Demand scenario the power plant portfolio consists of 590 GW installed capacity of which 508 GW are based on PV, CSP and wind power.

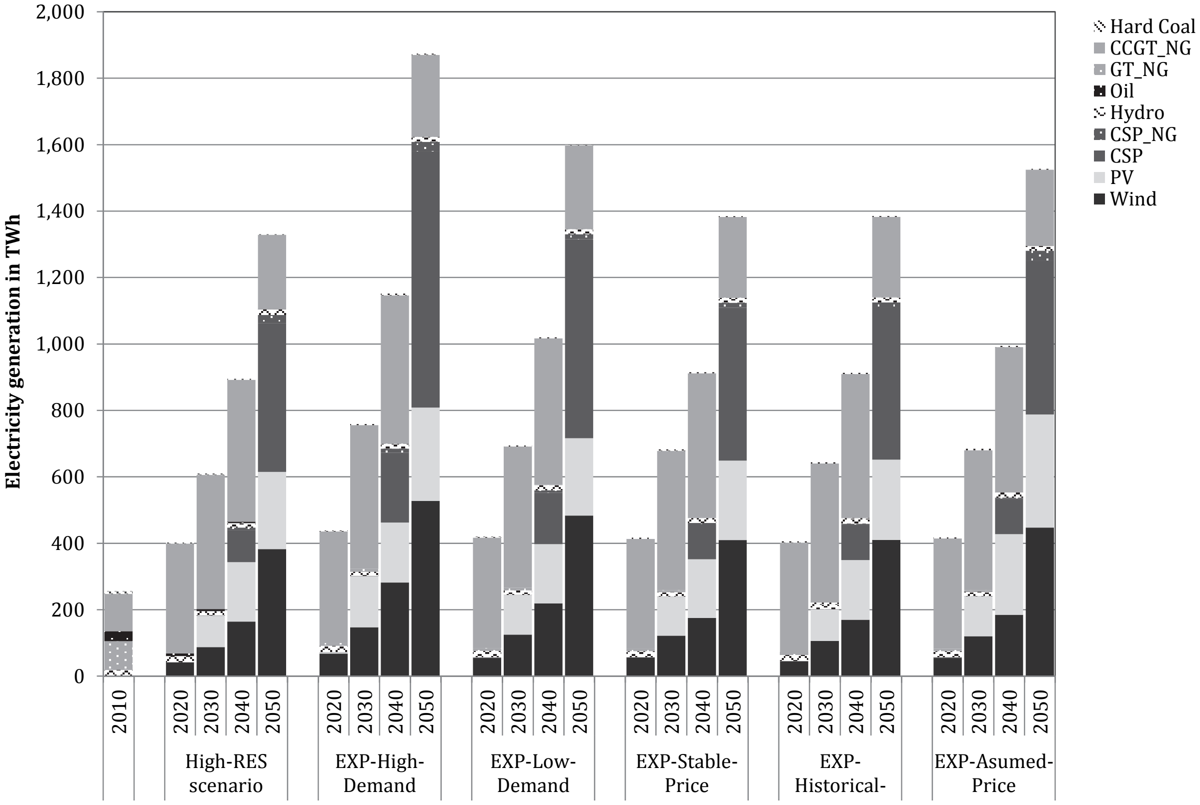

Figure 57: Electricity generation in export scenarios

The technology development paths show analogous phases to the High-RES scenario: Firstly, wind power plants are developed at sites with high average wind speeds. Secondly, PV potentials are exploited in regions with high electricity demand and medium to high irradiation. Thirdly, CSP plants substitute flexible conventional power plants to certain extend since CSP operates more flexibly in the system, but is more expensive than wind power and PV. Electricity generation from CSP is also higher in scenarios with defined hourly demand of electricity exports (High-Demand and Low-Demand scenarios) due to the flexible operation. In the price scenarios, export takes place only during hours which offer a sufficient tariff to the producers. Therefore, fluctuating generation from wind power and PV is higher in scenarios with a price mechanism as production is not mandatory during certain hours and generation costs of these technologies are lower.

In Figure 58, regional distribution of capacity expansion between 2010 and 2050 is compared with the High-RES scenario. As the figures for each scenarios show, distribution of power plants regarding technology selection is similar in all scenarios.

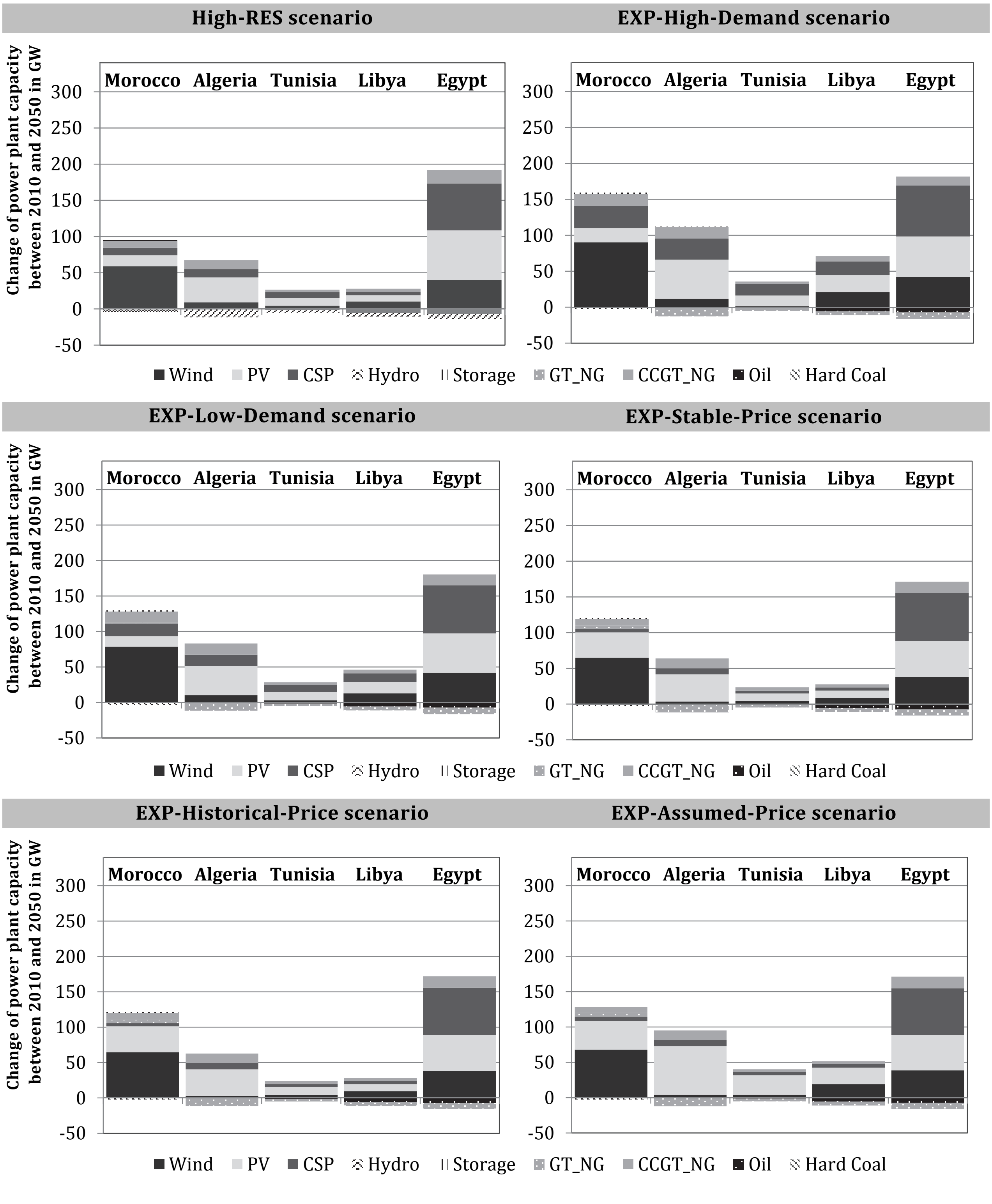

Figure 58: Change of power plant portfolio per country between 2010 and 2050

A defined hourly demand (in High- and Low-Demand scenario) requires higher flexible power plants such as CCGT, gas turbines and CSP plants in the main export countries Morocco, Algeria, Tunisia and Libya (see installations per country). But overall capacities of conventional power plants do not increase in all export scenarios although defined hourly demand is higher (in High- and Low-Demand scenarios). Conventional capacities of around 62 GW seem to be sufficient for the system, also with the increased export to Europe as RES generation is more widely distributed and capacity of flexible CSP power plants is also relatively increased.

Due to its geographical location and a missing direct connection to Greece or Turkey, Egypt has almost a similar power plant portfolio. A few flexible power plants (CCGT and CSP) are moved to Libya to increase the back-up capacity as Libya generates more electricity for export and has a higher RES capacity. Wind power is more intensively constructed in Morocco in scenarios with defined hourly demand as night hours will be more supplied by wind technologies.

More PV capacity is installed in the scenarios with price mechanisms, namely in countries with export connections to Europe (Morocco, Algeria, Tunisia and Libya). Mains reasons are the low generation costs of PV, lower transmission extension to other regions and the tariff structure in the Historical-price and Assumed-price which assume lower electricity prices during the night.

Additional RES projects for electricity export are realized in regions with lower distance to the export targets, according to the model results (Figure 59). Wind farms and PV power plants are significantly chosen in coastal regions to reduce additional grid extensions within the North African countries due to export requirements. However, the possibility to extend HVDC transmission lines directly to regions which are not at the coastal line was not implemented in the model. This option might improve the economic operation of power plants with longer distances to the coast. Wind power plants should be built in Morocco and Libya, whereas PV is mainly realized in Algeria, Tunisia and Libya. CSP power plants are more highly distributed and are mainly constructed at sites with high direct irradiation.

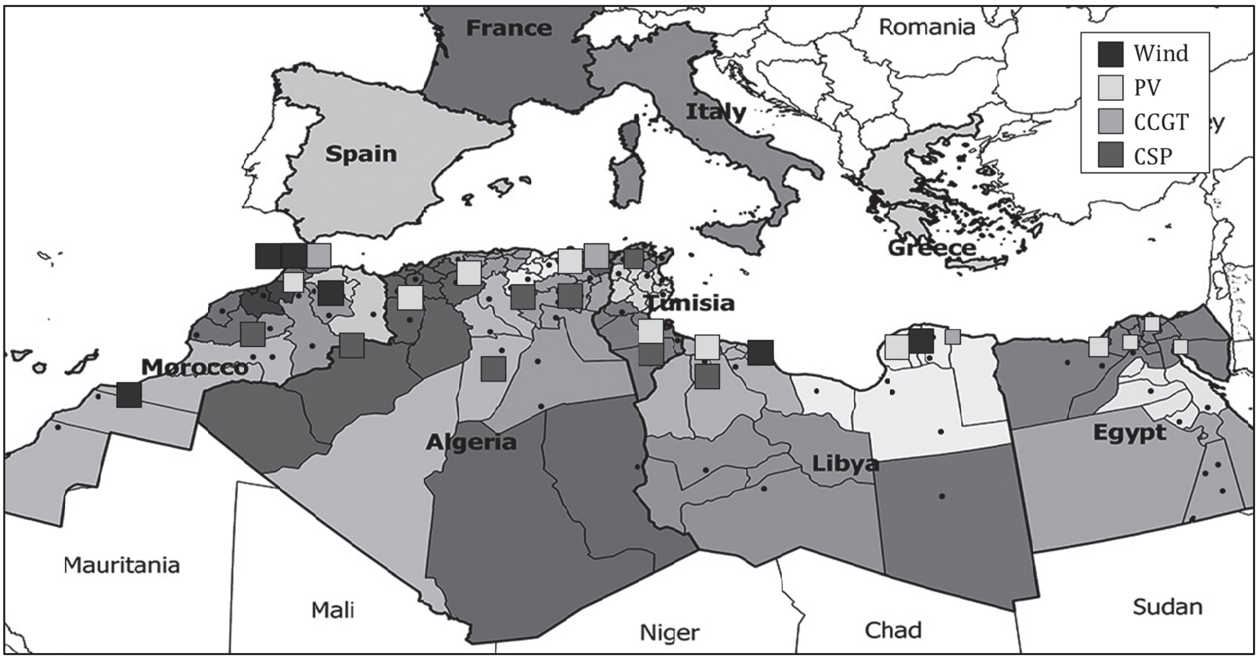

Figure 59: Additional power plant capacities (>+1.5 GW per site) due to export in High-Demand scenario compared to High-RES scenario in 2050 (1 GW = 2.5 mm²

According to the model results, regional HVAC transmission lines and HVDC to Europe have to be expanded in Export scenarios with large electricity export to Europe (Figure 60). In case of limited electricity export (Stable-Price and Historical-Price scenario), new transmission lines between different regions in North Africa are required less than in the High-RES scenario. Due to export of surplus electricity to Europe, electricity exchange between North African countries can be reduced. However, in scenarios with high electricity export regional transmission lines from the South of Morocco and South of Algeria to the North of both countries has to be strengthened. To transport 100 TWh in 2050 to Spain and 120 TWh to France, a net transfer capacity between Morocco and Spain of 35.8 GW has to exist and between Algeria and Spain of 1.8 GW. This line is extended until France with a capacity of 14.4 GW to allow electricity flow from Morocco to Southern France. Further transmission lines are required between Algeria and France with 9.6 GW. Algeria is also connected to Italy with transmission lines with 10.8 GW. The connection between Tunisia and Italy is relatively small with 3.6 GW due to lower RES potentials in Tunisia. Higher transmission capacity is needed between Libya and Italy with 13.6 GW as well as Libya and Greece with 8.0 GW. The availability of these large transmission capacities is required if huge amounts of electricity (200 to 400 TWh) are exported to Europe. The capacity exceeds existing transmission capacity between two countries globally. Therefore, realization of such a grid extension between Europe and North Africa is linked with high uncertainty regarding the future implementation.

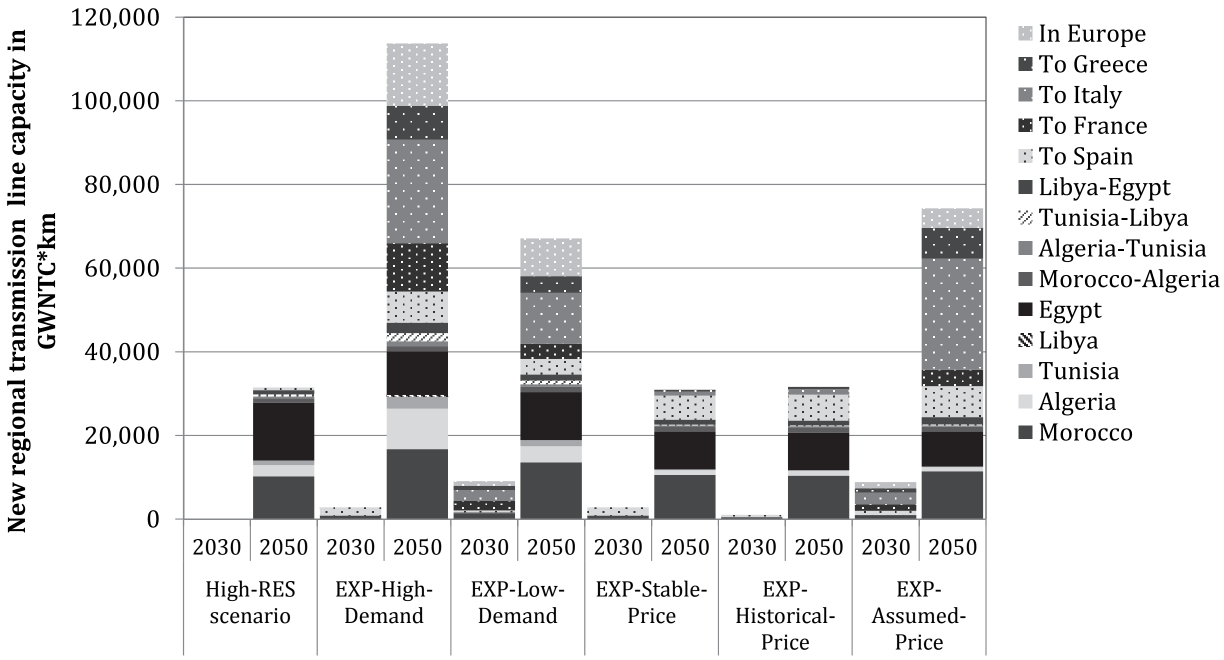

Figure 60: Extensions of regional transmission lines in Export scenarios

In the Stable-Price and Historical-Price scenario, electricity is exported to Spain with 90% to 92% of all exports; costs of transmission to other countries are more expensive and therefore less attractive. In the Assumed-Price scenario, export is more equally distributed between 11% to Greece and 29% to Italy (tariff is however limited to a maximum volume for each country, see Table 14).

Influence of the fixed quantity mechanism and the price mechanism on the average hourly profile of electricity exported to Europe in 2050 is very large (see Figure 61). In the scenarios with a fixed export demand supplied by RES in North Africa, this export profile is identical to the requirements of the assumptions as a predefined demand curve of European countries is supplied.

However, if price mechanisms (with optional use) are applied, the model results show a supply of European demand which depends on the generation costs of the electricity and the specific tariff. Therefore, export of electricity is possible during hours which are preferred by the optimization (optimal for the system and power plants). In case of tariffs using a stable price, a historical Spanish price and an artificially assumed price (with high prices in the morning and evening), the export profile shows a curve which is similar to the PV generation. The offered prices for RES-E from North Africa are not sufficiently defined to get continuous electricity imports during all hours of the day. However, the two scenarios with fixed demand indicate that such a continuous profile for electricity exports is possible. But in these scenarios, overall system costs are slightly higher as another system layout and more expensive generation technologies are required (Figure 62).

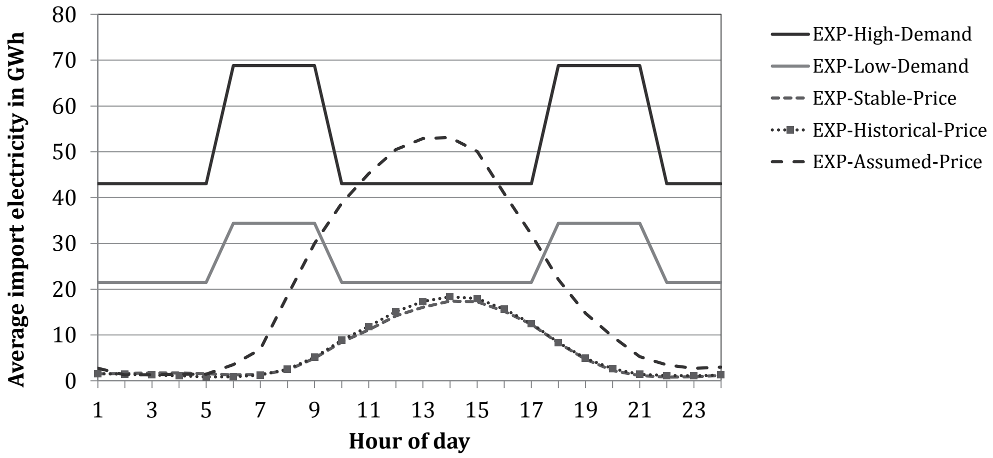

Figure 61: Average hourly electricity imports to Europe in 2050

Total system costs[13] of the export scenarios increase strongly compared to the High-RES scenarios if a fixed demand curve has to be supplied by RES in North Africa (Figure 62). In the scenarios with low export electricity (Stable-Price and Historical-Price scenario), surplus electricity (curtailed in High-RES scenario) is exported and additional RE capacity nearly not realized by the model. Therefore, total system costs are only slightly higher for these scenarios (transmission extension is also very similar, compare Figure 60). Therefore, total system costs of both scenarios until 2050 are only 11 bn euros higher than in the High-RES scenario. Furthermore, the complete electricity is exported to Spain which requires only limited grid extension costs as transmission to Spain is relatively short and based on HVAC. In the other scenarios with high electricity export, costs until 2050 increase between 174 and 713 bn euros correlated with the specific amount of electricity export.

Revenues for electricity export balance the higher costs as annual revenue between 3 bn and 28 bn euros can be obtained by electricity exports depending on the volume and price of electricity export.

Large growth of costs for transmission lines increase the average costs of each consumed MWh to over 91 EUR/MWh in the High-Demand scenario or to 89 EUR/MWh in the Assumed-Price scenario.

[13] Total system costs in this section do not include export revenues which are considered in the objective function of the model to be able to evaluate the scenario with price mechanism.

Compared to costs of RES-E generation in (Southern) Europe, these values seems to be not very attractive (compare also calculation of (Schubert and Möst, 2014)). However, if Europe increases the use of RES-E significantly, costs of own resources might exceeds these values as available own resources decrease, integration costs increase and curtailment of European RES generation can immensely limit a further integration. In such as case, electricity exports from North Africa can be cheaper as RES-E generation is widely distributed and the RES portfolio in North Africa with huge CSP plants is able to shift electricity generation during hours of large demand (compare results of (Zickfeld et al., 2012)).

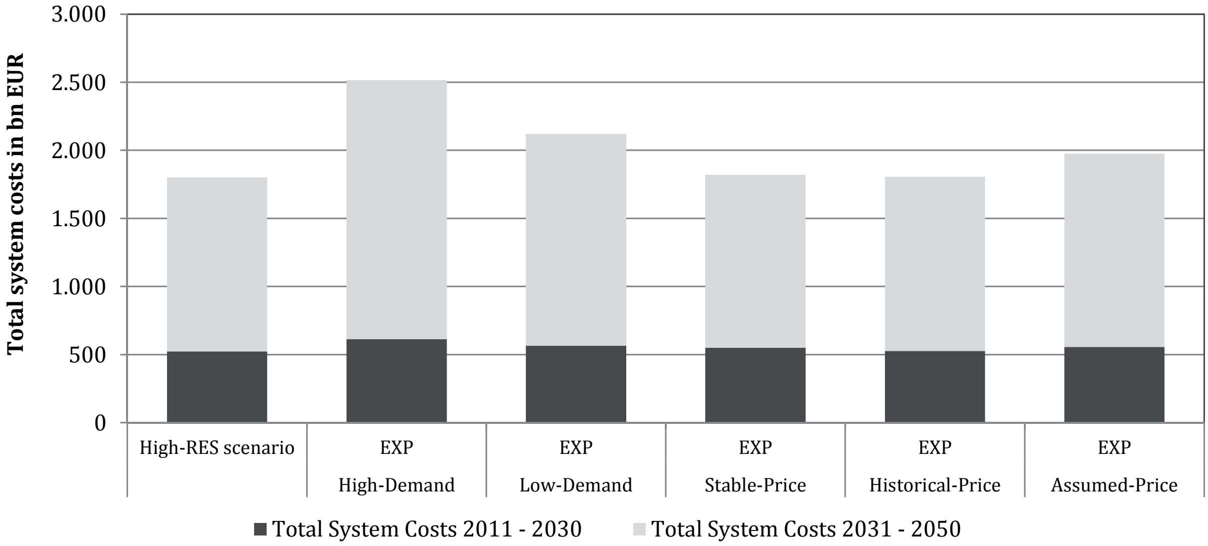

Figure 62: Total system costs of Export scenarios (export revenues not considered)

This huge transmission capacity between North Africa and Europe required in the export scenarios is a key challenging parameter for the realization of electricity exports. A coordinated infrastructure planning with all the technical constraints of the electricity systems is highly necessary, but also a very problematic task as many different stakeholders have to be integrated. From an economic view, a higher integrated electricity market certainly is a benefit. However, financing of these large investments seems to be only possible if a clear business case and regulatory framework exist. As explained in Kost et al. (2011a), in addition to the technical, economic and political barriers of these projects, also the chicken-and-egg problem exists to construct transmission lines in parallel to the construction of the RE power plants in North Africa.

5.9 Discussion of RESlion model and its results

Large-scale integration of RES is analyzed with a modeling approach using site specific scalable RE generation profiles and sub-national regions with demand and grid constraints compared to other models covering the electricity system of North Africa. Generation at many potential sites is evaluated by the optimization taking local demand, grid losses and transmission costs into account. Different development paths ranging from a “conventional” to a “100%-Renewable” solution represent options for the future electricity system of North Africa. The results of the expansion planning problem are only obtained by reducing operating hours. This reduction is necessary to model expansion and operation based on single power plants and transmission lines at a sub-national level in one linear optimization model over a longer time period (up to 20 years). This disadvantage is compensated with a validation of the results by using the detailed hourly operation dispatch which is implemented as two-step approach in one model structure. Direct connection of a full generation dispatch with the expansion planning problem proposed by Nicolosi (2011) seem to be only possible if the problem is simplified in terms of RES generation and regional resolution. The problem is implemented as linear program to include a large amount of input data, a high number of time steps and many different generation capacities in the model. Realization as MIP model would have advantages to specify, for instance, minimum power plant capacity, minimum operational output, start-ups, must-run constraints or part-load efficiencies. But requirements on computing time and random access memory (RAM) are already very high for the LP model approach.

Electricity export to Europe is limited to volumes which continuously increase between 2015 and 2050 to 200 TWh or 400 TWh. Very ambitious scenarios with targets to supply 20% of the European electricity market with electricity from North Africa (compare (Zickfeld et al., 2012)) are not proposed. Furthermore, target countries of electricity exports are Mediterranean neighbor countries (Spain, South of France, Italy and Greece) and not Central Europe (e.g. Germany), see Scholz (2012). Compared to Zickfeld et al. (2012), the European generation capacities and demand is not modeled in RESlion as the detailed model approach requires focusing on North Africa. Results of the Export scenarios have their focus on the effects on the North African electricity system and the technology portfolio under the quantity and price mechanisms. Very large volumes of RES for export (see scenarios of Zickfeld et al. (2012)) may completely prevent to import electricity from Europe. However, electricity imports from Europe into the North African system can beneficially reduce total system costs in the short-term (until 2030) as shown by Brand (2013).

Benefits from a regional integration of North African electricity systems presented by Ben Romdhane et al. (2013) are confirmed by the model results as scenarios with integrated electricity markets indicate higher electricity exchange compared to the National-Markets scenario. Beyond 2030, large grid extensions between countries and regions are necessary to balance fluctuating generation from RES. Nevertheless, RESlion cannot analyze grid extensions, energy flows and optimal positioning of RES in the distribution grid (within model regions). Effects of RES within each region have to be evaluated with specific grid models or models with a more detailed perspective on a single region or country.

In all scenarios with high RES-E shares, costs per generated MWh until 2050 (around 60 EUR/MWh) do not significantly increase as growth of integration costs is balance by technology learning and decreasing costs of RES. The assumption of increasing fuel prices lead to higher generation costs in scenarios based on gas-fired and coal-fired power plants (compare BAU scenario). However, costs per consumed MWh including curtailment and other system costs increase to over 80 EUR/MWh in scenarios with high RES-E share. Since costs of each consumed MWh include costs of system integration such as transmission losses and curtailment, costs of each consumed MWh increase to about values which are 20 EUR higher in 2050 than costs of each generated MWh. Average costs of exported electricity to Southern Europe are calculated at 90 EUR/MWh in 2050 which is above the values of Trieb et al. (2012) with 79 EUR/MWh and Zickfeld et al. (2012) with 57 EUR/MWh.

A variation of total system costs (of+/-20%) also shown by Scholz (2012) are presented in section 5.5.2 and 5.8. As RE technologies are selected very equally in year 2050, technology switches reported by Scholz (2012) due to deviation of technology costs are not foreseen in the modeling results. Prices of PV and wind power have decreased during the last years and will continue to decrease, but remaining cost reduction potentials are much lower. Similar to reality, wind power plants are selected as first choice and PV power plants due to cost reasons afterwards. CSP plants play an important role when dispatchable generation from RES is needed in scenarios with RES-E share above 50% after 2030 (compare Massetti and Ricci (2011)). Further sensitivity analysis on costs (in addition to the Storage scenario and Low-NG-Price scenario) might help to elaborate different price trends regarding fuels and technologies in North Africa. Especially the role of coal-fired power plants might be another conventional option in scenarios without CO_2 price and increasing natural gas price. In contrast to the model results, additional power plants running on gas turbines may be necessary in the system to provide more reserve capacity. With more detailed model approach including time resolutions of a few minutes or 15 minutes intervals in the model, the need for more gas turbines should be analyzed for system conditions in 2030 to 2050.

The power plant portfolios of RES consist of a very stable generation share of PV, CSP and onshore wind power (approximate technology ratio is 3/4/3) in year 2050 of all scenarios. Technology choice of Zickfeld et al. (2012) with 70% wind power installations and Scholz (2012) with 85% generated electricity from CSP cannot be confirmed by the North Africa scenarios and Export scenarios. Different geographical and technological coverage as well as time resolution of the model might be reasons why this confirmation is not possible. Certainly, twists and turns of real energy planning will slightly change the optimal solutions, which assume a central social planner, perfect foresight, an integrated electricity market and a common RE strategy. Scenarios with national tendencies (such as the National-Markets and the National-Targets scenario) show higher system costs due to higher RE installations in Algeria, Tunisia and Libya. Compared to an integrated market, more wind farms and PV projects are installed in these countries.

