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OPTIMIZING A HYBRID RENEWABLE ENERGY SYSTEM WITH A FOCUS ON OFFSHORE WIND IN THE US NORTHEAST

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BY

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ABSTRACT

The objective of this research is to quantitatively assess the energy transition of a New England State, Rhode Island, to a renewable energy-based system that mainly relies on offshore wind resources. Rhode Island has currently planned a 1,000 MW offshore wind capacity as a major step toward fossil-free energy. It is not clear how the energy demand of the state can be met and what will be the realistic contribution of renewables in the future (e.g., 2030). In this study, at first, the electricity demand in Rhode Island at the present and future (e.g., considering electrification of transportation using electric cars) was assessed using the most recent published data. The time series of the hourly electricity demand for a year was predicted for several scenarios, and the base load, the peak load, and other load parameters were estimated. Further, the supply of renewable energy resources based on offshore wind and solar PV was predicted. Several electricity mix scenarios assuming various shares of renewable penetration and natural gas were created to assess how the demand can be met with a hybrid energy system. To optimize and assess each electricity mix scenario, HOMER (Hybrid Optimization of Multiple Energy Resources) was implemented. HOMER, developed by National Renewable Energy Laboratory, can optimize a hybrid renewable energy system based on minimum cost (i.e., Net Present Cost) while including constraints such as minimum renewable energy contribution/penetration. Several scenarios including the present energy mix, using 1000 MW of offshore wind, 100% renewable, and other mixes were simulated and optimized in HOMER. For the cost estimation, available published data were used. It was found that the transition towards renewable energy based on offshore wind is very challenging due to the peaks in electricity demand (e.g., August) in the summer when the offshore wind production reaches a minimum due to lower wind speeds. Natural gas or other resources would be still necessary to meet the demand in peak time. A possible solution to solve the intermittency is energy storage and solar energy which were assessed in HOMER as another scenario. Results were discussed and some recommendations for energy transition and possible percentage of each resource in the mix were presented.

ACKNOWLEDGEMENTS

The following thesis was one of the major challenges I faced in order to achieve my graduation which is why I want to acknowledge everyone who supported me during that process.

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A great thank goes to the DAAD for giving me financial aid over the entire process of this thesis, so that I could focus on my work without having to accept further jobs. I also want to thank my homeschool TU Braunschweig and the University of Rhode Island itself for providing the exchange program I am in and giving me professional international experience.

Last, a special thanks goes to my family who supported me in any situation and keeps me motivated.

PREFACE

The following thesis is presented in the manuscript format defined by the guidelines of the University of Rhode Island. Its purpose is to prepare this study for publication in a scientific journal. Due to this fact the following text is appropriately compressed. Details for assumptions or derivations and methods can be found in the appendix at the end of this work. A chapter for literature review is omitted but the introduction provides the necessary background information for a proper understanding of the study.

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Publication Statement

The following thesis aims to be published in a scientific journal. The manuscript is prepared for submission to *Applied Energy*.

Chapter 1

1. Introduction

Since the start of industrialization in the 1900's, humans have continually emitted greenhouse gases into the atmosphere leading to global warming. Global average temperatures keep rising by 0.1°C per decade (Mideska & Kallbekken, 2010). Even for the best-case scenario, in which all greenhouse gas emissions would cease today, the global average temperature would still increase by 2°C (Mathiesen, et al., 2010). The effects of global warming are various and range from an increased sea level to more extreme weather events like hurricanes and drought periods. It is therefore critical for sustainable development, to avoid anthropogenic greenhouse gas emissions (Mideska & Kallbekken, 2010; Myhrvold & Caldeira, 2012). The main contributor of all greenhouse gases is CO_2, emitted during the burning of fossil fuels, such as oil, coal, and natural gas. Electricity production largely contributes to these emission rates. Worldwide, it is responsible for 39% of all anthropogenic CO_2 emissions (Myhrvold & Caldeira, 2012). Decarbonization of the electricity sector is the first step into a carbon free future and can be implemented with renewable energy sources like solar and wind (Bagheri, et al., 2019). Previously calculations have shown that in order to reduce current emissions by half, 46% of the global power supply would need to be produced by renewable sources (Mideska & Kallbekken, 2010). However, further challenges like storing energy and providing ancillary services need to be completed and coupled with renewable energy systems to ensure an integration with electricity grids. A possible solution for these challenges are hybrid renewable energy systems (HRES) that can diversify the supply system and manage similar tasks like conventional power plants.

Leading industrial countries and many other nations have formulated goals to increase the share of renewable energy sources. Several countries announced their commitment to transition to 100% renewable energy, including Denmark in 2006 (Mathiesen, et al., 2010).

To push the expansion of renewables, policies have been developed to give incentive for investment in new technologies. Examples are feed-in-tariffs which have been proven to be very successful in Europe, auctions, which help to ensure the lowest price for electricity through competition, and renewable energy certificates (REC's) (Aquila et al., 2017). REC's are given out to producers of renewable energy per produced MWh and are associated with renewable portfolio standards (RPS). RPS, also called RES (Renewable electricity standards), require that a minimum amount of electricity from a utility has to come from renewable sources. In the US, RPS are different for each of the 38 states they have been implemented in since there is no federal regulation. Furthermore, they can specify for a certain renewable energy source type, to push its development (EIA, 2021b). If the amount of renewable energy falls below RPS, the utility has to purchase REC's that are given out to producers of green energy. However, prices of REC's are very variable. For instance, their price in Rhode Island dropped from 60 $/MWh in 2013 to only 10 $/MWh in 2018 (US EPA, 2021).

To master the challenges of intermittent renewables, Lund et al. (2009) found that Denmark either needs to expand its biomass capacity to serve the baseload or implement hydrogen storage in combination with offshore wind (Lund & Mathiesen, 2009). To design a 100% renewable energy system without contribution of fossil fuels, a variety of challenges need to be solved. These challenges are energy use reduction, increased energy efficiency, and renewable energy sources. Furthermore, integrating renewable energy into the electricity grid means dealing with its intermittent character.

Lastly, the transportation sector has to be integrated, too. The recommendations of Lund et al's study among others are installing heat pumps and replace the traditional fuel heating, convert CHPs (Combined Heat and Power Plant) from natural gas to fuel cells or biomass, and increase the production of renewables like wave, wind, solar and biomass. To handle the intermittency of renewables, the study of Lund et al. proposes to either rely on biomass for which compromises with land use are necessary, or on wind combined with hydrogen as storage technology which could lead to inefficiencies in the system due to the hydrogen production (Lund & Mathiesen, 2009).

Another study for a 100% renewable electricity supply applied for the city of Victoria, Canada, concluded similar results. They found that biomass plays an important role in mitigating the costs of HRES and is way more efficient than only wind/solar systems. An attractive economical alternative is to keep natural gas implemented in the system up to 31%, helping to mitigate costs in the first place. To achieve 100% renewable however, more incentives for investments in renewables would be necessary. Another important parameter to increase the return of investment is a low interest rate (Bagheri et al., 2019).

The state of Rhode Island has proposed its plan to achieve 100% renewable energy by 2030 as (Murphy, et al., 2020). A major contributor for this target should be offshore wind energy, after the state government proposed further 600 MW of offshore wind farm (OWF) in October 2020, resulting in a total capacity of 1000 MW of offshore wind (Rhode Island Office of Energy Resources, 2020). Currently, Rhode Island's electricity demand is mainly supplied by natural gas power plants of more than 2000 MW total capacity (The Brattle Group, 2021), contributing for about 90% of the total electricity production, while renewables have a share of 10% (EIA, 2021a). These renewable energies consist of 75 MW wind (on- and offshore), around 40 MW biomass and 400 MW solar PV. The electricity grid of Rhode Island is connected to the grid of New England, regulated and overseen by the independent system operator (ISO) New England. Distribution is managed by utilities, such as national grid, who sell their electricity to the end costumer. For the region of New England, the renewable share is even less with 7% (ISO New England, 2021). Regardless of regional renewable installations, this share is expected to increase due to imported hydropower from Quebec, Canada, in the future (*Quebec Government Authorizes Hydropower Interconnection to U.S. | Hydro Review*, 2021; Dimanchev et al., 2020).

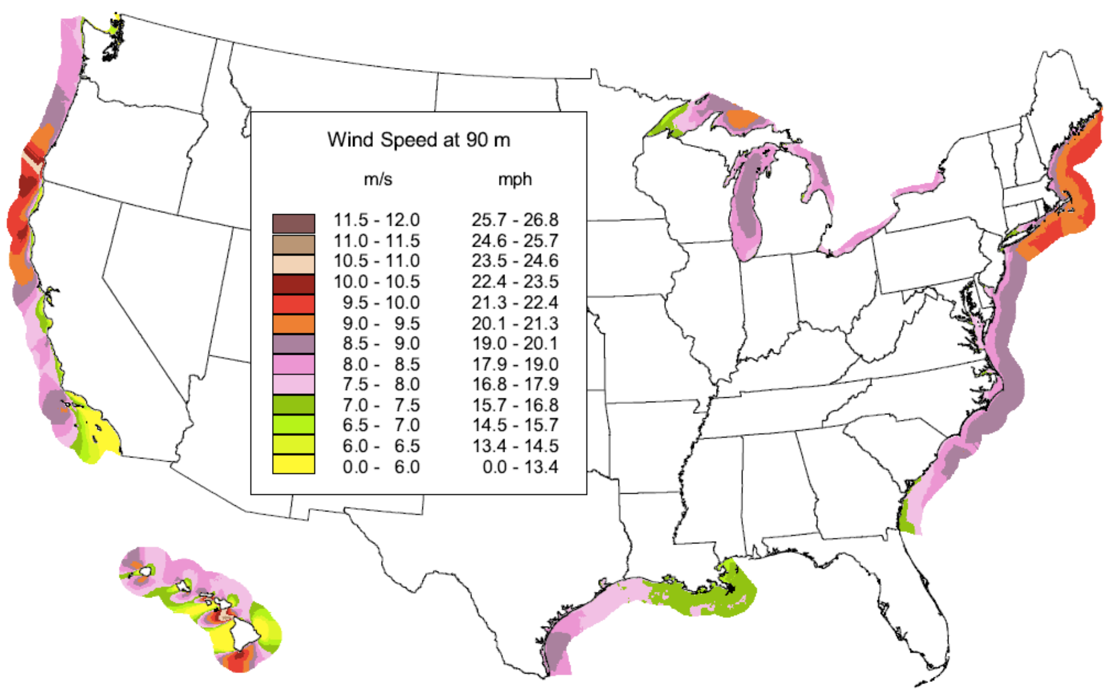

Figure 1: United States offshore wind resource at 90m above the surface with bright areas indicating low wind speed and dark areas indicating high wind speed (Schwartz et al., 2010).

However, energy resource assessment shows that the east-coast of New England possess vast resources of wind energy as seen in Figure 1. Consequently, the New England states, including Rhode Island, developed strategies to create an offshore wind industry and increase the share of renewables over the next years, providing renewable energy and economic growth due to jobs and increase in GDP to the region (Schwartz, et al., 2010).

Nevertheless, other states are having plans for offshore wind in progress as well. For example the Coastal Virginia Offshore Wind (CVOW) project is expected to be online by 2026 (Coastal Virginia Offshore Wind, 2021). By 2021 Rhode Island is still the only state in the US that is operating an offshore wind farm, the Block Island offshore wind farm with a capacity of 30 MW.

To realize 100% renewable energy only offshore wind resources are not sufficient. HRES have been shown to be beneficial since they have the ability to counteract the disadvantages associated with different technologies. Especially, the seasonal differences in wind speed and solar radiation combines wind and solar energy to an efficient system. For Rhode Island, in addition to offshore wind, an increased onshore wind capacity of 220 MW and further 470 MW of solar PV is expected to be online by 2030 (The Brattle Group, 2021).

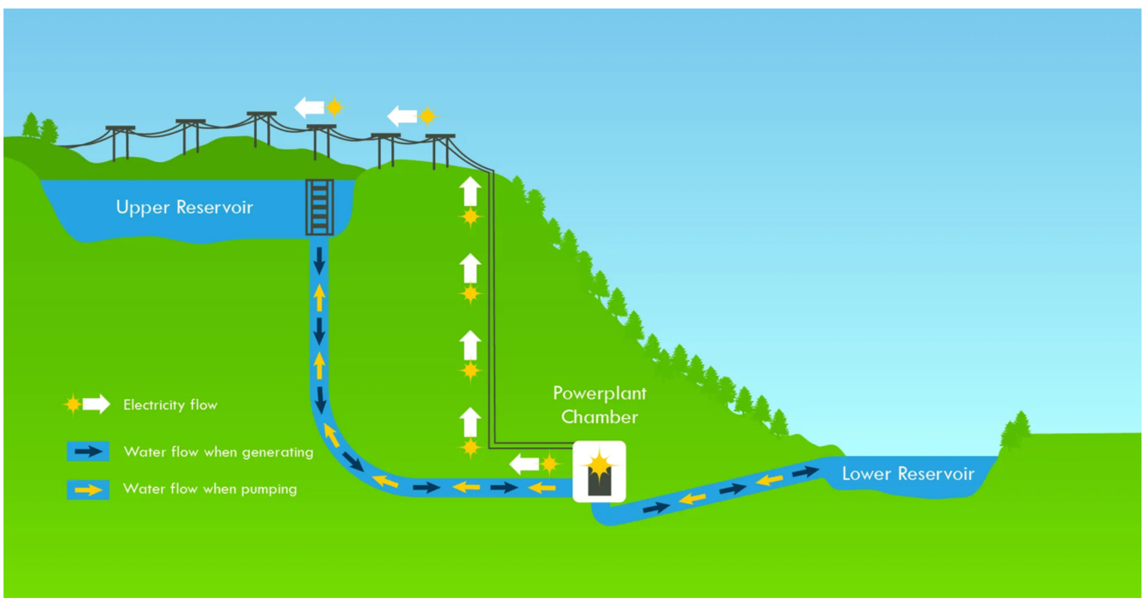

Figure 2: Schematic illustration of pumped hydro storage used as seasonal storage with elevation difference between upper and lower reservoir to utilize potential energy (Scottish Construction Now, 2016).

A further critical element for renewable electricity grids is energy storage. Due to the intermittency of renewable energy sources, excess electricity is produced when there is no demand for it, resulting in wasted energy (Nyamdash et al., 2010) . The most common large scale energy storage is pumped hydro-storage illustrated in Figure 2. This technology is relatively old and mature. However, it requires large elevation differences between the reservoirs to operate efficiently (Ekman & Jensen, 2010).

However, due to the relatively flat topography of Rhode Island, pumped hydro-storage is probably an uneconomical option. Several other storage technologies are in development. The most advanced is Li-ion battery storage. Primarily used for small-scale electronics (Poullikkas, 2013) large-scale variants have been developed. In 2017, the *Horsndale Power Reserve* from *Tesla* in Australia started to operate as the largest Li-ion battery in the world with additional expansion in 2020. It has a total storage capacity of 194 MWh for total construction cost of $121 M. In the first two years of operation, it could reduce costs for electricity nearly $150 M (Hornsdale Power Reserve, 2021). After this successful implementation in Australia, further large-scale batteries are planned, for example in Victoria, AUS, California and New York (The Guardian, 2020).

1.1. Research Objectives

The objective of this study is to analyze the temporal variability and uncertainty of energy supply and demand of Rhode Island considering OWF, and investigate energy transition toward a renewable based system.

Several scenarios of the Rhode Island electricity grid are created with varying shares of renewable penetration, including 100% renewables, to determine the optimal system configuration of natural gas and renewable energy sources.

The tool chosen for this study is HOMER Energy, a numerical optimization software, made to simulate HRES (Bahramara et al., 2016)

Chapter 2

2. Methodology

For the simulation and analysis of Rhode Island's potential electricity grid, several scenarios and models were created with assumptions described in Chapter 2.5. Figure 3 illustrates the methodology process. It shows the scenarios at the top which are determined by the system constraints like renewable penetration. The sides show the input parameter of the load profile in the demand side and the system architecture of renewable energy systems on the supply side. These data will be used by the HOMER software which performs the optimization resulting in an optimized system architecture at the bottom. The input parameter and are explained in the following sections.

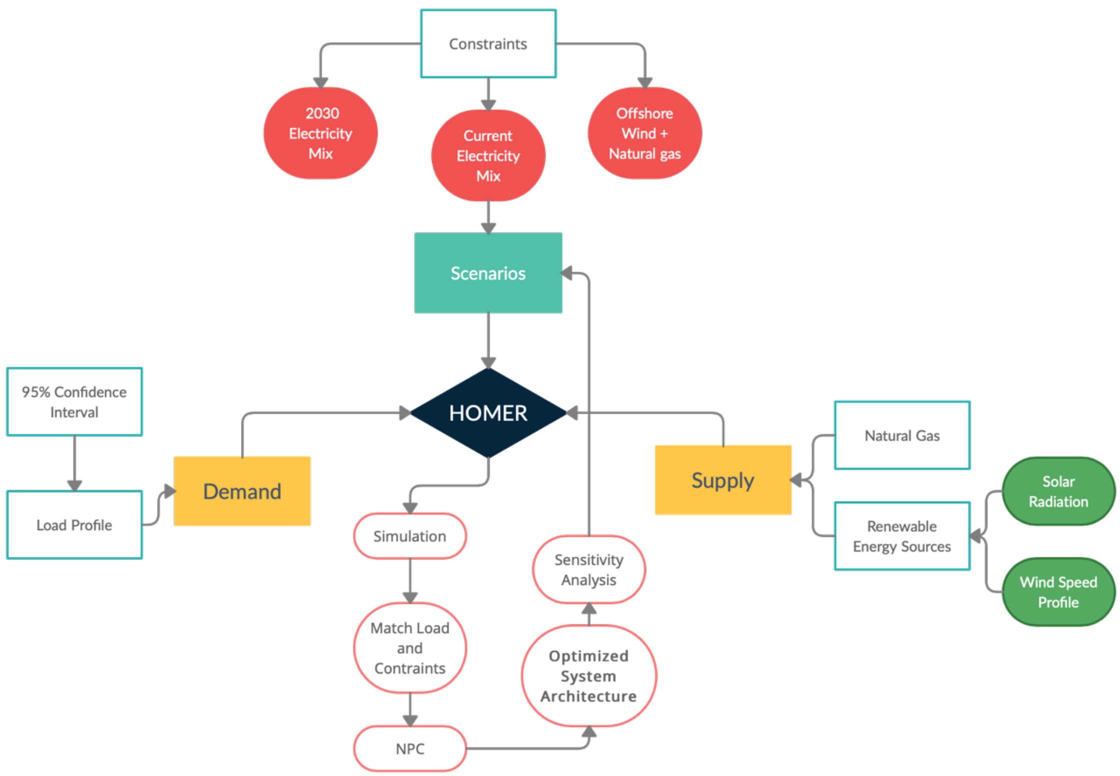

Figure 3: Flow chart of the methodology overview with input parameters (top, left, right) for HOMER and optimization process (bottom).

2.1. Electricity Demand

The electricity demand is determined by the load profile. The load profile represents the load that is put on the electricity grid per time step, for instance one hour. It varies dependent on the time of the year and time of the day. The load must be matched at every time by the supply side, consisting of conventional power plants and renewable energy systems. This is mandatory to keep the frequency and voltage stable and avoid a collapse of the electricity grid. The load is given in hourly time steps in the unit of power in MW. Integration of power or an annual load times series for example, results in annual energy consumption (Fezzi & Bunn, 2010).

Figure 4 shows the expected annual electricity demand of Rhode Island. It has remained relatively stable after 2005, between 7,000 and 8,000 GWh. However, it experiences a drop until the late 2020s due to improvements in energy efficiency. After that, the demand is expected to rise because of the implementation of electric heating using heat pumps and electric transportation by electric vehicles. Transportation and heating are still mainly supplied by natural gas and fossil fuels. To become carbon neutral, it is necessary to decarbonize not only the electricity sector but all sectors that demanding energy. Therefore, at some point both sectors, heating and transportation should be supplied by renewable electricity. By now, these developments are insignificantly low and expected to be about 5% of the demand by 2030, resulting in an annual electricity consumption of about 7,700 GWh. However, the electrification will increase exponentially afterwards and reach double the current annual load in 2050 or 16,000 GWh (Murphy et al., 2020).

