TECHNICAL AND ECONOMIC FEASIBILITY OF LARGE SCALE CONCENTRATING SOLAR POWER DEPLOYMENT IN KENYA

SUSTAINABLE ENVIRONMENT AND ENERGY SYSTEMS

MIDDLE EAST TECHNICAL UNIVERSITY

NORTHERN CYPRUS CAMPUS

BY

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IN PARTIAL FULFILLMENT OF THE REQUIREMENTS

FOR

THE DEGREE OF MASTER OF SCIENCE

IN

SUSTAINABLE ENVIRONMENT AND ENERGY SYSTEMS PROGRAM

AUGUST 2017

Approval of the Board of Graduate Programs

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ABSTRACT

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M.Sc., Sustainable Environment and Energy Systems

Supervisor: Assoc. Prof. Dr. Murat Fahrioğlu

August 2017, 80 pages

The electricity generation portfolio in Kenya has experienced some problems in the recent past due to the reliance on hydro power which in the event of poor hydrology has led to deployment of expensive diesel fired power plants. Energy planners have sought to diversify the sources utilized for power generation to mitigate risks related to over reliance on hydro and as a result the generation expansion plan for Kenya as outlined in the Least Cost Power Development Plan (LCPDP) is characterized by a significant drop in the share of renewables. It is specifically noted that solar power plants have been excluded from the list of potential generation sources, despite the abundance of solar resource in the country.

In this research, Concentrating Solar Power (CSP) plants are investigated and proposed as a candidate technology that can be integrated into the current generation mix. Aside from an evaluation of the best potential sites, some performance parameters as well as a few economic indicators are investigated. Four configurations of CSP plants are explored; solar power tower plant with storage, parabolic trough plant with storage, parabolic trough plant with fossil fuel back-up and parabolic trough plant with biomass back-up.

Results obtained indicate that the power tower technology configuration has a higher annual energy output than the parabolic trough technology and the power tower plant at Lodwar with storage is considered the most viable alternative in regard to location and minimal greenhouse gas emissions. In term of cost, specifically the levelized cost of electricity (LCOE), it is noted that CSP plants could already be cheaper than diesel plants by approximately 2 $ ¢/kWh and any favorable taxation terms would be sure to spur interest from investors in development of CSP plants. The parabolic trough with biomass back up is considered the second best alternative and achieves the lowest LCOE out of the four configurations at 18.8 $ ¢/ kWh which is observed to be competitive to that of a coal fired plant with a LCOE of 17.8 $ ¢/ kWh (assuming a discount rate of 12% for both plants.)

A key hindrance to the deployment of CSP is the current feed in tariff which falls short of the most conservative estimates for LCOE rates and would need to be reviewed or an alternative power purchasing agreement arrangement would have to be instituted between the power producers and the distributor in order to make development possible.

In general all four configurations are viable options to increase if not maintain the status quo in as far as the share of renewables in the electricity generation portfolio is concerned.

Keywords: parabolic trough, solar power tower**,** concentrating solar power

ÖZ

KENYA'DA BÜYÜK ÖLÇEKLİ KONSANTRE GÜNEŞ ENERJİSİNİN TEKNİK VE EKONOMİK FİZİBİLİTE

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Yüksek Lisans, Sürdürülebilir Çevre ve Enerji Sistemleri

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Ağustos 2017, 80 sayfa

Kenya'daki elektrik üretim portföyünde bazı sorunlar yaşanmıştır. Yağılarla ilgili sorunlar ve hidro elektriğe olan bağımlılık yakın geçmişte pahalı dizel yakıtlı elektrik santrallerinin kurulmasına yol açtı. Enerji planlamacıları da riskleri azaltmak için enerji üretimi için kullanılan kaynakları çeşitlendirmeye çalıştı. Hidro elektrik santrallerine aşırı bağımlılık sağlamak ve Kenya'nın En Az Maliyetli Güç Geliştirme Planı'nda (LCPDP) ana hatları ile tanımlanan yenilenebilir pazardaki payı önemli ölçüde düşürdü. Ülkede güneş enerjisi bolluğu olmasına rağmen güneş enerjisi potansiyel üretim kaynakları listesinden çıkarıldı..

Bu araştırmada, Yoğunlaştırılmış Güneş Enerjisi (CSP) üretim teknikleri incelenmiş ve Mevcut nesle entegre olabilecek bir aday teknoloji olarak önerilmiştir. En iyi potansiyel bölgelerin değerlendirilmesinin yanı sıra, bazı performans parametreleri ve birkaç ekonomik gösterge araştırılmaktadır. CSP'nin dört değişik opsiyonu araştırılmaktadır; Depolamalı kule tipi güneş enerjisi santralı, Depolamalı parabolik yoğunlaştırıcı güneş enerjisi santralı, fosil yakıt yedeklemeli parabolik yoğunlaştırıcı güneş enerjisi santralı ve biyokütle destekli parabolik yoğunlaştırıcı güneş enerjisi santralı.

Elde edilen sonuçlar, güç kulesi teknolojisi konfigürasyonunun daha yüksek yıllık enerji çıkışı olduğunu ve Lodwar'daki Depolamalı Parabolik yoğunlaştırıcının da Yer ve minimum sera gazı emisyonu bakımından en uygun seçenek olduğunu gösteriyor. Maliyetlere bakılırsa özellikle LCOE olarak, CSP tesislerinin daha önceki Dizel tesislerine göre yaklaşık 2 $ ¢ / kWh daha düşük maliyetli olduğunu ve bir vergi kolaylığında yatırım imkanı sağlayacağını gösteriyor. Biyokütle desteğiyle

parabolik yoğunlaştırıcı da ikinci en iyi alternatif olarak kabul edilir ve dört konfigürasyonun en düşük LCOE'sini 18.8 $ ¢ / kWh olarak gerçekleştirir; 17.8 $ ¢ / kWh'lik bir LCOE ile kömürle çalışan bir tesisin de rekabetçi olduğu gözlemlendi (Her iki tesis için de % 12 faiz oranı varsayılır.)

CSP'nin konuşlandırılmasının kilit engeli tarife için geçerli olan fiyatlardır.

LCOE oranları için en muhafazakâr tahminlerin altında ve gözden geçirilmiş veya alternatif bir güç satınalma sözleşmesi düzenlemesi olmalıdır. Bunu yapmak için güç üreticileri ile distribütörler arasında kurulacak anlaşmalar önemlidir.

Genel olarak, dört yapılandırmanın tamamı, Elektrik enerjisi üretim portföyündeki yenilenebilir enerjilerin payını arttıracaktır.

DEDICATION

To my family for their continuous support.

ACKNOWLEDGEMENTS

I am very grateful to my advisor, Assoc. Prof. Dr. Murat for his invaluable guidance and support throughout this work that has made the completion of this research possible.

Special thanks to my advisor and jury committee members, Asst. Prof. Dr. Onur Taylan and Prof. Dr. Serkan Abbasoğlu whose insightful feedback and critique has helped polish and improve this thesis work tremendously.

I would like to acknowledge and thank the national control centre, Kenya Power, for providing data on typical daily load curves.

The SEES program has been a great learning experience that has opened my mind to so many disciplines beyond energy matters and I am truly grateful to the SEES committee and coordinators for the program they have structured over the past four semesters. I am also thankful to my fellow students in the SEES program; Elham Jahani, Phebe Owusu, Remember Samu, Hope Nabwire, Fidan Abdullayeva and many others for being such great company and making the program that much more enlightening and enjoyable.

I would also like to thank the METU NCC Electrical Engineering department for the opportunity to work as a teaching assistant; it has been a truly edifying experience that has gone a long way to support the completion of my SEES program. It has been a pleasure and I would like to extend my gratitude to the department coordinator, Dr. Tayfun as well as my fellow teaching assistants who have been a great team to work with.

The support and encouragement from my family and friends has been unparalleled and I am forever grateful to my parents, Elsie Kiema, Musa Kiema, Charity Supeyo, Anthony Mulaimu, Githinji Kiama and Emmy Simotwo for being my biggest cheerleaders; without whom I would not be where I am today.

Finally I would like to thank God for the opportunity and strength to undertake this wonderful experience.

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LIST OF ACRONYMS AND UNITS

CSP	Concentrating Solar Power
DNI	Direct Normal Irradiance
DSG	Direct Steam Generation
ERC	Energy Regulatory Commission
FCC	Fuel Cost Charge
FiT	Feed In Tariff
GW	Gigawatt
GWh	Gigawatt hour
HFO	Heavy Fuel Oil
HTF	Heat Transfer Fluid
IPCC	Intergovernmental Panel On Climate Change
IPP	Independent Power Producers
ISCC	Integrated Solar Combined Cycle
KenGen	Kenya Electricity Generating Company
KETRACO	Kenya Electricity Transmission Company
KPLC	Kenya Power and Lighting Company
kWh	kilowatt hour
LCOE	Levelized Cost Of Electricity
LCPDP	Least Cost Power Development Plan
LF	Linear Fresnel
MMBTU	Million British Thermal Units
MW	Megawatt
NG	Natural gas
PD	Parabolic Dish
PT	Parabolic Trough
PTC	Parabolic Trough Collector
PV	Photovoltaic
SAM	System Advisor Model
SM	Solar Multiple
SPT	Solar Power Tower
SWERA	Solar and Wind Energy Resource Assessment
TES	Thermal Energy Storage
VAT	Value Added Tax

CHAPTER 1

INTRODUCTION

Since the advent of electricity to power homes and industries in the late 19th century, electricity now enables operations in virtually all sectors including transport, agriculture and finance. Despite the accelerated growth of electricity generation and transmission infrastructure, there are still approximately 1.2 billion people in the world who lack access to electricity [1]. According to global electricity access data as at 2013, the majority of this population was in Africa and developing Asia with the balance in Latin America, Middle East and some transition economies [1]. Kenya has an electrification rate of 30%-40% which means quite a bit of work has to be done to achieve country wide connectivity [2], [3]. It is within this context that concentrating solar power (CSP) is envisaged as a technology that can be incorporated into Kenya's electricity generation portfolio towards satisfying a growing energy requirement. The electricity demand grew from 5700 GWh in 2010 to 7300 GWh in 2015 and is expected to increase at a rate of between 9 - 16 % in the period between 2018-2033 [2], [4]. There is thus a need to investigate technologies that will be deployed in the capacity expansion of power generating units and this work forms a basis to evaluate whether CSP plants are a viable alternative.

Apart from meeting the energy need, CSP plants also provide an opportunity to increase the share of renewables in the electricity generation portfolio of the country which currently stands at 65%. The exploitation of renewable energy for power production is now an important consideration in electricity generation planning on a global scale cognizant to the fact that the power generation industry is a leading contributor to CO_2 emissions and its subsequent effects to the environment. According to the Intergovernmental Panel On Climate Change (IPCC) this contribution is estimated at 35% making the energy sector the single largest contributor to global CO_2 emissions [5]. It is therefore apparent that development of CSP plants would mitigate production of CO_2 especially given the current reliance on heavy fuel oil (HFO)/diesel powered plants in Kenya.

This thesis presents a technical and economic evaluation of four CSP plant configurations that can be developed based on parabolic trough and solar power tower technologies.

1.1 Motivation

The dominant electricity generation sources in Kenya are hydro, diesel/ HFO and geothermal with hydro and geothermal sources accounting for 65% of the installed capacity. However due to increased variations in climatic conditions including the hydrologic cycle, electricity generation from hydro plants is deemed to be potentially unreliable during dry hydrological years. In the recent past, failure of rains has led to low stream flows and subsequent declined hydro power production due to low water levels in reservoirs. The electricity deficit not met by the hydro plants has traditionally been met by diesel power plants which almost always translates into increased electricity cost per kWh. It is against this back drop that the electricity generation plan for Kenya outlined in the least cost power development plan (LCPDP) 2013-2033 proposes a diversified mix of power generation sources to meet the electricity demand in 2033. The proposed generation sources include geothermal, coal, natural gas, diesel, wind, nuclear and hydro [2]. As would be expected, the diversification of electricity generation sources minimizes the impact of variability of any one of the sources including hydro on the power system. The proposed mix of generation sources may be good news for the stability of the power system, but it is also interesting to note the drop in the share of renewable energy sources due to proposed addition of generation capacities reliant on fossil fuels. The LCPDP does not clearly outline the reasons if any for exclusion of solar power plants in the analysis of potential electricity generation sources.

This therefore serves as a motivation to investigate the viability of concentrating solar power (CSP) plants to supply a significant share of Kenya's electricity demand, and this forms the backbone of this research. There is an estimated 28,000 km^2 area of land receiving daily normal irradiance (DNI) of above 6 kWh/ m^2/ day which makes for very good potential sites for solar CSP power plants [2]. A figure of approximately 5 kWh/ m^2/ day or equivalently 1800 kWh/ m^2 /year is quoted in literature as being the threshold DNI for economically viable CSP plants [6], [7].

1.2 Objectives of the study

This thesis aims to fulfill three major objectives. The first is to add to the growing body of literature on national level assessment studies for CSP such as [8]–[13] and also provide a guideline on possible configurations of CSP plants that can be implemented based on current operational CSP plants and the resources available at a particular location.

The second objective is to evaluate and propose best potential sites for the various CSP configurations in Kenya based on geography; that is evaluate factors such as altitude, availability of water or biomass etc. and climatic conditions, of which direct normal irradiance (DNI) is the most important.

The third objective is to evaluate the expected performance of the proposed configurations in terms of energy production (GWh) and also in terms of cost specifically the levelized cost of electricity (LCOE) and make a determination of whether the current feed in tariff (FiT) rate applied to power produced from solar resources can accommodate or encourage development of these plants. Sensitivity analysis was also carried out with the aid of the optimization tool in the System Advisor Model software to determine optimal size of the solar field and sizes of the thermal storage component where applicable.

1.3 Thesis Structure

Chapter two presents a discussion of the electricity sector in Kenya beginning with a historical overview and proceeding to a recap of the major reforms that have been instituted to date. This includes a summary of current electricity generation facilities as well as the planned incremental capacity. The chapter also covers the status of solar power development in Kenya and there is a discussion on the factors that make CSP a suitable alternative for Kenya's generation portfolio as opposed to the main alternative which is solar PV. The solar resource required for CSP plants is also discussed in this section.

Chapter three covers the literature review which is split into three sections. The first deals with the components and working principle of the four main CSP technologies as well as a review of heat transfer fluids and thermal energy storage in CSP plants. The second and third sections discuss literature on the investigation into various CSP configurations and the studies that have been carried out on the exploitation of solar resource in Kenya respectively.

The methodology employed is presented in chapter four and it broadly describes the site selection and the model formulation of the two CSP technologies investigated in this research; solar power tower and parabolic trough.

Chapter five presents the results and discussion of the four CSP configurations analyzed. Major sizing and performance indicators such as capacity factor, LCOE and annual energy produced are discussed and thereafter the conclusions drawn and recommendations for future work are put forward in chapter six.

CHAPTER 2

ELECTRICITY SECTOR AND SOLAR RESOURCE DEVELOPMENT IN KENYA

2.1 Historical background and structure

The electricity utility company, Kenya Power and Lighting Company (KPLC) which is the sole power distributor in the country traces its origin to the Kenya Power Company (KPC) which was established in 1954 to facilitate electricity transmission infrastructure development between Nairobi and Tororo, Uganda. KPC which was a subsidiary of the East African Power and Lighting Company changed its name to KPLC in 1983 [2].

Major reforms were carried out in the electricity sector in 1997 most notably the decentralization/ unbundling of the transmission and distribution functions. KPLC remained with the transmission and distribution function while Kenya Electricity Generating Company (KenGen) took up the generating function [2]. Subsequent reforms were instituted as a result of the sessional paper No.4 on Energy in 2004, in which an attempt was made to separate the transmission and distribution functions. There were however difficulties in unbundling KPLC and as a result a new body was formed in 2008, the Kenya Electricity Transmission Company (KETRACO), which was tasked with the construction and maintenance of all new transmission infrastructure while the existing transmission system at the time remained under KPLC's jurisdiction [14]. Other significant reforms include the establishment of the Rural Electrification Authority (REA) in 2007 and the Geothermal Development Company (GDC) in 2009 to fast track development of geothermal power in the country; both as a result of the energy act No.12 of 2006 [15].

The current institutions in the power sector include the Ministry of Energy (MoE), Energy Regulatory Commission (ERC), KenGen, KPLC, REA, KETRACO, GDC and the Nuclear Energy Project Committee (NEPC) [2]. An overview of the structure of the power sector is presented in Figure 1 [2].

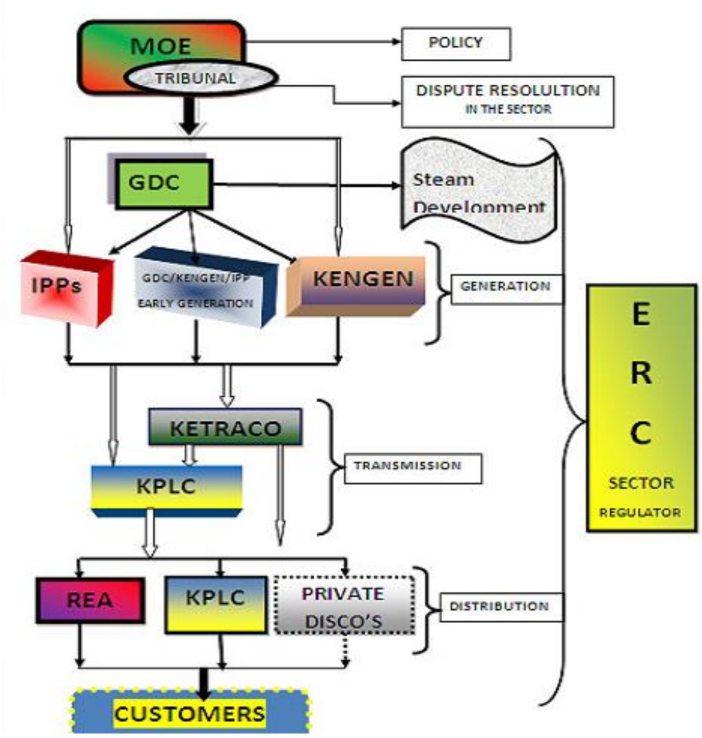


Figure 1: Structure of electricity sector [2]

2.2 Electricity generation portfolio and challenges in the industry

As aforementioned, the current predominant electricity generation sources are hydro and geothermal resources. Kenya has a total installed capacity of approximately 2,300 MW as at June 2016 and approximately 65% is constituted of renewables. These renewable technologies include hydro, geothermal, cogeneration (primarily from bagasse), wind and biomass and they constituted 87% of the total electricity generated (GWh) in the same year [4]. A table indicating current generating capacity as well as the planned capacity in 2030 is presented in Table 1 (imports were excluded from this analysis since essentially they cannot be considered as 'installed' capacity) [2], [4]. The term renewables in this research is assumed to include reservoir type hydro plants while diesel plants is used as a general term for plants utilizing diesel, HFO and kerosene.

The system peak demand in the 2015/2016 period was 1586 MW and the peak typically occurs in the evening as indicated in a typical daily load curve in Figure 2.

