THESIS FOR THE DEGREE OF LICENTIATE OF ENGINEERING

Insights from modeling renewable electricity systems and developing hydropower models

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ABSTRACT

One strategy for reaching a carbon-neutral electricity system is a large-scale deployment of wind and solar power. However, electricity systems with high shares of wind and solar power rely on other technologies, e.g., transmission and hydropower, to ensure that demand can be met at all times despite weather-dependent wind and solar power production. Moreover, the deployment of some technologies may be limited by public concern and land availability, which could increase the cost of decarbonizing electricity systems.

To analyze designs and costs for future electricity systems with high shares of renewables, energy system models are crucial. In such models, the representation of hydropower is often significantly simplified, overestimating how flexibly hydropower can operate and, thereby, the hydropower's ability to complement wind and solar power production.

This thesis has two overarching aims addressed separately in the two appended papers. First, to explore how deployment limits on wind and solar power, transmission, and nuclear power each affect the cost of future carbon-neutral electricity and how it differs between the Middle East and North Africa region (MENA) and Europe (Paper A). Second, to investigate the accuracy of the hydropower representations used in energy system models and to develop a method for a more accurate hydropower representation (Paper B).

In Paper A, we use an energy system model to show that the cost of a carbon-neutral electricity system is considerably lower in MENA than in Europe, which we link to MENA's better wind and solar resource potential. Also, limiting the deployment of wind and solar power, transmission, or nuclear power can significantly affect system costs. However, the effect is markedly different in the two regions.

Paper B examines how realistic different hydropower representations are by developing hydropower optimization models with different levels of detail and comparing them. We find that simple hydropower representations, such as those often used in energy system models, result in unrealistic production profiles and exaggerate the flexibility that hydropower can provide. In addition, we contribute a novel computationally efficient hydropower model that entails a more realistic hydropower production.

Keywords: modeling, electricity systems, renewables, hydropower, Europe, MENA, available land, transmission, nuclear

Appended publications

This thesis is based upon the following papers:

Paper A H. E. Fälth, D. Atsmon, L. Reichenberg, and V. Verendel (2021). MENA compared to europe: the influence of land use, nuclear power, and transmission expansion on renewable electricity system costs. *Energy Strategy Reviews* **33**, p. 100590. DOI: `10.1016/j.esr.2020.100590`.

Paper B H. Ek Fälth, N. Mattsson, L. Reichenberg, and F. Hedenus (2022). Exploring trade-offs between aggregated and turbine-level representations of hydropower in optimization models. *Renewable and Sustainable Energy Reviews. Submitted.*

Author contributions

Paper A: LR conceived the idea, and HEF, DA, and LR developed it. HEF and DA constructed the models and produced the results with input from LR. VV produced the demand data used in the model. HEF, DA, and LR analyzed the results and wrote the paper.

Paper B: HEF conceived and developed the idea with support from NM, LR, and FH. HEF and NM developed the models and produced the results. HEF, NM, LR, and FH analyzed the results. HEF, NM, and LR wrote the paper with input from FH.

Other publications

Other publications by the author not included in the thesis:

I F. Hassanzadeh Moghimi, H. Ek Fälth, L. Reichenberg, and A. S. Siddiqui (2023). Climate policy and strategic operations in a hydro-thermal power system. *The Energy Journal* **44** (1). DOI: `10.5547/01956574.44.4.fmog`.

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Contents

CHAPTER 1

Introduction

The latest IPCC report revealed that global greenhouse gas emissions continue to increase in all sectors and sub-sectors and that the energy sector is the largest contributor to global greenhouse gas emissions (about 34% of total global greenhouse gas emissions) [1]. Within the energy sector, the electricity sector is the single largest source of CO_2 emissions [2]. IPCC concluded that the electricity sector needs rapid decarbonization if the 2, or 1.5, degree target is to be met [2]. With regards to obtaining such rapid decarbonization of the electricity sector, mitigating CO_2 emissions in the electricity sector is less expensive than in other sectors [3]. All these reasons motivate research into the decarbonization of electricity systems.

A transition of the electricity system can take many different directions, depending on policy choices and technology development. What is certain is that a transition will lead to new challenges and system characteristics, which will depend on what technologies will dominate. Low-carbon technologies such as wind and solar power are progressing in terms of cost, performance, and adoption, and the deployment rate is increasing worldwide [4]. Hence, large-scale wind and solar power deployment could constitute one strategy for reaching a carbon-neutral electricity system. However, wind and solar power provide variable renewable energy (VRE), meaning that they are weather dependent and that the timing of their power output not can be controlled. Therefore, flexibility measures are essential in electricity systems with a high share of VRE, ensuring that the demand can always be met despite variations in the wind and solar power production levels [5–8]. Such flexibility measures can be, for instance, transmission, which enables wind power production over larger areas to reach the load centers and thereby smooths out the variability of wind power. Another example is flexible generation technologies such as hydropower.

The focus of this thesis is twofold, where each of the two appended papers covers one focus. The first focus is the cost and design of a future decarbonized electricity system for two regions with different weather conditions (Paper A). Second, the thesis investigates the modeling of one of the above-mentioned flexibility measures: flexible generation from hydropower (Paper B).

Regarding the first focus, i.e., the cost and design of a future decarbonized electricity system, the thesis addresses how choices on (1) restricting land for wind and solar power deployment, (2) allowing nuclear power or not, and (3) transmission expansion, could affect the cost of a future decarbonized electricity system.

First (1), increased competition for land and environmental concerns for wind and solar power reduces suitable sites for wind and solar farms, which affect the system cost for large-scale CO_2-neutral power systems. Yet, potential constraints due to public concern regarding large-scale wind and solar farms have received little attention in the energy system modeling community. Only a few studies examine how limited land for wind and solar power affects electricity system costs [9, 10].

Second (2), the role of nuclear power has been investigated in several energy system studies [11–18] with a large spread regarding its potential to reduce the system cost. Nuclear power is a contentious issue, both in society at large [19–23] and in the modeling community [13, 14]. Some authors have argued that nuclear power (or other carbon-neutral baseload technologies) is crucial for keeping costs down in a future low carbon emissions power system [12, 15, 16]. In contrast, others find only moderate cost benefits of including nuclear power [11, 17, 18].

Third (3), transmission expansion has shown to be essential to keep costs down in electricity systems dominated by VRE [6, 9, 24–34], but massive transmission expansion may not be politically feasible or publicly acceptable [10, 35–39], and the transmission expansion in, e.g., the EU is slow, despite promotion from the EU commission[40, 41].

In addition, regarding the first focus of this thesis, most energy system model studies investigate Europe, the United States, or other temperate regions [6, 9, 11, 27–29, 32, 42–47]. In contrast, energy system model studies on the Middle East and North Africa region (MENA) are less prevalent. Except for the study by Aghahosseini et al. [25], MENA has been modeled mainly as a potential provider of solar power for Europe [34, 48, 49]. However, the high carbon intensity of the MENA electricity generation, and concerns about pollution, among others, entail extensive potential benefits of decarbonizing the MENA electricity sector. Thus, there is a motivation for modeling MENA to analyze the cost and design of a renewable, or carbon-neutral, electricity system in MENA.