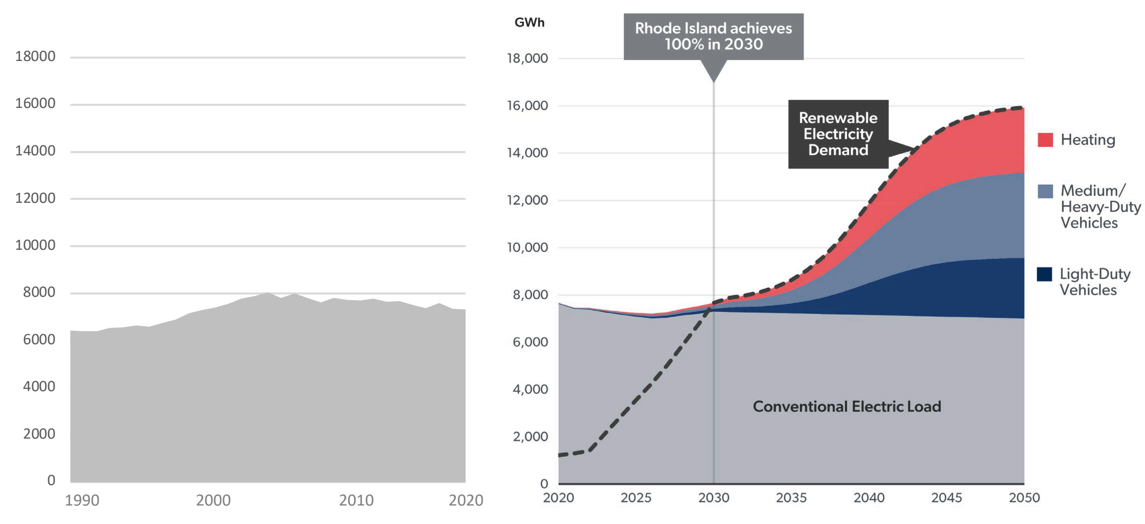

Figure 4: Past (left) and predicted (right) annual electricity demand of Rhode Island before and after 2020 due to electrification of the heating and transportation sector (Murphy, et al., 2020).

To create the load profile data series for Rhode Island that can be used as an input for HOMER energy, load data from the ISO NE of the past five years (2015-2019) was used. Instead of working with average values, the upper 95% confidence interval was chosen to cover the load variations over years (Murphy, et al., 2020).

This interval is defined by Equation 1 and 1.1, using the mean value *m*, and the 95% confidence level *CL*, calculated with the standard deviation *Std* and the sample size *n*. For the calculation of the 95% confidence interval of Rhode Island's electricity demand, five years of hourly data were used resulting in a sample size of five for each time step

$$UCI = m + CL \tag{1}$$

$$CL = 1.96 * \frac{Std}{\sqrt{n}} \tag{1.1}$$

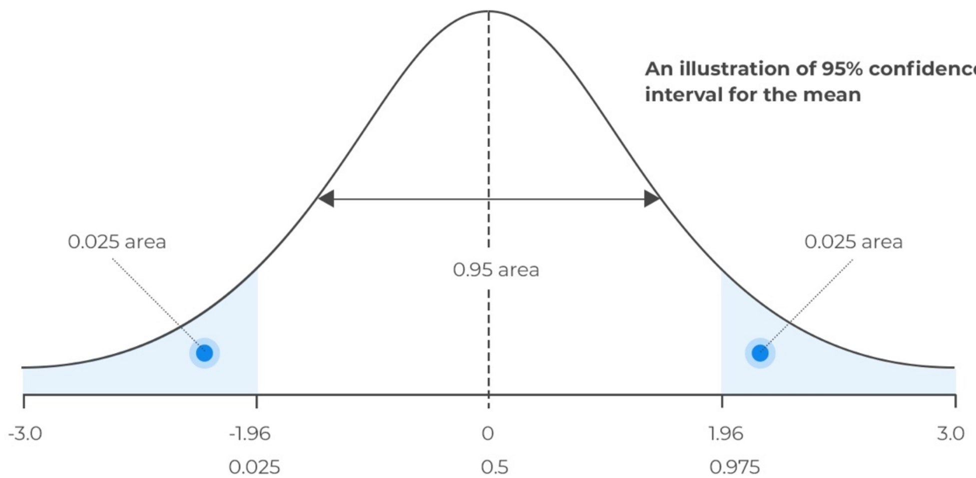

Figure 5: Illustration of the normal probability distribution with 95% confidence interval. The abscissa describing the confidence coefficient which is 1.96 for the 95% interval (AnalystPrep, 2019).

The 95% confidence interval is a statistical tool describing the distribution of a dataset. It means that for future or unknown data points there will be a 95% chance that a value lays within this confidence interval (see Figure 5). This value will be referred as the high load case and will be used for a detailed analysis in HOMER. The factors and uncertainties that influence the electric load growth are economic growth, energy efficiencies improvements, climate variability, pace of electrification, and long-term temperature trends due to global warming.

Further relevant parameters are baseload and peak load. The baseload is the minimum load that is put on the grid at any given time and usually does not fall below that value. For Rhode Island this is about 570 MW as can be seen in Figure 6. The peak load is the maximum load that is drawn from the grid in a year or a month. To match that load, additional power plants that are on reserve need to start operation and produce further electricity during peak hours (Fezzi & Bunn, 2010). The peak load of Rhode Island in the past five years was 1,850 MW in the summer of 2018 as shown in Figure 6. Both, baseload and peak load are important since they determine the load range of a system. High load ranges put a lot of pressure on the electricity grid since power plants need to ramp up and shut down spontaneously, which has technical limitations and can be very expensive (Fezzi & Bunn, 2010). An important parameter to characterize the peak load is the load factor which is the average load divided by the peak load. Therewith, it is an indicator for the variability and the peak load (HOMER Energy, 2020). The created data series of the high load case for Rhode Island has a load factor of about 50% seen in Figure 6, where the peak load is about double the average load.

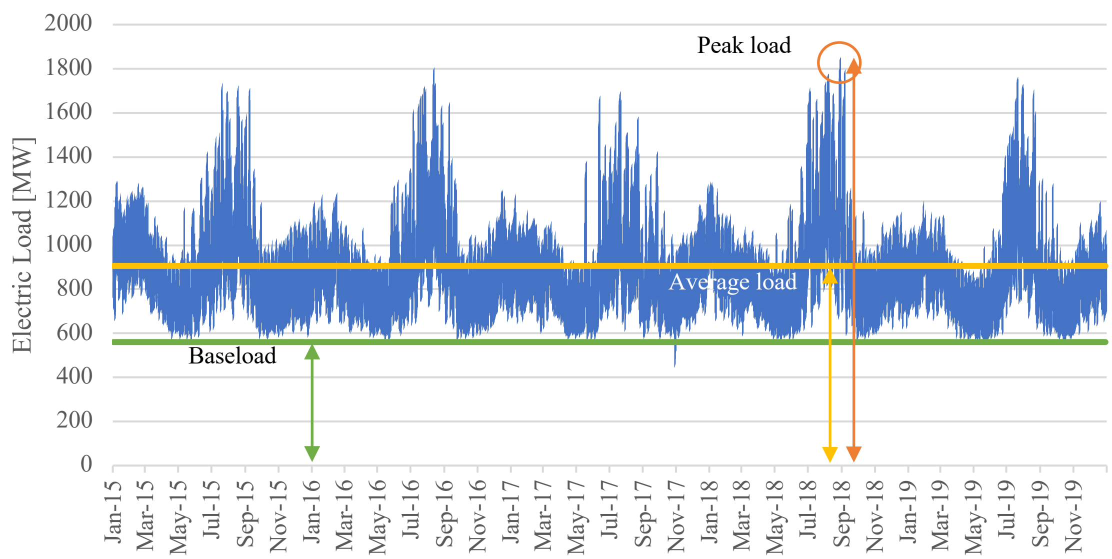

Figure 6: Hourly electric load series for Rhode Island from 2015-2019 provided by ISO NE with a baseload of 570 MW, peak load of 1,850 MW in 2018, average load of 910 MW and load factor of 50% over the course of five years showing the electricity demand every hour in MW.

It should be noted that due to the increase in electrification of the transportation and heating sector the distribution of the electricity demand over a year will make a large shift in the next decades. The reason for this is the increased heating demand covered by electrical heating in winter (Weiss et al., 2020) and less efficient batteries during cold temperatures (Iso-NE, 2020). Consequently, this change will result in an increased electricity demand during winter months. Furthermore, AC systems are supposed to become even more energy efficient while climate change will bring hotter summers and higher demand for cooling (McFarland et al., 2015). The dimension of the electrification developments will be very limited until 2030 and most likely not exceed 5% of the total electricity demand (Murphy et al., 2020). Due to the uncertainty of the pace of electrification, it was assumed for the models used in this study that the electric load will have similar characteristics as in the past years without electrification (2015-2019). However, some manual calculations were made to model the demand under electrification assumptions which are presented in the appendix.

2.2. Electricity Supply

To match the electricity demand, power plants and energy sources are required. The capacity P of the supply system needs to be at least as high as the electric load, so that demand is met at any given time (see Figure 6). The electricity production per time step results in electric energy E (see Equation. 2). The energy production of a power plant in a year is less than its full capacity and is defined by the capacity factor c_p. The capacity factor describes what percentage of the full capacity is used. For example, the Block Island Wind farm with a capacity of 30 MW (Table 2) would produce $30MW \cdot 365d \cdot 24h = 262GWh$ which is reduced by the capacity factor of 47.6% to $262GWh \cdot 0.476 = 125GWh$. The annual electricity production (AEP) is defined as follows.

$$E = Pt \tag{2}$$

$$AEP = P \cdot c_p \cdot 8760 \tag{2.1}$$

By 2021 the majority of electricity still comes from natural gas power plants. They have a total capacity of nearly 2,000 MW as shown in Table 1.

Table 1: Power plants capacity of Rhode Island using natural gas as primary fuel with a total capacity of 1,995 MW (Rhode Island Department of Administration: Division of Planning, 2015).

Power Plant	**Nameplate Capacity [MW]**
Entergy Rhode Island State Energy LP	596.0
Manchester Street	515.0
Tiverton Power Plant	272.5
Ocean State Power	254.2
Ocean State Power II	254.2
Pawtucket Power Associates	68.8
Toray Plastics	12.5
Central Power Plant	10.7
Rhode Island Hospital	10.4
Brown University Central Heating	3.2
Total	1,995

In comparison, Table 2 shows the capacity of renewable energy sources currently installed, as well as the expansion plans until 2030. Since renewable energy system are distributed all over the state with multiple installations only the total capacity is shown here.

Table 2: Renewable energy resource capacity of Rhode Island in the present and additional resources planned to be online by 2030 (Murph et al., 2020).

Renewable energy sources 2020	**Capacity [MW]**
Onshore wind	45
Offshore wind (Block Island)	30
Solar PV	400
Biomass	42
Total	517
Renewable energies planned for 2030	
Onshore wind (REG + long-term contracts (LTC)): *REG* *Cassadaga* *Copenhagen*	≈ 220 *19* *126* *80*
Offshore wind: *Revolution wind* *600 MW proposal*	1,000 *400* *600*
Solar PV (LTC + virtual net metering) *Gravel Pit Solar* *Virtual net metering*	≈ 470 *50* *300-480*
Total	2,207

For characterizing the degree to which a HRES or electricity grid is supplied by renewable energy sources several parameters can be used. In every timestep, HOMER calculates the renewable penetration using Equation 3 with P_{ren} as the total renewable electrical power output in this time step and L_{served} as the total electrical load served in this time step.

$$p_{ren} = \frac{P_{ren}}{L_{served}} \tag{3}$$

In HOMER, three different energy-based metrics for renewables are implemented (see Table 3). The first metric is the total renewable production divided by load. This refers to the annual load and is usually meant when countries state their renewable goals.

Table 3: Definition of the three different energy-based metrics to describe the renewable penetration of an electricity grid (HOMER Energy, 2020).

Energy-based metrics	Definition	Equation
I Total renewable production divided by load	Relates the total generation of all renewable sources to the annual electricity consumption	$p_{ren\ I} = \frac{AEP_{ren}}{E_{load}}$
II Total renewable production divided by generation	Relates the total generation of all renewable sources to the total generation all energy sources	$p_{ren\ II} = \frac{AEP_{ren}}{AEP_{total}}$
III One minus total nonrenewable production divided by load	Defines how much of the load is actually served by renewable sources	$p_{ren\ III} = 1 - \frac{AEP_{NG}}{E_{load}}$

The second metric is the total renewable production divided by generation relating it to the total generated electricity, including nonrenewable sources.

The third metric is one minus total nonrenewable production divided by load. This last metric is the best description of the renewable the supply since it determines how much of the load is served with nonrenewable electricity. The goal for an entirely renewable electricity supply is to achieve 100% for this metric, so that no fossil fuels are used anymore. Furthermore, this metric is listed as a constraint in HOMER. In the following chapters, this parameter will be also referred to as the *true renewable penetration* since it defines the actual renewable penetration in each time step over a year. The last two metrics can significantly differ from the first one. If the renewable production is just divided by the load, one gets a higher penetration because the excess electricity is included in the calculation which cannot be used (unless stored/exported). It should be also noted that even though the second and the third metrics appear to be similar, they can differ from each other due to excess electricity, shortages, and losses (HOMER Energy, 2020).

2.2.1. Wind Speed Profile

A key input parameter for HOMER is the wind speed profile. This is of special importance for Rhode Island due to the 1,000 MW planned offshore wind capacity which is about half of the current total nameplate capacity of all installed power plants (Rhode Island Department of Administration: Division of Planning, 2015).

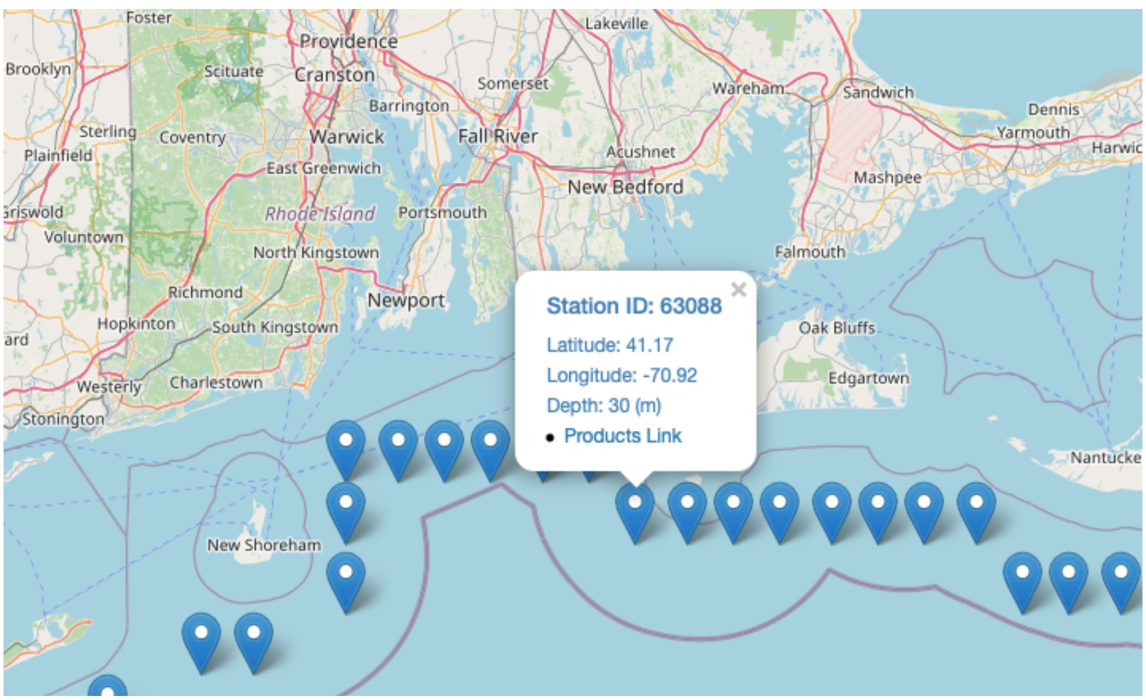

Figure 7: WIS station 63088 at the coast of Rhode Island providing wind speed data in 10m height from (1980-2014) used to create the wind speed profile.

First, the electricity production of the OWF planned to be installed in Rhode Island was calculated manually to verify the calculations processed in HOMER. The manual calculations can be found in the appendix. The annual electricity production is a multiple-step process derived from Hashemi and Neill, 2018. The first step, therefore, is to create a wind speed probability distribution. Wind speed data was obtained by the *Wave Information Study* (WIS) that tracked wind speed data in 34 years.

The stations' location offshore Rhode Island is shown in Figure 7. The wind speed is provided in a height of 10 m above sea level. With increasing height over the sea surface the wind speed increases. For OWF, the wind speed has to be converted to the turbine hub height using Equation 5, in which u_z is the wind speed at height z and u_{10} the wind speed 10m above ground.

$$u_z = u_{10}(\frac{z}{10})^{1/7} \tag{5}$$

The probability distribution function (PDF) of the annual wind pattern can be constructed with Equation 6. It describes the probability of wind speed falling in a specific range between u_1 and u_2.

$$P_r[u_1 \leq u \leq u_2] = \int_{u_1}^{u_2} f(u)du \tag{6}$$

For the purpose of this study, the probability was calculated for each month based on the PDF.

The energy that is theoretically available in the wind P_t can be described by Equation 7, dependent on the wind speed u, the air density ρ and the swept area A. However, only a part of this energy can be transformed in electrical energy P_{el}, determined by the power coefficient C_p. Due to physical limits this coefficient is limited to 59% called the Betz limit (Neill & Hashemi, 2018a).

$$P_t = \frac{1}{2}\rho A u^3 \tag{7}$$

$$C_p = \frac{P_{el}}{P_t} \tag{7.1}$$

The wind turbines used for the OWF *Revolution Wind* will be the 88 SG 8.0 167DD turbines from Siemens Gamesa with a rated power output of 8.0 MW (NS Energy business, 2020). It has a cut in speed of 3 m/s and a cut out speed of 25 m/s and properties shown in Table 4 (Wind-turbine-models, 2019). To achieve a total capacity of 400 MW, 50 turbines are required. It was assumed that the 600 MW OWF proposal will use the same turbine, resulting in further 75 turbines. Since there is no construction height for the turbines published yet, it was assumed that they have a height of 116 m as the same turbines in the *Borssele* OWF in the Netherlands (Offshore-Mag, 2020).

However, the wind turbine database in HOMER does not contain the 88 SG 8.0 167DD. It contains the MHI Vestas Offshore V164-8.0 turbine rated with 8.0 MW with similar properties like the 88 SG 8.0 167DD turbine shown in Table 4. Consequently, this turbine was chosen to replace the SG turbine for the simulated scenarios in HOMER.

Table 4: Properties of the 88 Siemens Gamesa 8.0 167DD and MHI Vestas V164-8.0 offshore wind turbines used for the Revolution Wind farm and simulation in HOMER (Wind-turbine-models, 2021).

Model	SG 8.0 167 DD	MHI Vestas Offshore V164-8.0
Rated Power	8 MW	8 MW
Diameter	167 m	164 m
Swept Area	21,900 m^2	21,160 m^2
Hub Height	116 m	116 m
Rated Wind Speed	12 m/s	13 m/s
Cut-in Wind Speed	3 m/s	4 m/s
Cut-out Wind Speed	25 m/s	25 m/s

To calculate the wind energy production in each month a power curve specified for each turbine is necessary which describes the power output of the turbine for different wind speeds. Since no power curve is published for the 88 SG 8.0 167DD it was manually constructed (see appendix for details). Multiplying the power curve by the probability of different wind speeds in every month results in electricity production for each month (see appendix for results).

HOMER energy requires hourly wind data over an entire year as an input for calculation of energy instead of a PDF, resulting in 8760 single values, one for each hour. To obtain these data for HOMER, hourly averages of wind speed over ten years (2005-2014) were calculated. An hourly wind speed time series was created. After that, HOMER uses the same relationship of power output for certain wind speeds (power curve) to calculate the wind energy production in each time step (one hour). As will be shown in the results (Table 8) and appendix (Figure 34), the calculated AEP of all OWF is about 4,500 GWh using the manual method while the AEP calculated by HOMER is about 4,970 GWh. The difference could be explained by increased wind speed, since HOMER only had data from the latest years while manual calculations were based on a longer period.

2.2.2. Solar Radiation

The solar radiation for Rhode Island is available in HOMER. It uses site specific data from NREL which is shown in Figure 8 for the location of Rhode Island. As expected, the solar radiation is higher in the summer and lower in winter, resulting in more solar power resources in summer.