Table 1: Current grid connected generating capacity per technology and planned generation capacity in 2030 (base case) [2], [4]

Generation technology	Installed capacity (MW)	
	2016	**2030**
Hydro	820	979
Diesel	817	988
Geothermal	632	5331
Cogeneration	26	18
Wind	25.5	1486
Biomass	2	0
Natural gas	0	1980
Nuclear	0	1800
Coal	0	2400
Total	**2322.5**	**14982.0**

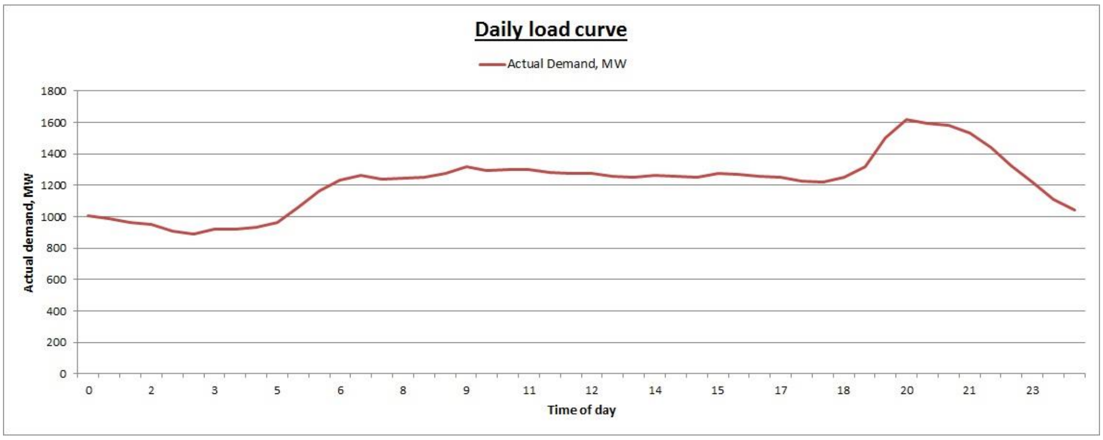


Figure 2: Typical daily load curve from February, 2017. Source: KPLC National Control Centre

Industrial consumption accounts for approximately 60% of the total and projections of the rate of increase of this consumption affects to a huge extent the planned generation capacities as will be discussed in the next section. A time series plot of both industrial and domestic demand over the period 2005-2015 is presented in Figure 3 [4], [16]. Domestic consumption has been observed to increase exponentially over time while industrial consumption has experienced some fluctuations. The latter is heavily reliant on the state of the economy and the dips in demand in the year 2008 and 2012 could be explained by slowed economic growth following the 2007 and 2012 general elections respectively.

Some of the major challenges faced in the sector that are relevant to this study include the fluctuation of electricity prices due to use of diesel power plants and occurrence of power interruptions that last for a few minutes up to several hours.

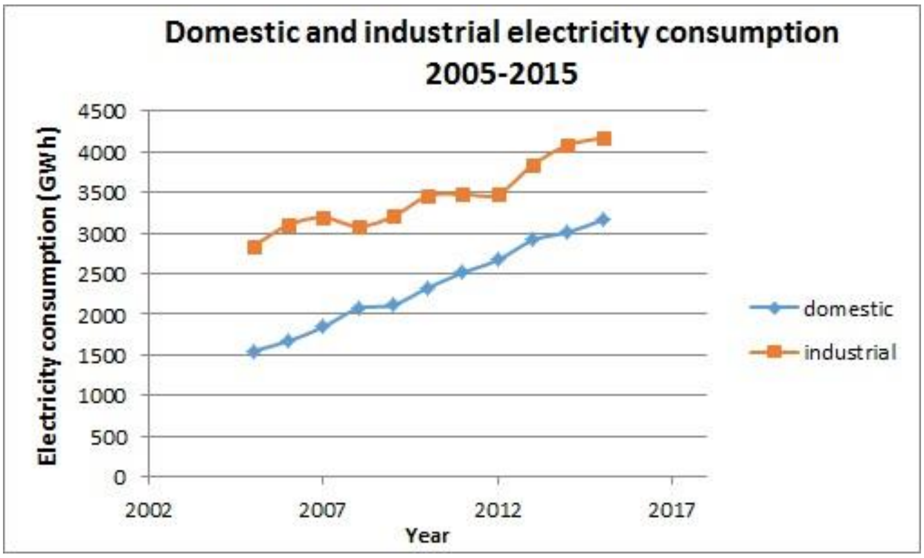


Figure 3: Domestic and industrial electricity consumption 2005-2015 [4], [16]

To illustrate the effect of the fuel cost on the retail electricity price, Table 2 presents a breakdown of the retail price for a domestic and industrial customer, category C2 (11 kV). The fuel cost charge (FCC) element of the electricity bill for the month of July varied by 5 $ ¢/kWh in 12 months between 2014-2015 due to volatility in fuel prices [17]. Reducing the share of power produced from diesel plants, in favor of renewables such as CSP plants would therefore result in more stable prices to the advantage of both industrial and domestic consumers. The FCC is a function of fuel cost and the number of units generated from the diesel plant operators among other considerations and in effect, increased generation from these units also translates into increased electricity price [18].

Power outages in the system could be as a result of a myriad of factors and a an analysis of the causes of approximately 200 load shedding events in the period between 2011-2012 in a thesis study in [19] provides some insight into the major causes. These were narrowed down into two, the first being unavailability of generating units, 70% of the cases being due to geothermal, diesel and combined heat and power plants with the balance as a result of hydro plants being out of service.

The other leading cause was due to insufficient stream flows in the hydro reservoirs as a result of poor rainfall patterns [19].

Table 2:Retail electricity price for domestic and industrial consumers in July 2014 and 2015 [17]

	Industrial retail price ($ ¢/kWh)		**Domestic retail price ($ ¢/kWh)**	
	Jul-14	Jul-15	Jul-14	Jul-15
Consumption	8.25	8	13.68	12.75
FCC (fuel cost charge)	7.22	2.51	7.22	2.51
VAT	2.55	1.86	3.42	2.62
FERFA	0.33	0.89	0.3	0.89
IA	0.18	0.23	0.18	0.23
WARMA	0.06	0.05	0.06	0.05
ERC	0.03	0.03	0.03	0.03
REP	0.41	0.41	0.68	0.64

These power outage causes indicate the need for additional generating capacity to increase the reserve margin while diversifying the sources so as to reduce the impact of poor hydrology on electricity generation. The Ministry of Energy developed a long term electricity generation planning blueprint, the Least Cost Power Development Plan (LCPDP), to deal with some of these highlighted issues and it is discussed in the next section.

2.3 LCPDP and the status of planned generation

2.3.1 Least Cost Power Development Plan

The LCPDP covers three major components which are electricity demand forecast, generation planning and transmission planning though the generation planning is of particular interest to this research. Three generation planning scenarios are developed based on demand growth projections. For instance the low growth scenario assumes a ‘business as usual’ stance where demand would grow as a result of increasing population/industrialization while the reference growth scenario takes into account the demand of energy intensive projects such as the electrification of the Nairobi-Mombasa railway line and infrastructure at the Lamu port. The planned generation capacities for the base case scenario (medium demand growth) are indicated in

Table *1* [2]. Of immediate interest is the fact that the share of renewables drops to approximately 45% (without considering the imports) down from the current 65% due to the introduction of natural gas, nuclear and coal fired power plants. This would seem to contravene the concept of decarbonizing the power industry which is the trend in most countries globally. The second thing to note would be the absence of both solar and biomass powered plants despite the recognition of the fact that both represent a significant potential for electricity generation. It is the intent in this research to show that CSP plants can indeed provide an alternative generation technology to reverse the trend of increased 'carbonization' of the generation portfolio.

Other potential shortfalls of the LCPDP generation plan include:

- Imports: The value of imports expected to be in use in 2030 is 2000 MW most of which is expected to be purchased from Ethiopia. This represents 12% of the capacity however there are concerns as to whether Ethiopia would be in a position to supply the projected power given the complications that may arise in development of mega hydro projects coupled with the fact that Ethiopia's electrification rate stands at 20% [20]. This would indicate that there is a need for energy planners to re-evaluate the share of imports and possibly develop other renewable energy options.
- Classification of wind power as a base load project: The LCPDP designates wind power as a base load plant contrary to the fact that the wind resource is highly variable and can cause major power system disturbances especially for small/autonomous electrical grids. Intermittent resources such as wind could be deployed to meet the base load if some form of storage is incorporated or if multiple plants are distributed and thus act as a 'single unit' [21]. It is however noted that for the Lake Turkana Wind Power (LTWP) plant, which is Kenya's first large scale wind farm (300 MW) which is set to be commissioned sometime in 2017, that there is no storage capability which calls to question the designation of wind power as being base load. It is worth mentioning that there are reports of development of a 500 kW flywheel storage system in Marsabit which is a town located 200 km form the LTWP

site and is currently not served by the grid. The storage however has no relation to the LTWP and is essentially expected to stabilize the off-grid system comprised of two 275 kW wind turbines and some diesel generators [22].

2.3.2 Status of planned generation

The current electricity demand seems to be falling short of the projections in the LCPDP. In 2015/2016 period, total electricity consumption was 7,300 GWh against an estimated 11,572 GWh for the year 2015 for the low growth scenario in the LCPDP report [2], [4]. It would therefore seem that the sequence of planned incremental generation may outstrip demand if implemented as it is. This concern came to the fore when KenGen decided to suspend the development of the 700 MW natural gas fired Dongo Kundu plant in Mombasa over concerns that this idle capacity would come at a cost to the consumers [23]. In light of this decision, it is very interesting to note that the ERC has recently given a go ahead for the development and construction of a 1000 MW coal plant at the coast at Lamu. Apart from the issue of using coal, which has the highest CO_2 emissions among fossil fuel technologies, there is a question about the possibility of capacity outstripping demand and it remains to be seen how the energy planners will handle this situation [24]. In relation to the ERC's decision, it is worth noting that political interference in form of using developments in the energy sector to gain political mileage could explain some of the seemingly miscalculated steps in regard to future generation projects, but this is a hallmark of the energy sector that is likely to reverse going forward if better accountability and regulation measures are instituted.

2.4 Status of solar power development in Kenya

There are currently no CSP plants in Kenya and the solar resource has been utilised most prevalently in solar home systems and in photovoltaic (PV) off-grid and mini grid systems where in some instances diesel is hybridized with solar PV such as in the diesel-solar hybrid system in Lodwar [2], [25]. The PV systems have been primarily small scale (≤ 1 MW) though there are several large scale plants under development by both the government and independent power producers (IPPs) [26]. Most recently (as at June 2017), the utility company Kenya Power has signed PPAs with IPPs for development of solar PV plants totaling to 160 MW expected to be grid connected in 2018/2019 [27]. Some of the operational PV plants are presented in Table 3 [25], [28].

Table 3: Selected operational PV plants [25], [28]

Plant	**Capacity (kW)**	**Location**
United Nations Environment Program (UNEP)	515	Nairobi
SOS Children's village	60	Mombasa
Williamson tea	1000	Bomet
Strathmore school	600	Nairobi

In terms of policy, there is a current feed in tariff (FiT) for solar power plants at $ 0.12/ kWh for grid connected plants with a name plate capacity of between 10 - 40 MW [29]. The viability of the current FiT policy in as far as facilitating development of CSP is discussed in section 5.1.2. There is also a waiver on VAT for solar PV equipment which stands at 16% which was initially implemented in 2013 but reversed in 2014 [30]. The move received mixed reactions from retailers of imported PV equipment and local manufacturers with the latter arguing that the waiver would stifle growth of the local PV manufacturing industry while the former argue that this would increase investment in solar PV due to cheaper costs to the consumer [31].

2.5 The choice of solar CSP

There are several technologies that have been utilized to harness solar energy for the purpose of electricity production including PV, CSP, concentrated PV and solar chimneys. PV and CSP are the most widely applied on a utility scale though the growth in the number of CSP plants has been slow as compared to that of solar PV as is evidenced by their respective global installed capacities. Towards the end of 2016, 4.8 GW of CSP plants were operational against 303 GW of PV [32]. The barriers to accelerated CSP deployment include long lead times, high capital cost, weak regulatory framework- which in some cases has led to reluctance of involvement by investors due to perceived low long term profits and reduction in component cost that has been slow as compared to PV [33]. However, in spite of these setbacks, CSP is increasingly being recognized as having a clear edge over PV based on certain criteria such as;

- Auxiliary fuel integration: CSP plants can be hybridized with other fuels such as diesel, natural gas or biomass thus increasing the efficiency of the power block and resulting in increased capacity factor. This can be a viable alternative to storage that can allow the plant to supply the base load.
- Process heat: CSP plants have the advantage of supplying both electricity and process heat if required for heating purpose or other industrial requirements. Some plants that have been employed to supply process heat are presented in Table 4 [34].
- Thermal storage: One of the greatest challenges in integrating large scale PV into the grid is the intermittency of the power produced which can be resolved by use of storage technologies such as batteries, flywheels and compressed air energy storage (CAES). Batteries have been employed only at a small scale and there is still no storage technology that can be considered a front-runner in terms of being economically viable on a large scale. Examples of battery storage that have been employed on a utility scale include the 1 MW Catania 1 solar PV plant which has a 2 MWh battery capacity, the Pelworm solar PV-wind hybrid plant with a 560 kWh lithium ion battery coupled with a 1.6 MWh redox flow battery and the 1.5 MW Glastonbury solar PV plant which employs 668 kWh of battery storage [35]–[37]. One of the main challenges of battery storage is that they require replacement after approximately 10 years and would also require careful planning on proper disposal and recycling in the absence of which the batteries pose a threat to the environment. It is in this context that CSP plants provide a storage solution in the form of thermal storage (most commonly using molten salt as the medium) which has already been proven commercially and would require no replacement throughout the life of the plant (approximately 30 years) [38]. Molten salt also has the added advantage of being environmentally friendly since it is essentially composed of sodium nitrate and potassium nitrate and may be used as fertilizer at the end of its life time [38].

Table 4:Selected CSP plants utilized for process heat [34]

Plant	**Country**	**Purpose**	**Status**	**Thermal output (MW_{th})**
Minera El Tesoro	Chile	Mining	Operational	7
Petroleum Development Oman	Oman	Enhanced oil recovery	Operational	7
KGDS Narippaiyur	India	Desalination	Operational	N/A
Hermosillo cement	Mexico	Cooling	Under construction	0.29
Frabelle tuna canning	Papua New Guinea	Packaging	Under construction	1

CSP does have its fair share of cons as highlighted in [19]. One of the major concerns is that the number of potential sites are limited since there are several criteria that must be fulfilled to make for a viable development site. This will be covered in detail in section 4.1 but to put it into context, out of the 28,000 km^2 area of land that would make for potential sites based on DNI only a few hundred square kilometers can be developed.

The water requirement for mirror cleaning and cooling of the condenser has been a cause for concern since most of the plants are located in water scarce, desert or arid climatic conditions. However this can be resolved by use of air cooling or hybrid cooling which significantly reduce the water consumption of CSP plants as is discussed further in section 4.2.

The fact that CSP is still a maturing technology can also be considered a barrier to its development. However given the advantages that CSP presents over PV and the steep learning curve coupled with subsequent standardization in CSP technologies, it is expected that the economies of CSP plants will improve and therefore increase their deployment. There is already a promising outlook in regard to the number of commercial plants which amount to 5.8 GW considering both plants that are operational and those that are under construction. This figure doubles to 10.6 GW if planned capacities and those under development are taken into account as at 2015 [34].

2.6 Solar resource suitable for CSP development

In regard to evaluating suitable sites, the solar resource parameter that is the most critical is the direct normal irradiance (DNI) also referred to as beam irradiance. DNI is defined as the solar radiation that is incident on a surface which is normal to the direction of the sun's position [39]. A map indicating various DNI classes is presented in Figure 4 and it is noted that generally the region surrounding Lake Turkana in the north, the western region and some parts along the coastline have the best DNI potential for CSP plants [40].

Accuracy of DNI data and other atmospheric conditions such as humidity are vital in development of CSP plants and lack of these data can hamper efforts to evaluate a location's suitability. Data on humidity for instance can greatly impact DNI since the scattering of sun's rays increases in humid conditions thus decreasing the DNI value [33].

In Kenya, lack of accurate data to facilitate planning has been cited as a challenge to increased renewable energy deployment. Currently there exists data on solar and wind resource developed by the Solar and Wind Energy Resource Assessment (SWERA) at a spatial resolution of 5 × 5 km in contrast to the previously available data from National Aeronautics and Space Administration (NASA) which had a resolution of 100 × 100 km [41].

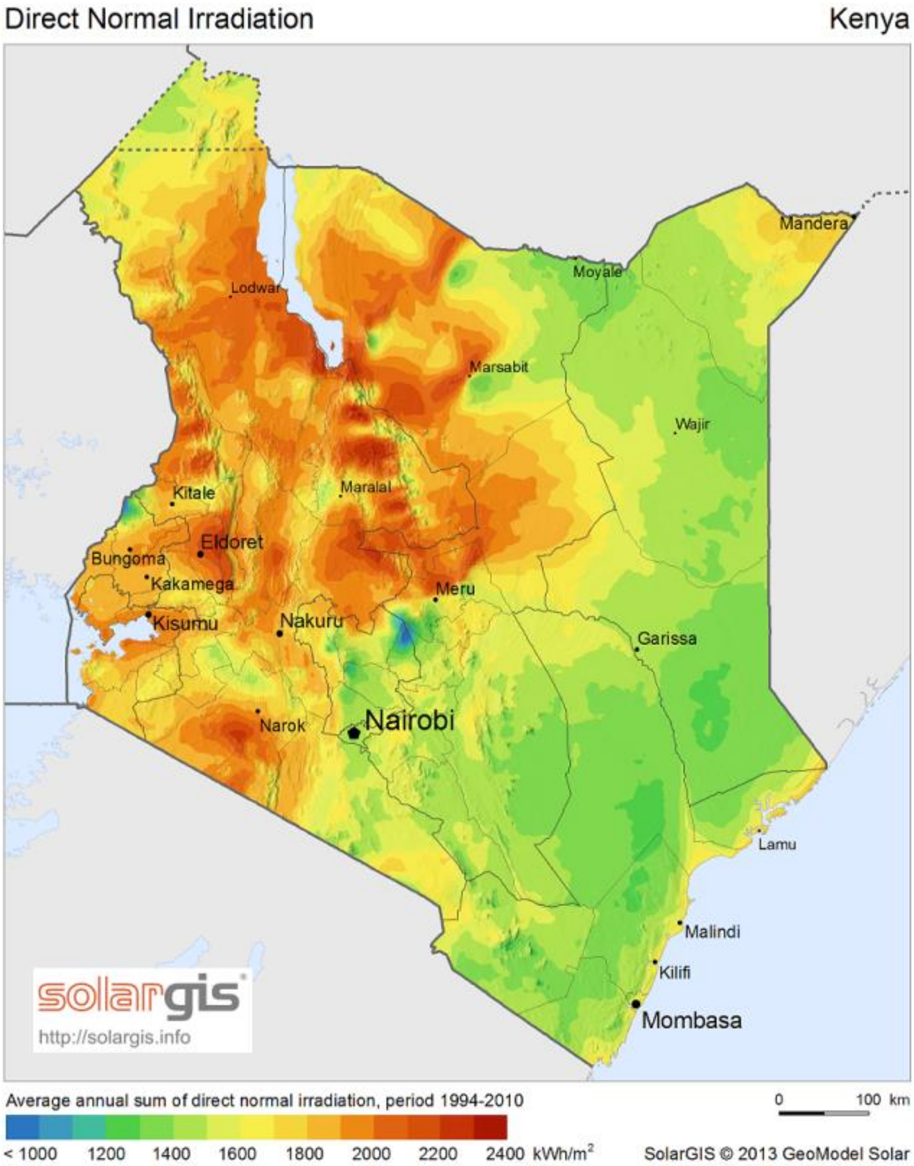


Figure 4: Classification of DNI resource in Kenya [40]

CHAPTER 3

LITERATURE REVIEW

This chapter is divided into three main sections, the first dealing with a review of the available solar CSP technologies and their operation while the second highlights studies that have been carried out on national level feasibility studies and performance of CSP plants in general and lastly a summary of studies on the exploitation of solar resources for power production in Kenya.

