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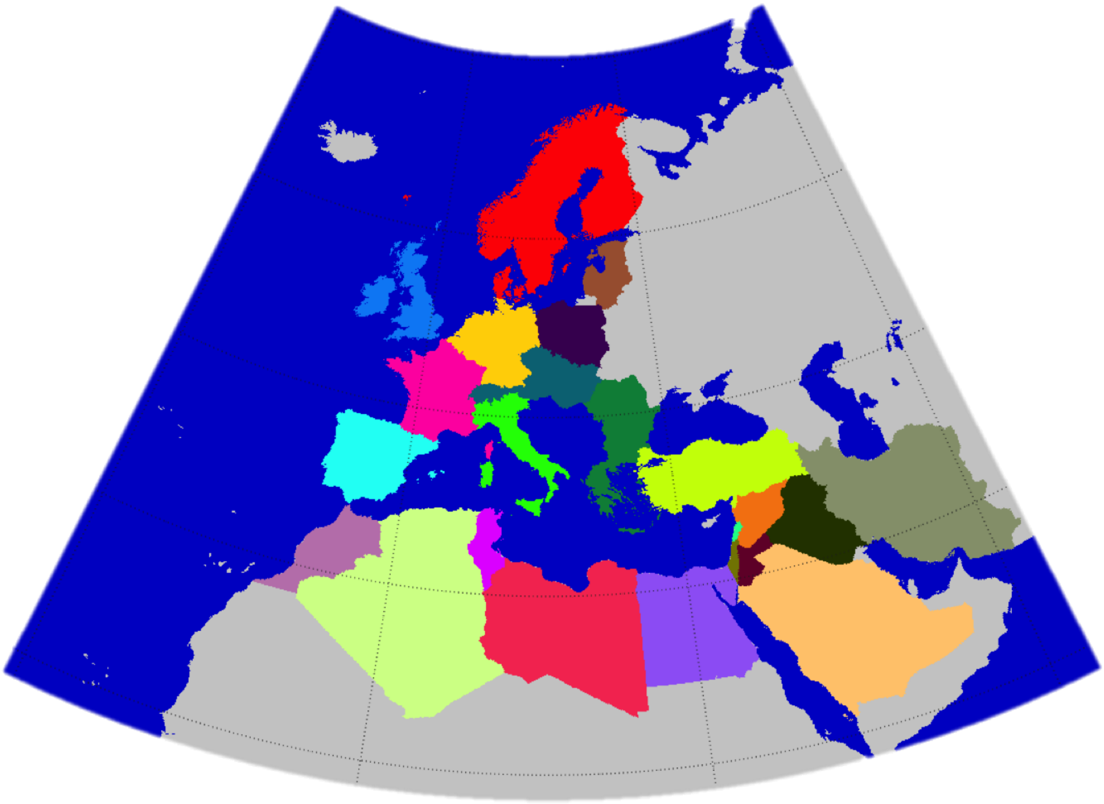

The Effect on System Cost of Decreasing Solar and Battery Costs in Regions with Different Climates

Comparing Renewable Power Systems in Europe and MENA

Master's thesis in Sustainable Energy Systems

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Cover: Map over the regions modelled in Europe and Middle-East and North Africa.

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Abstract

With a fossil fuel dependent power system and a growing electricity demand, decarbonisation of the power sector would have a large effect on carbon dioxide emissions in the Middle East and North Africa region (MENA). Compared to Europe and the United States there are few studies on power systems with a high share of variable renewable energy (VRE) in MENA. This thesis uses an energy system model with an hourly resolution to model a future high VRE continental scale power system in order to examine the changes in system cost of varying solar PV- and battery costs. The role of transmission and nuclear power is investigated by making three scenarios: one with the possibility to invest in transmission but not nuclear power, a second excluding nuclear power and transmission and a third including both nuclear power and transmission. In order to isolate the influence of climate, the results in MENA are compared to Europe using the same model.

The results show that there are no significant differences in how sensitive the electricity system cost is to varying solar PV- and battery costs between Europe and MENA. Decreasing both the solar PV- and battery costs, with 50% and 62% respectively, leads to up to 34% system cost reductions in MENA and 27% in Europe; while increasing the solar PV- and battery costs in the same order of magnitude give a cost increase by 9% in MENA and 7% in Europe. A lower system levelised cost of electricity (system LCOE) is found in MENA compared to Europe in all scenarios, ranging between 8-21% less costly in MENA, depending on solar PV- and battery cost and the use of transmission and nuclear power. Excluding the option to invest in inter-regional transmission increases the system cost with between 3-15% in MENA and 6-11% in Europe, depending on solar PV- and battery costs. By including nuclear power, the system cost decreases by 0-2% in MENA and between 0-10% in Europe. Nuclear power is not cost competitive in either Europe or MENA when solar PV- and battery costs are low.

Keywords: MENA, Variable Renewable Energy, Electricity System Modelling, Climate Conditions, Transmission, Nuclear Power

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To our parents, for bringing us to life and making us who we are today.

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Dan Atsmon & Hanna Ek Fälth, Gothenburg, December 2019

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Introduction

After COP21 in Paris, there is a broad consensus that comprehensive action is needed to reduce the greenhouse gas emissions and keep global warming in check. The questions about who should pay for it and where and how the abatement should be done are still under debate. The electricity sector is a major contributor to CO_2 emissions, accounting for 25% of total CO_2 emissions together with the heating sector [3], and its importance is projected to grow. The growth is due to rising living standards in the developing economies [4] and due to the drive to electrify other sectors such as transportation [5]. Studies show that it is affordable to reduce CO_2 emissions from the electricity sector, relative to other sectors in the economy [5].

With fast technological improvements and reductions in production costs, both solar and wind power are rapidly becoming more competitive in the power sector. Recent energy auctions from around the world show that solar and wind power often are the cheapest option [6, 7]. All types of generation have downsides and limitations; non-variable low CO_2 technologies are no exception. Hydropower production is limited by availability and environmental concerns [8], for nuclear power costs, proliferation concerns and public perception are obstacles and for biomass, there are land use issues as well as competition from other sectors such as transportation. Carbon Capture and Storage technologies are promising but there is still significant uncertainty around cost and large-scale feasibility. This points to the importance of studying the feasibility of an electrical system dominated by variable renewable production (hereafter referred to as VRE) such as wind power and solar power.

This thesis examines the power system in the Middle East and North Africa region (hereafter referred to as MENA) and compares it to Europe. The power system in MENA is currently dominated by fossil fuels, with a power plant mix comprising of 68% natural gas and 23% oil [9]. The high carbon intensity electricity generation coupled with increasing living standard, pollution concerns and the possibility of electrification of other sectors, such as transportation, means that there are large potential gains to be made by decarbonising the power sector in MENA. Like Europe, MENA has good wind resources but they differ greatly in their solar power potential. There has been much publicity about the possibility to export solar electricity from Sahara to Europe [10, 11, 12] but few studies about a separate MENA-grid. The absence of studies on decarbonised power systems in MENA is especially stark compared to the body of work that examines the power systems in Europe and the United States.

Although studies have been done on many different regions in the world, it is not clear to which extent the varying results in different geographical areas are attributed to different conditions (solar and wind resource availability, demand etc.) or differences in cost parameters and modelling assumptions. This study evaluates both MENA and Europe with the same energy system model and with the same cost parameters in order to isolate the influence of renewable resource availability and differences in demand.

Previous studies show that there are synergies between solar PV and batteries [13, 14], i.e. low-cost batteries increase the benefit of reducing solar PV cost and vice versa. This thesis varies solar PV- and battery costs in unison and examines the effect on the system cost. Do the more favourable solar conditions in MENA compared to Europe make the system cost more sensitive to changes in costs of solar PV and batteries?

Except for the effect on system cost of decreasing solar PV- and battery costs, the thesis examines two other issues identified in the literature. The first is the effect on system cost of including inter-regional transmission. Transmission expansion has been shown to be an important factor in keeping costs down in electricity systems dominated by VRE [13, 15, 16, 17, 18, 19, 20]. Do these conclusions hold for MENA and how does this factor vary in importance between Europe and MENA? In order to evaluate the importance of inter-regional transmission this thesis models both MENA and Europe with and without transmission. The strained political landscape in MENA also makes it relevant to examine a scenario with limited transmission.

The second is the effect on system cost of including nuclear power in the power system. Nuclear power is controversial with concerns about both sustainability and nuclear proliferation. In the reviewed literature some studies exclude nuclear ex-ante, while some studies are emphasising the importance of nuclear in low carbon power systems (see chapter 3.2). This thesis models MENA and Europe both with and without the possibility to invest in nuclear power.

The aim of this thesis is to answer the following research questions:

1. How sensitive is the power system cost to varying solar- and storage costs and how does it differ between MENA and Europe?

2. What effect does the possibility of inter-regional transmission expansion have on system cost and does the effect differ between MENA and Europe?

3. What effect does the possibility to install nuclear power have on system cost and does the effect differ between MENA and Europe?

1.1 Delimitations

The system boundary in this study is set around the electricity sector and does not include other sectors in the energy sector such as heat, transportation, food production etc. Geographically the boundaries are set as Europe and MENA separately. The study is modelling a future high VRE power system and does not take the transition pathway into account. The demand and technology costs estimations are based on projections for 2040.

The study does not evaluate the power system on a sub-hourly level and a full reliability analysis of the power system is outside the scope of this thesis.

No consideration for political realities is taken when modelling international transmission expansion.

2

Background

To give the reader prerequisites to understand the method, results and conclusion of this thesis, this chapter gives a brief overview of the basics of energy systems, energy system modelling and variability of power production and demand.

2.1 Basics of Energy Systems

Energy system is a term used to refer to a system containing information on energy production, energy demand and energy flows. For electricity systems, this translates to information about the power production units, the electricity demand and the transmission of electricity between production, storage and consumers. One important feature of an electricity system is that instant demand has to be fulfilled by instant production, available storage or import. Thus, in order to ensure a functioning electricity system, electricity generation should meet the demand at all times. This is often referred to as load balance.

2.2 Variability of Generation and Demand

There are different types of variability that can be present in an electricity system, one being variability in demand and another variability in electricity generation.

Demand for electricity varies in time based on consumer behaviour. As an example of demand variability, the hourly demand for electricity in Iran for a full year and for a week can be seen in figure 2.1. Both daily and seasonal variations can be seen. As an example, the electricity demand is higher in summer than in winter. The high demand in summer could be explained by the use of air conditioners while the electricity demand in winter is low even though significant heating is needed. This could be explained by the use of gas heaters rather than electrical heating.

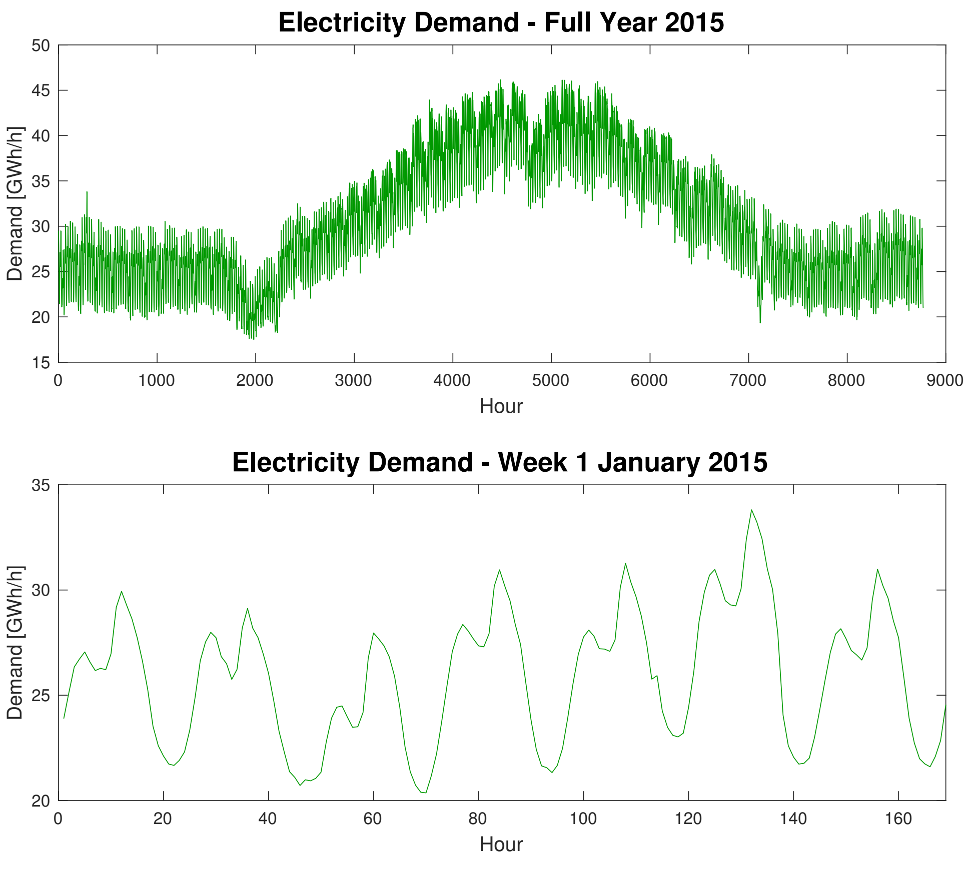


Figure 2.1: Hourly demand of electricity in Iran. The top graph shows the hourly demand of electricity in Iran for the full year of 2015. The lower graph shows the same demand but only for the first week in January. The demand data is retrieved from the Iran Grid Management Co. [1].

Variability in electricity **generation** coming from renewable power production sources such as solar and wind is caused by weather variations. Renewable power production technologies with these variations are usually referred to as variable renewable energy (VRE) technologies. As an example, hourly solar and wind profiles for Iran, both for a year and for a week, can be seen in figure 2.2. The figure shows the capacity factors for each hour and reflects how much of the installed capacity that can be delivered as produced electricity that hour, i.e. a capacity factor of 0.5 means that 5 MW can be produced if the installed capacity is 10 MW. For PV, the capacity factor can exceed 1. The reason for this is explained in Appendix B.1.

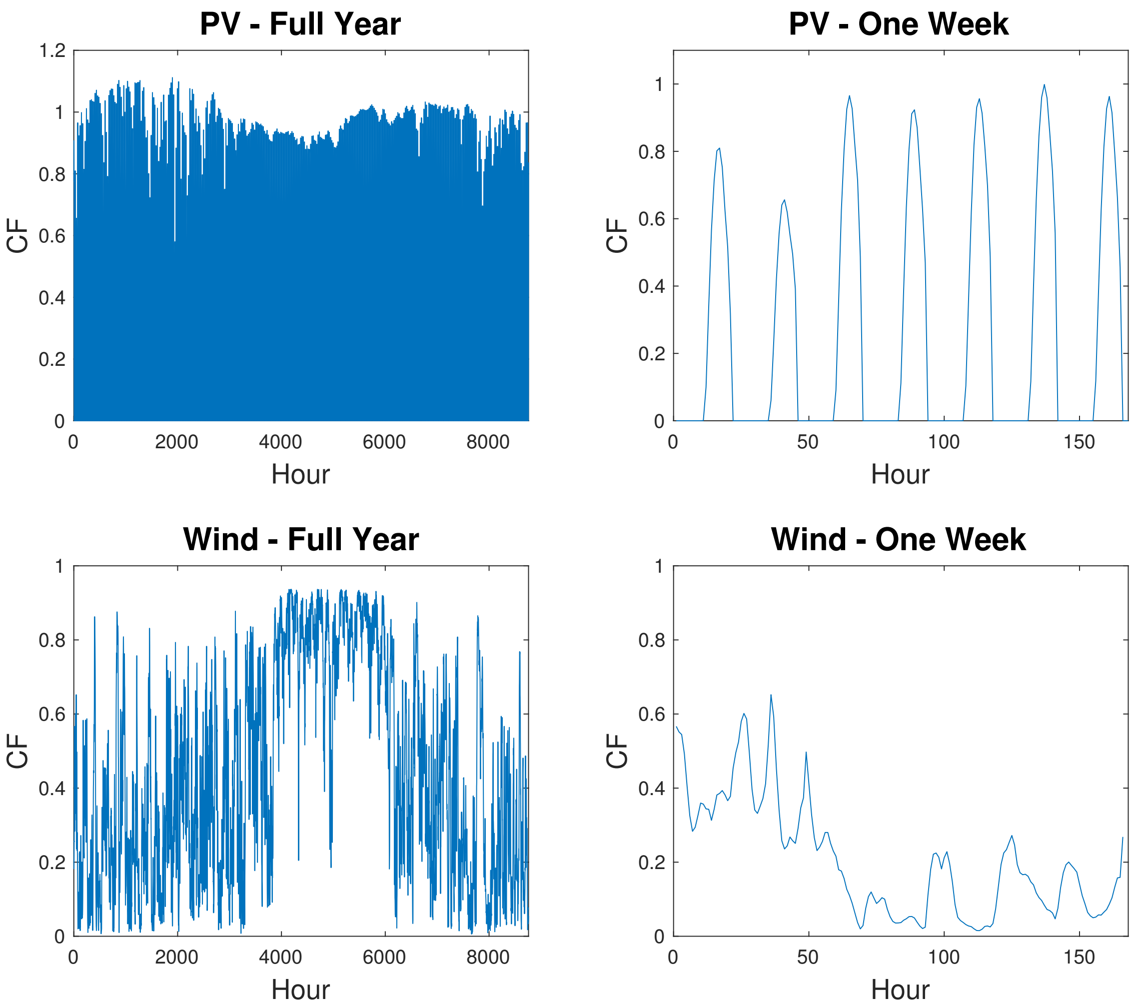


Figure 2.2: Average capacity factors for PV and onshore wind power for both a full year and one week, in Iran 2015. Capacity factor on the y-axis and hours on the x-axis. The capacity factors are calculated in a GIS model [2] using solar irradiation and wind speed from ECMWF ERA Interim reanalysis database.

