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A standardized process assessing off-grid PV-system investments in developing countries

Multi-horizon stochastic programming for valuing projects with high uncertainty

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Problem Description

The main purpose of this thesis is to develop a standardized process for private investors, in off-grid PV-system projects based in developing countries, to use in the initial decision and valuation process. Due to the high uncertainty present in developing countries, the valuation of projects through the standard process will be based on multi-horizon stochastic programming, as well as risk assessment. This particular topic is chosen as a result of our cooperation with the company SunTap Uganda, who wants us to assess their options for future growth through investing in a bigger solar based project in Uganda. Thus the standardized process which is developed will serve as a basis, and be tested through a case study executed on SunTap's behalf.

Preface

This thesis concludes our Master of Science at the Norwegian University of Science and Technology, Department of Industrial Economics and Technology Management. It is written within the fields of Managerial Economics and Operations Research, and Financial Engineering. The thesis is motivated by and written for SunTap, as a part of their goal of becoming an important actor for the electrification of Uganda using solar technology. Further, it is a continuation of the report written on the same topic in the fall of 2016.

Several individuals have contributed to the completion of this thesis. First of all we want to thank our supervisor, Asgeir Tomasgard, for the exceptional guidance, and at the same time the valuable autonomy he has provided us with throughout the process. Secondly we want to express our gratitude towards the time that our co-supervisor, Christian Skar, has spent on invaluable discussions with us this last semester.

We also want to thank the founder of SunTap, Helge F. Schjøtt, for providing us with the interesting problem on which this thesis is built. In addition we want to thank Loy Kyozaire and Esther Katete for the warm welcome they gave us in our visit to Uganda. We are truly grateful for the time and effort they have put into providing us with a case to study, and information to complete the study. Lastly, we want to thank everyone who has provided us with information and data for our case study, both through interviews and mail correspondence.

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Abstract

This thesis is written in cooperation with SunTap, as a step towards their goal of becoming an important actor in the market for electrification of Uganda using solar technology. More than 80% of the population in Uganda live in rural areas, and the vast majority without access to electricity. The country's geographical location makes it preferable for utilization of energy from the sun, and off-grid PV-systems are therefore regarded as attractive investments. A general processes for assessing the value of investments in off-grid PV-systems in developing countries does however not exist. Therefore, we have developed a standardized process for assessing these types of projects from a private investor's perspective. Further, we utilize the process developed to assess the investment opportunity that a mini-grid placed in a small village in Uganda can be for SunTap.

Uncertainty can be of great importance for the value of a project. To incorporate this in the project evaluation, our standardized process initially assesses fundamental questions essential for project success, before a risk analysis is proposed as a way to appropriately identify, assess and respond to risks. Utilizing the information obtained in these assessments in a stochastic program, based on a multi-horizon stochastic structure combined with a discounted cash flow analysis, the expected net present value of the project can be calculated. Further, both required return on equity and Conditional Value-at-Risk are separately implemented in the stochastic program as two ways for the investor to apply subjective risk measures on the investment.

Through the case study it becomes evident that the standardized process is a useful tool for private investors when assessing investments in off-grid PV-system projects located in developing countries. The results from the case study show that the investment opportunity assessed has a positive expected net present value. However, this value is highly influenced by the amount of grants awarded for the project and the subjective assessment of project risk made by the investor. Requirements concerning high shares of demand covered by solar powered electricity also result in a negative expected net present project value. For the case studied, the strategic uncertainty incorporated in the stochastic program provides a low value of stochastic solution. By incorporating additional long-term uncertainties, this effect can however be avoided.

Sammendrag

Denne masteroppgaven er skrevet i samarbeid med SunTap, som en del av deres mål om å bli en viktig aktør i markedet for elektrifisering av Uganda ved hjelp av teknologi basert på solenergi. Mer enn 80% av befolkningen i Uganda bor i distriktene, og den største andelen av dem uten tilgang på elektrisitet. Landets geografiske plassering gjør det til fordelaktig for utnyttelse av solenergi, og frittstående solenergi nettverk er dermed ansett som gunstige investeringer. En generell prosess som kan brukes til å vurdere verdien av investeringer i frittstående solenergi nettverk i utviklingsland eksisterer imidlertid ikke i dag. Derfor har vi utviklet en standardisert prosess for vurdering av av slike prosjekter sett fra en privat investors perspektiv. Videre bruker vi prosessen til å vurdere investeringsmuligheten som et mini-grid i en liten landsby i Uganda kan være for SunTap.

Usikkerhet kan ha stor påvirkning på verdien av et prosjekt. For å ta hensyn til dette i evalueringen av prosjektet, tar den standardiserte prosessen til å begynne med for seg noen fundamentale spørsmål som er avgjørende for prosjektets suksess, før en risiko analyse er foreslått for å kunne identifisere, analysere og respondere på prosjektets risikoer på en god måte. Gjennom å inkludere informasjonen som disse analysene gir, kan prosjektets forventede nåverdi regnes ut ved hjelp av et stokastisk program som baserer seg på en multi-horisont stokastisk struktur kombinert med en diskontert kontantstrømanalyse. I tillegg er både avkastningskravet på egenkapital og den betingede verdien som risikeres (Conditional Value-at-Risk) separat implementert i det stokastiske programmet, som to måter den private investoren kan evaluere risikoen subjektivt.

Gjennom casestudiet tydeliggjøres det at den standardiserte prosessen er et nyttig verktøy for private investorer som skal vurdere investeringer i frittstående solenergi nettverk lokalisert i utviklingsland. Resultatene fra casestudiet viser at investeringsmuligheten som evalueres har positiv forventet nåverdi. Denne verdien er imidlertid svært avhengig av mengden finansiell støtte prosjektet får, samt den subjektive vurderingen den private investoren gjør av prosjektets risiko. Krav til at en stor andel av etterspørselen skal dekkes av solenergi viser seg også å gi prosjektet negativ forventningsverdi. Den strategiske usikkerheten som er tatt hensyn til i casestudiet gjør at verdien av en stokastisk løsning er lav. Men denne effekten kan unngås ved å ta hensyn til flere langtidsusikkerheter.

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Abbreviations

BOS	Balancing Of System
CapEx	Capital Expenditure
CVaR	Conditional Value at Risk
DCF	Discounted Cash flow
EEV	Expected value of using the Expected Value solution
ERA	Electricity Regulatory Authority
EUR	Euro
EV	Expected Value
FCF	Free Cash flow
GETFiT	Global Energy Transfer Feed-in Tariff
kW	Kilowatt
kWh	Kilowatt-hour
LCoE	Levelized Cost of Electricity
MW	Megawatt
MWp	Megawatt peak
NPV	Net Present Value
NWC	Net Working Capital
O&M	Operational and maintenance
PV	Photovoltaic
REFiT	Renewable Energy Feed-in Tariff
RRE	Required Return on Equity
SP	Stochastic Problem
UECCC	Uganda Energy Credit Capitalisation Company
UGX	Ugandan Shilling
USD	United States dollar
V(S)SS	Value of Strategic Stochastic Solution
VaR	Value at Risk
VOLL	Value Of Lost Load
VSS	Value of Stochastic Solution

Chapter 1

Introduction

In recent years the awareness of off-grid solutions, being an important aspect in the electrification of developing countries, has increased alongside the development of renewable energy systems. The International Energy Agency (2011) emphasize that in order to achieve 100% modern energy access in the world, more than 70% of the rural areas which are today without electricity must be connected either through mini-grids or stand-alone solutions. Further, they state that private sector investments have to increase in order to achieve the same goal.

Until now, several actors have investigated the opportunities in off-grid renewable energy projects in developing countries, but mainly from a social perspective. Tools for risk assessment, decision making, technical considerations and evaluation of such projects exist. However, the focus on combining such tools to consider the value of investments in these projects, is limited.

This thesis is written as a part of the solar technology company SunTap's long term strategic plan. To be able to evolve and utilize the huge potential that is present in the un-electrified parts of the world, the company is interested in assessing its options and investigate whether they are profitable to invest in. The purpose of the thesis is thus to assess their most promising investment option. Therefore, the thesis assesses the value of investing in a mini-grid based on solar power, placed in the village of Mpunge in Uganda.

Through the development of a standardized process in the thesis fundamental decisions for, risks present in, and the expected value of investments in mini-grids based on solar power, can be assessed from a private investors perspective. Combining multi- horizon stochastic programming with the financial DCF analysis, the valuation which is part of the standardized process, can utilize the advantages of both. Thus, through utilizing the process, we have been able to assess the mini-grid in Mpunge as a part of enhancing SunTap's market position. However, the process does not focus on the technical parts of constructing a mini-grid based on solar power.

In the following chapter, chapter two, background information considering SunTap, the energy sector in Uganda and other aspects relevant for the project is provided. Chapter three gives a complete description of the problem is given followed by chapter four which introduces literature and theory covering central aspects utilized in the thesis. Further, chapter five presents and explains the different parts of the standardized process developed. The mathematical model of the stochastic problem, used as the valuation tool in the process, is given in chapter six. Chapter seven presents the case studied on behalf of SunTap as well as the results from the utilization of the process on the specific case. The conclusion and further work proposed is eventually provided in chapter eight and nine respectively.

Chapter 2

Background

The main part of this chapter is based on Bakke and Welhaven (2016), a report written on the same topic. Through the first part, section 2.1, information about SunTap and our relationship with the company is given. Further, to motivate the case assessed in this thesis and to provide SunTap with important information, the following sections are provided: An insight into the energy sector in Uganda in section 2.2, information on some financial support mechanisms in section 2.3, the importance of risk management in renewable energy projects and developing countries in section 2.4, an introduction to solar power in the context of developing countries in section 2.5 and off-grid electrification in section 2.6.

2.1 SunTap

SunTap consists of the Norwegian company SunTap Europe and the daughter company SunTap Uganda. SunTap Uganda is a small, recently started company in the market for solar power in Uganda. So far it has nine full-time employees, three technicians, one in marketing, five in sales, as well as some part-time employees working with installations. Today they sell PV-modules for houses, in addition to lampposts and solar hot water tanks. The two employees who have been working with SunTap from the very beginning are both woman, which is rare for a Ugandan company. Thus, SunTap is also taking part in creating jobs for women in Uganda. Their ambition is to grow into a company which is offering quality products, and has substantial market shares in Uganda. In order to grow, SunTap is also assessing the possibility of selling electricity from larger solar power installations. To evaluate if there is any potential for the company to expand through investing in projects of greater extent, the founder of SunTap Europe contacted us. Through earlier acquaintance he knew about our backgrounds and he wanted us to analyze this opportunity.

2.2 Energy in Uganda

In Uganda, approximately 15% of the population has access to grid electricity (Norad, 2015). Numbers from the Ugandan Bureau of Statistics state that the grid electricity covers 54.8% of people living in urban areas, while the same is true for only 7% living in rural areas (Heteu, 2015). The Ugandan population is reaching 40 million (Norad, 2015), and as more than 80% of them live in rural ares, the lack of electricity access effects a severe amount of people (Uganda Bureau of Statistics, 2013). Those living without electricity is dependent on other sources of energy for cooking, heating and lighting. According to the 2014 annual report by the Ministry of Energy and Mineral Development, the energy supply in Uganda consists of mainly biomass (88.8%), while electricity accounts for a modest 1.7% (Ministry of Energy and Mineral Development, 2014). The main source of biomass is firewood (79.9%), and the World Wide Fund for Nature's Energy Report for Uganda states that *the level of demand exceeds the sustainable biomass production levels and is adding to the deforestation taking place in the country* (Gustavsson et al., 2015, pp. 27). Additionally, the health effects of using such solid fuels for cooking and heating indoor are severe, and worldwide 4.3 million people die prematurely each year due to illness related to household air pollution (World Health Organization, 2016). With a rapidly growing population, having an annual growth rate of approximately 3%, according to numbers from Uganda Bureau of Statistics (2013), there is no doubt that the demand for electricity will increase. Further, increasing access to electricity will also increase the standard of living for the population, eventually leading to a higher demand for electricity.

2.2.1 Visions

In 2010, the Government of Uganda created a 2040 vision for the country (Government of Uganda, 2010). The vision includes a target of 80% access to electricity through the national grid within 2040. Two years later, the country opted-in the United Nations' Sustainable Energy for All Initiative. The goal of the program is that more than 98% of the population should have electricity access, and more than 99% of the population should have access to modern cooking solutions by 2030 (Heteu, 2015). In 2013, the Ministry of Energy and Mineral Development presented the Rural Electrification Strategy and Plan for 2013 until 2022. During this period, the goal is to increase electricity access in rural areas to 26% (Ministry of Energy and Mineral Development, 2013).

It is evident that the authorities in Uganda understand that the energy situation in the country has to change. However, in order to be able to follow their vision, the Government of Uganda is dependent on new installations of electricity. Through the 2040 vision for the country, there is also a focus on renewable sources of energy, mainly wind, solar and bio-gas. Actually, in 2007 the Renewable Energy Policy was initiated with the main purpose of increasing the use of modern renewable energy[1] by 2017 (Ministry of Energy and Mineral Development, 2007). The Sustainable Energy for All initiative also includes a target of 90% renewable energy production by 2030 (Heteu, 2015).

2.2.2 Energy sector institutions

There are several key institutions in the energy sector that are important to know of when entering into renewable energy projects in rural parts of Uganda, especially in connection to some of the parts in the licensing process. These are given a brief introduction in this section.

[1] Modern renewable energy is in this policy defined as *renewable energy resources that are transformed into modern energy services like electricity*, as well as *clean fuels derived from renewable energy sources* (Ministry of Energy and Mineral Development, 2007).

Ministry of Energy and Mineral Development

The supreme authority, the Ministry of Energy and Mineral Development, are responsible for all the political decisions in the sector (Norad, 2015). Some of their main tasks are *establish, promote the development, strategically manage and safeguard the rational and sustainable exploitation and utilization of energy and mineral resources for social and economic development in Uganda* (Electricity Regulatory Authority, 2015).

Electricity Regulatory Authority

As an effect of a reform in the electricity sector leading to the *Electricity Act* in 1999, the Electricity Regulatory Authority (ERA) was established in 2000 (Norad, 2015). The Electricity Act enabled private participation in the electricity sector. Thus, the ERA got the responsibility for the private and public actors within the sector, and of evaluating applications and issuing licences for transmission, generation and distribution of electricity (Electricity Regulatory Authority, 2013).

Electricity Disputes Tribunal

The Electricity Act also led to the establishment of the Electricity Disputes Tribunal. The Electricity Disputes Tribunal's primary objective is to hear and determine all matters referred to it relating to the electricity sector. When exercising some functions in connection to distribution, transmission and generation it has the power of the High Court of Uganda. One can also appeal decisions of ERA to the Electricity Disputes Tribunal. (Electricity Regulatory Authority, 2015).

Rural Electrification Agency

In 2001 the Rural Electrification Agency was established as a semi- autonomous agency by the Ministry of Energy and Mineral Development (Electricity Regulatory Authority, 2015), to deal with the problems related to poor access to electricity in rural parts of the country (Norad, 2015). Additionally the Rural Electrification Board, which is the governing body of the Rural Electrification Agency, provides subsidies to support rural electrification projects (Electricity

Regulatory Authority, 2015).

Uganda Electricity Transmission Company Limited

The Uganda Electricity Transmission Company Limited was also established due to the liberalization of the sector. The company is responsible for delivering electricity to the consumers, and to build, operate and maintain the main grid in the country (Norad, 2015). The Uganda Electricity Transmission Company Limited is the system operator and owns transmission lines above 33 kilo-volt, as well as being the only purchaser of power generated in Uganda which is fed into the main grid (Electricity Regulatory Authority, 2015).

Uganda National Bureau of Standards

As a statutory body, under the Ministry of Trade, Industry and Co-operatives, the Uganda National Bureau of Standards formulates and promotes the use of national standards. In the context of energy, the Uganda National Bureau of Standards is for instance responsible for developing and monitoring standards for renewable energy technologies. (Electricity Regulatory Authority, 2015).

National Environment Management Authority

In 1995 the National Environment Management Authority was established as a semi-autonomous institution (NEMA, 2017). It has the responsibility of monitoring, regulating, coordinating and supervising environmental management in the country (NEMA, 2017). Thus the National Environment Management Authority is responsible for regulating the impact of renewable energy investments on the environment. Further the National Environment Management Authority awards certificates of environmental clearance, following review and approval of Environmental Audits, Environmental Impact Assessment Reports and Resettlement Action Plans (Electricity Regulatory Authority, 2015).

Uganda Investment Authority

Uganda Investment Authority, established in 1991, is also a semi-autonomous agency, which drives national economic growth and development in partnership with the private sector (UIA, 2017). Their aim is promoting and facilitating private sector investment in Uganda (Electricity Regulatory Authority, 2015). As a way of doing this the Uganda Investment Authority offers services for registration of businesses and acquiring of licences for free (Electricity Regulatory Authority, 2015).

2.2.3 Licencing, electricity pricing and subsidies

When considering investing in a renewable energy project in Uganda, a specific procedure has to be followed in order to acquire a licence. This is the same for all investors in the sector. The procedure starts by the investor noticing the ERA of the project they intend to carry out. If the requirements for the notice are met it is published, and within 30 days directly affected parties and local authorities are invited to comment on the notice. Within 30 days after comments are received, the ERA may issue a permit allowing the investor to pursue the project early phases. Further, the investor has to send an application to the Chief Executive Officer of ERA. Within 45 days a notice of the application is published, and directly affected parties and local authorities are invited to lodge an objection in less than 30 days after the publication. Finally the ERA processes the application, and within 180 days it will be approved or denied. Thus the process is long-lasting and it may take more than 9 months to get a licence approved. If major investments are not put on hold until the licence is approved, an investor risks high losses accompanied by a denial. (Electricity Regulatory Authority, 2012)

The electricity prices for grid connected consumers in Uganda are set at the three points between generation, transmission, distribution and end-user consumers. Thus, tariffs for electricity to end-users are set by distributors and then approved by the ERA at the beginning of each year. Throughout the year these base tariffs stay unchanged, except for adjustments at a quarterly basis to account for international fuel prices, inflation rates and exchange rates (Electricity Regulatory Authority, 2014). The reason is that these factors affect the costs of generation, transmission and distribution, which then affects the end-user tariff. Thus, the end-user tariffs may decrease or increase at quarterly billing periods.

The Ugandan national on-grid tariffs are highly subsidized by the government to keep electricity prices low for end-users. Therefore, and due to economies of scale, the cost covering tariff for off-grid installations is usually higher than the on-grid tariff, if the off-grid tariff is not subsidized (Raisch, 2016). Generally there are different ways to set the tariffs for off-grid installations, mainly through fixed tariffs or tariffs based on consumption, which focuses on cost covering or small profit shares for the investors (Franz et al., 2014). Fixed tariffs payed upfront are called pre-payments and is usually paid on a monthly or quarterly basis (Franz et al., 2014). In a mini-grid there is no external distributor, thus the mini-grid owner is its own distributor. Mr. Dominic Mark Mugisha, manager of *Power Africa* in Uganda, emphasized in a meeting in connection with this thesis, that there are no existing regulations for how to set tariffs in off-grid systems in Uganda. However the ERA must approve the tariff that is chosen for the system, therefore it has to be in accordance with what the end-users are able to pay. Because mini-grids are quite new in Uganda, the ERA does not have any standard cost reflective tariff to compare with when deciding on approval or disapproval of the proposed mini-grid tariff.

To encourage and support more private sector investments in generation of electricity from renewable energy technologies the Renewable Energy Feed-in Tariff (REFiT) has been established. This feed-in tariff provides a fixed tariff, for a guaranteed period of time, for electricity generated from renewable energy technologies, which are based on the systems levelized cost production (Electricity Regulatory Authority, 2016). Today the REFiT is just provided to systems connected to the main grid, but off-grid projects may also be included in future developments of the feed-in tariffs. A program based on feed-in tariffs is the Global Energy Transfer Feed-in Tariff (GETFiT) Program, which was rolled-out in Uganda. The aim of the entire program is *to assist East African nations in pursuing a climate resilient low- carbon development path resulting in growth, poverty reduction and climate change mitigation* (Multiconsult, 2016, pp. 6). Also, as stated in the annual report of 2014 by Multiconsult (2016), the main feature of the program is a premium payment, meant to top up the REFiT and be paid out over the first five years of operation.

2.3 Financial support mechanisms

Because of the increased focus on the importance of electrification of developing countries through the use of renewable sources, several organizations and foundations have also been developed with the aim of supporting projects with such focus. The main focus will here be on a few who provide financial support, for instance through loans or non-repayable grants. The Energy and Environment Partnership is one, which was started in South-America in 2002, before it was implemented in Africa and South-East Asia (Energy and Environment Partnership, 2017). The partnership promotes clean technology investments, renewable energy and energy efficiency. In Southern- and East Africa they have developed a program, Energy and Environment Partnership Southern- and East Africa, which was started in 2010. With an overall objective including energy security and reduction of poverty, the program *supports projects in the two regions that can contribute to the reduction of poverty by promoting inclusive and job-creating green economy and by improving energy security while mitigating global climate change* (Energy and Environment Partnership, 2017).

Another possibility for acquiring financial support for projects focused on renewable sources is through the Sustainable Energy Fund for Africa, a multi-donor trust fund which is administered by the African Development Bank. Energy Efficiency and Renewable Energy, both small- and medium-scale, projects in Africa are supported by the fund (African Development Bank Group, 2017). One of the support mechanisms they provide is *cost-sharing grants and technical assistance to private project developers/promoters to facilitate pre-investment activities*. In addition they support the public sector activities enabling private sector investments in sustainable energy. Through the joint Project Facility, which is a result of collaboration between the International Renewable Energy Agency and the Abu Dhabi Fund for Development, soft loans are also provided to renewable energy projects in developing countries (IRENA/ADFD, 2016). Which projects are awarded with the loans is assessed by the International Renewable Energy Agency, while the loans are offered by the Abu Dhabi Fund for Development.

2.4 Risk and renewable energy in developing countries

Implementing a project in a developing country like Uganda will expose it to other risks than if it was to be carried out in a developed country. For instance, *the higher is per capita income on an internationally comparable measure, the lower is the risk of civil war* (Collier and Hoeffler, 1998, pp. 571), thus in developing countries this risk is usually higher. Also, for private investors from developed countries investing in Uganda, risks related to political stability, the customers ability to meet payments and corruption, among others, may be higher than what the investors are used to. For instance, the Poverty Status Report for Uganda states that 19.7% of the population lives below the income poverty line, and more than 22% lives on an income below the double amount (Economic Development Policy and Research Department, 2014). This implies that about 40% of the Ugandan population may struggle to meet payments. In addition, uncertainty related to future electricity prices, development of technology, investment incentives and efficiency of technology makes renewable energy projects highly uncertain compared to other investment opportunities. Investigating, analyzing and accounting for risks are therefore seen as essential in assessments of renewable energy projects in developing countries.

There is reason to believe that risks will have an even stronger influential force on projects in the future. Rasmussen (1997) presents how risks have been increasing for the last decades, by mentioning for instance the fast change of technology at the operational level of society and the aggressive and more competitive environment that companies operate within. The development in technology of PV-modules yields an example of how rapid changes may cause additional risk. By investing in the technology today there is uncertainty to whether or not new improved PV-modules are introduced to the market within a short time frame, which would have made it a competitive advantage to delay the investment. Additionally, risks related to extreme weather events due to climate changes, and growing differences in welfare across the world could yield risks that were not present earlier. On the other hand, the rapid development and increased risks could also open new business opportunities.

2.5 Solar power

Solar power utilizes energy from the sun to generate electricity. Through a photovoltaic (PV) cell, or a solar cell, the photons in light is absorbed by a semi conductor, which causes electron movements. Silicon is the most frequently used semi conductor in solar cells (Britannica Academic, 2016), and gives the cell a potential efficiency of 28% (Lied, 2016). However, Lied (2016) points out that actual efficiencies are often between 15% and 24%, which is in correlation with numbers stated in the presentation given by Thorud (2016). Because the energy flux that each year hits the earth is about 15,000 times larger than the earths total energy consumption (Hofstad, 2016), the potential for solar energy is enormous. According to Hofstad (2016) investment costs of PV-modules have also decreased dramatically over the last years, which has resulted in an average yearly increased installed capacity of about 40% for the last 10 years. According to the analysis from Mayer et al. (2015), the module costs can fall by between 60% to 75% from 2014 to 2050.

Most of the electricity production in Uganda today is based on hydro power (Norad, 2015). In contrast to hydro power dams, solar power is more challenging when it comes to storage of energy. When the sun shines on the solar panels they will immediately produce electricity, which at the same time has to be either used or stored. As electricity demand rarely follows solar irradiance patterns, batteries are used to store what is not demanded instantly. Batteries however contribute to high installation costs for solar systems. On the other hand, compared to for instance hydro power, solar power installations are relatively small and mobile. They can be placed in almost any location where sunshine will hit the panels. This makes it easier to place the generation source closer to where the electricity demand is, and thus minimize the transport through high-loss transmission lines.

With renewable energy sources, like the sun, developing countries have the opportunity to not introduce fossil-fueled electricity in their countries, and thus positively contribute to the world's climate change problems. Uganda is one of the countries which has great potential for solar power because of its location on the equator and high elevation. This is because their temperatures do not rise to the extreme, the seasonal variations are minimal and the sun shines at an angle direct to earth. However, today the cost of installation of solar power is high, and most developing countries depend on support and private investors from abroad, as well as a decrease in investment costs, to be able to increase the utilization of such renewable energy sources.

2.6 Off-grid electrification

Because of the large quantity of people living in rural areas of Uganda, the process of building a main grid that can connect everyone, is enormous. Therefore, local off-grid installations serves as an option for electricity in rural parts of the country. Terrado et al. (2008) state that the maturation of small scale renewable energy sources and service delivery models has resulted in stand-alone and off-grid solutions becoming viable alternatives for production of electricity, especially in rural areas.

Several factors affect what type of off-grid installation that should be utilized in an area. Terrado et al. (2008) point out that the willingness to pay, demand, available resources and concentration of customers are some of these factors. One type of off-grid system is the so called *stand alone systems*. These systems are not connected to a distribution network and thus just provide electricity to a small entity, for instance independent households (Alliance for Rural Electrification, 2016). All the technologies converting the energy from wind, waterfalls or rivers, biomass and sun to electricity, can be used in these stand alone installations. Further, *micro-grids* and *mini-grids* are other possible off-grid systems. Some distinguish these two expressions based on amount of installed capacity in the system (Franz et al., 2014), while others define the two as interchangeable expressions defining the same systems (Alliance for Rural Electrification, 2016). We will use the term mini-grid throughout this report, as electricity generation plants between 10 kilowatt (kW) and 10 megawatt (MW), as defined by Alliance for Rural Electrification (2016) and Franz et al. (2014). For mini-grid systems the generation is connected to a local grid for distribution of electricity to a small area, and provides *centralised generation at local level* (International Energy Agency, 2011, pp. 16). However, mini-grids can also utilize the same sources of electricity as the stand alone systems. A combination of renewable and non-renewable energy sources is also possible in a so-called hybrid mini-grid, to establish security of supply or increase the capacity (Franz et al., 2014). Figure 2.1 (a) shows a solar mini-grid from an island in Africa, while figure 2.1 (b) shows a stand alone system on the roof of a village house.

(a) (b)

Figure 2.1: A mini-grid on an island in Africa, and a stand alone system.

Because the off-grid system has to be scaled to cover the maximum system load, one of the advantages of a mini-grid compared to a stand alone system is that it can be designed to cover the peak-load of a large amount of customers. Assuming that not all customers will have their peak-demand at exactly the same time, less capacity per customer is needed in a mini-grid. Further, the amount of components in the system, such as inverters, will be reduced when combining the installation into one centralized capacity, which hence reduce costs. However, a mini-grid will per definition include a grid, connecting the customers to the generation source, which is not necessary in a stand alone system (International Energy Agency, 2011). Therefore, where a mini-grid is built, the population density should justify the increased cost of connecting everyone. Thus stand alone systems have higher costs per kilowatt-hour (kWh) (International Energy Agency, 2011), but avoid the distribution and transmission costs accompanying a mini-grid. In addition the International Energy Agency (2011) emphasize that mini-grids can be modified to handle growth in demand. With time, mini-grids also have the ability to be connected to the main grid if this reaches the mini-grid area (Franz et al., 2014).

Chapter 3

Problem description

In this chapter a more complete description of how we understand the underlying problem for SunTap is given. Because the underlying problem is handled through the creation of a standardized process, the aspects of this as a problem to be solved is also described.

As the interest in solar power and the electrification of countries like Uganda is growing at a fast pace, it is important for SunTap to take part in this market development. Thus, the underlying problem for the company is interpreted as how they can become an important actor in the market for electrification in Uganda through the use of solar technology. What is evident is that solar power has a great potential in Uganda. As outlined in section 2.2 the country is focusing on electrification, especially of rural areas, and the geographical location of the country makes the sun a valuable resource. But opportunities seldom appear without threats, and in Uganda, as in most developing countries, many of these threats differ from threats generally experienced in industrial countries, as emphasized in section 2.4. Both opportunities and threats are subject to uncertainty about the future and this makes risk important to evaluate and respond to.

Uncertainty and risk may be defined in different ways, but throughout this thesis the following definition of is used. A risk is *any uncertainty that, if it happens, could have a positive or negative effect on one or more project objectives* (Hillson, 2003, pp. 59). Thus risk and uncertainty basically covers the same aspects. Negative risk corresponds to threats, like positive risk does to opportunities.

Some of the biggest opportunities in the electrification of countries like Uganda are, as previously mentioned, present in the areas that are not yet connected to the utility main grid. Additionally the mini-grid solution has great potential as a part of contributing to off-grid electrification, when placed in a suitable area. Therefore, we consider the natural next step for SunTap to be the assessment of whether a mini-grid based on solar technology, placed in an area of Uganda not yet connected to the main grid, is a valuable investment opportunity. Due to the company's limited resources and capacity, it would be natural for SunTap to start out with one mini-grid project and further develop the company based on this project's outcome.

To evaluate whether such a project will be successful as a part of SunTap's development, it is important to identify critical factors affecting project success, assess the project risks, decide on the optimal grid-capacity, as well as calculate the expected net present value of the project. Because this process involves several elements, we believe that developing a standardized process for how it could be carried out is of great value. Although SunTap is focused on electrification in the Ugandan market, other project investors may also benefit from utilizing a standardized process when investing in a solar powered mini-grid in a developing country. Therefore developing a process generally applicable to solar powered mini-grid projects in developing countries, has been chosen as part of solving SunTap's underlying problem.

The standardized process should consider critical factors typical for solar powered mini-grid projects, and make sure that these are handled initially. In addition, the different aspects of risk analysis should be considered such that all important project risks are highlighted. Thus, when risks are identified their impact should be assessed, as well as classifying them based on theory of diversification can be helpful when deciding how to respond to the risks. What response is chosen for these risks should in turn impact the valuation of the project.

Risk, or uncertainty, may have great impact on the success of a project. Therefore, when deciding on what capacity to install and conducting a valuation of the project, it is important to incorporate the critical factors and risks assessed. By utilizing an optimization model incorporating uncertainty on an operational and strategic level, this is possible. In such a model the project cash flows, as well as an appropriate representation of the uncertain elements is of great importance. Some of the uncertain elements that could be incorporated in this type of optimization model are solar irradiance, demand for electricity, investment costs and foreign exchange rates.

The following chapter introduces theory and literature concerning different aspects of the problem we are assessing for SunTap. It covers frameworks and existing processes similar to the one developed in this thesis, financial assessment methods and aspects related to stochastic programming, to mention some. This is meant to give insights into the theoretic aspects of the problem, as well as to what parts of the problem that have already been assessed. Further it highlights how the problem solution method we have chosen utilizes, and is a contribution to, existing literature.

Chapter 4

Literature review and theory

In this chapter, a review of literature and theory relevant for the problem described, is presented. Some sections are based on the work we conducted in Bakke and Welhaven (2016). Section 4.1 presents other standardized processes and frameworks developed for renewable energy projects in developing countries, as well as general risk management procedures. An introduction to stochastic programming is given in section 4.2. Different financial assessment procedures, and examples of financial assessments of projects similar to the one we are assessing, are presented in section 4.3. Section 4.4 provides an insight into the subject of scenario generation. Conditional Value at Risk (CVaR) is described in section 4.5, before the concept of multi-horizon stochastic programming is presented in section 4.6. To round of this chapter, section 4.7 places our work into the context of the existing literature presented, and highlights our contribution to the field of study.