The second focus of this thesis is hydropower. Today, reservoir hydropower is the largest carbon-neutral generation technology worldwide, providing about 16% of the electricity [50]. Due to differences in, e.g., geography, hydropower is more or less prevalent in different regions worldwide. The Nordic countries are an example of a region where hydropower plays an essential role in the electricity system, both as a bulk electricity provider and as an important flexibility measure that facilitates increased shares of wind and solar power in the electricity system.

The power output from reservoir hydropower can be controlled on time scales from seconds to years, and can therefore be a crucial flexible resource in renewable electricity systems by complementing wind and solar power production. However, it is difficult to realistically represent the flexibility of hydropower production in models. Due to computational limitations, the representation of hydropower is highly simplified in energy system models [6, 28, 29, 32, 47, 51, 52] which may exaggerate the flexibility that hydropower can provide. Capturing a realistic level of flexibility from hydropower may be important since the level of flexibility afforded by hydropower affects the need for other flexibility measures.

1.1 Aims and contributions

The aims of this thesis are to i) add insights on how limiting the deployment of wind and solar power, transmission, and nuclear power affects the cost of a future carbon-neutral electricity, ii) investigate if there is any significant difference in the cost for a future carbon-neutral electricity system in regions with different wind and solar resources (Europe compared to MENA), iii) to investigate how well different existing hydropower models capture a realistic production for hydropower, and iv) to develop an improved representation of hydropower that is computationally efficient while capturing a more realistic level of flexibility for hydropower.

Paper A involves aims i-ii and contributes by modeling MENA and Europe separately, investigating the cost of renewable electricity systems for different futures regarding limits on the deployment of wind and solar power, transmission, and nuclear power. Paper B involves aims iii-iv and contributes with an extensive comparison between different ways of modeling hydropower. The analysis shows that the often-used simple hydropower representations significantly overestimate the flexibility of hydropower and, thus, the flexibility it can provide in a future renewable power system. In addition, Paper B suggests a new hydropower model that is computationally efficient while providing a more realistic level of flexibility. The computation efficiency is vital since the improved hydropower representation aims to be compatible with large-scale energy system models.

1.2 Thesis outline

After this introduction, the following two chapters (Chapter 2 and Chapter 3) focus on the methods used in the appended papers. Chapter 2 is on energy system models and aims to give an overarching understanding of energy system models and what they are used for, as well as a reflection on energy system models as a method. This chapter focuses on general methodological aspects regarding energy system modeling rather than specific modeling choices and descriptions, which are already documented in the appended papers. Chapter 3 addresses hydropower and hydropower modeling, aiming to provide a more extensive background to Paper B than what was covered in the paper it self. Chapter 4 provides a summary of the appended papers followed by a discussion and method reflection based on the background chapters (Chapter 2 and Chapter 3). Chapter 5 finalizes this thesis with some reflections on my research so far, as well as an outlook for the continued research in my doctoral studies.

CHAPTER 2

Energy system models

Models are crucial tools for understanding and exploring many energy systems since energy systems often involve large numbers of components interlinked in various ways. This chapter will focus on energy system models with a large geographical scope, typically country level or larger, in contrast to energy system models for, e.g., specific industries or cities. A motivation for gaining knowledge about such "large scale" energy systems is the energy sector's extensive contributions to the global CO_2 emissions [1]. The high CO_2 emissions from the energy sector and a global ambition to limit global warming have led to an interest in decarbonizing the energy sector. Many studies use energy system models to examine how and to what cost decarbonization of the energy sector can be achieved [53, 54].

2.1 What are energy system models used for?

Energy system models are tools for analyzing energy systems. The analyses performed using models can be divided into three categories: i) predictive, ii) prescriptive, and iii) exploratory.

Predictive modeling analysis has the intention of predicting the future in some way. An example of predictive model analysis is to forecast electricity prices for the coming week or year, which can be done with, e.g., the EMPS model by SINTEF [55]. Another example could be to predict more long-term development, such as forecasting emission trajectories. The extent to which long-term predictions are possible and meaningful is debated in [56].

When using energy system models for prescriptive analysis, the aim is to give recommendations of actions to achieve a specific goal. Hence, prescriptive studies are always normative. An example of a prescriptive analysis is to evaluate how a suggested new transmission line would affect the CO_2 emissions from a specific energy system and then, based on the results, give recommendations on whether it should be built. Another example of a prescriptive analysis is "production planning," where power plant owners use models to find the production schedule that gives the highest profit.

Lastly, exploratory analysis intends only to provide an understanding of the system studied rather than predicting or prescribing. It can be to use models to answer questions like: How does an emission target impact the cost of the energy system? Or does banning nuclear power lead to higher energy system costs?

Note that the same model could be used for either exploratory, prescriptive or predictive analysis. The critical difference is what type of question you chose to answer with the model. However, a model used for prescriptive or predictive analyses must represent reality in such a way that the model results can be applied to reality, while for exploratory analyses, it can also be valuable to look at more hypothetical cases to explore specific energy system characteristics.

2.2 Optimization models

This thesis focus on energy system optimization models, a subgroup of energy system models. Energy system optimization models is a widely used tool for research in energy systems with large geographical scope [5–7, 9, 11, 28, 29, 43–47, 57–61]. A model is a simplification of reality. In order to understand how your model relates to reality, it is important to understand the different building blocks of optimization models.

Optimization models use mathematical formulations to represent the energy system, and they inherently optimize something. This "something" is called the *objective function* and is typically to minimize cost or maximize social welfare. There are two reasons why these two objective functions are relevant when analyzing energy systems. The first and most straightforward reason is to find out how much the cheapest or most economically beneficial energy system will cost and how it may be designed. The second, more intricate reason, is related to economic theory and how the objective of minimizing cost (or maximizing social welfare) is connected to how the energy market work in reality. Economic theory tells us that, if there is a perfect market, maximizing each producer's profit will equal the solution for minimizing the cost or maximizing social welfare for a system in equilibrium. Hence, if the modeled market can be considered close to a perfect market in equilibrium, using optimization models that minimize cost or maximize social welfare has a direct connection to reality and the model can be expected to work reasonably well for prescriptive and predictive analysis. This is, of course, given that the model captures all other relevant aspects for the analysis.

In addition to the objective function discussed above, the building blocks of optimization models are *variables*, *parameters*, and *constraints*. The *vari-*

ables are the components that can be varied in the model. Variables are endogenous, meaning their values are determined by the model so that the objective function is minimized or maximized. Hence, the model output is the values of the variables. Examples of variables in a model are the power generation from each technology at each time and the amount of energy traded between regions at each time. The *parameters*, also called input data, are the parts considered fixed in the model. Parameters are given exogenously, meaning that they are decided outside of the model. Examples of parameters in a model are the cost of producing a Watt-hour with a gas turbine or the wind speed and solar irradiation at a given place and time. A *constraint* is a mathematical equation that describes a certain limitation to a variable. It can be, for example, that you can not invest in more wind power than there is land to place it on.