Projections of hourly electricity demand in each region clearly contain some uncertainty, but this problem can only solved by regional hourly demand data which are not available. Specific daily demand curves of regions with high electricity consumption from industry or with other regional specifications influence course and height of demand and consequently change capacity and use of RES within each region. However, the used approximation for regional demand offers an analysis on a sub-national level by considering economic, social and geographical differences between regions. By considering grid constraints, optimal site selection is not only related to highest natural resources such as wind speeds and solar irradiation. Sites for PV are not chosen in areas without local electricity demand. Instead to desert areas, sites in regions with high demand (metropolitan areas) are selected in scenarios with and without export. In export scenarios, PV installations at coastal areas have a higher priority than sites with long distances to export transmission lines. High curtailment of PV generation limits a larger expansion of PV beyond 2030 although generation costs of PV are very low. Potentially, demand-side-management can create additional demand during hours of high solar feed-in. However, lower prices for storage systems do not increase the installations of PV fundamentally.

6 Model development for socio-economic impact analysis

6.1 The idea of combining a cost-optimized electricity system with a socio-economic analysis

An electricity system with a high share of renewable energy is modeled and analyzed in chapter 5 by minimizing overall system costs, which include the most relevant costs caused by electricity generation and transmission. Large-scale deployment of RE technologies in North Africa creates important economic effects and industrial progress due to extensive infrastructure investments in new power plants. Additionally, investments will be undertaken to create production facilities where components and products for the new RE power plants are manufactured. If continuous RE deployment is realized, these activities can cause significant increase of technology know-how and are expanding employment in the renewable energy sector. For policy makers in North African countries, economic growth and socio-economic opportunities such as employment creation resulting from local value creation and manufacturing in different renewable energy sectors might be important decision variables when determining an optimal electricity system of the future. Hence, the most cost-efficient development scenario for the electricity system is not expected to be chosen by policy makers if it does not show a positive impact on creation of new industries and positive effects on the labor market. Instead, scenarios with a positive impact will be considered as preferred options. Therefore, the most conceivable objectives are a trade-off between a cost-optimized electricity system and business opportunities in new industry sectors.

Optimization models of electricity systems typically incorporate economic factors such as costs of energy systems. Socio-economic effects for the society and very specific future economic outcomes in terms of know-how creation or establishment of new industry branches are often neglected in the process of proposing future electricity scenarios. Foley et al. (2010) indicate a trend to include socio-economic and environmental effects in the modeling analysis, but this trend is mainly based on considering CO_2 emissions or policy effects in the model approaches. A direct link between socio-economic effects and optimal RES-E scenarios can be rarely found in the literature. Nevertheless, historical assessments of the impact of RE deployment are frequently reported as for example O'Sullivan et al. (2013) analyze the impact of RE on job creation in Germany by calculating 377,800 jobs in the RE sector in year 2012.

For Europe, the study *Employ-RES* presents model results of the impact of RE deployment by calculating employment and economic growth created by renewable energy in the European Union. Four RES-E scenarios (based on different policy frameworks and market assumptions of RES-E) are connected with large macro-economic models to obtain gross-employment effects per European country as a result of the different RE deployment scenarios. The study concludes by highlighting an "increased confidence in the economic effects of RE" and a future increase of economic benefit, but also adds some forecasting limits due to uncertainties in terms of general energy forecasts, economic uncertainties, modeling assumptions and model interactions (Ragwitz et al., 2009). The findings of the study are strongly connected to scenarios which represent different policy frameworks and overall market assumptions. Specific findings for each RE technology such as technology or component specific development paths of industry and employment are particularly not shown in the study. Furthermore, it remains unclear how existing industry sectors, available technical know-how and national characteristics influence the economic and socio-economic results of the study.

Therefore, this thesis proposes a new approach of linking an energy system analysis with a calculation of company sales and employment in the renewable energy sectors. Scenario results of the energy system analysis (annual installations of RE power plants per country) are used as input (market demand per technology) in a second model to evaluate sales and employment in each scenario. This model is developed as a decision model which helps to determine whether and when manufacturing and value creation of components as well as provision of services can be expected for a certain technology according to a given technology know-how and industry performance while considering dynamic temporal national and international developments. The model is based on the status quo of the national industries in North Africa by considering existing industries and available technical know-how. Finally, the model calculates the number of jobs and the volume of sales in the renewable energy sector caused by RE technologies in each scenario. This approach offers the opportunity to analyze technology and country specific results of each scenario regarding their potential of local value creation. There are several methods that can be used to compare the results of the electricity market and socio-economic analysis. They can be compared qualitatively or by methods such as cost-benefit analysis. Higher system costs for a certain renewable energy setting could be balanced with positive effects from the labor market as one technology could give more benefits to a country or region in terms of GDP increase or job creation. This might result from the economic development of the country as well as from the technology specification regarding the manufacturing process of components and equipment for one technology. Such a specific technology selection based on different macro- and microeconomic effects could play also a role for RE technologies.

For Middle East countries, van der Zwaan et al. (2013) also connect the output of an energy system analysis with an employment study, but their approach uses fixed assumption regarding the local impact of each technology, whereas this approach uses a dynamic decision model for calculating temporal potential for each year.

Initially, the model is developed as a tool to describe the value creation potential of CSP in North Africa. The model is published as *Solar Technologies Market Development Model (STMD)* in a study for the World Bank (Fraunhofer and Ernst&Young, 2011) and in an Energy Policy paper (Kost et al., 2012g). In this paper, model approach, key equations and input parameters of STMD are summarized roughly. Different market sizes of CSP are analyzed regarding the impact on (local) manufacturing and employment.

In this thesis, the model approach is described in detail by considering the link with the RESlion. The model is also extended to include PV and wind power. The model name is changed to *Renewable Energy Technologies Market Development Model (RETMD)*.

The following essential model extensions are included in RETMD model compared to the STMD model:

- Modeling of impacts from wind power plants
- Modeling of impacts from PV power plants
- Integration of new findings regarding the North African industry capabilities
- Extension of technological assumptions (costs, employment effects)
- Model output: component and country specific results
- Common model results over all RE technologies in North Africa possible

By adding all of these extensions to the basic model, RETMD is able to provide a complete analysis of manufacturing and employment impact for different electricity scenarios in North Africa. Only by providing country and components specific results, socio-economic impact of the technologies in each country can be analyzed.

An overview of the relation between the energy system analysis with RESlion and the assessment of the impact on manufacturing and employment with RETMD is given in Figure 63.

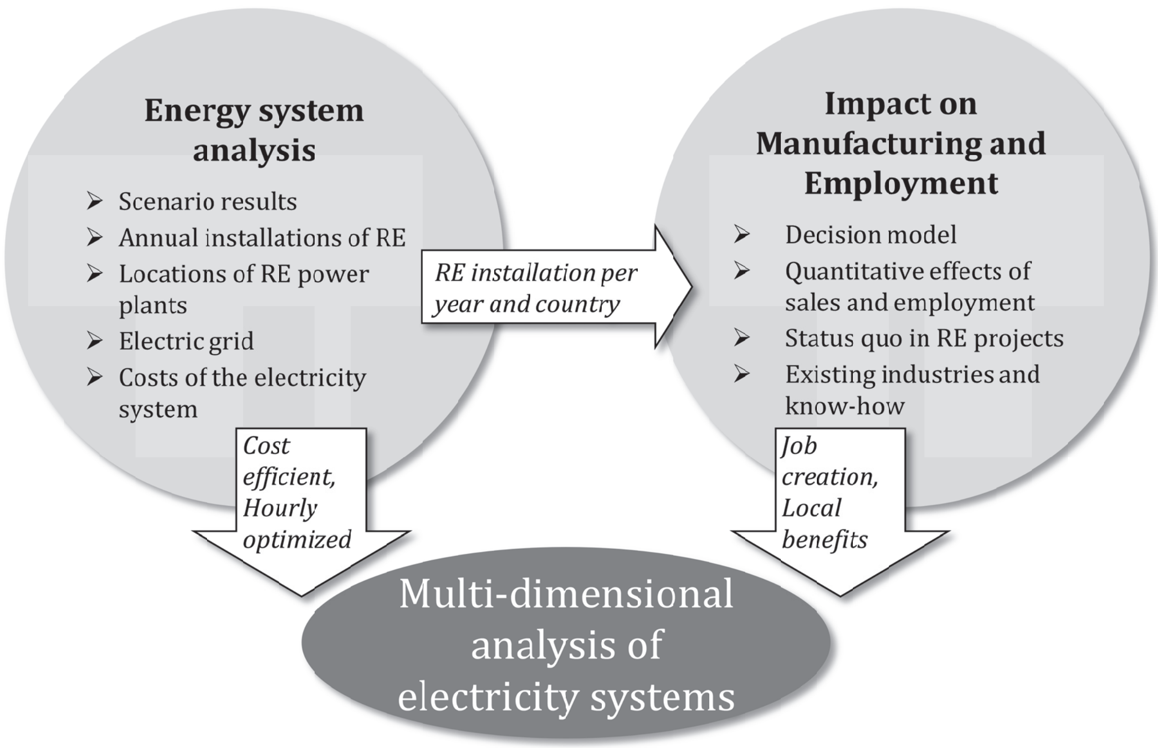

Figure 63: Scheme of the multi-dimensional analysis of the electricity systems in North Africa

Compared to the decision variables in the electricity market model RESlion (minimization of overall costs of generation and transmission), additional criteria for the development of the future technology portfolio in the electricity market can be considered.

The following issues can be included in an assessment of manufacturing and employment:

- Existing industry performance in sectors related to a specific RE technology
- Local industry involvement during construction and implementation of RE projects
- Sales due to component manufacturing and service contracts
- Employment created by power plant installation and component manufacturing
- Attractiveness of international investments in new production facilities
- Potential to increase available or non-existing technology know-how for a specific RE technology

Evaluation of these issues in addition to cost minimization in the electricity sector clearly supports the analysis by obtaining economic and socio-economic data of different deployment paths (multi-dimensional analysis). As technological requirements, industry structures and market conditions differ for each technology, the optimal technology choice and technology portfolio also depend on factors mentioned above.

This chapter is structured as follows. First, a theoretical introduction into the field of economic and socio-economic effects by manufacturing of RE technologies is given. Then, the model is presented by describing the model approach. Third, assumptions and data inputs included in the value creation analysis are summarized. Results of the value creation analysis of RE technologies are then presented for each scenario in the next chapter which highlights technology and country specific findings as well as the link to results of the electricity market scenarios.

6.2 Literature review and terminology

Positive effects of local value creation or local manufacturing of RE technologies are a frequently mentioned argument during decisions on support schemes for renewable energy or during processes of investing into specific projects or technology (IRENA, 2011). As subsidies for the market introduction of RE technologies were necessary in the past, policy makers justified these subsidies with the argument of additional national value creation and employment growth caused by locally manufactured components and the installation of the RE plants. Some countries decided to carry out a strategic large-scale deployment plan which created a long-term and stable market demand. This demand has led to important technology developments and the creation of large industries in some countries.

Policy driven achievements can be identified exemplarily in countries such as Denmark, Germany or India (Kost et al., 2012g). These countries tried to create local markets and a local industry base which manufacture products for the local and international RE market. In Denmark, industry development in the wind power sector was pushed and supported by different actions to launch important wind technology innovations and industry growth in a relatively small country (Buen, 2006). Germany with its ambitious RE targets created a wind and PV industry over the whole value chain. Politics triggered the market by the creation of the Renewable Energy Act (EEG - Erneuerbare-Energien-Gesetz) which promoted a broad market introduction of wind power and PV. This offered the opportunity of large employment creation in the renewable energy sector (Frondel et al., 2010). Later in time, India set up a local wind industry with a second mover strategy after the establishment of a wind industry in Europe.

India's market development of wind farms was facilitated by the acquisition of technology licenses. The Indian company Suzlon required manufacturing licenses from international competitors to start production of wind turbines for the Indian market. By achieving larger production capabilities, a renewable energy industrial sector was created in an emerging country (Lewis and Wiser, 2007). Creation of new industry sectors in all three countries was only realized by long-term governmental targets and a specific focus on certain RE technologies during the planning and decision processes regarding a future energy system based on renewable energy.

To analyze how new manufacturing capabilities and employment can be created in the national economy and how local industries are involved in the market introduction of renewable energy technologies, a closer look into the existing industry structure of the countries and the value chains of RE technologies is necessary. Additionally, the typical structure of RE projects should be characterized as it is specific in terms of cost and operation (Figure 64). A high share of project costs is spent for very specific components during the construction of RE power plants. Another high share is required for secondary equipment such as support structures or electrical components and installation of components and equipment on site. These initial costs represent a very high share of the total project costs as the expenses during operation such as fixed or variable operation costs over lifetime are relatively low[14]. That means that construction and installation create a higher economic impact compared to the operation. In contrast to RE projects, the cost structure of conventional power plants shows cash flows with higher expenses over total lifetime as cost for fossil fuels appears regularly.

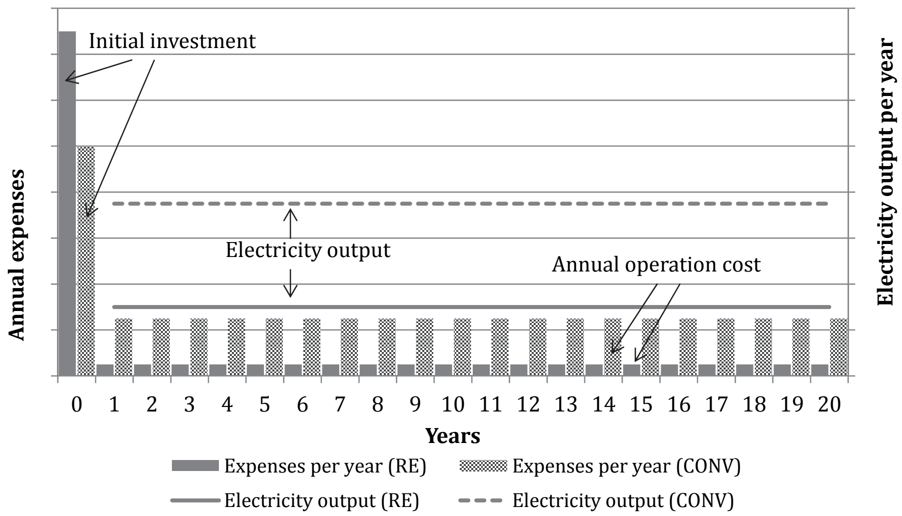

Figure 64: Schematic graph of annual expenses of RE power plants and conventional power plants

In case of high RES deployment, large demand for specific RE components and equipment creates new business opportunities of local production and component manufacturing. Therefore, political stakeholders aim to realize local manufacturing potentials by increasing investments in new production facilities or to secure the involvement of local industries during the construction of new RE power plants. This target is also identified and highlighted in the study *"MENA Local Manufacturing Potential of CSP Projects"* (Fraunhofer and Ernst&Young, 2011). As shown for countries like Denmark, Germany or India, the creation of new production

[14] Exception: biomass has a similar project structure as conventional power plants.

facilities are subject to many political, economic and social framework conditions which clearly impact the development of these capabilities. In literature, analyses of (local) value creation are mainly focused on two aspects: Firstly industry involvement and company sales in the value chain of a certain technology are assessed; secondly employment effects as a result of a market development are evaluated (Caldés et al., 2009; TERI, 2010; Deloitte, 2011; Fraunhofer and Ernst&Young, 2011; del Rio et al., 2012).

In recent literature, different methodologies can be found to analyze socio-economic impact such as employment effects. Analytical studies based on direct industry surveys are conceived to be more suitable for regions with less available data. Forecasts of job creation based on different RE scenarios are calculated in these studies by using employment rates for each technology. Another approach is to use input-output analysis to assess the macro-economic relations between different industry sectors. Input-output analyses are often applied to national or international studies with a sufficient macro-economic database (Lambert and Silva, 2012). Only one analysis in the literature uses input-output tables and examines renewable energy sources in North Africa: (de Arce et al., 2012) simulate the macroeconomic impact of a long-term RE scenario in Morocco with a forecasting period until 2040. For PV, CSP and wind technologies, the authors calculated an economic impact on the GDP between 1.21% to 1.99% in 2040 coupled with employment effects between 269,252 and 499,000 jobs in Morocco (de Arce et al., 2012).

Employment rates are often applied to calculate long-term job effects of RE projects for given market deployment scenarios. Employment rates per MW, per produced electricity (MWh) or per investment (million euros) indicate the number of jobs which can be created by RE projects. Unfortunately, a broad variety of these employment rates exist for each technology as different data, industry structures or research scopes are important underlying factors to obtain these rates. Rutovitz and Atherton (2009) summarize employment rates for electricity generation technology in different countries of the world. The specific findings of (Rutovitz, 2010) for the South African market are a benchmark for North African countries although the economy of South Africa is more competitive compared to North African economies. The main difference compared to world data of Rutovitz and Atherton (2009) is the use of a regional multiplier which increases the number of jobs compared to industrialized countries by a factor of 2.15 (Table 57, appendix). It can be observed that employment rates per MW are continuously decreasing over time, same as technology costs decrease due to technological progress.

As summarized in Kost et al. (2012g), technology specific value creation of CSP is discussed in different studies. An often used approach in CSP related work is the *Jobs and Economic Development Impact (JEDI)* model by NREL which is based on input-output tables to calculate direct, indirect and induced economic benefits and job creation (NREL, 2013). Two papers for the US states New Mexico and California analyze the influence on local economies from a CSP market development in the regions (University of New Mexico, 2004; Stoddard et al., 2006). In the paper of Stoddard et al. (2006), the number of jobs during operation of CSP plants exceeds the number of jobs in a conventional power plant by 93 to 56 (for a specific power plant capacity of 100 MW). However, this absolute number of jobs does not provide any information about the quality level of jobs (unskilled/skilled workers). Especially in CSP plants, a large amount of workers is required to maintain and clean the solar field. Caldés et al. (2009) calculated the number of jobs in the Spanish CSP market between 2007 and 2010 (~500 MW) with 63,485 direct and 45,508 indirect jobs also using input-output tables of Spain. Compared to the approach of using input-output tables, (Vallentin and Viebahn, 2010) presented a bottom-up approach which indicates the origin of components to calculate the market share of one country (Germany) in the world market while connecting it with a long-term projection approach about the future development.

So far, it is not proven which approach or method generates the most reliable results regarding best estimates of job creation based on market introduction of RE technologies (Lambert and Silva, 2012). Moreover, there are considerable constraints to compare results and findings regarding potential sales and employment effects in a region or country as methodologies, assumptions and long-term projections are differently defined in each study (Llera et al., 2013). Market scenarios, technology and component parameters, coverage of value chains and development of technology costs are assumed differently. However, they influence overall study results as strong dependencies exist between the different assumptions. Also, the definition of “direct jobs”, “indirect jobs” and “induced jobs” is used differently in the studies. Several sources suggest that job effects from market introduction of RE technologies are positive as conventional power sources are less labor intensive (Llera et al., 2013). But following the paper of Lambert and Silva (2012), no general rule or result can be postulated whether the market growth of RE technologies is always correlated to positive or negative employment effects.

In this study, following terminology is defined in analogy to (Rutovitz and Atherton, 2009) and (Fraunhofer and Ernst&Young, 2011):

- ***Local manufacturing / local value creation***: The terms “Local manufacturing” or “local value creation” represent the local contribution of national industries in terms of sales and employment due to local production or provision of services. “Local” indicates all effects from business activities of a local company or industry on a local workforce. The analysis of sales and jobs is broken down for each component, but is not subdivided further into materials or equipment. Instead total sales and jobs of component production are declared as “local” if the component is produced locally, although raw materials or machines might be purchased from an international company.
- ***Full-time equivalent (FTE) jobs***: The number of jobs created by a RE project is often expressed by the number of full-time equivalent jobs. All jobs are standardized to a number which summarizes all jobs to full-time jobs of one year (Example: 10 workers are employed fulltime for two years of construction; 20 FTE jobs are created totally.).

6.3 Data acquisition and further studies

Due to the demographical and political development in recent years, job creation and economic growth in North Africa are crucial for the economic and social situation (Estache et al., 2013). Therefore, several studies focus on economic and socio-economic impact of renewable energy in North Africa. An important issue is to identify the potential of local industries to produce components for the RE market. In 2006, ERC (2006) reported first findings of an interview based analysis of the manufacturing potential in the renewable energy sector with 84 companies which should estimate short-, medium- and long-term possibilities to produce components of PV, CSP, wind power, biomass and solar heater technologies. This paper finds different opportunities in the value chains of RE technologies to produce components in Egypt locally.

An international comparison for competitiveness of North African economies in the field of solar technologies is presented by del Rio et al. (2012). The authors evaluate attractiveness on a global level as very low compared to developed countries by using competiveness indicator in the field of production, demand, risk and business environment. Additionally a significant gap between the attractiveness of North African economies and other countries such as South Africa, India or European countries is identified. The study concludes that some companies in selected MENA countries such as Egypt and Morocco could become potential players in the regional PV and CSP component industry (del Rio et al., 2012). However, the local industry faces a lot of problems to become potential player in the solar market as sufficient market size and local capabilities as well as international competiveness are not given for Morocco (Mahia et al., 2014).

However, data on local manufacturing potential of CSP, PV and wind power in North Africa are relatively limited. In different research projects between the years 2010 and 2012, in-depth expert interviews with political stakeholders, companies, industry associations and researchers in Europe and North Africa have been carried out by the author of this thesis and colleagues[15] from the Fraunhofer ISE. With interviews, a large range of data related to manufacturing of renewable energy in North Africa was collected. Before providing an overview of the different research projects, the general approach for the interviews and data collection is explained.

The general approach used in all studies is based on qualitative interviews with experts from the existing and potential RE sector. Experts are recruited from the whole value chains with very different background and experiences in the markets of North Africa. For each technology or component, experts from international markets and from North African industry sectors are surveyed. Partly, the interviews are very specific to a certain component of a technology as a company normally produces only specific components of each technology. Some experts (such as experts from engineering or construction companies) provide a more general overview for a certain technology.

All expert interviews (face-to-face or by phone) took between 30 and 60 minutes. Standardized questionnaires are used with the option to add specific open questions (problem-centered interviews, compare (Witzel, 2000)). The standardized questions cover general topics of the North African market for RE technologies, the status-quo of local manufacturing in current RE projects and the potential for local companies to produce components. Each expert should identify components which high/medium/low potential to be locally manufactured in North Africa. Furthermore, each export from the industry should explain production processes of its products for the RE market or existing production processes that can be used to produce components for wind power, PV or CSP plants. Open questions are used to detail very specific information on the production processes, technology costs or employment data of a RE component or technology. Some of the interviews are recorded to facilitate evaluation of the interviews.

The interviews are evaluated by using a clustering method for specific theses and statements which are repeated by several experts. Especially, opinions of local and international companies regarding local manufacturing potentials are compared to assess the expectations of companies which are active in the local market and which are active in the international market. Specific data are collected for each component or technology. These data are compared with literature data which are available for international RE markets or projects.

[15] Maximilian Engelken, Jessica Thomsen, Noha Saad, Thomas Schlegl and Thomas Fluri

In addition to the data, four main results are extracted from the interviews as input for the RETMD model:

- Production process of each component is rated regarding its technical and economic requirements.
- Existing technical know-how for each component in each country is rated.
- The status-quo of local manufacturing in current RE projects in North Africa is available.
- Future expectations on potential investment in production capacities are summarized.

These four findings are directly implemented in the RETMD model (see section 6.4 and 6.5). The interviews were carried out in the following research projects.

In the study *"MENA Assessment Local Manufacturing Potential of CSP Projects"*, the local manufacturing of CSP is assessed by personally interviewing about 50 experts in the North African countries (Fraunhofer and Ernst&Young, 2011). During this study, interviews with 20 companies from Europe and North America represent the international perspective on the CSP market. The findings of these 20 interviews are summarized separately in two further papers to conclude on experiences and expectations regarding international direct investment in new production facilities and potential for local manufacturing of CSP components (Kost et al., 2011b; 2012g). Based on all of these 70 expert answers, the CSP components are rated regarding their production complexity and their potential to be locally manufactured within a time horizon of 20 years from now, see Figure 65. Within the interviews of the study *"MENA Assessment Local Manufacturing Potential of CSP Projects"*, companies from other RE sectors are also interrogated as the specific CSP experiences and existing production facilities are very limited in North Africa today. Therefore, companies involved in first wind farm projects (in Morocco, Tunisia and Egypt) participated in the interviews as well.

During this study mentioned above, the first model development of STMD was carried out by implementation of findings for CSP (compare Kost et al. (2012g)). However, the approach and the data are adjusted for this thesis after the following projects.

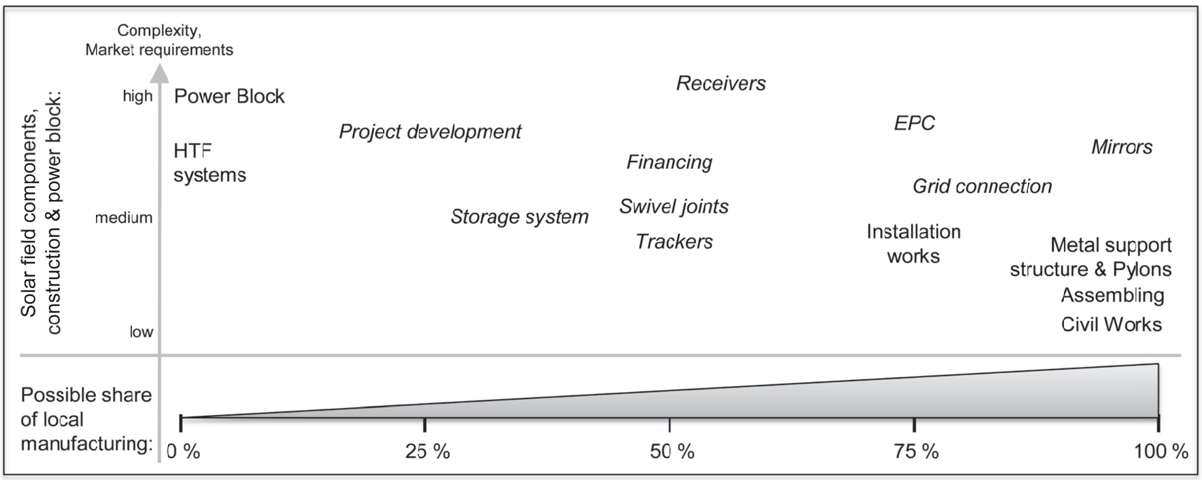

Figure 65: Summary of industry view on local manufacturing potential of CSP components in North Africa (Kost et al., 2011b)

During 2011 and beginning of 2012, a second series of research projects related to local value creation was conducted in Morocco and in Egypt. Model input regarding the potential of solar technologies is obtained by 55 interviews in Morocco and 15 interviews with the international PV industry. A similar approach and evaluation method (described above) is used for these interviews. PV manufacturing potential in emerging countries such as Morocco is identified in the paper (Kost et al., 2012c) and in the report *Support for Moroccan Solar Plan, Solar Technologies in Morocco – Industry and Value Chain Assessment* (Kost et al., 2012f) for the *Moroccan Agency for Solar Energy (Masen)* and *Gesellschaft für Internationale Zusammenarbeit (GIZ)*. However, in both publications the STMD (or RETMD) model is not used. Instead of using the model, the qualitative results of interviews for each component are presented. But results of both projects are used for the extension of the STMD model to the RETMD model in this thesis as PV specific information is obtained.

In Egypt, a local manufacturing assessment of CSP, PV and wind technologies for the *New and Renewable Energy Agency (NREA)* was undertaken in the project *Combined Renewable Energy Master Plan for Egypt* which was commissioned by KfW Bankengruppe in 2011. In this project, about 30 direct interviews with Egyptian industry were realized (by using a similar approach) to elaborate potentials for the industry to locally produce components and to provide services for CSP, PV and wind power projects. Similar to the projects before, RETMD model is also not used during this project. As key outcome, information and data regarding wind technology are available and can be used for the extension.

6.4 Model description of RETMD

6.4.1 Model objectives

Objective of the Renewable Energy Technologies Market Development (RETMD) model is to assess the dynamic potential of value creation in terms of sales and employment effects of PV, CSP and wind power projects. A quantitative model and decision tool endogenously provides a decision when and to what extend a component or service of a RE power plant is provided by a local or international company in North African countries. RETMD is a model extension of the Solar Technology Market Development (STMD) model which is created as bottom-up approach for CSP and which runs in Excel. The STMD model simulates the long-term and dynamic impact of local value creation in terms of economic benefit and employment effects for North African countries (Fraunhofer and Ernst&Young, 2011; Kost et al., 2012g). The *Jobs and Economic Development Impact (JEDI)* model by NREL serves as important input for the model development as it provides the possibility to assess economic impact and job creation of a single power plant on a component specific basis by using regional input-output tables. Compared to JEDI, RETMD can carry out a long-term scenario analysis with a project pipeline over twenty years. Dynamic increase of local manufacturing such as new business creation and adaptions in the industry is included in the model approach. Regional input-output tables are not applied to the problem as updated macroeconomic data for North African countries are not available. Structural changes with strong GDP growth over the last 20 years and uncertainties regarding the interactions between different industry sectors would make an analysis with input-output tables more difficult.