4.1 Existing processes and frameworks

There exist several standardized processes and frameworks concerning the implementation of renewable energy projects in developing countries. For instance, Kumar et al. (2009) present in their paper a standardized decision making process, meant to accelerate the implementation of such projects. This accounts for the whole process of planning and formulating off-grid electrification projects. The main focus in the paper is however on strategic decisions, but it also includes a financial framework for tariff determination.

Mandelli (2014) mainly focuses on system design, and the techno-economical aspects of mini-grid projects in developing countries. Further, he describes an approach for how sizing can be accomplished in rural energy projects. The approach involves a procedure for how scenarios on load profiles can be generated. To minimize the cost of electricity seen from the consumers perspective, the value of lost load (VOLL), investment costs and operational and maintenance (O&M) costs, are accounted for in his approach.

Different mini-grid[1] modeling-softwares, such as HOMER™ are available. The benefit of these softwares is the intuitive interface and standardized input. With HOMER, the user can combine technologies, do simulations of mini-grid operation, optimize the system design to obtain the lowest cost for the combination of equipment in the mini-grid, and do sensitivity analyses. On the other hand HOMER does not account for the long-term operation of the mini-grids. Sen and Bhattacharyya (2014) is one of many utilizing this software for planning an off-grid electricity project in India, and discuss some of the issues and considerations that must be made when relying on HOMER.

General risk management literature has also been reviewed in order to achieve an overview of this topic which is also affecting our problem. Larson and Gray (2014) presents a rather basic procedure of risk management. In this book, the term risk mainly refer to negative events that might occur, but Larson and Gray (2014) also consider opportunity management. The risk management procedure consist of identification, assessment and finding the appropriate reactions to handle risk.

Another book, which focus solely on risk and opportunity management is the book by Hillson (2003). Here the perception of risk as an event that could have either a negative or positive impact on project objectives is assumed, and it discusses the importance of investigating opportunities as well as threats. The risk management procedure described is relatively similar to that of Larson and Gray (2014), and includes identification, assessment, response and monitoring of risk.

Manetsgruber et al. (2015) have developed a guide for risk-management of mini-grids. Their procedure is relatively similar to the standardized approaches of managing risks presented by

[1]Referred to as micro-grid on the HOMER™-website.

Hillson (2003) and Larson and Gray (2014), but focuses on negative risks that could influence this specific category of projects. They further emphasize that a standardized risk-management process can help decrease the gap between the risk perception of mini-grid investors and developers, and that it is essential for speeding-up the rural electrification market.

4.2 Stochastic programming

In what is called a *deterministic* programming problem, all components are assumed to be known within the period of time considered (Muhammad and Pflug, 2014). For some problems, or parts of a problem, this assumption may be justified. But in many real life problems, assuming all data elements (parameters) in the problem to be known is somewhat presumptuous (Higle, 2005). In *stochastic* programming, as opposed to deterministic programming, some parameters in the original problem are observed as random or uncertain (Prékopa, 1995). Stochastic programming is thus optimization using uncertain parameters, and decision-making under uncertainty. Contrary to solving the problem as if it was deterministic and conduct a sensitivity analysis, stochastic programming offers a way to collectively, not individually, consider various scenarios of the uncertainty in the problem (Higle, 2005).

The timing of decisions made, in relation to the uncovering of uncertainty, is important in stochastic programming (Higle, 2005). A stochastic model is referred to as a *recourse model* when some problem decisions, *recourse decisions*, can be delayed until uncertainty has been resolved, while some decisions have to be made ”here and now” (Higle, 2005). Thus a recourse decision provides an opportunity to adapt to the outcome of the uncertain parameters in the problem assessed. According to Higle (2005), the recourse model is the only one designed to optimize the problem solution while balancing the potential impact of different scenarios. Thus the model actually provides a solution that is an expectation of the objective value in the problem.

Recourse problems, and the dependencies within them, can be structured using a *scenario tree*, which is the logically correct structure for a multi-stage stochastic decision problem (Wallace, 2000, pp. 32). According to Higle (2005), a *scenario* is defined as a specific, complete realization of the uncertain parameters that may appear in the problem. Hence, the scenario tree structures the scenarios according to the fashion in which they appear during the problem. One *scenario problem* can be seen as a deterministic optimization problem, representing one of the scenarios (Higle, 2005). For recourse problems, *non-anticipativity constraints* may also, for some dependencies, be necessary to ensure that the information structure in the problem is represented in its mathematical formulation (Higle, 2005). The information structure of a stochastic model also have additional terms referring to time. As in a deterministic problem *time periods* still refer to hours, weeks, months etc., however the term *stage* refers to *a point in time where it is possible to make decisions, and where it makes sense to make decisions* (Wallace, 2000, pp. 27). This implies that a new stage is where more information has become available, making it reasonable to make a recourse decision. In addition a stage can cover several time periods, if there is no uncertainty between them.

4.3 Financial assessments

Capital budgeting is the process of determining what projects to accept and which to reject (Berk and DeMarzo, 2014). The *Discounted Cash Flow* (DCF) analysis is one capital budgeting procedure used to evaluate projects based on the projects *Free Cash Flow* (FCF) and results in a *Net present Value* (NPV) for the project (Berk and DeMarzo, 2014). It is important to distinguish between the profit of a project, and the cash flows a project generates (Brealey et al., 2001; Berk and DeMarzo, 2014). In capital budgeting, the focus should be on cash flows and not profits[2] to calculate the NPV of a proposed project. This is because *projects are financially attractive because of the cash they generate [...]* (Brealey et al., 2001, pp. 380). In order to account for uncertainties, as they are not present in the valuation, the capital budgeting process often includes sensitivity analyses (Berk and DeMarzo, 2014).

The real options method is presented in Berk and DeMarzo (2014).The method constructs simple decision trees in order to include uncertainties in project valuation and add the value of options following an investment. The option to change scale, defer an investment or abandon a project are examples of types of real options (Yeo and Qiu, 2003). Dixit and Pindyck (1994) uti-

[2]Cash flows are the actual cash payments and cash received, while profits are occurring on the income statement, where, among other things, investments have been depreciated based on their expected lifetime (Brealey et al., 2001).

lize real options for project valuation, and emphasize the value of following stochastic processes to reflect the underlying uncertainties leading to options.

Our observation is that the valuation method used in stochastic programming is often based on simplified annualized values instead of the traditional cash flow analysis, but the uncertainty is reflected by utilizing scenarios, as described in section 4.2.

HOMER is often chosen to carry out the financial evaluation of mini-grid projects, like Sen and Bhattacharyya (2014) chose. Himri et al. (2008) also chose to use HOMER to investigate the potential for hybrid power systems in a remote village of Algeria, while Nfah et al. (2008) has utilized HOMER for projects based in remote villages of Cameroon. Al-Hammad et al. (2015) comprises seven existing hybrid mini-grid projects as seven different cases, and discuss two different scenarios. In one of the scenarios, the government can bear the financial investments on its own, while in the second scenario, private actors has to finance and operate the grid. The technical-financial analysis in all projects is performed using HOMER. Further, the paper also mentions some of the simplifications in the financial evaluation tool HOMER provides. Such simplifications are for instance constant discount rates, as well as improper considerations of revenue streams, tax effects and changes in financing structure.

Aziz and Chowdhury (2012) uses real options to perform a financial analysis of a PV mini-grid in Bangladesh. The options of abandonment, relocation, expansion and contraction are investigated, and shown to lower the cost compared to a conventional capital budgeting procedure utilizing NPV. But the options are explored individually, without interacting effects.

Ferrer-Martí et al. (2012) present a mixed integer linear programming model to minimize investment cost in order to meet demand for hybrid rural electrification projects in developing countries. The model is applied to real case studies in Peru, and finds solutions that reduces costs substantially. However, the model does not incorporate uncertainty.

4.4 Scenario generation

Depending on the algorithm used in a stochastic program, to be able to solve it, the probability distribution of the uncertain elements will most likely have to be transformed into a discrete distribution (King and Wallace, 2012). When such discrete values of a distribution are used to solve a stochastic programming problem in stages, they become the scenarios of the scenario tree (Kaut and Wallace, 2007). Thus scenario generation is the process of obtaining discrete values that can represent the uncertain elements of a problem.

There are several methods for generating scenarios to establish the scenario tree. One method is known as *plain sampling*. This is simply based on randomly drawing samples from the underlying distribution of the uncertain elements, ending up with a tree that is close to the original continuous distribution (King and Wallace, 2012). However, this method has some limitations. If the tree becomes too large the optimization problem will be unsolvable, but failing to have enough scenarios in the tree will result in a poor representation of the underlying distribution (King and Wallace, 2012).

Sampling is used in order to represent weather-data in a number of papers. Skar (2016) developed a special scenario generation routine to construct hourly data series of, among other things, wind and solar PV profiles. The routine involves preparing raw data, selecting a random year in the historical data, and for each regular season sample a random hour. Seasons with extreme loads are sampled by summing up all loads in a given hour, and selecting the hour with the highest load value. The sampled data is then checked, using a statistic test, to ensure that it closely matches the mean and variance of the historic data it is based on.

Seljom and Tomasgard (2015) have used sampling to generate stochastic scenarios based on historic wind-data. They generated scenarios as an iterative random sampling process, where for each node in the scenario tree, S scenarios are created by random sampling a day from the data, splitting it into 12 two-hour blocks. Following, the procedure is repeated U times, four statistic moments are calculated for all scenario trees and historic data, and the scenario tree with best statistical property match compared to the historic data is selected.

Load profile estimations are difficult in many rural areas, because historic data is often unavailable due to the lack of electricity access in the regions (Mandelli et al., 2016). As briefly mentioned, Mandelli et al. (2016) presents a stochastic method which creates realistic scenarios on daily load profiles for rural areas with no access to electricity. The approach groups targeted consumers into different user classes based on their expected consumption and collection of electric appliances. The time an appliance is in use per day, the functioning time and -windows for an appliance and its nominal power classifies the electricity usage of an appliance a class. All of this information is accounted for in the MATLAB algorithm called *LoadProGen*, developed by the authors. In addition a percentage quantifying the random variation of functioning time and functioning windows must be given. With this input, the algorithm does the following:

1. Randomize functioning times and windows.
2. The total required daily electric energy, for a user class, without taking time into account, its maximum peak power and peak time is calculated. A class coincidence factor[3] is computed based on the empirical correlation between the amount of users, a load factor and class coincidence factor.
3. Random sampling is conducted for the time the different appliances are switched on, within the functioning windows provided for the appliance. The amount of times an appliance is switched on in a day, is calculated based on the total time an appliance is functioning during a day, divided by the minimum functioning time required for the appliance once it is switched on.
4. Daily load profiles for each class are generated based on the functioning of all the appliances within the class.
5. (1) to (4) is repeated for each user class, before all class profiles are aggregated to total daily load profiles.

Mandelli et al. (2016) applies this methodology to generate the scenarios needed to obtain the optimum size of an off-grid PV-system in Uganda. The approach used, although based on a stochastic approach, does not include stochastic programming. One of their findings is that the optimum system configuration is significantly affected by which load profiles are utilized.

4.5 Conditional Value-at-Risk

In finance CVaR is used as a risk assessment technique. It is closely related to *Value-at-Risk* (VaR), where *the Value-at-Risk (VaR) of a portfolio at the α probability level is the left α-percentile of the losses of the portfolio* (Zenios, 2008, pp. 59). Using this definition Zenios

[3]The coincidence factor is defined as *the ratio of the maximum coincident total power demand of a group of consumers to the sum of the maximum power demands of the individual consumers comprising the group, both taken at the same point of supply and for the same period of time.* (Mandelli, 2014, pp. 66).

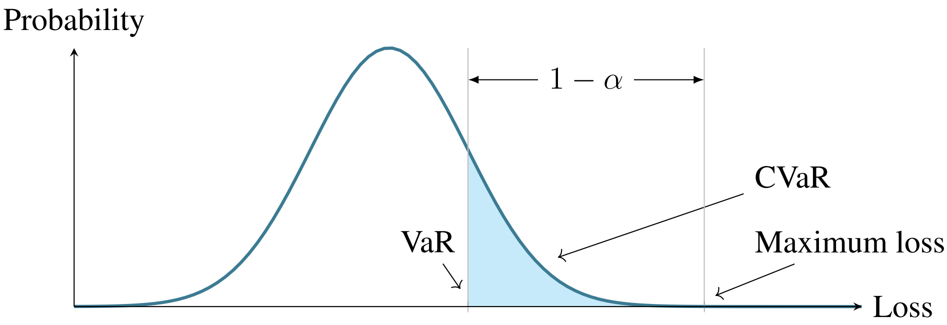


Figure 4.1: Illustration of CVaR and the loss distribution

(2008) interprets VaR as the lowest possible value ζ, which is such that the probability of losses less than or equal to VaR is greater than or equal to $100 \cdot \alpha\%$. CVaR is also known as *expected shortfall* as it measures the expected losses conditional on the losses being in excess of VaR (Zenios, 2008). These aspects are illustrated in the loss distribution in figure 4.1.

Optimization models can be used to minimize the CVaR of a financial portfolio, and this process is explained by Zenios (2008). Additionally, CVaR may be used to account for negative effects associated with uncertainty in stochastic programming problems. One particular way of incorporating CVaR into a two-stage stochastic programming problem is through the *mean-risk problem* (Noyan, 2012). The mean-risk problem, as described in the article by Noyan (2012), is derived from *mean-risk models* which minimizes the mean risk function, involving a specified risk measure, ρ. The mean-risk model is shown in (4.1), where λ is treated as a non-negative trade-off coefficient for the exchange rate of mean cost for risk, also called *risk coefficient* (Noyan, 2012). In the article, $f(x, \omega)$ is defined as the total cost function of the two stage problem, while $E(f(x, \omega))$ represents the two-stage stochastic linear programming problem.

$$\min_{x \in \mathbf{X}} \{E(f(x, \omega)) + \lambda \rho(f(x, \omega))\} \tag{4.1}$$

Using CVaR as the risk measure ρ, Noyan (2012) explains how (4.1) can be presented as the two-stage mean-risk stochastic programming problem shown in (4.2).

$$\min_{x \in \mathbf{X}} \{E(f(x, \omega)) + \lambda \text{CVaR}_\alpha(f(x, \omega))\} \tag{4.2}$$

Through several definitions Noyan (2012), as Zenios (2008) does for caculation of CVaR in financial portfolios, provides an explanation of how CVaR is defined, and thus calculated, in the two-stage mean-risk problem. This leads to the formulation of (4.2) as the following linear programming problem.

$$min \quad (1+\lambda)\mathbf{c}^T\mathbf{x} + \sum_{s=1}^{N} p^s(\mathbf{q}^s)^T\mathbf{y}^s + \lambda(\eta + \frac{1}{1-\alpha}\sum_{s=1}^{N} p^s v^s)$$

subject to

$$\begin{aligned}
W^s\mathbf{y}^s &= \mathbf{h}^s - T^s\mathbf{x} && s = 1, ..., N \\
\mathbf{x} &\in X && \\
\mathbf{y}^s &\geq 0 && s = 1, ..., N \\
v^s &\geq (\mathbf{q}^s)^T\mathbf{y}^s - \eta && s = 1, ..., N \\
\eta &\in \mathbb{R} && \\
v^s &\geq 0 && s = 1, ..., N
\end{aligned}$$

In the problem η is considered a first stage variable representing the VaR-value at the α percentile, and v^s is considered as auxiliary second stage variables. Noyan (2012) argues that CVaR is translation invariant, and thus $CVaR_\alpha(Z + a) = CVaR_\alpha(Z) + a$. This is the reason why, in the objective function of the two-stage mean-risk problem, the part of the CVaR associated with the first and second stage can be separated. Through varying λ the decision makers can construct the mean-risk efficient frontier (Noyan, 2012), and thus choose the optimal objective function value corresponding to their subjective risk preferences.

Soleimani and Govindan (2014) have used stochastic optimization to solve a typical multi-stage location-allocation problem. It is emphasized in the paper that traditional stochastic programming is risk neutral, where the optimal objective value is based on the expectation of the uncertain parameters. Thus, to be able to model the problem with a risk averse approach they have chosen CVaR to evaluate risk, utilizing the mean-risk problem. The problem maximizes profit, however the risk is evaluated merely on the problem costs. The results showed that when increasing the weight on CVaR, by increasing the values of λ, the model gave more conservative solutions, reducing the problem costs.

Figure 4.2 shows an example of an efficient frontier that can be created from the solution of the mean-risk problem, when minimizing expected costs, while increasing the weight on CVaR using λ. What can be observed is that for higher values of λ, the expected costs decrease, while the CVaR increases. Thus, when unfavourable scenarios become more relevant the expected cost decreases. The interpretation of the efficient frontier yields a weighting between expected costs and risk. Hence, the decision maker should invest at the level suggested by the solution of the CVaR problem for a given λ, and obtain expected costs corresponding to this point in the figure.

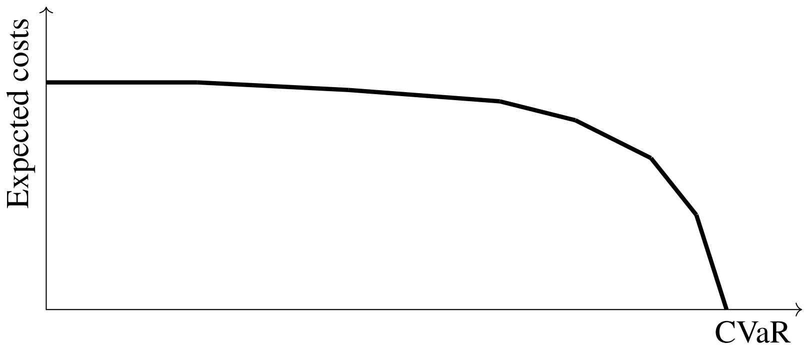


Figure 4.2: Example of efficient frontier curve. Increasing λ-values to the right.

4.6 Multi-horizon stochastic programming

The aspect of time is important when uncertainty is involved in a problem. Several problems, for instance infrastructure planning problems, make decisions both on strategic (long-term) and operational (short-term) levels, that can be affected by uncertainty. Kaut et al. (2013) introduced the concept of multi-horizon stochastic programming, which handles the difficulties with different time-scales for strategic and operational decisions in stochastic programming. The approach distinguishes between strategic and operational nodes, and takes advantage of the assumption that strategic decisions are not directly dependent on the operational scenarios, but rather on the total operational performance embedded in the previous strategic decision (Kaut et al., 2014). When represented in a scenario-tree, this implies that merely the strategic decisions are branched on the long-term time-scale, while the operational decisions are attached to their respective strategic node. Hence, an operational sub-tree is present under each strategic node, but there is no connection between the end of the operational sub-tree and the next strategic node. The scenario tree placed to the right in figure 4.3 illustrates the structure of a multi-horizon scenario tree.

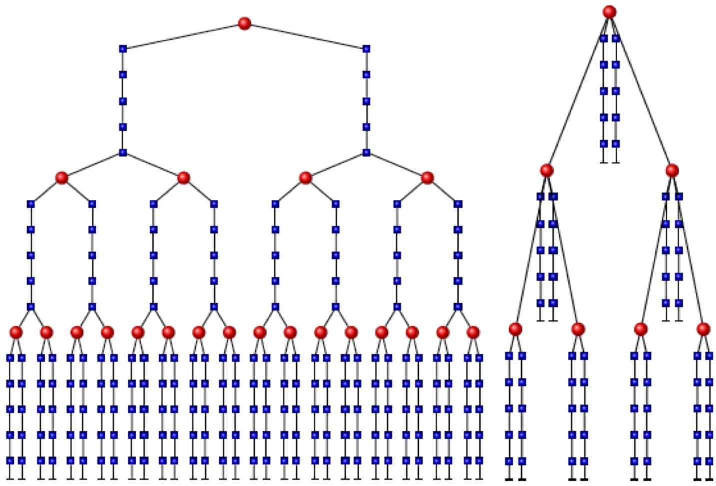


Figure 4.3: Standard scenario tree for both operational and strategic uncertainty, and its equivalent multi-horizon scenario tree. Illustration from (Kaut et al., 2013).

One of the main advantages of multi-horizon stochastic programming is that it reduces the size of the scenario tree substantially (Kaut et al., 2013). However, in order for the approach to be exact, two conditions for the problem must be met. A strategic decision must be independent of operational decisions, such that the strategic uncertainty is independent of the operational uncertainty. Further, there should be no dependencies between the last operational decision in a period, and the first operational decision in the following period (Kaut et al., 2013). Both of the requirements can be observed in figure 4.3. In the standard scenario tree, placed left of its multi-horizon counterpart in figure 4.3, there are dependencies between operational and strategic decisions through the link between the last operational (square) node in a branch and the following strategic (round) nodes. Further, the operational decision following a strategic node is dependent on the operational decision in the previous strategic period, through the link between square-round-square nodes. In the multi-horizon scenario tree, to the right in figure 4.3, there is clearly no link between operational decisions in two consecutive strategic periods, and the strategic decisions are independent of the operational.

Kaut et al. (2013) illustrate the use of multi-horizon stochastic programming in an example where PV-modules are installed on a building. The strategic decision is to decide how many modules should be installed and at what time, while at the operational level, demand must be covered on an hourly basis. The model is used for illustrative purpose only, and omits important aspects such as discount rates and depreciation.

A multi-horizon stochastic programming model, incorporating long-term and short-term system dynamics in the European power system, has been developed by Skar (2016). The model optimizes investments based on operational uncertainty in load profiles, wind and solar generation profiles and seasonable availability of water stored in reservoirs. However, perfect long-term foresight is assumed, thus there is no strategic uncertainty in the model.

Abgottspon and Andersson (2016) compared the multi-horizon stochastic programming model to three other modelling approaches on a complex pumped storage hydro power plant. The paper concludes that *For a medium-term hydro power planning optimization of complex hydro power plants with a few reservoirs of different sizes, multi-horizon models are a very efficient modeling approach both from the modeling as well as from the computational point of view.* (Abgottspon and Andersson, 2016, pp. 10). They conclude that, compared to the multi-horizon approach, the other approaches struggled with either high computational complexity, or modelling inaccuracies.

4.7 Our contribution

This chapter has pointed out that standardized processes are of importance to boost investments in electricity projects in rural parts of developing countries. However, to the best of our knowledge, today there exists no standardized process assessing investments in, and valuing off-grid PV-system projects placed in developing countries from a private investors perspective. It also becomes clear from the literature reviewed in this chapter, that valuations of such projects is often based on methods including many financial simplifications. Further, most valuation methods do not incorporate uncertainty and long-term investment opportunities, although real options can be utilized to incorporate flexibility measures. In addition, as far as we have seen, financial valuations using detailed capital budgeting procedures to value a project seen form an investors perspective, is not common in stochastic programming. However, by utilizing the structure of a two-stage multi-horizon stochastic model, both uncertainty and flexibility can be represented on more than one level, and the potential impact of possible outcomes is balanced in the valuation. Hence, by developing a process, based on multi-horizon stochastic programming and DCF analysis, which assesses investments in these types of projects and values them, we are convinced that this thesis contributes to the existing literature. Further, CVaR is in this thesis utilized to evaluate risk in multi-horizon stochastic problems, which to the best of our knowledge increases its area of application.

Chapter 5

Assessing off-gird PV-system investments

Throughout this chapter the standardized process for assessing off-grid PV-system investments in developing countries, that we have developed, is explained. The entire process is first illustrated through a flow chart, before the process within each part of the flow chart, and the importance of them, is explained to greater detail. Parts of the process is based on a framework developed in Bakke and Welhaven (2016), while other parts are inspired by interviews of, and articles by, several actors with experience in the field.

5.1 The standard process

The entire process is presented in figure 5.1. The first part of it consists of fundamental questions, or decisions, that has to be assessed initially. This part is highlighted in the flowchart. Each answer to the questions appearing in the diamond-shaped boxes, $\diamondsuit$, are vital for the decision on whether or not to continue towards the actual valuation of the project investment. If all answers are positive, the processes of analyzing project risks and gathering both the financial and technical data needed to perform a valuation, is started. Once this is done, all the information is quantified and becomes input into a stochastic model that optimizes the value of the investments in the project being assessed. The output from this model is then conclusive for whether the project is attractive for the investor or not.

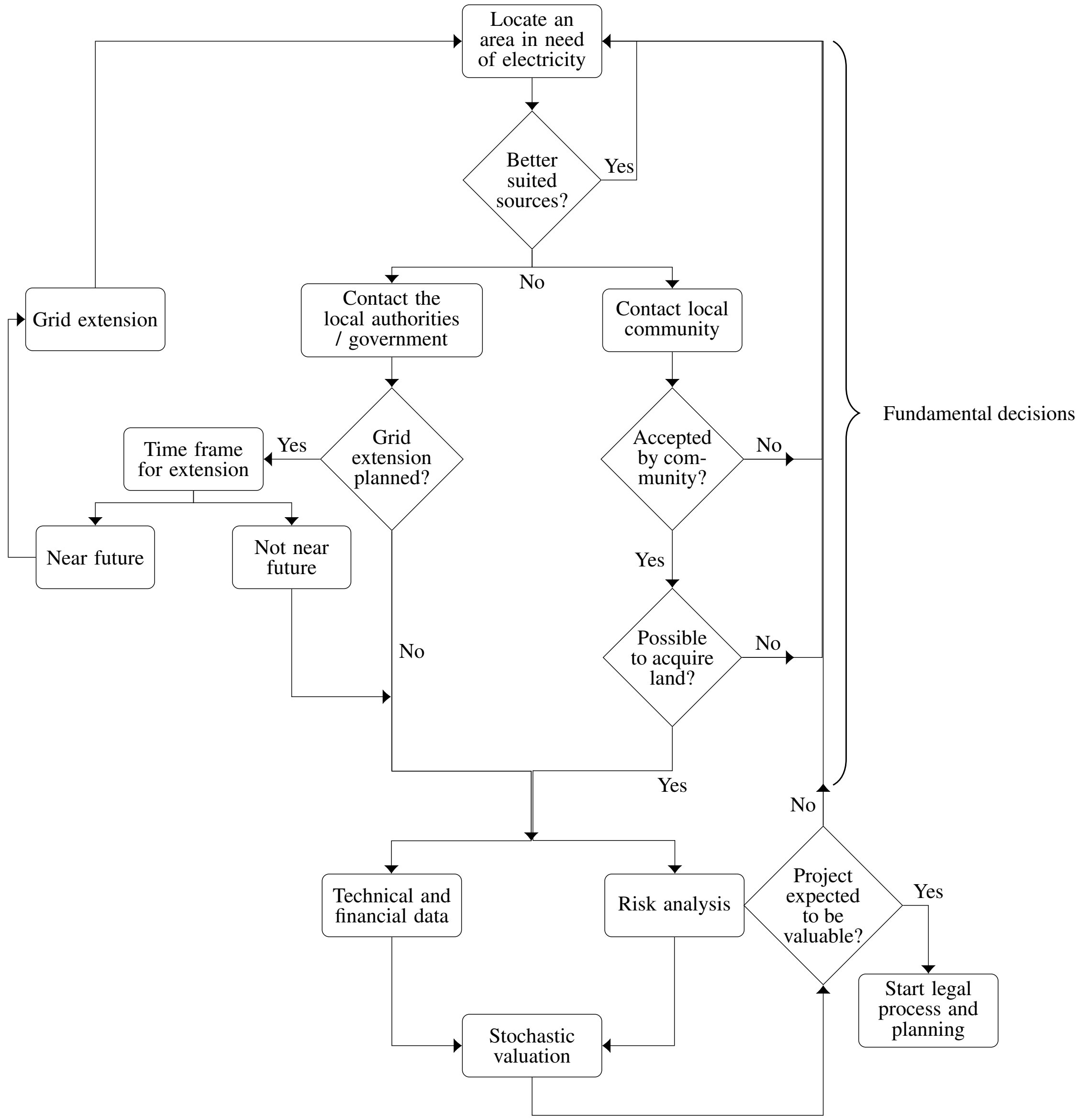


Figure 5.1: The standardized process for assessing off-grid PV-system investments in developing countries

5.2 Assumptions

Some assumptions that are essential to be aware of when utilizing the process have been made during the development of it. One such assumption is that the project is assessed from the private investors perspective. Further, an assumption has been made that the off-grid PV-systems assessed, are grid-based. Thus the process does not apply to solar home systems. Throughout the explanation of the entire process the term mini-grid will be used for these grid-based systems. Although the process is meant to assess PV-systems, it is also assumed that another source of electricity can be used to cover system slack, at a cost for the investor. The stochastic valuation model also make some assumptions and choices affecting what is included in the model, and these are explained in chapter 6, section 6.3.

5.3 Fundamental decisions

This section is divided into three subsections based on the main questions that are part of the fundamental decisions in the process. First the questions regarding the location for the mini-grid is assessed. Secondly, contact with local government and authorities is emphasized, before the importance of the local community at the chosen location is highlighted.

5.3.1 Location

The very first decision a private investor has to make when considering investing in a mini-grid project is where the mini-grid should be located. First and foremost the area should not be supplied by an existing grid already. Secondly it is emphasized in the article by IRENA (2016) that for mini-grids, one of the most important factors to consider is the population density in the area. Further, for mini-grids of a certain size, the presence of some anchor loads can be crucial (IRENA, 2016). That is, if more electricity is generated than what is consumed in the grid, financial viability is hard to achieve in such projects. Additionally the article point to the development of the demand in the area as another element to consider. It is important to choose an area for the mini-grid where growth is predicted, to be able to sustain or increase future incomes.

When an area with the wanted properties is found, the important question to ask is whether any other energy sources than solar is better suited in the particular area. It is stated in the article by Terrado et al. (2008) that the project design should not be technology driven, and a cost-benefit analysis is necessary to determine the least cost technology solution in a project. Therefore, if any other source of electricity is available at the location, costs less or has more benefits, we recommend the project investors to locate another area for their solar powered mini-grid.

5.3.2 Local government and authorities

The regulations and plans decided by the local government and authorities can have major impact on whether the investment in a mini-grid is profitable. Therefore, establishing contact with the relevant entities at an early stage is important. This can also help the investor in an early phase to gather all important information about legal processes, as well as the possibilities or restrictions that the project will have. However, the most important reason to contact these entities at an early point is to find out whether the utility main grid is planned to be extended to the area the investor has chosen for the mini-grid.

If an extension of the utility main grid is planned, the time-frame of when it will reach the area in question is important. In the article by Kumar et al. (2009), presented in section 4.1, it is emphasized that if the time-frame for the extension is above a threshold limit, the possibility of setting up a distributed generation based project should be considered. Thus we would recommend investors to identify when the utility main grid will reach their area, if the extension is planned. From that, it should be defined whether or not this will happen in the near future, in comparison with the project time-frame. For instance Kumar et al. (2009) defines less than five years as the near future. If the utility main grid extension will happen in the near future, we recommend investors to locate a new area in need of electricity and start over. If, on the other hand, extension is not seen as planned for the near future, we recommend considering going forward with the project. As Kumar et al. (2009) explains, it could be possible to operate the mini-grid as a distributed generation unit when the utility main grid reaches the site. That is, one can start the project such that it is ready when the utility main grid arrives, or start the project at once and connect to the utility main grid when it arrives at the mini-grid location. In spite what is chosen, Franz et al. (2014) emphasizes that *"a regulatory framework that protects the investor, guarantees fair compensation, and - ideally - offers transparent information about grid extension plans"* should be present upfront (Franz et al., 2014, p. 22). This should include agreements on financial issues, for instance due to tariff differences between the utility main grid and off-grid, and on the technical requirements of connection.

Another option available to the investor can potentially rule out the chance of any connection within the project lifetime; if the utility main grid is not planned to reach the location in the near future, or the extension is not discussed at all, the investor can enter into an agreement with the government to be the sole provider of electricity in that area, for the period of the project lifetime. If the agreement postpones the utility main grid connection it may be in conflict with what the community wishes, and thus not supported by the local government. But every project is unique and government regulations vary, therefore the relevance of this option is case-dependent. Whichever agreement is concluded, communication remain a very important factor in this process. To succeed with communication in such projects however, awareness of cultural differences is crucial, and this should also be emphasized in all similar processes throughout the project.