The following two sections will present and discuss two kinds of optimization models: capacity expansion models and dispatch models. The key difference between these two models lies in how investments in the energy system are treated. Investments are endogenous in capacity expansion models, while in dispatch models, they are exogenous.

2.2.1 Capacity expansion models

Capacity expansion models are used for analyzing cost-efficient future energy systems. Some examples of questions asked when using capacity expansion models are: How much more expansive is an energy system where nuclear power is prohibited compared to when it is not? How much would the cost of an energy system increase with a tighter carbon cap? At what cost does concentrated solar power enter a cost-minimized energy system?

There are plenty of studies on energy systems conducted using capacity expansion models [5–7, 9, 11, 28, 29, 43–47, 57, 60, 61]. The analysis in Paper A included in this thesis is also conducted using a capacity expansion model.

The objective function in capacity expansion models is finding the least-cost energy system. More specifically, to minimize the generation costs (i.e., fuel, operation, and maintenance costs) and investment costs of supplying energy to a population with a given demand.

The input parameters typically consist of, e.g., energy demand, technology costs, fuel costs, and weather data. The outputs from the capacity expansion model are the system cost, the dispatch (generation level at each time interval for each technology), and the investments in each technology.

Some constraints are applied in most capacity expansion models. For instance, the production at each time interval can not exceed the installed capacity, and the production must match the demand. Other constraints vary a lot between different models, like the amount of land available for wind-and solar farms, ramping constraints on thermal generation technologies, and different carbon budgets.

Capacity expansion models also differ in terms of what they assume about the existing energy system. In some models, it is assumed that the whole future energy system needs to be built from scratch, called a greenfield setting. Greenfield settings are often used when systems far in the future are studied, a future when the existing system is expected to have been decommissioned. One can think of greenfield studies as studying a target energy system. Other studies apply a brownfield setting, where some or all of the existing components in the system are assumed to still be in operation in the studied year. Brownfield studies are used for analyzing more near-term energy systems. Another common type of capacity expansion model is the pathway model. Pathway models analyze the transition from an existing energy system to a target system. These models basically find the cost-optimal investments in an energy system each year, or every five years or so, using a brownfield setting in the start year and then updating the energy system components with time in accordance with technology life-times and new investments.

Capacity expansion models are typically used for exploratory or prescriptive analysis but not predictive analysis, which these models are not well suited for. The reasons they are not well suited for predictive analysis are at least two. First, the long-time horizons often analyzed in capacity expansion models are associated with large uncertainties in, e.g., politics and technology development. Second, there are no good models for technology diffusion and how investments are made in reality, which largely influences how the energy systems develop. By contrast, capacity expansion models are potentially good tools for exploratory and prescriptive analysis if the models are designed properly for the question asked.

2.2.2 Dispatch models

Dispatch models are used for analyzing the operation of existing or near-future energy systems, in contrast to capacity expansion models typically used for investigating energy systems further in the future. One example is Göransson et al. [59], who explore the potential of reducing congestion by use of demand side management in Europe 2020. Another example is Helseth et al. [58], who studied the changes in the operational cost, or socio-economic surplus, for the Nordic electricity system induced by introducing a new transmission line in the system. The analysis in Paper B is also based on dispatch modeling.

Dispatch models consider only the operation of an energy system or a component within the energy system, in contrast to capacity expansion models, which also optimize investments in the energy system. In other words, dispatch models have investments as exogenous, while capacity expansion models have them as endogenous. The output from a dispatch model is the operational cost and the dispatch, i.e., the generation level or operation strategy at each time interval for each technology that minimizes the cost of operation of the entire system. The objective function in dispatch models is to either maximize the profit, minimize the cost (typically the fuel, operation, and maintenance costs), or maximize the welfare. Which one of these three objectives that are used depends on the user, scope, and purpose of the model.

For instance, dispatch models are commonly used among production companies for production planning, where they want to find the most profitable production schedule for their power plant and therefore choose to maximize profit. In such models, the dispatch of one or multiple specific power plants is optimized while the rest of the energy system is exogenous to the model, represented by electricity price time series. These production planning dispatch models are prescriptive, aiming to inform the production planners how they should operate the plants to obtain maximum profit.

Minimizing cost is often used by agents that want to use dispatch models to forecast electricity prices, i.e., making predictive analyses. In such models, the whole electricity is optimized, in contrast to only specific plants in the example above. The rationale for assuming that minimizing cost works well for price forecasting is that in a perfect market, minimizing the cost will equal the solution for maximizing each producer's profit, which is what they also aim to do in reality.

Minimizing cost, or maximizing social welfare, can also be applied by energy system planners or researchers who want to, for instance, find the change in cost or welfare induced by a proposed new power plant, transmission line, or other. Models that maximize welfare are driven by an endogenous demand represented by a demand function with a specified demand elasticity, while those that minimize cost often are driven by an exogenous demand. These studies, minimizing cost, or maximizing social welfare, can be used, for instance, for prescriptive analyses, such as the two examples mentioned at the beginning of this section, Section 2.2.2, [58, 59].

In addition to electricity prices, a demand function with specified price elasticity, or energy demand, the input parameters to dispatch models typically consist of installed capacities, running costs, and weather conditions. The outputs from the dispatch models are the cost or revenue and the dispatch. As for capacity expansion models, all dispatch models implement some constraints; for instance, the production at each time interval can not exceed the installed capacity, and the production must match the demand. Other constraints vary between different dispatch models, like ramping constraints on thermal generation technologies.

2.3 Modeling choices in energy system optimization models

As presented in Section 2.2.1 and Section 2.2.2, the only difference between capacity expansion models and dispatch models is whether the investments are exogenous or endogenous to the model. Endogenous investments are what make capacity expansion models more appropriate for analyzing future systems, while dispatch models are more appropriate for near-term analysis. However, this difference also means that there are more model choices to be made in capacity expansion models compared to dispatch models, relating to investment decisions. For example, in capacity expansion models, the modeler has to choose appropriate levels of investment costs, the amount of land available for wind and solar power, and technology diffusion rates.

With regard to technical detail and temporal and spatial resolution, there is no clear line between capacity expansion models and dispatch models. Both high and low technical detail and temporal and spatial resolution are found in both model types. Instead, it is, ideally, the intended analysis that decides the technical detail and temporal and spatial resolution of the model.

