AMERICAN UNIVERSITY OF BEIRUT

DECISION ANALYSIS FRAMEWORK FOR DECENTRALIZED HYBRID RENEWABLE ENERGY SYSTEMS IN LEBANON UNDER THE UNCERTAINTY OF GRID EXISTENCE AND TARIFF PRICES

by
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ABSTRACT
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Title: Decision Analysis Framework for Decentralized Hybrid Renewable Energy Systems in Lebanon Under the Uncertainty of Grid Existence and Tariff Prices

Electricity is forecasted to play a leading role in the final energy consumption of the future. Yet, many developing countries suffer from limited access to electricity and poor reliability of fragmented national grid infrastructure. In this context, a large body of research has investigated the development and optimization of household-level and microgrid off-grid and on-grid systems powered by a combination of various renewable and non-renewable electricity generation sources. Yet, from the perspective of the households and communities without access to a reliable central grid, investments in decentralized solutions happen under one major uncertainty: (i) Will the reliable central grid become available at any point in time; and if so, when will that happen? To complete the picture, two secondary uncertainties follow the first one necessarily: if the reliable central grid becomes available, what will be (ii) the price of the centralized electricity, and (iii) the feed-in tariff for purchasing the renewable electricity that is generated by decentralized agents? We develop an optimization-based decision analysis framework that addresses the decision context that such households and communities face while considering these three important uncertainties. We illustrate our methodology by applying it to a case from Lebanon: a country that witnessed a quick drop in the centralized electricity generation due to the ongoing economic crisis and the development of various distributed improvised solutions at household and community levels. We develop a deterministic model and generate different scenarios that show the effects of these uncertainties on the decision. Moreover, we propose a stochastic model and compare its results with the deterministic model to assess the value of energy policy certainty. We finally discuss practical and policy implications that are relevant to Lebanon.

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CHAPTER 1

INTRODUCTION

1.1. Overview

Energy is the vital component in the development of every society. It plays the major role in the growth and prosperity of economies (Strielkowski, Civín, Tarkhanova, Tvaronavičienė, & Petrenko, 2021). Due to many challenges, the world is currently passing through a critical period to deliver more secure, affordable and sustainable energy systems (IEA, World Energy Outlook, 2022). One of these major challenges is climate change. Since energy consumption resulted in more than 75% of the greenhouse gas emissions, it is critical to scale up renewable energy to provide clean energy to electrify households and critical infrastructures such as schools, hospitals and businesses (World Bank, 2023). In the recent years, renewable energy technologies had a great advancement in terms of prices and affordability. For example, the global weighted-average LCOE of solar photovoltaic (PV) and onshore wind technologies has dropped around 90% and 70% between 2010 and 2022-they dropped from 0.445 USD/kWh and 0.107 USD/kWh in 2010 to reach 0.049 USD/kWh and 0.033USD/kWh in 2022 respectively (IRENA, 2023). Therefore, renewable energy technologies are helpful for countries not only in mitigating climate change and being resilient against fuel prices fluctuations but in reducing the costs of energy and increasing energy security as well (Osman, et al., 2023).

Although renewable energy sources had drastic growth, still many people lack access to electricity. About 760 million people around the world don't have access to electricity and almost all of these people live in developing countries (IEA, SDG7: Data and Projections, 2023). Unlike developed countries, developing countries lack grid infrastructure and reliability in power supply especially in rural and remote areas (Elizondo & Poudineh, 2023). These areas suffer from the lack of the grid supply because one of two main issues. The first issue is that these areas are far from the grid transmission lines and connecting them to the centralized grid will cost a lot. The second issue is related to the lack of the power supply from the centralized grid even when these rural and remote areas are connected to the central grid transmission lines. As a solution of this problem, micro grids were used. Micro-grids are one of the low-cost generation technologies to bring clean and reliable energy to remote communities not connected to the grid to provide them with the minimum essentials of life (World Bank, 2023). One major type of micro-grid systems is the hybrid renewable energy systems (HRES). HRES mainly consists of renewable energy generation technologies, such as solar PV and wind turbines, in addition to diesel generators and/or battery storage used to make the system robust against renewable sources fluctuations (Zebra, van der Windt, Nhumaio, & Faaij, 2021). HRESs are important in terms of increasing the reliability and reducing the costs of off-micro-grid systems (Hassan, Algburi, Sameen, Salman, & Jaszczur, 2023). HRES can be both on-grid and off-grid systems, on-grid systems can interact with the central grid in terms of purchasing and selling electricity when possible and feasible while off-grid HRES are stand-alone systems (Basnet, Deschinkel, Le Moyne, & Péra, 2023).

Although HRES became a solution for rural areas in developing countries, there is still a gap in the green energy investments (IEA, World Energy Outlook, 2022). Political and macroeconomic uncertainties in developing countries discourages the investments of the private sector in renewable energy projects (World Bank, 2023). Usually, investors search for projects with an optimal return to risk ratio and they try to mitigate the risks involved in a certain project and if two projects have the same return with different risks, they will choose the less risky one. Similarly, energy investment projects have returns and risks; the risks are mainly generated from uncertainties. Beside the technical and meteorological uncertainties that are normal in HRES investments, there is a big uncertainty that is faced in HRES investments in developing countries which is the political/policy uncertainty. It is unknown whether the central grid electricity will be available at a certain year of the investment and the prices of the electricity are not known as well. Therefore, investments in decentralized HRES happen under a major uncertainty: (i) Will the centralized grid supply be available and reliable at any point in time of the planning horizon? And if so, at what time will that happen? To complete the picture, two secondary uncertainties follow the first one necessarily: if the reliable central grid becomes available, (ii) at what price will the centralized grid sell electricity? and (iii) What is the feed-in tariff that will be provided by the centralized grid to purchase the electricity produced from the decentralized HRES?

1.2. Lebanon

The electricity sector in Lebanon has been facing serious challenges causing frequent power outages across the whole country for several years (Ayoub, Rizkallah, & Abi Haidar, 2021). The frequent blackouts became a part of the daily life of the country's residents (Ahmad, 2020). Although all the Lebanese population have access to electricity (IEA, SDG7: Data and Projections, 2023), there is still a big gap in the central grid electricity supply. The highly inefficient electricity sector caused a significant economic and social cost on the country (de Soyres & Nakhle, 2019). In addition to the difficult situation the electricity sector was passing through, the economic and financial crisis that the country faced made the situation even worse and led to a near full collapse of Electricité du Liban (EDL), where the average electricity production per day decreased to 1-2 hours in 2022 (Ayat Boukather, 2023). The power supply deficit was mainly covered by private, polluting and expensive diesel generators that were distributed all over the country (Ahmad, 2020). The costs of these private generators have exceeded 50 USD cents/kWh. The collapse of the central grid in addition to the high prices of diesel generators has driven the installation of decentralized solar systems all over the country (Ayat Boukather, 2023).

In the midst of this crisis, for many households, communities and private businesses, solar PV became a substitute for both EDL and private diesel generators. The main reason of this shift was an economical one more than being an action to fight climate change and decreasing air pollution. This huge shift has increased the solar energy across the country by more than eight-fold between the years of 2020 and 2022, where more than 650 MW of solar PV were installed in 2022 alone (Delacloche, 2023). It was estimated that more than 50,000 households are currently equipped with rooftop solar (Delacloche, 2023). Lebanon achieved a great progress in the deployment of renewable energy but more could be achieved (Moore & Collins, 2020). According to the Lebanese Center for Energy Conversion (LCEC), the council of ministers has completed the licensing rounds of 180 MW solar tender including 12 projects covering different areas in Lebanon. Moreover, many legislations work was completed on the issue of smart grids, net metering and many other policies that promote decentralized renewable energy systems in the country.

Since the biggest obstacle of the electricity sector in Lebanon was the bad decision making since the 1990s (Ahmad, 2020), institutional and legal reforms need to be implemented to encourage private sector investment in RE infrastructure focusing on decentralization with citizen insights (Moore & Collins, 2020). Two major parties which are the government and the local community have critical roles to guarantee the success of the investments in HRESs projects (Zebra, van der Windt, Nhumaio, & Faaij, 2021). And as mentioned in the previous part, these investments in decentralized solutions happen under the major uncertainty of centralized grid supply existence and time, central grid (EDL) tariff and the feed-in tariff.

CHAPTER 2

LITERATURE REVIEW

In this section, we review related works in the literature. In section 2.1, we review some work on the optimization of hybrid renewable energy systems and it is divided into two parts. Off-grid systems are discussed in section 2.1.1 while on-grid systems are discussed in section 2.1.2. Furthermore, we will briefly review the related work that was done in Lebanon in section 2.2. Finally, the gaps and contributions will be discussed in 2.3.

2.1. Hybrid Renewable Energy Systems

As mentioned before, HRES consists of renewable energy generation technologies, such as solar PV and wind turbines, in addition to diesel generators and/or battery storage if needed. HRES can be both on-grid and off-grid systems, and in this section, we will dive deeper into recent literature that tackles both off and on-grid HRES.

2.1.1. Off-grid

In this part we will be having different examples from the recent literature related to off-grid HRES with examples and case studies.

(Islam, Das, & Das, 2021) used HOMER to optimize an off-grid hybrid system consisting of solar PV, wind and hydro integrated with Pumped Hydro Storage to meet the electricity demand of 50 houses with a peak load of 577.84 kw in a coastal community in Newfoundland, Canada. The optimal hybrid system was identified by comparing different hybrid combinations: PV/wind/hydro/PHES vs wind/hydro/PHES vs PV/wind/PHES. Moreover, the suggested optimal system was compared to diesel-only and conventional batteries and it was clear that the PV/wind/hydro/PHES is environmentally and economically superior. At the end a sensitivity analysis was conducted to check the effectiveness of meteorological data (wind speed and solar irradiation), load demand data and pipe loss.

(Onu, Silva, de Souza, Bonatto, & da Costa, 2022) suggested a PV system integrated with pumped hydro energy storage was proposed to provide an African community consisting of 50 households with electrical energy and water supply for both irrigation and domestic use. In addition to that, sensitivity analysis was done to assess the effectiveness of the electricity consumption on the initial capital cost, net present cost and cost of electricity.

For the purpose of satisfying electricity demand of a coastline community in Patani-Nigeria, (Nyeche & Diemuodeke, 2020) suggested a mini-grid system consisting of PV-wind-PHES. Genetic Algorithm was used to optimize the PHES. The objective function was to minimize the difference between energy generated and energy demanded and the number of PV panels, the number of wind turbines, blade diameter of wind turbine and height difference between the lower and the upper reservoir were set as decision variables. After that, the HOMER Pro software was used to perform the cost optimization of the system. As a result, the power of PV and wind needed to satisfy the demand was 217 KW and 226050 respectively and the LCOE of the system was 0.27USD/kwh.

In another study and for the sake of decarbonizing the Galapagos island, (Eras-Almeida, et al., 2020) used HOMER to simulate and optimize different techno-economic simulations for different scenarios. Three scenarios were generated: normal growth rate (growth rate considered as 7%), energy efficiency: 3.5% growth rate and the distributed generation scenario (distributed on-grid rooftops PV systems). Moreover, three configurations were suggested as well: PV/wind/batteries/diesel, PV/wind/batteries/Ecuadorian biodiesel, and PV/wind/batteries/Chinese biodiesel and a comparison between the different scenarios and configurations was done. Furthermore, a sensitivity analysis is conducted on the three scenarios to check the effectiveness of PV, wind and batteries cost on the first two and the effect of the PV technology prices on the distributed generation scenario.

(Arévalo, Eras-Almeida, Cano, Jurado, & Egido-Aguilera, 2022) continued the previous work. The purpose of the study was to reduce the diesel consumption in the Galapagos islands by the long-term planning of electrical energy for the year of 2031 using different RE technologies. The analysis of different RE technologies integrated with different storage systems (batteries and PHES) was performed on HOMER. The results showed that the target of 100% RE can be achieved by the combination of PV, wind, batteries, and PHES where diesel generators can be used as a backup only if necessary and this optimal configuration will help in decreasing the LCOE and CO2 emissions. At the end, a sensitivity analysis was made by varying diesel capacity, fuel consumption, PV area and WT capacities interest rate, loss of load, capital cost of equipment.

The main purpose of (Berna-Escriche, Vargas-Salgado, Alfonso-Solar, & Escrivá-Castells, 2022) was to check if a fully renewable energy system integrated with a storage can cover the high demand of the Canary Islands- Spain by the year of 2040. So, three electricity demand scenarios where suggested: business as usual plus efficiency measures, partial electrification, and total electrification scenario. HOMER was used to model the three scenarios. The optimal result was to install 2.5 GW PV, 1.2 GW wind, 9.73 GWH PHES (equivalent to 607 MW) and 5.82 GWh of Li-ion battery storage. The LCOE of the proposed system was 13.4 c€/kWh.

(Guezgouz, et al., 2019) proposed a new energy management approach that coordinates between PHES and battery storage. The PHES functions as the long-term storage while the batteries function as a short-term storage. The optimal system size was determined through multi-objective optimization using a grey wolf optimizer implemented in MATLAB software. The results showed that the LCOE of the systems was 0.162 €/kWh, 0.207 €/kWh and 1.462 €/kWh for hybrid storage, battery and pumped storage, respectively.

The aim of the study of (Abdul-Wahab, Mujezinovic, & Al-Mahruqi, 2022) was to provide the Dibba area in Oman, that has a peak demand of 27 MW, with an optimal solution of an off-grid system. The results from HOMER showed that the optimal solution is a combination of wind 56.9%, diesel 0.537% and natural gas 42.6%. with an LCOE of 0.0787USD/kwh.

Finally, in (Uwineza, Kim, & Kim, 2021), HOMER was used to simulate and optimize hybrid energy systems. After that, the probabilistic distribution of LCOE was calculated on Monte Carlo. The uncertainty of seven input variables were considered in the LCOE calculation: renewable energy, fossil fuel energy, OPEX, CAPEX, discount rate, project lifetimes, and fuel cost. At the end a sensitivity analysis was done to check the impact of the input values on the LCOE. The results showed that the main input parameters that affect on the LCOE outcomes the most are fuel cost, CAPEX, OPEX, renewable energy, fossil fuel, and discount rate.

Table 1: Off-grid HRES Summary

Reference	Objective	Country	Peak demand (MW)	Grid uncertainty considered?
(Islam, Das, & Das, 2021)	**Minimize costs**	**Canada**	**0.577**	**No**
(Onu, Silva, de Souza, Bonatto, & da Costa, 2022)	**Minimize costs**	**Nigeria**	**0.015**	**No**
(Nyeche & Diemuodeke, 2020)	**Minimize the difference between energy generated and energy demanded**	**Nigeria**	**12**	**No**
(Eras-Almeida, et al., 2020)	**Minimize costs**	**Ecuador**	**7.26**	**No**
(Arévalo, Eras-Almeida, Cano, Jurado, & Egido-Aguilera, 2022)	**Minimize costs**	**Ecuador**	**~10**	**No**
(Berna-Escriche, Vargas-Salgado, Alfonso-Solar, & Escrivá-Castells, 2022)	**Minimize costs**	**Spain**	**355**	**No**
(Guezgouz, et al., 2019)	**Minimize costs, lost power supply and curtailment**	**Algeria**	**- (available in monthly) MWh**	**No**
(Abdul-Wahab, Mujezinovic, & Al-Mahruqi, 2022)	**Minimize costs**	**Oman**	**27**	**No**
(Uwineza, Kim, & Kim, 2021)	**Minimize costs**	**Russia**	**0.78**	**No**

Table 1 summarizes the previous literature review. It states the objective of each paper, and it is clear that the most used objective is to decrease the costs. Moreover, the table shows the distribution of the off-grid HRES studied over different countries and most of these countries are considered to be developing countries. It also shows the peak load that is covered varies widely between few kilowatts and hundred megawatts showing the flexibility of HRES. But what is important to us is that all the covered literature didn’t discuss the issue of the grid uncertainty and whether the grid will be available at any point in the planning horizon.

2.1.1. On-grid

In this part we present different examples from the recent literature related to on-grid HRES with examples and case studies.

(Shahzad, et al., 2022) presented a RES-based system to be installed with the existing power grid in the region of Azad Jammu and Kashmir (AJK). The main objective was to satisfy the electricity demand (peak of 246.26 MW) with minimal costs and emissions and maximizing the utilization of renewable energy. Different combinations were proposed including: PV/DGen/Grid, Wind/Hydro/DGen, PV/Wind/Battery, and PV/Wind/Hydro/Grid. And after optimization it appeared that the first case: PV/DGen/Grid is the optimal solution with a COE of 0.198 USD/kWh. This system consists of 51.667 MW of solar PV and 3.4 MW of diesel generators. The annual grid electricity purchased and sold was about 11.2 GWh and 49.8 GWh, respectively.

(Arabi-Nowdeh, et al., 2021) examined the optimal design of a HRES consisting of PV-wind-battery in two operating modes: off-grid and on-grid. The objective was to decrease the cost of lost load and meeting the demand while minimizing the costs (net present cost) and emissions. At the beginning an off-grid system consisting of PV-wind-battery was designed without the consideration of emissions. After that the same system was designed as an on-grid system but with the consideration of emissions this time. The results show that PV/wind/battery combination is considered to be the most optimal combination.

In another study, (PÜRLÜ, Beyarslan, & TÜRKAY, 2022) designed a HRES to minimize the cost of energy and harmful emissions in a rural area in Turkey. HOMER was used to design a system that satisfies a peak load of 3.5 MW. Moreover, a sensitivity analysis was done to check the economic and environmental effect of increasing the share of renewable energy.

In order to examine the techno-economic feasibility of off-grid and on-grid HRES for Al-Karak, Jordan, (Al Afif, Ayed, & Maaitah, 2023) used HOMER the feasibility of maximizing the integration of renewable while minimizing the costs and the emissions of an on-grid and off-grid systems including wind, PV, biogas, flywheel and batteries. The results showed that PV/wind/grid/batteries is the optimal combination with a COE of 0.024 USD USD/kWh, high RE share and 53% less CO2 emissions that an only-grid system.

(Rachmanto, Juwana, Akbar, Prasetyo, & Bhre, 2023) analysed an on-grid HRES consisting of PV and a generator. They used HOMER to model the configurations and simulated the combination across different cities to check the efficiency of the system.

Moreover, (Barua & Ghosh, 2020) evaluated the feasibility of on-grid HRES in a coastal region in Bangladesh. They used HOMER to design and simulate the system. It evaluated the on-grid and off-grid combinations according to lowest cost of energy (COE), net present cost (NPC), short payback period, largest renewable fraction and internal rate of return (IRR). The optimal combination appeared to be PV/Bio/Grid system with a COE of USD0.0451/kWh, the least emissions and excess electricity can be sold to the grid.

Finally, (Malik, Awasthi, & Sinha, 2022) investigated the technical, economic and environmental feasibility of an on-grid HRES in a Himalayan region. Five combinations of solar PV, wind, and biomass were created with and without storage. It appeared that the combination of Biomass/PV/grid is the optimal combination with a COE of USD0.099/kWh. Additional to that, a sensitivity analysis was performed to check the effect of solar radiation, fuel price, biomass gasifier life, real interest rate, and capacity shortage on system outputs.

Table 2: On-grid HRES Summary

Reference	Objective	Country	Peak demand (MW)	Grid uncertainty considered?
(Shahzad, et al., 2022)	**Maximize RE Minimize emissions**	**Pakistan**	**246.26**	**No**
(Arabi-Nowdeh, et al., 2021)	**Minimize costs and emissions**	**Iran**	**0.05**	**No**
(PÜRLÜ, Beyarslan, & TÜRKAY, 2022)	**Minimize costs and emissions**	**Turkey**	**3.5**	**No**
(Al Afif, Ayed, & Maaitah, 2023)	**Minimize costs and emissions**	**Jordan**	**172.1**	**No**
(Rachmanto, Juwana, Akbar, Prasetyo, & Bhre, 2023)	**Minimize costs and emissions**	**Indonesia**	**0.002**	**No**
(Barua & Ghosh, 2020)	**Minimize costs**	**Bangladesh**	**5.8**	**No**
(Malik, Awasthi, & Sinha, 2022)	**Minimize costs and emissions**	**India**	**0.029**	**No**

Table 2 summarizes the previous literature review on on-grid HRES. It states the objective of each paper, and it is clear that the most used objective is to minimize the costs and emissions. Moreover, the table shows the distribution of the on-grid HRES studied over different countries and all of these countries are considered to be developing countries. It also shows the peak load that is covered varies widely between few kilowatts and tens of megawatts showing the flexibility of HRES. But what is important to us is that all the covered literature did not discuss the issue of the grid uncertainty and whether the grid will be available at any point in the planning horizon.

2.2. Electricity Planning in Lebanon

In this section, we discuss briefly recent literature work done in Lebanon.

(Abou Brahim, 2020) performed a study for a rural area in Lebanon, Rashayya to investigate the feasibility to install a micro-grid and dives into the barriers to such projects in Lebanon. The PV farm was modelled using HOMER and it appears that having such system would decrease the COE to 0.168USD/kWh and decrease the CO2 emissions as well and such investment will have a 7 years payback period.

(Chedid & Ghajar, 2019) analyzed the potential of microgrids in Lebanon to solve the existing energy crisis. They used HOMER to show the importance of introducing microgrids to reduce the impact of private power supply. Moreover, a case was done on 10 rural villages in Rashayya region and it appeared that a hybrid PV-Generator grid connected system is the optimal combination with a COE of USUSD0.132/kWh compared to the USUSD0.157/kWh when only the grid and diesel generators are used. Finally, they recommended some policies regarding the microgrid development in Lebanon.

(Chedid, Sawwas, & Fares, 2020) proposed a new methodology to redesign a microgrid that relies heavily on diesel generators. The approach included replacing the diesel generators by a HRES consisted of PV and batteries. Moreover, a case study on AUB campus was performed to validate the effectiveness of the proposed method.

In another study, (Chaplain & Verdeil, 2022) studied the existence of diesel generators decentralized systems and solar PV systems in Lebanon, focusing on technological, socioeconomic, and political factors. They also tackled some barriers that are affecting the sustainable transition.

Finally, (Mazloum, Abdelkader, & Mazloum, 2022) introduced the "Small-Scale Grid Sharing System" that is a cost-effective solution, enabling units to utilize excess energy and power in the midst of power shortages. Moreover, the method was implemented in small and medium-scale solar systems in Lebanon's Bekaa region.

2.3. Gaps and Contribution

So, after passing through recent literature tackling both off and on-grids HRES internationally and in Lebanon, it is clear that major gaps exist. The main gap is that none of the recent literature tackled the uncertainties related to the grid existence at any point in the planning horizon, nor did they take into consideration the uncertainties of the grid tariffs and feed-in tariffs prices. Moreover, according to the review paper of (Zebra, van der Windt, Nhumaio, & Faaij, 2021), a gap also exists in the literature concerning planning issues that involve the decision-making approach for HRES.

Therefore, our main contributions are as follows:

- Involving a decision-making framework for HRES that includes a deterministic model and a stochastic model
- Accounting for the grid existence uncertainty and taking into consideration the centralized tariff and the feed-in tariff uncertainties
- Including early retirements in the context of microgrids in developing countries
- Quantifying the value of energy policy certainty

CHAPTER 3

METHODOLOGY

To apply the proposed contribution, we formulate an optimization-based decision analysis framework that addresses the decision context that such households and communities face while considering these three important uncertainties. We first start with a deterministic mathematical model presented in section 3.1 including an objective function that will be discussed in section 3.1.1 and the required constraints in section 3.1.2. Moreover, we propose a stochastic mathematical model in 3.2. The model size and complexity are discussed in 3.3. The Value of Policy Certainty is calculated using a method discussed in 3.4. Finally, to apply the proposed methodology, a case study for the Higher Matn (Al-Matn Al-Aala), a rural community in Lebanon is given in section 3.5.

3.1. Deterministic Mathematical Model

A mathematical linear programming model was formulated to solve our optimization problem. As any optimization problem, it consists of inputs shown in table 3, decision variables in table 4, an objective function in section 3.1.1 and constraints shown in section 3.1.2. Moreover, a discussion of the model size and complexity is presented in section 3.1.3.

Table 3: Deterministic Model Inputs

name	Description	Unit
Y	Last year in model	Years
y	Index for years	Years
Ys	Year of start of planning	Years

i	Discount Rate	%
G	Number of generation technologies considered	
g	Index for generation technologies	
DG	Set of indices of diesel generation technologies	
PVG	Set of indices of PV generation technologies	
WG	Set of indices of wind generation technologies	
S	Number of storage technologies considered	
s	Index for storage technologies	
D	Number of representative days	Days
d	Index for representative days	Days
W^d	Yearly weight of representative days	
H	Total hours per day	Hours
h	Index for hours	Hours
T_{Grid}	Time where grid electricity will be available 24/24	Years
a	Index of year	Years
GUC^g	Generation unit capex of generation technology g	m$/MW
$SPUC^s$	Storage power unit capex of storage technology s	m$/MW
$SEUC^s$	Storage energy unit capex of storage technology s	m$/MWh
$GUFO^g$	Generation unit fixed opex of generation technology g	$/MW
$SPFO^s$	Storage power unit fixed opex of storage technology s	$/MW
$SEFO^s$	Storage energy unit fixed opex of storage technology s	$/MWh
$GUVO^g$	Generation unit non-fuel variable opex of generation technology g	$/MWh
$SUVO^s$	Storage unit non-fuel variable opex of storage technology s	$/MWh
$InpC^{g,a}$	Input capacity of generation technology g at year Ys installed at year a	MW
$InpSP^{s,a}$	Input power of storage technology s at year Ys installed at year a	MW
$InpSE^{s,a}$	Input energy of storage technology s at year Ys installed at year a	MW
$PVCF^{d,h}$	PV Capacity factor at day d and hour h	%
$WCF^{d,h}$	Wind Capacity factor at day d and hour h	%
HR^g	Heat rate of generation technology g	L/MWh
$FuPr^y$	Fuel price at year y	$/L
EUT	Emissions tax per Carbon dioxide emissions	$/Tonnes
PEF^g	Emission per fuel consumption of generation technology g	Kg/L
VLL	Value of lost load	$/MWh
VEL	Value of excess load	$/MWh
Tar	EDL tariff price	$/kWh
LT^g	Life time of generation technology g	Years

LT^s	Life time of storage technology s	Years
FiT	Feed in Tariff	\$/kWh
$Dm^{y,d,h}$	Electric demand at year y, day d and hour h	MW
CL^g	Installed capacity limit on technology g	MW
SL	Sold limit	MW
PL	Purchased limit from EDL	MW
$MaxSt^s$	Maximum storage of storage technology s	%
$MinSt^s$	Minimum storage of storage technology s	%
ChE^s	Charge efficiency of storage technology s	%
$DchE^s$	Discharge efficiency of storage technology s	%
$RmVal^{g,y}$	Remaining value of installed generation technology	%
$RmValS^{s,y}$	Remaining value of installed storage technology	%

Table 4: Deterministic Model Decision Variables

name	Description	Unit
Cx	Total capex	m$
FOx	Total fixed opex	m$
VOx	Total nonfuel variable opex	m$
$FlOx$	Total fuel opex	m$
ET	Total emissions tax	m$
LLC	Total lost load cost	m$
ELC	Total excess load cost	m$
PEC	Total Purchased electricity cost	m$
R	Total revenues	m$
VER	Value of Early Retirement	m$
SV	Salvage value	m$
$ic_{g,y}$	Installed capacity of generation technology g at year y	MW
$isp_{s,y}$	Installed power of storage technology s at year y	MW
$ise_{s,y}$	Installed energy of storage technology s at year y	MWh
$ac_{g,y}$	Added capacity of generation technology g at year y	MW
$asp_{s,y}$	Added power of storage technology s at year y	MW
$ase_{s,y}$	Added energy of storage technology s at year y	MWh
$rc_{g,y,a}$	Retired capacity of generation technology g at year y installed at year a	MW
$rsp_{s,y,a}$	Retired power of storage technology s at year y installed at year a	MW
$rse_{s,y,a}$	Retired energy of storage technology s at year y installed at year a	MWh

$rmc_{g,y,a}$	Remaining capacity of generation technology g at year y installed at year a	MW
$rmsp_{s,y,a}$	Remaining power of storage technology s at year y installed at year a	MW
$rmse_{s,y,a}$	Remaining energy of storage technology s at year y installed at year a	MWh
$de_{g,y,d,h}$	Dispatched electricity from generation technology g at year y, day d and hour h	MW
$usd_{y,d,h}$	unserved demand at year y, day d and hour h	MW
$ee_{y,d,h}$	excess electricity at year y, day d and hour h	MW
$pe_{y,d,h}$	Purchased electricity from grid at year y, day d and hour h	MW
$ch_{s,y,d,h}$	Charging capacity of storage technology s at year y, day d and hour h	MW
$se_{g,y,d,h}$	Sold Electricity from generation technology g at year y, day d and hour h	MW
$dch_{s,y,d,h}$	Discharging capacity of storage technology s at year y, day d and hour h	MW
$soc_{s,y,d,h}$	State of charge of storage technology s at year y, day d and hour h	MWh

3.1.1. Objective Function

Our objective function consists of two parts the first part is related to the costs including Capex (capital expenditure), Fixed Opex (operating expenditure), Variable Opex, Fuel Opex, Emissions Tax, Lost Load Cost, Excess Load Cost and Purchased Electricity Cost. The second part is related to the incomes including Revenues, Value of Early Retirement and Salvage Value. So, the two periods related to the existence of the grid (before and after) are included in our objective function. Moreover, the objective will include the objective and the motive of both off and on-grid investors. Usually, the motive of the off-grid investors is to minimize the costs of a reliable HRES system while the motive of the on-grid investors is to minimize the costs and emissions in addition to maximizing their profits (by selling electricity to the grid) and the renewable energy share (as mentioned in the literature review). So, both objectives are combined within one objective function that is shown below which minimizes the costs minus the revenues.

$$MIN(\,Cx + \ FOx + VOx + \ FlOx + \ ET + LLC + \ ELC + \ PEC - (R + VER + SV)\,)$$

3.1.2. Constraints

The required constraints are included in this section. Each component of the objective function is defined with the corresponding equation. After that, the constraints that are related to this component are stated below it.