3.1 CSP technology

The basic principle of operation of CSP plants is the use of steam heated by means of solar radiation to drive a steam turbine in the power block of the plant. The steam can either be heated directly when used as a heat transfer fluid (HTF) which is described as direct steam generation (DSG) or alternatively heat can be transferred to it in a heat exchanger from other HTFs such as synthetic oil or molten salt. Concentrators which are highly reflective mirrors are used to focus the solar radiation onto a collector [7]. There are four main configurations utilized for concentrating solar radiation, and these can be grouped into two categories; linear concentrators which include parabolic trough (PT) and linear Fresnel (LF) and point concentrators which cover solar power tower (SPT) /central receiver and parabolic dish (PD) [7]. A figure depicting basic components of each of these technologies is presented in Figure 5 [42].

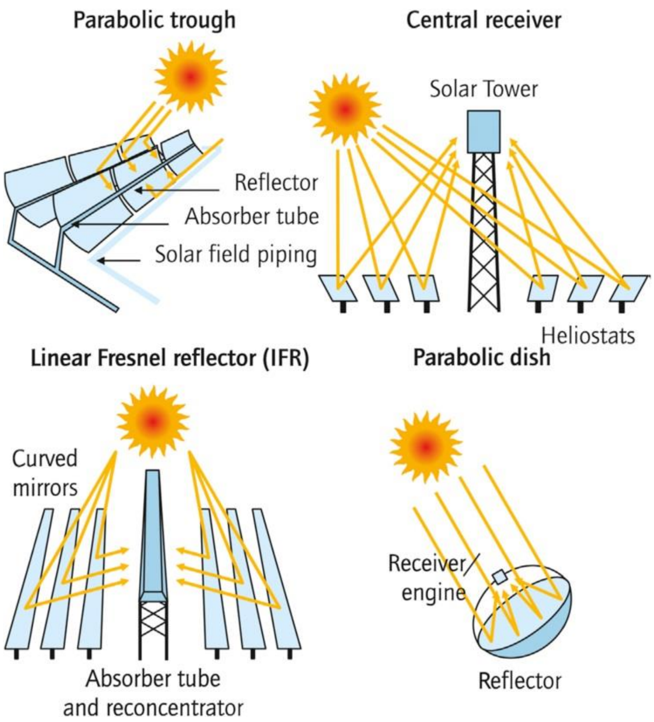


Figure 5: Schematic of the four major CSP collectors [42]

There exists vast literature on the operating parameters of each of the technologies outlining operational temperature, concentrating factor, HTF, range of installation sizes among others [7], [43]. A summary of some of these operational characteristics is indicated in Table 5 [7].

Table 5: A comparison of the operational characteristics of CSP technologies.

Tech.	**Capacity(MW)**	**Conc. factor**	**Peak solar efficiency**	**Annual solar efficiency**	**Thermal cycle efficiency**	**Capacity factor**	**Land use m^2/MWh/yr.**
PT	10–200	70–80	21% d	10–15% d	30–40% ST	24% d	6–8
LF	10–200	25–100	20% p	9–11% d	30–40% ST	25–70% p	4–6
SPT	10–150	300–1000	20% d	8–10% d	30–40% ST	25–70% p	8–12
Dish-Stirling	0.01–0.4	1000–3000	29% d	16–18% d	30–40%	25% p	8–12

(d) indicates demonstrated, (p) indicates predicted, ST indicates steam turbine

Of the four technologies, PT is the most mature in the market while conversely parabolic dish is mainly applied in small scale or off grid operations [33]. The distribution of the technologies among existing operational plants and those under construction is shown in Figure 6 [34], [44].

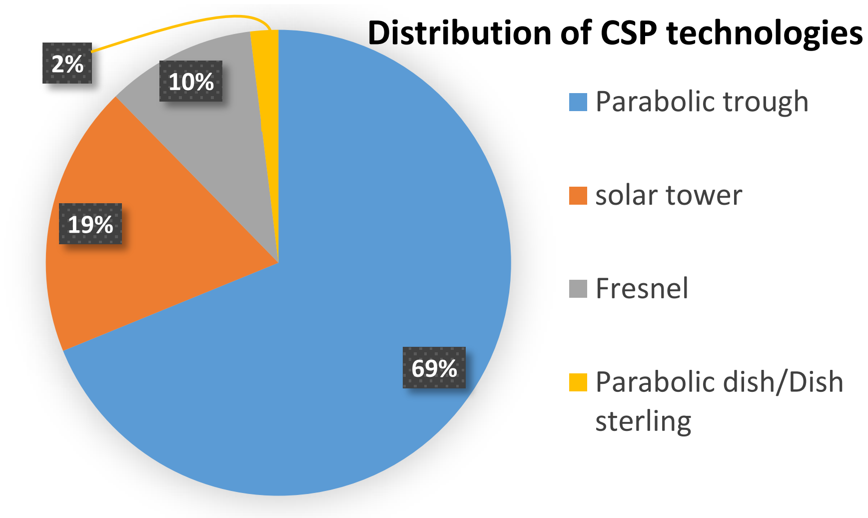


Figure 6: Distribution of concentrator technologies in commercial CSP plants that are operational or under construction

3.1.1 Parabolic trough

Parabolic trough collectors (PTCs) are typically comprised of a parabolic shaped mirror surface and a receiver tube. The basic principle of operation is that the incoming sun's rays are reflected off the mirror surface on to the fixed receiver which contains the HTF. The tube containing the HTF is usually contained in an evacuated transparent glass thus creating a vacuum around it in order to minimize heat losses. It is also usually coated with materials such as nickel-cadmium in order to maximize absorption of incoming radiation while at the same time minimizing long wave radiation emission [7], [42], [45]. A diagram depicting the major components of the parabolic trough collector is presented in Figure 7 [45]. PTCs usually have single axis tracking and can be oriented in the north-south direction or east-west depending on the latitude. As highlighted in [46], most parabolic trough systems are aligned on a north-south axis however those located at latitudes above 46° should be aligned on an east-west axis to minimize cosine losses. The temperatures that can be achieved are largely dependent on the HTF and a detailed discussion of these is presented later in this chapter in section 3.1.5.

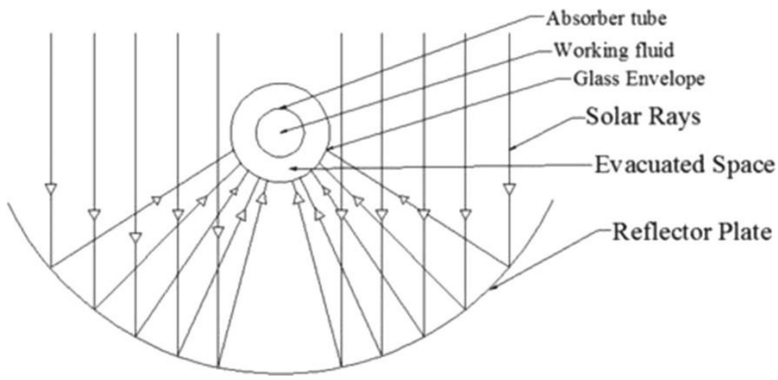


Figure 7: Major components of a parabolic trough collector [45]

There has been a great deal of research on performance of PTC which is a likely contributor to dominance of PTC among CSP technologies. One of the elements that has been investigated in literature is the use of inserts in the receiver tube in order to increase thermal efficiency. The proposed inserts are made out of metal foam or some porous material and achieve increased thermal efficiency by; increasing degree of turbulence by facilitating better fluid mixing, increasing thermal conductivity of the HTF by using a material for the insert with a good thermal conductivity and reducing the thermal resistance by causing disturbances to the boundary layer. One of the downsides of integrating inserts is the increased HTF pressure drop and thus a careful trade off needs to be made between gains in thermal efficiency versus the pressure drop [42]. Another study in [47] investigates the effect of incorporating dimples on the receiver tube surface. The analysis concludes that in comparison to a smooth tube, at a specific Grashof number, dimples with a depth of 1mm have a comprehensive performance factor of between 1.05-1.06 while dimples with a depth of 7mm have a performance range of 1.31-1.34. Authors in [48] evaluate a range of values of the deviation of the receiver tube's focal plane with respect to the direction of solar radiation and their related effect on thermal output of the PTC. The diameter of the receiver tube is found to have a significant impact on the angle of deviation and a larger diameter translates into a reduced concentration ratio.

3.1.2 Linear Fresnel

Linear Fresnel collectors are line concentrators similar to PTC and are usually either flat or slightly curved reflective mirrors which reflect the sun's rays on to a fixed receiver. LF collectors generally have greater cosine losses as compared to PTCs and thus have lower thermal efficiencies [49]. They do offer some advantages over PTCs, the most notable being the reduction in capital cost of up to 50% since they're cheaper to manufacture. They also occupy a smaller area and are easier to maintain in terms of mirror cleaning since the reflectors are at human height [43].

There is no standardization as yet of the layout of the receivers and they may be triangular, vertical or horizontal. The receiver can also be in the form of an array of tubes or in the form of a single tube in which case a secondary reflector is usually utilized so as to increase the optical performance of the receiver [49].

3.1.3 Solar power tower

SPTs are categorized as point concentrators since the solar flux is concentrated to a single receiver hence the name central receiver [50]. The receiver is usually mounted at the top of the tower and the heliostats are arranged mostly in a radial configuration around the tower [51]. The solar field represents up to 50% of the total cost and the configuration employed in regard to the layout of the heliostats affects the performance significantly [52]. For instance if the heliostats are placed close together this can reduce the land requirement and costs associated with wiring but at the same time may decrease the optical performance due to shadowing or blocking [43].

Generally there are four major types of receivers employed in SPT plants as indicated in the block diagram in Figure 8. Those that have been employed commonly are the volumetric and cavity receivers [52]. For cavity receivers, the incoming reflected radiation passes into a cavity and this makes for reduced thermal losses as compared to external receivers. However the aperture is obviously limited so several towers may be required for a particular solar field [33]. Volumetric receivers are usually made of some porous material and they usually act as a heat exchanger such that the HTF leaving the receiver is at a higher temperature than the porous surface receiving the incoming solar radiation [52].

It is worth noting that current heliostat sizes employed in operational plants range in size from 1.14 m^2 to 120 m^2 and it is expected that future standardization of components such as the heliostats can represent a good opportunity for capital cost reduction and present SPT plants a good candidate for CSP development [43].

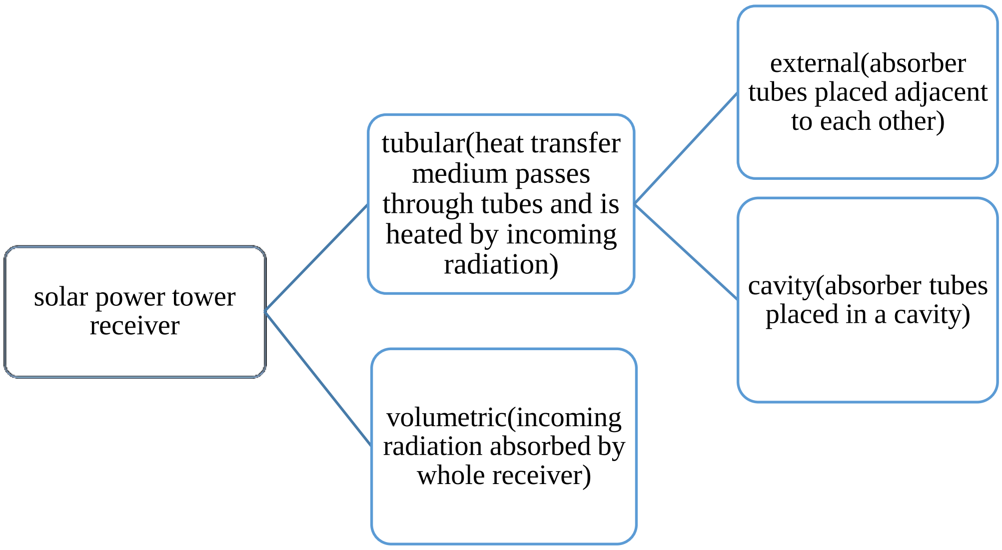


Figure 8: Major types of receivers employed in SPT plants

3.1.4 Parabolic dish

Parabolic dish concentrators are made out of reflective mirrors which focus the incoming solar radiation at its center. An engine can be placed at the center or alternatively the heat is converted by a plant on the ground level. The sterling engine is the most popular application which has been reported to obtain efficiencies of up to 30%, which ranks as the highest among all concentrator technologies [53]. PD concentrators also offer the best concentration factors of between 1000-2000 suns but in spite of this they are deemed as not being suitable for large scale applications due to high manufacturing costs and the fact that they do not present a good opportunity for storage [33].

3.1.5 Heat transfer fluid

As aforementioned the HTF is the working fluid which typically transfers heat from the collector to the power cycle. HTFs that have been employed in existing operational plants include water, synthetic oils and molten salts.

Water/steam is ideal for applications that operate at a temperature below 200 ^{o}C because above this there is need to use piping with reinforced joints that can increase the component cost significantly [43]. However it should be noted that this is a purely technical/operational constraint and theoretically water provides an opportunity to operate at higher temperatures than other fluids such as synthetic oil [42]. Water has been used as a HTF in both PT and SPT plants and one key advantage is the elimination of the heat exchanger component which is a significant cost saving. Two potential barriers to the use of water as a HTF are availability of water and the potential for thermal storage. As will be discussed further in section 5.2 water consumption required for condenser cooling in CSP plants already exceeds that which is utilized in other fossil fuel fired plants such as coal or nuclear as such an additional water requirement for use as HTF may pose a challenge and would limit its use to locations with adequate water supply. The other concern is related to the potential of steam to provide a viable means of storage for several hours. This is evidenced by a sample number of plants utilizing DSG in Table 10 which either have no storage capability or have a storage capacity of less than two hours. It can be inferred from this data on DSG plants that there are technical difficulties in thermal storage with steam as the medium and this could be a deterrent in the case where a CSP plant is envisaged for base load operation. This type of storage is investigated further in the next section.

Synthetic oils have been used extensively especially in parabolic trough plants and the most common is Therminol VP-1 and others in use include Therminol D-12 and Dowtherm A [42], [43]. Therminol VP-1 solidifies at a temperature of 12 ^oC and so some secondary heating mechanism may be required. It may also be mixed with an inert gas in the event operational temperature exceeds 257 ^oC which is its boiling point [43]. When temperatures exceed 400 ^oC for some synthetic oils, hydrogen may be produced which degrades the HTF by reducing its useful life and resulting in reduced thermal efficiencies [42].

Some of the characteristics of what may be referred to as an ideal HTF include low cost, minimal environmental impact, ability to facilitate simplified operation and ability to integrate into a simple storage mechanism [42]

Molten salt currently meets most of these criteria and is increasingly emerging as a superior HTF over existing alternatives for several reasons. Perhaps the most significant especially in the context of this study is the capability for use as both HTF and storage medium thus enabling 24-hour operation. From a technical perspective, heat transfer is carried out at a lower pressure as compared to steam and thus the piping does not require as much reinforcement and would thus be cheaper [33]. Molten salt also operates at higher temperatures than synthetic oils of up to 500 ^oC

which means the power block can obtain higher efficiencies. It is also cheaper in terms of upfront cost and it is estimated that replacing synthetic oils with molten salt can translate into a reduction of LCOE of up to 30% [33]. A major challenge of the use of molten salts similar to that of Therminol VP-1 is its high freezing point at 15 ⁰C, which also necessitates the use of auxiliary heating to ensure the molten salt remains above this temperature, failure to which freezing could result causing severe damage to pipes and pumps [42].

Other HTFs that have been investigated on an experimental level include pressurized gases and nanofluids. The main advantage that gaseous HTFs could present is the very high operational temperatures of up to 800 ⁰C and the fact that they are readily available and abundant. Major challenges include the very high energy requirement for pumping the gas and the relatively low heat transfer coefficients. Nanofluids are essentially HTFs such as water or synthetic oils that have been mixed with nano sized particles of elements such as silicon dioxide, zinc oxide or titanium dioxide. It is expected that utilizing nanofluids would translate into higher thermal efficiencies as compared to steam, however the requirement of high quality valves and pumps which are costly coupled with the risk of corrosion of the receiver tube has limited their use [42].

3.1.6 Thermal storage in CSP plants

Thermal energy storage (TES) systems can be said to be constituted of three major components which are the storage medium, the system which facilitates the heat transfer and the component which contains the storage medium [54]. They can be categorized according to the storage medium as sensible heat, latent heat or reversible chemical reactions and they can also be categorized according to the mechanism employed for heat transfer as either active or passive TES systems.

Sensible heat storage describes energy stored by change in the internal energy of a material which may be solid or liquid and molten salt and synthetic oils fall under this category [53]. Latent heat storage refers to energy stored when a material changes phase from one phase to another such as a conversion from solid to liquid or from liquid to vapour. Research is still ongoing on viable materials for this application and the major uncertainties lie in the duration of useful life of the storage medium and their low thermal conductivity factors. Reversible chemical reactions also referred to as thermochemical storage present the highest potential of thermal conductivity and related energy density in kWh/m^3 and application of this type of storage would translate into reduced storage material thus minimizing costs [54]. The storage medium in this case absorbs the heat from the solar field during the charging cycle and the chemical reaction reverses accompanied by a release of heat in the discharging cycle [53].

Active TES systems are described as utilizing a storage medium that is fluid and can thus flow between the storage containment chambers. Conversely passive TES mechanisms make use of storage mediums that are solid and include packed bed structures of materials such as rocks or ceramics and enhanced heat transfer systems such as the shell and tube heat storage [54], [55]. Active TES systems can be broadly classified into three as steam accumulators, thermocline systems and 2-tank thermal storage. The 2-tank system is the most mature technology among existing TES alternatives for CSP plants. It can be further categorized as direct or indirect with the former describing instances when the HTF is the same as the storage medium. The major focus among industry players and researchers is to reduce the quantity of storage medium, molten salt in this case or alternatively utilize a cheaper material since this is the most expensive component of the TES system as indicated in Figure 9.

Thermocline systems operate with a single tank and involve creating a thermal gradient by pumping a hot fluid to the top of the tank which displaces a cold fluid. Most thermocline systems make use of a filler material in which case they are categorized as passive systems.