2.4 Using energy system optimization models

Energy system optimization models are developed by modelers. Modelers and others interpret the model outputs, and in some cases, using prescriptive or predictive analysis, the results constitute a basis for planning purposes or policy making. When a model is constructed, multiple choices have to be made regarding system boundaries and technology assumptions. The objective function, variables, parameter values, and constraints are chosen by a modeler. The choices determine the space in which the model operates, affecting how the results relate to the reality in which the planning and policy-making take place. Hence, the model choices and their implications on the model output are essential to be aware of when using and communicating model results for planning purposes or policy making In line with these thoughts, DeCarolis et al. [62] emphasizes the importance of choosing the suitable model for the question asked and that a significant modeler judgment is required. Energy system modeling is not only technical work but requires reflection and thoughtful communication of the results.

In summary, there are two things I want to communicate here. First, reflection regarding the model choices when building a model is essential. Second, having enough knowledge about the model used is a prerequisite for analyzing the model outputs fairly and communicating the results by thoughtfully connecting the model results to reality.

Most energy system optimization models are techno-economic models that exclude social and political constraints. The results of such models give the cost-optimal solution in a solution space where these social and political constraints are non-existing. Thus, when the results of such models are analyzed for use in planning och policy making, the social and political aspects will have to be considered after the modeling is done if they are to be considered. This is one example of where energy system modeling goes from pure technical competence to reflection and judgment, in which knowledge behind the models is essential.

2.5 Variation management in energy system models

Energy system models have been used to explore large-scale energy systems since the 70s when the oil crisis was one of the important factors for driving the development of these models [63]. However, it was not until the mid-2000s that studies on 100% renewable energy systems became prominent [54]. Before renewable systems were studied, models had no focus on variation management strategies, since these strategies are important only in systems with high shares of variable renewables (wind and solar power). Thus, models have had to develop in terms of being able to fairly analyze renewable energy systems. One such development has been increased time resolution, where multiple studies have shown that a high time resolution is essential in models for renewable energy systems [64, 65]. Many models now run with an hourly resolution to better assess the need for, and operation of, variation management strategies such as transmission, storage, and flexible generation technologies. In Paper A, we use a capacity expansion model with an hourly resolution to asses how transmission affects the cost of a renewable electricity system.

Another modeling aspect potentially more important now when the energy systems analyzed contain more renewables is the representation of hydropower. However, hydropower representations in capacity expansion models have received limited attention in the literature. After the final method reflection in this chapter, the next chapter, Chapter 3, is on the subject of hydropower modeling and gives the motivation for Paper B in this thesis.

CHAPTER 3

Reservoir hydropower

The need for variation management strategies will increase with more solar- and wind power in future electricity systems. Reservoir hydropower is dispatchable on time scales from seconds to years and can therefore serve as a flexible resource, complementing, e.g., wind- and solar power production. Being dispatchable in this context means that the timing of the electricity production from hydropower can be controlled to meet demand by storing water in dams and steering how much water goes through the turbines at a given time.

Globally, hydropower constitutes about 16% of the electricity production [50]. In the Nordic countries, hydropower is an essential contributor to both the annual electricity production (about 55% of electricity generation [66]) and flexibility in the electricity system, which facilitates the introduction of cheap and renewable solar- and wind power to the electricity system.

Hydropower plants have different designs, which affect how much flexibility they can provide to the electricity system. The different types of hydropower can be categorized into reservoir hydropower and run-of-river hydropower, where the main difference between those two is whether they are connected to dams. Reservoir hydropower plants are connected to dams which are used for storing water. By storing the water in dams, the timing of the power production can be controlled. By contrast, run-of-river hydropower plants have no dams. Instead, run of river plants use the natural water flow for production, and therefore the timing of the production can not be controlled to the same extent as for reservoir hydropower.[1] This thesis focuses only on reservoir hydropower, and hereafter, the word hydropower always refers to reservoir hydropower.

This chapter first goes through some basics of reservoir hydropower and continues with the challenges of modeling hydropower. It further describes how and why hydropower has previously been modeled and why capacity expansion models could benefit from more detailed hydropower represen-

[1] In reality, there exists a range of hydropower plants in-between those two stylized categories.

tations when modeling future electricity systems. This chapter provides background and motivation for Paper B included in this thesis.

3.1 Electricity production with hydropower

Hydropower plants convert potential energy to electricity by using an elevation difference in water bodies. The elevation difference induces movement of the water, i.e., the potential energy is converted to kinetic energy, which is converted to electric energy via a turbine connected to a generator. Figure 3.1 illustrates a reservoir hydropower plant.

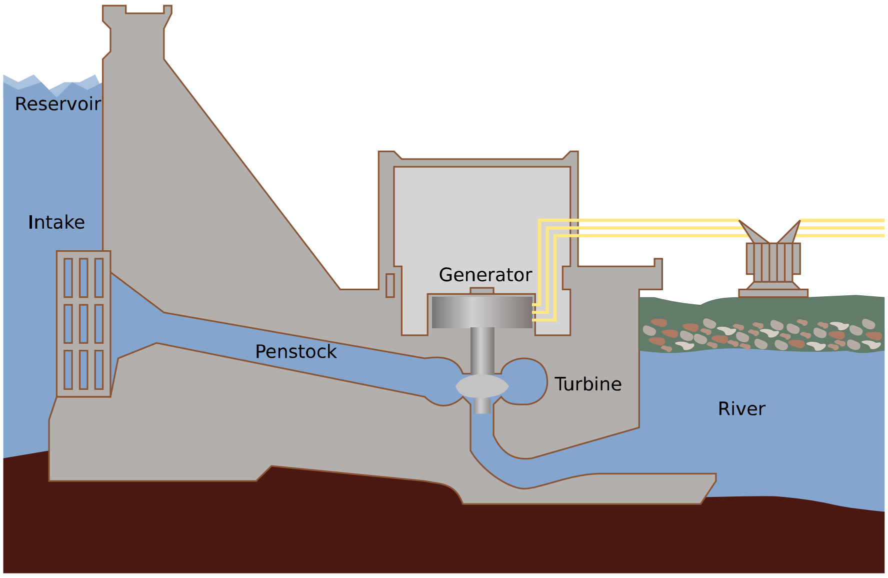

Figure 3.1: Schematic illustration of a reservoir hydropower plant (created by Tomia under the GNU Free Documentation License [67, 68]).

The power produced in a hydropower plant (P, in W) is determined by: the mass flow rate of the water flowing via the penstock through the turbine, which is called the discharge ($\dot{m}$, in kg/s); the gravitational acceleration constant (g, in m/s^2); the elevation difference, which is called the head (h, in m); the discharge- and head-dependent turbine-specific conversion efficiency ($\eta_T(\dot{m}, h)$); and the generator efficiency (η_G). In Figure 3.1, the head, h, is the height difference between the water level in the reservoir and the river.

$$P = \dot{m} \cdot g \cdot h \cdot \eta_T(\dot{m}, h) \cdot \eta_G \tag{3.1}$$

Multiple hydropower plants are often located in the same river to utilize as much of the elevation difference in the river as possible. This cascade of hydropower plants causes an inter-dependency between the plants since the operation of an upstream plant affects the operation of a downstream plant.