3.1.2.1. Total Capex

The total capex represents the total capital expenditure and is the summation of the product of the Generation Unit Capex (USD/MW) and the Added Capacity (MW) of each generation technology from one side and the product of the Storage Unit Capex (USD/MW or MWh) (power and energy) and the Added Storage (MW or MWh) (power and energy) of each storage technology on the other side over all the years.

$$Cx = \sum_{y=Ys} \left\{ \frac{1}{(1+i)^y} \cdot \left(\sum_{g=0} \left(GUC^g \cdot \ ac_{g,y} \right) + \sum_{s=0} [SPUC^s \cdot asp_{s,y} + SEUC^s \cdot ase_{s,y}\ ] \right) \right\}$$

Installed Capacity Limit Constraint: For all generation technologies g and for all years y, we cannot install more than the allowable capacity limit.

$$\forall g, \forall y \geq Ys, ic_{g,y} \leq CL^g$$

Installed Capacity Initial Constraint: For all generation technologies g and for the first year only, the installed capacity is equal to the added capacity (since no generation technology already exist)

If $Ys = 0$:

$$\forall g, ic_{g,Ys} = ac_{g,Ys}$$

Installed Capacity Constraint: For all generation technologies g and y greater than 1, the installed capacity at year y equals the installed capacity at year y-1 in addition to the newly added capacity minus the retired capacities.

Input: $InpC^{g,a}$

$$\forall g, \forall y > 0, y = Ys, ic_{g,y} = \sum_{a=0}^{a=y-1} InpC^{g,a} + ac_{g,y} - \sum_{a=0}^{a=y-1} rc_{g,y,a}$$

$$\forall g, \forall y > \max(0, Ys), ic_{g,y} = ic_{g,y-1} + ac_{g,y} - \sum_{a=0}^{a=y-1} rc_{g,y,a}$$

Retirement Initial Constraint: We cannot retire a generation technology g before being installed.

$$\forall g, \forall y \geq Ys, \forall a \geq y, rc_{g,y,a} = 0$$

Retirement Constraint: The retired capacity of a generation technology g at year y and installed at year a should be greater than the added capacity at year a if y is greater than the lifetime of the generation technology g minus the retired capacities throughout the previous years.

If early ret allowed:

$$\forall g, y > LT_g, y \geq Ys, \forall a < Ys, a = y - LT_g, rc_{g,y,a} \geq InpC^{g,a} - \sum_{y1=Ys}^{y1=y-1} rc_{g,y1,a}$$

$$\forall g, y > LT_g, y \geq Ys, \forall a \geq Ys, a = y - LT_g, rc_{g,y,a} \geq ac_{g,a} - \sum_{y1=a}^{y1=y-1} rc_{g,y1,a}$$

Else:

$$\forall g, y > LT_g, y \geq Ys, \forall a < Ys, a = y - LT_g, rc_{g,y,a} = InpC^{g,a}$$

$$\forall g, y > LT_g, y \geq Ys, \forall a \geq Ys, a = y - LT_g, rc_{g,y,a} = ac_{g,a}$$

Remaining Capacity Constraints: For all generation technologies g with y greater than one and a, the remaining capacity equals the remaining capacity at y-1 minus the retired capacity at year y. The second constraint states that remaining capacity at y=a is equal to the added capacity at the same year.

$$\forall g, y > 0, y = Ys, a < y, rmc_{g,y,a} = InpC^{g,a} - rc_{g,y,a}$$

$$\forall g, \forall y > \max(0, Ys), a < y, rmc_{g,y,a} = rmc_{g,y-1,a} - rc_{g,y,a}$$

$$\forall g, \forall y \geq Ys, a = y, rmc_{g,y,a} = ac_{g,a}$$

$$\forall g, \forall y \geq Ys, \forall a > y, rmc_{g,y,a} = 0$$

Same explanation applies for the storage energy and storage power components.

If $Ys = 0$:

Installed Storage Power Initial Constraint

$$\forall s, isp_{s,Ys} = asp_{s,Ys}$$

Else:

Installed Storage Power Constraint

$$\forall s, \forall y > 0, y = Ys, isp_{s,y} = \sum_{a=0}^{a=y-1} InpSP^{s,a} + asp_{s,y} - \sum_{a=0}^{a=y-1} rsp_{s,y,a}$$

$$\forall s, \forall y > \max(0, Ys), isp_{s,y} = isp_{s,y-1} + asp_{s,y} - \sum_{a=0}^{a=y-1} rsp_{s,y,a}$$

Retirement Storage Power Initial Constraint

$$\forall s, \forall y \geq Ys, \forall a \geq y, rsp_{s,y,a} = 0$$

Retirement Storage Power Constraint (1 early ret allowed, 2 early ret not allowed)

If early ret allowed:

$$\forall s, y > LT_s, y \geq Ys, \forall a < Ys, a = y - LT_s, rsp_{s,y,a} \geq InpSP^{s,a} - \sum_{y1=Ys}^{y1=y-1} rsp_{g,y1,a}$$

$$\forall s, y > LT_s, y \geq Ys, \forall a \geq Ys, a = y - LT_s, rsp_{s,y,a} \geq asp_{sa} - \sum_{y1=a}^{y1=y-1} rsp_{g,y1,a}$$

Else:

$$\forall s, y > LT_s, y \geq Ys, \forall a < Ys, a = y - LT_s, rsp_{s,y,a} = InpSP^{s,a}$$

$$\forall s, y > LT_s, y \geq Ys, \forall a \geq Ys, a = y - LT_s, rsp_{s,y,a} = asp_{s,a}$$

Remaining Storage Power Constraint

$$\forall s, y > 0, y = Ys, a < y, rmsp_{s,y,a} = InpSP^{s,a} - rsp_{s,y,a}$$

$$\forall s, \forall y > \max(0, Ys), a < y, rmsp_{s,y,a} = rmsp_{s,y-1,a} - rsp_{s,y,a}$$

$$\forall s, \forall y \geq Ys, a = y, rmsp_{s,y,a} = asp_{s,y}$$

$$\forall s, \forall y \geq Ys, \forall a > y, rmsp_{s,y,a} = 0$$

If $Ys = 0$:

Installed Storage Energy Initial Constraint

$$\forall s, ise_{s,Ys} = ase_{s,Ys}$$

Else:

Installed Storage Energy Constraint

$$\forall s, \forall y > 0, y = Ys, ise_{s,y} = \sum_{a=0}^{a=y-1} InpSE^{s,a} + ase_{s,y} - \sum_{a=1}^{a=y} rse_{s,y,a}$$

$$\forall s, , \forall y > \max(0, Ys)\,, ise_{s,y} = ise_{s,y-1} + ase_{s,y} - \sum_{a=1}^{a=y} rse_{s,y,a}$$

Retirement Storage Energy Constraint

$$\forall s, \forall y \geq Ys, \forall a \geq y, rse_{s,y,a} = \; 0$$

Retirement Storage Energy Constraint (1 early ret allowed, 2 early ret not allowed)

If early ret allowed:

$$\forall s, y > LT_s, y \geq Ys, \forall a < Ys, a = y - LT_s, rse_{s,y,a} \geq \; InpSE^{s,a} - \sum_{y1=Ys}^{y1=y-1} rse_{g,y1,a}$$

$$\forall s, y > LT_s, y \geq Ys, \forall a \geq Ys, a = y - LT_s, rse_{s,y,a} \geq \; ase_{s,a} - \sum_{y1=a}^{y1=y-1} rse_{g,y1,a}$$

Else:

$$\forall s, y > LT_s, y \geq Ys, \forall a < Ys, a = y - LT_s, rse_{s,y,a} = \; InpSE^{s,a}$$

$$\forall s, y > LT_s, y \geq Ys, \forall a \geq Ys, a = y - LT_s, rse_{s,y,a} = \; ase_{s,a}$$

Remaining Storage Energy Constraint

$$\forall s, y > 1, y = Ys, a < y, rmse_{s,y,a} = \; InpSE^{s,a} - rse_{s,y,a}$$

$$\forall s, , \forall y > \max(0, Ys)\,, a < y, rmse_{s,y,a} = rmse_{s,y-1,a} - rse_{s,y,a}$$

$$\forall s, \forall y \geq Ys, a = y, rmse_{s,y,a} = ase_{s,y}$$

$$\forall s, \forall y \geq Ys, \forall a > y, rmse_{s,y,a} = 0$$

Installed, Remaining, Added, Retired capacities/storage power/storage energy are all happening at the beginning of the year.

Process:

1- Retire

2- Add

3- Compute Installed and Remaining

This process happens at the beginning of the year and before running the powerplants. All variables and constraints related to dispatched electricity should start at Ys (so they are not important for us at years y<Ys for the purpose of including added capacities as an input)

3.1.2.2. Fixed Opex

The Total Fixed Opex is the fixed operating expenditure and it is summation of the product of the Generation Unit Fixed Opex (USD/MW) and the Installed Capacity (MW) of each generation technology from one side and the product of the Storage Unit Fixed Opex (USD/MW or MWh) (power and energy) and the Installed Storage (MW or MWh) (power and energy) of each storage technology on the other side over all the years divided by million.

$$FOx = \sum_{y=Ys} \left\{ \frac{1}{(1+i)^y} \cdot \left(\sum_{g=0} \left(GUFO^g \cdot ic_{g,y} \right) + \sum_{s=0} \left[SPFO^s \cdot isp_{s,y} + SEFO^s \cdot ise_{s,y} \right] \right) / million \right\}$$

3.1.2.3. Variable Opex

The Total Variable Opex is the variable operating expenditure and it is summation over all the years of the product of the Generation Unit Variable Opex (USD/MWh) and the summation of the dispatched electricity over all days and hours multiplied by the weight of the representative days from each generation technology g from one side and the product of the Storage Unit Variable Opex (USD/MWh) and discharging over all days and hours multiplied by the weight of the representative days from each storage technology s from the other side divided by million.

$$VOx = \sum_{y=Ys} \left\{ \frac{1}{(1+i)^y} \cdot \left(\sum_{g=0} \left(GUVO^g \cdot \sum_{d-0} (W^d \cdot \sum_{h=0} de_{g,y,d,h}) \right) + \sum_{s=0} \left(SPVO^s \sum_{d-0} (W^d \cdot \sum_{h=0} dch_{s,y,d,h}) \right) \right) / million \right\}$$

Energy Balance Equation Constraint: According to the energy balance equation and for every years y, days d and hours h, the electricity demand, minus the unserved demand, plus the summation of charging of all storage technologies s, plus the summation of the sold electricity of all generation technologies g, should be equal to the summation of the dispatched electricity over all the generation technologies g, minus the excess electricity, plus the summation of discharging of all storage technologies s, plus the purchased electricity.

$$\forall y \geq Y_s, \forall d, \forall h, Dm^{y,d,h} + \sum_{s=0} ch_{s,y,d,h} + \sum_{g=0} se_{g,y,d,h} - usd_{y,d,h} = \sum_{g=0} de_{g,y,d,h} + \sum_{s=0} dch_{s,y,d,h} + pe_{y,d,h} - ee_{y,d,h}$$

Dispatched Diesel Capacity Constraint: the dispatched electricity from diesel at year y, day d and hour h cannot exceed the installed capacity at year y.

$$g \in DG, \forall y \geq Y_s, \forall d, \forall h, de_{g,y,d,h} \leq ic_{g,y}$$

Dispatched PV Capacity Constraint: the dispatched electricity from PV at year y, day d and hour h cannot exceed the installed capacity at year y multiplied by the capacity factor of PV.

$$g \in PVG, \forall y \geq Y_s, \forall d, \forall h, de_{g,y,d,h} \leq ic_{g,y} \cdot PVCF^{d,h}$$

Dispatched Wind Capacity Constraint: the dispatched electricity from wind at year y, day d and hour h cannot exceed the installed capacity at year y multiplied by the capacity factor of wind.

$$\forall g = WG, \forall y \geq Y_s, \forall d, \forall h, de_{g,y,d,h} \leq ic_{g,y} \cdot WCF^{d,h}$$

Max Charging Constraint: the charging from technology s, at year y, day d and hour h cannot exceed the installed storage power.

$$\forall s, \forall y \geq Y_s, \forall d, \forall h, ch_{s,y,d,h} \leq isp_{s,y}$$

Max Discharging Constraint: the discharging from technology s, at year y, day d and hour h cannot exceed the installed storage power.

$$\forall s, \forall y \geq Y_s, \forall d, \forall h, ch_{s,y,d,h} \leq isp_{s,y}$$

Max Storage Constraint: the state of charge of technology s, at year y, day d and hour h cannot exceed the installed storage energy multiplied by the maximum storage percentage.

$$\forall s, \forall y \geq Y_s, \forall d, \forall h, soc_{s,y,d,h} \leq ise_{s,y} \cdot MaxSt^s$$

Min Storage Constraint: the state of charge of technology s, at year y, day d and hour h should be greater than the installed storage energy multiplied by the minimum storage percentage.

$$\forall s, \forall y \geq Y_s, \forall d, \forall h, soc_{s,y,d,h} \geq ise_{s,y} \cdot MinSt^s$$

State of Charge Constraint: the state of charge of technology s, at year y, day d and hour h greater than 1 is equal to the state of charge at h-1 in addition to the charging at h-1 multiplied by the charging efficiency minus the discharging at h-1 divided by the discharging efficiency.

$$\forall s, \forall y \geq Y_s, \forall d, \forall h > 0, soc_{s,y,d,h} = soc_{s,y,d,h-1} + ch_{s,y,d,h-1} \cdot ChE^s - \frac{dch_{s,y,d,h-1}}{DchE^s}$$

State of Charge Initial Constraint: the SOC at h=0 (beginning of the day) should equal to the SOC at h=23 (at the end of the day) in addition to the charging at h=23 multiplied by the charging efficiency minus the discharging at h=23 divided by the discharging efficiency.

$$\forall s, \forall y \geq Y_s, \forall d, soc_{s,y,d,h=0} = soc_{s,y,d,h=23} + ch_{s,y,d,h=23} \cdot ChE^s - \frac{dch_{s,y,d,h=23}}{DchE^s}$$

3.1.2.4. Fuel Opex

The Fuel Opex represents the cost of buying fuel to operate the non-renewable generation technologies (diesel generators). It is the summation, over all the years, of the product of the dispatched capacity, the heat rate and the fuel price over all hours and days d multiplied by the weight of the representative days over all the generation technologies g divided by million.

$$FlOx = \sum_{y=Ys} \left\{ \frac{1}{(1+i)^y} \cdot \left(\sum_{g=0} \left(\sum_{d-0} (W^d \cdot \sum_{h=0} de_{g,y,d,h}) \cdot HR^g \cdot FuPr^y \right) \right) / million \right\}$$

3.1.2.5. Emissions Tax

The Emissions Tax on CO2 emissions is the summation, over all the years, of the product of the dispatched capacity, the heat rate, pollution emissions factor and the emissions tax over all hours and days d multiplied by the weight of the representative days over all the generation technologies g divided by thousand divided by million.

$$ET = \sum_{y=Ys} \left\{ \frac{1}{(1+i)^y} \cdot \left(\sum_{g=0} \left(\sum_{d-0} (W^d \cdot \sum_{h=0} de_{g,y,d,h}) \cdot HR^g \cdot PEF^g \ \cdot EUT \right) \right) / thousand \ / million \right\}$$

3.1.2.6. Lost Load Cost

The Lost Load Cost is the cost of the unserved demand and it is the the summation, over all the years, of the product of the unserved demand and the value of lost load over all hours and days d multiplied by the weight of the representative days divided by million.

$$LLC = \sum_{y=Ys} \left\{ \frac{1}{(1+i)^y} \cdot \left(\sum_{d-0} (W^d \cdot \sum_{h=0} usd_{y,d,h}) \cdot VLL \right) / million \right\}$$

3.1.2.7. Excess Load Cost

The Excess Load Cost is the cost of the excess electricity load and it is the summation, over all the years, of the product of the excess electricity and the value of excess load over all hours and days d multiplied by the weight of the representative days divided by million.

$$ELC = \sum_{y=Ys} \left\{ \frac{1}{(1+i)^y} \cdot \left(\sum_{d-0} (W^d \cdot \sum_{h=0} ee_{y,d,h}) \cdot VEL \right) / million \right\}$$

3.1.2.8. Purchased Electricity Cost

The purchased electricity cost is the cost of purchased electricity from the central grid and it is the summation, over all the years, of the product of the purchased electricity and the central grid tariff over all hours and days d multiplied by the weight of the representative days divided by thousand.

$$PEC = \sum_{y=Ys} \left\{ \frac{1}{(1+i)^y} \cdot \left(\sum_{d-0} (W^d \cdot \sum_{h=0} pe_{y,d,h}) \cdot Tar \right) / thousand \right\}$$

Purchased Electricity Constraint: We cannot purchase electricity from the centralized grid before it exists.

$$\forall y\ , Y_s \leq y < T_{Grid}, \forall d, \forall h, pe_{y,d,h} = \ 0$$

Purchased Electricity Amount Constraint: We cannot purchase more than the allowable purchase limit.

$$\forall y \geq \max(Ys, T_{Grid)}, \forall d, \forall h, pe_{y,d,h} \leq PL$$

3.1.2.9. Revenues

The Revenues are the revenues generated by selling electricity to the central grid and it is the summation, over all the years, of the product of the sold electricity and the central grid feed-in tariff over all hours and days d multiplied by the weight of the representative days divided by thousand.

$$R = \sum_{y=Ys} \left\{ \frac{1}{(1+i)^y} \cdot \left(\sum_{g=0} \left(\sum_{d-0} (W^d \cdot \sum_{h=0} se_{g,y,d,h}) \cdot FiT \right) \right) / thousand \right\}$$

Sold Electricity Constraint: We cannot sell electricity to the centralized grid before it exists.

$$\forall g, \forall y\ , y_s \leq y < T_{Grid}, \forall d, \forall h, se_{g,y,d,h} = \ 0$$

Sold Electricity Diesel Constraint: We cannot sell electricity produced by diesel generators.

$$g \in DG, \forall y, \forall d, \forall h, se_{g,y,d,h} = \ 0$$

Sold Electricity Amount Constraint: We cannot sell more than the allowable purchase limit.

$$\forall g, \forall y \geq \max(Ys, T_{Grid)}, \forall d, \forall h, \sum_{g} se_{g,y,d,h}\ \leq SL$$

3.1.2.10. Value of Early Retirement

The Value of Early Retirement is revenues generated by selling the equipment we have before the end of their lifetime if that was feasible and it is stated in the equation below. It is the summation of the product of the Generation Unit Capex, the Retired Capacity and the linear depreciation of each generation technology from one side and the product of the Storage Unit Capex (power and energy), the Retired Storage (power and energy) and the linear depreciation of each storage technology on the other side over all the years.

If early retirement allowed

$$VER = \sum_{y=Ys} \left\{ \frac{1}{(1+i)^y} \cdot \left(\sum_{g=0} \left(\sum_{a=0}^{a=y} rc_{g,y,a} \cdot GUC^g \cdot RmVal^{g,y-a} \right) + \sum_{s=0} [\sum_{a=0}^{a=y} (rsp_{s,y,a} \cdot SPUC^s + rse_{s,y,a} \cdot SEUC^s) \cdot RmValS^{s,y-a}] \right) \right\}$$

else

$$VER = 0$$

3.1.2.11. Salvage Value

The Salvage Value is the value of the equipment we have at the end of the project's lifetime. It is the summation of the product of the Generation Unit Capex, the Remaining Capacity and the linear depreciation of each generation technology from one side and the product of the Storage Unit Capex (power and energy), the Remaining Storage (power and energy) and the linear depreciation of each storage technology on the other side at the last year.

$$SV = \left\{ \frac{1}{(1+i)^{Y+1}} \cdot \left(\sum_{g=0} \left(\sum_{a=0}^{a=Y-1} rmc_{g,y,a} \cdot GUC^g \cdot RmVal^{g,Y+1-a} \right) + \sum_{s=0} [\sum_{a=0}^{a=Y-1} (rmsp_{s,y,a} \cdot SPUC^s + rmse_{s,y,a} \cdot SEUC^s) \cdot RmValS^{s,Y+1-a}] \right) \right\}$$

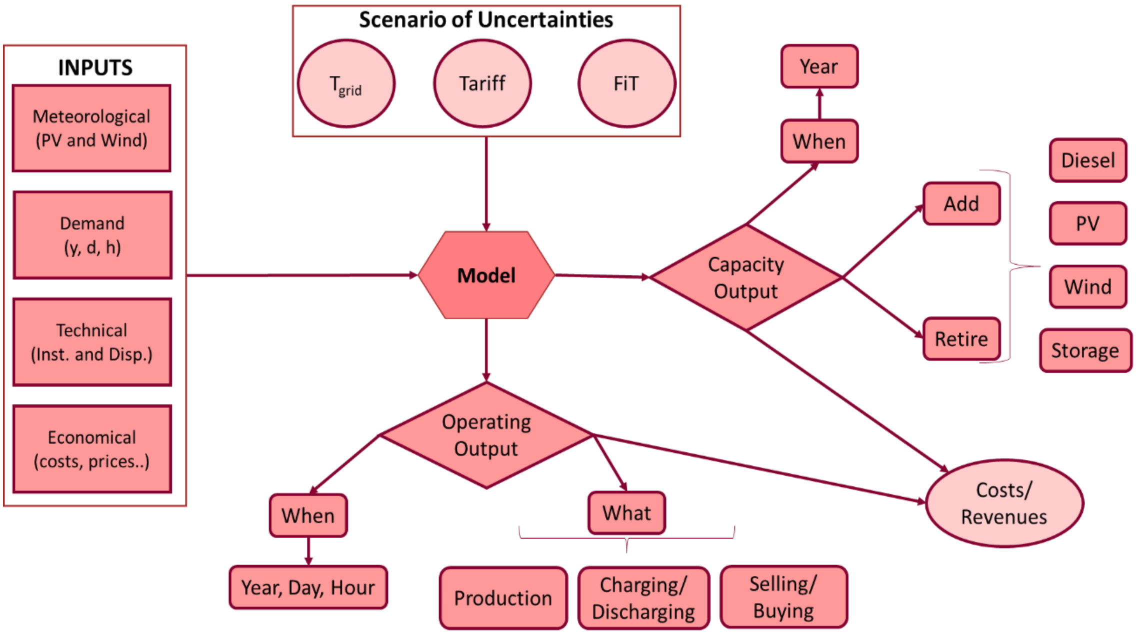

Figure 1: Deterministic Model Summary

Figure 1, shows how the deterministic model works. First of all, we have the inputs. The inputs (previously mentioned in the tables) are divided into several categories including meteorological data related to the solar PV and wind capacity factors (in terms of years, days and hours), electricity demand (in terms of years, days and hours), technical and economical data related to the technologies and policies. The uncertainties that are tackled are also fed into the model through a scenario. The model takes the inputs and constraints and optimizes accordingly. The output of the model (mentioned in the decision variables table) is basically divided into two parts capacity output and operating output. The capacity output is related to what technology to add or retire and when (in terms of years). The operating output is related to the dispatching, charging/discharging and selling/purchasing in terms of amounts and schedule (years, days and hours).

3.2. Stochastic Mathematical Model

The Purpose of the Stochastic Model is to have a plan that takes into account a wide variety of scenarios (scenario denoted by c and probability P). Our stochastic model is a two-stage stochastic model. The first stage decides on the installation decisions (what capacities to add/retire and when) for all scenarios, while the second stage decides on the operational decisions by each scenario. The decision variables and constraints that will be affected by the scenarios are those that are related to dispatching only while the other decision variables and constraints that are related to installations are not affected by the stochastic model's scenarios but takes into consideration all the scenarios together and gives an optimal installation plan for the given scenarios. Therefore, we will have two components in the objective function. Inputs are shown in table 5 and decision variables are shown in table 6.