5.3.3 Local community

A mini-grid providing electricity to a remote area, will in most cases be perceived as positive for the local community. For the advancement of the project however, the community acceptance can be crucial. Potential outcomes if acceptance is not achieved can be low demand due to boycott, vandalism, as well as potential positive effects of collaboration can be lost. Terrado et al. (2008) state that the investor should, in an early phase, make an effort to involve, support and inform the community, and emphasize that this is vital for project success. Therefore establishing contact and building a relationship with the community at an early point in the process is recommended. This can be achieved through regular meetings with the leaders in the community, focus-group meetings or promotional programs (Terrado et al., 2008).

With the involvement of the community, the importance of the project for the development of the community can be emphasized and thus more easily understood by the locals. Wiemann et al. (2014) explain that hybrid business models in mini-grid projects can take advantage of the positive effects and rule out shortcomings of other models. Although the mini-grid projects assessed in this process are private investment projects, the business model does not necessarily have to be solely private sector based. Due to the advantages of the hybrid model, we recommend that the investor investigates the possibility of, for instance, a private- and community based business model. What hybrid model is best suited is project specific, but involving the community in this way can make community acceptance easier. However, if for some reason acceptance seems hard to achieve, it is recommended that the investor starts looking for a new location for the project.

When contact with the local community has been established, another decisive factor also has to be uncovered. According to Mr. Mugisha, among others, in many mini-grid projects in developing countries, one of the bigger problems is to discover who owns the land where the mini-grid is planned to be positioned. Therefore one of the questions to be answered in this process is whether or not it is actually possible to acquire the land. If it turns out to be impossible or too demanding, either timely or economically, the investor should locate a new area for the project.

5.4 Risk analysis

When the fundamental questions have been assessed, the risk analysis is the next step. This section divides the analysis into four subsections discussing different elements of risk analysis that we suggest the private investors follow. These are risk identification, categorization, assessment and response, respectively. In this process, it is also important that the opportunities, and not merely the threats, are assessed as well.

5.4.1 Risk identification

When implementing a mini-grid in a developing country, depending on the business model applied, a variety of different stakeholders are present. According to Hillson, *The limitations of trying to identify risks from one person's limited perspective can be overcome by involvement of a wide group of project stakeholders in Risk Identification so that as many perspectives as possible are covered* (Hillson, 2003, pp. 69). Hence, by involving different stakeholders, the probability of detecting risks that could influence different parts of the project is increased, because stakeholders, such as contractors, authorities and inhabitants in the community, might have different perspectives on the project than the investor. Hillson (2003) mentions *structured brainstorming sessions*, where key-stakeholders are invited, as a recommended approach to reduce the possibility of ignoring important risks, and keep progression in the analysis. This is also what we would recommend for the investors. However, Hillson (2003), as well as Larson and Gray (2014), points out that brainstorming is often performed on the basis of a detailed project plan, such as a *work breakdown structure*. But in the front-end phase[1] of a project, this process might be too time consuming. An alternative we would recommend is therefore to focus the brainstorming around the risks listed in table 5.1. These are presented by Manetsgruber et al. (2015) as the risks that frequently appeared in the mini-grid projects that was included in the survey they carried out. Of course, each project is different and it is therefore important to look beyond this list as well. Further, a common mistake when identifying risks is to identify events that are not actually uncertain (Larson and Gray, 2014; Hillson, 2003). Thus, focusing on the real risks as a part of the brainstorming process is emphasized.

Table 5.1: Risks in mini-grid projects situated in developing countries, according to (Manetsgruber et al., 2015)

Type of risk:
Political and legal risk
Risk of non-payment of electricity bills
Technology risk
Construction completion risk
Risk of unpredictable electricity demand
Social acceptance risk
Environmental risk
Force majeure risk
Foreign exchange risk
Theft and vandalism
Operational risk

5.4.2 Risk categorization

For investors who have a portfolio of projects, we recommend that a risk categorization is carried out. That is to define what risks that are of importance for further analysis and which actor is best suited to handle them. Risks that are diversifiable will often be managed differently than those that are undiversifiable. Table 5.2 summarizes the difference between the two risk categories explained in the following.

In financial theory the term undiversifiable risks defines risks that cannot be diversified away in a large portfolio, and where the investor must take an offsetting position in order to reduce

[1]The front-end phase defined as the phase including activities performed prior to the decision to go ahead with the project

Table 5.2: Diversifiable and undiversifiable risks

Diversifiable risk	**Undiversifiable risk**
Firm specific	Market risk
Could be diversified away in portfolio	Could be hedged or responded to

the risk. On the other hand, by the application of the *Law of One Price*, an investor will not be compensated for holding firm-specific (diversifiable) risk, and the risk-premium will stay unchanged when holding this risk (Berk and DeMarzo, 2014). To utilize this financial theory on mini-grid projects in developing countries, the market that the investor is operating in should be defined. Diversifiable risks are then risks that will affect only individual projects in this market. These risks can be diversified away in a portfolio of projects. However, some risks are common for the entire market, and would thus be undiversifiable. If for instance all projects in a portfolio are located in the same country, a political risk could affect all projects at the same time. Therefore, such risks cannot be diversified away in a portfolio of projects.

5.4.3 Risk assessment

The risk assessment procedure we propose to follow, is to determine the probability and impact of each identified risk. According to Hillson (2003) this assessment is usually split into a qualitative and quantitative part. We recommend that the qualitative part of the assessment is conducted as a part of the risk analysis, while the quantitative part is accounted for in the stochastic model.

In order to conclude on a probability and impact for each specific risk, the project team members can evaluate the risks by using scenario analysis (Larson and Gray, 2014). This way, simple relationships between cause and effect can be established. Manetsgruber et al. (2015) also make use of interviews with stakeholders in different mini-grid projects in their study. We suggest that a scenario analysis is used, but that key-stakeholders is also included in this process, as this could enhance the reliability and objectivity of the assessment. Further both Hillson (2003) and Larson and Gray (2014) discuss the use of *numbers* and *labels* as the qualitative measure used in the assessment. Larson and Gray (2014) emphasize that the preferred type of scale could vary between projects, and Hillson (2003) emphasizes that there are advantages and drawbacks to both. Therefore we suggest that in each project a weighting between objectivity, which is sustained with numbers, and preciseness, which can be too extreme with numbers, is made as a part of this choice.

Based on this assessment of the risks, visualization using a *risk severity matrix* is a commonly used tool (Hillson, 2003; Larson and Gray, 2014; Manetsgruber et al., 2015). In a risk severity matrix, all the risks are placed out on a two dimensional diagram, where likelihood and impact are represented on the axes. A coloured background scale is used to indicate the importance of the risk, where a darker color corresponds to a more important risk. Often, the color is not proportionally distributed across the two axes. The reason is that impact is often considered more important than probability (Hillson, 2003; Larson and Gray, 2014), and hence have a darker color for a longer range of values. We recommend that risks identified for the project are presented in a risk severity matrix to illustrate which ones to be especially aware of due to their high impact and/or probability.

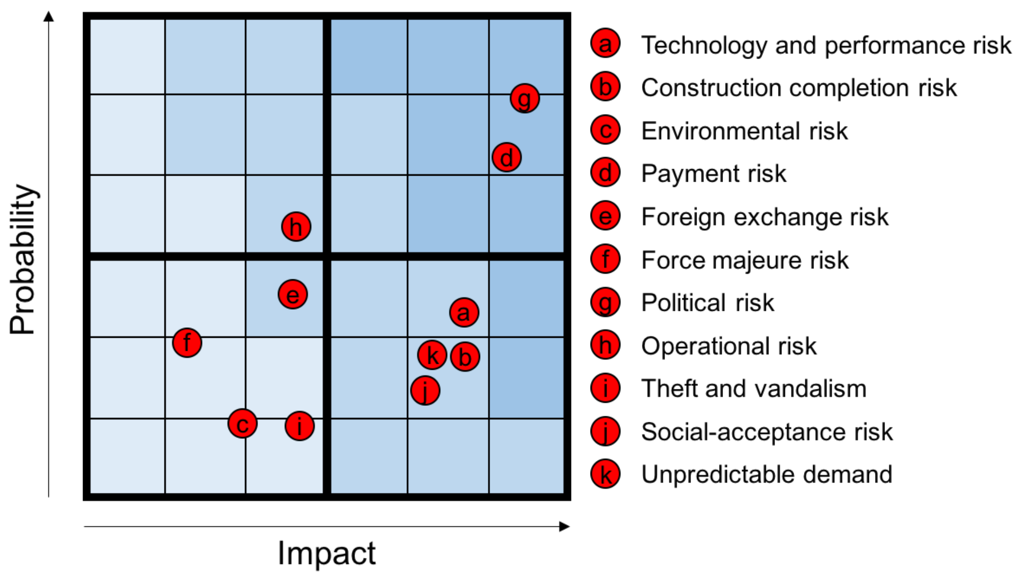


Figure 5.2: Risk severity matrix based on the results and illustration in Manetsgruber et al. (2015)

An illustration of a risk severity matrix is provided in figure 5.2, and it is based on the risks identified and assessed based on surveys conducted by Manetsgruber et al. (2015). The matrix is edited from the one presented in Manetsgruber et al. (2015) to fit the style of the matrix explained above. That is, the axes are swapped and risks are relocated correspondingly.

5.4.4 Risk response

The suggestions on how to respond to the project risks are based on the previous categorization and assessment of the risks. These are explained in the following.

Diversification and hedging

Depending on the degree of which the project investor is involved in a portfolio of projects, the diversifiable risks should be diversified in the portfolio, and accounted for through expected losses each year. On the other hand, in order to increase predictability in costs and reduce the undiversifiable risks, hedging is suggested. As mentioned this can be accomplished by taking an offsetting position. However, in the markets where the mini-grids, which this process is based on, are assessed, this is not always possible. For instance, many projects have no existing customers, making long-term agreements with customers difficult. In other instances, it can be possible to hedge some of the risks associated with such projects. If the mini-grid is developed in correspondence with an electricity-demanding unit, such as a water-cleaning system or a health centre, the possibilities of long-term agreements on price and demand could be viable. Also, risks associated with changes in foreign exchange rate could be hedged, because forward markets for exchange rates could be possible to find. We therefore suggest that the investors investigates the possibilities of hedging their undiversifiable risks.

Responses suggested by the risk severity matrix

We recommend that the risk severity matrix, which propose responses based on which quadrant the risks are assessed to be in, is utilized . The responses should however not be utilized without any form of consideration, because they might not always be applicable. Therefore it is suggested that the responses are discussed for each of the risks in the severity matrix, before a response is assigned to the risk. Based on the literature provided by Manetsgruber et al. (2015); Larson and Gray (2014); Hillson (2003), the most common responses to different risks, both opportunities and threats, are illustrated in figure 5.3.

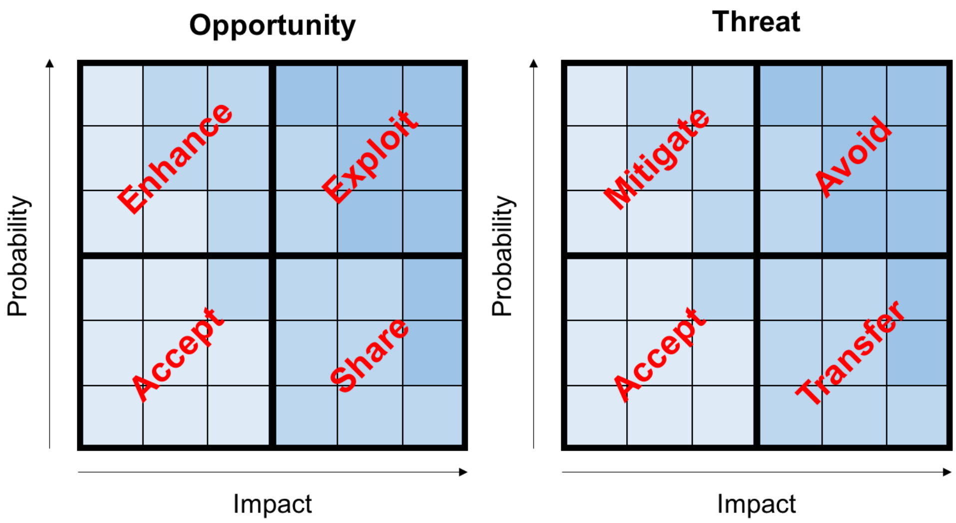


Figure 5.3: Responses to opportunities and threats based on (Manetsgruber et al., 2015; Larson and Gray, 2014; Hillson, 2003).

However, the theory differ on which responses are appropriate for the different quadrants. While most theory seems to agree on *transfer* as a strategy for high impact threats with low probability, and *mitigate* as a response for low impact threats with high probability, Hillson (2003) argues for the opposite. This further indicates that caution should be made when investigating responses. We suggest, as most literature argues for, that transfer of threats is most suitable for high impact threats with low probability. This is further justified with the argument that insurance policies is mostly used for threats with high impact and low probability, such as a fire. However, in the discussion defining suitable responses, this is not a strict rule. It should also be noted that for project investors that are not involved in a portfolio of projects, insurance can be used as a way to avoid diversifiable risks. That is, insurance companies diversify the risks of their customers, in their own portfolio, at a cost for the investor.

5.5 Data and scenario generation

This section explains what must be quantified in order to perform the project valuation based on the stochastic program. Because the mathematical model, on which the stochastic program is based, is explained in the next chapter, the reader is advised to remember that if anything is slightly unclear here, it will be clarified in the following chapter.

Because the project valuation is based on a stochastic optimization model, some choices concerning the input that decides how the project is represented, must be made. These choices should be made with regard to the detail needed to represent the problem, computer capacity and problem specific circumstances.

First of all it is important to decide what the lifetime of the project is assumed to be. A natural choice is for instance to set it equal to the life expectancy of the solar panels. Further the length of the periods between each possible extension of the mini-grid, or each investment, must be decided. For this decision, the assumed growth in demand is important to consider. It should also be decided how many investments that will be made without long-term uncertainty, that is, without different scenarios for the long-term uncertain parameters. Another timely aspect that has to be decided is how many seasons are needed to represent one year of operation, and how many hours are needed to represent each season. The appropriate amount of scenarios needed to represent the uncertainty in the problem should further be decided. This also implies that these scenarios has to be generated for all the uncertain parameters.

In addition, to be able to do a financial valuation of PV mini-grid projects in developing countries, different types of data is required. It is recommended that these data are based on previous experiences, data from suppliers, as well as on information from authorities and participants within the sector. However data can also be acquired form research.

First, what assets are needed to build the mini-grid must be decided, such as solar panels, distribution lines and batteries. The cost of each asset, per unit installed, and their life expectancy should then be uncovered. If the assets will be acquired from another country than the project country, the foreign exchange rates should also be investigated.

It could be challenging to collect information about the electricity demand in the area of the mini-grid. Most people living in areas in need of electricity have, in most cases, never had access to electricity in their homes, while some businesses might have access to small diesel generators to power some essential appliances. Thus detailed demand data, like hourly load profiles, is rarely available. As mentioned in section 4.4, Mandelli et al. (2016) has developed LoadProGen, for generation of daily load profiles in areas without electricity. We therefore recommend that this stochastic method, combined with interviews of people in the community, is used in the projects where no other data is available. However if actual historical data can be acquired, this should be utilized as a basis for scenario generation. Further, in connection with the demand data, estimating how many customers (households, businesses etc.) the mini-grid will be serving is necessary for the calculation of distribution line costs.

To be able to calculate cash flows from operational activities from the mini-grid, the electricity price, connection fee, operational costs and sales capacity must be investigated and decided. The solar panel generation capacity is dependent on historical data on solar irradiance and temperatures, and the panel efficiency. From these values the electricity actually generated can be accounted for. Further to account for how much can be sold, the storage capacity, power to energy factor and system losses must be quantified.

To finance the project the amount of loan and grants possible to acquire, compared to total investment costs, must be investigated. Additionally a payment structure for the loan must be decided upon. Further, the structure used for depreciation and how much of an assets terminal value is possible to retrieve, must be evaluated.

In case the electricity generated from the solar panels cannot fulfill demand, a cost associated with incomplete delivery of electricity should be quantified. Further to be able to do a cash flow analysis, lending rate and tax rates must be collected, and the required return on equity (RRE) must be settled. In addition if the risk analysis suggests that insurance should be bought as a risk response, this cost must be quantified based on the size of the grid. For using CVaR as a risk measure the α percentile must be set, and the investor's risk preference must be evaluated. Lastly, if the project will be needing any net working capital (NWC), this would also need to be quantified.

5.6 Stochastic valuation

The final valuation of the project is based on all the information that has been uncovered throughout the previous steps in the process. It is also based on a stochastic programming model, accounting for both operational and strategic uncertainty. Uncertainty, that is not handled through qualitative risk responses, is represented in the customer demand, solar irradiance, foreign exchange rates and investment costs. The possible outcomes of these uncertainties are approximated through scenarios. Additionally the risk responses that have quantitative consequences are incorporated as costs in the model. Because the process is based on private investments, the valuation is seen from the private investors point of view. By optimizing the investments in the project, the present value of cash flows is calculated. Thereafter, computing a sensitivity analysis is recommended in order to evaluate the effect of uncertain parameters. If the project is expected to be valuable for the investor after the evaluation and sensitivity analysis, and, based on the uncertainty present, it is decided to proceed with the opportunity we emphasize that the resources that energy sector institutions can provide should be investigated and utilized, as presented for Uganda in section 2.2. However, if the project is not expected to be valuable for the investor, we recommend that the standardized process is restarted by locating another project area. Further, exactly how the model is built and the assumptions behind it, is explained to greater detail throughout the next chapter concerning the mathematical model.

Chapter 6

Mathematical model

This chapter presents the mathematical model of the stochastic programming problem used as the valuation method in the standardized process. In the model we are interested in evaluating the risk in the project with two different measures, namely RRE, subject to the investors risk preference, and CVaR, accounting for long-term uncertainty. A description of the model is given in section 6.1. Further, explanations of the model choices concerning the information structure, valuation method and lost load are given in section 6.2. In section 6.3 the model assumptions and simplifications are explained, before the notation used in both of the model formulations is shown in tabular form in section 6.4. The mathematical formulation utilizing RRE to handle risk is given in section 6.5, and is referred to as model 1, while in section 6.6 the mathematical formulation based on CVaR, referred to as model 2, is presented and explained.

6.1 Model description

The model objective is to maximize the present value of all cash flows present in a mini-grid project based on solar power in developing countries, through deciding on the optimal project investment strategy. Investments decided by the model are defined as the amount of solar panels and batteries needed for the mini-grid in different project periods. The yearly loan annuity payments, depreciation tax shield, terminal value of investments, grants and loan received based on investments, asset investment costs based on panel and battery quantity, asset renewals, fixed investment costs, insurance costs based on grid size, investments in meters of distribution lines per household connected, yearly revenues from sales and connections, operational costs, VOLL and changes in NWC represent the project cash flows. All cash flows must additionally be discounted back to their value today, and tax on cash flow from operational activities accounted for. The discount factor can account for the project investors risk preference through RRE, or the risk can be measured through the use of CVaR, and a risk-free discount rate, formulated through the mean-risk problem.

The problem time horizon is the expected lifetime of the mini-gird, and the project starts in year zero. Strategic investments can be made at several occasions throughout the time horizon and will affect the operational capacity, and thus cash flows from sales, until the next investment is made. Operational choices should however not affect what is installed at a later stage in the project. Investment costs, insurance payments, cost of asset renewal as well as operational revenues and costs appear in the beginning of the year they are present. The same is true for the received grants and loan, while the loan annuity payments, depreciation tax shield and NWC are accounted for in the end of the year.

Uncertainty can also be present in several of the project parameters. Both the electricity produced from the solar panels constrained by the solar irradiance, and the electricity demanded from the consumers in the mini-grid may be subject to uncertainty. This is also true for the exchange rates for asset investments from foreign countries, and the costs of investments in assets that are dependent on the quantity of either panels or batteries invested in.

The sales of electricity in every hour of a year is dependent on the aggregated quantity of panels as well as batteries invested in at all previous occasions up to the year in question. What is generated during an hour depends on the panel capacity each hour, as well as what can be stored on the batteries is dependent on the capacity of all batteries installed. Further what is sold to the consumers each hour is dependent on what is generated and charged or discharged to of from the battery. However the electricity, from solar power generation, sold to consumers is not always coherent with what was demanded in the same hour, as there can be slack in the delivery each hour. The electricity stored on the batteries in the end of an hour is dependent on how much was stored in the beginning of the hour and what has been charged or discharged. The amounts possible to charge or discharge within an hour are restricted due to battery properties. In addition, charging or discharging of batteries, as well as distribution of electricity to consumers, is subject to system losses.

Depreciation of investments in different objects is based on a percentage of the initial costs. This is also true for their terminal value, which depends on the rate of depreciation and what values the project investor will be able to retrieve. The cost of renewing assets, either dependent on the quantity of panels or batteries, is subject to the life expectancy of each asset, which determines when it must be renewed. The project grants is a percentage of the total investment costs that the project will have based on all investments made in the same year. In addition to grants, the project is financed by equity and loan. The loan is, as for grants, a percentage of total investment costs and is paid back as an annuity each year in a period as long as the payback time set by the bank. The equity invested by the private investor however, is paid back through the actual project cash flows.

6.2 Model choices

When constructing the mathematical model from scratch, some choices were made that to a high degree affects the design or structure of the model. These choices and their implications will be explained through the following subsections.

6.2.1 Information structure

Uncertainty in several parameters makes it natural to model the problem using a stochastic structure. In chapter 4 it is emphasized that scenario trees represent the logical correct structure of stochastic problems, and how multi-horizon structures can reduce the size of the scenario tree when the problem has two time-scales. As indicated in the model description, electricity demanded and produced, exchange rates and investment costs are the parameters subject to uncertainty in the model. What is produced is typically linked to the operation of the mini-grid, while the electricity demanded by consumers can be linked to both its operation and strategic decisions. Other strategic decisions in the problem are the ones related to investments in solar panels and batteries, which are also affected by uncertainty in the exchange rates and investment

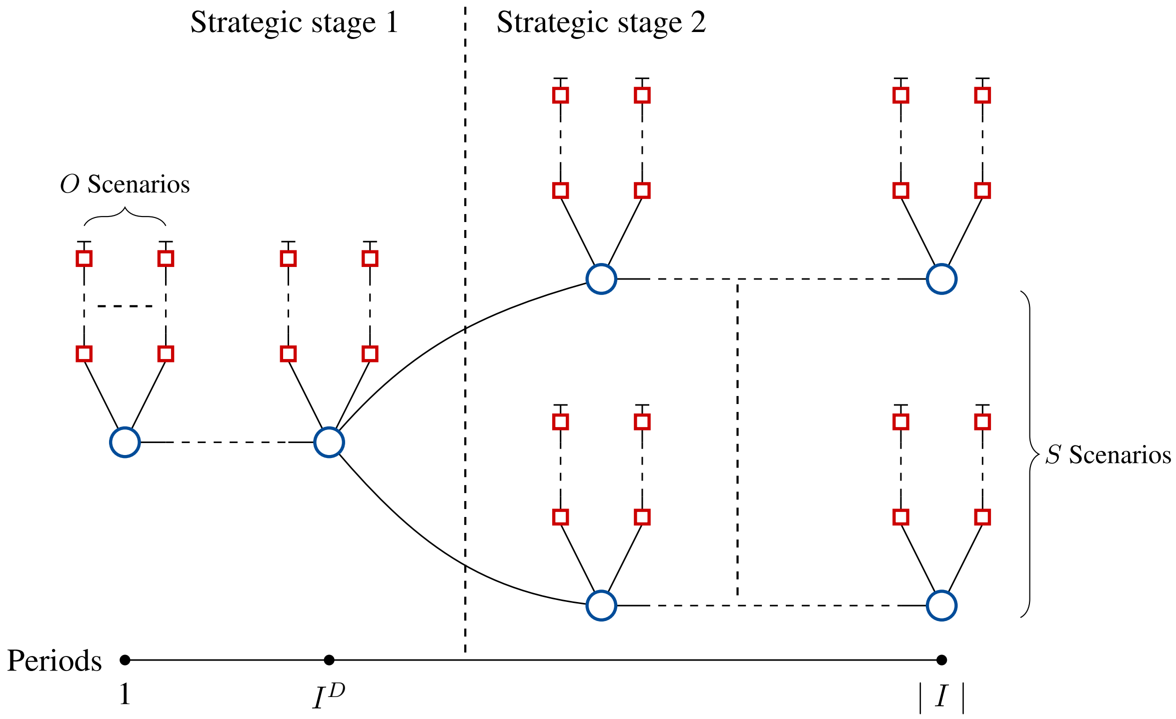


Figure 6.1: Scenario tree for the multi-horizon stochastic programming model

costs. Because the problem has decisions, as well as uncertainty, at both the operational and strategic level, a two-stage multi-horizon scenario tree structure has been applied to structure the flow of information in the problem. The general illustration of the scenario tree is presented in figure 6.1.

As indicated in figure 6.1, strategic nodes are represented by circles, ○, while operational nodes are represented by rectangles, □. There may be several strategic decision nodes in both the first and second strategic stage, indicating that investments are possible in different strategic periods within the project lifetime. The investment decisions made in the strategic second stage are therefore the model recourse decisions, as explained in section 4.2. Every strategic decision node has operational scenarios connected to it. Whenever a strategic decision has been made, the short-term operation throughout the strategic period is constrained by these decisions. Thus the decisions in the operational nodes are somewhat predetermined by the capacity already invested in. The uncertainty in demand and production capacity however, cause different operational decisions in the different operational scenarios. In contrast to the strategic nodes, decisions in the operational nodes does not affect the following strategic decisions. Therefore, as with all multi-horizon structured problems, the information flows as indicated in figure 6.2.1.

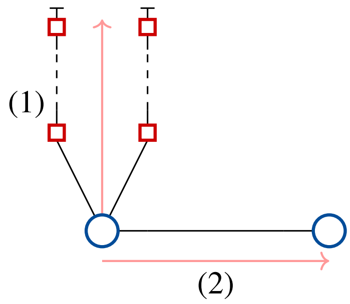


Figure 6.2: Information flow in the scenario tree.

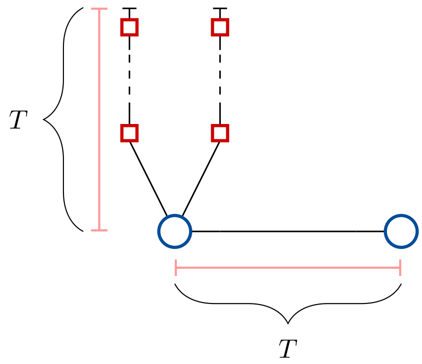


Figure 6.3: Time between strategic decision nodes and for operational period.

From a decision in a strategic node to the operational nodes (1), as well as from the strategic decision node to the next (2).

As illustrated by figure 6.3 the time between the strategic decision nodes, and thus between investments, equals the time-frame from the first operational decision node to the line at the end of the operational scenarios. These are collections of short-term periods, consisting of an appropriate number of years for the specific project handled. All strategic periods are assumed to be of the same length, implying a constant number of years between each possible investment. Each operational decision node represents the decisions made within an hour, and thus there is one hour between two operational nodes. The total project lifetime is defined as the period from the first strategic decision node until the line at the end of the last group of the operational scenarios.

Strategic decision nodes in the first stage of the strategic two-stage problem are deterministic, and thus the decisions made in each of these nodes are equal for all strategic scenario outcomes in the problem. This can be illustrated by separating the scenarios in the scenario tree as shown

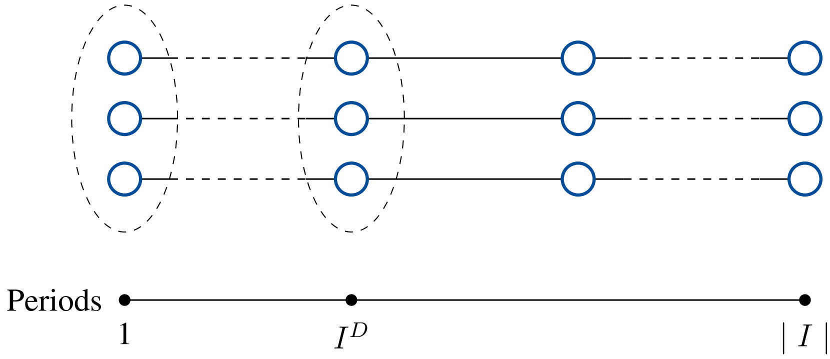


Figure 6.4: Non-anticipativity constraint on the deterministic, strategic scenarios

in figure 6.4. In the figure, the strategic decision nodes circled are the ones that should make the same decisions. This connection is handled by non-anticipativity constraints in the model. For the operational scenarios the first stage decision is the strategic decision, and therefore the operational decisions are only present in each of the scenarios of the operational second stage.

6.2.2 Valuation method

In order to make the financial valuation of the project as accurate as possible, the model objective function has been based on a DCF analysis, calculating the NPV of FCF for the project. Standard stochastic programming models utilize annualized values to compute an estimated NPV of the project. However, by utilizing the DCF method, the effects of tax, depreciation and changes in NWC can be accounted for. Further, the cash-flows from the project can easily be tracked by the user of the model. The standardized DCF calculation is given in equation (6.1).

$$\begin{aligned}\text{Free Cash Flow} = (\text{Revenues} - \text{Costs}) \times (1 - \tau_c) - \text{CapEx} - \Delta NWC \\ + \tau_c \times \text{Depreciation}\end{aligned} \tag{6.1}$$

$$PV(FCF_t) = \frac{FCF_t}{(1+r)^t} = FCF_t \times \underbrace{\frac{1}{(1+r)^t}}_{\text{t-year discount factor}} \tag{6.2}$$

The discount rate is based on weighted average cost of capital. Capital Expenditures (CapEx) is the cash used to acquire fixed assets, and will be referred to as investment costs throughout this thesis. However, some modifications to the standard DCF-analysis is proposed in our model. First, because of the difficulties in financing renewable energy projects in developing countries, grant funding is often necessary. As the grants are meant to reduce the investment costs for the project owner, it is not influencing the discount rate of the project. Thus, grants are simply added as a positive cash flow at the time(s) of investment(s) in our model. Also due to the high default rate of companies in developing countries, long-term loans that last for the whole project lifetime is often difficult to achieve. By amortizing debt sooner than equity holders receive their repayment of the project, the capital structure is changing during the project lifetime. We considered two different ways of dealing with this. First, changing the discount rate according to changes in capital structure is one solution. Second, adding the debt as a positive cash flow at the time of investment and subtracting the annuities of payments at the time they occur. This allows us to use the RRE as the discount rate for the project, because only the equity holders has a claim on the profit from the project. For the model we have chosen to use the second approach, because of its simplicity in modeling. We have also added a term called *Terminal value* to account for the terminal value of assets. Hence our modified FCF calculation is as presented in equation 6.3.

$$\begin{aligned} \text{FCF} = {} & (\text{Revenues} - \text{Costs}) \times (1 - \tau_c) + \text{Grants} + \text{Loan} \\ & - \text{CapEx} + \text{Terminal Value} - \text{Annuity on debt} \\ & - \Delta NWC + \ \tau_c \times \text{Depreciation} \end{aligned} \tag{6.3}$$

The modeling choice above implies the use of RRE as the discount rate for the entire project. However, if annuity payments are discounted merely by the RRE an arbitrage opportunity[1] is created in the model. This happens because the annualized payments on the debt includes interest payment similar to the lending rate. Hence, by discounting these payments for the whole project life-time with a RRE, higher than the lending rate, the present value of annuity payments will be lower than the cash inn-flow from the loan - we are earning money on what

[1]Arbitrage opportunity: riskless profit (Brealey et al., 2001)

we have borrowed. Because this will make an arbitrage profit, the model will utilize this to maximize the investment. However, as we do not want this effect to interfere with the model objective, we have solved this by discounting the annuity with the lending rate back to the year the loan was received, and then using RRE to discount them both back to year zero. This results in a NPV of loan and annuity payments equal to zero. With a RRE higher than the lending rate, this yields an underestimation of the influence of the future cash-flows on the NPV, because the lower lending rate is not incorporated in the discount rate.