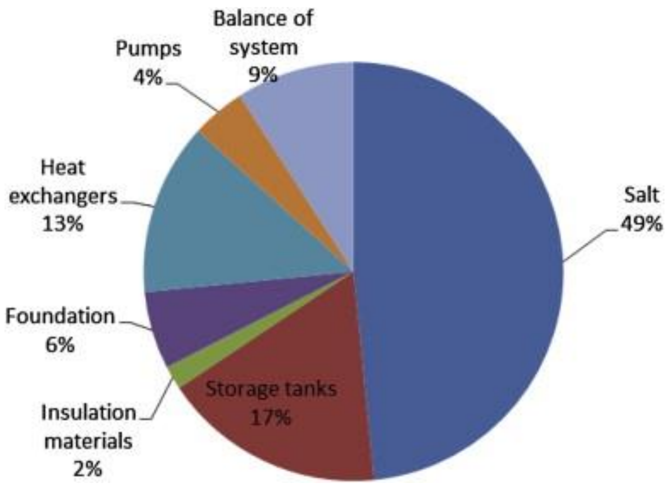


Figure 9: Cost breakdown of a 2-tank indirect TES system [54]

Steam accumulators can be considered to be a relatively mature storage technology since they have been employed in existing fossil fuel fired plants. They operate by injecting superheated steam or saturated water (depending on whether it is in the charging/discharging mode) into a tank that already contains both superheated steam and saturated water. For instance in the discharging mode, pressure is released in the tank thereby resulting in production of saturated steam [54]. This system as expected is especially convenient for DSG plants but a potential drawback as was mentioned in the preceding section is the seemingly limited duration of storage.

3.2 Studies on CSP performance

There are numerous studies on the performance of the four major technologies as well as investigations into their optimal operation. The authors in [56] investigate three CSP technologies, PT, LF and SPT to determine which of the three is better suited to hybridize with a fossil fuel plant designed for cogeneration, that is, heat and power. The main evaluation criteria is levelized cost of electricity (LCOE) and CO_2 avoidance and their results indicated that the best fit was LF technology incorporated to the steam side of a 50 MW gas fired plant.

A comparison between PT and LF is carried out in [57] where thermal oil is employed as the HTF and the power cycle makes use of an organic Rankine cycle with an efficiency of 24% rated at 1 MW. Their results indicate that LF has a higher electricity output per m^2 while PT has a higher output per unit area occupied by a collector. The latter was found to have a comparatively better optical efficiency and an overall efficiency of 10-11% while LF was estimated to have an overall efficiency of 7-8%.

In [58], the authors propose a configuration of a parabolic trough plant hybridized with a dairy farm based biogas plant. The key process of the hybridization is that waste heat from the biogas processing is channeled to the high pressure boiler in the PT power cycle thus boosting electricity production. The configuration was modelled for both wet and dry cooling and results indicated that the LCOE for dry cooling was slightly higher than that of the wet cooling option.

A study of several physical sizing parameters that are key to the performance of SPT and PT are analyzed in [59]. The effect of number of hours of thermal energy storage (TES) and solar multiple (SM) on the capacity factor (CF), net electricity produced and LCOE is investigated and a characteristic solar electricity output figure is developed for a location in Spain assuming average DNI values. The annual characteristic value was estimated to be 37 kWh/ m^2 for solar power tower and 66 kWh/ m^2 for parabolic trough.

An investigation into the economic comparison between PTC and LF collectors is carried out in [60]. For the purpose of comparison both plants are assumed to operate in DSG and it is observed that optical efficiency is a major determining factor in the breakeven costs. LF is found to be cheaper in regard to the upfront cost accounting for 28-79% of the PTC cost. A LF collector utilizing a vacuum receiver has a significantly higher net electricity efficiency of approximately 11% which is comparable to the efficiency of a PTC at 14.5%; this is compared to that of a standard LF receiver with a diameter of 14 cm which has a net efficiency of 8.9%.

There are also feasibility studies that have been carried out on a regional/county level to assess the potential of CSP plant development. These studies can be broadly categorized as being either techno-economic evaluations or focused on geographical factors with the aim of narrowing down specific sites for CSP development. A summary of these is presented in Table 6.

Table 6:Selected studies on regional/country level feasibility studies of CSP development

Reference	**Country**	**CSP type**	**Software**	**Conclusion**
Enjavi, Hirbodia & Yaghoubi, 2014 [61]	Iran	PT	SAM	3/6 selected sites demonstrated good annual electricity output and CO_2 avoidance is estimated at 378 million tons for the three plants.
Pidaparthi, Dall, Hoffmann & Dinter, 2015 [62]	South Africa	PT,SPT	SAM	SPT plants have a better annual performance than PT and monthly variations in DNI at a specific site are an important consideration.

Table 6, continued

Andreas Poullikkas, 2009 [63]	Cyprus	PT	IPP algorithm v ersion 2.1	Larger capacity plants provide a better economic incentive and the existing FIT rate can accommodate development of PT plants depending on variation of capital cost.
Balghouthi et al.,2016 [8]	Tunisia	PT	Greenius	A 50 MW PT plant would be feasible in the Tatouine region and economics of CSP would improve if the cost of fossil fuels increase and manufacture of components such as the mirrors is done locally.
Ziuku et al.,2014 [9]	Zimbabwe	N/A	N/A	Mapping of best sites to set up a CSP plant based on DNI data, land use and infrastructure
Boukelia & Mecibah, 2013 [6]	Algeria	PT	N/A	Factors for the determination of good potential CSP sites investigated and it is determined Algeria has a very good potential for Integrated Solar Combined Cycle plants (ISCC)
Purohit, Purohit & Shekhar, 2013 [12]	India	PT, SPT, LF, PD	SAM	Cost estimates of all four major technologies developed per unit of power generated for multiple locations and carbon trading under the clean development mechanism (CDM) improves the economics of the CSP plants considerably.
Malagueta et al.,2014 [13]	Brazil	PT	SAM & MESSAGE	Three PT configurations, without storage, with TE S and with hybridization with natural gas or bagasse are investigated. In the base case, no CSP plants are added to the grid since they're more expensive than other alternatives but in the alternative case up to 7200 MW are integrated in the year 2040.

From the literature it is clear that the parabolic trough plants have been investigated extensively and thus present the least risk in terms of investment. Based on this and the distribution shown in Figure 6, parabolic trough and solar power tower plants are the principal technologies investigated in this research. There are also well-established criteria in regard to evaluating site selection which will be employed in choosing probable locations for CSP development in the methodology section. It is also clear from Table 6 that the System Advisor Model (SAM) software has been utilized in numerous studies to simulate CSP plant performance and has been employed in this research as well.

3.3 Studies on solar exploitation for electricity production in Kenya

The bulk of studies on exploitation of solar resource are focused on solar PV in off grid systems and few investigate the grid integration aspect. One of the papers tackling integration of large scale PV into the generation portfolio is [28]. This study is based on the premise by the Kenyan energy planners that PV is still a long way from being economically viable. An estimate of the LCOE is made of 0.21 $/kWh and a scenario based sensitivity analysis which varies location, scrap value, operation and maintenance cost, degradation factor among others results in an LCOE range of between 0.165-0.3 $/kWh. The author concludes that solar PV is already comparable if not cheaper than the current peaking plants in the generation portfolio. Policy recommendations presented include institution of a public tender system (which is intended to divulge the lowest actual LCOE price), increasing of FiT rate and introduction of a net metering system. This current research proposes similar measures especially in regard to the FiT as discussed in section 5.1.2.

Another study which evaluates the feasibility of utility scale PV integration into the grid on a technical and economic level is in [19]. The author evaluates the feasibility of solar PV into the grid for the year 2012 and 2017 and one of the key findings is that the current reliance on hydro enables a high level of integration since the hydro plants can counter disturbances due to solar intermittence in the system. The author concludes that the FiT rate of 0.12 $/kWh is on the lower side and points out that even with a 10% decrease in fuel cost, there would still be a considerable cost saving that could be passed on to the PV plant operators in the form of a higher FiT rate. As aforementioned the FiT rate with respect to CSP plants will be discussed in a later section, however there are two things worth discussing from the perspective of energy planners that could probably provide a justification as to why the rate should remain at 0.12 $/kWh. The first is that the study in [19] assumes at most a

10% decrease in fuel price which does not account for a scenario of an unprecedented drastic fall in fuel prices such as that depicted in Table 2 for the year 2015. In this case there would be no substantial saving from avoidance of utilizing diesel plants and a FiT rate higher than the prevailing value would actually be counterproductive. The second consideration is that a diversified energy mix, such as the one envisaged in the LCPDP may render the savings accrued from avoided fuel cost and other diesel plant expenses inadequate to compensate the purchase of power from PV operators at a higher price than the prevailing set FiT rate.

As far as CSP studies in Kenya are concerned, there is only one study in [64] which focuses on the evaluation of potential sites for development of utility scale CSP plants. The methodology employed is similar to that found in literature and the main criteria include DNI, slope of land and land use factors. The map of best potential sites developed in this study is the basis of the site selection employed in the present research in addition to some secondary factors as will be discussed in the next chapter.

CHAPTER 4

METHODOLOGY

This chapter is split into four sections, the first covering the site selection procedure followed by two sections which highlight the configurations based on parabolic trough and solar power tower which are the CSP technologies that were selected for the feasibility analysis. There is then a section highlighting some of the major assumptions made in the simulations and finally a review of the dispatch strategy employed. Four configurations of solar CSP plants are investigated namely; parabolic trough with fossil fuel back up, parabolic trough plant with biomass back-up, parabolic trough with storage and solar power tower with storage. PT was selected based on its maturity in the market while SPT was selected given it has the best concentration factors among all the CSP technologies that can be commercially exploited on a large scale.

The four configurations are subsequently designated as case W-Z as indicated in Table 7.

Table 7: Summary and designation of the four configurations investigated

Case	Configuration	Storage	Backup	Proposed location
W	Parabolic trough with storage	☑	☒	Lodwar
X	Parabolic trough with fossil fuel back up	☒	☑	Malindi
Y	Parabolic trough plant with biomass back-up	☒	☑	Marsabit
Z	Solar power tower with storage	☑	☒	Lodwar

The System Advisor Model (SAM) was used to simulate the performance and economics of the four configurations of CSP plants.

4.1 Site selection

Three locations were selected based on the envisaged requirements for each of the plant configurations. However, before looking into the enabling factors of each of the configurations, there are some standard criteria that have been employed to access site suitability and these include; topographical features, population densities, infrastructure, water availability and others that have been summarised in Table 8 [9], [11], [12], [65].

For a case of Kenya, a study was carried out in [64] to assess locations for possible large scale CSP deployment. The criteria employed are similar to that indicated in Table 8. The authors developed an exclusion filter taking into account the aforementioned factors resulting in a mapping of best potential CSP sites. This map is presented in Figure 14 and was used as a guideline in selecting locations in this paper. One of the sites selected falls within the areas highlighted in the 10 best sites while the other is in the coastal region.

Table 8: Evaluation factors for CSP site suitability

Factor	**Comment**
Soil type	soil characteristics such as drainage may be a factor in construction cost of the foundation of various parts of the plant
Population density	very populous areas are undesirable due to related cost of relocation
Wetlands/lakes and other water bodies	can be either enabler or an inhibitor. Wetlands can be considered protected areas while proximity to a water body may be desirable for water cooling requirement and mirror washing.
Protected areas	forests, wildlife habitats, archaeological sites, threatened vegetation
Steep slopes	degree of slope of potential site. Higher slopes tend to increase construction cost significantly
Disputed territories	boundary conflicts among countries or at national level among communities
Infrastructure	proximity to power transmission infrastructure, roads, rail or other means of transport
Natural disasters	seismic activities, floods, wild fires
Land use	an area of at least 1 km^2 is recommended for consideration as a potential site

For the storage configuration, a location with excellent DNI was chosen so as to leverage on the TES. This follows the fact that locations with comparatively higher DNI will have higher electrical power output; this is assuming factors such as size of the solar field and size of storage are held constant as discussed in section 5.1.3. Lodwar which is an area around Lake Turkana in the northern part of the country was selected for this configuration.

For the natural gas back-up plant, a location at the coast was selected due to proximity to the port in view of minimizing the transportation cost of natural gas from the port at Mombasa/Lamu. There has been some exploration of natural gas locally off the coast at Malindi as well as proven commercial reserves in neighbouring Tanzania however in the short term it is assumed that imports will continue from the Gulf states [66], [67].

Lastly for the biomass back up plant, the key consideration was proximity to a consistent biomass source. In regard to biomass exploitation for electricity generation in Kenya on a large scale (≥1 MW), three biomass sources have been utilised; bagasse, horticultural waste and Prosopis Juliflora. Bagasse from the sugarcane industry is considered to be an ideal fuel for Kenya's case given an estimated potential power production of 830 GWh/year and an already existing installed capacity of 26 MW [2]. It is however noted that the western part of the country is hilly with generally high slopes of up to 4° thus making it prohibitive for CSP deployment [64]. A map indicating the degree of slope in various parts of the country is presented in Figure 13 and it should also be noted that SPT plants can usually benefit from a slightly inclined terrain but the requirement for flat ground is more stringent for PT plants [64]. Another possible issue with use of bagasse as fuel is that the current land use in Kakamega and other parts in the sugar belt in the western part of the country is under extensive cultivation as such there is not much ‘free’ land and any CSP development would require costly relocation procedures. Prosopis juliflora, also locally referred to as 'Mathenge' weed is therefore proposed as a backup fuel for a CSP plant in Marsabit. The weed has a very good calorific value as has been proven in its use for power production in a 2 MW plant in Baringo county [68], [69]. There is an estimated 500,000 ha of arid land across six counties proliferated by the weed and it is thus estimated that there will be adequate feedstock for the CSP plant over its lifetime (25 years) [70], [71].

Another factor that is taken into consideration that was not included in the study in [64] is the suitability of a location based on the existing electricity grid infrastructure. There has been a lot of progress in the recent past in regard to expansion of the transmission lines coverage by KETRACO and a map indicating existing and planned transmission corridors is shown in Figure 15 [72]. It should be noted that this map contains data on transmission lines under KETRACO’s management and may not include those that were built by KPLC and are under their jurisdiction.

From the map it is clear that the location of the 10 best sites (which happens to be the area receiving both the best wind and solar resource in the country) has a very poor grid coverage as with most of the north and northeastern parts of the country that are arid lands and for the most part are very sparsely populated. A close up of the location in Lodwar is shown in Figure 10 and from this map it can be inferred that it would be possible to have CSP plants with a capacity of between 50-150 MW given the planned construction of the Turkwel-Lodwar-Lokichogio 228 km 220 kV transmission line. The assumption of the range of CSP plant capacity is based on a guideline described in [73] where for instance a 132 kV line would be adequate to evacuate power from a 100 MW plant for a distance of up to 100 km with acceptable losses incurred. In the same vein 400 MW can be evacuated from a plant via a 400 kV line for a distance of up to 400 km with acceptable loss margins. Based on this reasoning, the location in Malindi also has the potential of a capacity of up to 150 MW given the ongoing construction of the Rabai-Malindi 328 km 220 kV transmission line. A close up of this line is shown in Figure 11. Lastly for the case Y plant, power could be evacuated via the planned Loiyangalani- Wajir 380 km 400 kV transmission line also depicted in Figure 10.

Of course these assumptions on the potential carrying capacity depend on other generating units that may be set up in these areas that may alter the requirement of the rating of the transmission lines. Usually the determination of the carrying capacity of the line is based on the quantity of power that needs to be evacuated as well as the distance to the load center [73]. This therefore reiterates the need for energy planners to strategize on the planned incremental capacities so as to have an optimal grid expansion plan.

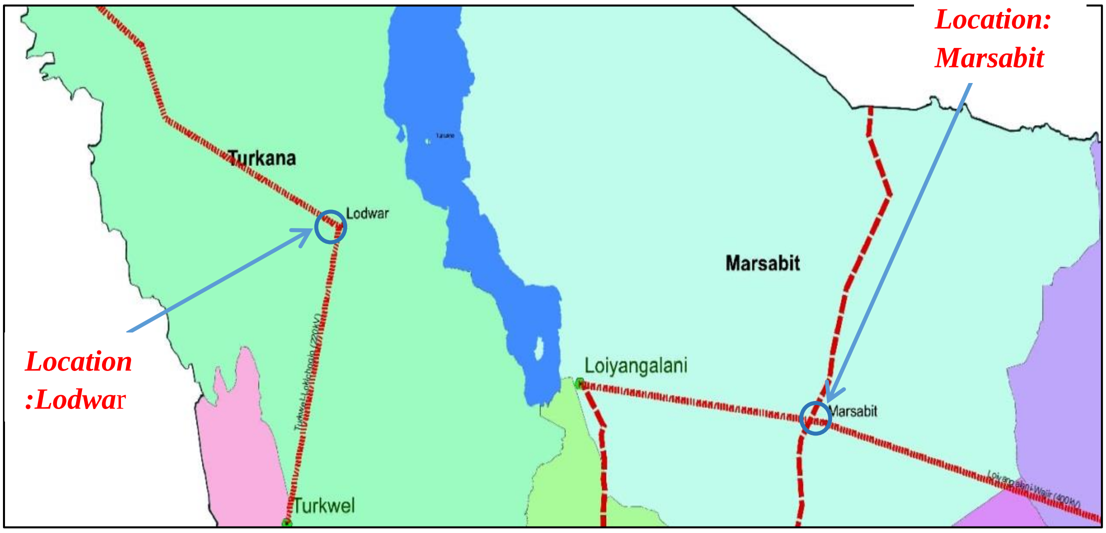


Figure 10: Planned Turkwel-Lodwar-Lokichogio 228 km 220 kV transmission line

A summary of some information on the three locations is presented in Table 9 [74]. Weather data for the locations was obtained from the SAM database.