Table 5: Stochastic Model Inputs

name	Description	Unit
Y	number of years	Years
y	Index for years	Years
Ys	Year of start of planning	Years
i	Discount Rate	%
G	Number of generation technologies considered	
g	Index for generation technologies	
DG	Set of indices of diesel generation technologies	
PVG	Set of indices of PV generation technologies	
WG	Set of indices of wind generation technologies	
S	Number of storage technologies considered	
s	Index for storage technologies	
D	Number of representative days	Days

d	Index for representative days	Days
W^d	Yearly weight of representative days	Days/year
H	Total hours per day	Hours
h	Index for hours	Hours
$T_{c,Grid}$	Time where grid electricity will be available 24/24 in scenario c	Years
a	Index of year	Years
c	Index of scenarios	
P_c	Probability of scenario c	
GUC^g	Generation unit capex of generation technology g	m$/MW
$SPUC^s$	Storage power unit capex of storage technology s	m$/MW
$SEUC^s$	Storage energy unit capex of storage technology s	m$/MWh
$GUFO^g$	Generation unit fixed opex of generation technology g	$/MW
$SPFO^s$	Storage power unit fixed opex of storage technology s	$/MW
$SEFO^s$	Storage energy unit fixed opex of storage technology s	$/MWh
$GUVO^g$	Generation unit non-fuel variable opex of generation technology g	$/MWh
$SUVO^s$	Storage unit non-fuel variable opex of storage technology s	$/MWh
$InpC^{g,a}$	Input capacity of generation technology g at year Ys installed at year a	MW
$InpSP^{s,a}$	Input power of storage technology s at year Ys installed at year a	MW
$InpSE^{s,a}$	Input energy of storage technology s at year Ys installed at year a	MW
$PVCF^{d,h}$	PV Capacity factor at day d and hour h	%
$WCF^{d,h}$	Wind Capacity factor at day d and hour h	%
HR^g	Heat rate of generation technology g	L/MWh
$FuPr^y$	Fuel price at year y	$/L
EUT	Emissions tax per Carbon dioxide emissions	$/Tonnes
PEF^g	Emission per fuel consumption of generation technology g	Kg/L
VLL	Value of lost load	$/MWh
VEL	Value of excess load	$/MWh
Tar^c	EDL tariff price in scenario c	$/kWh
LT^g	Life time of generation technology g	Years
LT^s	Life time of storage technology s	Years
FiT^c	Feed in Tariff in scenario c	$/kWh

$Dm^{y,d,h}$	Electric demand at year y, day d and hour h	MW
CL^{g}	Installed capacity limit on technology g	MW
SL	Sold limit	MW
PL	Purchased limit from EDL	MW
$MaxSt^{s}$	Maximum storage of storage technology s	%
$MinSt^{s}$	Minimum storage of storage technology s	%
ChE^{s}	Charge efficiency of storage technology s	%
$DchE^{s}$	Discharge efficiency of storage technology s	%
$RmVal^{g,y}$	Remaining value of installed generation technology	%
$RmValS^{s,y}$	Remaining value of installed storage technology	%

Table 6: Stochastic Model Decision Variables

name	Description	Unit
Cx	Total capex Present value of all	m$
FOx	Total fixed opex	m$
VOx_c	Total nonfuel variable opex in scenario c	m$
$FlOx_c$	Total fuel opex in scenario c	m$
ET_c	Total emissions tax in scenario c	m$
LLC_c	Total lost load cost in scenario c	m$
ELC_c	Total excess load cost in scenario c	m$
PEC_c	Total Purchased electricity cost in scenario c	m$
R_c	Total revenues in scenario c	m$
VER	Value of Early Retirement	m$
SV	Salvage value	m$
$ic_{g,y}$	Installed capacity of generation technology g at year y	MW
$isp_{s,y}$	Installed power of storage technology s at year y	MW
$ise_{s,y}$	Installed energy of storage technology s at year y	MWh
$ac_{g,y}$	Added capacity of generation technology g at year y	MW
$asp_{s,y}$	Added power of storage technology s at year y	MW
$ase_{s,y}$	Added energy of storage technology s at year y	MWh
$rc_{g,y,a}$	Retired capacity of generation technology g at year y installed at year a	MW
$rsp_{s,y,a}$	Retired power of storage technology s at year y installed at year a	MW
$rse_{s,y,a}$	Retired energy of storage technology s at year y installed at year a	MWh

$rmc_{g,y,a}$	Remaining capacity of generation technology g at year y installed at year a	MW
$rmsp_{s,y,a}$	Remaining power of storage technology s at year y installed at year a	MW
$rmse_{s,y,a}$	Remaining energy of storage technology s at year y installed at year a	MWh
$de_{c,g,y,d,h}$	Dispatched electricity from generation technology g at year y, day d and hour h in scenario c	MW
$usd_{c,y,d,h}$	unserved demand at year y, day d and hour h in scenario c	MW
$ee_{c,y,d,h}$	excess electricity at year y, day d and hour h in scenario c	MW
$pe_{c,y,d,h}$	Purchased electricity from grid at year y, day d and hour h in scenario c	MW
$ch_{c,s,y,d,h}$	Charging capacity of storage technology s at year y, day d and hour h in scenario c	MW
$se_{c,g,y,d,h}$	Sold Electricity from generation technology g at year y, day d and hour h in scenario c	MW
$dch_{c,s,y,d,h}$	Discharging capacity of storage technology s at year y, day d and hour h in scenario c	MW
$soc_{c,s,y,d,h}$	State of charge of storage technology s at year y, day d and hour h in scenario c	MWh

3.2.1. Objective Function

The first component is a fixed component that includes the costs and revenues that are related to installation only such as Capex, Fixed Opex, Value of Early Retirement and Salvage Value. The other component of the objective function is a probabilistic component that includes the expected value of the costs and the revenues that are related to the dispatching. The expected value of a certain component is calculated by multiplying each of cost/revenue of each scenario c by the probability of scenario c and then summing all of those values. The probabilistic components are: Variable Opex, Fuel Opex, Emissions Tax, Lost Load Cost, Excess Load Cost and Purchased Electricity Cost and Revenues.

$$MIN\left[Cx + FOx - (VER + SV) + \left(\sum_{c} P_c \cdot (VOx_c + FlOx_c + ET_c + LLC_c + ELC_c + PEC_c - R_c)\right)\right]$$

Net present value is always calculated at year 0.

Note: $\sum_g = all\ g\ technologies\ in\ (G), unless\ an\ upper\ bound\ is\ written (\sum_g^{G=i})$

similarly to all s,y,d,h

3.2.2. Constraints

The constraints are somehow similar to the constraints in 3.1.2. The only difference is adding a "$\forall c$" in every dispatching variable and constraint.

3.2.2.1. Total Capex

$$Cx = \sum_{y=Ys}\left\{\frac{1}{(1+i)^y} \cdot \left(\sum_{g=0}\left(GUC^g \cdot ac_{g,y}\right) + \sum_{s=0}[SPUC^s \cdot asp_{s,y} + SEUC^s \cdot ase_{s,y}]\right)\right\}$$

Installed Capacity Limit Constraint

$$\forall g, \forall y \geq Ys, ic_{g,y} \leq CL^g$$

Installed Capacity Initial Constraint

If $Ys = 0$:

$$\forall g, ic_{g,Ys} = ac_{g,Ys}$$

Else:

Input: $InpC^{g,a}$

Installed Capacity Constraint

$$\forall g, \forall y > 0, y = Ys, ic_{g,y} = \sum_{a=0}^{a=y-1} InpC^{g,a} + ac_{g,y} - \sum_{a=0}^{a=y-1} rc_{g,y,a}$$

$$\forall g, \forall y > \max(0, Ys), ic_{g,y} = ic_{g,y-1} + ac_{g,y} - \sum_{a=0}^{a=y-1} rc_{g,y,a}$$

Retirement Initial Constraint

$$\forall g, \forall y \geq Ys, \forall a \geq y, rc_{g,y,a} = 0$$

Retirement Constraint (1 early ret allowed, 2 early ret not allowed)

If early ret allowed:

$$\forall g, y > LT_g, y \geq Ys, \forall a < Ys, a = y - LT_g, rc_{g,y,a} \geq InpC^{g,a} - \sum_{y1=Ys}^{y1=y-1} rc_{g,y1,a}$$

$$\forall g, y > LT_g, y \geq Ys, \forall a \geq Ys, a = y - LT_g, rc_{g,y,a} \geq ac_{g,a} - \sum_{y1=a}^{y1=y-1} rc_{g,y1,a}$$

Else:

$$\forall g, y > LT_g, y \geq Ys, \forall a < Ys, a = y - LT_g, rc_{g,y,a} = InpC^{g,a}$$

$$\forall g, y > LT_g, y \geq Ys, \forall a \geq Ys, a = y - LT_g, rc_{g,y,a} = ac_{g,a}$$

Remaining Capacity Constraint

$$\forall g, y > 0, y = Ys, a < y, rmc_{g,y,a} = InpC^{g,a} - rc_{g,y,a}$$

$$\forall g, \forall y > \max(0, Ys), a < y, rmc_{g,y,a} = rmc_{g,y-1,a} - rc_{g,y,a}$$

$$\forall g, \forall y \geq Ys, a = y, rmc_{g,y,a} = ac_{g,a}$$

$$\forall g, \forall y \geq Ys, \forall a > y, rmc_{g,y,a} = 0$$

If $Ys = 0$:

Installed Storage Power Initial Constraint

$$\forall s, isp_{s,Ys} = \; asp_{s,Ys}$$

Else:

Installed Storage Power Constraint

$$\forall s, \forall y > 0, y = Ys, isp_{s,y} = \sum_{a=0}^{a=y-1} InpSP^{s,a} + asp_{s,y} - \sum_{a=0}^{a=y-1} rsp_{s,y,a}$$

$$\forall s, \forall y > \max(0, Ys), isp_{s,y} = isp_{s,y-1} + asp_{s,y} - \sum_{a=0}^{a=y-1} rsp_{s,y,a}$$

Retirement Storage Power Initial Constraint

$$\forall s, \forall y \geq Ys, \forall a \geq y, rsp_{s,y,a} = \; 0$$

Retirement Storage Power Constraint (1 early ret allowed, 2 early ret not allowed)

If early ret allowed:

$$\forall s, y > LT_s, y \geq Ys, \forall a < Ys, a = y - LT_s, rsp_{s,y,a} \geq \; InpSP^{s,a} - \sum_{y1=Ys}^{y1=y-1} rsp_{g,y1,a}$$

$$\forall s, y > LT_s, y \geq Ys, \forall a \geq Ys, a = y - LT_s, rsp_{s,y,a} \geq \; asp_{sa} - \sum_{y1=a}^{y1=y-1} rsp_{g,y1,a}$$

Else:

$$\forall s, y > LT_s, y \geq Ys, \forall a < Ys, a = y - LT_s, rsp_{s,y,a} = \; InpSP^{s,a}$$

$$\forall s, y > LT_s, y \geq Ys, \forall a \geq Ys, a = y - LT_s, rsp_{s,y,a} = \; asp_{s,a}$$

Remaining Storage Power Constraint

$$\forall s, y > 0, y = Ys, a < y, rmsp_{s,y,a} = \; InpSP^{s,a} - rsp_{s,y,a}$$

$$\forall s, \forall y > \max(0, Ys)\,, a < y, rmsp_{s,y,a} = rmsp_{s,y-1,a} - rsp_{s,y,a}$$

$$\forall s, \forall y \geq Ys, a = y, rmsp_{s,y,a} = asp_{s,y}$$

$$\forall s, \forall y \geq Ys, \forall a > y, rmsp_{s,y,a} = 0$$

If $Ys = 0$:

Installed Storage Energy Initial Constraint

$$\forall s, ise_{s,Ys} = \ ase_{s,Ys}$$

Else:

Installed Storage Energy Constraint

$$\forall s, \forall y > 0, y = Ys, ise_{s,y} = \sum_{a=0}^{a=y-1} InpSE^{s,a} + ase_{s,y} - \sum_{a=1}^{a=y} rse_{s,y,a}$$

$$\forall s,, \forall y > \max(0, Ys)\,, ise_{s,y} = ise_{s,y-1} + ase_{s,y} - \sum_{a=1}^{a=y} rse_{s,y,a}$$

Retirement Storage Energy Constraint

$$\forall s, \forall y \geq Ys, \forall a \geq y, rse_{s,y,a} = \ 0$$

Retirement Storage Energy Constraint (1 early ret allowed, 2 early ret not allowed)

If early ret allowed:

$$\forall s, y > LT_s, y \geq Ys, \forall a < Ys, a = y - LT_s, rse_{s,y,a} \geq \ InpSE^{s,a} - \sum_{y1=Ys}^{y1=y-1} rse_{g,y1,a}$$

$$\forall s, y > LT_s, y \geq Ys, \forall a \geq Ys, a = y - LT_s, rse_{s,y,a} \geq \ ase_{s,a} - \sum_{y1=a}^{y1=y-1} rse_{g,y1,a}$$

Else:

$$\forall s, y > LT_s, y \geq Ys, \forall a < Ys, a = y - LT_s, rse_{s,y,a} = \ InpSE^{s,a}$$

$$\forall s, y > LT_s, y \geq Ys, \forall a \geq Ys, a = y - LT_s, rse_{s,y,a} = \ ase_{s,a}$$

Remaining Storage Energy Constraint

$$\forall s, y > 1, y = Ys, a < y, rmse_{s,y,a} = \ InpSE^{s,a} - rse_{s,y,a}$$

$$\forall s,,\forall y > \max(0, Ys)\,, a < y, rmse_{s,y,a} = rmse_{s,y-1,a} - rse_{s,y,a}$$

$$\forall s, \forall y \geq Ys, a = y, rmse_{s,y,a} = ase_{s,y}$$

$$\forall s, \forall y \geq Ys, \forall a > y, rmse_{s,y,a} = 0$$

Installed, Remaining, Added, Retired capacities/storage power/storage energy are all happening at the beginning of the year.

Process:

1- Retire

2- Add

3- Compute Installed and Remaining

This process happens at the beginning of the year and before running the powerplants

All variables and constraints related to dispatched electricity should start at Ys (so they are not important for us at years y<Ys for the purpose of including added capacities as an input)

<u>3.2.2.2. Fixed Opex</u>

$$FOx = \sum_{y=Ys} \left\{ \frac{1}{(1+i)^y} \cdot \left(\sum_{g=0} \left(GUFO^g \cdot ic_{g,y} \right) + \sum_{s=0} \left[SPFO^s \cdot isp_{s,y} + SEFO^s \cdot ise_{s,y} \right] \right) /million \right\}$$

3.2.2.3. Variable Opex

$$\forall c, VOx_c = \sum_{y=Ys} \left\{ \frac{1}{(1+i)^y} \right.$$

$$\cdot \left(\sum_{g=0} \left(GUVO^g \cdot \sum_{d-0} (W^d \cdot \sum_{h=0} de_{c,g,y,d,h}) \right) \right.$$

$$\left. \left. + \sum_{s=0} \left(SPVO^s \sum_{d-0} (W^d \cdot \sum_{h=0} dch_{c,s,y,d,h}) \right) \right) /million \right\}$$

Energy Balance Equation Constraint

$$\forall c, \forall y \geq Y_s, \forall d, \forall h, Dm^{y,d,h} + \sum_{s=0} ch_{c,s,y,d,h} + \sum_{g=0} se_{c,g,y,d,h} - usd_{c,y,d,h}$$

$$= \sum_{g=0} de_{c,g,y,d,h} + \sum_{s=0} dch_{c,s,y,d,h} + pe_{c,y,d,h} - ee_{c,y,d,h}$$

Dispatched Diesel Capacity Constraint

$$\forall c, g \in DG, \forall y \geq Y_s, \forall d, \forall h, de_{c,g,y,d,h} \leq ic_{g,y}$$

Dispatched PV Capacity Constraint

$$\forall c, g \in PVG, \forall y \geq Y_s, \forall d, \forall h, de_{c,g,y,d,h} \leq ic_{g,y} \cdot PVCF^{d,h}$$

Dispatched Wind Capacity Constraint

$$\forall c, \forall g = WG, \forall y \geq Y_s, \forall d, \forall h, de_{c,g,y,d,h} \leq ic_{g,y} \cdot WCF^{d,h}$$

Max Charging Constraint

$$\forall c, \forall s, \forall y \geq Y_s, \forall d, \forall h, ch_{c,s,y,d,h} \leq isp_{s,y}$$

Max Discharging Constraint

$$\forall c, \forall s, \forall y \geq Y_s, \forall d, \forall h, dch_{c,s,y,d,h} \leq isp_{s,y}$$

Max Storage Constraint

$$\forall c, \forall s, \forall y \geq Y_s, \forall d, \forall h, soc_{c,s,y,d,h} \leq ise_{s,y} \cdot MaxSt^s$$

Min Storage Constraint

$$\forall c, \forall s, \forall y \geq Y_s, \forall d, \forall h, soc_{c,s,y,d,h} \geq ise_{s,y} \cdot MinSt^s$$

State of Charge Constraint

$$\forall c, \forall s, \forall y \geq Y_s, \forall d, \forall h > 0, soc_{c,s,y,d,h}$$

$$= soc_{c,s,y,d,h-1} + ch_{c,s,y,d,h-1} \cdot ChE^s - \frac{dch_{c,s,y,d,h-1}}{DchE^s}$$

State of Charge Initial Constraint

$$\forall c, \forall s, \forall y \geq Y_s, \forall d, soc_{c,s,y,d,h=0}$$

$$= soc_{c,s,y,d,h=23} + ch_{c,s,y,d,h=23} \cdot ChE^s - \frac{dch_{c,s,y,d,h=23}}{DchE^s}$$

3.2.2.4. Fuel Opex

$$\forall c, FlOx_c = \sum_{y=Ys} \left\{ \frac{1}{(1+i)^y} \right.$$

$$\left. \cdot \left(\sum_{g=0} \left(\sum_{d-0} (W^d \cdot \sum_{h=0} de_{c,g,y,d,h}) \cdot HR^g \cdot FuPr^y \right) \right) / million \right\}$$

3.2.2.5. Emissions Tax

$$\forall c, ET_c = \sum_{y=Ys} \left\{ \frac{1}{(1+i)^y} \cdot \left(\sum_{g=0} \left(\sum_{d-0} (W^d \cdot \sum_{h=0} de_{c,g,y,d,h}) \cdot HR^g \cdot PEF^g \ \cdot EUT \right) \right) / thousand \right. \\ \left. / million \right\}$$

3.2.2.6. Lost Load Cost

$$\forall c, LLC_c = \sum_{y=Ys} \left\{ \frac{1}{(1+i)^y} \cdot \left(\sum_{d-0} (W^d \cdot \sum_{h=0} usd_{c,y,d,h}) \cdot VLL \right) / million \right\}$$

3.2.2.7. Excess Load Cost

$$\forall c, ELC_c = \sum_{y=Ys} \left\{ \frac{1}{(1+i)^y} \cdot \left(\sum_{d-0} (W^d \cdot \sum_{h=0} ee_{c,y,d,h}) \cdot VEL \right) / million \right\}$$

3.2.2.8. Purchased Electricity Cost

$$\forall c, PEC_c = \sum_{y=Ys} \left\{ \frac{1}{(1+i)^y} \cdot \left(\sum_{d-0} (W^d \cdot \sum_{h=0} pe_{c,y,d,h}) \cdot Tar^c \right) / thousand \right\}$$

Purchased Electricity Constraint

$$\forall c, \forall y\ , Y_s \leq y < T_{c,Grid}, \forall d, \forall h, pe_{y,d,h} = 0$$

Purchased Electricity Amount Constraint

$$\forall c, \forall y \geq \max(Ys, T_{c,Grid)}, \forall d, \forall h, pe_{y,d,h} \leq PL$$

3.2.2.9. Revenues

$$\forall c, R_c = \sum_{y=Ys} \left\{ \frac{1}{(1+i)^y} \cdot \left(\sum_{g=0} \left(\sum_{d-0} (W^d \cdot \sum_{h=0} se_{c,g,y,d,h}) \cdot FiT^c \right) \right) / thousand \right\}$$

Sold Electricity Constraint

$$\forall c, \forall g, \forall y\ , y_s \leq y < T_{c,Grid}, \forall d, \forall h, se_{c,g,y,d,h} = 0$$

Sold Electricity Diesel Constraint

$$\forall c, g \in DG, \forall y, \forall d, \forall h, se_{c,g,y,d,h} = 0$$

Sold Electricity Amount Constraint

$$\forall c, \forall g, \forall y \geq \max(Ys, T_{c,Grid)}, \forall d, \forall h, \sum_{g} se_{c,g,y,d,h} \leq SL$$

3.2.2.10. Value of Early Retirement

If early retirement allowed:

$$VER = \sum_{y=Ys} \left\{ \frac{1}{(1+i)^y} \right.$$

$$\cdot \left(\sum_{g=0} \left(\sum_{a=0}^{a=y} rc_{g,y,a} \cdot GUC^g \cdot RmVal^{g,y-a} \right) \right.$$

$$\left. \left. + \sum_{s=0} [\sum_{a=0}^{a=y} (rsp_{s,y,a} \cdot SPUC^s + rse_{s,y,a} \cdot SEUC^s) \cdot RmValS^{s,y-a}\ ] \right) \right\}$$

Else:

$$VER = 0$$

3.2.2.11. Salvage Value

$$SV = \left\{ \frac{1}{(1+i)^{Y+1}} \right.$$

$$\cdot \left(\sum_{g=0} \left(\sum_{a=0}^{a=Y-1} rmc_{g,y,a} \cdot GUC^{g} \cdot RmVal^{g,Y+1-a} \right) \right.$$

$$+ \sum_{s=0} [\sum_{a=0}^{a=Y-1} (rmsp_{s,y,a} \cdot SPUC^{s} + rmse_{s,y,a} \cdot SEUC^{s})$$

$$\left. \left. \cdot RmValS^{s,Y+1-a} \,] \right) \right\}$$

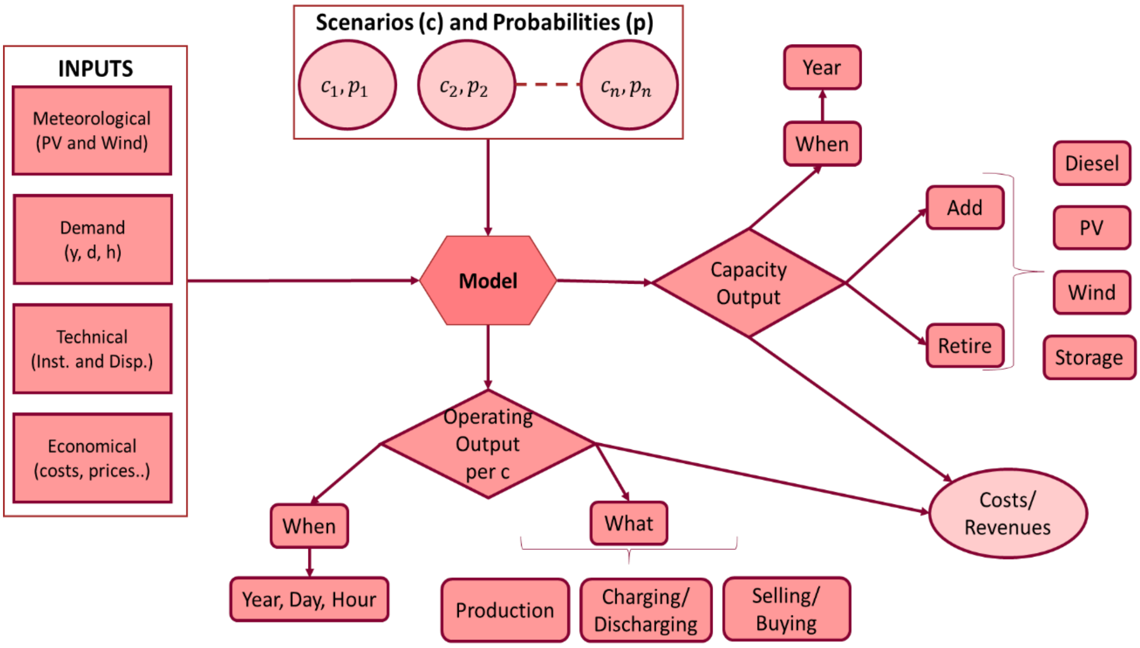

Figure 2: Stochastic Model Summary

Figure 2, shows how the stochastic model works. First of all, we have the inputs. The inputs (previously mentioned in the tables) are divided into several categories including meteorological data related to the solar PV and wind capacity factors (in terms of years, days and hours), electricity demand (in terms of years, days and hours), technical and economical data related to the technologies and policies. The uncertainties that are tackled are also fed into the model through a scenario. The model takes the inputs and constraints and optimizes accordingly. The output of the model (mentioned in the decision variables table) is basically divided into two parts capacity output (first stage) and it is common for all scenarios while the operating output (second stage) is per scenario (c). The capacity output is related to what technology to add or retire and when (in terms of years). The operating output is related to the dispatching, charging/discharging and selling/purchasing in terms of amounts and schedule (years, days and hours).

3.3. Model size and complexity

Since the objective function and all the constraints are linear and we don't have any integer decision variable, our models are considered to be Linear Programming Models. The complexity of our models is shown below by showing the number of the decision variables and constraints included in each of the deterministic, stochastic and dispatch model.

3.3.1. Deterministic Model

Decision variables number:

$$\begin{aligned} &Number\ of\ decision\ variables \\ &\qquad = 2(G \cdot Y) + 2(G \cdot Y \cdot Y) + 4(S \cdot Y) + 4(S \cdot Y \cdot Y) + 2(G \cdot Y \cdot D \cdot H) \\ &\qquad + 3(Y \cdot D \cdot H) + 3(S \cdot Y \cdot D \cdot H) \end{aligned}$$

Constraints number:

$$Number\ of\ constraints$$

$$= \ 2(G \cdot Y) + G + 5(G \cdot Y \cdot Y) + 2S + 2(S \cdot Y) + 10(S \cdot Y \cdot Y)$$

$$+ 2(G \cdot Y \cdot D \cdot H) + 7(Y \cdot D \cdot H) + 5(S \cdot Y \cdot D \cdot H)$$

For our case, G=3, S=1, Y=20, D=12, and H=24. Therefore, we will have 73,320 decision variables and 113,845 constraints.

3.3.2. Stochastic Model

Decision variables number:

$$Number\ of\ decision\ variables$$

$$= 2(G \cdot Y) + 2(G \cdot Y \cdot Y) + 4(S \cdot Y) + 4(S \cdot Y \cdot Y)$$

$$+ 2(C \cdot G \cdot Y \cdot D \cdot H) + 3(C \cdot Y \cdot D \cdot H) + 3(C \cdot S \cdot Y \cdot D \cdot H)$$

Constraints number:

$$Number\ of\ constraints$$

$$= \ 2(G \cdot Y) + G + 5(G \cdot Y \cdot Y) + 2S + 2(S \cdot Y) + 10(S \cdot Y \cdot Y)$$

$$+ 2(C \cdot G \cdot Y \cdot D \cdot H) + 7(C \cdot Y \cdot D \cdot H) + 5(C \cdot S \cdot Y \cdot D \cdot H)$$

For our case, C=12, G=3, S=1, Y=20, D=12, and H=24. Therefore, we will have 833,640 decision variables and 1,254,325 constraints.

Table 7: Model Size and Complexity Summary

	Decision Variables	Constraints
Deterministic	73,320	113,845
Stochastic	833,640	1,254,325

Error! Reference source not found. summarizes the number of decision variables and constraints in each of the proposed models.

3.4. Value of Policy Certainty

The main purpose of the proposed models is to assess and quantify the value of policy certainty. The uncertainties that we are tackling are purely related to energy policy and the good implementation of such policies. As mentioned in the introduction, Lebanon suffers in terms of electricity-related decision making. The value of policy certainty is obtained by calculating the NPV difference between planning under uncertainty (stochastic model) and planning under complete certainty (deterministic model). In order to calculate the value of policy certainty, we are using the following steps that are represented by figure 3:

1- Have a range of scenarios
2- Run each scenario into the deterministic model
3- Calculate the deterministic NPV_d
4- Feed all scenarios (C) with their probabilities into the stochastic model
5- Generate the installation results for all scenarios (first stage)
6- Retrieve the dispatching results and calculate the NPV_s by scenario
7- Calculate the value of policy certainty by subtracting NPV_s and NPV_d

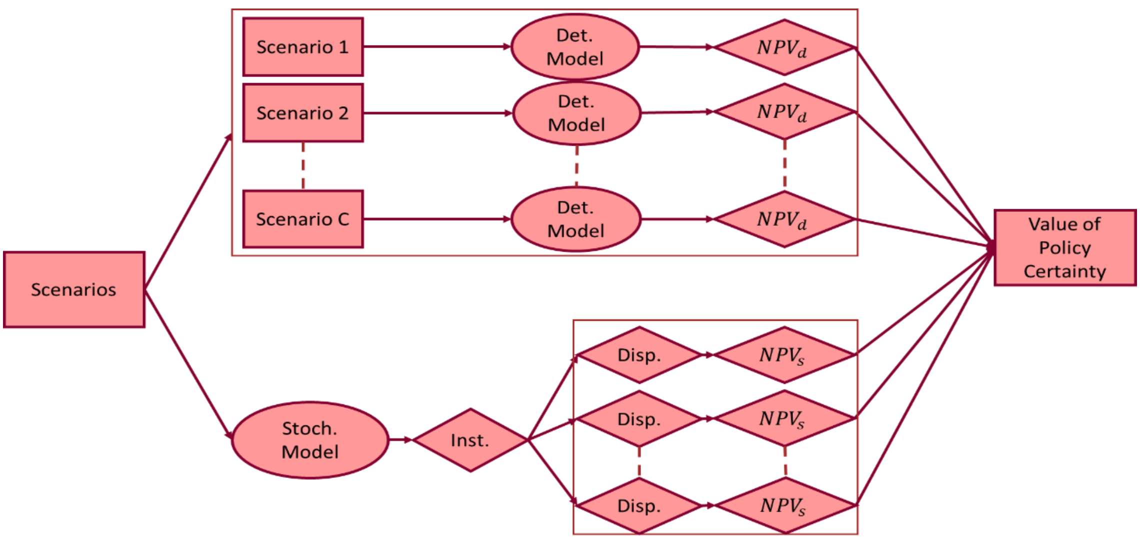

Figure 3: Value of Policy Certainty Calculation

3.5. Case Study Data

To apply the proposed mathematical model, “The Higher Matn” (Al-Matn Al-Aala) -a rural area in Lebanon that consists of around 25 villages - was chosen as a case study. As discussed in the introduction, Lebanon suffers from continuous electricity supply cutoff which affects the daily life of the citizens. And as a solution of this problem, households and communities improvised by investing in decentralized off-grid HRES to have access to a reliable, affordable and clean source of electricity.