By looking at the capacity factor profiles, it can be seen that variations of solar and wind differs from each other. Solar variations are, naturally, most significant on a daily basis. This is due to sunrise and sunset and makes the variations possible to predict to a large extent. Wind variations are more complex in the sense that they are hard to predict and that the variations are intra-hour, intra-day, weekly and seasonal [21]. Seasonal variations are easier to predict than those on lower timescales. As an example, the Nordic countries have a distinct seasonal pattern where the wind power production displays higher output in winter compared to summer [22]. As can be seen in figure 2.2 seasonal variations are present also for Iran, and the potential of wind power production was somewhat higher in summer than in winter for the year 2015.

When there is a large share of variable renewable energy (VRE) in an electricity system, in contrast to the conventional thermal based electricity systems, it is not obvious how to obtain load balance, i.e. to balance energy generation and demand at all times. By looking at the extremes, where wind or solar power is the only electricity generation available, this becomes easier to understand. The case with one week of demand covered only by wind or solar power in terms of total energy production is shown in figure 2.3. The left pictures show the demand in black and the power production in blue. Plus and minus signs have been added to the graphs to show where there is excess or deficit of energy compared to the demand. The right pictures show the net load (the demand subtracted from the power production) for the two cases.

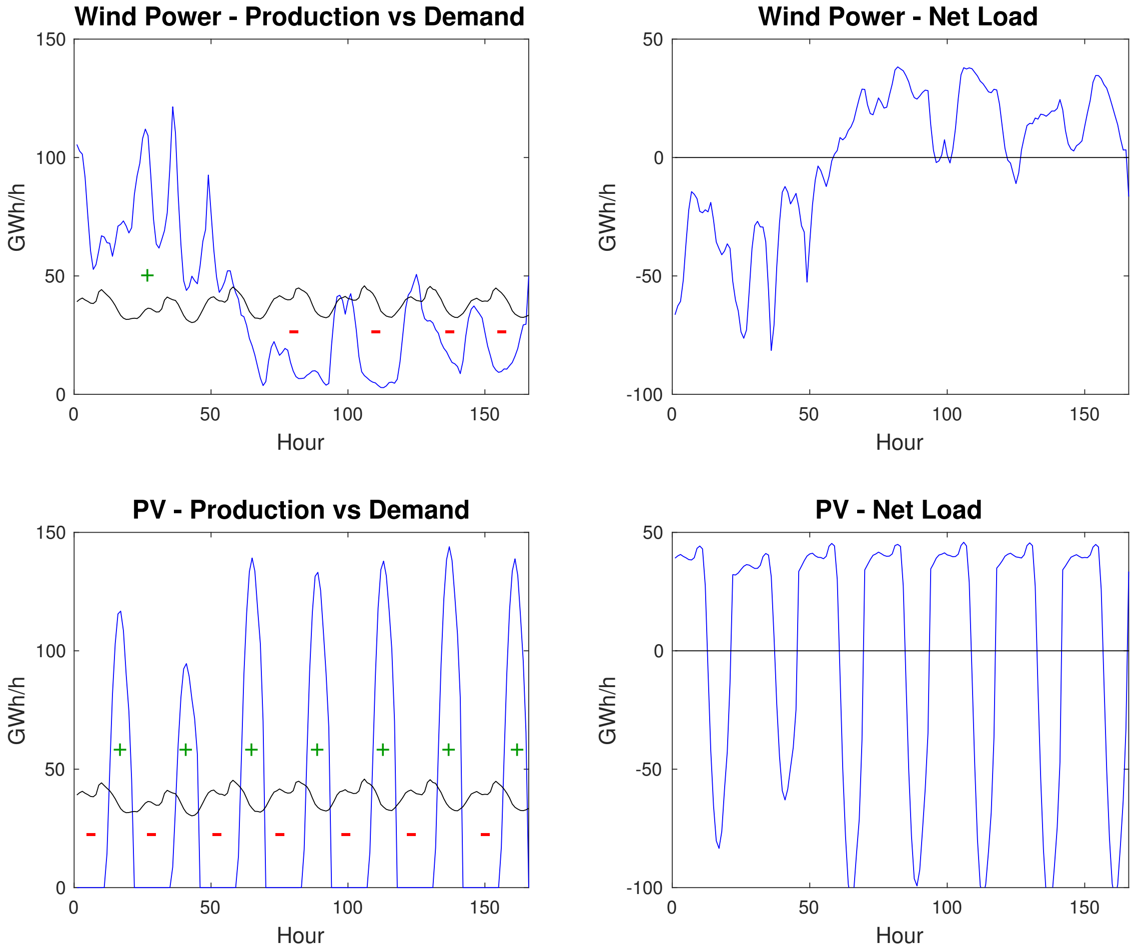


Figure 2.3: One week of demand covered only by wind power or PV, in terms of total energy production. The graphs to the left show the demand in black and the electricity production in blue. The electricity production is scaled so that the total demand for this week can be covered with the total production this week. The plus signs show where there are electricity excess and the minus signs where there is electricity deficit. The same phenomena can be seen in the right graphs which shows the net load (the demand subtracted from the power production) for this week, where the line at y=0 represents load balance.

The issue of obtaining load balance in a power system with a high share of VRE (see figure 2.3) can be handled with different variation management strategies. Transmission can be used to move electricity excess in a region to another region with electricity deficit. Storage can be used to move electricity from a time when there is electricity excess to a time of electricity deficit. Other types of variation management strategies are demand side management, sector integration, curtailment and dispatchable generation.

2.3 Energy System Modelling

Energy system modelling has been used to analyse energy systems since the early 1970s [23], often with the purpose of informing policy-making. There is a wide diversity in the types of models developed and used. This section intends to provide a context for the model used in this thesis.

There are hundreds of different energy system models used and developed with different scopes. The differences between energy system models are mainly the system boundaries and the level of economical, temporal, spatial and technological detail. One main categorisation is the distinction between top-down and bottom-up approaches [24, 25, 26]. The top-down approach aims to put the energy system in the context of macro economy and includes the economic connection between labour, capital and natural resources. The bottom-up approach focuses on technically balancing the supply and demand, often with an exogenous demand. Due to the bigger perspective and inclusion of more mechanisms, the top-down models require aggregation of temporal, spatial and technological resolution to a higher extent than the bottom-up models to run with the same computational effort [24]. Energy system models can be very computationally demanding and the computational difficulty is affected by the spacial-, temporal- and technical resolution. In order to reduce the computational demand, different ways of aggregating time steps have been utilised [27]. The methods of aggregating time steps were developed when electricity systems were dominated by thermal power plants, i.e. dispatchable generation. Instead of aggregating the temporal dimension, hours from a full chronological year can be used. This method has been used in studies on both country and continent level these last few years when the share of VRE is high [13, 15, 17, 20, 28, 29, 30]. This fine temporal resolution is computationally demanding and limits the possibility of high resolution on techno-operational detail [31]. Regarding this trade-off it has been shown that when the share of variable production increases, the importance of the level of temporal representation increases versus the level of techno-economic operational detail [31].

An important distinction between energy system models is simulation versus optimisation. Simulating an energy system aims to replicate the reality of a chosen system given certain inputs. Optimisation produces an output given a well-defined objective, decision variables and constraints.

The model in this thesis uses the bottom-up approach and is a linear programming optimisation model with an hourly resolution of a full chronological year. All the details about the model can be found in chapter 4.1.1. To facilitate the understanding of the model description in chapter 4.1, the next section explains the basics of optimisation with linear programming.

2.3.1 Optimising with Linear Programming

Optimising is the idea of finding maximum or minimum of a chosen function given certain decision variables and constraints [32]. The function chosen to minimise or maximise is called *objective function*. The objective might be for example to minimise system cost or to maximise profit. The *decision variables* make up the set of variables to be determined in order to find the optimal solution. Electricity generation at a specific plant at a specific time could be one of these variables. Given some *constraints*, the problem has a set of alternative solutions which together forms a feasible region, i.e. a solution space [32]. The optimisation is then to find the maximum or minimum value of the objective function within this region. A constraint could be for example a limit on yearly hydro dam power generation or a limit on how much carbon dioxide emissions that are allowed. The optimisation problem in this thesis is constructed as a linear problem, which means that the objective function and all the constraints are linear functions of the decision variables.

3

Literature Review

The literature review focuses on studies of high VRE continental scale power systems and covers literature related to the research questions (see chapter 1). The first topic is about the effect on system cost of decreasing solar PV- and battery costs as well as a comparison of studies of geographical areas outside of Europe and the United States. The second concerns the effect of inter-regional transmission on system cost and the third examines what effect the possibility of utilising nuclear power has on the system cost.

The last few years have seen an increasing number of continental scale power system studies with a high share of VRE [13, 14, 15, 16, 17, 18, 19, 20, 28, 29, 30, 33]. The studies of high VRE continental scale power systems approach the inherent uncertainties of cost assumptions differently. Some do not vary their cost assumptions [16, 17, 30, 33, 34], some model a transition pathway and assume gradually falling costs for PV and wind power [19, 28], and others model their system for different "packages" of cost combinations [18, 20]. Sepulveda et al. [29] evaluate nearly 1000 different combinations of costs and technology assumptions but do not present the results that are directly comparable to the research questions in this thesis. Schlachtberger et al. [13] vary the cost of PV and battery storage separately and evaluate the effect on system cost. They show a linear relationship between system cost and reduction in both PV cost and battery cost until the cost fall past a certain level, after which the cost-benefit increases. For PV this level is around 300 €/kW (50% of their assumed base cost) and for batteries, it is below 36€/kWh (25% of their assumed base cost). Reichenberg et al. [14] show that, for high VRE systems, the combination of low PV and storage costs have an larger effect on system LCOE compared to the additive effect of lowering PV- and battery costs separately.

There are studies about geographical areas outside of Europe and the United States. In addition to studies that model most countries in the world [28, 30, 33], there are studies of single continents or larger regions. These include Barbosa et al.'s study of South America [16], Bogdanov et al.'s study of North East Asia [20] and Haller et al's study of Europe and MENA [19]. Haller et al. [19] show that PV and wind generation have a roughly equal share of the generation mix in Europe while in MENA PV completely dominates the generation mix with the intercontinental transmission described as "minor". In addition to continental scale power system studies, there are several studies done on single countries outside of Europe and the

United States. Saudi Arabia [35], Turkey [36], India [37], Pakistan [38] and Iran [39] have all been modelled with the LUT energy model developed by Bogdanov and Breyer [20]. They all have solar dominated generation mixes and a system LCOE between 65 €/MWh to 45 €/MWh [35, 36, 37, 38, 39]. The generation mix in Australia, a country similar to MENA in that they have excellent solar and wind potential, is by two studies shown to be dominated by wind power [40, 41]. A study on the optimal mix of wind and solar generation in the future Chinese power system finds an almost 50/50 relationship between PV and wind.

We have not found studies which examine the effect on system cost of decreasing solar and battery costs in regions with different climates. Large differences between the resulting system LCOE and generation mixes can be observed in the reviewed literature, both for studies of different geographical regions but also for studies with the same geographical boundaries. However, it is not clear to which extent the varying results in different geographical areas are attributed to different conditions (solar and wind resource availability, demand etc.) or differences in cost parameters and modelling assumptions.

3.1 Regions and Transmission

One of the aspects of power system modelling is the spatial resolution and the possibility to expand transmission between regions. It is possible to differentiate between one-node models, where regions are isolated and the electricity demand has to be met by the respective region's own generation, and multi-node models that allow for inter-regional/international transmission expansion and power exchange. Most studies of high VRE continental scale power systems are multi-node models [13, 14, 15, 16, 17, 18, 19, 20, 30]. Two articles that use one node models, both examine high VRE power systems in around 145 countries with no international transmission, are the studies by Breyer et al. [28] and Pleßmann et al. [33].

Many studies show the importance of transmission in high VRE systems by running their models with and without the possibility of inter-regional transmission [13, 15, 16, 17, 18, 19, 20]. They all show that inter-regional transmission reduces system cost. The mechanism that lead to cost reduction is the "smoothing out" of wind power variability by interconnecting regions; this decreases the over-investment in VRE and decreases the use of expensive variation management/complementary generation. The exact benefits of transmission vary between the studies. MacDonald et al. [18] are looking at the United States and show a 13.4% increase in system cost when regions are isolated compared to an optional transmission grid, Haller et al. [19] also model the United States but get a 50% increase. Barbosa et al. [16] show a 10% increase for South America and Schlachtberger et al. [13] model Europe and get a 32% increase.

Brown et al. [15], Horsch et al. [42], Schlachtberger et al. [17] and Sepulveda et al. [29] show that the cost benefit of increased transmission is not linear. They restrict the transmission capacity in different ways and find that most of the reduction in system cost is achieved by a transmission capacity much lower than "the optimal". As an example Schlachtberger et al. [17] show that, in Europe, 85% of the cost benefits of the optimal grid expansion are captured with 44% of the optimal transmission volume.

Most studies, examining parts of Asia, Europe or the United States, show that increased transmission in a multi-node model favours wind energy at the expense of PV-generation [13, 15, 17, 18, 19, 20, 29]. One exception is Barbosa et al's [16] study of South America, where increased transmission led to a small decrease in both wind and PV generation.

3.2 The Importance of Nuclear

Nuclear power is a contentious issue, both in the society at large and in the modelling community. Many studies exclude nuclear ex ante [13, 14, 15, 16, 17, 20, 30] and some include the already existing nuclear capacity but do not allow for any new generation [19]. Others allow new nuclear capacity [18] and some, such as Sepulveda et al. [29], bundle nuclear power together with other thermal technologies. A number of papers model high VRE power systems without nuclear [13, 14, 15, 16, 17, 20, 30]) with a resulting low to modest system LCOE. There might be a cost penalty for not allowing nuclear power in the system, the magnitude of which is highly dependent on the cost of nuclear power and all other competing generation technologies. In addition, if there is a scarcity of dispatchable generation, whether that be gas technologies, batteries or nuclear, the variability per se increases cost if the share of VRE approaches 100% [14, 29].

4

Method

To examine how the system cost changes with different PV- and battery costs an energy system model is used. The model used is developed in this thesis to specifically answer the research questions, and is based on a model developed at the division of Physical Resource Theory at Chalmers. The modified and developed version is hereafter referred to as JuliaREX. By evaluating both MENA and Europe with the same model, the difference in results between the two regions may be attributed to actual differences in demand and weather conditions rather than being unsure of the impact of different model formulations and cost assumptions.

To investigate how sensitive the system cost is to varying PV- and battery costs, JuliaREX is fed with 25 combinations of PV and Li-ion battery investment costs. The range of costs for PV and batteries are divided into 5 steps each, yielding 25 combinations. This enables investigation of how system cost is affected by synergies between variations in PV- and battery costs. When the costs of both PV and batteries are fixed at their lowest, middle or highest of their respective cost ranges they are referred to as low-, mid-, and high-costs. Both Europe and MENA are modelled for all cost combinations with their different input data. The input data includes demand, hydropower and weather conditions (which effect capacity factors and capacity limits on hydropower, wind power, PV and concentrated solar power).

The roles of transmission and nuclear power are investigated by making three different scenarios. One scenario has the possibility to invest in transmission but not nuclear power. This scenario is used as a base for comparison with the other scenarios and is therefore referred to as the base scenario. The second scenario does not allow for nuclear power or transmission and the third scenario includes both nuclear power and transmission. These three different scenarios are shown in table 4.1. Note that all three scenarios are modelled for both MENA and Europe.

Table 4.1: The three different scenarios modelled in this thesis.

Scenario	Nuclear Power	Transmission
Base	No	Yes
No Transmission	No	No
Nuclear	Yes	Yes

4.1 Model

JuliaREX is a bottom-up long-term energy system optimisation model. It is an investment model that uses linear programming to minimise total system cost for an electricity system that meets the demand at all times, with an hourly resolution for a full chronological year. Technology costs and electricity demand are adjusted to represent the year 2040. All modelled regions are treated as "copper plates", i.e transmission within each region is not modelled and assumed to be unconstrained. HVDC transmission lines are assumed to be available for investment between neighbouring regions. Demand, weather and technology cost and performance is given exogenously. Variables subject to optimisation are the capacity mix, the generation mix of electricity, storage and transmission. The investments are done overnight in a greenfield setting, except for hydropower. The approach taken to hydropower modelling is described in section 4.2.6.

The model is implemented in Julia using JuMP. JuMP is a domain-specific modelling language for mathematical optimization embedded in Julia.

4.1.1 Model Formulation

The model formulation, as implemented in JuliaREX, can be found in Appendix A. This section explains the model formulation and its equations.

Variables subject to optimisation are the capacity mix, the generation mix of electricity, storage and transmission. These variables differ between the chosen regions $R = \{r_1, ..r_n\}$, the technologies possible to invest in $K = \{k_1, ..k_n\}$, different classes of solar and wind power $C = \{c_1, ..c_n\}$ and the hours chronologically over one year $H = \{h_1, ..h_n\}$. More about how solar and wind power are divided into different classes is found in chapter 4.2.5. Parameters given to the model include technology costs, technology efficiencies, demand, distance between regions, capacity factors etc. The variables are written in uppercase and the parameters in lowercase.