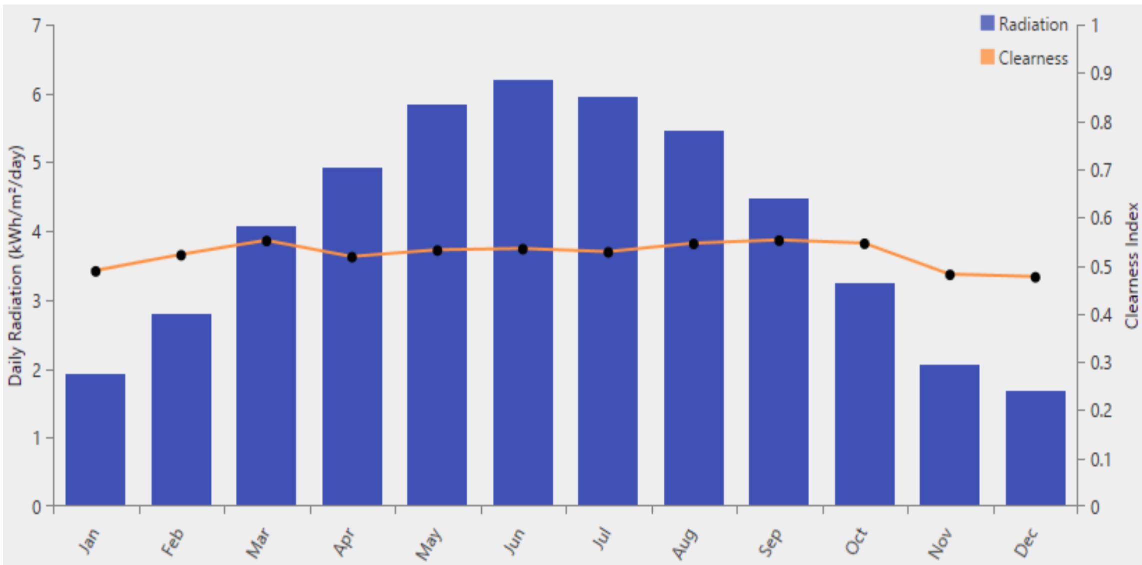

Figure 8: Daily solar radiation averages for each month as GHI for Rhode Island based on NREL databases.

The costs and capacity factors of solar panels varies and depends on the system size. However, it is uncertain how the distribution of small scale and utility scale PV panels will be for Rhode Island in the future. Consequently, a generic PV flat panel given in HOMER was assumed for all solar resources.

2.3. HOMER Energy

The tool for performing this study is the software for Hybrid Optimization of Multiple Energy Resources (HOMER), developed by NREL (Bahramara et al., 2016). It simulates hybrid renewable energy systems (HRES) to determine their optimal size, composition, as well as investment and maintenance costs (Srivastava & Giri, 2016). HOMER is commonly used for rural or remote areas but can also be applied for larger and more complex systems such as Rhode Island (Bahramara et al., 2016). For the purpose of this study, *HOMER Pro 3.14* version was used.

The analysis of HOMER consists of three steps: simulation, optimization, and sensitivity analysis; simulation and optimization are processed simultaneously. During the simulation step, the model tries to find the best system that matches the constraints (Bahramara et al., 2016). Optimization is the core of HOMER and is a tool for decision making. An optimization problem in general can be deterministic or stochastic. For the case of HRES, it is stochastic due to uncertainties of intermittent renewable resources such as wind and solar radiation. Furthermore, the optimization can be static or dynamic. The latter is the case HRES since electricity demand varies over time.

Every optimization problem requires an objective function which will be either minimized or maximized. For HOMER, the objective function is net present cost (NPC). The objective function depends on independent or decision variables illustrated by Equation 8. In this equation f is the objective function and x the decision variables, and Ω the search space.

$$minimize\ f(x_1, x_2, \dots, x_n) \tag{8}$$

$$subject\ to\ (x_1, x_2, \dots, x_n) \in \Omega \tag{8.1}$$

Decision variables can be physical parameters or technical parameters that define the system (e.g., the wind speed). To specify the solution of the optimization, constraints may be used which limit the system outcome to certain conditions. These define properties that have to be respected, otherwise the system is not feasible. Typical constraints for HRES are the renewable penetration or GHG emission.

In general, an optimization algorithm works based on iteration and aims to find the point that minimizes the objective function (see Figure 9). In each iteration, the decision variable vector x_k is updated using Equation 9 in which α is the step size and g is the step direction and (Neill & Hashemi, 2018b).

$$x_{k+1} = x_k + \alpha_k g_k \tag{9}$$

As mentioned, the objective function f in HOMER is the net present cost (NPC), which is defined as all costs of the system configuration, including investment, operation and maintenance cost, and replacement costs are summarized to a single value at the present. This objective function needs to be minimized. For a simulation, HOMER requires six different input data: meteorological data, load profile, equipment characteristics, search space, economic data and technical data. These input data are the independent/decision variables describes previously. A typical constraint in HOMER, besides meeting the electric load, is the renewable fraction. The latter is especially important for this study and defines the share of renewables matching the load and limit the scenarios regarding the production of fossil fuel generators (Neill & Hashemi, 2018b; Bahramara et al., 2016).

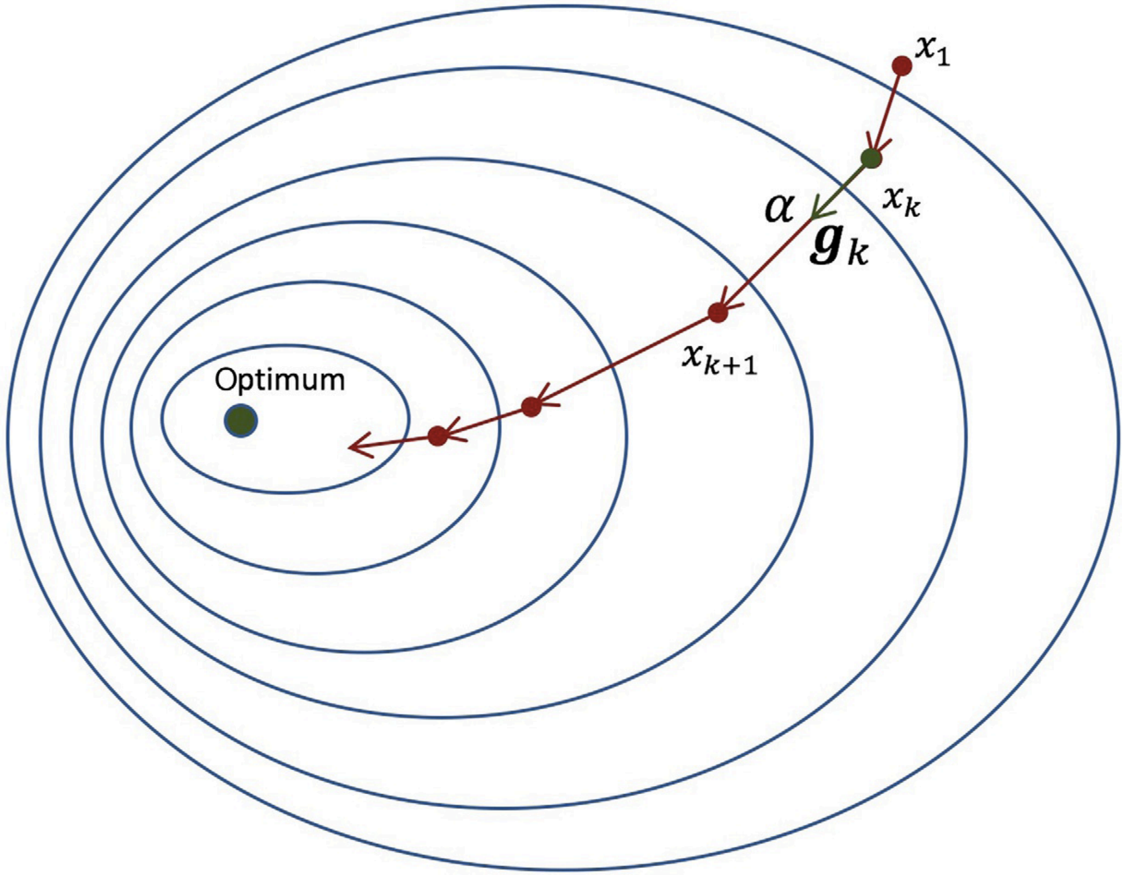

Figure 9: Two-dimensional schematic of optimization using iterative gradient techniques (Neill & Hashemi, 2018b).

The last feature of HOMER energy is the sensitivity analysis. It allows to deal with uncertainties in the parameters by giving them a range of values that will be simulated. Typical parameters therefore are a changing fuel price or interest rate. For this study, the electric load will be varied, resulting in base load for the predictions of the Rhode Island Office of Energy Resources (RI OER) and a high load case based on the statistical analysis of the electricity demand. In other words, the sensitivity analysis helps to assess the impact of changing circumstances (Bahramara et al., 2016).

2.4. Cost Consideration

The transition towards renewable energy and HRES is always related to cost with expenses. To assess the cost of these systems and compare them with existing conventional power plants, several economic parameters exist. The most common ones are the net present cost (NPC) and the levelized cost of energy (LCOE). NPC plays a central role for assessing HRES. It represents all costs of a system accumulated over its lifetime, including investment, operation and maintenance (O&M), and replacement cost which are converted to the present value taking into account the interest rate. The NPC can be described by Equation 10 where *TAC* is the total annual costs and *CRF* the capital recovery factor (Bagheri et al., 2019):

$$NPC = \frac{TAC}{CRF} \tag{10}$$

$$CRF = \frac{i * (1 + i)^n}{(1 + i)^n - 1} \tag{10.1}$$

The *NPC* is also the objective function of HOMER that will be used for the purpose of this study. Therefore, it plays a key role in the optimization process and is base of planning and decision for decision makers.

The LCOE is especially useful when different types of technology are compared because it relates their costs to their annual energy production (AEP). The simple LCOE formula is given by Equation 11 in which present investment cost is P_I and operation and maintenance cost is $C_{O\&M}$. LCOE is the average cost per produced kWh over the lifetime of the system or technology, respectively (NREL, 2021):

$$LCOE = \frac{P_I * CRF + C_{O\&M}}{AEP} \tag{11}$$

Due to the maturity and lower costs of foundations for onshore wind the LCOE is low compared to offshore wind. Offshore wind tends to be less expensive in the UK than in the US because of years of experience and other environmental factors. The cost for solar PV varies dependent on the system size. Utility scale solar tends to be less expensive than residential scale. It should be noted that all costs are estimates.

Based on the cost estimates from Table 5, the assumed costs in Table 6 were used for the simulation in HOMER. However, for the final scenario created in HOMER which aims to give investment recommendations a sensitivity analysis was performed to account for variations in capital costs.

Besides the costs of different technologies, the interest rate has shown to be a significant factor for the NPC of HRES (Bagheri et al., 2019). For the purpose of this study, an interest rate of 8% was chosen, representing a typical value of offshore wind systems in the US which make the majority of the expenses for Rhode Island (Grant Thornton, 2019).

Table 5: Cost components of renewable energy systems based on different resources used for the cost assumptions for the models including LCOE, CAPEX and OPEX.

Turbine/PV Panel Reference	LCOE [$/MWh]	CAPEX [$M/MW]	OPEX [$k/MW/yr]
Onshore Wind			
2.4 MW Onshore (Stehly & Beiter, 2019)	42	1.5	44 000
5.5 MW Onshore (Stehly & Beiter, 2019)	89	4.4	129 000
NREL Wind 1-10 MW updated 2016 (NREL, 2016)		2.0 – 3.0	20 000 -50 000
Offshore Wind			
UK Average Offshore (Bosch et al., 2019)	65 - 70	4.0 – 4.5	60 000 – 10 0000
5.5 MW Offshore Stehly & Beiter, 2019)	132	5.4	137 000
Fixed Bottom Offshore in NA online 2030 (Wiser et al., 2021)	60 - 80		
British Offshore Wind 2030 (Guide to an offshore wind farm, 2019)	35 - 55	3.3	105 000
Offshore Wind Farm approved for MA, USA (Sherman et al., 2020)	75		
Solar PV			
NREL PV Panel small scale < 100 kW (NREL, 2016)		2.5 – 5.0	0 – 40 000
NREL PV Panel large scale < 10 MW (NREL, 2016)		1.5 – 3.0	5 000 – 35 000
NREL Utility scale Panel in 2019 (Walker et al., 2020)			13 000 – 25 000
Residential PV 3 – 10 kW (Fu et al., 2018)		2.7	
Commercial PV 10 kW – 2 MW (Fu et al., 2018)		1.8	
Utility-Scale PV > 2 MW (Fu et al., 2018)		1.1	
Li-ion Battery			
Hornsdale Battery Reserve (Hornsdale Power Reserve, 2021)		0.64 [$M/MWh]	

Table 6: Assumed capital and O&M costs for the HRES components simulated in HOMER models based on value ranges in Table 4.

Turbine Reference	CAPEX [$M/MW]	OPEX [$k/MW/a]
Onshore Wind	2.5	40,000
Offshore Wind	5.0	100,000
PV Panels	2.5	20,000
Li-ion Battery [per MWh]	0.7	10,000

2.5. Renewable Mix Scenarios in HOMER

To analyze the electricity supply of Rhode Island from different perspectives, several electricity mix scenarios were created and modelled in HOMER as illustrated in Figure 10 as follows: The first model to be implemented in HOMER is the current electricity mix of Rhode Island (2020) with most of the capacity provided by the existing natural gas power plants. The purpose of this simulation is to test and verify the model for a known case in which the demand is met by the supply. To do so, the results of this simulation are compared to official data for Rhode Island. It contains about 2,000 MW of natural gas capacity, 75 MW of wind energy, including the Block Island wind farm and 470 MW of solar energy. The varying decision variable is the natural gas capacity.

In the second scenario, the model with exclusively offshore wind and natural gas was built to investigate the effect of offshore wind energy on the system. Therefore, the decision variable is the natural gas capacity using the search space. The offshore wind capacity is set to the total capacity of 1,030 MW, which is proposed for the year 2030, including Block Island, Revolution Wind and further proposed capacity of 600 MW. Onshore wind is not considered in this model since the development potential in Rhode Island is very limited (Murphy et al., 2020).

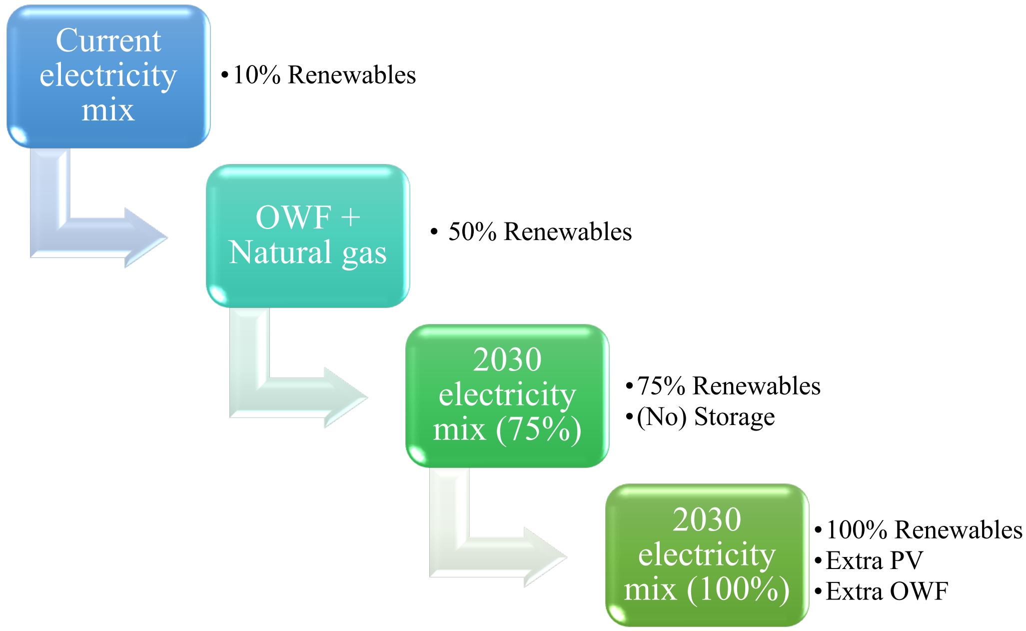

Figure 10: Illustration of the created scenarios and models in HOMER with varying shares of renewable penetration.

The third model represents the electricity mix that is expected by the RI OER in the year 2030. It contains the existing renewable energy source of the first model together with the offshore wind sources from the second model. Additionally, 220 MW of onshore wind and 470 MW of solar PV are added (The Brattle Group, 2021). Again, the decision variable is the natural gas capacity in the search space.

In a second step, Li-ion batteries will be added to the third model to investigate how storage can help the system to reduce natural gas capacity and increase renewable penetration. For this modification, the battery size is added to the decision variables with the HOMER optimizer. Figure 11 shows the HOMER interface of the electricity mix expected by 2030 with storage as an example. On the left side under schematic the system architecture can be seen, including wind turbines and PV panels, and battery storage.

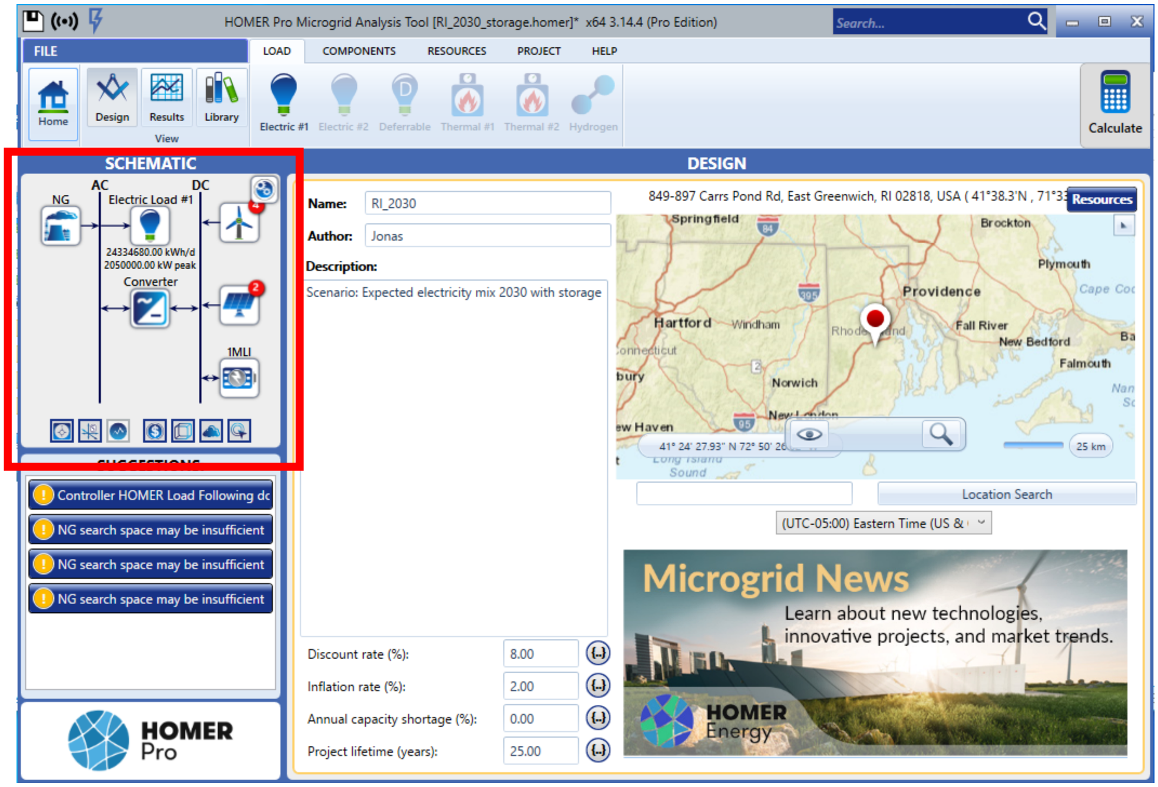

Figure 11: HOMER Energy Pro version 3.14.4 interface example of the model for the expected electricity mix in 2030 for Rhode Island with storage and the system architecture including natural gas generator, system converter, wind turbines, PV panels, Li-ion battery to match the electric load.

The fourth model has the same preconditions and settings as the previous one but aims to add solely offshore wind on the one hand or solar PV on the other hand until 100% renewable electricity supply can be achieved. It will be distinguished between annual (total renewable generation divided by load) and true (one minus nonrenewable generation divided by load) renewable penetration. It will also present cost estimations for further developments.

Lastly, a model with the conditions of 2030 and the most efficient combination of further renewables and batteries will be simulated and optimized. This aims to be a valid recommendation for the electricity supply plans of Rhode Island. For this last model, as well as for the previous one, a sensitivity analysis of the cost component will be performed to account for variations in price developments and give flexibility in the decision-making process. The decision variables for these models are the natural gas capacity as search space and the system size of wind turbines, PV panels, and battery string size. The true renewable penetration is the constraint limiting the feasibility of the systems.

2.5.1. Model Assumptions

The project lifetime of all scenarios was set to 25 years which is a typical lifetime for HRES (Grant Thornton, 2019). The costs components including the discount rate and average costs for renewable technologies presented in Chapter 2.4. are used for the first scenarios. However, for the 100% renewable scenario, a sensitivity analysis will be performed to account for variable and uncertain costs of renewables in the future and give a range of recommendations.