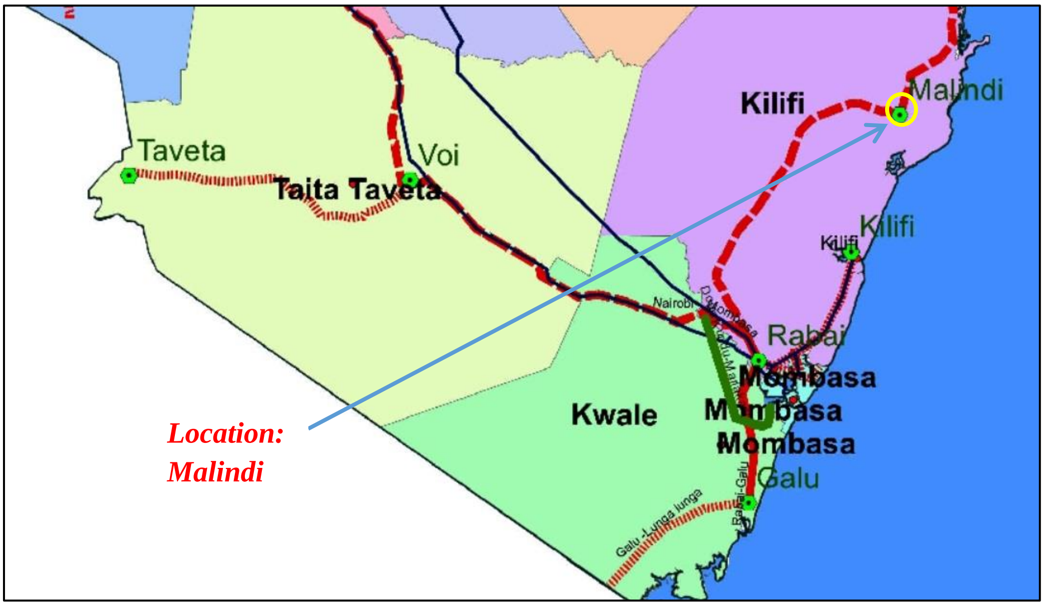


Figure 11: Rabai-Malindi 328 km 220 kV transmission line which is under construction

Table 9: Proposed CSP plant locations

Location	**Lodwar**	**Malindi**	**Marsabit**
County	Turkana	Kilifi	Marsabit
Longitude	35.62 °	40.1 °	37.9 °
Latitude	3.12 °	3.23 °	2.3 °
Elevation (m)	515	23	1345
DNI (kWh/m^2/day)	5.03	3.89	4.72
Wind speed (m/s)	4	4.6	8.9
Dry bulb temperature (°C)	29.7	26.4	20.1

The monthly DNI averages are presented in Figure 12 and the effects of cloud cover are observed from this graph. The long rain season runs from March-May in Lodwar and April-June for Malindi and Marsabit and for all three locations DNI is observed to be low in these periods due to heavy cloud cover which scatters incoming solar radiation. The short rain season runs between Oct-Nov in Lodwar and Marsabit resulting in the corresponding dips in DNI but Malindi mostly experiences a single rainy season.

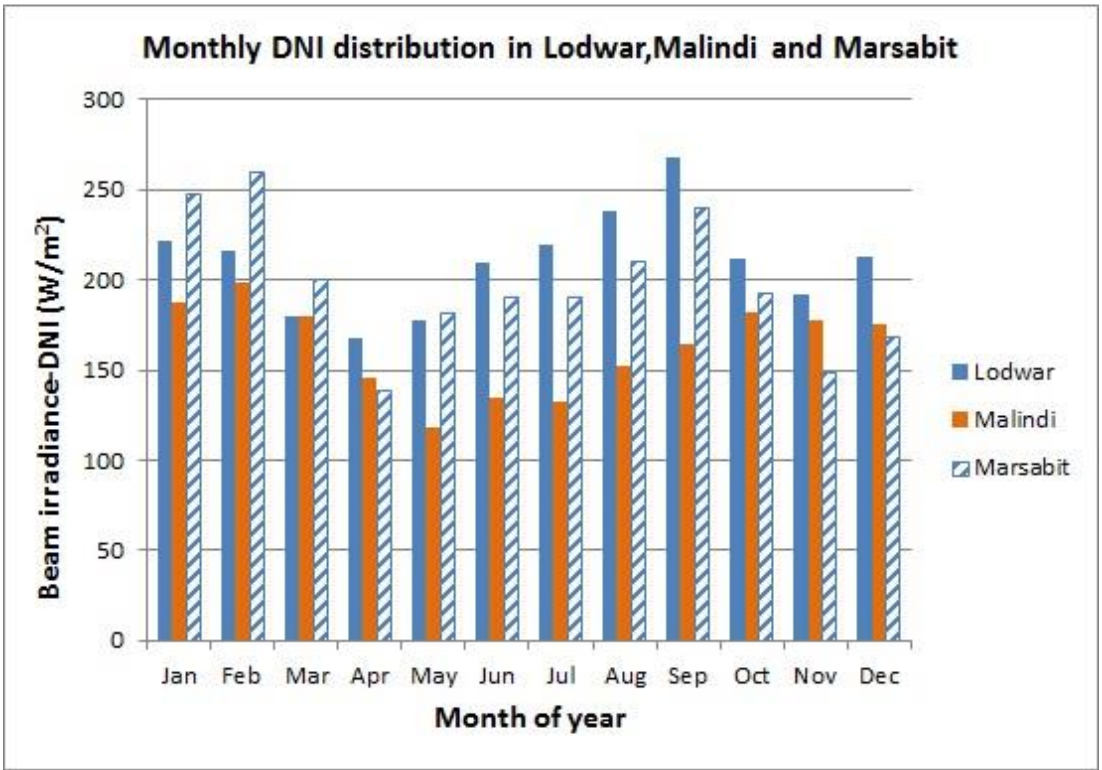


Figure 12: Monthly DNI distribution in Lodwar, Malindi and Marsabit [74]

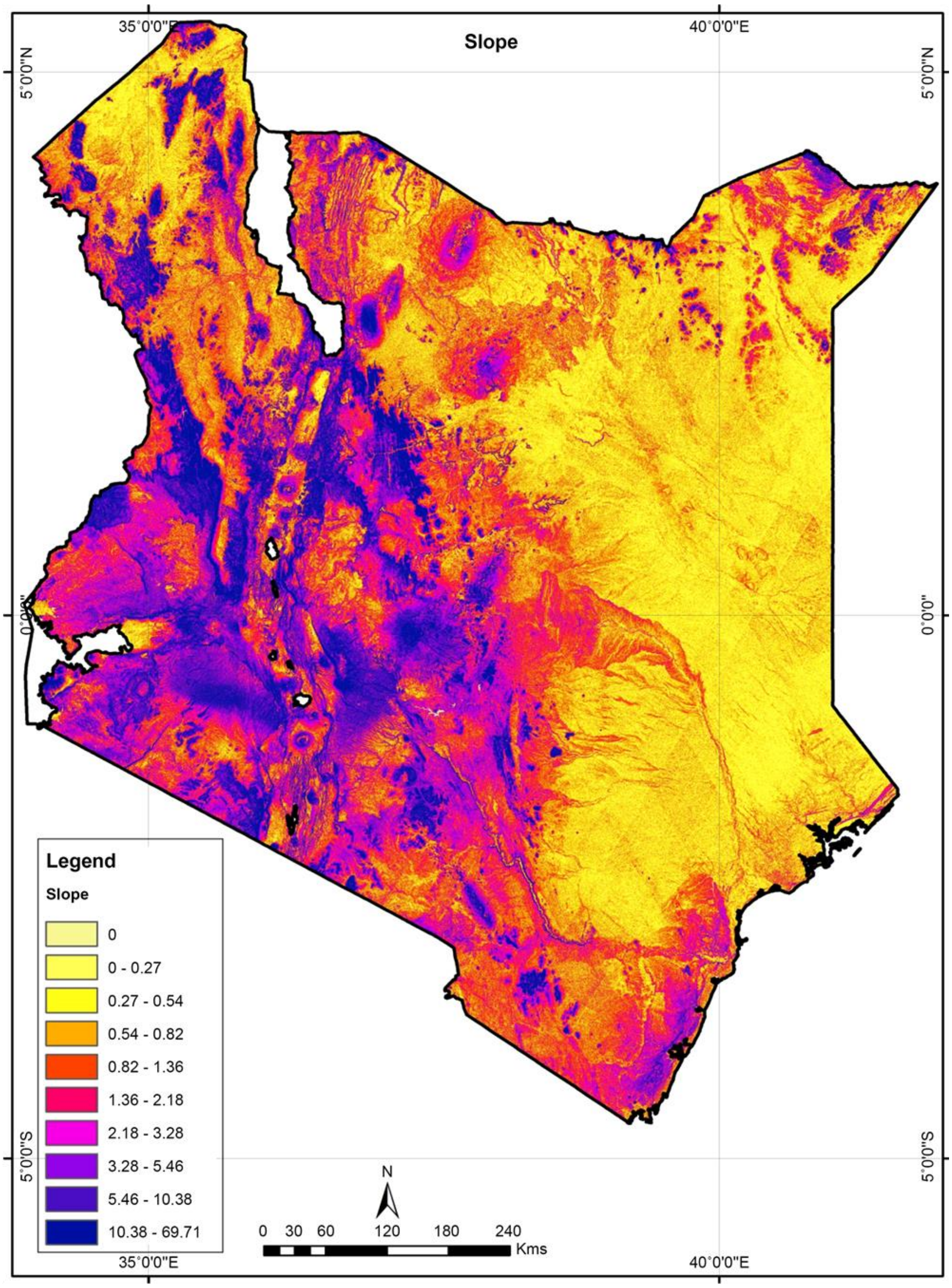


Figure 13: Classification of terrain according to degree of slope [64]

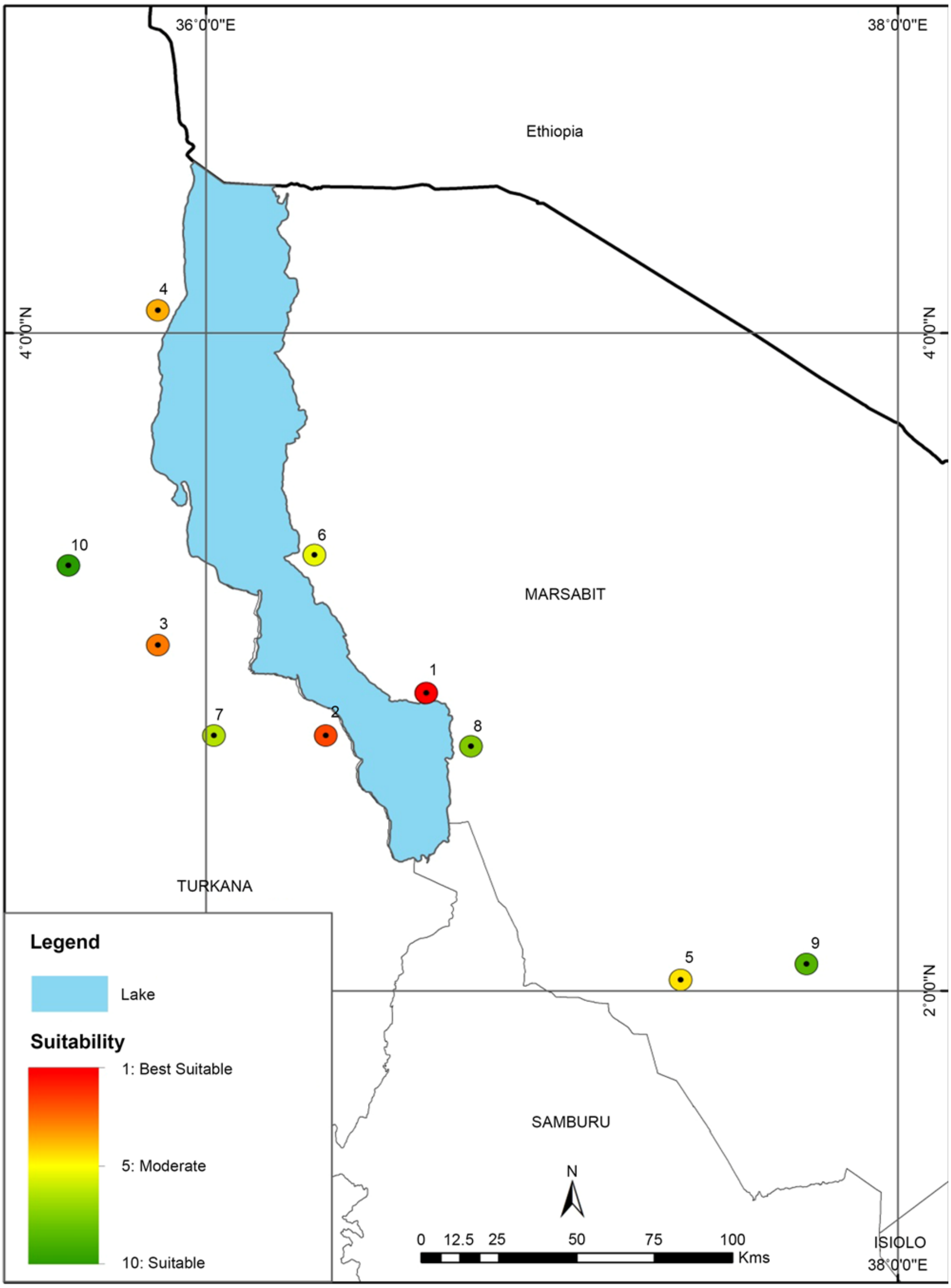


Figure 14: Best potential CSP sites in Kenya [64]

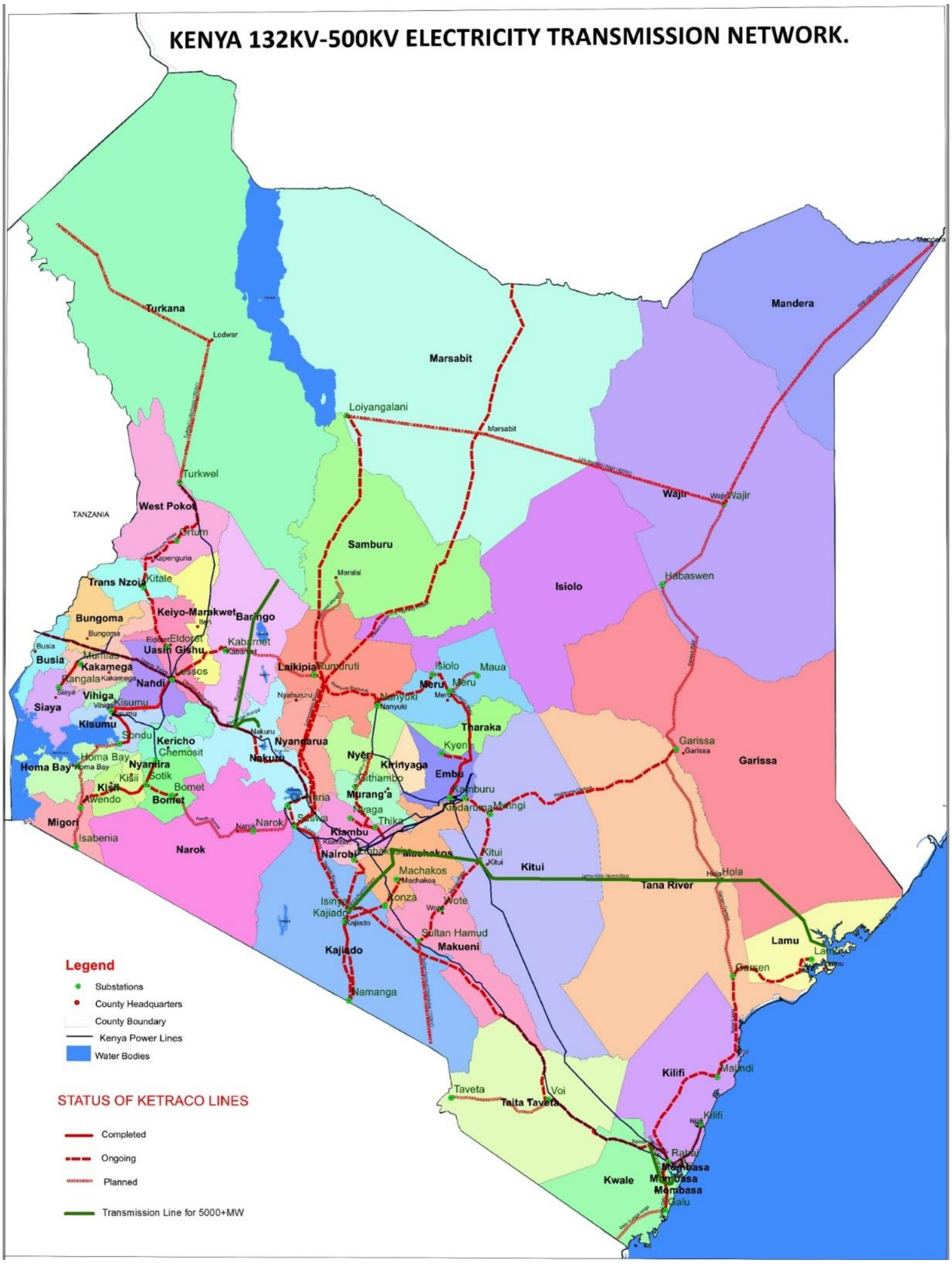


Figure 15:132 kV-500 kV KETRACO transmission network [72]

4.2 Solar power tower plant

In general, the two HTFs that have been employed in operational plants and those under development are molten salt/solar salt and steam. It is however noted that the plants which employ direct steam generation (DSG) have little (less than two hours) or no storage capacity and for this reason DSG plants were not considered in this study since significant storage capacity is preferred given that it is envisaged that the plant would achieve close to 24 hour operation. Table 10 provides a summary of selected DSG power tower plants with their corresponding thermal storage duration [34], [44], [50]. In terms of LCOE comparison between the two, it is noted that the DSG has a slightly lower LCOE than molten salt plants although there are other trade-offs in transients and power cycle efficiency [75]. From an investor perspective however, interest in new installations seems to be leaning towards molten salt SPT plants [76].

Table 10: Selected operational DSG power tower plants[34], [44], [50]

Name	**Rated capacity gross (MW)**	**Country**	**Purpose**	**Hours of TES**	**Storage medium**	**Status**
Planta solar 20	20	Spain	Commercial	1hr	steam*	Operational
Khi solar one	50	South Africa	Commercial	2hr	saturated steam	Operational
Ivanpah	392	USA	Commercial	0	N/A	Operational
Julich	1.5	Germany	Demonstration	1.5hr	Ceramic heat sink	Operational
Dahan	1.5	China	Demonstration	1hr	saturated steam/oil	Operational

The Gemasolar plant in Seville, Spain was taken as the reference plant and the key technical parameters are presented in Table 11[76], [77]. An air cooled condenser is assumed for all simulations in contrast to the wet cooled condenser in the reference plant due to the fact that all proposed locations are arid lands and water is generally scarce. It is interesting to note that CSP plants, especially parabolic trough type have the highest water requirement for condenser cooling out of all power generation technologies, excluding geothermal. Figure 16 presents comparative water consumption among the technologies per MWh [76], [78].