The **objective function** is to minimise total system cost. The total system cost ($SC, [M€/year]$) is a function of electricity generation ($G_{r,k,c,h}, [GWh/h]$), operation and management cost ($omc_k, [€/GWh]$), fuel cost ($fuc_k, [€/GWh]$), technology efficiency ($\eta_k, [-]$), installed capacity ($C_{r,k,c}, [GW]$), investment cost ($ic_k, [€/GW]$), annualisation factor (af_k), fixed cost ($fc_k, [€/GW/year]$), transmission capacity ($TC_{r_1,r_2}, [GW]$) and transmission cost ($tc_{r_1,r_2}, [€/GW]$). The system cost is implemented as:

$$SC = \sum_{r,k,c,h} G_{r,k,c,h}(omc_k + fuc_k/\eta_k) + \sum_{r,k,c} C_{r,k,c}(ic_k \cdot af_k + fc_k) + 0.5 \sum_{r_1,r_2} TC_{r_1,r_2} \cdot tc_{r_1,r_2} \tag{4.1}$$

The transmission cost is divided by two since the model is investing in transmission lines between both region r_1 and r_2 and between r_2 and r_1, even though only one line is needed. The transmission cost (tc, [€/GW]) is a function of transmission line cost ($tlc, [€/GW/km]$), distance between regions ($di_{r_1,r_2}, [km]$), transmission substation cost ($tsc, [€/GW]$), transmission intertie cost ($tic, [€/GW]$) and transmission fixed cost ($tfc, [\% of ic]$). Two substations are assumed to be needed for each transmission line. The transmission cost is then calculated as:

$$tc_{r_1,r_2} = (tlc \cdot di_{r_1,r_2} + 2 \cdot tsc + tic) \cdot (af + tfc) \tag{4.2}$$

Here follow all the **constraints** implemented in the model. First, a constraint is needed to make sure that the demand is met at all times, i.e to assure load balance. The total electricity generated ($G, [GWh/h]$), subtracting the electricity used for charging storage ($CH, [GWh/h]$), adding the imported electricity from transmission ($TG_{r_2,r,h}, [GWh/h]$) and subtracting the electricity exported ($TG_{r,r_2,h}, [GWh/h]$) to other regions by transmission needs to be greater than or equal to the demand ($d, [GWh/h]$) at each hour in every region. The transmission losses ($tl, [\%/1000km]$) depends on the distance between regions ($di_{r_1,r_2}, [km]$) and is assumed to occur only on import, in order not to double the effect of losses. The load balance is written as:

$$\sum_{k,c} G_{r,k,c,h} - \sum_{k,k=storage} CH_{r,k,h} + \sum_{r_2} (1 - tl_{r_2,r}) \cdot TG_{r_2,r,h} - TG_{r,r_2,h} \geq d_{r,h} \tag{4.3}$$

The electricity generation ($G, [GWh/h]$) cannot be greater than the installed capacity ($C, [GW]$) times the capacity factor (cf) for every technology for every hour in every region.

$$G_{r,k,c,h} \leq C_{r,k,c} \cdot cf_{r,k,c,h} \tag{4.4}$$

Storage constraints, for k = storage
Regarding the storage, it needs to be assured that the storage is not used if it is empty. The storage level ($SL_{r,k,h}, [GWh/h]$) can not be negative.

$$SL_{r,k,h} \geq 0 \tag{4.5}$$

The maximum storage level depends on the capacity installed ($C_{r,k,c}, [GW]$) and the discharge time ($dt_{r,k}, [h]$) for the storage technology. For batteries, this is given as 8 hours and for hydro dams it is dependent on the dam size.

$$SL_{r,k,h} \leq C_{r,k,c(k)} \cdot dt_{r,k} \tag{4.6}$$

The present storage level ($SL_{r,k,h}, [GWh/h]$) is modelled by a storage balance that depends on battery charging ($CH_{r,k,h}, [GWh/h]$), how much water that flows in to the dams, i.e. a capacity factor for hydro inflow ($cfh_{r,h}, [GWh/h]$), the installed capacity of hydro dams ($C_{r,dam}, [GW]$) and how much electricity that is lost due to efficiency of storage technologies, in this case batteries. The losses depend on the generation ($G_{r,k,c,h}, [GW]$) and the efficiency (η_k) [-]. The storage balance is written as, for h>1:

$$SL_{r,k,h} \leq SL_{r,k,h-1} + CH_{r,k,h} + cfh_{r,h} \cdot C_{r,dam} - \frac{G_{r,k,c,h}}{\eta_k} \tag{4.7}$$

If h=1, the first term after the inequality sign is instead the storage level in the last hour of the previous year. Note that the first term is less than or equal to and not only equal to. This is due to spillage when the water inflow is larger than the amount of water that the dam can handle, i.e when the capacity factor for hydro inflow is greater than 1.

Since hydro dams are modelled as storage technologies, but it is assumed that pumped hydro is not available, a constraint is needed to state that hydro charging is not possible. This is modelled, for k = hydro dams, as:

$$CH_{r,k,h} = 0 \tag{4.8}$$

To be able to charge batteries, there has to be batteries. Therefore a constraint as follows is needed, for k = batteries:

$$CH_{r,k,h} \leq C_{r,k,c(k)} \tag{4.9}$$

Transmission constraints: The transmission constraints assure that the transmitted electricity ($TG_{r_1,r_2}, [GWh/h]$) does not exceed the installed transmission capacity ($[TC_{r_1,r_1}, GW]$) and that the installed transmission between region r_1 and r_2 is the same as between r_2 and r_1.

$$\begin{aligned} &TG_{r_1,r_2,h} \leq TC_{r_1,r_2} \\ &TC_{r_1,r_2} = TC_{r_2,r_1} \end{aligned} \tag{4.10}$$

Nuclear constraints: In order to partially mimic realistic constraints on nuclear power plants, ramping constraints and a minimum generation level in percentage of installed capacity are imposed. The constraints are given for k = nuclear as:

$$\begin{aligned}
&G_{r,k,c(k),h} \leq G_{r,k,c(k),h-1} + 0.2 \cdot C_{r,k,c(k)} \\
&G_{r,k,c(k),h} \geq G_{r,k,c(k),h-1} - 0.2 \cdot C_{r,k,c(k)} \\
&G_{r,k,c(k),h} \geq 0.6 \cdot C_{r,k,c(k)}
\end{aligned} \tag{4.11}$$

Emission constraint: A cap on carbon emissions ($E_r, [ktonCO2/year]$) is set to obtain a system with a high share of renewable energy. The amount of carbon emissions depend on fuel use ($F_{r,f}, [GWh/year]$) and emission intensity ($coi_f, [ktonCO2/GWh]$). The total carbon emissions for each region is calculated as:

$$E_r = \sum_f F_{r,f} \cdot coi_f \tag{4.12}$$

The cap on emissions is then implemented as:

$$\sum_r E_r \leq P \tag{4.13}$$

P is a constant calculated for MENA and Europe respectively. It is calculated as 1% of the amount of carbon dioxide emissions if the whole demand were to be met by coal power plants.

4.2 Data

Input data to JuliaREX includes region classification; transmission distances; cost and performance data for technologies and fuels; hourly demand for a full historical year; capacity factors and capacity limits for solar-, wind-, and hydropower. This section contains information on how these input data were retrieved and implemented in the model. All tables containing input data can be found in Appendix B. All investment costs were annualised using a discount rate of 5%. JuliaREX uses cost inputs in dollars but the results are given in euros with a dollar conversion rate at 0.87 €/$.

4.2.1 Regions and Transmission

The modelled regions of MENA and Europe can be seen in figure 4.1 and 4.2 and a detailed description of how the countries are divided into regions can be seen in table B.1 in Appendix B. All regions are treated as "copper plates", i.e transmission within each region is not modelled and assumed to be unconstrained. HVDC transmission lines are assumed to be available for investment between neighbouring regions. How the regions can be interconnected and the distances between them are listed in table B.2 and B.3 in the appendix.

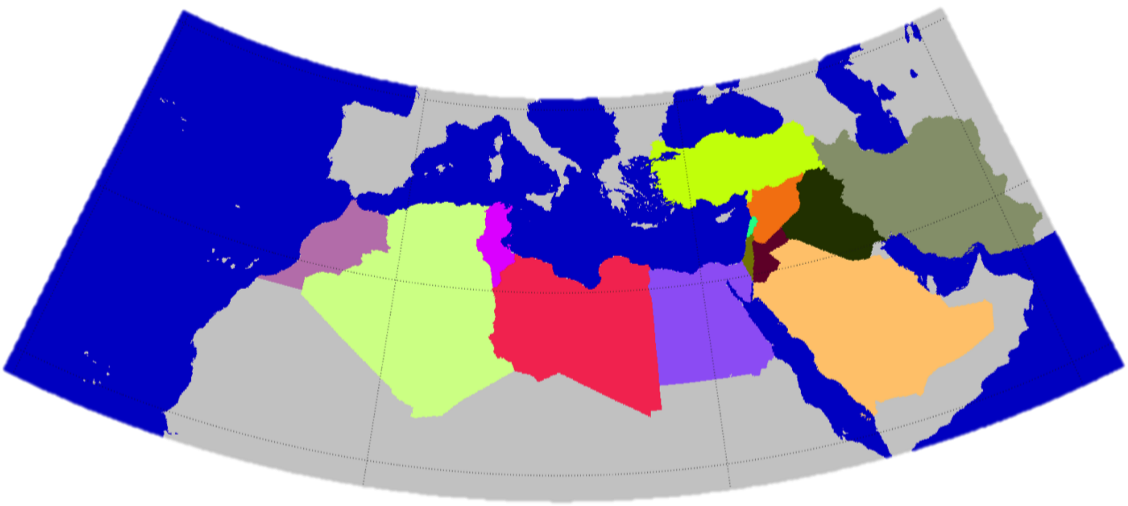


Figure 4.1: Map over the regions modelled in MENA. A detailed description of how the countries are divided into regions can be seen in figure B.1 in Appendix B.

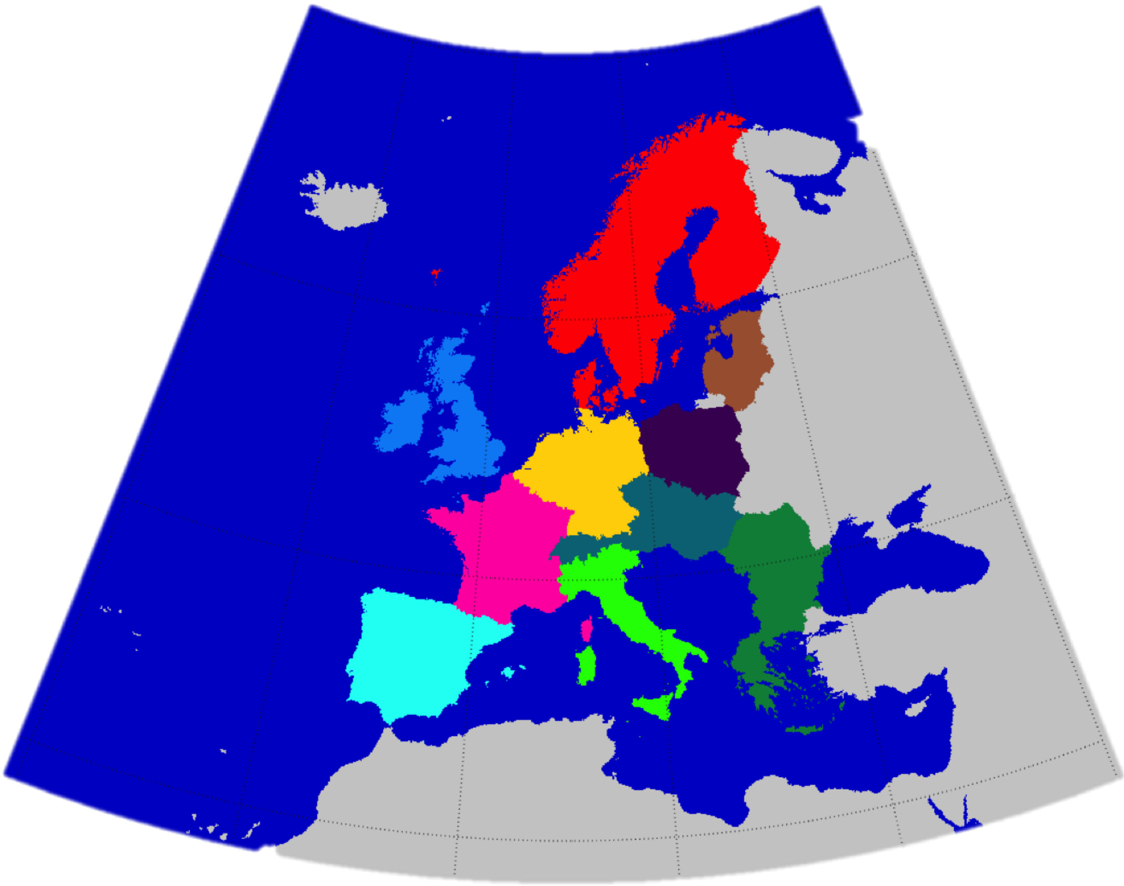


Figure 4.2: Map over the regions modelled in Europe. A detailed description of how the countries are divided into regions can be seen in figure B.1 in Appendix B.

The transmission costs are presented in table 4.2. Two substations for each transmission line are assumed to be needed. These costs are taken from ETSAP [43], except for the fixed cost which is reported by NREL [44]. The lifetime of HVDC lines is assumed to be 35 years [45].

Table 4.2: Transmission costs.

Trans. Line [$/MW/km]	**Substations [$/MW]**	**Intertie AC-DC-AC [$/MW]**	**Losses [%/1000km]**	**Lifetime [yr]**	**Fixed OM Cost [% of Inv. Cost]**
2030	17350	230000	3	35	0.8

4.2.2 Cap on Carbon Emissions

To investigate a system close to carbon neutral, a cap on carbon emissions is applied. The cap is set to 1% of the carbon dioxide emissions that would be present if the whole demand were to be met by coal power plants. It was calculated as $Cap = 0.01 \cdot C \cdot D$. Where C is the emission intensity for coal [ton/TWh] and D is the total demand [TWh/year].

4.2.3 Technology- and Fuel Costs

The power producing technology options are coal, nuclear, wind (onshore and offshore), PV (utility and rooftop), concentrated solar power (CSP), combined cycle gas turbines (CCGT) and gas turbines (GT). Both biogas and natural gas are fuel options in the modelled CCGT's and GT's.

The assumed costs and efficiencies for each technology are shown in table 4.3. The costs are retrieved from the National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB) Database for 2018 [46]. This database contains technology cost projections for every year until 2050 for a low-, mid- and high-cost scenario. The assumed costs used in this study are retrieved from the mid-cost scenario projection in NREL's database [46] (the costs are found in table 4.3). For PV, the examined cost range is assumed as the range between the low and high scenario [46]. For PV rooftop the cost is chosen as 50% higher than PV utility due to higher installation cost for smaller systems. This is in line with the cost projections from NREL's database 2018 [46]. The investment cost range for batteries is retrieved from utility-scale lithium-ion storage cost projections made by W. J Cole [47], which is very similar to the range given by NREL [46]. Lifetime and round-trip efficiency for the batteries are also from the lithium-ion storage cost projections [47].

Table 4.3: Technology costs and efficiencies. Note that the costs are given in dollars but the results are presented in euros. A dollar conversion rate at 0.87 €/$ is used.

	Investment Cost [$/kW]	**O&M Cost [$/MWh]**	**Fixed Cost [$/kW/yr]**	**Lifetime [yr]**	**Efficiency [-]**
Gas GT	821	7	12	30	0.38
Gas CCGT	966	3	10	30	0.54
Coal	3774	6	40	30	0.39
Nuclear	5570	2	99	60	0.32
Wind Onshore	1227	0	42	25	-
Wind Offshore	2317	0	130	25	-
PV Utility	400-1200	0	6	25	-
PV Rooftop	500-1500	0	6	25	-
CSP	5225	3.5	50	30	-
Hydro Power	0	0	0	-	-
Battery	700-3000	1.32	6	15	0.9

The fuel costs assumed in this thesis is found in table B.6 in Appendix B. Gas and coal prices are taken as a world average from IEAs World Energy Outlook 2017, Sustainable Development Scenario, for the year 2040 [48]. The price of uranium is taken from the 2050 projections by NREL [46]. It is difficult to obtain forecasts for biogas for the year 2040. This thesis uses the average biogas cost for the different scenarios presented in an optimisation study that explores the decarbonisation of the United States [29]. Emission factors for coal and natural gas were set to 0.330 and 0.202 kgCO2/kWh respectively.

4.2.4 Hourly Demand Profiles

The electricity demand is exogenous to the model and is given for every hour for every region. For Europe, this data is retrieved from ENTSO-E's database for power statistics [49]. Data on hourly electricity consumption for every region included in the MENA model could not be found. Therefore, hourly profiles have been created by scaling other regions hourly demand profiles to the annual consumption for each region. Hourly demand data was found for Iran [1], Saudi Arabia [50] and Turkey [50]. Which country's demand profile that was used for which country and the annual energy consumption that it was scaled according to, can be found in table B.7. The annual electricity consumption has been calculated using electricity consumption per capita and population for 2015 from [51]. The demand profiles were also time adjusted due to differences in time zone.

In addition, every region's demand profile is scaled to represent 2040 by using demand projections. The electricity demand in the Middle East is projected to increase 1.7% annually until 2040 [52], which is an increase of 52% compared to 2015. In this study, the demand in the North African countries is assumed to grow at the same rate.