The natural gas power plants of Rhode Island are represented by generic large natural gas generators. The capacities of the real power plants are accumulated and used as an input for the generator search space (see appendix Table 17 for details). A constant natural gas price of 0.300 $\$/m^3$ was assumed (EIA, 2021c). For the cost consideration, it is important that the generators were assumed to have a lifespan of 15,000 hours after which a replacement of 300 $/kW is necessary; additionally to 0.01 $/operation hour as O&M costs.

Except for the first model, the created load profile presented in Chapter 3.1. is used in all scenarios covering a high load case and base load case as expected by the RI OER (Murphy et al., 2020). It represents the demand of RI and does not distinguish between the different sectors, such as industrial, commercial, or residential.

The created wind speed profile presented in Chapter 3.2. is used for all scenarios. Nevertheless, only one wind speed profile can be used as an input in HOMER, although wind turbines are spatially distributed in onshore and offshore zones. Consequently, onshore wind turbines had to be converted to offshore wind turbines with lower capacity due to higher wind speed (see appendix for details Table 18). PV panels will be not distinguished between small-scale and utility-scale. Both renewable energy sources, wind and solar are assumed to have a DC output. This requires a converter on the other side for a conversion into AC. This setup was chosen to account for the final grid and infrastructure costs of the renewable energy system, especially for OWF. The standard converter of HOMER was used.

For this study, the electricity grid of Rhode Island is assumed to be closed and separated from the New England grid, meaning that no imports or exports are considered. This is due to uncertainties in electricity price fluctuation and to investigate what happens within the grid itself. In reality, the electricity grid of New England connects all states and can balance shortages where they occur, and electricity can be purchased wherever it is cheaply produced. Furthermore, this means that excess electricity cannot be utilized in the models unless it is stored.

Currently, Rhode Island possesses a biomass power plant capacity of about 40 MW (EIA, 2021d), mainly operated with landfill gas. However, simulating biomass requires an additional add-on for HOMER. Since the proportion of this biomass capacity is relatively low and is not expected to significantly increase soon (Murphy et al., 2020), biomass is neglected in the following simulation and analysis.

Another potential renewable energy source is hydropower. However, it is not expected that the installed capacity of these plants will exceed 13 MW(RI OER, 2016). Due to this small amount it was omitted by the RI OER for its brattle report and as well for this study (Murphy et al., 2020). New England plans to import hydropower from Canada in the near future. Since it is unclear how much of this energy will be available for RI it was neglected (Hydro Review, 2021).

Cost estimates of the scenarios are limited to new installations in the future since the capital costs of existing renewable systems are not published. This study only considers the cost estimates for upcoming projects and O&M for existing projects.

It should be noted that in HOMER, the only constraint regarding renewable penetration is one minus total nonrenewable production divided by load metrics (true renewable penetration). This is the reason why some of the following considerations regarding 100% renewable fraction of the annual load are not exactly 100% but differs slightly.

Chapter 3

3. Results

The following chapter presents the results of this study. It starts with the analysis of the input data of load and wind speed profile that were carried out for HOMER followed by the results of the model scenarios.

3.1. Rhode Island Load Profile

Figure 12 shows the average load per month based on the mean in comparison to the upper 95% confidence interval from Figure 13. Note how the means of the boxplots in Figure 13 are slightly lower than the averages of the years analyzed in Figure 12 due to the use of confidence intervals. One can also see the decline of annual electricity consumption since the bars for 2019 are lower than previously for 2015.

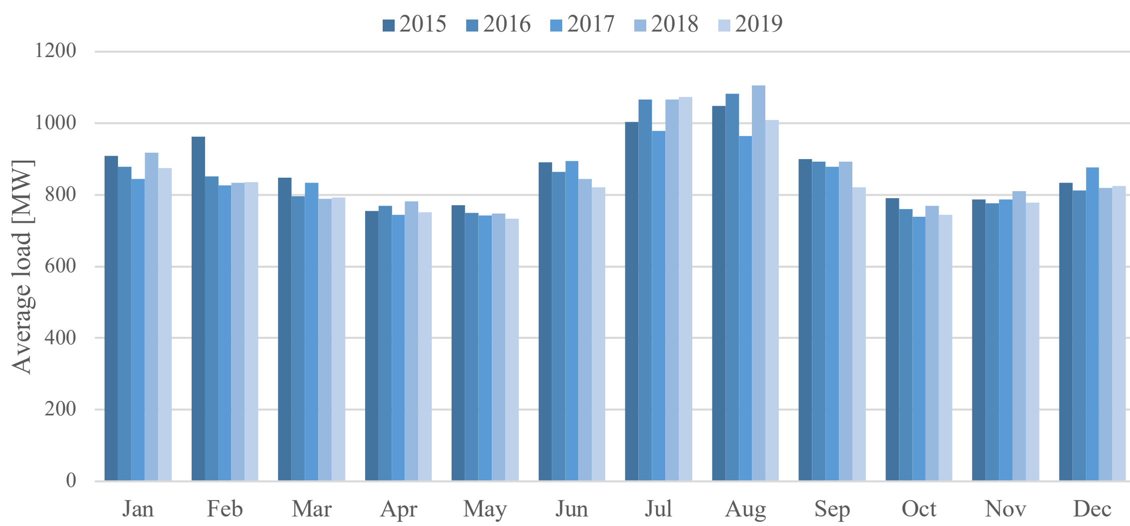

Figure 12: Average Load in MW on the electricity grid of Rhode Island in each month from 2015-2019 based on EIA data with slight decrease of the demand until 2019 and annual loads of: 2015: 7,640 GWh; 2016: 7,520GWh; 2017: 7,380GWh; 2018: 7,580 GWh; 2019: 7,350 GWh (EIA, 2021a).

Figure 13 shows the upper 95% confidence interval (high load case) of the hourly load profile of Rhode Island with a monthly resolution based on data from 2015-2019. The average load per day is 24,330 MWh, resulting in an annual load of 8,880 GWh. In addition to the high load case, the scaled average of the time series was calculated to be used in the sensitivity analysis in HOMER, representing the base load case of annual 7700 GWh which is expected for the year 2030 with an average daily load of 21,100 MWh (Murphy et al., 2020). The load is higher in the summer months due to higher electricity demand needed by air conditioners due to higher temperature in the summer. Not only the load is higher in summer but also the load range is wider, as it can be seen by the size of the boxplots. This is due to temperature variations caused by heat waves that require a lot of electricity and moderate weather when not much air condition is needed.

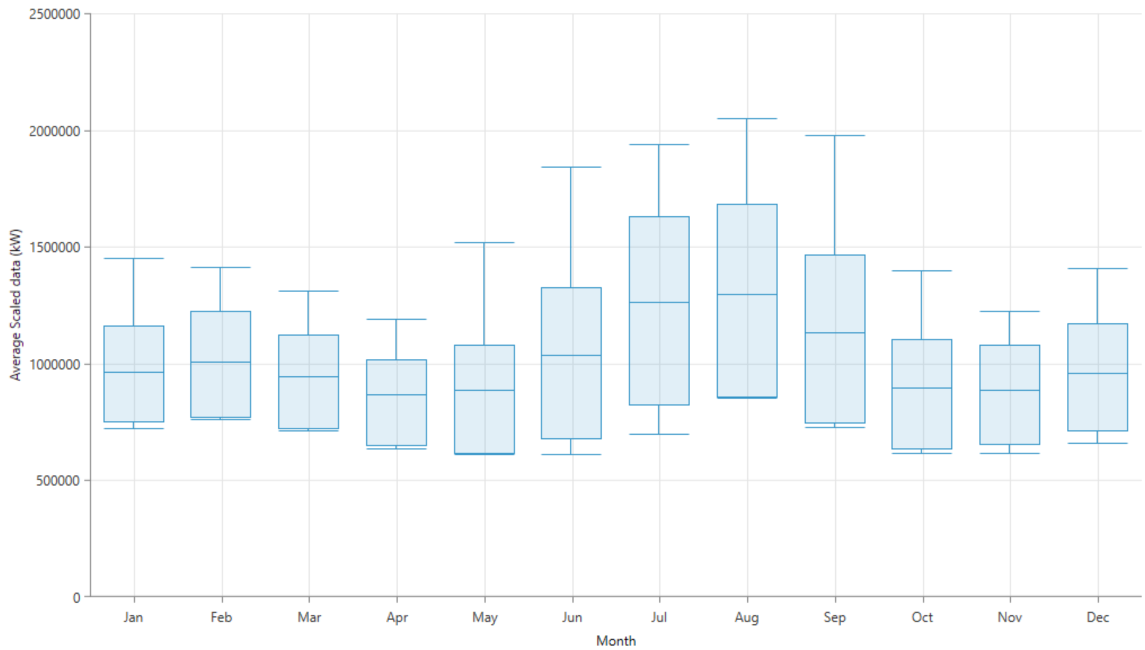

Figure 13: Upper 95% confidence interval of monthly electricity load of Rhode Island based on ISO data from 2015-2019 representing the high load case of 8,880 GWh annual electricity demand with 600 MW baseload and 2,050 MW peak load created in HOMER.

The load profile of Figure 13 has a baseload of 600 MW and a peak load of 2,050 MW, resulting in a load factor of 50% compared to the average load of about 1,000 MW.

For the load profile, the assumption was made that every day within a month has the same daily profile due to uncertainty in the forecast. This basically means that a typical day for each month was created and assumed to be constant over the course of the month. However, these profiles are scaled over the year as shown in Figure 14, showing the daily load profiles of each month. Additionally, a peak load based on the monthly peaks of the analyzed ISO data series was manually added to every 15th of a month. This should account for interannual peak loads. The highest peak, however, occurs in August with 2,050 MW, as mentioned previously. Similar to Figure 13, the daily variations are higher in the summer and flat in the spring and fall when there is moderate climate and low demand for heating or cooling.

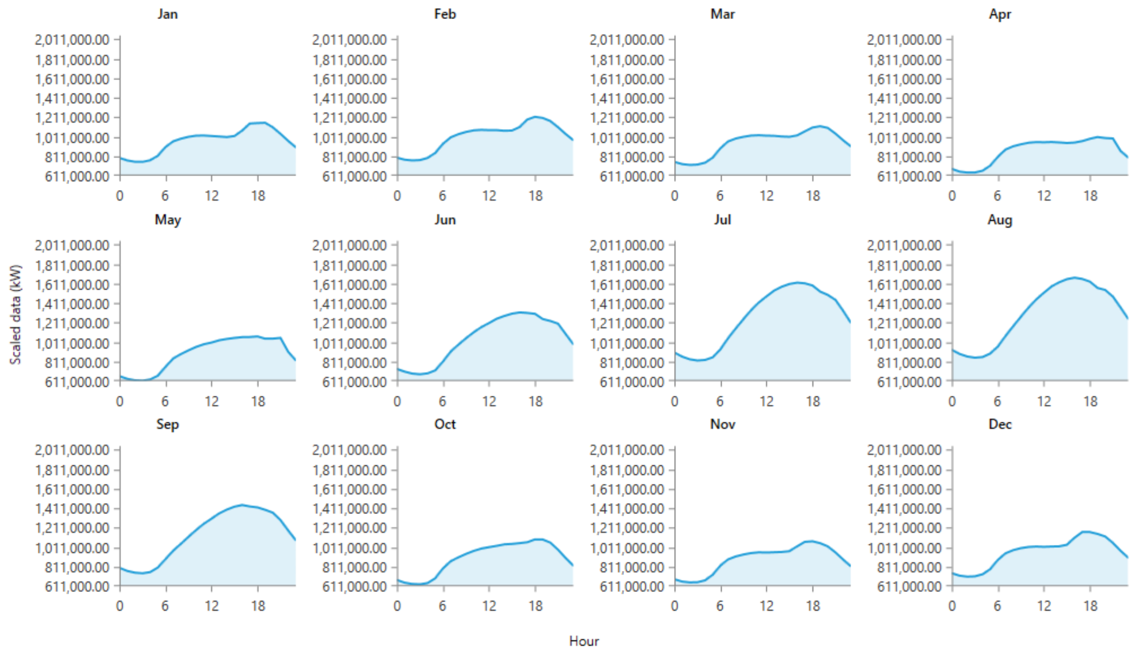

Figure 14: Daily load profiles of 95% confidence interval Rhode Island based on ISO data from 2015-2019 showing the range of the load which is highest in July and August and flat in spring and autumn

3.2. Wind Speed Profile

Based on 35 years of wind speed data, provided by the WIS, the histogram in Figure 15 was created. It shows the probability of different wind speeds in 116 m height, meaning how often they occur. The most frequent wind speed is between 6 and 9 m/s, to be utilized by the 88 SG 8.0 167DD.

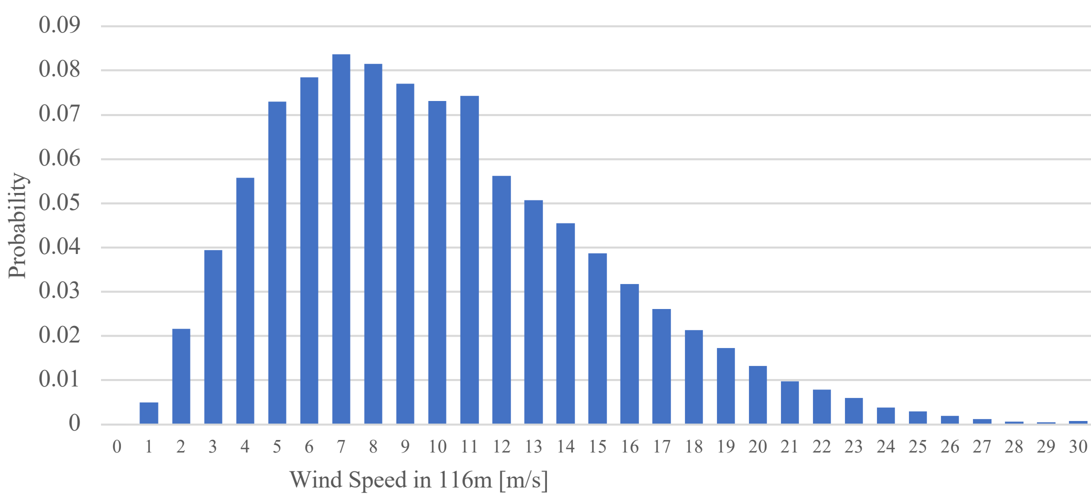

Figure 15: Histogram of wind speeds of past 35 years (1980-2014) at WIS station 63088 off the coast of Rhode Island used for hand calculation (see appendix) 116m above sea level with the probability on the ordinate.

For HOMER, an hourly time series is required. The resulting wind speed averages in 10 m height for each month are shown in Figure 16 with an annual average of 7.35 m/s. HOMER converts the wind speed to the turbine hub height using Equation 5. Wind speeds are highest during winter months and lowest in the summer. This characteristic leads to an increased wind energy production in the winter.

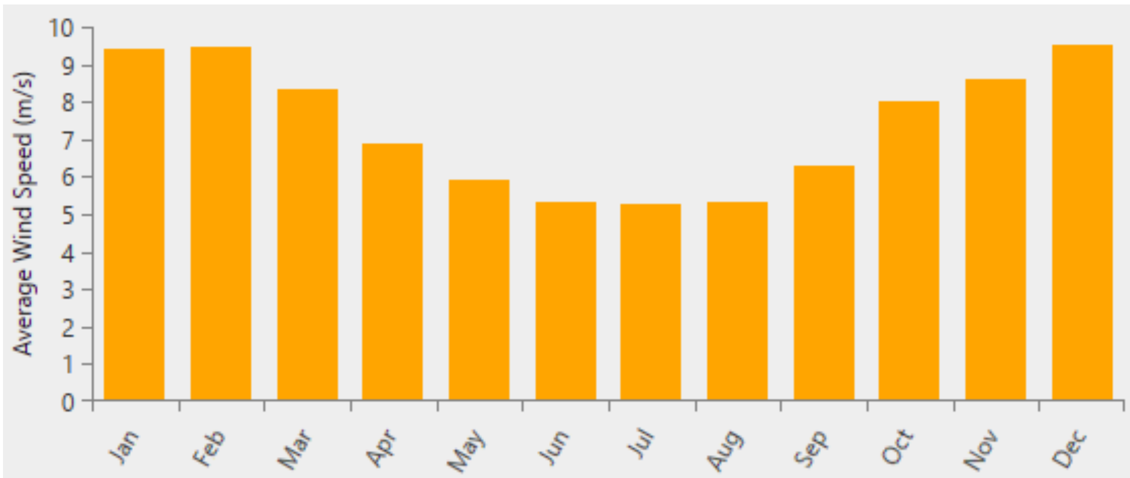

Figure 16: Monthly Averages of wind speed of the years WIS station data from 2005-2014 in 10m above sea level used as HOMER input with an annual average of 7.35 m/s.

3.3. HOMER Models and Analysis of Scenarios

The following section presents the key findings of the models simulated in HOMER as shown in Figure 10. It should be noted that only the most significant aspects are presented to keep the findings clear, though the simulations lead to many results that can be discussed in further detail.

3.3.1. Current Electricity Mix 2020

The model of the current electricity mix was simulated with the latest load profile of 2019, provided by the ISO NE and the generated wind speed profile from Chapter 3.2. Table 7 shows the simulation results of the components for generation and consumption illustrated in Figure 24. The monthly electricity production is shown in Figure 17, where natural gas is the dominant part.

Although the total natural gas power plant capacity is about 2,000 MW, only 1,740 MW are necessary to match the load of 2019. The renewable fraction is around 10% for both the annual and the true fraction due to the low amount of excess electricity. This is coherent to the official numbers of the RI OER, stating that 10% are coming from renewables (EIA, 2021a).

Table 7: Electricity production and consumption of the current electricity mix of Rhode Island for the load of the year 2019 with natural gas capacity as decision variable.

Component	Capacity [MW]	Production/Consumption [GWh/yr]	Share [%]
Annual load		7,720/7,700	
Natural gas	1,740	6,960	89.8
Solar PV	400	550	7.1
Wind (Onshore + Block Island)	75	230	3.1
Excess electricity		20	0.2
Renewable generation divided by load		780	10.3
One minus nonrenewable generation divided by load		740	9.6

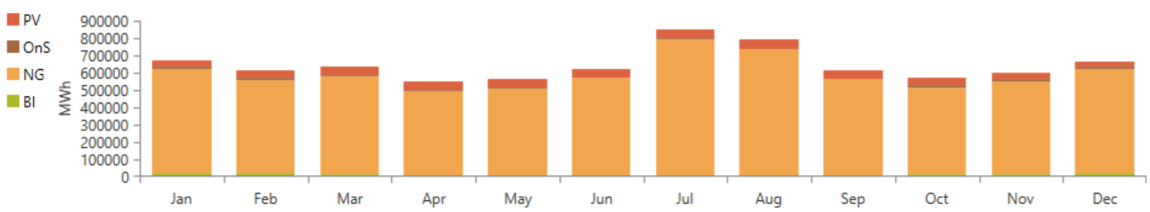

Figure 17: Monthly electricity production of the current RI electricity mix to match load data from 2019. PV = 400 MW solar PV; OnS = 45 MW onshore wind; NG = 1,740 MW natural gas; BI = 30 MW Block Island wind farm.

Since the resources for renewables are free, the only significant cost component in this scenario is fuel in the form of natural gas (in addition to initial cost and O&M cost). Assuming a constant natural gas price of 0.3 $/m^3 (EIA, 2021c) the annual costs for natural gas fuel are about $574 M. Together with replacement and O&M costs components the total annualized costs for the natural gas generators are about $1,015 M. This results in total NPC of about $13 B (see Figure 25). The caused CO_2 due to the burning of fossil fuels emissions are 3.7 M t CO_2/yr (see Figure 26)

3.3.2. Natural Gas and Offshore Wind

In the second scenario, the model with exclusively offshore wind and natural gas was built to investigate the properties and intermittency of the OWF generation and in which ways natural gas is still necessary to support the wind energy production. The OWF capacity is set to the total capacity of 1,030 MW, which is proposed for the year 2030, including Block Island, Revolution Wind and further 600 MW. Figure 18 presents the monthly electricity production of the model. The offshore wind production peaks in the winter months when wind speeds are highest and becomes low in summer when most of the load needs to be served by natural gas.