The last characteristic of hydropower that I want to mention is the presence of environmental regulations, which limit how a plant may be operated. By controlling the water flow in rivers, hydropower is associated with hindering fish migration and movements of sediments and nutrients, disrupting natural flooding, and fast changes in water levels leading to, e.g., erosion. Thus, hydropower impacts the ecosystems and their species in and around the rivers. The effect on ecosystems is normally, at least in Europe and the U.S., somewhat limited by different types of local or national environmental regulations [69]. There is no literature on how environmental regulations affect the operation of hydropower plants and the flexibility that hydropower may provide in energy systems. However, this is not something this thesis provides insights into, but something that I would like to focus on in my future work, see Chapter 5.

3.2 Challenges in hydropower modeling

There are four techno-physical characteristics of hydropower mentioned in the previous section (Section 3.1) that, in various ways, constitute challenges when modeling hydropower: i) head-dependent production, ii) discharge- and head-dependent turbine efficiencies, iii) network structures of hydropower plants in rivers, and iv) environmental regulations.

First, if we look at the hydropower production function (Eq. 3.1) provided in Section 3.1, there are two variables in the equation: the water discharge, $\dot{m}$, and the head, h. The discharge can be varied by controlling the intake to the turbines and the head varies with the water levels above and below the turbines. Thus, the discharge level and the head are both controlled by the plant operator and affect the power production output. This product of two variables means that the production function is non-linear, and representing such non-linearities in an optimization model is computationally demanding. In addition, the discharge and the head, i.e., the two variables, are connected. The water levels in the reservoir and below the turbine determine the head and they also depend on the water discharge. This connection further increases the computational effort.

Second, as we also see in the hydropower production function (Eq. 3.1), the turbine-specific conversion efficiency is discharge- and head-dependent. The dependency is non-linear, which imposes a modeling challenge. Figure 3.2 shows an example of how efficiency can depend on discharge. Modeling the efficiency curves as discharge or head-dependent, or both, can be approached in different ways. In Paper B, we describe multiple ways of modeling discharge-dependent turbine efficiency curves. As an example, the curve in Figure 3.2 can be captured by a linear segment from zero discharge to the point where the curve intersects the x-axis and a segment with a polynomial curve from that point. However, using two segments like this is non-convex, which increases the computational effort significantly.

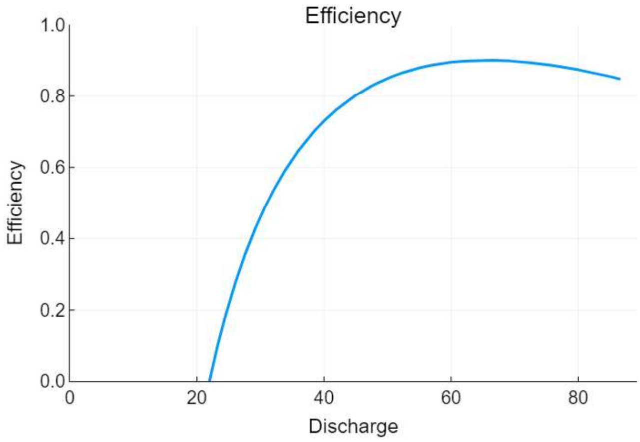

Figure 3.2: An example of a discharge-dependent efficiency curve for a hydropower turbine. The y-axis shows the conversion efficiency, and the x-axis shows the water discharge (in m^3/s) through the turbine. The data used to create this example is retrieved from one of the turbines in the river modeled in Paper A but slightly modified due to the confidentiality of the data.

Third, multiple hydropower plants and reservoirs are typically located in the same river. Waterways connect the plants and reservoirs with delay times for the water flowing between the plants, and the operation of an upstream plant affects the operation of a downstream plant. Thus, in order to model the real operation of hydropower plants, the cascade of plants and reservoirs should be modeled as a network. Modeling a network is more computationally demanding than modeling hydropower plants separately.

Last, environmental regulations impact the operation of hydropower plants. However, Schäffer et al. [69] present a review of environmental regulations in optimization models and state that long-term hydropower models rarely represent environmental regulations, while some short-term models do. They also show that some environmental constraints require nonlinear representations. Hence, capturing all environmental regulations in hydropower models can be computationally demanding or impossible to solve in large hydropower optimization problems.

3.3 Hydropower in different types of optimization models

There are several reasons for conducting hydropower optimization. Two such examples are to maximize profit as a hydropower plant owner or to minimize production costs as a centralized electricity system operator in systems containing hydropower. Other reasons could be to estimate the benefit of transmission investments as a transmission expansion planner or to analyze future energy systems to inform policymakers as a researcher. The following three sections describe how hydropower has previously been modeled in the literature, dividing the different modeling approaches into three categories based on system boundaries. The first section addresses hydropower scheduling models, a dispatch model where only hydropower is modeled, and the remaining parts of the energy system are exogenous to the model. Second, there is a section on hydropower representations in energy system dispatch models, and lastly, a section on hydropower representations in capacity expansion models. The chapter ends with a section that summarizes the different model approaches and defines and discusses a literature gap.

3.3.1 Hydropower scheduling models

Hydropower scheduling models are dispatch models (described in Section 2.2.2) used for hydropower production planning for various time scales. In these models, only the hydropower production is optimized and the surrounding energy system is exogenous to the model in the form of electricity prices (in contrast to energy system dispatch models, described in Section 3.3.2, which optimize the operation of the entire energy or electricity system).

The objective function applied in hydropower scheduling models depends on the market setting. In competitive markets, such as those in, e.g., Norway, Sweden, Portugal, and the U.S, the objective in hydropower scheduling models is typically to maximize profit [70–79]. In these maximizing profit models, the surrounding system is represented by exogenous electricity prices [70–79]. In regions with centralized electricity distribution, such as in Brazil, or regions with, for instance, on-grid prices (fixed prices for sold electricity), such as China, the objective function is typically to maximize production or to minimize losses or water usage [80–83]. The surrounding energy or electricity system is represented as a net demand curve in these models.

Hydropower scheduling models can be categorized into short and long-term based on the time horizon considered in the model. Short-term models have time horizons of around one day to a couple of weeks, while long-term models consider one or several years. For short time horizons, hydropower scheduling models are used to plan the hourly operation of each plant by finding optimal water flows through turbines. For power producers in regions with competitive electricity markets, hourly production determines the revenue since the producers are paid according to the time-based electricity prices set by market clearing. For longer time horizons, the models are used to plan the approximate water content in the reservoirs over one or multiple years. Planning the reservoir content over time is vital since the water inflow, i.e., melted snow from mountains and rain, varies drastically over the year, as does the electricity demand. Hence, reservoir planning is used to determine when to save water in the reservoirs, and how much.