Table 11: Selected technical parameters for Gemasolar power tower plant [76], [77]

Parameter	Value
Heliostat field	
Solar multiple	2.5
Heliostat width(m)	10.9
Heliostat height(m)	10.9
Ratio of reflective area to profile	0.96
Heliostat stow/deploy angle (^{0})	10
Max heliostat distance to tower height ratio	8
Solar field land area multiplier	1.4
Mirror reflectance & soiling	0.93
Power cycle	
Gross to net conversion factor	0.875
Power cycle thermal efficiency	0.42
Turbine gross output(MW)	20
Min turbine operation	0.2
Tower and receiver	
HTF hot temperature (^{0} C)	565
HTF cold temperature (^{0} C)	288
Receiver height (m)	14.22
Receiver diameter (m)	8.89
No. of panels	16
Tower height (m)	140
Thermal storage	
Full load hours of storage (hrs)	15
Parasitics	
Piping loss coefficient (W_t/m)	8000

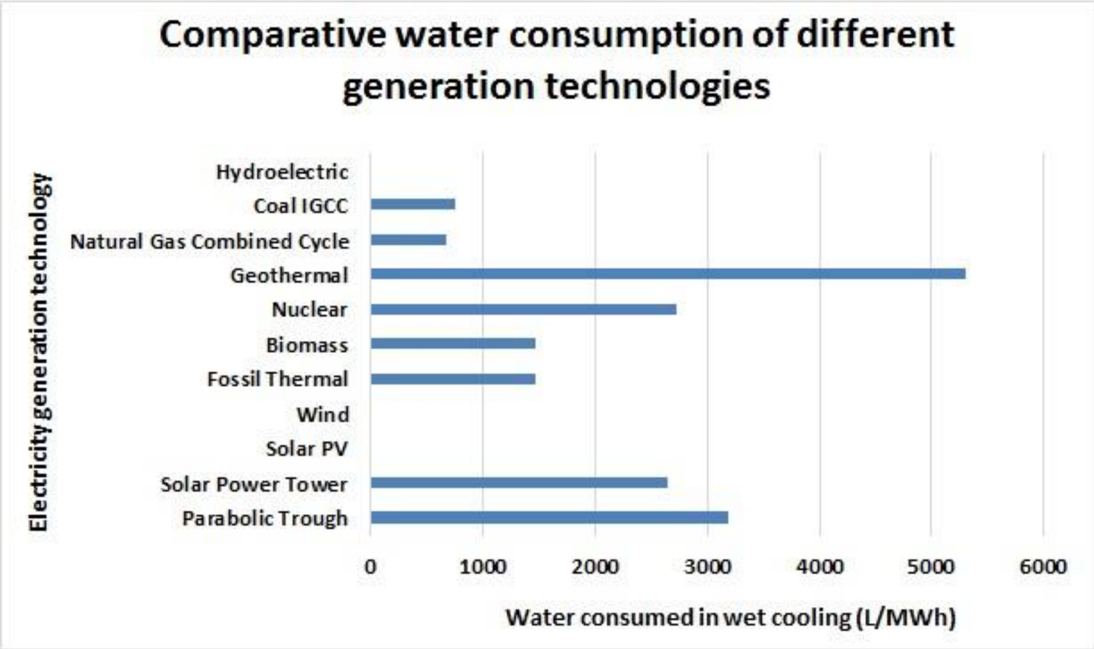


Figure 16: Comparative water consumption/MWh of various electricity generation technologies

An alternative to the excessive water consumption in the wet cooling scheme and the loss in thermal efficiency in dry cooling is the hybrid cooling configuration which employs wet cooling on days with high ambient temperature. Hybrid cooling has been found to cut down on water consumption by half of what the wet cooled system utilizes with a corresponding loss of only 1% of thermal efficiency. Alternatively 90% reduction in water consumption of the wet cooled system can be achieved while maintaining 97% of the thermal efficiency [12], [78]. The hybrid configuration certainly provides an agreeable trade-off however it was not simulated because it is not considered to be a mature technology in the context of this study. Current employment of the hybrid cooling technology exists in the Julich SPT plant in Germany which is for demonstration purposes and the Crescent Dunes plant in the United States which is on a utility scale [50].

Simulations were carried out for 20 MW and 100 MW size plants and the SAM optimization tool was used to obtain optimum number and size of key sizing parameters namely; number of heliostats, tower height, area of the receiver and hours of TES. In terms of economic considerations, the major system costs were adopted from the SPT road map in [76] and details of these costs are presented in Table 12. Site specific values were adopted for cost of land per acre, discount rate, sales tax and contingency as percentage of the total [76], [79]–[81].

Table 12: Selected solar power tower system costs [76]

Category	**Cost**
Heliostat field ($/ m²)	200
Receiver ($/ kW_t)	200
Thermal energy storage ($/ kW_t)	30
Power block ($/ kW_e)	1000
Steam generator system($/ kW_e)	350
Operation & Maintenance ($/ kW-yr.)	65
Sales tax (%)	7.75
Contingency (%)	8.6
Land cost($/acre)	30,000
Nominal discount rate (%)	15

For case Z, overall efficiency is estimated for multiple locations as is shown in section 5.1.1. The overall efficiency is the net solar to electric conversion efficiency and factors in optical and thermal losses, parasitic loads required in various operations and losses due to equipment unavailability [76] The efficiency values were estimated making use of Equation 1 [82].

$$overall\ efficiency = \frac{energy\ production/year\ (kWh)}{DNI\left(\frac{\frac{kWh}{m^2}}{year}\right) \times numberof\ heliostats \times single\ heliostat\ area\ (m^2)} \qquad (1)$$

4.3 Parabolic trough plant

The 50 MW Andasol-1 plant in Spain was taken as the reference plant for case W-Y. Selected technical parameters of the plant are presented in Table 13 [44], [83]. SAM enables users to model PT plants with either the physical model, which makes use of theoretical heat transfer and thermodynamic concepts or the empirical model which computes performance based on a set of equations obtained from regression analysis of data from plants in operation [74]. For the sake of accuracy, the empirical model was used for most of the analysis in this study. Estimates of costs of selected PT plant components are shown in Table 14 while other general economic indicators such as discount rates & cost of land remain similar to those of the SPT model [83], [84].

Table 13: Selected technical parameters for Andasol-1 parabolic trough plant [44], [83]

Parameter	**Value**
Solar field	
Field size	510120 m^2
HTF	Dowtherm A
Design loop outlet temp (^{0} C)	393
Number of collector assemblies per loop	4
Number of collector assembly loops	156
Collector configuration model	EuroTrough ET150
Receiver configuration model	Solel UVAC 3
Power cycle	
Gross to net conversion factor	0.875
Power cycle thermal efficiency	0.381
Turbine gross output(MW)	55
Thermal storage	
Full load hours of storage (hrs)	7.5

Table 14: Selected parabolic trough system costs [83], [84]

Category	**Cost**
Site Improvements($/$m^2$)	28
Solar Field($/$m^2$)	170
HTF System($/$m^2$)	78
Storage ($/$kWh_{th}$)	78
Fossil Backup($/$kW_e$)	60
Power Plant($/$kW_e$)	850
Balance of Plant($/$kW_e$) (steam generation)	105
O&M fixed cost by capacity ($/$kW_e$-yr)	66
Fossil fuel cost ($/MMBTU)	6

Dowtherm Q was used as a HTF instead of Dowtherm A which is not available in SAM libraries for the empirical model and therefore Dowtherm Q is considered a practical substitute. Simulations were carried out for turbine output of 20, 50 and 100 MW capacities. The Andasol-1 plant makes use of natural gas back-up to supplement the power generation from the solar resource up to 12% of total electricity produced and the relevance and possible impact of this value is discussed in section 5.3.

4.3 Assumptions

The useful life of each of the plants in case W-Z was assumed to be 25 years based on a study on the performance of the Andasol-1 plant in [83]as well as the fact that the existing FiT rate applicable to CSP in Spain is a value of 27 € ¢/kWh for a PPA period of 25 years [83]

The plant capacities simulated are based on the two reference plants selected, that is the 20 MW Gemasolar SPT plant and the 50 MW Andasol-1 PT plant. In order to investigate whether there is a cost saving in terms of LCOE and capital cost/ Watt especially for the SPT plant, an arbitrary size of 100 MW was selected. The simulated output of the 100 MW case Z plant was compared to an existing SPT plant of similar capacity, that is, the 100 MW Crescent Dunes SPT plant.

The selection of the two reference plants was based primarily on availability of data on technical parameters as well as data on cost of principal components which are considered vital to enable the development of models that can estimate the performance of the plants in case W-Z as realistically as possible.

In terms of the economic analysis, the main parameter that was investigated is the LCOE. This cost in SAM accounts for expenses such as; procuring equipment, operation and maintenance costs, interest payments, tax remittances and benefits as well as the salvage value. There is also an alternative to include investment or capacity based cash incentives into the computation however these fields were not included in the simulation since there is currently no legislation in Kenya on any such incentives.

The computation of the nominal LCOE which is the main economic parameter that has been discussed for all the cases is indicated in Equation 2 [74],

$$nominal\ LCOE = \frac{-X_O - \frac{\sum_{n=1}^{N} X_n}{(1+d_n)^n}}{\frac{\sum_{n=1}^{N} Q_n}{(1+d_n)^n}} \qquad (2)$$

where Q_n is the total annual energy generated in kWh, X_o is the equity investment, N is the project useful life which in this case is 25 years, X_n is the annual project cost for a particular year (n), d_r is the real discount rate which doesn't account for inflation while d_n is the discount rate which accounts for inflation.

4.3.1 Sizing the solar field

For the SPT plant, the sizing of major components of the solar field such as the tower height and receiver is carried out using the SAM optimization tool. The tool optimizes the length of the tower, length and diameter of the receiver as well as computes the heliostat positions. Reducing the cost of LCOE to the least possible value is the main objective and constraints include a limit of the maximum flux that can be incident on the receiver as well as instances where the power obtained from the receiver falls short of the design value after the piping losses and losses from the receiver surface are taken into account [74]. After obtaining an optimal heliostat field layout and optimal height of the tower as well as receiver size, a parametric analysis was carried out to determine optimal size of the solar field that yields the lowest LCOE as discussed in section 5.1.4.

For the PT plant, the layout in regard to the number of collectors in a loop was selected based on the Andasol-1 reference plant as indicated in Table 13. In as far as the actual size of the field is concerned; a parametric analysis is carried out to determine the solar multiple that results in the largest possible annual energy output but at a minimized installation cost. Checking for the lowest LCOE is therefore the most convenient way to narrow down an appropriate size of the solar field as has also been discussed in [74].

4.3.2 Model validation

Validation of the model developed in SAM was done by comparing simulated values to those reported of the actual performance of the respective reference plants. For the solar power tower plant, a 20 MW plant with technical and economic parameters indicated in Table 11 and Table 12 was simulated for Seville whose weather file is available in SAM. It is not possible to replicate all of the operational conditions of the Gemasolar SPT plant due to limitations in the software since for this case there is no option to integrate NG backup for a SPT plant. Nonetheless as discussed in section 5.1.1 the simulated annual energy value falls short of the actual value by 13%, that is a simulation value of 93 GWh versus a reported value of 107 GWh. Since the NG backup accounts for 15 % of the annual energy output, [77] coupled with the approximate difference of 5 % of the gross to net conversion efficiency between dry cooled and wet cooled condenser plants (assumption from results in section 5.2.1), it is estimated that there is a 7 % error margin of the SAM model for the SPT plant. This is considered to be an acceptable error margin for the purpose of estimating the performance of the case Z plant.

For the PT plant cases W-Y; a model was first developed for the Andasol-1 plant based on parameters highlighted in Table 13 and Table 14. This plant is noted to have a 12 % NG fuel backup and this was included in the simulations as well [83]. The results of the comparison between the simulated and reported values are indicated in Table 15.

Table 15: Comparison of reported against simulated values for Andasol-1 plant

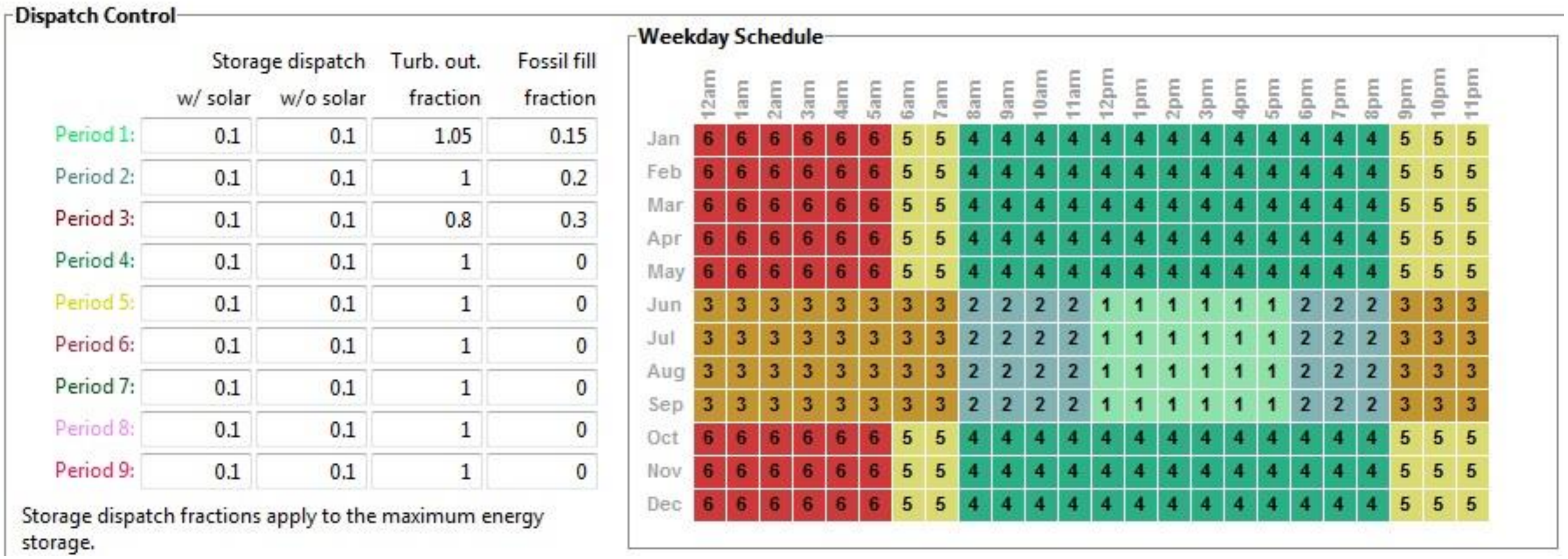
Parameter	Reported	Simulated	Difference (%)
Annual energy	174 GWh	173 GWh	0.5
Capacity factor	40.20 %	39.90 %	0.7
Fossil fuel backup	12 %	10 %	2
land area	476.8 acres	460 acres	3.5

Since no weather file for the actual location in Aldeire, Spain exists on the SAM database, a location was selected that has a similar DNI value which is 2,136 kWh/m^2/year and this value is equivalent to 5.85 kWh/m^2/day. The location selected is Chula Vista brown field in California which has a DNI value of 5.75 kWh/m^2/day.

Based on the results in Table 15, the PT plant model developed in SAM is assumed to be able to estimate the performance of the proposed plants in case W-X with an approximate error margin of 2 %.

Fossil fill fractions were varied for the Andasol SAM simulation in order to get as close as possible to the reported 12 % share of annual energy production from the NG backup boiler. In order to achieve the 10 % fossil fuel share in the simulation, fractions of 0.15, 0.2 and 0.35 were used for period 1, 2 and 3 respectively.

For both PT and SPT simulations for the Andasol and Gemasolar plants, a summer peak dispatch period is used as indicated in Figure 17 which matches the seasonal demand load curves for the respective locations in Spain.



Dispatch Control

	Storage dispatch w/ solar	Storage dispatch w/o solar	Turb. out. fraction	Fossil fill fraction
Period 1:	0.1	0.1	1.05	0.15
Period 2:	0.1	0.1	1	0.2
Period 3:	0.1	0.1	0.8	0.3
Period 4:	0.1	0.1	1	0
Period 5:	0.1	0.1	1	0
Period 6:	0.1	0.1	1	0
Period 7:	0.1	0.1	1	0
Period 8:	0.1	0.1	1	0
Period 9:	0.1	0.1	1	0

Storage dispatch fractions apply to the maximum energy storage.

Weekday Schedule

	12am	1am	2am	3am	4am	5am	6am	7am	8am	9am	10am	11am	12pm	1pm	2pm	3pm	4pm	5pm	6pm	7pm	8pm	9pm	10pm	11pm
Jan	6	6	6	6	6	6	5	5	4	4	4	4	4	4	4	4	4	4	4	4	4	5	5	5
Feb	6	6	6	6	6	6	5	5	4	4	4	4	4	4	4	4	4	4	4	4	4	5	5	5
Mar	6	6	6	6	6	6	5	5	4	4	4	4	4	4	4	4	4	4	4	4	4	5	5	5
Apr	6	6	6	6	6	6	5	5	4	4	4	4	4	4	4	4	4	4	4	4	4	5	5	5
May	6	6	6	6	6	6	5	5	4	4	4	4	4	4	4	4	4	4	4	4	4	5	5	5
Jun	3	3	3	3	3	3	3	3	2	2	2	2	1	1	1	1	1	1	2	2	2	3	3	3
Jul	3	3	3	3	3	3	3	3	2	2	2	2	1	1	1	1	1	1	2	2	2	3	3	3
Aug	3	3	3	3	3	3	3	3	2	2	2	2	1	1	1	1	1	1	2	2	2	3	3	3
Sep	3	3	3	3	3	3	3	3	2	2	2	2	1	1	1	1	1	1	2	2	2	3	3	3
Oct	6	6	6	6	6	6	5	5	4	4	4	4	4	4	4	4	4	4	4	4	4	5	5	5
Nov	6	6	6	6	6	6	5	5	4	4	4	4	4	4	4	4	4	4	4	4	4	5	5	5
Dec	6	6	6	6	6	6	5	5	4	4	4	4	4	4	4	4	4	4	4	4	4	5	5	5

Figure 17: Summer peak dispatch schedule [74]

4.4 Dispatch schedule in SAM

For case W-Z, the dispatch strategy assumed is identical. As can be observed from Figure 18 three periods were designated in accordance with the typical daily load curve which is presented in Figure 2. Since the peak demand occurs in the evening, the turbine output fraction was set to 1.05 for this period and in the same vein the early morning hours between 12am-6am which represent the period with the lowest demand was designated the lowest turbine output fraction of 0.8. The period corresponding to the base load from 7am-8pm is set to a fraction of one. A value of one for the turbine output ratio indicates a desired output that is equal to the nameplate capacity of the power block [74].

In the case of the fossil fill fraction in scenario X and Y, the same periods were applied. The fossil fill fraction stipulates the fraction of energy produced from the back-up boiler for each hour of a given dispatch period and for instance if the fossil fill fraction is set to 0.2 in period one then this would indicate that up to 20% of the electrical energy produced in this period would be contributed by the backup boiler [74].

There are possibly tens of variations of fossil fill fractions for scenario X and Y that can achieve a percentage fossil fuel share value of anywhere between 0-100 %. In the analysis of effect of fossil fuel fractions in case X, the first set of values is adapted from the study in [83] and is designated as fraction set A. Another fraction set B is selected by increasing the share of energy that can be produced from the NG backup boiler during the peak load (period 1 in the dispatch schedule) to 0.45 from 0.15 in fraction set A and also decreasing the fraction for period 3 to 0.15 from 0.45. As can be inferred from the results of this analysis in section 5.3, there is not an optimal value that can be selected rather the values of the fossil fill fraction depend solely on the stipulated value of the cut-off maximum energy produced by the backup boiler.

For scenario Y, the effect of fossil fill fractions is also investigated for two cases. The first makes use of fraction set A and the other was selected such that only period 1 (peak demand period as indicated in Figure 18) has a 15 % cut off maximum energy that can be produced from the biomass boiler while no backup is used for periods 2 and 3. This set of fractions is designated as fraction set C. A summary of fossil fuel fractions discussed and their respective designations is presented in Table 16.