The component specific decision regarding local manufacturing connects a know-how based decision with a market-based decision. The long-term projection includes a cost and employment forecast for CSP, PV and wind power which is modelled by using learning curves (see also approach of Llera et al. (2013)). Additional economic impact which results from electricity sales during operation of the power plants and expenditures for public research is not considered in the model.

The decision tool uses two important findings from the research field of location planning and relocation of production facilities. The investment decision for new production facilities is often influenced by actual market demand and level of industrialization which includes aspects of available resources and existing technology know-how (Kinkel, 2009). Both issues are implemented as key decision parameters in RETMD. Stable market demand and a continuous project pipeline of RE installations are also reported in the experts interviews as the most important drivers for localization of component manufacturing in North Africa (Kost et al., 2011b). Therefore, results of RETMD strongly depend on the underlying market scenario.

6.4.2 Model structure and decision modeling

For each technology, RETMD covers the main components and services of the value chain. As described in section 6.3, interviews with stakeholders from industry, research and government provided qualitative and quantitative input for existing business sectors, specific requirements on production processes and production factories, available technological know-how and the status quo of local manufacturing in recent RE projects in North Africa. Installed capacity per technology and year serves as market demand in the RETMD model (see model structure in Figure 66). For simplicity reasons, only one reference power plant per technology is implemented in RETMD although in reality a variety of technology designs and technology options are possible. Each reference power plant includes a detailed description of the technology design and power plant data regarding components and services for which a breakdown of costs and number of jobs is implemented (see section 6.5.1).

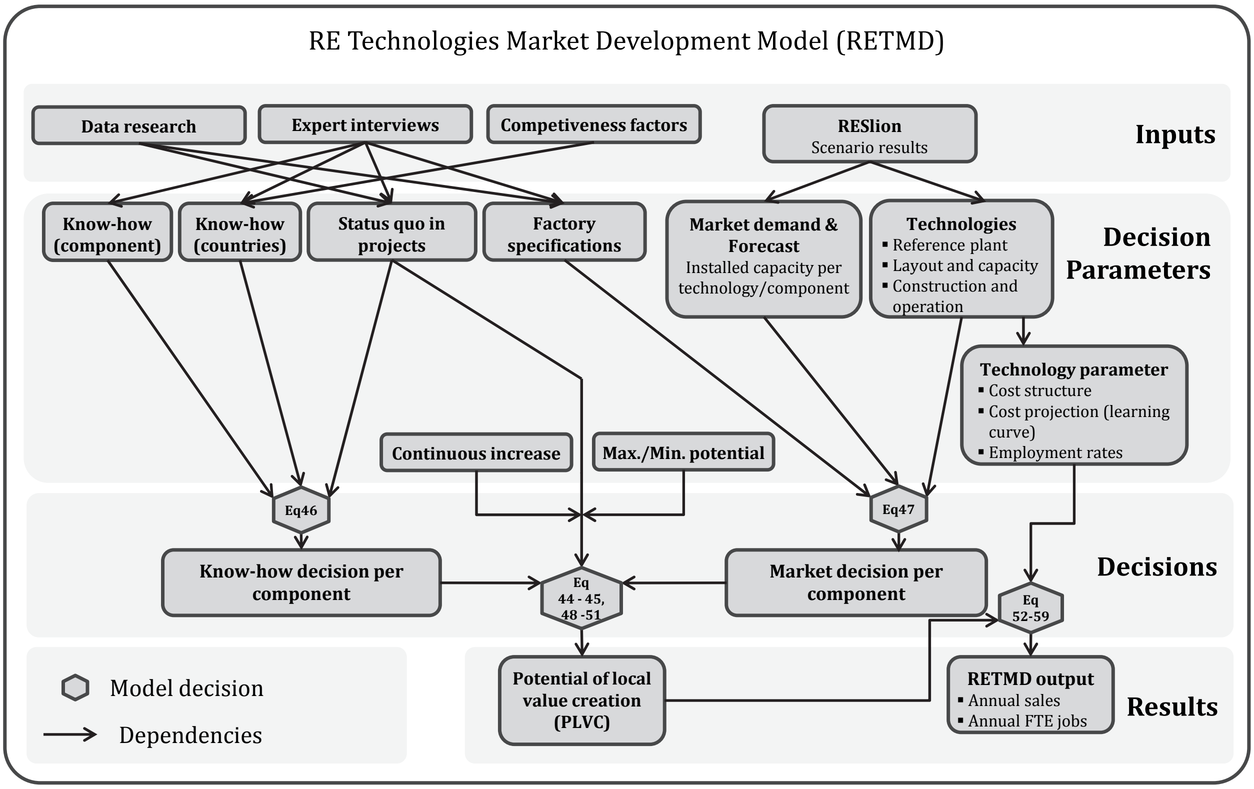

Figure 66: Model structure of RETMD

The model covers all items in the value chain which are necessary to construct and operate power plants: all (large) components, engineering services, financing, power plant erection and installation, operation and maintenance. Employment effects in terms of FTE jobs are derived from dynamic employment rates per component or service. The model is implemented for CSP, PV and wind power and applied to the North African countries (Morocco, Algeria, Tunisia, Libya and Egypt).

First model development (including equations) and model parameters for CSP are published in (Kost et al., 2012g). The model description is now extended, some model dependencies are adjusted and additional calculations are added to obtain a component specific decision model for wind power, CSP and PV.

To quantify the annual (local or international) sales and employment over the total value chain, the model calculates the potential of local value creation (PLVC) per component/service or technology as share of the total value creation as one of its key model outputs. In the following, the model equations and data input of RETMD is explained. In the model, a component/service (n) specific decision regarding PLVC in each country (c) is made based on a know-how based decision and a market based decision for each year (t). In case of t = 0 (respectively in the year 2012), $PLVC_{n,c,t=0}$ is equal to the status quo of local manufacturing ($SQ_{n,c}$) which is determined by data research and direct interviews related to real-world projects in North Africa in the years 2010 to 2012.

$$PLVC_{n,c,t=0} = SQ_{n,c,}$$

(Eq 44)

The future development of PLVC (with t > 0) is subject to two basic requirements which have to be fulfilled annually (decisions in the model). Only if a know-how based decision and a market based decision for PLVC are positive, PLVC can be increased from the status quo. Otherwise $PLVC_{n,c,t}$ is set to $SQ_{n,c}$ as the decision for local value creation is negative. The model dynamically makes these decisions for a time horizon from 2012 to 2030.

In the know-how based decision process, available technological know-how (TKH) in a country has to be higher than the technological know-how which is necessary to be able to run a production line or a single production process of a certain component. This decision provides only a positive or negative answer to the question if local manufacturing is possible (no answer about the height of PLVC).

In the market based decision process, a decision is modelled to define local potential from market perspective. Current and future market demand per component is compared with typical sizes of production facilities and manufacturing condition. Only if a sufficient market demand over the next five years exists, RETMD indicates potential for a local company or for a local subsidy of an international company to set up a new production facility or to update existing production lines. Therefore, mid-term market stability directly influences annual sales and FTE jobs for each component and service. Expectations of future market demand are modeled by perfect knowledge of the market demand over the next five years. Market demand ($MD_{n,c,t}$) of each component in country (c) and year (t) is equal to power plant installations per technology in the market scenarios. The average market demand should be higher than the minimum economic throughput ($Output_{n,min}$). Additional output of a factory in form of other products besides the certain component is also implemented ($Output_{other}$). Therefore, the following equations are valid:

$$PLVC_{n,c,t} \geq SQ_{n,c,} \qquad if \qquad \textbf{(Eq 45)}$$

$$\begin{cases} TKH_{n,t} \geq TKH_{c,t} \\ and \\ \frac{1}{5}\sum_{t}^{t+5} MD_{n,c,t} \geq Output_{n,min} - Output_{n,other} \end{cases} \begin{matrix} \text{(Know-how decision)} \quad \textbf{(Eq 46)} \\ \\ \text{(Market decision)} \quad \textbf{(Eq 47)} \end{matrix}$$

Only if both decisions (know-how and market) are positive, PLVC can be calculated for each component or service.

The know-how based decision per component is influenced by the following decision parameters (Kost et al., 2012g):

- **Status quo of local manufacturing in year 2012**: Existing industry capabilities are included in the model as starting point or benchmark for further development.[16]
- **Know-how (country)**: To including existing technological know-how and competiveness of the economy in each country, each country is rated according to the expert interviews and the global competiveness index (GCI) (World Economic Forum, 2013). It is assumed that know-how continuously increases due to the exchange of knowledge, knowledge transfer and learning (Table 24).
- **Know-how (component)**: Each component and service of the value chain is technically evaluated in terms of required production processes and technological know-how for manufacturing or providing the service.[16]

Table 24: Technological know-how in North African countries related to RE technologies based on expert interviews and competiveness indices (own rating).

	Wind	CSP	PV	Annual increase of know-how	Comments
Morocco	4.0	4.0	4.0	2.50%	- Few activities in all three technologies - High annual decrease due to economic strategy on manufacturing in the field of RE
Algeria	4.5	4.2	4.0	1.50%	- Activities to set up a production line for PV modules - Low annual decrease due to economic framework conditions
Tunisia	4.0	4.0	4.0	2.50%	- Few activities in all three technologies - High annual decrease due to active business relations with EU
Libya	4.5	4.5	4.5	1.50%	- Limited activities in the field of RE - Low annual decrease due to economic and political framework conditions
Egypt	3.5	3.5	4.0	2.00%	- Existing companies in the field of wind and CSP - High capacities of construction sector and manufacturing sector

(Scale for know-how: 1.0 to 5.0; 1.0 represents highest know-how)
(Annual increase = annual increase of know-how)

[16] Component and service specific data can be found in Table 58, Table 59 and Table 60 (appendix)

The market decision requires the following decision parameters (Kost et al., 2012g):

- **Factory specification**: Production of a component in a production factory is only possible if a sufficient factory output or throughput is fulfilled by the market demand. The demand for components and services is given by the amount of power plant capacity which is constructed according to the market demand scenarios.[16]
- **Market demand and forecast**: Creation of local production factories is based on the long-term expectations about future market demand in a country or region (Lewis and Wiser, 2007; Kinkel, 2009).

The temporal development of $PLVC_n$ also depends on the potential in the time period before and the specific market demand in year t. If $PLVC_n$ is larger than zero in the year before, $PLVC_n$ is increased by the factor (inc_n). But $PLVC_n$ is restricted to a range of a minimum and maximum potential ($Min.PLVC_n$, $Max.PLVC_n$). In case of $PLVC_{n,c,t-1} = 0$ and a positive decision in year t, $PLVC_n$ is set to the minimum potential ($Min.PLVC_n$).

$$PLVC_{n,c,t} = inc_n + PLVC_{n,c,t-1}, \qquad if\ PLVC_{n,c,t-1} > 0 \tag{Eq 48}$$

$$PLVC_{n,c,t} = \ Min.PLVC_n, \qquad if\ PLVC_{n,c,t-1} = 0\ and\ PLVC_{n,c,t} > 0 \tag{Eq 49}$$

$$Min.PLVC_n \leq PLVC_{n,c,t} \leq Max.PLVC_n, \qquad ifPLVC_{n,c,t} > 0 \tag{Eq 50}$$

The limitations of $PLVC_n$ are based on the following assumptions:

- **Minimum and maximum potential per component**: Some components obtain a reasonable minimum and maximum potential which can be localized, as international suppliers certainly remain in the market regardless of ongoing local production.[16]
- **Continuous increase of local production**: The potential of local companies increases due to constant learning or better sales channels. Annual increase is assumed with 2% to 4% per year depending on already realized potential.

After calculating $PLVC_n$ of each component (n), it is possible to sum up the PLVC of each technology per country (c) and year (t).

$$PLVC_{c,t} = \sum_n PLVC_{n,c,t} \tag{Eq 51}$$

By using the component specific results, potential sales and employment impact for each technology are calculated. Results on annual sales and annual FTE jobs are separated in values for the local and international market. Operation and maintenance of power plants are assumed to be carried out by local companies and local workforce. Only for replacement of specific components and major power plant revision, international experts or technology providers are considered. Therefore potential of local value creation during operation and maintenance $PLVC.O\&M_{c,t}$ can be deducted from the calculation of $PLVC_{n,c,t}$.

Sales and employment effects created by the construction of new power plants are calculated on country level by the use of component specific costs ($C_{n,t}$) and employment rates ($ER_{c,n,t}$). Both values depend on learning rates ($LR_{n,t}$).

$$Construction.sales_{c,t} = \sum_n C_{n,t}(LR_{n,t}) \ * MD_{n,c,t} \tag{Eq 52}$$

$$Construction.jobs_{c,t} = \sum_{n} ER_{c,n,t}(LR_{n,t}) * MD_{n,c,t} \quad \textbf{(Eq 53)}$$

Similar to construction effects, sales ($O\&M.sales_{c,t}$) and jobs ($O\&M.jobs_{c,t}$) of operation and maintenance are calculated for all years (T).

$$O\&M.sales_{c,t} = C_{O\&M,c,t} * \sum_{t=0}^{T} MD_{c,t} \quad \textbf{(Eq 54)}$$

$$O\&M.jobs_{c,t} = ER_{O\&M,c,t} * \sum_{t=0}^{T} MD_{c,t} \quad \textbf{(Eq 55)}$$

Finally, annual total values of sales and employment caused by construction and operation of RE power plants in each country can be calculated for each country (or for the total region, if the sum of all countries is calculated).

$$Total.sales_{c,t} = construction.sales_{c,t} + O\&M.sales_{c,t} \quad \textbf{(Eq 56)}$$

$$Total.jobs_{c,t} = construction.jobs_{c,t} + O\&M.jobs_{c,t} \quad \textbf{(Eq 57)}$$

After defining $PLVC_{c,t}$ and $PLVCO\&M_{c,t}$ for all components/services, countries and time steps, as well as calculating sales and employment effects of each market scenario, potential economic impact in terms of sales of local companies and potential employment effects in terms of local jobs are determined by the model.

$$Total.local.sales_{c,t} = PLVC_{c,t} * construction.sales_{c,t} + PLVC.O\&M_{c,t} * O\&M.sales_{c,t} \quad \textbf{(Eq 58)}$$

$$Total.local.jobs_{c,t} = PLVC_{c,t} * construction.jobs_{c,t} + PLVC.O\&M_{c,t} * O\&M.jobs_{c,t} \quad \textbf{(Eq 59)}$$

The volumes of sales and amounts of jobs per scenario are then compared regarding economic and socio-economic effects. In addition to the calculation of economic and socio-economic effects, the model can display the specific year of breakthrough for component manufacturing by a local company.

6.4.3 Model limitations and uncertainties

As the RETMD model tries to project long-term industry development and economic impact of a very large, complex and heterogeneous region, the model has to abstract a complex economic process including the decision on industrial localization, market creation, business development and strategic investment decisions. Therefore simplifications of real-world problems have to be made to model the economic and socio-economic impact in RETMD. Additionally, the model results underlie a range of uncertainties which are summarized briefly (compare Kost et al. (2012g)).

Five basic model assumptions and limitations regarding the economic framework, market behavior and long-term market development are integrated in the RETMD model:

1) Local value creation refers to companies which produce the required components in production capabilities in North Africa or provide services from offices in North Africa. Impact of the company’s ownership and tax payments is neglected in the model.

2) All economic effects of a product are declared as local if the product is produced locally. Further analyses on the used sub-components, materials or equipment are not carried out although materials, equipment, labor or further inputs could have their origin abroad.
3) The model cannot decide if an investment gives an expected or required return on investment. The model summarizes only potential manufacturing options for different scenarios as they are mainly possible due to available technical know-how and sufficient local market demand related to specific production processes and factory specifications. International competiveness is not considered and thus not proven.
4) The model indicates potential developments in terms of local manufacturing and employment effects, but it does not solve single investment problems. Investment decisions of new manufacturing capabilities depend on a number of additional decision parameters which are not includes in the model.
5) If the model decides that production of a certain component is possible in a certain year, the component production is also possible in all following years, if market demand exists.

The RETMD uses the market scenarios of RESlion with the same technology parameters and future cost developments. However, the model cannot include further uncertainties regarding political, economic and technological developments in the future. Political and economic developments (such as political changes, revolutions, economic recessions, specific RE laws, new investment programs, etc.) in North Africa are not covered by the market scenarios. Furthermore, the RE technologies (CSP, PV and wind power) are modeled by the use of reference technologies. Wind power plants consist of single wind plants with capacity of 2.0 MW each; the CSP technology is implemented as CSP parabolic trough plant with a net-capacity of 50 MW and a thermal storage of 8 hours and the PV technology is modeled as power plant with a basic size of 20 MWp. Even though these reference plants represent state-of-the-art technology, technology design can be changed. In the future, large technology changes and disruptive developments might appear. By forecasting the cost development of the technologies (and their components) with learning curves, further uncertainties can be expected. Due to these limitations and uncertainties the model is only applied for the time horizon until 2030. Prognoses of economic and industrial development beyond this time horizon are very challenging and may pretend accuracy which cannot be provided.

6.5 Data input of RETMD

6.5.1 Construction of reference power plants

The volume of newly installed power plants per year and RE technology creates an annual market demand for reference power plants in RETMD. Reference power plants are implemented by using common power plant layouts, all typical components and services of the value chain as well as further specific construction parameters (e.g. construction time, workforce). The reference power plants represent existing state-of-the-art technology in 2012. Future developments in terms of economic effects and employment effects are accounted for by using learning curves. With this approach decreasing costs and employment effects of the RE technologies can be projected.[17]

- **Onshore wind power plant**: Single onshore wind turbine with a capacity of 2.0 MW at a height of 80 m
- **Concentrating solar power (CSP) plant**: Parabolic trough technology, turbine capacity of 50 MW with 8 hours of thermal storage, solar field size of 510,120 m^2
- **Photovoltaic (PV) power plant**: Fixed ground-mounted system with a peak capacity of 20 MWp, mono-crystalline modules

The reference power plants are summarized with a focus on cost and employment data in Table 25.[18] All three reference power plants are implemented with common technology designs, standard components and medium power plant size at average cost levels.

Table 25: Cost and employment data of reference power plants (extended tables in appendix)

Technology	Plant size and configuration	Total costs (2012)	Specific cost	Total jobs (2012)	Employ-ment rate	Ratio costs/jobs
		[Mio EUR/PP]	[EUR/W]	[jobs/PP]	[jobs/MW]	[tEUR/jobs]
CSP	CSP Parabolic Trough, 50 MW + 8 hours of storage	251.3	5.03	2517.5	50.4	99.8
PV	PV 20 MWp, mono-crystalline modules	31.0	1.41	247.0	9.8	125.5
Wind	Onshore wind plant with 2.0 MW, tower height: 80 m	2.81	1.41	22.6	12.3	142.9

The number of jobs per component is adjusted to market conditions in North Africa. This means a doubling of the workforce during on-site installation of power plants due to lower productivity compared to construction of benchmark power plant in Spain or the USA. Specific cost per MW of CSP exceeds the values of PV and onshore wind as CSP could not realize similar cost reduction as PV. But full-load hours of CSP are higher in the selected configuration, as both the use of a thermal storage and the oversized solar field increase electricity output per MW. Consequently total and specific investment of CSP is higher and hence, specific jobs per MW are also higher for CSP than for the other technologies.

Employment rates presented in this study are calculated at lower values for wind and PV compared to historical findings in some other studies (Rutovitz, 2010; Llera et al., 2013). But similar values for employment in the wind sector were calculated with 15.1 jobs per MW by EWEA (2009) or with 13.5 jobs per MW for Brazil (Simas and Pacca, 2014). The reason for decreasing employment rates are process, material and product improvements linked with higher automation and reduction of labor intensity, which strongly fostered the decline of specific employment rates in the last years. By using recent project data, especially the values for PV are significantly lower compared to two or three years ago.

[17] The learning curves used in RESlion are also applied in the RETMD model.

[18] Extended data of the reference plants can be found in Table 58, Table 59 and Table 60 (appendix).

The ratio cost/jobs indicates a smaller difference between the technologies. CSP has the lowest ratio as the highest amount of onsite installation and assembling is necessary to construct the solar field with large mounting systems and piping tubes. Again, PV has followed a strong optimization in the last years due to highly automated production and installation of PV power plants has been facilitated.

The job analysis includes jobs for construction, installation and project development and jobs for manufacturing of components and equipment.

The future cost development of RE technologies is identical to the assumptions in RESlion. According to these assumptions, specific investment is for PV at 745 EUR/kWp in 2030, for CSP at 3550 EUR/kW and for onshore wind power at 1305 EUR/kW.

6.5.2 Operation of reference power plants

While a large share of employment is created during the construction of RE power plants, further long-term socio-economic impact exists for operation over the full lifetime of the power plants. Although economic impact from electricity sale is not covered by RETMD, the economic impact caused by operation and maintenance at the power plant site is implemented, e.g. job creation through the power plant operator with onsite-workforce or maintenance companies. Onshore wind and PV power plants are operated with a very limited number of permanent workers at the site of the power plant, with exceptions for maintenance work or security staff in case of security issues. Maintenance is provided by flexible technical staff.

In contrast to wind and PV, operation of large CSP plants has to be controlled and operated by a local team at the site of the power plant. Cleaning of mirrors and maintenance of the power block are the main tasks for the power plant operator in addition to power plant security. Operation costs of PV include the exchange of inverters every ten years which increases the indirect operation costs of PV compared to wind power plants for which replacement of components is assumed to be lower during lifetime.

Operation costs and jobs of CSP and wind power plants are based on results of NREL (2013). The required operational staff is calculated for each task during operation and all expenses for component replacement and maintenance are assessed (Table 26). Based on this bottom-up calculation, employment and sales assessment of the operation can be adapted to the conditions of North Africa by using a larger workforce, especially for cleaning and security issues, compared to the US. Data regarding the operation of PV power plants are obtained by a Fraunhofer research project in Morocco.

Table 26: Operation costs and jobs of reference power plants ((NREL, 2013), own calculations)

Technology	Operation costs		Operation jobs	
	Operation	Component manufacturing	Operation	Component manufacturing
	[tEUR/ MW*year]	[tEUR/ MW*year]	[Jobs/MW*year]	[Jobs/MW*year]
Wind	13.0	13.7	0.26	0.13
CSP	28.9	43.6	0.82	0.5
PV	8.9	39.5	0.15	0.4

6.5.3 Status quo of local manufacturing in recent RE projects

Based on expert interviews, country visits and analysis of existing RE projects, the status quo of local manufacturing in current RE projects in North African countries is evaluated[19]. The average potential of local value creation as share of the total sales in a typical RE project is defined as the status quo for years 2010 to 2012 in the countries (Table 27).

Table 27: Status quo of local manufacturing in different countries of North Africa

Technology	Country	Share of local sales (2010 – 2012)
Wind	Egypt, Tunisia, Morocco	35.5%
Wind	Algeria, Libya	27.8%
CSP	Morocco, Algeria, Tunisia, Libya	17.5%
CSP	Egypt	43.0%
PV	All	19.6%

PV power plants are not yet constructed as large-scale projects in North African countries. Therefore findings for PV are based on expert interviews and analyses of other existing industry sectors which might be able to supply first PV projects in the regions with components or provide services (installation and erection). By summing up the existing local sales potential of each component and service to an overall value, the current status quo is assumed to be about 19.6% which especially includes the use of local workforce for onsite installation and some metal components for the mounting structure.

As first large-scale wind projects have been carried out in Egypt, Tunisia and Morocco during the last five years, the local industry had time to develop first businesses in the wind sector. Some companies have started to extend their product portfolio by producing towers for large wind power plants. Also first suppliers of electrical components entered the market in North Africa. The share of local sales for wind power plants is calculated to about 35.5% for Egypt, Tunisia and Morocco. In Egypt, a wind power plant manufacturer started to produce further components which are in particular necessary in wind projects such as electronic components or parts within the nacelle. Countries without any wind projects so far obtain a lower local value creation potential of 27.8% (Algeria, Libya).

Local industry involvement for the first CSP projects shows a large variety as the case studies of Morocco (Ain Beni Mathar), Algeria (Hassi R'Mel) and Egypt (Kuraymat) show significant differences (Fraunhofer and Ernst&Young, 2011). In Egypt, the local EPC company (Orascom) participates strongly in the project which leads to a higher local economic impact as this company was in charge of overall project organization and production of the CSP collector under a license of a German company. Therefore, the status quo of the local sales share in the Kuraymat project can be calculated up to 43%. Compared to Egypt, the share of local value creation of projects in Morocco and Algeria is relatively small with only 17.5% as most components are imported from abroad and also the EPC company has an international background (Abener/Abengoa from Spain). Tunisia and Libya have not installed CSP plants

[19] Publications with the results of the expert interviews, country visits and project analysis are summarized in section 6.3.

until today, but their status quo of local value creation is assumed to be identical to Algeria and Morocco.

6.6 Sensitivity of RETMD on market size and know-how

To show functionality, adaptability, applicability and sensitivity of the RETMD model, a variation of input parameters and assumptions for a growing demand of CSP in North African countries and economies are investigated in a sensitivity analysis, see also Kost et al. (2012g). Relations and dependencies of different potential CSP market developments are tested and evaluated with the following cases (1) to (3). The cases should show how the potential of local value creation (as local share on the total annual sales per year) develops over time if different model inputs are changed:

(1) Dependency on annual installations

(2) Component specific results

(3) Dependency on technological know-how of a country

Dependency of annual installations (1) on model results is tested by three different market scenarios. A first scenario (Small-Market scenario) assumes 2 GW of new CSP capacities in North Africa by 2030, a second scenario assumes 20 GW (Medium-Market scenario) and a third scenario 31 GW (Large-Market scenario). Figure 67 displays the results of case (1). If a low market demand (BAU scenario) is assumed, current and future potential of local value creation on the total sales (sum of all components) is limited because local production capabilities are not developed over time. As the status quo of local manufacturing (in 2012) shows a small share of about 20% local value creation on average for CSP projects, this result is also obtain by the model. By 2020 and 2030 only a few additional components and services are forecasted by the model to be provided by local companies. Therefore, the potential in this scenario remains at about 30% in the long-term.

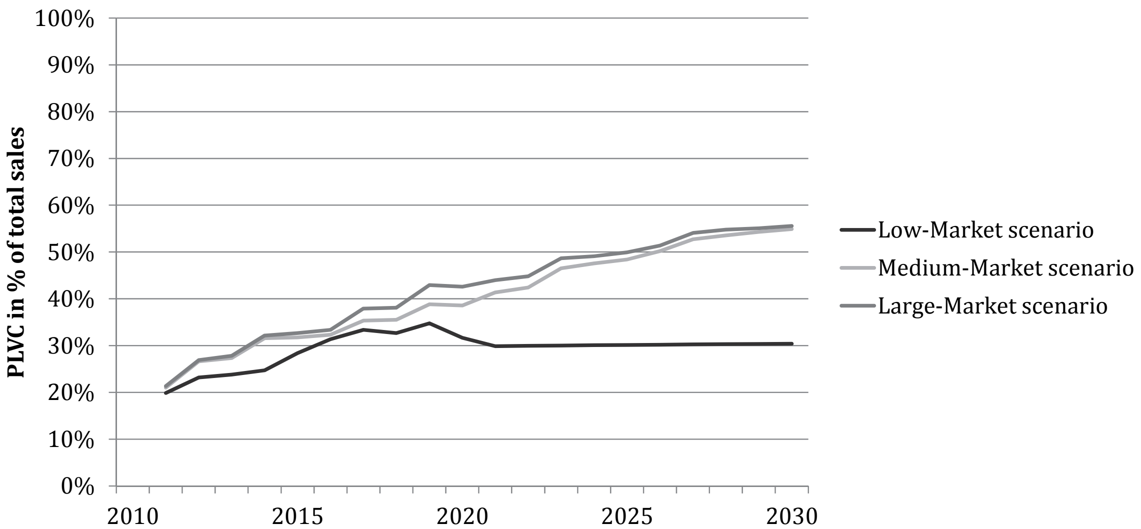

Figure 67: Potential of local value creation of CSP in different market scenarios

In the Medium-Market and Large-Market scenario, the model outcomes reflect the larger project pipeline by forecasting an increase of local manufacturing. The higher PLVC after 2020 is based on the positive decision in the model that development of local production capacity for a range of components is feasible and useful due to the large market size. Parts of the engineering and project management are also partly provided by local experts who are constantly employed by international companies or increase their know-ledge project by project.

If the Low-Market scenario and Medium-Market scenario of case (1) are analyzed in detail regarding the component specific results (case 2), the first year of a specific component production at a location in North Africa can be evaluated. The model results show a huge dependency on the market demand. In the case of Low-Market scenario, components such as CSP mirrors are not produced in North Africa (due to the model results). If a stronger demand in North Africa is anticipated (in Medium-Market scenario), production of these CSP mirrors with their parabolic shape (used in CSP Parabolic Trough plants) is started in North Africa in year 2020. In the Large-Market scenario, CSP mirrors have the potential to be produced even earlier as the model decision sets the year 2016 as first production year.