4.2.5 Capacity Limits and Capacity Factors for Solar and Wind Power

The **capacity limits** are numbers representing the maximum capacity allowed to be installed in each region. In JuliaREX, there are capacity limits on PV, CSP, off- and onshore wind power and hydropower. Information on capacity limits for hydropower is described in 4.2.6. **Capacity factors** are different for every hour and reflects how much of the installed capacity that can be delivered as produced electricity that hour, i.e a capacity factor of 0.5 means that 5 MW can be produced if the installed capacity is 10 MW. For solar power, the capacity factors are calculated from solar irradiation and for wind power the capacity factors are calculated from wind speed. Details on how the capacity factors relates to solar irradiation and wind speed are found in Appendix B.1.

Limits on how much wind and solar power capacity that can be installed are calculated in a GIS model (described in [2]) and is based on assumptions on typical wind and PV farm densities ($W/m2$) and available land ($m2$). These assumptions are shown in table 4.4. Note that the available land is given in % of land where populated areas, natural parks, lakes, mountains etc. are already excluded in every region.

Table 4.4: Capacity limit assumptions. Density is given as of a typical solar or wind farm. Available land is given in % of land where natural parks, lakes, mountains etc. are already excluded in every region.

	PV Utility	PV Rooftop	CSP	Wind Onshore	Wind Offshore
Density [W/m2]	45	45	35	5	8
Available land [%]	10	10	10	10	33

To capture the different weather conditions and therefore different capacity factors for wind and solar power within each region, wind and solar technologies have been divided into 5 classes each. For the solar technologies these classes are determined by the annual average capacity factor and for on- and offshore wind power the classes are based on annual average wind speed. The classification is made for each $0.75° x 0.75°$ pixel in each region. The capacity factors are calculated and divided into classes in a GIS model [2] using solar irradiation and wind speed from ECMWF ERA Interim reanalysis database. More about how this is done is found in Appendix B.1.

The percentages of available land for wind onshore and the solar power production technologies are varied in a sensitivity analysis on available land (see chapter 4.3).

4.2.6 Hydropower

This study implements hydropower as "brownfield", i.e as it was already installed (all costs are set to zero). The hydropower capacities installed and annual production in each region are assumed to be as in 2016 according to the World Energy Council [53]. The capacities and annual production for each region can be seen in table B.8.

Input data on dam size and the hydro inflow profiles for each region is needed. Monthly hydro inflow profiles were taken from the GRanD data base [54], [55]. The inflow profiles are converted to hourly inflow assuming an even flow within each month. This inflow is given as a capacity factor and means that if the capacity factor is 0.5, the produced electricity can be maximum 50 % of the installed capacity of the hydropower plant. The dam size is needed to simulate how much energy that can be stored before the dam is overloaded and spillage occurs. Data on dam size is hard to find and differ between regions. In this study, the dam size is assumed to be equal to the annual production divided by 12, i.e that the dam roughly can hold the energy for a month before spillage occurs, depending on the inflow profile.

4.2.7 Batteries

Batteries are assumed to be lithium-ion battery packs. When modelling the batteries, a discharge time of 8 hours is used to constrain the maximum energy level in the batteries. The maximum energy level in the batteries is given by the installed capacity times the discharge time. The batteries are assumed to be able to charge and discharge at the same rate as the full installed capacity every hour.

Utility-scale battery storage cost projections done by W. J. Cole et al. [47] are done for lithium-ion battery packs with a discharge time of 8 hours. These cost projections are used in this study and are presented in table 4.5. This is also very similar to the projected cost range presented by NREL in their Annual Technology Baseline Database 2018 [46]. The variable cost and fixed cost are from NREL [46] and the lifetime and round trip efficiency from the battery cost projections by W. J. Cole et al. [47].

Table 4.5: Battery Costs and Efficiency.

	Investment Cost [$/kWh]	**Variable Cost** [$/MWh]	**Fixed Cost** [$/kW/yr]	**Lifetime** [yr]	**Efficiency** [-]
Battery	87.5-375 (231.25)	1.32	6	15	0.9

The cost range can be translated into 700 - 3000 [$/$kW$] due to the discharge time of 8 hours.

4.3 Sensitivity Analysis on Land Availability

When modelling a power system with a high share of VRE, land availability might be an important factor. This is due to the possibility that land availability constraints the capacity limits on solar- and wind power. To investigate the impact of land availability on the electricity system, a sensitivity analysis on the percentage of available land is conducted. The percentage of land available for PV and wind power is varied between 2 and 15 percent in both MENA and Europe for mid-costs on PV and batteries. In addition, all cost combinations of PV- and battery costs are modelled for 5% and 10% available land for PV and wind power. This enables a greater understanding of how land availability affects the sensitivity of the electricity system cost to varying solar and storage costs in Europe and MENA.

4.4 Limitations

JuliaREX models every region as a copper plate, i.e that the electricity transmission within each region is assumed to be unlimited. Due to this, internal transmission requirements are not considered.

In this study the demand is given exogenously and is assumed to be inelastic. Fuel and technology costs are also exogenous to the model even though these costs are likely to be dependent on demand, this might be especially true for biogas.

There are many different variability management strategies that could be applied to an electricity system with a high share of VRE technologies. Storage, transmission and dispatchable generation are included in this thesis. Demand-side management and sector integration are two examples of variability management strategies that are not included. In a low carbon electricity system, it might also be an option to have carbon capture and storage (CCS) technologies. CCS technologies are not included in this study.

Only one type of storage is included. Pumped hydro and hydrogen storage are two examples of storage technologies that are not included. Also, there are multiple types of batteries that could be integrated into an electricity system. In this study, only one type of lithium-ion battery packs is considered.

The resolution of technological detail in JuliaREX does not capture all costs and constraints on thermal generation. These constraints include ramping constraints on the different gas turbines and information on start and stop costs for all technologies.

5

Results

The system cost and generation mix in Europe and MENA for a range of PV- and battery costs are presented for the three different scenarios. The different scenarios are a base scenario (including inter-regional transmission and excluding nuclear power), a no transmission scenario (excluding inter-regional transmission and nuclear power) and a nuclear scenario (including inter-regional transmission and nuclear power). The range of PV- and battery costs are 400-1200 €/kWh and 87.5-375 €/kWh respectively (presented in section 4.2 in table 4.3 and 4.5). When both PV- and battery costs are at the highest, middle and lowest of the ranges, this is referred to as low-, mid- and high-costs.

The system LCOE for the base scenario and mid-costs of PV and batteries is 60.0 €/MWh for Europe and 51.6 €/MWh for MENA. A lower system LCOE is found in MENA compared to Europe in all scenarios, ranging from 8% to 21 % less costly in MENA depending on solar PV- and battery cost and the availability of transmission and nuclear power. Average system cost increases with about 10% in both MENA and Europe when transmission is excluded. However, the effect of excluding transmission is smaller when costs for PV and batteries are low compared to when the costs are high. The system cost increases between 3-15% in MENA, depending on PV- and battery costs. In Europe the range is 6-11%. The possibility to invest in nuclear power has almost no effect on system cost in MENA, with a reduction of system LCOE of around 1% for all cost combinations of PV and batteries. In Europe, the system LCOE reduction varies between 0-10% with the highest reduction for high-costs of PV and batteries. System LCOE for the three different scenarios in both MENA and Europe, using mid-costs of PV and batteries, are found in figure 5.1.

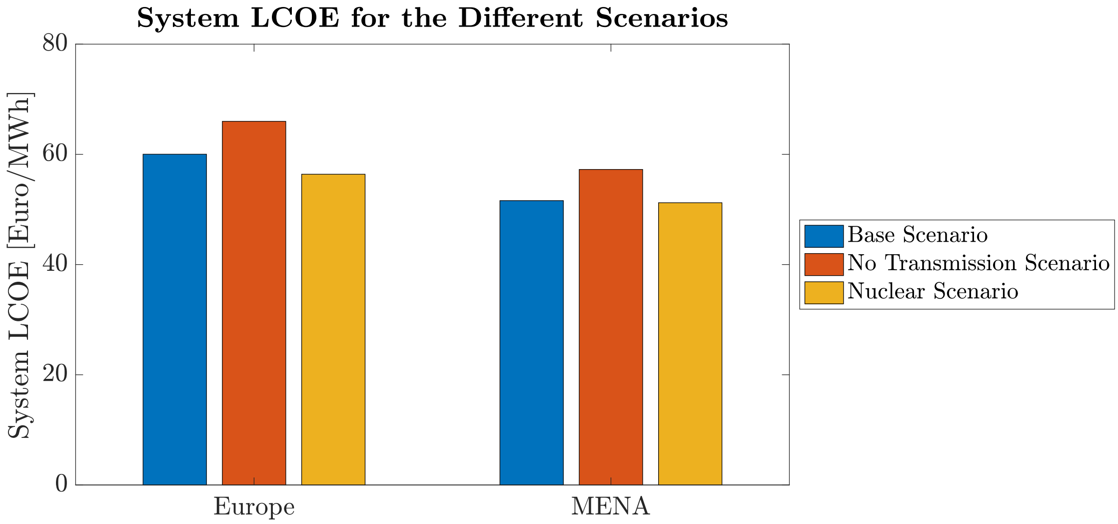
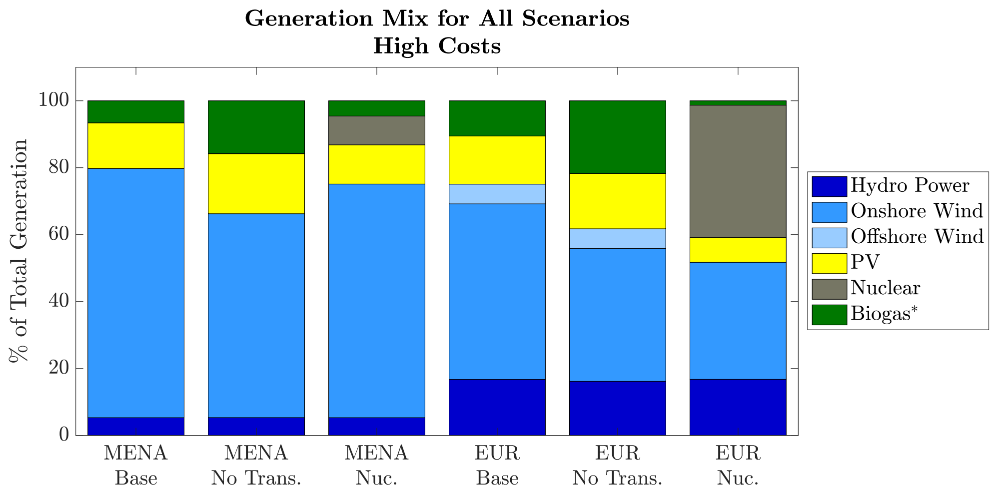
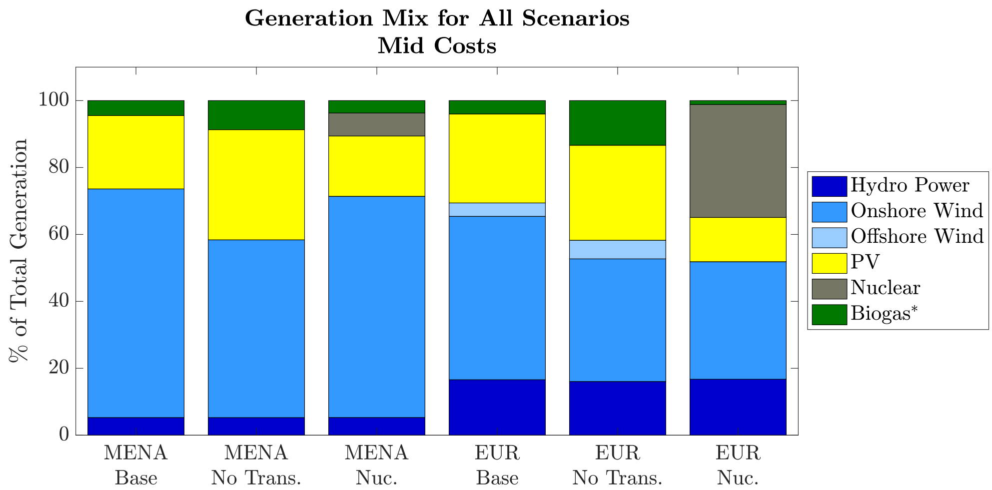


Figure 5.1: System LCOE for the three different scenarios in both MENA and Europe, using mid-costs of PV and batteries. The system LCOE is presented on the y-axis in €/MWh.

The power generation in MENA and Europe is dominated by wind power when PV and batteries are at their mid- and high-costs for all scenarios, except when nuclear power is included in Europe. When PV- and battery costs are at their lowest, PV is the dominating generation technology in all scenarios. The generation mixes for all scenarios in MENA and Europe are presented for low- mid- and high-costs in figure 5.2. More about how the generation mix is affected by different the scenarios and varying PV- and battery costs is presented in section 5.2.





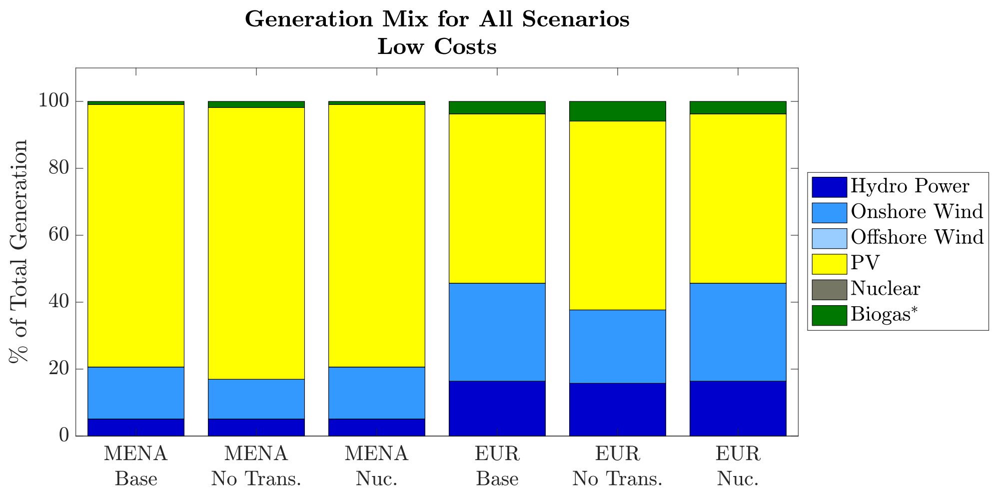


Figure 5.2: The generation mixes for all scenarios, for both Europe and MENA. The top figure corresponds to when PV- and battery costs are at their highest, the middle figure to PV- and battery cost at their mid-costs and the bottom figure to PV- and battery costs at their lowest. * *Around 1% of the total generation mix is natural gas, the rest of the biogas field is biogas.*

5.1 Varying PV- and battery costs

Decreasing the cost of PV with 50% (from 800 to 400 €/kW) and batteries with 62% (from 231 to 88 €/kWh) decreases system cost between 28-34% in MENA and 19-27% in Europe depending on the scenario. In absolute numbers, the system cost reduction corresponds to 14-19 €/MWh in MENA and 11-18 €/MWh in Europe. Increasing the cost of PV with 50% (800-1200 €/kW) and batteries with 63% (231-375 €/kWh) has a minor effect on the total system cost, 4-9% in MENA and 3-7% in Europe depending on the scenario. The system cost increase corresponds to 2-5 €/MWh for both Europe and MENA. Figure 5.3 shows how the system cost varies with changing PV- and battery costs relative the mid-costs.

There is no significant difference between the sensitivity of system cost for changes in PV- and battery costs in MENA and Europe. However, in the base scenario, the system cost sensitivity is slightly higher in Europe than in MENA, the exception being for the lowest battery cost combinations (blue line in figure 5.3). The slight difference in sensitivity correlates to the slight difference in the share of PV in the generation mix (figure 5.2), where a higher share of PV and batteries correlates to a more sensitive system cost. Comparing the different scenarios, the system cost sensitivity on variations in PV- and battery costs does not change significantly. Even though the differences in system cost sensitivity between the scenarios are very small, two slight differences can be observed. Within Europe, the system cost is slightly less sensitive to changes in PV- and battery costs if nuclear is allowed and within MENA, the system cost is slightly more sensitive when transmission is excluded. In Europe, the PV share is about the same in the base and no transmission scenario but lower in the nuclear scenario, correlating to a less sensitive system cost in the nuclear scenario. In MENA, the share of PV is almost the same in the base and the nuclear scenario but higher in the no transmission case, correlating to a higher system cost sensitivity in the no transmission case. Despite these slight differences, it is important to note that overall the system cost sensitivity to changes in PV- and battery costs does not change significantly between Europe and MENA and the three scenarios.

By looking at figure 5.3 it can be seen that the sensitivity to changes in only battery cost is similar to the sensitivity to changes in only PV cost, i.e the contribution to system cost changes is rather similar between PV- and battery cost changes. If either PV or battery cost is restricted to mid-cost, the system cost benefit is limited to 6-11%, while a low-cost combination results in a system cost decrease of 19-34%. Low battery prices increase the benefits of low PV prices and vice versa.

A figure, similar to figure 5.3, containing the system LCOE in absolute terms [€/MWh] can be found in Appendix D as figure D.3.