3.5.1. Electricity

The Higher Matn region is connected to Sawfar transformation station. Sawfar station is one of the stations that are responsible for transforming high voltage (66 kV) electricity produced from the power plants to medium voltage (15 kV). As shown in figure 4, the station consists of two transformers: Transformer 1 (14 MW) and Transformer 2 (20 MW). After transformation, it distributes medium voltage electricity through distribution lines to more than 50 surrounding villages. Transformer 1 includes three distribution lines that are Shbeneyyi Line, Bhamdoun and Sawfar lines. Whereas, Transformer 2 includes three distribution lines that are Sharoon, Hammana and Mdayrej lines. The figure below represents the transformation and distribution process.

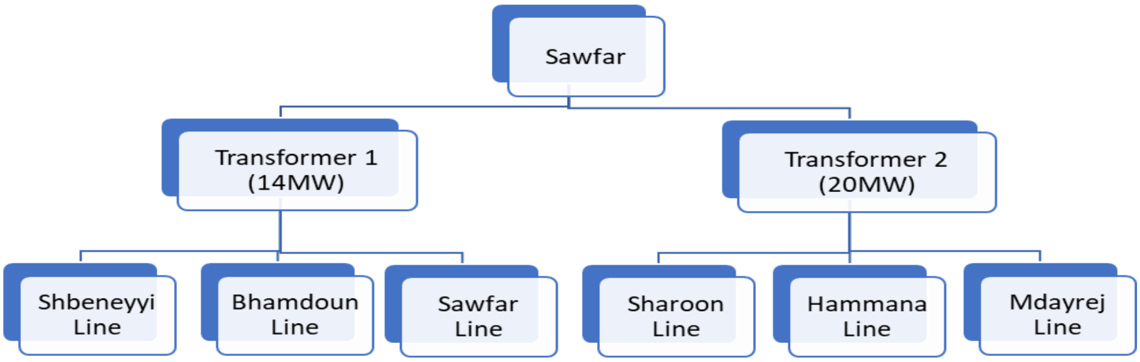

Figure 4: Sawfar Station Transformers Diagram

Hourly demand data (MW) is provided for each distribution line. Figure 5, shows the variations of power demand with respect to the hours of a day for a September average day.

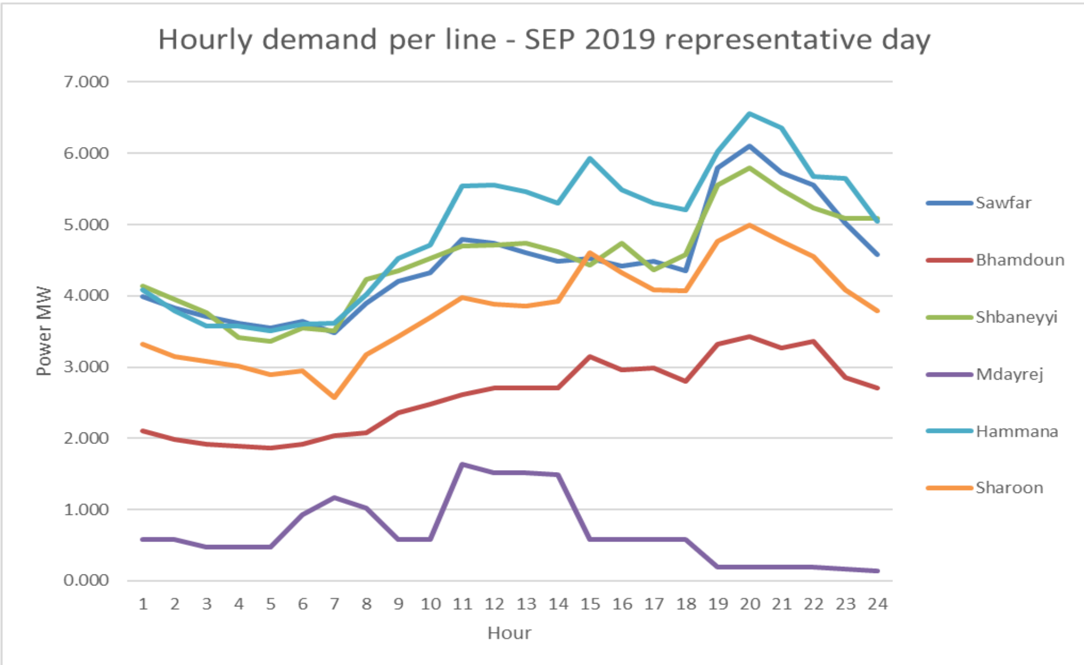

Figure 5: Variations of power demand with respect to the hours of an average day in September

For the case study purposes the group of three lines that cover the Higher Matn region were chosen which are Shbeneyyi, Hammana and Mdayrej lines. Figure 6 shows the map of the region including the transformation lines.

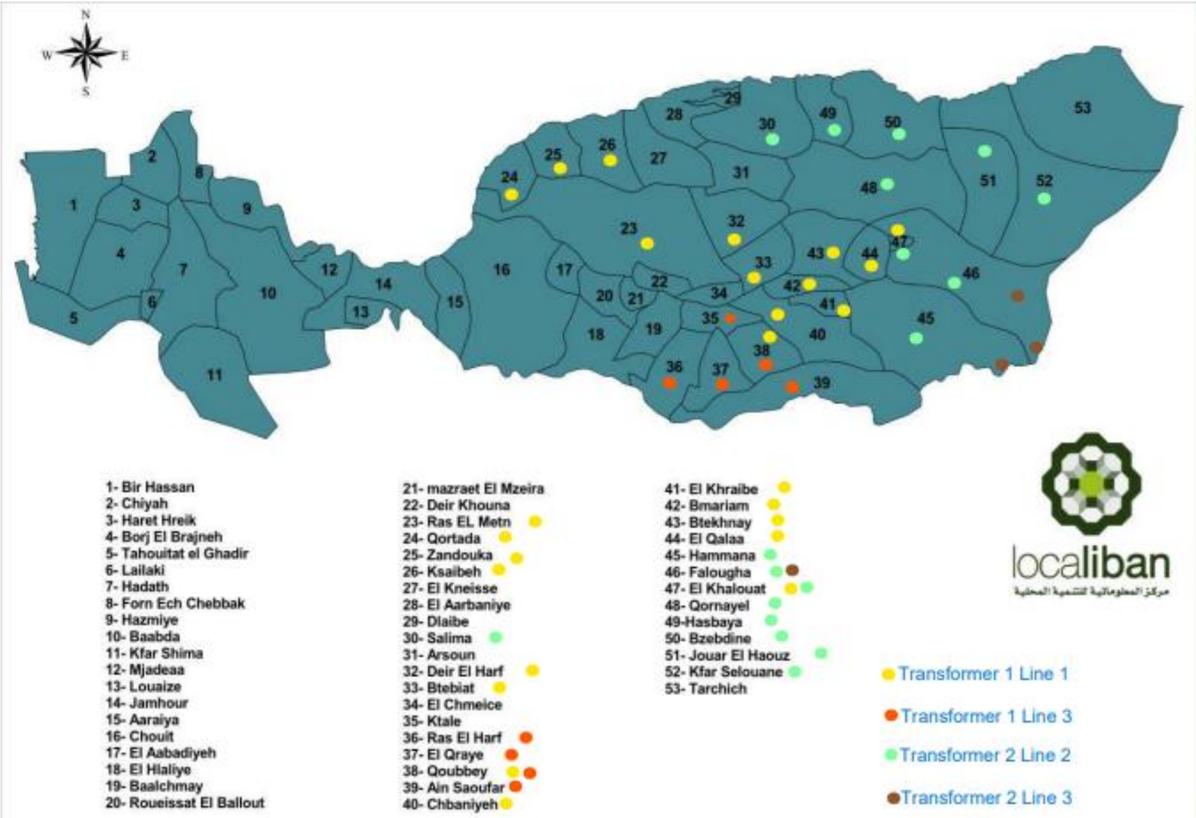

Figure 6: Higher Matn Region with Transformation Lines

After selecting the lines that we are targeting, we combined them into a common load profile as shown in figure 7. The August 4 Beirut Blast has had a significant impact on EDL (Ayoub, Rizkallah, & Abi Haidar, 2021). The data center was damaged because of the blast, and that prevented us from getting more data related to the demand. Therefore, the data of September is populated according to the demand of Lebanon as a whole and the results appear in figure 8.

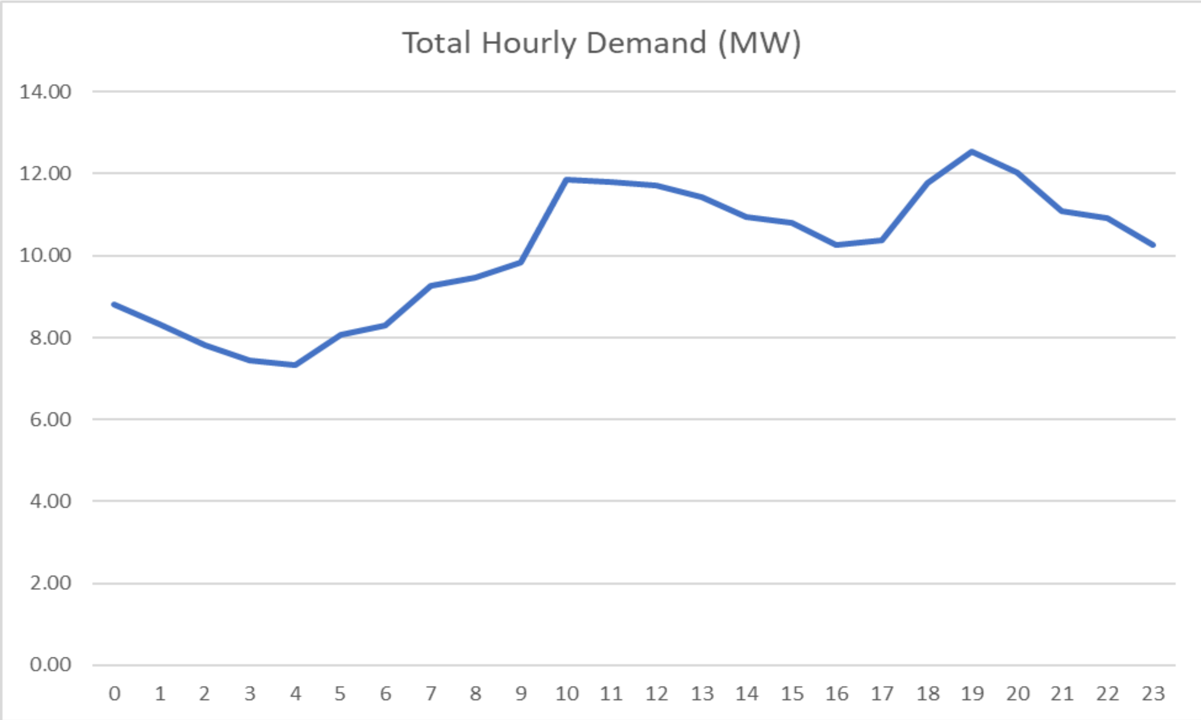

Figure 7: Combined Load Profile

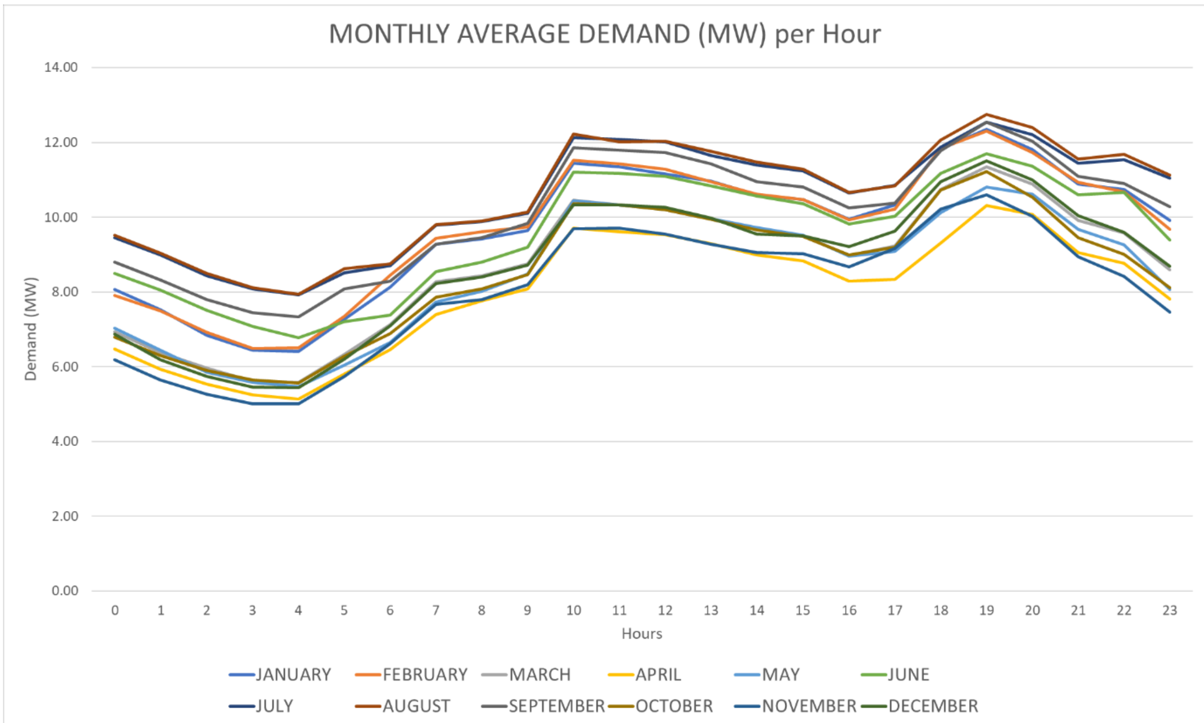

Figure 8: Monthly Load Profiles

3.5.2. Meteorological

Meteorological data of the region was retrieved from Renewables.Ninja (Renewables.ninja, n.d.). Solar PV and wind capacity factors are shown in Figures 9 and 10 respectively.

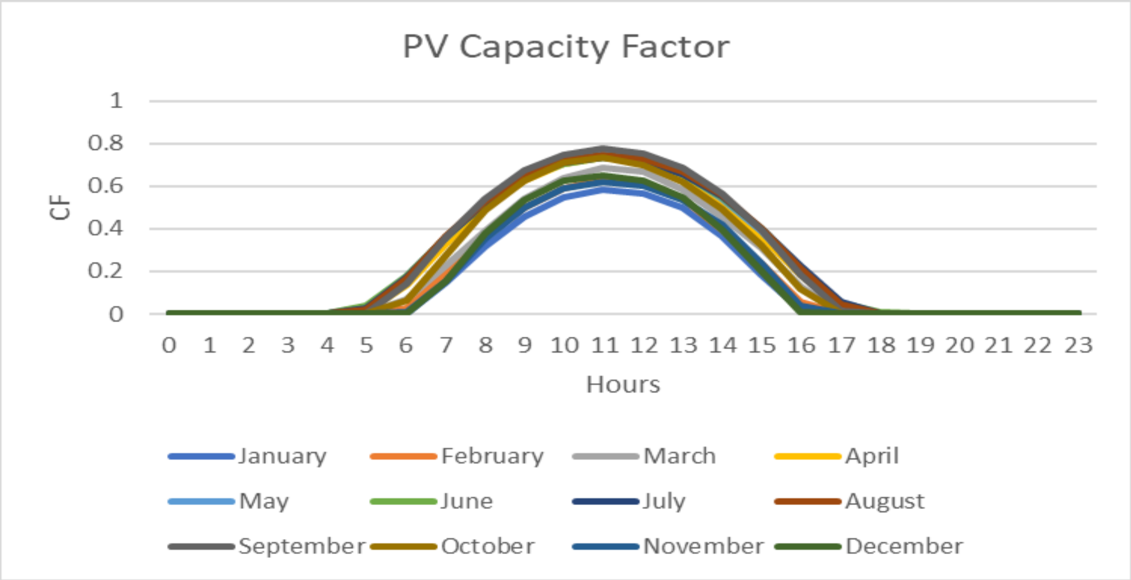

Figure 9: Solar PV Yearly Capacity Factor

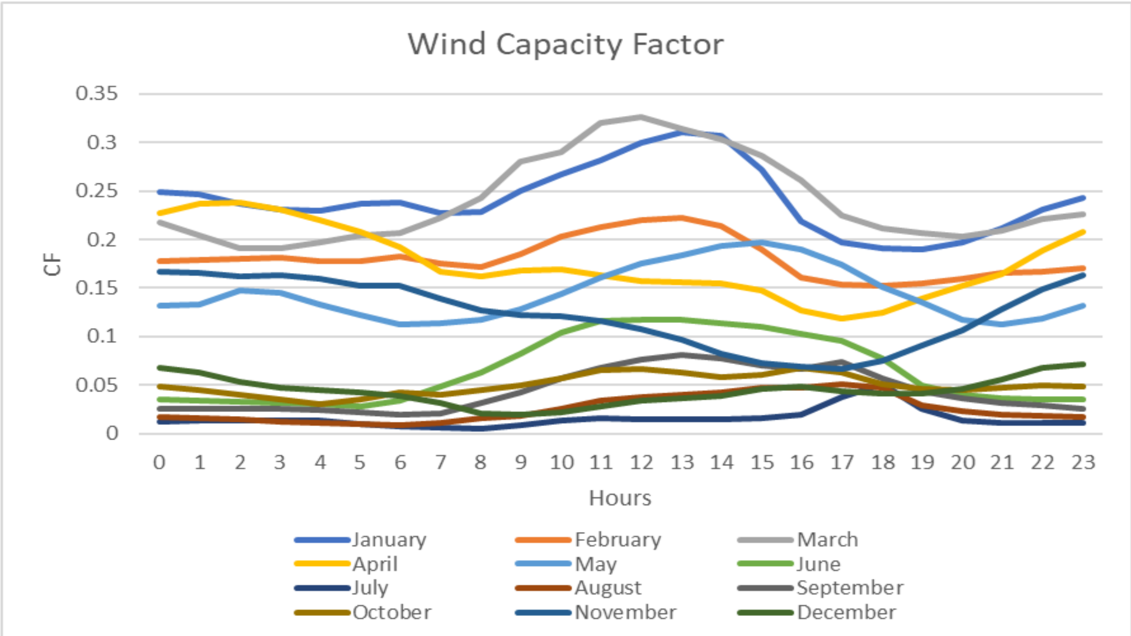

Figure 10: Wind Yearly Capacity Factor

CHAPTER 4

RESULTS

4.1. Deterministic Model

In this part we show the results of the suggested deterministic optimization model. We modeled the problem using Python and solved it using Gurobi solver. First we show the results of the base case in 4.1.1. The effect of grid uncertainty, centralized tariff and the feed-in tariff are shown in sections 4.1.2, 4.1.3 and 4.1.4 respectively.

4.1.1. Base Case (T_{grid}= 5, EDL Tariff= 0.15, Feed-in Tariff= 0.08)

The base case is a generated scenario of having the reliable central grid (T_{grid}) available after 5 years, having a centralized (EDL) tariff of 0.15 USD/kWh (selected based on the current EDL tariff range 0.09 and 0.27 USD/kWh) and having a feed-in tariff of 0.08 USD/kWh (selected based on the feed-in tariffs in near and similar developing countries). Figure 11, shows the net present value distribution of each component of the objective function. The red color represents the costs while the green color represents the revenues.

Moreover, the results of the yearly installed capacities of diesel, PV, wind and batteries are shown in figure 12. It is clear that no more diesel generators and batteries are installed after year 5- the year where the grid existed. The diesel generators and batteries, as shown in figure 13, are being retired (bars with the negative y-axis) at this year because it is not economical to operate diesel anymore after EDL electricity is available at a tariff of 0.15 USD/kWh while other technologies didn't retire.

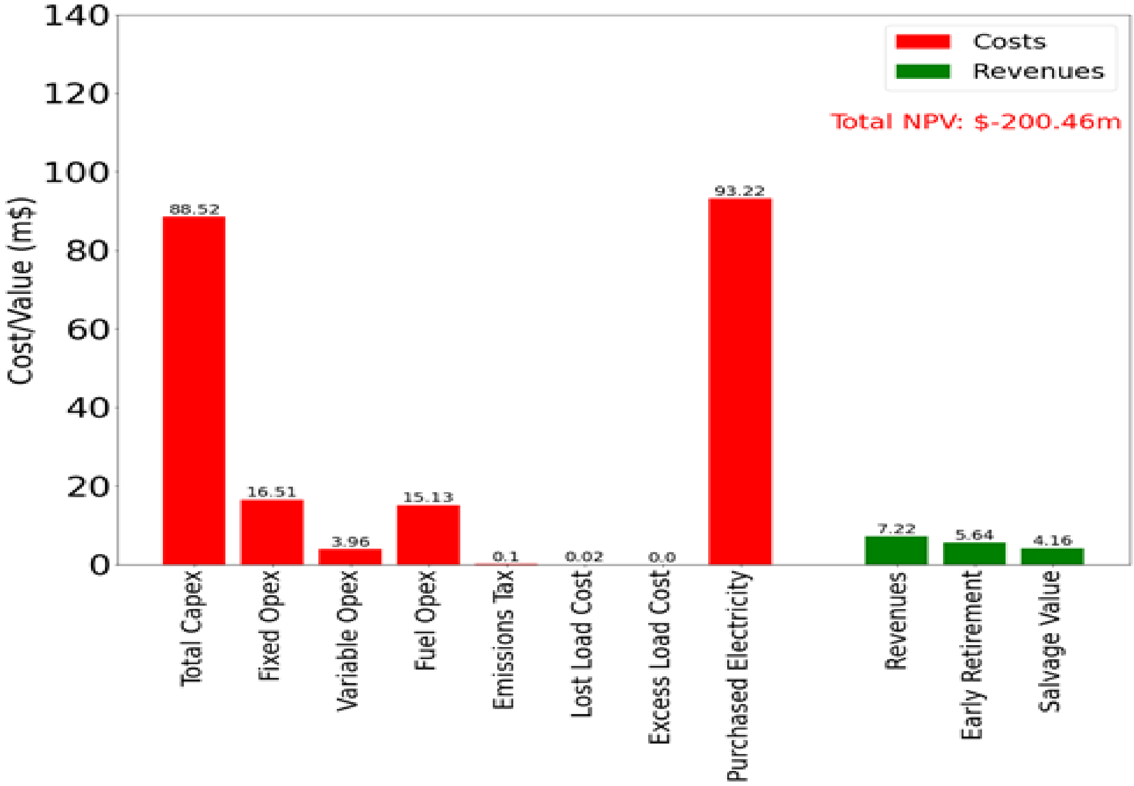

Figure 11: Base Case: NPV Breakdown

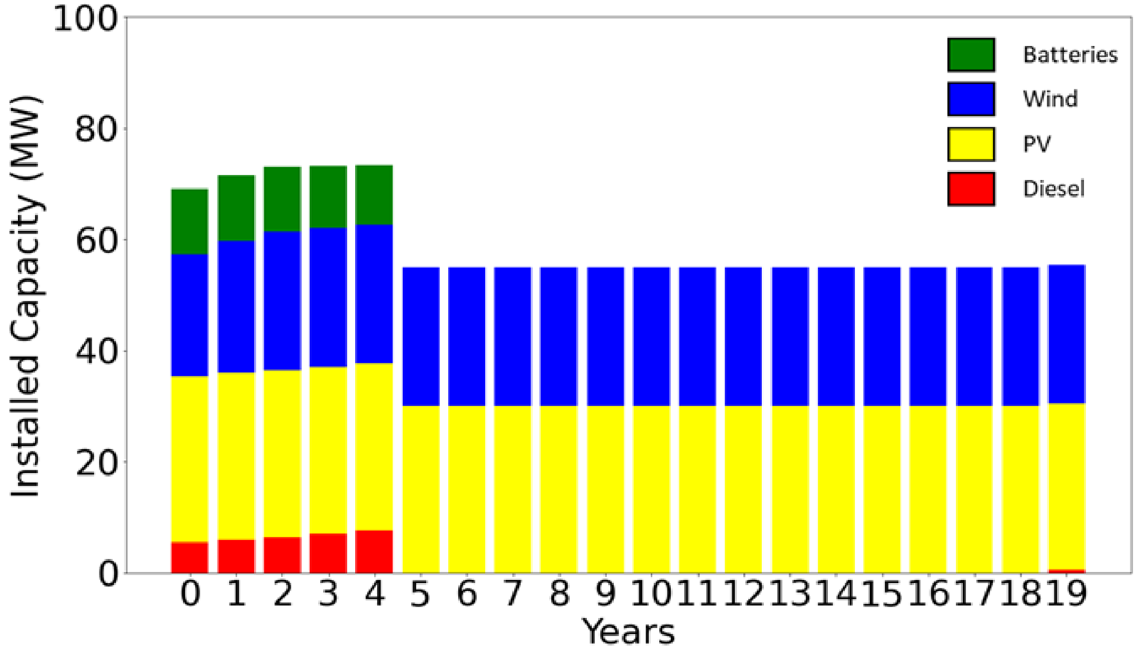

Figure 12: Base Case: Yearly Installed Capacities of Diesel, PV, Wind and Batteries

Figure 14 shows the yearly distribution of electricity supply to satisfy the demand (black line). The system relied on diesel generators, PV, wind and batteries at the beginning but didn't rely at all on diesel after the grid electricity was available (year 5). The rest of the demand, which was not covered by PV and wind, was satisfied by purchasing electricity from the grid. To have a deeper dive into the daily operations, we selected a random day (representative day 5 in year 3) and the daily electricity supply distribution is represented in figure 15. As shown in figure 15, the daily demand that is represented by the black line varies during the day and has a certain trend. The demand is satisfied during this day by the discharging of the batteries and the operations of diesel generators during the night. While electricity produced from Solar PV will satisfy the demand and charge the batteries during the day. The supply from wind is considered to be minimal.