Table 8: Electricity production and consumption of the natural gas and offshore wind electricity mix of Rhode Island for the high load case of 2030 with natural gas as decision variable

Component	Capacity [MW]	Production/Consumption [GWh/yr]	Share [%]
Annual load		10,600/8,880	-
Natural gas	1,740	5,630	53.1
Offshore wind	1,030	4,970	46.8
Excess electricity		1,550	14.6
Renewable generation divided by load		4,970	56.0
One minus nonrenewable generation divided by load		3,250	36.6

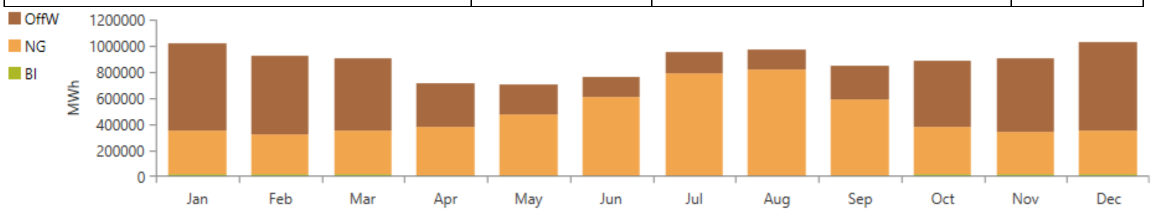

Figure 18: Monthly electricity production of the natural gas and offshore wind model to match the high load case. OffW = 1000 MW offshore wind; NG = 1,740 MW natural gas; BI = 30 MW Block Island wind farm

Table 8 shows the generation and consumption properties of the high load case for 2030 of solely natural gas and offshore wind, as illustrated in Figure 24. The majority of energy is still coming from natural gas, but offshore wind can serve up to 56% of the annual load. This fraction increases to 64.3% for the base case while the true renewable penetration remains around 36%. However, for the high load case, a natural gas capacity of 1,740 MW is mandatory due to the peak loads in August that exceed the 2,000 MW (see Figure 13) and the OWF operate at reduced capacity. For the base case, a natural gas capacity of 1,638 MW is sufficient due to lower peak loads in summer.

Figure 19 shows the natural gas power output and the renewable penetration per time step. For most of the year, a natural gas capacity of 1,000 MW (green areas) is sufficient. Just during summer afternoons, additional capacity reserves are necessary to match the demand. In contrast, offshore wind can supply almost the entire load over the winter. Here, a natural gas capacity of 400 MW (black areas) is sufficient. The maximum renewable penetration occurs in winter nights when the electric load is low and wind speeds are high. Since there is no storage in this scenario, this behavior results in large amounts of excess electricity making up to 15% of the annual production (see Table 8).

In comparison to the current mix, the annual fuel expenditures could be reduced by 17% to \$476 M (see Figure 22), similarly to the CO_2 emissions which can be reduced to 3.0 M t CO_2/yr, as shown in Figure 26. The total costs of the natural gas generators per year are \$918 M. Even though the NPC of the entire offshore wind is about \$6.3 B due to the high capital costs of \$5 B (see Figure 25), the annual cost of offshore wind is still lower than natural gas by $487 M. Compared to the current electricity, mix about $100 M natural gas expenses could be saved per year through the OWF installation. With the cost assumptions made previously, the offshore wind would have a LCOE of 101 $/MWh.

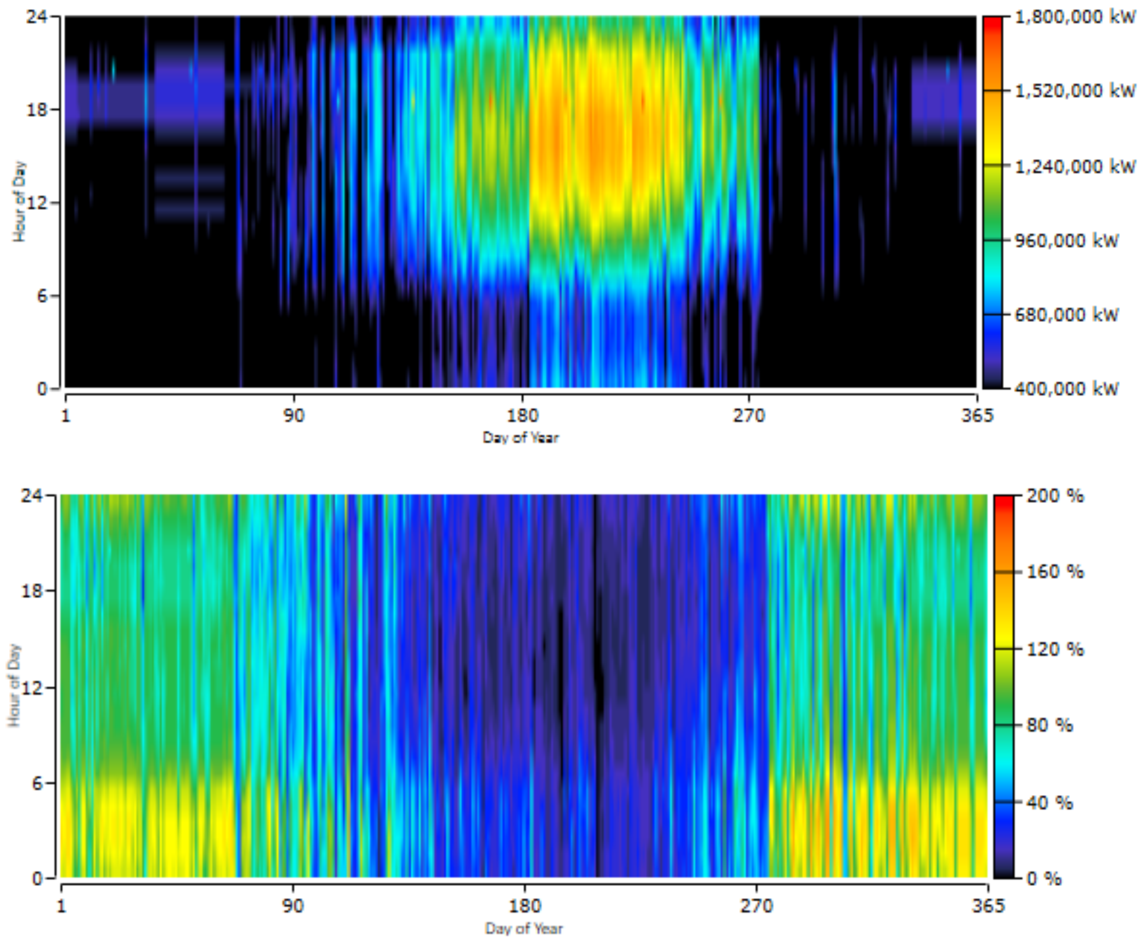

Figure 19: DMAP (dmap) of the natural gas generator power output (top) and renewable penetration (bottom) for the high load case of natural gas and offshore wind electricity mix. The ordinate describes the day of the year starting with January 1st while the abscissa describes the time of the day starting with 0 as midnight and 12 as noon. Red areas indicating higher generator capacity or renewable penetration, respectively.

3.3.3. Electricity Mix in 2030

The remaining renewable energy sources that are expected to be online by 2030, were added to the previous scenario (The Brattle Group, 2021). With the additional renewable production of solar PV and onshore wind, the share of natural gas of the electricity production can be reduced to 43% for the high load case (see Table 9). However, the total required natural gas capacity is still 1,740 MW. This is necessary to cover the summer peaks in the afternoon hours when the solar energy production begins to collapse. The base load case needs

1,638 MW of natural gas capacity due to lower summer peaks. However, solar power helps to reduce the demand of natural gas during noon hours (see Figure 21) linked with an increased renewable penetration.

Table 9 Electricity production and consumption of the expected electricity mix of Rhode Island in 2030 for the high load case with natural gas capacity as decision variable.

Component	Capacity [MW]	Production/Consumption [GWh/yr]	Share [%]
Annual Load		11,500/8,880	-
Natural Gas	1,740	5,030	43.0
Offshore Wind	1,030	4,970	42.5
Onshore Wind	265	400	4.2
Solar	870	1,210	10.3
Excess electricity		2,620	22.4
Renewable generation divided by load		6,570	75.1
One minus nonrenewable generation divided by load		3,860	43.3

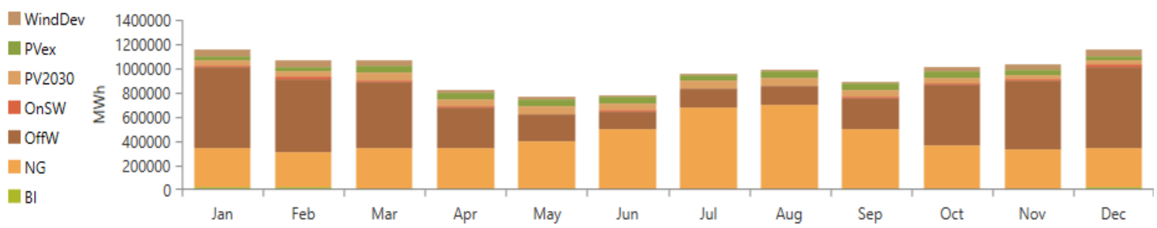

Figure 20: Monthly electricity production of the expected electricity mix by 2030 to match the high load case. WindDev = 220 MW additional onshore wind development until 2030; PVex = 400 MW exisiting solar PV; PV2030 = 470 MW additional solar PV expected until 2030; OnSW = 45 MW existing onshore wind; OffW = 1,000 MW offshore wind; NG = 1,740 MW natural gas; BI = 30 MW Block Island wind farm.

The annual renewable fraction could be increased by 20 percent units up to 75% for the high load case as shown in Table 9 while the true fraction just increased by 8 percent units to 43.3% compared to the natural gas and offshore wind model. For the expected base case of 2030 (7,700 GWh), renewables contribute up to 86.2% of the annual load while the true fraction relative to the production remains the same. The excess electricity reaches almost a quarter of the total annual production. The main reasons for this are noon hours in winter when solar power is added to the high wind resources resulting in high renewable penetration as seen in Figure 21 which is not used due to low AC and electricity demand.

Figure 22 gives an overview of the costs related to the renewable resource that will be added for the proposed electricity mix in 2030. Shown are the annual costs occurring over the project's lifetime of 25 years without salvage credits. Despite the large capital cost of OWF, they are less expensive over their lifetime compared with natural gas while having about the same production amount (see Table 9). This is due to high natural gas fuel costs and replacement costs. The saved fuel costs compared to the current scenario are $141 M/yr. The natural gas power plants emit about 2.8 M t CO_2/yr (see Figure 26), a reduction of about 25% compared to the current mix.

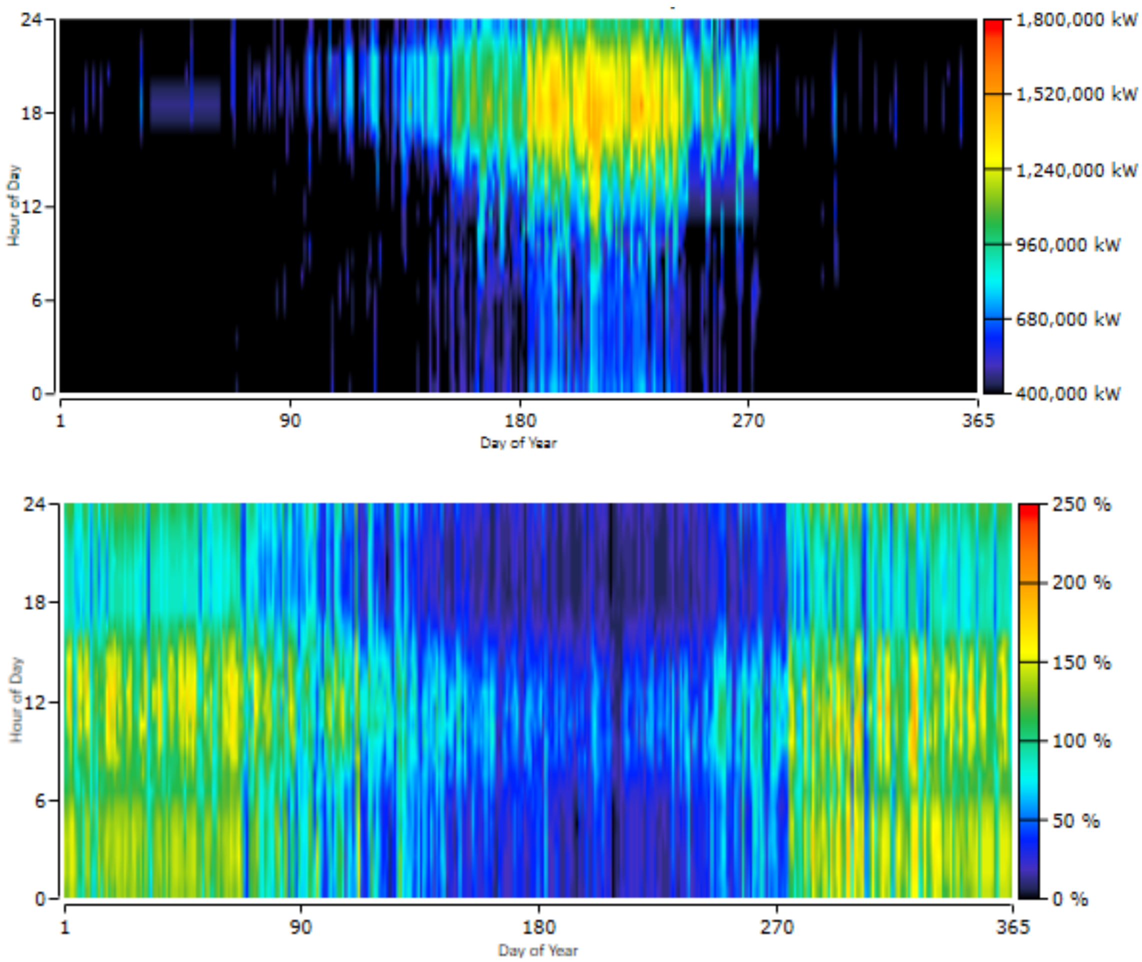

Figure 21: DMAP(data map) of the natural gas generator power output (top) and renewable penetration (bottom) for the high load case of the expected electricity mix in 2030. The ordinate describes the day of the year starting with January 1st while the abscissa describes the time of the day starting with 0 at midnight and 12 at noon. Red areas indicating higher generator capacity or renewable penetration, respectively.

After assessing the existing and planned electricity mixes of Rhode Island, it was investigated how the renewable penetration could be extended to meet the state goals and increase the renewable fraction, installing energy storage to utilize excess electricity. For this study Li-ion batteries were used, represented by generic 1 MWh Li-ion battery strings in HOMER. They are assumed to have a lifetime of 15 years, leading to one replacement over the project's lifetime. Using the costs assumed in Chapter 2.4. Table 10 shows the costs and effects on renewable penetration due to battery storage.

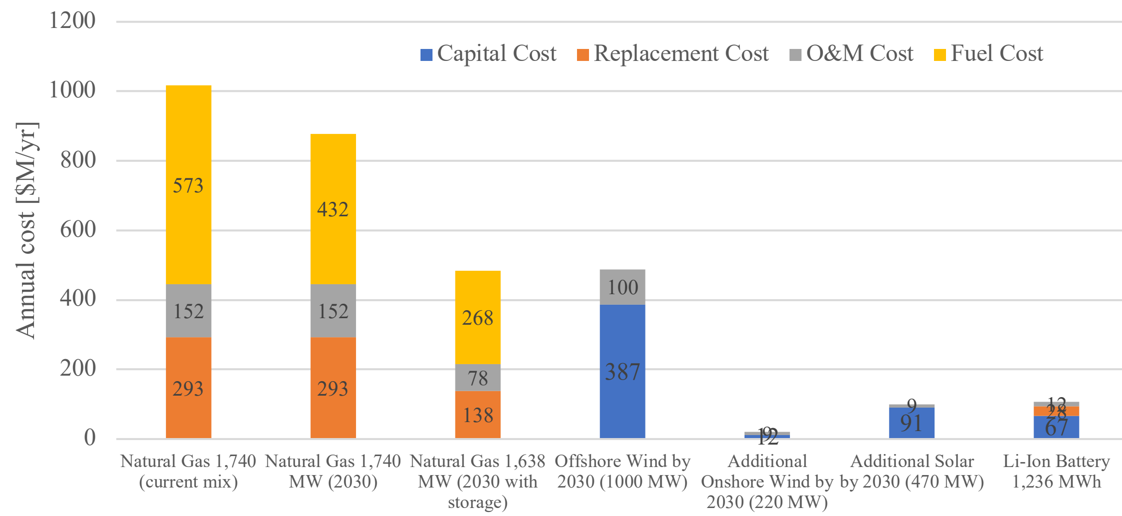

Figure 22: Annual costs components of natural gas and planned renewable energy sources of the expected electricity mix of 2030 in $M without salvage credits.

The 1,236-battery string system was found with the HOMER optimizer, meaning that this system is the most efficient alternative considering NPC. Beyond that, only small improvements in the renewable penetration and reduction of the excess electricity can be accomplished along with savings in fuel costs but with a disproportional and uneconomical increase of battery costs.

Table 10 Effects and costs of additional energy storage through Li-ion batteries for the high load case of the expected electricity mix in 2030 with natural gas and battery size as decision variables. The bolt configuration was found as most efficient size.

Installed battery capacity [MWh]	0	500	**1,236**	1,922	4,640	49,629
Annual throughput [GWh]	0	122	**194**	250	322	433
One minus nonrenewable generation divided by load [%]	43.3	48.4	**63.8**	65	66	67
Excess electricity [GWh]	2,620	2,146	**688**	566	470	365
NPC of batteries [Mio USD]	0	535	**1,320**	2,060	4,970	48,840

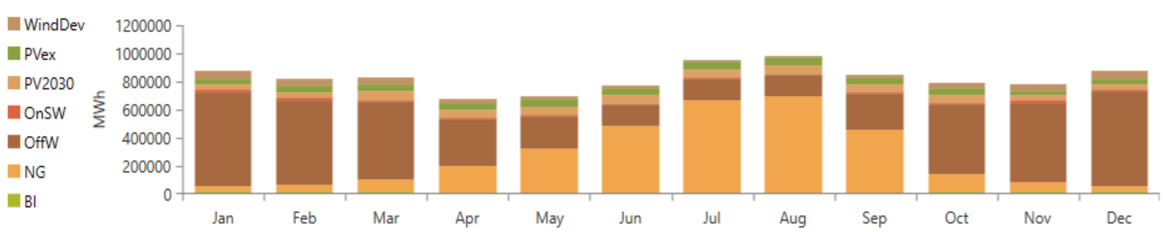

Figure 23: Monthly electricity production of the expected electricity mix by 2030 with energy storage (Li-ion battery with 1,236 MWh) to match the high load case. WindDev = 220 MW onshore wind development until 2030; PVex = 400 MW exisiting solar PV; PV2030 = 470 MW additional solar PV until 2030; OnSW = 45 MW Existing onshore wind; OffW = 1000 MW Offshore wind; NG = 1384 MW Natural gas; BI = 30 MW Block Island wind farm.

In Figure 23, it can be seen how the 1,236 battery strings can help improve the renewable fraction of the monthly electricity production. In the winter months with strong winds, excess electricity can be stored (see Figure 21) and released at another period when the winds are weaker and the demand higher, so that nearly all electricity comes from renewables. The renewable fraction of the annual load, however, does not change since the total renewable electricity amount generated over a year remains the same.

The battery storage helps to decrease the natural gas capacity for the high load case from 1,730 MW to 1,638 MW, and for the base load case even to 1,384 MW. This results in reduced annual cost of all components for natural gas of $482 M/yr, an improvement of nearly 50% ($400 M/yr) compared with the high load case without any storage (see Figure 22 and Figure 25). Furthermore, CO_2 emission could be reduced to 1.7 M t CO_2/yr, which is 40% less than the same scenario without battery storage that emits 2.8 M t CO_2/yr, and 55% reduction compared with current emissions (see Figure 26). These observations are interesting considering the relatively low NPC for the battery installations of $1.3 B helping to avoid NPC of natural gas of $4 B (Figure 25).