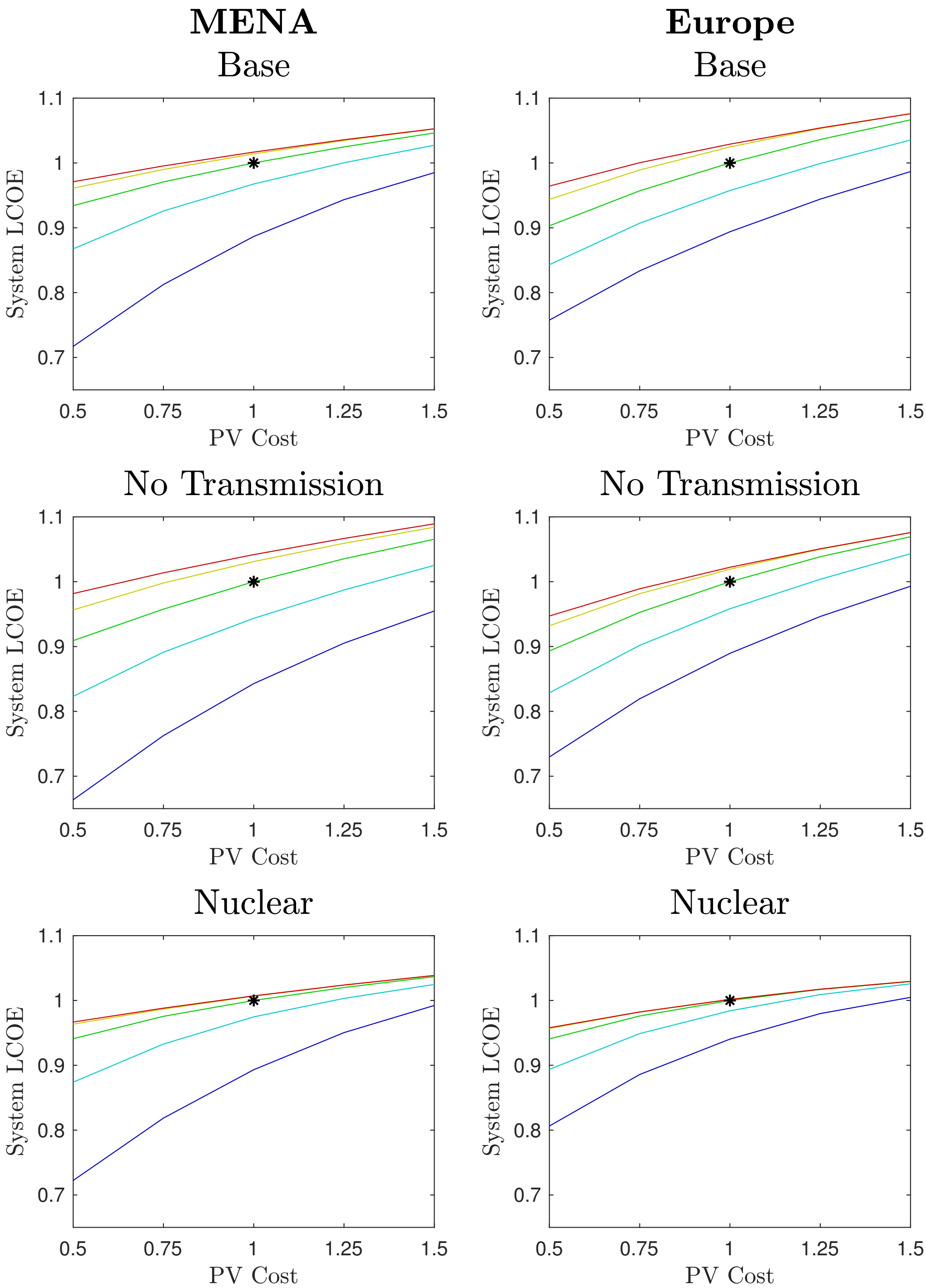


Figure 5.3: Result of how system cost changes with PV- and battery costs. This is presented for all three scenarios in both MENA and Europe. System LCOE is on the y-axis and PV cost is on the x-axis, both normalised to their mid-costs. The coloured lines represent different battery costs. The middle line (green) represents the mid-cost, the top line (red) corresponds to the highest battery cost and the bottom line (blue) corresponds to the lowest battery cost. Mid-costs on both PV and batteries is marked with a black asterisk.

5.2 Changes in Generation Mix

This section presents changes in the generation mix when excluding transmission or including nuclear power.

The no transmission scenario changes the optimal generation mix for both Europe and MENA. Energy produced by wind power decreases sharply in both geographical regions when PV- and battery costs are at mid- and high-costs (see figure 5.2). Both Europe and MENA increases the share of PV and biogas to replace the decrease in wind power. However, MENA uses PV to a larger extent while Europe relies more on biogas. The resulting utilisation of biogas is greatly dependent on the cost combinations of PV and batteries. The share of biogas in Europe goes from 5% to almost 20% when the combination of PV- and battery costs change from low to high, while the share in MENA changes from 1-14%. The increased share of biogas highlights the increasing need for dispatchable generation or other variation management strategies in order to balance the high VRE share when transmission is not allowed. When PV- and battery costs are at their lowest, the exclusion of transmission does not have a significant impact on the generation mix in either Europe or MENA. However, the share of PV and biogas increases slightly to replace a decrease in wind power.

Including nuclear power results in different changes in the generation mix for MENA and Europe (see figure 5.2). In Europe, nuclear power supplies up to 40% of the demand and is tied to a sizeable reduction in wind power, PV and biogas (compared to when nuclear power is not an option). In MENA nuclear power provides up to 10% of the total demand, with the most significant reduction in PV and a small reduction in wind power and biogas. The highest nuclear power supply is found for high-costs of PV and batteries. The installed battery capacity is significantly smaller in both regions when comparing the nuclear scenario to the base scenario. For the mid-costs of PV and batteries, the usage of batteries decreases by half in MENA and by 86% in Europe. The competitiveness of nuclear power is dependent on the alternative generation available. For the lowest combination of PV- and battery cost, nuclear is not competitive in either region and no nuclear power is installed. The cost of PV and batteries where no nuclear enters the optimal capacity mix is different in MENA and Europe. In Europe the combination of the second lowest PV- and battery costs results in a 50% reduction in nuclear energy compared to mid-costs and for MENA this cost level drives nuclear investment to zero.

5.3 Sensitivity Analysis on Land Availability

The results presented in chapter 5 use a land availability percentage of 10% for both PV and onshore wind power (more about land availability is found in chapter 4.2.5). In the sensitivity analysis, both MENA and Europe were modelled with 5% and 10% land availability, for all combinations of PV- and battery costs. The results from the sensitivity analysis are presented in figure 5.4. An increase from 5% to 10% land availability doubles the capacity possible to invest in for PV and wind onshore.

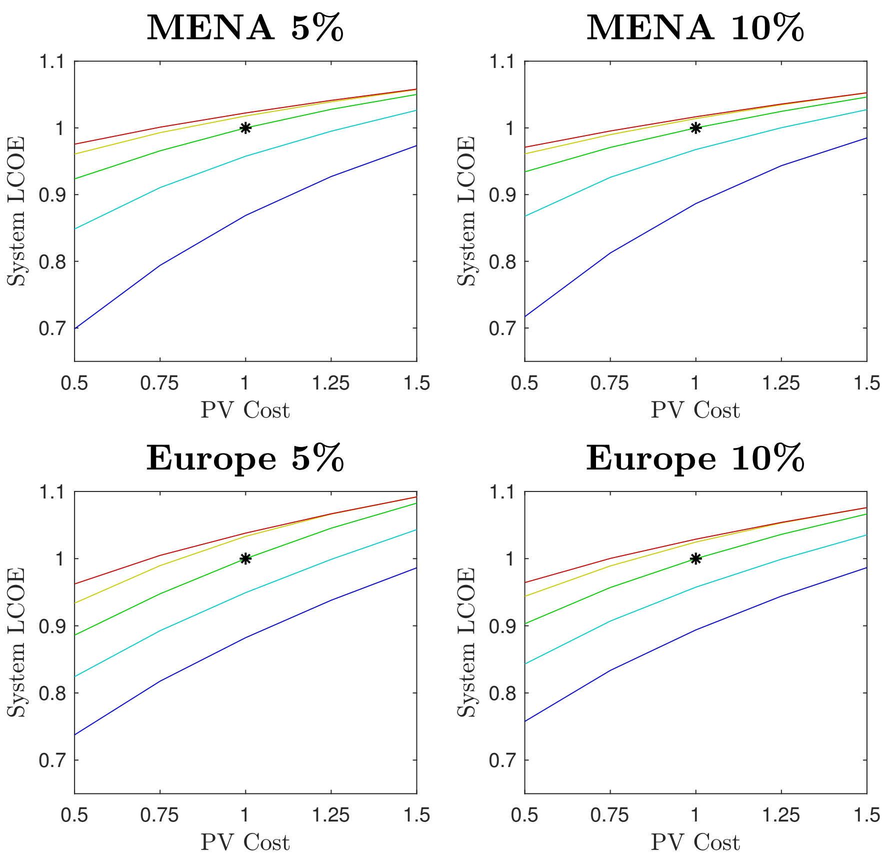


Figure 5.4: Sensitivity analysis on land availability. System LCOE is on the y-axis and PV cost is on the x-axis. Both are normalised to their mid-cost. 10% corresponds to a case where the land availability is set to 10% for all solar power technologies and also for wind onshore. The same goes for 5%, i.e 5% land availability applies to all solar power technologies and to wind onshore. The coloured lines represent different battery costs. The middle line (green) represents the mid-cost, the top line (red) corresponds to the highest battery cost and the bottom line (blue) corresponds to the lowest battery cost. Mid-costs on both PV and batteries is marked with a black asterisk. System LCOE for the mid-costs are 53.5 €/MWh for MENA 5%, 51.6 €/MWh for MENA 10%, 64.4 €/MWh for Europe 5% and 60.0 €/MWh for Europe 10%.

Changing the available land from 5% to 10% does not change how sensitive the system cost is to varying PV- and battery costs for either Europe or MENA. This can be seen by looking at figure 5.4, where the system LCOE (normalised to the system LCOE for the mid-costs) does not change between 5% and 10% available land.

However, increasing the available land from 5% to 10% results in a lower system cost. The resulting system LCOE (in €/MWh) for the mid-costs are 53.5 €/MWh for MENA 5%, 51.6 €/MWh for MENA 10%, 64.4 €/MWh for Europe 5% and 60.0 €/MWh for Europe 10%. In figure 5.5) it can be seen that system cost is more sensitive to land availability in Europe than in MENA.

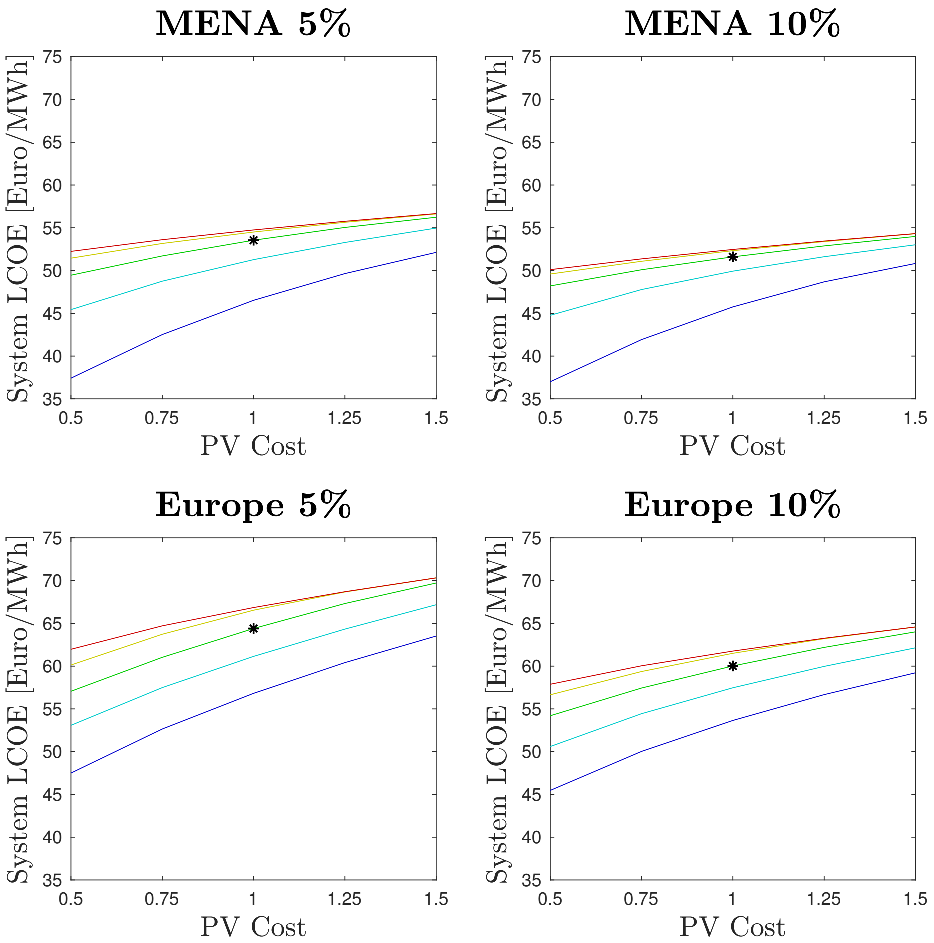


Figure 5.5: Sensitivity analysis on land availability. System LCOE in €/MWh on the y-axis and PV cost on the x-axis normalised to mid-cost. 10% corresponds to a case where the land availability is set to 10% for all solar power technologies and also for wind onshore. The same goes for 5%, i.e 5% land availability applies to all solar power technologies and to wind onshore. The coloured lines represent different battery costs. The middle line (green) represents the mid-cost, the top line (red) corresponds to the highest battery cost and the bottom line (blue) corresponds to the lowest battery cost. Mid-costs on both PV and batteries is marked with a black asterisk.

Europe is more affected by land availability (see figure 5.5). The reason for this is that the generation mix is constrained by the available land and Europe has less land per energy demand. The changes in optimal generation mix with the percentage of available land is shown in table 5.1 and 5.2. Tables with the full generation mix for the sensitivity analysis are found in Appendix E. These tables tell us that optimally installed wind power approaches the capacity limit while the installed PV does not. Increasing the available land allows for more wind power which decreases the system cost. The effect of higher land availability is more pronounced in Europe, where the production of wind power increases with 32% when the available land is raised from 5% to 10%. The equivalent increase for MENA is 8%. It can also be seen that the system LCOE in Europe is much more affected by increasing available land compared to MENA; the LCOE changes from 65.5-58.9 €/MWh in Europe and 53.6-51.1 €/MWh in MENA. This shows that the possible wind and PV production in relation to demand is higher in MENA than in Europe. For 10% land availability MENA can produce 23 times its demand by PV utility and 3 times its demand by wind power due to the capacity limits and capacity factors. The same numbers for Europe are 4.8 and 1.2 respectively. For the case of 5% land availability these numbers are reduced by a factor 2.

Table 5.1: Generation mix in Europe depending on available land for PV utility and onshore wind power. All numbers are in TWh, except for system LCOE which is given in €/MWh.

	2%PV 5%W	**5%PV 5%W**	**5%PV 10%W**	**10%PV 10%W**	**15%PV 15%W**
PV Utility	922	1046	817	827	792
Wind Onsh	1172	1155	1524	1518	1662
Wind Offsh	207	203	125	124	40
System LCOE	65.5	64.4	60.2	60.0	58.9

Table 5.2: Generation mix in MENA depending on available land for PV utility and onshore wind power. All numbers are in TWh, except for system LCOE which is given in €/MWh.

	2%PV 5%W	**5%PV 5%W**	**5%PV 10%W**	**10%PV 10%W**	**15%PV 15%W**
PV Utility	512	519	430	431	399
Wind Onsh	1252	1246	1344	1344	1378
Wind Offsh	0	0	0	0	0
system LCOE	53.6	53.5	51.6	51.6	51.1

6

Discussion

This chapter starts by discussing the differences between MENA and Europe, especially their system costs and how their power system responds to variations in PV- and battery costs. It continues with the impact of transmission and nuclear power and lastly gives some indications on further research.

6.1 Comparing MENA and Europe

Decreasing the cost of PV with 50% (from the mid-cost of 700 €/kW) and batteries with 62% (from the mid-cost of 1600 €/kW) decreases system cost between 28-34% in MENA and 19-27% in Europe depending on the scenario. Increasing the cost of PV and batteries in the same order of magnitude has only a minor effect on the total system cost, 4-9% in MENA and 3-7% in Europe depending on the scenario. The minor system cost increase implies that the solution space is flat around the optimum when PV- and battery costs are high, i.e. there are different possible generation mixes able to deliver a system cost close to the one for mid-costs even though PV- and battery costs are high. Regarding resource availability, MENA can produce 23 times its demand by PV utility and 3 times its demand by wind power while the corresponding values in Europe are 4.8 and 1.2. Thus, even if MENA has excellent solar resources, there are also great resources of wind power available. When PV and batteries are expensive, both MENA and Europe can install more wind power which limits the effect of increased battery and PV costs. When PV and batteries are low-cost, both MENA and Europe has solar resources to take advantage of the low-cost generation. These two conditions explain the similarities between Europe and MENA in how the system cost changes depending on variations in PV- and battery costs. The system cost in MENA decreases slightly more at low-costs compared to in Europe which may be explained by MENA's better solar resources. One might expect a different result on system cost sensitivity to PV- and battery cost for a region with poor wind or solar resources.