Because assets in the project could be highly subsidized by grants, another arbitrage opportunity is revealed if the terminal value of the asset is set too high. The terminal value is calculated as a shear of the assets value based on their remaining lifetime. Thus, if the terminal value is not restricted, the model could find an arbitrage opportunity by investing in an asset that is highly subsidized by grants, and then receive a terminal value higher than the actual cost for the investor. Thus the amount possible to retrieve from the asset terminal value must be adjusted accordingly.

We have also chosen to present the expected NPV maximized by the objective function in local currency, implying that the owner will receive profits in local currency independent on whether he or she is a foreign investor. This implies that foreign project investors should hedge their investments against foreign exchange rate risk. This is a modeling choice and a simplification that is not always realistic. Additionally this type of hedging is difficult because of the exchange rate volatility, lack of forward markets and inaccurate predictions of future cash flows.

Finally, the user should be consistent in the use of real[2] and nominal terms when inserting parameters in the model. Real interest rates are used with real values, and nominal interest rates are used with nominal values. For calculations of real and nominal rates, see appendix A, section A.1.

6.2.3 Lost load

According to Mandelli (2014), for mini-grids placed in areas without access to electricity prior to the project, constraining the amount of lost load in the grid is not necessary. This is because

[2]Current or nominal dollars refer to the actual number of dollars of the day; constant or real dollars refer to the amount of purchasing power.(Brealey et al., 2001, pp. 63)

the consumers in such communities have access to simpler forms of energy, like fires for cooking, and only rely on electricity for basics like lights, radio and phone charging. The consumers thus easily adapt to the actual electricity supply they have, and is not severely affected by lost load. In addition fulfilling demand merely using solar panels and batteries can be costly. An alternative to the constraint on lost load is to account for the electricity not delivered by quantifying a VOLL. Adding this as a cost per unit electricity that is not delivered from solar power in the objective function, it can be interpreted as a punishment. If the project requires that demand is covered, the punishment can represent for instance the extra cost of using a diesel generator to supply what is not delivered by the solar panels, based on the levelized cost of electricity (LCoE) for diesel generators in mini-grids. Another possibility is that the VOLL is used merely as a model choice to increase the investments in solar power, but that the actual lost load is assumed to be handled by the consumers themselves. This choice implies that the project value will be underestimated, and it assumes that the consumers do not change their view on the impact of lost load, within the project lifetime. Using the VOLL can additionally give insights into when it is optimal, with regard to project value, to stop increasing the solar powered part of the mini-grid and use another source of electricity. Therefore we have chosen to incorporate VOLL in the model formulation.

6.3 Model assumptions and simplifications

In the process of modeling, some assumptions and simplifications have been made regarding different aspects of the problem. These, and their influence, are explained in the following subsections. First the assumptions regarding the time-frames for the project cash flows are explained, followed by the assumptions affecting the technical- and economic properties of the project.

6.3.1 Cash flow time-frames

Because the objective of the model is to maximize the present value of all cash flows, the timing of the different cash flows, and thus discounting, is important. To be able to model this, assumptions have been made to adjust the real life problem to the model structure. One of these assumptions is that the project has no construction phase. That is, at project start there is no initial period without production. According to Mr. Mugisha the actual construction of a mini-grid does not take longer than a week. Thus, because sales are modeled on a yearly basis, this is seen as a fair assumption.

All the costs related to project investments are assumed to appear in the start of the year in a new investment period. In addition the grants and loan approved for the project investment are received at the same point in time. This implies that if an new investment is made five years into the project, these cash flows are discounted back by five years. Although it usually takes around three months from an asset is ordered until it arrives at the mini-grid location, also according to Mr. Mugisha, the model assumes that assets can be acquired instantly. Therefore, dependent on whether the cost of assets occur at the same time as orders are set or when assets are received, this assumption can be both an over- or underestimation of costs. Grants and loan are also assumed to be provided for each of the investment periods separately, and not as a single amount at project start. In reality this might be true for some projects, because delaying parts of the investment, and thus hold back money for some years, can be a method of saving for the grant and loan providers. However, if this is not the case in a project, the amount of grants and loan provided will be underestimated in the model. The project insurance costs are assumed to be directly linked to the investments, because the mini-grid will need a higher insurance premium the bigger it is. Thus the insurance costs appear at the start of those periods where more panels are invested in. For projects where the insurance is a yearly cost, this would be an overestimation of costs due to discounting.

Operational costs, consumer payments and connection fees are all assumed to appear at the beginning of every year. For the consumer payments this is quite natural to assume because pre-payments are widely used in developing countries, and also recommended to reduce the risk of non-payments (Manetsgruber et al., 2015). For projects where pre-payments are not used, this assumption will be an overestimation of revenues. However, in most countries electricity is paid on a quarterly or monthly basis, for instance in Uganda as presented in section 2.2.3. Thus, for most projects that choose to collect payments on this basis, the assumption is somewhat an overestimation of revenues. Operational costs are also in most projects monthly costs, and are thus overestimated by discounting them at the start of the year. The same is true for connection fees, that are normally revenues spread out randomly through the year.

Re-investments in assets whose expected lifetime has expired are, as other investment costs, accounted for in the start of the year of the investment period where they must be renewed. Therefore an assumption has been made that the expected lifetime of each asset must correspond with the length of the strategic periods. For instance if the strategic periods are five years long, the asset expected lifetime must be for example five, ten or fifteen years long. This assumption can either overestimate or underestimate costs, depending on whether the asset life expectancy is over- or undercalculated. In addition it is assumed that the distribution lines have a life expectancy of 25 years, which underestimates costs in cases where this is not true and they must be renewed.

6.3.2 Technical properties

When a mini-grid is being increased in size, panels or batteries are being replaced or reparations are needed, at least parts of the operation must be stopped. In the model however, it is assumed that the production has no downtime and that the new installations instantly increase grid capacity. Thus the model overestimates the electricity generated in such cases, throughout the project lifetime. Another assumption that decreases the realistic picture the model presents of the mini-grid, is that the efficiency of the panels and batteries do not decrease throughout their lifetime. For batteries, including this in a model could be a difficult task, according to Dufo-López et al. (2014), because of the high dependency on operational conditions. Solar panels and battery capacities are thus overestimated in the model, which implies that it is overestimated how much it is possible to generate, charge and thereby sell. The last assumption affecting the realism of the modeled mini-grid is that the battery is reset at the start of every new season. The initial amount stored on the battery at the start of a new season is thus a parameter in the model. This assumption may therefore either over- or underestimate the electricity available to be sold. If there is no electricity stored on the battery in the end of a season, the initial amount stored will provide the grid with ”free” electricity. On the other hand, if there is electricity stored on the battery in the end of a season, the fixed initial amount at the start of the new season can be lower than the stored amount, such that electricity is lost. These are all assumptions taken to simplify the modeling of the real problem.

6.3.3 Economic properties

The fixed costs of investments are assumed to appear in all of the investment periods, thus binary variables are not incorporated. Thereby, reluctant of whether additional investments are made in each of the investment periods, the fixed costs will occur. This would be equivalent to reducing the feasible region for the problem by setting all binary variables equal to one, if the problem had binary variables. The result is that we, with this assumption, underestimate the expected project value. The assumption is merely a simplification made to reduce the problem size, because the binary variables needed to account for fixed costs makes the problem more complicated to solve. Solution algorithms have not been the focus of this thesis, and therefore the assumption is necessary to reduce computational time. Variable investment costs are also simplified as they are assumed to be linear, and thus neglect economies of scale. Dependent on what assets are chosen for the specific project assessed and how much is invested, this can be an overestimation or an underestimation of costs. In most cases it would be an overestimation because of the lost scale advantages. In addition it is assumed that the investment costs for all assets except batteries can be accounted for based on the amount of solar panels invested in. Thus, for instance the costs related to the balancing of system (BOS) must be calculated per panel installed. This assumption is also a model simplification, and can make it difficult to set the correct costs for the different assets affected by it. Whether it is an over- or underestimation must be decided based on the costs set in each specific project. All the asset investment costs are also represented by the same parameter notation. This makes it essential that the cost of batteries are represented as the last asset in the set of assets. This simplification makes the model less flexible and was made in an effort to simplify the notation.

Another assumption affecting the model economic realism is that the corporate tax rate is assumed to be constant. However, changes in this rate is rare, and if they appear it is hard to predict whether it will change for the better or worse. The same is true for RRE and lending rate, where a constant rate is assumed for simplicity. The last assumption in an economic perspective is that assets are possible to sell, or that they have value to the investor, if their life expectancy has not expired at project end. This is an assumption made because the model has to end the project at some point, whether or not it in reality terminates at this point.

6.4 Notation

This section formally defines all sets, indices, parameters and variables included in the model formulations. Sets are denoted as capital and calligraphic letters. Indices and variables are defined using lowercase Latin letters, while parameters are capitalized also using Latin letters. Greek letters are used for parameters and variables that in most contexts are defined using Greek letters. In order to differentiate between variables and parameters used in the two model formulations evaluating risk in different ways, the model formulation based on RRE, is referred to as *model 1*, while the one based on CVaR is referred to as *model 2*. Where nothing is specified, the notation is used in both model formulations.

Sets

$\mathcal{S}$	Set of all strategic scenarios
$\mathcal{I}$	Set of all strategic investment periods
$\mathcal{O}$	Set of all operational scenarios
$\overline{\mathcal{T}}$	Set of all years in project lifetime
$\mathcal{T}$	Set of all years of operation in each strategic period ($\mathcal{T} \subset \overline{\mathcal{T}}$)
$\mathcal{V}$	Set of all seasons within a year
$\mathcal{H}$	Set of all hours representing a season
$\mathcal{J}$	Set of all assets invested in

Indices

s	Strategic scenario $s \in \mathcal{S}$
i	Period $i \in \mathcal{I}$
i'	Period $i' \in \mathcal{I}$
o	Operational scenario $o \in \mathcal{O}$
t	Year $t \in \overline{\mathcal{T}}$
t'	Year $t' \in \overline{\mathcal{T}}$
v	Season $v \in \mathcal{V}$
h	Hour $h \in \mathcal{H}$
j	Asset[3] $j \in \mathcal{J}$

Parameters

I_{sij}	Investment cost per unit installed of asset j, in period i, strategic scenario s
F_i	Fixed cost related to investments in period i
P_{itv}	Price for electricity per kWh sold in season v, year $t \in \mathcal{T}$, period i
P_C	Connection fee per customer(household/business etc.) connecting to the grid
C^O_{it}	Operational cost per kWh sold in year $t \in \mathcal{T}$, period i
C^I	Insurance cost per panel installed
C^D	Cost per meter distribution line needed (Includes cost of distribution poles)
C^L	Value of lost load per kWh not delivered from solar powered generation
N^C_{sit}	Number of customers connecting to the grid in year $t \in \mathcal{T}$, period i, strategic scenario s
N^D_{sit}	Number of meters of distribution line needed in year $t \in \mathcal{T}$, period i, strategic scenario s

[3]The last element in the set, $\mid J \mid$, always represents batteries invested in, in the model. This was explained as an assumption in 6.3.

T_j^{RA} Percentage of asset j's terminal value actually retained by project owner at project end

T_{ij}^{LA} Percentage quantifying the remaining lifetime of the investments made in asset j, in period i, at project end

T^{RD} Percentage of the distribution lines terminal value actually retained by project owner at project end

T_i^{LD} Percentage quantifying the remaining lifetime of the investments made in distribution lines in period i, at project end

$Q_{itj}^{Dep,A}$ Percentage of investments in asset j, that is to be depreciated in year $t \in \overline{\mathcal{T}}$, invested in period i

$Q_{it}^{Dep,D}$ Percentage of investments in distribution lines in period i, that is to be depreciated in year $t \in \overline{\mathcal{T}}$

$R_{i'ij}^{W}$ Binary matrix determining which asset j, invested in in period i', that must be renewed in what period i

G_{si}^{P} Percentage of investment costs financed by grants in period i, strategic scenario s

B_{si}^{P} Percentage of investment costs financed by loan in period i, strategic scenario s

$Q_{it}^{Annuity}$ Loan annuity factor in year $t \in \overline{\mathcal{T}}$, period i

D_{siotvh} Demand for electricity each hour h, in season v, year $t \in \mathcal{T}$, operational scenario o, period i, strategic scenario s (kWh)

K_{otvh} Panel production capacity based on irradiance, temperature and efficiency for each hour h, in season v, year $t \in \mathcal{T}$, operational scenario o (kW/m^2)

E_{sij} Foreign exchange rate for asset j, period i, strategic scenario s (*Local currency/Foreign currency*)

Δ_t^{NWC} Change in net working capital in year $t \in \overline{\mathcal{T}}$

V^{max} Power to energy factor - quantifying the maximum power possible to discharge from or charge to the batteries within an hour

$V^{initial}$ Percentage initial electricity stored on the batteries at the start of a new season (kWh)

$\eta^{Dischar}$	Percentage quantifying the battery discharge efficiency
η^{Char}	Percentage quantifying the battery charge efficiency
η^{D}	Percentage quantifying the distribution line efficiency
A	Area of each solar panel (m^2)
H^{Cap}	Battery capacity ($kWh/battery$)
W_v	The number of total days in season v, divided by the number of days representing season v
Π_s^S	Probability of strategic scenario s
Π_o^O	Probability of operational scenario o
τ^C	Corporate income tax
I^D	Number of strategic periods without strategic uncertainty
R^D	Discount factor - Lending rate

Parameters - model 1

R^E	Discount factor - RRE

Parameters - model 2

α	Probability of strategic scenario cash flow values below threshold VaR-value
λ	Risk coefficient of mean-risk problem
R^{CVaR}	Discount factor - CVaR

Variables

x_{si}	Number of solar panels installed in the beginning of period i, strategic scenario s
y_{si}	Number of batteries installed in the beginning of period i, strategic scenario s

w_{si} Aggregated number of solar panels installed up to and including period i, strategic scenario s

z_{si} Aggregated number of batteries installed up to and including period i, strategic scenario s

u_{siotvh} Electricity distributed (sold) to consumers from solar power generation, during hour h, in season v, year $t \in \mathcal{T}$, operational scenario o, period i, strategic scenario s (kWh)

v^{Gen}_{siotvh} Electricity generated from solar power during hour$h$, in season v, year $t \in \mathcal{T}$, operational scenario o, period i, strategic scenario s (kWh)

v^{Char}_{siotvh} Electricity charged to batteries during hour h, in season v, year $t \in \mathcal{T}$, operational scenario o, period i, strategic scenario s (kWh)

v^{Dishar}_{siotvh} Electricity discharged from batteries during hour h, in season v, year $t \in \mathcal{T}$, operational scenario o, period i, strategic scenario s (kWh)

v^{Stored}_{siotvh} Electricity stored on batteries in the end of hour$h$, in season v, year $t \in \mathcal{T}$, operational scenario o, period i, strategic scenario s (kWh)

l^{slack}_{siotvh} Amount of electricity not delivered to consumers from solar power generation - slack variable, in hour h, season v, year $t \in \mathcal{T}$, operational scenario o, period i, strategic scenario s (kWh)

d_{sit} Yearly total depreciation amount for all assets, in year $t \in \overline{\mathcal{T}}$, period i, strategic scenario s

n_{sij} Cost of renewal of asset j, in period i, strategic scenario s

t^V_{si} Total terminal value of all assets in period i, strategic scenario s

g^T_{si} Total amount of grants in period i, strategic scenario s

b^T_{si} Total amount of loan in period i, strategic scenario s

$b^{Annuity}_{sit}$ Loan annuity amount in year $t \in \overline{\mathcal{T}}$, period i, strategic scenario s

Variables - model 2

η Threshold VaR-value

v_s Auxiliary variable representing the difference between the threshold VaR-value and the strategic scenario cash flow values, in each strategic scenario s

6.5 Mathematical formulation - Model 1

This section presents the mathematical formulation of the stochastic program, where risk is accounted for by discounting the cash flows using the RRE. Firstly the section presents and explains the main features of the objective function. Following, different groups of constraints are presented and each constraint is explained in greater detail.

6.5.1 Objective function

$$\begin{aligned}
\max \quad & \sum_{s\in\mathcal{S}} \Pi_s^S (\sum_{i\in\mathcal{I}} \{ (\sum_{t\in\overline{\mathcal{T}}} (-b_{sit}^{Annuity} \frac{1}{(1+R^E)^{((i-1)|T|)}} \frac{1}{(1+R^D)^{(t-(i-1)|T|)}} \\
+ \quad & d_{sit}\tau^C \tfrac{1}{(1+R^E)^t})) + (t_{si}^V \tfrac{1}{(1+R^E)^{|\overline{T}|}}) + ((g_{si}^T + b_{si}^T - \sum_{j\in\mathcal{J}} n_{sij} \\
- \quad & \sum_{j=1}^{|J|-1} I_{sij}E_{sij}x_{si} - I_{si|J|}E_{si|J|}y_{si} - F_i - C^I w_{si} - C^D \sum_{t\in\mathcal{T}} N_{sit}^D) \frac{1}{(1+R^E)^{(i-1)|T|}}) \\
+ \quad & (\sum_{o\in\mathcal{O}} \Pi_o^O \sum_{t\in\mathcal{T}} ((\sum_{v\in\mathcal{V}} W_v \sum_{h\in\mathcal{H}} P_{itv} u_{siotvh} + P^C N_{sit}^C \\
- \quad & (\sum_{v\in V} W_v \sum_{h\in H} (C_{it}^O u_{siotvh} + C^L l_{siotvh}))) \frac{1-\tau^C}{(1+R^E)^{(i-1)|T|+(t-1)}}))\}) \\
- \quad & \sum_{t\in\overline{\mathcal{T}}} \Delta_t^{NWC} \frac{1}{(1+R^E)^t}
\end{aligned} \tag{6.4}$$

The objective function (6.4) maximizes the expected NPV for the investors. It consists of the different cash flows in the project and the coherent discount factors, used to represent the value of the project at its start, as explained in section 6.2.2. Because the problem has a multi-horizon structure, the objective function sums over all the operational scenarios, o, for each strategic scenario, s. Naturally each scenario, both strategic and operational, is given a probability, Π_s^S

and Π_o^O respectively, as seen in (6.4). Thus the objective function value of the optimal solution is the expected value of the total sum of all cash flows throughout the project, when each cash flow is discounted back to its value at project start. With one part of the objective function being independent on all scenarios, one part not dependent on operational scenarios and one dependent on both strategic and operational scenarios, the objective function can naturally be explained to greater detail in three separate parts as follows.

$$\begin{aligned}&\sum_{s \in \mathcal{S}} \Pi_s^S (\sum_{i \in \mathcal{I}} \{(\sum_{t \in \overline{\mathcal{T}}} (-b_{sit}^{Annuity} \frac{1}{(1+R^E)^{((i-1)|T|)}} \frac{1}{(1+R^D)^{(t-(i-1)|T|)}} \\ &+ d_{sit}\tau^C \tfrac{1}{(1+R^E)^t})) + (t_{si}^V \tfrac{1}{(1+R^E)^{|\overline{T}|}}) + ((g_{si}^T + b_{si}^T - \sum_{j \in \mathcal{J}} n_{sij} - \sum_{j=1}^{|J|-1} I_{sij} E_{sij} x_{si} \\ &- I_{si|J|} E_{si|J|} y_{si} - F_i - C^I w_{si} - C^D \sum_{t \in \mathcal{T}} N_{sit}^D) \frac{1}{(1+R^E)^{(i-1)|T|}})... \end{aligned} \tag{6.5}$$

(6.5) presents the part of the objective function where cash flows are not linked to operation, but are uncertain on a strategic level. The first two cash flows, loan annuity amount, $b_{sit}^{Annuity}$, and depreciation tax shield, $d_{sit}\tau^C$, respectively, are both yearly cash flows and are therefore discounted in all years $t \in \overline{\mathcal{T}}$. However, loan annuity payments must be discounted with the lending rate, R^D, in the years the annuity payments are made, but with the RRE, R^E, for the remaining years back to present, in order to achieve zero NPV on debt. This must be accounted for because loans are possible to acquire at the start of each investment period. The following cash flow in the objective function, total terminal value of investments, t_{si}^V, is restricted to the end of the final project year, and is thus merely discounted back from year $\mid \overline{\mathcal{T}} \mid$. The last collection of cash flows in (6.5) are the cash flows appearing at the beginning of each strategic period i. These are the grants provided, g_{si}^T, loan acquired, b_{si}^T, costs of asset renewal, n_{sij}, and all the investment costs for the project. The investment costs are made up of the costs of investments in assets directly dependent on the number of panels, x_{si}, invested in, I_{sij}, the cost of investments in batteries, y_{si}, $I_{si|J|}$, fixed costs of investments, F_i, insurance costs, C^I, and the costs of investments in distribution lines, C^D, respectively, as given in (6.5). Insurance costs are based on the aggregated amount of panels installed in period i, w_{si}, while the distribution line costs are based on the cost per meter distribution line, N_{sit}^D. The investment costs are all discounted back from the years $(i-1) \mid I \mid$, based on the period they are present in, as well as the exchange rates, E_{sij}, are accounted for where appropriate.

$$
\begin{aligned}
...+ \quad & (\sum_{o \in \mathcal{O}} \Pi_o^O \sum_{t \in \mathcal{T}} ((\sum_{v \in \mathcal{V}} W_v \sum_{h \in \mathcal{H}} P_{itv} u_{siotvh} + P^C N_{sit}^C \\
- \quad & (\sum_{v \in V} W_v \sum_{h \in H} (C_{it}^O u_{siotvh} + C^L l_{siotvh}))) \frac{1 - \tau^C}{(1 + R^E)^{(i-1)|T| + (t-1)}})) ...
\end{aligned}
\tag{6.6}
$$

The second part of the objective function is shown in (6.6) and is a collection of the cash flows which are dependent on the uncertainty at the operational- and strategic level. These are the sales revenues based on the price for electricity, P_{itv}, and the connection fees, P^C, as well as the operational costs in each year, C_{it}^O, and the cost represented by the VOLL, C^L. Total amount of revenues and costs from operation is here based on the electricity generated form solar power which is sold, u_{siotvh}. Further, the revenues from connection fees are based on the number of connected customers, N_{sit}^C, while the cost related to the VOLL is based on the slack in the generation from solar power, l_{siotvh}. All the cash flows are discounted on a yearly basis. However, because year t within these summations is in the set $\mathcal{T}$, representing the years within each strategic period i, the actual year to discount back from is represented by $(i - 1) \mid I \mid +(t - 1)$. This implies, as assumed, that these cash flows are accounted for at the start of the year. As explained earlier, these revenues and costs are subject to corporate income tax, and thus this tax is also subtracted from each year's cash flow from operation by multiplying the total yearly cash flows by $(1 - \tau)$.

$$
... - \sum_{t \in \overline{\mathcal{T}}} \Delta_t^{NWC} \frac{1}{(1 + R^E)^t} \tag{6.7}
$$

Lastly (6.7) represents the part of the objective function which is independent of all scenarios. This cash flow is the change in NWC, Δ_t^{NWC}, for the project in each year $t \in \overline{\mathcal{T}}$, and is thus also discounted yearly. It is kept separate from the other cash flows discounted yearly, because it is neither affected by strategic or operational uncertainty. Thus the cash flow is kept outside the summation of all cash flows present in the different scenarios.

6.5.2 Constraints

In the following the different groups of constraints in the model are presented and explained.

Aggregation of installed capacity

$$x_{si} = w_{si} \qquad \forall \qquad s \in \mathcal{S}, i = 1 \tag{6.8}$$

$$y_{si} = z_{si} \qquad \forall \qquad s \in \mathcal{S}, i = 1 \tag{6.9}$$

$$x_{si} + w_{s(i-1)} = w_{si} \qquad \forall \qquad s \in \mathcal{S}, i \in [2, ..., \mid I \mid] \tag{6.10}$$

$$y_{si} + z_{s(i-1)} = z_{si} \qquad \forall \qquad s \in \mathcal{S}, i \in [2, ..., \mid I \mid] \tag{6.11}$$

Constraints (6.8) until (6.11) handles the aggregation of installed units of both panels and batteries. (6.8) and (6.9), set the initial total number of installed panels and batteries, w_{s1} and z_{s1}, equal to what is installed in the first strategic period $i = 1$, x_{s1} and y_{s1} respectively. For the following periods (6.10) and (6.11) ensure that the total number of installed panels and batteries is the aggregation of the total installed number of units in the previous strategic period $(i - 1)$ and the new units installed in the current strategic period i.

Generation and storage capacity

$$K_{otvh} w_{si} A \geq v^{Gen}_{siotvh} \qquad \forall \qquad s \in \mathcal{S}, i \in \mathcal{I}, o \in \mathcal{O}, t \in \mathcal{T}, v \in \mathcal{V}, h \in \mathcal{H} \tag{6.12}$$

$$H^{Cap} z_{si} \geq v^{store}_{siotvh} \qquad \forall \qquad s \in \mathcal{S}, i \in \mathcal{I}, o \in \mathcal{O}, t \in \mathcal{T}, v \in \mathcal{V}, h \in \mathcal{H} \tag{6.13}$$

Electricity generation and battery storage has limits as to how much can be generated from the panels and stored on the batteries. Constraint (6.12) sets the generation capacity limit based on the product of solar panel production capacity for one panel each hour of the day, K_{otvh}, the area of one panel, A, and the number of panels actually installed, w_{si}. What is generated each hour, v^{Gen}_{siotvh}, cannot exceed this limit. In the same manner (6.13) sets the storage capacity limit based on the product of the capacity in each battery, H^{Cap}, and the number of batteries actually installed, z_{si}. The electricity stored each hour, v^{store}_{siotvh}, can thus not exceed this limit.

Electricity demand, distribution and slack

$$D_{siotvh} = u_{siotvh} + l_{siotvh} \qquad \forall \qquad s \in \mathcal{S}, i \in \mathcal{I}, o \in \mathcal{O}, t \in \mathcal{T}, v \in \mathcal{V}, h \in \mathcal{H} \quad (6.14)$$

The connection between what is demanded, represented by the hourly load profiles D_{siotvh}, and what has been distributed to consumers from solar power generation each hour, u_{siotvh}, is given by (6.14). The difference between them represents what the solar power generation has not been able to deliver to the consumers, the slack, l_{siotvh}. Therefore what is demanded has to be equal to the sum of what is distributed to consumers and what is not delivered.

Storage

$$\eta^{D} v^{Gen}_{siotvh} + \eta^{Dischar} v^{Dischar}_{siotvh} - v^{Char}_{siotvh} = u_{siotvh} \qquad \forall$$
$$s \in \mathcal{S}, i \in \mathcal{I}, o \in \mathcal{O}, t \in \mathcal{T}, v \in \mathcal{V}, h \in \mathcal{H} \qquad (6.15)$$
$$V^{initial} z_{si} - v^{Dischar}_{siotvh} + \eta^{Char} v^{Char}_{siotvh} = v^{store}_{siotvh} \qquad \forall$$
$$s \in \mathcal{S}, i \in \mathcal{I}, o \in \mathcal{O}, t \in \mathcal{T}, v \in \mathcal{V}, h = 1 \qquad (6.16)$$
$$v^{store}_{siotv(h-1)} - v^{Dischar}_{siotvh} + \eta^{Char} v^{Char}_{siotvh} = v^{store}_{siotvh} \qquad \forall$$
$$s \in \mathcal{S}, i \in \mathcal{I}, o \in \mathcal{O}, t \in \mathcal{T}, v \in \mathcal{V}, h \in [2, ..., \mid \mathcal{H} \mid] \qquad (6.17)$$
$$v^{Dischar}_{siotvh} \leq V^{max} H^{Cap} z_{si} \qquad \forall$$
$$s \in \mathcal{S}, i \in \mathcal{I}, o \in \mathcal{O}, t \in \mathcal{T}, v \in \mathcal{V}, h \in \mathcal{H} \qquad (6.18)$$
$$v^{Char}_{siotvh} \leq V^{max} H^{Cap} z_{si} \qquad \forall$$
$$s \in \mathcal{S}, i \in \mathcal{I}, o \in \mathcal{O}, t \in \mathcal{T}, v \in \mathcal{V}, h \in \mathcal{H} \qquad (6.19)$$

Electricity distributed to consumers from solar power generation, u_{siotvh}, can either be distributed directly from generation, v^{Gen}_{siotvh}, or through battery discharge, $v^{Dischar}_{siotvh}$. In hours of excess electricity production however, what is not to be distributed to consumers is charged to the batteries, v^{Char}_{siotvh}. This is controlled by constraint (6.15) as shown above, where discharge efficiency is represented by $\eta^{Dischar}$ and distribution line efficiency by η^{D}. Following, constraint (6.16) and (6.17) handles the storage balance. Because the storage variable, v^{store}_{siotvh}, represents what is stored on the batteries at the end of hour h, (6.16) is needed to explain the storage balance in the first hour of every season, v , where the initial amount of electricity stored is given as $V^{initial}z_{si}$. The two constraints make sure that what is stored on the batteries within an hour equals the amount stored at the end of the previous hour, minus the amount discharged and plus the amount charged. The charged amount is here adjusted by the charge efficiency η^{C}. Both charge and discharge efficiencies account for losses in distribution lines and inverters between the generation source, batteries and the grid, as well as losses in the actual batteries. In addition to accounting for losses in storage, the model accounts for the charge and discharge capacities of the batteries within an hour, through constraint (6.18) and (6.19). These set the maximum amount of electricity possible to charge or discharge to or from the batteries within an hour to a percentage, V^{max}, of the battery capacity installed at that point, $H^{Cap}z_{si}$.

Depreciation

$$\begin{aligned} d_{sit} = & \sum_{j=1}^{|\mathcal{J}|-1}(Q^{Dep,A}_{itj}(I_{sij}E_{sij}x_{si} + n_{sij})) + Q^{Dep,A}_{it|J|}(I_{si|J|}E_{si|J|}y_{si} + n_{si|J|}) \\ + & \ Q^{Dep,D}_{it}C^{D}\sum_{t' \in \mathcal{T}} N^{D}_{sit'} \qquad \forall \qquad s \in \mathcal{S}, i \in \mathcal{I}, t \in \overline{\mathcal{T}} \end{aligned} \tag{6.20}$$

The percentages of the investment in each asset j and in distribution lines, made in period i, which is to be depreciated in each year $t \in \overline{\mathcal{T}}$, are represented by $Q^{Dep,A}_{itj}$ and $Q^{Dep,D}_{it}$. Based on these percentages, constraint (6.20) sets the total yearly depreciation amount of all assets and distribution lines, d_{sit}. For each asset the product of investment costs, I_{sij}, exchange rates, E_{sij}, and quantity invested in panels, x_{si}, or batteries, y_{si}, is added to the amount used to renew assets previously invested in, n_{sij}. Further these values are multiplied by the calculated percentages and the depreciation amounts for all assets are added together. The depreciation amount for the investments in distribution lines, based on the cost per meter, C^{D}, number of meters invested in in each period i, $\sum\limits_{t' \in \mathcal{T}} N^{D}_{sit'}$, and $Q^{Dep,D}_{it}$, is further added to the depreciation amount for asset investments and thereby concludes the total yearly depreciation amount, d_{sit}.

Asset renewal

$$n_{sij} = \sum_{i' \in \mathcal{I}} R^W_{i'ij} I_{sij} E_{sij} x_{si'} \qquad \forall \qquad s \in \mathcal{S}, i \in \mathcal{I}, j \in [1...| \mathcal{J} | - 1] \tag{6.21}$$

$$n_{sij} = \sum_{i' \in \mathcal{I}} R^W_{i'ij} I_{sij} E_{sij} y_{si'} \qquad \forall \qquad s \in \mathcal{S}, i \in \mathcal{I}, j =| J | \tag{6.22}$$

Constraint (6.21) and (6.22) set the cost of asset renewal in strategic scenario s, period i, for each asset j, originally invested in in period i', n_{sij}. In the binary matrix, $R^W_{i'ij}$, a value of one indicates that asset j, originally invested in in period i', will be renewed in period i. Whether an asset should be renewed is dependent on its lifetime. The cost of the asset renewal is dependent on how much was invested in either panels, $x_{si'}$, or batteries, $y_{si'}$, originally. However the cost of renewing the asset in period i is based on the new investment cost for the period, I_{sij}. Thus (6.21) ensures that all assets, whose cost depends on the number of panels invested in, are renewed when their lifetime has expired. Additionally the costs of the batteries that need to be renewed are handled by constraint (6.22). Because the investments may have been made in foreign currency, the exchange rate, E_{sij}, is included in the calculations to convert all cash flows to local currency.