To analyze the impact of the parameter "technological know-how (country)" on the model results, different temporal developments of the increase are tested in case (3). This case should also show how the know-how based decision influences the results for PLVC. The level of know-how (country) is assumed to increase constantly (see Table 24). In this sensitivity analysis, the annual increase of the country specific value for know-how is varied by +50%/-50%. This should represent different developments of the available production processes and industry performances in the countries. Figure 68 shows the effects of different developments for (country) know-how. The know-how based decision is positive earlier in time for some components or services if the know-how of a country increases faster than the standard assumption. In case of slow increase, PLVC is up to 20% lower than in the standard assumption. In this case, the know-how based decision is negative for some components as the existing know-how in the countries is not sufficient. Therefore, local suppliers are not able to start manufacture specific CSP components.

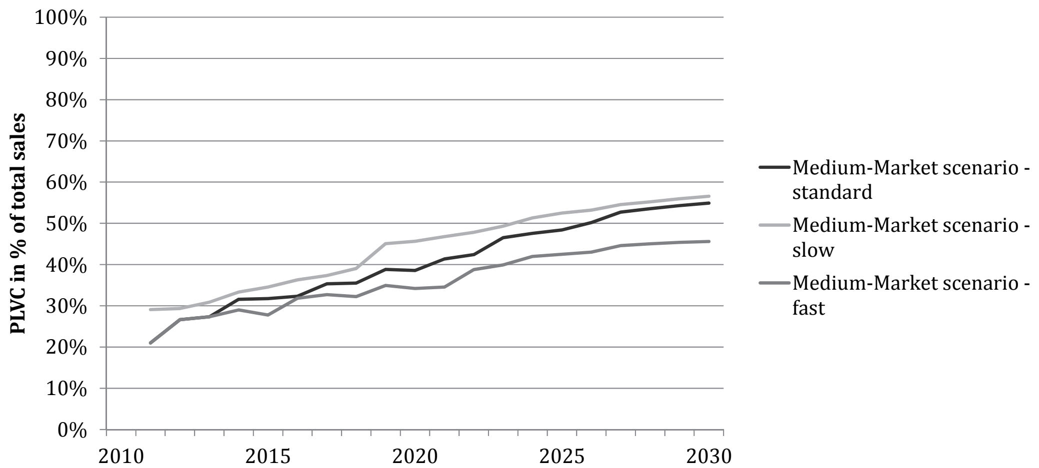

Figure 68: Potential of local value creation of CSP with different developments of (country) know-how

To sum up, results of the RETMD model are strongly related to the specific market demand of a technology in a certain country or region. Continuous and stable market demand is mandatory for the decision tool to decide positively on the potential of local value creation. However, the RETMD model also expects certain components to be produced by international technology providers and companies in the long-term anyway. Technical and economic barriers for very specific components such as steam turbines are defined as very high so that a positive decision concerning their local production in North Africa is not possible. The sensitivity analysis also shows that the component specific decisions influence the overall result in terms of PLVC. If know-how based decision or market-based decision is negative for some components in a specific scenario, the model results for PLVC are directly changed. It is important to notice that countries can influence their results in terms of local sales and employment by adjusting the market size of a technology and by improving the technological know-how and technical competences of companies and workforce.

6.7 Discussion of model achievements

The RETMD model simulates the continuous market introduction of RE technologies and quantifies annual sales volumes and annual jobs in the North African economies related to the RE market. However, the model cannot provide an analysis of the net impact of the market introduction of renewable energy in North Africa yet. Substitution of goods in the conventional power sector or higher investment in the power market can negatively affect national GDP and employment statistics. But the identification of net impact is also difficult with macroeconomic data, as they are not available or do not show sufficient quality and accuracy for this evaluation. Interactions within the economies caused by the market introduction of renewable energy also have many different dependencies and relationships.

Compared to other analyses, the model tries to forecast the industry development by applying a decision model to local manufacturing. This decision model uses extensive data input from a large number of expert interviews. The approximations of requirements regarding production processes and technological know-how in the local companies to enter the RE market by opening own production capabilities are especially important for the model performance. They are carefully derived from the expert interviews with international and local stakeholders, as they have an important effect on the model decision regarding local potential or international supply for each component. The model provides quantitative data of local industry involvement and job creation which can enrich the decision process regarding the market deployment of renewable energy in the national electricity systems of North African countries. This gives the user the advantage to use an endogenous model decision on the potential of local value creation in the renewable energy sector over a time period of 20 years.

With the high model resolution and ability to separately analyze each component or service of a technology, the results for each technology are based on specific data for each component. This means that the calculation of sales and jobs is closely linked with each component and service. For example, employment effects of the component “PV module assembling” are directly related to the technical and economic assumption for a module production line. The JEDI model by NREL, like other macro-economic models, uses only sector specific assumption which means that an employment factor from the manufacturing sector is taken to quantify the number of jobs created by PV module assembling.

By analyzing the three most relevant RE technologies in the electricity systems of North Africa, the model enables the comparison of the potential of the three technologies. As the technologies (CSP, PV and onshore wind power) are standardized within the model, the real-world problem is far more complex than assumed in the model. For instance, the market demand from CSP is assumed to consist entirely of parabolic trough technology instead of the other sub-technologies such as Solar Tower or Fresnel Systems with smaller market shares. But quantitative and qualitative results for those technologies are expected to be relatively similar to the reference results. By calculating average values in terms of PLVC for each component, unexpected market entrance of smaller local companies is also included within the model approach.

In addition to their use in the RETMD model, recent findings from local RE projects and employment rate adjustments due to those projects improve the data and information about current developments in the North African RE market. The ongoing debates on optimal strategies for the national energy policies and industrial policies are buttressed by analyzing the latest RE projects in the region. The evaluation of the interviews with project developers and international EPC companies in the region provides a profound analysis of local manufacturing in RE projects between the years 2010 and 2012 in North Africa. The knowledge of the status quo supports policy makers to define first political strategies regarding the creation of a local industry in the renewable energy sector.

Documentation of employment rates using recent project and cost data helps to specify the socio-economic impact of RE technologies in North Africa and also in other regions. Additionally, the approach of implementing learning rates in the employment assessment enables the user to forecast the long-term development of employment caused by renewable energy.

7 Manufacturing and employment impact of optimized electricity scenarios

7.1 Demand scenarios for the RE markets from 2012 to 2030

With the RETMD model, a selection of six electricity scenarios presented in chapter 5 is analyzed. The scenario results of the electricity market modeling with RESlion in terms of the annual amount of newly installed capacity per RE technology in each country are incorporated in the impact analysis. The scenarios are selected due to their differences in terms annual installations per technology in each country (Table 28, detailed data in appendix: Table 61 to Table 66).

Table 28: Scenarios for impact analysis of manufacturing and employment

Scenario	Short description of scenario
High-RES scenario	Scenario with a RES-E share of 80% by 2050
Low-RES scenario	Scenario with a RES-E share of 50% by 2050
100%-RES scenario	Scenario with a RES-E share of 100% by 2050
National Targets scenario	National targets with a national RES-E share of 80% by 2050
High-CSP scenario	Scenario with a high share of CSP (RES-E share of 80% by 2050)
Export scenario (High-Demand)	Export scenario with a RES-E share of 80% in 2050 in North Africa and additional high RES-E export to Europe

The development of newly installed power plants shows steep growth periods, declines and waves over time as the RESlion model tries to endogenously fulfill the requirements of the RE targets of each scenario during the specific time period. The amount of installations also differs strongly between the countries. A country can have very limited own RE installation as the cost optimization selects sites for RES-E generation with better local wind and solar resources or sites from a system integrated view. It might also happen that one technology is not selected at all due to its cost disadvantages compared to the other technologies. The annual values per technology in each country of the High-RES scenario are shown exemplary for the years 2012 until 2030 in Figure 69 (the installed capacities of all scenarios can be found in the appendix: Table 61 to Table 66). In the High-RES scenario, only a few CSP projects are carried out by 2030. Continuous installations of wind power take place in Morocco and Egypt between 2012 and 2030 with annual installations of 500 MW to 2100 MW per year and country. From 2020 on, a large amount of PV installations ranging from 300 to 1000 MW per year appears in Morocco, Algeria and Libya. Only a few projects are undertaken in Tunisia due to the limited size of the electricity system. An outstanding market growth of PV (up to 4.5 GW per year) appears in Egypt due the large Egyptian electricity system compared to the other countries.

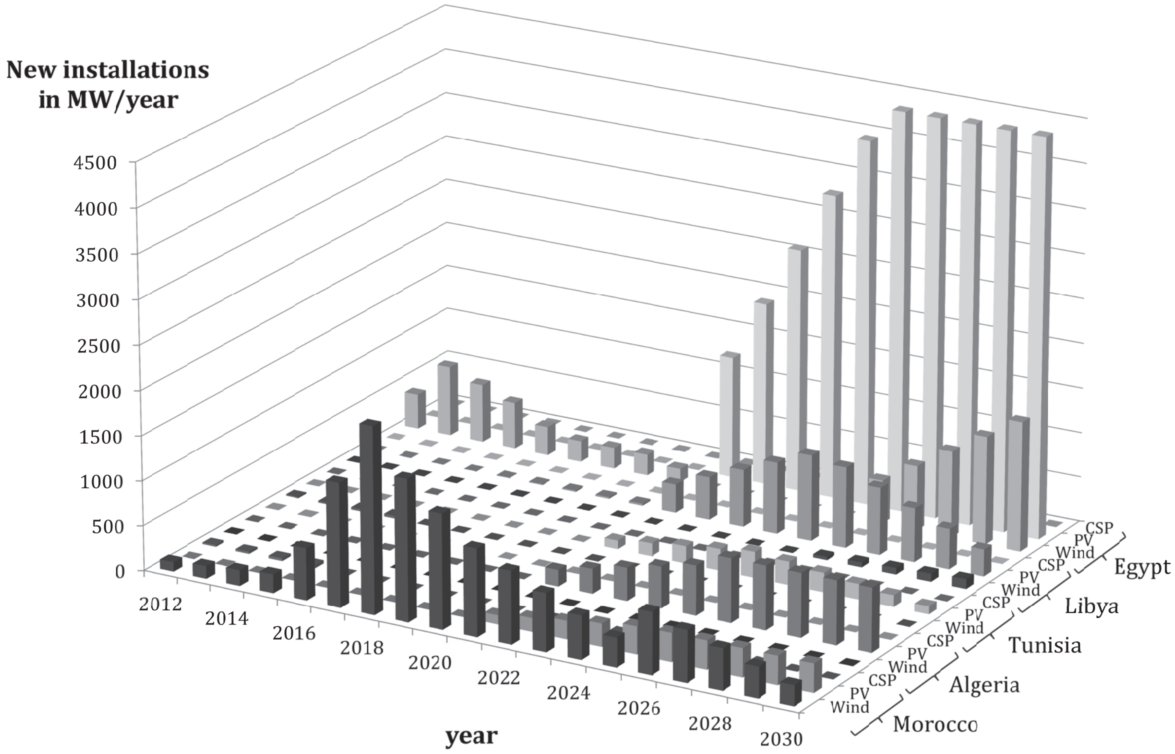

Figure 69: Annual installed capacity per technology and per country in the High-RES scenario

7.2 Economic impact and employment creation

Between 2012 and 2030, overall economic impact is calculated based on the total sales directly being created by construction and operation of new RE power plants (Figure 70). In the High-RES scenario with a RES-E share of 32% in 2030, total sales of components and services per year increase from about 2 bn euros (in time period of 2016 to 2020) to about 10 bn euros (2026 to 2030). The RE market in the Low-RES scenario only reaches 5 bn euros per year between 2026 and 2030 due to a lower RE deployment under a target for RES-E of 20% in 2030. Compared to this, the 100%-RES scenario (RES-E share of 40% by 2030) can increase the total sales in the RE market to over 12 bn euros per year during the time frame between 2026 and 2030. The National Targets scenario comes to a similar result compared to the High-RES scenario. But the contribution of each country differs strongly as the RE deployment is spread over all countries more equally, whereas the optimization of the RE deployment in the High-RES scenario, which aims to reach an overall North African RE target of 32% RES-E, prefers a higher share of installations in Morocco and Egypt compared to the National Targets scenario. Although the same RES-E share (32%) has to be reached, total sales of the High-CSP scenario exceeds the sales of the High-RES scenario. Higher costs of CSP compared to wind power and PV are the main reason for this development. In an export case, an additional investment volume of about 20 bn euros into RE projects is required until the year 2030. A high share of these additional sales is created until 2015 and between 2020 and 2025.

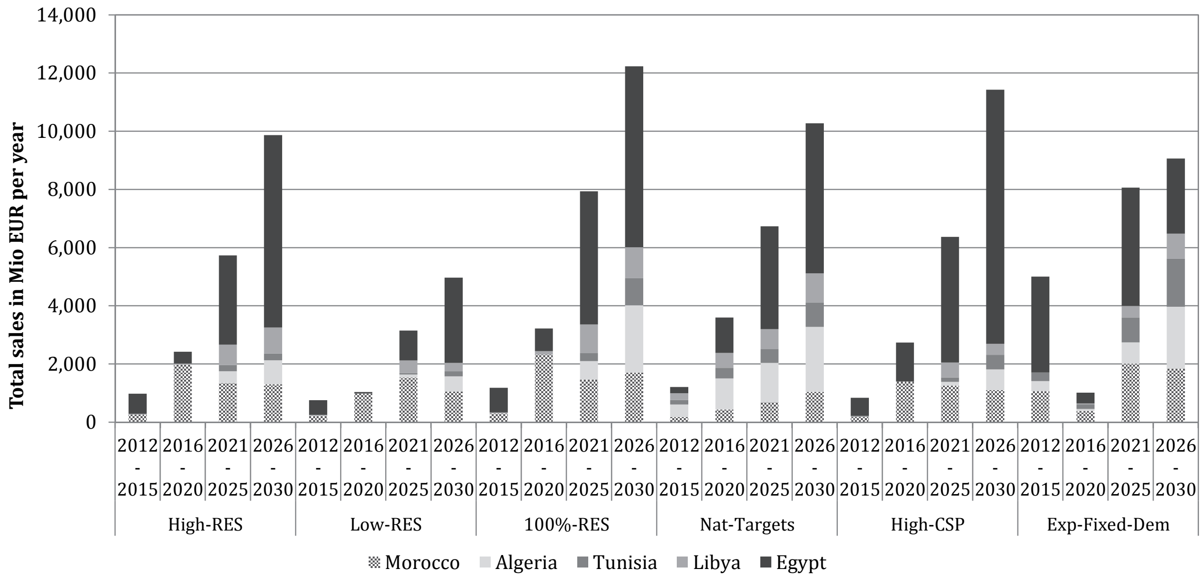

Figure 70: Economic impact of RE technologies in terms of total sales between 2012 and 2030

Total employment in the RE sector which is caused by the different deployment scenarios develops equally with the temporal growth of sales in the RE sector (Figure 71). In the High-RES scenario 93,000 FTE jobs per year are created directly by construction and operation of RE power plants between 2026 and 2030. A cumulative total number of 853,000 FTE jobs is generated between 2012 and 2030.

The National-Targets scenario also increases the number of jobs (1,003,000 FTE jobs by 2030) compared to the High-RES scenario although the total sales are almost equal. Main reason for this development is the lower share of Moroccan wind installation. Thus a high focus on strong RE development on a few countries with high RE potentials (especially wind in Morocco) does not always give the most attractive employment developments. In the High-CSP scenario, the highest number of jobs is obtained with 1,167,000 FTE jobs between 2012 and 2030 due the high demand for jobs during on-site installation of the power plants. At the same time, the ratio sales to jobs is the lowest in this scenario as the job creation based on on-site installation and power plant operation is higher for CSP than PV and wind (High-CSP scenario 92,000 euros per FTE job, National Target scenario 102,000 euros per FTE job). In the Export scenario analyzed here, about 1,027,000 FTE jobs are created by 2030. This number is comparably low as a higher share of wind projects with a lower employment impact than PV or CSP are realized in this scenario.

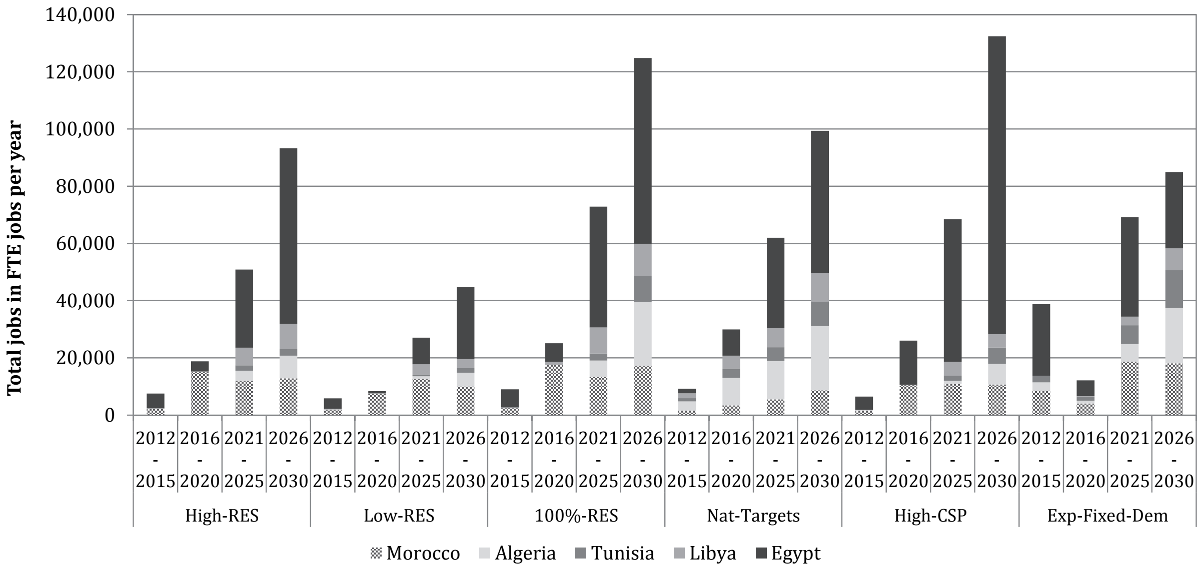

Figure 71: Employment of RE technologies in terms of total FTE jobs between 2012 and 2030

RE deployment obtained by RESlion strongly influences the growth of component sales and services. However, the specific paths positively or negatively impact the creation of additional jobs. Moreover, the selection of a technology can further increase the number of jobs which are totally generated during construction and operation of the power plants. Respectively, the High-CSP scenario shows a high job creation due to its labor intensive erection of the solar field and storage system with the installation of storage tanks, mounting structures, solar mirrors and piping system for the heat-transfer fluid. The distribution of projects over more countries (in the National-Targets scenario) also improves the number of jobs created. Nevertheless, the quality of jobs as well as the number of localized jobs will be assessed more deeply in the following sections under consideration of the different electricity market scenarios.

7.3 Technology specific development of local manufacturing

Depending on the market size of each scenario, the technology specific development measured by calculating the average potential of local value creation as share of the total sales develops differently over time. The endogenous calculation of component specific results strongly influences this development displayed for all countries from 2012 to 2030 (Figure 72 to Figure 74). The overall results are based on country specific results. These country specific results can slightly differ from overall results as the countries provide different industry capacities. In addition availability of know-how related to RE technologies as well as market demand reveal considerable differences in each country (Figure 69). Therefore, potential of local value creation of one country can vary due to comparative advantages or disadvantages of the supply chains compared to neighboring countries.

For PV projects, local companies can supply most of the components and services required to construct and install power plants at the sites (Figure 72). These services include civil works, installation, grid connection and project development. Components such as mounting structures and PV cables would also be possible. In terms of specific PV components, a new PV module production is only feasible if a reliable project pipeline is announced in a country, respectively in the 100%-RES scenario after 2020. Production of silicon, PV cells and inverter is currently not expected to become an issue in North Africa. Until 2020, the average potential of local value creation consequently does not exceed about 12% of the total sales. This development is based on very slow market growth in all countries except a few PV projects in Libya (75 MW). After 2020, a project pipeline of 2 to 6 GW per year over all countries leads to a growth of the local industry contribution from 30% to nearly 50%. With a larger PV project pipeline, the potentials could already increase over 30% before 2020 and exceed over 50% until 2030 as technology learning starts earlier.

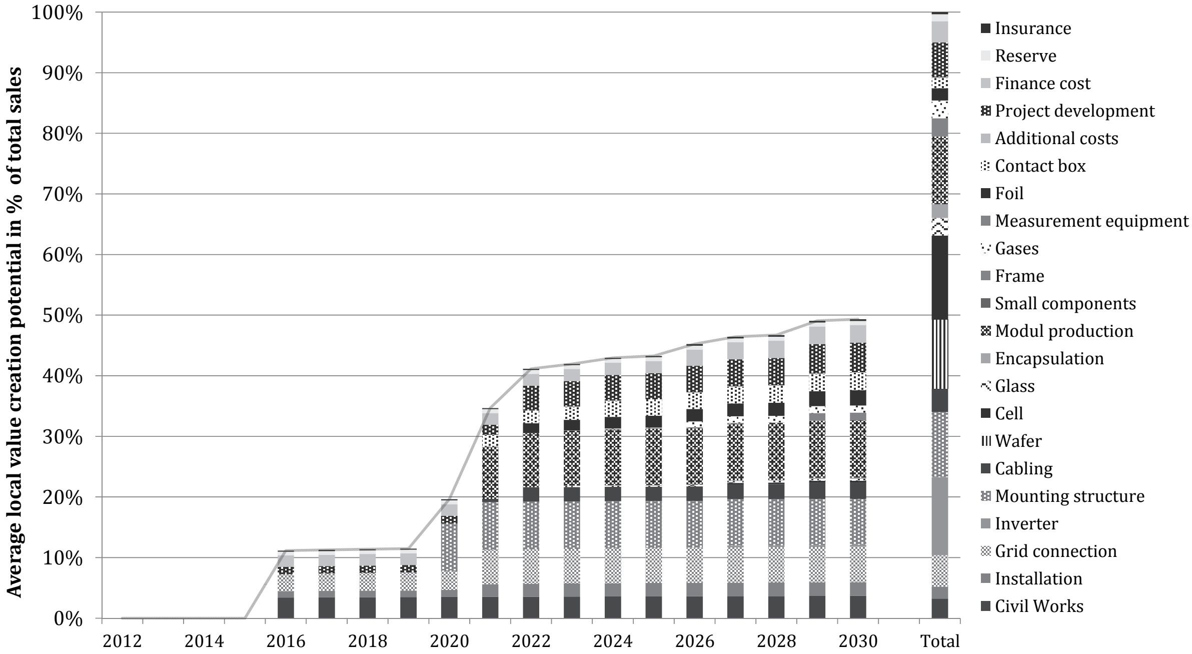

Figure 72: Average local value creation potential of PV in % of total sales (High-RES scenario)

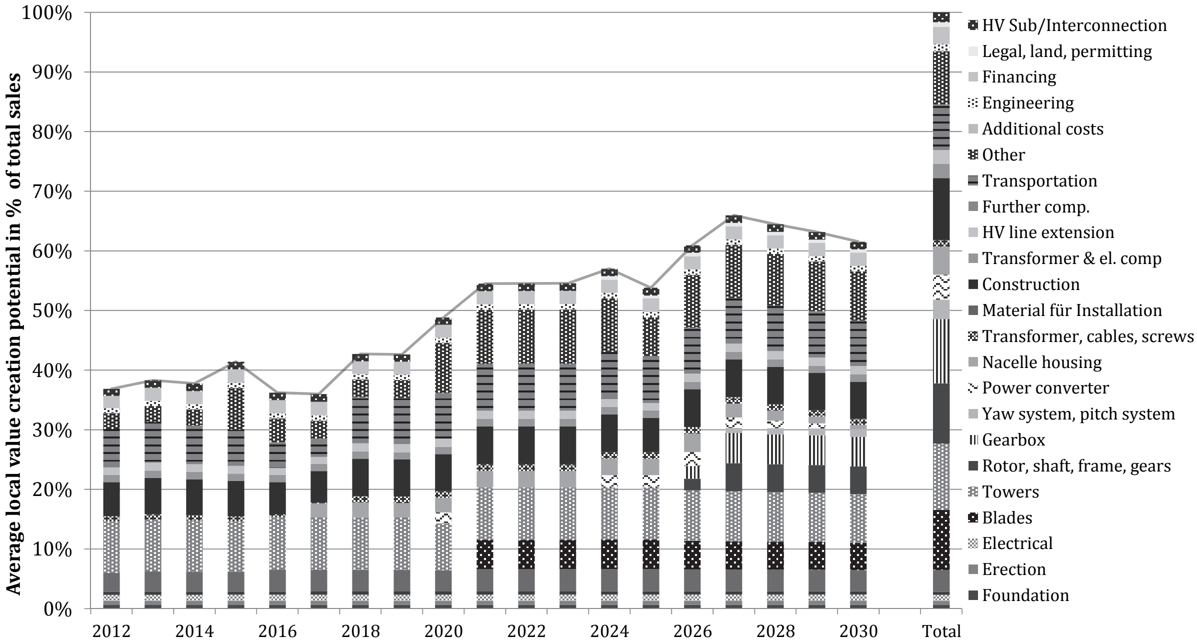

Figure 73: Average local value creation potential of wind in % of total sales (High-RES scenario)

The average local value creation potential of wind continuously increases in the High-RES scenario, however the average value underlies some waves due to a changeable project pipeline in different countries (Figure 73). Until 2015, already a share of 30% to 40% of the total sales can be supplied by local companies, namely electrical installation and components, construction and civil works, basic engineering and logistics. Between 2015 and 2020, the slightly reduced installed capacity in Egypt limits a stronger market development and local industry contribution. After 2018, an increasing number of components can be potentially produced in the countries, respectively in Morocco. After 2020, blades and parts of the nacelle have a potential to be produced in countries with high annual installations (a few hundred MW per year) to avoid transportation of equipment and components over long distance, according to the model results. Then the potential share of local value creation could increase to 55% or 65%. A decrease of the average potential after a few years is possible if the installed capacity per country changes and a country with a lower potential installs a higher share of wind power plants.

The potential for local CSP component manufacturing suffers from the lack of large CSP installations in the High-RES scenario as a project pipeline for CSP is expected only beyond 2030. However, the analysis of the High-CSP scenario in Figure 74 shows an increasing potential after 2015 due to continuous market demand within a range of 1 and 2 GW per year. By 2030, the potential is in the range of 55% to 60% of the total sales. A potential development of production capacities for solar mirrors and solar receivers is mainly responsible for higher shares of local products beyond 2020.

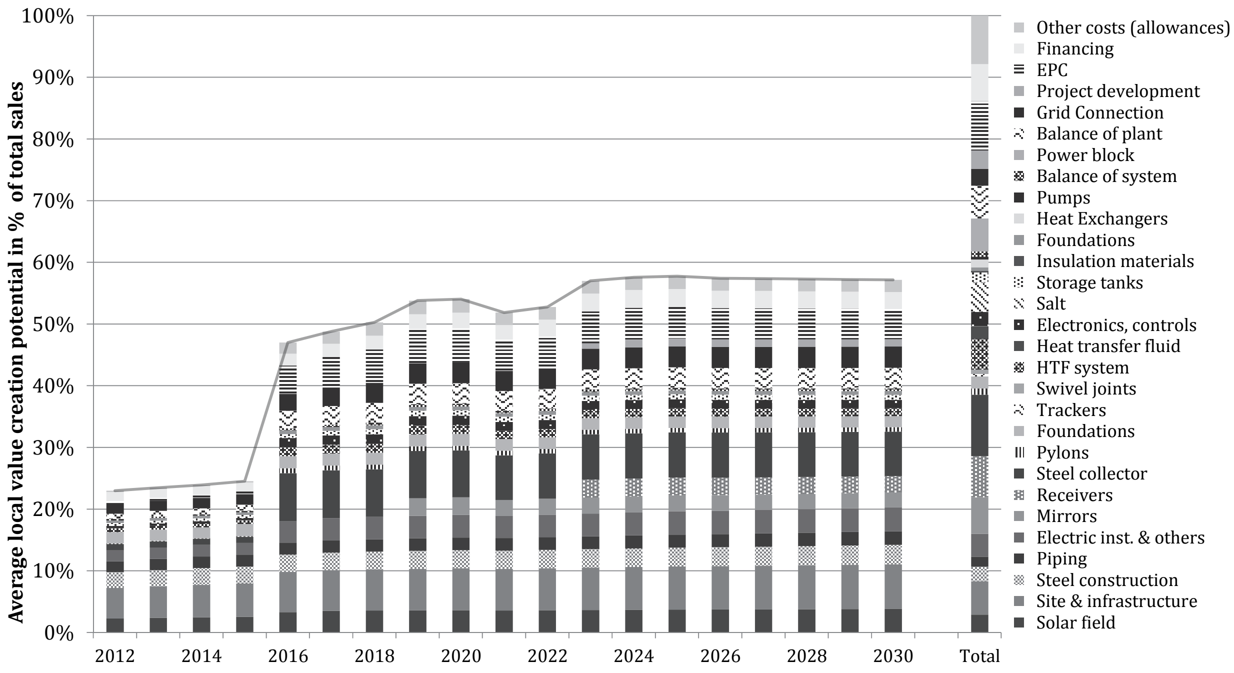

Figure 74: Average local value creation potential of CSP in % of total sales in the High-CSP scenario

To further increase the potential of local value creation, the industrial policy for renewable energy in North African countries can elaborate the option of a cooperative approach (Kost et al., 2012g). If countries take the comparative advantage to focus their industry sectors in the field of RE technologies and components as well as additionally facilitate international trade and business relations between the countries (e.g. a free trade zone for RE components), such cooperation can increase local potentials as a larger common market would be created. Today, the problem exists that the national economies are highly separated which reduces international businesses for many companies. Some industry sectors with comparative advantages can benefit from opening markets for RE technologies as companies with higher competences and competiveness can sell their products on a larger market. Of course, this approach requires an international cooperation, coordination and adjustment of economic framework conditions, trade policies and RE targets.