Short-term models, as used for instance in [70–73, 78, 79, 83–89], typically consider time horizons of one day to one week, with hourly resolution. Short-term hydropower scheduling models are often detailed, capturing large parts of the non-convexities and non-linearities in the hydropower production function (see Chapter 3.1), i.e., the head-dependent production as well as all, or parts of, the turbine efficiency functions, as for instance in [71, 73, 78, 79, 83, 85]. Catalao et al. [78] argue that modeling the head-dependency is important, showing that a non-linear formulation that captures head-dependent production outperforms a corresponding linear model that neglects head dependency when maximizing profit in short-term models. Short-term models are often deterministic, motivated by the short time horizon, and therefore subject to less uncertainty regarding inflows and electricity prices. However, Belsnes et al. [77] shows that uncertainties could affect the optimal real-time operation of hydropower plants.

Long-term models consider time horizons of one or several years, often with time resolutions of one week to one month. Some of these models are deterministic [80, 82, 90, 91], and some stochastic [74–76, 81]. Stochastic modeling is motivated by the fact that there are significant uncertainties regarding inflow and prices. However, stochastic modeling is computationally more demanding, and real operation characteristics, such as turbine efficiency curves and head-dependent production, are often more simplified in stochastic models than in deterministic models. The optimal operation obtained by long-term models is often used as input to short-term models in terms of boundary conditions on reservoir levels [77, 92], i.e., long- and short-term models are often used in conjunction so that the results from long-term models set the boundaries for the operation of short-term models.

3.3.2 Hydropower in energy system dispatch models

Energy system dispatch models are presented and discussed in Chapter 2.2.2. This section focuses on energy system dispatch models applied to areas where hydropower production plays a prominent role in the energy system, and where the hydropower representation is well developed within the model. These models can be used, for instance, by plant owners for production planning in existing energy systems or by system planners or researchers to explore the effect of changes on the existing energy system. As an example of the latter, Helseth et al. [58] investigated the effect on socio-economic surplus from increasing the capacity of a transmission line between Germany and Norway and found that the socio-economic surplus generally increases with increased cable capacity but not for all cases.

Energy systems with large shares of hydropower have been studied in the literature with both short-term dispatch models, considering time-horizons between a day and a couple of weeks, [93–103] and long-term dispatch models, considering one or several years, [58, 104–106]. Similarly as for the hydropower scheduling models discussed in Chapter 3.3.1, the short-term energy system dispatch models are often deterministic [93–103] while the long term are more often stochastic [58, 104, 105].

Regarding the detail of hydropower representation in energy system dispatch models, one can generally conclude that the short-term models more often include the head-dependent hydropower production function and the nonlinear turbine efficiency functions explained in Chapter 3.1. For example, references [93, 94, 98, 100] model the head-dependency and turbine efficiency functions for cascaded hydropower plant systems in short-term energy system dispatch models. By contrast, for computational reasons, no long-term model (neither hydropower scheduling nor energy system dispatch) is found with that level of detail.

3.3.3 Hydropower in capacity expansion models

Capacity expansion models explore conceivable future energy systems (see Chapter 2.2.1), and variation management strategies are essential in energy systems with increasing shares of wind and solar power. Moreover, the level of flexibility that hydropower provides affects the need for other variation management strategies. Hence, capturing a realistic level of flexibility from hydropower becomes more important when assessing its role in future renewable power systems as the share of wind and solar power increases. However, the representation of hydropower is highly simplified in capacity expansion models.

Often, all hydropower plants in a region are modeled as one single plant that can produce electricity without any other restrictions than the aggregated installed capacity, the aggregated reservoir size, and an annual limit on total production [6, 28, 29, 32, 47, 51, 52]. In reality, several more characteristics affect hydropower production, such as cascade effects, head-dependency, and turbine efficiency functions, as explained in Chapter 3.1.

As presented in Chapter 3.3.1 and 3.3.2, the literature on hydropower scheduling and energy system dispatch models with detailed hydropower representations is extensive. By contrast, only a few studies on capacity expansion models incorporate more detailed hydropower representations than the aggregated representations explained above [107, 108]. Liu et al. [107] include the hydropower network effect by modeling several cascaded hydropower plants in a capacity expansion model for China. Ramírez-Sagner and Muñoz [108] examine the error in investments and system cost from neglecting the head-dependency by modeling one head-dependent hydropower plant, aggregating all hydropower plants into one. They find that ignoring the head dependency leads to significantly more wind and solar power investments and a lower system cost than if head-dependent production is considered. This result is explained by the fact that including the head dependency puts a restriction on hydropower production and its flexibility, inducing an increased need for other variation management strategies and thereby reducing the cost-competitiveness of wind and solar power and increasing the system cost.

Instead of implicitly representing the real characteristics of hydropower in a model, another approach is to use *hydropower equivalents*. Hydropower equivalents is a concept that has been developed to represent a fully complex hydropower network system with a much-simplified system, that ideally produces similar results. The most basic hydropower equivalent is the aggregation method commonly used in capacity expansion models explained above, where all turbine capacities and reservoirs are aggregated. More sophistical efforts to find equivalents have been performed in [82, 109–112], where nonlinear hydropower models have been replaced by a simplified river structure with constraints constructed to imitate the behavior of the detailed model. However, these are calculated and presented for either just one week or with monthly time resolution, and the detailed model used to find the equivalents does not fully capture the head dependency and turbine efficiency functions. In addition, these more sophisticated hydropower equivalents have not yet been incorporated in capacity expansion models in the previous literature.

3.4 Summarizing the chapter and discussing the litterature gap

As we saw in Section 3.3.3, the simplified hydropower representations used in capacity expansion models miss out on several real characteristics of hydropower. Moreover, we have seen from the literature review in Section 3.3.1 and Section 3.3.2 that, in the existing hydropower modeling literature, the level of detail in the hydropower representations and the time resolution decrease with the modeled time horizon and system size. The literature presents detailed hourly short-term planning models and less detailed monthly long-term ones. However, in capacity expansion models, a high time resolution and long time horizon are essential to correctly asses the need for different variation management strategies such as storage, transmission, and flexible generation technologies. Therefore, there is a need for a new strategy to represent hydropower in capacity expansion models with high time resolution for a full year, if the actual characteristics of hydropower are to be represented.

The vast simplifications on hydropower production applied in capacity expansion models exaggerate the flexibility that hydropower can provide in the system, since several real characteristics of hydropower are ignored, but to what extent has not been studied. Before answering that, a way to better represent hydropower in capacity expansion models has to be found. Paper B takes a step in this direction, where a computationally efficient detailed nonlinear long-term hourly hydropower model is developed. In addition, to shed light on the error induced by simplified aggregated representations, Paper B displays the difference in the hydropower production obtained with the developed detailed model compared to a naive aggregated representation.