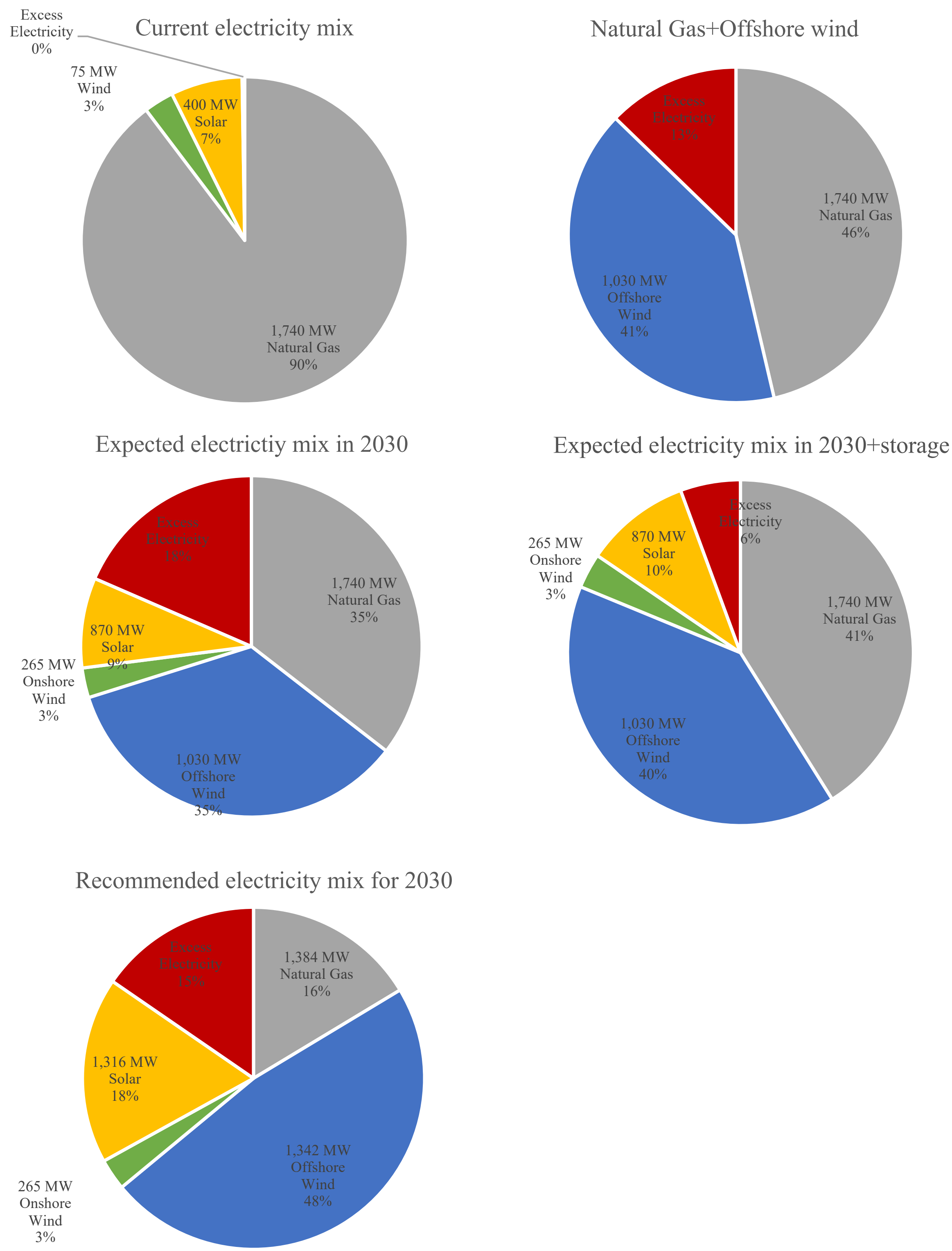

Figure 24: Shares of renewables of the total annual electricity production including excess electricity for different scenarios: Top left: Current electricity mix; Top right: Natural gas and offshore wind; Mid-left: Expected mix in 2030; Mid-right: Expected mix in 2030 with storage; Bottom: Recommended mix in 2030 for 100% renewables.

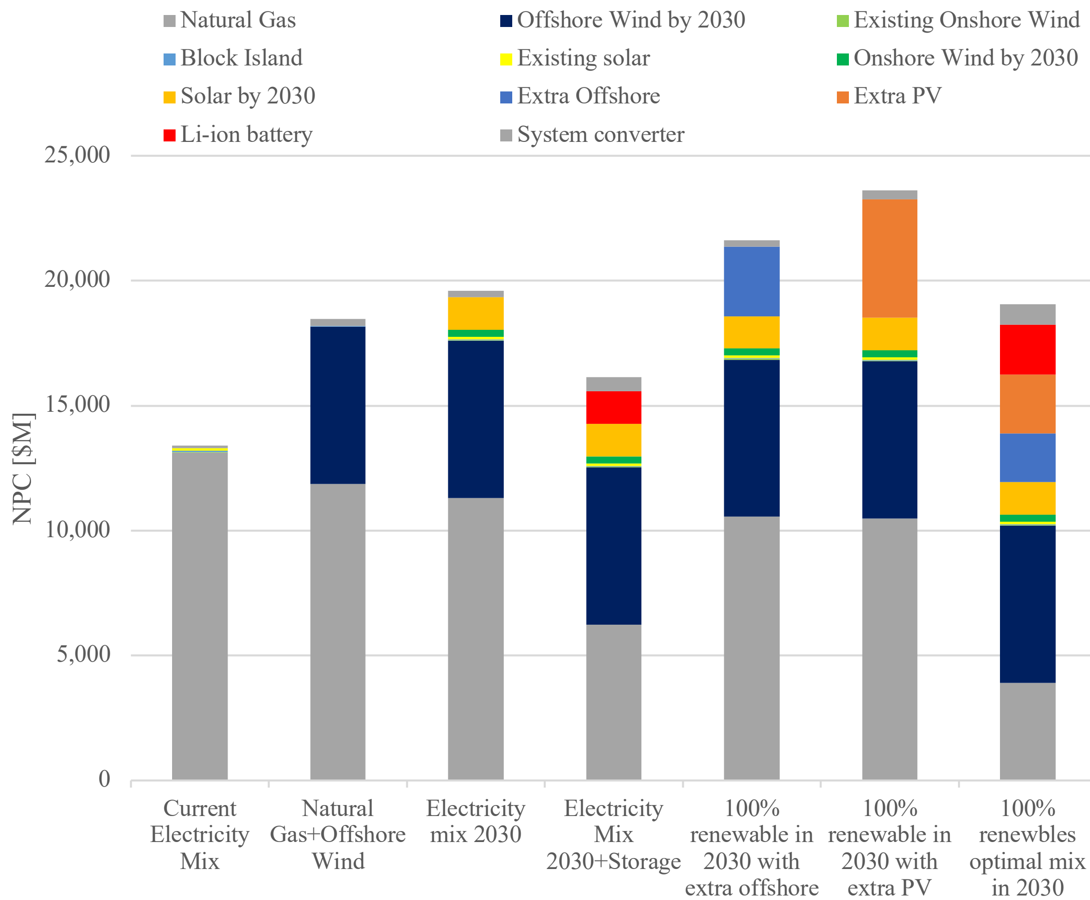

Figure 25: Total net present cost (NPC) of each scenario created in HOMER with the contribution of each component in $M with the expected electricity mix by 2030 with storage as the least expensive alternative compared to the current/original mix.

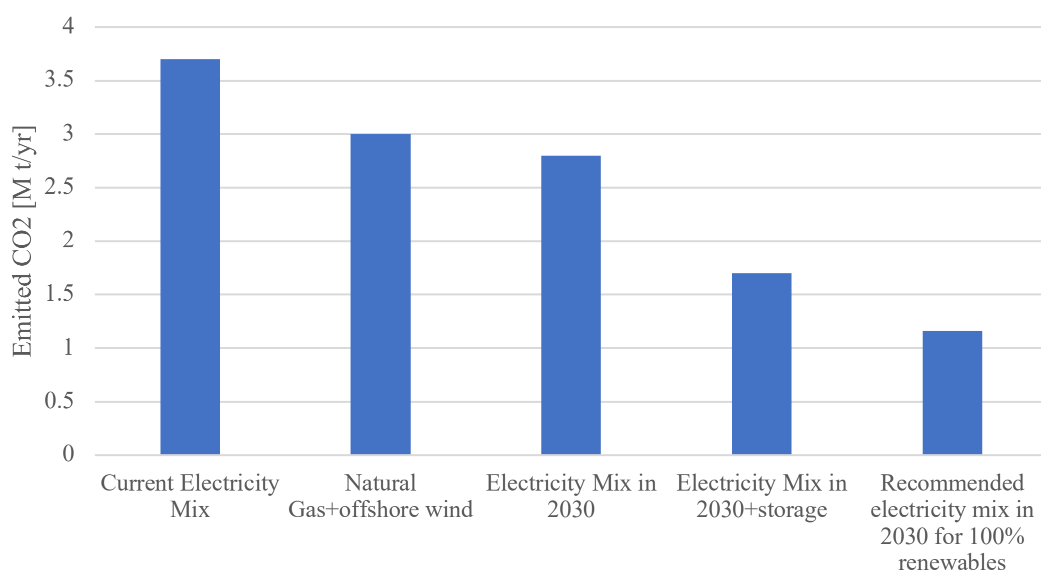

Figure 26: Annual emitted CO2 emission due to natural gas of each scenario in M t CO_2. Best case emission can be reduced by 70% with the recommended electricity mix for 2030 compared to current levels.

3.3.4. 100% Electricity Mix for 2030

Analyzing the renewable penetration in previous scenarios showed that in Model III about 75% for the high load case and 86% for the base load case of the annual electricity comes from renewable source by 2030. Model IV shall show how the gap to 100% renewables can be closed using either further offshore wind turbines or solar PV. In the end, a recommended mix including battery storage will be proposed with minimum NPC.

3.3.4.1. Adding further Renewables

The first scenario for adding further renewables assumes no battery storages and simply adds offshore wind turbines of the same type as the previous offshore wind farms. Table 11 shows the results with respect to the renewable penetration that can be achieved with the appropriate number of turbines. Furthermore, the cost range for the turbines is demonstrated with varying capital costs.

Table 11: System requirements and costs of the 2030 model with additional 8 MW offshore wind turbine to achieve varying renewable penetration degrees with natural gas and wind turbines as decision variables. The base load case could achieve over 100% renewable penetration relative to the annual load by adding 33 further turbines in addition to model III.

Load scenario	High	Base	High	Base	High	Base	High	Base
Additional offshore 8.0MW wind turbines	23	33	**55**	44	73	107	152	111
Renewable penetration divided by load [%]	85.1	103.0	**99.0**	108.0	107.0	140.0	141.0	142.0
One minus nonrenewable penetration divided by load [%]	45.1	45.1	47.5	46.1	50.1	59.9	60.1	60.7
Excess electricity [GWh]	3,350	4,270	4,360	4,620	4,810	5,930	6,930	6,010
NPC [$M] (30 $M capital cost)	930	1,330	2,030	-	2,940	-	6,130	4,480
NPC [$M] (40 $M capital cost)	1,160	1,660	**2,770**	2,220	3,680	5,390	7,650	5,590
NPC [$M] (50 $M capital cost)	1,420	1,990	-	2,660	4,400	6,460	9,170	6,860

Achieving about 100% renewable electricity relative to the annual load could be realized by adding 55 turbines for the high load case and 33 turbines for the base load case. However, to improve the true renewable penetration a disproportionable number of turbines is necessary to improve that fraction by just a few percentages while the excess electricity increases dramatically (see Figure 27). This is because of missing storage and most of the electricity produced in winter when demand is low.

Additionally, only PV panels were added to increase the renewable fraction. The results can be found in Table 12. 100% renewable penetration regarding the annual load can be achieved with about 800 MW additional panel capacity for the base case. For the high load about 1,700 MW are necessary. However, a similar observation to the offshore wind turbines can be made. Therefore, to achieve more renewable penetration with respect to the nonrenewable generation a large amount of extra PV panel capacity is needed to increase the renewable penetration as shown in Figure 27.

Table 12: System requirements and costs of the 2030 model with additional solar PV to achieve varying renewable penetration degrees with natural gas and PV panel capacity as decision variables.

Load scenario	High	Base	High	Base	High	Base	High	Base
Additional PV capacity [MW]	358	813	777	1,672	2,659	4,519	12,871	8,742
Renewable penetration divided by load [%]	80.7	101.0	87.2	116.0	117.0	167.0	276.0	243.0
One minus nonrenewable penetration divided by load [%]	45	45	46	46	50.1	50	60	60
Excess electricity [GWh]	2,960	4,130	3,450	5,190	5,670	8,860	18,880	13,890
NPC [$M] (Capital cost 2,000)	810	1,840	1,750	3,640	6,000	10,200	29,070	19,750
NPC [$M] (Capital cost 2,500)	990	2,250	2,140	4,520	7,330	12,470	35,500	24,120
NPC [$M] (Capital cost 3,000)	1,170	2,650	2,530	5,340	8,660	14,730	42,000	28,500

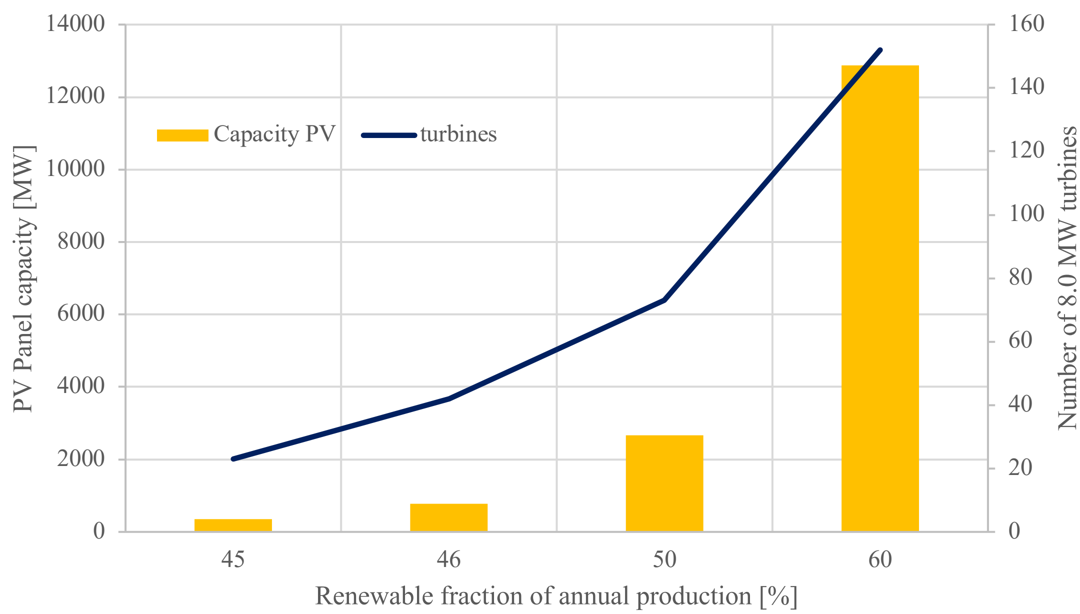

Figure 27: PV panel capacity and number of 8.0 MW offshore wind turbines needed to increase the true renewable penetration (metric III).

For example, if the PV panel and OWF turbine approach for 100% renewable penetration relative to the annual load in the base load case are compared to each other, the offshore wind solution seems to be more economically attractive. This is because $2,250 M for 810 MW PV panels are $600 M more expensive than $1,660 M for 33 wind turbines assuming average values. However, the sensitivity analysis shows that assuming low PV panel capital costs and higher turbine capital costs, the PV alternative would be more cost effective.

3.3.4.2. Recommended Electricity mix for 2030

Lastly, an optimal configuration of renewable energy sources was assessed for Rhode Island. OWF, solar PV, and battery storage were entered into the HOMER optimizer to find the best combination of them. For the natural gas generator capacity, the search space was used (see Table 17 for details). As a constraint the true renewable penetration metrics was set to 75%, resulting in approximately 100% renewable penetration relative to the annual load as seen in Table 13. For the high load case 1,384 MW natural gas capacity is required. Despite large battery capacity of 1,880 MWh, still 18% of the electricity generated will be wasted in excessive electricity.

Table 13: System architecture and electricity production and generation of the recommended high load case scenario of 2030 with 75% renewable fraction as constraint and natural gas, solar PV, wind turbines and battery size as decision variables.

Component	Capacity [MW]	Production/Consumption [GWh/yr]	Share [%]
Annual load		11,410/8.880	-
Natural gas	1,384	2,210	19.5
Offshore wind	1,342	6,430	55.5
Onshore wind	265	400	4.2
Solar	1,716	2,380	21.0
Li-ion battery	1,880	156	
Excess electricity		2,080	18.4
Renewable generation divided by load		9,210	103.0
One minus nonrenewable generation divided by load		6,660	75.1

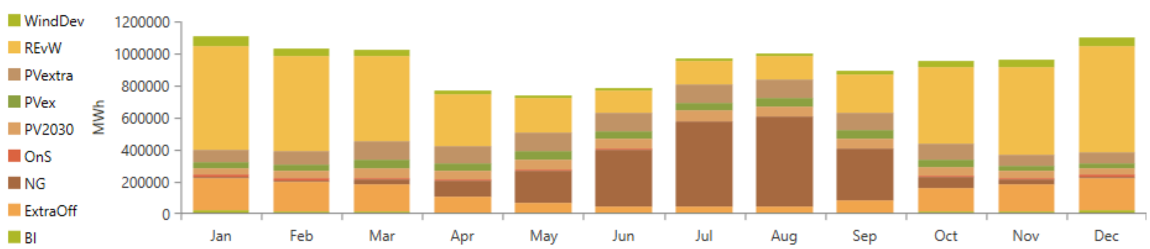

Figure 28:Monthly electricity production of the recommended 2030 electricity mix to match the high load case with 75% true renewable penetration load as constraint and 1,880 MWh Li-ion batteries. WindDev = 220 MW onshore wind development until 2030; RevW = 1000 MW offshore; PVextra = 846 MW solar PV expansion; PVex = 400 MW exisiting solar PV; PV2030 = 470 MW additional solar PV until 2030; OnS = 45 MW Existing onshore wind; OffW = 1000 MW Offshore wind; NG = 1384 MW Natural gas; ExtraOff = 312 MW offshore wind expandion; BI = 30 MW Block Island wind farm.

Assuming average values for the turbines and PV panels, about 312 MW additional offshore wind (39 8.0 MW turbines), about 850 MW PV panels, and 1,880 MWh Li-ion battery capacity is recommended by the HOMER optimizer (see Table 13). However, Table 14 shows how optimal turbine and PV capacity would change dependent on their capital costs. Low-cost turbines and high-cost PV panels would lead to more than double the turbine number and almost no PV panel capacity. On the other hand, high-cost turbines and low-cost panels would result in a slight increase of panel capacity and a decrease in number of turbines.

Table 14: Number of turbines, PV capacity and battery storage capacity of the recommended high load case scenario of 2030 dependent on variable capital cost of offshore wind and solar PV with 75% true renewable penetration as constraint.

Capital Cost for Offshore Wind and Solar	Natural Gas Capacity [MW]	Number of 8 MW-Turbines	PV Panel Capacity [MW]	Li-ion Battery Capacity [MWh]
Average 40 Mio$/turbine 2,500$/kW PV	1,384	39	846	1,880
Cheap Wind 30 Mio$/turbine Expensive PV 3,00$/kW	1,384	90	166	1,183
Expensive Wind 50 Mio$/turbine Cheap PV 2,000$/kW	1,384	36	920	1,820

Figure 28 shows the monthly electricity production. From December until February the supply is entirely renewable with almost no contribution from the natural gas power plants (Figure 29). The only exception is evening hours. The share of natural gas remains insignificantly low during fall (October and November) and spring (March and April) when a natural gas capacity of about 600 MW is sufficient. In the summer months, the contribution of natural gas rises over 50% of the electricity production, especially in July and August.

Figure 29 shows that natural gas is primarily needed in the evening hours of summer past 6 pm. Except for 1,400 MW peaks, indicated in red, a capacity of about 1,000 MW is sufficient. The black areas indicate that during most time in winter no natural gas is necessary at all.

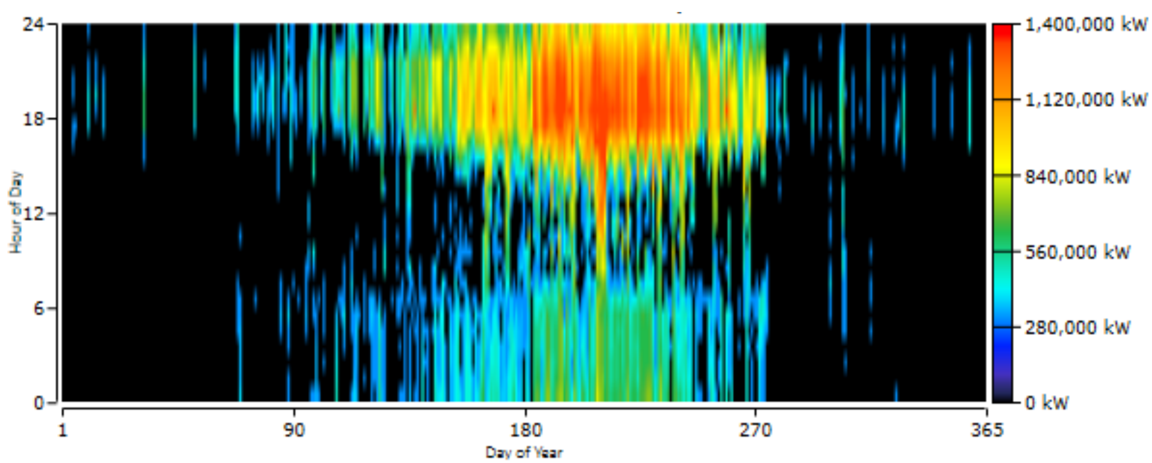

Figure 29: DMAP (data map) of the natural gas generator power output for the high load case of the recommended electricity mix in 2030. The ordinate describes the day of the year starting with January 1st while the abscissa describes the time of the day starting with 0 at midnight and 12 at noon. Red areas indicating higher generator capacity for natural gas.