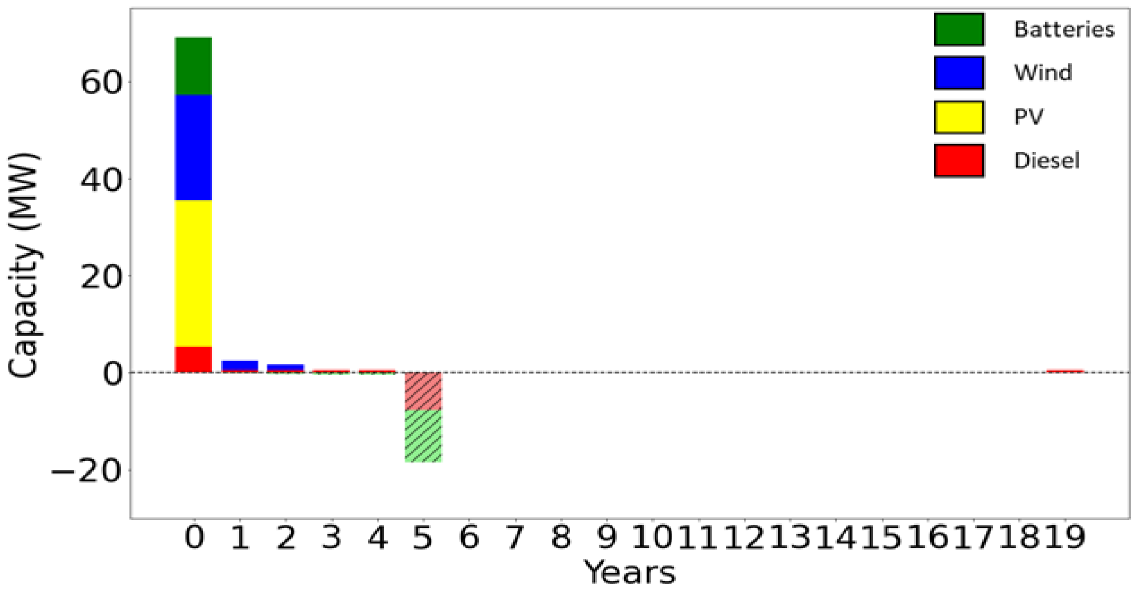

Figure 13: Base Case: Yearly Added and Retired Capacities

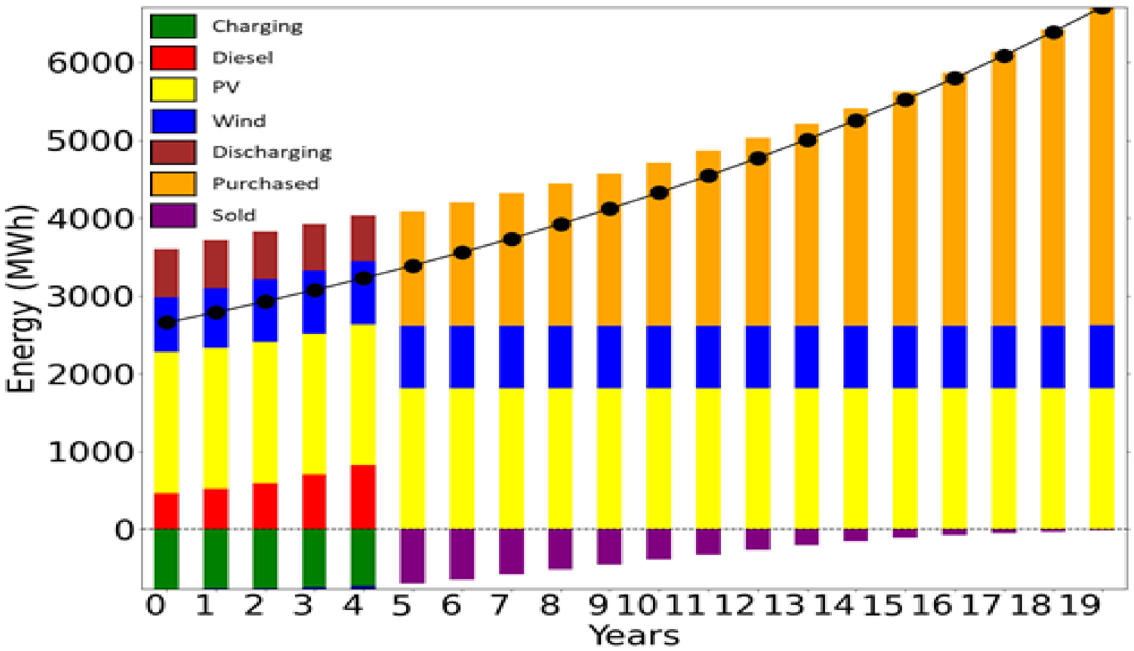

Figure 14: Base Case: Yearly Electricity Supply Distribution

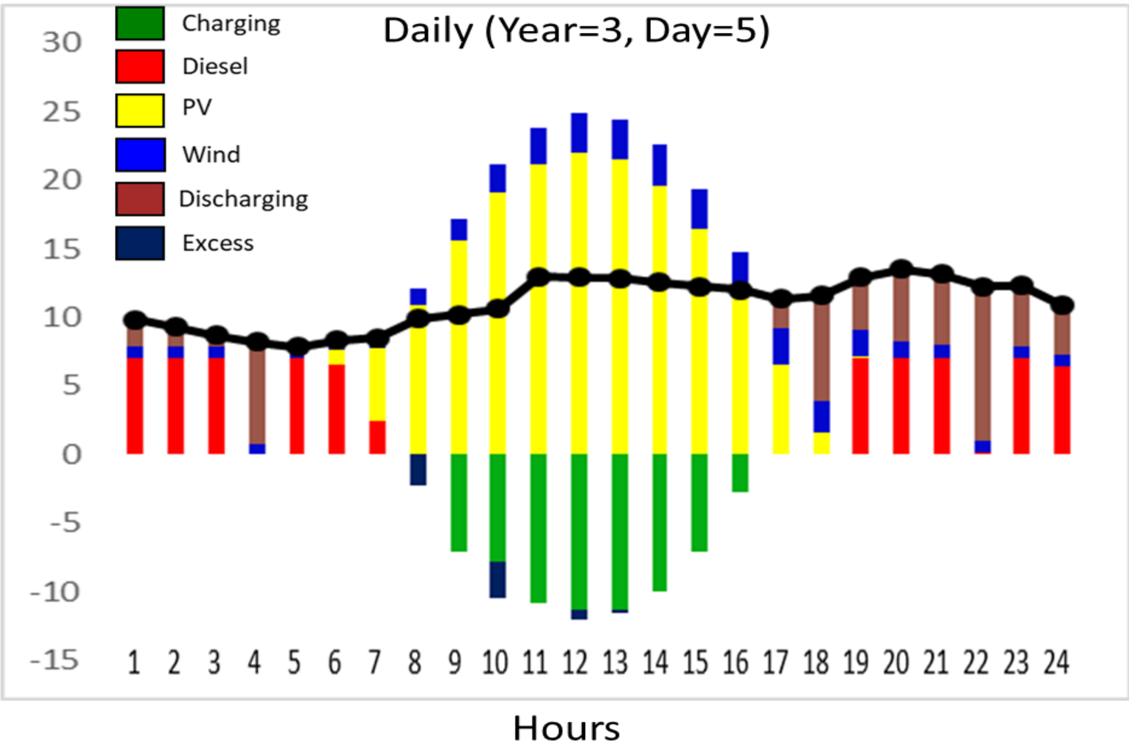

Figure 15: Base Case: Daily Electricity Supply Distribution

4.*1.2. Effect of timing of grid availability*

To show the effect of the time when the centralized electricity will be available, the base case scenario is modified into two new scenarios. An early scenario of T_{grid}=3 years is presented in 4.1.2.1 and a later scenario of T_{grid}=12 years is presented in 4.1.2.2.

<u>4.1.2.1. (T_{grid}= 3, EDL Tariff= 0.15, Feed-in Tariff= 0.08)</u>

When the T_{grid} was decreased to 3, the NPV decreased around 5 mUSD compared to the base case (Figure 11: Base Case: NPV Breakdown). As shown in figure 16, the total capex and fuel opex decreased, while the purchased electricity costs and revenues increased since there is a longer interaction with the grid.

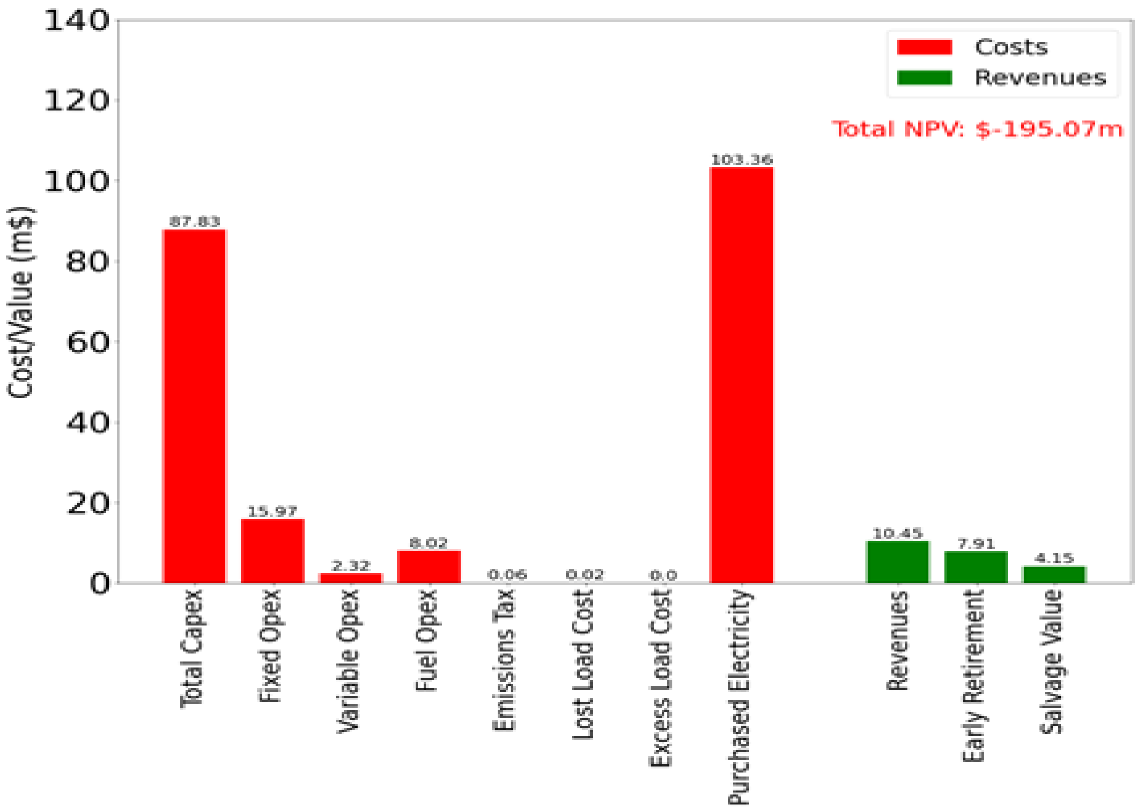

Figure 16: Year Effect (3): NPV Breakdown

Figures 17 shows that the initial energy mix will almost similar to the base case. Moreover, figures 17 and 18 show that the diesel generators and batteries are going to be retired completely at year 3. This is due that it is not economical to operate them anymore (given the EDL tariff of 0.15 USD/kWh). Similar to what happened in the base case but at year 3 instead of year 8.

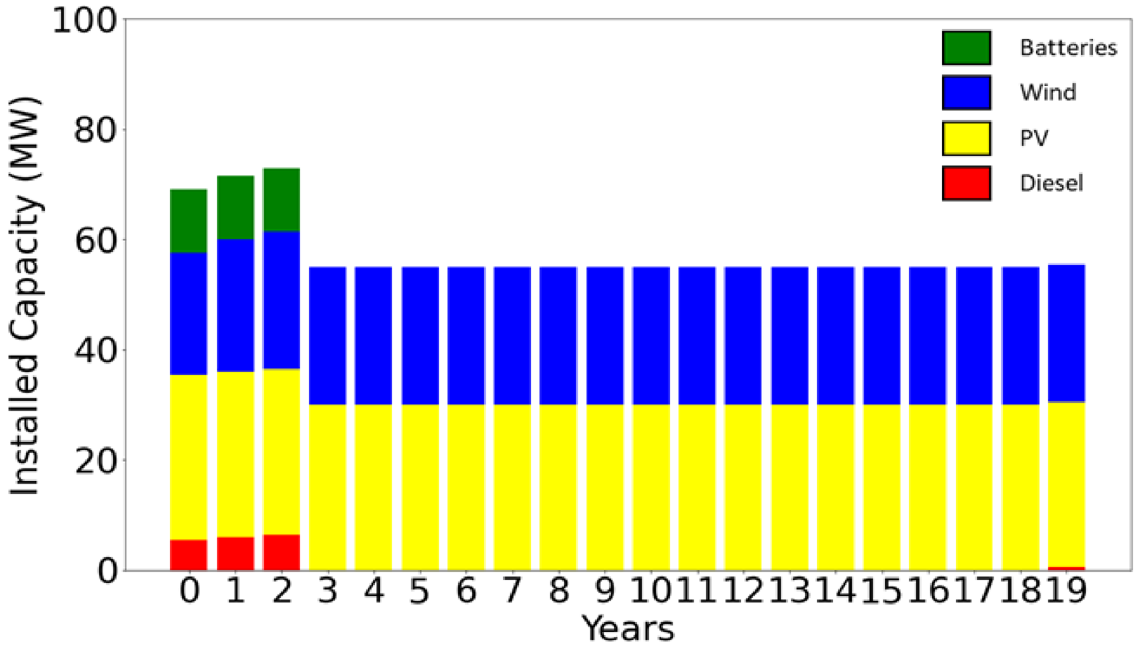

Figure 17: Year Effect (3): Yearly Installed Capacities of Diesel, PV, Wind and Batteries

Figure 19 shows the yearly distribution of electricity supply. The system relied on diesel generators, PV, wind and batteries at the beginning but didn't rely at all on diesel after year 3. The rest of the demand, which was not covered by PV and wind, was satisfied by purchasing electricity from the grid. Moreover, it is clear that the amounts of electricity that was sold to the grid increased compared to the base case.

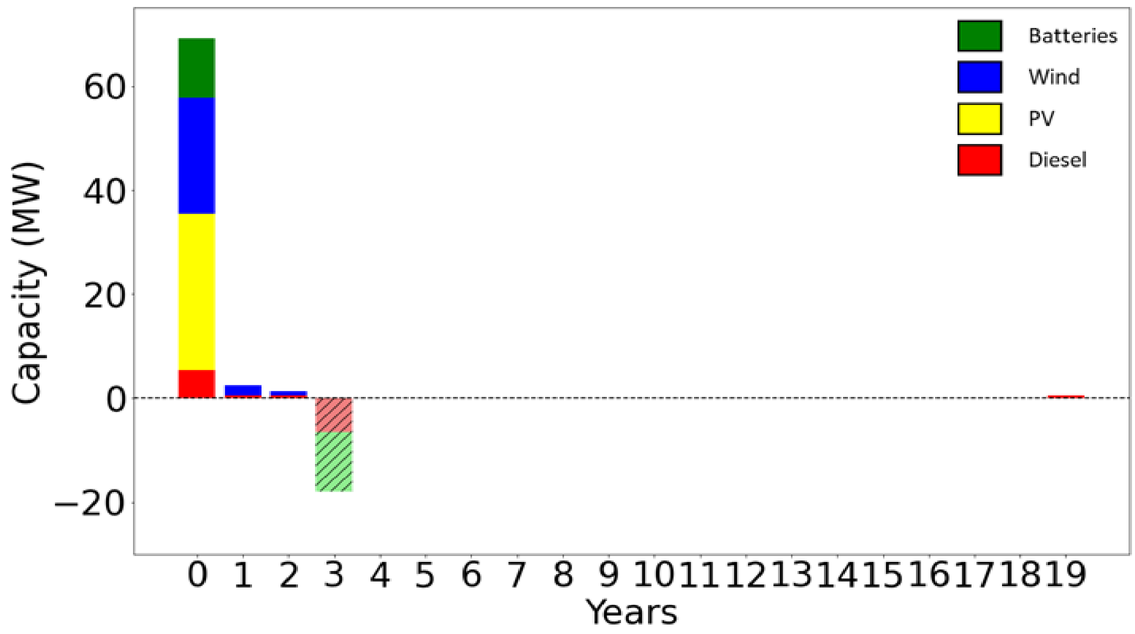

Figure 18: Year Effect (3): Yearly Added and Retired Capacities

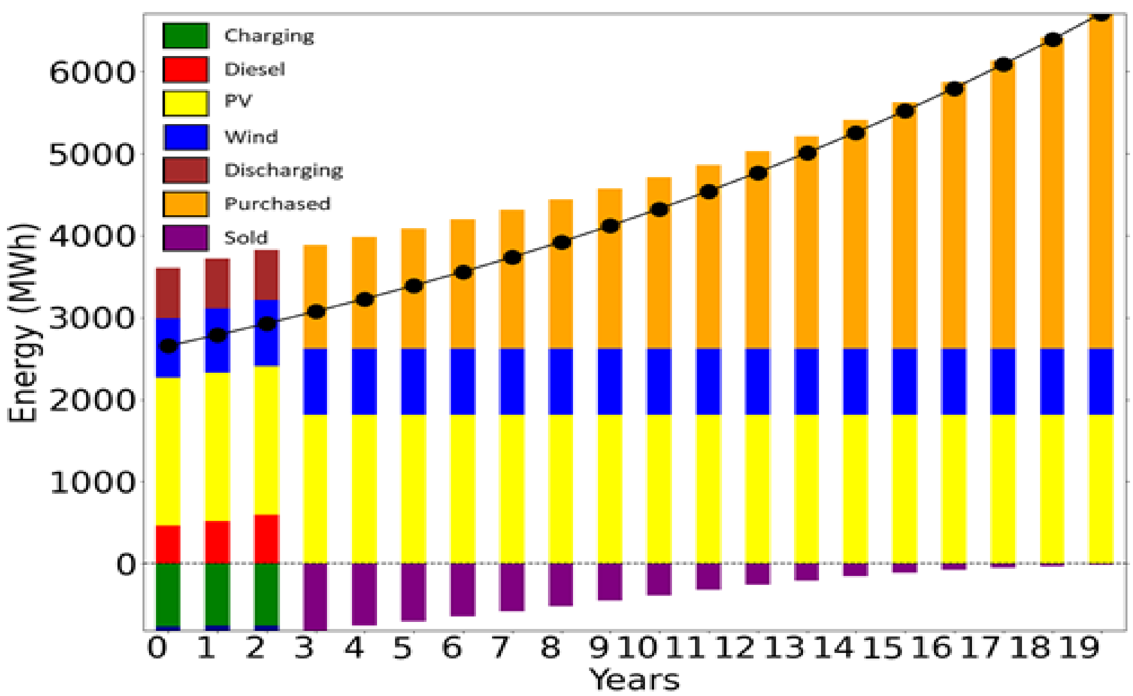

Figure 19: Year Effect (3): Yearly Electricity Supply Distribution

4.1.2.2. (T_{grid}= 12, EDL Tariff= 0.15, Feed-in Tariff= 0.08)

When the T_{grid} was increased to 12, the NPV increased around 27 mUSD compared to the base case. As shown in figure 20, the total capex and fuel opex increased, while the purchased electricity costs decreased since there is a longer interaction with the grid.

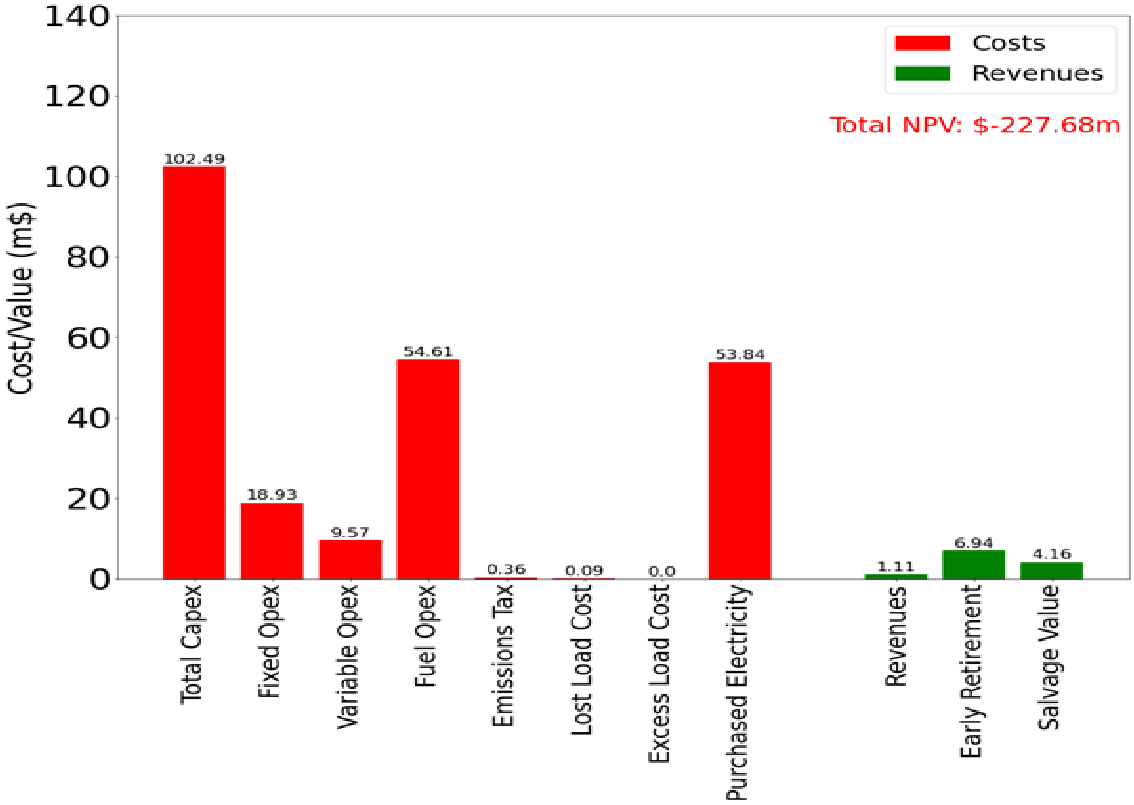

Figure 20: Year Effect (12): NPV Breakdown

Figures 21 shows that the initial energy mix will stay almost the same as the base case. Moreover, figures 21 and 22 show that the diesel generators and batteries are going to be retired completely at year 12. This is due that it is not economical to operate them anymore (given the EDL tariff of 0.15 USD/kWh). Similar to what happened in the base case but at year 12 instead of year 5. We can notice two types of retirements for diesel generators the first one is at the end of lifetime (years 5 and 10) and the early retirement that is happening when the grid electricity is available (year 12).

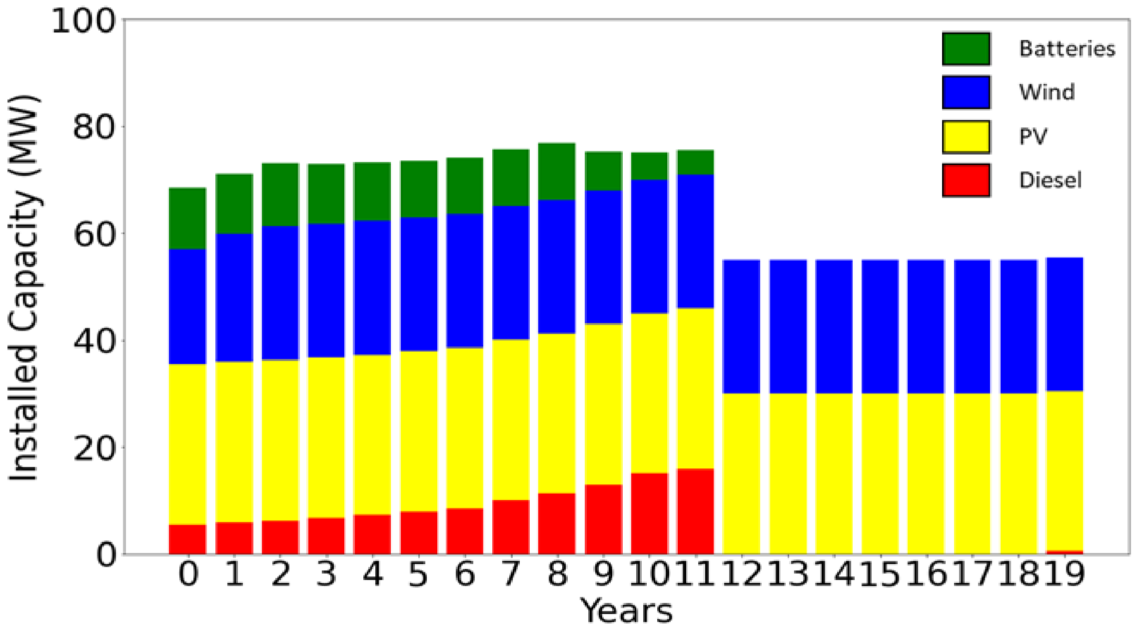

Figure 21: Year Effect (12): Yearly Installed Capacities of Diesel, PV, Wind and Batteries

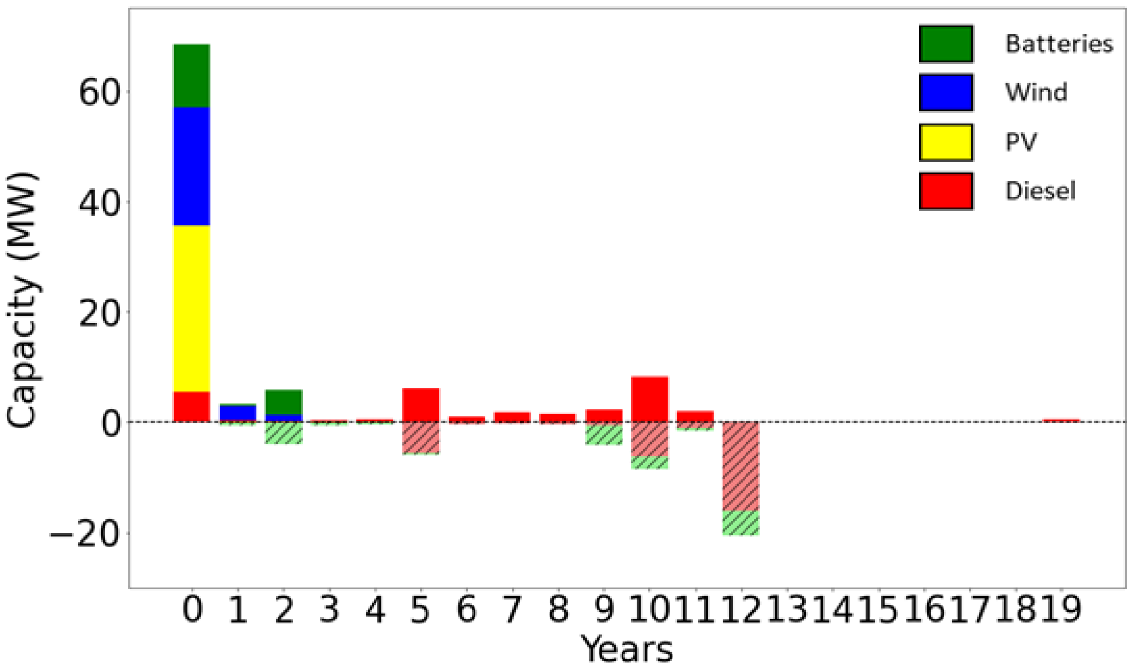

Figure 22: Year Effect (12): Yearly Added and Retired Capacities

Figure 23 shows the yearly distribution of electricity supply. The system relied on diesel generators, PV, wind and batteries at the beginning but didn't rely at all on diesel after year 12. The rest of the demand, which was not covered by PV and wind, was satisfied by purchasing electricity from the grid. Moreover, it is clear that the amounts of electricity that was sold to the grid decreased compared to the base case. Therefore, our system changed from being an off-grid PV/wind/diesel/battery system to an on-grid PV/wind/grid system after year 12 (grid existence year).