The cost-benefit of decreasing both PV- and battery cost is larger than the added cost-benefits of decreasing PV- and battery costs separately, which shows a synergy effect of PV- and battery costs on system cost. This synergy effect could be explained by the electricity system dynamics of PV and that batteries can interact with the PV generation to smooth out the PV generation variations and therefore increase the system value of PV. That the combination of low battery and PV costs have a large effect on system LCOE is also shown by Reichenberg et al. [14]. In both MENA and Europe, the relationship between system cost and PV cost is found to be close to linear when battery costs are high and vice versa. When the costs of PV or batteries are low, the cost-benefits increases with decreasing cost of the other technology.

The results in this study show a lower system LCOE in MENA than in Europe for all three scenarios, despite the fact that Europe has larger hydropower resources. A lower average system cost is found in MENA compared to Europe, ranging from 8 to 21 % less costly in MENA depending on solar PV- and battery cost and the use of transmission and nuclear power. When comparing the difference in system LCOE between Europe and MENA in the nuclear scenario, Europe has more cost-benefit of using nuclear power than MENA. One probable explanation to the lower system LCOE in MENA and Europe's larger cost-benefit of nuclear power is MENA's abundant solar and wind resources. However, the effect of MENA's abundant wind and solar resources, or that it better matches the demand, might be exaggerated by the assumption on unconstrained transmission within each region. The regions in MENA are larger in terms of area and the population density is generally more unevenly distributed than in Europe. Assuming unconstrained transmission within the regions leads to advantages for MENA compared to Europe as the model underestimates the real need of transmission. The advantage is that the electricity system can use a greater variety of wind and solar conditions to meet the regional demand without the need to invest in transmission or batteries. How much the unconstrained transmission contributes to the lower electricity cost in MENA could be further investigated by increasing the spatial resolution in the model, i.e implementing smaller and more regions. In addition, the lesser degree to which land is available for VRE capacity in Europe likely contributes to the slightly higher system cost in Europe, compared to MENA. MENA has a larger share of wind power than Europe in all scenarios at mid- and high-costs and installed capacity of offshore wind in Europe points at limitations in onshore wind capacity in Europe. This limitation is corroborated by the sensitivity analysis of land availability conducted in this study, which shows that capacity limits of wind power in Europe are constrained by land availability. The land-constricted wind power capacity also points at land use competition as a more pressing issue in Europe than in MENA.

MENA is currently dominated by fossil fuel; with a power plant mix comprising of 68% natural gas and 23% oil [9]. This coupled with increasing living standards, pollution concerns and the possibility of electrification of other sectors, such as transportation, means that there are large potential gains to be had by decarbonising the power sector in MENA. As shown in this study, a close to carbon-free power system in MENA is less expensive than a comparable system in Europe and the lowest system LCOE is found to be 37 €/MWh in MENA. This suggests that decarbonising the power sector is a viable and efficient option for reducing global carbon dioxide emissions.

6.2 The Role of Transmission

The increase of system cost in the no transmission scenario compared to the base scenario is in line with the literature reviewed in chapter 3. The 3-15% increase in system cost when regions are isolated in both MENA and Europa is smaller than the around 32% increase Schlachtberger et al. [13] find in their study, but more similar to the 13.4% increase from Macdonald et al. [18] and the 10% increase from Barbosa et al [16]. The importance of transmission in systems with a high share of VRE is also shown in several of the articles reviewed in chapter 3 [13, 16, 17, 18, 19, 20]. This is despite large differences in model formulations, assumptions, and data handling. Therefore, a significant system cost increase due to exclusion of transmission is a robust result. It can be explained by an increased need to over-invest in VRE (leading to large curtailment), storage and thermal generation with potentially low full load hours.

This thesis only investigated two scenarios regarding inter-regional transmission capacity: an optimal expansion of the transmission capacity (the base scenario) and a scenario excluding all transmission. For political reasons, it might not be possible to expand the transmission capacity between all the modelled countries in MENA. That said, many countries already today have international transmission installed. Studies by Schlachtberger et al. [17] and Brown et al. [15] have shown that the benefits of transmission are non-linear: the largest share of cost-benefits are achieved already with a more modest transmission expansion. As the penalty found in this study was 10% for the no transmission scenario it means that a high VRE electrical system could be affordable even without improvements in the political landscape.

Less wind power is used in the optimal generation mix for the no transmission scenario for both Europe and MENA which is similar to the results in earlier studies [13, 15, 17, 18, 19, 20, 29]. In MENA, the use of PV increased sharply in the no transmission scenario and is also in line with the previous studies. Biogas plays a more important role when replacing wind power in Europe than in MENA. The utilisation of biogas peaks at the most expensive combination of PV- and battery costs at a level of 19% in Europe and 14% in MENA. Shares of biogas this high might run into resource availability constraints, especially with possible competing demand from other sectors. The resulting share of biogas highlights the increasing need for flexibility measures in order to balance the high VRE share when transmission is not allowed, rather than defining the actual need of biogas. Two possible providers of this flexibility are demand-side management and hydro power expansion. There is a significant potential for expansion of hydro capacity, not least in MENA.

This study finds that wind power is the largest contributor of electricity generation in both MENA and Europe, except for when PV- and battery cost are at their lowest. Even though there are differences in the articles reviewed in chapter 3, this is in line with most of them. One of the articles that instead gets a PV dominated system [28] is using a model that does not allow for transmission. Several of the reviewed articles conclude that increased transmission favours wind generation over PV [13, 15, 17, 18, 29]. That transmission favours wind power is also seen in this study, as the wind power share decreases when transmission is not allowed. This can be explained by that wind power variability gets smoothed out over large regions when allowing for transmission.

6.3 Allowing Nuclear Power in the system

The importance of nuclear power is contingent on the costs of the alternative generation technologies. At mid- and high-costs of PV and battery, nuclear power has the potential to lower the total system cost. The cost reduction is limited in our results to 11% in the case with the most expensive PV- and battery costs in Europe and 2% in MENA. At low-costs of PV and battery, the nuclear option is not cost-efficient in either MENA or Europe. The difference between MENA and Europe, regarding the impact of nuclear power on system cost, can be explained by their solar and wind resource availability. The abundance of high-quality solar and wind resources in MENA reduces the competitiveness of nuclear power. In comparison, Europe has less high-quality wind and solar to install which allows nuclear power to be cost-competitive. The sensitivity analysis of land availability conducted in this study shows that wind power capacity is more constricted in Europe than in MENA. The importance of nuclear power in a carbon-free power system depends on solar and wind resources and available land for wind and solar. The insignificant system cost decrease when nuclear is available in MENA points at the possibility to decarbonise MENA's fossil fuel dominated power system without installing nuclear power with its associated concerns about safety and proliferation.

6.4 Further Research

This study has shown that land availability for solar and wind power is of great importance when conducting power system modelling. We have shown that land availability is an important factor when comparing system cost and the role of nuclear power between Europe and MENA. In addition to this, lowering the available land for PV and onshore wind in Europe from 10% to 5% has a system cost penalty of around 7% and is in the same order of magnitude as the system cost penalty of excluding transmission or nuclear power. Therefore, land availability is an important and interesting future research question within the field of energy system modelling.

There is a reason to believe that batteries play an important role when examining the research questions in this thesis due to synergies between batteries and PV. This thesis models one type of storage, namely lithium-ion battery packs with a discharge time of 8 hours as describes in the method chapter, section 4.2.7. This simplification might affect the results, as different storage technologies exhibit different characteristics and are suitable at different timescales. Lithium-ion cells can be produced with different combinations of energy to power ratio. Except for other variations of lithium-ion batteries, potential storage technologies not included in this study are pumped hydro, flow batteries, hydrogen storage etc. Some of these technologies could provide seasonal storage, a function the lithium-ion batteries in this study do not perform. To model a combination of batteries with different characteristics would probably lead to lower system cost as well as increase the synergies with solar and wind.

Regarding the optimal generation mix, there is a possibility that there are multiple solutions very close to the optimal value, i.e. there could be different capacity and generation mixes generating system costs near optimum. Schlachtberger et al. [13] note that the total system cost tends to be flat in the optimisation space and that "it indicates a certain degree of freedom to consider additional factors like public acceptance in the choice of cost-optimal system layouts". Thus, examining different solutions near the optimum is of interest as further research.

Many of the parameters needed in this optimisation are subject to uncertainty to some extent. This could, for example, be due to uncertainty in future cost projections or in assumptions in data handling. To investigate this and verify the robustness of the results, a Monte Carlo analysis could be conducted.

This study considers the power system in isolation and does not include other energy sectors such as heating and transportation. Brown et al. [15] show that a cost-optimal, close to carbon neutral, energy system in Europe does not need any stationary electricity storage when the total energy system is optimised as a whole. This is due to the use of batteries in electric vehicles, power to gas technologies etc. as variation management strategies. Our study uses exogenous demand profiles from 2015 scaled with a projected electricity consumption growth rate to represent the year 2040. However, electrification of the transport sector or other significant societal energy changes would drastically change the demand profile and electricity demand. Thus, sector integration is necessary to see how system cost varies with PV- and battery costs for the whole energy system. However, sector integration should not be as important when comparing relative system cost sensitivity on varying PV- and battery costs between MENA and Europe, if sector integration is excluded in both regions.

7

Conclusion

With a fossil fuel dependent power system and a growing electricity demand, decarbonisation of the power sector would have a large effect on carbon dioxide emissions in MENA. This thesis model a future high VRE continental scale power system in order to examine the changes in system cost of varying solar and battery costs. In order to isolate the influence of climate, the results in MENA are compared to Europe using the same model.

The results show that there is no significant difference in how sensitive the power system cost is to varying PV- and battery costs between Europe and MENA. This is true with and without inter-regional transmission and nuclear power. The explanation is that Europe and MENA do not have fundamentally different climate conditions; both have sufficient wind and solar resources to adjust to changes in PV- and battery costs.

We show that a near carbon-free power system in MENA is less expensive than a comparable system in Europe, with a system LCOE as low as 37 €/MWh for the lowest estimate of PV- and battery costs used in this study. Continued cost development on both solar PV and batteries is shown to have a large potential to lower system cost, due to their synergy effect on system cost. This study shows a possible reduction of system cost of 30% in both Europe and MENA for the evaluated range of PV- and battery costs. PV- and battery costs also impact the system cost-benefit of inter-regional transmission. When the option to build inter-regional transmission is removed, the cost penalty is shown to be limited to 3-15%, depending on PV- and battery costs. Excluding nuclear power from the electricity system in MENA is shown to increase the system cost with only 2% even when the PV- and battery costs are at their highest. In conclusion, a high VRE electricity system in MENA is a viable and cost-efficient option for reducing global carbon dioxide emissions and could be affordable even without an expansion of inter-regional transmission. In addition, MENA's fossil fuel dominated power system can be decarbonised without installing nuclear power with its associated concerns about safety and proliferation.

This thesis has shown that the assumptions on land availability for solar and wind is of great importance. Land availability assumptions has shown to affect system cost in Europe in the same order of magnitude as excluding nuclear power or inter-regional transmission. In addition, available land is an important factor when analysing the cost-benefit of nuclear power and the power system generation mix. Therefore, more care and consideration should be taken on the issue of land availability in the research field of energy system modelling.

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A

Model Formulation

The variables and parameters are written in uppercase and parameters in lowercase. How the variables and parameters are dependent on different sets is indicated by subscripts.

Sets:

REGION, r

TECH, k

CLASS, c

HOUR, h

FUEL, f

Variables:

SC – Total system cost [M€/year]

$G_{r,k,c,h}$ – Electricity generation [GWh/h]

$C_{r,k,c}$ – Installed Capacity [GW]

$TG_{r1,r2,h}$ – Transmission [GWh/h]

$TC_{r1,r2}$ – Transmission Capacity [GW]

E_r – Carbon dioxide emissions [kton CO2/year]

$F_{r,f}$ – Fuel use [GWh fuel/year]

$CH_{r,k,h;k=storage}$ – Charging of storage [GWh/h]

$SL_{r,k,h;k=storage}$ – Storage level [GWh/h]

Parameters:

$cf_{r,k,c,h}$ – Capacity factor [-]

$tl_{r1,r2}$ – Transmission losses [%/1000km]

$d_{r,h}$ – Demand [GWh/h]

hc_r – Installed hydro capacity [GW]

$cfh_{r,h}$ – Capacity factor representing the hydro inflow [-]

$cl_{r,k,c}$ – Limits on installed capacity of wind power, PV and CSP [GW]

η_k – Efficiency [-]

$dt_{r,k;k=storage}$ – Discharge time for storage [h]

isl – Initial storage level [-]

coe_f – Emissions intensity of CO2 [kgCO2/GWh]

ic_k – Investment cost [€/GW]

fc_k – Fixed cost [€/GW/year]

omc_k – Operation and Management cost [€/GWh]

fuc_f – Fuel cost [€/GWh]

tc – Transmission cost [€/GW]

- tlc – Transmission line cost [€/GW/km]
- tsc – Transmission substation cost [€/GW]
- tic – Transmission inter tie cost [€/GW]
- tfc – Transmission fixed cost [% of ic]

af_k – Annualisation factor, as a function on lifetime and discount rate [-]

$di_{r1,r2}$ – Distance between regions [km]

Objective Function
Minimise system cost, min(SC)

$$SC = \sum_{r,k,c,h} G_{r,k,c,h} \cdot (omc_k + fuc_f/\eta_k) + \sum_{r,k,c} C_{r,k,c} \cdot (ic_k \cdot af_k + fc_k) + 0.5 \cdot \sum_{r1,r2} TC_{r1,r2} \cdot tc_{r1,r2}$$

where

$$tc_{r1,r2} = (tlc \cdot di_{r1,r2} + 2 \cdot tsc + tic) \cdot (af + tfc)$$

Constraints
Load balance:

$$\sum_{k,c} G_{r,k,c,h} - \sum_{k,k=storage} CH_{r,k,h} + \sum_{r2} (1 - tl_{r2,r}) \cdot TG_{r2,r,h} - TG_{r,r2,h} \geq d_{r,h}$$

Generation constraint:

$$G_{r,k,c,h} \leq C_{r,k,c} \cdot cf_{r,k,c,h}$$

Storage constraints, for k=storage:

$$SL_{r,k,h} \geq 0$$
$$SL_{r,k,h} \leq C_{r,k,c(k))} \cdot dt_{r,k}$$
$$SL_{r,k,h} \leq SL_{r,k,h-1} + CH_{r,k,h} + cfh_{r,h} \cdot C_{r,k,c} - G_{r,k,c,h}/\eta_k$$

No pumped hydro, for k=hydro:

$$CH_{r,k,h} = 0$$

Charging needs batteries, for k=batteries:

$$CH_{r,k,h} \leq C_{r,k,c(k)}$$

Transmission constraints:

$$TG_{r1,r2,h} \leq TC_{r1,r2} TC_{r1,r2} = TC_{r2,r1}$$

Nuclear constraints, for k = nuclear:

$$G_{r,k,c(k),h} \leq G_{r,k,c(k),h-1} + 0.2 \cdot C_{r,k,c(k)}$$
$$G_{r,k,c(k),h} \geq G_{r,k,c(k),h-1} - 0.2 \cdot C_{r,k,c(k)}$$
$$G_{r,k,c(k),h} \geq 0.6 \cdot C_{r,k,c(k)}$$

Emission constraints:

$$E_r = \sum_f F_{r,f} \cdot coi_f$$
$$\sum_r E_r \leq P$$

Positive Variables:

$$
\begin{aligned}
&F_{r,f} \geq 0\\
&G_{r,k,c,h} \geq 0\\
&CH_{r,k,h;k=storage} \geq 0\\
&TG_{r1,r2,h} \geq 0\\
&TC_{r1,r2} \geq 0\\
&C_{r,k,c} \geq 0
\end{aligned}
$$

B

Input Data

Table B.1: Region classification.

Regions	**Countries**
Europe Model	
NOR	Sweden, Norway, Denmark, Finland, Faroe Islands
IT	Italy, San Marino, Vatican City
FRA	France, Monaco
GER	Germany, Netherlands, Belgium, Luxembourg
UK	United Kingdom, Ireland, Guernsey, Isle of Man, Jersey
GR	Greece, Bulgaria, Romania
BAL	Estonia, Latvia, Lithuania
POL	Poland
SPA	Spain, Portugal, Andorra
CEN	Austria, Switzerland, Czechia, Hungary, Slovakia, Liechtenstein
MENA model	
MOR	Morocco
ALG	Algeria
TUN	Tunisia
LIB	Libya
EGY	Egypt
ISP	Israel, Palestine
LEB	Lebanon
JOR	Jordan
SYR	Syria
TUR	Turkey
IRAN	Iran
IRAQ	Iraq
SA	Saudi Arabia

Table B.2: Transmission distances in MENA [km].

	MOR	ALG	TUN	LIB	EGY	ISP	LEB	JOR	SYR	TUR	IRAN	IRAQ	SA
MOR		1000											
ALG	1000		500										
TUN		500		700									
LIB			700		1800								
EGY				1800		700							
ISP					500		200	100	200				
LEB						200			100				
JOR						100			200			800	1300
SYR						200	100	200		900		800	
TUR									900		1700	1300	
IRAN										1700		700	1300
IRAQ								800	800	1300	700		1000
SA								1300			1300	1000	

Table B.3: Transmission distances in Europe [km].