Figure 30 shows the annual cost components of the current natural gas scenario compared with the recommended scenario for 2030. Moreover, the expansion costs for renewables that will be additionally installed compared to the current mix are presented. It is obvious that the annual costs for natural gas can be reduced to only 1/3 compared to the current mix. The largest cost component of the renewables are the offshore wind turbines due to the sheer amount of turbines (164 turbines) followed by solar PV. The total NPC ($19 B) of the system still exceeds the NPC of the current mix dominated by natural gas ($13 B) (see

Figure 25). Furthermore, the recommended mix is more expensive than the natural gas and offshore wind mix and the electricity mix in 2030 with storage. Nevertheless, the recommended mix brings several advantages since its renewable fraction is way higher. Also, a reduction of CO_2 emission is also realized to 1.16 M t CO_2/yr, a decrease of almost 70% relative to the current mix (see Figure 26).

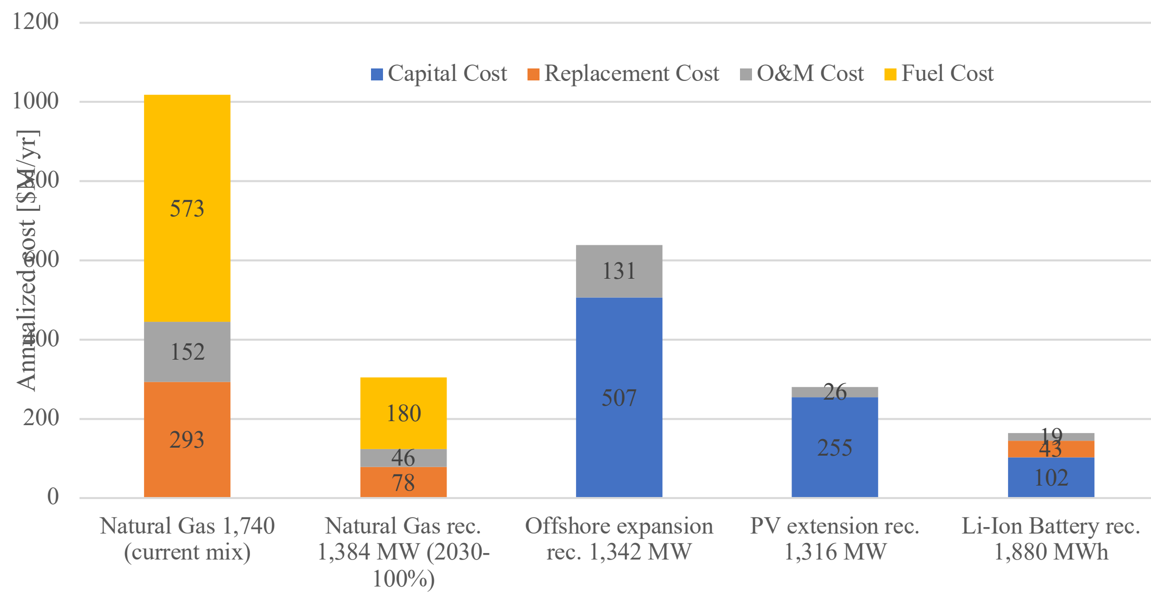

Figure 30: Annualized Cost Components of Natural Gas and recommended renewable energy sources for 100% renewable energy in 2030 in Mio USD over the projects lifetime of 25 years.

Finally, Table 15 summarizes the main results of all simulated models in HOMER which have been illustrated in Figure 25. For easier comparison a cost factor related to the NPC of the current electricity mix was introduced. It can be read from less expensive scenarios on the left more expensive scenarios to the right. The annual cost and LCOE are linked with the NPC and increase to the right, as well.

Table 15 reveals that simply adding one type of renewable technologies is by far the most expensive alternative. They were able to increase the renewable penetration relative to the annual load but achieved very less improvement in the third penetration metrics and in mitigating the contribution of natural gas. This fact underlines the importance of hybrid systems. The more diverse the system, the more efficient it is. This also means that keeping natural gas in the mix reduces costs in the first place, slightly improving the CO_2 emissions.

The models with battery storage are characterized with low natural gas contribution. This results in lower fuel cost and total cost in the end, as well as less emitted CO_2. It should be noted how adding batteries to the expected electricity mix by 2030 decreases the NPC by almost 20% while reducing the CO_2 emission by 40%. Without storage, no model could achieve a natural gas contribution of less than 50%. These observations underline the importance of storage and shows that the cost saving for fuel exceed the costs for renewables and storage. With the end goal in mind of becoming carbon-free, energy storage is indispensable.

Table 15: Summery table of all models with the most important parameters for comparison.

Component	**Current Electricity Mix**	**Electricity Mix 2030+Storage**	**Natural Gas+Offshore Wind**	**100% renewables optimal mix in 2030**	**Electricity mix 2030**	**100% renewable in 2030 with extra offshore**	**100% renewable in 2030 with extra PV**
Energy storage	-	Yes	-	Yes	-	-	-
Total NPC [$M]	13,400	16,130	18,460	19,060	19,600	21,630	23,600
Total annual Cost [$M]	1,040	1,250	1,430	1,470	1,520	1,670	1,880
Cost factor to current mix	1.00	1.20	1.38	1.42	1.46	1.61	1.76
LCOE [$/kWh]	0.135	0.1405	0.1608	0.166	0.171	0.188	0.205
Annual emitted CO_2	3.70	1.70	3.00	1.16	2.80	2.57	2.53
I Renewable generation divided by load [%]	10.3	75.0	56.0	103.0	75.0	99.0	102.0
II Renewable generation divided by generation [%]	10.2	67.5	47.0	80.5	57.0	65.3	66.4
III One minus nonrenewable generation divided by load [%]	9.6	63.8	36.6	75.0	43.3	47.5	48.4
Natural gas contribution to serve the load [%]	91.4	36.2	63.4	25.0	56.7	52.5	51.6

Chapter 4

4. Discussion

The presented results revealed that 100% renewable electricity production by 2030 is not realistic with the currently planned expansion of renewable energy sources. However, 86% of the annual load of the base load case will come from renewables, so that only about 30 more offshore turbines with a capacity of 240 MW (see Table 11) would be required to become 100% renewable with respect to the annual load. Accordingly, more turbines are needed for the high load case or remain 100% renewable past 2030 when electricity supply rises. However, the planned additions of renewables are only estimated by the RI OER and different developments will bring different results. Especially, the expansion of retail solar is very hard to predict due to private users that install retail solar.

An economic option for the expected electricity mix of 2030 is using battery storage (see Figure 25). However, this scenario still has a natural gas contribution of about 36% (see Table 15). These results are similar to the findings of the Victoria case study in which the mixed scenario with 31% natural gas is the most economical one (Bagheri et al., 2019). Accordingly, it is valid from an economical perspective not to get 100% renewable relative to the natural gas generation in the near future but transition over a longer time schedule.

To become 100% renewable (i.e. the one minus nonrenewable generation divided by load metrics) does not seem to be economically feasible in the previous observations. This would mean that no electricity would be coming from natural gas which cannot be realized, especially during summer evenings. This characteristic is the critical element in the electricity supply. Since winds are weaker in summer it becomes disproportional expensive to increase the renewable fraction with installing further offshore wind capacity while solar PV is more expensive than offshore wind. It should be noted at this point that the costs for both offshore wind and solar are only estimates and can vary in reality. Especially, solar energy was assumed to be more expensive, considering residential installations. If large amounts of utility scale solar is installed, which is less expensive due to a higher capacity factor and economics of scale, it could help increase the renewable fraction in the summer, even though they cannot supply the peak hours in the evening when the sun is down. Short time energy storage with batteries could solve this problem (Zahedi, 2011).

It should be noted that for the models of this study many assumptions were made. Due to the amount of input parameters in HOMER many inaccuracies can occur. Even if the costs for renewable components are considered to be in a correct range, there is an uncertainty of natural gas generators. Since HOMER was originally made for small scale remote areas, it only has generic natural generator with adjustable search space for their capacity. It is unclear if these generators with their default costs components can represent the real gas power plants of Rhode Island. Further research should clarify the detatils of these power plants, as well to figure out, which of them operate most effective. However, it appears that in the future most of the natural gas power plants will only be needed during the peak hours in summer.

A key component of the renewable energy system is seasonal storage since large amounts of electricity are produced by the offshore wind farms in the winter when the demand is low. The topography of Rhode Island is not optimal for an economical operation of pumped hydro-storage. Battery storage on the other hand is not efficient for long-term storage. New technologies like hydrogen or compressed air energy storage (CAES) could help solving these challenges (Ekman & Jensen, 2010; Cavallo, 2007). For instance, Denmark is currently planning to make large investments in hydrogen storage paired with offshore wind farms using the economics of scale. The so called *hydrogen islands* will help reducing the intermittency of the wind production and supply not only Denmark but also parts of Europe with green electricity (BBC News, 2021). However, the battery storage in the simulated models proved to be very efficient in reducing natural gas capacity and fuel expenditures, as well as CO_2 emission, for relatively small investment costs.

To reduce natural gas portion further, Rhode Island could consider a reconstruction of its natural gas power plants by biogas to serve the base load (Lund & Mathiesen, 2009). Even though, the biomass resources are limited in Rhode Island an improved utilization of waste and wastewater to create biogas can be considered. However, biomass has some negative environmental impacts that should be considered for a sustainable and green electricity supply including monoculture, competition against food supply, or pollution of water resources (Field et al., 2008).

Geothermal energy was not considered in this study. Even though it does not contribute to electricity production, it can be a viable source for heating and cooling on a residential scale. This can decrease the electricity demand in summer, as well as in winter. Depending on the degree of new geothermal installations this could significantly help to lower the electricity demand and the peak load.

Even though hydropower was neglected in the previous analysis, it should be noted that the New England states plan to import large amounts of hydropower electricity from Canada, especially from Quebec. The interconnection transmission line is about to be authorized in 2021 with a commissioning start in 2023 (Hydro Review, 2021). The transmission would allow a two-way trade of electricity. New England could import electricity in times of scarcity and export electricity in hours of excess wind and solar generation. Especially, the fact that the electricity demand in Quebec is higher during winter, supports the excess electricity pattern of the OWF (Hydro-Québec, 2021). Research has shown that this trading could reduce the power system cost of about 5-6%. Furthermore, adding a 4 GW transmission is estimated to lower the cost of a zero-emission power system in New England and Quebec between 17-28%. However, Canadian hydropower is more a compliment than a substitute for low carbon technologies in the US and should not be seen as the single solution (Dimanchev et al., 2020).

Consequently, it is highly recommended to research and simulate the electricity grid of Rhode Island as a part of the New England electricity grid, allowing imports and exports of electricity. In doing so, it could be less expensive for instance, to import electricity during summer peaks instead of holding the natural gas power plants at reserve and making further revenues in exporting electricity of the offshore wind farms in winter. However, the export could get complicated since the entire region of New England plans to develop an offshore wind infrastructure leading to similar electricity supply pattern as in Rhode Island in a similar climate. Consequently, export of the electricity even further towards central states of the US using the PJM transmission line and to Quebec, as previously mentioned, although the energy losses increase with farther distances (Budischak et al., 2013). Research is needed to find an economical equilibrium.

It was not considered in this study, that the transportation and heating sector will experience increased electrification in the future as explained in Figure 4. It should be noted that their growth is very uncertain. The OER RI expected a contribution of about 5% until 2030 (Murphy et al., 2020). However, President Joe Biden announced to boost incentives for costumers to purchase electric vehicles, as well as to support electric transit vehicles, as a part of his infrastructure plans (Utility Dive, 2021). This could result in a stronger growth than previously expected. Especially after 2030, when the penetration of electrification starts to grow exponentially, the results of this study need to be reassessed. This is due to the fact that electrification of both sectors brings a shift of increased demand in the winter during cold temperatures, when batteries are inefficient and heating demand in higher (Iso-NE, 2020). On the one hand, more of the excess electricity of OWF could be utilized. On the other hand, it could also increase peak hours in summer when people coming home and plug their EV's in. In contrast, the batteries of EV's could be used as a temporary energy storage if combined with demand side management. This could even utilize the vast amounts of electricity to charge the battery at minimum cost since electricity prices fall when large amount of electricity are produced (Aoun et al., 2019; López et al., 2015). However, it should be noted that in addition to the increased electricity demand due to electric heating another cost component will be added. Since the current heating systems are designed for natural gas or oil, they would have to be replaced and with electric heat pumps. The costs of these installations are not included in this study and could significantly affect the NPC of the future electricity grid. Further research will be necessary to investigate the effects of electric heating and electrification on the electricity grid of Rhode Island.

For the last scenario regarding 100% renewable electricity, it should be noted that the results were presented for the high load case of 8,880 GWh. However, if the base load case of the RI OER forecast will show to be correct this would be the annual load in 2035, so that the configuration would be valid for 5 more years after 2030 (Murphy et al., 2020). Furthermore, it was shown how the electricity demand will increase exponentially in the next decades due to electrification. Consequently, the electricity supply needs to be expanded proportionally, too. Nevertheless, it is difficult at which point renewable energies and storage technologies will be developed. Due to this uncertainty, these developments past 2035 are not considered in this work but it can be element of future research while monitoring the performance of the present system.

In contrast to the load profile, the wind speed profile was assumed to have average values of the past ten years. Further simulation with varying wind speeds should be considered, to account for years with lower and higher wind speeds, as well as the interannual variability of wind resources. A side effect of changing climate conditions due to global warming could be an increase of wind speeds in the next years (Zheng et al., 2016; Harvey, 2019). This increase was 3.35 cm/s per year for the global oceanic sea surface wind speeds in the time period from 1988-2011. If a year with less wind speed occurs it would mean that the fuel demand for natural gas will increase, especially in winter. Although the maximum capacity to cover the peak loads in the summer would not change significantly since wind speeds in summer are low anyways.

Regarding the peak load values, it should be noted that these are significantly higher than past peak loads due to planning safety. However, these peak loads may not increase because the increase in efficiency surpasses the rise in temperature due to global warming. On the other hand, global warming could also lead to a significantly increase in electricity demand in the summer. Even though a buffer was included for the peaks, this could not be enough for future increases in temperature. Especially, heat waves lasting for several days would increase the demand for the natural gas and could deplete potential energy storage. To avoid sudden collapses of the electricity grid, it is recommended to keep most of the natural gas power plants on reserve in the near future. Furthermore, it should be kept in mind that the suggested natural gas capacities in the models are a result of the search space inputs for the natural gas generator, so that the entire nameplate capacity of the real power plants are represented.

Overall, it is not recommended to get rid of the natural gas power plants within the next decades. What could be removed are power plants running with oil. These plants are currently on reserve in winter when large amounts of natural gas are needed for heating and oil power plants have to produce electricity. With offshore wind electricity and a shift to electric heating, these power plants will become redundant. This would result in further costs saving which are not considered here.

Since the capital cost for existing renewable energy sources were not considered it should be kept in mind that only the capital cost of future installations are included in the cost considerations together with the operation and maintenance costs of the existing installations. Even though the NPC of the current electricity mix is lower than the recommended mix for 2030, this does not mean that natural gas is less expensive in general. Since the natural gas power plants already exist there was no capital cost for their construction and only replacement cost was included. For entirely new electricity grids the natural gas model will most likely be more expensive than a HRES.

A further important note about the costs is that only the system cost of capital expenditures, replacement, O&M, and fuel costs are included. However, switching to renewables brings further cost and benefits at the same time. For example, the grid has to be expanded and transmission lines for the offshore wind farms have to be constructed. The costs for these development can be variable and are dependent on the conditions of the current grid which is why they are not considered here. Also, it should be kept in mind that Europe is more mature in the field of offshore wind which first has to be implemented in the US. This expertise must first be developed in New England which could result in way higher cost for offshore wind than expected (Snyder & Kaiser, 2009). On the other hand, HRES bring several benefits that can reduce costs over long term or bring revenues that are hard to measure in present numbers. These effects include local economic impacts, including taxes, job creation, increase in GDP, electricity exports and REC's. Another important benefit is reduced GHG emissions. Due to climate change and global warming CO_2 is considered to have social cost. The social costs of CO_2 are estimated from $29 and $51 per emitted ton (van den Bergh & Botzen, 2015). For example, an assumed mean value of about $40 per ton CO_2, would result in a further costs reduction of about $100 Mio for the recommended scenario form compared to the current electricity mix. However, this amount seems to be low compared to the billions of investment cost. Another aspect not considered in this study are renewable energy certificates (REC's), which can be a further source of income and cost reduction for renewables. The price for these certificates fluctuates over years and is hard to estimate for this case. If 10 $/ produced MWh renewable electricity would be assumed as a REC price like 2018 (US EPA, 2021), $90 M could be made with REC's of all production for the recommended 100% renewable scenario every year. This could result in $2.25 B over the whole lifetime of 25 years, though this would require that all certificates are being sold.

Not considered in this study, but subject of worldwide importance was the COVID 19 pandemic, started in the end of 2019. Besides various sectors, the pandemic also affected the global economy and the electricity sector. In the beginning, electricity consumption was lower than in typical years but steadily recovered to normal levels. The major change was an increased demand in the residential sector and lower demands in the commercial and industrial sector since people worked from home (IEA, 2020b). Due to the lower electricity demand, the share of renewables in the electricity mix increased, revealing the challenges associated with renewables, as discussed in Chapter 1. From an economical aspect, the pandemic damaged incentives and support from governments for renewable enrgies (Navon et al., 2021). Even though the new installations of renewables, in particular solar PV and onshore wind, were slowed down for about 11% in the first half of the pandemic in 2020, their development pace stabilized in the second half, similar to the electricity demand. Especially, the disruption of supply chains and the uncertainty of future economic circumstances are important factors for renewable energy installations and investments (IEA, 2020a). The latter could play an important role for the future development of the renewable energy sector in Rhode Island.

Offshore wind is still emergent in the US and therefore dependent on imports from the EU. If these supply chains are disrupted due to new lockdowns and variants of the COVID 19 pandemic it could lead to problems for the proposed 1,000 MW OWF capacity by 2030. Furthermore, economic damages could hinder investments in infrastructure, necessary for commissioning and maintaining the offshore wind farms. Overall, the progress of the pandemic is uncertain and could play an important role for the implementation of an 100% electricity grid which is not considered in this study.

Chapter 5

5. Conclusions and Recommendations

In this study, several scenarios for the electricity grid of Rhode Island were presented with an emphasis on energy transition towards renewable sources. The scenarios aim to increase the penetration of renewable energy sources with the long-term goal of becoming 100% renewable by the year 2030. To achieve that goal, it is necessary to minimize the percentage of natural gas. With the HOMER optimization software, several scenarios were assessed, and the following conclusion were made:

- Offshore wind plays the key role in the renewable electricity supply. However, its maximum production is in the winter months resulting in large amounts of excessive electricity. The wind energy production is lower in summer months.
- Solar PV helps to increase the renewable penetration in the summer but collapses in the evening hours. A mix of offshore wind and solar energy results in a supply gap in the evening hours of the summer when electricity supply is low and the demand peaks.
- Though the production of natural gas could be drastically decreased in each scenario, still more than half of the current capacity will be needed as reserve in the near future to match the peak hours in summer. This capacity will be necessary during a short period time in summer.
- Energy storage is as key element to increase renewable fraction with perspective to total electricity production and helps to reduce the natural gas capacity and therewith GHG emissions in a very cost-effective way.
- The current planned expansions of renewable energy sources, including the 1,000 MW OWF, will not be sufficient to become 100% renewable until 2030 or further. For the high load case one scenario is to set up a total offshore wind capacity of 1,350 MW (164 8MW-turbines), 1,716 MW of solar PV, 265 MW onshore wind and an 1,880 MWh Li-ion battery capacity, resulting in 100% renewable fraction with perspective to the annual load and 75% true renewable penetration, minimizing the natural gas generation, respectively (see Figure 31). These measures would not be more expansive than the current plans for 2030 but bring more benefits regarding the renewable penetration and less natural gas and GHG emission, respectively. These numbers need more

assessment based on more accurate cost estimates and other constraints of renewable energy development.

- For the case of Rhode Island, 100% renewable, does not mean that the whole electricity supply comes from renewable source. By100% renewable the RI OER refers to the fraction relative to the annual load. As shown, natural gas remains important to serve the baseload and still have a contribution of about 56% to serve the load.