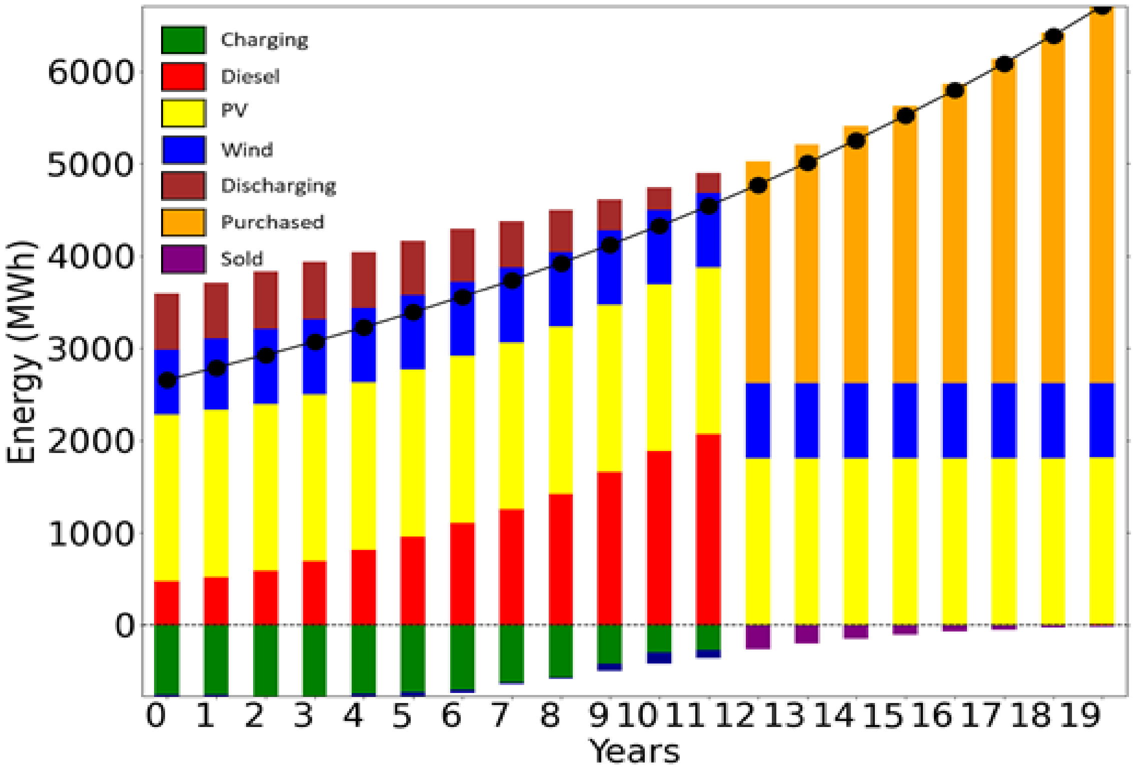

Figure 23: Year Effect (12): Yearly Electricity Supply Distribution

It is clear that the uncertainty of the grid existence affects the results of our optimization especially in the part that is related to the installation and retirement as shown in Figure 24. Therefore, knowing the year when the grid electricity will be available is really important to the investment decision that will be taken.

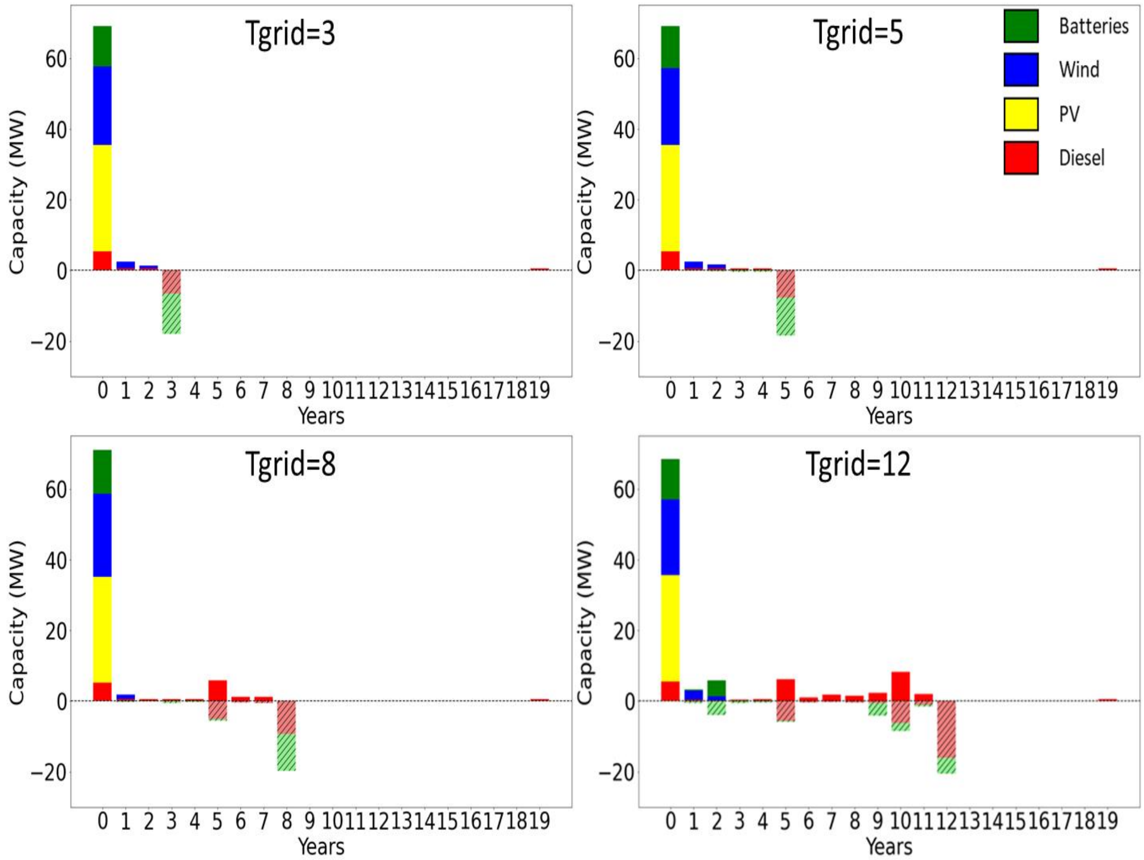

Figure 24: Year Effect Comparison: Yearly Added and Retired Capacities

4.1.3. Effect of Centralized Grid Tariff

Now, we will move to the centralized grid (EDL) tariff uncertainty. To show the effect of the centralized grid tariff, the base case scenario is modified into two scenarios. An inexpensive scenario of EDL tariff of 0.09 USD/kWh is presented in 4.1.3.1 and an expensive scenario of EDL tariff of 0.3USD/kWh is presented in 4.1.3.2.

4.1.3.1. (T_{grid}= 5, EDL Tariff= 0.09, Feed-in Tariff= 0.08)

When the EDL tariff was decreased to 0.09 USD/kWh, the NPV decreased around 60 mUSD compared to the base case. As shown in figure 25, the total capex decreased and fuel opex increased (the system relied on more generation capacities especially diesel generators), while the purchased electricity costs decreased since the tariff is less, the value of early retirement increased in this scenario since the model retired the diesel and wind technologies when the grid existed as shown in figures 26 and 27.

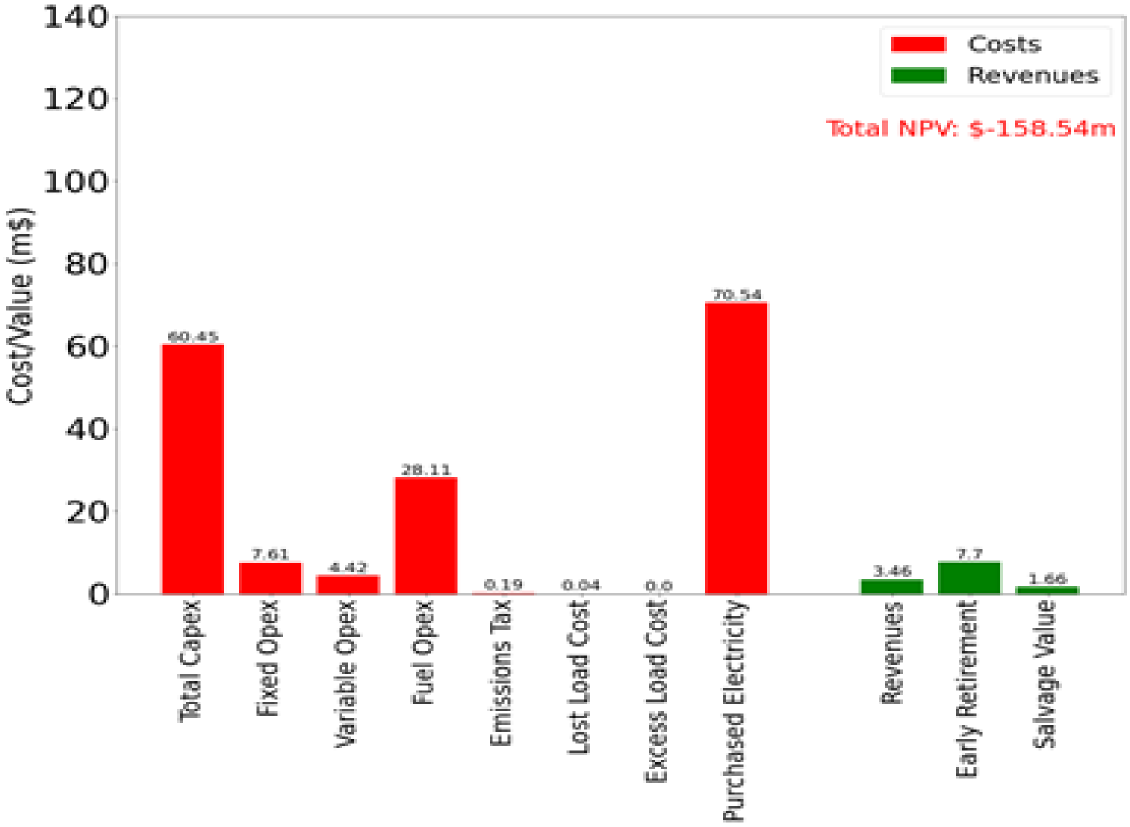

Figure 25: Centralized Tariff Effect (0.09): NPV Breakdown

Figures 26 shows that the initial energy mix will be different than the base case by having minimal wind, the system will be relying on diesel, PV and batteries instead. Moreover, figures 26 and 27 show that the diesel generators, wind technologies and batteries are going to be retired completely at year 5. This is due that it is not economical to operate them anymore (given the EDL tariff of 0.09 USD/kWh).

Figure 28 shows the yearly distribution of electricity supply in the suggested scenario. The system relied on diesel generators, PV, wind and batteries at the beginning but retired all technologies and kept the solar PV only. The rest of the demand, which was not covered by PV, was satisfied by purchasing electricity from the grid.

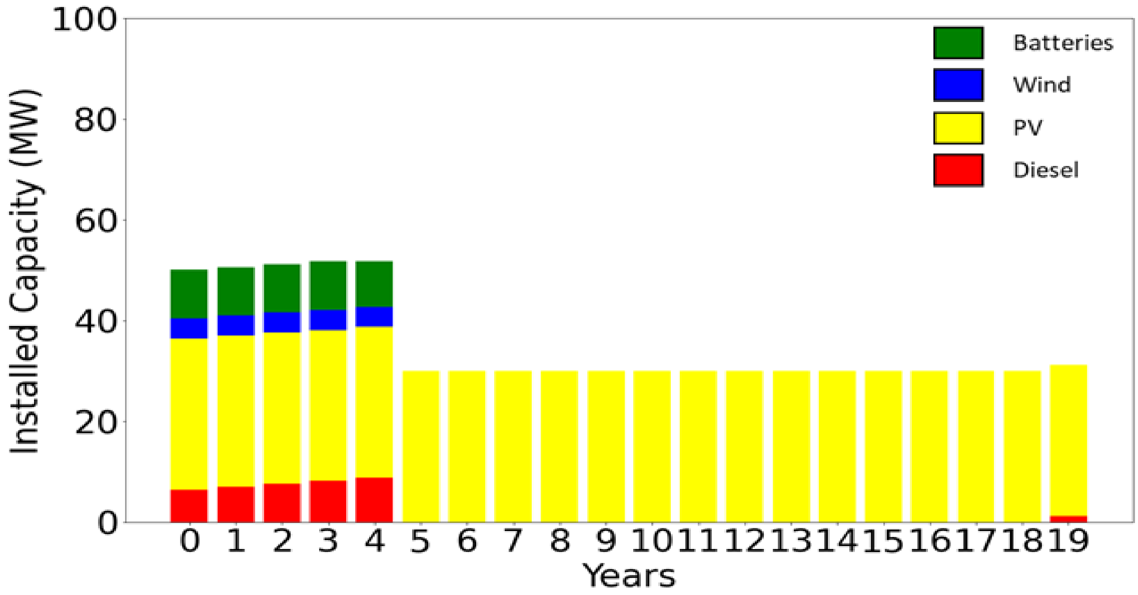

Figure 26: Centralized Tariff Effect (0.09): Yearly Installed Capacities of Diesel, PV, Wind and Batteries

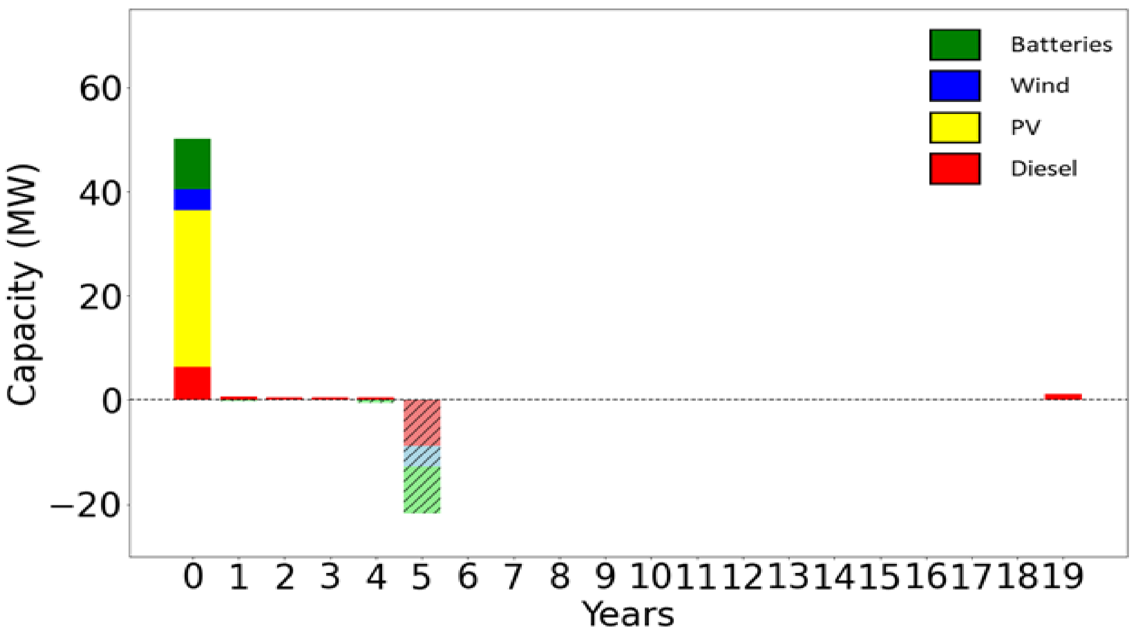

Figure 27: Centralized Tariff Effect (0.09): Yearly Added and Retired Capacities

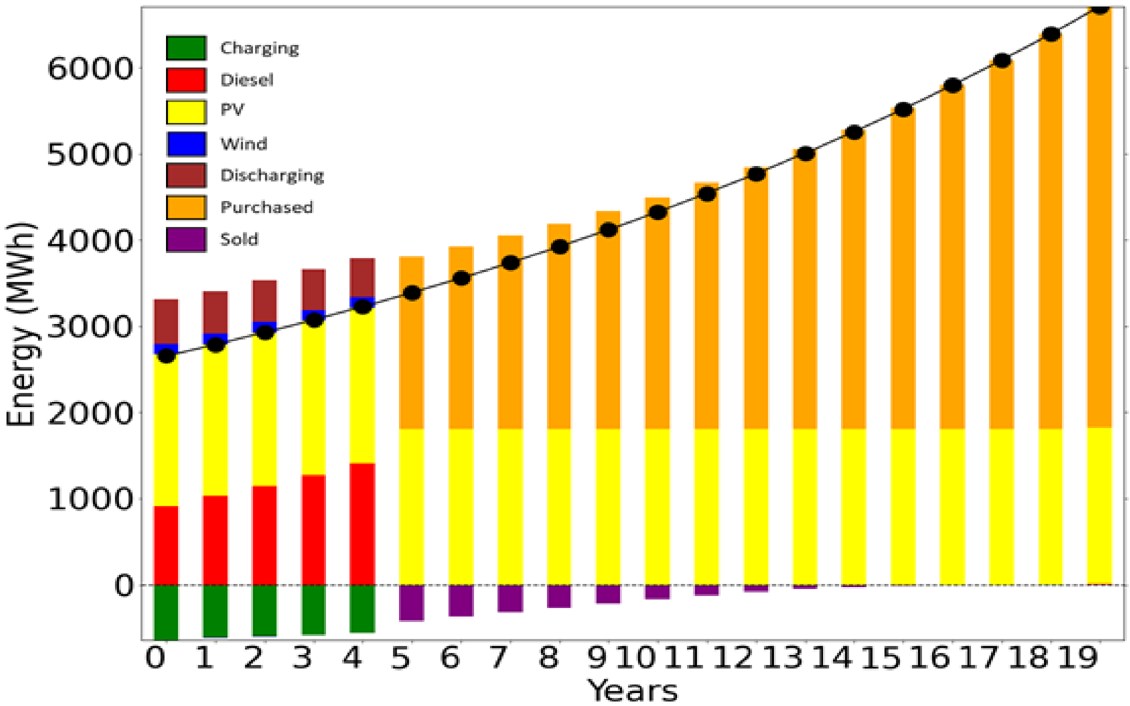

Figure 28: Centralized Tariff Effect (0.09): Yearly Electricity Supply Distribution

4.1.3.2. (T_{grid}= 5, EDL Tariff= 0.27, Feed-in Tariff= 0.08)

When the EDL tariff was increased to 0.27 USD/kWh, the NPV increased around 60 mUSD compared to the base case. As shown in figure 29, the total capex and fuel opex increased (the system relied on more generation capacities especially diesel generators), while the purchased electricity costs decreased since it is more economical to keep running diesel generators than purchasing expensive electricity from the grid. We had no early retirements as shown in figures 30 and 31.

Figures 30 shows that the initial energy mix will be different from the base case. Year after year the installed capacity of diesel generators will be increasing until the end of the planning horizon. Moreover, figures 30 and 31 show none of the technologies are going to be early retired, instead we will going to have normal retirements at the end of the technology's lifetime followed by adding new capacities of the same technology.

This is due that it is not economical to purchase electricity from the grid (given the EDL tariff of 0.27 USD/kWh).

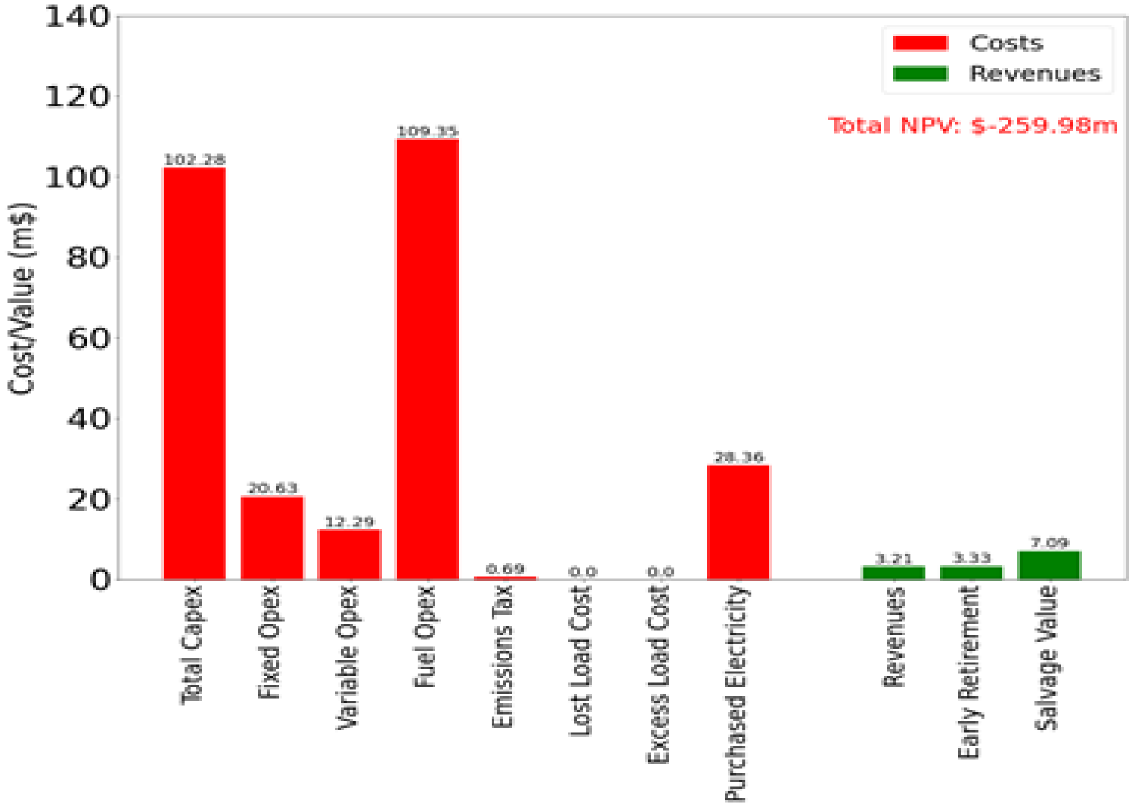

Figure 29: Centralized Tariff Effect (0.27): NPV Breakdown

Figure 32 shows the yearly distribution of electricity supply in the suggested scenario. The system kept relying on diesel generators, PV, and wind a minimal capacity of batteries. Minimal amount of the demand was satisfied by purchasing electricity from the grid.

Therefore, and as a conclusion the EDL tariff uncertainty greatly affects the decision that we are taking according to the scenarios that were generated affecting both installations and dispatching decision variables. Therefore, knowing tariff of the grid electricity is really important to the investment decision that will be taken.

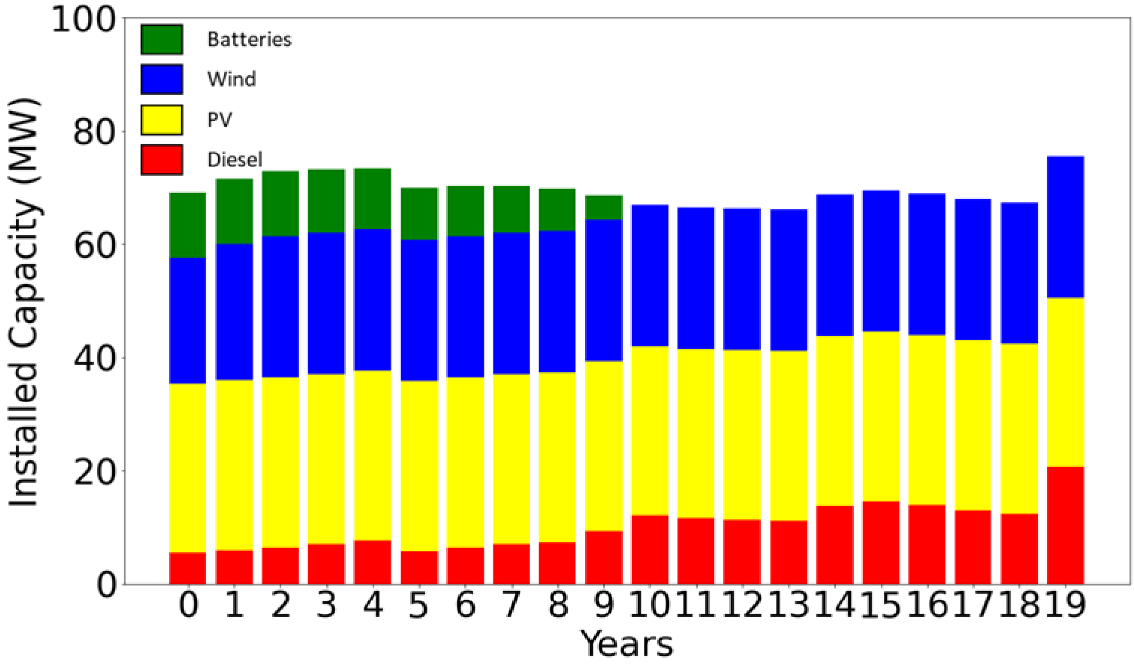

Figure 30: Centralized Tariff Effect (0.27): Yearly Installed Capacities of Diesel, PV, Wind and Batteries

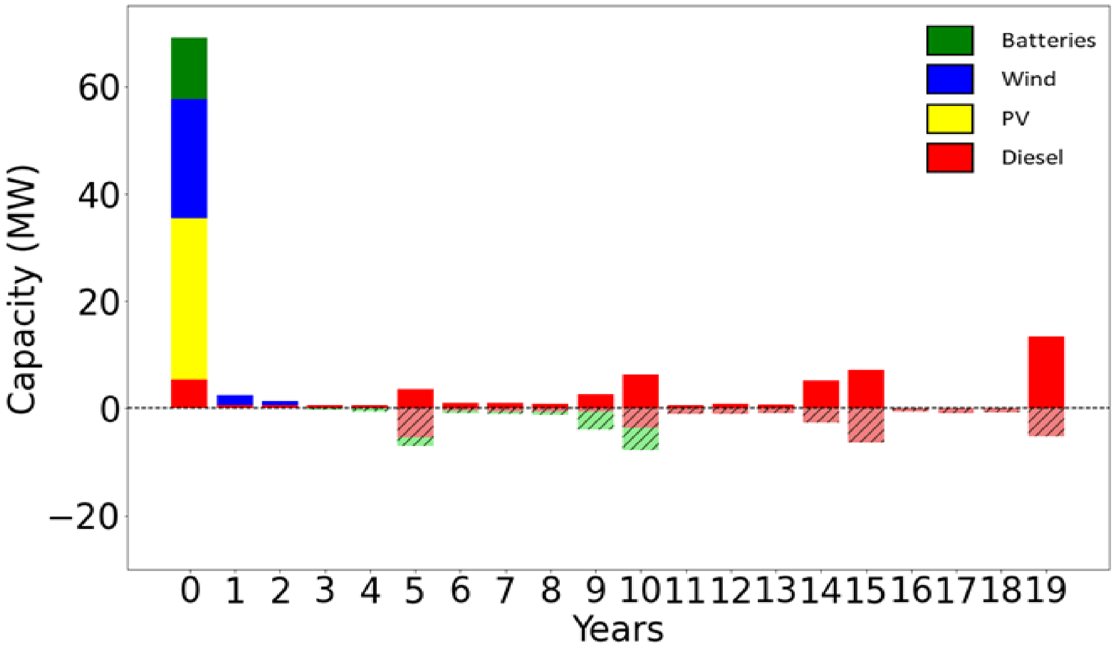

Figure 31: Centralized Tariff Effect (0.27): Yearly Added and Retired Capacities

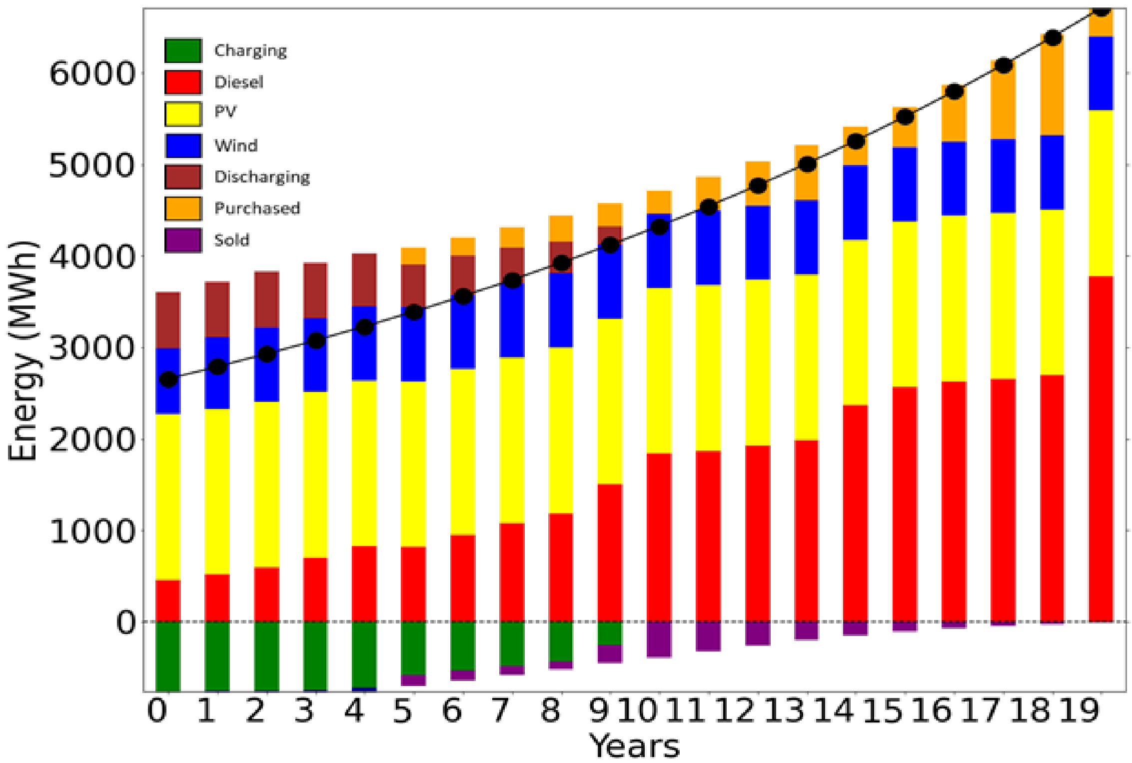

Figure 32: Centralized Tariff Effect (0.27): Yearly Electricity Supply Distribution

4.1.4. Effect of Feed-in Tariff

Now, we will move to the feed-in tariff uncertainty. To show the effect of the feed-in tariff, the base case scenario is modified into two new scenarios. A scenario with a low feed-in tariff of 0.04 USD/kWh is presented in 4.1.4.1 and a scenario of a high feed-in tariff of 0.14USD/kWh is presented in 4.1.4.2.