Table 16: Fossil fill fractions designation

Type	period 1	period 2	period 3
Fraction set A	0.15	0.2	0.45
Fraction set B	0.45	0.2	0.15
Fraction set C	0.15	0	0

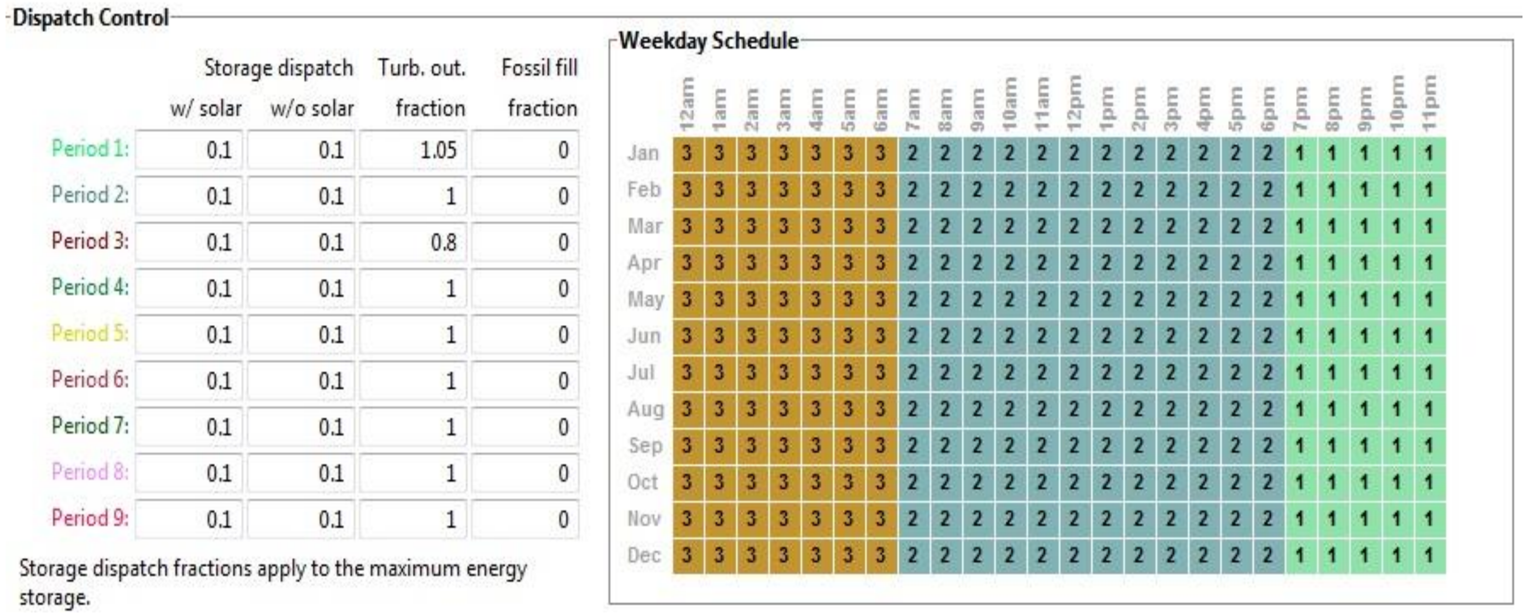


Figure 18: Dispatch schedule in SAM

CHAPTER 5

RESULTS AND DISCUSSION

This chapter is split into five major sections; the first four detailing results of the four configurations and the last part summarizing the implications of this results to possible integration of these plants into Kenya's generation portfolio.

The performance of the two technologies, that is case W and Z, were compared for a 20 MW plant in Lodwar. It is noted that the SPT plant (case Z) has significantly higher output for most months with an exception of the rainy seasons, which is March-May and Oct-Nov as indicated in Figure 19. The higher output can be attributed to the fact that SPTs generally operate steam cycles at higher temperatures leading to a higher thermal efficiency. At the same time, PT plants experience higher thermal losses due to increased surface area of the collectors as compared to SPT plants [85]. Another major factor affecting power cycle output of both technologies is the optical efficiency which is mostly a function of the cosine effect and it is especially significant for parabolic trough plants since they have one-axis tracking and this could explain the comparatively lower annual energy output [82]. This would however warrant further investigation because Lodwar lies very close to the equator which means the cosine effect is minimized considerably as has been reported in [86]. For the purpose of making this comparison, both plants were simulated using molten salt as the HTF, a SM value of 2.5 and 15 hours of TES.

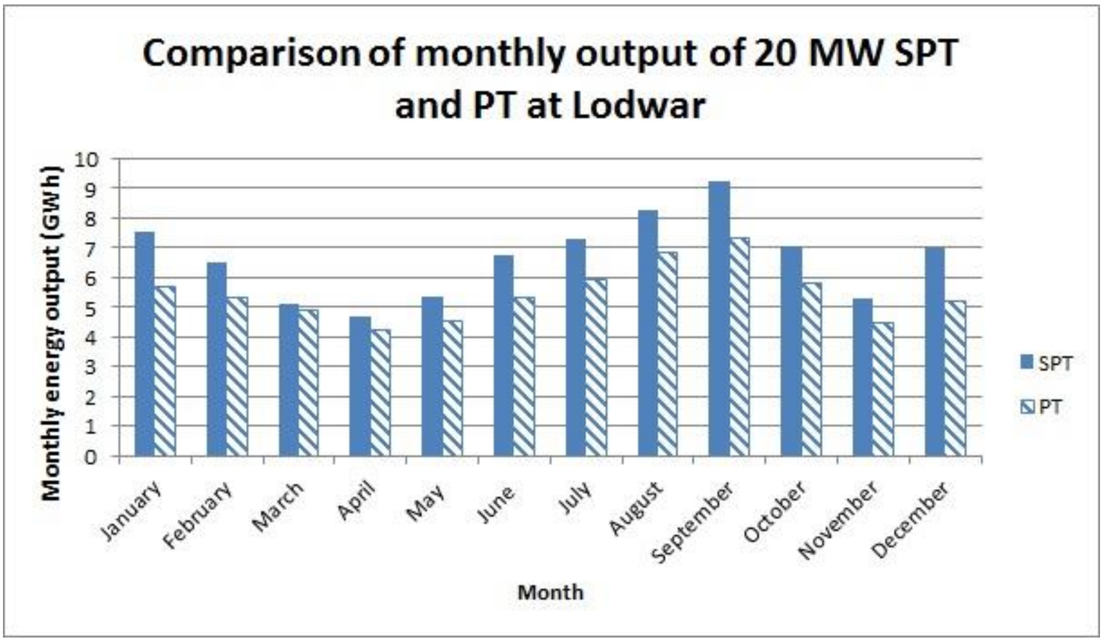


Figure 19: Comparison of case W vs case Z performance for a 20 MW plant at Lodwar

It can be inferred that SPT plants are generally likely to provide a higher annual gross output than PT plants for a particular location assuming the same HTF is employed in both. However in terms of cost, PT has a lower capital cost given it is a more mature technology with a higher level of standardisation. SPT plants still have a lot of variability in their design especially in the heliostat applications where sizes vary in range from 2.2 m^2 to 140 m^2 among the leading industry players [87]. This was reflected in the results for the two technologies and the 20 MW case Z plant had an estimated net capital cost of 248 million \$ while the case W plant had a cost of 162 million \$, the respective LCOE values were 27.9 and 29.7 \$ ¢/kWh for the case Z and case W respectively and as expected the SPT plant has a lower cost per kWh due to the higher annual output.

5.1 Solar power tower with storage (Case Z)

5.1.1 Comparison of reference plant to simulated plant

The reference plant was first simulated using a dry cooled condenser and the results compared to those reported for a SAM case study of the same plant in [77]. Results of annual energy, capacity factor and annual water usage are 93 GWh, 61% and 20,396 m^3 for the Gemasolar simulation and 107 GWh, 70.4% and 368,347 m^3 for the reported Gemasolar values respectively. The difference in annual energy production can be attributed to use of dry cooling which results in decreased thermal efficiencies and also in this case the 15% fossil fuel share was not taken into account. The latter also explains the difference in the capacity factor since the natural gas heater would facilitate supplemental steam generation for night time or daytime hours of low solar insolation.

The performance of the reference plant compared to the two proposed locations is indicated in Table 17. Lodwar has a higher DNI value as compared to Seville, however due to use of fossil fuel back-up, the Gemasolar plant has a higher energy output. In analyzing the estimated energy production from the proposed sites, the effect of change of location or varying DNI is observed in the difference in output at Malindi and Lodwar, which confirms that DNI is a critical factor in determining a site's suitability. This is also related to the LCOE since increased energy output translates into cheaper production cost per kWh as is observed for the two plants; Lodwar which has the better DNI also has a lower LCOE value.

In regard to the accuracy of the simulated annual energy output, it should be noted that an assumption about the heliostat aiming strategy in the SAM software may overestimate the expected value. SAM employs a strategy such that the heliostats aim at the centre point of the receiver for simplicity purposes [74]. In practice however, this may cause damage to receiver tubes and for this reason an appropriate aiming strategy must be employed to redistribute incident flux on the receiver surface which inevitably reduces the thermal energy on the receiver due to spillage losses. A value of 1000-1200 kW_t/ m^2 is recommended as the maximum receiver flux for molten salt SPTs and a value of 1000 kW_t/ m^2 was used in this study [88]. Overall net efficiency in Table 17 is on the basis of an assumed plant availability of 90% [76] and the exchange rate as at February 2017 is 1 $ =0.945 €.

Table 17: Comparison of results of dry cooled Gemasolar plant and proposed sites

	Plant		
Annual performance	**Seville dry cooled**	**Lodwar**	**Malindi**
Total annual energy (GWh)	94.53	80	59.78
Overall efficiency (gross)	0.17	0.16	0.14
Overall efficiency (net)	0.16	0.14	0.13
LCOE (nominal) $ ¢/kWh	24.78	27.93	38.55
LCOE (nominal) € ¢/kWh	23.41	26.39	36.42
Sizing Parameter			
Tower height (m)	140	133	152

The efficiency values indicated in Table 17 were estimated making use of Equation 2 and an efficiency of ≥ 15% is considered to be fairly good in the operation of SPT plants and the Lodwar site seems to perform well in this regard [82].

5.1.2 Economic considerations

The economic analysis is considered to be indicative and by no means conclusive since there are various fiscal incentives and policies that can influence the cost of energy production in CSP plants and indeed most electricity generation technologies. One of the most important factors is the discount rate which is majorly influenced by inflation rate, perceived risk of the project and real return on investment [89].

Taking an example of the case Z plant, it is noted that an increase in inflation rate ranging from 5-11% translates to increased nominal LCOE value from 24.1 $ ¢/kWh to 30.2 $ ¢/kWh, this is assuming a fixed real discount rate of 5.5%. SAM reports two LCOE values; the real and nominal values with the former being the current dollar value while the latter is adjusted to take inflation into account [74]. A similar observation on the effect of discount rates is made in [90] in a study on costs of electricity generation. For a case of a 100 MW PT plant in the US, a discount rate of 5% resulted in a LCOE of 16.5 $ ¢/kWh while a 10% discount rate yielded a cost of 26.9 $ ¢/kWh.

The nominal LCOE values for the two proposed plants(that is Lodwar and Malindi) are indicated in Table 17 but these values were not compared with the numbers for the Gemasolar plant due to lack of data as has also been noted in [77].This notwithstanding, an analysis of the FiTs of electricity produced from solar thermal plants in Spain indicated that the value as at 2007 was in the range of 22.9-26.9 € ¢/kWh [91]. The simulated LCOE value was 23.1 € ¢/kWh and assuming an actual discount rate lower than the applied value in this study, it is likely that the Gemasolar plant proved profitable to investors.

For a case of Kenya as aforementioned, the current feed in tariff for all solar generated power stands at 12 $ ¢/kWh and given the indicative LCOE values for Lodwar at 27.9 $ ¢/kWh, it is clear that this FiT rate would be prohibitive to any CSP plant development. A good argument to justify the increase of the FiT rate would be to analyse the approximate cost at which the utility company, Kenya Power, purchases power from the diesel plants. The respective LCOE of these plants at discount rates of 10% and 12% is 25.1 and 26.5 $ ¢/kWh respectively (assuming an exchange rate of 1 $ = 102.9 Kenya shilling) and making a conservative estimate that the difference between power purchase agreement (PPA) price and LCOE is 4-5 $ ¢/kWh, the utility would purchase power from the diesel plants at 29.1 $ ¢/kWh [2]. Therefore given that the simulation values were obtained with the worst case scenario discount rate of 15% and no subsidies, it can be inferred that the LCOE for the proposed CSP plants may be in the same range as the diesel thermal plants. This of course would be hinged on favourable taxation terms, revised FiT policy and other regulatory terms which would serve to reduce the perceived risk of investing in CSP plants thus lowering the discount rate and making it a cheaper alternative [92].

It should be noted that this analysis applies to both the solar power tower and parabolic trough plants.

5.1.3 Up scaling the reference plant size

A 110 MW plant was simulated in Lodwar and results obtained were compared to the Crescent Dunes SPT project in the US which also employs molten salt as the HTF. The comparison was made in order to verify the practicability of the results for the up scaled plant. The results are indicated in Table 18, and again here the effect of change of location, difference in DNI is illustrated given that the Crescent Dunes location has a DNI of 7.3 kWh/ m^2/ day versus a value of 5.3 kWh/ m^2/ day for Lodwar [44].

Table 18: Comparison of 100 MW Lodwar plant to Crescent Dunes 100 MW solar power tower plant

Parameter	Simulated	Crescent Dunes
Annual energy (MWh)	401,032	500,000
Capacity factor	45.50%	52%
Annual Water Usage (m^3)	97,373	-
Number of heliostats	13023	10347
Tower height (m)	205.237	195
DNI (kWh/ m^2/ day)	5.03	7.35

The effect of economies of scale is evaluated for the two plant sizes at Lodwar, 20 MW and 110 MW and the resultant nominal LCOE value was found to be 28 $ ¢/kWh and 26.1 $ ¢/kWh respectively. The net capital cost per Watt was also evaluated yielding 12.4 $ /W for the 20 MW plant and 11.2 $ /W for the 110 MW plant. Though the LCOE and capital cost per Watt do not exhibit a drastic reduction in cost for this case, it has been reported in literature that SPTs do benefit considerably from economies of scale, in instances of both increased capacity rating as well as merging several plants into a solar park [88], [93]. The region surrounding L.Turkana including Lodwar certainly provides an opportunity to set up a solar park.

5.1.4 Sizing the solar field

The solar field can be measured in terms of land area in hectares/ acres and also by relation in size between the solar field and the receiver thermal power rating/ turbine gross power rating. The latter is referred to as the solar multiple (SM) and a value of 1 is considered to be the area of solar field required to produce rated turbine output under design conditions [94]. A parametric analysis was carried out to analyze the effect of SM size on the gross power output (kWh_e) and for a SM of 1.2 the power output is at the lowest given that very little surplus energy is being stored in the TES system. On the other hand over sizing the solar field only accrues the benefit of increased energy production up to an optimum point after which the output decreases and this could be attributed to increased convective heat loss due to the increased difference in temperature between the receiver and the ambient air. The LCOE was also analyzed alongside the SM and power cycle output as indicated in Figure 20. For a SM value of 1.2 the LCOE is highest due to fact storage is underutilized yet its cost is taken into account for the LCOE computation. Conversely the LCOE increases after a SM value of 2.4 because the surplus number of heliostats do not contribute significantly to the power cycle output; this is especially crucial given that the solar field accounts for the highest share of SPT systems direct costs at approximately 38% [76].

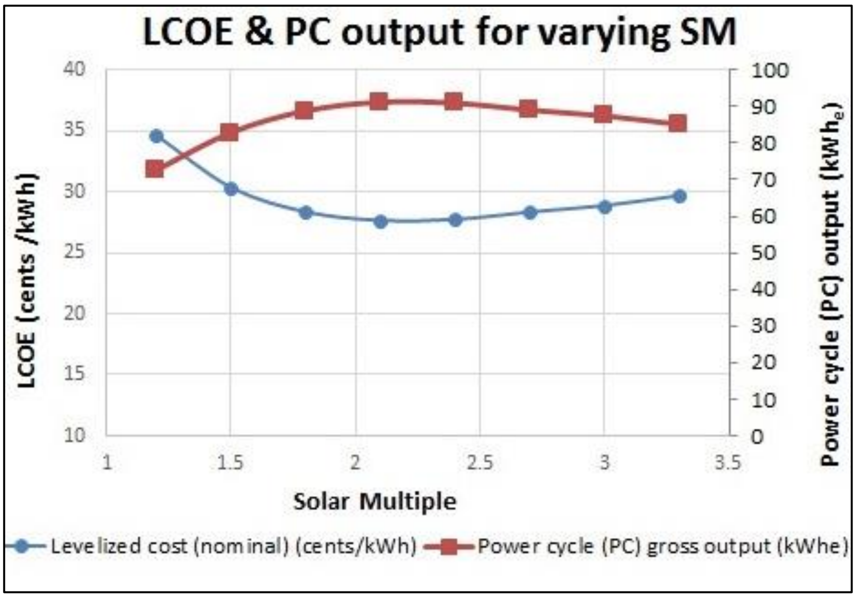


Figure 20: Variation of LCOE and power cycle output with solar multiple

The variation of LCOE for different solar multiples and hours of TES is depicted in Figure 21. For a value of SM close to 1, any increase in number of full load storage hours translates to a very high LCOE since the storage is redundant. For large values of SM, the LCOE drops with a corresponding increasing in no. of hours of TES up until limitations in parameters such as maximum receiver incident flux render the surplus solar field redundant. For the case Z plant, minimum LCOE is achieved for SM value of 2.1 and 9 hours of TES.

It is also noted in Figure 21 that the lowest LCOE achieved for the various SM values shifts to the right progressively starting with the SM value of 1.2 through to 3. This can be explained by the fact that an increased SM is only economical if there is sufficient thermal storage capacity to make use of the excess energy in the absence of which there would be dumping. For instance for a SM value of 1.5 the lowest LCOE is obtained for 6 hours of TES while a larger SM of 3 achieves the lowest LCOE for 12 hours of TES which would explain the progressive shift to the right in the graph.