The RETMD model provides the option to evaluate economic and socio-economic effects of such an international cooperation. In this case of cooperation, the market based decision is related to the market demand of all countries. Market demand per component is consequently higher and set-up of a new factory can be facilitated. Furthermore, the know-how based decision uses the restriction for existing technological know-how from the country which the highest ranking. Therefore, specific components can be manufactured earlier in time and dependency on annual national market demand is lower with this assumption (see also section 6.6). If the model runs with assumption of allowing component production in the country with the highest potential per component and of opening the borders for free trade to increase the market demand, the model consequently shows continuous increasing and higher potentials of about 10% to 40 % for each technology (Figure 75). In this figure, the average local value creation potential over all components is compared for the cases with and without cooperation (without cooperation is the basic assumption used in all other evaluations).

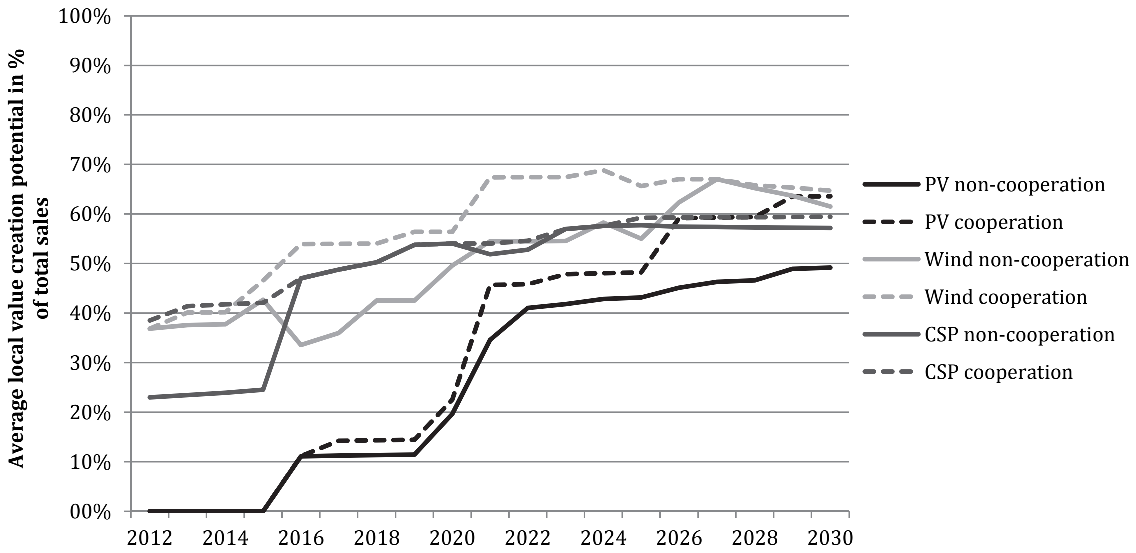

Figure 75: Impact of cooperation between North African countries on average local value creation potential

Under the assumption described above, the potential for local value creation for CSP strongly increases with cooperation between 2012 and 2015 as production of the mounting structure and supply of EPC services are increasingly possible by local companies. A potential production of mirrors could start about two to three years before the production would start without cooperation. A local wind power industry sees an enormous growth of local production around 2020 in the case of international cooperation as the stable market growth leads to an increase of component manufacturing of wind components such as gears, gearbox, nacelle or power converter equipment. Local PV markets can benefit from an international cooperation as key elements of the PV technology might be produced partly in this scenario in contrast to the base conditions. Production of PV inverters and PV cells represent a key element of the value chain. With cooperation, production of both components can start on larger scale level in 2025 to fulfill the market demand in the region. Later, wafer might also start to be locally produced in North Africa.

Certainly, these findings are difficult to prove in reality as a common market is hardly to be expected in the next years. However, these findings should indicate that the small market size of each country is an important factor which reduces the potential of local markets. Furthermore, some specialized companies in North Africa have some know-how on manufacturing RE components, but the number is currently limited in each country.

7.4 Country specific development of local manufacturing

To test the local potentials of each country in terms of sales and employment independently from the scenario assumptions, a constant project pipeline of 500 MW per year and per country is assumed between 2012 and 2030. That means that a total capacity of 9.5 GW per technology and per country is installed between 2012 and 2030. Although this volume of installations clearly might be above reasonable national values for each technology, a similar deployment path is implemented to obtain comparable country specific values. By assuming the same market size per country, the country specific results are only depending on the know-how based decision and the assumption for the country specific know-how rating (see Table 24). As described before, the rating for technological know-how is based on the competiveness index of each country and the expert interviews with local and international companies.

Figure 76 presents the deviation of the country specific cumulated local sales to the average of all countries between 2012 and 2030. Morocco and Tunisia show higher local potentials of about 10% to 12% than the average over all five countries due to their higher technological rating for RE technologies. In contrast to this, lower potentials of about 20% are calculated for Libya for all three technologies. Potentials of Algeria are slightly positive for PV whereas the potentials for wind and CSP are significantly below the average as both countries have very little economic activities in the industry sector of both wind power and CSP. Egypt can reach higher potentials in the wind energy market (+24%) and in the CSP market (+22%) due to its larger industry potentials compared to the other countries. Several local Egyptian companies are already active in the wind power market as well as in the CSP market. However, the local potentials for PV are slightly below the average (-4%) as currently only a few PV systems are installed and a local PV industry is not developed.

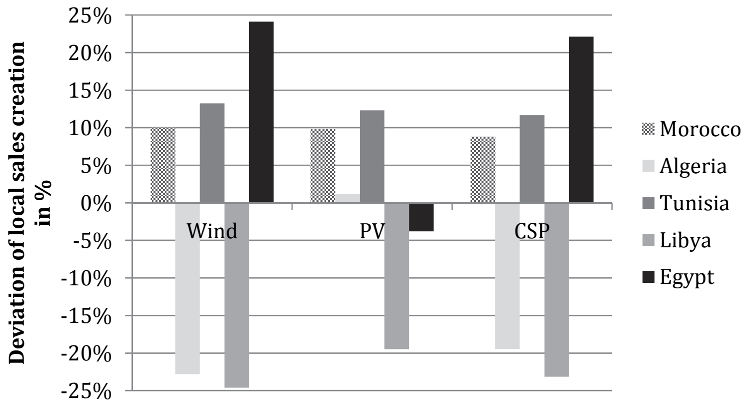

Figure 76: Deviation of local sales from the average value under the assumption of an equal and constant market demand (500 MW per year and per country)

A comparison of job effects does not provide the same large differences (especially for CSP) between the countries like in the previous sales analysis due to the stronger dependency of job creation on the operation of power plants (Figure 77). Differences between job effects for operation are smaller compared to the impact of construction. Therefore, the deviation of local jobs is lower as the calculation is based on absolute FTE job numbers. Again Tunisia shows higher job creation potentials for all technologies between 4% and 11%. Libya is about 11% to 20% below the average. The highest positive deviation can be found in the wind market for Egypt with about 19% higher local potential compared to the average. For CSP, Egyptian local potential is about 10% higher as the average.

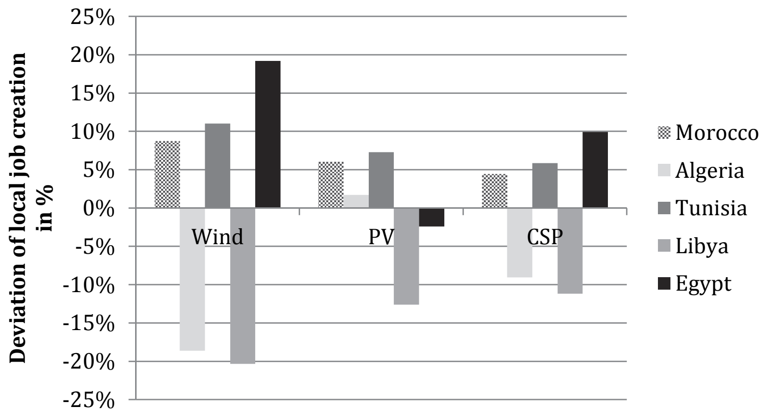

Figure 77: Deviation of local jobs from the average value under the assumption of an equal and constant market demand (500 MW per year and per country)

These country specific results have to be taken into account in the following evaluation of the scenario results, as installed capacity of each RE technology per country is optimized by the requirements of the electricity market (by the RESlion model).

7.5 Potentials of local manufacturing in each scenarios

Potentials of local PV manufacturing increase to a share of about 50% in all scenarios according to the RETMD model results. Nevertheless, the National-Targets scenario shows higher local potentials compared to the other scenarios as PV is installed in all countries and also before 2020. Lower shares of local value creation are calculated in the Low-RES and High-CSP scenario as both scenarios have low PV installations by 2030 (Figure 78). The Export scenario is the only scenario with a larger volume of PV installations before 2015. However, due to a lack of local production capabilities, local potential for PV is only between 20% and 30% until 2015. After 2015 also in this scenario, only a few PV projects are installed which leads to a lower share of local manufacturing (10%) until 2020.

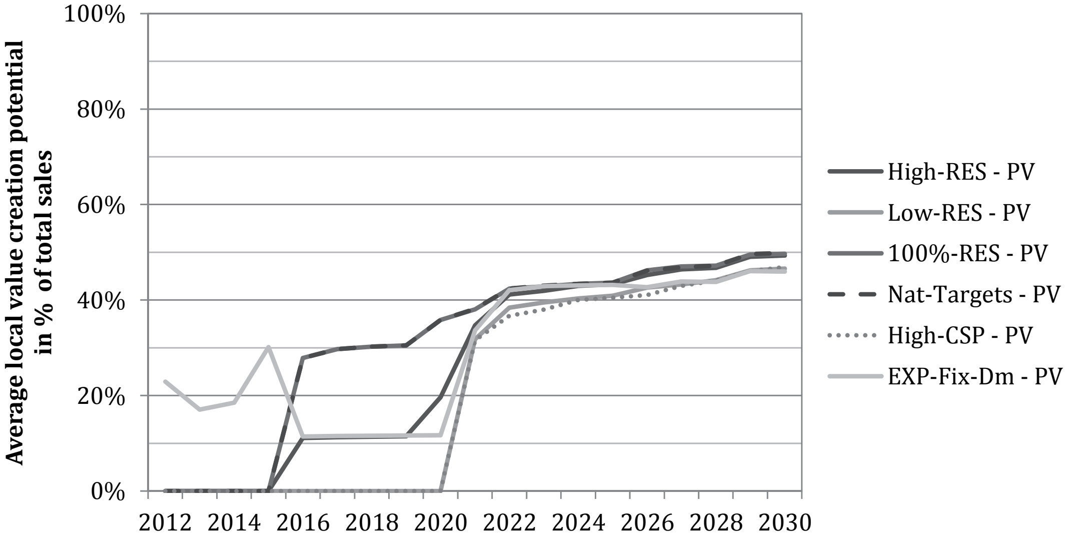

Figure 78: Average local value creation potential of PV in different scenarios

As wind power is installed above a minimum level for economic local production in all scenarios, the development shows an increase from about 40% in 2012 to above 60% by 2030 (Figure 79). Due to a lower project pipeline in different countries by 2015, the potential in the National-Targets scenario is lower than in the other scenarios. The increase after 2015 results from a high share of Egyptian projects compared to all projects. In the other scenarios, most of installations take place in Morocco which leads to a lower potential in 2016 to 2020 as the industry capabilities of Morocco are evaluated as not fully sufficient to produce a large range of components for wind power plants by 2020. After 2025, again a higher share of projects are installed in Egypt by the model and consequently the potential increases further as now also specific wind components (such as blades and nacelle) can potentially be produced in North Africa, especially in Egypt.

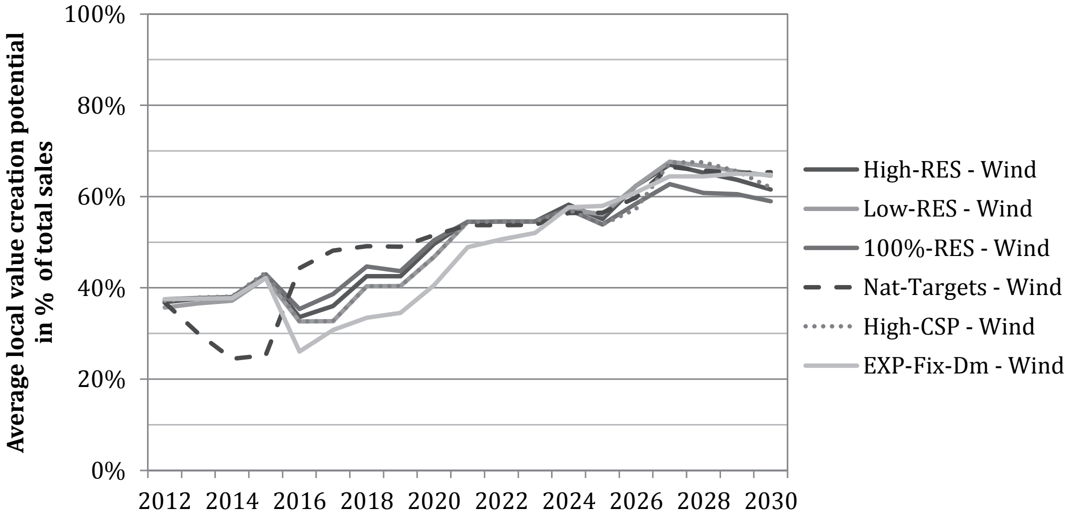

Figure 79: Average local value creation potential of wind in different scenarios

In case of CSP, except for the High-CSP scenario, potential is limited to 30% as market demand is lacking due to the scenario results which preferred to install wind and PV instead of CSP by 2030. Therefore, only in the High-CSP scenario with mandatory installation of CSP plants in North Africa, a localization of component production can take place. This development is similar to results shown in Figure 74 with a long-term increase of local sales to a share of almost 60%. In the Export scenario, a few CSP projects are installed in Morocco by 2030. Therefore a constant local potential around 40% can be assumed in this scenario.

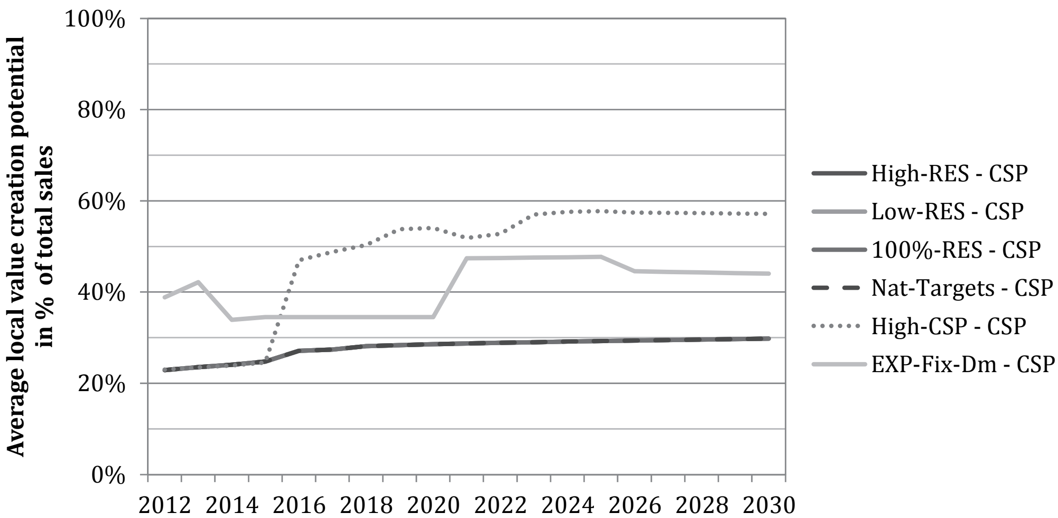

Figure 80: Average local value creation potential of CSP in different scenarios

The analysis of average potentials is an indicator of the volume of local sales and employment creation in each scenario. This is assessed in the following section.

7.6 Local economic impact

By 2030, the potential of local economic impact in the High-RES scenario can range over 5 bn euros per year compared to the total impact of almost 10 bn euros per year (see section 7.2). This means that on average the local sales per year can exceed 1 bn euros by 2030. In the Low-RES scenario, the potential of local sales per year is limited to about 3 bn euros, whereas the 100%-RES scenario can provide local sales per year of about 7 bn euros. Similar to the total sales, the potential of local sales is calculated at higher values in the National-Targets scenario and the High-CSP scenario compared to the High-RES scenario (Figure 81).

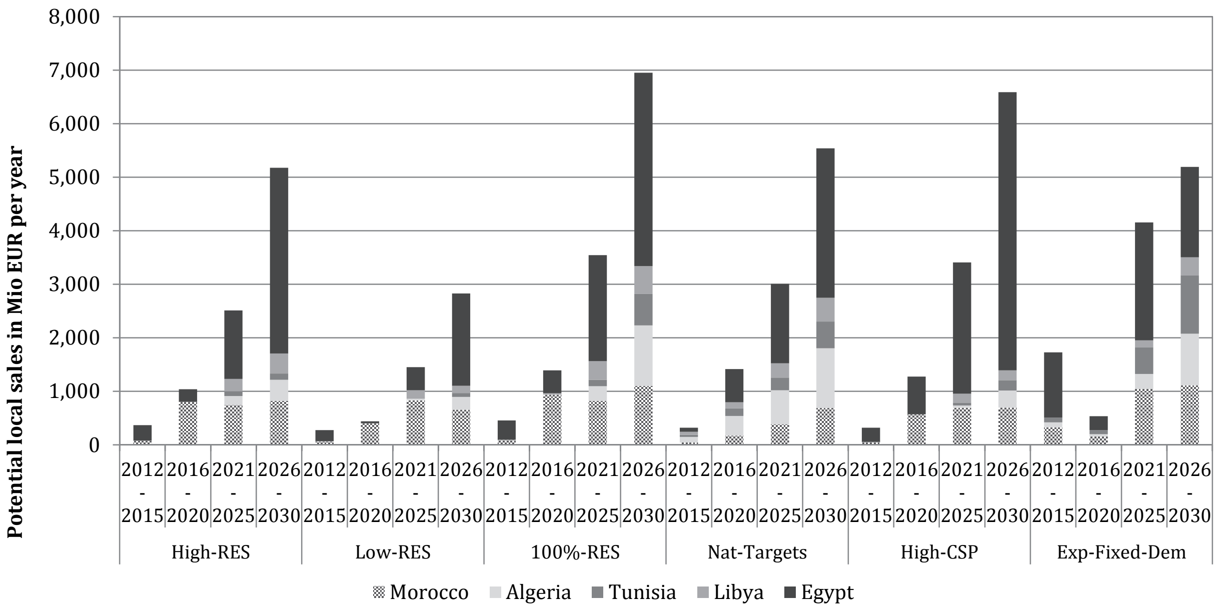

Figure 81: Potential of local economic impact from RE technologies in terms of total sales between 2012 and 2030

In the High-RES scenario, the RE installations mainly take place in countries with excellent solar and wind resources and with proximity of RE project sites to high electricity demand (Morocco and Egypt). Regarding the deployment path of wind energy, Morocco sees a continuous growth of projects which consequently provides potential annual sales in Morocco between 500 Mio and 1000 Mio euros from year 2016 to 2030 (Figure 82).

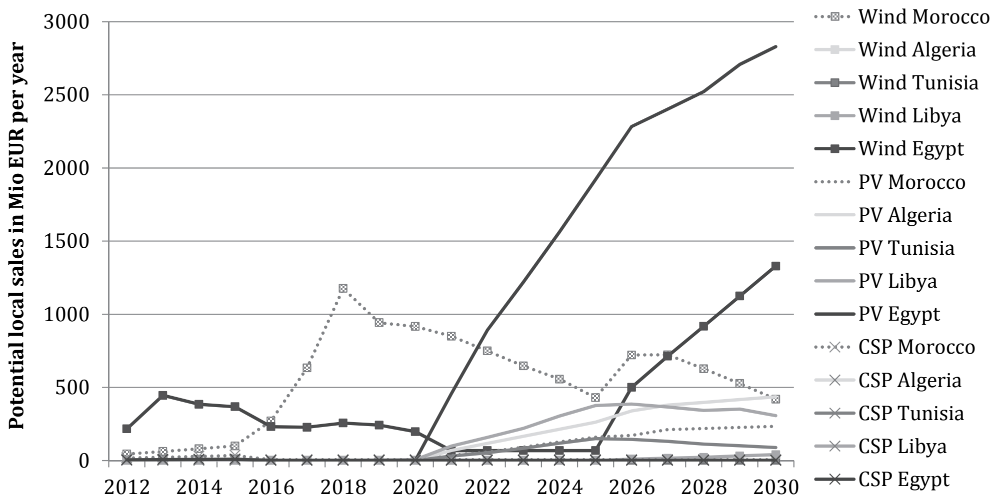

Figure 82: Potential local sales between 2012 and 2030 (High-RES scenario)

Following moderate deployment until 2020, the wind energy market in Egypt will cease over five years due to scenario results in RESlion, before it recovers with considerable progressive increase with potential annual sales in the wind industry of over 1000 Mio euros. A PV market will develop in all countries only after 2020. This leads to small markets of about 100 to 500 Mio euros per year in Libya, Algeria and Morocco. In Egypt, the PV industry shows, similar to the wind industry, a strong growth of potential local sales to over 2500 Mio euros per year. In the High-RES scenario, CSP projects do not provide any relevant economic impact on the national economies as only a few projects emerge.

7.7 Local employment impact

The cumulative number of locally created jobs by RE deployment ranges from about 310,000 FTE jobs in the Low-RES scenario up to 841,000 FTE jobs in the High-CSP scenario from 2012 to 2030. Development of jobs is in line with the creation of local sales presented in section 7.6. In the High-RES scenario, 599,000 FTE jobs are created which are still 107,000 FTE jobs less than in National-Targets scenario. PV installations in Algeria, Tunisia and Libya create additional jobs after 2015. As the 100%-RES scenario also includes a higher share of projects in Algeria, Tunisia and Libya compared to the High-RES scenario, the employment potential increases especially in these countries. In addition to the low project pipeline of RE power plants in the Low-RES scenario, job creation indicates also proportionally lower values than in the High-RES scenario. This can be explained by limited market dynamics and lower market demand intrinsic to the scenario. In the Export scenario, local job creation is already initiated between 2012 and 2015 with a total of 736,000 FTE jobs by 2030.

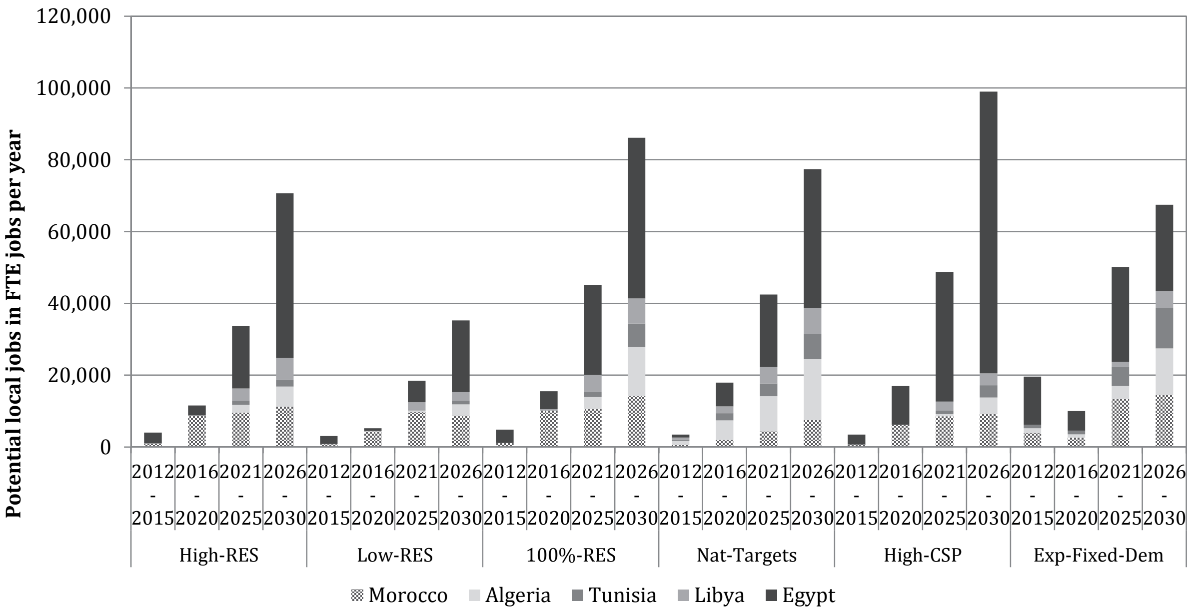

Figure 83: Potential of local employment from RE technologies in terms of FTE jobs between 2012 and 2030

Technology and country specific employment analysis of the High-RES scenario shows an increasing number of local jobs in the Moroccan and Egyptian wind industry up to 10,000 per year (Figure 84). Especially the Moroccan wind industry profits from a continuous project pipeline which causes a near-balanced employment despite a moderate decrease of installations can be recognized over time. Higher local manufacturing potential for an increasing number of components stabilizes the total number of employment. The Egyptian PV industry can provide over 40,000 annual jobs by 2030 due the vast investment in PV projects in Egypt ranging between 3 and 4 GW per year. Additionally, the annual FTE jobs increase stronger than the project pipeline as the potential of local component manufacturing rises. About 5,000 jobs can be established in the PV industry of Algeria and Libya which both show smaller PV project pipelines than Egypt between 2020 and 2030.

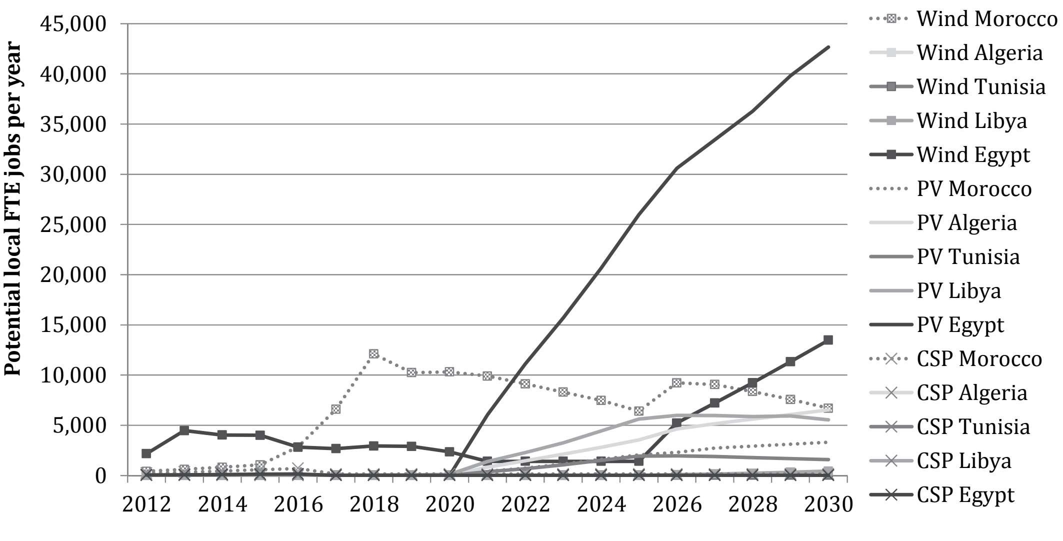

Figure 84: Potential local employment between 2012 and 2030 (High-RES scenario)

Existing statistics on employment in the RE sector of North Africa are very limited as recent data cannot be found in the literature.[20] Employment occurs in industry sectors directly related to installation and operation at the site of the power plant (construction site). However, a large share of jobs is created in the supply chains of RE components which are indirectly related to the installation (supply chain). It can be assumed that jobs in the manufacturing sector of RE components acquire high salaries than jobs in the construction sector. Furthermore, over 30% of all local jobs are related to the operation of the power plants. In 2030, more than 70,000 jobs in total will be created in the High-RES scenario. By then, the amount of jobs in the PV and wind supply chain industry is substantial (Figure 85).