Overall, Rhode Island can drastically increase its renewable fraction over the next decade if further investments are in offshore wind energy made. Special focus should be on energy storage which is critical to reduce the natural gas power output in combination with offshore wind. Consequently, future research should be made for seasonal storage like hydrogen and CAES or even if the biomass production could be increased. Furthermore, simulations and investigations should be processed how the Rhode Island electricity grid interacts within the New England, inland grids using the PJM transmission, and the interconnection to Quebec's hydropower to detect how electricity import and export could help closing the summer gap and utilizing excessive electricity, respectively.

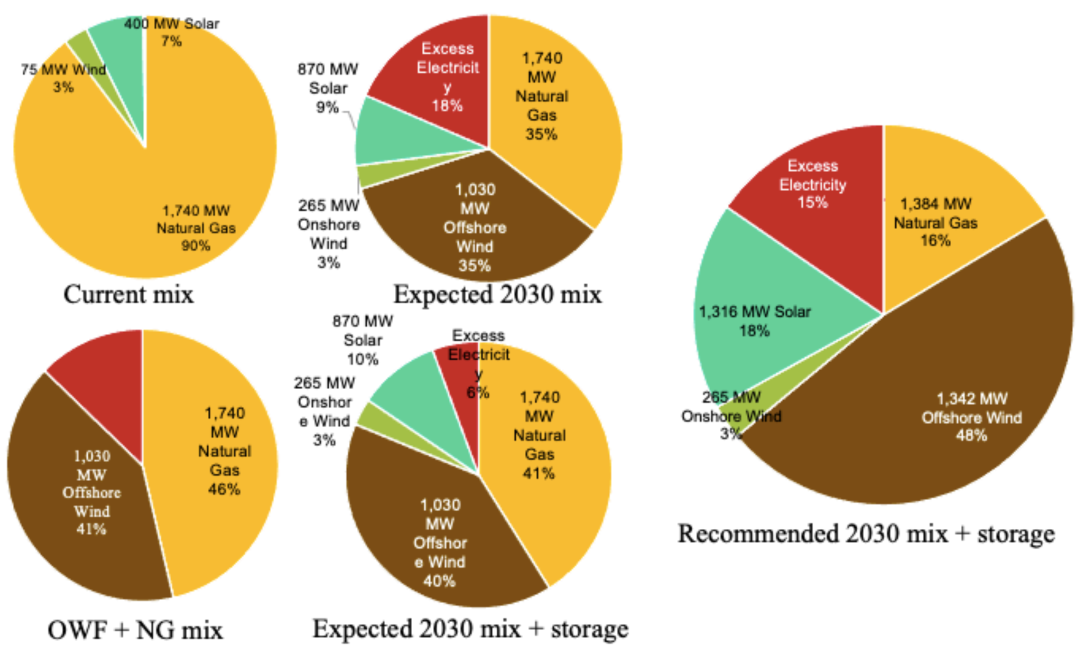

Figure 31: Similar to Figure 24: Shares of renewables of the total annual electricity production including excess electricity for different scenarios: Top left: Current electricity mix; Bottom right: Natural gas and offshore wind; Mid-top: Expected mix in 2030; Mid-bottom: Expected mix in 2030 with storage; Right: Recommended mix in 2030 for 100% renewables.

Chapter 6

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APPENDIX

The following section provides details about assumptions that were made for the models but not mentioned in the presented work.

Even though it was partially presented in the result section, Figure 32 gives an overview of all cost components of the different energy systems implemented in the scenarios with exception of the existing renewable energy systems since their capital costs were uncertain.

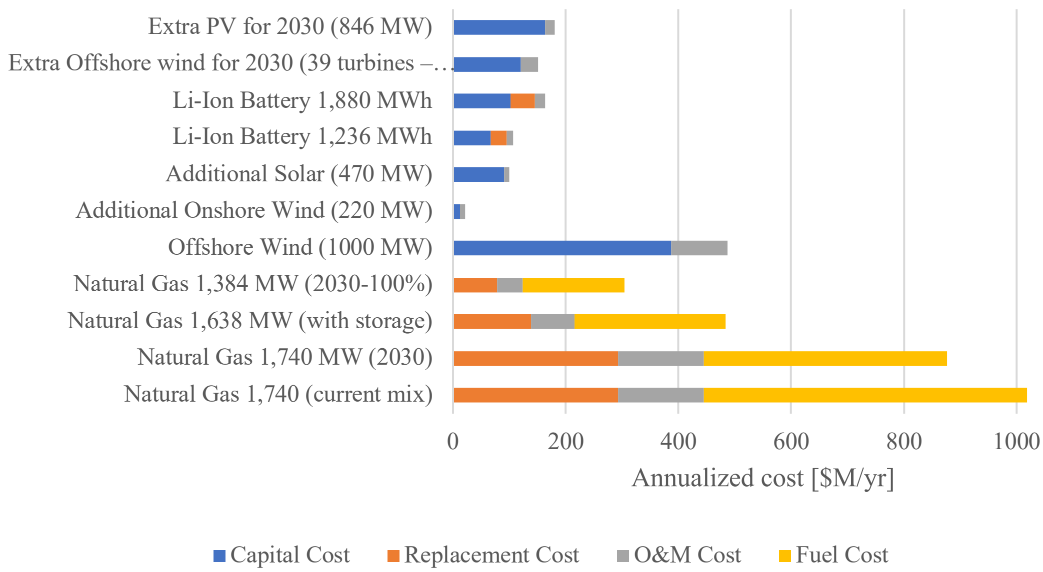

Figure 32: Annualized cost components of the production sources used in the different scenarios.

To assess the capacity of renewables including onshore wind and solar PV that will be online by 2030 estimation from the Brattle Report and its technical support document were used. However, the estimations can differ. After direct contact with the Rhode Island Office of Energy Resources, there are no certain numbers for 2030. Consequently, Table 16 shows the parts that are most likely expected by the OER based on the 100% Brattle Report with resulting total capacity that was used for the simulated models (Murphy et al., 2020; The brattle group, 2021).

Table. 1 shows all natural gas power plants that are currently installed in Rhode Island. For HOMER, a search space for the natural gas generator capacity was required. This search space was created by adding up parts of the existing natural gas power plants clarified in Table 17.

Table 16: Estimation and expectations for the growth of renewable energies presented in the Brattle Report. Table 2 is based on this data.

Source	Capacity [MW]
Onshore Wind	
REG Program	19
Cassada Wind Farm (LTC)	126
Copenhagen Wind Farm (LTC)	80
Total	225
Solar PV	
LTC (long-term contract) Program	71
Gravel Pit Solar	50
RI REG and virtual net metering program	(300)
National Grid Forecast (virtual net metering and REG)	(480)
Total	421-501

Table 17: Natural gas generator capacity entered HOMER search space, accumulating the existing natural gas power plants.

Included Natural Gas Power Plants in the Search Space	Accumulated Capacity [MW]
Entergy Rhode Island State Energy LP	596
Entergy Rhode Island State Energy LP+ Manchester Street	1,110
Entergy Rhode Island State Energy LP+ Manchester Street+ Tiverton Power Plant	1,384
Entergy Rhode Island State Energy LP+ Manchester Street+ Tiverton Power Plant+ Ocean State Power	1,638
Entergy Rhode Island State Energy LP+ Manchester Street+ Tiverton Power Plant+ Ocean State Power+ Pawtucket Power Associates+ Toray Plastics+ Central Power Plant+ Rhode Island Hospital	1,740
Entergy Rhode Island State Energy LP+ Manchester Street+ Tiverton Power Plant+ Ocean State Power+ Ocean State Power II	1,892
All Power Plants	1,995

Figure 33 shows the power curve used to calculate the monthly electricity production of all OWF for Rhode Island online by 2030 which are shown in Figure 34. Further, it can be seen that the OWF can match a large portion of the demand in winter months. Nevertheless, there occurs a large gap in the summer occurs due to lower wind speeds (see Figure 16).

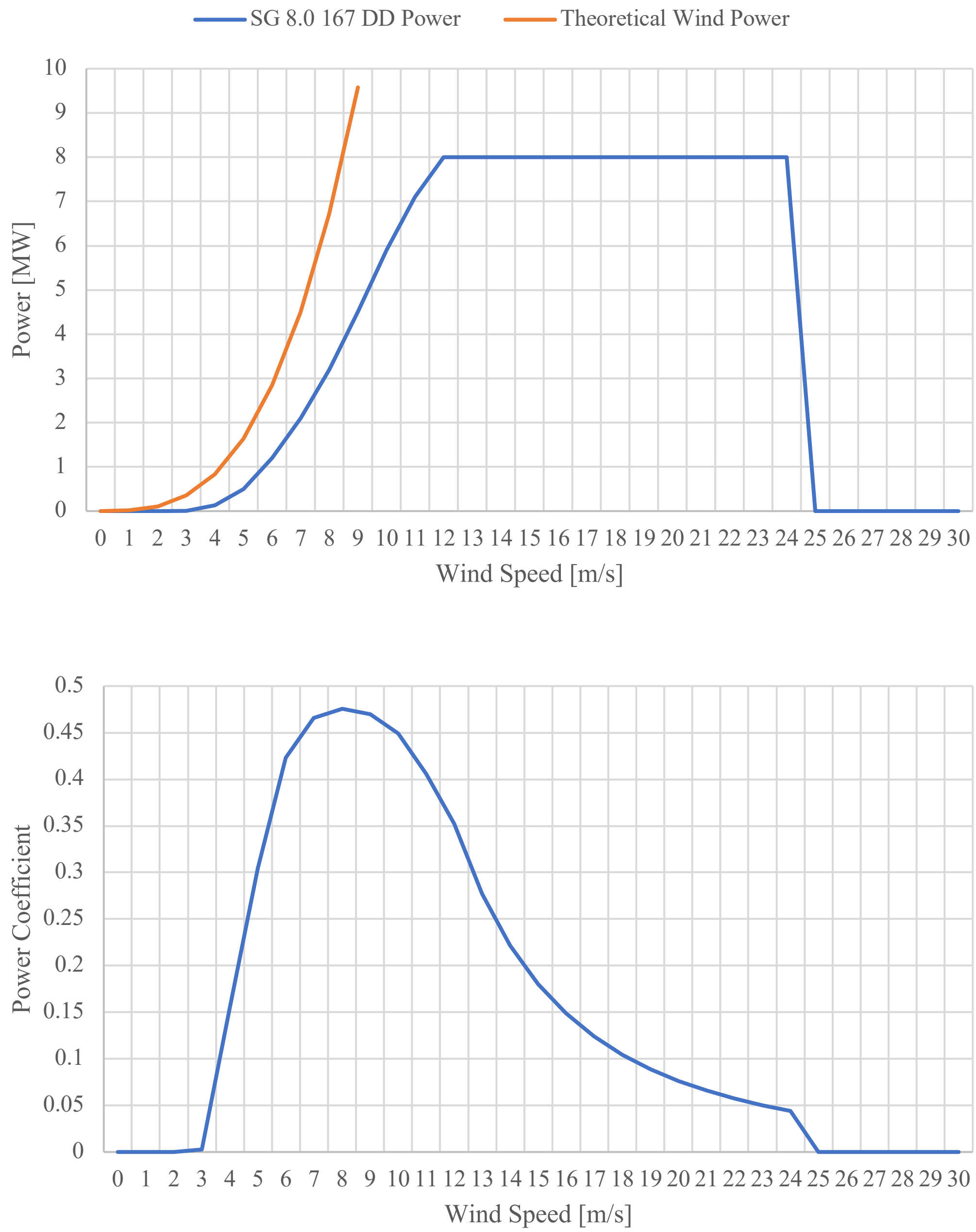

Figure 33: Power curve (top) with rated wind speed of 12 m/s, cut in speed of 3 m/s, cut out speed of 25 m/s, and power coefficient (bottom) of the 88 SG 8.0 167DD used for the OWF proposed for Rhode Island.

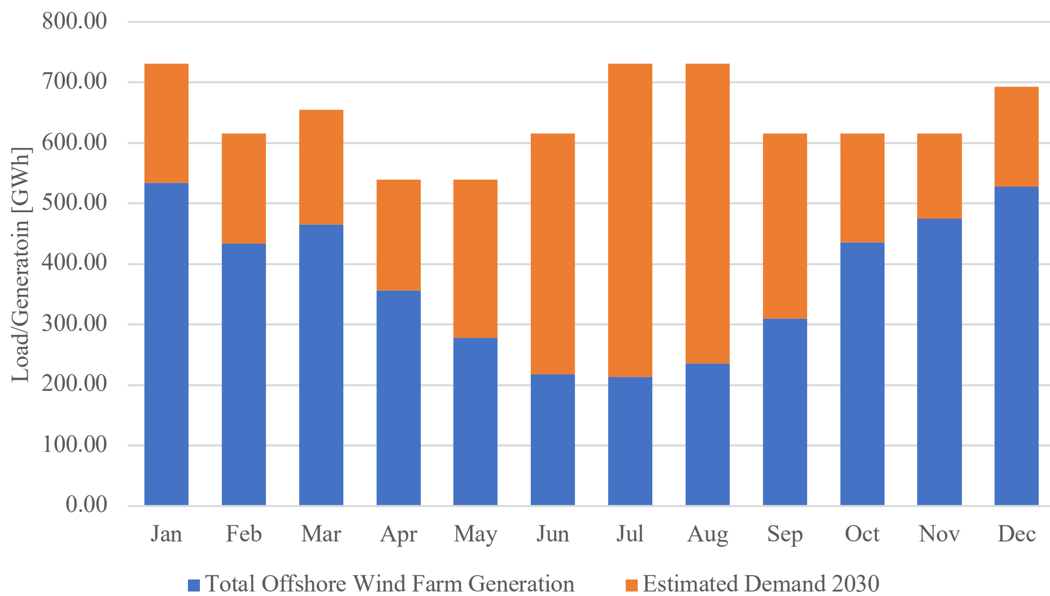

Figure 34: Monthly electricity production of OWF proposed for 2030 using the power curve from fig. 29 and the monthly PDF of WIS station 63088. The energy production is compared to the estimated electricity demand by 2030 of Rhode Island with a total AEP of 4,500 GWh.

Since HOMER only allows to account for one wind speed resource only the offshore wind was included. Consequently, the onshore wind turbines had to be downsized to respect the higher wind speed offshore and the resulting increased annual energy production. To do so, the difference in capacity factors was used. The installed onshore wind of 45 MW in Rhode Island has a capacity factor of about 25% (see Table 18). Assuming a capacity factor of 48% for offshore wind means that the capacity for onshore wind in HOMER has to be reduced by about the half. This will result in an equivalent production.

Table 18: Exemplary calculation of the capacity factor of onshore wind in Rhode Island and conversion to offshore wind resources.

Onshore wind capacity	45 MW
AEP	100 GWh (EIA, 2021d)
Theoretical energy output	0.045*8760 = 400 GWh
Capacity factor	100GWh/400GWh = 25%
Capacity factor of offshore wind	≈ 48%
Converted onshore wind capacity	(25/48) *45MW = 23.74 MW

As mentioned in Chapter 2.1. the peak load is an important parameter for the electricity demand supply since it determines the maximum capacity of power plants. Figure 35 shows the time series of the peak load in the past years, all occurring in July and August. One can see that they slightly decrease due to higher efficiencies in air conditioners. However, the peak load time series for the HOMER models was assumed significantly higher since the upper 95% of the electricity demand was implemented. This assumed to be 10% higher than in the past 5 years in 2018, resulting in a peak for 2030 of about 2,040 MW. In addition, it is expected that global warming will bring more severe heat waves in summer increasing the demand for air conditioning and peak loads.

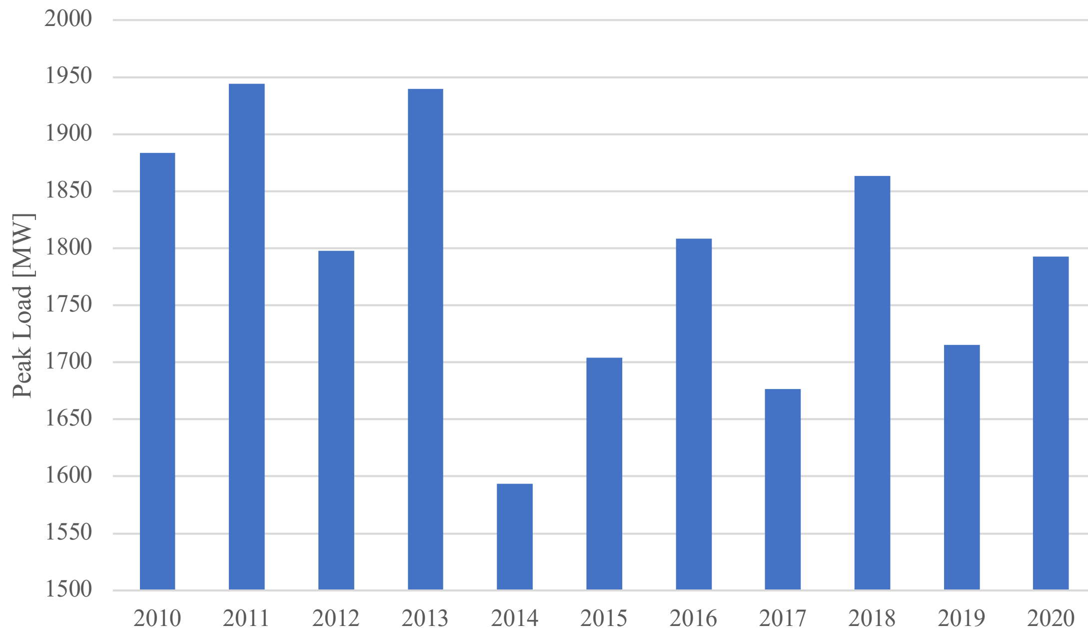

Figure 35: Peak loads for Rhode Island of past years with peaks occurring in July and August.

Though the electrification was neglected for creating the electricity demand, a short demonstration is given. This electrification could be around 5% of the annual electricity demand by 2030 (Murphy et al., 2020). As mentioned in Chapter 4., the electrification of the heating and transportation sector would mean an increased electricity demand in the winter months (Iso-NE, 2020; Weiss et al., 2020). Figure 36 shows the monthly electricity consumption for 2030 with adjusted values in summer and winter compares to the annual load profile of 2019. It shows how the demand could be flattened throughout the year. This could result in a higher efficiency of offshore wind farms because less excessive energy would be generated.

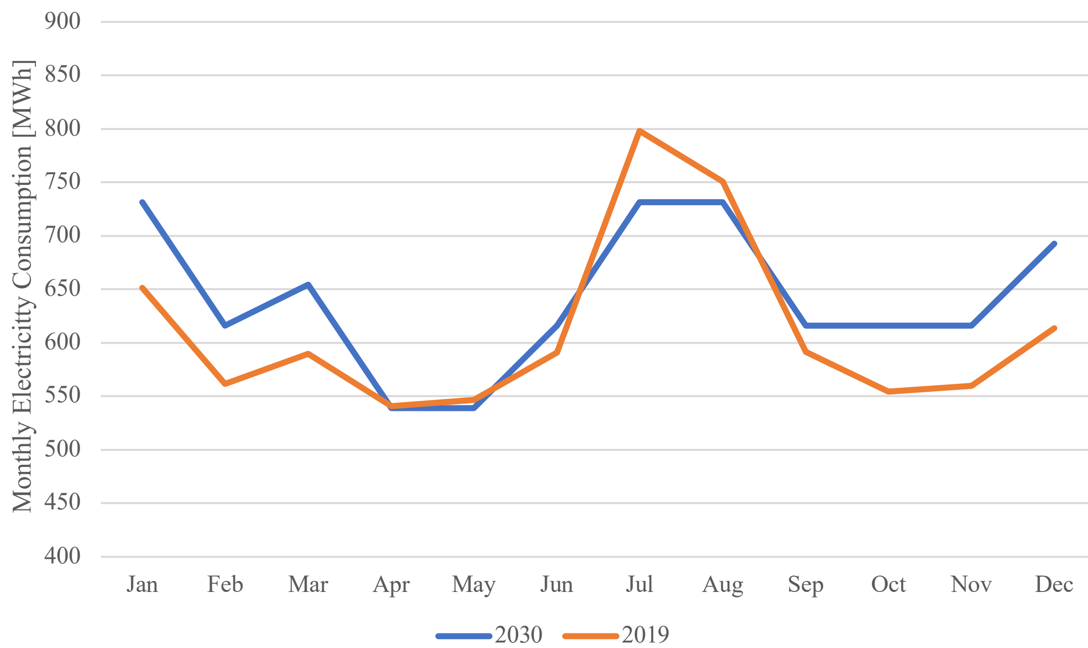

Figure 36: Monthly electricity consumption of 2030 with integrated electrification of the heating and transportation sector compared with 2019 electricity consumption.