4.1.4.1. (T_{grid}= 5, EDL Tariff= 0.15, Feed-in Tariff= 0.04)

As shown in figure 33, when the feed-in tariff was decreased to 0.04 USD/kWh, the NPV stayed almost the same compared to the base case with no major changes in the components except by the decrease of the revenues due to the low feed-in tariff of 0.04 USD/kWh.

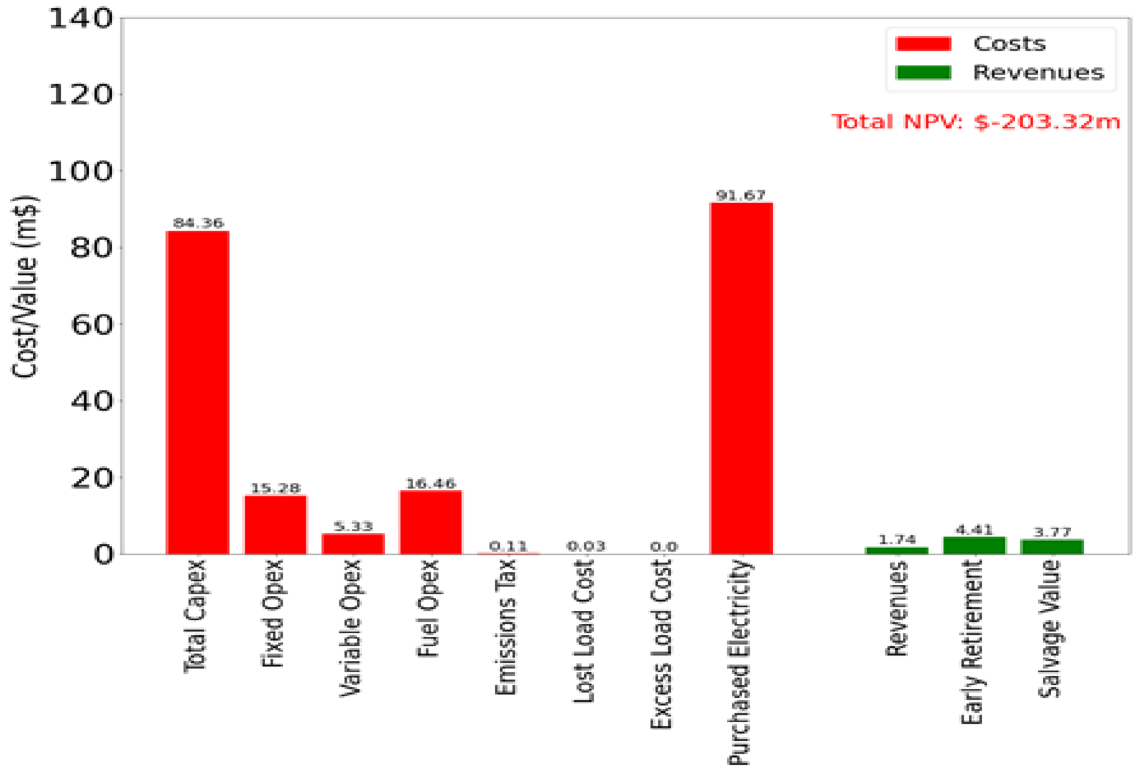

Figure 33: Feed-in Tariff Effect (0.04): NPV Breakdown

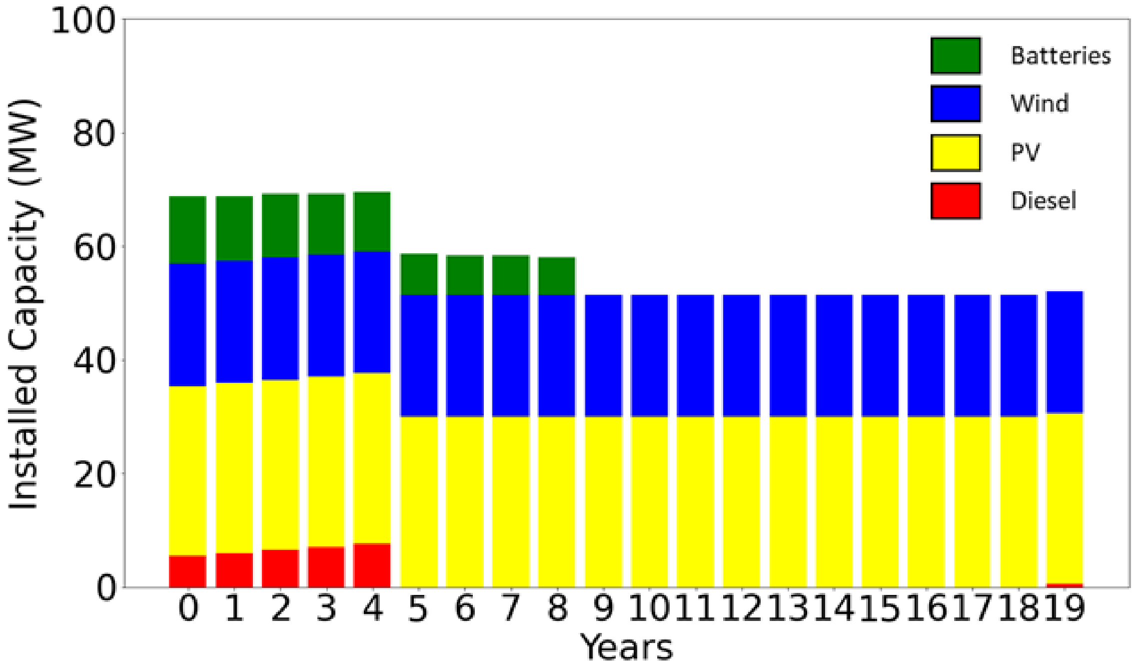

Figure 34: Feed-in Tariff Effect (0.04): Yearly Installed Capacities of Diesel, PV, Wind and Batteries

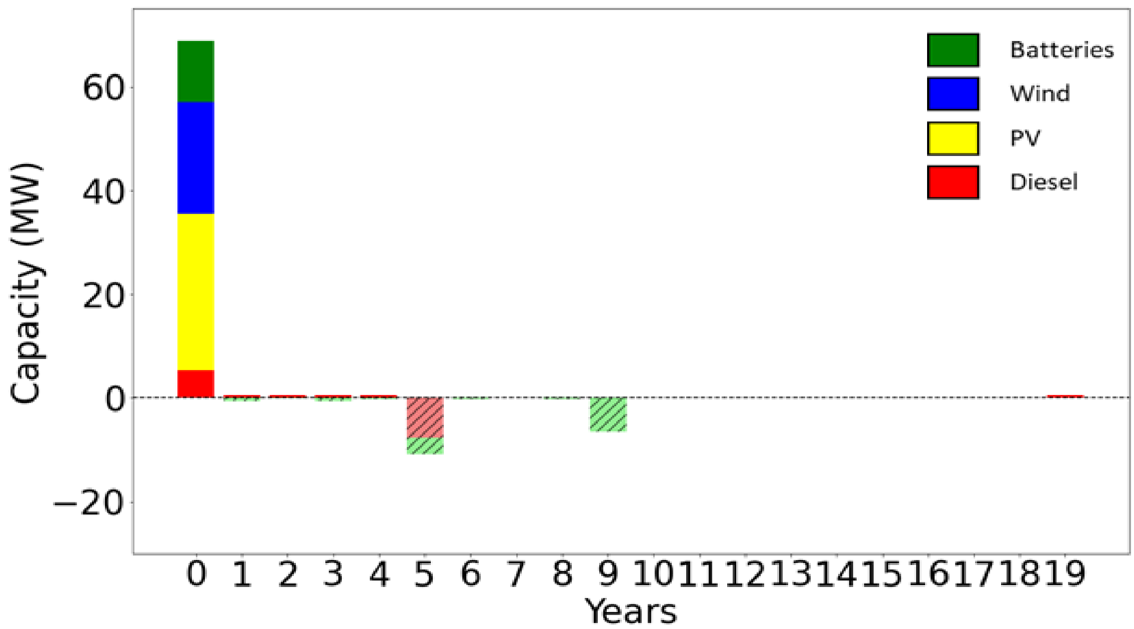

Figure 35: Feed-in Tariff Effect (0.04): Yearly Added and Retired Capacities

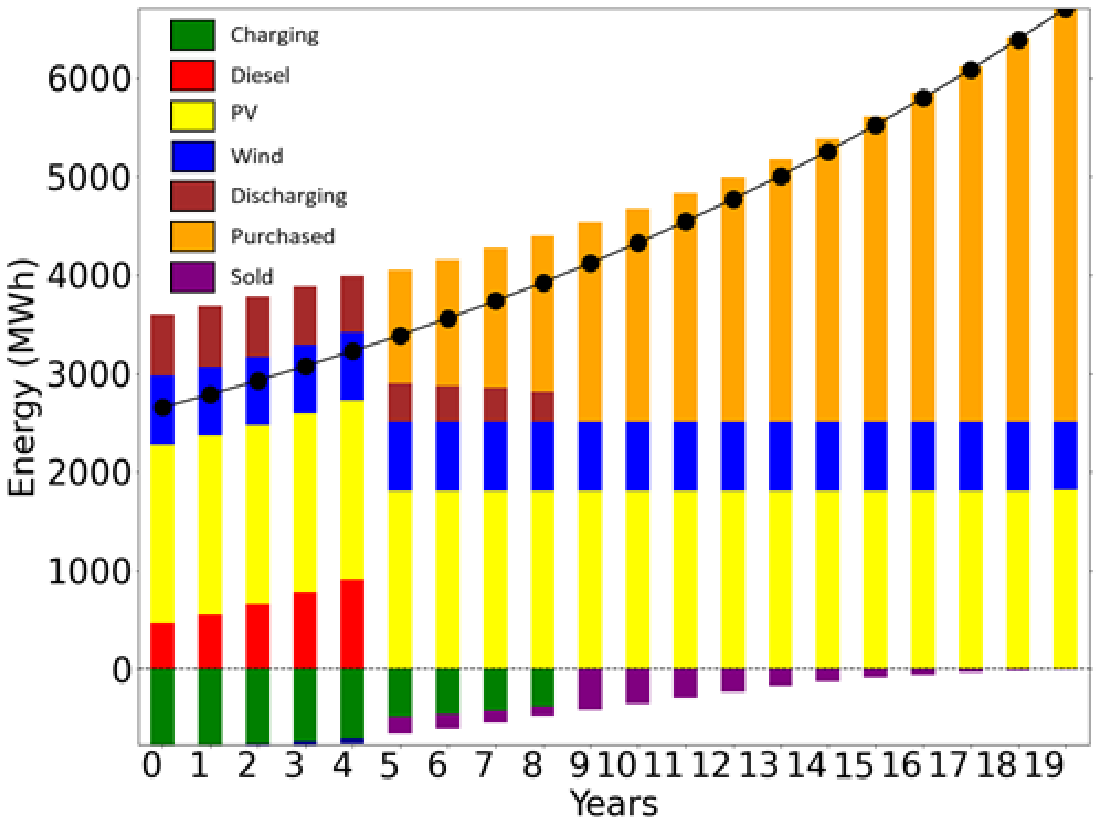

Figure 36: Feed-in Tariff Effect (0.04): Yearly Electricity Supply Distribution

As figures 34, 35 and 36 shows, we don't have major changes in this scenario compared to the base case scenario except of not retiring the batteries early so they can be used to satisfy the demand by storing the energy produced by PV and wind that used to be sold.

4.1.4.2. (T_{grid}= 5, EDL Tariff= 0.15, Feed-in Tariff= 0.14)

As shown in figure 37, when the feed-in tariff was increased to 0.14 USD/kWh, the NPV stayed almost the same compared to the base case with no major changes in the components except in the increase of the revenues.

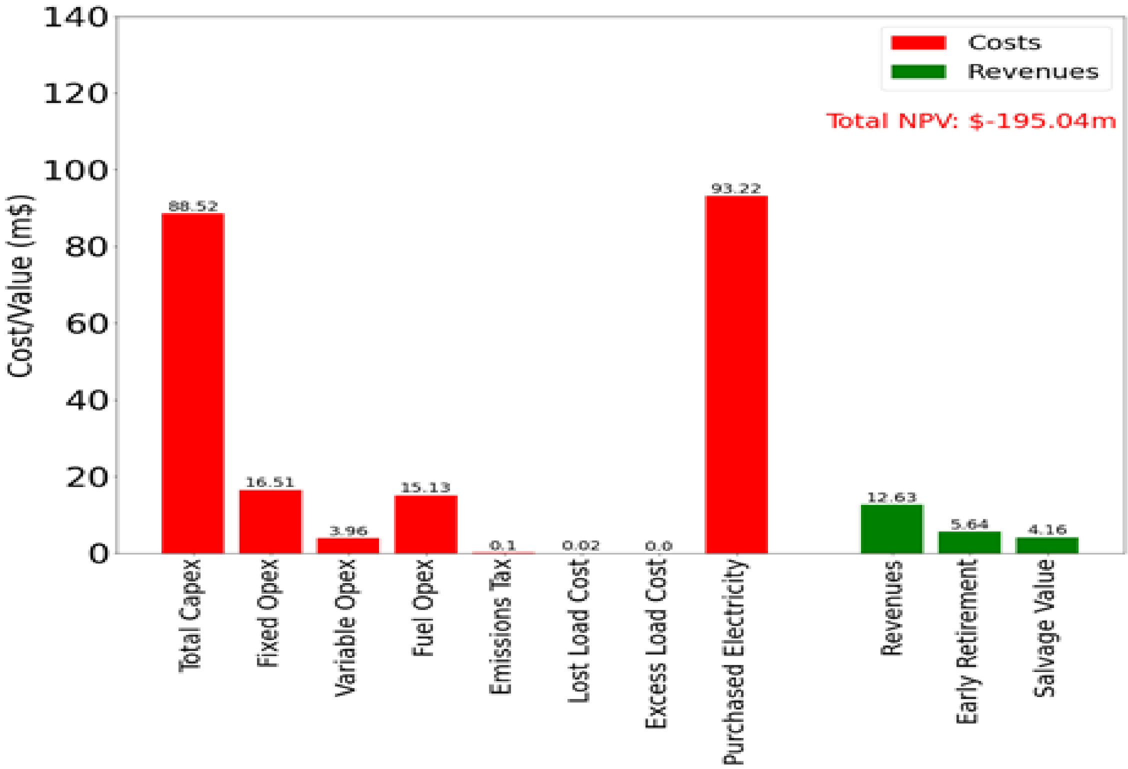

Figure 37: Feed-in Tariff Effect (0.14): NPV Breakdown

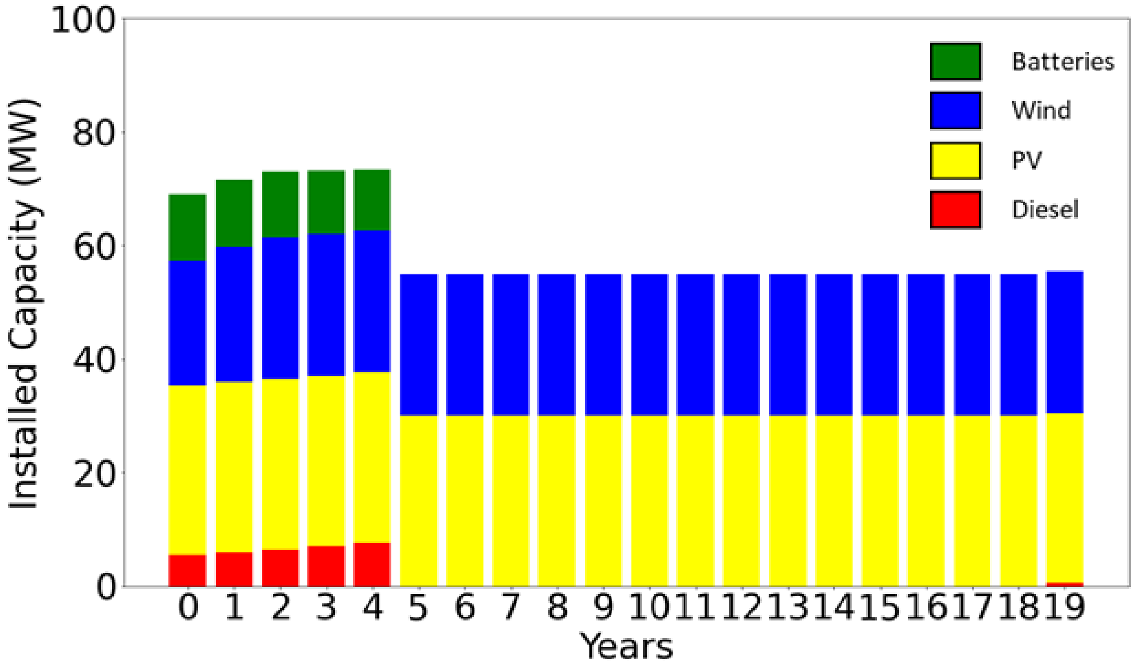

Figure 38: Feed-in Tariff Effect (0.14): Yearly Installed Capacities of Diesel, PV, Wind and Batteries

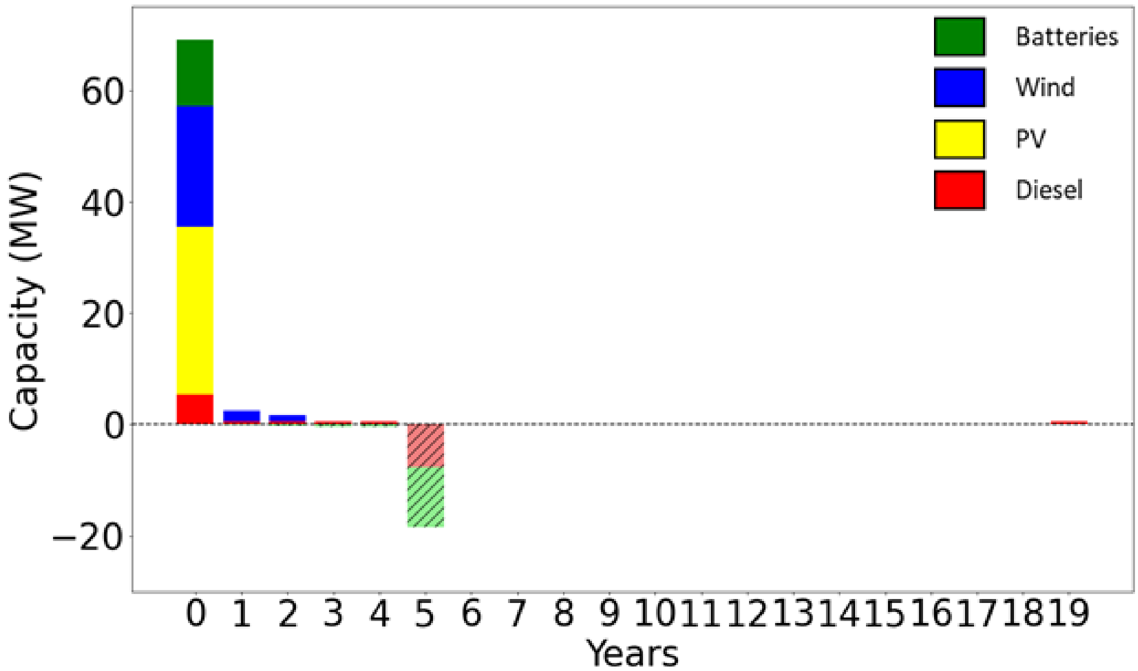

Figure 39: Feed-in Tariff Effect (0.14): Yearly Added and Retired Capacities

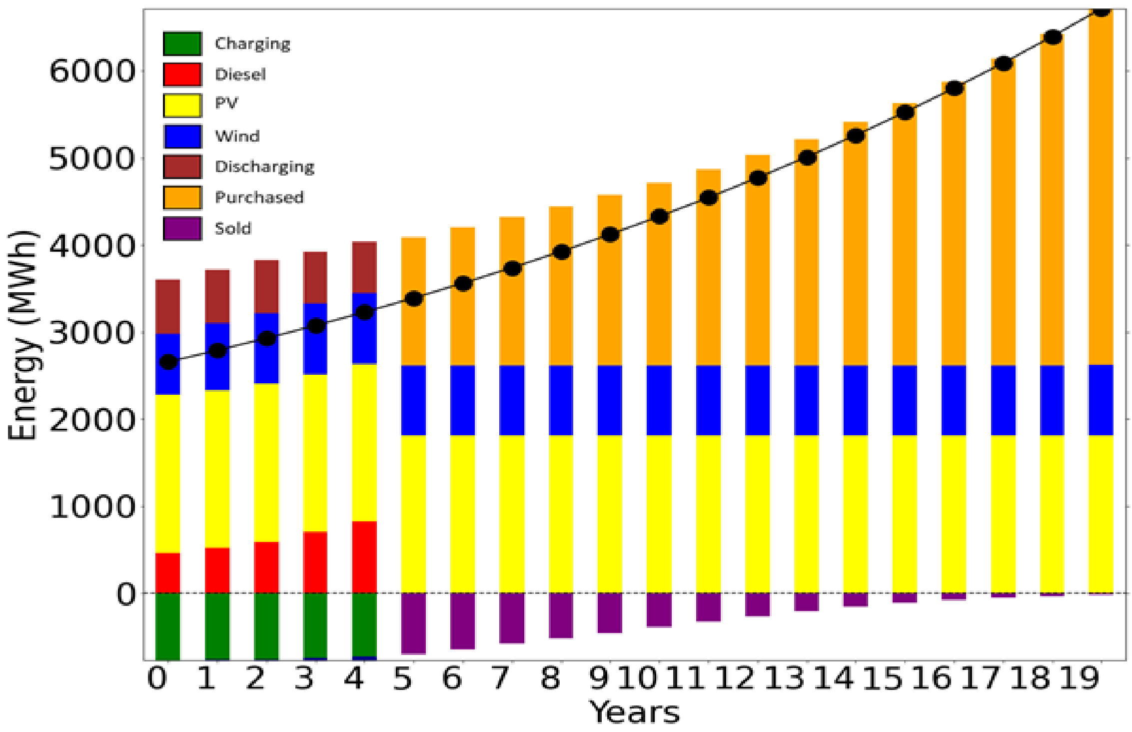

Figure 40: Feed-in Tariff Effect (0.14): Yearly Electricity Supply Distribution

As figures 38 and 39 shows, we don't have major changes in this scenario compared to the base case scenario. Figure 40 shows that the sold electricity increased. Therefore, and as a conclusion the feed-in tariff uncertainty does not affect the decision that we are taking according to the scenarios that were generated and conditions we have.

As a conclusion for the generated scenarios, it is clear that some uncertainties (Time and EDL tariff) affect the decision more than other uncertainties (Feed-in Tariff). Although only 7 scenarios were taken into consideration, we can see that the results may differ completely in terms of the energy mix (initially and throughout the planning horizon) in addition to variations in the NPV, dispatching, retirements and additions. Therefore, more investigation will be done on these uncertainties in the following part.

A number of scenarios will be taken into consideration and included in the Stochastic Model in order to tackle the studied uncertainties and hedge the imbedded risks.

4.2. Stochastic Model

In this part we show the results of the suggested Stochastic optimization model. As a result of the deterministic results above we may conclude that the effect of the feed-in tariff is minimal under the constraints we have in our case study on the "Higher Matn" region. To examine the effect of the Feed-in Tariff (FiT) we have doubled the allowed capacities of both PV and Wind and then varied the FiT and the results appear in Figures 41 and 42 below. It is clear that varying the FiT between 0.04 and 0.14 $/kWh will affect the decisions related to both installation and dispatching.

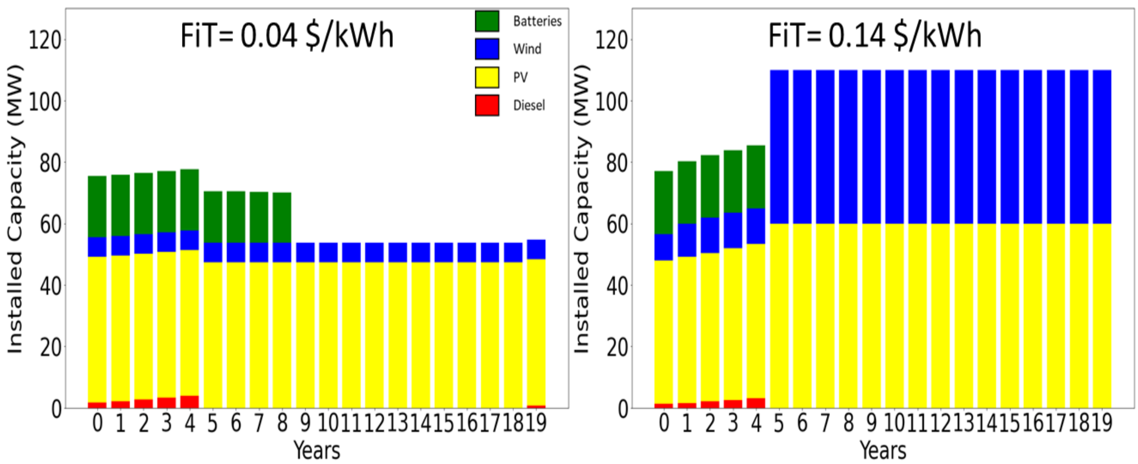

Figure 41: FiT Comparison Under New Conditions- Installed Capacities

Therefore, and as a conclusion related to the effect of FiT, FiT do have a significant effect on the decisions only when the constraints related to the installed renewable energy technologies aligns with that. But in the case study we have on "Higher Matn" region we are limited on the capacity of renewable energy we can install so the FiT does not have a big effect.