There are several reasons why a better hydropower representation in capacity expansion models could be valuable regarding informing policy makers working with the energy system. An example in the Swedish context regards the infected political debate on whether nuclear power is needed or not to achieve a carbon-neutral electricity system at a low cost. Using an energy system optimization model is a way to approach that question, and the representation of hydropower could affect the results since exaggerating the flexibility of hydropower could underestimate the overall system cost and the potential cost-benefit of using nuclear power.

Another example in the Swedish context of why an improved hydropower representation would be valuable regards environmental regulations for hydropower plants. It is decided that all hydropower plants in Sweden will get new environmental permits, and the government wishes to know how different designs of the new permits would affect the electricity system. This question around environmental permits is something I would like to focus on in my future research, as discussed in Chapter 5.

CHAPTER 4

Summary and discussion of present work

The following sections go through the appended papers one by one, providing a summary and a discussion section for each paper. In the discussion section, I elaborate on how they are connected to the background chapters in this thesis (Chapter 2 and Chapter 3), in contrast to discussing the results, which was done in the papers themselves.

4.1 MENA compared to Europe: The influence of land use, nuclear power, and transmission expansion on renewable electricity system costs (Paper A)

4.1.1 Summary of the paper

Most studies examining CO_2-neutral, or near CO_2-neutral, power systems using energy system models investigate Europe or the United States, while similar studies for other regions are rare. However, the high carbon intensity of electricity generation in the Middle East and North Africa region (MENA), and concerns about pollution, among others, entail extensive potential benefits of decarbonizing the MENA power sector. In MENA, the weather conditions differ substantially from those in Europe. In this paper, we modeled MENA and Europe separately to asses how weather conditions play out for future decarbonized energy systems.

How the future electricity systems will evolve is uncertain, and a transition of the electricity system can take many different directions, depending on policy choices and technology development. However, some technologies have raised public concern, such as i) massive transmission expansion, ii) large-scale wind and solar deployment, and iii) nuclear power. In this article, we addressed how potential limits to deploying these technologies (i-iii) could affect the cost of future electricity systems and how it differs between MENA and Europe.

The research questions in Paper A are:

- What is the difference in cost of a CO_2-neutral future electricity system between MENA and Europe?
- What is the impact of (i)-(iii) on system cost, and how does this differ between MENA and Europe?

To answer these questions, we built one greenfield capacity expansion model (see Section 2.2.1) for each of the two regions to minimize total system cost, given a predefined demand for electricity in each country within MENA and Europe.

We found that the cost of a carbon-neutral electricity system is considerably lower in MENA than in Europe. The system cost, normalized by total demand, is 6-35% lower for MENA compared to Europe, depending on deployment limits for specific technologies and the investment cost for solar PV and batteries. Given the study design, where the weather and demand data is the only difference between the regions, the results show that the lower system cost in MENA is linked to better wind and solar resources.

Limiting transmission, available land for wind- and solar power, and nuclear have markedly different impacts on system cost depending on the region. Public acceptance of wind and solar farms may significantly impact the cost of a CO_2-neutral power system. Our results indicate that reduced available land for wind and solar deployment (from 10 to 2%) can increase system cost by about 50% in MENA and 25% in Europe. Allowing for nuclear power reduces the system cost by 0-19% in Europe and 0-4% in MENA. The magnitude depends on investment costs for solar PV and batteries, resource quality, and the availability of land for wind and solar. Because the last two factors are more favorable in MENA, the availability of nuclear power has a more significant impact on system cost in Europe than in MENA. Allowing for optimal transmission expansion decreases the system cost by between 5 and 25% depending on the investment cost for PV and batteries. The cost impact from the optimal transmission is similar in Europe and MENA.

4.1.2 Discussion

The analysis in Paper A was conducted using a capacity expansion model (see Section 2.2 for an explanation of capacity expansion models). The purpose of this study was exploratory (see Chapter 2.1). It contributed knowledge about how weather conditions and deployment limits affect the cost of a future electricity system. As an example, it tells modelers that assumptions on deployment limits for wind and solar power may affect system costs considerably.

This paper has prescriptive elements to it as well. Based on the finding that the cost reduction from using nuclear power in MENA is minimal, it can be concluded that nuclear power should not be built in MENA with the argument that it is a necessary part of cheap carbon-neutral electricity. However, this only holds in a future where transmission lines and trade are accepted between many countries in MENA. This limitation of the result is an example of what was discussed in Section 2.4, that social and political constraints that are not in the model, such as the political feasibility of building transmission lines between particular countries in MENA, need to be considered outside the model when analyzing and communicating the results.

In the models used in Paper A, we apply very simple hydropower representations, similar to many other studies using capacity expansion models (see Section 3.3.3). We have not examined how this affects the results in Paper A. However, since a more detailed hydropower representation contains more restrictions on how the hydropower plants can operate, the total system cost would be slightly higher with a more realistic representation of hydropower. The underestimation of cost is likely higher for the case of Europe, which holds a larger share of hydropower than MENA and slightly poorer wind and solar resources. One can also suspect that the cost of limiting the deployment of transmission, wind and solar power, and nuclear should be slightly higher in reality since the flexibility of hydropower is exaggerated in the model and the need for other variation management strategies is underestimated. The magnitude of the difference in result induced by an overly simplified hydropower representation remains to be analyzed.

4.2 Exploring trade-offs between aggregated and turbine-level representations of hydropower in optimization models (Paper B)

4.2.1 Summary of the paper

It can be essential to capture the flexibility of dispatchable technologies such as hydropower to model a future power system with high shares of variable renewables. However, due to computational limitations and a lack of available data, the representation of hydropower is highly simplified in capacity expansion models in a way that potentially overestimates the flexibility of hydropower (see Section 3.3.3).

Some important techno-physical characteristics that are neglected in these simplified hydropower representations are i) the network effect (including the environmental regulations), ii) head-dependent production, and iii) nonlinear turbine efficiency functions, which are all explained in Section 3.1.

These three characteristics constitute, in various ways, challenges when modeling hydropower, explained in Section 3.2. Moreover, there is no previous literature with capacity expansion models that capture these three characteristics of hydropower, nor is there any literature that compares including and ignoring these characteristics in hydropower models (see Section 3.4).

Paper B has the following research aims:

1. To examine how a simple hydropower model differs from a more physically sound model that includes the three characteristics mentioned above. The goal is to highlight the features of optimal hydropower generation that are omitted in typical formulations in capacity expansion models.

2. To explore the trade-offs between accuracy and computational time for different hydropower models, including various characteristics of hydropower. The goal is to evaluate the potential merits of using all the characteristics rather than only a select few.

3. To evaluate a new novel hydropower model developed in this study. This model uses Taylor approximation to linearize the hydropower production function.

We developed a series of deterministic hydropower scheduling models with an hourly resolution for a full year (see Section 3.3.1) for a single river, with various levels of techno-physical detail. We confirmed that a simplistic hydropower representation with only a single plant and reservoir, similar to those often used in capacity expansion models, significantly overestimates the flexibility of hydropower.