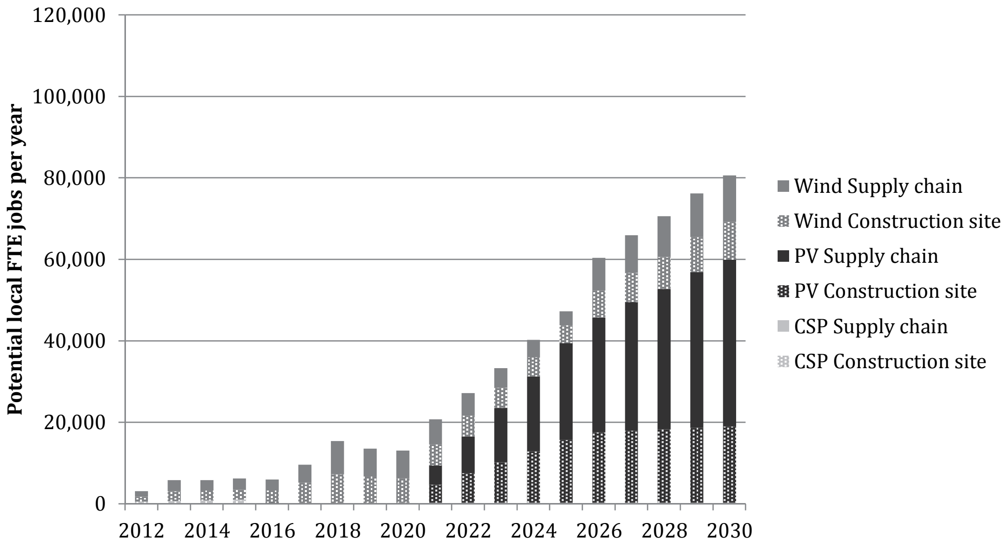

Figure 85: Potential local direct and indirect employment between 2012 and 2030 (High-RES scenario)

In opposite to the High-RES scenario, the National-Targets scenario limits the local jobs in the Moroccan wind industry due to a lower number of onshore wind projects by 2020 with less than 3000 jobs in total (Figure 86). However, in Egypt a stronger wind project pipeline is assumed which leads to 7,000 to 10,000 locally employed workers in the long-term. The PV industry in Algeria profits the most in this scenario as construction of new power plants can employ up to 15,000 people by 2030 due to a larger project pipeline and an increase of local capabilities and technological know-how. Job creation increases even more steeply than the growth of the project pipeline due to an expanding quantity of locally produced components for PV projects. Overall local job creation in the Egyptian PV industry is slightly lower compared to the High-RES scenario as about 25,000 to 30,000 annual FTE jobs will be created.

[20] General data on employment created by infrastructure investments can be found in (Estache et al., 2013)

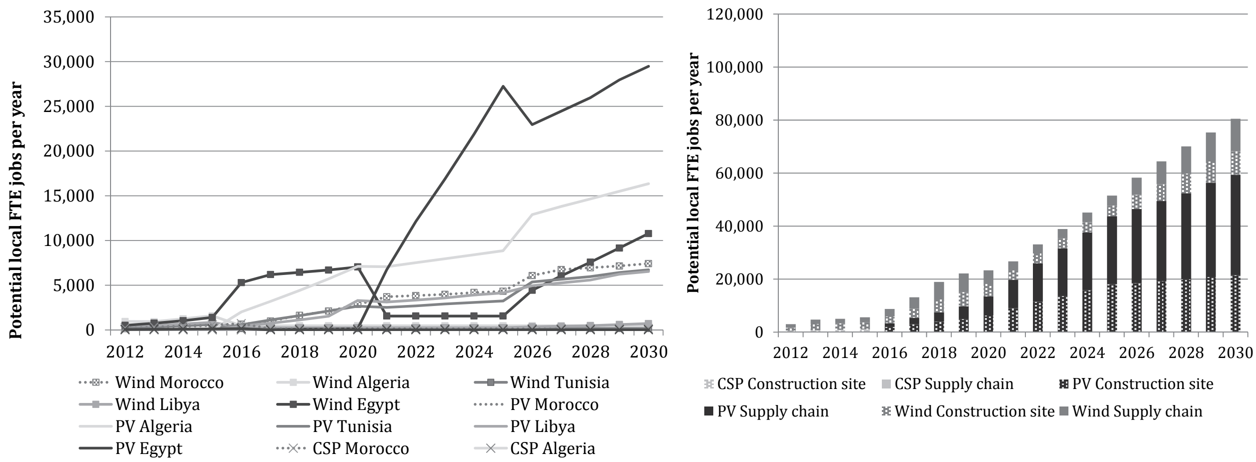

Figure 86: Potential local employment between 2012 and 2030 (National-Target scenario)

In the National-Targets scenario, the total number of local employees, 80,000 in 2030, is slightly higher compared to the High-RES scenario as already explained. The key driver for this development is job creation in the supply chain of PV components which mainly takes place in the countries Algeria, Tunisia and Libya.

In opposite to the other scenarios, the High-CSP scenario leads to substantial installations of CSP projects in Egypt between 2015 and 2030 (Figure 87). As a consequence, development of a CSP industry can be expected with an annual CSP project volume ranging between 1 and 2 GW. Annual jobs increase continuously up to 70,000 by 2030. In 2030, one third of these jobs are related to operation of existing power plants. PV and wind industries, however, suffer under this development as only in Morocco wind industry is expected to be developed with up to 10,000 employees. By 2030, Egyptian PV industry will have also about 10,000 employees, but the growth is slower than in other scenarios.

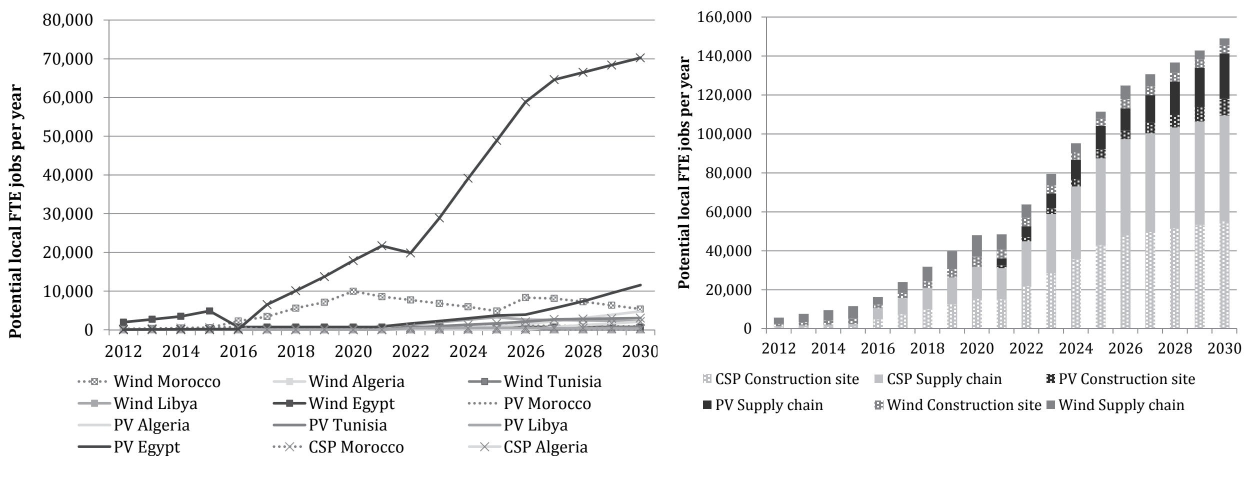

Figure 87: Potential local employment between 2012 and 2030 (High-CSP scenario)

The potential of local employment during construction is considerably higher in CSP projects due to the large number of workers required to construct CSP solar fields with a wide range of different components installed. Therefore, the number of jobs for construction of CSP plants (55,000 jobs in 2030) represents almost half of the total local jobs in all sectors (150,000 jobs in 2030). The number of jobs in the supply chain of CSP component manufacturing also reaches almost 54,000 jobs in 2030. This development is possible as the large CSP project pipeline creates a high potential of locally produced CSP components. Some of these local jobs are only possible to be created if international technology providers (world market leader) establish local subsidiaries and production factories of their components. It can be assumed that these prospects create considerable potential to attract these international companies as the market size of about 2 GW would represent the largest world market from today's perspective.

To summarize the results of this section, the analysis of potential job creation in different scenarios for renewable energy in North Africa provides a quantitative basis. Ambitious expansion targets for RES-E implies the creation of a large number of local and international jobs related to the RE deployment (ranging up to 1,200,000 FTE jobs by 2030, according to the model results). Local employment effects can be created for all three technologies CSP, PV and wind onshore. However, the specific amount of jobs depends on the mid-term and long-term structure of the project pipelines and on the competiveness, performance and know-how of the industries in a specific country.

Among the technologies being investigated, CSP yields considerable higher amount of direct jobs than the other technologies due to higher share of construction workers and work force required for regular operation of the power plant. Regarding PV, a higher share of indirect jobs in the supply industry can be established in the time horizon until 2030. In addition to local impact, also international companies can profit from a market entrance into local RE markets. Development of local production facilities will still allow remaining sales markets for companies with very specific solar and wind components. Those require a strong technological know-how and experience in the field of manufacturing and component production.

7.8 Evaluation of scenario results

Comparable scenario results and other references are very rare in the literature. Technology comparison for local manufacturing potential shows a slightly lower potential of PV compared to wind and CSP (compare section 7.3). However, this finding is primarily due to the fact that PV silicon, PV wafers, PV cells and inverters are expected to be localized later in time and only if competiveness to Asian and European companies is given. Nevertheless, the high number of PV installations lead to an increase of local value creation of the Egyptian PV supply chain for component production (e.g. module production).

In terms of CSP and wind power the local impact is based on economic activities in the field of construction and operation or on manufacturing of components with lower technological requirements such as towers for wind turbines or collector structures for CSP. Still, countries with less suitable resources can also profit from investments in RE manufacturing capabilities. As shown by the results of the National-Targets scenario, a dynamic start of local manufacturing at an early stage (from 2015 on) increases the benefits provided by a strong project pipeline. Investments in new production capacities linked to technological learning and continuous local supply can additionally raise the socio-economic impact.

An effectiveness analysis of the scenarios in terms of the ratio between total sales and number of jobs created shows little difference between the scenarios (Figure 88). Especially, Egypt, Tunisia and Algeria profit from local production of PV and CSP components in most of the scenarios. The Low-RES scenario shows higher values due the slow market development of RE technologies. As expected, economic and socio-economic impact in the RE sector is lower in scenarios with limited RES expansion plans. Due to large differences in the project pipeline and technology selection, results for the Export scenario show an increase of the ratio between total sales and local jobs. Employment in Algeria and Libya does not profit very much from large wind installations in this scenarios. Therefore, the ratio for both countries increases as in the other scenarios only PV projects are realized in both countries.

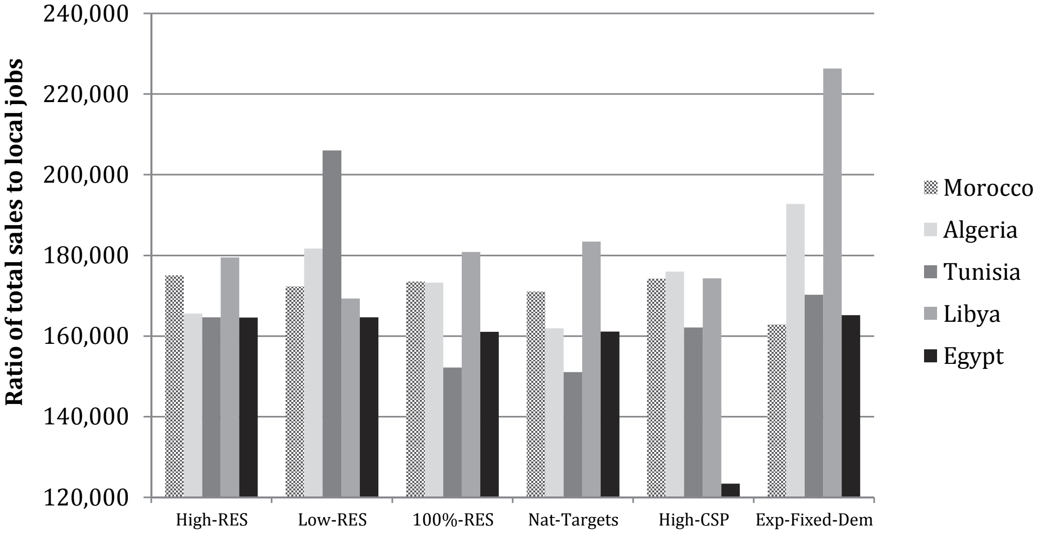

Figure 88: Ratio of total sales to local jobs in the six selected scenarios

In general, all scenarios (including the sensitivity cases) can be sorted in four different groups regarding their country and technology specific impact on manufacturing and employment (see Table 29). The first group of scenarios shows high impact from PV and wind in Morocco and Egypt. Representative scenarios are the High-RES and the 100%-scenario. Scenarios with lower RE expansion plans are expected to have lower impact on employment and manufacturing (e.g. Low-RES scenario in the second group). A third group is represented by the High-CSP scenario which leads to very dynamic CSP market creation in Egypt due to a high CSP pipeline. Scenarios with large PV installations benefit from the strong focus by an above-average market development in the PV supply chain. This market creation starts very early and therefore positively develops over time (group 4)

Table 29: Generalization of impact in four groups

No.	Main effect	Reasons and impact	Other countries	Scenarios	Other scenarios with similar effects
1	**High impact from PV and wind in Morocco and Egypt**	Growth of local manufacturing capabilities in both countries due to large amount of RE projects in Egypt and Morocco	Low development	High-RES, 100%-RES,	National-Markets, Isolation, Low-grid-cost, Low-NG-price Storage, EXP-High-Demand, EXP-Low-Demand, EXP-Assumed-Price,
2	**Low impact from PV and wind in Morocco and Egypt**	Limited RE project pipeline leads to low manufacturing and employment impact	No impact	Low-RES	BAU, (but very limited RE installations)
3	**High impact from CSP in Egypt**	Large CSP project pipeline stimulates the CSP market mainly in Egypt with a huge number of jobs during construction and operation of CSP plants, but also in the component manufacturing supply chain.	No impact	High-CSP	-
4	**Large impact from PV in all countries after 2015**	Strong growth of PV manufacturing due to earlier market entrance in difference countries (Morocco and Egypt, later also in Algeria and Libya). High share of jobs in the component manufacturing supply chain.	-	National-Targets	High-PV, No-Target, EXP-Stable-Price, EXP-Historical-Price

7.9 Electricity system analysis and RE manufacturing: Results and discussion of the combined analysis

The analysis of cost-optimized electricity market results with RETMD regarding their manufacturing and employment impact expands the overall evaluation of the large-scale RES integration into the North African electricity system. Other approaches to evaluate the impact of RE deployment in Europe use large macro-economic models, e.g. Ragwitz et al. (2009). A scenario ranking which connects results of both analyses (RESlion and RETMD) however requires weighting factors to rank the results of each model to the other and to obtain a "complete evaluation". Still these factors strongly depend on systemic preferences. Therefore, this last section focuses on the relations and dependences between the results of both models.

The assessment of manufacturing and employment impact clearly supports the decision making process to create an optimal electricity system as the results demonstrate large ranges and variations of potential local economic and socio-economic impact. However, one disadvantage of the sequential approach with an initial optimization model of electricity markets and an ensuing assessment of local manufacturing potentials is the dependency of the RETMD results on the deployment paths which are a direct result of the optimization with RESlion. This implies that the optimal path in terms of local manufacturing for one country or North Africa is not calculated. Nevertheless, the assessment of different electricity scenarios until 2030 provides the possibility to compare results and localization options obtained by RETMD. The time constraint on the period from 2012 to 2030 is necessary due to increasing uncertainties beyond 2030 regarding economic development and industry structures in North Africa. With significant installations of CSP after 2035 in most of the scenarios, the impact of this technology is negatively influenced by this limitation. Only the High-CSP scenario with its mandatory CSP deployment can evaluate the outcomes of a large CSP project pipeline and the creation of local demand markets. As shown in the last section, each scenario presented in section 5.2 closely follows one of the four development paths due to their analogous RE market deployment to the representative scenarios which are analyzed with RETMD.

Four central conclusions can be derived for the combined system analysis which includes the RESlion and RETMD model results:

1) Scenario results of RESlion, which have fewer boundaries for the specific RE deployment, generally show a high focus of RE deployment in certain countries. This could lead to lower local economic and socio-economic benefits for the total region as countries with lower industry capabilities could be selected. Furthermore, the focus on one technology can have temporally strong dependency (e.g. wind projects with a peak before 2020, PV market development mainly after 2020). This could contradict the basic requirement of having continuous project pipelines which help to develop long-term benefits in terms of manufacturing capabilities and employment.
2) Scenarios with higher total system costs can create stronger economic and socio-economic impact. The National-Targets scenario and the High-CSP scenario both show higher total system costs, but they have a stronger impact on local manufacturing and employment in different countries. Local benefits (manufacturing and job creation) may justify the burden of higher expenses for the electricity system.
3) When optimizing local potential, country specific results of section 7.4 have to be taken into account. In this analysis, local potential for all technologies in Morocco and Tunisia is always above average whereas Libya is always below average due to limited technological know-how and existing industry structure. Egypt shows the highest local potential for wind and CSP, but is currently below average for PV. Algeria shows above-average local potential only for PV.
4) If a focus is set to increase local impact by a strategic RE deployment within one country, a continuous, reliable and strong project pipeline for a certain technology is mandatory in the national (or international) energy strategy. The decision should be directly linked to the availability of local resources and existing local industry know-how. Attractiveness for international investors in this industry sector can further positively affect the development of a certain industry within the economy of a country.

A qualitative overview of the outcomes for the key scenarios regarding “RES-E share”, “CO_2 emissions”, “total system cost” and “creation of local employment” is presented in Table 30.

Table 30: Qualitative comparison of scenario results between 2010 and 2030

Scenario	RES-E share (in 2050)	CO_2 emissions (in 2050 compared to 2010)	Total system costs (between 2010 and 2050 in trillion EUR)	Creation of local employment (2010-2030 in FTE jobs)	Total
BAU scenario	**-** (20%)	**--** (increasing)	**0** (1.99)	**-** (not calculated)	**-**
No-Target scenario	**+** (72%)	**0** (stable)	**+** (1.76)	**+** (not calculated)	**+**
Low-RES scenario	**0** (50%)	**-** (increasing)	**+** (1.78)	**-** (310,000)	**0**
High-RES scenario	**+** (80%)	**0** (stable)	**0** (1.8)	**+** (599,000)	**+/0**
National-Targets scenario	**+** (80%)	**0** (stable)	**0** (1.84)	**++** (706,000)	**+/0**
100%-RES scenario	**++** (100%)	**++** (decreasing)	**-** (2.06)	**++** (759,000)	**+/0**
EXP-High-Demand scenario	**+** (80% + RE export)	**0** (stable)	**0** (2.51 EUR)	**++** (736,000)	**+/0**

(Scenario comparison: „-" = negative rating, „0" = medium rating, „+" = positive rating)

A high RES-E share is often linked with a positive impact regarding local job creation as found in the evaluation in section 7.2 to 7.7. In most of the scenarios, high employment effects are linked with slightly higher total system costs. The No-Target scenario profits from fast transformation to an electricity system based on high shares of RES-E as new RE power plants are evaluated as cheaper than a conventional option based on oil, gas or coal. However, the transformation process of this scenario seems to be faster than a realistic deployment path for RE projects in North Africa. The 100%-RES scenario and National-Targets scenario profit from a large-scale and widely distributed installation of RE projects compared to the other scenarios. Similar to the scenarios with export, these scenarios benefit from the positive development of employment in the RE sector (100%-RES scenario with 759,000 FTE jobs and National-Targets scenario with 706,000 FTE jobs). In both scenarios, total system costs are slightly higher due to the larger RE installations (2060/1840 trillion euros). The evaluation of the Low-RES scenario and BAU scenario resulted in a lower rating due to lower impact in the RE sectors of these countries (310,000 FTE jobs by 2030 in the Low-RES scenario). However, the conventional power sector would still employ workers, mainly for fuel extraction and power plant operation.

8 Conclusions and outlook

By constructing first renewable energy projects, North Africa has forged new paths in order to transform its energy production to a system predominately based on renewable energy. The Moroccan Solar Plan with a first large CSP parabolic trough plant in Ouarzazate is one example of these steps to comprehensively use wind and solar technologies in order to accomplish this transformation. Wind farms at the coasts of the Red Sea in Egypt or of the Mediterranean Sea in Tunisia already generate green electricity for national supply. Currently, energy strategies are in the decision process to define RES deployment, technology portfolios, optimal sites for RE power plants and grid structures of the future electricity system.

In the presented thesis, potential electricity scenarios for North Africa are modeled and evaluated to support this decision process and research on electricity systems with high RES-E shares. Large deployment of RE power plants and their interaction are analyzed for an integrated North African electricity system which allows exchange of electricity between the countries. Additional Export scenarios investigate large electricity transport to Southern Europe regarding quantity and price mechanism from today to 2050.

Scenario results of the optimization model RESlion which is specifically developed for the North African electricity market are combined with an analysis of manufacturing and employment impact of PV, CSP and onshore wind power plants. With the qualitative and quantitative decision model RETMD, the analysis of socio-economic impact enriches the electricity scenarios by evaluating long-term effects of RE technologies on economy and society.

8.1 Conclusion on model developments

The multi-dimensional analysis on renewable energy in North Africa is conducted by linking the energy system analysis with an assessment of socio-economic impact. The importance of economic growth and job creation in North Africa requires including factors such as technological know-how and local manufacturing into the analysis of an optimal electricity system. This linkage is successfully achieved by analyzing the electricity system with two modeling approaches:

1) Electricity market model RESlion as optimization model (linear program) for expansion planning and detailed hourly operation dispatch
2) Renewable Energy Technology Market Development model RETMD as decision model to calculate (local) sales and employment of PV, CSP and wind power

Important constraints and problems, which are postulated for energy system modeling and large-scale RES integration into future electricity markets, are the combination of power plant and grid planning in order to counterbalance optimal use of RES and required grid extension between sub-national regions. Furthermore, dependency of demand on transmission losses and integration of existing power plants (>10 MW) into the model significantly influence the technology selection and optimal deployment paths.

The model development of RESlion fulfills these requirements by implementing a continuous development plan for the electricity system, long-term achievement of RES targets until 2050, optimal site selection according to solar and wind resources, regional exchange of electricity, grid constraints and costs for transmission. They are considered in an expansion planning of power plants and transmission lines as well as in an hourly generation dispatch. To connect long-term energy system planning with the diversity of operation due to many different system conditions (high/low demand, fluctuating generation, seasonal effects, etc.), expansion planning and detailed hourly generation dispatch are implemented in the same model. However, a set-up of a direct iterative model between both is not recommended due to long computing time of the expansion planning problem, since expansion planning of conventional and RE power plant is linked with planning of new transmission capacities.

Modeling of socio-economic impact including continuous market development and dynamic local value creation from PV, CSP and wind power plants represents an approach which has not been found in literature. The RETMD model uses sector specific data of the North African renewable energy market by taking existing local industry competences and performance into account. RETMD model includes a large range of the sector and country specific data, which are condensed from personal interviews with stakeholders. This large data makes the model very powerful to evaluate the development in the North African RE industry sectors. It prognosticates the continuous growth of local capabilities and technological know-how related to the deployment of RE technologies. Depending on local market demand and competiveness in North African countries, development of (local) sales and employment created by construction and operation of RE power plants is quantified.

Main limitations of the RETMD model consist of the simplification of a complex real world problem. As the model simplifies long-term industry development in multifaceted and heterogeneous industry sectors, the model cannot represent single strategic investment decisions, disruptive changes of industries or all foreign investments. Nevertheless, its approach to calculate country, time, technology and component specific values for international and national (local) industry sales as well as the number of jobs provides a very detailed assessment on the socio-economic impact of RES in North Africa. Certainly, an analysis of net impact and substitution effects in other industry sectors may improve the results. However, availability of data and uncertainties of interactions between sectors complicate such an analysis.

8.2 Conclusion on renewable energy in North Africa

Large-scale expansion of renewable energy sources in North Africa will significantly accelerate during the next decade. Large potential of excellent wind and solar resources and economic competiveness to fuel-fired power plants perfectly offer the opportunity to transform the existing national conventional power systems in an integrated RES based system. Growth of renewable energy in North Africa can be beneficial in terms of local energy supply, independency from fuel prices and total system costs.

Until 2050, total electricity consumption is assumed to increase from 250 TWh today to over 1000 TWh due to economic development and population growth. The scenario analysis indicates that a generation share of approximately 72% from RES is optimal for the system because low generation costs of RES are realized and back-up capacity running on natural gas can be used to generate electricity during hours without sunshine and wind. Storage systems are not widely placed in the system (except to CSP plants with integrated thermal heat storage) and curtailment does not increase to very high values.

The optimal power plant portfolio for North Africa is based on a mixture of different technologies according to the model results. Onshore wind provides about 26%, PV 17%, CSP 33%, Hydro 1% and conventional sources 23% of the total electricity generation in 2050 in the scenario with a complete least-cost assumption. RE power plants are distributed over all countries with a focus of onshore wind power on Morocco and Egypt as well as PV on Algeria, Tunisia and Libya. CSP plants are primarily constructed at sites with high direct irradiation with low distances to load centers. In the literature, only scenarios with high shares of onshore wind power (Zickfeld et al., 2012) and CSP (Scholz, 2012) are presented so far. The technology-balanced scenarios using CSP, PV, wind onshore and gas-fired power plants are a result of integrating recent cost data, specific site conditions, grid constraints and regional demand into the RESlion model. From a time perspective, today's power plant portfolio is extended firstly by onshore wind power plants at sites with excellent wind conditions, secondly by PV plants close to the demand and thirdly by large CSP plants which flexibly operate by using their large thermal heat storages. Typical operation of CSP shows a dominating storage use during evening and night hours as well as a frequent reduction of electricity generation during hours of sunshine to store energy for later use. Overproduction and curtailment at midday reduce the potential for PV in the system.

RES capacity planning prefers sites which offer good solar or wind resources, but are also located close to the demand. Sites far away from existing infrastructure and electricity demand are not selected in the model for future years. An essential expansion of existing high voltage transmission lines between regions takes place in the model with a length of about 30,000 kilometers (with a capacity of one GW_{NTC}) between 2030 and 2050 to transport electricity from its point of generation to demand centers (mainly from sites of CSP plants and wind power plants to coastal metropolitan areas).

Cumulative total system costs for all five North African countries are about 1800 bn EUR until 2050 including costs for construction and operation of power plants and high voltage transmission lines between sub-national regions (medium and low voltage grids are not considered). Costs for electricity consumption are between 60 and 100 EUR/MWh depending on scenario and year. Cost competiveness of renewable energy technologies reduces the need for large support mechanisms as renewable energy technologies are preferred according to the model results.

Electricity export to Europe with annual volumes up to 400 TWh increases installed RES capacity equally distributed to all technologies. Total electricity generation exceeds 1800 TWh per year, if Europe imports 400 TWh from North Africa. Electricity generation close to access points for HVDC transmission lines to Europe is preferred. If sites for RES with long distance to the coast are chosen, it would be conducive to extend HVDC transmission lines to the point of electricity generation.

Price mechanisms with a stable tariff of 70 EUR/MWh or a historical electricity pool price (from the Spanish market) plus a premium of 30 EUR/MWh (average total 67 EUR/MWh) only uses surplus electricity which would be curtailed without export in the model. But, a specific tariff which aims to create imports during morning and evening hours at an average price of 91 EUR/MWh creates a demand of 168 TWh in 2050.

In general, electricity imports from North Africa are neither a cheap nor a very expensive option for Europe to be supplied by external RES. The results indicate that the North African electricity system is able to provide additional flexible RES generation for Europe by exporting electricity during hours with high demand to Southern Europe. Flexible electricity generation from CSP might obtain a high value in the future as technologies such as wind power and PV does not provide this option.

Large problems still exist to realize exchange of electricity between North Africa and Europe as well as to install an intercontinental Supergrid caused by a diversity of political strategies, distributed responsibilities, many different stakeholders, temporal uncertainties and long-term planning process for grid extensions and large power plants. Results of this energy system analysis clearly extend quantitative knowledge of potential developments and facilitate discussion between different stakeholders by providing a first in-depth analysis of the North African electricity system on a sub-national basis.

North African countries can also benefit from the use of RE technologies in a second dimension. Manufacturing of components and providing services related to PV, CSP and onshore wind power plants can significantly be extended due to large local market demand, technological learning and know-how transfer. In 2030, between 40,000 and 100,000 FTE jobs (depending on market scenario and industrial development) can be predicted in the renewable energy sector to manufacture components and equipment as well as to install and operate power plants. Local companies can have annual sales in a range between 3 and 7 bn euros. National economies can profit from an industrial policy to specialize industry and companies on one specific technology. Therefore electricity market scenarios with high installations of a certain technology in one country improve the potential for local manufacturing and increase socio-economic impact. In opposite to this finding, low penetration of one technology does not provide many opportunities to localize large parts of the value chain. Ambitious RE targets can additionally increase job creation due to larger market demand for RE components.