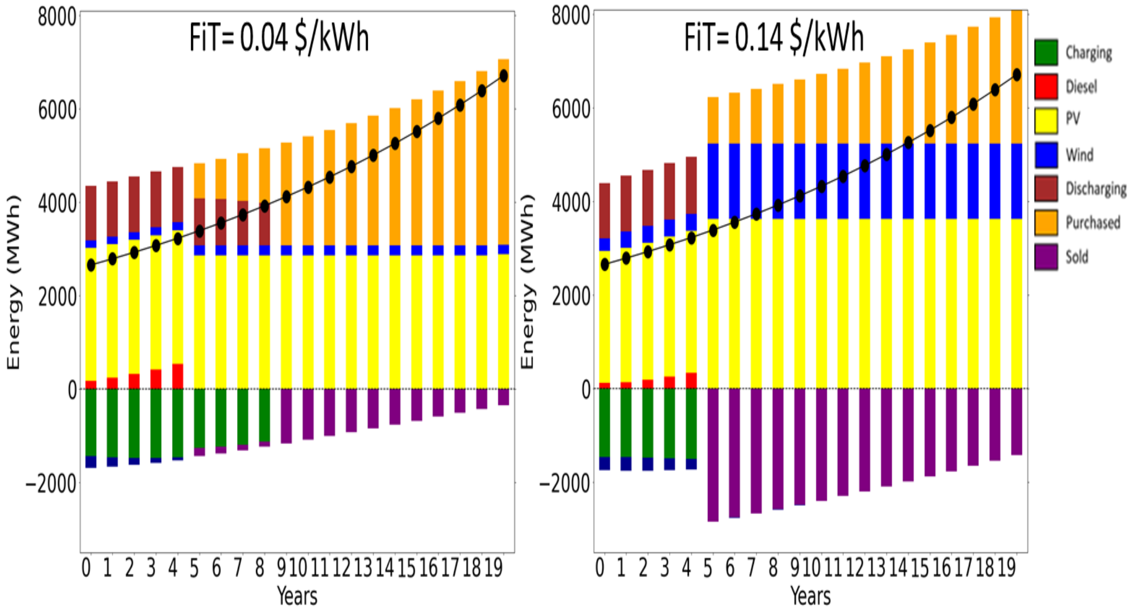

Figure 42: FiT Comparison Under New Conditions- Electricity Supply

That being mentioned and in order to decrease the complexity of the stochastic model we are suggesting, we decided to remove the variability of the FiT in the scenarios and fix it on 0.08 $/kWh. The scenarios are represented in table 8. T_{grid} will be have the values of 3, 5, 8 and 12 years while the EDL Tariff will have the values of 0.09, 0.15 and 0.27 $/kWh. The scenarios are generated by having all the possible combinations of the above numbers. The total number of scenarios is 12 and the probability of each scenario is 1/12 which is 8.333%. Due to the large uncertainty the electricity sector is currently facing we decided to consider the scenarios as complete ignorance.

4.2.1. Installations Results (First Stage)

The results that are generated by the stochastic model are the NPV (figure 43), installed capacities (figure 44) and the added/retired capacities (figure 45). The results that we need are the installations results since they will be used as an input for the dispatch model.

Table 8: Scenarios and Probabilities

Scenario	T grid	EDL Tariff	Feed-in Tariff	Probability
1	3	0.09	0.08	1/12
2	3	0.15	0.08	1/12
3	3	0.27	0.08	1/12
4	5	0.09	0.08	1/12
5	5	0.15	0.08	1/12
6	5	0.27	0.08	1/12
7	8	0.09	0.08	1/12
8	8	0.15	0.08	1/12
9	8	0.27	0.08	1/12
10	12	0.09	0.08	1/12
11	12	0.15	0.08	1/12
12	12	0.27	0.08	1/12

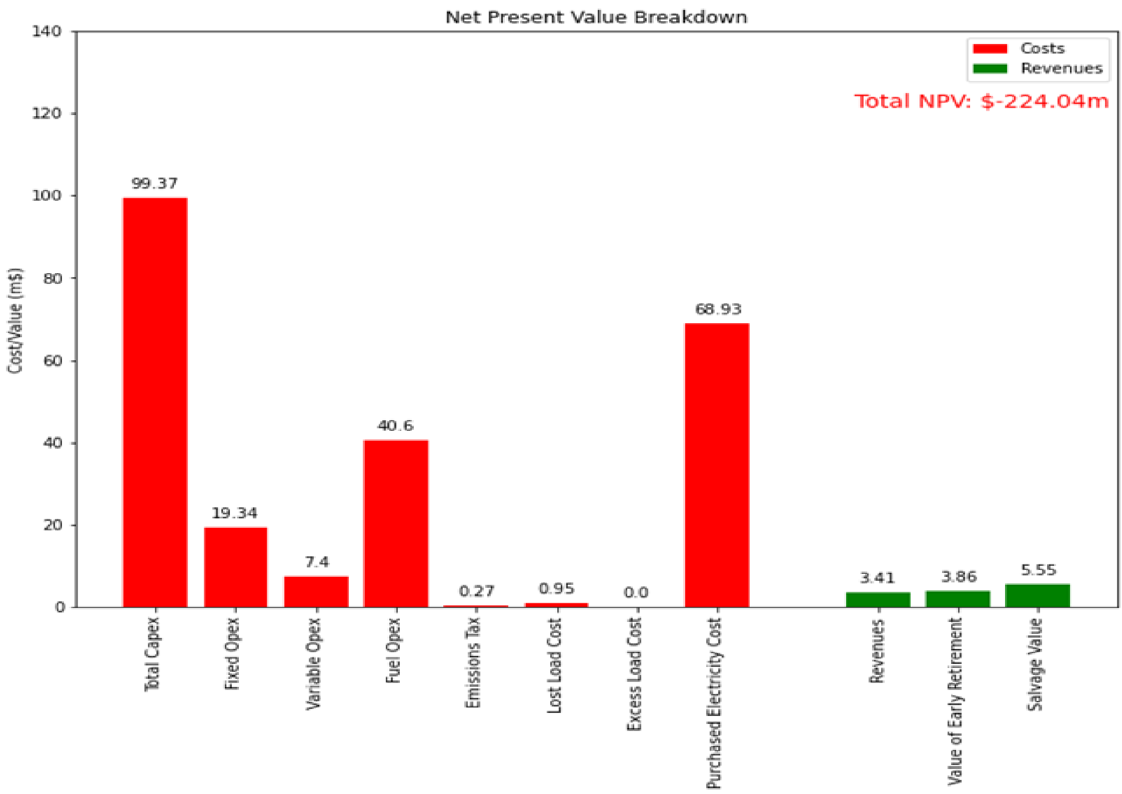

Figure 43: Stochastic Model: NPV Breakdown

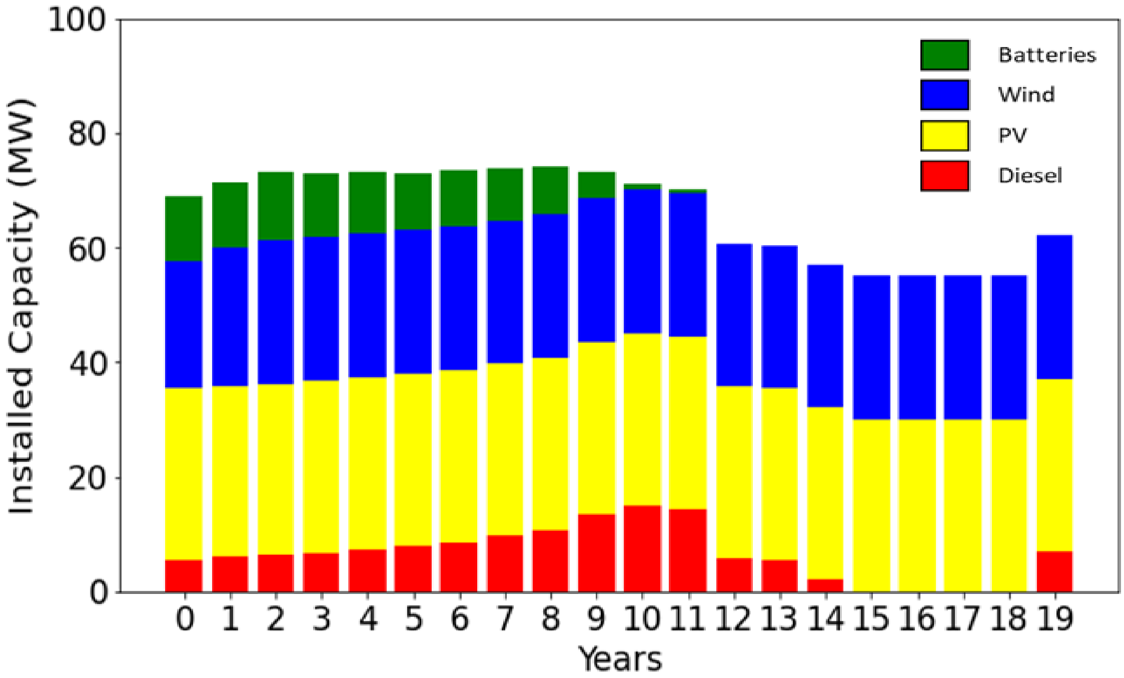

Figure 44: Stochastic: Yearly Installed Capacities of Diesel, PV, Wind and Batteries

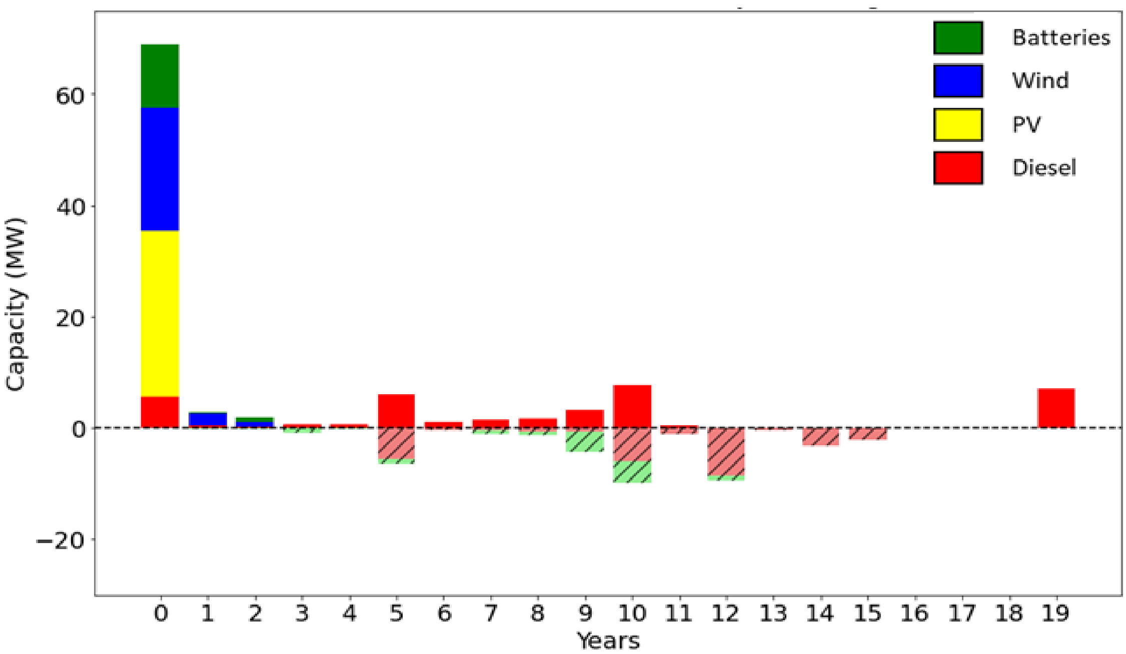

Figure 45: Stochastic: Yearly Added and Retired Capacities

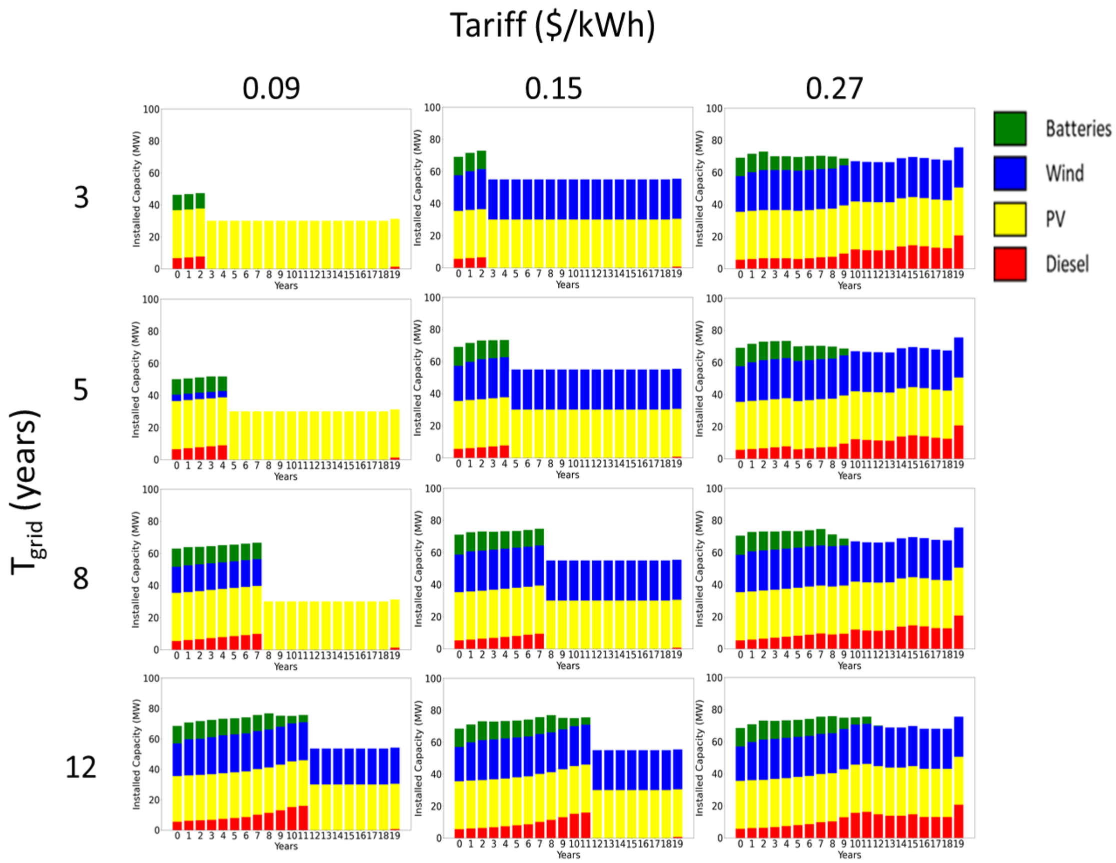

Figure 46: Installed Capacities for Each Scenario of the Deterministic Model

We can see a big difference between the result in figure 44 (stochastic) and figure 46 that contains all the results of the 12 deterministic scenarios we discussed previously. The stochastic result comes as an optimal solution for all scenarios combined together with their probabilities. The biggest difference in the installation happens when the T_{grid} is earlier and the Tariff is lower.

4.2.2. Dispatching Results (Second Stage)

As mentioned previously, the second stage of the stochastic model is related to the dispatching decisions. The dispatching results of all the scenarios included in our stochastic model are represented below in comparison with the dispatching of the deterministic model. The results are represented in figure 47. They do not differ a lot from the deterministic dispatching results for the tariffs of 0.09 and 0.15 $/kWh but differs in the expensive tariff (0.27 $/kWh).

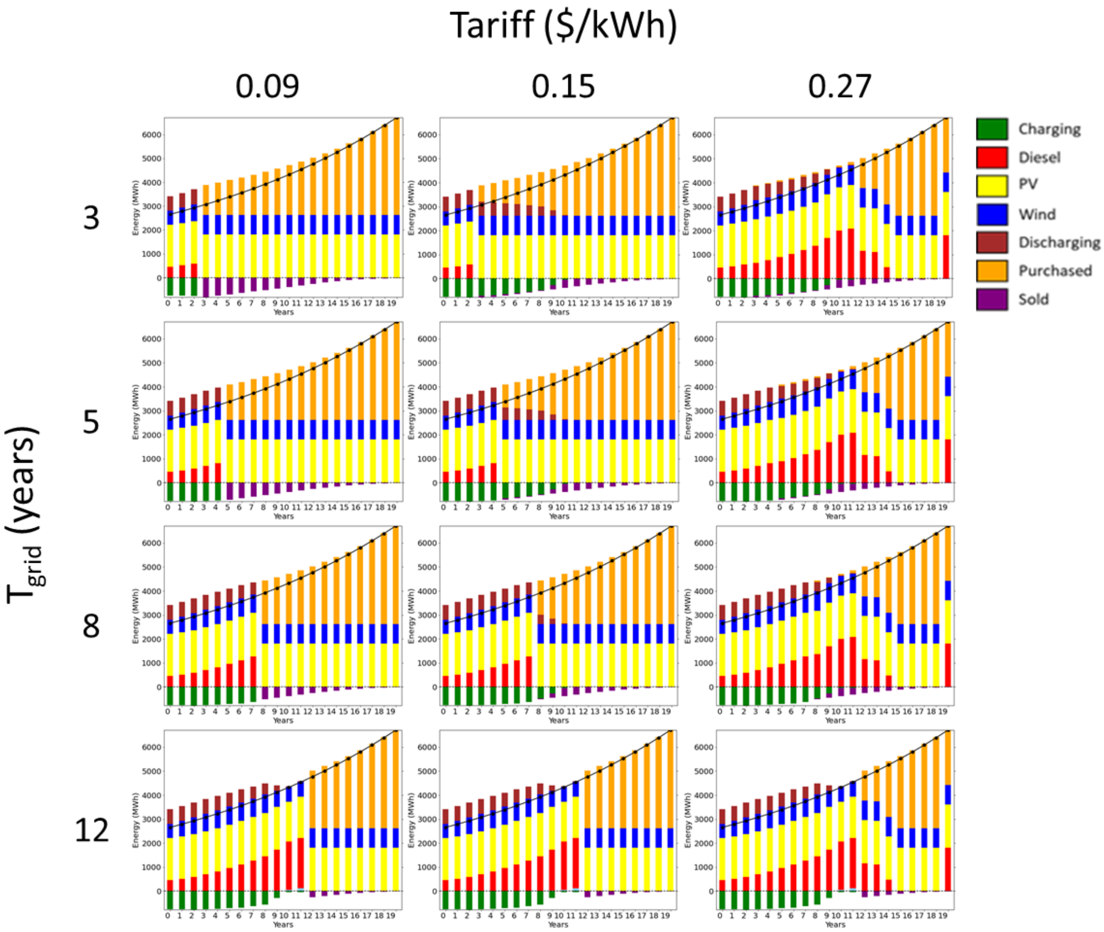

Figure 47: Yearly Electricity Supply per Scenario

4.3. Value of Policy Certainty

After having the results of the deterministic and stochastic models above, we are now able to quantify the value of policy certainty in such projects. This assessment is done by calculating the difference between NPV of the stochastic and the NPV of the deterministic model. The difference between planning under uncertainties (stochastic) and planning under complete certainty is considered to be the value of policy certainty. The results are presented in table 9. Figures 48 and 49 shows the Value of Policy Certainty in Million Dollars and percentage respectively. The biggest difference in terms of money and percentage happens when the T_{grid} is earlier and the Tariff is lower as shown in scenarios 1, 2, 4 and 5. Whereas, the longer the duration of T_{grid} is and the more expensive the Tariff is, the value of policy certainty is lower.

Table 9: Value of Policy Certainty Results

Scenario	T grid	EDL Tariff	NPV Stoch.	NPV Det.	Difference (m$)	Difference (%)
1	3	0.09	171	146	25	17%
2	3	0.15	212	195	17	9%
3	3	0.27	266	259	6	2%
4	5	0.09	177	159	19	12%
5	5	0.15	214	200	14	7%
6	5	0.27	266	260	6	2%
7	8	0.09	188	179	9	5%
8	8	0.15	218	210	8	4%
9	8	0.27	266	261	6	2%
10	12	0.09	209	206	3	2%
11	12	0.15	231	228	3	1%
12	12	0.27	270	263	7	3%

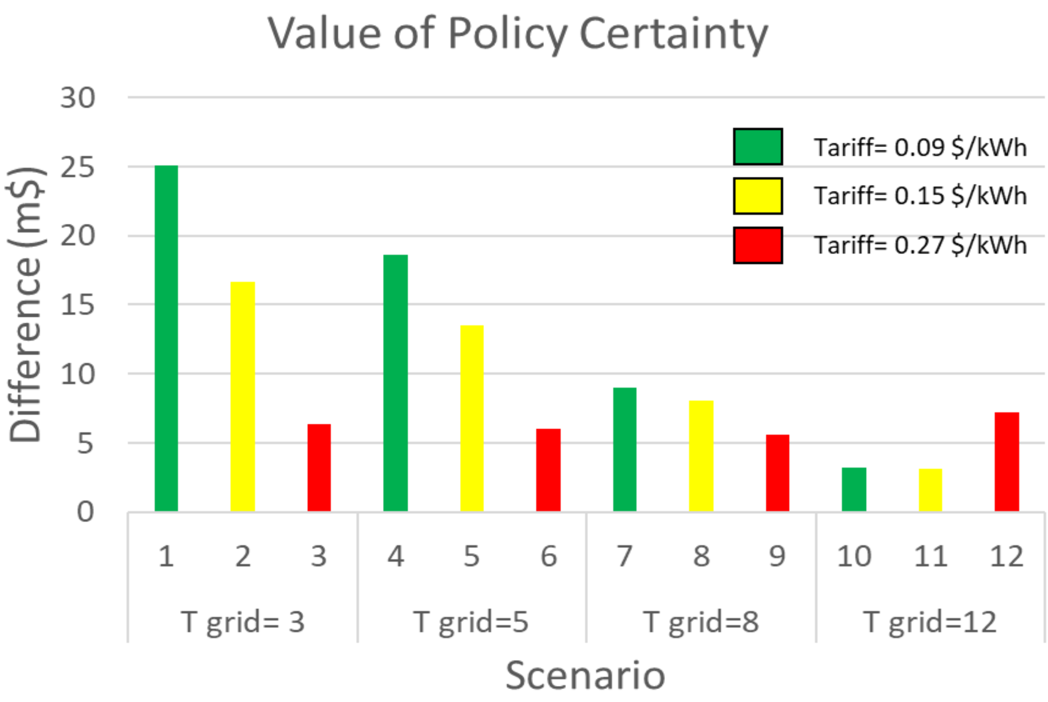

Figure 48: Value of Policy Certainty (in Million Dollars)

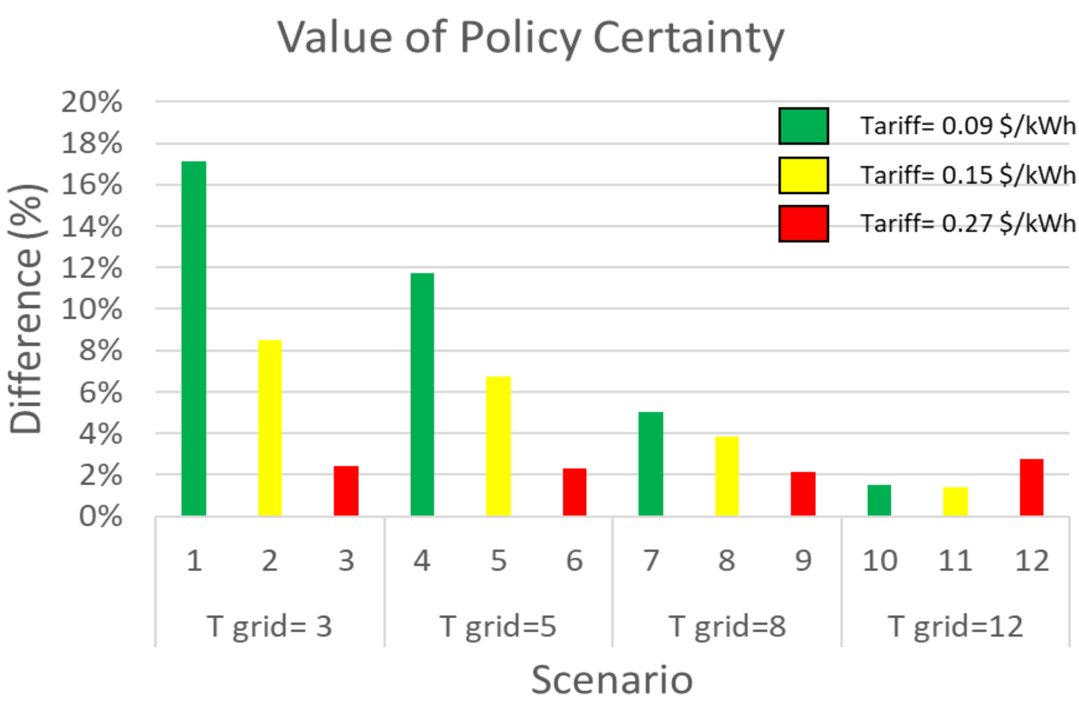

Figure 49: Value of Policy Certainty (in Percentage)

CHAPTER 5

LIMITATOINS AND FUTURE WORK

The main limitation in our current work is that we are planning for the whole planning horizon once at the first year. This is not realistic since there should be additional information related to the uncertainties and the probabilities when moving from year to year so the model will be updated with new inputs accordingly. Moreover, the Grid Existence is considered to be binary not considering the realistic conditions we have of 2-4 unscheduled hours of central grid electricity supply, we are just considering that the grid either exists or no. The last limitation is related to the scenarios' probabilities assumption. To tackle some of the mentioned limitations, a multi-stage rolling horizon model is proposed.

A multi-stage rolling horizon model will be used to decide on the next period only without targeting the whole planning horizon (the number of stages is not determined yet). For example, after planning for the next stage, new data and information may be available before reaching the stage after and the decision should be adjusted. By using this method, we believe that the decision will become more optimal because we are including new and more accurate information and data.

CHAPTER 6

CONCLUSION

Lebanon has suffered for decades in its electricity sector due to bad decision making and policy implementation. As a solution of the electricity crisis in the country, many communities and households decided to invest hybrid renewable energy systems. Yet, investments in decentralized solutions happen under major energy-related policy uncertainties related to the time when the reliable central grid will exist (T_{grid}) in addition to the tariff and feed-in tariff. In this research, we propose a linear optimization model to optimize a HRES for the Higher Matn region in Lebanon. After running the model on a base case scenario, we ran the model on different scenarios to check how the decisions will be affected by the 3 main uncertainties that we are tackling which are the year when the grid electricity will exist (T_{grid}), the centralized grid tariff and the feed-in tariff provided. According to the results, T_{grid} and Tariff uncertainties affected our decisions more than the Feed-in Tariff under the conditions we have. These uncertainties affected the investment decision on different levels including the energy mix at the initial year and the whole planning horizon in addition to the other operational decisions as well. To investigate more on the tackled uncertainties, a two-stage stochastic model was proposed. This model takes all the scenarios with their probabilities of happening as an input and returns two types of results, capacity decisions (first stage) for all scenarios and operating decisions (second stage) for each scenario by itself. After that we assessed and quantified the value of policy certainty by comparing the results of the deterministic and stochastic models. As a conclusion, the policy certainty is a significant factor that affects the decisions and the costs related to the investments in HRES.

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