Terminal value

$$\begin{aligned} t^V_{si} &= \textstyle\sum_{j=1}^{|\mathcal{J}|-1} T^{LA}_{ij} T^{RA}_j (I_{sij} E_{sij} x_{si} + n_{sij}) + T^{LA}_{i|J|} T^{RA}_{|J|} (I_{si|J|} E_{si|J|} y_{si} + n_{si|J|}) \\ &+ T^{LD}_i T^{RD} C^D \textstyle\sum_{t \in \mathcal{T}} N^D_{sit} \qquad \forall \qquad s \in \mathcal{S}, i \in \mathcal{I} \end{aligned} \tag{6.23}$$

The total terminal value of all investments made in the strategic periods i, for each strategic scenario s, t^V_{si}, is determined by constraint (6.23). Percentages quantifies the remaining lifetime of each asset at the project end, T^{LA}_{ij}, and is based on the rate of depreciation of the asset. Further not all of the assets remaining value is actually retained by the investor at project end, and the parameter T^{RA}_j accounts for this decline in value. The equivalent percentages, T^{LD}_i and T^{RA} are used to determine the terminal value of the investments in distribution lines. Thus the terminal value determined by (6.23) is the value of the investment costs for the all assets, the cost of those renewed in period i and the cost of distribution lines, adjusted by these percentages. The different elements of the constraint are multiplied and added together in the same manner as explained for the depreciation constraint, (6.20).

Grants and loan

$$g_{si}^{T} = \quad G_{si}^{P}\Big(\sum_{j=1}^{|\mathcal{J}|-1}(I_{sij}E_{sij}x_{si} + n_{sij}) + I_{si|J|}E_{si|J|}y_{si} + n_{si|J|} + F_i + C^D\sum_{t\in\mathcal{T}}N_{sit}^{D}\Big)$$
$$\forall \qquad s \in \mathcal{S}, i \in \mathcal{I} \tag{6.24}$$

$$b_{si}^{T} = \quad B_{si}^{P}\Big(\sum_{j=1}^{|\mathcal{J}|-1}(I_{sij}E_{sij}x_{si} + n_{sij}) + I_{si|J|}E_{si|J|}y_{si} + n_{si|J|} + F_i + C^D\sum_{t\in\mathcal{T}}N_{sit}^{D}\Big)$$
$$\forall \qquad s \in \mathcal{S}, i \in \mathcal{I} \tag{6.25}$$

$$b_{sit}^{Annuity} = Q_{it}^{Annuity} b_{si}^{T} \qquad \forall \qquad s \in \mathcal{S}, i \in \mathcal{I}, t \in \overline{\mathcal{T}} \tag{6.26}$$

The total amount of grants, g_{si}^{T}, and loan, b_{si}^{T}, in the project is determined based on percentages of the total investment costs, fixed costs and costs of renewed assets, for each period i and strategic scenario s, G_{si}^{P} for grants and B_{si}^{P} for loans. The total amount of grants is given by constraint (6.24), while (6.25) calculates the amount of loan the project receives in each investment period. The calculation of the total costs is in this constraint also similar to the calculations of the depreciation amount in (6.20), except for the different percentages and the inclusion of fixed costs of investments in (6.24) and (6.25). Lastly, constraint (6.26) ensures that the yearly loan annuity amount for the loan from strategic period i and strategic scenario s, $b_{sit}^{Annuity}$, equals a percentage, $Q_{it}^{Annuity}$, of the total loan amount for the same strategic period.

Non-anticipativity constraints

$$t_{si}^{V} = t_{i}^{V} \qquad \forall \quad s \in \mathcal{S}, i \in [1...I^{D}] \tag{6.27}$$

$$b_{si}^{T} = b_{i}^{T} \qquad \forall \quad s \in \mathcal{S}, i \in [1...I^{D}] \tag{6.28}$$

$$g_{si}^{T} = g_{i}^{T} \qquad \forall \quad s \in \mathcal{S}, i \in [1...I^{D}] \tag{6.29}$$

$$w_{si} = w_{i} \qquad \forall \quad s \in \mathcal{S}, i \in [1...I^{D}] \tag{6.30}$$

$$z_{si} = z_{i} \qquad \forall \quad s \in \mathcal{S}, i \in [1...I^{D}] \tag{6.31}$$

$$x_{si} = x_{i} \qquad \forall \quad s \in \mathcal{S}, i \in [1...I^{D}] \tag{6.32}$$

$$y_{si} = y_{i} \qquad \forall \quad s \in \mathcal{S}, i \in [1...I^{D}] \tag{6.33}$$

$$n_{sij} = n_{ij} \qquad \forall \quad s \in \mathcal{S}, i \in [1...I^{D}], j \in \mathcal{J} \tag{6.34}$$

$$u_{siotvh} = u_{otvh} \qquad \forall \quad s \in \mathcal{S}, i \in [1...I^{D}], o \in \mathcal{O}, t \in \mathcal{T}, v \in \mathcal{V}, h \in \mathcal{H} \tag{6.35}$$

$$v_{siotvh}^{store} = v_{iotvh}^{store} \qquad \forall \quad s \in \mathcal{S}, i \in [1...I^{D}], o \in \mathcal{O}, t \in \mathcal{T}, v \in \mathcal{V}, h \in \mathcal{H} \tag{6.36}$$

$$v_{siotvh}^{Dischar} = v_{iotvh}^{Dischar} \qquad \forall \quad s \in \mathcal{S}, i \in [1...I^{D}], o \in \mathcal{O}, t \in \mathcal{T}, v \in \mathcal{V}, h \in \mathcal{H} \tag{6.37}$$

$$v_{siotvh}^{Char} = v_{iotvh}^{Char} \qquad \forall \quad s \in \mathcal{S}, i \in [1...I^{D}], o \in \mathcal{O}, t \in \mathcal{T}, v \in \mathcal{V}, h \in \mathcal{H} \tag{6.38}$$

$$v_{siotvh}^{Gen} = v_{iotvh}^{Gen} \qquad \forall \quad s \in \mathcal{S}, i \in [1...I^{D}], o \in \mathcal{O}, t \in \mathcal{T}, v \in \mathcal{V}, h \in \mathcal{H} \tag{6.39}$$

$$l_{siotvh} = l_{iotvh} \qquad \forall \quad s \in \mathcal{S}, i \in [1...I^{D}], o \in \mathcal{O}, t \in \mathcal{T}, v \in \mathcal{V}, h \in \mathcal{H} \tag{6.40}$$

Constraints (6.30)-(6.40) are the non-anticipativity constraints in the model. These are necessary to be able to model the stochastic structure of the problem. The structure implies that the values of the different deterministic variables in the problem should be equal in all strategic scenarios, as explained in section 6.2. Therefore each of the non-anticipativity constraints ensure that the value each variable takes in a deterministic period, $i \in [1..I^{D}]$, for a strategic scenario s, stays unchanged for all other strategic scenarios. For the operational scenarios, o, however there are no operational decisions in the first stage, and thus there is no need for non-anticipativity constraints to explain the structure of the operational part of the scenario tree.

Non-negativity constraints

Non-negativity constraints are imposed on all the model variables.

6.6 Mathematical formulation - Model 2

This section presents the mathematical formulation of the stochastic program, adjusted to evaluate risk by including CVaR in the formulation. The section starts by presenting and explaining the changes made to the objective function that was originally introduced in section 6.5.1. Further, new constraints, included in addition to the ones presented in 6.5.2, are introduced and explained in the end of the section.

6.6.1 Objective function

$$
\begin{aligned}
\max \quad & \sum_{s \in \mathcal{S}} \Pi_s^S \big(\sum_{i \in \mathcal{I}} \{ (\sum_{t \in \overline{\mathcal{T}}} (-b_{sit}^{Annuity} \frac{1}{(1+R^E)^{((i-1)|T|)}} \frac{1}{(1+R^D)^{(t-(i-1)|T|)}} \\
& + d_{sit} \tau^C \tfrac{1}{(1+R^E)^t})) + (t_{si}^V \tfrac{1}{(1+R^{CVaR})^{|\overline{T}|}}) + ((g_{si}^T + b_{si}^T - \sum_{j \in \mathcal{J}} n_{sij} \\
- \quad & \sum_{j=1}^{|J|-1} I_{sij} E_{sij} x_{si} - I_{si|J|} E_{si|J|} y_{si} - F_i - C^I w_{si} - C^D \sum_{t \in \mathcal{T}} N_{sit}^D) \frac{1}{(1+R^{CVaR})^{(i-1)|T|}}) \\
+ \quad & (\sum_{o \in \mathcal{O}} \Pi_o^O \sum_{t \in \mathcal{T}} ((\sum_{v \in \mathcal{V}} W_v \sum_{h \in \mathcal{H}} P_{itv} u_{siotvh} + P^C N_{sit}^C \\
- \quad & (\sum_{v \in V} W_v \sum_{h \in H} (C_{it}^O u_{siotvh} + C^L l_{siotvh}))) \frac{1-\tau^C}{(1+R^{CVaR})^{(i-1)|T|+(t-1)}}))\} \big) \\
- \quad & (1+\lambda) \{ \sum_{t \in \overline{\mathcal{T}}} \Delta_t^{NWC} \frac{1}{(1+R^{CVaR})^t} \} + \lambda \{ \eta - \frac{\sum_{s \in S} \Pi_s^S v_s}{\alpha} \}
\end{aligned}
\tag{6.41}
$$

The objective function (6.41) is based on (6.4), however it has been adjusted to account for CVaR by formulating it as a two-stage mean-risk problem, as explained in section 4.5. Because the problem tries to maximize the present value of future cash flows, some changes have also been made to the mean-risk problem formulation presented earlier, to adjust it to this particular problem. These changes are best explained through the use of figure 6.5. In this maximization problem the scenarios giving the highest objective function values are the preferable ones, in contrast to minimization problems. Thus the scenarios with objective function values in the right tail of the normal distribution seen in figure 6.5, are the best scenarios in the problem. Therefore in this problem α should represent the percentile of the distribution containing the worst outcomes, and not the high objective function values, as it does in a minimization prob-

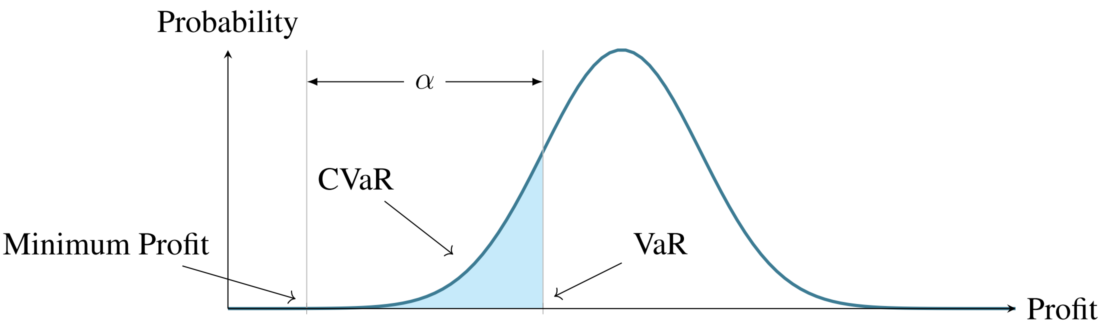


Figure 6.5: Illustration of CVaR and the profit distribution

lem. This is indicated in figure 6.5, where α represents the percentile in the left tail of the distribution. In the figure, η represents the threshold VaR value, of which maximum α percent of the expected values of the strategic scenario cash flows can be below. Due to this change, the objective function of the mean risk problem naturally changes accordingly. The last element of objective function (6.41) represents the stochastic CVaR value. Because the unwanted scenarios have expected values lower than η, in the calculation of CVaR, $\frac{\sum_{s \in S} \Pi_s^S v_s}{\alpha}$ is subtracted from η, to determine the positive CVaR value. Additionally the shift makes it necessary to divide the weighted sum of all v_s by α and not $(1 - \alpha)$, because now α represents the part of the distribution where the worst solutions are found.

6.6.2 Constraints

$$
\begin{aligned}
v_s \geq \quad & \eta - \sum_{i \in \mathcal{I}} \{ (\sum_{t \in \overline{\mathcal{T}}} (-b_{sit}^{Annuity} \frac{1}{(1 + R^E)^{((i-1)|T|)}} \frac{1}{(1 + R^D)^{(t-(i-1)|T|)}} \\
& + d_{sit} \tau^C \tfrac{1}{(1+R^E)^t})) + (t_{si}^V \tfrac{1}{(1+R^{CVaR})^{|\overline{T}|}}) + ((g_{si}^T + b_{si}^T - \sum_{j \in \mathcal{J}} n_{sij} \\
- \quad & \sum_{j=1}^{|J|-1} I_{sij} E_{sij} x_{si} - I_{si|J|} E_{si|J|} y_{si} - F_i - C^I w_{si} - C^D \sum_{t \in \mathcal{T}} N_{sit}^D) \frac{1}{(1 + R^{CVaR})^{(i-1)|T|}}) \\
+ \quad & (\sum_{o \in \mathcal{O}} \Pi_o^O \sum_{t \in \mathcal{T}} ((\sum_{v \in \mathcal{V}} W_v \sum_{h \in \mathcal{H}} P_{itv} u_{siotvh} + P^C N_{sit}^C \\
- \quad & (\sum_{v \in V} W_v \sum_{h \in H} (C_{it}^O u_{siotvh} + C^L l_{siotvh}))) \frac{1 - \tau^C}{(1 + R^{CVaR})^{(i-1)|T|+(t-1)}})) \} \qquad \forall \qquad s \in \mathcal{S}
\end{aligned}
\tag{6.42}
$$

$$v_s \geq 0 \qquad \forall \qquad s \in \mathcal{S} \tag{6.43}$$

$$\eta \in \mathbb{R} \tag{6.44}$$

Constraint (6.42), (6.43) and (6.44) are the only new constraints added to this formulation of the problem, and they represent the constraints particular to the mean-risk problem. However, (6.42) is adjusted to account for the shift to the other end of the distribution as explained. This is the reason why the expected strategic scenario cash flow values are subtracted from η, and not the other way around. This way, the constraint ensures that if the expected strategic scenario has a cash flow value below the value of η, v_s is given the value of their difference. If not, due to the non-negativity constraint (6.43), v_s is set to zero. Thus the percentage of strategic scenarios whose expected cash flow value place them below η in the distribution, can be accounted for based on α and the probability of each scenario. Finally constraint (6.44) categorize η as a free variable.

Chapter 7

Case study

This chapter presents our work related to the specific case we were provided with by SunTap. Section 7.1 presents the case of the mini-grid in Mpunge and useful knowledge acquired on our visit to Uganda. In section 7.2 an assessment of the fundamental decisions in our standardized process on the case of Mpunge is performed, before section 7.3 completes the risk analysis on the case. Section 7.4 provides information about how input has been obtained and decided on, as well as the scenario generation procedures. The chapter is rounded off with a presentation and analyses of the results from the project valuation using the stochastic programming model in section 7.5.

7.1 SunTap - Mini-grid in Mpunge

The problem case SunTap presented to us was initially quite wide and vaguely defined. In our problem description, chapter 3, we presented our interpretation of SunTap's underlying problem based on their own ambitions. Further, based on the opportunities present in the market we defined the next step for SunTap, and thus our case; ”the assessment of whether a mini-grid based on solar technology, placed in an area of Uganda not yet connected to the main grid, is a valuable investment opportunity”. Through conversations with the founder of the company and employees in SunTap Uganda, the location for the mini-grid was decided to be Mpunge, a small village located approximately three hours south of Kampala, as indicated on the map in figure

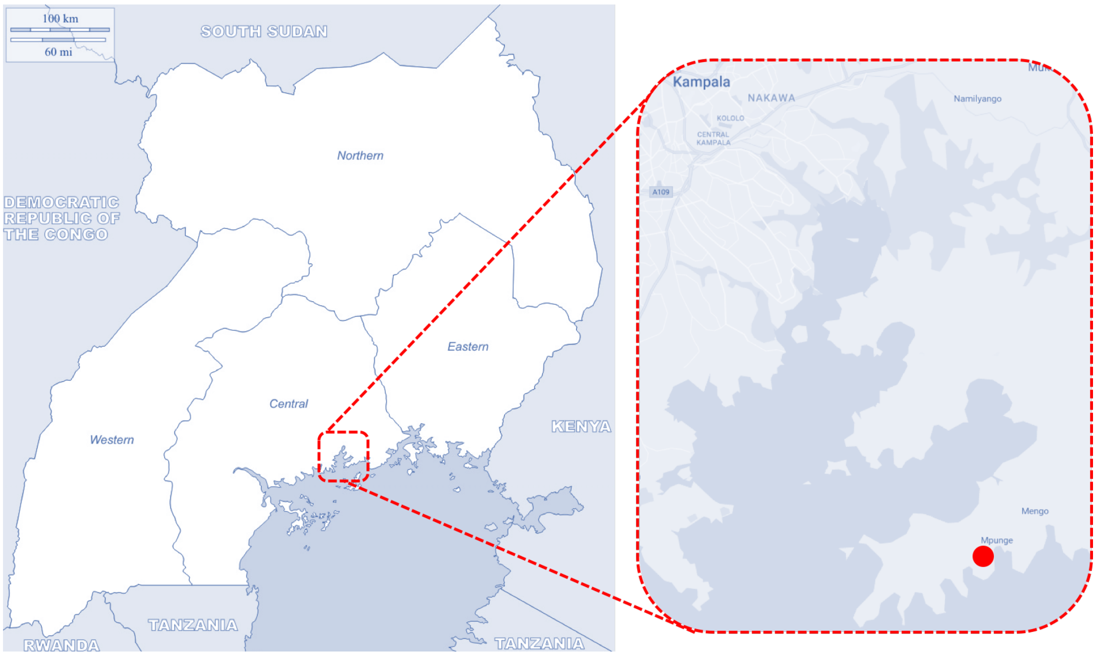


Figure 7.1: Map of Uganda and the area around Kampala and Mpunge (red dot).

7.1. Further, to decide on how to carry out a valuation of this project, literature was reviewed, as presented in chapter 4. This made it clear that improvements are possible for the processes concerning mini-grid investment decisions for private investors in developing countries, and gave us a starting point for the development of the standardized process explained in chapter 5. When the main frames for this process was developed, more information on the specific case was needed in order to follow the process in our study. Therefore we traveled to Uganda and visited SunTap.

7.1.1 Visiting SunTap in Uganda

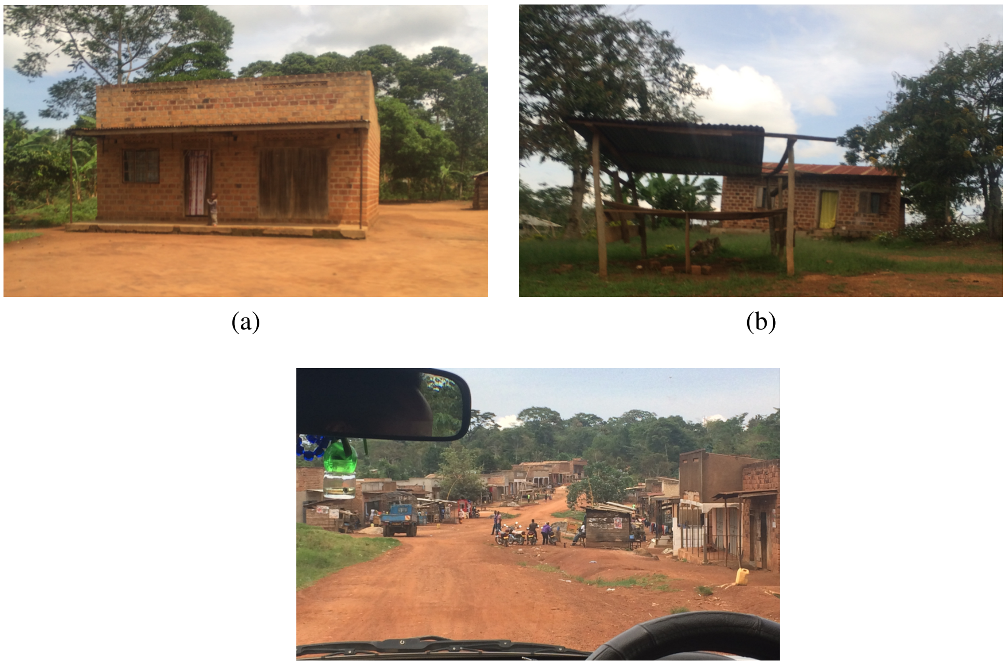
The main purpose of the visit was to get to know SunTap, the Ugandan culture, the area and community of Mpunge, as well as to gather the information needed to assess our case. However the trip turned out to also give us insights into how we could further improve the standardized process. Thus the information for the case study was gathered at the same time as the process was further developed. This was valuable for the development of the standardized process, but for the case study this was not optimal. Limited time and resources however made two trips to Uganda difficult.

At SunTap's office in Kampala we experienced how different the circumstances are for busi-

Figure 7.2: SunTap office building in Uganda.

nesses in developing countries compared to industrial countries. SunTap's small cubicle office in the only large, modern building in the area illustrated this. The building is shown in the picture in figure 7.2, showed . Visiting SunTap at the office made it possible for us to observe how the company works and what their limitations are. On the way to the office we also witnessed how traffic can be a major challenge in the country, both due to the enormous amount of people and cars as well as the lack of infrastructure. By interviewing the technology manager in SunTap Uganda we got more insight into the firm, their suppliers, and their thoughts on the mini-grid market in the country. In addition, we were able to ask them questions in relation to project risks. However, as the employees were busy also with other work the risk analysis procedure was not conducted as planned. One of the cultural differences we experienced was that efficiency of meetings is not in focus to the same extent that we are used to. Thus, not everything we had planned for was possible to conclude, like for instance the risk analysis, because interviews took a lot longer than expected.

SunTap also brought us to Mpunge, the area picked out for the mini-grid project. From the nearest electrified city centre, Mukono, to Mpunge there was approximately 10 kilometres of dirt road, and there were several small households along the road all the way to the small centre of Mpunge, as shown in the picture (a) and (b) in figure 7.3. In this centre there was a collection of small businesses and some households, where some of the businesses were supplied by electricity through a shared diesel generator. Picture (c) in figure 7.3 shows a picture of the centre of Mpunge. In the end of the dirt road, about one kilometre from the centre, the health centre and school for the village was located. Neither of these facilities has access to electricity.



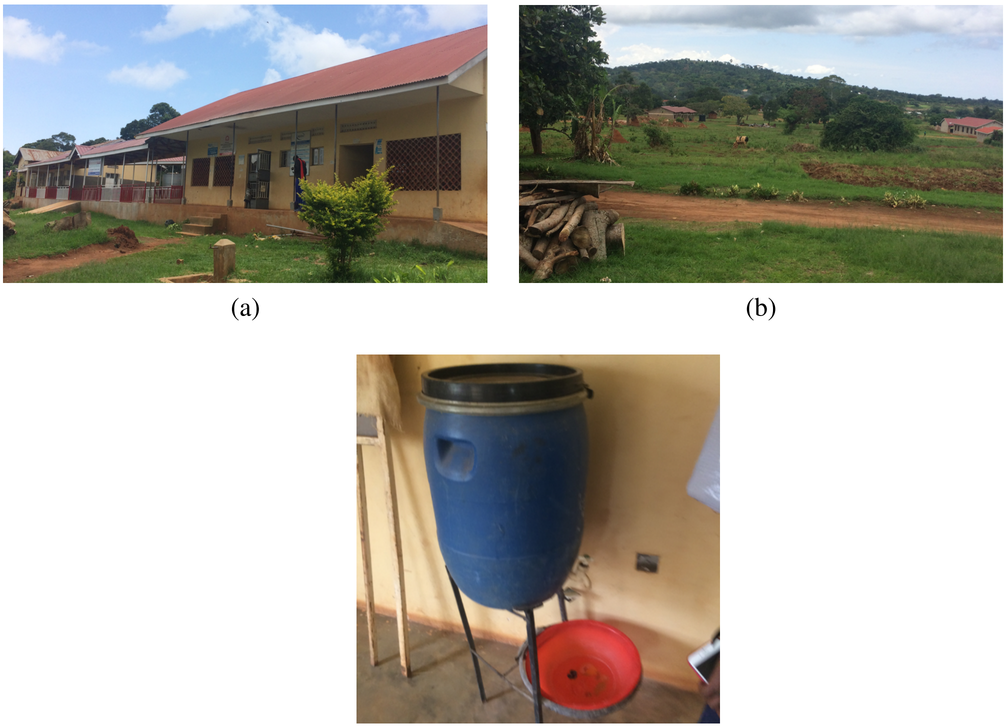
(a) (b)

(c)

Figure 7.3: Households and business along the road to, and in Mpunge.

SunTap had primarily been in contact with the health centre and therefore meetings with people involved in the health centre was set up for us. In Mukono we met with the doctor in charge of the entire health service sector in the district. We were able to ask him questions about Mpunge and the development plans for the health centre, and he told us about the importance of projects like ours for the community. At the health centre a meeting with the community leader as well as the main staff was arranged. This way we were able to listen to their perception on how a mini-grid would affect their lives. We were also given a tour of the centre, and the area around it. Picture (a) in figure 7.4 shows the health centre from the outside, while (b) shows the area in front of the facility, including the village school in the background. In picture (c) the poor conditions of the health centre is illustrated by a barrel, the only source of water at the facility. Thus through the visit we were able to observe and collect information regarding several factors concerning both the area and the community of where the mini-grid project is located.

To gather information about mini-grid projects counducted in Uganda in general, we had a meting with Mr. Mugisha, introduced earlier. We were able to ask him questions regarding all processes important in the front-end phase of mini-grid projects, financing and what risks he saw as the most important in these types of projects. With his personal experience as being



(a) (b)

(c)

Figure 7.4: Health centre in Mpunge, the area around it and a water barrel used at the facility.

the head of a mini-grid project on the Ugandan island of Kalangala in cooperation with an Italian investor, his insights were useful for the further development of the standardized process. Another meeting that was very helpful for our understanding of the funding opportunities in Uganda, especially with regards to loans, was with Mr. Elisha Dux, employed at Uganda Energy Credit Capitalisation Company (UECCC). Because UECCC provides help and financial support to mini-grid projects he was also able to give us detailed information about their future plans that could be relevant for our project.

Through the following sections we will explain how we have utilized the standardized process for the mini-grid project in Mpunge. As emphasized above the process was further developed while we were gathering information, and additionally some processes were not carried out due to both limited time with stakeholders as well as miscommunication. Therefore we have used the information we have available, our insights and experience from other projects as the basis for the different processes. For other projects we would however recommend to take into account our experiences, by planning meetings based on cultural differences, and communicating clearly in advance what is expected from the meetings. This will both save time and make the utilization of the standardized process easier.

7.2 Fundamental decisions

7.2.1 Location

Because the location for the mini-grid had to be decided upon before the trip, the employees in SunTap Uganda had to do most of the work on locating a suitable area. This was done at an early stage of our process, and thus not all recommendations in the standardized process was emphasized to them. Also, due to miscommunication, they did not know that the project was based on a mini-grid, just that it was a solar electrification project. However, with their experience on solar powered projects, they focused on an area without electricity from the utility main grid, with anchor loads and with high probability for population increase.

In Mpunge only a few households have small solar home systems, while most people are living without access to electricity. The health centre, school and businesses could be anchor loads, and in addition farming, which requires water pumping, is widespread. In communication with the managers of the health centre it also became clear to us that if the facility were to be connected to a grid, it would not take long before it would be upgraded to a health centre of a higher category. Today it is a health centre of type three, which implies that they do deliveries, vaccinations and simple health checks. When it becomes a category four facility however, more electricity demanding processes like surgeries will be possible, as well as the capacity and thus the general electricity need will increase. Today many people growing up in the village are forced to move closer to the bigger cities to look for work, but it is a common understanding among the people we talked to that once electricity is available more people will stay in the village and start businesses there. Fishing, which is big in this area is a good example. With electricity the fishermen can store and sell their products from the village, and thereby settle in the area. The only downside to the location is that the population density is not very high today. We believe however, that due to the expected development for both the health centre and the general population, the project can still be attractive.

The main argument for a solar powered mini-grid in Mpunge is that it is easily scalable. Due to the expected growth in demand, an easy process for increasing capacity is important. In addition Uganda is located on the equator and has conditions perfect for solar power utilization, and the source is renewable compared to other easily scalable sources, for instance diesel. Thus a solar powered mini-grid has the most benefits in this particular area.

7.2.2 Local government and authorities

While we were in Uganda the meeting we had planned with the ERA was cancelled due to changes in their schedule. Interviewing Mr. Mugisha was however very helpful to obtain necessary information on the processes that must be started when the decision to go through with the project has been made. On the other hand, we did not get to discuss with them the exact plans on the extensions of the utility main-grid, and we never got any reply to the emails we sent them. In conversation with SunTap, their opinion on the matter was that the government would not prioritize to extend the grid to an area already covered by a mini-grid. Additionally, the doctor in charge of the health centres in Mukono said he had not heard of any plans for extensions to Mpunge. Mpunge is also a peninsula, which implies that it is a dead end for an extension. This can also be observed on the map in figure 7.1. Thus it might be reasonable to believe that an extension to the area is not planned within the near future. However, in case the extension is planned further into the future, we will assume that an agreement will be possible to make with the authorities, either on the postponement of the extension or on the technical and financial implications an extension would have for the mini-grid.

7.2.3 Local community

Our main contact with the community was the was the meeting with the health centre employees and the community leaders at the health centre. This meeting gave us the impression that a mini-grid project was very important for the community, and for the health centre in particular. Electricity is considered important to save lives, thus their gratitude just for our consideration of the community was enormous. The doctor in Mukono also told us that there is a community group in Mpunge consisting of people who take interest in the development of the village, and which has a big influence on the rest of the community. It was in both the doctor's and the community leader's opinion that this group would be willing to cooperate with us to make this project successful. Therefore it is also assumed that people in the community can be interested in taking part in the operation of the mini-grid. A hybrid business model where SunTap owns the mini-grid while while people in the community operate it, is thus assumed to be possible. Acquiring land for the mini-grid is also not seen as very challenging. For instance the area around the health centre, about ten acres of land, is owned by the facility and thus the government. Today only some farming is done on the property, and thus the process of buying the land would for instance not involve relocating households. If agreements are possible to make with the authorities on grid extension, buying the land could be a part of this agreement. However, part of the land is also needed for the growth of the health centre and future extensions of the mini-grid may not be possible without restrictions.

7.3 Risk analysis

The risk analysis is based on the work conducted in the report by Bakke and Welhaven (2016), and is highly influenced by investigation of the risks identified by Manetsgruber et al. (2015). In addition some input from SunTap and Mr. Mugisha has been helpful, together with a discussion of these risks related to our specific project. Because SunTap does not have a portfolio of projects in the market for mini-grids, this risk analysis only considers the risk identification, assessment and responses for the project. The assessment and responses are however, for simplicity, presented together.

7.3.1 Risk identification

The main risks in mini-grid projects are according to SunTap related to the licensing- and permit processes. Mr. Mugisha also pointed out foreign exchange rates, licensing problems and vandalism as risks he had experienced first hand in mini-grid projects. To identify several risks that will be present in the mini-grid project in Mpunge, we have elaborated on the risks listed in section 5.4.1, which are based on Manetsgruber et al. (2015).

Manetsgruber et al. (2015) define political risk as *the risk that an investment's returns could suffer as a result of political changes or instability in a country* (Manetsgruber et al., 2015, pp. 10). Even though Uganda has moved to be relative stable compared to other countries in the region (BBC, 2017) the political situation is still unstable. This means the mini-grid in Mpunge could be affected by political instability. In addition, the previously mentioned extension of the utility main grid also pose legal risks in the project, although this have already been assessed as a part of the fundamental decisions in the project.