	NOR	IT	FRA	GER	UK	GR	BAL	POL	SPA	CEN
NOR				1300	2000		900	1400		
IT			1400			1300				1100
FRA		1400		600	800				1300	1200
GER	1300		600		900			1000		900
UK	2000		800	900						
GR		1300								1000
BAL	900							700		
POL	1400			1000			700			700
SPA			1300							
CEN		1100	1200	900		1000		700		

Table B.4: Transmission costs.

Trans. Line [$/MW/km]	**Substations [$/MW]**	**Intertie AC-DC-AC [$/MW]**	**Losses [%/1000km]**	**Lifetime [yr]**	**Fixed OM Cost [% of Inv. Cost]**
2030	17350	230000	3	35	0.8

Table B.5: Technology costs and efficiencies.

	Investment Cost [$/kW]	O&M Cost [$/MWh]	Fixed Cost [$/kW/yr]	Lifetime [yr]	Efficiency [-]
GT	821	7	12	30	0.38
CCGT	966	3	10	30	0.54
Coal	3774	6	40	30	0.39
Nuclear	5570	2	99	60	0.32
Wind Onsh	1227	0	42	25	-
Wind Offsh	2317	0	130	25	-
PV Utility	400-1200 (800)	0	6	25	-
PV Rooftop	500-1500 (1000)	0	6	25	-
CSP	5225	3.5	50	30	-
Hydro Dam	0	0	0	-	-
Hydro RoR	0	0	0	-	-
Battery	700-3000 (1850)	1.32	6	15	0.9

Table B.6: Fuel price.

	Fuel Price [$/MWh]
Coal	8
Uranium	7
Bio Gas	60
Natural Gas	25

Table B.7: Demand profiles.

	Demand Profile Used	Annual Energy Consumption [TWh]
Morocco	Spain	30.7
Algeria	Spain	57.6
Tunisia	Greece	16.5
Libya	Spain	10.4
Egypt	Iran	160.5
Israel+Palestine	Spain	86.4
Lebanon	Greece	16.9
Jordan	Spain	17.4
Syria	Iran	15.0
Turkey	Turkey	229.3
Iran	Iran	236.4
Iraq	Iran	44.3
Saudi Arabia	Saudi Arabia	312.7

Table B.8: Installed capacities and annual production of energy of hydro power in each region.

Regions	**Installed Capacity [GW]**	**Annual Hydro Power Prod. [TWh]**
Europe Model		
NOR	49.9	229.5
IT	21.9	45.8
FRA	25.4	57.3
GER	11.3	24.5
UK	4.4	8.6
GR	13.2	24.0
BAL	2.5	3.7
POL	2.3	1.8
SPA	18.6	32.0
CEN	35.1	89.5
MENA model		
MOR	1.3	2.5
ALG	0.3	0.3
TUN	0.07	0.05
LIB	0	0
EGY	2.8	13.7
ISP	0.007	0.03
LEB	0.2	0.7
JOR	0.01	0.06
SYR	1.5	2.8
TUR	25.9	66.9
IRAN	10.2	13.8
IRAQ	2.8	4.4
SA	0	0

B.1 Capacity Factors and Capacity Limits

Capacity limits are numbers representing the maximum capacity allowed to be installed in each region. In JuliaREX, there is a capacity limit on PV, CSP, off- and onshore wind power and hydro power. Information on capacity limits for hydro power is described in 4.2.6. Capacity factors are different for every hour and reflect how much of the installed capacity that can be delivered as produced electricity that hour, i.e a capacity factor of 0.5 means that 5 MW can be produced if the installed capacity is 10 MW. For solar power, the capacity factors are calculated from solar irradiation and for wind power from wind speed.

Limits on how much capacity of wind and solar power that can be installed are calculated in a GIS model (described in [2]) and are based on assumptions on typical wind and PV farm densities ($W/m2$) and available land ($m2$). These assumptions are shown in table **??**. Note that the available land is given in % of land where natural parks, lakes, mountains etc. are already excluded in every region.

Table B.9: Capacity limit assumptions. Density is given as of a typical solar or wind farm. Available land is given in % of land where natural parks, lakes, mountains etc. are already excluded in every region.

	PV Utility	**PV Rooftop**	**CSP**	**Wind Onshore**	**Wind Offshore**
Density [W/m2]	45	45	35	5	8
Available land [%]	10	10	10	10	33

To capture the different weather conditions and therefore different capacity factors for wind and solar power within each region, wind and solar technologies have been divided into 5 classes each. For the solar technologies, these classes are determined by the annual average capacity factor, where class 1 to 5 are given by the ranges 0.1-0.15, 0.15-0.2, 0.2-0.24, 0.24-0.28, 0.28-1. For the on- and offshore wind power the classes are based on annual average wind speed, where the classes 1 to 5 for onshore wind is 4-5, 5-6, 6-7, 7-8, 8-99 m/s and for offshore wind is 5-6, 6-7, 7-8, 8-9, 9-99 m/s.

Every modelled region is divided in to pixels ($0.75°x0.75°$) containing information on solar irradiation and wind speed with a temporal resolution of 3h. The solar irradiation is then used to calculate the capacity factors assuming the PV technology to be fixed latitude tilted. The capacity factor is calculated as the power generation (dependent on the pixel) divided by the top power for solar power. The top power is defined as 1000 W/m2. It should be noted that this top effect can be exceeded when the solar irradiation is very high close to the equator. Therefore, the capacity factor for solar power can exceed 1. Every pixel is put in to the classes (described in the previous paragraph) by their annual average of capacity factor for solar power and wind speed for wind power. The wind speed is translated into capacity factors based on a power curve for a wind park with Vestas 112 3.075 MW wind turbines [2].

The capacity limits are also divided into the 5 classes, since there are differences in amounts of available land for the different capacity factors for solar and wind power. When, as mentioned earlier, the available land is assumed to a certain %, it is also assumed that this available land have the same distribution of classes as the total land. I.e. the model can not invest in all the best classes for wind and solar power, but the assumed percentage (in table B.9) of every class of land.

C

Examples of technology LCOE and definition of system LCOE

System LCOE

LCOE for the total electricity system (system LCOE) is calculated as the system cost divided by the total demand. Since the hydro power is modelled as no-cost in this study, the LCOE is calculated as the system cost divided by the demand minus the annual production of hydro power.

$$SystemLCOE = \frac{SC}{D - H} \tag{C.1}$$

where SC is the total electricity system cost, D is the total demand and H is the annual hydro power production.

Technology LCOE

LCOE for each technology is calculated as the cost of producing one unit of electricity. This includes the investment cost, variable cost, fixed cost, annuity factor (dependent on life time and discount rate) and efficiency. A list of technology LCOE is provided in table C.1.

$$LCOE = \frac{ic \cdot af}{h \cdot cf \cdot} + omc \cdot + \frac{fc}{h} + fuc \cdot \eta \tag{C.2}$$

where ic is investment cost, af is annuity factor, h i hours per year, cf is capacity factor, omc is operation and management cost, fc is fixed cost, fuc is fuel cost and η is efficiency. af is calculated as:

$$af = \frac{r}{1 - \frac{1}{(1+r)^n}} \tag{C.3}$$

where r is the discount rate and n is the lifetime.

Table C.1: LCOE for the different technologies. It should be noted that these values depend on what capacity factor they operate at. In this LCOE values, the capacity factor is assumed to be 1 for all technologies except for wind, PV and CSP where the capacity factor is taken as the average capacity factor (for the best class available) of every hour in Iran and the Nordic countries respectively.

	LCOE - Iran [€/MWh]	**LCOE - Nordic Countries [€/MWh]**
PV Utility	20.1	35.3
PV Rooftop	25.2	44.1
CSP	105.3	233.3
Wind Onsh	20.1	20.6
Wind Offsh	74.3	34.7
Gas GT	61.5	61.5
Gas CCGT	49.1	49.1
Bio GT	148.8	148.8
Bio CCGT	105.5	105.5
Nuclear	50.1	50.1
Coal	47.4	47.4

D

Results

Table D.1: Generation mix for the three scenarios at mid-costs on PV and batteries for both MENA and Europe. The generation is in TWh.

	MENA	**MENA w.o Trans**	**MENA w. Nuc**	**Europe**	**Europe w.o Trans**	**Europe w. Nuc**
PV Utility	431.2	636.7	353.5	826.6	880.1	408
PV Rooftop	0	12.7	0	0	0	0
Wind Onshore	1343.8	1047.2	1297.2	1517.6	1135.6	1082.2
Wind Offshore	0	0	0	124.1	172.7	0
Hydro	103.8	103.8	103.8	515.7	497.25	515.7
Gas GT	0.05	0.21	0.07	0.26	0.28	1.05
Gas CCGT	12.2	12.0	12.2	27.1	27.0	25.9
Bio GT	0.12	0.7	0.15	0.49	1.01	0.28
Bio CCGT	75.6	158.2	60.3	96.6	384.7	8.6
Nuclear	0	0	135.0	0	0	1040
Battery	67.6	192.2	39.0	207.6	200.2	29.9
Total Generation [TWh]	1966.8	1971.6	1962.2	3108.4	3098.6	3081.8
Total Demand [TWh]	1950	1950	1950	3070	3070	3070
LCOE [€/MWh]	51.6	57.3	51.2	60.0	66.0	56.4
Transmission [GWkm]	71342	0	60557	125720	0	72933

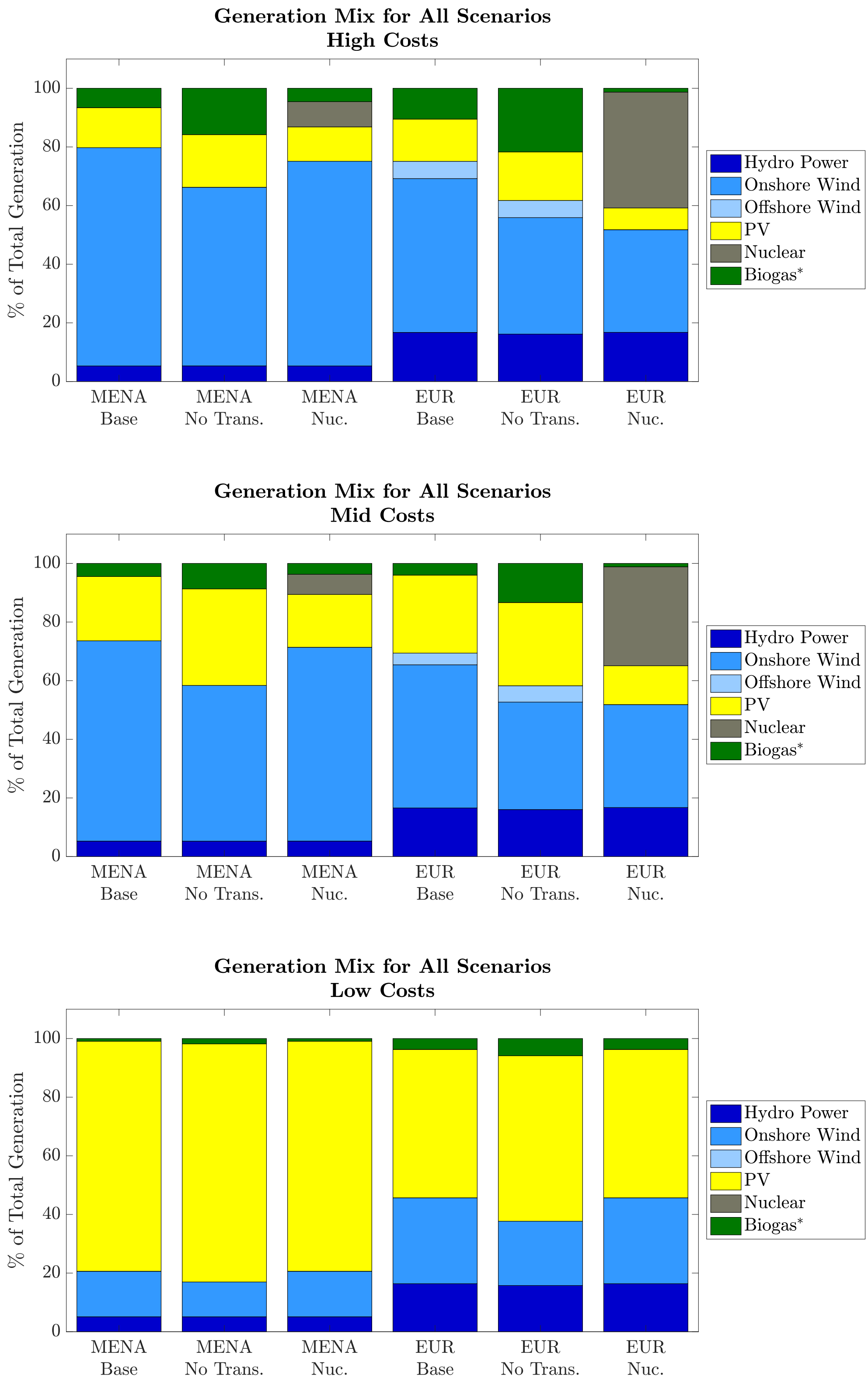

Figure D.1: The generation mixes for all scenarios, for both Europe and MENA. The top figure corresponds to when PV and battery costs are at there highest, the middle figure to PV and battery cost at their mid-costs and the bottom figure to PV and battery costs at their lowest. * Around 1% of the total generation mix is natural gas, the rest of the biogas field is biogas.

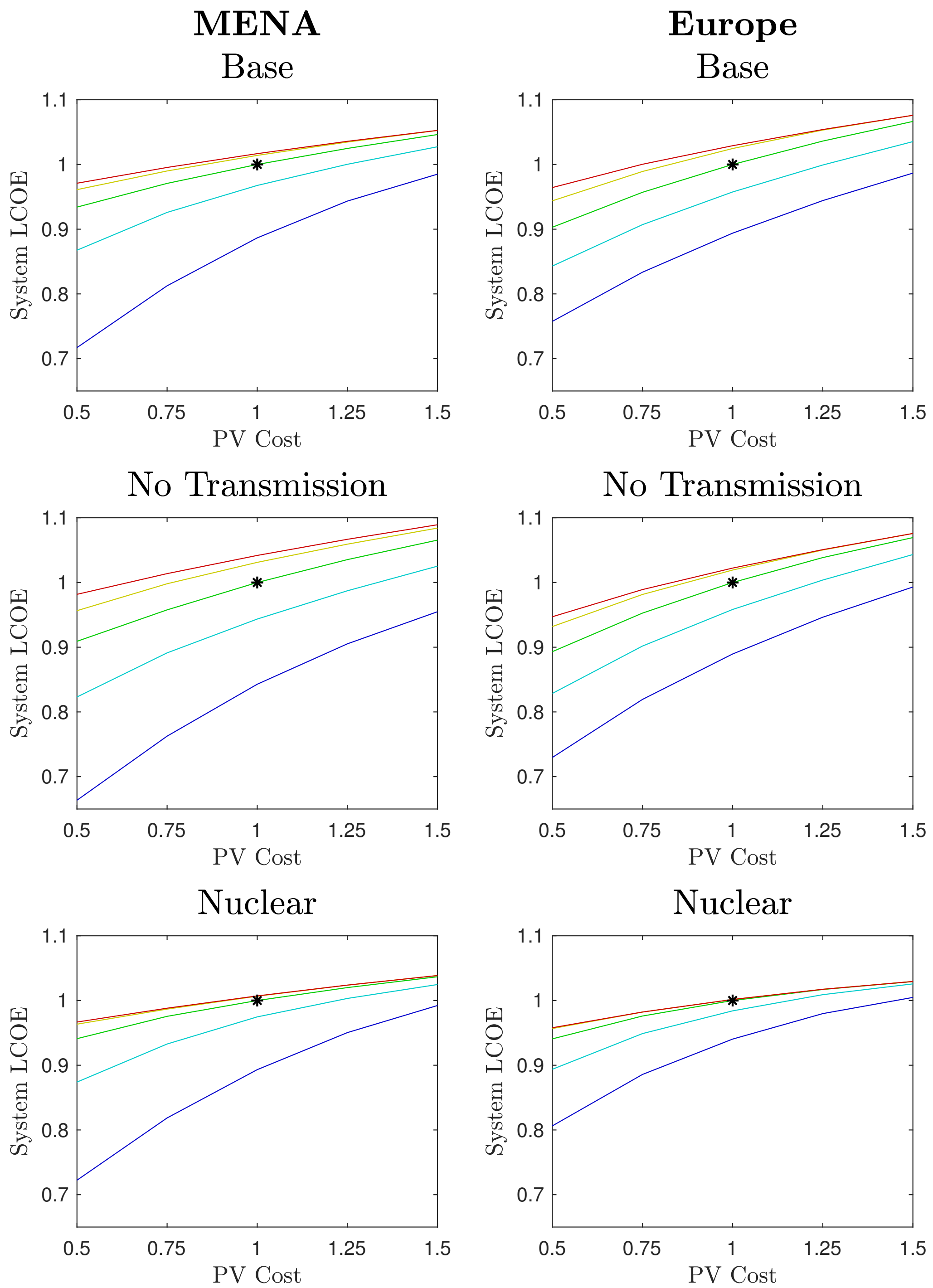

Figure D.2: Result on how system cost changes with PV and battery costs. This is presented for both MENA and Europe and all three scenarios. LCOE on they-axis and PV cost on the x-axis, both normalised to their mid-costs. The coloured lines represents different battery costs and the middle line (green) represents the mid-cost. The top line (red) corresponds to the highest battery cost and the bottom line (blue) corresponds to the lowest battery cost. The case with mid-cost on both PV and batteries is marked with a black asterisk.