To conclude on the overall technology choices and the optimal strategy for the energy transformation in North Africa, a trade-off exists between an optimal technology portfolio from an electricity system perspective and the opportunities through local manufacturing. However, cooperation in the field of energy system planning and formulating of a common RE strategy can improve system security and predictability of system developments as well as decrease uncertainty. Long-term international cooperation in the field of industrial policy will positively influence economic development and business creation. By using competitive advantages, local manufacturing can take place in areas of high local knowledge and competences. Trade of components and services as well as exchange of electricity with neighboring countries will increase the economic benefits from the long-term deployment of RES in North Africa.

8.3 Outlook and further research

The modeling approaches of RESlion and RETMD can be extended and more directly connected in future research activities to address further questions of RES integration, exchange of electricity and socio-economic impact of renewable energy technologies.

The RESlion model is specifically developed for the large-scale integration of RES in electricity systems by solving the expansion and dispatch problem concurrently and applying a regional approach. By developing model approaches which can solve models with a larger amount of data, the integration of more technology options, more different sites and higher geographical resolution and consequently the reproduction of the electricity system can be more detailed. Additionally, coverage of the model can be extended to Southern Europe by including the electricity markets of Portugal, Spain, France, Italy, Croatia, Albania or Greece. However, countries like France have many interactions with countries in the North. If these relations are not included, system borders of the model are arbitrary. Another option would be to add a detailed grid model with AC/DC flow to extend the analysis on the grid impact from RES.

The two-step approach used in the model improves solving the problem by incorporate adequate levels of time and many time slices. This approach can be extended by implementing a higher temporal resolution or by logically separating the problem in further sub-problems. However, a careful formulation is necessary to still fulfill the basic requirements of an electricity system with high RES-E shares and to simultaneously optimize power plants and electric grid in the same model instead of a sequential approach.

Many optimization models for electricity markets definitely have to be extended to consider more non-economic issues in their modeling approach. Minimization of total system costs is a widely used approach to represent real world decisions based on cost aspects. However, "optimal" scenarios for an electricity system have to reflect other decision parameters in addition to the economic valuation. A direct implementation of RETMD and RESlion into a single optimization model requires to economically quantify benefits of socio-economic impact compared to costs of the electricity system. This might be a reason why the connection of both analyses will remain challenging.

The findings of this research should encourage developing more multi-dimensional analyses of energy systems by connecting an economic analysis with the socio-economic or social impact of future energy systems using renewable energy sources and enabling technologies.

To accomplish the large-scale integration of RES in North Africa which is technically and economically feasible according to the model results, existing barriers such as limited electricity exchange and coordination between countries, subsidies for fossil fuels or non-discriminatory market entrance of new stakeholders have to be reduced. Furthermore, synchronized investments in new power plants and transmission lines are certainly accelerated if a clear energy roadmap and an efficient legal framework are declared for each country. Then, a renewable energy based energy system can benefit from its cost advantages, sustainability and socio-economic impact.

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10 Appendix

Table 31: Distance between centers of the regions in km

Length in km		To																											
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
From	1		500		750																								
	2	500		350	450																								
	3		1920		300	350																							
	4	750	450	300		350	450																						
	5			350	350		550															200							
	6				450	550																							
	7								500													500							
	8							500		800	340												1200						
	9								800		720			350															
	10								340	720		280	400																
	11										280		400		300									800					
	12										400	400		750		500													
	13									350			750																
	14											300				280									700				
	15												500		280		300												
	16															300		400											
	17																400		580	580					1000				
	18																	580											
	19																	580			580					1000	1000		
	20																			580									
	21					200		500															1000						
	22								1200													1000		1000					
	23											800											1000		500				
	24														700			1000						500		1200			
	25																			1000					1200				
	26																			1000								420	
	27																										420		500
	28																											500	

Table 32: Existing net transfer capacity between regions (own calculation based on (AUPTDE, 2011a), potential HVDC connections to and within Europe are marked with "X"

NTC in MW		To																											
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
From	1		2110		570																								
	2	2110		1920	1350																								
	3		350		1920	190																							
	4	570	1350	1920		2510	1540																						
	5			190	2510		190															1400							
	6				1540	190																							
	7								2110													X							
	8							2110		770	1340												X						
	9								770		190			770															
	10								1340	190		1540	380																
	11										1540		1730		380									X					
	12										380	1730		960		380													
	13									770			960																
	14											380				1920									X				
	15												380		1920		1730												
	16															1730		200											
	17																200		1340	960					X				
	18																	1340											
	19																	960			380					X	180		
	20																			380									
	21					1400		X															X						
	22								X													X		X					
	23											X											X		X				
	24														X			X						X		X			
	25																			X					X				
	26																			180								2570	
	27																										2570		2770
	28																											2770	

Table 33: Population of each model region (Brinkhoff, 2013)

Model region	Country	Geographical regions	Population	Population share of country
1	Morocco	Guelmin, Souss, Laayoune	3,665,000	13%
2	Morocco	Doukkala, Marrakech	5,207,000	18%
3	Morocco	Grand Casa, Rabat, Chaouia	7,363,000	26%
4	Morocco	Meknes, Fez	5,300,000	13%
5	Morocco	Tanger Gharb	4,498,000	16%
6	Morocco	Oriental, Taza	3,785,000	13%
7	Algeria	Aïn Témouchent, Béchar, El Bayadh, Mascara, Mostaganem, Naâma, Oran, Relizane, Saïda, Sidi bel Abbès, Tiaret, Tindouf, Tlemcen	7,544,756	22%
8	Algeria	Aïn Defla, Blida, Bouira, Boumerdès, Chlef, El Djazaïr , Algiers], Médéa, Tipaza, Tissemsilt, Tizi Ouzou	10,089,874	30%
9	Algeria	Adrar, Djelfa, Ghardaïa	2,311,098	7%
10	Algeria	Béjaïa, Bordj Bou Arreridj, Jijel, Sétif	5,425,456	16%
11	Algeria	Annaba, Constantine, El Tarf, Guelma, Mila, M'Sila, Skikda, Souk Ahras	3,775,625	11%
12	Algeria	Batna, Biskra, El Oued, Khenchela, Ouargla, Oum El, Bouaghi. Tébessa	4,704,251	14%
13	Algeria	Illizi, Tamanrasset	228,970	1%
14	Tunisia	Ariana, Béja, Ben Arous, Bizerte, Jendouba, Manouba, Nabeul, Tunis, Zaghouan	4,697,100	44%
15	Tunisia	Le Kef, Mahdia, Monastir, Kasserine, Kairouan, Sfax, Sidi Bouzid, Siliana, Sousse,	4,403,900	41%
16	Tunisia	Médenine, Gabès, Gafsa, Kébili, Tataouine, Tozeur	1,572,700	15%
17	Libya	Al-Jabal al-Gharbi, Al-Jifārah, Al-Marqab, An-Nuqāṭ al-Khams, Az-Zāwiyah, Miṣrātah, Nālūt, Ṭarābulus,	3,460,358	61%
18	Libya	Al-Jufrah, Ghāt, Marzūq, Sabhā, Wādī al-Ḥayāt, Wādī ash-Shāṭī	442,090	8%
19	Libya	Al-Buṭnān, Al-Jabal al-Akhdar, Al-Marj, Al-Wāḥah, Banghāzī, Darnah, Surt	1,706,916	30%
20	Libya	Al-Kufrah	48,328	1%
26	Egypt	Dakahlia, Beheira, Gharbia, Alexandria, Ismaïlia, Giza, Monufia, Cairo, Qalyubia, Sharqia, Suez, Port Said, Damietta, Kafr el-Sheikh, Maṭrūḥ, South Sinai, North Sinai	57,400,000	71%
27	Egypt	Red Sea, Fayoum, Al-Minyā, Asyut, Beni Suef, Sohag	18,600,000	23%
28	Egypt	Luxor, New Valley, Aswan, Qena,	5,396,000	7%
Total			160,253,422	

Table 34: Sites for large RE installations in the RESlion model

Location	Region	Name	Coordinates	Wind	PV	CSP
1	1	Souss-Massa-Draa	30,259067;-8,972169	x	x	x
2	1	Tarfaya	27.92078;-12.9394	x		
3	1	Boujdour	26.168735;-14.447222	x		
4	1	Ouarzazate	30.982561;-6.878915		x	x
5	1	Sebkhat Tah	26887780;-11712341			x
6	1	Guelmim1 CSP	28968499;-10059586			x
7	1	Boudjdour	26372185;-13003235			x
8	2	Doukkala-Abda	32,509762;-8,444825	x	x	x
9	2	Essouira	31.459125;-9.775314	x	x	
10	3	Rabat-Sale-Zemmour-Zaer	33,83392;-6,379395	x	x	x
11	3	Casablanca	33.521934;-7.709885	x	x	
12	4	Meknes-Tafilalet	32,694866;-5,280763	x	x	x
13	4	Meknes	33.935385;-5.520859	x		
14	4	Enjil	33.20652;-4.527283		x	
15	4	Ait Halwane	32.219772;-6.647186		x	
16	4	Meknes	33.922851;-5.597992		x	
17	5	Tanger-Tetoun	34,994004;-5,632325	x	x	x
18	5	Haouma	35.83178;-5.3546	x		
19	5	Tangier 2	35.8216;-5.6783	x		
20	6	Oriental	34,016242;-3,127442	x	x	x
21	6	Taza	34.090186;-4.030162	x		
22	6	Ain Beni Mathar	34.012619;-2.019235		x	x
23	7	Tlemcen	35,101934;-1,193849	x	x	x
24	7	Oran/Tighennie	35.393528;0.323181	x		
25	7	Naâma, Algeria	33.450464;-0.879364		x	x
26	8	Tissemsilt	35,728677;1,995849	x	x	x
27	8	Algier	36.421282;2.347412	x	x	
28	8	Oran/Tighennie	35.393528;0.323181		x	
29	9	M*Sila	34,849875;4,412841	x	x	x
30	9	Gardaia	32.4;3.8	x		
31	9	Djelfa	34.669359;3.22051		x	x
32	9	Hassi-R'mel ISCC, Hassi-R'mel, Algeria	33.131341;3.608551		x	x
33	10	Jijel	36,738884;6,192627	x	x	x
34	10	Batna	35.5;6.2	x		
35	10	Setif	36.141756;5.428505		x	x
36	11	Oum El Bouaghi	35,639441;7,445068	x	x	x
37	11	Annaba	36.55;7.513046	x	x	
38	12	Khenchela Province	34,488448;7,181396	x	x	x
39	12	Biskra	34.397845;6.038818	x		
40	12	Meghaïer, Algeria	33.979809;5.841064		x	x
41	13	Ouargla	33,192731;6,566162	x	x	x
42	13	Inamenass	27.936181;9.708252	x		

Location	Region	Name	Coordinates	Wind	PV	CSP
43	13	Ouargla2	32.026706;5.326538		x	x
44	14	Jendouba	36,774092;9,006958	x	x	x
45	14	Bizerte	37.292669;9.787073	x		
46	14	Kelibia, Sidi Daoud, Haouaria, Nabeul, Tunesien	36.898293;10.933914	x		
47	14	Le Kef	36.244273;8.758392		x	x
48	14	Tebourba (Nähe Tunis)	36.85545;9.741669		x	x
49	15	Sfax	34,894942;10,292358	x	x	x
50	15	Thala	35.601486;8.673248	x		
51	15	Monastir	35.719758;10.790863	x		
52	15	Kairouan	35.877924;10.150909		x	x
53	16	Medenine	33,247876;10,665893	x	x	x
54	16	Gabes	33.830498;10.107193	x		
55	16	Gafsa	34.424279;8.780036		x	x
56	16	Tataouine	32.157768;10.106621		x	x
57	17	Az-Zawiyah	32,509762;12,498779	x	x	x
58	17	Misrata	32.29642;15.223846	x	x	
59	17	Sirt	31.158759;16.794891	x	x	
60	17	Bani Walid	31.802893;13.861084			x
61	18	Wadi Ash-Shati	29,190533;13,948974	x	x	x
62	18	Sabha	27.780772;10.775757		x	x
63	19	Darnah	31,522361;22,342529	x	x	x
64	19	Derna	32.694866;22.724762	x	x	
65	19	Al Maqrun	31.217499;20.28305	x		
66	19	Adjdabia	30.704058;20.39978		x	x
67	20	Al Wahah	29,113775;21,262206	x	x	x
68	20	Srir West	26.283565;21.999206		x	x
69	21	El Dabaa	31.010571;28.173523	x	x	
70	21	Suez (east)	29.764377;32.798767	x	x	x
71	21	Kairo (west)	30.050077;30.470123	x	x	x
72	22	Zafaga	27.110479;33.760529	x	x	x
73	22	Minya	27.945886;30.551147	x	x	x
74	23	Luxor	25.76032;32.232055	x	x	x
75	26	Port Said	31,052934;32,440796	x	x	x
76	26	Alexandria	31.198706;30.041656		x	
77	26	Kairo	30.104742;31.294098		x	
78	27	Red Sea Governate1	28,613459;32,647705	x	x	x
79	27	Kuraymat	29.24327;31.236649		x	x
80	28	Red Sea Governate2	25,582085;32,647705	x	x	x
81	28	Kom Ombo	24.470276;32.836647		x	x

Table 35: Historical efficiency of conventional power plants in North Africa based on (UNFCCC, 2010; 2012b; a)

	1960	**1970**	**1980**	**1990**	**2000**	**2010**
	eff. [%]	eff. [%]	eff. [%]	eff. [%]	eff. [%]	eff. [%]
Coal	34.0%	36.0%	38.0%	42.0%	44.0%	46.0%
CCGT	45.0%	46.0%	48.0%	50.0%	55.0%	58.0%
GT (oil)	18.0%	19.0%	25.0%	30.0%	32.0%	36.0%
GT (NG)	27.0%	28.0%	29.0%	30.0%	32.0%	36.0%

Table 36: Additional economic and technical parameter

Parameter	**Value**	**Source**
Interest rate / WACC (power plants, transmission lines)	8.0%	own assumption
Discount factor	3.0%	own assumption
Maximum load change (hard coal, CCGT, CSP)	50.0%	own assumption
Maximum load change (GT, Oil)	100.0%	own assumption
Storage losses (per hour)	0.2%	own assumption
Distribution losses	8.0%	own assumption
Security of Supply by national generation	75.0%	own assumption
Parameter for CSP		
Maximum charge of CSP thermal storage	340 MWh_{th}	(Madaeni et al., 2012)
Maximum discharge of CSP thermal storage	325 MWh_{th}	(Madaeni et al., 2012)
CSP storage losses (per hour)	0.031%	(Madaeni et al., 2012)
Roundtrip efficiency	1.5%	(Madaeni et al., 2012)
Minimum operating power block	120 MWh_{th}	(Madaeni et al., 2012)
Maximum operating power block	280 MWh_{th}	(Madaeni et al., 2012)
Start-up energy	58.3 MWh_{th}	(Madaeni et al., 2012)
Maximum share of natural gas	10%	(Madaeni et al., 2012)

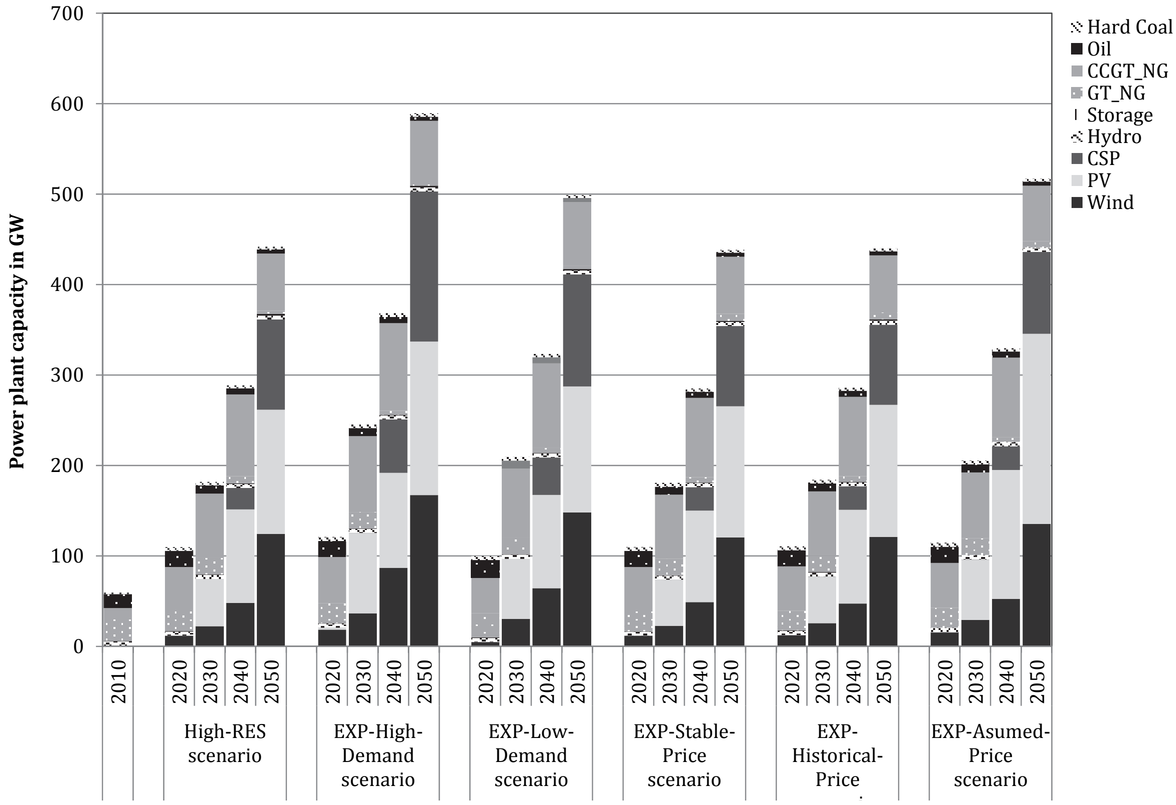

Figure 89: Installed capacity in Export scenarios

Table 37: Installed capacity per country (Base scenario)

	Morocco	Algeria	Tunisia	Libya	Egypt
2030	[in MW]	[in MW]	[in MW]	[in MW]	[in MW]
Wind Power	7209	0	0	0	4237
PV	1047	1250	424	1848	2629
CSP	120	20	0	0	20
Hydro	1265	271	40	0	2870
Oil	2457	341	340	5757	0
GT_NG	0	5304	2579	4501	5800
CCGT_NG	9082	23882	4417	6056	25199
Hard Coal	4898	3543	1815	2464	15894
Storage	500	0	0	0	0
2050					
Wind Power	15862	0	0	0	6450
PV	4902	5268	1285	8204	58713
CSP	120	20	0	0	639
Hydro	1265	271	40	0	2870
Oil	1700	0	0	2800	0
GT_NG	0	1200	500	0	4495
CCGT_NG	24038	20874	6643	5708	50062
Hard Coal	9246	7644	3916	5315	34289
Storage	500	0	0	0	0

Table 38: Installed capacity per country (No-Target scenario)

	Morocco	Algeria	Tunisia	Libya	Egypt
2030	[in MW]	[in MW]	[in MW]	[in MW]	[in MW]
Wind Power	19108	0	59	4407	12578
PV	5354	19457	6944	7273	42011
CSP	120	20	0	0	5559
Hydro	1265	271	40	0	2870
Oil	2457	341	340	5757	0
GT_NG	0	5304	2579	4501	5800
CCGT_NG	5309	12163	4633	5242	32856
Hard Coal	3340	0	0	0	750
Storage	500	0	0	0	0
2050					
Wind Power	50677	4533	3340	9223	40167
PV	17492	39611	10018	8776	57267
CSP	5458	6351	4491	3704	60592
Hydro	1265	271	40	0	2870
Oil	1700	0	0	2800	0
GT_NG	1852	1200	25	0	2101
CCGT_NG	17145	19716	6298	6044	25557
Hard Coal	2420	0	0	0	869
Storage	1057	0	0	0	0

Table 39: Installed capacity per country (Low-RES scenario)

	Morocco	Algeria	Tunisia	Libya	Egypt
2030	[in MW]	[in MW]	[in MW]	[in MW]	[in MW]
Wind Power	10838	0	0	0	7960
PV	1215	3013	1033	2884	9553
CSP	120	20	0	0	20
Hydro	1265	271	40	0	2870
Oil	2457	341	340	5757	0
GT_NG	0	5304	2579	4501	5800
CCGT_NG	9176	13695	5013	6890	38678
Hard Coal	3340	0	0	0	750
Storage	500	0	0	0	0
2050					
Wind Power	32817	0	0	3142	18772
PV	24299	39396	12909	13411	79522
CSP	120	20	780	15	26805
Hydro	1265	271	40	0	2870
Oil	1700	0	0	2800	0
GT_NG	594	2164	500	0	8560
CCGT_NG	25955	25450	9370	9608	27955
Hard Coal	2420	305	0	0	25542
Storage	500	0	0	0	0

Table 40: Installed capacity per country (High-RES scenario)

	Morocco	Algeria	Tunisia	Libya	Egypt
2030	[in MW]	[in MW]	[in MW]	[in MW]	[in MW]
Wind Power	13136	0	0	365	8638
PV	2624	5448	1843	6292	35970
CSP	120	20	0	0	20
Hydro	1265	271	40	0	2870
Oil	2457	341	340	5757	0
GT_NG	0	5304	2579	4501	5800
CCGT_NG	7955	13193	4904	6506	38674
Hard Coal	3340	0	0	0	750
Storage	500	0	0	0	0
2050					
Wind Power	59218	9315	4641	10358	40692
PV	15187	34380	10696	8722	68367
CSP	10541	11256	8187	4784	64920
Hydro	1265	271	40	0	2870
Oil	1700	0	0	2800	0
GT_NG	0	1067	0	0	2397
CCGT_NG	11938	16435	4811	5021	25186
Hard Coal	2420	0	0	0	750
Storage	1779	0	0	0	0

Table 41: Installed capacity per country (National-Targets scenario)

	Morocco	Algeria	Tunisia	Libya	Egypt
2030	[in MW]	[in MW]	[in MW]	[in MW]	[in MW]
Wind Power	7444	1652	484	1301	8664
PV	0	17940	6553	7694	31605
CSP	120	22	0	0	20
Hydro	1265	271	40	0	2870
Oil	2457	341	340	5757	0
GT_NG	0	5304	2579	4501	5800
CCGT_NG	11032	12071	4632	6184	38674
Hard Coal	3340	0	0	0	750
Storage	500	0	0	0	0
2050					
Wind Power	58913	10926	4187	10022	40243
PV	15679	34280	10677	9123	65652
CSP	5430	19658	10618	5981	63371
Hydro	1265	271	40	0	2870
Oil	1700	0	0	2800	0
GT_NG	0	29	0	0	914
CCGT_NG	18522	11287	4745	5143	27253
Hard Coal	2420	0	0	0	3099
Storage	1085	0	0	0	0

Table 42: Installed capacity per country (100%-RES scenario)

	Morocco	Algeria	Tunisia	Libya	Egypt
2030	[in MW]	[in MW]	[in MW]	[in MW]	[in MW]
Wind Power	14418	0	0	1372	10065
PV	5234	14658	5919	7736	42590
CSP	120	20	0	0	20
Hydro	1265	271	40	0	2870
Oil	2457	341	340	5757	0
GT_NG	0	5304	2579	4501	5800
CCGT_NG	7221	12672	4734	6159	38674
Hard Coal	3340	0	0	0	750
Storage	500	0	0	0	0
2050					
Wind Power	52928	810	937	2526	30050
PV	39767	54261	18887	18877	114014
CSP	39030	32946	17026	22066	121628
Hydro	1265	271	40	0	2870
Oil	1700	0	0	2800	0
GT_NG					
CCGT_NG	3484	7283	1950	1085	18497
Hard Coal	2020	0	0	0	0
Storage	3793	2632	621	1017	939

Table 43: Installed capacity per country (National-Markets scenario)

	Morocco	Algeria	Tunisia	Libya	Egypt
2030	[in MW]	[in MW]	[in MW]	[in MW]	[in MW]
Wind Power	12342	0	0	377	8638
PV	3012	6111	1917	6359	36356
CSP	120	20	0	0	20
Hydro	1265	271	40	0	2870
Oil	2457	341	340	5757	0
GT_NG	0	5304	2579	4501	5800
CCGT_NG	8188	13341	4893	6585	38852
Hard Coal	3340	0	0	0	750
Storage	500	0	0	0	0
2050					
Wind Power	56258	11493	4800	7718	42834
PV	14013	34644	10960	12977	65738
CSP	8942	14251	6816	5982	65895
Hydro	1265	271	40	0	2870
Oil	1700	0	0	2800	178
GT_NG	3372	1200	0	0	2517
CCGT_NG	13252	16320	4942	5207	25205
Hard Coal	2420	0	0	0	750
Storage	1668	0	0	0	0

Table 44: Installed capacity per country (Isolation scenario)

	Morocco	Algeria	Tunisia	Libya	Egypt
2030	[in MW]	[in MW]	[in MW]	[in MW]	[in MW]
Wind Power	13059	0	0	375	8639
PV	2740	5750	1825	6287	35704
CSP	120	20	0	0	20
Hydro	1265	271	40	0	2870
Oil	2457	341	340	5757	0
GT_NG	0	5304	2579	4501	5800
CCGT_NG	7946	13219	4900	6502	38674
Hard Coal	3340	0	0	0	750
Storage	500	0	0	0	0
2050					
Wind Power	58686	10445	4080	10480	41232
PV	13788	34381	11824	8707	66817
CSP	9324	13030	7331	4971	65560
Hydro	1265	271	40	0	2870
Oil	1700	0	0	2800	0
GT_NG	76	1200	0	0	2309
CCGT_NG	12909	16341	5169	4986	25150
Hard Coal	2420	0	0	0	750
Storage	1616	0	0	0	0

Table 45: Installed capacity per country (High-CSP scenario)

	Morocco	Algeria	Tunisia	Libya	Egypt
2030	[in MW]	[in MW]	[in MW]	[in MW]	[in MW]
Wind Power	11158	0	0	0	1837
PV	1434	3254	561	3327	8246
CSP	127	387	831	180	18080
Hydro	1265	271	40	0	2870
Oil	2457	341	340	5757	0
GT_NG	0	5304	2579	4501	5800
CCGT_NG	9002	13340	4560	6606	27269
Hard Coal	3340	0	0	0	750
Storage	500	0	0	0	0
2050					
Wind Power	53713	3608	1091	6650	40668
PV	9320	29620	7016	7577	33259
CSP	11218	11977	9982	6005	73821
Hydro	1265	271	40	0	2870
Oil	1700	0	0	2800	0
GT_NG	0	763	0	0	0
CCGT_NG	11786	15448	4345	4221	18852
Hard Coal	2420	0	0	0	750
Storage	907	0	0	0	0

Table 46: Installed capacity per country (High-PV scenario)

	Morocco	Algeria	Tunisia	Libya	Egypt
2030	[in MW]	[in MW]	[in MW]	[in MW]	[in MW]
Wind Power	10769	0	0	0	6881
PV	4359	6671	2256	7400	41410
CSP	120	20	0	0	20
Hydro	1265	271	40	0	2870
Oil	2457	341	340	5757	0
GT_NG	0	5304	2579	4501	5800
CCGT_NG	8779	13078	4868	6608	38657
Hard Coal	3340	0	0	0	750
Storage	500	0	0	0	0
2050					
Wind Power	58876	803	2378	8834	42261
PV	33599	57920	18467	18068	138964
CSP	4062	7220	7250	3031	59324
Hydro	1265	271	40	0	2870
Oil	1700	0	0	2800	0
GT_NG	2903	1200	228	0	2452
CCGT_NG	14349	19053	5785	6705	27589
Hard Coal	2420	0	0	0	1165
Storage	2466	0	0	0	0

Table 47: Installed capacity per country (Low-Grid-Cost scenario)

	Morocco	Algeria	Tunisia	Libya	Egypt
2030	[in MW]	[in MW]	[in MW]	[in MW]	[in MW]
Wind Power	13676	0	0	365	8650
PV	2952	5466	1845	6292	34171
CSP	120	20	0	0	20
Hydro	1265	271	40	0	2870
Oil	2457	341	340	5757	0
GT_NG	0	5304	2579	4501	5800
CCGT_NG	7690	13134	4903	6506	38674
Hard Coal	3340	0	0	0	750
Storage	500	0	0	0	0
2050					
Wind Power	60126	7200	4308	12861	40090
PV	12675	33949	9969	7575	65463
CSP	9959	10755	9300	4046	64150
Hydro	1265	271	40	0	2870
Oil	1700	0	0	2800	0
GT_NG	0	657	0	0	1141
CCGT_NG	11616	16710	4905	5041	25733
Hard Coal	2420	0	0	0	750
Storage	1076	0	0	0	0

Table 48: Installed capacity per country (High-Grid-Cost scenario)