Customers not being able to pay electricity bills is another risk that is present in this project. This is because the community in Mpunge is in the low-income range. Further, technology risk concerning occasional failures in the mini-grid system, is present in most technology projects, and there is no reason for its absence in this particular project. Cost-overruns, or other challenges during the construction phase is what Manetsgruber et al. (2015) consider as reasons for the construction not being completed on time. Thus the risk of construction incompletion is considered as a risk that is present for the mini-grid project in Mpunge, based on the occurrence of random incidents and due to the uncertainty related to the time consuming licensing- and permit processes, also presented in section 2.2.3.

Unpredictable electricity demand is a risk that is present because accurate predictions of the electricity demand can be challenging. With Mpunge being an unelectrified area today, there is a great uncertainty about demand, and the risk is present. Predictions that are too low can negatively affect the project value, while if they are too high it can cause shortages and system damage. However, in Mpunge risk concerning electricity demand can also affect the project positively. With time the demand can increase rapidly because of an increased standard of living in the area.

The community's opinion on the project, or parts of the project, can be negative. This causes a risk of social acceptance, as assessed as a part of the project fundamental questions. Further, environmental risk is related to environmental influence. The risk is present in this solar power based project because weather events are hard to predict, and this can be of great importance for the the electricity production. The risk can however be both positive and negative, dependent on whether the weather is highly favourable or unfavourable for longer periods of time compared to what is expected. Force majeure risk, the risk of environmental disasters such as storms and forest fires, are risks that can occur almost everywhere, and can have a devastating affect on the mini-grid. Thus we identify this risk also for the mini-grid in Mpunge.

Manetsgruber et al. (2015) define foreign exchange rate risk as the risk in project-related investments made using foreign currencies, if the cash flows in the project are in local currency. Assets for the mini-grid in Mpunge will mainly be bought abroad or traded on international markets. The payments for electricity on the other hand, will be made in local currency (Ugandan Shilling, UGX). Therefore this risk is present in this particular project as well. The currency fluctuations could move in both favourable and unfavourable directions, and therefore this risk can be observed as both positive and negative for the project. The risk of theft and vandalism is present because of the high value of project assets, combined with Uganda being a country where poverty is widespread.

Operational risks are mainly caused by imperfections such as miscommunication between business and customer, lack of skilled technical or managerial personnel, conflicts of interests, fraud, temporary power outages, etc. (Manetsgruber et al., 2015, pp. 29). Because such problems could affect any project, especially in developing countries, these negative risks are also present for the mini-grid in Mpunge. On the other hand, positive operational risk is also present, for instance through the possible advancement in technology. Another identified risk having positive effects on the project is the rapidly falling costs of technical equipment, such as PV-modules, batteries and inverters, as emphasized by Mayer et al. (2015). Another identified risk is the risk of not receiving the amount of grant funding that was first predicted. The last identified risk is the risk that the land needed to build the PV mini-grid can not be acquired.

7.3.2 Risk assessment and responses

Because of the subjectivity in our risk assessment, the use of a numbered scale to assess risks will in our opinion give a wrong picture of the accuracy of the risks. We have therefore decided to use labels to assess risks. The probability of a risk is given on the five-point range from *very unlikely* to *very likely*, and the impact of a risk is given on the similar range from *very small impact* to *very large impact*, as shown in figure 7.5.

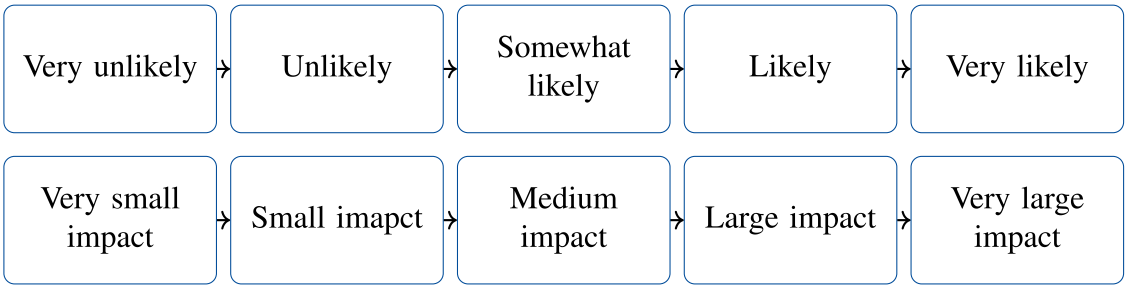


Figure 7.5: Labels used for the risk assessment.

Figure 7.6 illustrates how all the risks for the project have been assessed in the risk severity matrix. Risks that are assessed with the same likelihood and impact are placed close to each other, according to our opinion of their magnitude. In the following an explanation of why each of the risks have been placed this way, and how we have chosen to respond to them, is given.

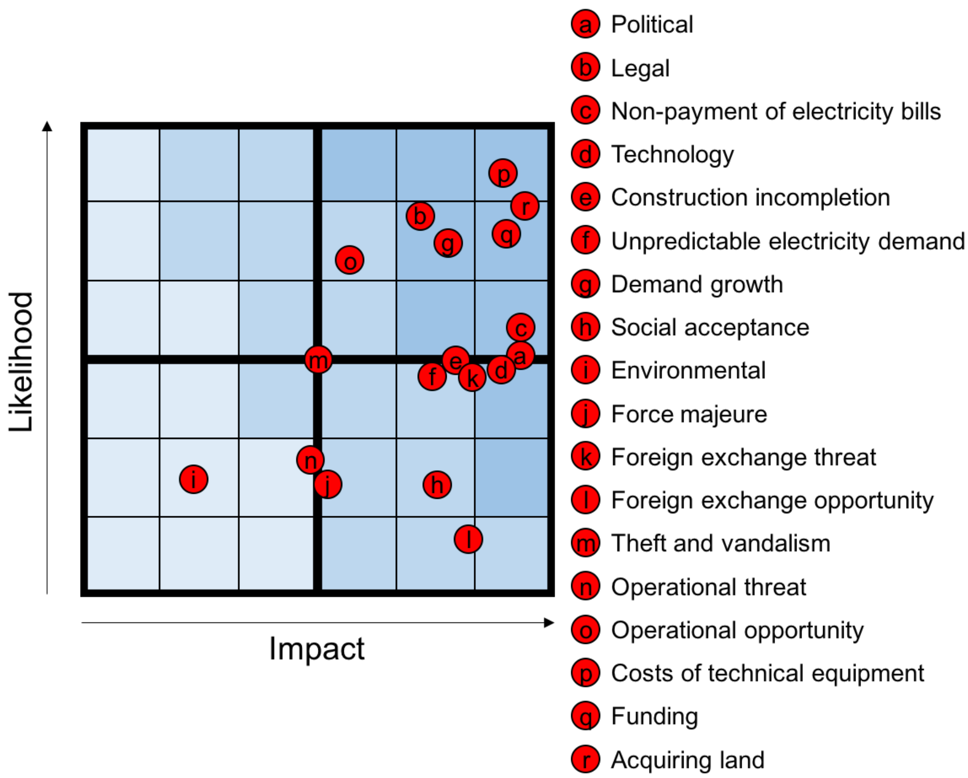


Figure 7.6: Risk severity matrix for the risks assessed.

Political risk

Because Uganda has become a more stable country we assess the probability of political instability affecting the project merely as somewhat likely, however the impact would be severe if it was realized. An effect of the risk can, for instance, be eruption of war or a sudden transfer of ownership of private properties to the government. The matrix suggests to either avoid or transfer this risk. But transferring it, for instance by finding insurance companies who are willing to take this risk, might be difficult. Instead, some of the risk can be avoided by negotiating contracts with local authorities on the investors rights in the occurrence of such events. This will not completely eliminate the risk, but it can reduce the probability of it becoming a problem.

Legal risk

The extension of the utility main grid has already been given a response in the earlier phases of the standardized process. However, to place it in the risk severity matrix it has been assessed as a risk which is likely to occur and comes with large impact. Thus the responses as given in section 7.2.2 are important to be able to avoid the risk.

Non-payment of electricity bills

Although the income in most households of Mpunge is low today, electricity provide opportunities for higher income, and thus more certainty in the ability to pay among customers. However, there are several government-owned facilities in the village, and according to Mr. Mugisha the government is not always a secure source of payment. Therefore the likelihood of this risk is seen as somewhat likely, and the impact as very large. Because the matrix suggests to avoid this risk, we have decided that pre-payments for electricity should be used for the project. However, an implication of this strategy is that some customers might find it difficult to pre-pay, and the demand may therefore be reduced. On the other hand the other alternative is to sell electricity for free to these customers, which we consider to be an even worse solution.

Technology risk

We believe that this risk is relatively the same for all PV mini-grid projects. Therefore we have chosen to assess the risk similarly to the result of the survey computed by Manetsgruber et al. (2015). Hence the risk is assessed to be somewhat likely, but with very high impact. The matrix' response to this risk is to transfer it. We consider it possible to find insurance companies that can diversify this risk, at a predictable cost for us. Also, warranties on technical components is a response already embedded in the system. The response for this risk in the mini-grid in Mpunge is therefore to examine which suppliers that can provide the best warranties on assets, and further transfer the remaining risks to insurance companies. This will lead to an insurance cost each year that must be accounted for in the mathematical model.

Construction completion risk

The unpredictability of the long-lasting licensing- and permit processes has been emphasized earlier, and could have large impacts on the project. However, because the interest in these types of projects is increasing, the processes may be forced to improve with time and the effect of learning may improve the efficiency of the processes. In addition cost-overruns can be the product of other unforeseen events in the project, which generally are more likely in developing countries like Uganda. Based on this the risk is assessed as somewhat likely and with large impact. As seen from the matrix, one possible response is to transfer this risk. For instance insurances that will cover unforeseen events in the construction phase could be acquired. Further, good project management and planning can significantly reduce the probability of cost-overruns or other risks related to the construction phase, and is a risk mitigation response. Our response is therefore to mitigate this risk by good project management routines, and investigate the opportunity for insurances that will cover unforeseen events in the construction phase.

Risk of unpredictable electricity demand

Because there is no data to quantify the electricity use in Mpunge today and the growth is unpredictable, the chances of overestimating are assumed to be similar to the chances of underestimating the demand in the area. However, as emphasized in the risk identification the consequences can be severe. Therefore the risk is assessed to be somewhat likely and have large impact on the project. The matrix' response to the risk is to transfer it, but in practice it could be difficult to find other parties who are willing to take this risk. Another possibility is to mitigate the risk by doing thorough research on the area and utilizing an appropriate tool to represent the demand in the best possible way. This is what we have chosen to do, by utilizing LoadProGen in generating several scenarios, both short- and long-term, to represent uncertainty in demand in the stochastic program.

Risk of demand growth

The growth in demand, independent on its unpredictability, can increase the project value. In addition, ECA (2014) emphasize how electricity access within a few years highly increase demand in similar projects. The probability of this risk is assumed to be relatively high for Mpunge and with a corresponding large impact. The risk severity matrix therefore suggests to exploit this positive risk. We have chosen to exploit it by incorporating the possibilities for capacity expansions every fifth year throughout the project. Another response that could enhance the opportunity in demand growth is to put an effort into facilitating local business start-ups in Mpunge, at no cost.

Social acceptance risk

Without proper responses to the risk of not being accepted by the community of Mpunge, the impact can be large. This is because, as previously mentioned, if the inhabitants do not accept the project some might resist supporting it, thus demand will be low and the overall growth in the area will suffer. In addition, it increases the probability of vandalism and theft. However, seeing that SunTap is a Ugandan company, their brand reputation is good and electricity is seen as desirable in the community, the risk is initially assumed to be unlikely. The responses we have chosen to handle this risk have also been assessed earlier in the standardized process. These are given in section 7.2.3, and has more focus on mitigation than transferring, which is what is suggested by the matrix.

Environmental risk

The survey from Manetsgruber et al. (2015) define these risks as unlikely and with small impact. We believe this risk can be assessed equally for most mini-grid projects, and thus we have chosen to rely on this assessment for both outcomes of the risk. Hence, the risk is assessed as unlikely and with small impact. The matrix' response is to accept both the negative- and positive part of this risk. However, to be able to capture some of the uncertainty in such short-term weather changes, we have decided to generate short-term scenarios and use them as input in the stochastic program.

Force majeure risks

Because this risk can be observed anywhere, and there is no apparent reason why it should be of larger impact or probability in Mpunge, we have chosen to assess it similar to Manetsgruber et al. (2015). Thus the risk is seen as unlikely and with medium impact. The matrix suggests to transfer this risk. Therefore, our response is to find an insurance company who is willing to take this risk. For an insurance company, insuring businesses in larger regions, such risks are diversifiable and this should thereby not be a problem. Because insurance comes at a cost, this has been incorporated into the stochastic program. In addition, by investing in fire-security, the impact of the risk can be further reduced, and this is incorporated as a cost in the stochastic program. This can also reduce the impact of the technology risk if system failure leads to fire.

Foreign exchange risk

This risk was pointed out by Mr. Mugisha as the largest risk for mini-grid projects in Uganda. In addition, because of the re-investments of assets and scaleability proposed in this project, the impact of this risk is higher than for projects where the whole investment is made at project start. For the negative side of the risk, it is assessed as somewhat likely, and with high impact. The impact of a positive change in foreign exchange rate is also assessed as high. However, because of the instability in Uganda relative to that of the markets in which we are buying the assets, we assess the risk related to a positive change in foreign exchange rates to be very unlikely. The matrix' response to the negative risk is to transfer it. However, finding parties willing to take this risk could be difficult. Hedging might be an option to avoid the risk, but this demands a market place for forward trading of the currency and good estimates on the future investment costs. For the positive risk it is suggested by the matrix that this should be shared, but this is not applicable in this case. Therefore our response is to accept both risks, and incorporate uncertainty in foreign exchange rates in the stochastic program as a long-term uncertainty using scenarios.

Theft and vandalism

Based on our perception of the community in Mpunge, theft and vandalism do not pose any threat in particular for the project. This is mainly because of their appreciation of the project, which will provide them with electricity being placed in Mpunge. However, people living outside the community still pose a considerable threat. Based on this, we have assessed the risk to be somewhat likely and of medium impact. Thus no response in particular is suggested by the risk severity matrix. We have chosen to mitigate the risk by investing in security systems such as fences, alarms and surveillance systems for the mini-grid. We also assume that social acceptance will further mitigate the risk, due to community protection. This is based on the interview we had with Mr. Mugisha, where he told us about how he had witnessed an entire community stop a fire to protect their only source of electricity. Social acceptance will also be important in connection to force majeure risk.

Operational risk

We believe that negative operational risk has approximately the same impact and probability in most renewable energy mini-grid projects in developing countries. Therefore we have assessed the risk to be unlikely and with a medium impact. Based on its position in the risk severity matrix it is suggested that the risk is accepted. Therefore part of the risk is accepted, but we also choose to mitigate the risk of miscommunication and lack of skilled personnel further, by introducing well organized training programs. The positive operational risk is set to have medium impact on the project, and is likely to occur. This is because it is seen as likely that equipment improves with time, however the improvements are not necessarily of big impact. The natural response from the matrix is thus to exploit the opportunity the risk poses. We have chosen to do this in the same way as for demand growth, by incorporating the possibilities for capacity expansions, where equipment can be updated every fifth year. However, in the stochastic program the additional cost of buying the most recent technical solutions is not incorporated.

Cost of technical equipment

According to Mayer et al. (2015), costs of technical components of PV power plants are expected to fall substantially within the next decades, but there is of course an uncertainty to how much they will fall. Because the investment cost is the main cost of mini-grid projects, the impact of falling investment costs will have a huge impact on the project. Hence, we assess this opportunity as very likely and with a very high impact. It can be seen from the risk severity matrix that this risk should be exploited. Our response is therefore to model the long-term uncertainty in the investment costs as scenarios in the stochastic program, together with the opportunity to expand the mini-grid every fifth year. In this way the project valuation can incorporate the uncertainty within the opportunity.

Funding risk

The risk of not receiving the amount of grant funding that has been assumed for the entire project, has very high impact on solar mini-grid projects in developing countries. This is because of the high LCoE in such projects, and the low ability to pay among customers. Further, due to the increased interest in the market for mini-grid projects based on renewables, the competition for funding increases. Therefore we have assessed this risk as likely, and with very high impact. The obvious response, based on the risk severity matrix, is thus to avoid this risk. Therefore we have chosen to respond by trying to enter into an agreement with the funding organizations, ensuring a set percentage funding for all future investments.

Acquiring land

The risk of being unable to acquire the land needed for the mini-grid would be devastating on the project, and is therefore given a very high impact. Because it is often uncertainty concerning ownership of land areas, this risk is seen as likely. Our response to this risk has also been assessed earlier in the standardized process, in section 7.2.3. The response suggested there is to avoid the risk by making agreements with authorities. Avoidance is also the suggested response by the risk severity matrix.

Table 7.1 summarizes the responses to the risks present in the project as presented above, and provides a short detail into how they are carried out.

Table 7.1: Risk response strategies

Risk	**Response**	**Detail**
Political risk	Avoid	Negotiating contracts with local authorities
Legal risk	Avoid	Avoided early in the standardized process
Non payment of electricity bills	Avoid	Utilizing pre-payments
Technology risk	Avoid, transfer	Warranties and insurance
Construction completion risk	Mitigate, transfer	Project management routines and insurance
Unpredictable electricity demand	Accept	Scenarios in the stochastic model
Demand growth	Exploit	Capacity expansion in the stochastic model
Social acceptance risk	Mitigate	Mitigated earlier in the standardized process
Environmental risk	Accept	Scenarios in the stochastic model
Force majeure risk	Transfer mitigate	Insurance and fire-security
Foreign exchange risk	Accept	Scenarios in the stochastic model
Theft and vandalism	Mitigate	Security systems
Operational risk	Mitigate, exploit	Training programs and capacity expansion in the stochastic model
Cost of technical equipment	Exploit, accept	Capacity expansion and scenarios in the stochastic model
Funding risk	Avoid	Agreements with funding organizations
Acquiring land	Avoid	Avoided early in the standardized process

7.4 Data and scenario generation

This section presents how the data used as input in the stochastic program has been gathered and quantified, as well as how the scenario generation has been carried out. Because this is important information for SunTap when deciding on whether the project should be implemented, a relatively detailed explanation of these processes is given. In addition, gathering data for the different parameters describing the project has been one of the more challenging parts of the case study. First of all, because SunTap has not conducted similar projects before, no project data was available to us, and no contact information of suppliers used to handling such projects was at our disposal. Due to limited time and resources we have not focused on deciding what suppliers to use for the project, but we have rather done research to be able to approximate different costs. The same is true for loan-, grants- and insurance providers, as well as other parameter values that are based on research and subjective opinions. In the following a short explanation of how the data- and other model input values are set is provided, before the scenario generation procedures used is explained.

Data collection

As described in section 5.5, the time-horizons of the different project parts must be decided to be able to solve the stochastic programming problem explained in chapter 6. In this project the lifetime has been set equal to the solar panel life-expectancy of 25 years, which is the life expectancy that most suppliers give warranties for (Maehlum, 2014). At this point, the investor will have to decide on whether to continue or end the project. Based on the assumption of high demand growth in Mpunge the number of years between each investment is set to five years. Thus the project has five strategic periods in its lifetime, of which the initial two are assumed to be deterministic. One operational year in the project is represented by one season, consisting of 72 hours. One season is chosen because Mpunge, being close to the equator, have minimal seasonal variations. On the other hand, representing each season by more than 72 hours was restricted based on computational time. By choosing 72 hours as opposed to 24 hours however, the differences in irradiation between days can be captured in the model and we avoid the effect of resetting batteries every 24$^{\text{th}}$ hour throughout a year.

We have decided to utilize real terms in our model, hence all prices and costs are given in 2017 values. The lending rate and RRE is given in real terms. Thus, an assumption of yearly regulation of electricity prices and costs according to the inflation rate is present. However, for easier comparison with other projects, the RRE and lending rate is presented in nominal terms in this section. A calculation of real terms utilizing the method in appendix A, section A.1 has been performed to put the correct values into the model.

The project investment costs have been decided based on different articles and adjusted to our specific case. Panel, battery and inverter costs are based on the costs presented in Mandelli et al. (2016) and ECA (2014). The chosen panel cost, not including the panel inverter cost as in ECA (2014), is somewhat reduced compared to the cost presented in the articles to account for yearly price reductions since the article publication year. The inverter cost on the other hand, is assumed to be the same as indicated in Mandelli et al. (2016). The battery cost is based on ECA (2014) and adjusted for fall in battery prices from the article publication year. The battery costs presented by Mandelli et al. (2016) are somewhat lower, but it is not indicated whether protections and cabling is included in the cost, as it is in ECA (2014). As indicated in the risk analysis, some risk response costs will be present to account for fire-security, fences, alarms and surveillance. These costs are estimated to be low because the probability of events requiring such equipment is not very high, which indicates that less equipment is needed. Other investment costs are assumed to be the costs related to BOS. Mayer et al. (2015) have quantified these costs, but for grids with installed capacities of more than one Megawatt peak (MWp) [1]. The article also accounts for costs not present in our mini-grid project, and thus the BOS cost set has been reduced to account for this difference, but not by a big amount because of the scale advantages not applicable in our project. Further the cost per meter distribution line set is based on numbers from ECA (2014) and includes costs of both the distribution line and poles. The project fixed cost of investments is also based on costs presented in ECA (2014). The cost set is assumed to include costs for project management, technical design, acquiring land, transport and training at project startup. For later investments the cost merely represent transport-, land acquiring- and technical design costs. A summary of the costs is presented in table 7.2. Note that the numbers in tables are provided in the same format as in the sources, and that we have

[1] The peak power of a PV-module. This value is the output power on a solar-module under standard test conditions (25°C, 1000 W/m^2 irradiance.)

calculated values per unit installed to be put into the model.

Table 7.2: Investment costs.

Assets	**Costs**	
Panel	900	EUR/kWp
Battery	200	EUR/kWh
Inverter	500	EUR/kWp
Risk response	2	EUR/kWp
BOS-components	300	EUR/kWp
Distribution line	30	EUR/meter
Fixed cost period 1	120,000	EUR
Fixed cost period 2 - 5	60,000	EUR

The cost of all the mentioned assets, except of risk response related assets and distribution lines, are also set to decrease throughout the project. Thus, each of the assets investment cost is decreased by a percentage from one strategic period to the next one. These percentages are based on the prognoses presented by Mayer et al. (2015), and we have assumed that the development of these costs is independent of grid size. Table 7.3 shows these cost developments for each of the assets. We have also set the life expectancy for each asset, as for panels explained above. The type of battery we have chosen is based on the battery both Mandelli et al. (2016) and ECA (2014) refer their costs to; lead-acid (sealed) battery. These batteries have an average life expectancy of six years (ECA, 2014). In order not to overestimate and because, as explained in section 6.3, the expected lifetime of each asset must correspond with the length of the strategic periods, the life expectancy of each battery is set to five years. According to ECA (2014) the average life expectancy of inverters used in mini-grids is 12 years, and for the same reason as for batteries the life expectancy is set to 10 years. However. for assets related to risk responses, BOS and the distribution line, the life expectancy is assumed to be equal to the project lifetime of 25 years.

Table 7.3: Yearly reduction in costs in the three scenarios.

Asset	**Scenario 1**	**Scenario 2**	**Scenario3**
Panel	1.6%	2.1%	2.6%
Battery	7.0%	5.0%	3.0%
Inverter	3.0%	3.4%	3.8%
Risk response	0.0%	0.0%	0.0%
BOS-components	1.4%	2.0%	2.9%
Distribution line	0.0%	0.0%	0.0%
Probability	**20%**	**50%**	**30%**

The currency exchange rates for each asset is based on the spot-rate at the time when the stochastic programming model was computed. Because SunTap today use suppliers in China to buy modules, inverters and BOS components, and these are sold in United States dollar (USD), a UGX/USD currency exchange rate is applied to these costs. As batteries are assumed to be bought in Euro (EUR), a UGX/EUR currency exchange rate is applied to this cost. For the costs of risk responses, we assume that such equipment is bought locally in UGX, and hence a currency exchange rate of 1 is applied. Further the development of the currency exchange rates throughout the project is based on the following relationship presented in Brealey et al. (2001); *if you have to make a long-term forecast of the exchange rate, it is very difficult to do much better than to assume that it will offset the effect of any differences in the inflation rates* (Brealey et al., 2001, pp. 605). However, this applies to the nominal inflation rate. Hence, for real terms, there should be no changes in currency exchange rate as long as the electricity prices in Uganda are adjusted in correspondence with the local inflation rate, and the prices of assets are in real terms. However, we have checked the average currency exchange rate for UGX/USD for the last 10 years, and found that on average, the currency exchange rate has been 2.5% higher than the inflation rate. Our opinion is that this difference is because of the political instability in Uganda. Hence, a 2% increase in currency exchange rate per year for the first years of the project is chosen for both the UGX/USD and UGX/EUR exchange rates. Further it is assumed that the rates will increase by less than 2% in the last project periods. Table 7.4 shows the spot rates, while table 7.5 shows the yearly increase in the exchange rates, in the tree scenarios.

Table 7.4: Currency exchange rates.

Currency	Spot rate
UGX/EURO	4006.91
UGX/USD	3626.82

Table 7.5: Yearly increase in exchange rates in three scenarios.

Scenario	Period 1	Period 2	Period 3	Period 4	Period 5	Probability
Scenario 1	2.5%	2.5%	2.5%	2.5%	2.5%	**20%**
Scenario 2	2.5%	2.5%	2.0%	1.5%	1.0%	**40%**
Scenario 3	2.5%	2.5%	1.5%	0.5%	0.0%	**40%**

In mini-grids based on solar power, the cost of operation is usually not high. Based on experience with such projects, Mr. Mugisha explained in the interview that these costs in most cases are merely ”people costs”. The O&M costs of this project is thus set to include salaries for security, technicians and cleaners. The costs are approximated based on the current salaries in Uganda, and is presented as a cost per kWh solar powered electricity sold. The O&M costs in the different strategic periods are reduced with time, because the extra people capacity needed is limited, but the electricity sold increase rapidly. Further, electricity price per unit sold is set based on the price used in the Kalangala mini-grid mentioned previously, which is based solely on electricity from solar panels connected to batteries. Because Kalangala is also a low income area, we assume that the price used there will also be in accordance with the willingness to pay in Mpunge. Thus, an assumption is made that this price will be approved by the ERA. However, as emphasized in section 2.2, it is likely that the REFiT will be provided to off-grid systems in the years to come which will make it possible to provide lower electricity prices to customers. For the project connection fee this is set equal to the actual fee used in similar projects based in Kenya, Uganda’s neighbouring country, as presented in ECA (2014). Because contacting insurance companies was not prioritized, project insurance cost has been set based on our experience and is seen in connection with the size of other costs. NWC of the project is assumed to be unnecessary, simply because of the revenue and costs are assumed to appear simultaneously, and that delays in payments from customers are avoided by utilizing pre-payments. The product sold to the customer is also a service, and does not require an inventory, and payments to suppliers are therefore minimal. In table 7.6, the operational values for period 1 is presented.

Table 7.6: Operational parameters for the initial period

Operational parameter	**Value in period 1**
Electricity price	0.28 USD/kWp
O&M costs	0.03 USD/kWp
Connection fee	500 USD/customer
Insurance cost	5 USD/kWp

The project battery capacity is based on an assumption that batteries are found in all sizes and that the cost per kWh is the same, independent of size. With this assumption the capacity per battery is set at one kWh per battery. According to tests conducted by ITP Renewables (2016), lead-acid batteries normally have round-trip efficiencies between 75% and 85%. We have therefore assumed that the product of the charge and discharge efficiencies of the system can be set to equal a round-trip efficiency of 81%. The distribution line losses are estimated at 10%, as indicated by ECA (2014). An illustration of these system losses in the grid is given in figure 7.7. In addition, based on Mandelli et al. (2016), the power to energy factor[2] of the lead-acid batteries are set to be 50%. The initial battery capacity at the start of a new season is set at 1% of the total battery capacity. The cost of solar powered electricity not fulfilling demand, the VOLL, is assumed to be analogous with the difference between the LCoE of diesel generators in solar-diesel mini-grids, which according to Al-Hammad et al. (2015) is between 0.34 EUR/kWh and 0.48 EUR/kWh, and the electricity price set.

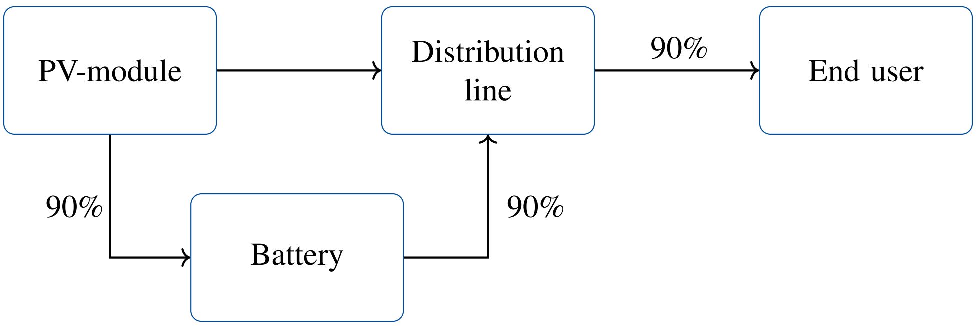


Figure 7.7: System losses in batteries and distribution line.

Based on the findings in ECA (2014), it is evident that privately based solar mini-grids are dependent on support in terms of grants or subsidies. The projects investigated in Kenya was

[2]The factor determening how quick a battery can charge or discharge. Assumed here to be for one hour intervals

financed by grants amounting to between 84% and 94% of capital costs (ECA, 2014). However, the possibility of acquiring grants is very dependent on the competition in the market. These high grants are necessary to keep tariffs at a low rate, as customers in rural areas like Mpunge have an upper limit for their willingness to pay. Franz et al. (2014) states that the willingness to pay in Sub-Saharan Africa is estimated at 0.38 EUR/kWh, but that this is very dependent on the quality of the service and availability of other alternatives. As emphasized in the risk analysis however, the inhabitants of Mpunge have very limited resources, making it even more important to keep the tariffs at a reasonable amount such that demand does not fall considerably. Based on these insights the amount of grants assumed possible to acquire in the project is set at 60%, due to assumed increased competition for grants and in fear of overestimation. The project part financed by loan is correspondingly set to 20% and the same goes for the equity provided by the private investor. As for the loan payments an annuity structure is chosen.

The different loans possible to acquire in Uganda was explained to us through the interview with Mr. Dux. The lending rates for mini-grid projects in the country are high and the payback time is short due to the low knowledge of such projects, and the high risk of default due to the country's circumstances. For instance Mr. Dux stated that no loans are offered for periods longer than 5 years, and that corporate loans have nominal rates of between 16% and 20%. Further Franz et al. (2014) states that local institutions often work with 16% to 24% interest rates. However, Mr. Dux also emphasized that his company, UECCC, is working together with the World Bank Group to be able to offer loans to mini-grid projects with lower rates, between 10% and 15%. Based on this information, we have set the nominal lending rate to 20%. However, according to Brealey et al. (2001), this rate must be multiplied with a factor of $1 - \tau_c$ to account for the debt tax-shield. Hence, the interest rate must be reduced by this factor and by the inflation rate in order to represent the real after tax lending rate. Further, the risk assessment performed earlier has made us aware of what risks that are present in the project. Therefore, the RRE is based on a subjective assessment of the riskiness of the project. In general increased debt will increase the RRE (Brealey et al., 2001), and RRE is usually higher than the lending rate. However, as pointed out by Mr. Dux, the financial institutions in Uganda are not used to these type of projects and might therefore allocate higher risk than what is actually evident. Therefore our RRE is set equal to the lending rate, and a relatively small addition of 2% to compensate the investor for the extra risk of equity. The risk free interest rate, which is to be used with model

2, is based on the treasury bond interest rate from (Bank of Uganda, 2017), which is 15.44% (nominal). The corporate tax rate used for the project is based on PWC (2016); a 30% rate applicable to the chargeable income of companies.