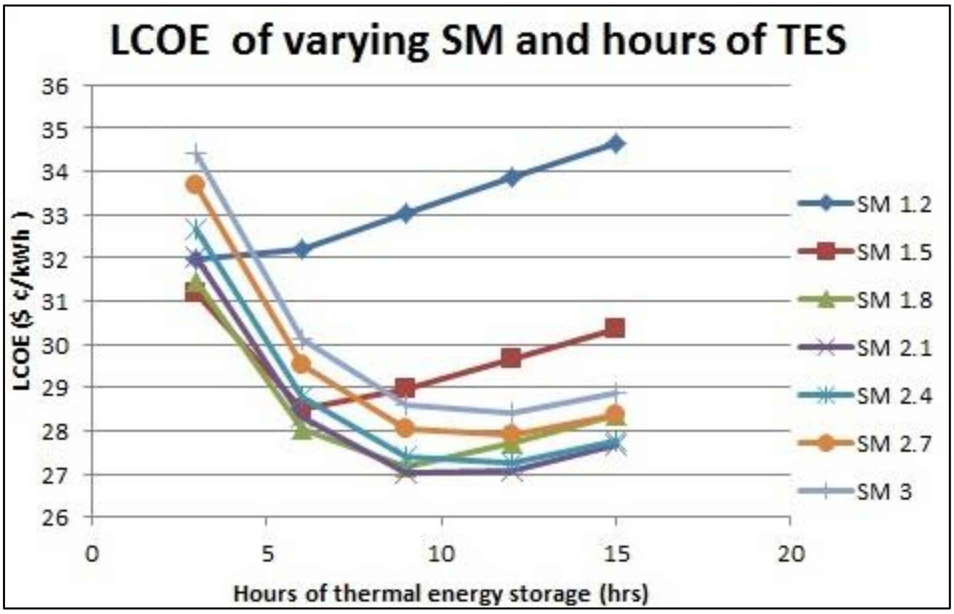


Figure 21: Variation of LCOE with SM and hours of TES

5.2 Parabolic trough plant with storage (case W)

The Andasol-1 performance as reported in [83] was compared to the simulated values and it is observed that the values are a close match. The annual energy, capacity factor and total land area were found to be 173 GWh, 39.9% and 460 acres for the Andasol plant simulated while the reported values were 174 GWh, 40.2% and 476.8 acres respectively. A wet cooled condenser was used for the sake of making the comparison, but subsequent analysis of the case W plant was simulated with a dry cooled condenser. The physical sizing parameters were optimized by carrying out a parametric analysis similar to that in section 6.1.4 for the SPT plant, such that values of SM and TES hours were adopted that resulted in lowest LCOE and higher annual output energy. For the 100 MW case W plant, a table indicating the variation of LCOE, annual energy produced and net capital cost for varying ranges of solar multiple and hours of TES capacity is shown in Table 19. The highlighted row corresponding to SM of 2.6 and 6 hours of TES provides the highest annual energy output with lowest LCOE and net capital cost.

Table 19: Variation of capital cost, LCOE and annual energy for a specified range of solar multiple and hours of TES for a 100 MW case W plant

Solar Multiple	Full load hours of TES (hours)	Net capital cost (million $)	LCOE (nominal) (cents/kWh)	Annual energy (GWh)
1.2	4	551.16	37.81	177.75
1.5	4	619.26	32.50	227.72
1.8	4	687.33	29.89	270.23
2.1	4	755.38	28.90	302.68
2.4	4	823.39	28.95	325.07
2.6	4	868.72	29.32	335.96
1.2	6	614.20	41.20	177.70
1.5	6	682.30	35.02	228.58
1.8	6	750.40	31.4	276.57
2.1	6	818.46	29.61	316.05
2.4	6	886.50	28.85	347.57
2.6	6	931.85	28.78	363.80
1.2	8	677.25	44.60	177.68
1.5	8	745.35	37.65	228.60
1.8	8	813.45	33.38	278.22
2.1	8	881.53	30.81	323.38
2.4	8	949.59	29.40	361.86
2.6	8	994.96	28.88	383.82
1.2	10	740.29	47.99	177.67
1.5	10	808.39	40.28	228.60
1.8	10	876.49	35.52	278.39
2.1	10	944.58	32.49	325.27
2.4	10	1012.67	30.33	370.75
2.6	10	1058.04	29.50	396.47

Results for the 20 and 100 MW plant sizes in Lodwar are presented in Table 20 indicating corresponding sizing parameters in terms of SM and TES. In terms of unit cost there is a minimal difference in LCOE between the two; which can be assumed to be as a result of the error margin of the model (approximately 2 %) so we can infer that PT plants do not offer a significant economy of scale for higher name plate capacities.

Table 20: Annual performance of 20 MW and 100 MW case W plant

	Plant size	
Annual performance	**100 MW**	**20 MW**
Total annual energy (GWh)	363.80	61.46
LCOE (nominal) $ ¢/ kWh	28.78	29.72
Sizing Parameter		
Solar multiple	2.6	2.4
Full load hours of TES	6	6

5.2.1 Comparison of wet and dry condenser cooling

Since parabolic troughs consume the most water out of all existing power generation technologies as discussed in section 4.2, an analysis is carried out to compare wet and dry condenser cooling for a 50 MW case W plant with seven hours of storage. In this case the SAM physical model for parabolic trough systems was used. The dry cooled configuration presents a 90% reduction in water consumption as indicated in Table 21 but as the same time presents a higher LCOE given that the annual energy output is lower as compared to the wet cooled configuration. Similar results are reported in literature with a study in [12] highlighting a 77% reduction in water consumption per MWh when switching from wet to dry condenser cooling for a PT plant.

Table 21:Comparison of wet and dry condensor cooling for 50 MW case W plant

Parameter	case W (dry cooled)	case W (wet cooled)
Annual energy (GWh)	99.3	110.7
Gross to net conversion (%)	84.1	89.8
Capacity factor (%)	22.9	25.6
Annual water consumption(m^3)	36,334	399,413
LCOE (real) $ ¢/ kWh	18.2	16.37
LCOE (nominal) $ ¢/ kWh	39.44	35.45

5.3 Parabolic trough with fossil fuel back-up (case X)

For this plant configuration, the most important consideration is the fossil fill fractions which are specified for dispatch control. The fossil fill fraction stipulates the fraction of energy produced from the back-up boiler for each hour of a given dispatch period [74].Two sets of fossil fill fractions were used, as described in section 4. For a 50 MW turbine output rating, the fraction set B values resulted in annual energy of 235 GWh with the fossil back up constituting 56.8 % while the solar contribution was 43.1 %. On the other hand fraction set A values resulted in annual energy of 136 GWh with fossil back-up and solar contributing 30.3 % and 69.6 % respectively. From this it is clear that the mode of operation selected for the fossil back-up has a large impact on the net annual energy produced. In Spain, there is a cap on total contribution of fossil back-up to annual energy production at 12-15 % while in California the cap is at 25 % [33].

For the case of Kenya, it is concluded that a cap ranging from 20-30 % would allow the case X plant to prove to be a feasible CSP plant configuration. This configuration is of particular interest because there is a planned development of a 700 MW natural gas plant in Dongu Kundu, approximately 100 km from the proposed site in Malindi. This proposed plant has however been shelved due to concerns of overcapacity and it is therefore envisaged that a 50 MW or 100 MW case X plant would be a good option for consideration by generation planners for the short term.

5.4 Parabolic trough with biomass back-up (case Y)

The key difference between case X and Y is the heating value efficiency and the cost of fuel. The heating value can be described as the heat that is released when the fuel is combusted. In the case where the original water and that which is a byproduct is in a condensed state, this is referred to as the higher heating value while the case where the water generated is in a gaseous state is referred to as the lower heating value [95]. SAM uses a parameter which is called the boiler lower heating value efficiency to determine the quantity of fuel needed by the boiler for backup operations.

Since NG generally has a higher heating value than biomass, an efficiency value of 0.85 was utilized for case X while for case Y a value of 0.65 was used. These values were adapted from a study in [13] where the authors carried out a similar analysis for both NG and biomass in the form of bagasse.

A summary of the results obtained for a 50 MW plant in Marsabit is presented in Table 22. A price of 1.47 $/MMBTU is adapted from the study in [13] and it is interesting to note that this configuration presents the lowest LCOE at 23.99 $ ¢/

kWh out of all the four configurations. The annual energy produced for this plant is higher than the NG plant estimation of 136 GWh (assuming fraction set B values) since Marsabit has a comparatively good DNI as compared to Malindi. The low LCOE can be explained by the avoidance of cost related to a storage system coupled with the fact that the proposed biomass fuel is very cheap.

The effect of the fossil fill fraction is investigated for the biomass case as well. The first scenario is fraction set B values hereafter referred to as scenario 1 and the other is fraction set C values referred to as scenario 2. Scenario 2 is noted to have a reduced capacity factor as compared to scenario 1 of 31.2% down from 42.7% as indicated in Table 22.

Table 22: Summary of results for 50 MW plant at Marsabit for scenario 1 and 2

Parameter	Scenario 1	Scenario 2
Annual energy (GWh)	185	135
Capacity factor (%)	42.7	31.2
LCOE (nominal) $ ¢/ kWh	23.99	30.55
LCOE (real) $ ¢/ kWh	12.47	15.88
Capital cost ($)	340,978,688	339,516,320

A comparison of the monthly performance of the two scenarios is also presented in Figure 22. The output contribution of the biomass backup in scenario 1 is 36.7% while in scenario 2 it corresponds to 14.8%. The effect of the percentage share of biomass contribution to annual energy production on the LCOE is especially critical here as compared to the NG case due to the fuel price difference. As indicated in Table 22 there is a potential variation of up to 7 $ ¢/ kWh between the two scenarios and this points to the fact that the development of this configuration warrants special attention to the level of contribution of the biomass system.

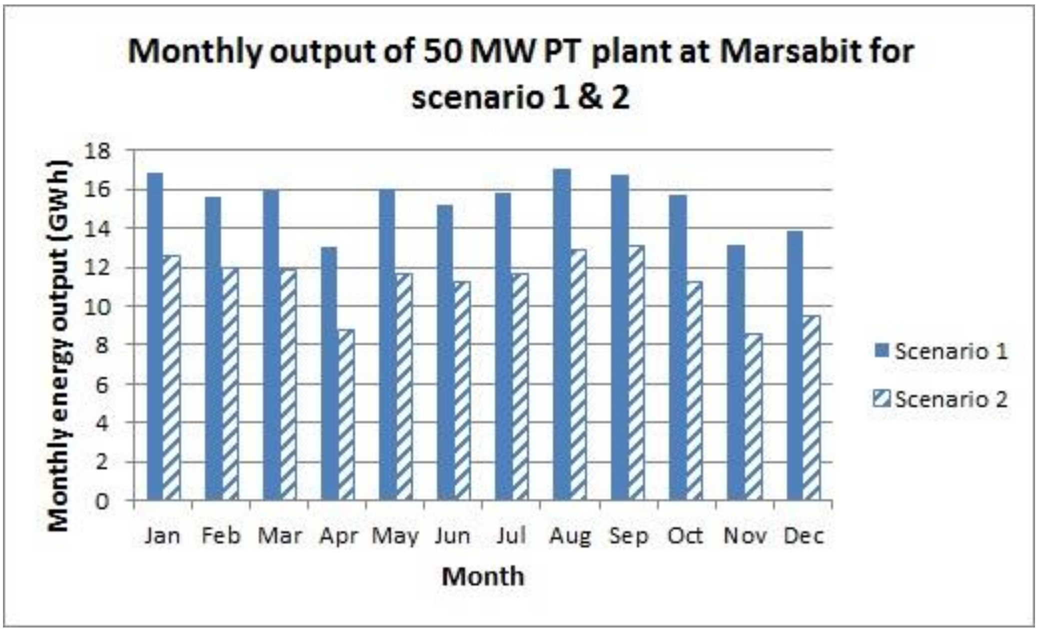


Figure 22: Monthly output of 50 MW case Y plant

5.5 Discussion

The preceding sections in this chapter have presented the key results of the analysis of the four configurations and this section highlights the major implications of these findings.

Given that Lodwar has one of the best DNI values in the country coupled with the land use factors in this region, the case Z plant is considered the most viable alternative to kick start CSP development in Kenya. In regard to the choice between SPT and PT, it is proposed that SPT would be a better option due to the higher operational temperatures and related higher annual energy outputs.

The case Y plant can be considered as the second best alternative especially since it offers the lowest LCOE of all the four configurations. Assuming an inflation rate of 4% and a real discount rate of 8%, this configuration has an estimated LCOE of 18.8 $ ¢/ kWh which is comparable to the LCOE for a coal plant as is highlighted in the LCPDP of 17.8 $ ¢/ kWh (assuming a discount rate of 12%). Apart from the careful selection of the percentage of energy generation from the biomass backup the other possible challenge stems from the biomass fuel itself. Prosopis Juliflora is an invasive species and its use as a fuel would go towards mitigating its risk of spreading however depending on how it is sourced from the surrounding communities, this may have the reverse effect of promoting its proliferation. There would therefore have to be some careful planning around this and fortunately there may already be a strategy at play at the 2 MW biomass plant in Baringo that utilizes the same weed.

A summary of the best performing configurations is presented in Table 23 and the major considerations factored in the selection of the two plants are indicated.

Table 23: Summary of main evaluation criteria for best performing plants

Parameter	**Case Z**	**Case Y**
DNI	5.03	4.72
Fuel cost	☒	☑ 1.47 $/MMBTU
Storage	☑	☒
LCOE ($ ¢/ kWh) – assuming 15% discount rate and 50 MW plant	27.91	23.99 (assuming 30% biomass contribution)
Grid infrastructure	☑Planned Turkwel-Lodwar-Lokichogio 228 km 220 kV line	☑ Planned Loiyangalani-Wajir 380 km 400 kV line

An important observation to make is that all the plants investigated are envisaged to offer 24-hour operation which means they can be used to meet the base load. In the context of the generation portfolio in Kenya, it is proposed that CSP plants could be deployed in the short term to relieve the use of expensive leased diesel generation. Since it cannot be a direct one on one substitution, the system operator can for instance, shift some of the hydro production and other quick dispatch generation sources to evening hours to meet the peak load while the CSP generation is employed to meet the base load, a similar approach is proposed in a study in [96] on integration of solar PV into the generation portfolio in Kenya.

In regard to optimal sizing of the solar field and storage system, it can be inferred from the analysis presented in Table 19 for the PT plant that the objective function changes the ideal SM and number of hours of TES. In this study minimizing LCOE has been the primary goal and in the table had the focus been on achieving 24-hour operation then the optimal size would be a SM of 2.6 with 10 hours of storage which has a marginally higher LCOE and capital cost than the selected SM of 2.6 and 6 hours of storage.

In a general sense, the PT plants seem to achieve a lower capital cost requirement than SPT plants as was mentioned in section 5.1. However apart from the standardization issue with components in SPT plants, they also have a substantially higher land requirement of 8-12 m^2/MWh versus 6-8 m^2/MWh for the PT plants. For the 20 MW plant in Lodwar the land requirement was estimated to be 130 acres and 237 acres for case W and Z plants respectively and going by the reported estimates of cost of land in Lodwar as is indicated in Table 12, this would translate to a difference in cost of up to \$3 million. This reiterates the importance of selecting sites that are not over developed in terms of land use so as to minimize the risk of very high land rates.

CHAPTER 6

CONCLUSIONS AND FUTURE WORK

6.1 Conclusion

In this research the feasibility of integrating CSP plants into the generation portfolio within the next 10-15 years is investigated. Four configurations based on the most mature CSP technologies, that is, parabolic trough and solar power tower have been simulated for three locations; Lodwar, Marsabit and Malindi. The major factors influencing performance of the proposed configurations have been investigated including effect of varying plant sizes, solar multiple and hours of thermal energy storage on the LCOE.

The conclusions drawn can be broadly summarized into two categories, the first being the performance analysis and the other being the economic analysis.

6.1.1 Performance analysis

In regard to comparing the performance of the two technologies, it was inferred that power tower plants would be the best option for the three locations evaluated given the higher annual energy output albeit the net capital cost is higher as compared to the parabolic trough plants. This may change in the near future as more power tower plants are developed leading to a higher degree of standardization and expected subsequent drop in component prices especially for the heliostats.

Out of the four configurations, the SPT plant at Lodwar and the PT plant with biomass backup in Marsabit are proposed as the best alternatives for deployment. Apart from the good potential of setting up a solar park in Lodwar, the SPT plant has the highest energy output and on the other hand the PT plant with biomass backup presents the lowest LCOE.

In terms of the integration of CSP plants into the generation portfolio, it is noted that there is an opportunity to displace expensive leased diesel generation. It would not be a direct one for one substitution due to differences in ramp rates rather the system operator can for instance, shift some of the hydro production and other quick dispatch plants to evening hours to meet the peak load while the CSP generation is employed to meet the base load.

It is noted that optimal sizing of the solar field is dependent on the objective and in this research the main goal was obtaining the least possible LCOE value.

For the two configurations which employ backup, the fossil fill fraction is observed to be a crucial performance factor and it is proposed that a value of between 20-30% would significantly boost the power produced by the solar field while at the same time limiting the related emissions to some extent.

It is also recommended that weather stations be set up in Lodwar and the regions surrounding L.Turkana as indicated in Figure 14 so as to enable more accurate estimation of CSP plant performance in the region.

6.1.2 Economic analysis

Assuming the difference between PPA price and LCOE is 4-5 $ ¢/kWh, it was estimated that for the best performing plant, that is, SPT plant at Lodwar, that the PPA price would be 31.9 $ ¢/kWh (at 15% discount rate) while the diesel plants were estimated to have a PPA price of 29.7 $ ¢/kWh (at 12% discount rate). It is thus concluded that CSP plants can prove to be a viable alternative especially if any form of subsidy or tax relief is applied to the capital cost. Another angle of analyzing the cost of diesel plants that would improve economics of CSP plants would be to incorporate the social cost of carbon due to the greenhouse gas (GHG) emissions related to diesel plants and other fossil fuel fired power plants.

There is also a need to ascertain the cost of Prosopis juliflora since the estimate employed in this research was adapted from a case of bagasse. This could potentially drive down the LCOE of the PT with biomass backup even further and thus make it cheaper than coal fired plants.

From a policy perspective, two major recommendations are proposed as follows;

- Revision of the solar FiT rate: As was mentioned in section 5.1.2 the current tariff lumps together all solar generated power under a rate of 0.12 $/ kWh. Given the marked differences between solar PV and CSP technologies and the benefits they can afford to the power system, such as the fact that CSP plants can supply the base load and provide ancillary services, it may be prudent to establish different FiT rates for the two. In this case it would be possible for instance for a choice to be made between the case Y plant at Marsabit versus the proposed coal plant at Lamu since they can both achieve base load operation and have comparative LCOEs. However if the FiT rate structure remains as is, it would almost definitely disqualify development of CSP plants for upwards of 15 years.

- Establishment of additional weather stations: As is discussed in section 2.6, the best dataset available for solar resource which is also the source of the data set in SAM is the data made available through the SWERA study at a spatial resolution of 5 × 5 km. Especially with the possibility of setting up a solar park in the sites highlighted in Figure 14, more accurate data on DNI and other weather parameters would prove to be beneficial in the development of CSP plants.

6.2 Future work

Further investigation on hourly performance can be carried out to quantify the loss in optical efficiency due to the cosine effect and also a weather data set spanning several years can be used to estimate the performance of the CSP plants more accurately.

Also in regard to the parabolic trough plants, an optimization can be carried out to determine the optimal number of loops in the solar field which achieves the lowest LCOE as well as the minimum HTF temperature at which the power cycle can operate. It would also be interesting to compare molten salt versus thermal oil in the PT system to check whether there is indeed a cost saving in utilizing molten salt as had been reported in some literature.

An alternative configuration that could be considered for development is the integrated solar combine cycle (ISCC) which is essentially a combination of a CSP plant and a NG combine cycle (NGCC) plant. The CSP solar field is utilized to supplement steam generation or alternatively it can be used to superheat the air in the gas cycle that is leaving the compressor before it enters into the combustor [97].

These plants are estimated to produce power at a lower LCOE than NGCC for a NG price exceeding 13.5 $/MMBTU. This is especially relevant and would act as a substitute for the planned 1980 MW incremental capacity of NG planned for the period extending from 2021-2030 (for the base case scenario in the LCPDP).

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