Our most detailed model includes all three characteristics mentioned above. We describe techniques that can be used to solve this model in just one hour. Furthermore, we show how this model can be linearized, thereby reducing computation time to one minute while featuring production dynamics substantially more similar to the full non-convex model than a naive linear network model.

These contributions pave the way for a computationally efficient hydropower representation that can be implemented in capacity expansion models without overestimating the flexibility that hydropower may provide.

4.2.2 Discussion

The analysis in this paper is based on results from hydropower scheduling models. As discussed in Section 3.3.1, hydropower scheduling models can be used for production planning where they make prescriptive analyses that aim to find how hydropower plants should be operated to maximize profit. In this paper, the goal of maximizing profit implemented in the model corresponds to the strategies used by the plant operators. However, as we will see, the analysis in this paper is exploratory.

In contrast to the typical weekly or monthly time resolution used in long-term hydropower scheduling models, all our models operate hourly over a full year. This choice of time resolution and time horizon is motivated by the interest in finding hydropower representations for capacity expansion models with such time characteristics. Despite the long time horizon, we ignored the uncertainties in prices and inflow, which are significant for such long time horizons. Therefore, the model does not aim to be a detailed production planning model or a model for predicting electricity prices. Instead, the aim was to demonstrate the difference in including techno-physical characteristics compared to rough aggregations when modeling hydropower. Thus, the analysis in this paper is exploratory. The optimal production obtained by the most detailed model in this paper can be seen as an upper boundary to how well hydropower can follow price signals. It provides an upper boundary since, in reality, the plant owners do not have perfect information on inflows and prices, which makes it more difficult to find the optimal production schedules.

The contributions in this paper partially fill the gap introduced in Section 3.4. It does so by providing knowledge on how large the error in the optimized hydropower dispatch is when ignoring physical constraints for hydropower. In addition, this paper filled the gap by proposing a novel computationally efficient hydropower representation that could be implemented in capacity expansion models.

The contributions of this paper are directly beneficial for the modeling community. However, it also allows for new model-based studies emphasizing hydropower to inform policymakers. One example regards the question of new environmental permits for hydropower plants in Sweden, as discussed in Section 3.4 and Chapter 5.

CHAPTER 5

Future work

This chapter is divided into three sections. The first addresses policy and modeling implications following the two appended papers. The second provides the research direction for my continued doctoral studies. Lastly, I reflect on my learning process throughout working on this thesis.

5.1 Policy and modeling implications

Starting with policy implications from Paper A, we found that allowing for nuclear power in MENA enables very limited reductions in system costs. This result supports strategies to decarbonize power systems in this region without nuclear power and thereby avoid associated concerns about safety and proliferation. However, this limited benefit of using nuclear energy is found when allowing for optimal transmission expansion, while transmission expansion may only be politically feasible in some places. By analyzing different scenarios regarding which technologies are allowed, we found that decarbonizing the electricity sector may entail hard-to-swallow features, such as large-scale transmission or large amounts of batteries or nuclear power.

Another finding from Paper A that could have implications for policy and the model community is the importance of available land for wind and solar power deployment. For instance, in MENA, the cost of a renewable electricity system is affected more by limits on available land for wind and solar deployment than transmission or nuclear power. Hence, land-availability assumptions should feature more prominently than currently in policy discussions and the modeling community. Furthermore, the difference in system cost incurred by assumptions on available land could be interpreted as an opportunity to give financial incentives to the part of the population negatively affected by wind and solar power construction. We also conclude that while the land available for wind and solar exploitation, which is affected by public acceptance issues, seems important for the system cost, this issue has not been thoroughly investigated in model-based research. Future research could explore its importance in greater detail, with more realistic assumptions on wind and solar expansion restrictions.

Switching focus to Paper B, the findings have implications for the modeling community. By comparing different modeling approaches with varying levels of detail on the hydropower representation, we show that ignoring techno-physical facts misrepresents how hydropower can be operated and, thus, how much flexibility it may provide in an energy system. With this knowledge, modelers can recognize this limitation when analyzing and communicating model results. Furthermore, if the analysis calls for it, there might be room for modeling improvements based on the new model presented in Paper B. However, the proposed model in Paper B relies on significant amounts of closed-source data. A possible direction for future research is to explore ways to generalize the proposed model to reduce the need for such closed-source data.

Paper B has no direct policy implications; however, it provides a step towards capturing a realistic representation of hydropower in capacity expansion models, which can be valuable for several policy-relevant modeling studies, as described in Section 3.4. Furthermore, the model development presented in Paper B constitutes the basis for my continued doctoral studies, which I expand on in the next section (Section 5.2).

5.2 Research direction for my continued studies

As mentioned, Paper B provided a step toward finding a hydropower representation that captures a realistic level of flexibility while being computationally fast enough to implement in capacity expansion models. I plan to continue in that direction, developing the method presented in Paper B and implementing an improved hydropower representation in a capacity expansion model. The motivation for doing so is to obtain a better tool for answering policy-relevant questions about renewable energy systems with large shares of hydropower, such as in the Nordics.

One area where an improved capacity expansion model would be valuable for answering policy-relevant questions is the environmental regulations posed on hydropower plants. Sweden is facing a long period of legal processes, providing all roughly 2000 hydropower plants in the country with renewed environmental permits. This process results from the EU water framework directive, which commits European Union member states to achieve good ecological status in all water bodies, or good ecological potential in water bodies that are allowed exemptions [113]. However, experts and policymakers are uncertain about how new environmental permits will affect the electricity system and the potential of electrifying multiple sectors in Sweden. This uncertainty has led to the Swedish government suggesting, in December 2022, a temporary stop in the process of providing all plants with new permits until the beginning of 2024 [114]. In my future research, I would like to focus on how environmental permits may affect Sweden's existing and future energy systems.

Hence, in my current thinking, the theme for my continued research is twofold. First, improving the hydropower representation in energy systems optimization models. Second, to use a model with an improved hydropower representation to explore how environmental regulations affect the role of hydropower in the existing and future renewable energy system.

5.3 My learning process

In many ways, Paper A and Paper B are very different, and I acknowledge that this kappa could be perceived as somewhat incoherent when connecting these two papers. However, these two papers are clearly connected in terms of my learning process and future research.

I began my research education by working on Paper A. That work has helped me understand how to build capacity expansion models, their typical features and how to make analyses based on these models. Moreover, after working on Paper A, I worked with environmental regulations for hydropower at the Swedish energy agency for a year. This working experience made me realize that the representation of hydropower may be too simplified in capacity expansion models, which was the starting point for Paper B.

Since my future research builds on finding a hydropower representation for capacity expansion models, it is valuable to have learned about capacity expansion models while working with Paper A. In addition, working with the process of giving all hydropower plants new environmental permits at the energy agency has made me aware of the knowledge gaps regarding how new environmental permits may affect the electricity system in Sweden. Thus, the two papers and my working experience at the energy agency have been essential learning processes that will improve my intended future work.

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