	Morocco	Algeria	Tunisia	Libya	Egypt
2030	[in MW]	[in MW]	[in MW]	[in MW]	[in MW]
Wind Power	12899	0	0	370	8663
PV	2498	5523	1890	6378	36442
CSP	120	20	0	0	20
Hydro	1265	271	40	0	2870
Oil	2457	341	340	5757	0
GT_NG	0	5304	2579	4501	5800
CCGT_NG	8070	13177	4903	6502	38674
Hard Coal	3340	0	0	0	750
Storage	500	0	0	0	0
2050					
Wind Power	39621	14128	4810	9240	30011
PV	28728	37032	12953	11031	70238
CSP	18596	15681	8142	6118	73135
Hydro	1265	271	40	0	2870
Oil	1700	0	0	2800	0
GT_NG	0	348	0	0	0
CCGT_NG	11940	14994	3661	4067	24040
Hard Coal	2020	0	0	0	966
Storage	2339	228	212	461	220

Table 49: Installed capacity per country (Storage scenario)

	Morocco	Algeria	Tunisia	Libya	Egypt
2030	[in MW]	[in MW]	[in MW]	[in MW]	[in MW]
Wind Power	13136	0	0	365	8638
PV	2624	5448	1843	6292	35970
CSP	120	20	0	0	20
Hydro	1265	271	40	0	2870
Oil	2457	341	340	5757	0
GT_NG	0	5304	2579	4501	5800
CCGT_NG	7955	13193	4904	6506	38674
Hard Coal	3340	0	0	0	750
Storage	500	0	0	0	0
2050					
Wind Power	59141	9237	4585	10304	41160
PV	15208	34439	10662	9222	74253
CSP	10282	10950	7990	4622	62415
Hydro	1265	271	40	0	2870
Oil	1700	0	0	2800	0
GT_NG	0	1109	0	0	2509
CCGT_NG	11963	16542	4837	5078	25280
Hard Coal	2420	0	0	0	750
Storage	2125	0	0	200	2790

Table 50: Installed capacity per country (Low-NG-Price scenario)

	Morocco	Algeria	Tunisia	Libya	Egypt
2030	[in MW]	[in MW]	[in MW]	[in MW]	[in MW]
Wind Power	13547	0	0	397	8249
PV	2729	7070	2293	6792	33295
CSP	120	20	0	0	20
Hydro	1265	271	40	0	2870
Oil	2457	341	340	5757	0
GT_NG	0	5304	2579	4501	5800
CCGT_NG	7045	11852	4436	5658	38665
Hard Coal	3340	0	0	0	750
Storage	500	0	0	0	0
2050					
Wind Power	59174	8771	4424	10281	40706
PV	14716	34110	10304	8773	69322
CSP	10435	11972	8716	5000	62470
Hydro	1265	271	40	0	2870
Oil	1700	0	0	2800	0
GT_NG	790	1200	169	0	4216
CCGT_NG	11077	16028	4692	4187	25231
Hard Coal	2420	0	0	0	750
Storage	1899	0	0	0	0

Table 51: Installed capacity per country (NT-Low-Fuel-Price scenario)

	Morocco	Algeria	Tunisia	Libya	Egypt
2030	[in MW]	[in MW]	[in MW]	[in MW]	[in MW]
Wind Power	12401	0	0	278	8252
PV	3227	7221	2372	6893	35023
CSP	120	20	0	0	20
Hydro	1265	271	40	0	2870
Oil	2457	341	340	5757	0
GT_NG	0	5304	2579	4501	5800
CCGT_NG	8658	11870	4425	5732	38654
Hard Coal	3340	0	0	0	750
Storage	500	0	0	0	0
2050					
Wind Power	31731	0	0	1085	23489
PV	22974	37777	13010	12410	64104
CSP	120	20	213	0	43776
Hydro	1265	271	40	0	2870
Oil	1700	0	0	2800	203
GT_NG	2183	4061	665	31	12106
CCGT_NG	24344	24305	9497	11603	30808
Hard Coal	2420	0	0	0	750
Storage	500	0	0	0	0

Table 52: Installed capacity per country (EXP-High Demand scenario)

	Morocco	Algeria	Tunisia	Libya	Egypt
2030	[in MW]	[in MW]	[in MW]	[in MW]	[in MW]
Wind Power	22625	0	0	3096	10769
PV	3845	23416	9387	8950	43036
CSP	120	20	0	0	20
Hydro	1265	271	40	0	2870
Oil	2457	341	340	5757	0
GT_NG	0	5304	2579	4501	5800
CCGT_NG	11034	19152	7654	7460	38673
Hard Coal	3340	0	0	0	750
Storage	500	0	0	0	0
2050					
Wind Power	90425	11669	1254	21034	42803
PV	20062	54651	15269	23527	56190
CSP	30495	29277	16334	19256	70725
Hydro	1265	271	40	0	2870
Oil	1700	0	0	2800	0
GT_NG	1329	43	0	0	0
CCGT_NG	18833	19626	4656	8088	19149
Hard Coal	2420	689	0	0	750
Storage	1845	0	0	0	0

Table 53: Installed capacity per country (EXP-Low Demand scenario)

	Morocco	Algeria	Tunisia	Libya	Egypt
2030	[in MW]	[in MW]	[in MW]	[in MW]	[in MW]
Wind Power	19511	0	0	1373	9483
PV	2322	11970	3414	8184	40256
CSP	120	20	0	0	20
Hydro	1265	271	40	0	2870
Oil	2457	341	340	5757	0
GT_NG	0	5304	2579	4501	5800
CCGT_NG	9067	15592	6266	6992	38677
Hard Coal	3340	0	0	0	750
Storage	500	0	0	0	0
2050					
Wind Power	78932	10408	3191	12816	42671
PV	14862	41016	11862	16268	55160
CSP	17662	16105	10209	12192	67778
Hydro	1265	271	40	0	2870
Oil	1700	0	0	2800	0
GT_NG	2888	1001	0	0	0
CCGT_NG	17720	19467	5086	6093	21969
Hard Coal	2420	0	0	0	750
Storage	1450	0	0	0	0

Table 54: Installed capacity per country (EXP-Stable Price scenario)

	Morocco	Algeria	Tunisia	Libya	Egypt
2030	[in MW]	[in MW]	[in MW]	[in MW]	[in MW]
Wind Power	19551	0	0	694	9033
PV	10648	6441	2182	6925	39312
CSP	120	20	0	0	20
Hydro	1265	271	40	0	2870
Oil	2457	341	340	5757	0
GT_NG	0	5304	2579	4501	5800
CCGT_NG	8496	13240	4900	6378	38677
Hard Coal	3340	0	0	0	750
Storage	500	0	0	0	0
2050					
Wind Power	65188	3478	4438	8921	38439
PV	35652	38216	10665	10169	50297
CSP	4664	8424	4115	4341	67151
Hydro	1265	271	40	0	2870
Oil	1700	0	0	2800	0
GT_NG	6004	1200	320	0	474
CCGT_NG	11379	17585	6105	5294	22550
Hard Coal	2420	0	0	0	750
Storage	1091	0	0	0	0

Table 55: Installed capacity per country (EXP-Historical Price scenario)

	Morocco	Algeria	Tunisia	Libya	Egypt
2030	[in MW]	[in MW]	[in MW]	[in MW]	[in MW]
Wind Power	16627	0	0	334	8572
PV	2929	4746	1682	5430	36511
CSP	120	20	0	0	20
Hydro	1265	271	40	0	2870
Oil	2457	341	340	5757	0
GT_NG	0	5304	2579	4501	5800
CCGT_NG	7477	13379	4927	6531	38678
Hard Coal	3340	0	0	0	750
Storage	500	0	0	0	0
2050					
Wind Power	64854	2919	4470	9461	39069
PV	36743	37628	11166	10046	50528
CSP	4586	8574	4138	4321	67051
Hydro	1265	271	40	0	2870
Oil	1700	0	0	2800	0
GT_NG	5544	1200	295	0	637
CCGT_NG	11891	17466	6062	5273	22554
Hard Coal	2420	0	0	0	750
Storage	1246	0	0	0	0

Table 56: Installed capacity per country (EXP-Assumed Price scenario)

	Morocco	Algeria	Tunisia	Libya	Egypt
2030	[in MW]	[in MW]	[in MW]	[in MW]	[in MW]
Wind Power	18889	0	0	1154	9082
PV	4770	10720	3867	8332	39099
CSP	120	20	0	0	20
Hydro	1265	271	40	0	2870
Oil	2457	341	340	5757	0
GT_NG	0	5304	2579	4501	5800
CCGT_NG	7009	14568	5932	6910	38678
Hard Coal	3340	0	0	0	750
Storage	500	0	0	0	0
2050					
Wind Power	68292	4292	4297	19120	39249
PV	40838	68695	27625	23504	49658
CSP	5924	8443	4287	5264	66638
Hydro	1265	271	40	0	2870
Oil	1700	0	0	2800	0
GT_NG	6082	698	0	0	0
CCGT_NG	10563	17534	5905	4559	22873
Hard Coal	2420	0	0	0	750
Storage	500	0	0	0	0

Table 57: Employment factors for South Africa (Rutovitz, 2010)

Technology	**Jobs during construction/installation**	**Jobs of manufacturing**	**Operation & Maintenance**	**Fuel**
	FTE jobs/MW	FTE jobs/MW	Jobs/MW	Jobs/GWh
Coal (existing and refurbished)	5.2 (local)	1.5	0.3 (local)	0.13 (local)
Supercritical coal	10.4 (local)	1.5	0.294 (local)	0.11 (local)
Gas, oil, diesel	6.2	0.07	0.09	0.22
Nuclear	10.8	1.2	0.66 (local)	0.002
Biomass	6.9	0.8	5.51	0.40
Hydro	19.4	0.9	0.04 (local)	
Wind	4.5	22.5	0.72	
PV	52.3	16.8	0.73	
Geothermal	5.6	5.9	1.33	
Solar thermal (CSP)	10.8	7.2	0.54	
Ocean	16.2	1.8	0.58	
Solar Water Heating	11.7 (local)	10.7 (local)		
Energy Efficiency	0.5 jobs per GWh			

Table 58: PV reference plant and components for RETMD

PV	Cost per 20 MW plant	Jobs per 20 MW plant	Status quo of PLVC	Maximum PLVC	Know-how	Minimum factory size
Labor and installation	**3.2 Mio €**	**52.0**				
Civil Works	1.0 Mio €	20.0	100%	100%	4.0	0 MW
Installation	0.6 Mio €	12.0	50%	100%	4.0	0 MW
Grid Connection	1.6 Mio €	20.0	60%	100%	4.0	0 MW
Main components	**23.5 Mio €**	**177.1**				
Inverter	4.0 Mio €	24.0	0%	90%	3.0	200 MW
Mounting Structure	3.3 Mio €	30.0	0%	90%	4.0	100 MW
Cabling	1.2 Mio €	10.0	0%	90%	3.5	120 MW
Wafer	3.5 Mio €	22.0	0%	90%	2.6	400 MW
Cell	4.3 Mio €	30.0	0%	90%	2.8	300 MW
Glass	0.9 Mio €	6.0	0%	90%	3.2	400 MW
Encapsulation	0.7 Mio €	6.0	0%	90%	3.0	400 MW
Modul production	3.5 Mio €	30.0	0%	75%	4.0	50 MW
Frame	0.9 Mio €	10.0	0%	100%	3.5	100 MW
Measurement equipment	0.0 Mio €	0.1	0%	60%	3.0	200 MW
Foil	0.6 Mio €	5.0	0%	75%	3.5	200 MW
Contact box	0.5 Mio €	4.0	0%	100%	3.8	100 MW
Project development and financing	**3.3 Mio €**	**17.9**				
Project Development	1.8 Mio €	10.0	20%	75%	3.5	50 MW
Finance Cost	1.1 Mio €	5.0	50%	75%	3.2	50 MW
Reserve	0.4 Mio €	2.4	50%	50%	3.5	50 MW
Insurance	0.1 Mio €	0.5	20%	50%	3.2	200 MW
Total	**31.0 Mio €**	**247.0**				

Table 59: CSP reference plant and components for RETMD

CSP	Cost per 50 MW plant	Jobs per 50 MW plant	Status quo of PLVC	Maximum PLVC	Know-how	Minimum factory size
Labor Cost Site and Solar Field	**42.2 Mio €**	**1010**				
Solar Field	7.7 Mio €	200	70%	100%	4.0	0 MW
Site Preparation and Infrastructure	14.3 Mio €	370	80%	100%	4.5	0 MW
Steel Construction	6.2 Mio €	150	80%	100%	3.5	0 MW
Piping	4.3 Mio €	90	80%	100%	3.5	0 MW
Electric installations and others	9.8 Mio €	200	40%	80%	3.5	0 MW
			0%			
Equipment Solar Field and HTF System	**95.0 Mio €**	**930**				
Mirrors	15.7 Mio €	150	0%	50%	3.0	250 MW
Receivers	17.5 Mio €	105	0%	50%	2.8	200 MW
Steel construction	26.4 Mio €	375	0%	100%	3.8	40 MW
Pylons	2.6 Mio €	37.5	0%	100%	4.0	40 MW
Foundations	5.3 Mio €	45	0%	100%	4.2	150 MW
Trackers (Hydaulics und Electrical Motors)	1.1 Mio €	7.5	0%	50%	3.0	300 MW
Swivel joints	1.8 Mio €	15	0%	50%	3.0	200 MW
HTF System (Piping, Insulation, Heat Exchangers, Pumps)	13.2 Mio €	120	10%	30%	3.0	20 MW
Heat Transfer Fluid	5.3 Mio €	30	0%	0%	X	X
Electronics, Controls, Electrical and Solar Equipment	6.2 Mio €	45	10%	70%	3.5	0 MW
Thermal Storage System	**26.0 Mio €**	**200**				
Salt	12.6 Mio €	75	0%	0%	X	X
Storage Tanks	4.5 Mio €	60	25%	50%	4.0	0 MW
Insulation Materials	0.4 Mio €	5	25%	0%	X	X
Foundations	1.6 Mio €	15	60%	100%	5.0	0 MW
Heat Exchangers	3.4 Mio €	22.5	0%	0%	X	X
Pumps	1.1 Mio €	7.5	0%	0%	X	X
Balance of System	2.4 Mio €	15	25%	50%	4.0	0 MW
Conventional Plant Components and Plant System	**35.2 Mio €**	**277.5**				
Power Block	14.1 Mio €	120	0%	0%	X	X
Balance of Plant	14.0 Mio €	105	10%	50%	4.0	0 MW
Grid Connection	7.1 Mio €	52.5	50%	100%	4.0	150 MW
Project development and financing	**53.0 Mio €**	**100**				
Project Development	7.7 Mio €	20	0%	50%	3.0	1000 MW
Project Management (EPC)	20.4 Mio €	50	0%	75%	3.5	25 MW
Financing	16.8 Mio €	20	0%	50%	4.0	100 MW
Other costs (allowances)	8.1 Mio €	10	0%	75%	3.5	25 MW
Total	**251.3 Mio €**	**2517.5**				

Table 60: Wind power reference plant and components for RETMD

Wind Power	Costs per 2.0 MW plant	Jobs per 2.0 MW plant	Status quo of PLVC	Maximum PLVC	Know-how	Minimum factory size
Labor and installation	**0.18 Mio €**	**4.0**				
Foundation	0.02 Mio €	0.5	100%	100%	4.0	0 MW
Erection	0.02 Mio €	0.5	100%	100%	4.0	0 MW
Electrical	0.03 Mio €	0.6	100%	100%	4.0	0 MW
Management/supervision	0.01 Mio €	0.1	40%	100%	4.0	200 MW
Misc.	0.10 Mio €	2.2	40%	100%	4.0	100 MW
Main components	**1.56 Mio €**	**9.9**				
Blades	0.28 Mio €	1.5	0%	90%	3.2	250 MW
Towers	0.31 Mio €	3.1	100%	100%	4.0	100 MW
Diverses (Rotor hub, Rotor bearings, Main shaft, Main	0.28 Mio €	1.5	0%	90%	2.8	500 MW
Gearbox	0.30 Mio €	1.5	0%	90%	2.8	500 MW
Yaw system & Pitch system	0.09 Mio €	0.5	0%	90%	2.6	500 MW
Power converter	0.12 Mio €	0.6	0%	90%	3.0	500 MW
Nacelle housing	0.13 Mio €	0.9	0%	90%	3.2	350 MW
Transformer, Cables and Screws	0.03 Mio €	0.2	0%	100%	3.5	100 MW
Materials for installation	**0.42 Mio €**	**0.0**				
Construction (concrete rebar, equip, roads and site pre	0.29 Mio €	0.0	100%	100%	3.5	100 MW
Transformer & Electrical (drop cable, wire,)	0.07 Mio €	0.0	50%	50%	3.5	200 MW
HV line extension	0.06 Mio €	0.0	50%	60%	3.5	200 MW
Further project cost	**0.47 Mio €**	**4.9**				
Transportation	0.22 Mio €	2.5	30%	100%	3.5	0 MW
Other	0.25 Mio €	2.5	30%	100%	3.3	200 MW
Project development and financing	**0.18 Mio €**	**0.8**				
Labor Engineering	0.03 Mio €	0.2	20%	75%	4.0	50 MW
Financing	0.08 Mio €	0.3	50%	75%	3.5	50 MW
Legal Services, Land Easements, Site Certificate/Permit	0.02 Mio €	0.1	0%	75%	3.0	50 MW
HV Sub/Interconnection	0.05 Mio €	0.3	50%	50%	3.5	200 MW
Total	**2.81 Mio €**	**19.6**				

Table 61: Market scenario (High-RES scenario) of installed RE capacities for impact analysis of local manufacturing and employment

Scenario High-RES

Wind

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Morocco	71	106	141	176	212	582	1382	2082	1582	1282	979	816	653	490	326	693	577	462	346	231
Egypt	262	393	786	655	524	322	236	236	236	150	0	0	0	0	0	484	726	968	1210	1452
Tunisia	10	15	20	25	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Algeria	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Libya	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	37	55	73	91	110
Total	342	514	947	856	765	904	1618	2318	1818	1432	979	816	653	490	326	1213	1358	1503	1647	1792

PV

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Morocco	0	0	0	0	0	0	0	0	0	0	103	154	206	257	308	319	319	319	319	319
Egypt	0	0	0	0	0	0	0	0	0	0	1360	2041	2721	3401	4081	4473	4473	4473	4473	4473
Tunisia	0	0	0	0	0	0	0	0	0	0	97	145	194	242	290	262	219	175	131	87
Algeria	0	0	0	0	0	0	0	0	0	0	186	279	372	464	557	718	718	718	718	718
Libya	0	0	0	0	0	8	11	15	19	23	320	481	641	801	961	904	753	602	452	301
Total	0	0	0	0	0	8	11	15	19	23	2066	3099	4132	5166	6199	6677	6482	6288	6094	5899

CSP

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Morocco	12	18	24	30	36	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Egypt	2	3	4	5	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tunisia	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Algeria	2	3	4	5	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Libya	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	16	24	32	40	48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 62: Market scenario (Low-RES scenario) of installed RE capacities for impact analysis of local manufacturing and employment

Scenario Low-RES

Wind

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Morocco	56	84	112	140	168	334	500	667	834	1001	1322	1101	881	661	441	575	646	517	488	358
Egypt	190	285	570	475	380	0	0	0	0	0	0	0	0	0	0	606	909	1212	1515	1818
Tunisia	10	15	20	25	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Algeria	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Libya	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	256	384	703	641	579	334	500	667	834	1001	1322	1101	881	661	441	1181	1555	1729	2003	2176

PV

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Morocco	0	0	0	0	0	0	0	0	0	0	77	177	277	197	157	99	83	66	50	33
Egypt	0	0	0	0	0	0	0	0	0	0	449	674	898	1123	1347	1212	1012	1012	1012	812
Tunisia	0	0	0	0	0	0	0	0	0	0	20	30	40	51	61	83	125	166	208	249
Algeria	0	0	0	0	0	0	0	0	0	0	46	70	93	116	139	255	382	510	637	765
Libya	0	0	0	0	0	0	0	0	0	0	193	393	493	493	393	275	229	183	138	92
Total	0	0	0	0	0	0	0	0	0	0	786	1344	1802	1980	2097	1925	1831	1938	2044	1951

CSP

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Morocco	12	18	24	30	36	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Egypt	2	3	4	5	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tunisia	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Algeria	2	3	4	5	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Libya	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	16	24	32	40	48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 63: Market scenario (100%-RES scenario) of installed RE capacities for impact analysis of local manufacturing and employment

Scenario 100%-RES

Wind

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Morocco	88	132	176	220	264	819	1419	2119	2119	1619	991	826	660	495	330	657	547	438	328	219
Egypt	325	488	650	813	975	643	543	443	343	243	0	0	0	0	0	453	680	906	1133	1359
Tunisia	10	15	20	25	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Algeria	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Libya	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	137	206	274	343	412
Total	423	635	847	1058	1270	1462	1962	2562	2462	1862	991	826	660	495	330	1247	1433	1618	1804	1990

PV

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Morocco	0	0	0	0	0	0	0	0	0	0	140	209	279	349	419	384	576	768	960	1151
Egypt	0	0	0	0	0	25	38	51	63	76	2101	3152	4203	5253	6304	4265	4265	4265	4265	4265
Tunisia	0	0	0	0	0	0	0	0	0	0	126	189	252	315	378	466	699	932	1165	1398
Algeria	0	0	0	0	0	0	0	0	0	0	304	456	608	760	913	1162	1742	2323	2904	3485
Libya	0	0	0	0	0	48	72	96	121	145	462	693	924	1155	1386	790	658	526	395	263
Total	0	0	0	0	0	74	110	147	184	221	3133	4700	6266	7833	9400	7066	7940	8814	9688	10562

CSP

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Morocco	12	18	24	30	36	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Egypt	2	3	4	5	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tunisia	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Algeria	2	3	4	5	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Libya	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	16	24	32	40	48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 64: Market scenario (National-Targets scenario) of installed RE capacities for impact analysis of local manufacturing and employment

Scenario National-Targets

Wind

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Morocco	38	57	76	95	114	138	207	277	346	415	459	459	459	459	459	587	687	787	687	687
Egypt	79	119	159	198	238	528	728	1128	1128	628	0	0	0	0	0	373	560	746	933	1119
Tunisia	58	88	175	146	117	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Algeria	165	248	496	413	330	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Libya	90	134	269	224	179	0	0	0	0	0	0	0	0	0	0	41	61	81	101	122
Total	431	646	1174	1076	978	666	935	1404	1473	1043	459	459	459	459	459	1001	1308	1614	1721	1928

PV

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Morocco	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Egypt	0	0	0	0	0	11	17	22	28	34	1556	2333	3111	3889	4667	3588	3188	3188	3188	2788
Tunisia	0	0	0	0	0	140	209	279	349	419	390	360	330	360	360	471	571	671	771	871
Algeria	0	0	0	0	0	418	628	837	1046	1255	1075	975	875	975	975	1176	1376	1776	2076	2376
Libya	0	0	0	0	0	201	301	402	502	603	594	494	394	494	494	543	643	643	643	743
Total	0	0	0	0	0	770	1155	1540	1926	2311	3614	4162	4710	5717	6495	5778	5778	6278	6678	6778

CSP

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Morocco	31	46	62	77	93	0	0	0	0	0	222	222	222	222	222	79	66	52	39	26
Egypt	4	6	8	10	12	0	0	0	0	0	0	0	0	0	0	1	2	2	3	3
Tunisia	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Algeria	4	6	8	10	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Libya	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	39	58	78	97	117	0	0	0	0	0	222	222	222	222	222	80	67	55	42	29

Table 65: Market scenario (High-CSP scenario) of installed RE capacities for impact analysis of local manufacturing and employment

Scenario High-CSP

Wind	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Morocco	41	61	82	102	123	484	725	967	1209	1451	990	825	660	495	330	399	566	533	500	666
Egypt	238	356	475	594	713	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tunisia	10	15	20	25	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Algeria	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Libya	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	289	433	577	721	866	484	725	967	1209	1451	990	825	660	495	330	399	566	533	500	666

PV	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Morocco	0	0	0	0	0	0	0	0	0	0	93	139	186	232	279	152	126	101	76	51
Egypt	0	0	0	0	0	0	0	0	0	0	210	315	420	525	630	615	922	1229	1536	1844
Tunisia	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	56	84	112	140	168
Algeria	0	0	0	0	0	0	0	0	0	0	56	84	113	141	169	269	404	538	673	807
Libya	0	0	0	0	0	0	0	0	0	0	206	310	413	516	619	379	316	253	189	126
Total	0	0	0	0	0	0	0	0	0	0	566	848	1131	1414	1697	1470	1852	2233	2615	2996

CSP	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Morocco	12	18	24	30	36	0	0	0	0	0	0	0	0	0	0	1	1	1	2	2
Egypt	2	3	4	5	6	230	345	460	575	690	601	902	1203	1504	1804	1949	1949	1949	1949	1949
Tunisia	0	0	0	0	0	0	0	0	0	0	29	43	57	72	86	109	109	109	109	109
Algeria	2	3	4	5	6	0	0	0	0	0	0	0	0	0	0	37	55	73	92	110
Libya	0	0	0	0	0	0	0	0	0	0	26	26	26	26	26	15	12	10	7	5
Total	16	24	32	40	48	230	345	460	575	690	656	971	1286	1602	1917	2110	2126	2143	2159	2175

Table 66: Market scenario (EXP-High-Demand scenario) of installed RE capacities for impact analysis of local manufacturing and employment

Scenario EXP-High-Demand

Wind	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Morocco	332	498	996	830	664	66	99	132	166	199	439	658	877	1097	1316	1292	1077	861	646	431
Egypt	995	1492	2984	2487	1990	0	1	1	1	1	807	1210	1613	2017	2420	1436	1196	957	718	479
Tunisia	86	128	257	214	171	47	71	94	118	141	293	440	587	734	880	1099	1099	1099	1099	1099
Algeria	14	21	28	35	42	0	0	0	0	0	324	324	324	324	324	205	170	136	102	68
Libya	0	0	0	0	0	3	4	5	6	8	135	202	270	337	405	216	180	144	108	72
	1426	2139	4264	3565	2866	116	175	233	291	349	1998	2835	3672	4509	5346	4248	3723	3198	2673	2149

PV	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Morocco	7	10	14	17	21	26	22	18	13	9	26	21	17	13	9	19	16	13	10	6
Egypt	275	413	825	688	550	0	0	0	0	0	562	1362	1862	1662	1362	520	433	347	260	173
Tunisia	31	46	61	76	92	0	0	0	0	0	2	3	4	6	7	20	31	41	51	61
Algeria	113	169	225	282	338	1	2	3	3	4	105	157	209	262	314	905	1357	1810	2262	2715
Libya	0	0	0	0	0	6	9	12	15	18	15	22	29	36	44	312	468	624	780	936
	425	638	1126	1063	1001	34	33	32	31	31	709	1566	2122	1979	1735	1777	2305	2834	3363	3892

CSP	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Morocco	31	46	62	77	93	0	0	0	0	0	122	222	322	222	222	79	66	52	39	26
Egypt	4	6	8	10	12	0	0	0	0	0	0	0	0	0	0	1	2	2	3	3
Tunisia	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Algeria	4	6	8	10	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Libya	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	39	58	78	97	117	0	0	0	0	0	122	222	322	222	222	80	67	55	42	29

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Abstract

The transition of the North African electricity system towards renewable energy technologies is analyzed in this thesis. Large potentials of photovoltaics (PV), concentrating solar power (CSP) and onshore wind power provide the opportunity to achieve a long-term shift from conventional power sources to a highly interconnected and sustainable electricity system based on renewable energy sources (RES). A multi-dimensional analysis evaluates the economic and technical effects on the electricity market as well as the socio-economic impact on manufacturing and employment caused by the large deployment of renewable energy technologies.

The integration of renewable energy (RE) into the electricity system is modeled in a linear optimization model RESlion which minimizes total system costs of the long-term expansion planning and the hourly generation dispatch problem. With this model, the long-term portfolio mix of technologies, their site selection, required transmission capacities and the hourly operation are analyzed. The focus is set on the integration of renewable energy in the electricity systems of Morocco, Algeria, Tunisia, Libya and Egypt with the option to export electricity to Southern European countries. The model results of RESlion show that a very equal portfolio mix consisting of PV, CSP and onshore wind power is optimal in long-term scenarios for the electricity system. Until the year 2050, renewable energy sources dominate with over 70% the electricity generation due to their cost competiveness to conventional power sources. In the case of flexible and dispatchable electricity exports to Europe, all three RE technologies are used by the model at a medium cost perspective.

The socio-economic impact of the scenarios is evaluated by a decision model (RETMD) for local manufacturing and job creation in the renewable energy sector which is developed by incorporating findings from expert interviews in the RE industry sector. The electricity scenarios are assessed regarding their potential to create local economic impact and local jobs in manufacturing RE components and constructing RE power plants. With 40,000 to 100,000 new jobs in the RE sector of North African countries, scenarios with substantial RE deployment can provide enormous benefits to the labor market and lead to additional economic growth.

The deployment of renewable energy sources in North Africa is consequently accelerated and facilitated by finding a trade-off between an optimal technology portfolio from an electricity system perspective and the opportunities through local manufacturing. By developing two model approaches for evaluating the effects of renewable energy technologies in the electricity system and in the industrial sector, this thesis contributes to the literature on energy economics and energy policy for the large-scale integration of renewable energy in North Africa.