For this project a linear depreciation structure has been chosen. Further, as emphasized in 6.3, the amount of the terminal value possible to retrieve at project end should be adjusted based on the amount of grants received in the project to not create an arbitrage opportunity in the model. Thus, only 40% of each assets terminal value will be possible to retrieve after 25 years of operation. In addition, based on the life expectancy of the different assets, the timing of renewal for each asset has been set.

Scenario generation

In order to demonstrate both operational and strategic uncertainty, different methods have been utilized to generate scenarios. We have chosen to represent the operational uncertainty with 20 different scenarios and the strategic uncertainty with 27 different scenarios. The exact amount of operational scenarios is merely a pragmatic choice, because the amount was constrained by time due to the time consuming method used for generating scenarios on demand[3]. The choice of 27 strategic scenarios is however selected based on subjective opinions, where three scenarios are seen as suitable to represent each of the three strategic uncertainties. To represent all combinations of these uncertainties, 27 scenarios is thus needed. Table 7.7 summarizes the number of scenarios chosen for each of the uncertain parameters.

Table 7.7: Number of scenarios in the model.

Uncertainty	**Operational scenarios**	**Strategic scenarios**
Generation Capacity	20	0
Electricity demand	20	3
Investment costs	0	3
Foreign exchange rate	0	3

Generation capacity

The calculation of the generation capacity from the solar panels is based on Huld et al. (2010)

[3] A limitation of LoadProGen is that it is time consuming to use. Because of the front-end interface, looping through the process of generating scenarios can, to our knowledge, not be achieved, and all iterations must be handled manually.

and their formula for calculation of the power output from PV-modules. In this formula, the output from a given PV-module is only dependent on the module temperature and in-plane irradiance. In addition, system losses are accounted for, as emphasized by JRC (2012). The total loss inquired from irradiation until where the electricity generated is distributed to the batteries, and in distribution lines to consumers, is thereby made up of several types of losses. In the solar panels, losses occur due to both peak power and relative efficiency[4], while further system losses occur due to losses in power inverters, dirt covering panels and as losses in cables connecting the panels to the grid and batteries. Figure 7.8 shows the sequence of how these losses occur and their respective values.

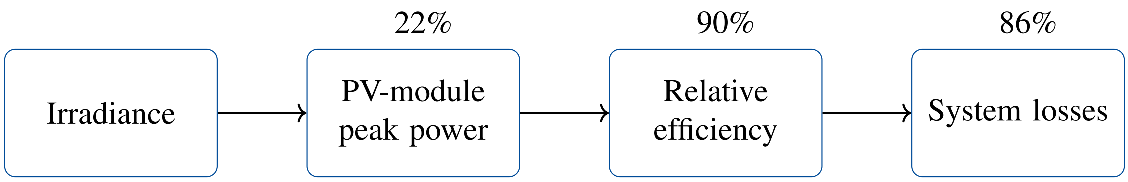


Figure 7.8: Example of losses in the PV module

The historical hourly irradiation data from Mpunge, with corresponding temperatures, that is used in the calculations for the generation capacity has been obtained from SoDa (2017). This consists of approximately two and a half years of consecutive data. In order to randomly generate scenarios for the amount of electricity possible to generate from one solar panel, as time-series representing five years of operation, each of these steps were followed:

1. For the entire historical data-set all UTC times were converted to local times. Based on this process, the shift in year, season, month, day and hour also had to be corrected accordingly.
2. A start hour for the time-series was selected, based on the best link between two consecutive days. 08:00 hours was selected as the start hour for our time-series, as this is the first hour of the day where solar irradiance is measurable in Mpunge. Starting a the time-series at 00:00 hours, which could seem like an obvious choice at first, would result in a lack of electricity for the first eight hours of each time-series, because there is no irradiance to produce electricity in these hours.
3. The entire historic data-set was used as basis for random sampling of 72 consecutive hour

[4] Relative efficiency is dependent on temperature and irradiance and therefore it varies. 90%, as given in figure 7.8, is therefore only one example of what the efficiency typically could be.

time-series, with a start hour of 08:00, representing one year of operation. To generate the entire time-series representing the generation capacity in the model, the following was conducted for each year in one strategic period:

(a) The desired number of scenarios (20), length of time-series (72 hours), number of seasons to be represented (1) and the number of years in each strategic period (5) were given as input parameters to a code, implemented in Excels Visual Basic.

(b) The number of observed hours stating at 08:00 in one season in the historical data-set was counted. Because only one season is used to represent one year for our problem, this includes all occurrences of the 08:00 hour in the data set.

(c) The Visual Basic code randomly drew numbers representing the different start hours. Thus, the numbers drawn were lower than or equal to the total number of start hours counted in the historical data-set. From this, the start hours drawn was set as the starting hour for a 72 hour long time-series. These time-series were aggregated to represent 20 different five year periods, with one 72 hour time-series for each year. This way, 20 different operational scenarios were generated.

4. To obtain the entire scenario tree, the operational scenarios for each of the strategic investment periods and strategic scenarios in the project were set equal to these operational scenarios initially generated. Thereby it is assumed that weather and temperature patterns only vary on a short-term basis.
5. When the entire scenario tree was constructed, a statistical test was conducted to ensure that we chose the best possible representation of the historical data. That is, the first four moments of the scenario tree were compared to that of the historical data. This procedure was repeated, and the scenario tree that best represented the historical data was selected.
6. The generation capacity was calculated for all hours of in scenario tree, based on the historical data for irradiance and temperatures, the formula in Huld et al. (2010), and the losses as previously explained.

Parts of this procedure is also executed in accordance with the routine developed by Skar (2016), as presented in chapter 4. More information on how the statistical test was conducted can be found in appendix A, section A.2. Using this method for scenario generation, based on randomly drawing complete time-series from an historical data-set, time-correlation, as well as the statistical properties of the historical data, is preserved. Although the historical data-set used is not very large, this was the largest one we could obtain at no cost. Further, because weather-patterns are relatively stable on average within a year in the historical data-set, as can be observed in figure 7.9, we find it is reasonable to not divide the data-set based on different seasons. This choice also limits the inaccuracy of utilizing a small set of historical data, in our opinion. The simplifying choice of generating one scenario tree which represents the generation capacity in all strategic periods, was also made because of these stable weather-patterns. We believe that representing each of the periods with individual scenario trees would yield marginal improvements in representing the real distribution. It should also be noted that the average hourly temperatures for each month has even smaller variations.

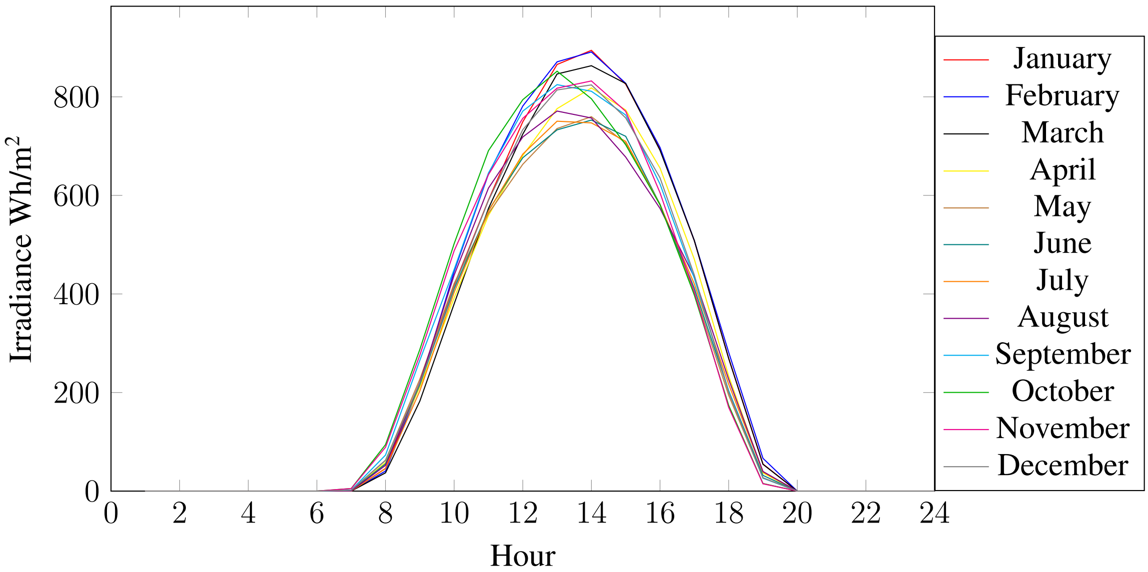


Figure 7.9: Average solar irradiance per hour for the historical data

Load profiles

Scenarios representing the electricity demand have been generated using LoadProGen, as explained in section 4.4. We have chosen this scenario generation method because Mpunge does not have access to electricity today, and LoadProGen is the only tool, to our knowledge, for generating proper load profiles with limited information on consumer demand. The output form LoadProGen is a number of different load profiles, or scenarios, representing the operational uncertainty in demand, based on different user classes. However, because demand is also subject to long-term (strategic) uncertainty, the following steps were the basis of our scenario generation procedure:

1. For the first year in all the strategic periods, in addition to the first year after project

end, and in each of the three strategic demand scenarios (for the periods with strategic uncertainty), the following was done:

(a) The classes that is assumed to exist in the given year and strategic scenario were constructed, based on information on the known appliances used in different classes in a rural town in Uganda, presented by Mandelli et al. (2016). For classes not presented in the study by Mandelli et al. (2016), our experiences from the visit to Uganda was used to construct classes, in addition to numbers from USAID (2006), used to construct additional electric appliances for the health centre in Mpunge.

(b) The number of users within each class was set for the given strategic scenario and year, based on the information we have on the population of Mpunge, given by the doctor in Mukono, the assumed growth in demand and subjective beliefs on how many households, businesses etc. will actually connect to the mini-grod.

   i. For each year, at the start of a new strategic period further into the future, the number of users in each class was increased, based on the expected growth of demand. The expected growth has been based on ECA (2014), emphasizing a 30% growth rate in consumption the first few years of operation, in an area initially without electricity, which further stabilizes around 10%.

   ii. From the first year of period three and on, it was assumed that the type of appliances used in the households and businesses will have become more advanced due to an increased standard of living. This is based on Wolfram et al. (2012), which explains how the consumption in newly electrified areas normally follows an S-curve, where the big increase in growth comes when the consumers have earned enough to invest in more advanced appliances. However after some years this increase in advanced appliances flattens out.

   iii. To create three different scenarios, the expected growth in demand was increased and decreased compared to the expected growth in demand initially used for each of the years.

(c) One run of LoadProGen constructed 20 load profiles, each consisting of 24 hours. Thus three runs were conducted to generate the operational scenarios for one year, each consisting of 72 hour long load profiles. Further the first 7 hours of each time series was moved to the end of it, in order to have the same starting time (08:00) for both the generation capacity and load profiles.

(d) To create strategic scenarios, the LoadProGen runs creating operational scenarios were run for the collection of user classes with the expected demand first increased and then decreased. This was therefore done for the first years in each period from period three until the first year after project end.

2. To obtain load profiles for the years in-between two strategic periods, and between the first year of the last period and the first year after project end, the demand growth rate between each of the calculated load profiles was obtained. From this, load profiles for each year between two generated load profiles could be calculated based on this growth rate. To obtain all load profiles needed to represent uncertainty in the problem, this was also done for each of the operational and strategic scenarios.

Excel has been used for many of the calculations in this procedure, and the initial choices of user classes, appliances within each class and the number of users within the classes are shown in appendix B, section B.1. It should also be noted that the LoadProGen input parameters considering the random variation in functioning time and functioning windows for appliances, was set at 10% each. This implies that the load profiles have been generated based on low variation in the set functioning times and -windows for the appliances. Thus, if the variation turns out to be higher, the mini-grid, which is based on these load profiles, will not always be adequate to fulfill demand. However, as emphasized in section 6.2.3, the consequences of not delivering what people are demanding all the time are not very big in communities like Mpunge. Therefore we have assumed that this will be solved within the community, with for instance schedules for when different households, businesses etc. use electricity. It should also be noted that because there are many classes and with different types and amounts of appliances, a large variation between operational scenarios can still be achieved.

The strategic scenarios for investment costs have been created based on projections and scenarios from Mayer et al. (2015) and our selection of the, in our opinion, three most realistic scenarios. Further for currency exchange rate the strategic scenarios have been created based on the historic values as presented previously, and our subjective opinions about how the political instability in Uganda will develop. In order to put together all combinations of strategic scenarios, an excel model was created to, for each strategic uncertainty, produce nine equivalent sets of each of the three scenarios, and set them together to a total of 27 scenarios.

A weakness of the scenario generation methods we have used is that they make it difficult to test for stability. For the strategic scenarios, they are not created randomly, hence stability testing would be based on creating a larger set of subjective scenarios. As these scenarios are already subjective, we are aware of and accept that the opinion of the user can influence the solution of the stochastic program, and therefore we do not perform stability-testing. However, Kaut and Wallace (2007) emphasizes the importance of running stability tests on the scenario generation method chosen, when it includes randomness, to test its practical performance. Stability is obtained if several scenario trees are generated with the same input, and the objective function value of the optimization problem solved with these trees is approximately the same (Kaut and Wallace, 2007). Thus, the stability of the operational scenarios generated using methods including randomness should preferably have been tested for us to be able to say something about the performance of these scenario trees. However, due to the complicated and time-consuming process of generating load profiles using LoadProGen we decided, as a pragmatic choice, to not utilize our time generating more scenarios to test for stability. For sampled data, the discrete distribution converges to the true distribution (Kaut and Wallace, 2007), thus, as emphasized in section 4.4, representing historic data with two few scenarios could result in solutions dependent on the sampled scenarios, and not the underlying data. On the other hand, having many scenarios can influence the computational time and effort, negatively. We believe that by comparing the statistical properties of the sampled data to the historical data, some of these effects are avoided. For the data generated in LoadProGen, too few scenarios could lead to an inaccurate picture of the actual demand where, for instance, some rather extreme scenarios could be given a higher probability than what is realistic.

7.5 Project valuation and analyses

In this section the results from the optimization of the different model formulations are presented and analyzed. In addition, each of the different sensitivity analyses we have conducted for model 1, taking risk into account through RRE, is presented and analyzed. Because the result of the stochastic programming model is of great importance for the decision to go ahead with the project, a thorough analysis is accomplished. For the entire section the results are presented in USD, to make the interpretation of the results easier. The exchange rate that has been used is 3,626.82 UGX/USD, the same spot-rate as in the model. However, as previously mentioned, the currency used to calculate the expected NPV of the project in the models is UGX. It is important to emphasize that the results are given as *expected*, and not *certain*, values because we are dealing with uncertainty in the model.

7.5.1 Model 1

With the input parameters presented in the explanation in the previous section, the optimal objective function value of the stochastic program based on model 1, or the optimal expected NPV of the project, is **36,209.38** USD. Thus the project, with the assumptions we have made and the data we have based the project on, is that the project is attractive in expectation for the investor.

To further highlight what parts of the project have more impact on the project value than others, the graph in figure 7.10 shows the expected present value of the future cash flows for each of the elements in the cash flow analysis, as presented in section 6.2.2. The blue columns represent positive cash flows, while the red columns represents the negative ones. As the graph illustrates, investment cost is the dominant project cash flow, and it is evident that it would not be possible to cover it just by relying on the total cash flow from operations. That is, the project is highly dependent on the grants and loan to finance investments. In addition, it can be observed that the present value of the loan annuity cash flows amount to the exact same as the present value of initial cash flow of loan received, thus the arbitrage opportunity has been eliminated. Another important take-away from this representation of the expected present value of the project cash flows is that the depreciation tax shield is of relatively high value, which is an element specific for the DCF analysis. Actually, the value of the depreciation tax shield is in the case larger than the project value, and omitting it would thus yield a negative project value. On the other hand, due to grants accounting for a great amount of investment costs, the terminal value of assets has small impact on the total project value. However, the terminal value might be of grater value in reality, as it has been reduced due to the arbitrage opportunity it created in the model. Because its value is accounted for far in the future, the discounting also greatly reduces the impact of its value on the expected NPV.

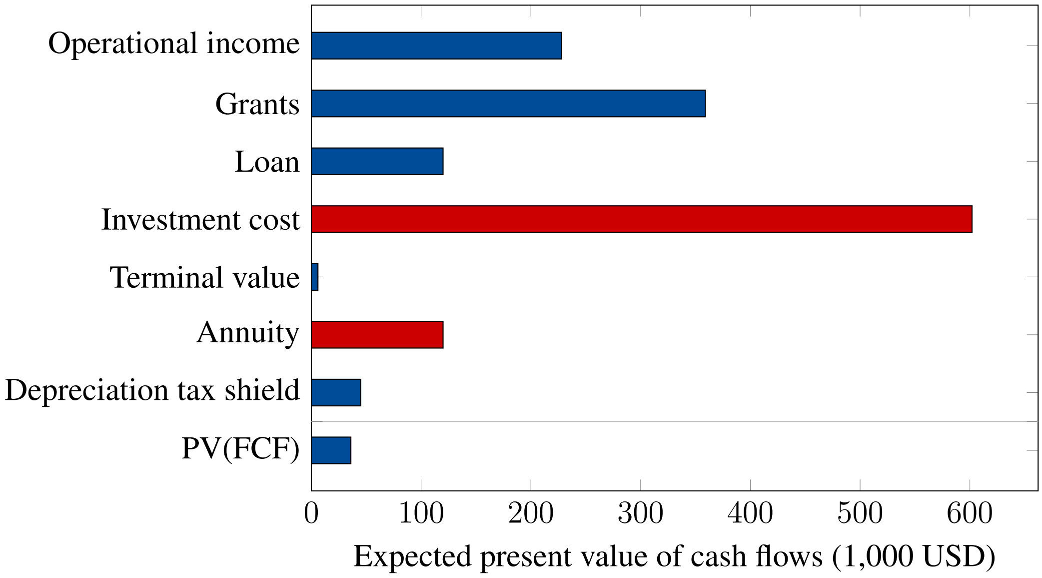


Figure 7.10: Overview of the different parts in the DCF analysis, and their contribution to expected NPV.

In figure 7.11 the cash flows from investment costs for each project investment period, not discounted to present value, is plotted in a box-plot. In appendix A, section A.3 a short explanation is given on how the box-plots we have created can be interpreted. In many projects, the initial investment cost is high because this investment has to cover the demand for a long period. In this project however investments are spread out through the project lifetime, which becomes clear form the plot. In addition the investment cost at project start is higher than the investment cost in the second strategic period, mainly because of the higher fixed costs at project start. It can also be observed that the spread in investment costs increase severely from period three to five. This is reasonable seeing that the model strategic uncertainty makes the decrease in investment costs turn in different directions for the different scenarios, in each of the periods. In addition the same effect is present for the increase in demand and increase in foreign exchange rates, such that the accumulation make some scenarios turn out a lot worse or better than others. The box plot is also illustrative for the order of magnitude of the investors equity investment in each period, which is 20% of the investment cost in each period. The spread in investment costs thus illustrate how dependent on future scenarios the investors equity contribution is. However, the model merely decides on the "here and now" decisions for the project, thus it cannot be decided today exactly what the investor must be prepared to invest in the future, but the box-plot provide an indication on the order of magnitude.

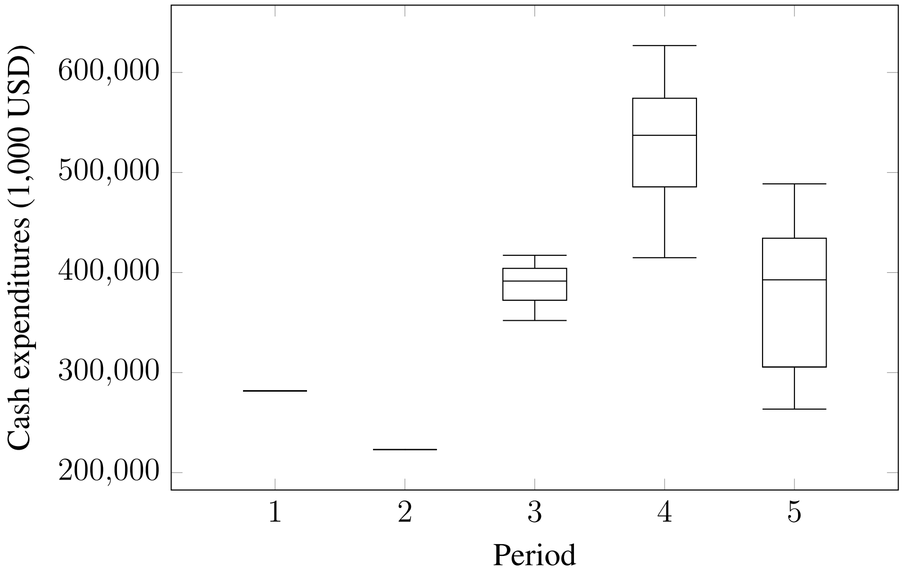


Figure 7.11: Investment costs for each strategic period.

The expected percentage of the demanded electricity, over the project lifetime, covered by solar powered generation is 91.97%, based on the probabilities of the different scenarios. However, it is evident when observing the coverage in each year within different periods, operational- and strategic scenarios, that the coverage may be far lower in some years. As the graph in figure 7.12 exemplifies, the demand coverage is in several occurrences lower in the end of a strategic period. Because investments are possible with five-year intervals, this can be an effect of the cost related to investing in additional solar power generation capacity, at period start, being more expensive than covering the incremental increase in demand the last years of the period using a diesel generator.

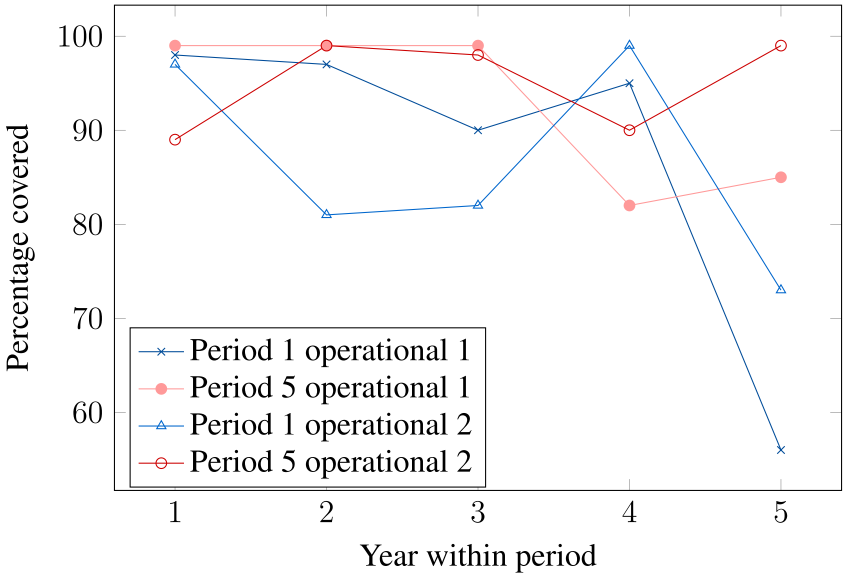


Figure 7.12: Electricity demand covered by solar panels in some operational scenarios in strategic scenario 1.

Observing the difference between period one and five in both the plots in figure 7.12 and 7.13, it also becomes clear that the reduced growth in demand within the later periods almost eliminates the effect of reduced demand coverage in the last year within a period. The coverage is of course dependent on the operational- and strategic scenarios, and therefore in some periods and scenarios this trend is not observed. The box plots in figure 7.13 indicate that for the initial period the trend follows this pattern, and this is also observed for the other periods, and in the strategic scenarios not presented here.

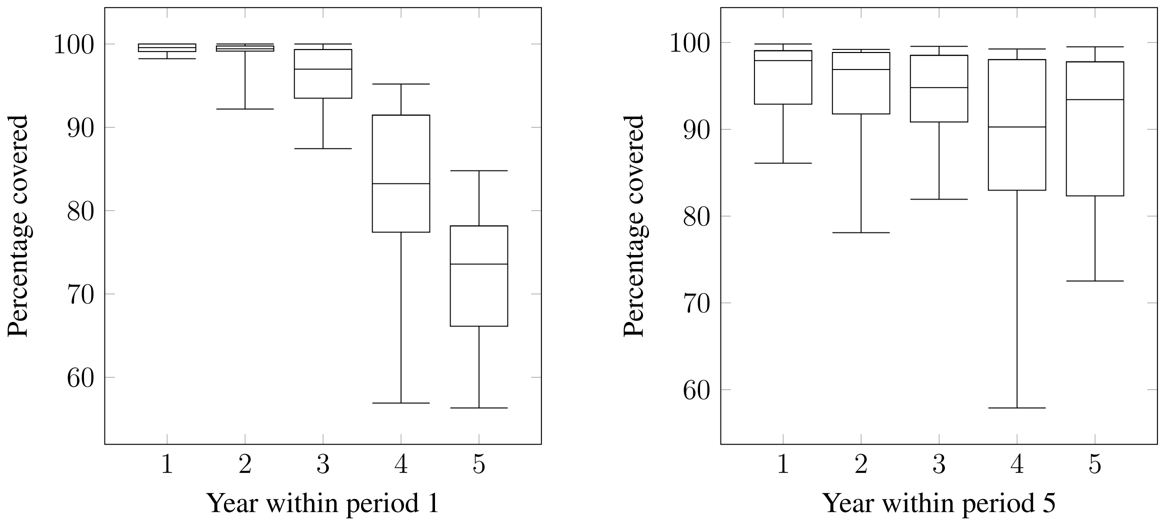


Figure 7.13: Electricity demand covered by solar panels in strategic scenario 1.

By calculating the expected total costs of the project over its lifetime and the sum of electricity produced within the same time, the expected LCoE can be calculated, as a cost for the electricity generated per kWh produced. For this project the expected subsidized LCoE, counting only the costs not covered by grants and the electricity generated from solar power, is 0.2234 USD/kWh. This is however based on the optimal model solutions, where the cost of lost load affects the investment in solar power, and the assumption that electricity from the diesel generator can still be sold at 0.28USD/kWh. It can be observed that this cost is lower than the electricity price of 0.28 USD/kWh that was set for the mini-grid in Mpunge, implying that the project will earn a profit for each kWh, generated from solar power, that is sold. Taking into account the electricity generated from the diesel generator as well, the LCoE increases to 0.25 USD/kWh. ECA (2014) present the unsubsidized LCoE for the different projects they have analyzed. For instance in one project which is based on solar PV, batteries and diesel, the LCoE has been calculated to be 0.82 USD/kWh with a private business model. For the mini-grid project in Mpunge, the expected unsubsidized LCoE for the entire system is 0.77 USD/kWh. It is important to mention that this is the unsubsidized LCoE of the project calculated based on the project with subsidies incorporated. Thus the costs set for the project seem reasonable in comparison to other projects with approximately the same features. However, because our LCoE is somewhat lower, it could be questioned whether some costs are estimated too low, or if demand is to some extent overestimated.

Figure 7.14 illustrates the amount of PV-modules and batteries that, according to the model input, will be optimal to install for the project, taking into account the long-term uncertainty within the last three project periods. As observed for the investment costs, the spread in how much it is optimal to install increases with time for both panels and batteries. It is also evident how the demand-increase between the periods makes it necessary to invest higher amounts of panels and batteries. The decrease in the investments between period four and five however, is present mainly because the demand growth flattens out at the end of the project.

To comment on the realism of the optimal solution for the project, the area that the PV-modules will take up can be compared to the actual area available in Mpunge. The area of one panel is estimated at 1.65 m^2, thus the maximum total area needed for just the panels, based on the maximum number of panels invested in each period, is approximately 2346 m^2. On the other hand, the minimum total area needed for just the panels is approximately 1701 m^2. With ten acres of land in the area surrounding the health centre owned by the government, this equals approximately 4046 m^2. If it is assumed that the health centre will need 30% of the area for growth etc., 2832 m^2 is available for sale. Because panels are installed with a certain area in between the rows of panels, and in general the entire grid with batteries, inverters, cables etc. takes up more area than merely the panels, the area available may be somewhat restrictive for the project. However, there may be additional area, not owned by the government, that is possible to acquire in Mpunge.

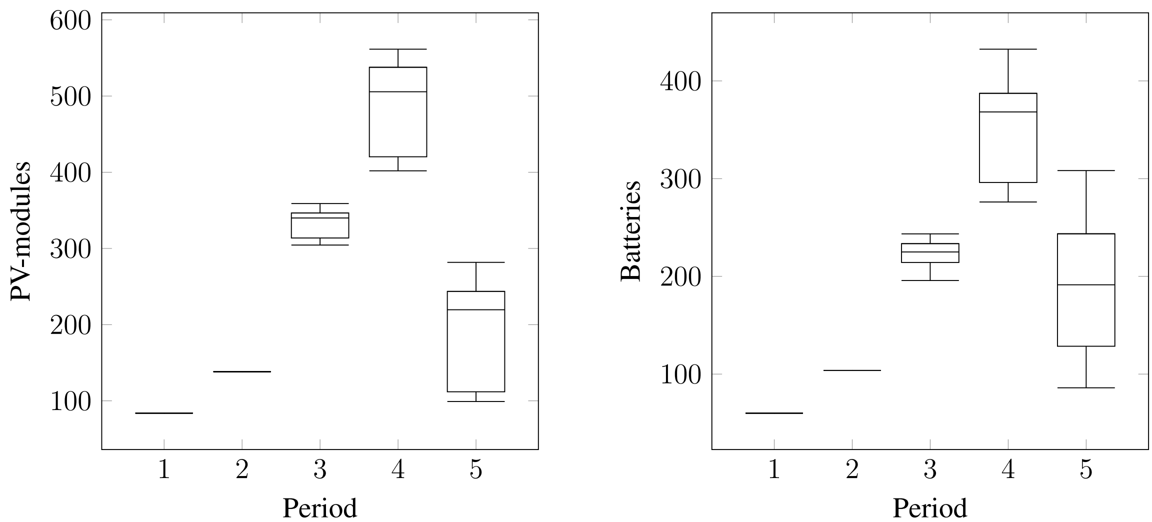


Figure 7.14: Number of installed PV-modules and batteries in strategic periods

In figure 7.15 the operational cash flows for period one and period five, in two arbitrary strategic scenarios, one and nine, are plotted. The big difference between the two periods is the increase in the spread from period one to period five. This is a result of the development of demand, where in later periods there are both more customers connected to the grid and a bigger variation in types of households, businesses etc., which affects the variation in load profiles. This is also illustrated by the low spread in the first year of period one. In this year, there is not a high amount of customers connected to the grid, and because of their simple way of living their electricity use is simple, and there are limited types of appliances in use. The reason for the high operational income this year however, is that the initial number of customers connecting is high compared to the yearly increase in the number of customers connected. Obviously, the plots also illustrate that the increased demand leads to increased income. But because the cash flows are not illustrated using present values, the cash incomes in period five do not have the corresponding high effect on the expected NPV of the project. From the box-plots it can also be noted that the minimum operational incomes are quite extreme compared to the rest of the scenarios, where the biggest share of the scenarios have operational incomes that are a lot closer to the maximum operational income. This indicates that there is one or a few operational scenarios that are a lot worse with regard to the cash income. Hence, as discussed in section 7.4, if stability is not achieved in our model, the effect of such extreme scenarios could be allocated with a higher weight in our solution than if stability was achieved.