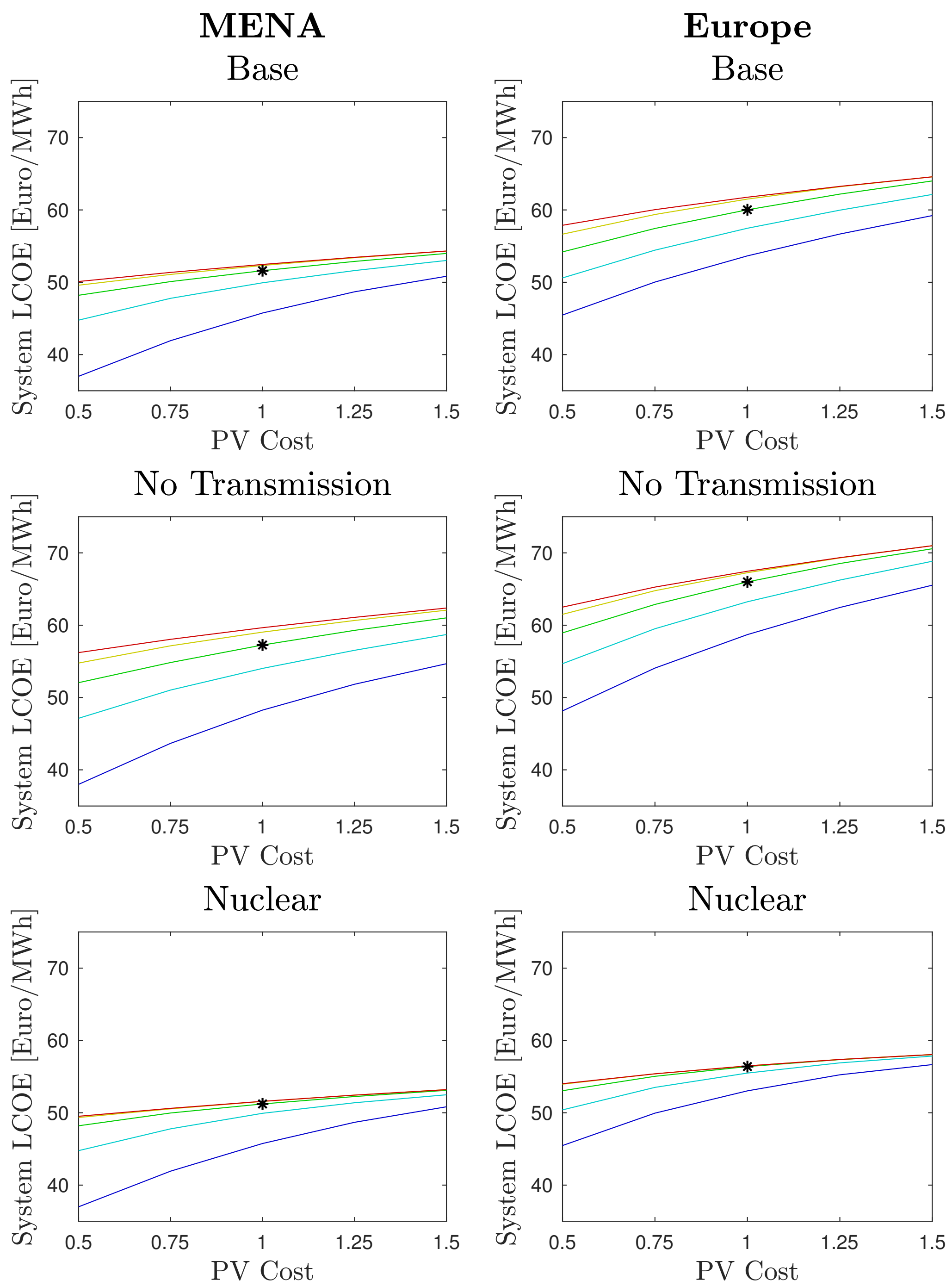

Figure D.3: Result on how system cost changes with PV and battery costs. This is presented for both MENA and Europe and all three scenarios. System LCOE on they-axis and PV cost normalised to mid-costs on the x-axis. The coloured lines represents different battery costs and the middle line (green) represents the mid-cost. The top line (red) corresponds to the highest battery cost and the bottom line (blue) corresponds to the lowest battery cost. The case with mid-cost on both PV and batteries is marked with a black asterisk.

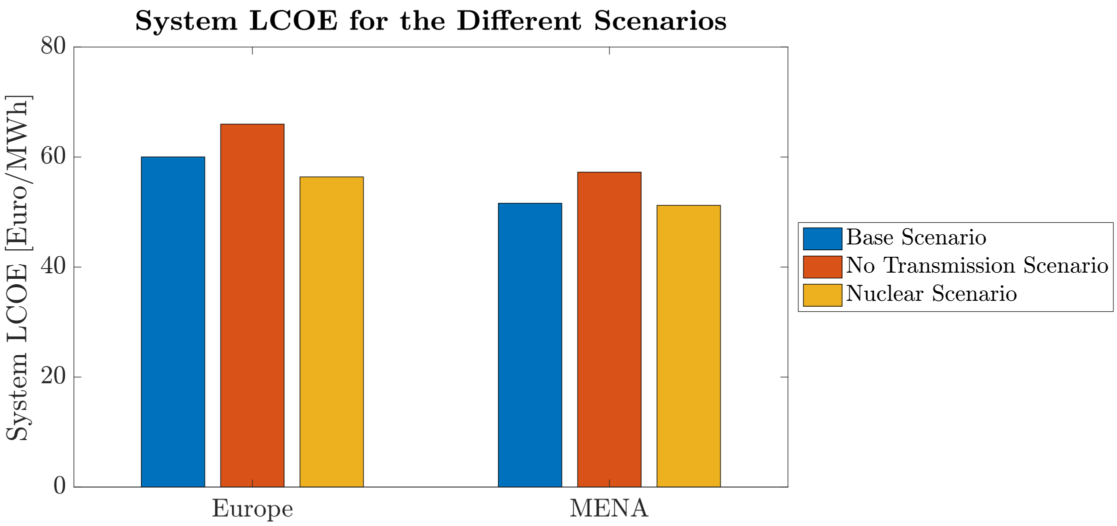

Figure D.4: System LCOE for the three different scenarios in both MENA and Europe, using mid-costs of PV and batteries. The system LCOE is presented on the y-axis in €/MWh.

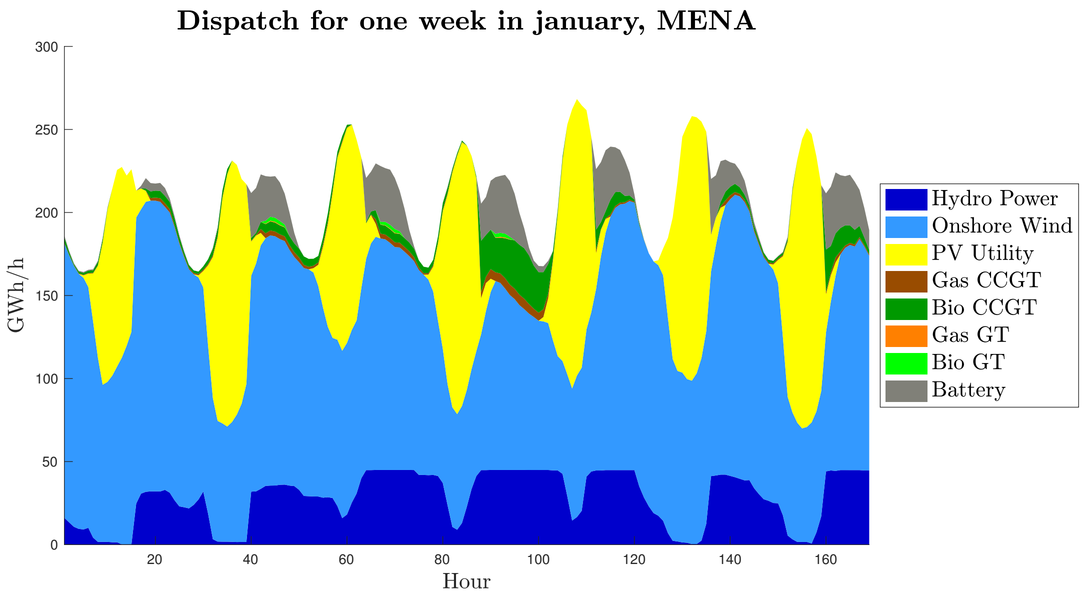

Figure D.5: An example on how the electricity production units are operated. This is for one week in January in MENA for the base scenario and mid-costs for both PV and batteries.

E

Sensitivity Analysis on Land Availability

Table E.1: Generation mix depending on available land for PV utility and onshore wind power in Europe. The generation is given in TWh.

	2%PV 5%W	**5%PV 5%W**	**5%PV 10%W**	**10%PV 10%W**	**15%PV 15%W**
PV Utility	922	1046	817	827	792
PV Roof	9	0	0	0	0
Wind Onsh	1172	1155	1524	1518	1662
Wind Offsh	207	203	125	124	40
Hydro	516	516	516	516	516
Gas GT	0	0	0	0	0
Gas CCGT	27	27	27	27	27
Bio GT	0.2	0.1	0.5	0.5	0.6
Bio CCGT	253	169	99	97	72
Battery	222	300	204	208	197
LCOE	65.5	64.4	60.2	60.0	58.9

Table E.2: Generation mix depending on available land for PV utility and onshore wind power in MENA. The generation is given in TWh.

	2%PV 5%W	**5%PV 5%W**	**5%PV 10%W**	**10%PV 10%W**	**15%PV 15%W**
PV Utility	512	519	430	431	399
PV Roof	0	0	0	0	0
Wind Onsh	1252	1246	1344	1344	1378
Wind Offsh	0	0	0	0	0
Hydro	104	103	104	104	
Gas GT	0	0	0	0	
Gas CCGT	12	12	12	12	
Bio GT	0	0	0	0	0
Bio CCGT	90	89	76	76	72
Battery	112	117	67	68	57
LCOE	53.6	53.5	51.6	51.6	51.1

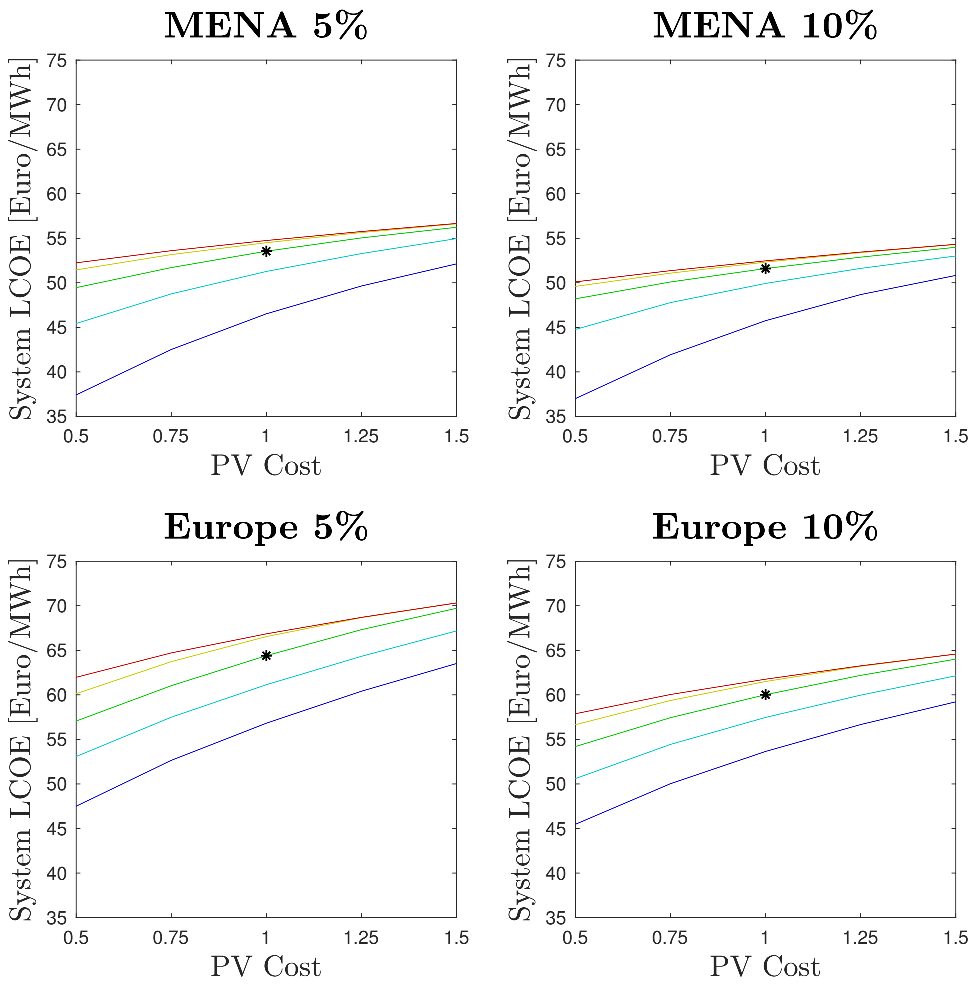

Figure E.1: Sensitivity analysis on land availability. System LCOE in €/MWh on the y-axis and PV cost on the x-axis normalised to mid-cost. 10% correspond to a case where the land availability is set to 10% for all solar power technologies and also for wind onshore. The same goes for 5%, i.e 5% land availability applies to all solar power technologies and to wind onshore. The coloured lines represents different battery costs. The middle line (green) represents the mid-cost, the top line (red) corresponds to the highest battery cost and the bottom line (blue) corresponds to the lowest battery cost. Mid-costs on both PV and batteries is marked with a black asterisk. System LCOE for the mid-costs are 53.5 €/MWh for MENA 5%, 51.6 €/MWh for MENA 10%, 64.4 €/MWh for Europe 5% and 60.0 €/MWh for Europe 10%.

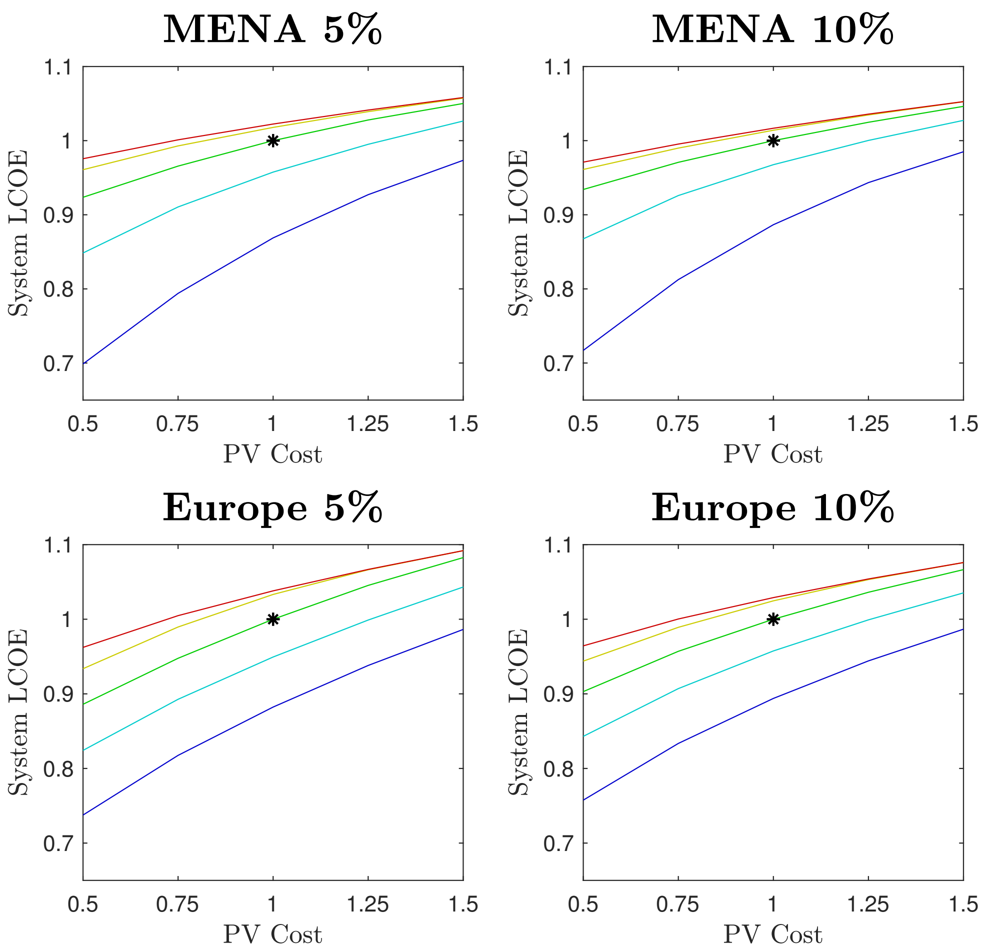

Figure E.2: Sensitivity analysis on land availability. System LCOE on the y-axis and PV cost on the x-axis, both normalised to their mid-cost. 10% correspond to a case where the land availability is set to 10% for all solar power technologies and also for wind onshore. The same goes for 5%, i.e 5% land availability applies to all solar power technologies and to wind onshore. The coloured lines represents different battery costs. The middle line (green) represents the mid-cost, the top line (red) corresponds to the highest battery cost and the bottom line (blue) corresponds to the lowest battery cost. Mid-costs on both PV and batteries is marked with a black asterisk. System LCOE for the mid-costs are 53.5 €/MWh for MENA 5%, 51.6 for MENA 10%, 64.4 €/MWh for Europe 5% and 60.0 €/MWh for Europe 10%.