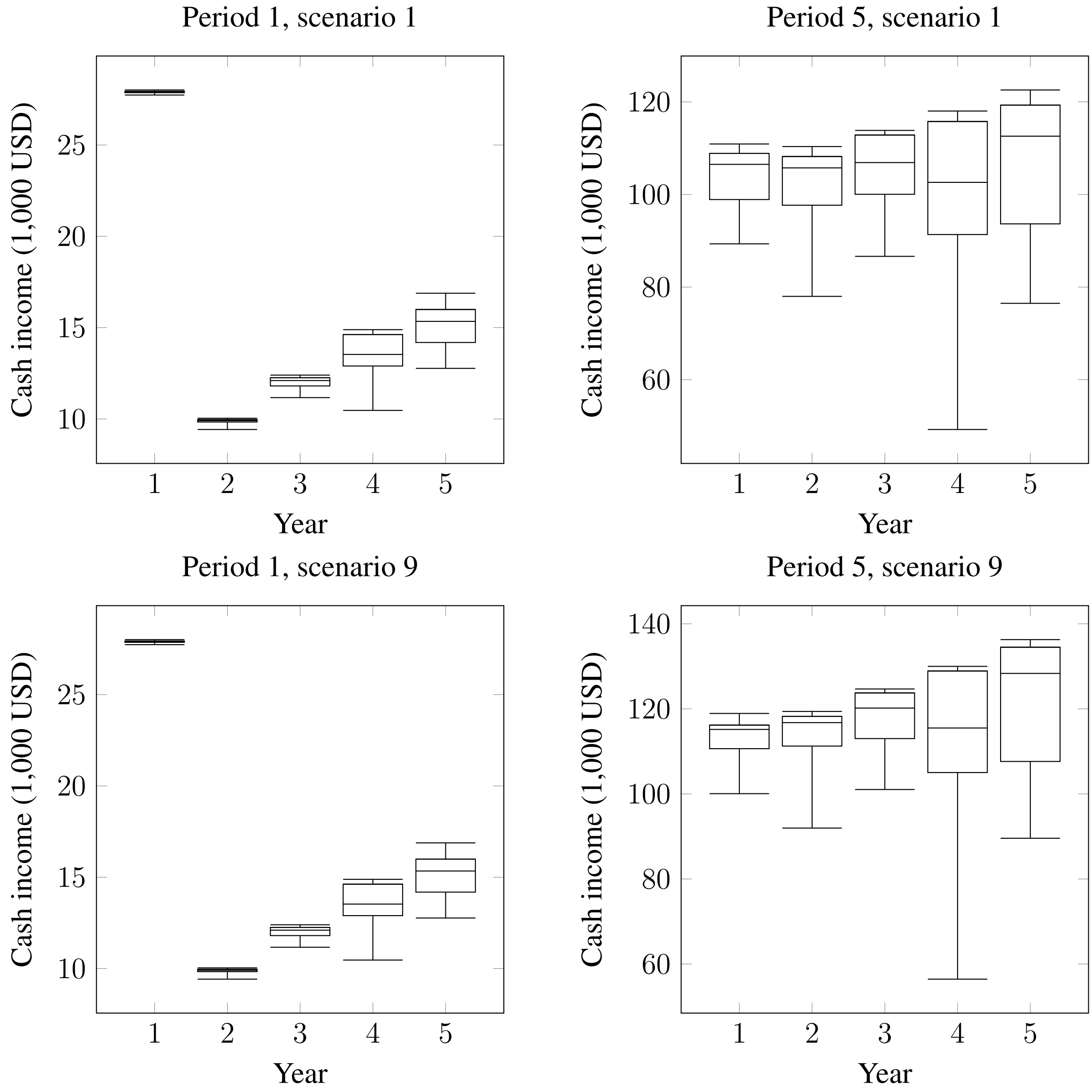


Figure 7.15: Cash flow from operational activities in strategic scenario 1 and 9, period 1 and 5.

7.5.2 Sensitivity analyses

Investment costs

When initiating the project of building a mini-grid based on solar power in Mpunge the costs for the investments in different assets, used in the model analyzed above, are not necessarily the exact costs that the suppliers will set for the investments in the project. Therefore we have analyzed how increasing and decreasing the different asset costs will affect the expected NPV of the project. This is presented in table 7.8. It is evident from the results presented in the table that changes in these costs does not have a severe impact on the expected NPV of the project. This is an effect of the high amount of grants in the project, as 60% of the cost change is absorbed by the grant. A weakness of the analysis is however that the costs have been changed one at a time. However severe differences in both directions for several of the assets costs simultaneously is assumed to be unlikely. Further it should be noted that the objective function value of the model is highly affected by changing the type of battery used in the project. An expected NPV of 6,553 USD is observed when vanadium redox batteries[5], which have a lifetime of 25 years, are used in the project. That is, because the cost initially is higher, the demand is low initially and the costs decrease with project lifetime, the increased lifetime of the batteries is not as valuable due to the effect of discounting.

Table 7.8: Sensitivity analysis on investment costs

Asset	Original cost	New cost (EUR)	Expected NPV (USD)
Battery	221	332	29,760
		166	39,617
Vanadium redox battery		831	6,553
BOS	121	161	32,345
		80	40,114
PV-module	362	482	24,748
		241	48,082
Inverter	201	241	32,877
		121	42,974
Risk response	2	4	35,992
		1	36,318

[5]Vanadium Redox batteries are relatively new on the market and are seen as ideal for mini-grid installations, because of scaleability and long lifetime.

Grants and loan

The percentage grants that can be received in a project is difficult to predict, and therefore the effect of changing this percentage is important when analyzing the value of the mini-grid in Mpunge. We have chosen to illustrate how the expected NPV of the project change when the project receive between 0% and 80% of the investment cost in grants. For all percentages below 60% the loan amounts to 20% of investment costs and equity the remaining part, however for 70% grants, 10% loan and 20% equity is assumed. Grants above 80% of investment costs would, with the data in this model, give the project a levelized cost of electricity below zero and is thus not analyzed. This is illustrated in the second graph in figure 7.16, representing the LCoE for different amounts of grant. The first graph in the figure illustrates how the expected NPV of the project increase with the percentage of investment costs covered by grants in the project. What can be observed is that if grants are below approximately 55% of investment costs, the project will have a negative expected NPV and therefore not be attractive. In addition if the project was to be financed by zero grants and 20% loan, the expected project value would be negative with a loss of 271,460 USD. The LCoE for solar powered electricity with zero grants is 1.05 USD/kWh, which would be impossible for the inhabitants in Mpunge to pay. Thus, as was pointed out for figure 7.10, the project is highly dependent on grant funding.

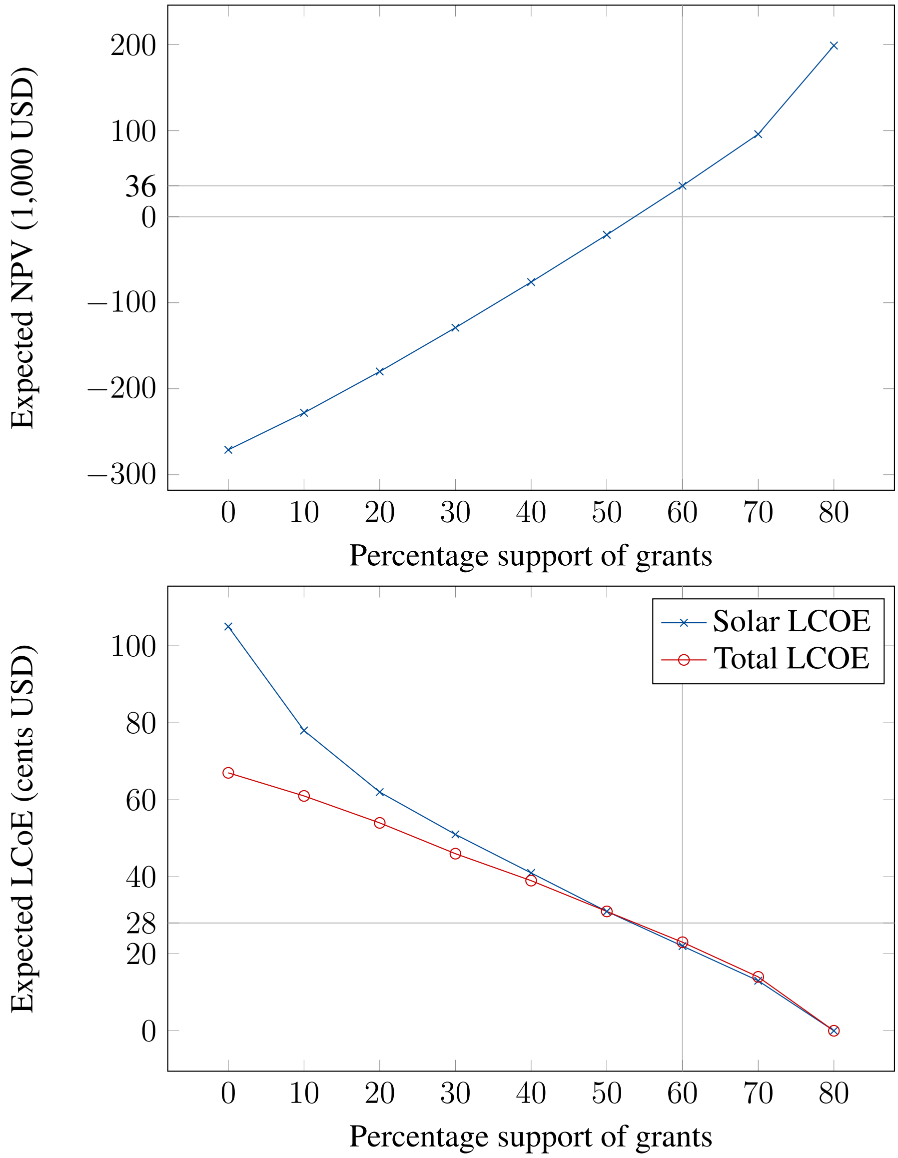


Figure 7.16: Expected NPV and grants.

Loss of load

The graph in figure 7.17 illustrates how the expected NPV of the project changes, based on the amount of demand each year that is covered by electricity generated from solar power. Thus a constraint has been implemented on the maximum slack in the distribution of electricity from solar power generation in each year. The result indicates a small decrease in the objective function value when the requirement of coverage from solar power is increased from 50% to 60% each year. Thus the expected NPV for the project is found for a constraint on coverage between 50% and 60%. An indication of this can also be observed from the plots in figure 7.13, where the low coverage in some periods, in the optimal solution, is between these percentages. When the lost load in the system is below approximately 40%, severe changes in the project value is observed. That is, when it is demanded that more than 60% of the demand in each year is covered by electricity generated from solar power, the expected NPV of the project is rapidly reduced. A requirement of approximately 75% coverage sets the project value at zero, and if 100% of the demand each year was to be covered by the electricity generated from the solar panels, the project would have a highly negative expected NPV.

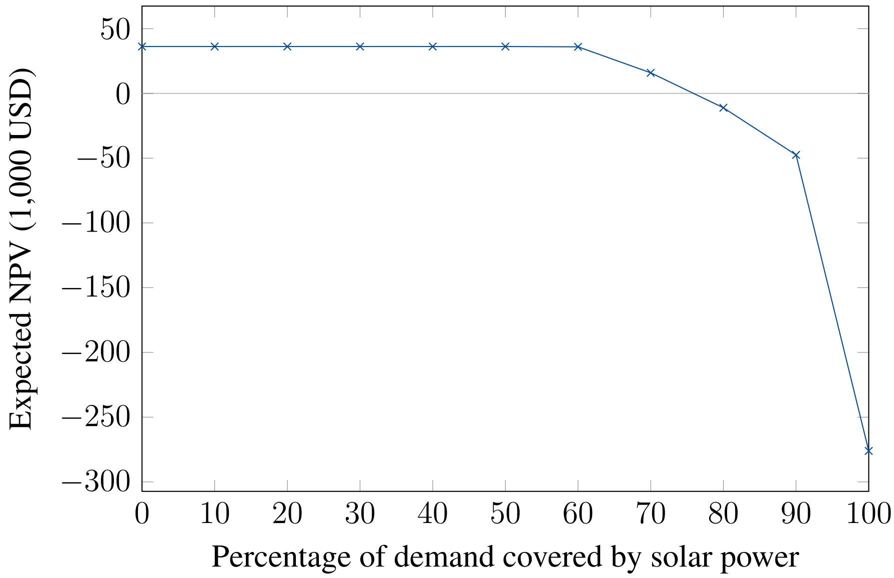


Figure 7.17: Expected NPV of the project for restriction of demand covered by solar power generation each year.

Overestimated demand

If the investor initially invests according to the ”here and now” solution as suggested by the optimal solution from model 1, additional capacity cannot be invested in before year five. Thus if demand in reality is, for instance, 20% below what is estimated, the model cannot affect the initial decision until five years later. When this possibility is modeled, the expected NPV of the project is reduced to 10,135.17. The reduction in project value represents how changes in demand affects the investments from period two up to five, and the losses due to lowered demand in period one. However, the reduction is not severe, indicating that such an error in the estimation of demand is not critical for the project value, also seeing that the project is still giving a positive expected NPV. One reason for this could be the possibility to react to the falling demand relatively early, by reducing the investments in future periods.

Delayed start

The expected NPV of the project reported by model 1 is based on data for the project as if it were to be started this year. However, when this thesis is handed over to SunTap, the mini-grid project in Mpunge will probably not be initiated immediately. Most likely it will be considered and further investigated by the investors, and when it is decided to be initiated, at least one year will pass before the mini-grid is built and electricity can be sold. Therefore it is interesting to analyze how a delayed start will affect the project value. By shifting all parameter values one period ahead, such that now, the data input for period one is equal to the data in period two from the original run of model 1 etc., except for demand, the project will be optimized as if it had been delayed by five years. The demand is not assumed to shift because it is mainly the access to electricity that drives the demand growth in the area. Further, when shifting all other parameter values an additional period, year 25 until 30 seen from present, must be added. This is handled by further decreasing the investment costs at the same constant rates that has been used for all other periods, and adjusting the increase in exchange rates such that the increase is reduced compared to the previous period.

With a five year delayed start for the project, the expected NPV five years from now increases to 36,647.14 USD. That is, the delay increases the expected project value by 437.80 USD. Because the only difference is decrease in costs with further delays, this increase in project value is assumed to continue with further delays. But what the model is not accounting for is that the longer the project is delayed the higher is the probability of other investors entering the market, hence the lower the probability of receiving a high amount of grants become. Therefore the investor must weight the value of the possible decrease in costs against the possible decrease in grants when making the decision on when to initiate the project.

Required return on equity

The RRE in the project is decided based on what risk preference the investors have, and is influenced by the project lending rate. Therefore we have chosen to illustrate how the expected

NPV of the project changes, both due to different risk preferences, and due to changes in the lending rate when the risk increment is set constant at 2%, as set in model 1. For the latter analysis, two lower lending rates that may be possible to obtain through the help of UECCC in the future, 10% and 15%, as presented in section 7.4, have been used. With a nominal rate of 15% the expected NPV of the project is 143,590.71, while with a nominal rate of 10%, this value increases to 411,062.49. Thus it is evident that the lending rate that the bank is willing to give for project loans has a huge impact on the project value if the investor consider this as the lowest project risk. However, since the present value of debt is 0, the mathematically change in expected NPV of the entire project is due to the changed RRE, while there will, of course be a change in the cash-flows from debt.

The project investors preference on risk does not necessarily have to coincide with the bank's opinion of the project risk, that it has based its lending rate on. For instance, the lending rate in Uganda is especially high because banks are not familiar with mini-grid projects based on solar power and the risk of failure of such projects. However, an investor in the market is usually more familiar with this, and could decide to set the required rate on equity for the project below the lending rate, if the lending rate is regarded as too high by the investor. Additionally in projects that have high amounts of grant financing, the project risk as perceived by the investor may be reduced. On the other hand, some investors may also be highly risk averse and choose a higher increase of the lending rate to compensate for the risk of equity. The graph in figure 7.18 shows how the RRE, based on different risk preferences, affects the expected NPV of the project. It is evident that the RRE, as for the previous analysis, is decisive for the project value. With a real RRE above approximately 17%, which corresponds to approximately 5.2% higher rate than the lending rate with a nominal lending rate of 20%, the project gives a negative expected NPV. Thus the investors risk preference is of great importance for the project and should be carefully evaluated.

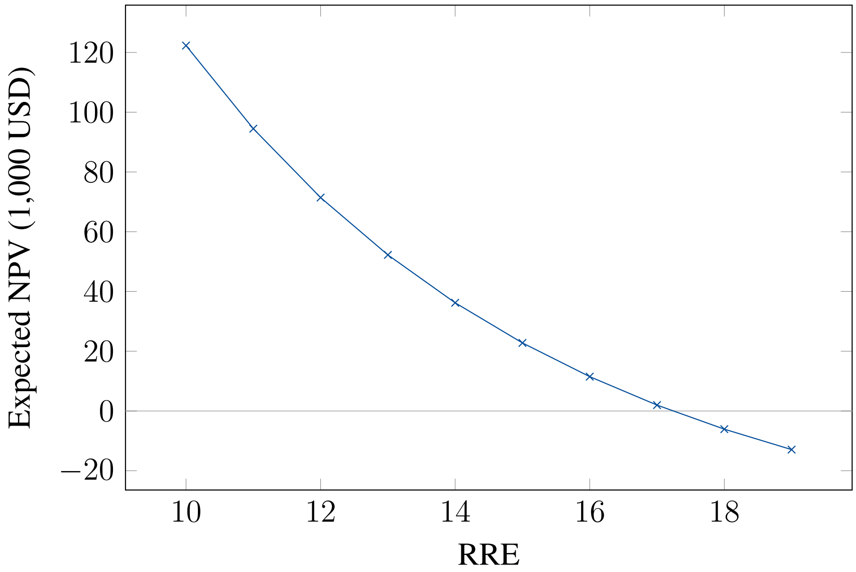


Figure 7.18: Expected NPV of the project for different (real) RRE.

7.5.3 Model 2

When the project is optimized through the formulation in model 2, the expected NPV of the project can be observed for different risk preferences, from the investors perspective, on the long-term risk modeled using strategic scenarios. To illustrate this, α was set at 10%, and model 2 was optimized for values of λ between 0 and 10 as shown in table 7.9. What is evident from the results in this table is that there is almost no reduction in expected NPV for the increase in the weight put on the risk, using λ, that the strategic scenarios pose on the project. The only visible reduction is between $\lambda = 1$ and $\lambda = 3$, however this reduction is insignificant. Based on this observation it is clear that the composition of data used for this project, representing the strategic scenarios, yields high flexibility in the model. The strategic scenarios does not create any incentives for the model to over-invest in the initial periods, because the alternative of ”wait-and-see” is always preferable. As the changes in decision variables, CVaR-value and expected NPV of the project is minimal for varying λ, there is no point in showing an efficient frontier in this case.

Table 7.9: Results of Model 2: conditional value at risk. Values in USD

Lambda	CVaR	Expected NPV	Difference in expected NPV
0	0	201960.0967	-
0.1	173,013.4747	201,960.0967	0
0.3	173,013.4747	201,960.0967	0
0.5	173,013.4747	201,960.0967	0
0.7	173,013.4747	201,960.0967	0
1	173,013.4747	201,960.0967	0
3	173,013.5711	201,959.8402	0.2564
5	173,013.5711	201,959.8402	0
7	173,013.5711	201,959.8402	0
10	173,013.5711	201,959.8402	0

The effect of this high flexibility in the model for this particular problem can also be observed by looking closer at the sensitivity analysis discussing the effects of overestimated demand. When demand is reduced by 20%, the effect of this is not severe in period one, as it would be if the optimal first stage solution was to overestimate the investments in period one. Thus it is not critical for the project value that the demand is lower than first expected.

A measure that can quantify whether, for a specific problem, there is any value in utilizing a stochastic approach to represent uncertain parameters, instead of a deterministic approach, is the value of stochastic solution (VSS) (Birge and Louveaux, 2011). Because the model we have developed incorporates both strategic- and operational uncertainty, the VSS should be calculated based on one uncertainty type at a time. This is because it would not be possible to evaluate the value of representing only short- or long-term uncertainty by calculating a VSS incorporating both. For the purpose of illustrating that the uncertainty in the strategic scenarios is of marginal value in this particular problem, the value of the strategic stochastic solution (V(S)SS) must be calculated.

As indicated by equation (7.1), in order to determine the VSS the difference between the value of the optimal solution of the stochastic problem (SP), and expected value of using the expected value solution (EEV) is calculated. The expected value (EV) solution is obtained by replacing all stochastic parameters with their expected values and solving the resulting optimization problem. The EEV is then obtained by solving the SP with the first-stage solutions fixed as the fist stage solutions of the EV problem. (Birge and Louveaux, 2011).

$$VSS = EEV - SP \tag{7.1}$$

The project V(S)SS is calculated through merely fixing the first stage solution of the strategic scenarios when determining the EEV. Thus the EV solution is also obtained by calculating the expected values of the strategic scenarios. This implies that the operational uncertainty is still accounted for in the calculations. For this particular project this results in a V(S)SS of $6.31809 * 10^{-5}$, or approximately zero. The long-term uncertainty in the project is therefore not affecting the "here and now" solution, or the first stage solution, because it is not optimal to invest more than what is actually required in the first stage. This implies that the recourse decision is of importance for the expected NPV because the decision on how much to further invest is made here. Also, the value of using a stochastic programming model for the strategic uncertainty is low. Generally, in the stochastic programming approach a decision has to be made "here and now", which stays unchanged and will affect the project operations for a long period of time. After this long period an adjusting recourse decision can be made to account for the new information that has become available. If the decision today would have been the same independent of whether the information revealed in the second stage was available today or not, the stochastic programming approach has low value.

When analyzing the strategic scenarios against the model formulation of the problem, it can be observed that the combination of scenarios merely have uncertainties in the future that will have positive effects on the project. That is, strategic demand increases while investment costs decreases. The foreign exchange rates increases and counteract to this effect, but only by a small amount. Of course, this could be different in other projects. On the other hand, there are elements not incorporated in the model that does not contribute to this effect and thus could have made the V(S)SS higher. For instance there is, as emphasized in the sensitivity analysis, uncertainty in how much grants the project will receive. The probability is higher that a higher amount of grants is possible to acquire at early stages in the project. Thus long-term uncertainty on the development of the percentage grants received could have been incorporated to increase the risk associated with the strategic scenarios, and thus provide an incentive to, in some scenarios over-invest today. This would yield a higher V(S)SS.

The project variable costs are modeled without the effect of economies of scale. But high scale advantages can also make it more important to increase investments initially, when some investments must be made anyway. Another factor increasing the importance of investing more than what is necessary in the period ahead, when actually investing, is fixed costs that only appear if an investment is made. Thus by modeling both economies of scale and binary variables accounting for fixed costs, the model formulation of the problem would incorporate several aspects contributing to an increase in the V(S)SS. An additional factor that is present in projects in developing countries, which has not been incorporated in the model formulation is the probability of project failure due to political instability. For instance the project could be stopped if the government were to withdraw all the contracts that the project was built on, or if war erupts in the country. By incorporating this uncertainty in the model, it could encourage a discretion of initial investments due to the possible losses connected to it.

Chapter 8

Concluding remarks

In this thesis the main objective has been to highlight whether SunTap, as a private investor, can evolve in the solar power market by investing in a mini-grid project in a rural area of Uganda. To assess this, we have developed a standardized process and utilized it to assess the investment opportunity that the unelectrified village of Mpunge poses. The process has through this case study proven to be a tool that can be used by private investors to assess investments in off-grid PV-systems located in developing countries. By including risk analysis and exploiting the advantages of the financial DCF-analysis and multi-horizon stochastic programming, the process makes it possible for investors to consider the uncertainty present at different levels throughout a projects lifetime in the valuation of it. We believe that this tool will make it easier for private investors to take part in the important electrification of the less developed parts of the world.

The output from the process, when utilized for the mini-grid project located in Mpunge, shows that the project has a positive expected NPV. However, sensitivity analyses indicate that the amount of grants possible to acquire for the project has a huge impact on this value. The size of the grants the project receives can also be dependent on when the project should be initiated, as the competition for grants is likely to increase with time. It can also be affected by the amount of demand covered by solar power, if the grant is provided based on the fact that the project is renewable. Further, the expected NPV of the project turns out negative when the project covers a certain part of the yearly demand. In addition, the size of the mini-grid can be a restriction in the project because of the area possible to acquire in Mpunge. Further, the lending rate of project loans, in connection with the investors risk preference, can be conclusive for whether the project is attractive for the investor or not. On the other hand, possible overestimations in demand does not affect the expected NPV of the project severely. This, as well as insignificant decreases in objective function values with increased weight on CVaR, points to the low value in representing strategic uncertainty observed for the project.

Combining DCF analysis with stochastic programming also showed to be valuable, as the depreciation tax shield for the project largely contributed to its positive NPV. Overall, the results presented as output from the standardized process are interpreted as realistic, and therefore we conclude that the optimization model functions as intended.

Given that it is possible to acquire a high amount of grants, a big enough area for the construction of the mini-grid, and that all essential agreements with authorities are feasible, while the investors risk preference gives the project a positive expected NPV, we conclude that the project should be initiated. Thus a few further investigations are necessary to make the final decision on whether the project will contribute to enhance SunTap's market position in the solar technology market of Uganda.

Chapter 9

Further work

Both the standardized process that we have developed and the stochastic programming model within could be improved with further work. The standardized process could be extended to incorporate other aspects important in the type of projects discussed in the thesis, while aspects that have been neglected in the stochastic program can be included.

Firstly, where our process ends, at the beginning of legal processes and project planning, further guidance could be provided to ensure that this next project phase is concluded efficiently. This would ensure that the entire process from project idea to construction is preserved. In addition, technical aspects such as energy system design could be embedded in the process to increase the technical realism of the project assessed.

To increase the value of utilizing long-term uncertainty in the stochastic program as well as the realism of it, we first want to recommend that some of the model aspects that we have neglected through assumptions are incorporated. This includes incorporating binary variables to allocate fixed costs solely when investments are actually made in the project. But binary variables will make the problem an integer problem, and it will thereby require increased computational power to solve it. Adding different solution algorithms to the stochastic program is therefore also recommended. In addition we want to suggest that economies of scale for investment costs are implemented. This will increase the incentive of pooling larger investments together in fewer periods, which can also possibly increase the V(S)SS for problems where this otherwise would be low.

Another option that will increase the value of utilizing long-term uncertainty in the stochastic program is incorporating additional strategic uncertainties. We recommend that the uncertainty in future allocation of grants and the uncertainty of whether political instability will shut down the project are incorporated as different scenarios in the model formulation. Of course, the incorporation of these uncertainties also increase the realism of the model.

To further increase the realism of the model we suggest that the decrease in panel- and battery efficiency is included in the model. Therefore an approach for tracking both the age of these assets and the charge-cycles of batteries is our final recommendation for further work.

Appendix A

Calculations and illustrations

A.1 Real and nominal values

The relationship between real and nominal values are given by the relationship in equation A.1:

$$r_r = \frac{1+r}{1+i} - 1 \tag{A.1}$$

where r_r is the real interest rate, r is the nominal interest rate and i the inflation rate (Berk and DeMarzo, 2014, pp. 148).

A.2 Statistical properties

The statistical properties of the data-series sampled are compared to the historical data by the first four moments (mean, variance, skewness and kurtosis). All the four moments are equally weighted, and the sum of the four moments on temperature and irradiance are used to compare the data sets. The following procedure is performed for each scenario tree generated, U. For each hour,h, in a 24 hour period, and each data-type (irradiance and temperature),w, the four moments,u, is calculated. $m_{\text{tree}}^{h,u,w}$. The same is done for the historical data, resulting in $m_{\text{hist}}^{h,u,w}$. The absolute relative difference is taken, and the sum over each hour, moment and weather type is calculated. Thus, from all the scenario-trees generated, U, the scenario tree with the lowest statistical difference,$u*$ is selected to represent the irradiance and temperature in our model. A modified version of the formula presented by Seljom and Tomasgard (2015) shows our procedure.

$$\begin{aligned} d^u =& \sum_{w=1}^{2}\sum_{v=1}^{4}\sum_{h=1}^{24}[\frac{m_{\text{hist}}^{w,v,u} - m_{\text{tree}}^{w,v,u}}{m_{\text{hist}}^{w,v,u}}] \qquad (A.2)\\ u =& 1, ..., U \\ u* =& min(u^1, ...u^U) \end{aligned}$$

A.3 Box plot description

A.1 below shows an illustration of the box-plot. Here, $\bar{x}$ is the mean, and is not shown in our plots, M is the median, Q1 is the first quartile and Q3 is the third quartile. The minimum and maximum value in the data-series is at the end of the lines, according to the marks MIN and MAX. Our box-plots are generally vertically aligned, where the maximum value is at the top.

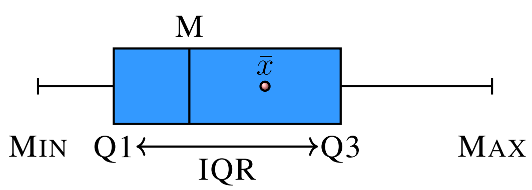


Figure A.1: Illustration of the box-plot, as utilized in this thesis

A.4 Levelized cost of electricity

The calculations of levelized costs of electricity, is calculated utilizing (A.3).

$$\text{LCoE} = \frac{\text{PV (Project costs)}}{\text{Discounted electricity sold}} = \frac{\displaystyle\sum_{t\in\mathcal{T}} \text{Project costs}_t \frac{1}{(1+r)^t}}{\displaystyle\sum_{t\in\mathcal{T}} \text{Electricity sold}_t \frac{1}{(1+r)^t}} \tag{A.3}$$

In (A.3), *Project costs* is the sum of all incoming and outgoing cash flows from the project, except of electricity sales. These cash flows are thus discounted back to obtain present value. The *Discounted electricity sold* is the sum of electricity sold to customers (in kWh) in a given year, discounted back to present with the same discount rate as for the project cash. Thus, the LCoE shows the costs of producing one kWh of electricity.

Appendix B

Input parameters

B.1 Input parameters for LoadProGen

This section shows the input-parameters used for LoadProGen. The detailed data for each appliance is found in Mandelli et al. (2016) and USAID (2006). First, table B.1 shows an overview of the number of each type of class in each strategic time period. The increasing number of classes is based on an assumption of increased development, and standard of living in the area. The households have increasing number as part of their class name corresponding to an increase in how advanced they are. This is illustrated in table B.2, which shows the type of appliances in each class in the first period they are introduced. Generally, the more advanced classes has an increased amount of each appliance. Further, some classes are upgraded with more advanced equipment during the periods within the project.

Table B.1: Number of each type of class in each time period

Classes:	**Period 1:**	**Period 2:**	**Period 3:**	**Period 4:**	**Period 5:**
Household 1	38	105	50	11	8
Household 2	7	21	113	46	85
Household 3	5	8	20	150	193
Household 4	0	3	10	30	62
Household 5	0	0	0	14	35
Household 6	0	0	0	0	2
Health center 3	1	1	1	0	0
Health center 4	0	0	0	1	1
Primary school	1	1	1	1	1
Secondary school	0	0	0	1	1
Mobile money	1	3	4	5	6
kiosk	1	10	15	15	16
Pharmacy	0	1	2	3	3
Barber	0	2	3	4	4
Tailor	0	2	3	3	3
Fish sales	0	5	10	13	13
Hair salon	0	2	3	4	4
Meat shop	0	2	5	8	8
Laundry(simple)	0	0	1	3	4

Table B.2: Appliances in each class when the class is introduced

Classes:	Appliances
Household 1	Lights, phone charger, security lights
Household 2	Lights, phone charger, security lights, radio, AC-TV (small)
Household 3	Lights, phone charger, security lights, radio, AC-TV (small), fridge (small)
Household 4	Lights, phone charger, security lights, radio, AC-TV (small), fridge (small), standing fan, decoder, internet router, laptop (small)
Household 5	Lights, phone charger, security lights, radio, AC-TV (big), fridge (big), standing fan, decoder, internet router, laptop (big)
Household 6	Lights, phone charger, security lights, radio, AC-TV (big), fridge (big), standing fan, decoder, internet router, laptop (big), hair dryer, printer, stereo, water heater
Health center 3	Fluor. Tube (small), security lights, fridge (small), phone charger
Halth center 4	PC, microscope, freezer, sterilizer oven, incubator, water bath, centrifuge, fluor tube, security light, phone charger, fridge (small), fridge (big), ceiling fan, standing fan
Primary school	Flour. Tube (small), phone charger, security light
Secondary school	Flour. Tube (small), phone charger, security light, PC
Mobile money	Light, phone charger, standing fan
kiosk	Light, phone charger, standing fan, fridge (small), fridge (big)
Pharmacy	Light, security light, fridge (small), fridge (big), standing fan
Barber	Light, 12V shaver, ceiling fan, UV sterilizer
Tailor	Light, sewing machine, ceiling fan
Fish sales	Light, freezer (small), fridge (big)
Hair salon	Light, ceiling fan
Meat shop	Light, freezer (small), fridge (small)
Laundry(simple)	Light, water heater

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